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The Emergence of Carbon Capture and Storage Techniques in the Power Sector

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Executive summary

This thesis analyses the techno-economic and social conditions required for the emergence of Carbon Capture and Storage (CCS) techniques in the power sector, in compliance with CCS role in long-term mitigation scenarios. The research combines two complementary approaches: the positive one deals with the economic and social determinants necessary to trigger CCS investments in the power sector, and addresses in particular two significant issues: (1) for which CO_2 price is it worth investing in CCS plants, and (2) when is CCS use socially optimal? The normative approach gives recommendations on how CCS can best be deployed as part of a least cost approach to climate change mitigation. Notably, recommendations are provided about the optimal combination of CCS policy supports that should be implemented, emphasising particularly the need for a subsidy dedicated to carbon storage. This Ph.D. dissertation is composed of four chapters. The first two chapters embrace the investor's vision and highlight the economic determinants necessary for the commercial emergence of CCS techniques, in line with endorsed climatic goals at least cost for economic growth. The last two chapters embrace the public decision-makers' vision. Based on the fact that, although cost-effective, one technology may not be deployed because of social acceptance issues, Chapter 3 deals with CCS public acceptance and optimal pollution. Chapter 4 goes further and addresses the optimal CCS investment under ambiguity (deep uncertainty) by providing a decision criterion with simulations on the European Union's 2050 Energy Roadmap.

Keywords: Carbon Capture and Storage Techniques, CCS, power sector, CO_2 price, investment, climate change mitigation.

Résumé

La problématique de cette thèse porte sur les conditions technico-économiques et sociales d'émergence des techniques de Captage, transport et Stockage géologique du Carbone (CSC) dans le secteur électrique. Il existe en effet un hiatus entre le niveau actuel de déploiement du CSC et son rôle significatif dans les scénarii d'adaptation au changement climatique. Les travaux s'appuient sur deux approches complémentaires ; l'approche positive met en exergue les principaux déterminants économiques et sociaux nécessaires à l'émergence de la filière CSC et répond à deux interrogations : (1) pour quel prix du CO_2 devient-il intéressant d'investir dans des centrales CSC ? (2) quand l'usage du CSC s'avère-t-il socialement optimal ? Sur le plan normatif, diverses recommandations relatives au déploiement optimal du CSC sont apportées. Elles concernent notamment le portefeuille optimal d'instruments de soutien au CSC, insistant particulièrement sur l'intérêt d'une subvention dédiée au stockage géologique du CO_2. Cette thèse s'articule en quatre chapitres. S'inscrivant dans l'optique de minimiser les coûts de la transition énergétique, les deux premiers chapitres embrassent la vision investisseur et mettent en évidence les déterminants économiques indispensables au déploiement commercial du CSC. Les deux derniers chapitres adoptent la vision de la puissance publique. Bien que compétitive, une technologie peut ne pas se développer en raison de problèmes d'acceptabilité sociale ; c'est l'objet du modèle développé dans le Chapitre 3. Le Chapitre 4 élargit le propos et intégre la problématique de décision dans le CSC en univers ambigu, en s'appuyant sur les scénarios de la Roadmap 2050 de l'Union Européenne.

Mots-clefs : Techniques de Captage, transport et Stockage géologique du Carbone, CSC, secteur électrique, prix du CO_2, investissement, atténuation du changement climatique.

Contents

General Introduction

The likely responsibility of human activities on global warming has been widely recognised among scientists (IPCC, 2013 [86]). Nonetheless, total anthropogenic greenhouse gas (GHG*) emissions have continued to rise from 1970 to 2010, with a peak in the last decade (390 ppm CO_2*eq in 2011; IPCC, 2013 [86]).
To limit further changes in the earth's climate and the related social, economic and environmental consequences, the Intergovernmental Panel on Climate Change (IPCC*) estimates that the increase in long-term global average temperature should be held below 2°C above pre-industrial levels (IPCC, 2005 [84], 2013 [86]). This ambitious climatic goal was endorsed by the Copenhagen Agreement (COP15, 2009).
In order to have a chance to achieve this 2°C target, GHG emissions will need to be cut substantially (atmospheric concentration of approximately 450 ppm CO_2eq in 2100). According to the IPCC (2013, [86]), global GHG emissions will have to be 40% to 70% lower in 2050 than in 2010, with net emission levels near zero tCO_2eq in 2100. Thereby, developed countries (and to a lesser extent, developing countries) will need to almost completely decarbonise (*i.e.* reduce the carbon intensity of) their power sector. Indeed, in 2011, the power sector contributed to 40% of total CO_2 atmospheric emissions (GCCSI, 2014 [63]) and the global consumption of fossil fuels, particularly coal, continues to increase: its decarbonisation is thus a key component of mitigation strategies.
Public studies and scientists (IPCC, 2014 [87]; IEA, 2014 [119]) agree on the fact that the least cost pathway to achieve a carbon neutral power sector requires a portfolio of three main low carbon technologies in combination with energy efficiency measures: renewable energy sources (RES*), nuclear power plants and Carbon Capture and Storage (CCS*) fuel plants. No single option is sufficient by itself: the current concentration of GHG emissions in the atmosphere combined with the momentum of climate trends requires swift action as well as the investigation of any technical options that could contribute to reach the internationally agreed 2°C. Some studies go even further, assessing that the 2°C target cannot be achieved without CCS techniques, or at a cost that could be substantially higher (IPCC, 2014 [87]; IEA, 2014 [119]).

CCS is a suite of techniques designed to capture the CO_2 contained in industrial flue gases from large point sources, notably fossil fuel plants, before it is released in the atmosphere. Then, the captured CO_2 is transported (e.g., by pipelines or trucks) and is finally injected into a suitable underground storage facility (e.g., depleted oil and gas fields or deep saline aquifers). CCS is currently considered as the only large-scale mitigation option available in industrial sectors (e.g., iron and steel, cement, refining) as well in the power sector (IEA, 2013 [118]; IPCC, 2014 [87]). Indeed, these techniques allow the capturing up to 90% of the CO_2 emitted from a power plant. In countries whose energy mixes are highly reliant on fossil fuels, CCS power plants may be an interesting option to provide decarbonised electricity at base-load. In countries with a significant share of low carbon electricity supply techniques - nuclear and renewable energy sources - in their electricity mixes and an increasing use of intermittent RES, dispatchable electricity supply techniques are required. CCS plants may be an interesting option since they can supply low-carbon electricity on demand and are dispatchable. Consequently, CCS applied to power generation represents a significant potential in curbing CO_2 emissions. In addition, CCS may be "competitive on a levelised cost of electricity basis with solar, wind..." (IPCC, 2014 [87]; IEA, 2011 [79]), CCS can also reduce the adverse effect of mitigation on the value of fossil fuel reserves and existing infrastructures, and last but not least, can supply electricity on demand and does not suffer from intermittency contrary to RES. As a consequence, the cost of the decarbonisation is higher without CCS techniques (IEA, 2013 [118]; IPCC, 2014 [87]). CCS is thus an interesting option to decarbonise the power sector, in both developed and developing countries whose energy demands are still growing and whose energy mixes are highly fossil fuel dependent. Thereby, in scenarios with ambitious climatic goals, one can observe a tripling if not a quadrupling of low-carbon energy supply by the year 2050, notably from CCS fossil energy.

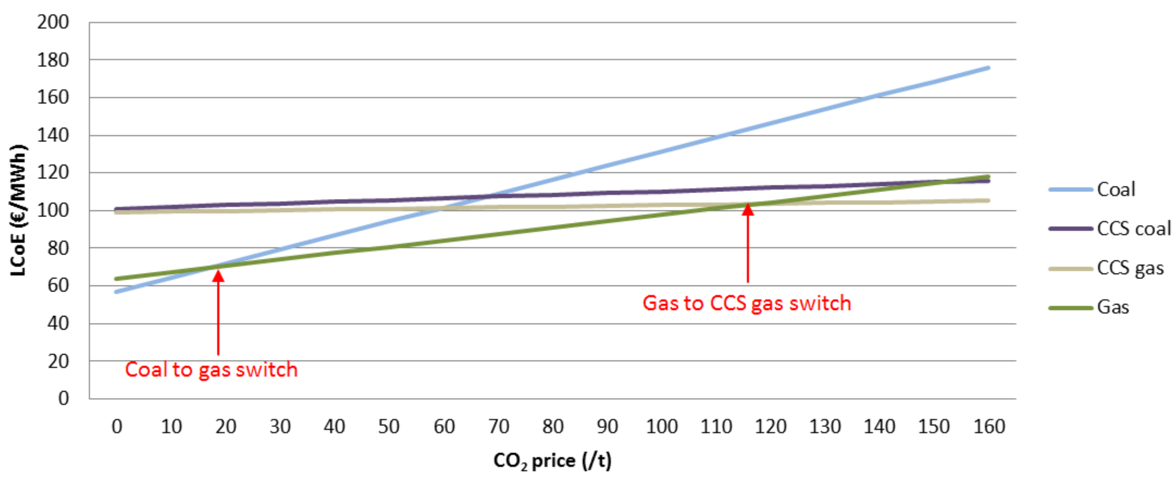
However, while all components of integrated CCS systems exist and have been used for decades by some industries such as natural gas processing, CCS techniques have not yet been commercially deployed. Nonetheless, the first large scale integrated (capture, transport and storage) project, SaskPower Boundary Dam 3 (110 MWe^*, Canada), commenced operation in late 2014, and two additional demonstrators should be operational respectively in 2015 and 2016: Kemper County (580 MWe, United States) and Petra Nova (250 MW slip stream from 610 MW unit, United States).
High CCS costs can partly explain why CCS development has progressed slower than anticipated in terms of large scale demonstration (GCCSI, 2014 [63]). For instance, in the European Union, over the twelve large-scale demonstrators planned in 2015, none has been built. Indeed, although CCS plants may be cost-effective with other low carbon generation options, they are currently highly capital intensive. In addition, carbon capture and compression induce efficiency penalties which increase the variable costs (notably fuel cost) of CCS plants. If a high enough CO_2 price can offset the additional investment and operational costs due to CCS, international CO_2 prices are currently too low (e.g., €6/t in the European carbon market). In addition, existing measures to support CCS do not seem relevant to trigger large investment.
Public acceptance issues constitute the second main explanation for the delay in CCS deployment. Indeed, over the last years, many low-carbon generation technologies and their infrastructures like RES and CCS have faced public acceptance issues limiting their deployment (IPCC, 2014 [87]). For CCS, social acceptance issues are due to the Not In My Back Yard (NIMBY*) problematic but also to concerns about the operational safety

and long-term integrity of CO_2 transport and storage infrastructures (carbon leakage). This CCS slow down raises uncertainties and threatens its commercial and worldwide deployment, which is highly paradoxical regarding the mitigating role of CCS techniques in most energy scenarios with ambitious climatic goals (IEA, 2013 [118]; IPCC, 2014 [87]; GCCSI, 2014 [63]).

To shed new light on this paradox, this thesis aims to study the techno-economic and social conditions required for the emergence of Carbon Capture and Storage techniques in the power sector, in compliance with CCS role in long-term climate change scenarios. The focus is thus on the two significant hurdles to CCS development: cost and social acceptance. The research is conducted by combining two complementary approaches: the positive one deals with the economic and social determinants necessary to trigger CCS investment in the power sector, and addresses particularly two important issues: (1) for which CO_2 price is it worth investing in CCS plants, and (2) when is CCS use socially optimal? The normative approach gives recommendations on how CCS can best be deployed as part of a least cost approach to climate change mitigation. The research carried out also allows proposing recommendations for investors and organisations in charge of CCS development. Notably, recommendations are provided about the optimal combination of CCS policy supports that should be implemented, emphasising particularly the need for a subsidy dedicated to carbon storage. This dissertation is composed of four chapters, each of them being based on an article published or under publication. The first two chapters embrace the investor's vision and are mostly techno-economic studies highlighting the economic determinants necessary for the emergence of CCS techniques, in line with endorsed climatic goals at least cost for economic growth. The last two chapters embrace the public authority's or decision-maker's vision. Based on the fact that, although cost-effective, one technology may not be deployed because of social acceptance issues, Chapter 3 deals with public acceptance and optimal pollution. Chapter 4 goes further and addresses the optimal CCS investment decision under ambiguity (deep uncertainty) with simulations on the European Union's 2050 Energy Roadmap (2011, [54]).
Chapter 1 is a techno-economic analysis which: (1) studies the profitability of CCS plants with respect to non-CCS power plants, (2) assesses the cost and performance of carbon capture techniques (pre-combustion, oxy-combustion, post-combustion) to indicate which one is the most profitable, and (3) determines the CO_2 price beyond which CCS power plants become more profitable than the analogous non-CCS power plants. These three main issues are addressed with the same unifying thread: which CO_2 price will trigger CCS investment? The literature review has revealed that a straight comparison of CCS techno-economic studies would only lead to misleading CCS cost information. Indeed, there are large discrepancies in the way CCS costs are currently calculated and reported by various public studies and organisations. A specific methodology was thus elaborated to correctly compare CCS public studies. Thereby, the CCS cost heterogeneity among public studies was quantified. The case study is the European Union (EU*).
To ensure which particular type of power plant is the most cost-effective, it is necessary to distinguish between intra- (CO_2 price required to switch: from a coal plant to a CCS

coal plant or from a gas plant to a CCS gas plant; studied in the CCS literature) and inter-technique CO_2 switching prices (CO_2 required to switch from a coal to a gas plant, from a coal to a CCS gas plant, etc.; not studied in the CCS literature). In the CCS literature, one can usually read that CCS coal plants become competitive when the CO_2 price exceeds approximately €60/tCO_2, whereas for CCS gas plants the price is €90-100/tCO_2. The above distinction has shown that when the CO_2 price is higher than €65/tCO_2[1], CCS coal plants are more profitable than reference coal plants (in accordance with the CCS literature) but are less cost-effective than gas plants. In fact, given current power plant costs and international fuel price assumptions (IEA, 2012 [117]),the CO_2 price required to trigger CCS investment is €115/tCO_2 and surprisingly, CCS gas plants might be more attractive than CCS coal plants in liberalised electricity markets, even if the intra-technique CO_2 switching price is lower for CCS coal plants (€65/tCO_2 by 2020) than for CCS gas plants (€115/tCO_2[2] by 2020). However, as underlined by sensitivity analyses, the relative appeal of CCS gas plants over CCS coal plants depends heavily on relative fuel prices. In addition, the fact that CCS coal plants might be more attractive than CCS gas plants when considering the Short Run Marginal Cost, might also nuance the relative appeal of CCS gas plants over CCS coal plants.

Figure 1: Profitability[a] of the different power plants types with an increasing CO_2 price.



[a]Average LCoEs from public studies. For more details, see Chapter 1.

As there is a large gap between the CO_2 price required to trigger CCS investment (respectively €115/t in 2015-2020, €85/t in 2030), and the forecast CO_2 market price (IEA, 2012 [117]) (respectively €20/t in 2020, €30/t in 2030), the EU will need to implement significant CCS supports. Chapter 1 concludes thus by reviewing and analysing the best

[1]Off-shore Transport and storage (T&S) costs.

[2]This CO_2 switching price value is slightly higher than the one that can be found in the CCS literature. This gap can mainly be explained by the fact that very recent studies (e.g., DECC's) - which gives higher CCS costs due to the delay in CCS deployment -, are taken into account as well as the normalised set of techno-economic assumptions, particularly fuel prices.

combination of CCS support measures. Nonetheless, whatever the chosen combination, the public cost of supporting CCS deployment will be significant for the EU (IPCC, 2014 [87]; IEA, 2012 [117]).

In view of those considerations, Chapter 2 assesses two options that could reduce the cost of CCS deployment and therefore would minimise the economic burden due to the power sector decarbonisation. The first option is geographical: indeed, one solution could be to deploy CCS in low building and operating cost countries such as China or India. Once the technology is mature and less costly, it could be re-introduced in developed countries. It is shown that CCS plants could be the most profitable power plant type in China in the 2020s. Thus, given the goal of minimising the cost of the ecological transition linked with the idea of burden sharing in GHG mitigation, the EU (and similarly other developed countries) should consider the option of supporting CCS deployment in a low building/operating cost country like China within the framework of international climate change negotiations. Such support from the EU to China could include monetary/technology transfers, research and development agreements, etc. One can refer, for instance, to the four partnership acts signed in July 2014 under which the United States and China agreed to collaborate on CCS demonstrators.
The second option enabling a CCS cost decrease is technological and relies on partial capture. Most public studies use a carbon capture rate of 90%. Nonetheless, there are no techno-economic justifications for this high level of CO_2 capture, particularly in the current context of low CO_2 price without any expectation to see a sudden rise in the short- and medium-terms. Indeed, by treating only one part of the flue gases or by reducing the capture efficiency, partial capture reduces CCS investment and operating costs (better ranking in the merit order). Therefore, first movers face lower risks and the CO_2 price required to trigger CCS investment is significantly lower. Consequently, CCS developers may be interested in considering partial capture. Once the technology is economically attractive, *i.e.* the CO_2 price is high enough, power plants will be upgraded to full CCS. In addition, partial capture can reinforce the operating flexibility of CCS plants by better preserving their efficiency and enabling them to vary their power output in response to the variable electricity demand on the grid. This last point is very interesting. Indeed, with the increasing proportion of intermittent renewable energy sources, CCS plants are likely to operate with a certain degree of flexibility. The operating flexibility of CCS plants can also be increased by several techniques which are described and analysed. New insights into the problem of minimising the costs of the ecological transition are thus provided.

As the economic determinants of CCS deployment have been highlighted in the two previous chapters, Chapter 3 deals with the second main hurdle to CCS deployment: public acceptance. Indeed, over the last years, public acceptance has appeared to be a prerequisite for the successful adoption of new technologies like renewable energy sources (IPCC, 2014 [87]). There is mixed evidence of public acceptance with respect to carbon storage: for instance, a CCS project was accepted in France (Lacq) but another was cancelled in the Netherlands (Barendrecht). Thus, assessing accurately social preferences is important in determining whether CCS use is socially optimal, and if it is, to what extent. The issue is investigated through a model determining, from the social point of view, the optimal amount of the output (electricity) as well as the optimal allocation of CO_2 emissions between the atmosphere and underground storage sites. From a methodological point of view, the novelty of this model is to consider the problem as a whole. Indeed, in addition to the two marginal disutilities due to atmospheric and underground pollution, as has been modelled previously, we introduced the marginal disutility due to the simultaneous pollution of the atmosphere and underground storage sites. With numerical simulations, we show that social welfare is most often higher when CCS is used. From a normative point of view, interestingly, given the model specifications, CCS implies the introduction of a new fiscal tool: a subsidy to CO_2 storage, in addition to a tax on the carbon content of fossil fuels (like the “Contribution Climat Energie” in France). From the perspective of minimising the cost of the ecological transition, the model also enables us to assess the transfers required to encourage CCS deployment from developed countries like the European Union to developing countries like China.

The techno-economic and social conditions required for CCS deployment being identified, Chapter 4 goes further, keeping the decision-maker (DM*) point of view. The last piece of information policy-makers need to know is: which CCS installed capacity should be chosen for the 2050 electricity mix? Indeed, public DMs need to decide in the short-term the relative proportion of nuclear, CCS, RES, etc. in their electricity mixes in 2050. Thereby, some investment decisions to decarbonise the power sector are already needed at this stage. The lifetime for a nuclear power plant is more than 60 years, 40 years for a coal plant, 30 years for a gas plant, etc., and the related investments are irreversible. Therefore, the action needs to start early so that the restructuring of the energy system runs in parallel with investment cycles thereby avoiding stranded investments as well as lock-ins of medium carbon intensive technology. In addition, public decision-makers need to know the 2050 targets for low carbon technologies such as CCS, offshore wind, etc., because they determine the energy policy required to support their deployment - through research and development programs, specific support mechanisms such as purchase contracts/capital grants, etc. - and regulation policies (e.g., large carbon transport and storage infrastructures for CCS). When facing these kinds of issues, decision-makers may seek the advice of experts who, nonetheless, often provide conflicting and ambiguous information. Consequently, public decision-makers know neither the CCS installed capacity they should put in their electricity mix (and therefore the investments they should proceed with), nor the related policy support measures they should implement. Thus through a decision model, we address the following question: how can public DM decide the CCS installed capacity in 2050 on the basis of imprecise/ambiguous information coming from several experts with divergent opinions? We give to public DMs a decision criterion in ambiguous situations. One interesting result is that contrary to casual intuition, more ambiguity aversion will not necessarily reduce the CCS installed capacity in 2050. This result can be interpreted as a precautionary effect and it emphasises the importance of taking into account ambiguity and ambiguity aversion in the decision-making process.

Finally, the conclusion provides an overview of the results, suggests some recommendations regarding policy measures that would encourage CCS deployment at the minimum cost, and gives some perspectives related to the future deployment of CCS techniques.

Chapter 1

Which CO_2 Price Triggers CCS Investments in the Power Sector? An Updated and Objective Techno-Economic Comparison of Public Studies[1]

1.1 Context

1.1.1 A challenge: reducing anthropogenic GHG emissions responsible for global warming

The likely responsibility of human activities on global warming as well as the need to reduce substantially greenhouse gas emissions to limit further changes in the earth's climate have been widely recognised among scientists (IPCC, 2005 [84], 2013 [87]).
To limit the social, economic and environmental consequences (rise in sea levels and flooding leading to the dislocation fo human settlements, rise in extreme events such as heat waves and storms combined with changes to rainfall patterns causing drought and desertification, extinction of animal and plant species thereby influencing agricultural yields and human mortality rate, etc.; IPCC, 2007 [85]) of global warming, the Intergovernmental Panel on Climate Change estimates that the increase in long-term global average temperature should be held below 2°C above pre-industrial levels (IPCC, 2005 [84]).
This ambitious climatic goal was endorsed by the Copenhagen Accord (COP15, 2009). In order to have a likely chance to achieve this 2°C target, GHG emissions need to peak by 2020 and be halved by 2050 compared to the 1990 level. According to the IPCC (2007, [85]), it means that developed countries need to reduce their GHG emissions within the

[1]The reader can also refer to: M. Renner. Quel Prix du CO_2 pour le déploiement des techniques de captage, transport et stockage géologique du CO_2? *Les Cahiers de la Chaire Economie du Climat, Série Information et débats n°25*, 2013.

range of 80 to 95% below 1990 emission level by 2050 (factor 4).
But if current trends persist, CO_2 emissions will almost double by 2050 due to a 85% global energy demand rise (IEA, 2012 [117]). The last report from the IPCC (2013, [86]) has underlined that the worldwide coal consumption is still rising, including in the European Union where one currently speaks about coal rival because of the switch from gas to coal in the power sector. This might put the world on the path toward a 6°C rise in average global temperature.
Thus, the current concentration of GHG emissions in the atmosphere combined with the momentum of climate trends[2] requires swift action as well as the investigation any technical options that could contribute to reaching the 2°C .

1.1.2 Several technical options are available to tackle the issue of climate change

Achieving decarbonisation at least cost is a challenge requiring the use of four main clean technical energy options (IEA, 2012 [117]; Gerlagh and Van der Zwaan, 2006 [64]):

- A massive development of clean energies (renewable energy sources and nuclear),
- The reduction of fossil fuel consumption by switching to lower-carbon alternatives (e.g., coal to gas),
- An increase of energy efficiency in industrial applications and in the power sector, particularly in technologies used to convert fossil fuels into energy, as well as on the demand side, and
- Carbon capture and storage techniques.
  CCS is a suite of techniques designed to capture the CO_2 contained in industrial flue gases from large point sources (fossil fuel plants, blast furnaces, cement manufacturing, etc.) before it enters the atmosphere, to transport it (by trucks, ships, pipelines) and then to inject it in a suitable storage facility (depleted oil and gas fields and deep saline aquifers).

1.1.3 Most energy scenarios with ambitious climatic goals use CCS techniques

International organisations such as the IPCC (2005 [84], 2014 [87]), the IEA* (2013, [118]) and the GCCSI* (2014, [63]) identify CCS as the only currently available mitigation technology that would enable the power sector as well as industrial sectors (e.g., iron and steel, cement, chemicals and refining) to meet deep emission reduction targets (IEA, 2014 [119]).
Thus, energy scenarios with ambitious climatic goals rely on CCS to significantly reduce global CO_2 emissions in the coming decades. For instance, the IEA develops a 2°C (2DS*)

[2]One ton of CO_2 which is emitted today will have a global warming potential for more than a century.

scenario (2013, [118]) in which CCS accounts for up to 14% of the total emission reductions globally through to 2050 (17% in that year)[3]. About half of the total volume of CO_2 comes from the power sector and the other half from energy intensive industry.

CCS plays an important decarbonisation role because many industrial processes emit large CO_2 amounts related to raw material conversion (not to energy) which limits the potential for further energy efficiency improvements to cut CO_2 emissions. Consequently, CCS may provide approximately one quarter of the cumulative emission reductions required in industrial sectors to reach the 2DS target (IEA, 2014 [119]). For instance, in the 2DS scenario, in 2050, the iron and steel sector captures approximately 40% of its direct CO_2 emissions, the cement sector 34% and the chemical and petrochemical sector 28%. Note that except for the iron and steel sector, CCS decreases efficiency and/or increases operating expenditures. However, for top gas recycling blast furnace, the separation of blast furnace off-gases into components for reuse in the furnace as reducing agents decreases coke needs and can facilitate CCS performance (IEA, 2010 [81], 2014 [119]). Consequently, in contrast with the other industrial applications or the power sector, CCS may represent a direct interest for the iron and steel industry by improving the economics of blast furnaces.

When applied to the power sector, CCS has the potential to significantly reduce GHG emissions: in 2009, power generation contributed to 40% of total CO_2 atmospheric emissions (IEA, 2012 [114]). Around two thirds of the world's electricity was generated from fossil fuels, with 40% from coal and 21% from natural gas, and the use of coal and gas to generate electricity is still rising (IEA, 2012 [114]).
Considering the world's continuing dependence on fossil fuels, CCS is an interesting transitional low carbon technology for countries with high shares of fossil fuels in their energy mix. Indeed, CCS enables a continued use of fossil fired plants that would otherwise be shut down to respect carbon emission constraints (e.g., emission performance standards[4]). Thus, by postponing the retirement of valuable production, CCS is a real strategic asset in a carbon-constrained world. One of the arguments for CCS deployment in the UK is notably that it would avoid the closure of the remaining underground coal mines.
In addition, for countries with large proven reserves of fossil fuels, CCS can be seen as a hedging response to conserve the economic value of their reserves and the related infrastructures in a world undertaking actions to reduce GHG emissions.
In addition, even if CCS techniques remain costly, they can be "competitive on a levelised cost of electricity (LCoE) basis with solar, wind (...)" (IEA, 2011 [79]). Indeed, one might tend to focus on the high extra-costs of CCS power plants without replacing them in the merit order of low carbon energies.
Finally, CCS power plants present a significant advantage upon RES: they can provide

[3]Nuclear: 8% (8% in 2050), Power generation efficiency and fuel switching: 3% (1% in 2050), Renewables: 21% (23% in 2050), End-use fuel switching: 12% (12% in 2050), End-use fuel and electricity efficiency: 42% (39% in 2050) (IEA, 2013 [118]).

[4]Two countries, the UK (UK*) and Canada, have already regulations prohibiting the construction of new coal plants without CCS. It could also be the case of the United States if the Environmental Protection Agency's proposal were adopted.

both base-load and balancing generation in an electricity system with an increasing share of variable renewable energies. CCS plants do not incur any additional cost for grid balancing.

To summarise, CCS is the only mitigation technology currently available in the power sector with "the potential to protect the climate while preserving the value of fossil fuel reserves and existing infrastructures" (IEA, 2013 [118]).

1.1.4 Industrial state of play of CCS in the power sector

1.1.4.1 Short description of CCS techniques

As their name suggests, CCS involves three stages: carbon capture, carbon transport and carbon geological storage.

The CO_2 capture is already performed as part of the standard process in some industries: natural gas processing, chemical production, coal gasification, coal to liquid, synthetic natural gas, fertilizer production, hydrogen production and ethanol production. However, capturing CO_2 emissions from fossil fuel power plants, blast furnaces or cement kilns is uncommon because these flue gases have low carbon content. Flue gases are a mixture of CO_2 but also oxygen, water vapour, or nitrogen. Thus, depending on the industry, the carbon content varies from a few percentage points to nearly 20%. For instance, the CO_2 content is approximately 10-14% for Super Critical Pulverised Coal (SC* PC*) plants hereafter coal plants, and only 3-5% for Combined Cycle Gas turbines (CCGTs*), hereafter gas plants. The effort required for CO_2 capture is proportional to the purity of the gas stream: CO_2 capture is easier and less expensive when flue gases are CO_2 rich. Thus, to reduce their CO_2 emissions, utilities, cement and steel manufacturers have to develop specific techniques to capture CO_2 and move them to demonstration scale.

Currently, three main processes are being developed to capture CO_2 (for more details, see Appendix A):

- Pre-combustion carbon capture

  The carbon contained in the fossil fuel is removed before the combustion process. The problem is tackled at its root.

  It is the most complex carbon capture process. The feedstock (coal for instance) is turned into a synthesis gas (mixture of dihydrogen H_2*, and carbon monoxide CO*). Then, the syngas undergoes the water-gas shift reaction to produce a H_2 and CO_2-rich gas mixture. The CO_2 concentration can range from 15 to 50%. The CO_2 is separated from H_2 in a similar way as in the post-combustion process[5]. H_2 can be used directly (e.g., in refineries) or as a fuel in combined-cycle gas plant (electricity or heat without CO_2) or to produce synthetic fluids.

  There are many CO_2 capture installations downstream, notably coal gasification or methane reformers in the chemical industry, particularly in China and in the United

[5] In the post-combustion process, the flue gas stream is at low pressure and with a low CO_2 content: from 5 to 15%. In the pre-combustion process, the shifted synthesis gas stream is CO_2 rich and at higher pressure: the CO_2 removal is easier.

States. In the power sector, the pre-combustion capture technology can only be used for new fossil fuel power plants: Integrated coal Gasification Combined Cycle (IGCC*) plants. Indeed, the capture process requires significant modifications of the power plant design. The first commercial IGCC plant with pre-combustion capture, Kemper County (United States), is expected to be operational in 2015 (see 1.1.4.2).

- Oxy-combustion carbon capture
  In traditional fossil fuelled power plants, combustion is carried out with air: the flue gas has a low CO_2 content so it is costly to separate it. In the oxyfuel process, the combustion is performed with enriched or high purity oxygen streams. As a result, the flue gas contains only steam and CO_2 with a high concentration (greater than 90% by volume). These two components are then easily separated through cooling: the water condenses and a CO_2 rich gas-stream is formed.
  Oxy-combustion is sometimes presented as the most promising carbon capture process. Further innovations are expected to reduce the cost of pure oxygen production (chemical looping).
  There are currently four industrial plants of 20 to 30 $MWth^*$ - Schwarze Pumpe which is a Pulverised Coal plant in Germany, Lacq which is an integrated pilot[6] in France, and CUIDEN, in Spain, which tests the oxy-combustion process on two boilers, from a PC plant and a Circulating Fluidised Bed plant - and one of 30 MWe - Callide which is an Australian retrofitted pulverised coal plant, the captured CO_2 being transported by trucks to be stored in a saline aquifer -.

- Post-combustion carbon capture
  This process has been used for decades in natural gas processing. Many installations have produced industrial or food-grade CO_2 for years. The biggest installations produces 100 to 300 ktCO_2*/yr (e.g., NGCC* plants, or Pulverised Coal plants). The process consists in separating and removing the CO_2 diluted in the flue gas produced by the combustion of a fossil fuel. Several options are available. The most common process is absorption which is based on a chemical reaction between CO_2 and a suitable chemical, also called an absorbent. The absorbed CO_2 is separated from the absorbent through a thermal regeneration process. Typical absorbents that are used today are amines and carbonates. Cryogenic separation, calcium looping and adsorption are the three other processes.
  Positioned downstream, this capture process can be added to existing coal or gas power plants, blast furnaces, cement kilns, and other large CO_2 emitters.
  Post-combustion carbon capture is the most mature and widely used process.
  The first two PC plants (20-25 MWe) with post-combustion capture and CO_2 transport and storage (100 to 125 ktCO_2/yr) infrastructures started in the United States, in 2009 (AEP's[7] Mountaineer stopped in 2011) and 2011 (Southern's Plant Barry). Note that most CCS demonstrators (more than 100 MWe-eq.) planned in 2015

[6] Natural gas processing with storage.
[7] American Electric Power.

will use chemical absorption, particularly SaskPower Boundary Dam 3, the first commercial Pulverised coal plant with post-combustion capture in the world (see 1.1.4.2).

1.1.4.2 CCS penetration

LSIPs in operation around the world

As of November 2014, according to the GCCSI (2014, [63]), there are only 13 Large Scale Integrated Projects[8] (LSIPs*) operational in markets around the world. These 13 LSIPs would have captured and stored underground around 55 MtCO_2 (IEA, 2014 [119]).
Among them, four large scale Enhanced Oil Recovery (EOR*) projects demonstrating elements of carbon capture, transport and storage began operational in 2013: Air Product Steam Methane Reformer EOR Project (United States, Hydrogen production), Coffeyville Gasification Plant (United States, Fertiliser Production), Lost Cabin Gas Plant (United States, Natural Gas Processing) and Petrobras Lula Oil Field CCS Project (Brazil, Natural Gas Processing) (Table 1.1, Figure 1.1).
In total, there are eight projects using anthropogenic CO_2 for EOR (Table 1.1, Figure 1.1). It means that two-thirds of the operational LSIPs were partly driven by CO_2-EOR (additional revenues that partially offset CCS costs). Note that to be qualified as CCS-EOR, a project needs to prove sufficient monitoring, measurement and verification. It is the case for the Weyburn project (Table 1.1) but not the case of many CO_2-EOR projects in operation all around the world, particularly in the United States.

Among the 13 LSIPs in operation, only one is in the power sector: SaskPower Boundary Dam 3 (110 MWe, Estevan, Canada) that started operation in late 2014. Boundary Dam is the world's first commercial scale post-combustion carbon capture project at a coal fired generating station.

LISPs in different stages of development planning

In addition to SaskPower, two LSIPs should be complete in the power sector, in 2015 and 2016 respectively: Kemper County (580 MWe, Mississippi, United States), the only IGCC with CCS under construction worldwide, and Petra Nova[9] (250 MW slip stream from a 610 MW unit, Texas, United States, EOR), the first existing coal plant with post-combustion capture (CCS retrofit). These two CCS projects nearing operation are thus very important because they are the first to be developed on a commercial scale in the power sector. Both are located in North America (Figure 1.1, Table 1.1).
In addition to Kemper County and Petra Nova, there are 7 LSIPs under construction in

[8] The definition of a LSIP is from the GCCSI and involves projects with the capture, transport and storage of CO_2, at a scale of 800 000 tCO_2/yr for coal-based power plants or 400,000 tCO_2/yr for gas-based power plants and other emission-intensive facilities.
[9] Formerly NRG Energy Parish CCS Project.

Australia[10], Canada[11], Saudi Arabia[12], United Arab Emirates[13] and the United States[14].
These 7 LSIPs under construction could capture and store an additional 14 MtCO_2/yr.
Another 14 projects in advanced stages of planning (define stage) could capture and store an additional 30 MtCO_2.
Overall, with 19 projects in early stages of development planing (evaluate and identify states), the GCCSI (2014, [63]) identifies 55 LSIPs around the world.
More than 75% of the LSIPs are located in OECD* countries. North America (United States, 19; Canada, 7) is the front runner in LSIPs, mainly because of the market opportunity of using CO_2 as a commodity through EOR, followed by China (12) and the European Union (8).

By around the 2020 time frame, approximately 10 LSIPs should be operational in the power sector. These LSIPs should cover both coal and gas plants and the three main capture processes.

Figure 1.1: Map of the 13 LSIPs operational in markets around the world.

[10] Gorgon Carbon Dioxide Injection Project, Natural gas processing (NGP*), 2016, dedicated storage.
[11] Alberta Carbon Trunk Line with Agrium CO_2 stream, Fertilizer production, 2015, EOR. Quest, Hydrogen production, 2015, dedicated storage.
[12] Uthmaniyah CO2 EOR demonstration project, NGP, 2015, EOR.
[13] Abu Dhabi CCS Project, formerly ESI CCS project, Iron and steel, 2016, EOR.
[14] Illinois Industrial Carbon Capture and Storage project, Chemical production, 2015, dedicated geological storage.

Table 1.1: Short description of the Large Scale Integrated Projects in operation (GCCSI data base, November 2014).

Project Name	Region	Industry	Operation date	Volume CO_2 (Mt/yr)	Capture Type	Transport Type	Storage Type
Sask Power Boundary Dam 3	Saskatchewan (Canada)	Power generation	2014	1	Post-combustion	Onshore pipeline	EOR
Air products Steam Methane Reformer EOR Project	United States (Texas)	Hydrogen	2013	1.0	Pre-combustion (gasification)	Onshore pipeline	EOR
Century Plant	United States (Texas)	NGP	2010	8.4	Pre-combustion (natural gas processing)	Onshore pipeline	EOR
Coffeyville Gasification Plant	United States (Kansas)	Fertiliser	2013	1.0	Industrial Separation	Onshore pipeline	EOR
Enid Fertilizer CO_2-EOR Project	United States (Oklahoma)	Fertilizer	1982	0.7	Industrial Separation	Onshore pipeline	EOR
Great Plains Synfuel Plant and Weyburn-Midale Project	Canada (Saskatchewan)	Synthetic Natural Gas	2000	3.0	Pre-combustion (gasification)	Onshore pipeline	EOR
In Salah CO_2 Storage	Algeria	NGP	2004	1[a]	Pre-combustion (NGP)	Onshore pipeline	Dedicated Geological Storage
Lost Cabin Gas Plant	United States (Wyoming)	NGP	2013	0.8-1.0	Pre-combustion (NGP)	Onshore pipeline	EOR
Petrobras Lula Oil Field CCS Project	Brazil (Santos Basin)	NGP	2013	0.7	Pre-combustion (NGP)	Not required	Direct Injection - EOR

Table 1.1: Short description of the Large Scale Integrated Projects in operation (GCCSI data base, November 2014) -Continued.

Project Name	Region	Industry	Operation date	Volume CO_2 (Mt/yr)	Capture Type	Transport Type	Storage Type
Shute Creek Gas Processing Facility	United States (Wyoming)	NGP	1986	7.0	Pre-combustion (NGP)	Onshore pipeline	EOR
Sleipner CO_2 injection	Norway (North Sea)	NGP	1996	0.9	Pre-combustion (NGP)	Not required	Direct Injection - Offshore deep saline formation
Snøhvit CO_2 injection	Norway (Barents Sea)	NGP	2008	0.7	Pre-combustion (NGP)	Onshore to offshore pipeline	Offshore deep saline formation
Val Verde Natural Gas Plants	United States (Texas)	NGP	1972	1.3	Pre-combustion (NGP)	Onshore pipeline	EOR

[a]Injection suspended in 2011.

1.1.4.3 Uncertainty on CCS costs

As CCS has not yet been commercially deployed, sets of cost data come from engineering and feasibility studies, as well as from CCS pilots and LSIPs.

LSIPs provide sets of cost data that correspond to First-of-a-Kind (FOAK*)[15] projects, that is to say projects with technologies at early stage of development. From these sets of cost data, up-scaling deduce full scale plant costs taking into account learning-by-doing effects and economies of scale as well as a different level of contingencies depending on the number of equipments/similar plant type already built. This enables to compute Nth of a Kind (NOAK*) CCS costs[16].

As previously said, in 2013, none of the three capture processes were used at a commercial scale in the power sector. Even if in late 2016, three large scale projects should be complete, SaskPower Boundary Dam 3 (Canada, 2014), Kemper County (United States, 2015) and Petra Nova (United States, 2016), it is a small number[17].

[15]The technology is at an early stage of development/deployment.

[16]The technology is mature.

[17]In Europe, two CCS power plant projects have received a £1 billion capital funding from the United Kingdom Government: White Rose (coal plant) and Peterhead (gas plant). Note that in July 2014, the

Regarding carbon transport, the American Enhanced Oil recovery (EOR) experience[18] along with the Norwegian experience of offshore transport (Snøhvit) may provide valuable information.
As for carbon storage, more than 150 sites are currently injecting CO_2 underground, either for EOR or explicitely for CO_2 storage. Four large sites with dedicated monitoring are operating (Table 1.1): In Salah (Algeria, 1 MtCO_2/yr from natural gas processing), Sleipner (Norway, 1 MtCO_2/yr from natural gas processing), Snøhvit (0.7 MtCO_2/yr from natural gas processing) and Weyburn (2 MtCO_2/yr from a synfuel plant for EOR). Several EOR projects, demonstrating elements of carbon transport and storage (Table 1.1), are also currently operating. With respect to carbon storage, the main uncertainty relies on deep saline formations that are not well known. However, valuable information and experience were acquired due to the two Norwegian LSIPs, the Algerian one as well as to several pilot facilities (e.g., Lacq in France). In addition, three LSIPs with deep saline formations (Quest Project, Canada; Gorgon Carbon Dioxide Injection Project, Australia; Illinois Industrial Carbon Capture and Storage Project, United States) are in construction around the world. These projects should provide reliable information and experience in the short-term since they are expected to be commissioned in 2015/2016.
However, two significant techno-economic uncertainties still need to be removed: i) the safety and reliability of geological CO_2 storage in deep saline aquifers, ii) the availability of technologically accessible and economically feasible storage sites.

Consequently, to resolve these issues and to refine capital and operating expenditures (cost and contingencies), the next step is to move to the commercial scale through the construction of several LSIPs (close to the industrial and commercial scale) as well as to increase efforts characterising and identifying appropriate geological storage sites around the world.

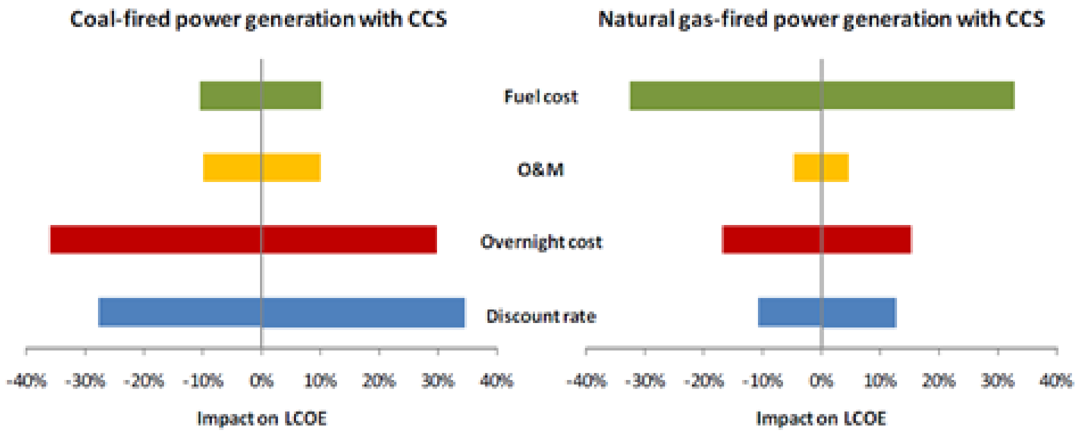
1.2 Objectives

In order to assess more precisely the potential of CCS as a key option for climate change mitigation, this chapter reviews, analyses and compares public studies to draw an objective techno-economic panorama of CCS when applied to the power sector.
Comparing CCS cost data across public studies is not trivial and presents a major challenge.
Indeed, there are large discrepancies in the way CCS costs are currently calculated in public studies. Indeed, most studies employ their own methodology to calculate some economic data (capital cost, fuel cost, etc.) and there is no set of commonly agreed data on boundary conditions such as the discount rate or fuel prices. Such differences of methodologies, terminologies and techno-economic assumptions often appear with limited transparency in CCS public reports. These different sets of techno-economic assumptions and methodologies can dramatically affect the results (Rubin et al., 2007 [128]), particularly because the Levelised Cost of Electricity (LCoE*) is very sensitive to certain parameters (Figure 1.2).

White Rose CCS project received up to €300 million in funding within the framework of the second call of the EU's NER300. Final Investment decisions are expected for 2015-2016.

[18]Each year, 6,200 km of pipelines currently handle about 50 Mt of dehydrated CO_2 (mostly from natural fields) in a supercritical state (IEA ETSAP, 2010 [81]). The first pipeline has been operating since 1972.

Figure 1.2: LCoE sensitivity to +/-50% variation of key parameters. From IEA (2011, [79]).



Consequently, a straight comparison of public studies would only lead to a misleading and confusing CCS cost information. "These inconsistencies [in the way CCS costs are currently calculated and reported by various authors and organisations] hamper the ability to correctly and systematically compare the cost of different carbon capture options. They also distort comparisons between CCS and other greenhouse gas reduction measures - with potential consequences for both technology and policy developments" (GCCSI, 2013 [62]).
Thus, the objective is to elaborate a methodology to compare relevantly CCS public studies, in order to: (1) study the profitability of CCS plants with respect to non-CCS power plants (marginal economic analysis), (2) assess the costs and performance of carbon capture techniques - pre-combustion, oxy-combustion, post-combustion - to indicate which one is the most profitable, (3) determine the CO_2 price beyond which CCS power plants become more profitable than non-CCS power plants also called reference plants.
In other words, the CO_2 price that will trigger CCS investment is determined. Indeed, like RES, CCS emerges endogenously as a cost effective response to the carbon restriction. When the carbon price is high enough, decision makers/investors face this choice: either they invest in a CCS power plant to reduce their carbon burden, or they decide not to install CCS and pay for emitted CO_2. When the CO_2 price is high enough, it becomes more profitable to invest in a CCS plant than in the analogous non-CCS plant. It explains why it is interesting to assess the CO_2 price beyond which CCS plants become more profitable than reference plants.

1.3 Methodology and data

1.3.1 Public studies selection and scope of analysis

1.3.1.1 Public studies selection

The selected public studies are the following: IEA (2010 [113], 2011 [79]), Alstom (2011, [8]), DECC* (2012 [34], 2013 [35]), Global CCS Institute (2011, [61]), ZEP*[19] (2011, [143] [145] [144]), DoE*-NETL* (2010, [40] [39]) and WorleyParsons (2009 [141], 2011 [140]).
These studies are considered as references in the "CCS sphere" and were published over the last five years. Significantly, the Global CCS Institute (GCCSI, 2011 [61]) noted that "The levelised cost estimates in the studies [DOE NETL, WorleyParsons, IEA, ZEP] are consistently higher than those estimated three or more years ago. Due to changing methodologies and the inclusion of previously omitted items, costs are now suggested to be 15 to 30 per cent higher than earlier estimates" (p66).
It explains why the MIT*'s study (2007 [107]), for instance, was not considered here.

1.3.1.2 Two limits on the independence of public studies

The literature review has then raised two limits on the independence of public studies:

- As for the national energy mix and context.
  By comparing the sets of cost data provided by those different public studies, two discernible trends appear (Table 1.2).

  The American studies tend to give the highest sets of cost data for coal plants whereas ZEP (European) tends to favour coal plants.
  DoE and WorleyParsons' studies tend to minimise gas plant costs (with the lowest overnight and O&M* costs) while they tend to give higher coal plant costs than the other studies (highest O&M values).
  Therefore, the difference between coal and gas plant LCoEs is rather low for the American studies in comparison with the other public studies.
  Are the American studies influenced by the national energy context, particularly the dash for gas due to the shale gas exploration and development? This might be a bias. The idea should, at least, be raised.
  Note that the IEA, sometimes criticised for its too optimistic scenarios, gives the lowest LCoEs for coal and gas plants. In contrast, DECC'studies (2012 [34], 2013 [35]) which are very recent, provide updated costs which are relatively higher than those from the other public studies.

[19] Zero Emissions Platform. Founded in 2005, ZEP is a coalition of 300 experts from 19 countries and approximately 40 companies and organisations. ZEP serves as advisor to the European Commission on the CCS research, demonstration and deployment.

Table 1.2: Sets of cost data directly provided by public studies.

	ZEP	**IEA**	**DECC**	**DoE-NETL**	**Worley-Parsons**
Gas plant overnight cost[a] [€$_{2011}/kW$]	615	475	647	**473**	**547**
Coal plant overnight cost [€$_{2011}/kW$]	1283	1363	1765	1333	1477
Multiplication factor between overnight costs	*2.1*	*2.4*	*2.8*	*2.8*	*2.7*
Gas O&M costs [€$_{2011}/MWh$]	6	1	2	**3**	**3**
Coal O&M costs [€$_{2011}/MWh$]	7	5	10	**11**	**8**
Gas plant LCoE [€$_{2011}/MWh$]	68	61	64	63	63
Coal plant LCoE [€$_{2011}/MWh$]	54	52	62	58	57
Ratio of coal LCoE by gas LCoE %	*26%*	*17%*	*3%*	***9%***	***10%***

[a]Cost of a power plant constructed in a single day (Appendix B).

- The one from each other: how much independent are CCS public studies?
  This question is raised by two factors:
  - For most of these public studies, cost data sources are kept secret (lack of transparency).
  - A rather high homogeneity in cost data is observed after the standardisation of several techno-economic parameters and calculation methodologies (see 3.3.4.).
    One can wonder whether these sets of cost data are rather similar because studies refer to one another and might eventually use identical sets of data.

  The cross analysis of bibliographies shows that most studies refer to each other (Table 1.3).

Table 1.3: Cross analysis of studies' bibliographies.

Quotes \ Quoted by	EPRI (2009, [49])	GCCSI	IEA	Worley-Parsons	DoE-NETL	ZEP	Alstom	DECC
EPRI (2009, [49])		✓		✓	✓	✓		✓
GCCSI						✓		✓
IEA		✓		✓		✓	✓	✓
Worley-Parsons								
DoE-NETL	✓	✓	✓	✓				✓
ZEP		✓						✓
Alstom					✓			✓
DECC								

IEA's costs (2010 [113], 2011 [79]) come from its Member States, the DoE-NETL and its own estimations.
WorleyParsons' cost estimates (2009 [141], 2011 [140]) come from its "experience in the design, construction and operation of large infrastructure facilities that are likely candidates to apply CCS and direct engagement in assisting proponents to develop CCS projects. The cost estimates of storage are provided by Schlumberger and are similarly informed by their leading global position in this space" (WorleyParsons, 2011 [140] p10).
The DoE (2010 [40], 2010 [39]) used the ASPEN Plus modelling program "to size major pieces of equipment. These equipment sizes formed the basis for cost estimating. Performance and process limits were based upon published reports, information obtained from vendors and users of the technology, performance data from design/build utility projects, and/or best engineering judgement. Capital and operating costs were estimated by WorleyParsons based on simulation results and through a combination of vendor quotes, scaled estimates from previous design/build projects, or a combination of the two. Baseline fuel costs for this analysis were determined using data from the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2008" (DoE, 2010 [39] pp 27-28).
ZEP (2011, [143] [145] [144]) makes its cost calculations with detailed engineering studies, data from CCS demonstration projects and data provided by some of its industrial and utility members. Cost calculations are then "reviewed by the working group, based on their own extensive knowledge and experience" (ZEP, 2011 [143] p5).
DECC's capture cost estimates (2012 [34], 2013 [34]) come from Front and Engineering Design studies lead by the DECC in 2011 and confidential project estimates. CO_2 pipeline and shipping costs are from ZEP's studies (2011, [144] [145]).
GCCSI's study (2011, [61]) is very close to a literature review: although some sets of cost data are re-computed, most of them are directly from existing studies.

Consequently, it is pretty hard to state about the total independence of these public studies.

1.3.1.3 Scope of analysis

This chapter focuses on the following:

- Newly constructed large-scale base-load operating coal and gas plants (more than 350 MW).
- Mature CCS techniques (not pilot projects). Sets of cost data provided by the above studies are for 2015-2020. Note that sets of cost data presented in this study do not intend to represent specific projects, but indicate a global trend.
- Capture techniques whose capture rate is larger than 85%.
- The European Union (EU) region.

Indeed, fuel price assumptions determine the geographical area which is studied (see 1.3.3). The focus is on the EU for several reasons. With the EU-ETS*, the EU has introduced a CO_2 price since 2005. As previously said, carbon regulation plays a key role in CCS profitability and deployment (Giovanni et al., 2010 [68]), thereby implying a CO_2 cost pass-through to electricity prices. It exists in the EU (Jouvet and Solier, 2013 [91]). In addition, in the late 2000s, the EU viewed CCS techniques as able to play a critical role in meeting its climate targets, well known as the "20-20-20" in the climate and energy package framework (European Council, 2009 [57]))[20]. Thus the EU has committed to support CCS, from a financial and regulatory point of view. Following the 2007 Spring European Council's decision to support up to 12 large-scale demonstration projects by 2015, the Commission took several regulatory measures. The CCS Directive 2009/31/EC was adopted to provide a legal and common framework for CO_2 capture, transport and storage (national transposition deadline set at June 2011). In addition, CO_2 transport pipelines were included in the European regulation about energy infrastructures. To establish a demonstration support framework, CCS has become an integral part of the EU R&D* program, in the frame of the European Industrial Initiative on CCS that is part of the Strategic Energy Technology Plan (SET-Plan/COM/2007/0723 final). Two funding instruments have also been created: the European Energy Program for Recovery and the NER*300[21]. In 2008, the EU agreed to set aside 300 million Emission Unit Allowances (EUA*) from the NER under the European Union-Emission Trading System (EU-ETS) Directive. This financing instrument is dedicated to subsidise installations of innovative renewable energy technology and CCS. However, the current weak EUA price has slowed down CCS demonstration projects and threatens CCS deployment[22]. As a result, the European Union, pioneer in the CCS field may not be leader[23] since other countries like China are currently investing in CCS techniques.

[20] A 20% reduction in GHG emissions from 1990 levels, raising the share of EU energy consumption produced from renewable resources to 20%, a 20% improvement in the EU's energy efficiency.

[21] New Entrance Reserve. ETS Directive 2009/29/EC.

[22] No CCS projects were selected in the first call for proposals of NER300. One project was submitted and awarded in the second call (July 2014): White Rose (UK).

[23] Alstom, for instance, has namely been involved in these pilots: Lacq (France), Le Havre (France), the Technology Center Mongstad (Norway) which is the world's largest facility for testing CO_2 capture, or White Rose demonstrator (United Kingdom).

1.3.2 Two key metrics for assessing CCS power plant profitability

CCS techniques will be commercially deployed if and only if they are profitable for industrials/investors.
CCS power plant profitability is directly linked to CCS extra-costs of which are of two types:

- Fixed costs: incurred at the start of the project,
- Variable costs: incurred during operation, because of the following:
  - Net efficiency penalties (from 8 to 10 points) which means higher fuel consumption.
  - Higher operating and maintenance expenditures.

The extra-costs induced by CCS devices are assessed through the two following key metrics:

- The Levelised Cost of Electricity (LCoE).
  The LCoE is equal to the minimum selling price of electricity for which the power plant becomes profitable (the NPV is null). LCoE is a uniform annual value giving the same net present value as the year-by-year case. The LCoE is expressed in €/MWh and is equal to the present value of the sum of discounted costs divided by total production adjusted for its economic time value[24]. Box 1 explains why the LCoE was chosen rather than the cost of CO_2 avoided.

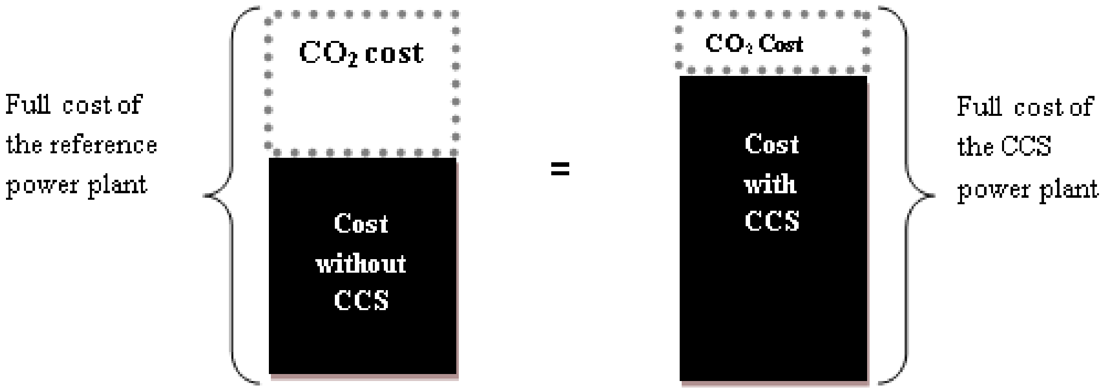
- The CO_2 switching price[25].
  When the CO_2 price is not null, power plants without CCS are significantly charged for their CO_2 emissions on the contrary to CCS power plants. Consequently, there is a CO_2 price that equals the LCoEs of both CCS and non-CCS power plants. In other words, there is a CO_2 price beyond which CCS power plants become more profitable than the analogous non-capture plants (Figure 1.3). This is the CO_2 price for which the NPV of the differential project (NPV CCS - NPV ref) is null.

  These two key metrics will enable us to establish a merit order between CCS and non-CCS power plant LCoEs according to different CO_2 price scenarios.

[24] With my simplifying assumptions (costs are constant over time), the LCoE is: $\frac{Constant\ Investment\ Annuity + O\&M + Fuel\ cost + Carbon\ cost}{Electricity\ production}$

[25] $\frac{Constant\ Invt\ Annuity^A - Constant\ Invt\ Annuity^B + O\&M\ cost^A - O\&M\ cost^B + Fuel\ cost^A - Fuel\ cost^B}{Em.\ Factor^A(1 - capture\ rate^A) - Em.\ factor^B(1 - capture\ rate^B)}$

Figure 1.3: The CO_2 switching price concept.



There is still a CO_2 cost for the CCS power plant because the capture rate is 90%, not 100%.

Box 1. Why the LCoE rather than the cost of CO_2 avoided?

In many public studies, coal and gas-fired generation with and without CCS are compared on the basis of the cost of CO_2 avoided.

On this basis, coal-fired generation is more interesting than gas-fired generation. Indeed, coal plants have a higher emission factor[a] than gas plants. Consequently, CO_2 avoided costs are higher for CCS coal plants than for CCS gas plants, using analogous non-capture plants as the reference[b]. In addition, as the CO_2 concentration in flue gases is higher for coal plants than for gas plants (See 1.1.4.1), carbon capture is less expensive for coal plants. As a result, gas-fired generation has higher CO_2 avoided costs than coal-fired generation. This observation explains why, until recently, analysts and policy makers focused more on CCS coal plants than on CCS gas plants (e.g., demonstration funding programs such as NER300 favoured projects with the lowest cost of CO_2 avoided).

However, in practice in the power sector, firms seek to minimise electricity generation costs. Consequently, investors take their decisions with respect to the cost of electricity rather than the cost of CO_2 avoided. Indeed, the price of electricity takes into account the costs related to the capture, transport and geological storage of one tonne of CO_2, as well as the amount of CO_2 to capture per MWh. On the LCoE basis, depending on fuel prices, gas-fired generation may be more interesting than coal-fired generation, and particularly, gas-fired generation with CCS can provide lower LCoE than coal-fired generation with CCS. As there is no reason to favour coal- over gas-fired plants when considering the costs of securing low-carbon electricity, CCS gas plants have been receiving an increasing attention from analysts, policy makers and industrials over the last few years (e.g., in the UK, Peterhead CCS Project consists in retrofitting a 340 MW existing train of a 1,180 MW combined cycle power plant, or the Norwegian (Mongstad) pilot-scale project).

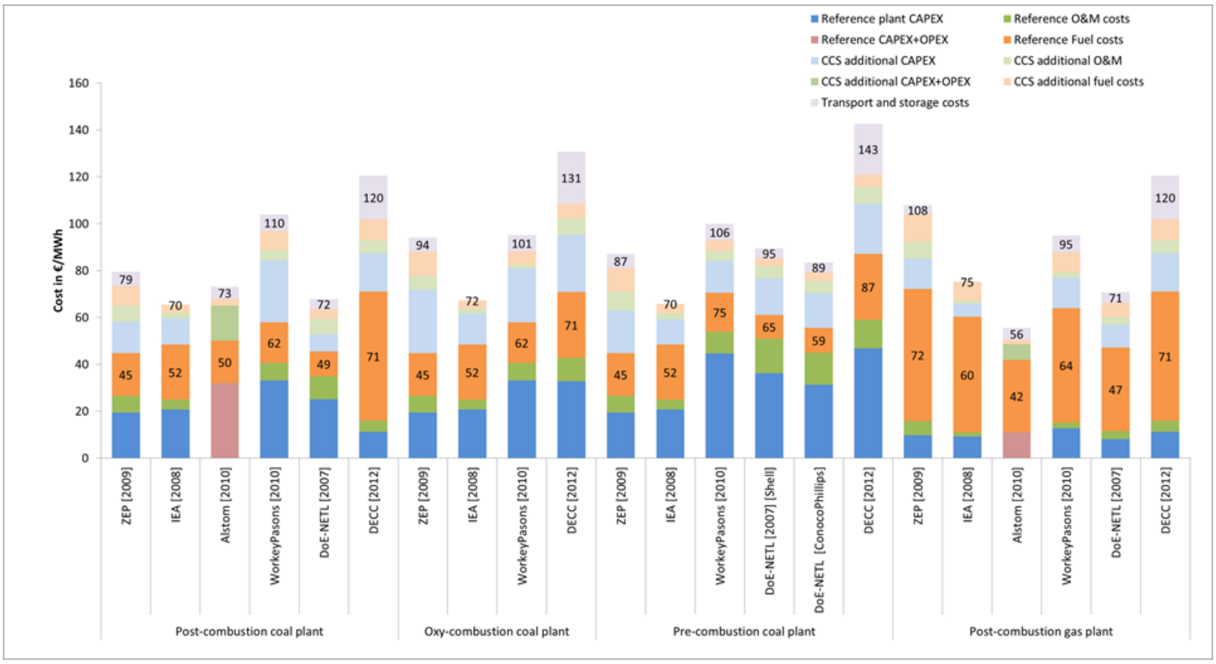
[a] Ratio of the CO_2 amount which is emitted (in tons) by the hourly production (MWh) (Appendix B).

[b] For gas-fired generation, the cost of carbon capture and storage is divided by a smaller amount of CO_2.

1.3.3 How can we turn techno-economic information from different studies into a comparable set of data?

To be noted, the purpose is to draw an objective techno-economic panorama of CCS applied to the power sector to assess more precisely the potential of CCS as a mitigation option.
As previously said, there are large discrepancies in the way CCS costs are currently calculated in public studies. Indeed, most of them employ their own methodology to calculate some economic data (capital cost, LCoE, etc.) and there is no set of commonly agreed conditions on boundaries such as the discount rate or fuel prices. CCS costs are thus very heterogeneous (Figure 1.4) and there is a significant degree of misrepresentation in the information available to the public.

Figure 1.4: Sets of cost data directly issued from public studies.



Note: the figures indicated correspond to the LCoEs of reference plants [below] and CCS plants [above].

These inconsistencies hamper the ability to compare the costs of different carbon capture options investigated in various public studies. To address this issue, the following methodology is used:

- A literature review is conducted to select the most recent and relevant public techno-economic studies.

- For each public study, the most representative original economic data is kept but is updated to current cost level (Table 1.4):

  - Two sets of economic data are considered to be representative: the overnight cost[26] and the operating and maintenance (O&M) costs.

[26] Cost of a power plant constructed in a single day to reflect technological and engineering costs in a given country. Interests during construction (IDC*) and owner's cost (land, administration and associated buildings, site works, etc.) are excluded. This method requires the standardisation of the costing scope across studies, as the definition of overnight cost is not always the same across studies. Thus, provided costs were recalibrated by subtracting IDC and/or owner's costs when required. Net power output is unchanged. Indeed, studies might take into account scale effects.

- These costs are updated to €$_{2011}$ cost level.

- Calibration of sets of economic data (discount rate, fuel prices, carbon transport and storage costs, etc.; Table 1.6) and calculation methodologies (Table 1.5):

  - Standardised parameter values and calculation methodologies come from the comparison of public studies.

  - Note that carbon Transport and Storage costs (T&S*), detailed in Table 1.6, come from ZEP (2011 [145], [144]) which is considered as a reference by the DECC (2012 [34], 2013 [35]) and the GCCSI (2011, [61]). ZEP has provided very detailed reports that differentiate onshore and offshore carbon transport and storage costs. Due to social acceptance issues, the focus is on offshore transport and storage infrastructures which are less controversial than onshore infrastructures.

- Standardised calculation of LCoEs and CO_2 switching prices.

  - Based on a common set of techno-economic parameters (Table 1.6) and calculation methodologies (Table 1.5), LCoEs and CO_2 switching prices are computed with the two original but updated sets of cost data reported in each public study (overnight and O&M costs, Table 1.4).

- Data analysis and result discussion.

- Conclusions and recommendations.

Table 1.4: Unchanged techno-economic parameters.

Unchanged parameters	**Unit**	**Range of values**
Overnight cost[a]	€$_{2011}$/kW	
Ultra-supercritical coal plant		[1283; 1765] [ZEP; DECC]
IGCC plant		[1546; 2588] [DoE; DECC]
CCS coal plant		
		[2116; 3225] [IEA; DECC]
Post-combustion		
		[2513; 3229] [WP; DECC]
Oxy-combustion		
		[2475; 3734] [ZEP; DECC]
Pre-combustion		
Combined Cycle Gas plant		[473; 647] [DoE; DECC]
CCS gas plant		[854; 1589] [IEA; DECC]
Operation & Maintenance costs	€$_{2011}$/MWh	
Ultra-supercritical coal plant		[4; 12] [IEA]
IGCC plant		[5; 22] [IEA; DoE]
CCS coal plant		[6; 22] [IEA; DoE]
Combined Cycle Gas plant		[1; 6] [IEA; ZEP]
CCS gas plant		[3; 13] [IEA; ZEP]
Net power	MWe	[400; 800]

[a]Cost data are for 2015-2020.

Table 1.5: Standardised calculation methodologies.

Calculation methodology	**Applied to public studies since the beginning**	**Applied to public studies at the standardisation time**
CO_2 **emission factor**	✓	✓
Constant investment annuity[a]	✓	✓
LCoE	✓	✓
Fuel cost		✓
CO_2 **cost**		✓
CO_2 **switching price**	✓	✓

[a]Constant investment annuity is from Park Chan (2003, [121]).

Table 1.6: Standardised techno-economic parameters.

Standardised techno-economic parameters	**Unit**	**Values**
Currency[a]	€$_{2011}$	
Capacity factor	%	85 [7446 hrs/yr]= BASE-LOAD
Capture rate	%	90
Emission Factor	tCO_2/MWh	Coal plant= 0.744; Gas Plant= 0.337
Plant efficiency (LHV)		
Coal plant	*%*	*45% (2015)*
CCS coal plant	*%*	*36% (2015)*
Gas plant	*%*	*60% (2015)*
CCS gas plant	*%*	*52% (2015)*
Construction time		
Coal plant	*years*	*4*
CCS coal plant	*years*	*5*
Gas plant	*years*	*2*
CCS gas plant	*years*	*3*
Lifetime		
Coal plant	*years*	*40*
Gas plant	*years*	*25*
Fuel price[b]		
Black coal (Illinois n°6)	$\$_{2011}/GJ$	*2015: 4.34 ($108.5/t)*
Natural gas	$\$_{2011}/GJ$	*2015: 11.61 ($11/MBtu)*
CO_2 **price**	€/t	0
Owner's cost	Overnight cost %	15
Discount rate [real after tax]	%	8
Transport costs[c]	€$_{2011}$/MWh	Onshore:1.8 - Offshore: 5.8
Storage costs[d]	€$_{2011}$/MWh	Onshore: 1.8 for gas/4.6 for coal - Offshore: 8.7

[a]Exchange rates are from OECD statistics (2014, [2]). Cost data are calibrated to 2011 cost levels by using cost indices (OECD statistics (2013, [1]), Oxford Economic and Asia Pacific Consensus Forecast (2013, [3])).
[b]European assumptions come from IEA (2012, [117]).
[c]Onshore: 180 km pipe. For a single CCS coal plant (2×700 MW), CO_2 transported: 10 Mtpa, for a single CCS gas plant: 2.5 Mtpa. Offshore: 500 km pipe. Cluster of CCS coal (3×700 MW) and CCS gas (2×360 MW) plants. CO_2 transported: 20 Mtpa. Mid scenario (ZEP, 2011 [145]).
[d]Deep saline aquifer. Mid scenario (ZEP, 2011 [144]).

Note that like almost every public study, a standard load factor of 85% has been chosen for coal and gas plants, with and without CCS, which means they operate at base-load. Indeed, the objective is to be able to compare the relative cost of one MWh produced by these different power plants types (coal and gas plants, with and without CCS). Besides, as CO_2 switching prices are assessed, coal and gas plants have been compared with an exogenous plant load factor even if in practice, it is endogenous. Nonetheless, this 85% generic load factor is higher than the average value usually observed, especially for gas plants that have significant load factors than those of coal plants. Indeed, many gas plants are frequently used in mid- or peak-load because operators may choose to shut them during base-load periods, when wholesale electricity prices are low, due to their higher marginal cost. If such consideration of portfolio optimisation does not directly enter into the methodology since the overarching concern of this Chapter is with base-load, a sensitivity analysis on the load factor was performed (see 1.5.4).
As the values of standardised technical parameters are relatively close to each other among public studies (the load factor ranges from 80 to 85% and the capture rate from 85 to 90%), we assume that turning them into standardised values (load factor of 85% and capture rate of 90%) does not modify the power plant design.
Furthermore, Zhai and Rubin (2010, [147]) have shown that there are substantial differences in other technical assumptions such as CO_2 purity, CO_2 compression etc., between different public studies. These divergent technical assumptions can have a significant impact on LCoEs as well as CO_2 switching prices (Rubin et al., 2007 [128]; IEA, 2011 [79]). However, the standardisation of these parameters is not required because these discrepancies reveal CCS actors' anticipations. It is one the interesting aspects of this comparative analysis.

These different elements are used to constitute a calculation file in order to compute the two key metrics: LCoE and CO_2 switching price (Figure 1.5). The different headings are detailed in Appendix B.

Figure 1.5: Preview of the calculus file.

Currency	€ or $
Rate to get a 2011 constant currency	2011
Exchange rate	2011
Reference year of the study	
Power plant net capacity	MWe
Net full load plant efficiency (LHV)	%
Eff. Diff to reference plant (LHV)	%
Plant load factor	%
Capture rate	%
CO_2 emissions calculated from fuel carbon content	t/MWhe
Building time	year
Plant life	year
Overnight cost	$/kW or €/kW
Overnight cost in constant currency	$/kW or €/kW
Investment cost in constant currency (with owner's costs)	$/kW or €/kW
Investment cost diff. to reference plant	%
O&M costs	$ or €/MWh
O&M costs in constant currency	$ or €/MWh
O&M cost diff. to reference plant	%
Fuel price in constant 2011$	$
Fuel price in constant 2011€	€
Fuel cost (constant currency)	$ or €/MWh
Fuel cost diff. to reference plant	%
Transport costs	$/MWh or €/MWh
Transport costs in constant currency	$/MWh or €/MWh
Storage costs	$/MWh or €/MWh
Storage costs in constant currency	$/MWh or €/MWh
CO_2 price	$/t or €/t
CO_2 price in constant currency	$/t or €/t
Discount rate	%
Elements to calculate the LCoE	
Annuity Investment	€/MWh
Fuel cost	€/MWh
O&M costs	€/MWh
CO_2 costs	€/MWh
Carbon transport and storage costs	€/MWh
LCoE	€/MWh
CO_2 switching price	€

1.3.3.1 Main results from the standardisation of techno-economic assumptions and calculation methodologies

This standardisation process allows a rigorous calculation and comparison of LCoEs and CO_2 switching prices between various public studies.

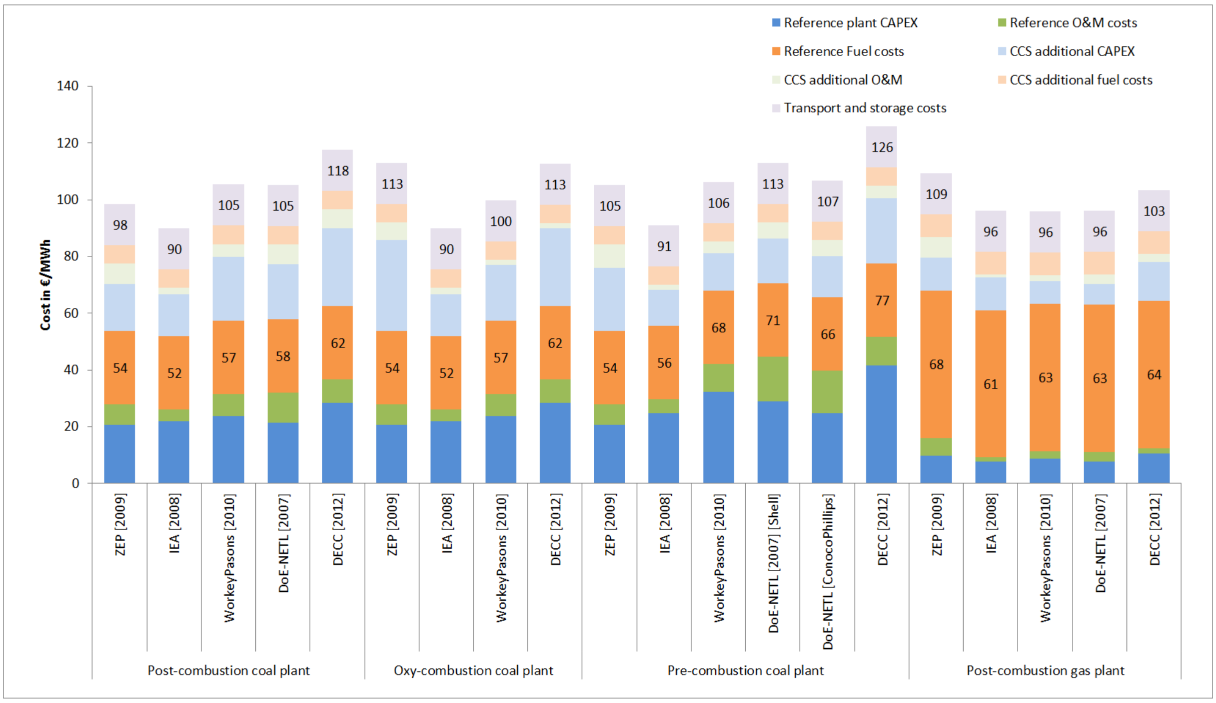
After this standardisation, sets of cost data from studies are less heterogeneous. Indeed, across studies, LCoE values could:

- Range from 5 to 75% for a specific coal power plant type as shown in Figure 1.4,
- Range from 5 to 115% for a specific post-combustion gas plant type as shown in Figure 1.4.

After the standardisation, one can observe that LCoEs:

- Range from 5 to 30% for a specific coal power plant type as shown in Figure 1.6,
- Range 0 to 10% for a specific post-combustion gas plant type as shown in Figure 1.6.

Figure 1.6: Costs after standardisation.



This higher homogeneity in cost data is in accordance with the GCCSI (2011 [61]): "The different cost estimates observed in the various studies arise due to differences in assumptions regarding technology performance, cost of inputs or the methodology used to convert the inputs into levelised costs. Many of these differences disappear when the assumptions are normalised and a common methodology is applied".

For a specific power plant type, the residual differences between studies in terms of LCoE are mainly due to discrepancies in O&M assumptions, which can vary of three (Table 1.4). For instance, LCoE residual differences are reduced by 70% when IEA's (2010 [113], 2011 [79]) O&M assumptions are applied.

1.4 Economic panorama of CCS power plants

LCoE and CO_2 switching price calculations as well as interpretations are presented below. CCS plants have offshore transport and storage costs (Table 1.6).

1.4.1 None of the carbon capture techniques have a clear cost advantage

For gas plants, only one carbon capture technique, namely post-combustion capture, has been studied except the IEA (2010 [113], 2011 [79]) that also consider the oxy-combustion capture. However, gas plants with oxy-combustion capture are introduced later (2020) than gas plants with post-combustion capture (2015).

For coal plants, none of the carbon capture techniques have a clear cost advantage.

- For ZEP, the carbon capture technique with the lowest LCoE is post-combustion (€98/MWh), then comes pre-combustion capture (€105/MWh) and finally oxy-combustion capture (€113/MWh). This ranking is rather wide since there is a 15% difference between the lowest and the highest LCoE.

- For the IEA, oxy-combustion and post-combustion capture techniques have the lowest LCoE (€90/MWh) closely followed by pre-combustion (€91/MWh). Contrary to ZEP's studies, there is a tiny difference between the lowest and the highest LCoE.

- For WorleyParsons, the carbon capture technique with the lowest LCoE is oxy-combustion (€100/MWh), then post-combustion (€105/MWh) and pre-combustion (€106/MWh). Here again, the difference between the lowest and the highest LCoE is small: 6%.

- For DECC, in 2013, the capture technique with the lowest LCoE is oxy-combustion (€113/MWh) then post-combustion (€118/MWh) and finally pre-combustion (€126/MWh). Note that DECC's LCoEs are higher than those provided by the other public studies. Indeed, DECC's studies are more recent and updated: notably, they take into account the delay in CCS commercial deployment.

- DoE's studies do not consider oxy-combustion capture. Uncertainty tends to be reinforced: according to the case which is studied - ConocoPhillips or Shell data -, the LCoE ranges from €107/MWh to €113/MWh whereas the LCoE associated with the post-combustion technique is €105/MWh. This small difference does not allow to clearly discriminate between these two carbon capture techniques.

This observation is shared by the Global CCS Institute (2011[61], p66): "Given the uncertainties, at this stage, it is difficult to identify any single technology with a clear cost advantage."

It can be noticed that the post-combustion carbon capture technique is the only one to be analysed by every public study. Although this capture technique does not have a clear cost advantage, it should be the first to be deployed at a commercial scale because it is the most mature. Pre-combustion capture only concerns IGCC plants which are still few[27]. Oxy-combustion

[27] In its last Energy Technology Perspectives report (2014, [119]), the IEA insists on the benefits of IGCC which is supposed to reduce the costs of CO_2 capture. The IEA quotes the Kemper County project among others.

capture seems to be a promising technique but still needs research and development efforts to reduce energy consumption for the oxygen production (chemical looping could be part of the solution) (see Appendix A for more details).

1.4.2 Extra-costs due to CCS devices

A CCS plant undergoes an increase in both investment and O&M costs.

- Fixed costs:

  - The coal overnight cost increases on average by 70%.

  - The gas overnight cost increases on average by 110%.

- Variable costs:

  - Net efficiency penalties of 9 percentage points for coal plants *vs.* 8 points for gas plants. These efficiency penalties imply an increase of 25% *vs.* 15% in fuel costs, respectively.

  - O&M costs increase on average by 80% for coal plants and 100% for gas plants.

With CCS, coal LCoE increases on average by 80% in European countries (€110/MWh).
With CCS, gas LCoE increases on average by 55% in European countries (€105/MWh).

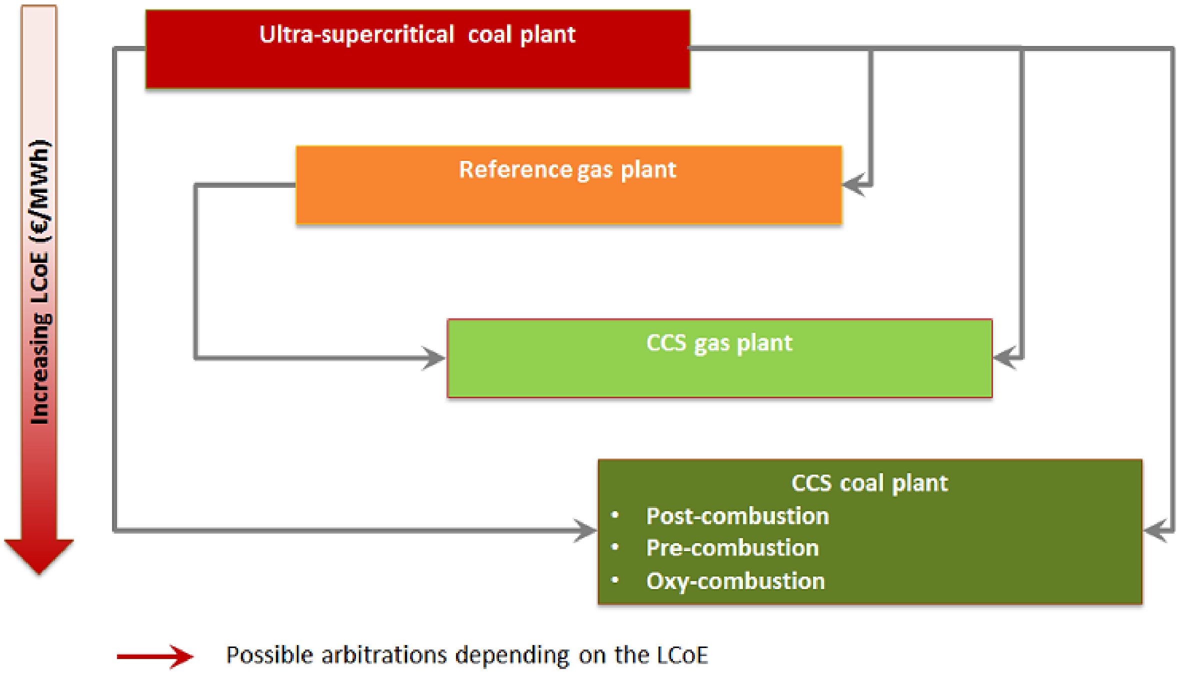
1.4.3 CO_2 price and breakeven point

On average, CCS coal plants become more profitable than reference coal plants beyond €65/tCO_2 in the EU.
On average, CCS gas plants become more profitable than reference gas plants beyond €115/tCO_2 in the EU.
Those CO_2 breakeven points are slightly higher than those observed in the specialised literature which gives €50-60/tCO_2 for CCS coal plants and €90-100/tCO_2 for CCS gas plants. However, these results are in line with the most recent studies (DECC, 2012 [34], 2013 [35]) and are mainly due to updated fuel price assumptions.

1.4.4 Investing in CCS: which power plant type is most profitable given the CO_2 price?

Until now, only intra-technique CO_2 switching prices (CCS coal plant *vs.* reference coal plant// CCS gas plant *vs.* reference gas plant) have been calculated. However, in practice, whatever the CO_2 price, an investor will compare all the possible types: **reference coal plant *vs.* reference gas plant**, **reference coal plant *vs.* CCS gas plant**, etc. (Figure 1.7). Then, he will choose the power plant type with the lowest LCoE. The power plant type with the lowest LCoE varies with the CO_2 price.
Comparisons in bold correspond to inter-technique CO_2 switching prices, which have not been studied in the CCS literature. By taking into account all possible scenarios, using both intra- and inter-technique CO_2 switching prices better represents the complex reality of an investor.

Figure 1.7: All the possible arbitrations depending on the LCoE.



1.4.4.1 When the CO_2 price is lower than €20/t

Without carbon price, CCS plants are far away to be competitive with traditional power plants. Reference coal and gas plants have the lowest LCoE.
The primary determinant for investment decision is relative fossil fuel prices. This priority echoes the "fuel switch" concept. With current fuel prices, in the EU, coal plants have the lowest LCoE.
What happened in Europe a few months ago is a good illustration of this prioritisation. Indeed, because of the increased shale gas exploration, the United States has increased coal exports to Europe. Thus, the European coal price dropped lower the gas price (with the economic recovery observed since 2010, the gas price has increased in international markets). Given that the European CO_2 price is currently lower than €6/t, it does not encourage a coal to gas switch. Thus, coal plants became increasingly competitive with gas plants. As a consequence, in April 2013, GDF Suez mothballed three of four Combined Cycle Gas plants (CCGs*): two for several months (Combigolfe and Spem) and one for an indeterminate period (Cycofos).
Thus, below €20/tCO_2, coal plants are the most cost-effective power plant type.

1.4.4.2 When the CO_2 price is more significant: from €20 to 65/t

When the CO_2 price increases, the carbon burden becomes significant for reference power plants. For instance, when the CO_2 price equals €40/t, reference coal plant LCoEs increase by 40% (+€30/MWh) and reference gas plant LCoEs increase by 15% (+€15/MWh)[28].
As a result, when the CO_2 price is not null, the investment decision depends on relative fuel

[28]For the record, the emission of a gas plant (0.337 tCO_2/MWh) is twice as low a coal plant (0.744 tCO_2/MWh) (Table 1.6).

prices and CO_2 costs.
From €20/t until €65/tCO_2, reference gas plants are the most profitable power plant type *i.e.* have the lowest LCoE. It means that when public authorities implement more stringent carbon pricing policies, they tend to favour gas plants over coal plants.
Note that as demonstrated in 1.5.5, the CO_2 switching price from coal- to gas-fired generation is very sensitive to fuel prices.

1.4.4.3 When the CO_2 price is between €65 and 115/t

Under this price range, coal-fired generation with CCS becomes more competitive than reference coal plants.
However, coal-fired generation with CCS has still a higher LCoE than gas-fired generation. This result is rather surprising since in the specialised literature, one can read that CCS coal plants become competitive when the CO_2 price is higher than €60-65/t. This results shows that in fact, when the CO_2 price exceeds €65/t the cost-effectiveness of CCS coal plants is relative (with respect to coal plants) but not absolute (with respect to gas plants).
Reference gas plants are thus the most cost-effective power plant type.

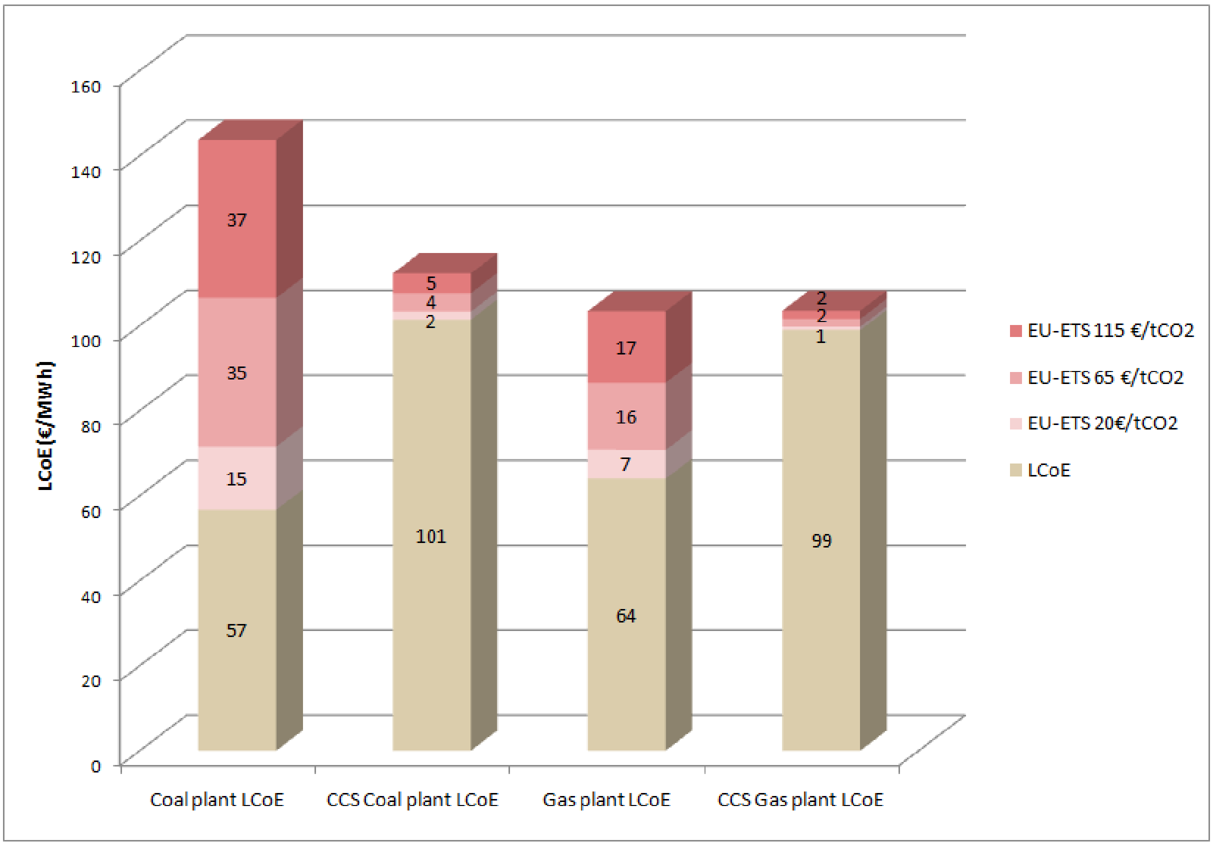
1.4.4.4 When the CO_2 price is higher than €115/t

Under this price range, CCS power plants become more cost-effective than reference power plants. More precisely, CCS gas plants rather than CCS coal plants have the lowest LCoE, except for ZEP (2011, [143]).
This result is surprising because the intra-technique CO_2 switching price is lower for coal plants than for gas plants (respectively €65 /t *vs.* €115/t). However, with their lower LCoE, CCGTs with CCS are potentially more attractive than CCS coal-fired plants in liberalised electricity markets. Recent reports (IEA, 2014 [119]), declarations and LSIPs tend to confirm this result. During ZEP's Assembly (2012), funding CCS gas pilots was a stated priority, and in England, the Peterhead CCS project is a CCS gas plant.
Nonetheless, it has to be pointed out that the relative appeal of CCS gas plants over CCS coal plants depends heavily on relative fuel prices (see 1.5.3).

1.4.4.5 Conclusion: for which CO_2 price is it worth investing in CCS plants?

To summarise, in European countries, the investment choice first depends on relative profitability due to fossil fuel prices. Currently, from €0 to 20/tCO_2, coal plants are the most cost-effective power plant type, but from €20 to 115/tCO_2, gas plants are the most cost-effective. Then, beyond €115/tCO_2, CCS (gas) power plants are the most cost-effective.
Using the distinction between intra- and inter-technique CO_2 switching prices, it was found that in the EU, contrary to common beliefs, CCS coal plants are not profitable beyond €65/tCO_2, a price at which they are more profitable than reference coal plants but are less cost-effective than gas plants (Figure 1.8).

Figure 1.8: Average LCoEs of the different power plant types for several CO_2 price scenarios.



1.5 Sensitivity analyses

As one of the objectives of this Chapter is to provide reliable information on key factors affecting the economics of electricity generation using several technologies (e.g., ultra-supercritical coal plants, post-combustion/pre-combustion/oxy-combustion coal plants, gas plants and post-combustion gas plants), sensitivity analyses were performed for the standardised parameters: capture rate, load factor, construction time, lifetime, fuel prices, discount rate and plant efficiency (Table 1.7). Parameters were changed independently, *ceteris paribus*, to compare their relative impact on LCoEs and CO_2 switching prices[29].

Only discount rate, fuel prices and load factor variations have a real impact on LCoEs and CO_2 switching prices in the model (Tables 1.8 and 1.9). This result is interesting because there are uncertainties regarding these parameters whose related risks are real for energy markets.

[29]The arbitrations between the different power plant types are not always very clear. Therefore, sensitivity analyses have been drawn for both intra- and inter-CO_2 switching prices.

Table 1.7: Parameters used to perform sensitivity analyses.

Standardised parameters	**Unit**	**Values**	**Variations**
Capacity factor	%	85	42
Capture rate	%	90	-5
Plant efficiency			
CCS coal plant	*%*	*36% (2015)*	*± 1 point of %*
CCS gas plant	*%*	*52% (2015)*	*± 1 point of %*
Construction time			
Coal plant	*years*	*4*	*+1*
CCS coal plant	*years*	*5*	*+1*
Gas plant	*years*	*2*	*+1*
CCS gas plant	*years*	*3*	*+1*
Lifetime			
Coal plant	*years*	*40*	*-5*
Gas plant	*years*	*25*	*[-5;+5]*
Fuel price			
Black coal (Illinois n°6)	$\$_{2011}/GJ$	*2015: 4.34*	*±20%*
Natural gas	$\$_{2011}/GJ$	*2015: 10.55*	*±20%*
Discount rate	%	8	[-4;+4]

Table 1.8: Sensitivity analysis results on European LCoEs.

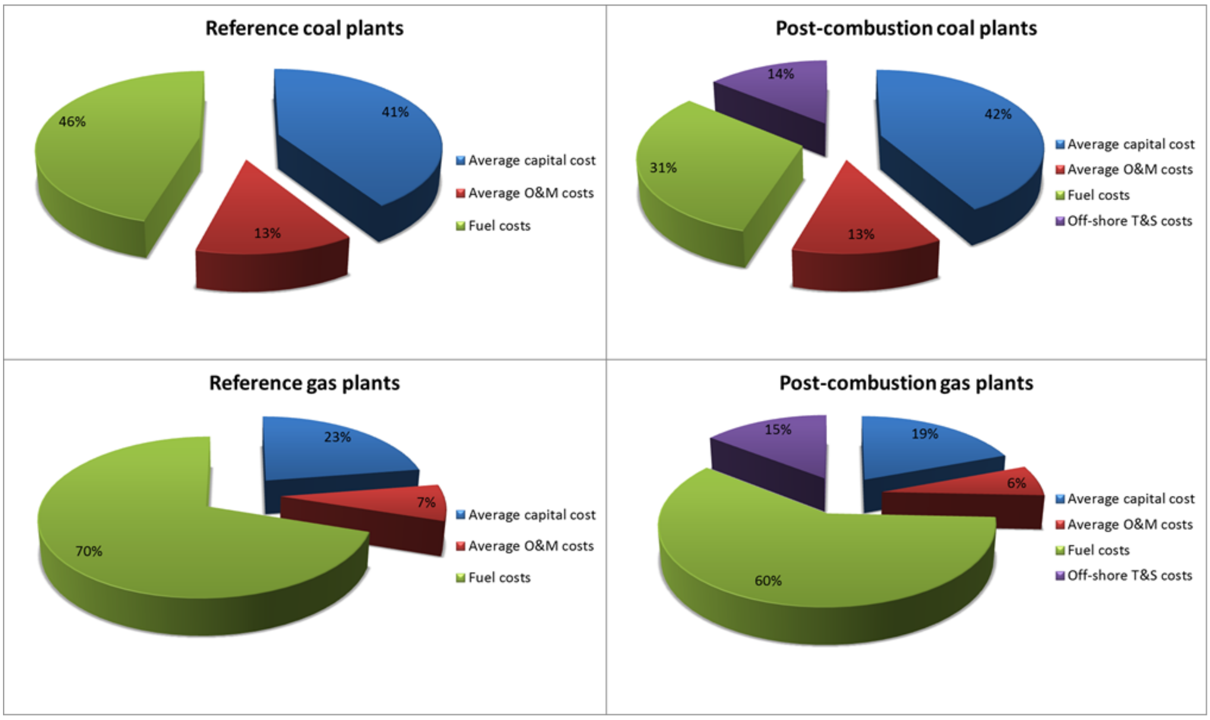
	BAU [€/MWh]	Discount rate: ± 4 pts of %	Coal price: ±20%	Gas price: ±20%	CCS gas eff.±1 pt	CCS coal eff. ±1pt	Mid-load
Coal plant	60	± 24%	±9%	-	-	-	48%
CCS coal	106	±28%	±7%	-	-	± 1%	49%
Gas plant	68	±6%	-	±18%	-	-	16%
CCS gas	104	± 7%	-	±13%	± 1%	-	22%

1.5.1 Sensitivity analysis on the discount rate

Electricity generation technologies do not share the same cost structure: for instance, coal plants (w/*[30] and w/o* CCS) require very high upfront overnight costs compared with gas plants (w/ and w/o CCS) that have lower upfront investment costs for entering the market but have variable fuel costs that outweigh capital costs in their LCoE. On average, for coal plants, the capital cost share in LCoE is 41% w/o CCS and 42% w/ CCS, the fuel cost share is 46% w/o CCS and 31% w/ CCS. On average, for gas plants, the capital cost share is 23% w/o CCS and 19% w/ CCS and the fuel cost share is 70% w/o CCS and 60% w/CCS (Figure 1.9).

[30] w/ stands for with and w/o for without.

Figure 1.9: LCoE decomposition for different power plant types.



Consequently, higher discount rates affect coal plants (w/ and w/o CCS) more than gas plants (w/ and w/o CCS) which have relatively lower investment costs[31]. In the EU, coal plant LCoEs are four times more sensitive to a 4 percentage point change in the discount rate than gas plants (Table 1.8). Note that CCS plants, which are more capital intensive, are more sensitive to a discount rate variation than reference plants: a 4 percentage point change in the discount rate leads to 4 additional percentage points of variation for CCS coal plant LCoEs with respect to reference coal plants and 1 additional percentage point of variation for CCS gas plant LCoEs with respect to reference gas plants.

1.5.2 Sensitivity analysis on the efficiency of CCS power plants

When the energy penalty caused by CCS device varies by ± 1 point of percentage, the LCoE of CCS plants is rather sensitive since it varies by ± 1% (Table 1.8).
More concretely, when the efficiency of a CCS gas plant varies by ± 1 point of percentage, the intra-technique CO_2 switching price varies by ± 4% and the CO_2 price to switch from a coal plant to a CCS gas plant varies by ± 3%. In the same way, when the efficiency of a CCS coal plant varies by ± 1 point of percentage, the intra-technique CO_2 switching price varies by ± 2% and the CO_2 price to switch from a coal plant to a CCS gas plant varies by ± 3%. The intra-technique CO_2 switching price for gas plants is more sensitive to energy efficiency variation than the one of coal plants because of their lower fuel cost weight in LCoE.

[31] Note that to compute the LCoE, one uses the following mathematical formula to convert the investment cost into a constant annuity: $\frac{Investment}{\sum_{k=1}^{n}\frac{1}{(1+discountrate)^k}}$. This conversion explains why an increase in the discount rate increases the constant annuity investment and thus the LCoE.

1.5.3 Sensitivity analysis on fuel prices

Fuel costs have a relatively lower impact than the discount rate on the LCoE of coal plants, (w/ and w/o CCS), in contrast with gas plants (w/ and w/o CCS): coal plant LCoEs are two times less sensitive than gas plants to a 20% change in fuel prices (Table 1.8). Indeed, coal plants require capital costs significantly higher than those of gas plants which reduces the impact of a fuel cost variation on LCoE. Despite thermal efficiency penalties, CCS plants are less sensitive than reference plants to a 20% fuel price variation (2 percentage points less) because the relative effect of the fuel cost variation on the LCoE is offset by the higher share of the capital cost in LCoE.

There is a gap between the current fuel prices observed in the EU and IEA's international fuel prices for 2015. In Tendance Carbone (May 2014, [22]), the European coal price is $75.7/t and the gas price (spot TTF) is €20.4/MWh[32]. A new simulation, based on these fuel prices, was performed to assess the impact of these different fuel price assumptions on LCoEs and CO_2 switching prices (sets of cost data for 2015/2020). On average, the CO_2 price triggering CCS profitability is €110/t. So this value is very close to the one got with IEA's assumptions (€115/t), and there is no major change in the merit order.

1.5.4 Sensitivity analysis on the load factor

As previously indicated, a standard load factor of 85% was chosen, which models power plants operating at base-load. However, it is likely that the share of renewables in electricity systems will become more significant in the future, particularly in developed countries like the EU. Thus, future CCS power plants might have to be operated on a more flexible intermediate load-basis[33]. To illustrate that point, the case of mid-load power-plants was studied. Note that only post-combustion capture was considered. Indeed, fossil plants with post-combustion capture are rather flexible, as the ramp rate and the start-up times do not seem affected by the capture unit or the minimum load with parallel trains. It is not the case for IGCCs and oxy-combustion plants which have an intrinsically constrained operating flexibility. The operating flexibility of IGCCs is relatively limited mainly because of the inertia of the gasifier and the air separation unit (ASU*) with a hot start-time of at least 6 hours. Regarding oxy-combustion plants, very little information has been published about their operating flexibility, but the load ramp rate and the start-up time are restricted by the ASU (Domenichini et al., 2013 [42]) (please refer to Chapter 2 for more details).

As there is no available public data, the extra-costs related to a mid- rather than a base-load operation (e.g., higher efficiency penalties) were not taken into account. Consequently, the related LCoEs and CO_2 switching prices correspond to an optimistic scenario.

By considering both base- and mid-load plants, with and without CCS, two questions are addressed: (1) If the investment concerns base-load plants, what is the CO_2 price required to make CCS plants competitive? Currently, coal plants are still operating on base-load in several Euro-

[32] Hansen and Percebois (2010, [74]) give the following conversion factor: $1\,MBtu = 293\,kWh$.

[33] The operating flexibility of a power plant can be assessed through four main criteria: ramp rates, minimum load, part load efficiency, cycling capability. This flexibility issue impacts the overall chain from the power plant source to the CO_2 injection. Although the flexibility of power plants with CO_2 capture has already been studied, the flexibility of the whole CCS chain is a relatively new issue with still quite few publications. For more details, see Chapter 2.

pean countries, such as Poland, Germany (lignite) and the United Kingdom. (2) If the electricity mix has a high share of renewables and if fossil plants are required to be more flexible, what is the CO_2 price that will trigger CCS investment in this scenario?
As coal plants with and without CCS have higher fixed costs than reference gas plants, their LCoE is three times more affected by the load factor variation from base- to mid-load. Of all generating technologies, gas, whose fuel cost most affects LCoE, is the least affected by the load factor variation. In other words, running or not running a gas plant makes a much smaller difference to the profitability of a project than running or not running a coal plant, given the latter's higher fixed costs. Likewise, because they are more capital intensive, CCS gas plants are more sensitive than reference gas plants to the load factor variation (6 additional percentage points of variation).
In line with the capacity payment idea, the difference between the LCoE of a CCS plant operating on base- and on mid-load (e.g., €50/MWh for CCS coal plants, Table 1.8) could be seen as the justification for subsidising CCS power plants, as the subsidy would encourage the plants to operate at a more flexible intermediate load-basis. This kind of subsidy could be particularly interesting in electricity systems with high renewable shares because it reduces the risk of return on capital expenditures.

To summarise, this analysis confirms that for capital intensive technologies such as coal plants (w/ and w/o CCS), the most important parameter affecting their LCoEs is the load factor, followed by the discount rate. The picture is partly reversed for gas plants (w/ and w/o CCS), whose key cost driver is the gas price followed closely by the load factor.

1.5.5 Sensitivity analyses and their effects on CO_2 switching prices

When the CO_2 price is null, base-load coal plants have the lowest LCoE for all scenarios in the EU except for when the discount rate is 12% (Tables 1.8 and 1.9).
Note that when fuel prices increase by 20% (respectively decrease by 20%), intra-CO_2 switching prices change little ($\pm$ 4% for coal, Figure 1.11; $\pm$ 4% for gas, Figure 1.12).
When the CO_2 price is not null, the European coal to gas CO_2 switching price exhibits a high sensitivity to fuel price fluctuations (Table 1.9). *Ceteris paribus*, when the coal price (gas price) varies by $\pm$ 20%, this CO_2 switching price varies by $\pm$ 70% (by $\pm$ 100%). As previously noted, gas-fired plants are very sensitive to fuel price variations. Thus, although gas price volatility is not necessarily a decisive issue for gas plant investors, because in many cases, gas plants are marginal plants that set wholesale electricity prices (pass-through), the absolute gas price level is important for investors facing the choice between gas-fired and alternative generation technologies (Figure 1.12).

Table 1.9: Sensitivity analysis results on European CO_2 switching prices.

		BAU	Discount rate: 4%	Discount rate: 12%	Coal price: ± 20%	Gas price: ± 20%	CCS coal eff. ± 1pt	CCS gas eff. ± 1pt	Mid-load
Intra-technique	Coal-CCS coal	67	-22%	35%	± 3%	-	-	± 2%	46%
	Gas-CCS gas	117	-9%	11%	-25%	± 4%	± 4%	-	30%
Inter-technique	Coal-gas	18	104%	-100%	∓ 71%	-100/ 142%	-	-	-100%
	Coal-CCS gas	60	11%	-17%	∓ 12%	± 28%	± 3%	-	-15%
	Gas-CCS coal	153	-48%	68%	± 17%	∓ 30%	-	± 3%	100%

In the EU, when the CO_2 price is high enough (approximately €115/t), base-load CCS gas plants are, on average, the most profitable power plant type except in two scenarios in which CCS coal plants are the most profitable: when the coal price is reduced by 20% (Figure 1.11) and when the discount rate is 4% (public policy rate, Figure 1.10). Gas-fired generation with CCS is thus potentially more attractive than coal-fired generation with CCS in liberalised electricity markets (for current European relative fuel prices). And CCGTs with CCS have an additional advantage on CCS coal plants: they have a lower emission factor and thus a lower exposure to the carbon price per megawatt (CCS plants have a 90% capture rate). However, in practice, the relative appeal of CCS gas plants over CCS coal plants is deeply linked with fossil fuel price assumptions. To be noted, fuel prices correspond to international fuel prices provided by the IEA (2012, [117]).

At mid-load, gas plants are the most competitive power plant type from €0 to 150/tCO_2 (Figure 1.13). Beyond €150/tCO_2, CCS (gas) plants have the lowest LCoE.

Consequently, when power plants operate with load factors significantly lower than 85%, gas plants have the lowest LCoE. CCS gas plants with mid-load factors are not remotely competitive until CO_2 prices are particularly high, and/or CCS costs are significantly reduced and/or policy mechanisms are implemented to support a more flexible operation of CCS plants.

Note that there are dedicated techniques to improve the operational flexibility of CCS plants by increasing peak power output (e.g., turning off CO_2 capture, storage of liquid oxygen or hydrogen, CO_2 buffer storage, etc.). These techniques should increase CCS competitiveness (see Chapter 2).

Figure 1.10: Sensitivity of the power plant type with the lowest LCoE to a ± 4 points of % of the discount rate variation.

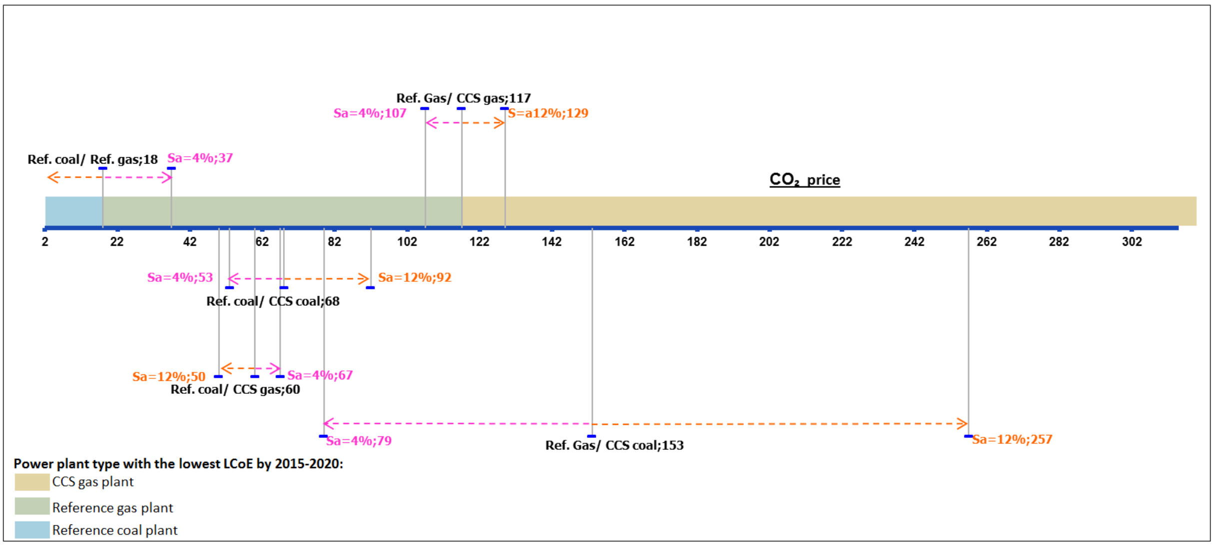


Figure 1.11: Sensitivity of the power plant type with the lowest LCoE to a ± 20% of coal price variation.

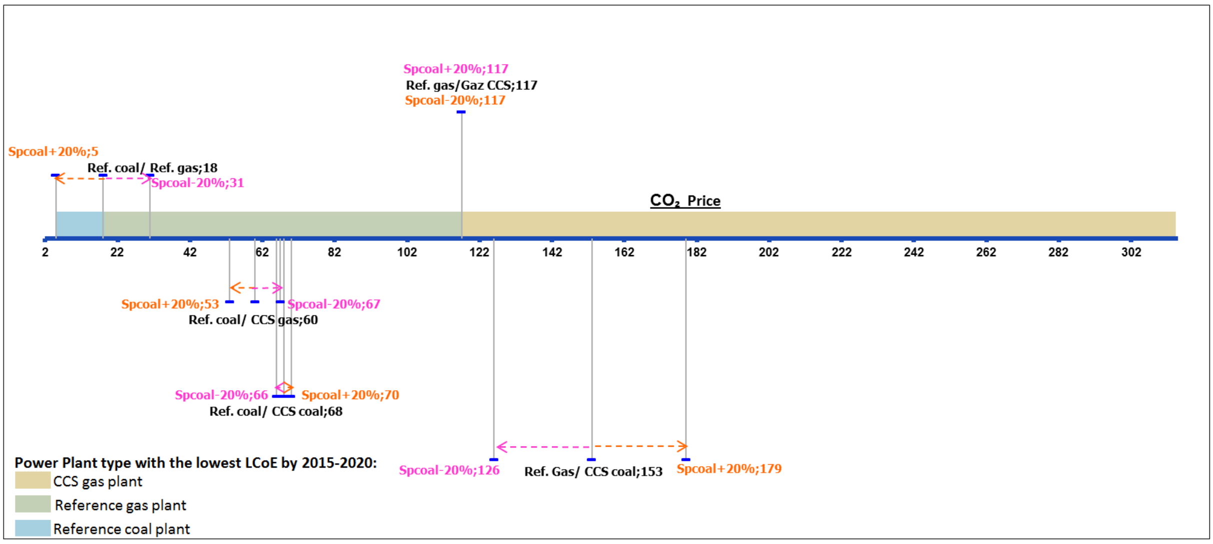


Figure 1.12: Sensitivity of the power plant type with the lowest LCoE to a ± 20% of gas price variation.

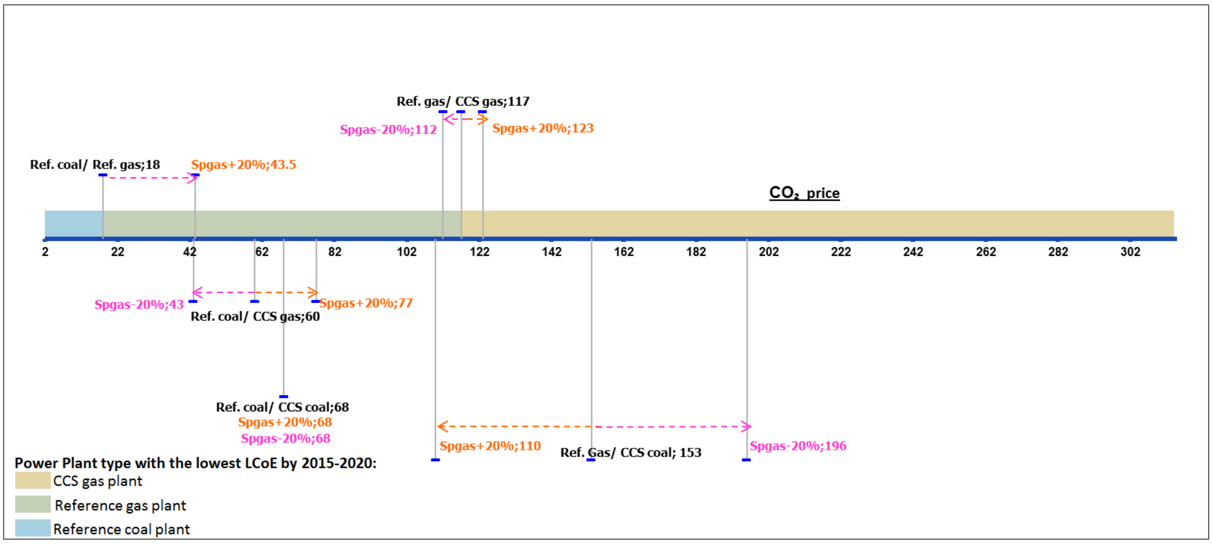
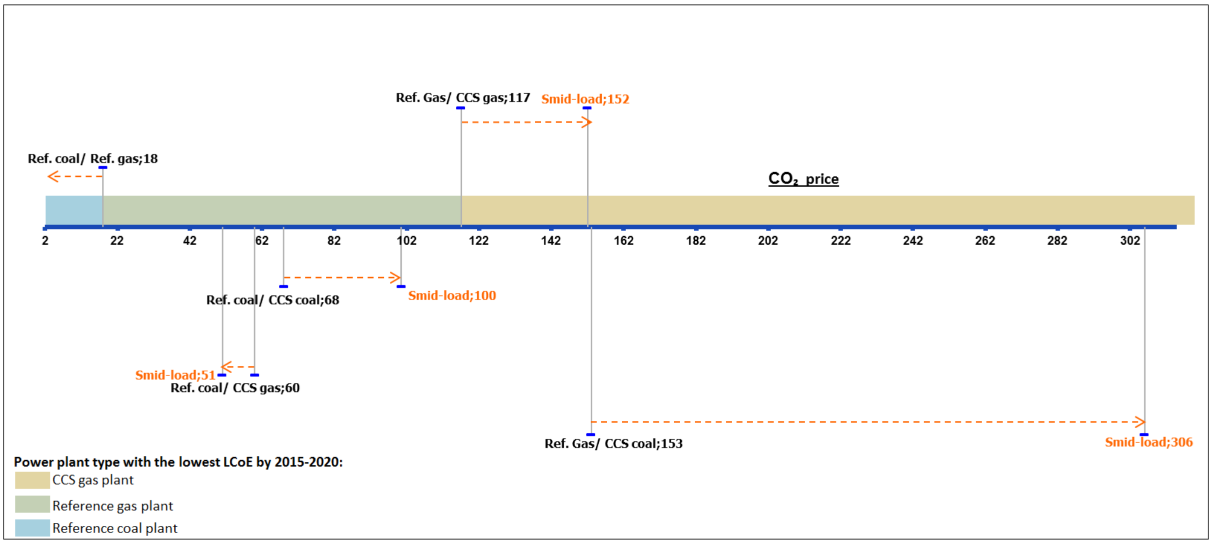


Figure 1.13: From base-load to mid-load: Sensitivity of the power plant type with the lowest LCoE by 2015-2020.



1.6 To go further: focus on the 2030 horizon

According to several studies, CCS techniques could be fully mature by 2030. Thanks to R&D investments, economies of scale and learning-by-doing effects, the costs and energy efficiency of CCS plants should be improved. As a consequence, the CO_2 price required to switch from reference plants to CCS plants should be significantly reduced (Rubin et al., 2007 [129]; Jones et al., 2012 [89]; IEA, 2013 [118]).

1.6.1 CCS cost reduction from 2015 to 2030

As explained in 1.3.2, CCS plants have higher LCoEs than non-CCS power plants because they require:

- additional capital equipment cost to capture, compress, transport and store the emitted CO_2,
- additional energy to run the CO_2 separation and compression,
- additional operating costs due to the consumption of solvents and other chemicals (catalysts, chemical reagents, etc.) as well as the formation of waste products.

There are thus potentially three levers to reduce CCS costs.

Economies of scale are expected to significantly reduce the cost of several CCS equipments (DECC, 2013 [35]). Among them, there are: ASU (Air Separation Unit) cold boxes, air and CO_2 compressors, pumps, heat exchangers, columns (distillation, absorbers, regenerators) and gasifiers.
Incremental innovations and/or improvements in existing capture technologies are also expected to decrease significantly CCS costs between 2015 and 2030. Indeed, as the DECC (2013, [35]) and the IEA (2013, [118]) underline, there are currently several technology improvements, developed at the pilot-scale, which represent potential cost savings in the late 2020. Among them can be found, for instance, solvent improvements or alternative solvents (to amines) to reduce regeneration energy needs (pre- and post-combustion carbon capture), and corrosion issues, or improvements in critical equipment performances like column packing, CO_2 compressors and heat exchangers.
Improvements of design, capture integration process, or in materials of construction are also expected to decrease CCS costs between 2015 and 2030.
Radical innovations could also reduce dramatically CCS costs in the late 2020. These novel techniques have only been identified: they require continued R&D efforts. Among them, the DECC (2013, [35]) and the IEA (2013, [118]) emphasise: alternative technologies like flue gas recirculation for gas plants with post-combustion capture as well as oxy-fired gas turbines, advanced oxygen production technologies (e.g., membrane) to reduce the cost of oxygen and consequently oxy-combustion costs, chemical looping which can be considered as an advanced oxyfuel process whereby the ASU disappears, advanced post-combustion capture or hybrid capture systems with novel regeneration methods (e.g., electrolysis and electrodialysis) which have the potential to drive a step change reduction in energy consumption.

Consequently, CCS power plants should be less expensive and thus more attractive in 2030. Thus the question is: how much cheaper advanced CO_2 capture systems will be as regards to current technology.

1.6.2 Assumptions and scope of the analysis

To more precisely assess CCS costs in 2030, the most recent studies are used: DECC's (2012 [34], 2013 [35]) which calculate costs for 2013, 2020 and 2030. Note that to forecast CCS costs in 2030, the DECC refers to Rubin et al. (2007, [129]) which is considered as the reference[34].
ZEP (2011, [145] [144]) does not give projections for carbon transport and storage costs in 2030. As DECC's low-cost path is "broadly in line with ZEP estimates for early commercial costs", carbon transport and storage costs for 2030 are from DECC's study (2013, [35]). These costs correspond to offshore infrastructures[35]: €2.9/MWh for gas plants and €6.8/MWh for coal plants.
Wu et al. (2013, [142]) consider CCS costs in 2030 by reducing capital and O&M costs, but they do not modify their fuel price assumptions. This constant fuel price scenario has the advantage of isolating the effects of learning-by-doing and economies of scale (Table 1.10, Scenario 1), but it is rather unrealistic. Thus, an international fuel price scenario based on IEA projections ("New Policies scenario", 2012 [117]) (Scenario 2) was also introduced in this Chapter.

Table 1.10: Fuel price assumptions for the EU in 2030.

	Scenario 1: constant fuel prices (IEA, [117])	**Scenario 2: fuel prices** (IEA, [117])
Natural gas imports in 2030 $\$_{2011}$/MBtu	11	12.2
Steam coal imports in 2030 $\$_{2011}$/t	108.5	114

1.6.3 Main results

The below results corresponds to scenario 2 which is more realistic (Table 1.10).

For the EU in 2030, there is no projected change in the merit order (Table 1.11).

From €0 to 20/tCO_2, coal plants have the lowest LCoE, and then, from €20 to 85/tCO_2, gas plants are the most profitable power plant type. CCS gas plants have the lowest LCoE beyond €85/tCO_2 compared to the €115/tCO_2 threshold in 2015 (1.4.3).
Note that the European profitability frontier between CCS gas plants and CCS coal plants is thin.

[34] Historical experience curves are used for estimating future cost trends for CCS power plants. Rubin et al. (2007, [129]) first assess the rates of cost reductions achieved by other energy and environmental process technologies in the past. Then, by analogy with leading capture plant designs, they estimate future cost reductions that might be achieved by power plants with CO_2 capture.

[35] Onshore pipe of 30 km and offshore pipe of 300 km. The storage is not a saline aquifer but a depleted oil and gas field (less expensive).

By 2030, without specific support measures, European CCS power plants are thus projected to be the most profitable given the CO_2 price threshold of €85/tCO_2, in contrast to the IEA forecast of €30/tCO_2 (2012, [117])[36]. The large gap between these two CO_2 values is a good indicator of the extent of policy measures that the EU should undertake to make CCS competitive and thus emerge. As the long term economic profitability of CCS plants depends on the carbon price, revitalising the EU-ETS is essential (De Perthuis and Trotignon, 2014 [32]). Additional measures are also required to encourage developers of large scale CCS demonstration project to take final investment decision (ZEP, 2012 [146]) (see 1.7).

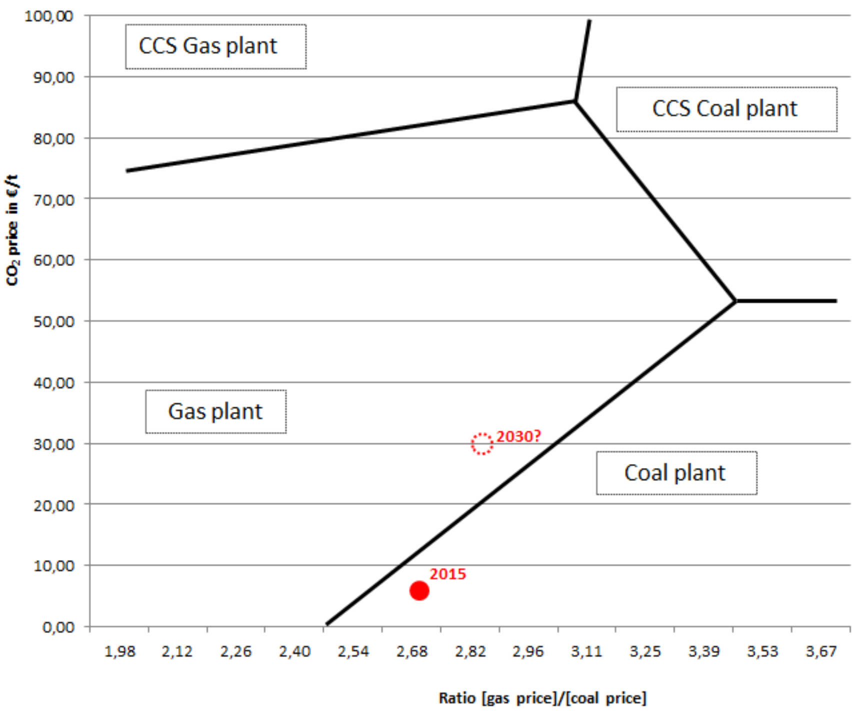
If no policy measure is implemented to support CCS deployment, revitalize the EU-ETS, and provide a secure framework *i.e.* "a credible and predictable pathway for the gradual deployment of CCS" (ZEP, 2012 [146]), European investors would have interest in choosing non-CCS plants from an economic point of view (Figure 1.14). Given our assumptions, in 2030, gas plants are potentially more attractive than coal plants in liberalised electricity markets, particularly if power plants are required to operate at mid-load. In that case, gas plants have the lowest LCoE, and CCS (gas) plants become competitive beyond €130/tCO_2.

Table 1.11: European CO_2 switching prices by 2030 - offshore T&S costs.

		2015	2030 - Scenario 1	2030 - Scenario 2	2030 - Scenario 2 Mid-load
Intra-technique	Coal to CCS coal	67	35%	-3%	46%
	Gas to CCS gas	117	11%	-	30%
Inter-technique	Coal to gas	18	-100%	71%	-100%
	Coal to CCS gas	60	-17%	12%	-15%
	Gas to CCS coal	153	68%	-18%	100%

[36] 2030 fuel and CO_2 price assumptions are indicated by the dotted red circle on Figure 1.14.

Figure 1.14: Profitability areas for the different power plant types based on fuel price ratio and CO_2 price in the European Union. Simulations on DECC's studies (2012, 2013), offshore T&S costs.[a]



[a]Methodology from Blyth et al. (2007, [19]). The gas price varies by more or less 30% whereas the coal price is fixed. Interpretation: when the fuel price ratio equals 2, the gas price is twice as high as the coal price.

1.7 Conclusion

1.7.1 CCS is a promising technique but a current weak CO_2 price threatens its demonstration and deployment...

A methodology has been developed to objectively compare the sets of CCS cost data provided by public studies.
Then, it has been emphasised that several CO_2 switching prices can be distinguished. To know which particular type of power plant is the most profitable investment, both intra- and inter-technique CO_2 switching prices need to be taken into account. This distinction have pointed out that in the EU, contrary to common beliefs, CCS coal plants are not profitable beyond €65/tCO_2, a price at which they are more profitable than reference coal plants but are less cost-effective than gas plants.
Given current power plant costs and international fuel price assumptions (IEA, 2012c), a CO_2 price of €115/tCO_2 is required for CCS (gas) plants with offshore carbon T&S costs to become the most profitable power plant type in the EU.

The result claiming that CCS gas plants have a lower LCoE than CCS coal plants (Renner, 2013 [126]) has also been emphasised by the IEA's latest report (2014, [119]): "CCGT with CCS has a lower levelised cost of electricity (LCOE) than CCGT alone, and is less costly than ultra-supercritical pulverised coal with CCS". However, this result shall be nuanced.

- Global context *vs.* local context
  As previously underlined, the results are obtained with international fuel prices. Given the sensitivity to fuel prices (see 1.5.3), conclusions can differ significantly with a local assessment (e.g., local coal like in Poland, or, in the future, an European shale gas production). Consequently, only strong confidence in fuel price assumptions can ensure a strong preference of CCS-gas over CCS-coal.
  In addition, natural gas is not (currently?) an endogenous European resource: for instance, one cannot exclude that the current context with Russia might lead to a rush for gas. The security of supply issue might call into question the preference of CCS gas over CCS coal.

- Results are cost-data dependent
  Some studies, particularly ZEP's, show that CCS coal is more competitive than CCS gas. This result introduces uncertainty about the relative appeal of CCS gas over CCS coal.
  In addition, for comparison purposes, similar carbon transport and storage costs are sometimes applied to CCS gas and CCS coal plants. However, on a MWh basis, a CCS gas plant captures and stores half the amount of CO_2 compared to a CCS coal plant. Given the smaller volume involved per MWh produced, there are therefore fewer economies-of-scale for the transport and storage of CCS gas. Thus, it is quite possible that the CO_2 from CCS-gas will cost more to transport and store than the CO_2 from CCS-coal (the profitability of carbon transport and storage infrastructures depends on the amount of transported CO_2).

In 2030, the CO_2 price required to trigger CCS investment is lower: €85/tCO_2 in the EU (CCS gas plants). There is thus a large gap between the CCS CO_2 switching price (higher than €85/t) and the forecast CO_2 price (€30/t in EU-ETS): significant policy measures to make CCS competitive and revitalise the EU-ETS are thus required in the EU.

1.7.2 ..requiring specific measures to support CCS deployment from its early pilot and demonstration scale through to wide scale

1.7.2.1 Supply push *vs.* demand-pull?

CCS needs thus specific tools to encourage its deployment from its early pilot and demonstration scale through to wide scale. As for support instruments, the standard economic literature distinguished between (Bonnet and Renner, 2013, [20]):

- Supply push instruments (working on supply): they are involved in the initial stages of the process by supporting innovation on products and production techniques without focusing on consumer's needs.
  Supply support instruments help the "absorption capacity" of new technologies/products,

i.e. the propensity of an industry to integrate and put in practice the opportunities offered by the innovation. Support for supply therefore primarily promotes radical innovations. State support is of major importance for the development of radical innovations, since they are "discrete, discontinuous events usually involving deliberative effort; and they may have only a minor relatedness to existing products" (Nemet, 2009 [110]). Last but not least, supply support instruments can favour national firms (regional/national policy).

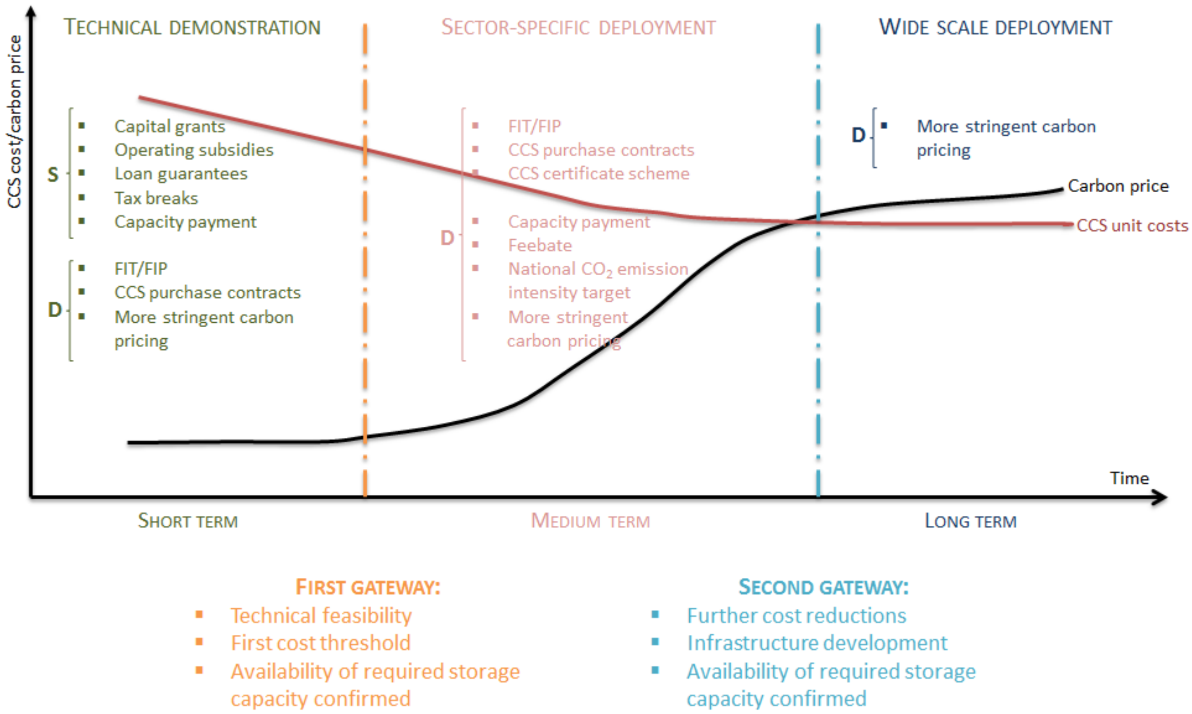
- Demand-pull instruments (creating and stimulating demand): they are involved in the downstream part of the process by ensuring that there is a market for the new product/production technique, to provide investment security through the existence of private income.
  Demand is an effective driver of innovation: the size of the market and consumer expectations influence the private income that the innovative firm gets from a product or a production method. The main limitation of this kind of support is that it focuses on existing consumer needs and can be ineffective in stimulating fundamental research because any potential market emerges in the long term and involves a high level of uncertainty (intrinsically linked to political and legal developments). Thereby, support for demand primarily promotes incremental innovations and diffusion (favour most mature technologies).

The debate on the instruments to implement to better stimulate innovation goes back to the 1950s, or even further by referring to Say's Law (1803, [133]) or to the demand stimulus advocated by Keynes (1936, [94]). However, in recent years, a consensus as for the complementarity of these two types of instruments has emerged. A CCS policy based on supply may be very costly for governments and the results may be disappointing, while support for demand, even if strong, has difficulty in triggering radical innovation. Policies to support supply emphasise companies Research, Development and Diffusion (RD&D*) efforts, while policies to support demand create the niche market that precedes commercial deployment, by protecting innovative companies from competition and enabling them to build up the necessary skills for innovation.

1.7.2.2 A combination of supply-push and demand-pull instruments with a gateway approach to support CCS deployment

To support CCS, the IEA and ZEP advocate "a policy framework where the policy mix would evolve over time, with explicit phases of policy punctuated by break points or ‟gateways″" (IEA, 2012 [116]). Consequently, support measures would be "designed with clear sunset clauses to phase them out when the market failures they are created to address diminish in importance as the technology matures" (ZEP, 2012, [146]). Short-term (-2020), medium-term (2020-2030) and long-term (beyond 2030) support tools are thus distinguished, each period addressing specific issues related to CCS deployment. Short-term support tools are mainly supply-push instruments whereas long-term support tools are mainly demand-pull instruments (Figure 1.15).

Figure 1.15: CCS policy framework including gateways.



Source: IEA (2012, [116]) and ZEP (2012, [146]).

ZEP (2012, [146]) provides an assessment of the different instruments listed in Figure 1.15. This assessment (Table 1.12) shows that, each support tool presents pros and cons, which is hardly surprising.

Table 1.12: ZEP's assessment of CCS support measures.

Policy tool	Economic impact effectiveness	Environmental effectiveness	Cost effectiveness	Ease of application	Political acceptability	Total
Capital grants (e.g., structural funds)	Payment over short period of time: +	No guarantee of operations if uneconomic in current market unless combined with other incentives, or a claw-back clause is included: ++	Should be done competitively; lower cost of capital for government: 0	++	Claw-back clause for non-performance would enhance acceptability: 0	+
Operating grants (e.g., NER300)	++	++	-	+	-	+
Loan guarantees	++	No guarantee of operations if uneconomic in current market unless combined with other incentives, or a claw-back clause is included: –	++	++	++	+
Tax breaks	+	Depends on condition: -	0	++	Claw-back clause for non-performance would enhance acceptability: 0	0

Table 1.12: ZEP's assessment of CCS support measures -Continued.

Policy tool	Economic impact effectiveness	Environmental effectiveness	Cost effectiveness	Ease of application	Political acceptability	Total
Capacity payments	Helps to get demo projects started: ++	No guarantee of operations if uneconomic in current market unless combined with other incentives, or a claw-back clause is included: –	Could be managed through a competitive process: 0	Raises question of how to deal with moral hazard: 0	Already used in electricity markets, but for different purpose: ++	+
Feed-in-tariff	Contract law guarantees feed-in-tariff for economic lifetime of project: ++	Only payment for actual generation of power with CCS (clarity needed on verification of actual storage): ++	Risk of under- or over-funding, but risk premium of investor very small. No upfront payment increases capital costs. Could be combined with electricity purchase obligation: 0	In demonstration phase, needs to be more project-specific, evolving into a pure feed-in tariff as the technology matures. Administratively easy, but setting correct level presupposes cost discovery. CCS providing base-load may require more balancing capacity in grid: +	Already successful for RES. Bill can be passed on to electricity consumers or tax-payers (flexible): ++	++
CCS purchase contracts through reverse auctions	Reverse bidding for CCS leading to contract with government has a low political risk: ++	Only payment for actual CO_2 abatement: ++	Lowest-cost projects delivered, but sponsors need to take development risk. No upfront payment increases capital costs. Would be enhanced if organised as project contracts with government: ++	In principle easy following cost discovery, provided sufficient competition: +	Already used for RES. Bill can be passed on to electricity consumers or taxpayers (flexible): ++	++
CCS certificate scheme	Certainty that lowest-cost CCS projects will be funded, but no long-term guarantee for investors that certificates from their project will always be preferred: +	Only payment for actual CO_2 abatement: ++	Lowest-cost projects delivered, but sponsors need to take development risk. No upfront payment increases capital costs. Investors will require risk premium to compensate for uncertain demand for certificates from individual projects: +	In principle easy following cost discovery, provided sufficient competition: +	Already used for RES. Bill can be passed on to electricity consumers or tax-payers (flexible): ++	+
Emissions Performance Standards for power plants, with exemption and transitional periods	Provides little investment incentive: -	Effective in controlling emissions, but does not support level playing field: 0	Can be costly by setting same standards for all players: -	Standards are vulnerable to lobbying, but relatively easy to enforce: ++	Would probably be acceptable if technology is mature and cost is low: ++	0

As underlined by the ZEP (2012, [146]), feed-in-tariffs and CCS purchase contracts score rather well on economic impact, environmental effectiveness and political acceptability. Note that these two tools[37] were chosen by the UK, the CCS European leader, to support CCS deployment, as well as capital grants (£1 billion capital funding to support the UK's first commercial-scale

[37] FITs* are linked with contracts for difference to give stable revenue streams for producers of low-carbon electricity. By reducing the operating risks, this kind of support can incentivise private sector investments in CCS projects.

CCS projects), a capacity market, Emission Performance Standards (EPS)[38] and a Carbon Price Floor (CPF*)[39].
Hereafter, Box 2 analyses what could be the best measures to support CCS deployment in France given the national potential of this technology.

Box 2. A CCS case-study: France
The French energy industry sector[a] represents only 12% of national GHG emissions with 57 Mt$CO_2 eq.$[b]. Indeed, made of 53.3% nuclear[c] and 15.7% hydro electricity[d], the French electric power mix has a low carbon content, fossil fuel plants being only used in mid-peak hours or to meet peak loads. Thus, one could say that France does not have a favourable electricity market for CCS deployment.
However, this nuclear power could be reduced in the next few years according to national policy options. Indeed, the French law "La transition énergétique pour la croissance verte (2014, [12])" plans to reduce the nuclear proportion in the electric power mix to 50% by 2025. According to RTE (Bilan prévisionnel 2014, [127], scenario "Référence"), in 2020, coal plants will produce 17.1 TWh while gas plants will produce 13.4 TWh. Assuming that all coal and gas plants would have a CCS disposal, the total amount of CO_2 emissions that could be captured is approximately 19 Mt/yr (74% from coal plants, 26% from CCG plants)[e].
In addition, CCS deployment may find a strong echo among carbon-intensive industries - iron and steel, cement, petroleum refineries and petrochemicals -, where technical options to reduce dramatically GHG emissions are scarce.
Last but not least, French expertise exists both among European industrials - Total, Alstom, Air Liquide, Schlumberger, etc. - that are positioned on all CCS segments and are used to collaborate, and among internationally recognised research organisations - BRGM, IFP, CCG Veritas, etc. -. Thus, potential synergies between these European industrials and research centres could give to France/the EU a comparative advantage in CCS techniques that could be further exported.
Yet, France has only 2 CCS pilots: Lacq (monitoring stage) - integrated CCS pilot (gas plant, oxy-combustion), led by Total, 60,000 tCO_2 captured for 2 years (2011-2013), investment cost of €60M - and Le Havre - CO_2 capture (coal plant, post-combustion), led by EDF, Alstom and Dow Chemical started in 2013 and stopped as planned in 2014, investment cost of €22M funded up to 25% by the French environmental agency Ademe.
In this context, national CCS deployment needs strong incentive policies that would vary over time (with technology maturity and climate policies) to support first-mover demonstration projects and wider deployment. In the short-term, 2015-2020, policy mechanisms that seem most appropriate to French semi-base load fossil fuel plants are: 1st capital and operating grants (certainty), Feed-in-tariffs with a sliding premium scheme (merit-order respected) and 2nd *ex-aequo* CCS purchase contracts (merit-order not respected but more attractive for

[38] A standard of 450 gCO_2/kWh was set to ensure that no new-coal plants above 50 MW are built without CCS.
[39] The CPF came into effects in April 2013. It corresponds to the CO_2 price from the EU-ETS plus the carbon price support rate per tCO_2 which is the UK-only additional tCO_2 in the power generation sector. It reduces investment uncertainty and reinforces the incentive to invest in low-carbon generation technologies.

developers than FITs). Public loans and forward CCS contracts (risk management measure rather than a subsidy) can be considered in parallel with capital and operating grants. In the mid-term (2020-2030), a capacity market (capacity remuneration covering partially the fixed costs) could take over capital and operating grants, with public loan guarantees in parallel. In the long term (beyond 2030), the most adapted CCS support measures should be European rather than French (more ambitious EU-ETS cap, EUA reserve price auction, etc.). EPS does not seem appropriate for France because it could compromise the flexibility of electricity supply if EPS does not recognise well the different operating regimes needed for power supply.

[a] Electricity and heat generation, excluding Land-Use Change and Forestry. Source: Citepa, 2013.

[b] Contrary to the European Union (EU) where the energy sector is the largest emitter of greenhouse gases (GHG) (26%). Source: Citepa, June 2012.

[c] 74.1% of the produced electricity in 2012, source: EDF Group (2014).

[d] 8.5% of the produced electricity in 2012.

[e] Before capture, CCS coal plants emit 0.930 tCO_2/MWh, CCS gas plants emit 0.388 tCO_2/MWh. The capture rate is 90%.

1.7.2.3 Combining both short- and long-term cost-efficiency approaches to create a secure environment for CCS investment

To go further in the creation of a stable environment encouraging CCS investment, one should differentiate two stages in the decision process:

- In the long term, the LCoE is one of the key indicators for investors. As previously noted, the LCoE is the long term price required to bring forward investment in a specific technology, as well as a useful tool to compare the costs of several power generation technologies. Utilities often select the lowest cost type of generation when determining which kind of new power plant to build. As a consequence to trigger CCS investment, specific measures are required to cover the gap between the full cost of a CCS power plant and a non-CCS power plant or other competitive low carbon technologies.
  Support measures compensating for the higher costs of CCS plants with respect to conventional plants are as follows:

  - Capital grants,

  - Loan guarantees,

  - Tax breaks and

  - Capacity payment: the capacity market provides a regular payment to reliable forms of capacity. In return, such capacity needs to be available during peak periods. Capacity payments are designed to bridge the gap due to CCS fixed extra-costs (not variable extra-costs).

- In the short-term (day-to-day), the key indicator for a power plant operator is the Short Run Marginal Cost (SRMC*) (with respect to the market price).
  Indeed, to minimise the costs of electricity production, available sources of energy (solar plants, coal/gas plants, nuclear plants, etc.) are ranked in ascending order of their SRMC

of production, so that plants with the lowest marginal costs are the first ones to be brought online to meet demand. The dispatch cost of a plant is composed of its variable operating cost and its fuel cost which is intrinsically linked with the plant efficiency[40]. CCS plants have a lower efficiency than non-CCS plants: when the CO_2 price is low, CCS dispatch cost is thus higher. As a result, their location on the dispatch curve shifts such that it will be relatively less economic for these plants to be turned on. It is not a real problem when every power plant is equipped with CCS: the entire dispatch curve shifts, and the relative position of power plants in the merit order is not dramatically changed. However, when there are only a few CCS power plants, their dispatch costs can be so affected that they do not dispatch electricity as often, unless particular support measures are implemented. As a consequence, specific tools are needed to ensure that CCS plants are dispatched over their lifetime. Support measures granting priority to CCS when they are running are the following:

- FIT (fixed remuneration guaranteed for a specified period) or FIP* (additional premium in addition to the electricity market price): they can oblige grid operators to enable CCS plant operators to connect to the grid and guarantee grid access for their electricity supply, as well as fixed remuneration.

- Operating subsidies.

- CCS purchase contracts.

CCS support mechanisms enabling the filling of the LCoE and SRMC gaps existing between CCS plants and non-CCS plants could be particularly interesting, combining both the short- and the long-term approach.
Among these specific support tools, one can refer to the UK that has implemented feed-in-tariffs combined with contracts for difference (CfDs*): under CfDs, operators will get operational support, a top-up payment that pays the difference between the LCoE (long term price needed to trigger CCS investment) and the market price.
Subsidies, a higher carbon price as well as a CPF (UK) are also both long- and short-term support measures.

The Table (1.13) below compares long-term CO_2 switching prices (the CO_2 price required to fill the gap between the LCoE of plant A and the LCoE of plant B) and short-term CO_2 switching prices (the CO_2 price required to fill the gap between the SRMC of plant A and the SRMC of plant B).
Please, note that long-term CO_2 switching prices are presented in Table 1.11. In 2020, intra-technique CO_2 switching prices are approximately: €65/t for CCS coal plants and €115/t for CCS gas plants. When the CO_2 price exceeds one of these thresholds, it sends a positive signal to investors and can trigger CCS investment.

[40]Capital and other fixed costs are not taken into account in day-to-day operations.

Table 1.13: Long- (LT) and short-term (ST) CO_2 switching prices in the EU.

		LT CO_2 switching prices		**ST CO_2 switching prices**	
		2015-2020	2030	2020	2030
Intra-technique	Coal to CCS coal	65	65	15	15
	Gas to CCS gas	115	85	40	40
Inter-technique	Coal to gas	20	20	95	105
	Coal to CCS gas	60	50	70	75
	Gas to CCS coal	155	135	-120	-130

Cost data are from the DECC (2013, [35]), fuel price assumptions from the IEA (2012, [117]) (Table 1.6) and exchange rates (euro/dollar and pound sterling/euro) are from the IEA (2014, [120]). Note that power plant efficiencies, with and without CCS, differ from 2020 to 2030 (Table 1.6).

Once the CCS investment is realised, the key indicator for power plant operators is short-term CO_2 switching prices. In Table 1.13, it can be observed:

- For CCS Coal plants:

  With respect to gas plants, CCS coal plants are naturally brought on line to meet the demand (negative short-term CO_2 switching price). As a consequence, with respect to gas plants, CCS coal plants do not need particular support to ensure their priority dispatch.

  Similarly with respect to coal plants, when the CO_2 price is higher than €15/t, CCS coal plants do not need specific support giving them priority access to the grid.

- For CCS gas plants:

  With respect to gas plants, CCS gas plants are naturally brought on line in the merit order when the CO_2 price is higher than €40/t.

  The SRMC of CCS gas plants becomes lower than the SRMC of coal plants beyond €70/t (€75/t in 2030).

- Finally, the switch from coal to gas plants is not cost-effective (higher value than all the other CO_2 switching prices).

To summarise, when the CO_2 price is higher than €15/t, CCS coal plants are naturally brought on line to meet demand since their SRMC is lower than the SRMC of non-CCS plants. According to IEA's forecasts (2012, [117]), the European CO_2 market price would approximate to €20/t in 2020 and to €30/t in 2030. Therefore, no particular support may be necessary to ensure that CCS coal plants will be well ranked in the merit-order (Table 1.14). This result is rather reassuring for investors in CCS coal plants.
However, for CCS gas plants, the CO_2 price required to guarantee them a continuous operation with respect to CCS gas plants is approximately €40/t (and €70-75/t with respect to coal

plants). Consequently, in contrast to the CO_2 market price forecast by the IEA (2012, [117]), additional support will be required to make CCS gas plants dispatch electricity (Table 1.14). To summarise, when considering the short-term vision, CCS coal plants might be more cost-effective than CCS gas plants, whereas when considering the long-term vision, CCS gas plants might be more attractive than CCS coal plants. This result introduces additional complexity to design efficient economic supports for CCS demonstration.

Table 1.14: Short Run Marginal costs in 2020 and 2030.

	Coal plants	CCS coal plants	Gas plants	CCS Gas plants
SRMC in 2020	41	37	71	78
SRMC in 2030	46	36	73	76

One could nuance the previous results by taking into account carbon transport and storage costs. Indeed, they represent a significant burden for CCS plants. Thus, to really guarantee that CCS plants will continuously operate when available (lower SRMC than non-CCS plants), it could be relevant to add transport and storage costs to CCS short-term CO_2 switching prices. By assuming for example, that one tonne of CO_2 costs €15 to transport and store, the short-term CO_2 price required for CCS coal plants is around €30/t, and is approximately €55/t for CCS gas plants (with respect to gas plants; €85/t with respect to coal plants). By comparing these short-term CO_2 switching price values with IEA's forecasts (2012, [117]), additional support will thus be necessary to grant priority grid access for CCS plants, particularly for CCS gas plants.

Finally, CCS plants required to operate with a certain degree of flexibility because of the large penetration of RES (Chapter 2) may deserve specific support measures. Indeed, the CO_2 price required to trigger CCS investment is significantly higher when power plants operate with a load factor lower than 85%. Nonetheless, CCS plants need to operate at high load factor to recover their high capital costs. Rewarding the ancillary services provided by flexible CCS plants could help investors to cope with the higher capital and operating costs due to CCS.

Complementary to relevant economic supports for CCS demonstration, governments need to explicitly announce the proportion of CCS plants in their future energy mixes through credible long-term deployment strategies and commitments. The UK Government seems to be moving in this direction: its Electricity Market Reform gives specific CCS financial supports, and its CCS Roadmap (DECC, 2012 [33]) and more recently its Policy Scoping Document (DECC, 2014 [37]) establish a stable policy and regulatory framework for CCS deployment.

Whatever the chosen combination between demand-pull and supply-push tools, CCS support policies will have a significant cost. In the UK, the Electricity Market reform and the specific support measures for the CCS deployment are already criticised for their high burden on public finance. The DECC (2013, [36]) estimates that the investments required to decarbonise the power sector will be up to £110bn from now until 2020.
Therefore, in line with endorsed climatic goals at minimum cost to economic growth and the idea

of burden sharing in GHG mitigation, the EU and by extension developed countries, could also consider several options to reduce CCS costs. Among them, one solution could be to support CCS commercial deployment in low building and operating cost countries such as India or China. This geographical approach could accelerate CCS deployment and thus, with the combination of learning-by-doing and scale effects, accelerate the CCS cost reduction process.

Another technical option could be partial capture rather than full capture since it reduces the capital and operating costs of CCS. Consequently, partial capture strengthens the cost-competitiveness of CCS plants in the current context of low CO_2 prices. Partial capture could thus be deployed more quickly and easily than full capture and could be seen as a transitional strategy to foster the uptake of CCS.

These two potential options are explored in Chapter 2.

Chapter 2

Minimising the cost of CCS deployment to optimise the decarbonisation costs

2.1 Introduction: CCS is part of the equation to decarbonise the power sector at the lowest cost

As previously emphasised, CCS is widely recognised as a key technology in helping public authorities to deliver ambitious climatic actions. For instance, the UK Department of Energy and Climate Change stated in its CCS Roadmap (2012, [33]): “In 2010, fossil fuels were used for 72% of the UK’s electricity generation. CCS technology is currently the only means by which fossil fuels can be maintained in the UK generation mix, whilst meeting our legally binding target” to reduce GHG emissions by 80% from 1990 levels by 2050 (2008, Climate Change Act).

2.1.1 In spite of its high cost, CCS may be competitive with several low carbon generation technologies...

Current cost estimates suggest that although CCS fossil fuel plants have a higher LCoE than nuclear plants or photovoltaic farms, they could be competitive with other low carbon techniques such as offshore wind farms or concentrating solar power plants (IEA, 2011 [79]; DECC, 2012 [33]).
“CCS is a competitive power sector emissions abatement tool when compared to other low carbon technologies. Hydropower and onshore wind technologies are among the least-cost technologies identified for reducing emissions from the power sector. Once these relative low-cost technology options are fully exploited - because of their limited availability - or in countries where these technologies are not an option, CCS becomes very competitive” (GCCSI, 2011 [4]).

2.1.2 ...and present some advantages enabling some savings...

As underlined in Chapter 1, CCS presents a double advantage in the power sector: (1) CCS allows a continued use of fossil fired plants, that would otherwise be shut down to respect carbon emission constraints. CCS seems to be an interesting transitional low carbon option for countries with large fossil reserves and/or heavily dependent on fossil fuels such as India, China or the United States. Thus, CCS can avoid the economic consequences of fossil plant premature closures. (2) Electricity from CCS power plants can be supplied on demand, and do not suffer intermittency. To avoid the system costs and drawbacks related with supply intermittency (RES) or even inflexibility (nuclear), there are benefits, in the longer term, to introducing CCS coal and gas plants alongside intermittent renewable generation.
As CCS avoids spending on more expensive alternatives for reducing GHG emissions, savings occur.

2.1.3 ...that reduce the global cost required for a low carbon economy

These savings explain why several studies underline that abandoning CCS as a mitigation option would increase the investment required to decarbonise the power sector. According to the IEA, the decarbonisation cost would be increased by 40%, *i.e.* an extra cost of USD 2 trillion over 40 years (Best and Levina, 2012 [18]). For the IPCC (2014, [87]), "if CCS technologies are not available then the full cost of meeting 450 ppm stabilisation could be 1.5 times to 4 times greater than compared to full CCS availability". Energy system modelling by the Energy Technologies Institute also suggests that successful deployment of CCS would be a major prize for the UK economy, cutting the annual costs of meeting carbon targets by up to 1% of Gross Domestic Product by 2050.

Thereby, in a context of ecological transition intrinsically linked to economic growth, CCS is said to be a critical component of a least-cost portfolio approach to decarbonise the power sector (Grimston et al., [72]) in both developed and developing countries whose energy demands are still growing and energy mixes are highly reliant on fossil fuels.
However, as previously shown, CCS has not yet been deployed at a commercial scale. Thus, the technology is not fully mature and is costly. Chapter 1 has shown that in developed countries like the European Union, the current (and also forecast) CO_2 market price is not high enough to make CCS *de facto* competitive (included with analogous fossil fuel plant CO_2 switching price values). As developing countries have not yet implemented a national CO_2 price (e.g., only pilots in China), it is reasonable to assume that CCS plants are currently not cost-effective with respect to non-CCS plants.
To trigger CCS investment in the power sector, significant political and financial supports will thus be necessary. These kinds of policy supports, particularly financial tools such as capital and operating grants, feed-in-premium, etc., will be costly.

Consequently, it comes that minimising the decarbonisation cost, implies to minimise the cost of CCS deployment.

2.2 Objectives

The objectives of this Chapter are to review and assess the available options enabling a decrease in the cost of CCS deployment, since the technology is said to be necessary to decarbonise the power sector at least cost (Best and Levina, 2012 [18]; IPCC, 2014 [87]).
These options are of two kinds: either geographical or technical.
The geographical approach assumes that one solution to reduce CCS costs could be to deploy the technology in countries where it is less expensive. Then, when mature and therefore less costly, the technology could be re-introduced in high cost countries at a lower cost.
The technical solution considers partial capture of the emitted CO_2. Partial capture consists in reducing the overall capture rate, either by adopting a CO_2 capture rate lower than 90% or by treating only part of the flue gases, or by combining the two options. Partial capture presents several significant advantages: capital and operating expenditures due to CCS are reduced, the technical feasibility is higher and the operating flexibility of CCS plants can be increased. These advantages reinforce the cost-competitiveness of CCS plants in the current context of low CO_2 prices. Consequently, this technical option could accelerate CCS deployment and thus the cost reduction process, notably due to learning-by-doing and economies of scale effects.

2.3 Minimising CCS deployment costs trough a geographical approach[1]

2.3.1 Methods and data

2.3.1.1 Scope of analysis: CCS cost comparison between the European Union and China

The EU and China were chosen to compare CCS costs for several reasons:

1. In contrast to China, a CCS slowdown can be observed in the EU.
   As said in Chapter 1, in the late 2000s, the EU considered CCS playing a critical role in meeting its climate targets, particularly the 20% reduction in GHG emissions from 1990 levels (one of the three "20-20-20" targets in the climate and energy package framework; European Council, 2009 [57]). Consequently, the EU has implemented both economic and political measures to support CCS deployment. However, the current weak EUA price has slowed the development of CCS demonstration projects and threatens CCS commercial deployment. Over the target of 12 new large scale CCS projects by 2015, none has been built. First round of NER300 revenues failed to fund CCS demonstration (ULCOS project withdrawal at the last minute). Nonetheless, in July 2014, NER300's second call for proposals awarded White Rose (UK) CCS project, one of the two projects chosen by the DECC to take forward detailed feasibility work under the UK competition. So, as of November 2014 in the EU (GCCSI, 2014 [63]), there are two LSIPs in operation - Sleipner and Snøhvit - and eight planned. Four of them are in advanced stages of planning (define stage): White Rose (UK, power generation), Peterhead (UK, power generation),

[1] The reader can also refer to: M.Renner. Carbon Prices and CCS Investment: a Comparative Study between the European Union and China. Energy Policy (75), pp327-340, 2014.

Don Valley Power project (UK, power generation) and ROAD project (Netherlands, power generation).

Although the EU was pioneer in the CCS field, it might not take the leadership in CCS deployment. In contrast, CCS future in China seems promising. Indeed, China has committed to reduce its carbon intensity by 40% to 45% by 2020 compared to 2005 levels (Wu et al., 2013 [142]). However, the coal share in the Chinese electricity mix was 78% in 2010 and is projected to reach 60% in 2020 (IEA, 2012 [117]). Thus, CCS has a high potential market in China, and the inclusion of CCS in China's 12^{th} Five-Year Plan may reflect a strong commitment. China has also launched a Research and Development program on CCS and has already sustained several projects[2]. As of November 2014, China has twelve Large Scale Integrated Projects planned compared to five in 2010, ranking second only to the United States in terms of total number of LSIPs (GCCSI, 2014 [63]). Four of the twelve LSIPs are at an advanced stage of planning: Yanchang Integrated CCS demonstration project (chemical production), Petrochina Jilin Oil Field EOR project (natural gas processing), Sinopec Qilu Petrochemical CCS project (Chemical production) and Sinopec Shengli Power Plant CCS project (power generation). "There is optimism that the projects in advanced planning will move into construction in 2014-2015, although timing is subject to decision-making processes of the state-owned enterprises responsible of these projects." (GCCSI, 2014 [63]). One can note that four out of four projects will capture CO_2 in the purpose of EOR. It can mainly be explained by the fact that the Chinese demand for crude oil has been rising quickly.

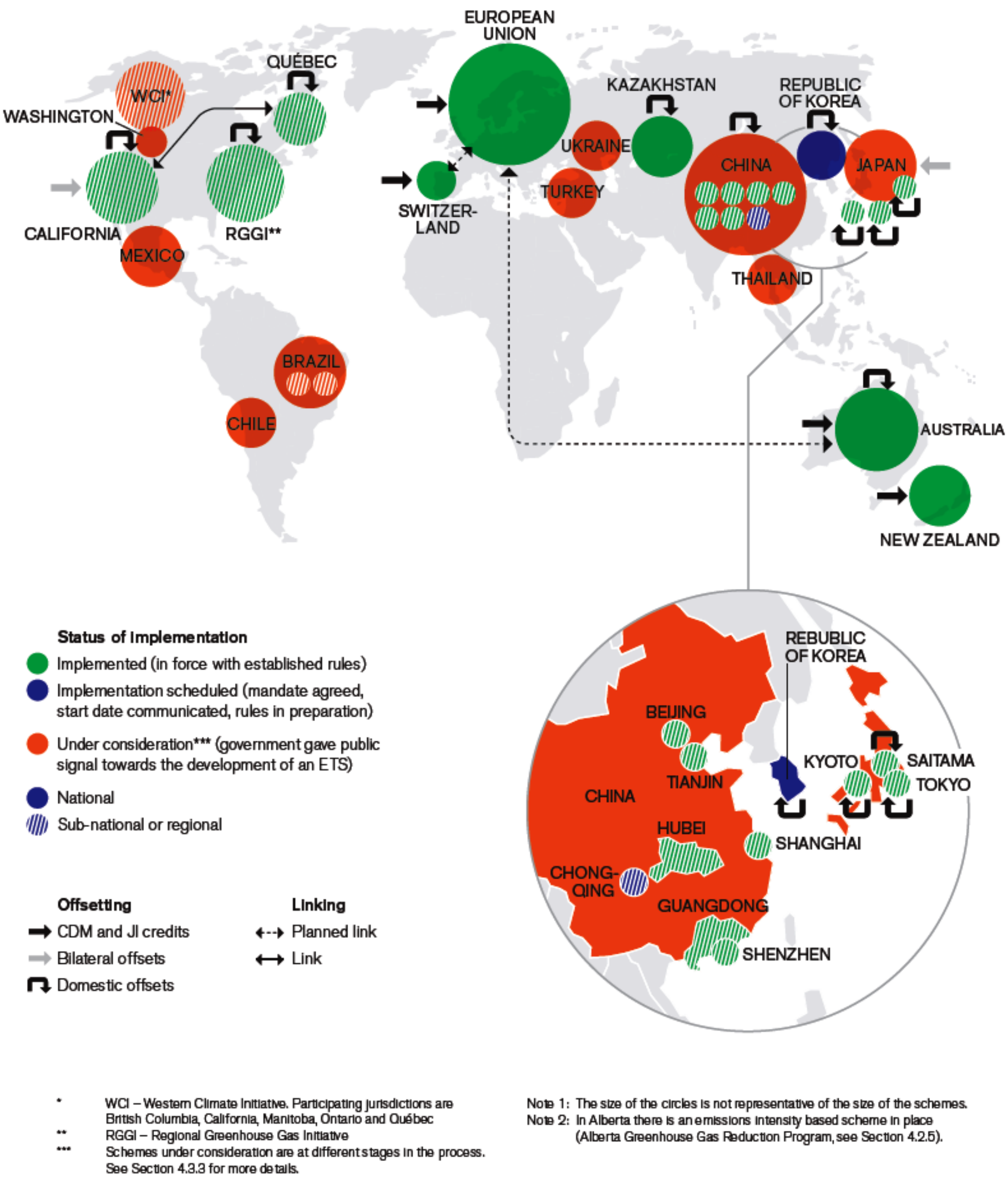
2. Both have introduced carbon price regimes: as underlined in Chapter 1, carbon regulation plays a key role in CCS profitability and deployment (Giovanni et al., 2010 [68]).
   Indeed, the use of CCS can emerge endogenously as a cost-effective response to carbon restriction. When the carbon price is high enough, decision makers/investors face the choice to either invest in a CCS power plant to reduce their carbon burden, or to not install CCS and pay for emitted CO_2.
   For the record, a carbon price was introduced in the EU in 2005 with the European Union Emission Trading Scheme.
   In China, the National Development and Reform Commission announced, in 2011, its plan to develop seven official ETS pilots (Beijing, Shanghai, Tianjin, Chongqing, Guangdong, Hubei, Shenzhen) (Figure 2.1) as a policy tool to reduce its carbon intensity by 40-45% from 2005 to 2020. More recently, China and the United States reached in mid-November 2014 a climate change agreement in which China has committed to achieve the peaking of CO_2 emissions around 2030. In June 2014, seven out of seven ETS pilots had started trading. With these pilots, China has now the second largest carbon market in the world, covering 1,115 MtCO_2e[3], after the EU-ETS with its 2,084 MtCO_2e in 2013. Note that both pilots have a growing cap in line with China's overall 40-45% carbon intensity reduction target by 2020 compared to 2005, but they have different designs. Indeed, as

[2]However, no official document/statement has confirmed the roadmap published by Administrative Center for China's Agenda 21 which is linked to the Ministry of Science and Technology. This roadmap has quantitative targets: the capture of 300,000 tCO_2/year and CCS demonstration unit in 2012 and 1MtCO_2/year and unit by 2020.

[3]Guangdong ETS, the biggest of the Chinese ETS pilots, itself covers 388 MtCO_2e in 2013 (World Bank, 2014 [138]). This amount is similar to the size of France's emissions in 2012.

China committed to implementing a national level ETS pilot during the 13^{th} Five-Year-Plan (2016-2020), the objective is to assess which ETS design would be the best. However, a carbon regulation has a real effect on CCS deployment only if there is a CO_2 cost pass-through to electricity prices. This cost pass-through exists in the EU (Jouvet and Solier, 2013 [91]) but is currently impossible in China because of regulated electricity prices. Nonetheless, reforms are currently undergoing to partially deregulate gas prices (IEA, 2012 [115]): the reform of electricity regulations is thus perfectly conceivable.

Figure 2.1: Map of existing, emerging and potential emission trading schemes.



Source: World Bank and Ecofys (2014, [138]).

3. The EU is a developed region, whereas China is a developing country.

> Power plant costs significantly vary by country, and the contrast is particularly striking between the emerging economies of East Asia, including China, and the mature markets of North America and Europe. At least four explanations for this cost difference can be put forward: lower labour costs in China, economies of scale from building multiple power plants with standardised designs in China, lower raw material/commodity prices (national abundance and state-set prices significantly lower than free-market prices) and fewer constraining regulations in China. According to the IEA data base (2014, [120]), as for the 2012 capital costs of ultra-supercritical coal plants, the ratio between the EU and Chinese values is 2.8. For the 2012 capital costs of CCGTs, the ratio between the EU and the Chinese values is 1.8. Thus, with the goal of minimising the cost of the ecological transition, the case of CCS in China may be significant. If it is, then some transfers (monetary/R&D, etc.) or policy agreements between the EU and China to support and incentivise CCS deployment should be considered within the framework of climate change negotiations.
> It partly echoes the position stated by the Chinese Minister of Science of Technology during the 2009 Carbon Sequestration Leadership Forum (London): "The developed countries should take the lead in demonstrating CCS technology, and provide the support of funding technology transfer and capacity building to developing countries and help them to develop CCS technology".

As power plant costs strongly differ between China and the EU, one can expect CCS costs to vary between China and the EU. Two questions thus arise: how much is the extra-cost of a CCS plant in the EU in comparison with China? Second, what is the CO_2 price beyond which CCS power plants become more profitable than power plants without CCS, in the EU and in China? The behind idea is the following. If within a particular country, there is a large gap between the CO_2 price triggering CCS investment and the forecast CO_2 market price, then this country could support CCS deployment in a lower cost country to minimise the cost of the ecological transition. Such support may include monetary/technology transfers, R&D agreements (MOU), or other elements.

2.3.1.2 How to relevantly use sets of data provided by CCS studies and get Chinese costs?

Similarly to Chapter 1, to address these issues and assess the potential of CCS as a key option for climate change mitigation, the purpose is to provide an objective comparison of CCS costs when applied to the power sector in the EU and in China.

Methodology and data

As emphasised in Chapter 1, there are large inconsistencies in the way CCS costs are currently calculated in public studies[4]. These discrepancies hamper the ability to correctly compare straightforwardly the cost of different carbon capture options investigated in various public studies.

[4] Each public study employs its own methodology to calculate some economic data (capital cost, LCoE, etc.) as well as its own set of techno-economic assumptions (fuel prices, discount rate, etc.).

This issue is addressed on the basis of the methodology provided by Chapter 1. Hereafter are given a short summary as well as sets of data.

- A literature review is conducted to select the most recent and relevant public techno-economic studies.
  The selected public studies are: IEA (2010 [113], 2011 [79]), Alstom (2011, [8]), DECC (2012 [34], 2013 [35]), Global CCS Institute (2011, [61]), ZEP (2011, [143] [145] [144]), DOE NETL (2010, [40] [39]), WorleyParsons (2009 [141], 2011 [140]), NZEC* (2009, [112]) and Wu et al. (2013, [142]).
  As in Chapter 1, these studies are considered as references in the "CCS sphere" and were published over the last five years.

- For each public study, the most representative economic data is kept original but is updated to current cost level (Table 2.1):

  - Two sets of economic data are considered to be representative: the overnight cost and the operating and maintenance (O&M) costs.

  - These costs are updated to €$_{2011}$ cost level.

- Calibration of sets of economic data (discount rate, fuel prices, carbon transport and storage costs, etc. Table 2.2) and calculation methodologies (Table 2.3):

  - Standardised parameter values and calculation methodologies come from the comparison of public studies.

  - Note that carbon transport and storage costs, detailed in Table 2.2, come from ZEP (2011, [144] [145]) which is considered as a reference, notably by the DECC (2012 [34], 2013 [35]) and the GCCSI (2011, [61]). ZEP has provided very detailed reports that differentiate onshore and offshore carbon transport and storage costs. It seems that the EU has mostly offshore storage capacities, whereas China would have both (2009, [28]).

- Standardised calculation of LCoEs and CO_2 switching prices, the two key metrics to assess CCS power plant profitability.

  - Based on a common set of techno-economic parameters (Table 2.2) and calculation methodologies (Table 2.3), LCoEs and CO_2 switching prices are calculated with the two original but updated sets of cost data reported in each public study (overnight and O&M costs, Table 2.1).

- Data analysis and result discussion.

- Conclusions and recommendations.

Table 2.1: Unchanged techno-economic parameters.

Unchanged parameters	Unit	European Value Range	Chinese Value Range
Overnight cost	€$_{2011}$/kW		
Ultra-supercritical coal plant		[1283; 1765] [ZEP; DECC]	[549; 851] [IEA; Wu et al.]
IGCC plant		[1546; 2588] [DoE; DECC]	1961 [Wu et al.]
CCS coal plant			
Post-combustion		*[2116; 3225] [IEA; DECC]*	*[1023; 1370] [IEA; Wu et al.]*
Oxy-combustion		*[2513; 3229] [WP; DECC]*	
Pre-combustion		*[2475; 3734] [ZEP; DECC]*	*2942 [Wu et al.]*
CCG		[473; 647] [IEA; DECC]	407 [IEA]
CCS gas plant		[854; 1589] [IEA; DECC]	733 [IEA]
Operation & Maintenance costs	€$_{2011}$/MWh		
Ultra-supercritical coal plant		[4; 12] [IEA]	[1.6; 2.8] [IEA; NZEC]
IGCC plant		[5; 22] [IEA; DoE]	9 [Wu et al.]
CCS coal plant		[6;22] [IEA; DoE]	[3.3; 17.7] [IEA; NZEC]
CCG		[1; 6] [IEA; ZEP]	1.3 [IEA]
CCS gas plant		[3;13] [IEA; ZEP]	2.3 [IEA]
Net power	MWe	[400; 800]	[600; 800]

Table 2.2: Standardised techno-economic parameters.

Standardised parameters	Unit	European values	Chinese values
Currency[a]	€$_{2011}$		
Capacity factor	%	85 [7446 hrs/yr]= BASE-LOAD	
Capture rate	%	90	
Emission Factor	tCO_2/MWh	Coal plant= 0.744; Gas Plant=0.337	
Plant efficiency			
Coal plant (PCI)	*%*	*45% (2015)*	
CCS coal plant	*%*	*36% (2015)*	
Gas plant	*%*	*60% (2015)*	
CCS gas plant	*%*	*52% (2015)*	
Construction time			
Coal plant	*years*	*4*	

Table 2.2: Standardised techno-economic parameters-Continued

Standardised parameters	Unit	European values	Chinese values
CCS coal plant	*years*	*5*	
Gas plant	*years*	*2*	
CCS gas plant	*years*	*3*	
Lifetime			
Coal plant	*years*	*40*	
Gas plant	*years*	*25*	
Fuel price[b]			
Black coal	*$_{2011}/GJ$*	*2015: 4.34* *($108.5/t)*	*2015: 3.8* *($95/t)*
Natural gas	*$_{2011}/GJ$*	*2015: 11.61* *($11/MBtu)*	*2015: 10.55* *($10/MBtu)*
CO_2 **price**	€/t	0	
Owner's cost	Overnight cost%	15	
Discount rate [real after tax]	%	8	
Transport costs[c]	€$_{2011}$/MWh	Offshore: 5.8	Onshore: 1.35 Offshore: 4.35
Storage costs[d]	€$_{2011}$/MWh	Offshore: 8.7	Onshore: 3.45(coal) /1.8(gas) Offshore: 6.5

[a]Exchange rates are from OECD statistics (2014, [2]). Cost data are calibrated to 2011 cost levels by using cost indices (OECD statistics (2013, [1]), Oxford Economic and Asia Pacific Forecast (2013, [3]).

[b]European assumptions come from IEA (2012, [117]). Chinese assumptions come from the comparison of: Henderson (2011, [77]) and Wu et al. (2013, [142]). Indeed, there are no official fuel prices in China: prices are administered.

[c]Onshore: 180 km pipe. For a single CCS coal plant (2×700 MW), CO_2 transported: 10 Mtpa, for a single CCS gas plant: 2.5 Mtpa. Offshore: 500 km pipe. Cluster of CCS coal (3×700 MW) and CCS gas (2×360 MW) plants. CO_2 transported: 20 Mtpa. Mid scenario (ZEP, 2011 [145]).

[d]Deep saline aquifer. Mid scenario (ZEP, 2011 [144]).

Table 2.3: Standardised calculation methodologies.

Calculation methodology	Applied to public studies since the beginning	Applied at the standardisation time
CO_2 emission factor	✓	✓
Constant investment annuity[a]	✓	✓
LCoE	✓	✓
Fuel cost		✓
CO_2 cost		✓
CO_2 switching price	✓	✓

[a] Constant investment annuity is from Park Chan (2003, [121]).

Chinese cost calculation

As of June 2014, only a few studies have investigated CCS costs in China: NZEC (2009, [112]), IEA (2010 [113], 2011, [79]) and Wu et al. (2013, [142]). In contrast, many studies have compared Chinese IGCC and ultra-supercritical coal plant costs, but without considering CCS, particularly CCS gas plants, nor the CO_2 price beyond which a particular kind of power plant become profitable in relation to other power plant types.

However, it is possible to assess Chinese CCS costs thanks to cost location factors. Cost location factors are conversion indices used to transfer the costs of one project from the reference location to specific locations. To define those regional cost indices, WorleyParsons (2011, [140]) uses sets of data from Richardson's manual (2010, [124]), which is usually considered as the reference. These cost location factors are also applied in this study (Table 2.4).

Table 2.4: Regional indices used to transfer projects from USGC to specific locations.

	Capital and O&M Costs		
Region	**Equipment**	**Materials**	**Labour**[b]
United States (USGC[a])	1	1	1
Europe (Euro region)	1.19	1.16	1.33
China	0.81	0.81	0.05[c]

[a]United States Gulf Coast

[b]The labour index incorporates two key elements: the relative cost of labour and the relative labour productivity as compared to the USGC.

[c]The labour index from Richardson (2010, [124]) was reduced by WorleyParsons (2011, [140]) to take into account the fact that, generally, the setting of most power plants is in rural areas.

As underlined by WorleyParsons, the regional indices correspond to specific locations and can vary significantly, particularly with respect to labour, depending on the project location. Additionally, the type of labour used (e.g., union, non-union, work camps) can considerably affect the labour cost within a given region. Further, the locally sourced raw materials and equipments as well as labour indices, will vary with changes in currency exchange rates. Nonetheless, as previously underlined, the purpose of this study is not to represent the costs of specific CCS projects, but to provide general trends.

For the cost of a power plant, without carbon transport and storage costs, cost location factors can be applied straightforwardly for two studies: DoE NETL's (2010, [40] [39]) and WorleyParsons' (2009 [141], 2011 [140]). Indeed, in these two studies, the Labor/Equipment/Raw Materials items appear clearly. However, ZEP, DECC and Alstom studies provide global/concatenated investment and O&M costs. Thanks to DoE and WorleyParsons' studies, an allocation key (one for investment costs and one for O&M costs) was determined and then applied to the other studies.

Note that cost location factors cannot be used to convert European carbon transport and storage costs into Chinese costs. Rather, ZEP provides aggregated sets of data: CAPEX* and OPEX*. The relative proportion of equipment, materials and labour is thus unknown. To determine Chinese T&S costs, the following ratio is applied[5]: $\frac{Purchasing\ Power\ Parity\ (€/RMB)}{Market\ exchange\ rate\ (RMB/€)}$. Using OECD sets of data (2013, [2]), a value of 0.75 is obtained. In the absence of reliable information about Chinese T&S costs, a reduction of 25% is applied to the European sets of data (Table 2.2).

Consequently, thanks to this cost location factor approach, this study fills the current gap by providing and comparing CCS costs in China using eight studies instead of three.

2.3.2 CCS cost comparison in the EU and China

Hereafter are presented the main results.

2.3.2.1 None of the carbon capture techniques have a clear cost advantage

CCS costs are mainly provided by the studies used in Chapter 1.
Consequently, results are similar.
For coal plants, none of the carbon capture techniques have a clear cost advantage.
For gas plants, the question does not arise since only one carbon capture technique, namely post-combustion, has been studied: post-combustion capture. Whereas all OECD studies analyse CCS gas plants, only one of the three Chinese studies analyses CCS gas plants: IEA (2010 [113], 2011 [79]). This is not surprising given that in 2010, gas plants generated only 2% of the Chinese electricity and may generate only 3.5% by 2015 (IEA, 2012 [115]).

2.3.2.2 Extra-costs due to CCS

A CCS plant undergoes an increase in both investment and O&M costs.

- Fixed costs:

  - The coal overnight cost increases on average by 70% *vs.* 60% in China.

  - The gas overnight cost increases on average by 110% both in Europe and China.

  The differences between the EU and China are due to dissimilar capital and O&M costs (Tables 2.1 and 2.4).

- Variable costs:

  - Net efficiency penalties of 9 percentage points for coal plants *vs.* 8 points for gas plants. It implies an increase of 25% *vs.* 15% in fuel costs, respectively.

  - O&M costs increase on average by 80% for coal plants and 100% for gas plants.

[5] *RMB** stands for Renminbi.

With CCS, coal LCoE increases on average by 60% (€65/MWh, onshore) or 75% (€70/MWh, offshore) in China *vs.* 80% in European countries (€110/MWh). Chinese LCoEs for CCS coal plants are thus 35% to 45% lower than European values.
With CCS, gas LCoE increases on average by 30% (€75/MWh, onshore) or 45% (€85/MWh, offshore) in China *vs.* 55% in European countries (€105/MWh). Chinese LCoEs for CCS gas plants are thus 20% to 30% lower than European values.

2.3.2.3 CO_2 price and breakeven point

Chinese CO_2 switching prices are almost half the value of the Europeans.
On average, CCS coal plants become more profitable than analogous coal plants beyond €35/tCO_2 (onshore T&S costs) or €45/tCO_2 (offshore T&S costs) in China *vs.* €65/tCO_2 in the EU.
On average, CCS gas plants become more profitable than analogous gas plants beyond €55/tCO_2 (onshore T&S costs) or €80/tCO_2 (offshore T&S costs) in China *vs.* €115/tCO_2 in the EU.

2.3.2.4 Investing in CCS: which power plant type is most profitable given the CO_2 price?

Relying on the distinction between intra- and inter-technique CO_2 switching prices established in Chapter 1, the optimal power plant type is determined for different CO_2 price scenarios, for both the European Union and China.

In the European Union

Results are identical to those described in Chapter 1. They are shortly reminded. For more details, please refer to Chapter 1.
In European countries, the investment choice first depends on relative profitability due to fossil fuel prices. Currently, from €0 to 20/tCO_2, coal plants are the most cost-effective power plant type, but from €20 to 115/tCO_2, gas plants are the most cost-effective. Then, beyond €115/tCO_2, CCS[6] (gas) power plants are the most profitable power plant type.

In China

One needs to differentiate two cases: onshore and offshore carbon transport and storage infrastructures.
Onshore carbon transport and storage costs
When the CO_2 price is lower than €35/t, coal plants have the lowest LCoE. Beyond €35/tCO_2, CCS coal plants become the most cost-effective power plant type.
Note that beyond €55/tCO_2, CCS gas plants become more profitable than reference gas plants but are still less competitive than CCS coal plants.
Offshore carbon transport and storage costs
When the CO_2 price is below €45/t, coal plants are the most profitable power plant type.
Beyond €45/tCO_2, CCS coal plants become the most cost-effective power plant type.
Note that beyond €80/tCO_2, CCS gas plants become more profitable than reference gas plants but are still less competitive than CCS coal plants.
Thus, in China, the investment choice only depends on the CO_2 price.

[6] Offshore T&S costs.

China and EU CCS costs comparison

To conclude, in China, coal plants with and without CCS, always have the lowest LCoE, whereas in the EU, beyond €20/tCO_2 gas plants, with and without CCS, have the lowest LCoE.
The CO_2 switching price beyond which CCS power plants become more profitable than all the other power plant types is €115/tCO_2 in Europe *vs.* €35/tCO_2 (onshore T&S costs) or €45/tCO_2 (offshore T&S costs) in China.
This last result is mainly due to lower investment and O&M costs in China than in the EU, and to a lesser extent, cheaper raw materials and fuel prices.

2.3.3 Sensitivity analyses

As one of the objectives of this Chapter is to provide reliable information on the key factors affecting the economics of electricity generation using several technologies (e.g., ultra-supercritical coal plants, post-combustion/pre-combustion/oxy-combustion coal plants, gas plants and post-combustion gas plants), similarly to Chapter 1, sensitivity analyses were performed for the standardised parameters: capture rate, load factor, construction time, lifetime, fuel prices, discount rate and plant efficiency (Table 2.5). Parameters were changed independently, *ceteris paribus*, to compare their relative impact on LCoEs and CO_2 switching prices.

Table 2.5: Parameters used to perform sensitivity analyses for both the EU and China.

Standardised parameters	Unit	Values	Variations
Load factor	%	85 (=Base-load)	42 (=mid-load)
Capture rate	%	90	-5
Plant efficiency			
CCS coal plant	*%*	*36% (2015)*	*± 1 point of %*
CCS gas plant	*%*	*52% (2015)*	*± 1 point of %*
Construction time			
Coal plant	*years*	*4*	*+1*
CCS coal plant	*years*	*5*	*+1*
Gas plant	*years*	*2*	*+1*
CCS gas plant	*years*	*3*	*+1*
Lifetime			
Coal plant	*years*	*40*	*-5*
Gas plant	*years*	*25*	*[-5;+5]*
Fuel price[b]			
Hard coal (2015)	*$\$_{2011}$/t*	*EU: 108.5 China: 95*	*±20%*
Natural gas (2015)	*$\$_{2011}$/MBtu*	*EU: 11 China:10*	*±20%*
Discount rate	%	8	[-4;+4]

As demonstrated in Chapter 1, only discount rate, fuel prices and load factor variations have a real impact on LCoEs and CO_2 switching prices (Tables 2.6, 2.7, 2.8, 2.9 and Table 2.10). The related results are detailed hereafter.

Table 2.6: Sensitivity analysis results on European LCoEs.

	BAU [€/MWh]	Discount rate: ± 4 pts of %	Coal price: ±20%	Gas price: ±20%	Mid-load
Coal plant	60	± 24%	±9%	-	48%
CCS plant	106	± 28%	±7%	-	49%
Gas plant	68	± 6%	-	±18%	16%
CCS gas	104	± 7%	-	± 13%	22%

Table 2.7: Sensitivity analysis results on Chinese LCoEs.

	BAU [€/MWh]	Discount rate: ± 4 pts of %	Coal price: ±20%	Gas price: ±20%	Mid-load
Coal plant	40	± 16%	±12%	-	35%
CCS coal on-shore T&S	63	±18%	±10%	-	38%
CCS coal off-shore T& S	70	±16%	± 10%	-	38%
Gas plant	54	±5%	-	±20%	12%
CCS gas on-shore T&S	70	± 6%	-	±17%	16%
CCS gas off-shore T&S	80	± 5%	-	±18%	16%

2.3.3.1 Sensitivity analysis on the discount rate

As previously shown, electricity generation technologies do not share the same cost structure. For example, coal plants (w/ and w/o CCS) require very high upfront overnight costs compared with gas plants (w/ and w/o CCS) that have lower upfront investment costs for entering the market but have variable fuel costs that outweigh capital costs in their LCoE (See Chapter 1 for more details).

Consequently, higher discount rates affect coal plants (w/ and w/o CCS) more than gas plants (w/ and w/o CCS) which have relatively lower investment costs. In the EU (respectively in China), coal plant LCoEs are four times (respectively three) more sensitive to a 4 percentage point change in the discount rate than gas plants (Tables 2.6 and 2.7). The EU and China differ on this metric because Chinese overnight costs are lower: the capital cost weight in LCoE is thus lower, which slightly reduces the impact of a discount rate variation. Note that CCS plants, which are more capital intensive, are more sensitive to a discount rate variation than reference plants: a 4 percentage point change in the discount rate leads to 4 additional percentage points of variation for CCS coal plant LCoEs with respect to reference coal plants and 1 additional percentage point of variation for CCS gas plant LCoEs with respect to reference gas plants.

2.3.3.2 Sensitivity analysis on fuel prices

Fuel costs have a relatively lower impact than the discount rate on the LCoE of coal plants, (w/ and w/o CCS), in contrast with gas plants (w/ and w/o CCS): coal plant LCoEs are two times less sensitive than gas plants to a 20% change in fuel prices (Tables 2.6 and 2.7). Indeed, coal-fired generation requires capital costs significantly higher than gas-fired generation which reduces the impact of a fuel cost variation on LCoE. Despite thermal efficiency penalties, CCS plants are less sensitive than reference plants to a 20% fuel price variation (2 percentage points less) because the relative effect of the fuel cost variation on the LCoE is offset by the higher share of the capital cost in LCoE.
Note that Chinese plants are more sensitive to fuel price variations than European plants: because Chinese capital cost weight in LCoE is lower, the share of fuel cost over LCoE is higher, which increases the impact of fuel price variations.

2.3.3.3 Sensitivity analysis on the load factor

As previously said, a standard load factor of 85% was chosen which models power plants operating at base-load.
Nonetheless, it is likely that the share of renewables in electricity systems will become more significant in the future, particularly in the EU. Thus, future CCS power plants might have to be operated on a more flexible intermediate-load basis.
To illustrate that point, the case of mid-load power-plants was studied. As explained in Chapter 1, only post-combustion capture was considered and the extra-costs related to a mid- rather than a base-load operation (higher efficiency penalties, etc.) were not taken into account (no available public data).
Thanks to this sensitivity analysis, two questions are addressed: (1) When the investment decision concerns base-load plants, what is the CO_2 price required to make CCS plants competitive? Indeed, coal-fired generation still operates at base-load in several countries like Poland, Germany (lignite) and China. (2) When the electricity mix has a high proportion of renewables and if fossil plants are required to be more flexible, what is the CO_2 price that will trigger CCS investment in this scenario?
As coal plants with and without CCS have higher fixed costs than reference gas plants, their LCoE is three times more affected by the load factor variation from base- to mid-load. Of all generating technologies, gas, whose fuel cost most affects LCoE, is the least affected by the load factor variation. In other words, running or not running a gas plant makes a much smaller difference to the profitability of a project than running or not a coal plant, given the latter's (higher fixed costs). Likewise, because they are more capital intensive, CCS gas plants are more sensitive than reference gas plants to the load factor variation (6 additional percentage points of variations in the EU, *vs.* 4 in China). For the same reasons, Chinese plants are less sensitive to the load factor variation than European plants.
In line with the capacity payment idea, the difference between the LCoE of a CCS plant in base-

and in mid-load (e.g., €50/MWh for CCS coal plants, Table 2.6) could be seen as the justification for subsiding CCS power plants, *i.e.* as the subsidy that would encourage the plants to operate on a more flexible intermediate load-basis. This kind of subsidy could be particularly interesting in electricity systems with high renewable proportions because it reduces the risk of return on capital expenditures.

To summarise, this analysis confirms that for capital intensive technologies such as coal plants (w/ and w/o CCS), the most important parameter affecting their LCoEs is the load factor, followed by the discount rate. The picture is partly reversed for gas plants (w/ and w/o CCS) whose key cost driver is the gas price followed closely by the load factor.

2.3.3.4 Sensitivity analyses and their effects on CO_2 switching prices

Table 2.8: Sensitivity analysis results on European CO_2 switching prices.

		BAU	Discount rate: 4%	Discount rate: 12%	Coal price: ±20%	Gas price: ±20%	Mid-load
Intra-technique	Coal-CCS coal	67	-22%	35%	±3%	-	46%
	Gas-CCS gas	117	-9%	11%	-25%	± 4%	30%
Inter-technique	Coal-gas	18	104%	-100%	∓ 71%	-100/ 142%	-100%
	Coal-CCS gas	60	11%	-17%	∓12%	± 28%	-15%
	Gas-CCS coal	153	-48%	68%	±17%	∓30%	100%

Table 2.9: Sensitivity analysis results on Chinese CO_2 switching prices, onshore T&S costs.

		BAU	Discount rate: 4%	Discount rate: 12%	Coal price: ±20%	Gas price: ±20%	Mid-load
Intra-technique	Coal-CCS coal	35	-23%	33%	±5%	-	34%
	Gas-CCS gas	56	-11%	12%	-	± 9%	38%
Inter-technique	Coal-gas	42	19%	-26%	∓ 27%	-56/ 56%	-43%
	Coal-CCS gas	48	4%	-7%	∓14%	± 32%	-3%
	Gas-CCS coal	19	-178%	252%	±123%	∓205%	394%

Table 2.10: Sensitivity analysis results on Chinese CO_2 switching prices, offshore T&S costs.

		BAU	Discount rate: 4%	Discount rate: 12%	Coal price: ±20%	Gas price: ±20%	Mid-load
Intra-technique	Coal-CCS coal	47	-18%	26%	±4%	-	41%
	Gas-CCS gas	81	-7%	8%	-	± 6%	26%
Inter-technique	Coal-gas	44	19%	-26%	∓ 56%	±27%	-42%
	Coal-CCS gas	60	4%	-6%	∓26%	± 11%	-2%
	Gas-CCS coal	39	-77%	109%	±89%	∓53%	170%

When the CO_2 price is null, base-load coal plants have the lowest LCoE for all scenarios in China, and for all scenarios in the EU except for when the discount rate is 12% (Tables 2.8 to 2.10).

When the CO_2 price is not null, the European coal to gas CO_2 switching price exhibits a high sensitivity to fuel price fluctuations (Table 2.8). *Ceteris paribus*, when the coal price (gas price) varies by +/-20%, this CO_2 switching price varies more than proportionally by +/-50% (+/-95%). As previously noted, gas-fired plants are very sensitive to fuel price variations. Thus, although gas price volatility is not necessarily a decisive issue for gas plant investors because, in many cases, gas plants are marginal plants that set wholesale electricity prices (pass-through), the absolute gas price level is important for investors facing the choice between gas plants and alternative generation technologies (IEA, 2010 [113]).

In the EU, when the CO_2 price is high enough (approximately €115/t), base-load CCS gas plants are the most profitable power plant type except for two scenarios in which CCS coal plants are the most profitable type: when the coal price is reduced by 20% and when the discount rate is 4% (public policy rate). In China, when the CO_2 price is high enough (approximately €35 to 45/t), CCS coal plants are always the most profitable power plant type.

At mid-load, in the EU, gas plants are the most competitive power plant type from €0 to 150/tCO_2. Beyond €150/tCO_2, CCS (gas) plants have the lowest LCoE. In China, when fossil plants operate at mid-load, reference coal plants are the most competitive power plant type until €25/tCO_2. From €25 to 75/tCO_2 (onshore T&S costs; €105/tCO_2 with offshore T&S costs), reference gas plants have the lowest LCoE. Beyond €75/tCO_2, CCS gas plants are the most competitive power plant type.

Consequently, when power plants operate with load factors significantly lower than 85%, gas plants have the lowest LCoE. CCS gas plants with mid-load factors are not remotely competitive until CO_2 prices are particularly high: €150/t CO_2 in the EU *vs.* €75 to 105/tCO_2 in China.

2.3.4 What about about 2030?

As in Chapter 1, the 2030 horizon was also studied to evaluate the potential future course of CCS profitability, in the EU and in China. Indeed, R&D developments as well as economies of scale and learning-by-doing effects due to LSIPs should have driven down CCS costs between 2015 and 2030.

2.3.4.1 Main assumptions

To assess CCS costs in 2030, the most recent study is used: DECC (2013, [35]), which calculates costs for 2013, 2020 and 2030. ZEP (2011, [145] [144]) does not look at the cost reduction process, *i.e.* does not give projections for carbon transport and storage costs in 2030. As DECC's low cost path is "broadly in line with ZEP estimates for early commercial costs", carbon transport and storage costs for 2030 are from the DECC (2013, [35]). These costs are for offshore infrastructures[7].
As previously, Chinese costs are obtained by applying cost location factors. Projections for 2030 are publicly available for fuel prices but not for the labour, raw material and equipment indices which were kept constant. However, these indices between China and the EU might vary between 2015 and 2030, particularly the labour index. Indeed, the increasing Chinese labour costs might not be entirely balanced by the increasing Chinese labour productivity. As a consequence, although less costly than European CCS plants, Chinese CCS plants might be relatively less attracting for European CCS actors. The latest data base from the IEA (2014, [120]) takes into account this kind of evolution by differentiating sets of cost data by region, technology (coal; gas; with or without CCS) and time horizon (2012; 2020; 2035). It shows that, between 2020 and 2035, the gap between Chinese and the EU capital and O&M costs tends to decrease: by 25% for CCS coal plants, and by 20% for CCS gas plants. Although the use of regional indices on DECC's data does not allow to take into account this catch-up, the related results (see below) are rather similar to those obtained with IEA's data. By 2030-2035, the CO_2 price value required to trigger CCS investment is still considerably lower in China than in the EU: around €30/t in China *vs.* €70-80/t in the EU. Nevertheless, as CCS costs may decrease at a lower rate in China than in the EU (IEA, 2014 [120]), taking the best advantage of the current geographical differentiation of costs requires quick reaction. In other words, an urgent climate change negotiation/agreement, under which developed countries will be encouraged to support CCS deployment in developing countries, is required.

Similarly to Chapter 1, a fuel price scenario (Scenario 2) based on IEA projections ("New Policies scenario", 2012 [117]) was introduced in addition to a constant fuel price scenario which can isolate the learning-by-doing and economies of scale effects (Table 2.11, Scenario 1). According to the IEA, the OECD coal price is "a proxy for international coal prices"; this value is applied for the EU and China. For natural gas prices, the IEA projection is used for the EU but there is no available projection for China. Future Chinese fuel prices are uncertain because they are regulated and often kept lower than the market price to avoid triggering high inflation rates. Besides, there is high fuel price heterogeneity between regions. The future price uncertainty is thus significant and to our knowledge, there are no public projections on the future level of

[7] Onshore pipe of 30 km and offshore pipe of 300 km. The storage is not a saline aquifer (assumption for 2015-2020) but a depleted oil and gas field (less expensive).

Chinese fuel prices. It is assumed that, by 2030, Chinese gas prices follow either Japanese prices (in 2011, 54% of Chinese imports were liquefied natural gas, the price of which is supposed to follow the Japanese price; IEA, 2012 [117]) or European prices (relative to the high volumes of natural gas which are imported, China has a bargaining power) (Table 2.11).

Table 2.11: Fuel price assumptions for the EU and China in 2030.

	Sc.1: Constant fuel prices		Scenario 2: Fuel prices based on IEA		
	EU	*China*	*EU*	*China-European hyp.*	*China-Japanese hyp.*
Natural gas imports in 2030 ($\$_{2011}$/MBtu)	11	10	12.2	12.2	14.7
Steam coal imports in 2030 ($\$_{2011}$/t)	108.5	95	114	114	

2.3.4.2 Main results

Table 2.12: European CO_2 switching prices by 2030 - offshore T&S costs. DECC's data for 2015 and 2030.

		2015	2030 - Scenario 1	2030 - Scenario 2	2030 - Scenario 2 Mid-load
Intra-technique	Coal to CCS coal[a]	77	63	65	109
	Gas to CCS gas	**131**	**81**	**84**	**130**
Inter-technique	Coal to gas	**5**	**8**	**20**	X
	Coal to CCS gas	58	40	48	32
	Gas to CCS coal	198	149	133	344

[a]CCS coal plants are coal plants with post-combustion capture.
2030 EU offshore T&S costs; gas plants: €2.9/MWh, coal plants: €6.8/MWh.

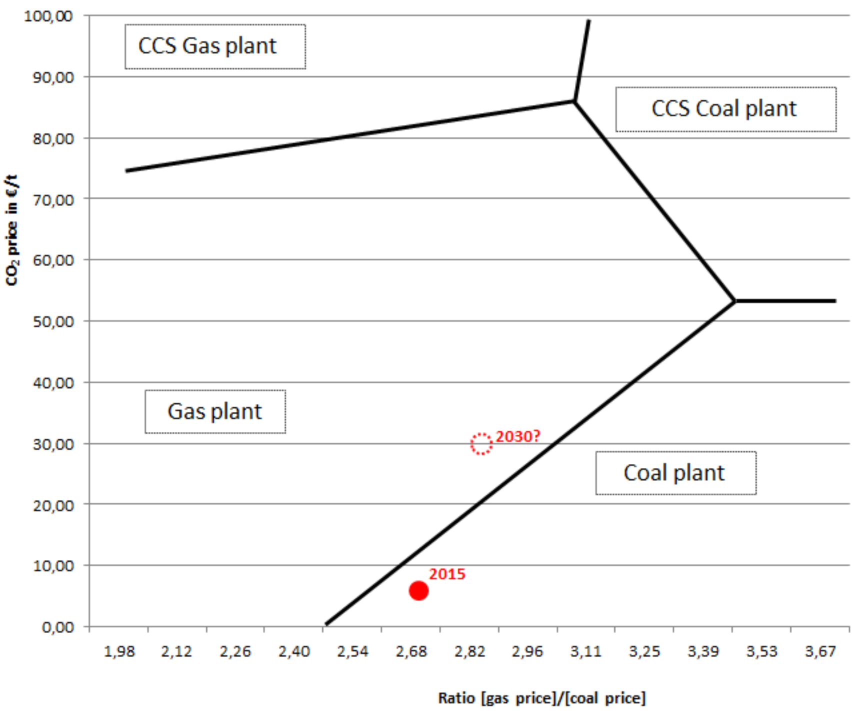
Table 2.13: Chinese CO_2 switching prices by 2030 - offshore T&S costs. DECC's data for 2015 and 2030.

		2015	2030 - Sc.1	2030 - Sc.2 Euro. hyp.	2030 - Sc.2 Japanese hyp.	2030 - Sc.2 Euro. hyp. mid-load
Intra-technique	Coal to CCS coal[a]	50	**31**	**33**	**33**	48
	Gas to CCS gas	91	55	61	67	84
Inter-technique	Coal to gas	**34**	47	65	99	**36**
	Coal to CCS gas	58	51	69	84	58
	Gas to CCS coal	**65**	9	X	X	**64**

[a]CCS coal plants are coal plants with post-combustion capture.
For Chinese T&S costs, a 25% cost reduction factor is still applied to EU T&S costs.

For the EU in 2030, there is no projected change in the merit order (Table 2.12). From €0 to 20/tCO_2 (scenario 2, more realistic), coal plants have the lowest LCoE and then, from €20 to 85/tCO_2, gas plants are the most profitable power plant type. CCS gas plants have the lowest LCoE: €85/tCO_2 compared with the €115/tCO_2 threshold of 2015 (Part 2.3.2.4). Note that the European profitability frontier between CCS gas plants and CCS coal plants is thin. European CCS power plants are thus projected to be the most profitable given the CO_2 price threshold is €85/tCO_2, in contrast to the IEA forecast of €30/tCO_2 (2012, [117]). The large gap between these two CO_2 values is a good indicator of the extent of policy measures that the EU should undertake to make CCS competitive (e.g., feed-in tariff, capacity payments, CCS purchase contracts, etc.) and revitalise the EU-ETS. Consequently, without specific measures to support CCS, from an economic point of view, European actors should invest in gas plants (Figure 2.2), particularly if power plants are required to operate at mid-load. In that case, gas plants have the lowest LCoE, and CCS (gas) plants become competitive beyond €130/tCO_2.

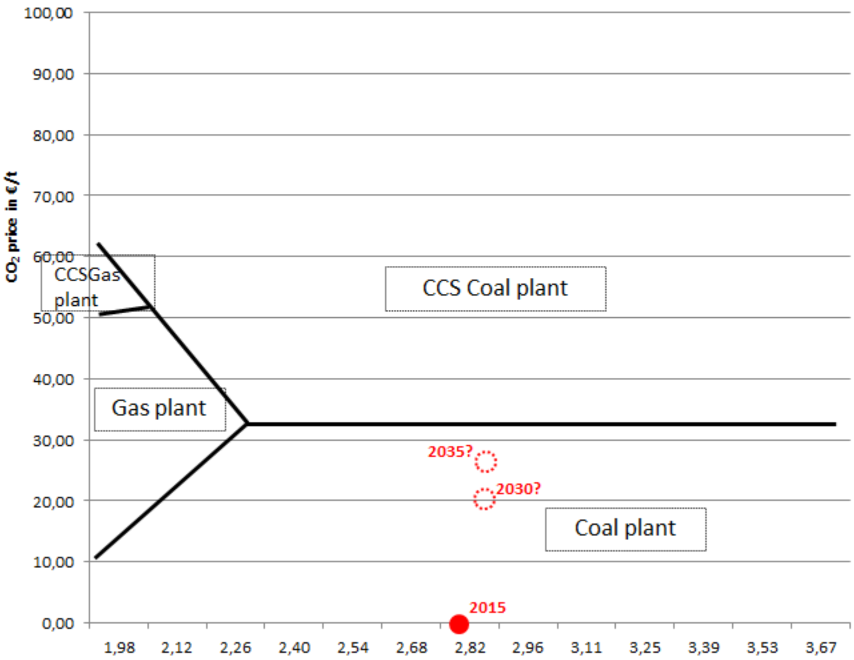
Figure 2.2: Profitability areas for the different power plant types based on fuel price ratio and CO_2 price in the European Union. Simulations on DECC's cost data (2012, 2013), offshore T&S costs.



Methodology from Blyth et al. (2007, [19]). The gas price varies by more or less 30% whereas the coal price is fixed. Interpretation: when the fuel price ratio equals 2, the gas price is twice as high as the coal price.

For China in 2030, CCS (coal) plants are projected to become the most cost-effective power plant type beyond €35/tCO_2 (Table 2.13) compared with the 2015 threshold of €45/tCO_2 (Part 2.3.2.4). This CO_2 price level could be reached realistically, as the IEA (2012, [117]) forecasts CO_2 prices to be €20/t in 2030 and €25/t in 2035 (Figure 2.3). In addition, as onshore T&S costs are half as expensive as offshore costs, CCS coal plants with onshore T&S infrastructures may be the most profitable plant type for a CO_2 price lower than €30/t. Thus, Chinese actors should keep these considerations in mind when they invest in new power plants in the early 2020s (and choose CCS coal plants) or should be ready to retrofit plants to CCS by 2030 (Figure 2.3).
At mid-load, coal plants have the lowest LCoE from €0 to 35/tCO_2, followed by a switch favourable to gas plants; beyond €65/tCO_2, CCS coal plants have the lowest LCoE.

Figure 2.3: Profitability areas for the different power plant types based on fuel price ratio and CO_2 price in China. Simulations on DECC's cost data (2012, 2013), offshore T&S costs.



Methodology from Blyth et al. (2007, [19]). The gas price varies by more or less 30% whereas the coal price is fixed. Interpretation: when the fuel price ratio equals 2, the gas price is twice as high as the coal price.

To summarise, given the prospective of carbon/fuel/cost prices, CCS should be competitive in China by 2030. Thus, no considerable support measures are required unless the Chinese government wants to accelerate CCS deployment, for instance, for sanitary reasons (e.g., smog in Chinese cities with high death rates). In contrast, in the EU, there is a large gap between the CO_2 price that would trigger CCS investment (over than €85/t) and the forecast CO_2 market price (€30/t).
Given the goal of minimising the cost of the ecological transition linked with the idea of burden sharing in GHG mitigation, the EU could thus consider the option of supporting CCS deployment in a low building/operating cost country such as China. Such support from the EU to China could include monetary/technology transfers, R&D agreements (MOU*), etc. One can refer, for instance, to the R&D "US-China Joint agreement on climate change", signed in April 2013 between China and the United States. A Climate Change Working Group was created. Within this framework, four of eight partnership acts signed in July 2014 are joint carbon capture, transport, use and storage demonstration projects. In addition, under the framework of the US-China Agreement on their respective carbon emissions signed in November 2014, the two countries reaffirmed the importance of strengthening their bilateral cooperation on climate change and emphasised a commitment to advance Carbon Capture Use and storage demonstration. In this perspective, they will undertake a LSIP in China (1 MtCO_2/yr), coupled with enhanced water recovery (1.4 million cubic meters per year; water scarcity is another main is-

sue in China). To give another example of such collaboration, one can cite the cooperation agreement between the Guangdong province and the UK based research institutes, or the International organisation for standardisation (ISO) technical committee, co-lead by China and Canada, that writes the international Carbon Capture Use and Storage for the entire process (including EOR). The advantage of such collaborative efforts is significant for both countries: developing CCS technology at the lowest cost will reduce the burden for China and will enable developed countries to use the technology when mature (and thus cheaper).
Similarly, investors/utilities from developed countries should also consider developing CCS investment and collaborations with China.

There is another option to decrease CCS deployment costs which is not based on a geographical approach but on a techno-economic one: partial capture. Partial capture allows to improve the economics of CCS plants (see 2.4.1.3). As partial capture may be less costly to deploy than full capture, it could accelerate the commercial development of CCS techniques. CCS being mature more quickly, the overall cost of CCS deployment, and thus of a carbon neutral power sector, would be reduced. Countries which intend to widely use CCS in their future energy mix may be interested in making CCS a technology to export[8]: in this perspective, partial capture is an interesting option.

2.4 Minimising CCS cost deployment trough a techno-economic approach

2.4.1 Partial capture

As previously underlined, most public studies use a carbon capture rate of 90%. However, there are no techno-economic justifications for this high level of carbon capture rate, particularly in the current economic context of low CO_2 prices and no expectation to see a sudden rise, at least in short- to medium-term. Indeed, full capture has considerable impacts on the plant efficiency and project economics. The higher the capture rate, the higher CCS costs and the lower the plant efficiency (Hildebrand and Herzog, 2009 [78]).
Consequently, investors interested in demonstrating carbon capture technology often consider the option of partial capture. Once the technology is mature and economically attractive, power plants are upgraded to full CCS.
Few public reports or scientific papers deal with the economic aspect of this issue. To our knowledge, they are: DoE-NETL (2011, [41])[9], Zhai and Rubin (2012, [148]), Coussy and Raynal (2013, [26]) as well as Clare et al's (2013, [24]).
Hereafter will be presented the advantage of partial capture with respect to full capture as well as the policy implications.

[8] This is one the arguments used the UK Government to justify CCS support measures: they are costly but will create jobs and will constitute a technology to export around the world, *i.e.* that will contribute to economic growth.

[9] IEA-ETSAP's report (2010, [80]) relies on sets of cost data from a previous version of the DoE-NETL's report (2011, [41]).

2.4.1.1 What is partial capture?

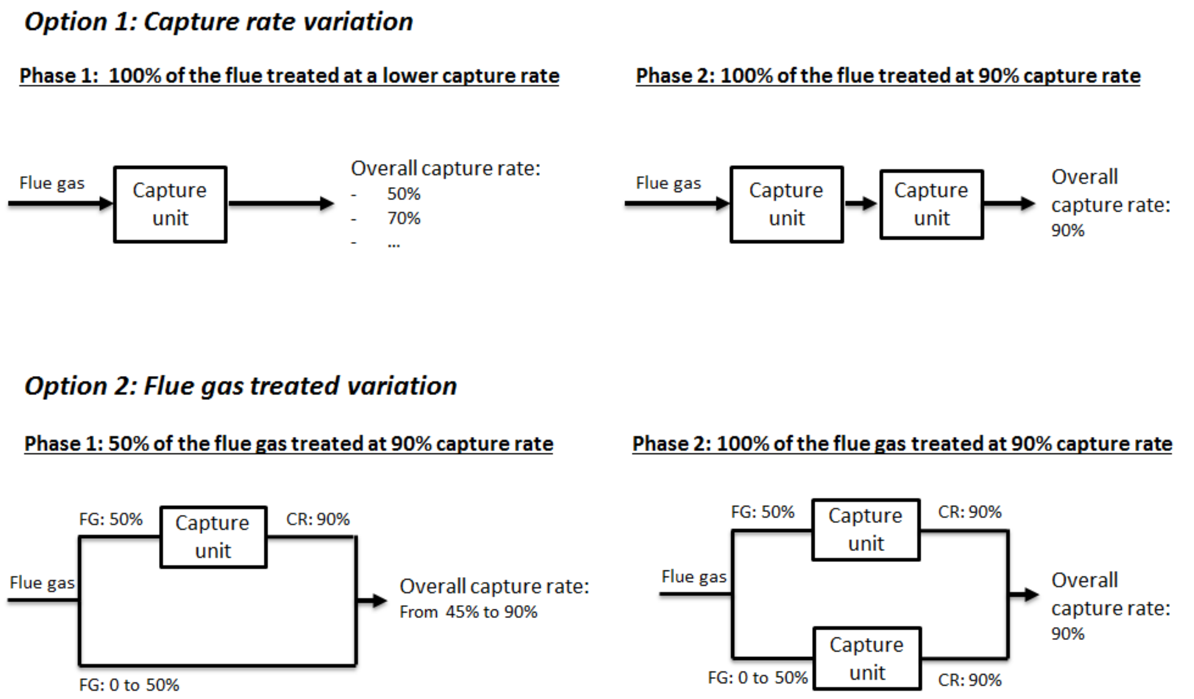
Most power plants have several power generation units. We do not consider as partial capture, cases where a power plant with several units would capture CO_2 in one or more power generation units, and would not capture CO_2 at the other units. Partial capture corresponds thus to cases where the overall capture rate is reduced within an individual power generation unit.
There are two significant options to decrease the overall capture rate:

- Capturing a relatively low fraction of CO_2 emissions, by adopting a CO_2 capture rate lower than 90% (e.g., 70% or 50%). Option 1 in Figure 2.4.

- Treating only part of the flue gas. For instance, for a pulverised coal plant, it would consist in capturing CO_2 in one or more combustion trains, and not capturing CO_2 at the other trains. Treating 50% of the flue gas instead of 100% would require to equip one combustion train instead of two. Option 2 in Figure 2.4.

The first option (reducing the capture rate) means that changes would have to be done for each generation unit/capture train when higher capture rates are required. This might implies more modifications and longer overall plant shutdown (IEA GHG R&D Programme, 2009 [82]).
The second option (treating only part of the flue gas) has the advantage that when tighter CO_2 regulations are introduced, carbon capture can be implemented to the unabated generation trains, without any change for the trains already equipped with capture devices.

Figure 2.4: Partial capture concept.



[a] CR stands for Capture Rate and FG for Flue Gas.

2.4.1.2 Technical feasibility of partial capture

The technical feasibility of partial capture depends on the capture technology: pre-combustion combined with IGCCs, oxy-combustion plants, and post-combustion with (Ultra)Super-Critical Pulverised Coal plants and NGCCs.

Pre-combustion

The overall CO_2 capture rate can be manipulated varying:

- The extent of the water shift gas reaction. The amount of CO turned into CO_2 is varied by shifting more or less syngas stream.
- The solvent circulation rate and thus the CO_2 removal efficiency (in the acid gas removal unit).

Oxy-combustion

According to the IEA-GHG R&D Programme (2009, [82]), partial capture within an individual power generation unit is not feasible.
In a very recent article, Perrin et al. (2015, [122]) have stated that partial capture can apply to oxy-combustion power plants. However, the authors explain that to achieve a 50% CR, the boiler can operate twelve hours in air mode (see 2.4.3.3) and twelve hours in oxy-mode while the ASU, whose size is divided by two with respect to full capture, is operated at constant load. In fact, it corresponds to "phased-capture" rather than to partial capture (in which the overall capture rate is constantly lower than the capture rate observed with full capture, not decreased on average as with "phased-capture").

Post-combustion

The two options are available.
It is possible to decrease the percentage capture in post-combustion scrubbing processes. The entire flue gas steam passes through the scrubbing unit at reduced solvent rates. In other words, the solvent circulation rate is reduced thereby decreasing the amount of CO_2 which is captured.
If there are several units or trains of combustion, it is also possible to feed part of the flue gas to a capture unit, maintaining the same high solvent circulation rate and stripping steam requirement, and to bypass the rest of the flue gas around the capture unit *i.e.* the scrubber (Figure 2.4).

2.4.1.3 Why partial capture rather than full capture?

Partial capture is less capital intensive than full capture which reinforces the cost-competitiveness of CCS power plants in a context of low carbon prices.

Indeed, contrary to full capture, partial capture implies lower capital costs because smaller or fewer pieces of equipment are required. For instance, for post-combustion, a single capture train instead of two is required, and for pre-combustion, a smaller number of reactor stages is required for the conversion of CO into CO_2.
Partial capture can also save auxiliary loads related to capture, can reduce water demand and can also potentially save on consumables such as solvent and catalyst. It means that a lower

capture rate decreases the operating costs with respect to full capture (IEA-GHG, 2009 [82]). To summarise, partial capture leads to lower capital and operating costs and thus improves the economics of CCS power plants resulting in lower financial risks, which is particularly interesting in the current context of credit crunch (consequence of the 2009 economic downturn).

Hereafter are presented the economic implications of partial capture for coal plants. The carbon capture process is post-combustion. The following cases are compared: capture rate of 90% *i.e.* full capture, capture rate of 70% and capture rate of 45% due to a bypass. Ultra-supercritical coal plants with a 45% CR have a CO_2 emission factor similar to open-gas cycle plants (480-585 kgCO_2/MWh; IEA-ETSAP, 2010 [80]). Note that gas plants as well as the oxy-combustion and pre-combustion processes are not studied because of the lack of available public data.
As previously mentioned, few public reports or scientific papers deal with the economic aspect of this issue: DoE-NETL (2011, [41]), Zhai and Rubin (2012, [148]), Coussy and Raynal (2013, [26]) as well as Clare et al (2013, [24]). DoE's (2011, [41]) as well as Zhai and Rubin's (2012, [148]) sets of cost data are analysed with techno-economic assumptions consistent with the ones used in Chapter 1 and part 2.3 (Table 2.14). Coussy and Raynal (2013, [26]) and Clare et al (2013, [24]) only provide aggregated sets of cost data which do not allow us to apply the standardisation process. Therefore, their studies are used as benchmarks.

Table 2.14: Underlying techno-economic assumptions for studying partial capture.

Techno-economic hypothesis	**Unit**	**Figures**
Lifetime	years	40
Capacity factor	%	85
Discount rate	%	8
Carbon content of coal (Douglas premium)	%m	38
Coal price	€/MWh	10
Solvent price	€/tCO_2	6
Price of carbon capture consumables	€/tCO_2	1

Table 2.15: Comparison of partial and full capture costs.

Cost component	Unit	90% CR	45% CR	70% CR
LCoE	% of variation with respect to ref.plant	+100%	+45%	+70%
Efficiency	Difference in points of % with respect to the ref. plant	-8	-4	-6
Additional investment	Diff. in points of % with respect to the ref. plant	+80%	+45%	+70%
Additional O&M costs	Diff. in points of % with respect to the ref. plant	+40%	+15%	+30%
Additional fuel cost	Diff. in points of % with respect to the ref. plant	+20%	+10%	+15%
Additional solvent cost	Diff. in points of % with respect to the 90% CR plant	X	-50%	-40%
Additional T&S costs	Diff. in points of % with respect to the 90% CR plant	X	-55%	-25%

With respect to the reference coal plant, the LCoE increases by (Table 2.15):

- 100% for coal plants with a 90% capture rate[10].
- 70% for coal plants with a 70% capture rate.
- 45% for coal plants with a 45% capture rate.

One can observe that decreasing the capture rate from 90% to 70% reduces extra CCS costs (in terms of LCoE) by 15-20%.
When using a capture rate of 45% instead of 90%, extra CCS costs are reduced by 55%. To simplify, the investment and operating costs due to CCS are divided by two plus a 10% increase. This 10% additional increase corresponds to the extra-costs caused the bypass system. CCS extra-costs are thus significantly reduced. In comparison with ultra-supercritical coal plants, it costs a third more to build it with a 45% CR[11]. The increase in costs is considerable but the extra-costs due to the capture process are significantly lower with partial capture than with full capture.

Partial capture leads to a lower LCoE than full capture due to several reasons:

- In comparison with full capture, efficiency penalties due to the carbon capture and compression processes are reduced, on average:
  - By 20% when the capture rate is 70%.
  - They are divided by two when the capture rate is 45%.

[10] This percentage is higher than the average value observed in Chapter 1 (80%). It might be explained by the fact that it corresponds to FOAK power plants.
[11] It costs approximately two thirds more to build it with a 90% CR.

- In comparison with full capture, the additional investment costs due to CCS equipments and infrastructures are reduced, on average:

  - By 15% when the capture rate is 70%.

  - They are divided by two plus a 10% increase when the capture rate is 45%.

- In comparison with full capture, the additional fixed and variable operating and maintenance costs due to CCS are reduced, on average:

  - By 30% when the capture rate is 70%.

  - By 60% when the capture rate is 45%.

- In comparison with full capture, the additional fuel costs due to CCS efficiency penalties are reduced, on average:

  - By 25% when the capture rate is 70%.

  - By 50% when the capture rate is 45%.

- In comparison with full capture, the additional solvent costs due to carbon capture are reduced, on average:

  - By 40% when the capture rate is 70% (the solvent is regenerated at a lower temperature).

  - By 50% when the capture rate is 45%.

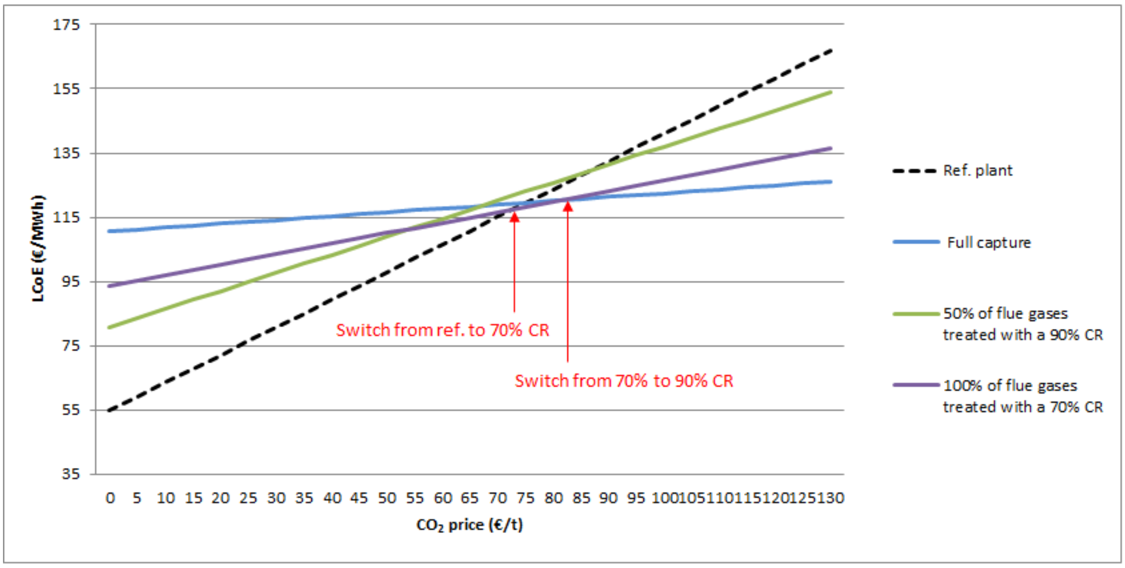
- In comparison with full capture, the additional carbon transport and storage costs are reduced, on average:

  - By 25% when the capture rate is 70%.

  - By 55% when the capture rate is 45%.

Consequently, one can deduce that varying the amount of treated flue gas (option 2) decreases more significantly the additional costs due to CCS than decreasing the capture rate (option 1). Thereby, CO_2 switching prices from reference plants to CCS plants with partial capture are lower than CO_2 switching prices from reference plants to CCS plants with full capture (Figure 2.5).

Figure 2.5: The effects of partial capture on the CO_2 switching prices.



Power plants with partial capture have lower investment an operating and maintenance costs than power plants with full capture. Consequently, one could expect that beyond a given CO_2 price threshold, a first switch happens from reference plants to power plants with partial capture, and then, beyond a higher CO_2 price threshold, a second switch happens from power plants with partial capture to power plants with full capture.

This scheme can be observed in Coussy and Raynal's paper (2013, [26]), Clare et al's paper (2013, [24]) and with DoE's data (2011, [41]), *i.e.*, one can note a switch from reference to 70% CR power plants, and then from the the latter to 90% CR power plants (Figure 2.5).

However, when the power plant with a 70% CR is a full size CR power plant operating at a lower capture rate *i.e.* is not a power plant with an optimised design for a 70% CR, one can observe a direct switch from reference to full capture plants (Figure 2.5; Clare et al's, 2013 [24]; DoE, 2011 [41]).

Which is rather surprising is that one cannot observe a switch from reference coal plants to 45% CR plants when the CO_2 price is high enough, and then from the latter to 70% CR and so on. In other words, 45% CR plants never have the lowest LCoE[12]. Nevertheless, although 45% CR power plants are never the most profitable power plant type for a certain range of CO_2 prices, they might still be an interesting option, notably more interesting than 70% CR power plants. Indeed, the switch from 45% to 70% CR power plants is very close to the switch from 70% to 90% CR power plants (Figure 2.5) (Clare et al., 2013; [24]; DoE, 2011 [41]). More precisely, from €0 to 55-60/tCO_2, 45% CR power plants have a higher LCoE than reference plants but a lower generating cost than power plants with a 70% and 90% CR. As the switch from reference to 70% CR power plants is around €60/t, and the switch from 70 to 90% CR power plants is approximately €65/t, it might be more interesting to build 45% CR power plants, particularly if the CO_2 market price remains below €55/tCO_2 for a long time and does not increase sharply but steadily.

[12]The switch from 45% CR to 70% CR power plants occurs earlier than the switch from reference to 45% CR power plants.

Detailed business plans taking into account the year of construction, fuel prices as well as the CO_2 price evolution during the lifetime of the power plants might be required to really optimise the choice between 45% and 70% capture rates.

During the CCS commercial deployment phase, low CO_2 market prices are expected around the world. Using partial capture could considerably decrease the extra-costs due to CCS devices. With a 45% capture rate and low CO_2 prices, the additional costs due to CCS might be reduced by 35 to 45% with respect to full capture (DoE, 2011 [41]; Zhai and Rubin, 2012 [148]; Clare et al., 2013 [24]), with the possibility to switch from partial to full capture when the CO_2 price is high enough.

As partial capture is less costly than full capture when CO_2 prices are low, it could facilitate CCS implementation from first movers compared to full capture. One could thus expect that partial capture will be deployed sooner and faster than full capture. Partial capture may thus be seen as a transitional strategy to accelerate the large-scale deployment of full capture.

In the long term, more stringent carbon regulations are expected. One can expect that full capture will gradually become more economically attractive than partial capture. Indeed, when the CO_2 price is high enough, the relative higher capital and operating expenditures of full capture with respect to partial capture are offset by a lower cost of emitting CO_2. Consequently, upgrading CCS plants to full capture becomes interesting.

Technical advantages of partial capture with respect to full capture.

Partial capture is often easier to implement technologically. For instance, according to the IEA-GHG (2009, [82]), turbine modifications for IGCC plants are required in the full capture case but not in the partial capture case.

Consequently, first movers may face lower risks.

Furthermore, operational issues are likely to arise for the first demonstrators: having a bypass system will facilitate servicing carbon capture equipments with limited impacts on the remainder of the plant. The economics of CCS plants may thus be reinforced.

Partial capture can strengthen the operating flexibility of power plants with post-combustion.

Some power plants need to vary their power output to match the daily and seasonal variations in power demand.

With the increasing share of intermittent RES in most electricity mixes, it is likely that future fossil-fired power plants will be required to provide flexible generation and to ensure that reliable electricity supplies are maintained. CCS power plants will thus be required to operate with a certain degree of flexibility, with frequent load variations and even cycling load regimes (Domenichini et al., 2013 [42]). Thereby, in its last report, the GCCSI (2014, [63]) noted that "one increasingly important feature of capture system is designing for flexibility in power plants with CCS".

In comparison with full capture, partial capture can better preserve efficiency (particularly, less steam is consumed by capture equipments) and the ability to change the power output in response to the variable electricity demand of the grid, thereby reducing the risk of stranding and ensuring that emission reductions will occur (DoE-NETL, 2011 [41]).

In addition, partial capture through a bypass system is particularly interesting for power plants

with post-combustion capture because it allows to operate the capture unit at continuous full load, and to vary the flow-rate of the bypass stream (Chalmers et al., 2009 [23]; IEA-GHG, 2009 [82]). By referring to Figure 2.4, option 2 - Phase 1, the power plant can operate from base- to mid-load and thus can vary its output to match the demand. Typically, with a bypass system, it is possible to reduce the flow through the capture equipment during peak demand, and thus to increase the output.
For power plants with oxy-combustion capture, liquid oxygen storage (air-mode) can help to increase the operating flexibility (see 2.4.3.3).
Consequently, partial capture can improve the economics of CCS plants in comparison with full capture.
Partial capture can optionally be exploited to increase the operating flexibility of CCS plants (Hildebrand and Herzog, 2009 [78]), but dedicated techniques, intrinsically linked with the technology of the power plant, can also improve their operating flexibility as well as increase their peak power output when the electricity demand from the grid is high.

2.4.2 From partial capture to operating flexibility

There is currently little information available in the public domain on the operating flexibility of CCS power plants for the three CO_2 capture processes (IEA GHG, 2012 [83]). Additional LSIPs, empirical research as well as dynamic modelling are required.
In addition, the flexibility issue concerns the overall chain, including the CO_2 compression, transport, injection and underground storage (IEA-GHG, 2012 [83]). However, a few public studies deal with this issue (see for instance IEA-GHG, 2012 [83]). Particularly, to our knowledge, there is no study analysing the case of carbon transport and storage networks (several power plants and/or injection sinks).[13]
As little work has been conducted about the operating flexibility of carbon transport and storage infrastructures, hereafter, the focus will only be on carbon capture.

The intrinsic operating flexibility is related to the plant process: ultra-supercritical pulverised coal (USC PC) plants[14], IGCCs, oxy-combustion plants and natural gas combined cycles (NGCCs). The operating flexibility of a power plant can be assessed through four main parameters: part-load efficiency, ramp rate[15], minimum load level, and start-up time. These four parameters are used as criterion to assess the impact of the CO_2 capture on the operating flexibility of a given power plant type.

2.4.2.1 Part-load efficiency

NGCCs, IGCCs and USC PC plants with carbon capture have rather similar part-load efficiencies to the analogous power plants without carbon capture. Oxy-combustion power plants have the same figures as the analogous plants in air-firing mode (IEA-GHG, 2012 [83]).

[13] According to the IEA-GHG (2012, [83]), implementing a CO_2 buffer storage could be a possible solution to maintain a constant CO_2 flow rate in transport pipelines and injection sinks. The extra-cost due to this CO_2 buffer storage could even be offset by a reduction in the size of the pipeline(s) and injection well(s). This solution can be adapted to all the power plant and capture types.

[14] Supercritical or ultra-supercritical pulverised coal plants are the coal power plant types adapted for post-combustion capture.

[15] The ramp rate corresponds to the % of maximum load per minute.

2.4.2.2 Ramp rate

The ramp rate does not seem significantly affected by the capture unit (IEA-GHG, 2012 [83]; Domenichini et al., 2013 [42]).
It can be noticed that for IGCC and oxy-combustion plants, the ramp rate is intrinsically limited by the ASU (Air Separation Unit producing the oxygen).

2.4.2.3 Minimum load level

The minimum load level of a power plant with CO_2 capture is not significantly affected by the capture unit.
Indeed, every capture system shall be able to operate with a minimum load of 30%, except CO_2 compressors. The minimum load level of a CO_2 compressor train is around 70%, so that it could penalise the minimum load level of a CCS power plant. However, the use of several compressors can address this issue.
One needs to notify that the minimum load of ultra-supercritical pulverised coal plants is lower than IGCC plants: 30-35% *vs.* 50-60% (IEA-GHG, 2012 [83]).

2.4.2.4 Start-up time

For oxy-combustion plants, start-up times are limited by the ASU with a hot start-up time of at least 6 hours *vs.* 1.5 to 2.5 hours without carbon capture. However, as recently reported by the GCCSI (2014, [63]), the ASU itself may be used as buffer system by producing and storing extra oxygen during low demand period to release it during peak demand period (see 2.4.3.3).
IGCC plants with pre-combustion capture have similar start-up times to IGCCs without CCS. Note that the operating flexibility of IGCC plants is intrinsically limited, mainly because of the inertia of the gasifier and the air separation unit with hot start-up time of at least 6 hours. In addition, the syngas generation is made for an immediate use in either power/chemical units, which makes the operating flexibility difficult for IGCC plants (IEA-GHG, 2012 [83]).
One interesting point is that post-combustion capture does not seem to increase the start-up time of USC PC and NGCC power plants. However, according to the IEA-GHG (2012, [83]), a compatibility problem could raise for NGCCs. Indeed, the hot/warm start-up time is quicker for NGCCs than for the capture unit (total unit hot start-up time below 40 minutes *vs.* 2 hours for the hot start-up of the strippers of the capture unit). USC PC plants are not concerned with this issue because their hot start-up time is, like the capture unit (strippers), of approximately 2 hours.

To summarise, adding a capture unit affects neither the ramp rate of a given power plant type, nor its ability to operate at part load.
Nonetheless, for oxy-combustion plants, the Air Separation Unit start-up is long (approximately 36 hours; IEA-GHG, 2012 [83]), and for NGCCs, the hot/warm start-ups are quicker for the gas plant than for the capture unit.

2.4.3 Additional techniques improving the operating flexibility of CCS power plants

Depending on the specific characteristics of power plants, there are several technical options able to improve their operating flexibility when equipped with CCS devices (Chalmers et al., 2009 [23]; IEA-GHG, 2012 [83]) (Table 2.16).

Table 2.16: Additional techniques improving CCS power plant operating flexibility.

	IGCC	USC PC	NGCC	Oxy-combustion
Turning-off/down CO_2 capture	Yes	Yes	Yes	No
Storage of CO_2 capture solvent	No	Yes	Yes	No
Storage of liquid Oxygen	Yes	No	No	Yes
Storage of Hydrogen	Yes	No	No	No

2.4.3.1 Turning off/down CO_2 capture

The net electric output of a power plant can be increased by turning-off/down the CO_2 capture and compression units. As a consequence, this power plant will emit more CO_2 in the atmosphere. Except in the case of free CO_2 emission allowances, it implies a trade-off between selling more electricity and purchasing quotas for the emitted CO_2.
As underlined in 2.4.1.2, an IGCC plant cannot turn-off CO_2 capture, but can turn it down by varying the solvent circulation flow rate in the acid gas removal unit.
Turning-off CO_2 capture is possible for power plants with post-combustion capture, by bypassing the capture unit.

However, turning-down/-off CO_2 capture has a cost: it notably increases the capital cost (larger equipments are required, particularly the steam turbine)[16].
Consequently, the cost-efficiency of turning-off CO_2 capture will depend on the related extra-costs, the carbon price, the peak electricity selling prices, the number of peak hours, as well as the cost of the other peak load generation techniques, particularly simple cycle gas turbines.

2.4.3.2 CO_2 capture solvent storage

For both USC PC and NGCC plants with post-combustion capture, solvent storage can improve their operating flexibility. Indeed, during low electricity demand periods, the stored solvent is regenerated and the captured CO_2 is compressed. In contrast, during high electricity demand periods, the electricity production can be increased: the temporary storage of CO_2 rich solvent in dedicated storage tanks enables the reduction of the energy penalty due to capture process,

[16] As the steam turbine is over-sized, the net efficiency of the power plant decreases, but it can be solved with an additional steam turbine.

particularly by saving the steam extracted from the steam cycle and the CO_2 compressor power demand.
In addition, the net thermal efficiency also increases which improves the overall economics of such plants.
Note that if the number of peak hours is too high (e.g., several hours a day), the capacity required to store the CO_2 capture solvent would be very large. This kind of scenarios is not cost-competitive with alternative peak load technologies. In contrast, scenarios with a few peak hours (a day) during which solvent regeneration is shut down completely, are cost-competitive with alternative peak load technologies, particularly simple gas turbines (IEA-GHG, 2012 [83]).

2.4.3.3 Liquid oxygen storage

In both IGCC and oxy-combustion plants, the production of oxygen (ASU) negatively impacts the overall net electricity generation (high energy consumption).
Liquid oxygen storage can decrease the energy consumption required by the ASU.
During low electricity demand periods, the plant operates at part-load whereas the ASU operates at full load to produce the liquid oxygen that will be stored. In high electricity demand periods, the power plant operates at full-load whereas the ASU operates at minimum load: the amount of oxygen required by the power plant is released from the storage. The switch from air to oxy-mode (and vice-versa) can be realised in less than 30 minutes (Perrin et al., 2015 [122]). This flexibility enables the maximisation of the power output during peak time.
From the IEA-GHG (2012, [83]), to increase the amount of electricity during peak hours still further, two smaller air compressors can be considered instead of one. This would allow to tun-off one air compressor during peak hours.
According to the IEA-GHG (2012, [83]), the capital costs of extra-peak generation are relatively low because storage volumes are smaller than for solvent storage, and no additional power generation equipment are required. Indeed, the increased peak power is achieved by reducing the plant's ancillary power consumption (ASU). As a consequence, the capital cost of this extra-peak generation, in the daily storage scenarios, is cost-effective with respect to single cycle gas turbines, with a significant advantage: the peak electricity is decarbonised.

2.4.3.4 Hydrogen storage in IGCC plants

The plant is designed for the co-production of electricity and hydrogen. In that case, the hydrogen production is independent from the electricity production. As a consequence, the gasification, carbon capture, transport and storage equipments can operate at continuous full load, while the power plant varies its output to match the variations of power demand.
During low electricity demand periods, the excess of syngas is stored underground. In high electricity demand periods, the stored hydrogen is released to produce more electricity, or supply other energy consumers.
In that case, large underground buffer storage of decarbonised hydrogen rich-gas or high purity hydrogen is required (IEA-GHG, 2012 [83]).

It seems likely that power plants with CO_2 capture will be deployed in a wide range of operating situations. Consequently, the use of this kind of techniques improving the operating flexibility of CCS plants will depend on the characteristics of the electricity market.

As progress is made in future carbon capture processes, these techniques warrant further investigation to get public data allowing us to assess their potential to make CCS plants more attractive and cost-effective.

2.5 Conclusion

It has been shown that there are two options to reduce the cost of CCS techniques during the demonstration phase.
The first one is based on the geographical differentiation of costs: it could be economically advantageous for developed countries to commercially demonstrate and deploy CCS techniques in low building and operating cost countries like China. Then, once the technology is mature and thus less expensive, developed countries could deploy CCS. Within the framework of international climate change negotiations, European CCS actors should thus consider the opportunity of supporting CCS deployment in developing countries.
To decrease the costs due to CCS deployment, there is another option which is based on a techno-economic approach: partial capture. Indeed, partial capture allows to improve the economics of CCS plants which could accelerate the commercial deployment of CCS techniques. CCS being mature more quickly, the overall cost of CCS deployment, and thus of a carbon neutral power sector, would be reduced.
Countries which intend to widely use CCS in their future energy mix may be interested in making CCS a technology to export. In this perspective, the geographical approach is not relevant. Partial capture becomes a really interesting option because it reduces immediately the global costs of CCS commercial deployment.
When the geographical approach is considered by developed countries, partial capture can also be an interesting option for developing countries. Applying this technical option could reduce even further the cost of CCS deployment and thus the overall cost of the power sector decarbonisation.

Chapter 3

Public Acceptance and Optimal Pollution: CCS or Tax?[1]

3.1 Introduction

As emphasised in Chapters 1 and 2, although CCS is an expensive and capital intensive technology, it may be cost-effective with other low carbon energy supply technologies such as offshore wind, and even with fossil fuel plants provided that the CO_2 price is high enough.

Nonetheless, the potential cost-effectiveness of CCS techniques is a necessary, albeit not sufficient, condition for their future deployment. Indeed, a technology can be economically attractive but not deployed because of social acceptance issues. As mentioned earlier, in addition to the cost, public acceptance is the second significant obstacle to CCS deployment. To clarify, social acceptance of CCS projects here is understood as not being for or against CCS projects: they are just accepted.

More broadly, as underlined by the latest report from the IPCC (2014, [87]), public acceptance has appeared to be a prerequisite for the successful adoption and diffusion of low-carbon energy supply technologies over the last years. Indeed, public opposition can impede or delay their development: "Many low-carbon energy supply technologies (including CCS) and their infrastructural requirements face public acceptance issues limiting their deployment" (IPCC, 2014 [87]). As for renewable energy sources, widespread opposition towards new projects, particularly wind farms[2], has been observed over the last few years, despite economic viability for several applications (Ekins, 2004 [47]). As a consequence, RES have been deployed to a smaller fraction than their potential.

For CCS, early misgivings[3] include the ecological impacts related to carbon transport and storage infrastructures on a national site, inducing the famous NIMBY (Not In My Back Yard) problematic, as well as the potential risk of a carbon leakage (Tokushige et al., 2007 [135]). Thereby, some projects that envisaged onshore storage have faced prohibitive public opposition. Examples of this problem include the failure of a carbon storage pilot on the Kona coast (Hawaii)

[1]The reader can also refer to: P.-A.Jouvet, M.Renner. Social Acceptance and Optimal Pollution: CCS or Tax? *Environmental Modeling & Assessment*, 2014.

[2]For large wind projects, concerns primarily relate to landscape impacts as well as potential nuisance effects (e.g., noise).

[3]CCS deployment has been slower than anticipated in terms of LSIPs. To note, as of January 2015, there is only one LSIP in operation in the power sector (see Chapter 1 for more details).

because of environmental organisations (De Figuereido et al., 2003 [30]) and fierce controversies in Germany and Poland concerning the CCS Directive (2009/31/CE Directive) implementation in national law.
This social opposition seems paradoxical: public opinion surveys have shown growing awareness that urgent action is required to reduce GHG emissions, whereas growing opposition to clean energies, such as nuclear power plants and RES, is observed. Likewise, CCS power plants face this type of opposition, which can mostly be explained by the following:

- Low levels of awareness or understanding of CCS (GCCSI, 2014 [63]; Ha-Duong et al., 2009 [73]; de Best-Waldhober et al., 2009 [29]).
  The literature review indicates that respondents better understand CCS when climate issues are explained (*i.e.*, the legitimacy of this technical option) and that additional information can increase social acceptance (Tokushige et al., 2007 [135]).

- The existence of storage risks (e.g., carbon leakage) for which safety has not yet been proven due to the lack of numerous large-scale demonstrators in the power sector (Chapter 1).

As social acceptance weighs heavily on the prospects for CCS deployment, assessing accurately social preferences is thus important in determining whether CCS use is socially optimal.

Over the last years, a multitude of integrated assessment models (IAMs) have been developed to characterise future GHG emissions and to analyse the cost of policies for reducing such emissions. These models have become an important tool in the political decision making process (Edenhofer et al., 2012 [45]). Among these IAMs, some focus more specifically on low-carbon technologies like CCS and nuclear. Without being exhaustive, one can quote McFarland et al. (2003, [105]), Edmonds et al. (2004, [46]), Kurosawa (2004, [98]) and Luderer et al. (2011, [102]). Like stylized models (e.g., Moslerner and Requate, 2007 [108]), they generally give the determinants of an optimal climate policy with CCS and conclude that an early CCS use would substantially reduce the social cost of climate change.
The theoretical economic review on CCS is less abundant. Grimaud and Rougé (2014, [71]) study the effects of the availability of CCS techniques on the optimal use of polluting exhaustible resources and on optimal climate policies within an endogenous growth model. By considering carbon storage rate instead of the storage flow, Ayong Le Kama et al. (2013, [14]) develop a model to emphasise the main driving forces that should determine the optimal CCS policy. Lafforgue et al. (2008, [99]) determine an optimal CCS policy in a model of energy substitutions in which carbon emissions can be stored into several reservoirs of finite size. Amigues et al. (2012, [9]) assess the optimal timing of CCS policies by characterising the optimal path of energy price, energy consumption, carbon emissions and atmospheric abatement for several types of CCS cost functions. More recently, Amigues et al. (2014, [10]) have developed a model determining the optimal path of three energy sources (non-CCS coal, CCS coal and solar) taking into account learning-by-doing in CCS techniques.
However, none of these papers focused on CCS social acceptance.

3.2 Objectives, approach and main contributions

As a few economic models deal with CCS social acceptance, this Chapter focuses on it and aims to provide a framework addressing two related questions: is the CCS use socially optimal? And if it is, to what extent?
To determine the optimal use of CCS techniques from the social point of view, we quantify simultaneously the amount of production as well as the optimal allocation of pollution (CO_2) between the atmosphere and underground storage sites.
The objective is to address the problem as a whole contrary to academic papers. Indeed, they usually have a dichotomous approach: they consider either the atmospheric pollution (first source of marginal disutility) or the underground pollution (second source of marginal disutility). For instance, Moslerner and Requate (2007, [108]) use two stock variables and study the problem of the optimal emissions of pollutants when there may exist complementary or substitutability in emission cost. In their model, the disutility of the various pollution stocks enters in a separable way in the objective function.
We differ by considering all aspects of the issue. Straightforwardly, the use of CCS techniques creates a globally positive externality by reducing the atmospheric CO_2 concentration, but also introduces a locally negative externality due to the geological storage of carbon. To consider the problem as a whole, a third source of marginal disutility also needs to be taken into account. Indeed, considering each source of disutility separately, individuals might not be concerned by climate change issues, or by living nearby carbon storage sites. However, individuals might be reluctant to have CO_2 both above their head and under their feet. Thereby, when CCS is used, there are three sources of marginal disutility: the two sources of marginal disutiliy which are usually modelled - the marginal disutility caused by the atmospheric pollution and the marginal disutility caused by carbon storage -, and also the marginal disutility which is due to the simultaneous presence of CO_2 in the atmosphere and in underground storage sites. To summarise, both positive (the atmospheric concentration of CO_2 is reduced) and negative (disutility related to the underground concentration of CO_2 and additional disutility caused by the co-existence of two sources of pollutant) externalities due to the use of CCS techniques are taken into account. This idea is originated from Crettez and Jouvet´s (2010, [27]) paper: the authors note that when there is only one source of pollutant emissions, stocks of pollutants can still be complementary or substitutable.
As commercial CCS deployment relates to long term scenarios and the purpose of this Chapter is not to study the mechanisms of the transition, we chose the static approach rather than the dynamic one. Numerical simulations (see 3.5) were run to perform comparative statics *i.e.* to analyse the effects that changes in the parameters featuring social acceptance have on the levels of output, tax and social welfare.
With respect to Crettez and Jouvet´s (2010, [27]) paper, the novelty is to consider two cases:

- (1) Only one country is considered. It determines whether CCS is socially optimal with respect to its social preferences (see 3.4.1 and 3.4.2).
- (2) Two countries are considered, one with CCS and one without CCS (see 3.4.3).
  As there are interactions between these two countries/regions, we notably analyse how changes in the parameters featuring public acceptance in one country can affect its social welfare but also the one of the other country, and *vice versa*.

It can be noticed that this geographical approach can echo the idea developed in Chapter 2: it can be more interesting to commercially deploy CCS in a low building and operating cost country (e.g., China) than in a developed country. Vennemo et al. (2013, [137]) study the macroeconomic impact of CCS in China, comparing two finance scenarios: an internal scenario where CCS is financed by China itself through a carbon tax and an external scenario where CCS is financed by international investors. Concerning the latter scenario, Vennemo et al. (2013, [137]) state that "In the NGO community, and in China, there is an expectation that the international community will finance a significant share of CCS". For instance, external finance may come from Kyoto Protocol carbon credits, notably Clean Development Mechanisms (CDMs*), because in 2011, the United Nations Framework Convention on Climate Change agreed and adopted Modalities and Procedures for CCS as a CDM. The comparison of two cases, when countries have their own climate policy or have set their climate policy jointly, allows us to assess the transfers (monetary, technological, etc.) that OECD countries should implement to encourage low-cost countries to commercially deploy CCS within the framework of international climate change negotiations.

One can notice that the framework developed in this Chapter might be extended to nuclear waste issues, and even to social waste management issues. Indeed, nuclear waste could be seen as a good analogue to CCS, since both technologies may contribute to the power sector decarbonisation (positive externality) but have a downside: they produce waste requiring long term monitoring since future generation inherit from them for hundreds of years. As a consequence, both may raise social acceptance issues and NIMBY syndromes. Similarly to CCS, a few papers deal with this kind of trade-off for instance, Le Kama and Fodha (2010, [13]). A parallel could also be drawn with social waste management, particularly the trade-off between incinerating and burying waste. The incineration of waste could be assimilated with a power plant without CCS (emission of pollutants) and landfilling with CO_2 underground storage. Here again, a few articles deal with this issue. See for instance Dijkgraaf and Volleberg (2004, [38]).
However, because of CCS specificities, the below model may be even more appropriate for CCS techniques than for the other abatement technologies. Indeed, nuclear power plants and renewable energy technologies do not emit CO_2 when they supply electricity, in contrast to CCS power plants whose capture rate cannot reach 100% (partial capture can even be chosen to optimise the power plant costs when CO_2 market prices are low; for more details, see Chapter 2). The arbitrations related to CCS use are thus not completely identical to that of the other abatement technologies.

3.3 The model

We consider the producers of an output (for instance, energy). To produce this output, producers use a well-behaved production function (increasing and concave) $F : \mathbb{R}_+ \to \mathbb{R}_+$ with a unique input E (for instance oil, gas or coal). This function satisfies the Inada conditions: $\lim_{E\to 0} F_E(E) = +\infty$, $\lim_{E\to\infty} F_E(E) = 0$ and $F(0) = 0$. The unit cost of the input is denoted by q (in terms of the produced good).

A representative firm maximises its profit, π:

$$\max_{E} \pi = F(E) - qE \tag{3.1}$$

With perfect competition, the factor price q is given and is equal to the marginal productivity:

$$F_E(E) = q \tag{3.2}$$

We assume that pollutant emissions are a joint product of the input used in the production, E. In this static framework, we consider that only a fraction of E may contribute to the atmospheric concentration of pollutants, $A(E)$. With the function $A(.)$, we accept that the effect of E on the atmospheric concentration of pollutants is not necessarily one to one. We assume that $A_E(E) \geq 0$ and $A_{EE}(E) \geq 0$[4].

Each agent derives its utility from the consumption of goods, $C = F(E) - qE$ and is negatively affected by the atmospheric concentration of pollutants, $A(E)$. Household preferences are represented by a utility function $U(C, A(E))$:

$$U(C, A(E)) = F(E) - qE - \theta_1 A(E) \tag{3.3}$$

where $\theta_1 > 0$ is a preference parameter, representing the marginal disutility caused by the atmospheric concentration of pollutants.

Introducing CCS techniques implies that the effect of E on the atmospheric concentration of CO_2 can be reduced. We denote by Z, the quantity of pollutant emissions which is captured and then stored underground between 700 and 5,000 m (depleted oil and gas fields or deep saline aquifers). The effect of carbon storage on the atmospheric CO_2 concentration implies $A(E, Z)$ with $A_Z(E, Z) < 0$. In other words, the use of CCS techniques creates a globally positive externality.

The geological storage of carbon dioxide creates an additional and local pollution denoted $S(Z)$ with $S_Z(Z) \geq 0$ [5]. This storage affects agent's preferences in two ways.

Firstly, the underground storage induces a new direct disutility, $\theta_2 S(Z)$ where $\theta_2 > 0$ is a preference parameter. It represents the marginal disutility caused by storage sites. One can notably think about the NIMBY problematic: individuals may be reluctant to have a carbon storage site in their neighbourhood.

Secondly, pollutants are now simultaneously both in the atmosphere and underground. This double pollution induces a new effect: $G(A(E, Z), S(Z))$. Considering each source of pollution separately, individuals might not be concerned by climate change issues, or by living nearby carbon storage sites. However, individuals might be reluctant to have CO_2 both above their head and under their feet. In other words, they may be reluctant to be exposed to two simultaneous sources of pollutants. Consequently, unlike most academic papers that have a dichotomous approach and consider either the atmospheric or the underground pollution, with $G(.)$ we consider the problem as a whole: CCS introduces a third source of disutility due to the simultaneous presence of CO_2 in the atmosphere and in geological formations. $G(.)$ is not assumed separable. It means that each pollution affects the marginal disutility of the other. The effect can be one

[4]The atmospheric concentration of pollutants increases with the emissions of pollutants with an accumulation effect. The convexity of A has a climatic justification (IPCC, 2013 [86]).

[5]The underground storage capacity decreases with pollutant emissions.

of two kinds. On the one hand, an increase in atmospheric/underground pollution may increase the marginal disutility of the other (the pollutants would be complementary), on the other hand, the effect could be negative. That is to say, an increase in the atmospheric/underground pollution could lead to a decrease in the marginal disutility of the second one. Note that when CCS techniques are not used, the related externalities disappear and we have: $A(E,0) = A(E)$, $G(A(E,0), S(0)) = 0$ and $S(0) = 0$.
Furthermore, we also assume that the use of CCS techniques is costly, $\Phi(Z)$. This cost is measured in terms of production through a symmetrical function: $\Phi : \mathbb{R} \to \mathbb{R}_+$, which is increasing, convex and smooth ($\Phi(0) = \Phi_Z(0) = 0$). The profit function then becomes:

$$\max_E \pi = F(E) - qE - \Phi(Z) \tag{3.4}$$

In this case, household preferences are represented by[6]:

$$U(C, A(E,Z), S(Z)) = F(E) - qE - \Phi(Z) - \theta_1 A(E,Z) - \theta_2 S(Z) - G(A(E,Z), S(Z)) \tag{3.5}$$

3.4 Results: Social optimum without and with CCS

In this section, we consider that a social benevolent planner corrects environmental externalities without and with CCS techniques. Then, we decentralise the studied economy and determine the optimal carbon tax level(s) required to implement the social optimum.

3.4.1 Social optimum without CCS and decentralisation, with a tax on input

In this case, only the atmospheric concentration of pollutant is considered to compute the social optimum. The central planner objective function is:

$$\max_E U(C, A(E)) = F(E) - qE - \theta_1 A(E) \tag{3.6}$$

The First Order Condition (FOC*) is:

$$F_E(E^*) - q - \theta_1 A_E(E^*) = 0 \tag{3.7}$$

The FOC is a standard condition for the optimal solution. It states that the marginal utility loss caused by an additional pollution should be equal to the marginal utility gain due to an additional consumption.

[6] A metafunction $\widetilde{G}$ could replace the sum $\theta_1 A(E,Z) + \theta_2 S(Z) + G(A(E,Z), S(Z))$. However, as one of the main objectives is to perform comparative statics and isolate the effects of θ_1 (respectively θ_2 and $G(.)$) variations on the levels of the output/tax/social welfare, the three potential sources of marginal disutility were differentiated.

If environmental externalities are internalised due to a tax τ applied to the input used in the production, E, from (3.1), a representative firm will maximise its profit:

$$\max_{E} \pi^{\tau} = F(E) - qE - \tau E \tag{3.8}$$

We obtain the following condition:

$$F_E(E) - q - \tau = 0 \tag{3.9}$$

Comparing (3.7) and (3.9), the optimal tax is defined by:

$$\tau = \theta_1 A_E(E^*) \tag{3.10}$$

The optimal Pigouvian taxation is equal to the effects of the pollution accumulation on the utility of agents. It is clear that τ increases with E.

3.4.2 Social optimum with CCS and decentralisation

In this case, the social planner corrects environmental externalities by considering environmental damage and by using CCS techniques. The objective function is:

$$\max_{(E,Z)} U(C, A(E,Z), S(Z)) = F(E) - qE - \Phi(Z) - \theta_1 A(E,Z) - \theta_2 S(Z) - G(A(E,Z), S(Z)) \tag{3.11}$$

There are two possible cases: the interior solution ($E > 0$ and $Z > 0$) and the corner solution ($E > 0$ and $Z = 0$[7]).

The optimality conditions of the interior solution ($E > 0$ and $Z > 0$) are:

$$F_E(E^{CCS}) - q - \theta_1 A_E - G_A A_E = 0 \tag{3.12}$$

and:

$$-\Phi_Z(Z^*) - \theta_1 A_{Z^*} - \theta_2 S_{Z^*} - G_A A_{Z^*} - G_S S_{Z^*} = 0 \tag{3.13}$$

The corner solution ($Z = 0$) arises if and only if:

$$F_E(E) - q - \theta_1 A_E(E, 0) = 0 \tag{3.14}$$

and

$$-\theta_1 A_Z(E, 0) - G_A(A(E, 0), 0) A_Z(E, 0) \leq 0 \tag{3.15}$$

The first optimality condition can be interpreted as above (3.7). The second condition shows that decreasing the first pollution at the margin yields a benefit which is more than cancelled out by the increase in the damage due to the second pollution.

[7] The case where $Z < 0$ is not studied here because it would correspond to a carbon leakage.

Considering the interior solution $Z > 0$, we have:

$$-\Phi_Z(Z^*) - \theta_1 A_{Z^*} - \theta_2 S_{Z^*} - G_A A_{Z^*} - G_S S_{Z^*} = 0 \tag{3.16}$$

In this case, if environmental externalities are internalised due to: a tax, ρ, applied the input used in the production, E; CCS techniques; and a new tax, γ, applied to the underground storage, from (3.1) a representative firm will maximise its profit:

$$\max_{E,Z} \pi^{\rho,\gamma} = F(E) - qE - \Phi(Z) - \rho E - \gamma Z \tag{3.17}$$

We obtain the following conditions:

$$F_E(E) - q - \rho = 0 \tag{3.18}$$

and

$$-\Phi_Z - \gamma = 0 \tag{3.19}$$

Comparing (3.12), (3.16) and (3.18), (3.19) yields the optimal policy which is defined by:

$$\rho = \theta_1 A_E(E^{CCS}, Z^*) + G_A(A(E^{CCS}, Z^*), S(Z^*)) A_E(E^{CCS}, Z^*) \tag{3.20}$$

and

$$\gamma = \theta_1 A_{Z^*} + \theta_2 S_{Z^*} + G_A A_{Z^*} + G_S S_{Z^*} \tag{3.21}$$

The signs of $G_A A_{Z^*}$ and $G_S S_{Z^*}$ are indeterminate but we know that $\theta_1 A_{Z^*} < 0$ and $\theta_2 S_{Z^*} > 0$. Thus, *a priori*, γ has an indeterminate sign which reflects the fact that the introduction of CCS techniques causes both positive and negative externalities. The sign of this optimal fiscal tool depends on the global assessment of this double externality: the carbon storage is thus either taxed or subsidised.

In order to compare the production, tax and welfare levels when CCS techniques are used and when they are not, one needs to specify the technology which is used and the external effects of pollution.

3.4.3 Global and/or local pollution

Considering CCS as a local pollution effect and assuming two different regions, region A without CCS and region S with CCS, we can draw the welfare effects related to the introduction of CCS in only one region. Technologies are assumed identical between the two regions. Thus, from the aforementioned equations, region A and S welfares are respectively given by:

$$U^A(C^A, A(E^A + E^S, Z)) = F(E^A) - qE^A - \theta_1^A A(E^A + E^S, Z) \tag{3.22}$$

and

$$U^S(C^S, A(.,.)) = F(E^S) - qE^S - \Phi(Z) - \theta_1^S A(.,.) - \theta_2^S S(Z) - G(A(.,.), S(Z)) \tag{3.23}$$

The first order conditions are given by:

$$F_E(E^A) - q - \theta_1^A A_{E^A} = 0 \tag{3.24}$$

$$F_E(E^S) - q - (\theta_1^S + G_A) A_{E^S} = 0 \tag{3.25}$$

and

$$-\Phi_Z - (\theta_1^S + G_A) A_Z - (\theta_2^S + G_Z) S_Z = 0 \tag{3.26}$$

Optimal production and tax/subsidy levels for each region are equivalent to the previous results.

If we compute the total welfare, the program to solve is:

$$\max_{(E^A, E^S, Z)} U^A(C^A, A(E^A + E^S, Z)) + U^S(C^S, A(E^A + E^S, Z)) \tag{3.27}$$

The optimal conditions are the following:

$$F_E(E^A) - q - (\theta_1^A + \theta_1^S + G_A) A_{E^A} = 0 \tag{3.28}$$

$$F_E(E^S) - q - (\theta_1^A + \theta_1^S + G_A) A_{E^S} = 0 \tag{3.29}$$

and

$$-\Phi_Z - (\theta_1^A + \theta_1^S + G_A) A_Z - (\theta_2^S + G_Z) S_Z = 0 \tag{3.30}$$

The comparison of the FOCs (3.24, 3.25, and 3.26 with 3.28, 3.29 and 3.30) shows that when the two countries/regions are aggregated *i.e.* have set their climate policy jointly, the marginal disutility due to pollution felt in one of the two countries directly affects the other one.

In order to analyse the sensitivity of the tax/production/social welfare levels to the variations of social acceptance parameters in the two regions as well as the total welfare sensitivity, we need to specify the technology which is used and the external effects of pollution.

3.5 Numerical simulations and discussion

Some numerical simulations are presented for illustrational purposes. Note the term illustrational: we do not intend to quantify tax and social welfare levels but rather to illustrate their sensitivity/evolution to parameter changes *i.e.* to the variation of social acceptance levels regarding atmospheric pollution, underground pollution or both.

3.5.1 Model specification and assumptions

To specify the model and acquire simple analytical developments, we assume that the production function is a Cobb-Douglas with a unique input E, and constant yield β with $0 < \beta < 1$. Classically, we have: $F(E) = E^{\beta}$.

Hereafter, the BAU case refers to the case where CCS techniques are not used and a tax, applied to the polluting input, internalises environmental externalities (See 3.4.1). The CCS case refers to the case where: CCS, a tax applied to the polluting input as well as a tax applied to the amount of CO_2 which is stored underground, are used to internalise environmental externalities (See 3.4.2).

When CCS is not used (BAU case), we assume that the atmospheric CO_2 concentration is: $A(E) = \frac{1}{2}(\alpha F(E))^2 = \frac{1}{2}\alpha^2 E^{2\beta}$ where α is the carbon content of the production and $\alpha F(E)$, the emissions of pollutant. The condition $A_{EE}(E) \geq 0$ implies that $\beta \geq \frac{1}{2}$.

When CCS techniques are used, we assume that the atmospheric and underground CO_2 concentrations are respectively:

- $A(E, Z) = \frac{1}{2}(\alpha F(E) - Z)^2 = \frac{1}{2}(\alpha E^{\beta} - Z)^2$ where $\alpha F(E) - Z$ represents the net atmospheric emissions of pollutants.
- $S(Z) = \frac{1}{2}Z^2$.

The effect induced by the double pollution is assumed to be:
$G(A(E, Z), S(Z)) = \epsilon(\alpha F(E) - Z)Z$ where ϵ intercepts both the underground and atmospheric effects of the pollutant emissions on the objective.

The cost related to the use of CCS techniques is assumed to be: $\Phi(Z) = \frac{1}{2}\phi Z^2$.

By referring to the aforementioned specifications and equations (3.10) for the BAU case and (3.20) (3.21) for the CCS case, the optimal taxation levels are:

- In the BAU case:
  $\tau = \theta_1 A_E(E^*) = \theta_1 \beta \alpha^2 (E^*)^{2\beta - 1}$
- In the CCS case:
  $\rho = \theta_1 A_E(E^{CCS}, Z^*) + G_A(A(E^{CCS}, Z^*), S(Z^*)) = \theta_1 \beta \alpha (E^{CCS})^{\beta - 1}[\alpha (E^{CCS})^{\beta} - Z^*] + \epsilon \alpha \beta (E^{CCS})^{\beta - 1} Z^*$
  and $\gamma = -\phi Z^* = \theta_1[Z^* - \alpha (E^{CCS})^{\beta}] + \theta_2 Z^* + \epsilon[\alpha (E^{CCS})^{\beta} - 2Z^*]$

Result 1: τ and ρ are taxes on the carbon intensive input and are decreasing functions of the production level (for ρ, it implies $\theta_1 \geq \epsilon$).
When CCS techniques are used, a second fiscal tool is required: γ. As $Z \geq 0$, γ is a negative tax[8], *i.e.* a subsidy dedicated to CO_2 storage[9]. $-\gamma$ is an increasing function of Z.

This idea of a subsidy dedicated to carbon storage can be found in Grimaud and Rougé (2014, [71]). Indeed, they explain that many reasons exist which prevent policy makers from implementing the Pigouvian level of the carbon tax, for instance, the lack of an international consensus. Among the second best economic policies they study, there is a subsidy to carbon storage.
Note that a subsidy dedicated to carbon storage was included in the proposals made by the US Secretary of Energy, Ernest Moniz, in February 2015. Indeed, in addition to President Barack Obama's \$30 billion Fiscal Year 2016 Budget, he proposed the payment of \$50 for each tonne of CO_2 stored underground (fund of \$2 billion).
This result has significant policy and normative implications. Subsidising carbon storage increases the absolute profitability of CCS plants with respect to non CCS plants. Consequently, the additional financial supports (FIT, CCS purchase contracts, etc.) required to trigger CCS commercial deployment would be lower, therefore reducing the risk of inefficient policies and windfall effects.

To perform numerical simulations, several techno-economic assumptions are made (Table 3.1).

[8] Note that if the public DM chooses to tax CO_2 emissions rather than the carbon intensive input, gamma is a subsidy only with specific configurations of social acceptance parameters. We chose to tax the carbon intensive input because it is rather similar to the French energy taxation system.

[9] As this model is not a general equilibrium macro-economic model, related questions such as: who will finance the subsidy dedicated to carbon storage? or is the amount of the subsidy covered by the tax revenues? are not in the scope of this Chapter and consequently are not treated here.

Table 3.1: Techno-economic assumptions required to perform numerical simulations.

Fixed parameters	Character	Value	Comments
Production CO_2 content	α^a	0.76	tCO_2/MWh
Coal price[b]	q	0.09	€/kg
CCS cost[c]	ϕ	0.046	€/kg
Coefficient of the production function	β	0.5^d	-

[a]α corresponds to the emission factor of a supercritical coal plant using hard coal. Note that simulation results are similar for a CCS gas plant.
[b]The coal price is from the New Policy Scenario (IEA, 2012 [117]) for 2015.
[c]CCS cost comes from Renner (2013, [126]) (it is similar to a CO_2 avoided cost calculated from the IEA study, with its 2030 cost projections).
Note that the subsidy is expressed in €/tCO_2 whereas taxes applied to the polluting input are expressed in €/t. In order to compare their level, we convert τ and ρ into €/tCO_2. The multiplying factor is from ADEME (2005, [5]).
[d]By referring to the aforementioned specifications and equations (3.10) for the BAU case and (3.20) (3.21) for the CCS case, the optimal production levels are: $E^* = (\theta_1\alpha^2 + 2q)^{-2}$, $E^{CCS} = [2q + \alpha^2 \frac{\epsilon^2 - \theta_1\theta_2 - \theta_1\phi}{2\epsilon - \theta_1 - \theta_2 - \phi}]^{-2}$ and $Z^* = \frac{\alpha(\epsilon - \theta_1)}{2q(2\epsilon - \theta_1 - \theta_2 - \phi) + \alpha^2(\epsilon^2 - \theta_1\theta_2 - \theta_1\phi)}$.

3.5.2 Optimal taxation and social welfare, with and without CCS: numerical simulation results

We study, *ceteris paribus*, the effects of a marginal variation of θ_1, θ_2 and ϵ on the input consumption, tax and social welfare levels (Table 3.2).

Table 3.2: Variation range for the parameters featuring social acceptance.

Variable parameters	Character	Range
Marginal disutility due to the atmospheric concentration of pollutants	θ_1	[0.10; 1]
Marginal disutility due to the underground storage of pollutants	θ_2	[0.10; 1]
Marginal disutility due to the atmospheric and underground concentrations of pollutants	ϵ	[0; 0.35]

Numerical simulations when only one country is considered are presented through figures 3.1 to 3.6.

Figure 3.1: Pollutant emissions and tax levels sensitivity to θ_1.

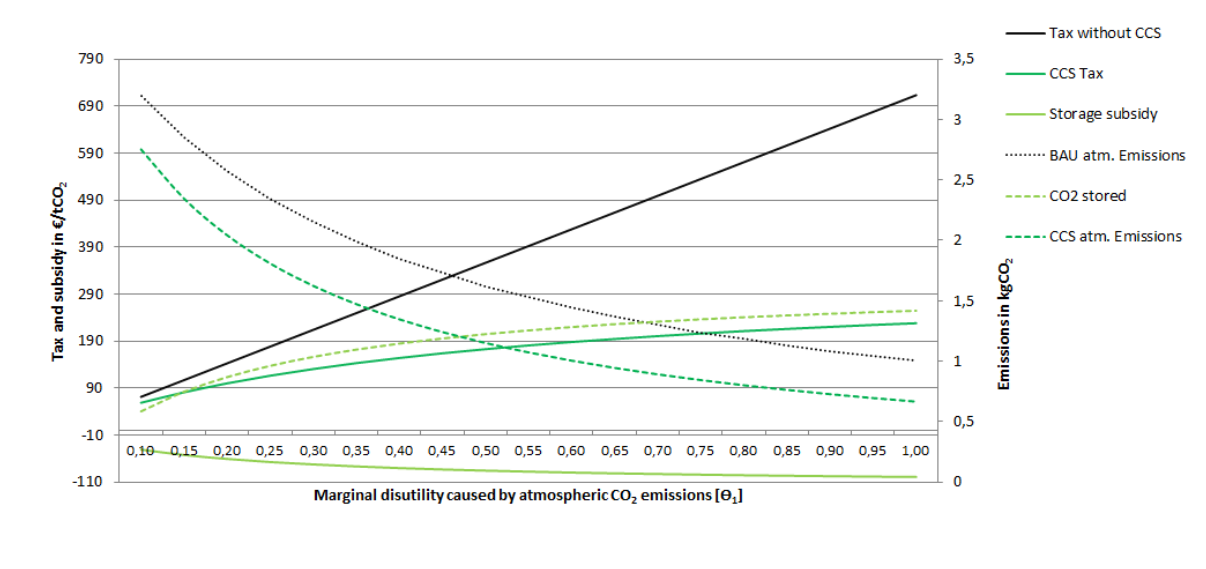


Figure 3.2: Social welfare sensitivity to θ_1.

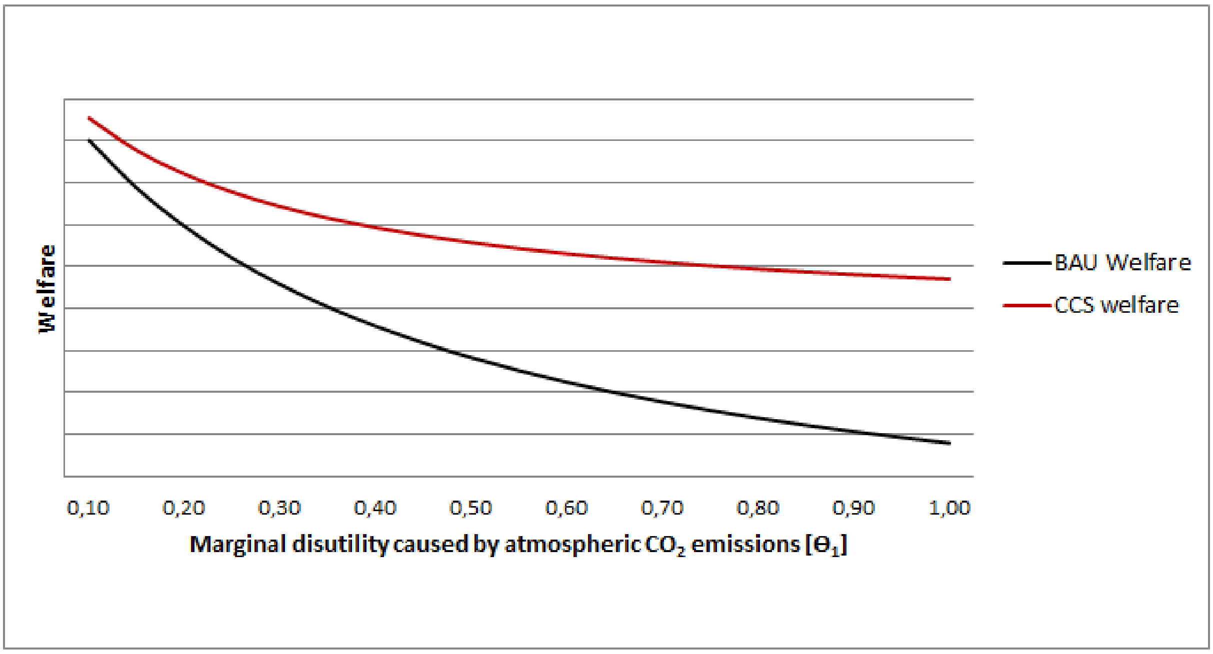


Figure 3.3: Pollutant emissions and tax levels sensitivity to θ_2.

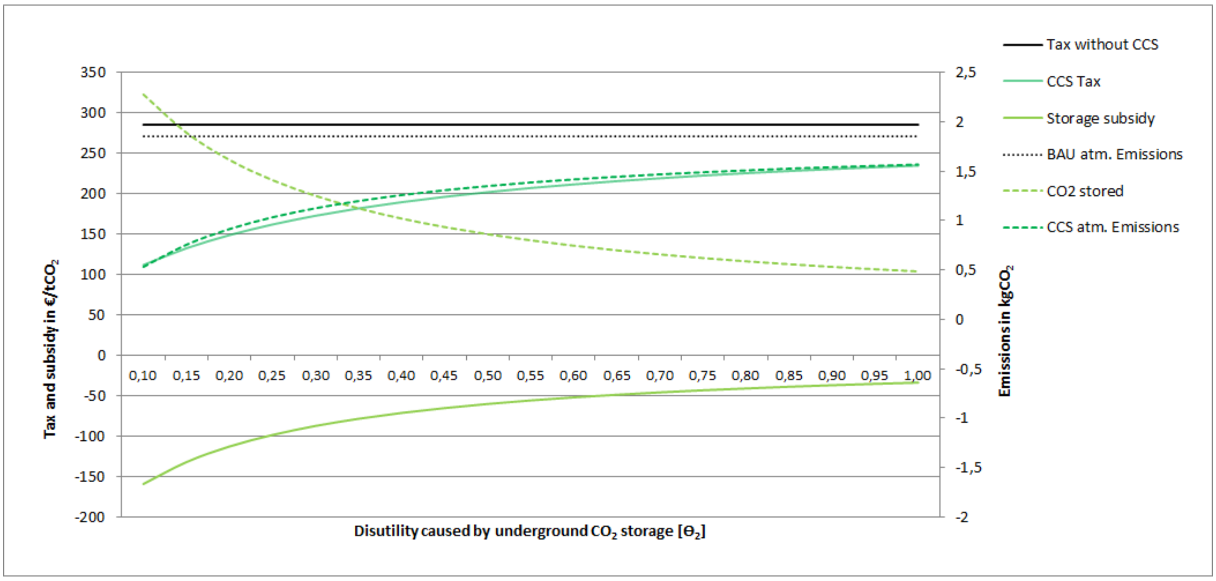


Figure 3.4: Social welfare sensitivity to θ_2.

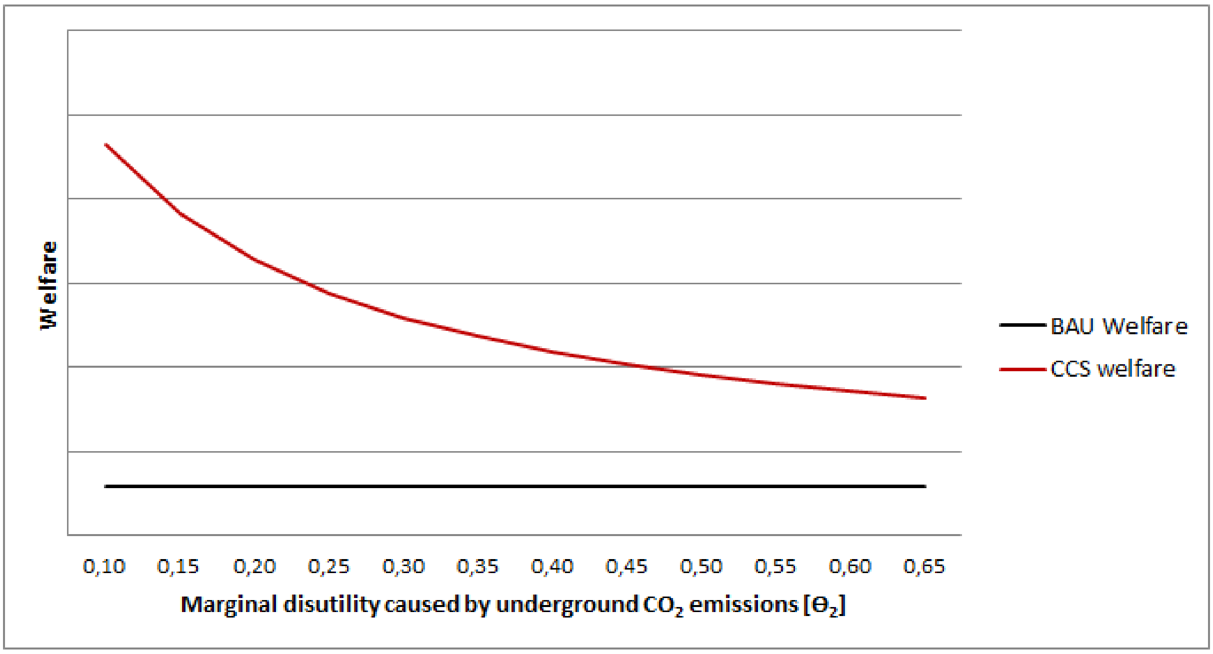


Figure 3.5: Pollutant emissions and tax levels sensitivity to ϵ, $\theta_1 > \theta_2$.

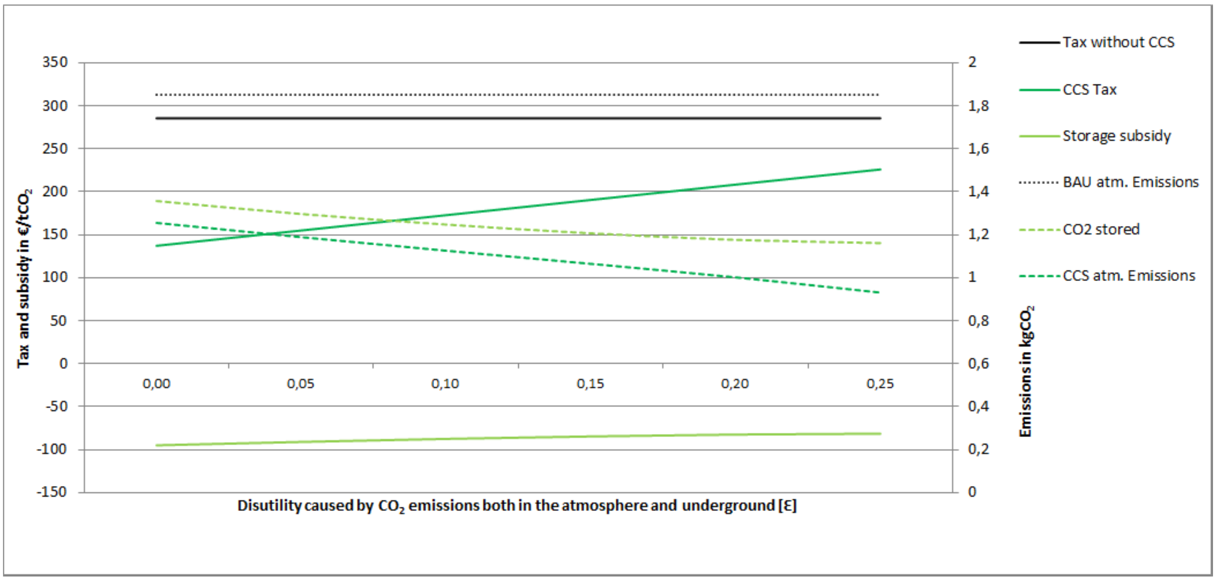
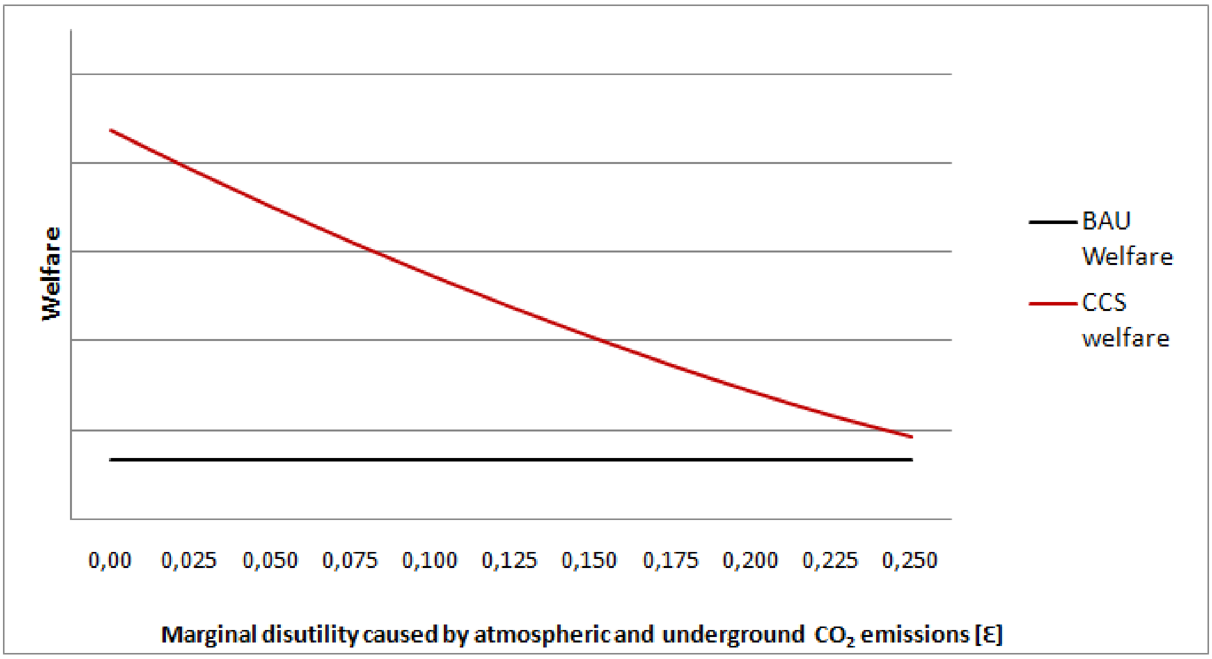


Figure 3.6: Social welfare sensitivity to ϵ, $\theta_1 > \theta_2$.



As Figure 3.1 shows, the higher the value of θ_1, the lower the input consumption and the higher the tax level on the polluting input, Z and γ become.
Figure 3.2 underlines that the levels of social welfare, with and without CCS techniques, decrease with θ_1. Indeed, to reduce the atmospheric CO_2 concentration, the production level decreases. CCS social welfare is higher and less sensitive to θ_1 variations than BAU welfare.

As Figure 3.3 indicates, in the BAU case, the polluting input consumption, the production and tax levels etc., are not affected by θ_2 variations.
The higher the value of θ_2, the lower Z and γ become. As Z decreases, net atmospheric emissions of pollutant, as well as ρ, increase until reaching the BAU level. Consequently, CCS social welfare decreases with θ_2 until reaching the BAU level (Figure 3.4).

Similarly to θ_2, ϵ variations have no effect in the BAU case.
Figures 3.5 and 3.6 show that the higher the value of ϵ, the lower the input consumption (and thus the production level) as well as the lower value of Z and γ. As a consequence, CCS social welfare decreases with ϵ until reaching the BAU level (Figure 3.6).

To summarise, the main results issued from these numerical simulations are:

- **Result 1:** To note, γ is a subsidy to the underground storage of CO_2.

- **Result 2:** The input consumption, and thus the production level, is higher when CCS techniques are used.
  The intuition behind this result is the following: when CCS techniques are used, the CO_2 is captured before it enters the atmosphere and thus the disutility caused by the atmospheric CO_2 concentration is reduced. Consequently, the production level is higher when CCS techniques are used.

- **Result 3:** The tax level on the polluting input is higher in the BAU than in the CCS case.

- **Result 4:** Usually, the use of CCS techniques in a given country enables it to increase its social welfare[10].
  The reasoning behind is the following: CCS techniques are a new tool to reduce the atmospheric CO_2 concentration and introduce a preference for diversity. This result is in accordance with Grimaud and Rougé (2014, [71]). They demonstrate that the availability of CCS techniques increases social welfare.
  CCS social welfare decreases with θ_2 and ϵ variations until reaching the BAU level (*i.e.* no CCS). Indeed, the lower the social acceptance level with respect to carbon storage, the smaller the use of CCS techniques.
  When the use of CCS techniques does not increase social welfare, it means that this country have no interest in deploying CCS techniques, *i.e.* $Z = 0$, due to the particular combination of its social preferences. More precisely, numerical simulations have shown that when the marginal disutility due to the atmospheric CO_2 concentration is considerably lower than the marginal disutility caused by underground storage, itself lower than the marginal disutility caused by both stocks of pollutant, the use of CCS technique does not increase social welfare. In other words, when people have little concerns for the global warming issue, and are reluctant to consider carbon storage, the use of CCS techniques is not optimal. It can illustrate/explain the failure of some CCS projects around the world.

- **Result 5:** Social welfare levels, with and without CCS techniques, decrease with θ_1. CCS social welfare is less sensitive to θ_1 variations than BAU welfare. Indeed, in the CCS case, some of the CO_2 emissions can be stored to reduce the atmospheric pollution.

[10]More precisely, with $E^{CCS} \geqslant E^*$, the level of social welfare is higher with CCS than without if $\theta_1 \geqslant \epsilon$.

3.5.3 Global and/or local pollution: numerical simulation results

Until now, we have studied the acceptance conditions under which the use of CCS techniques is socially optimal.
Now, we consider that the atmosphere is a public good, *i.e.* the atmospheric emissions of pollutant from one country, but also those from other countries/regions have an impact on the quality of the air we breathe. We also consider that the use of CCS techniques generates a local pollution. It means that optimal climate policies need to consider both local and global externalities.

Two cases are distinguished: (1) each country/region optimises its own climate policy by taking into account global and local pollution, (2) a unique social planner aggregates the two regions/countries. In each case, one country/region uses CCS techniques (S) whereas the other does not (A).
We assume that the two countries/regions are technologically identical (β is identical in A and S) but can have different acceptance levels regarding the atmospheric CO_2 concentration (θ_1^A, θ_1^S).
We study the effects of a marginal variation of θ_1^A, θ_1^S, θ_2 and ϵ on the input consumption and thus the production, tax and social welfare levels. As previously, we adopt a *ceteris paribus* approach (Table 3.3).

Table 3.3: Variation range for the parameters featuring social acceptance - geographical approach.

Variable parameters	Character	Range
Marginal disutility due to the atmospheric concentration of pollutants in country A	θ_1^A	[0.10; 1]
Marginal disutility due to the atmospheric concentration of pollutants in country S	θ_1^S	[0.10; 1]
Marginal disutility due to the underground storage of pollutants	θ_2	[0.10; 1]
Marginal disutility due to the atmospheric and underground concentrations of pollutants	ϵ	[0; 0.3]

For the first case (two countries with separate climate policies), the optimal taxation levels are issued from the comparison of equations (3.24) for country/region A and (3.25), (3.26) for country S and by referring to 3.4.1 and 3.4.2:

- In country/region A:
  $\tau = \theta_1^A A_{E^A}(E^A + E^S, Z) = \theta_1^A \alpha\beta(E^A + E^S)^{\beta-1}\left[\alpha(E^A + E^S)^\beta - Z\right]$
- In country/region S:
  $\rho = \theta_1^S A_E^S(E^A+E^S, Z)+G_A(A(E^A+E^S, Z), S(Z)) = \alpha\beta(E^A+E^S)^{\beta-1}\left[\theta_1^S\alpha(E^A + E^S)^\beta - \theta_1^S Z + \epsilon Z\right]$
  $\gamma = -\phi Z = \alpha(E^A + E^S)^\beta \dfrac{\epsilon - \theta_1^S}{2\epsilon - \phi - \theta_1^S - \theta_2^S}$

Figures 3.7 to 3.14 illustrate numerical simulations when there are two countries, one with CCS and one without, each of them with its own climate policy.

Figure 3.7: Emission and tax levels sensitivity to θ_1^A.

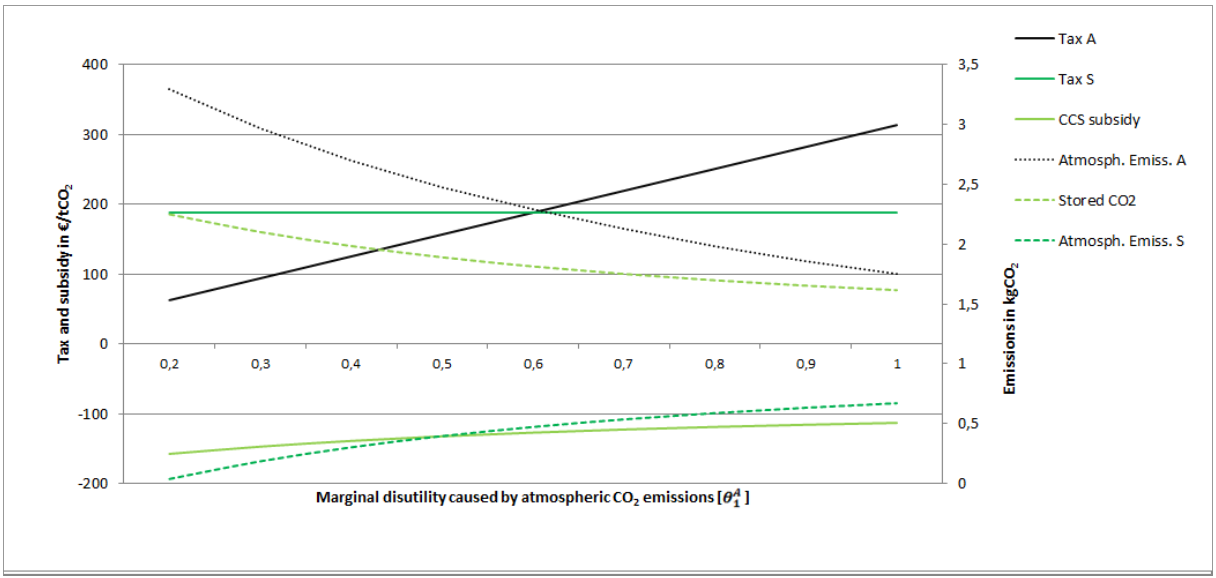


Figure 3.8: Welfare sensitivity to θ_1^A.

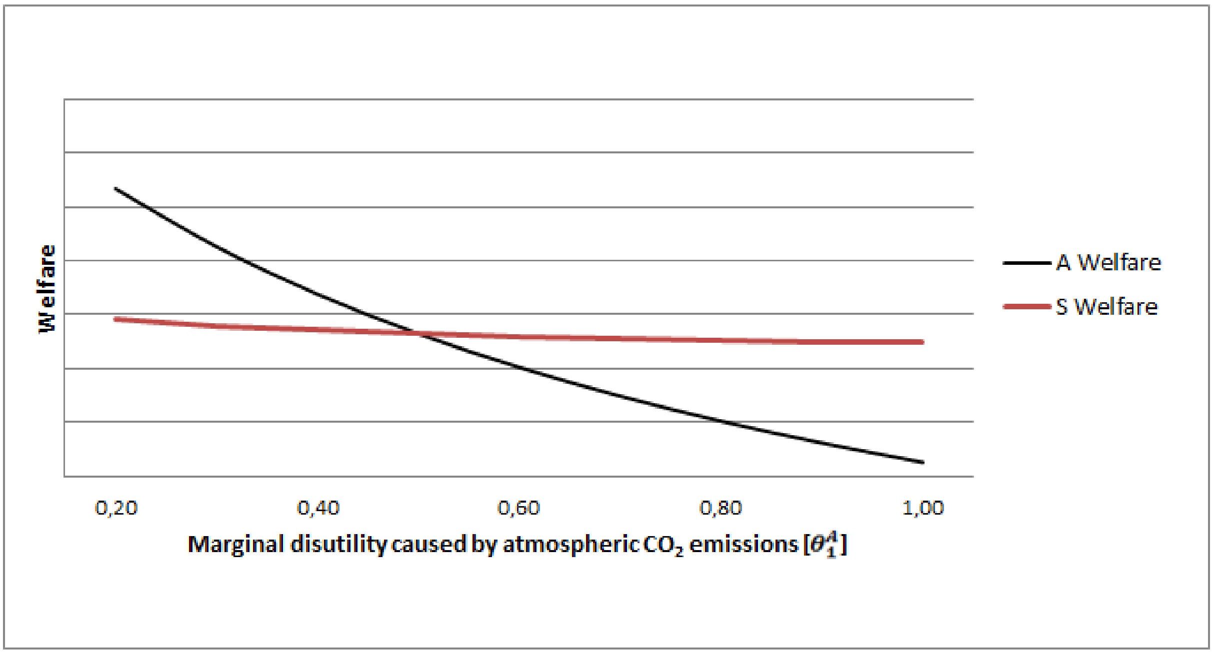


Figure 3.9: Emission and tax levels sensitivity to θ_1^S.

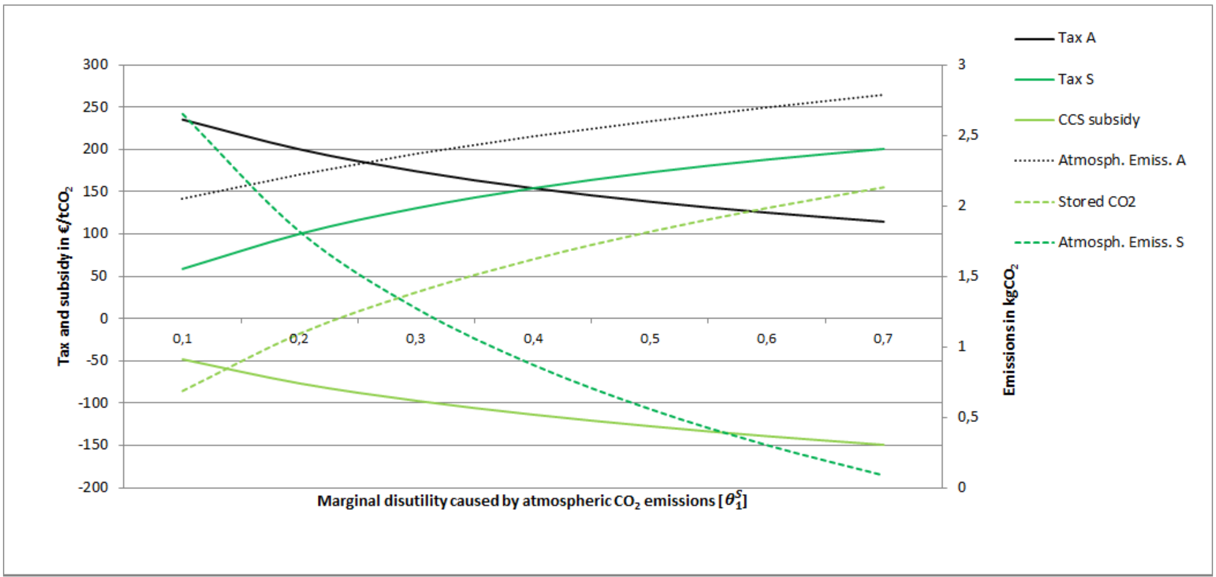


Figure 3.10: Welfare sensitivity to θ_1^S.

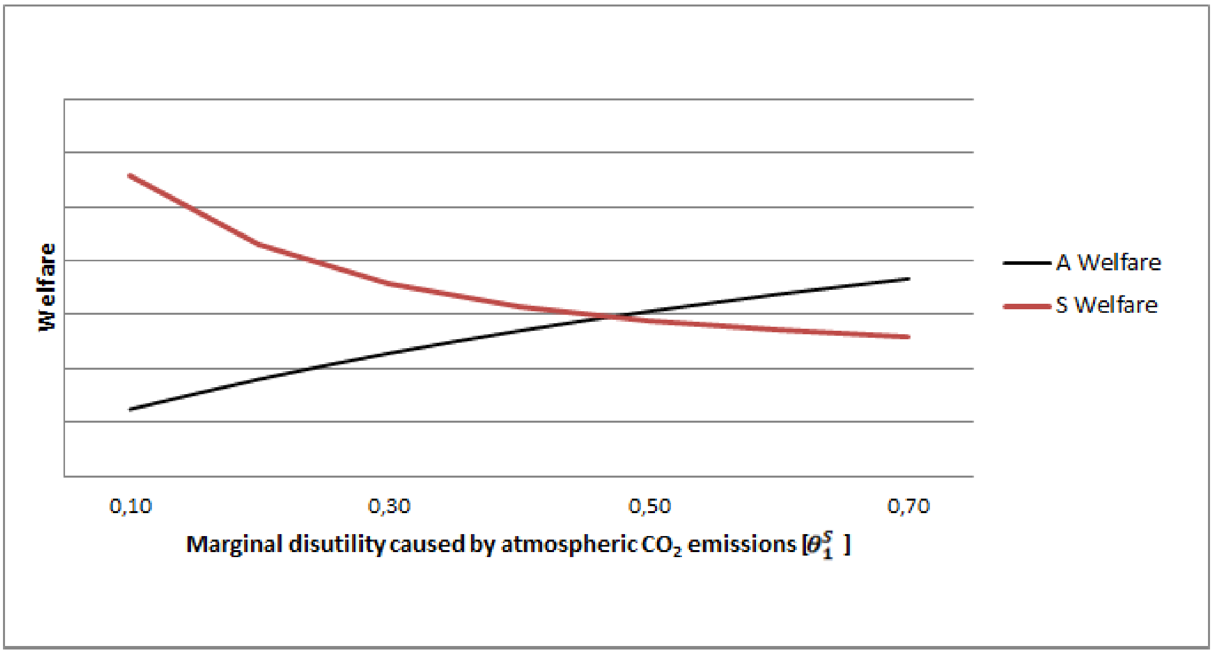


Figure 3.11: Emission and tax levels sensitivity to θ_2, $\theta_1^A > \theta_1^S$.

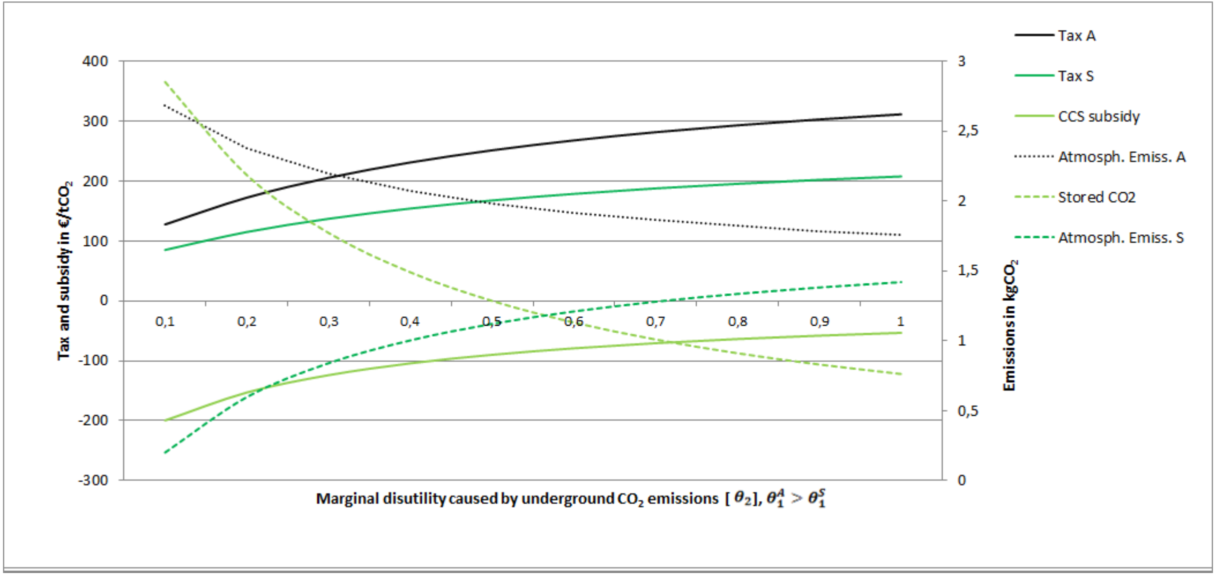


Figure 3.12: Welfare sensitivity to θ_2, $\theta_1^A > \theta_1^S$.

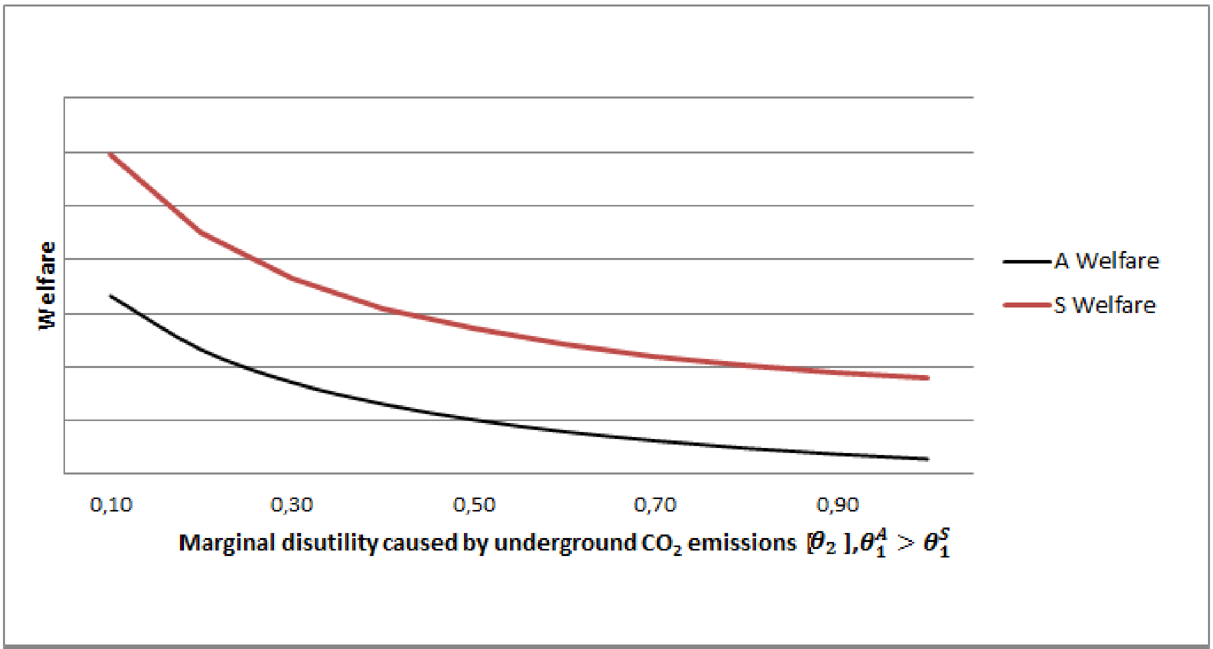


Figure 3.13: Emission and tax levels sensitivity to θ_2, $\theta_1^A < \theta_1^S$.

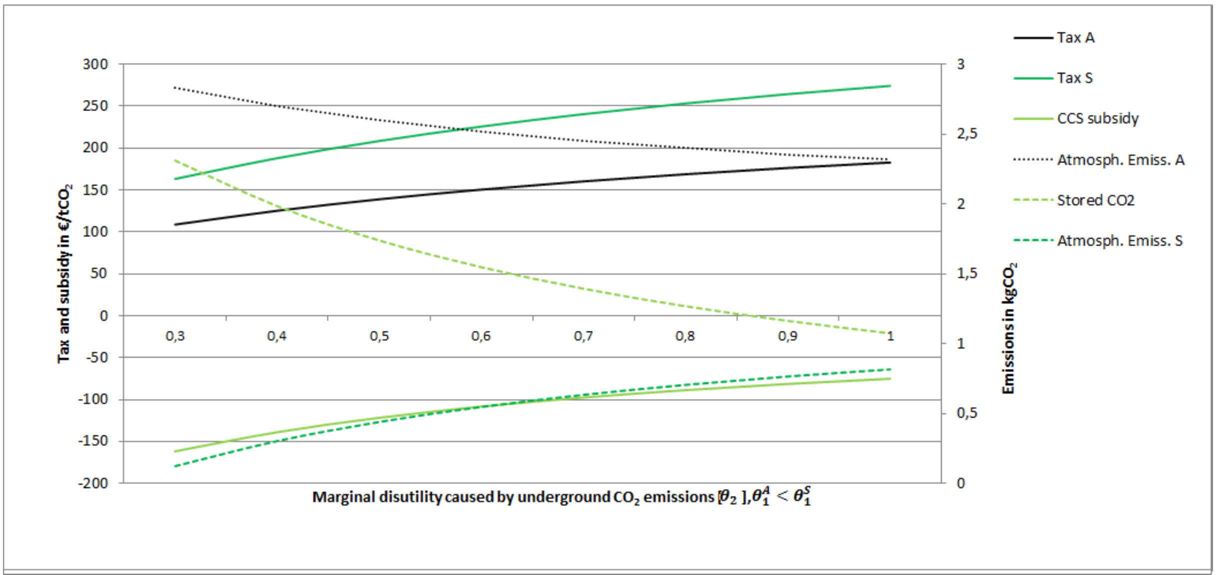


Figure 3.14: Welfare sensitivity to θ_2, $\theta_1^A < \theta_1^S$.

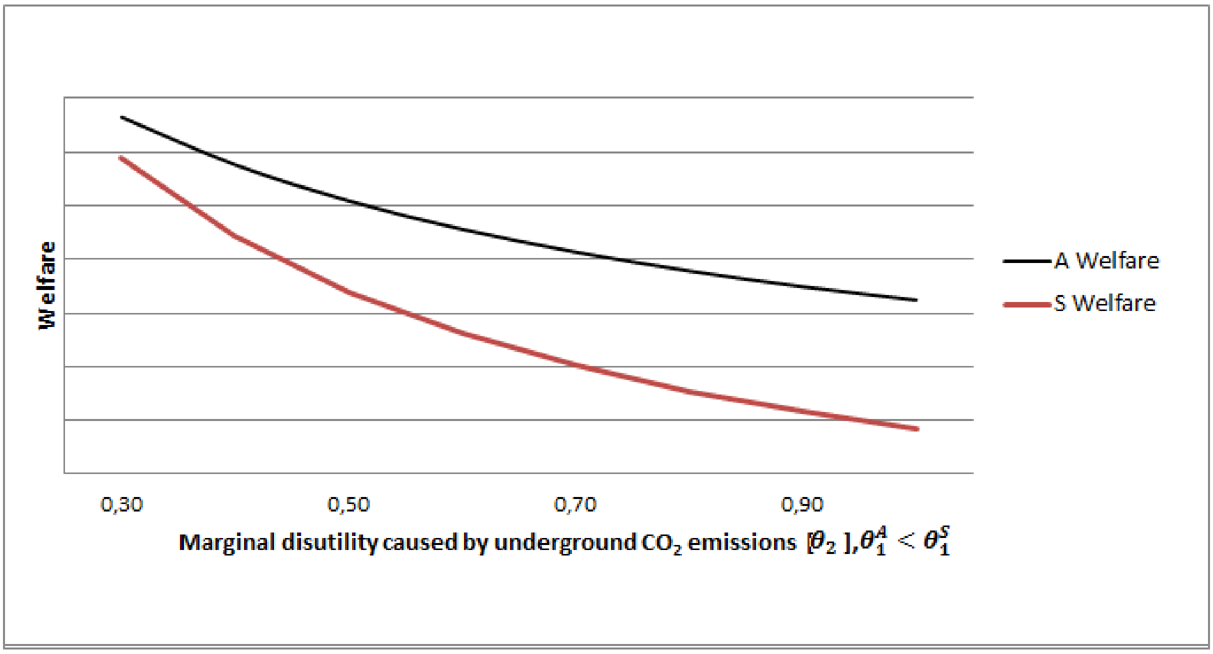


Figure 3.15: Emission and tax levels sensitivity to ϵ, $\theta_1^A = \theta_1^S < \theta_2$.

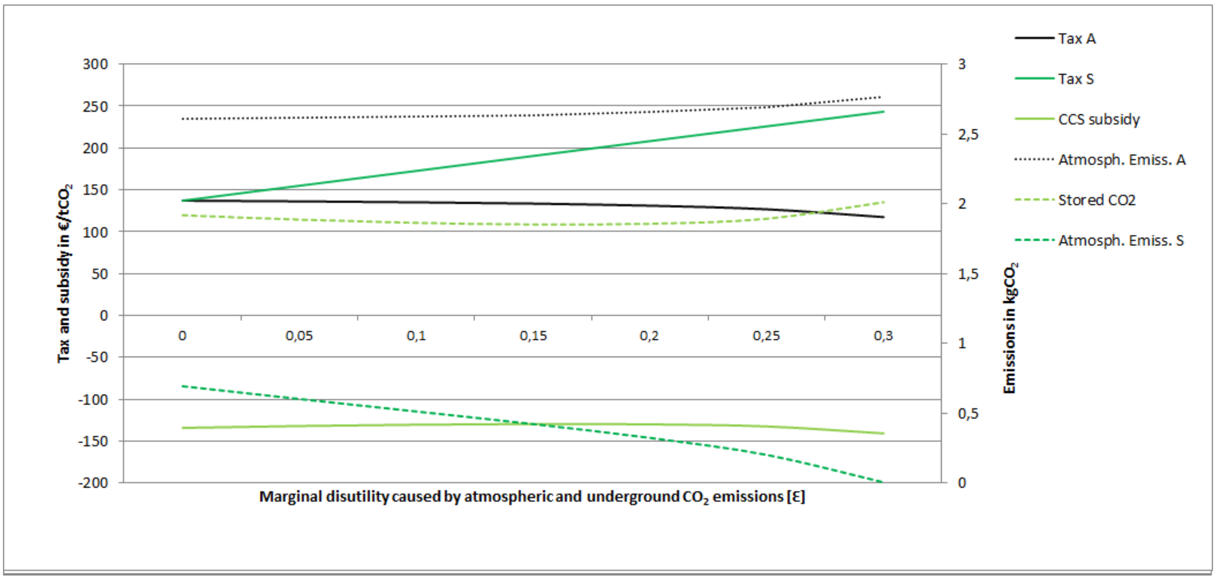
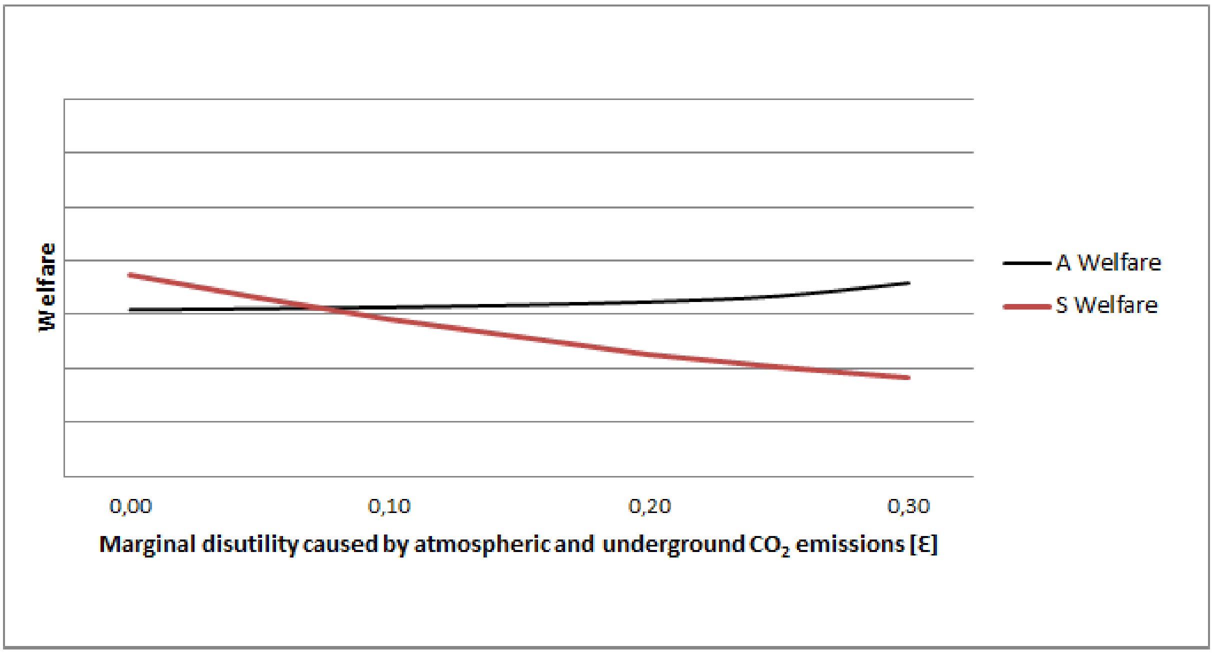


Figure 3.16: Welfare sensitivity to ϵ, $\theta_1^A = \theta_1^S < \theta_2$.



As figures 3.7 and 3.8 suggest, when θ_1^A increases, in country/region A, the levels of production and social welfare decrease. Note that although θ_1^A variations have no impact on the production level of country S, they have a slightly negative impact on its social welfare (Z decreases with E^A).

As figures 3.9 and 3.10 show, when θ_1^S increases, in country S, Z as well as the levels of production and social welfare decrease. In contrast, in country A, the production and social welfare levels increase with θ_1^S. It can be explained this way: as S decreases its atmospheric pollution, A can partly increase its polluting input consumption (the other parameters of social acceptance are steady).

As figures 3.11, 3.12, 3.13 and 3.14 indicate, when θ_2 increases, the production level in the two regions as well as Z decrease. Indeed, a lower social acceptance level regarding the geological storage of carbon dioxide reduces the amount of CO_2 which is stored underground. Consequently, the global atmospheric CO_2 concentration increases. As the social acceptance level regarding the atmospheric CO_2 concentration is unchanged in the two countries, they need to reduce their consumption of the carbon intensive input, thereby decreasing their social welfare level.
Note that when $\theta_1^A \leq \theta_1^S$, the social welfare of country S is more sensitive to a higher disutility regarding the geological storage of CO_2 than the one of country A. In contrast, when $\theta_1^A > \theta_1^S$ and θ_2 increases, the level of social welfare tends to decrease similarly in the two countries (the slope curve is similar). This result can be interpreted as follows: a lower level of social acceptance regarding the geological storage of carbon dioxide conduces country S to decrease the amount of CO_2 that can be stored underground, thereby implying a reduced production level. When country S is less concerned than country A by climate change issues, it can partly compensate for S additional effort in the reduction of its atmospheric CO_2 emissions due to a lower social acceptance level with respect to carbon storage.

With figures 3.15 and 3.16, it can be seen that when ϵ increases with $\theta_1^A = \theta_1^S < \theta_2$, the production and social welfare levels increase in A whereas they decrease in S in spite of an increase of Z.
When $\theta_1^A = \theta_1^S > \theta_2$, A and S social welfares decrease with ϵ.

- **Result 6:** When the atmospheric CO_2 concentration is seen as a global public bad (GHG responsible for climate change) and CCS as a local pollution (negative externality related to storage sites), changes in social preferences in one country affect the social welfare in another country.
  More precisely, when the social acceptance level regarding one of the three sources of marginal disutility decreases, it systematically reduces the social welfare of country S. In contrast, country A can benefit from a higher environmental conciousness level in country S, as well as from a lower level of social acceptance regarding the simultaneous stocks of pollutants provided that the marginal disutility due to the geological storage of carbon dioxide is higher than the one due to the atmospheric CO_2 concentration. Thus, A can sometimes increase its welfare level under particular circumstances regarding social acceptance levels in country S.

Now, we shall consider the second case, *i.e.* the planner aggregates the climate policies of the two countries.

By referring to the model specification and equations 3.28, 3.29 and 3.30, the tax levels on the atmospheric and underground emissions of CO_2 are the following:
$\tau = (\theta_1^A + \theta_1^S + G_A)A_{E^A}$
$\rho = (\theta_1^A + \theta_1^S + G_A)A_{E^S}$
$-\gamma = (\theta_1^A + \theta_1^S - G_A)A_Z + (\theta_2^S + G_Z)S_Z + G_A A_Z$
With our set of parameters and hypothesis, it implies that $E^A = E^S$ and $\tau = \rho$.

Figures 3.17 to 3.21 illustrate numerical simulations when there are two countries, one with CCS and one without, that have set their climate policy jointly.

Figure 3.17: Emission and tax levels sensitivity to θ_1^A, unique planner.

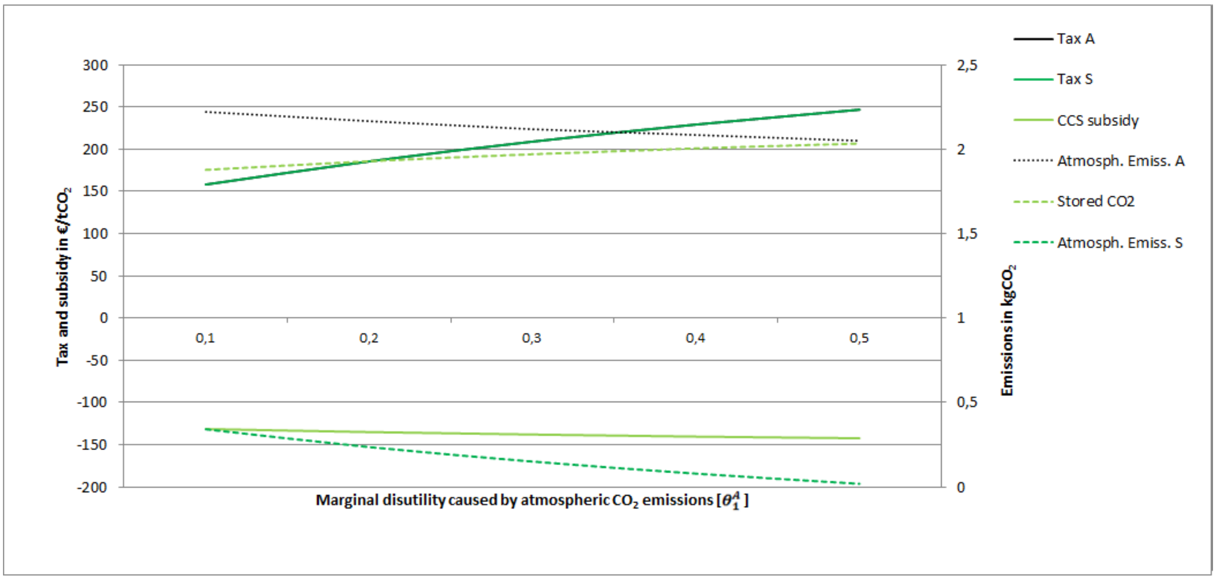


Figure 3.18: Emission and tax levels sensitivity to θ_1^S, unique planner.

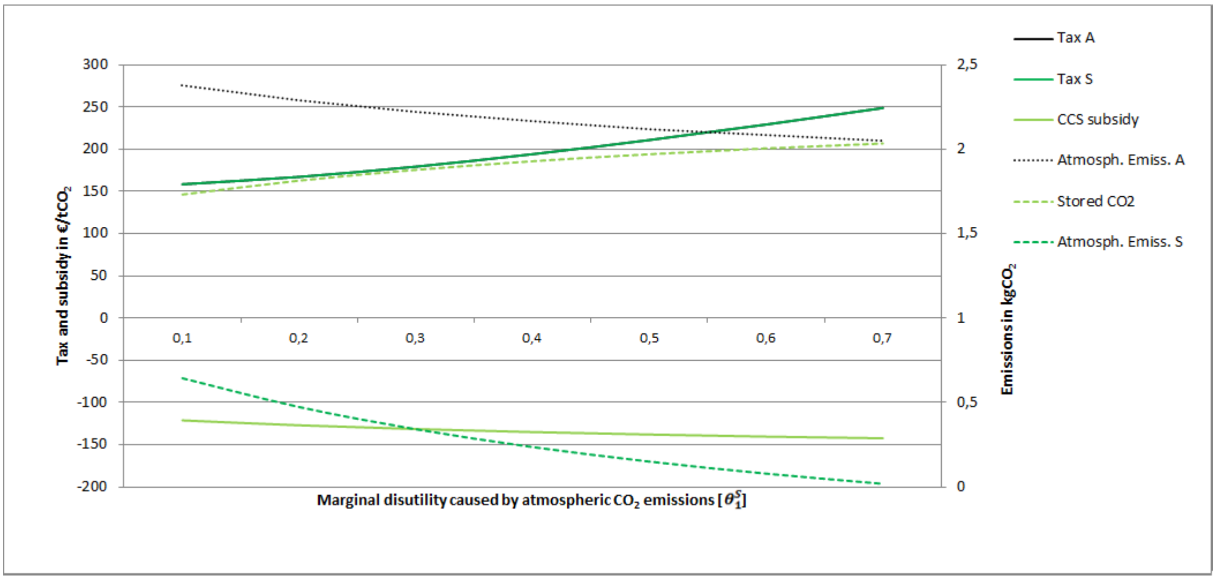


Figure 3.19: Emission and tax levels sensitivity to θ_2, $\theta_1^A > \theta_1^S$, unique planner.

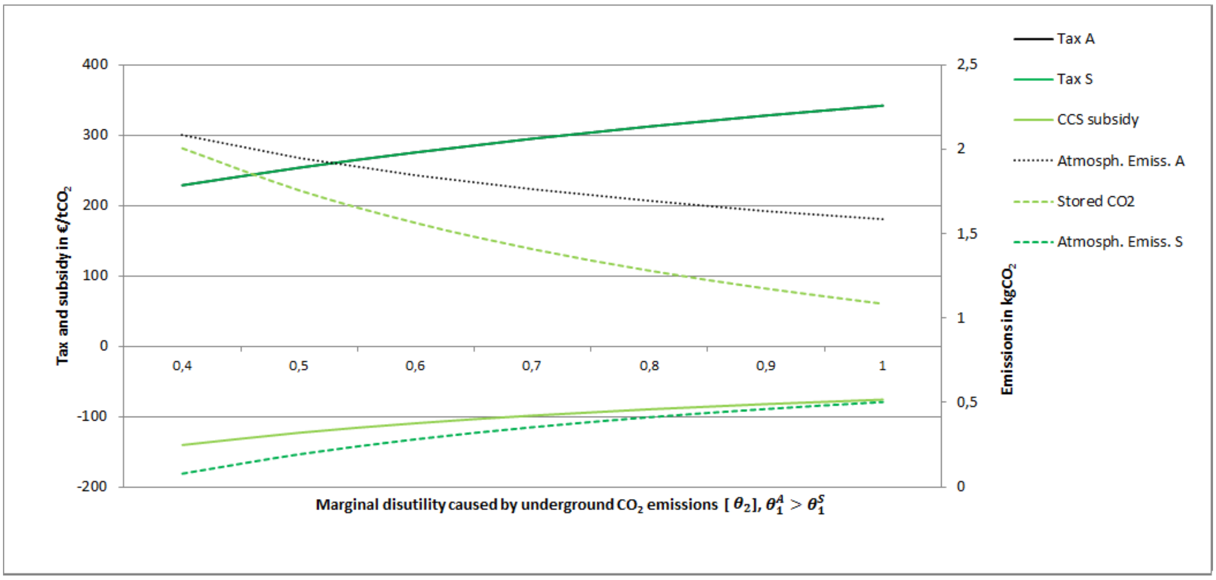


Figure 3.20: Emission and tax levels sensitivity to ϵ, $\theta_1^A = \theta_1^S < \theta_2$, unique planner.

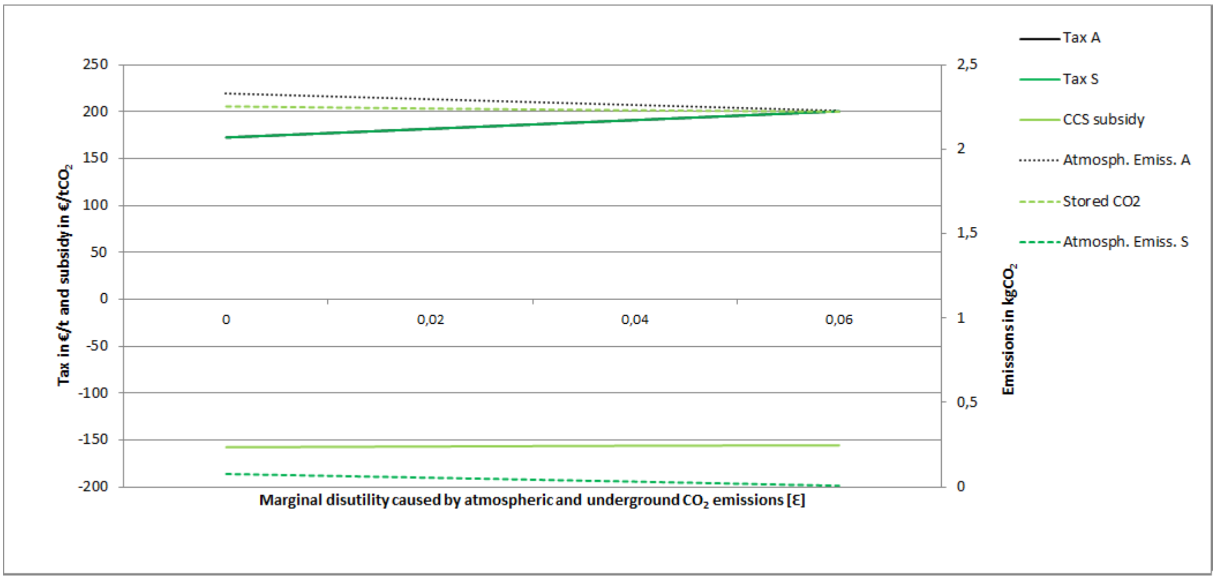
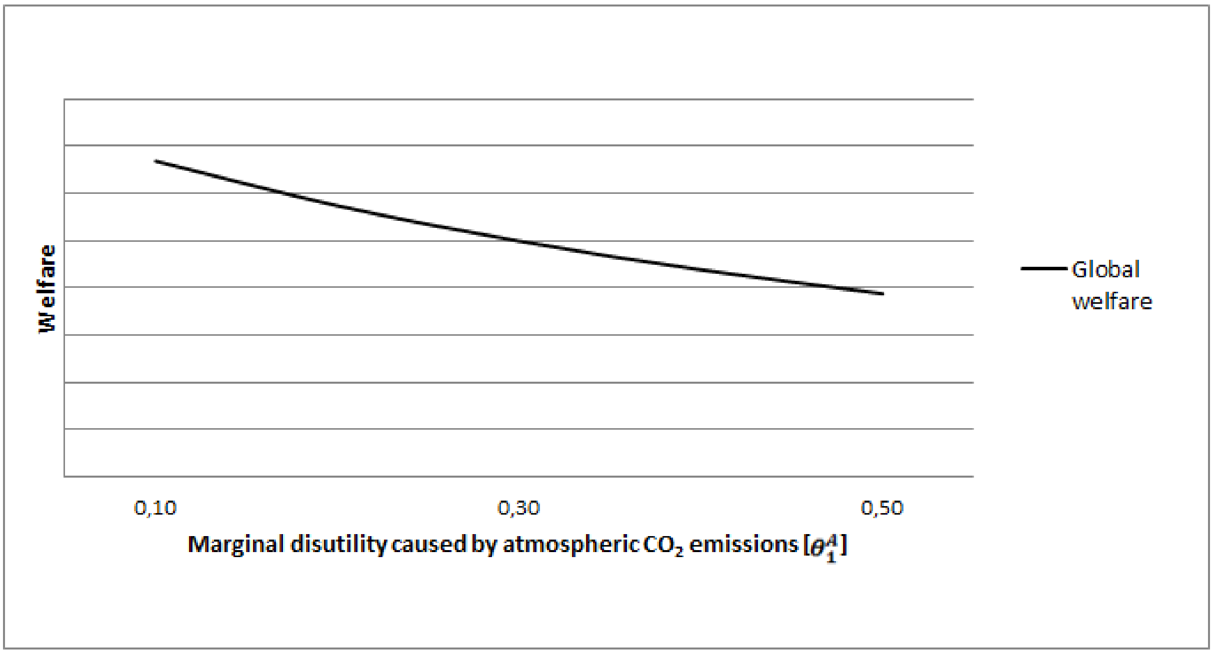


Figure 3.21: Global social welfare sensitivity to θ_1^A.



As figures 3.17 to 3.21 indicate[11], when θ_1^A (respectively θ_1^S, ϵ) increases, the production level of the two countries/regions decreases as well as global welfare even if Z increases.
When θ_2 increases, the production level and Z decrease. Consequently, global welfare is reduced.

- **Result 7:** Global social welfare decreases as soon as the marginal disutility with respect to underground/ atmospheric/ both pollution increases.
  To note, when the two countries/regions are not aggregated, a variation of θ_1^A, θ_1^S, θ_2 or ϵ in one country/region can increase the social welfare of the other country/region.

- **Result 8:** Global social welfare corresponds to a Pareto optimum.
  Indeed, when the two countries/regions are not aggregated and that one of them is affected by a lower social acceptance threshold regarding pollution (atmospheric, underground, both), its production level has to be decreased to reduce pollution, while the other country/region can partly increase its pollution and thus its social welfare level.
  The comparison of the two cases, when countries are or are not aggregated, can enable us to assess the transfers from A to S to encourage S to deploy CCS in order to improve the global air quality.

For illustrational purposes, different types of country can be classified in order to assess more precisely social welfare level sensitivity to the parameters featuring the disutility caused by the pollution sources. Four main cases are represented: (1) people who do not like atmospheric pollution but are not disturbed by underground pollution: it could possibly represent Norway - where two LSIPs are currently in operation - or the United Kingdom - where CCS is considered

[11]Only one figure represents social welfare sensitivity to θ_1^A since results are very similar to the other parameters of social acceptance.

as a key option to decarbonise the electricity mix (see Chapter 1 and Chapter 2 for more details). Note that these two countries have the widest number of suitable offshore storage sites in the European Union (Geocapacity, 2008 [51]). CCS social acceptance issues crystallise mainly around onshore carbon transport and storage infrastructures: offshore infrastructures are significantly less controversial. Therefore, social acceptance issues are likely to be less acute in these two countries than in the other European countries. (2) People who like neither underground nor atmospheric pollution: it could possibly represent Germany where the implementation in national law of the CCS Directive (2009/31/CE) was highly controversial. As a consequence, the maximum amount of CO_2 that can be stored in a storage site is capped to 1.3 MtCO_2/yr and the total yearly storage capacity in Germany cannot exceed 4 MtCO_2/yr. (3) People who are not disturbed by atmospheric pollution and do not like underground pollution: it could possibly represent Poland. Poland has a carbon intensive electricity mix: according to the GCCSI (2013), coal generates approximately 90% of Poland's electricity. Therefore, Poland could be interested in deploying CCS. However, there were fierce controversies with respect to the CCS Directive (2009/31/CE). The amount of the required investments is probably the main reason of its opposition with respect to CCS and more generally to all GHG abatement techniques. (4) People who are not disturbed by underground and atmospheric pollution: it could possibly represent the United States. The United States is the front runner in LSIPs (19 out of 55) mainly because of the market opportunity of using CO_2 as a commodity. As carbon transport is already implemented in the United States (6,200 km of pipelines currently handle about 50 Mt of dehydrated CO_2 in a supercritical state for EOR purposes) *i.e.* is part of the landscape, social acceptance with respect to carbon transport may not be a crucial issue.
Tables 3.4 and 3.5 give, for each country, the values of the social acceptance parameters as well as the levels of social welfare obtained for each configuration[12].

Table 3.4: Social acceptance parameters for four types of countries.

Country[a]	θ_1	θ_2
Poland	0.4	1
Germany	0.7	1
Norway/UK	0.7	0.4
United States	0.4	0.4

[a] $\epsilon = 0.01$

For these values of social acceptance parameters, if each country only considers its pollution, social welfare is higher with than without CCS techniques.
What happens when global as well as local pollution are considered?
For Germany: without CCS techniques, German social welfare is lower than the other countries using CCS. When CCS techniques are used, German social welfare is slightly higher than the

[12]France was not considered because of its low carbon electricity mix: nuclear power plants provide approximately 75% of the produced electricity. Thereby, with the increasing share of RES in the French electricity mix, the primarily role of CCS plants would consist in balancing the intermittency of RES, implying semi-base or peak-load operation modes. It is likely that CCS plants would represent a relatively small share in the French electricity mix in comparison with highly carbon intensive countries such as Poland.

Table 3.5: Social welfare simulations for four types of countries.

	Germany with CCS	Poland with CCS	Norway/UK with CCS	USA with CCS
Germany	X	$W_A = 1.1$ $W_S = 1.5$	$W_A = 1.5$ $W_S = 1.6$	$W_A = 1.3$ $W_S = 1.7$
Poland	$W_A = 1.6$ $W_S = 1.2$	X	$W_A = 1.8$ $W_S = 1.6$	$W_A = 1.6$ $W_S = 1.7$
Norway/UK	$W_A = 1.2$ $W_S = 1.2$	$W_A = 1.1$ $W_S = 1.5$	X	$W_A = 1.3$ $W_S = 1.7$
USA	$W_A = 1.4$ $W_S = 1.5$	$W_A = 1.6$ $W_S = 1.2$	$W_A = 1.8$ $W_S = 1.6$	X

other countries except Poland. Thus, on average, Germany would be interested in using CCS techniques. However, the level of global social welfare (with and without CCS) is higher when Germany does not use CCS whilst the other countries do. Indeed, Germany has a disutility to atmospheric pollution lower than or equal to the other countries and a social acceptance level to CO_2 storage higher than or equal to the other countries (that can bury CO_2 to produce more). Thus Germany would be interested in subsidising CCS deployment in other countries.
It is the same for Poland: on average, its social welfare level is higher when CCS techniques are used in the other countries.
For Norway (similarly UK): whatever the configuration (either A or S), Norwegian social welfare is lower than in other countries, except when Germany does not use CCS techniques (same disutility to atmospheric pollution but more CO_2 can be stored in Norway). However, the level of Norwegian social welfare, as well as global social welfare, is higher when Norway uses CCS techniques. Thus, Norway/UK would be interested in acquiring support to deploy CCS techniques from countries such as Poland and Germany.
For the United States: the level of American social welfare is higher when the country uses CCS techniques.
Global social welfare is the highest when CCS is deployed in Norway/UK.

3.6 Conclusion

As with the cost, social acceptance is also the main obstacle to widespread CCS deployment. As there is mixed evidence of public acceptance of CO_2 storage - e.g., a CCS project was authorised in France (Lacq) but another was cancelled in the Netherlands (Barendrecht) -, accurately assessing social preferences can help public decision-makers determine the optimal level of CCS use.
This Chapter investigates this issue and determines, from the social point of view, the amount of production as well as the optimal allocation of CO_2 emissions between the atmosphere and underground storage sites.

From a methodological point of view, the novelty lies the introduction of the marginal disutility due to the simultaneous CO_2 concentration in the atmosphere and in underground storage

sites, in addition to the two marginal disutilities due to, respectively, the atmospheric and the underground pollution as has been modelled previously. With this third source of marginal disutility, we can consider all aspects of the issue.
In addition, two cases are differentiated: in the first case, only one country is considered and determines whether CCS is socially optimal with respect to its social preferences whereas in the second, two countries are considered, one without CCS the other one with, where CCS is considered as a local pollution and CO_2 atmospheric pollution as a public bad. In line with a least cost approach to climate change mitigation, this second case allows us to assess the transfers required to encourage CCS deployment, notably from OECD to low cost countries.

From a normative point of view, interestingly, given the model specifications, the use of CCS techniques implies the introduction of a new fiscal tool: a subsidy to CO_2 storage rather than a tax.
This result has significant policy implications. Indeed, subsidising carbon storage increases the absolute profitability of CCS plants with respect to non CCS plants. Therefore, the additional financial supports (FIT, CCS purchase contracts, etc.) required to trigger CCS commercial deployment might be lower, thereby reducing the risk of inefficient measures and windfall effects.

To assess the sensitivity of tax and welfare levels to social acceptance parameters, the model was specified and numerical simulations were performed. They show that, usually, the use of CCS techniques is socially optimal *i.e.* enables the improvement/increase in social welfare. Furthermore, when the geographical dimension is taken into account, there are configurations of social preferences for which one country can, by using CCS techniques, simultaneously increase its social welfare and that of its neighbour that does not use CCS.
This result of social welfare being higher with CCS than without can be explained as follows: when CCS techniques are used, the CO_2 is captured before it enters the atmosphere, and thus the disutility caused by atmospheric pollution is reduced. Thus, the polluting input consumption and consequently, the production level can be higher with CCS. In addition, the use of CCS techniques introduces a new tool to curb CO_2 emissions from fossil fuel plants. Therefore, the preference for diversity can also explain a higher welfare with the use of CCS techniques than without.
Social welfare can usually be improved by the use of CCS techniques except when the marginal disutility due to the atmospheric CO_2 concentration is lower than the marginal disutility caused by the underground CO_2 concentration, which is itself lower than the marginal disutility caused by both concentrations of pollutant. These specific configurations of social preferences for which CCS is not socially optimal enable us to explain the failure of some CCS projects in the world.

In this stylized model, individuals take their decision with respect to CCS projects (opposition, tolerance, support) on the basis of perfect information. However, in practice, information is imperfect and social preferences partly depend on the level of information.
CCS techniques are currently rarely mentioned in the media or in political debates, notably because of the lack of LSIPs in the power sector (only one LSIP is in operation as of February 2015). This low level of awareness or understanding of CCS can partly explain public acceptance issues (GCCSI, 2014 [63]; Ha-Duong et al., 2009 [73]; de Best-Waldhober et al., 2009 [29]). However, additional information may improve CCS social acceptance (Tokushige et al., 2007 [135]): some individuals may get over their disutility due to a storage site near their home/or their fear of a carbon leakage when considering the positive impact of CCS on the atmospheric

CO_2 concentration.

Consequently, if CCS is seen as able to play an important role in the electricity mix of one region/country, then working actively to increase public knowledge of CCS will be required. Broader communication on CCS will be needed to explain both the pros and cons: the potential role of CCS in climate change mitigation but also the potential health and environmental risks due to its use (e.g.: carbon leakage) as well as the potential ways to solve them (e.g.: monitoring and measurement).

Lessons from LSIPs and pilots (failures and successes) show that involving the local community from the very beginning of the project (site selection process) is crucial. Effectively, national and local authorities, non governmental organisations, project partners, the community, etc. all have to accept the CCS project.

Working actively to increase public knowledge of CCS is thus one of the keys for the success of any single CCS project, and thereby for a wider commercial deployment. As suggested by the GCCSI (2014, [63]), this argues for multi-level engagement, knowledge sharing and a communication approach to cope with these challenges.

Chapter 4

Optimal Electricity Mix and CCS Investment under Ambiguity [1]

4.1 Introduction

The previous Chapters have enabled us to identify the techno-economic and social conditions required for CCS commercial deployment. When CCS use is socially optimal, Policy- and Decision-Makers know notably which combination of supply-push and demand-pull tools they should implement to support and trigger CCS investment.
The last piece of information they need to know is the CCS installed capacity that should be put in the 2050 electricity mix.
Indeed, public DMs need to decide, in the short-term, on the relative share of nuclear, CCS, RES, etc. in their electricity mixes in 2050. Indeed, some investment decisions to decarbonise the power sector are already needed at this stage. The lifetime for a nuclear power plant is more than 60 years, 40 years for a coal plant, 30 for a gas plant etc., and the related investments are irreversible. Therefore, the action needs to start early so that the restructuring of the energy system runs in parallel with investment cycles thereby avoiding stranded investments as well as lock-ins of medium carbon intensive technology. In addition, public decision-makers need to know the 2050 targets for low carbon technologies such as CCS, off-shore wind, etc., because they determine the energy policy required to support their deployment (Golombek et al., 2011 [70]; Nemet and Baker, 2009 [111]) - through R&D programs, support mechanisms such as FIT/purchase contracts/capital grants/a carbon price with cap and floor (Kettunen et al., 2001 [93]), etc. - and regulation policies (Reinelt and Keith, 2007 [125]) (e.g., for cross-border carbon transport and storage infrastructures in the EU).
This question is particularly relevant for developed countries, that need to near completely decarbonise their power sector to reach the 2°C target (COP15, 2009), but also for developing countries, like China, that face increasing health issues due to a growing use of fossil fuels and thus atmospheric pollution.

When facing these kinds of issues, decision-makers may seek the advice of experts to choose the optimal electricity mix in 2050.

[1] The reader can refer to J. Etner and M. Renner. Optimal Electricity Mix and CCS Investment under Ambiguity. Mimeo, 2015.

Experts provide many studies with a low carbon electricity mix in 2050. Nonetheless, although most public studies have the same CO_2 emission reduction target by 2050, each of them explores significantly different combinations of the three decarbonisation options. As a result, scenarios of electricity mix vary considerably from one study/expert to another. For instance, there are five main roadmaps for a low carbon European Union economy by 2050. In the chronological order: Power Choices, Pathways to carbon-neutral electricity in Europe by 2050 (Eurelectric, 2011 [52]), Roadmap 2050: A practical guide to a prosperous low-carbon Europe (European Climate Foundation, 2011 [44]), Energy Roadmap 2050, Impact assessment and scenario analysis (European Commission, 2011 [54]) and Power Choices Reloaded: Europe's Lost Decade? (Eurelectric, 2013 [53]).
In addition, in the absence of a consensus between experts due to many sources of uncertainty, one roadmap can consider different low-carbon pathways. For instance, the Energy Roadmap 2050 (2011, [54]) provides six different scenarios achieving a 85% greenhouse gas reduction in 2050 compared to 1990 levels, each of them with a specific electricity mix. Therefore, the CCS share ranges from 6.9 to 31.9%. Similarly, the European Climate Foundation's Roadmap (2011, [44]) presents four different electricity mixes, in which the CCS proportion ranges from 0 to 30%. These findings show that the CCS share in the 2050 electricity mix completely differs from one study/expert to another.

Due to conflicting expert's opinions, public DMs do not know the CCS installed capacity they should put in their electricity mix (and therefore the investments they should proceed with). Consequently, they are also ignorant of the related policy support measures they should implement. Thus the arising question is: how could public DMs decide on the basis of imprecise/ambiguous information coming from several experts with divergent[2] opinions?

4.2 Objectives and global approach

Over the last few decades, ambiguity or imprecise probabilistic information has raised much interest, because except games of chance, DMs often do not know the precise probabilities of the potential outcomes. For example, the decision of undergoing medical treatment or undertaking a business operation is generally taken without a clear idea of the chances of success. This issue has already been pointed out by Knight (1921, [97]); he distinguished risk (there is a precise probability to guide choices) from unmeasurable uncertainty (the DM is uncertain about the probability measure because of informational or cognitive constraints). Ambiguity corresponds thus to situations where there is too little information to easily pin down probabilistic beliefs (Machina, 1987 [103]; Camerer and Weber, 1992 [21]; Gilboa and Marinacci, 2011 [66]; Etner et al., 2012 [50]; Machina and Siniscalchi, 2014 [104]). Decision-makers are said to be ambiguity averse when they take into account how well they know the relevant odds and prefer actions for which the odds of the prospects/consequences are known.
Although ambiguity aversion is commonly observed, it is inconsistent with classic models, particularly Savage's Subjective Expected Utility set up (1954, [132]). Indeed, Ellsberg experiments (1961, [48]) have shown that when facing ambiguity, decision-makers can undertake actions

[2]Divergences still persist despite appropriate communication protocols and procedures aiming to reduce the disagreements between experts (Gajdos and Vergnaud, 2013 [60]).

incompatible with the Savage's Subjective Expected Utility (SEU) model, even in simple situations.

Hereafter is presented one of the Ellsberg's experiments. An urn contains 90 balls, of which 30 are red (R). The other balls are either blue (B) or yellow (Y) but their relative share/number is unknown. One ball will be drawn at random from this urn. The following lotteries are considered (Table 4.1):

- A: Receive €100 if R, 0 otherwise.
- B: Receive €100 if B, O otherwise.
- A': Receive €100 if R or Y, 0 otherwise.
- B': Receive €100 if B or Y, O otherwise.

Table 4.1: Ellsberg's lotteries.

	Red	Blue	Yellow
A	100	0	**0**
B	0	100	**0**
A'	100	0	**100**
B'	0	100	**100**

Ellsberg has demonstrated that most people will prefer A to B whereas they will prefer B' to A' which is in contradiction with a representation of preferences by the subjective expected utility model. More precisely, this contradicts one of the main principles of the SEU model (the sure thing principle).
Indeed, $A \succ B \Leftrightarrow P(R) \times u(100) > P(B) \times u(100)$ which leads to $P(R) > P(B)$; the risk is preferred to uncertainty.
$B' \succ A' \Leftrightarrow P(B) \times u(100) + P(Y)u(100) > P(R) \times u(100) + P(Y) \times u(100)$ which leads to $P(B) > P(R)$.
There is thus a contradiction which is due the common part Yellow (in bold in Table 4.1).

Over the last twenty years, several theoretical breakthroughs have thus occurred in the decision theory to provide representations of preferences consistent with ambiguity aversion (for a survey, see: Machina, 1987 [103]; Camerer and Weber, 1992 [21]; Gilboa and Marinacci, 2011 [66]; Etner et al., 2012 [50]; Machina and Siniscalchi, 2014 [104]). From a theoretical point of view, most of these new models generalise Savage' set up by weakening the sure thing principle. They often rely on the following idea: when information is scarce and uncertain, allowing imprecise subjective beliefs (*i.e.* a set of probability distribution or prior) is more realistic and appropriate than asking for a single underlying probability distribution.
Among them, Klibanoff, Marinacci and Mukerji (2005, [95]) (hereafter KMM) provide "a fully subjective model of ambiguity aversion, in which attitude toward ambiguity is captured by a smooth function over the expected utilities associated with a set of prior" (Gajdos T. et al., 2008 [59] p9). The decision maker comes-up with a prior over the set of prior, so-called second order

belief. We chose KMM's model for its ability to define the ambiguity neutrality *vs.* aversion, to differentiate ambiguity and ambiguity attitude (tastes)[3], as well as its ability to perform the comparative statics of a change in ambiguity aversion.
Such a framework is particularly relevant to assess the impact of ambiguity aversion on investment decisions. As Health and Tversky (1991, [76]) state: "the ambiguity aversion is particularly strong in cases in which people feel that their competence in assessing the relevant probabilities is low". Determining how a risk neutral and ambiguity averse agent decides to invest in emerging capital intensive technologies is an important issue in entrepreneurial and public decision-making (Jouvet et al., 2012 [90]). It is particularly adapted to CCS investments and more generally, to public investment in capital intensive mitigation technologies.
Although many articles have explored the role played by ambiguity aversion in the fields of health (Treich, 2010 [136]; Berger et al., 2013 [17]), insurance (Snow, 2011 [134]; Alary et al., 2013 [6]) and finance (Gollier, 2011 [69]; Jahan-Parvar and Liu, 2014 [88]), a few of them deal with investment decisions and give numerical analysis to provide concrete implications for policy-makers. However, a few empirical papers suggest that taking into account uncertainties is relevant for public decisions in mitigation and adaptation (Fontini et al., 2010 [58]; Alpizar et al., 2011 [7]).
The purpose of this Chapter is to explore the implications of ambiguity and ambiguity aversion for investment decisions in capital intensive techniques. DMs are concerned with ambiguity and seek robust decision-making. The following questions are addressed: how to decide the optimal CCS installed capacity, and thus the optimal electricity mix, when experts provide imprecise and contentious information? Without probabilities, what is a rational decision? The below model provides a decision tool allowing DMs facing ambiguous situation, to determine the optimal CCS installed capacity by 2050, X^*, which itself determines the relevant energy policy design as well as the required investments. Part 4.3 details the model and its resolution. The comparative statics allows us to isolate the pure effect of introducing ambiguity and of increasing ambiguity aversion into a given economic situation. Part 4.4 provides numerical simulations on a real case, to illustrate the model and to give recommendations to public decision-makers. Part 4.5 discusses the results and concludes.

4.3 The model

Through a static approach, we consider that the DM chooses the CCS installed capacity X among proposed scenarios. The set of scenarios can be viewed as a set of possible states of nature, which is denoted by S. More precisely, if we denote by $\underline{x}$ (respectively $\bar{x}$) the minimal CCS installed capacity (respectively the maximal CCS installed capacity), the set S is simply the interval $[\underline{x}; \bar{x}]$.
The CCS proportion that will effectively be built in 2050 is unknown and is represented by a random variable $\tilde{x}$ which takes values in $[\underline{x}; \bar{x}]$.
In the model, the DM can be seen as a public authority that will suffer a loss if it deviates from the optimal path[4]. In other words, either the DM bets on the "right" CCS installed capacity by 2050, x, and there is no cost, or he is wrong and will suffer a loss, C, which is proportional to the

[3] Attitudes can be different for the same information and beliefs.
[4] If the DM has over-invested, it means that he could have saved money. If the DM has under-invested, it means he could have invested in a more efficient technology, off-shore wind for instance.

difference between the chosen/forecast CCS installed capacity and the realised CCS capacity in 2050. C is such as: $C : \mathbb{R} \to \mathbb{R}_+$, convex and smooth[5] (moreover, $C(0) = C'(0) = 0$).
There are two distinct cases: when the probability distribution over S, G, is known and when it is not. Although we suppose that the DM is risk neutral, when the probability distribution over S is unknown, the DM may exhibit ambiguity aversion.

4.3.1 Case 1: The DM knows the probability distribution over the scenarios

When the probability distribution over S is objectively known, the DM chooses the CCS installed capacity that minimises the expected loss or maximises the expected gain. For technical convenience, we determine the optimal value of CCS installed capacity which maximises the expected gain with R, the exogenous level of investment benefit[6].

$$\max_X R - \int_{\underline{x}}^{\bar{x}} C_x(X)dG(x) \tag{4.1}$$

First order condition:

$$\int_{\underline{x}}^{\bar{x}} C'(x - X)dG(x) = 0 \tag{4.2}$$

The optimal CCS installed capacity, X^* can be deduced from (4.2).

We now assume that C is a quadratic function such as: $C_x(X) = (x - X)^2$. It is as if the DM minimises the square of the errors.
When the DM is risk neutral and the distribution of scenarios is perfectly known, the optimal CCS installed capacity is simply the expected capacity, $\overline{X} = \int_{\underline{x}}^{\bar{x}} xdG(x) = E(X)$.

This standard result can be used as a benchmark for the analysis of the case with ambiguity. Indeed, this case is similar to the one of an ambiguity neutral DM coping with a distribution of scenarios which is not perfectly known.

4.3.2 Case 2: The DM doesn't know the probability distribution over the scenarios

Now, we consider that the probability distribution over S, G is not perfectly known.
We shall interpret this second case by drawing a comparison with the above case. In the first case, it is as if the DM chooses the CCS installed capacity in 2050 by relying on one expert (no ambiguity). In the second case, when taking his decision, the DM is confronted to several experts providing conflicting probability distributions over the scenarios, thereby introducing ambiguity.

Distribution G depends on the value of a parameter θ which is the realisation of the random variable $\tilde{\theta}$ such as: $\tilde{\theta} \in [\underline{\theta}; \overline{\theta}]$. Without loss of generality, we assume that $G(., \theta)$ is strictly monotone with θ.

[5]A smooth function is a function with continuous derivatives up to some desired order over some domain.
[6]R does not intervene in the optimal solution calculation. Indeed, the aim of this Chapter is to conduct a marginal analysis, particularly assessing X's behaviour to ambiguity aversion.

Let $F(.)$ be the distribution function of the random variable $\tilde{\theta}$ supported on $\Theta = [\underline{\theta}; \overline{\theta}]$, which measures the subjective relevance of a particular distribution (describes the DM's beliefs). In other words, the DM aggregates findings from different conflicting experts. For each plausible probability distribution G_θ (set of prior), the DM computes the expected welfare. Then, to take a decision, the DM gives a particular weight to each expected welfare (the prior over the set of prior). Ambiguity is captured by the irreducibility of compound distributions.
As Klibanoff et al. (2005, [95]), we consider second-order probability distributions, or equivalently "smooth ambiguity". The investor's attitude toward ambiguity, *i.e.* its attitude towards the differences in expected welfare measures implied by the different probability distributions, is described by the shape of a function ϕ. As the DM is ambiguity averse, ϕ is an increasing and concave function[7]. The more ϕ is concave, the more the DM is ambiguity averse.

With ambiguity, the problem to solve becomes:

$$\max_X V^{KMM}(X) = \phi^{-1} \int_\Theta \phi(W(X,\theta))dF(\theta) \tag{4.3}$$

with:

$$W(X,\theta) = R - \int_{\underline{x}}^{\bar{x}} (x-X)^2 dG(x,\theta) = R - \int_{\underline{x}}^{\bar{x}} (x-X)^2 g(x,\theta)dx \tag{4.4}$$

where $g(x,\theta)$ is the density and $W(X,\theta)$ is the expected welfare for a given θ.

As C is convex and ϕ is concave, the objective function is concave in X and the solution to program (4.3), when it exists is unique.

The optimal solution, X^*, verifies the condition:

$$\int_\Theta \left\{ \phi'(W(X^*,\theta)) \times \int_{\underline{x}}^{\bar{x}} (x-X^*)g(x,\theta)dx \right\} dF(\theta) = 0 \tag{4.5}$$

Condition (4.5) is also equivalent to:

$$\int_\Theta \left\{ \phi'(W(X^*,\theta)) \times (E(X|\tilde{\theta}=\theta) - X^*) \right\} dF(\theta) = 0 \tag{4.6}$$

4.3.2.1 The effects due to the introduction of ambiguity on the investment decision

As ϕ is not linear but concave, the optimal CCS installed capacity in 2050 is not the same in the case where ambiguity aversion is not taken into account (Case 1) and where it is (Case 2). The comparison between the two cases is not straightforward.
Suppose that in Case 1, without ambiguity, the distribution function G corresponds to that of Case 2 with $\overline{\theta} = E\tilde{\theta}$. Assumptions on the distribution function $G(.,\theta)$ are required to highlight some results. The simplest case is the one where the distribution function is linear with respect to θ. In this case, if the DM decides a relatively low level of capacity, the introduction of ambiguity incites him to increase his investment, else it will decrease his investment.

[7] If ϕ was linear, the DM would be ambiguity neutral. The representation of the uncertain context can be reduced to a single compound probability distribution. The model reduces to the standard expected gain model.

Proposition 4.3.1. *If the distribution function, $G(x, \theta)$, is linear with respect to θ, when the DM decides a relatively low (high) level of capacity under certainty, the introduction of ambiguity incites him to increase (decrease) his investment.*
If the distribution function, $G(x, \theta)$, is convex with respect to θ, when the DM decides a relatively low level of capacity under certainty, the introduction of ambiguity incites him to increase his investment. When the DM decides a relatively high level of capacity under certainty, the effect of an introduction of ambiguity is not clear.
If the distribution function, $G(x, \theta)$, is concave with respect to θ, when the DM decides a relatively high level of capacity under certainty, the introduction of ambiguity incites him to decrease his investment. When the DM decides a relatively low level of capacity under certainty, the effect of an introduction of ambiguity is not clear.

Proof. See Appendix C. □

To interpret the linearity of function $G(x, \theta)$, we consider the case of an ambiguity neutral DM. The linearity of G implies that $\int_\Theta \frac{\partial W(X,\theta)}{\partial X} dF(\theta) = \frac{\partial W(X, \int_\Theta \theta dF(\theta))}{\partial X} = \frac{\partial W(X, E\tilde{\theta})}{\partial X}$. This means that the introduction of θ as a risk parameter does not change the investment decision. One can draw a parallel with the decision theory under risk, particularly with the case of an individual who does not change his decision when risk is introduced (risk neutral DM). Indeed, even with risk neutrality, we show that the investment decision can be increased or decreased under ambiguity aversion. In addition, we do not need any assumption on the convexity of function ϕ' which, following Baillon's terminology (2013, [15]), corresponds to ambiguity prudence[8].

Nonetheless, the effect of introducing ambiguity depends on the decision made in the certain framework. If the DM chose a relatively low level of CCS, the presence of ambiguity incites him to increase his level of investment in order to deal with ambiguity. If he chose a relatively high level of CCS, the presence of ambiguity incites him to decrease it. The both decisions can be viewed as precautionary effect: the presence of ambiguity makes the DM less inclined to be exposed to a potential loss due to the deviation from the optimal path.

4.3.2.2 Effects of an ambiguity aversion increase on the DM's investment decision

It is likely that several competent bodies will be consulted/confronted to decide the CCS installed capacity in the future electricity mix, for instance the 2050 EU electric power mix.
By drawing a parallel between the comparative statics of risk aversion for investment decisions and ambiguity aversion, one could expect that two decision-makers or competent bodies facing the same situation will not decide the same CCS target for 2050 if they do not have the same ambiguity aversion level. More precisely, as Arrow (1963, [11]) and Pratt (1964, [123]) have

[8] Since Leland (1968, [101]), Sandmo (1970, [131]), and Dreze and Modigliani (1972, [43]), it is well known that the addition of a pure risk affecting future incomes incite the DM to increase its savings if the DM is prudent, that is to say $u''' > 0$. Recently, Berger (2014, [16]) has defined the "notion of ambiguity prudence as an individual characteristic leading him to save extra money if his future income is ambiguous".

established that the demand for the risky asset decreases when risk aversion increases, one could expect that a higher ambiguity aversion level will decrease the investment in CCS installed capacity.
Hereafter, we study the effects of an ambiguity aversion increase on the DM's investment decision. We obtain a similar result as the previous one but both the interpretation and its consequences are different.

Proposition 4.3.2. *In the case of an ambiguous probability distribution over S, if the optimal level of CCS installed capacity, X^*, is relatively small, an increase in ambiguity aversion incites the DM to increase his investment in CCS installed capacity. Otherwise, a higher level of ambiguity aversion incites the DM to decrease his CCS investment.*

Proof. See Appendix C. □

This proposition demonstrates that contrary to casual intuition, more ambiguity aversion will not necessarily reduce the investment in CCS installed capacities.
This result suggests that ambiguity aversion incites the DM to be careful. If the initial level of capacity is relatively high, ambiguity aversion conduces the DM to diminish it and conversely if not. The importance of taking into account ambiguity aversion in decision-making is thus underlined.
More precisely, if we interpret this proposition by referring to two DMs/competent bodies facing the same ambiguous situation with different levels of ambiguity aversion, it means that the DM with the high ambiguity aversion level will suggest a higher CCS installed capacity than the DM with the low ambiguity aversion level if this last DM has under-invested (X^* is lower than a certain threshold). Conversely, the DM with the high ambiguity aversion level will give a lower CCS installed capacity than the DM with the low ambiguity aversion level if this last DM has over-invested (X^* is higher than a certain threshold).

Note that Gollier provides a similar result in his portfolio choice application (Gollier, 2011 [69]); ambiguity aversion may yield an increase in demand for the risky and ambiguous asset, as well as a reduction in the demand for the safe one. In addition, it is not necessarily true that ambiguity aversion raises the equity premium in the economy. Gollier concludes that the "potential existence of a counter-intuitive demand effect arising from ambiguity aversion plays a role similar to the potential existence of Giffen goods in consumption theory."

4.4 The European Union case study

To be consistent with the first two Chapters, here again numerical simulations are based on the European Union. Indeed, as previously underlined, in the late 2000s, CCS generated a real interest in the EU which has committed to support CCS, from a financial[9] and regulatory[10] point of view.

However, the economic crisis as well as the current weak EUA price (approximately €6/tCO_2) has slowed CCS deployment. Currently, there is no new large scale demonstrator in the EU (in addition to Sleipner and Snøvit) whereas it was planned to get twelve in 2015. Nonetheless, CCS is still part of the 2030 Policy Framework for Climate and Energy proposed by the European Commission (January 2014, [56]), and the White Rose CCS Project (Yorkshire, UK) has just secured up to €300 million under the European NER300 programme (July 2014).

There are thus contradictory signals as regards to CCS deployment in the EU. This uncertainty can be found back in the five European Roadmaps for a low carbon economy by 2050 (see the introduction part) in which the CCS share in the electricity mix varies from 0 to 35%.

Hereafter, the focus will be on the Energy Roadmap 2050 (2011, [54]). This Roadmap is from the European Commission one and further publications have partially updated it (e.g., European Commission, 2013 [55]).

The Energy Roadmap 2050 (2011, [54]) provides five scenarios of electricity mix consistent with the 2°C goal by 2050. Tables 4.2 and 4.3 present the relative share of nuclear plants, RES, CCS and classic fossil plants in the 2050 electricity mix.

Table 4.2: Scenarios of cumulative installed power capacity (GW) in 2050. Source Energy Roadmap 2050 (2011, [54])

	Sc 1bis: CPI	Sc 2: Eff. Energy	Sc 3: Diversified techno	Sc 4: High RES	Sc 5: Delayed CCS	Sc 6: Low nuclear
Nuclear	117	79	102	41	127	16
	8%	5%	6%	2%	8%	1%
RES	784	1012	1081	1749	1093	1193
	52%	69%	67%	79%	67%	69%
CCS	39	149	193	53	148	248
		(146)[a]	(190)	(49)	(145)	(244)
	3%	10%	12%	2%	9%	14%
Fossil	562	233	246	376	271	265
plants[b]	37%	16%	15%	17%	16.5%	15%

[a]Figures in brackets refer to the cumulative CCS installed capacity from 2015 to 2050 (slightly different with respect to the CCS installed capacity from 2011 to 2050).
[b]Fossil plants include biomass waste fired, hydrogen plants and geothermal heat.

[9]European Energy Program for Recovery and the NER300 (see Chapters 1 and 2).
[10]2009 CCS Directive to provide a legal and common framework for CO_2 capture, transport and storage, with a national transposition deadline set at June 2011.

Table 4.3: Scenarios of relative share of energy sources in the gross electricity production in 2050. Source Energy Roadmap 2050 (2011, [54])

	Sc. CPI	Sc. Eff. Energy	Sc. Diversified techno	Sc. High RES	Sc. Delayed CCS	Sc. Low nuclear
Nuclear	20.6%	14.2%	16.1%	3.6%	19.2%	2.5%
RES	48.8%	64.2%	59.1%	86.4%	60.7%	64.8%
CCS	7.6%	20.5%	24.2%	6.9%	19%	31.9%
Fossil plants	23%	1.1%	0.6%	3.1%	1.1%	1.6%

4.4.1 Model specification and numerical assumptions

With respect to Table 4.2, $S = \{1, 2, 3, 4, 5\}$. Scenarios are ranked by increasing order of CCS installed capacities in 2050. Consequently, the first state of nature corresponds to the scenario High RES (49 GWe of CCS between 2020 and 2050), the second to the scenario Delayed CCS (145 GWe), the third to the scenario Efficiency Energy (146 GWe), the fourth to the scenario Diversified technology (190 GWe between 2020 and 2050) and the last one to the scenario Low nuclear (244 GWe between 2020 and 2050). It means that: $x_1 \leqslant x_2 \leqslant ... \leqslant x_5$.
The deviation from the optimal path is the argument of $C(.)$, with $C_{x_j}(X) = A_j(x_j - X)^2$ when scenario j happens. A_j is the parameter related to the cost of scenario j. The average cost of one MWe of CCS varies from one scenario to another. A_j takes into account, for each scenario, the particular share of CCS gas *vs.* CCS coal, the speed of CCS deployment and the related cost by decade, from 2020 to 2050. With data from the EU's Roadmap (2011, [54]), for each $j = 1, ..., 5$, A_j={2.244, 2.043, 2.0378, 2.141, 2.215}.

As the Energy Roadmap 2050 (2011, [54]) provides no probability distribution over S, the DM constructs a subjective probability distribution over S. The probability of scenario j is denoted $p_j(\theta)$. The DM assumes that $\tilde{\theta}$ follows a uniform distribution with $\underline{\theta}$ =0 and $\bar{\theta}$=20. The higher the difference between $p_j(\bar{\theta})$ and $p_j(\underline{\theta})$, the higher the level of ambiguity.
Two years after the publication of the Roadmap 2050 (2011, [54]), the EU has released a new report: Trends to 2050, Reference Scenario 2013 (2013, [55]). The total net CCS generation capacity in 2050 amounts to 38 GW. Among the five scenarios of the EU's Roadmap, the first scenario (49 GW) seems thus to be more plausible than the others. It explains why in the below subjective probability distribution over S, scenario 1 has a higher probability than the other scenarios[11]. Note that although the energy mixes of scenarios 2 and 3 are not similar, the related CCS installed capacities are very close. Consequently, the probabilities of scenario 2 and 3 are assumed to be identical.

[11] If one thinks that scenario 2 is more realistic than scenario 1, it means that p_2 becomes p_1 and so on.

Hereafter is the subjective probability distribution over S:
$p_2(\theta) = p_3(\theta) = \frac{1}{5} \times \frac{1}{1+d\theta}$
$p_4(\theta) = \frac{1}{5(1+2d\theta)}$
$p_5(\theta) = \frac{1}{5(1+5d\theta)}$

$p_1(\theta) = 1 - p_2 - p_3 - p_4 - p_5$

Note that parameter $d \geqslant 0$ was introduced to assess the impact of the probability distribution shape on the optimal CCS installed capacity given $[\underline{\theta};\overline{\theta}]$. Hayashi and Wada (2010, [75]) found that subjects were sensitive to the shape of the sets of probability distribution given to them.
It can be noticed that the introduction of ambiguity considerably increases the probability of scenario 1 while significantly decreasing the probabilities of the other scenarios. Indeed, $p_1(\theta)$ increases with $d\theta$, whereas p_2, p_3, p_4 and p_5 decrease with $d\theta$. When $d\theta$ is very high, p_1 tends to 1, whereas p_2, p_3, p_4 and p_5 tend to 0[12]. On the contrary, when $d\theta = 0$, scenarios are equiprobable ($p_j = 1/5 \; \forall \, \theta \in [\underline{\theta};\overline{\theta}]$).
By considering that the different CCS installed capacity values are provided by several conflicting experts, scenario probabilities can also be interpreted this way: when $d\theta$ increases, the weight granted to the first expert (and thus scenario 1) rises. When $d\theta = 0$, the same weight is granted to experts.

We henceforth specify the functional form of DM's ambiguity, represented by ϕ such as: $\phi(x) = \frac{x^{1-2a}}{1-2a}$ with $a > 1/2$. ϕ is a Decreasing Absolute Ambiguity Aversion (DAAA)[13] function which is a "reasonable property of uncertainty preferences" (Gierlinger and Gollier, 2008 [65]). Note that when the ambiguity aversion tends toward infinity, ϕ is such all the weights are on the worst expected W-utility; the criterion amounts to Gilboa and Schmeidler's (1989, [67]) maxmin expected utility (KMM, 2005 [95]).

Consequently, the program to solve is the following[14]:

$$\max_X \int_\Theta \phi(R - \sum_{j=1}^{S} A_j \times (x_j - X)^2 \times p_j(\theta)) \times \frac{1}{\bar{\theta} - \underline{\theta}} d\theta \tag{4.7}$$

Which is equivalent to:

$$\max_X \frac{1}{1-2a} \times \frac{1}{\bar{\theta} - \underline{\theta}} \int_{\underline{\theta}}^{\bar{\theta}} (R - \sum_{j=1}^{S} A_j \times (x_j - X)^2 \times p_j(\theta))^{1-2a} d\theta \tag{4.8}$$

The advantage of such model, *i.e.* the ability of distinguishing between ambiguity and ambiguity aversion, clearly appears.
One can measure level of ambiguity by comparing, for each $j = 1, ..., 5$, the values of $p_j(\underline{\theta})$ and

[12] In other words, $p_1(\theta) \in [1/5; 1[$ whereas $p_j(\theta) \in]0; 1/5]$ with $j \neq 1$.
[13] Similarly to the coefficient of risk aversion, the coefficient of ambiguity aversion is given by: $\alpha(x) = \frac{-\phi''(x)}{\phi'(x)}$. In our case, $\alpha(x) = \frac{2a}{x}$ with $a > 1/2$, which is an increasing function of x.
[14] R is assumed to be equal to $150,000$ in order to have $R - \sum_{j=1}^{S} A_j \times (x_j - X)^2 \times p_j(\theta) \geq 0$.

$p_j(\overline{\theta})$.
As previously said, the ambiguity level is also deeply linked with parameter d. When d varies, the ambiguity level also varies.
The ambiguity aversion level can be measured with the value of parameter a. The higher a, the higher the DM's ambiguity aversion.

According to the proof related with proposition 2 (Appendix C), we know that W is an increasing function of θ if and only if X^* is lower than a certain threshold denoted $\widehat{X}_\theta$.
In the discrete case, $\widehat{X}_\theta$ is such that: $\widehat{X}_\theta = \dfrac{2\sum_{j=1}^{S} A_j x_j p_j^{'}(\theta) + \sqrt{\triangle}}{2\sum_{j=1}^{S} A_j p_j^{'}(\theta)}$ with
$\triangle = 4(\sum_{j=1}^{S} A_j x_j p_j^{'}(\theta))^2 - 4\sum_{j=1}^{S} A_j p_j^{'}(\theta) \times \sum_{j=1}^{S} A_j x_j^2 p_j^{'}(\theta)$.
It means that when, $\forall \theta \in [\underline{\theta};\overline{\theta}]$, $X < \widehat{X}_\theta$, the DM increases the CCS installed capacity when the ambiguity aversion increases.

4.4.2 Results

First of all, if we assume that the probability distribution is known and corresponds to the equiprobable distribution, the optimal CCS installed capacity equals 155 GWe (*i.e.* the average weighted value).

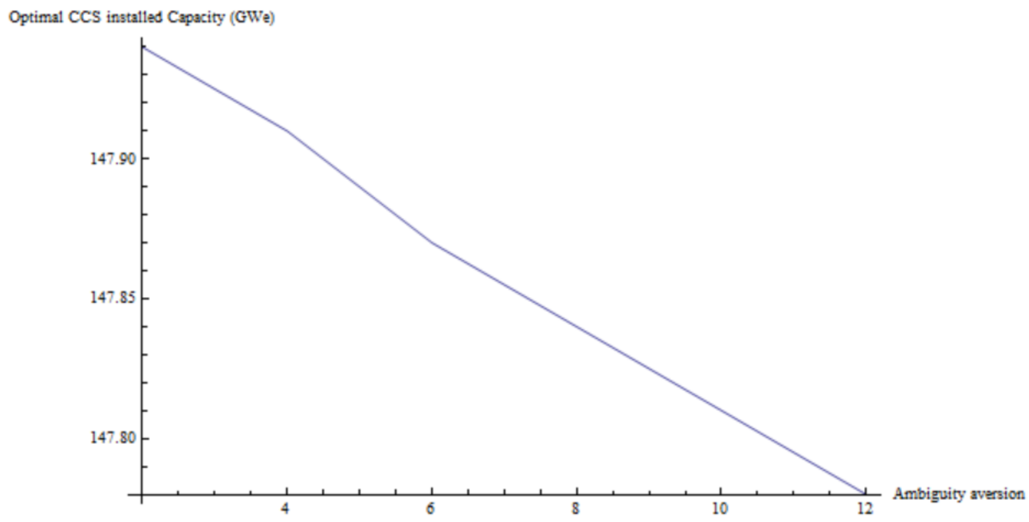
Now, let us turn to the case where the probability distribution is unknown, *i.e.* when the DM faces ambiguity. The optimal CCS installed capacity X^* is lower than or equal to 155 GWe. As the initial level of CCS, in case of certainty, is considered as relatively high, this result is consistent with proposition 1 (G is concave with respect to θ[15]).
The KMM framework extension is suited to isolate the effects that ambiguity introduces into decision-making. Taking into account ambiguity leads to an optimum value which is lower than the one obtained with the certain framework. As a consequence, ambiguity does not increase the investments in the CCS abatement technology.

We shall precisely analyse the effects of ambiguity aversion variations on the decision related to the CCS installed capacity in 2050. As shown by proposition 2, the effect of ambiguity aversion depends on the initial level chosen by the DM.
In this section, we present two opposite case.

(i) When d tends to 0, mechanically, the weight of the random variable $\tilde{\theta}$ decreases and scenarios tend to have the same probability (0.2). In other words, the same weight is attributed to each expert. Consequently, the optimal CCS investment tends to 155 GWe (value when the probability distribution is known).
In this case, the optimal CCS investment *decreases* with ambiguity aversion (Figure 4.1). With respect to the investment values given by $\widehat{X}_\theta$ for each scenario θ, it is as if the DM had over-invested in CCS techniques. As a consequence, when ambiguity aversion increases, the DM reduces the CCS installed capacity.

[15] More weight on the low outcomes.

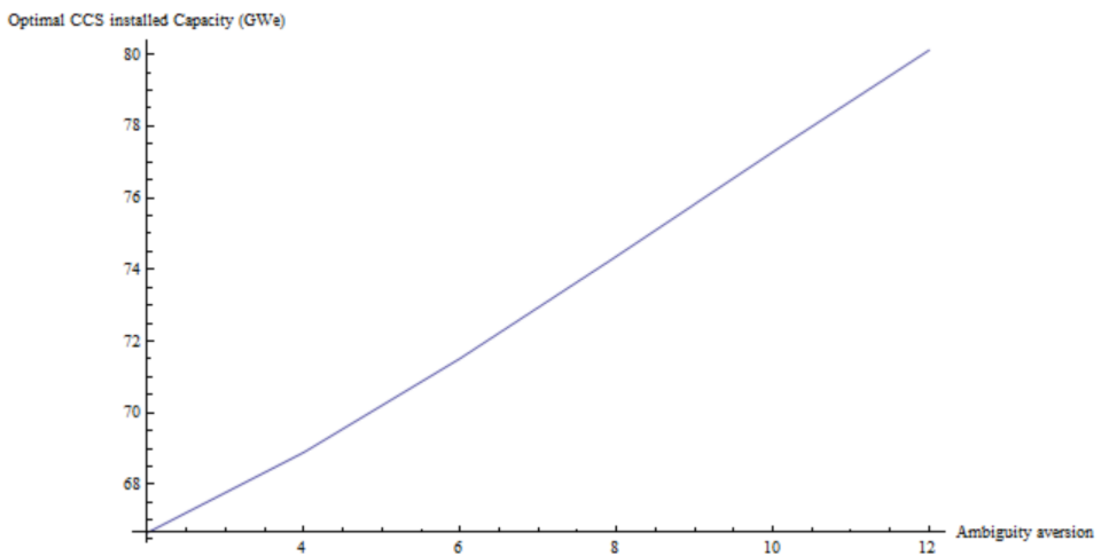
Figure 4.1: CCS investment sensitivity to ambiguity, d=0.003.



(ii) When d tends to 1, the weight granted to expert 1 is very important: the probability of his scenario tends to 1 whereas the probabilities related to the other scenarios tend to 0. Therefore, the optimal CCS installed capacity is close to the CCS installed capacity given by expert 1 *i.e.* 49 GWe.

In this case, the optimal CCS installed capacity *increases* with ambiguity aversion (Figure 4.2). It is as if the DM had under-invested in CCS techniques with respect to the values defined by $\widehat{X}_\theta$ for each scenario θ; therefore, even if the level of ambiguity aversion increases, the CCS installed capacity also increases. As previously underlined it can be interpreted as a precautionary effect.

Figure 4.2: CCS investment sensitivity to ambiguity, d=0.5.



If the optimal CCS installed capacity, X^* is not always above or below $\widehat{X}_\theta$ $\forall\, \theta \in [\underline{\theta}; \overline{\theta}]$, we do not know how the investment decision will be impacted by an ambiguity aversion change. In other words, it is not possible to establish, *a priori*, which effect will dominate.

In our framework, the turning point is approximately $d = 0.013$.

4.5 Conclusion

To choose the optimal electricity mix in 2050, decision-makers may seek the advice of experts. However, they usually provide imprecise and contentious information, leading to ambiguous situation.

In this Chapter, we offer to DMs a decision criterion enabling them to choose, in this ambiguous context, the optimal CCS installed capacity (or other generation technology) in 2050. This CCS target will determine the required investments as well as the relevant energy policy design to support CCS deployment (Chapter 1).

Numerical simulations illustrate the case of the EU and give practical recommendations for DMs.

The developed framework enables us to perform comparative statics. We characterised the conditions under which the introduction of ambiguity leads to decreasing (respectively increasing) the CCS installed capacity. Similarly, without perturbing the information structure (ambiguity is kept unchanged), we also characterised how the equilibrium would change if the perceived ambiguity aversion were increased/decreased. In other words, this static approach enables us to know how different degrees of ambiguity aversion are likely to affect the choice of energy policy, more precisely, the decision about the CCS capacity to be installed in 2050.

Drawing a parallel with comparative statics of risk aversion for investment decisions, one could expect that an increase in ambiguity aversion may yield to decrease the CCS installed capacity. However, this Chapter demonstrates that more ambiguity aversion does not necessarily reduce the CCS installed capacity which can be interpreted as a precautionary effect. This result underlines the importance of taking into account both ambiguity and ambiguity aversion in the decision-making process.

We shall illustrate the above result. Facing exactly the same ambiguous situation, two decision-makers might not take the same CCS decision if they do not share the same ambiguity aversion. For instance, the Council of the European Union may want to increase/decrease the CCS target proposed by the European Commission, depending on if he is more or less ambiguity averse than the European Commission as well as on the suggested amount of CCS installed capacity. Note that this result is obtained by assuming that the DM is risk neutral *i.e.*, the DM will not change his level of investment if the risk increases.

To further understand the decision made by the Council of European Union with respect to the European Commission's choice, we need to obtain some information about their levels of ambiguity aversion. A new challenge appears: shall we consider their respective ambiguity aversion degree as if they were individuals or shall we consider an aggregated ambiguity aversion degree?

As this framework is static, we only consider the effects of ambiguity aversion when the DM cannot expect new information before making his decision in further periods. However, ambiguity

aversion may vary over time. Information relative to CCS costs/maturity/social acceptance/etc. will be improved with time, which may change the underlying probability distributions. Since DMs frequently update their beliefs to take into account new information, one extension of this work could be dynamic modelling. This issue of re-evaluating ambiguity aversion in further periods is particularly relevant for long-term decision process, and thus for CCS since the related investments will be phased in over three decades: from 2020 to 2050.
However, as underlined by Lange and Treich (2008, [100]), introducing dynamic can be technically difficult, particularly when there are numerical simulations, and most of all, raises one of the main issue of the decision theory: how are preferences updated to take into account new information (Etner et al., 2012 [50])? In other words, which updating rule should be chosen? Klibanoff, Marinacci and Mukerji (2009, [96]) have proposed a dynamic model with learning under ambiguity, and some extensions have been developed. For instance, Millner and al (2013, [106]) provide insight on how ambiguous knowledge and aversion to ambiguity can impact the welfare analysis of climate change abatement policies. They simplify the dynamic problem by "computing welfare for two sample exogenous learning scenarios, one in which ambiguity resolves after one step, and one in which ambiguity persists unchanged for all time". Collard et al. (2011, [25]) as well as Ju and Miao (2012, [92]) investigate a dynamic infinite horizon portfolio problem in which the ambiguity averse DM copes with time-varying ambiguity about the second order distribution of the plausible probability distributions of the consumption growth. Although these two articles notably consider different specifications of risk (u) and ambiguity (ϕ) attitude, they both conclude that ambiguity aversion raises the equity premium. Nonetheless, dynamic models dealing with investment decision under ambiguity are still largely unexplored, and are subject to future research.

General conclusion

Context and Problematic

The power sector is responsible for approximately 40% of total CO_2 atmospheric emissions (IEA, 2012 [117]) and its fossil fuel consumption is still rising. This sector is thus key in climate change mitigation.

The latest reports from international organisations or experts such as the Intergovernmental Panel on Climate Change (IPCC), the International Energy Agency (IEA) or the European Commission have reaffirmed the crucial role of Carbon Capture and Storage (CCS) techniques in decarbonising the power sector. Indeed, CCS might present several advantages.

First, CCS is said to be the only available technology enabling the power sector to deeply cut CO_2 emissions: up to 90% of the CO_2 emitted by a fossil fuel plant provided that the CO_2 is efficiently stored underground. In countries whose energy mixes are highly reliant on fossil fuels, CCS power plants may be an interesting option to provide decarbonised electricity at base-load. In countries with a significant share of low carbon electricity supply techniques - nuclear and renewable energy sources (RES) - in their electricity mixes and an increasing use of intermittent RES, dispatchable electricity supply techniques are required. CCS plants may be an interesting option since they can supply low-carbon electricity on demand and are dispatchable: it can represent the second advantage of these techniques. Some benefits may thus be derived from the introduction of CCS coal and gas plants alongside intermittent renewable generation, notably avoiding the system costs and drawbacks related with supply intermittency or even relative inflexibility (nuclear). Thirdly, current cost estimates suggest that CCS equipped fossil fuel plants may be competitive with other low carbon techniques such as offshore wind farms or concentrating solar power plants (IEA, 2011 [79]; DECC, 2012 [33]). Fourthly, considering the important part played by fossil fuels in the world's energy supply, CCS can be an interesting transitional low carbon technology. Indeed, CCS can preserve the value of fossil fuel reserves and also existing infrastructures by enabling a continued use of fossil fired plants that would otherwise be shut down to respect carbon emission constraints. Consequently, CCS enables the avoidance of the economic consequences of fossil plant premature closures.

These different potential savings explain why CCS is considered as a critical component of a least-cost portfolio approach to decarbonise the power sector (Grimston et al., [72]). Several studies show that without CCS, the investment required to decarbonise the power sector would be considerably increased (Best and Levina, 2012 [18]; IPCC, 2014 [87]).

Nevertheless, it seems that there is a large hiatus between the long term projections from energy scenarios where CCS plays a significant role in the power sector decarbonisation, and the current CCS deployment. For instance, in the IEA's 2°C scenario (2013, [118]), CCS accounts for up to 14% of the total emission reductions globally through to 2050, half of the volume coming from the power sector, whereas CCS needs to be demonstrated on a larger scale to comply with long term scenarios. The next step is to scale up to large, integrated projects but the number of demonstrators has progressed slower than anticipated: as of January 2015, there is only one Large Scale Integrated Project (LSIP)[16] in operation in the power sector in the world (GCCSI, 2014 [63]).

Thereby, the main objective of this thesis was to identify the techno-economic and social conditions required for the emergence of CCS in the power sector, in compliance with the role played by these techniques in scenarios with ambitious climatic goals.
The research carried out focuses on the two significant hurdles to CCS development, cost and social acceptance, and combines two complementary approaches: a positive approach - emphasising the determinants necessary to trigger CCS investment in the power sector -, and a normative one - providing recommendations for investors and organisations on how CCS can best be deployed as part of a least cost approach to climate change mitigation -.

Synthesis of the main findings and recommendations
The positive approach led us to establish a techno-economic overview of CCS applied to the power sector. It was shown that there are large discrepancies in the way CCS costs are currently calculated and reported by various studies and organisations: comparing them straightforwardly would only lead to misleading CCS cost information. A specific methodology was thus elaborated in Chapter 1 to correctly compare CCS costs and quantify CCS cost heterogeneity.
The CCS cost analysis has shown that CCS power plants suffer from significant extra-costs, incurred at the start of the project and also incurred during operation, due to net efficiency penalties and higher operating and maintenance expenditure. Nonetheless, similar to RES, CCS emerges endogenously as a cost effective response to the carbon restriction. Therefore, the extra CCS costs can be offset by a CO_2 price high enough to make CCS power plants more competitive than classic plants. Thus the following question arose: for which CO_2 price is it worth investing in CCS plants? To correctly answer this question, Chapter 1 of this thesis has demonstrated that it is necessary to distinguish between intra-technique CO_2 switching prices[17], and inter-technique CO_2 switching prices[18] to ensure which power plant type is the most cost-effective.

CCS gas plants may be more attractive than CCS coal plants in liberalised electricity markets.
In the CCS literature, one can usually read that in the European Union (EU), CCS coal plants become competitive when the CO_2 price exceeds approximately €60/tCO_2, whereas for CCS gas plants, the price is €90-100/tCO_2.
The above distinction between intra- and inter-technique CO_2 switching prices has shown that when the CO_2 price is higher than €65/tCO_2[19], CCS coal plants are more profitable than reference coal plants but are less cost-effective than gas plants. In fact, the CO_2 price required

[16]The definition of a LSIP is from the Global CCS Institute and involves projects with the capture, transport and storage of CO_2, at a scale of 800 000 tCO_2/yr for coal-based power plants or 400,000 tCO_2/yr for gas-based power plants and other emission-intensive facilities.
[17]Intra-technique CO_2 switching prices refer to the CO_2 price necessary to switch from a coal to a CCS coal plant, and from a gas to a CCS gas plant. They have been studied in the CCS literature. See Chapter 1 for more details.
[18]Inter-technique CO_2 switching prices refer to the CO_2 price necessary to switch from a coal to a gas plant, from a gas to a CCS coal plant, etc. They have not been studied in the CCS literature.
[19]Off-shore Transport and storage (T&S) costs.

to trigger CCS investment, regardless the fuel type, is €115/tCO_2. Surprisingly, CCS gas plants might be more attractive than CCS coal plants in liberalised electricity markets, even if the intra-technique CO_2 switching price is lower for CCS coal plants (€65/tCO_2 by 2020) than for CCS gas plants (€115/tCO_2[20] by 2020). However, as underlined by sensitivity analyses, the relative appeal of CCS gas plants over CCS coal plants depends heavily on relative fuel prices. In addition, the fact that CCS coal plants might be more attractive than CCS gas plants when considering the short-term vision *i.e.* the Short Run Marginal Cost (SRMC) (Chapter 1), may also nuance the relative appeal of CCS gas plants over CCS coal plants, or at least underlines the complexity in designing appropriate CCS support tools.

In the current context of low CO_2 prices, specific transitional support measures are required to trigger CCS commercial deployment.

The issue of designing and implementing relevant and efficient CCS support tools is particularly important in the current context of low CO_2 prices. Indeed, in the EU's example, a CO_2 price of €115/t is required to encourage CCS investment, whereas the current CO_2 price in the EU-ETS is approximately €6/t. And in 2030, even if the CO_2 price required to offset extra-CCS cost might be lower (€85/t), it will still be considerably higher than the forecast CO_2 market price (€30/t in 2030; IEA, 2012 [117]). There is thus a large gap between the CO_2 price required to initiate CCS investment and the current/forecast CO_2 market price. To compensate for this gap, policy-makers can implement specific transitional support measures capable of offsetting extra CCS costs. Chapter 1 of this thesis has shown that the best combination of CCS support instruments should rely on a gateway approach, support tools being associated with clear sunset clauses to phase them-out when the market failures they are created to address disappear. Short-term (2015-2020) support tools are mainly supply-push instruments (driving radical innovation) whereas long-term (beyond 2030) support tools are mainly demand-pull instruments (creating and stimulating demand). In addition, to create a stable environment encouraging CCS investment, the best portfolio should contain mechanisms which enables the gap between the LCoE of CCS and non-CCS power plants to be filled, but also the gap between the SRMC of CCS and non-CCS power plants to be filled, to ensure that CCS plants are dispatched over their lifetime. Nevertheless, currently there is no significant CCS support tool in the EU, except in the UK (see below).

The gap between current/forecast low CO_2 prices and the threshold required to trigger CCS investment, as well as the absence of CCS policy support tools can mostly explain the delay observed in CCS deployment in terms of LSPIs in the European Union. Indeed, there is currently no economic rationale for operators to invest in CCS plants: they are too expensive with respect to conventional plants and there is currently no credible and/or predictable signal of a potential change. For instance, although forecast CO_2 market prices are too low with respect to the threshold required to trigger CCS commercial deployment, structural reforms of the EU-ETS have been delayed. One can also note the failure of the NER300 first round. Other explanatory factors can also be advanced. Indeed, another issue is the present overcapacity in continental Europe: over the past five years in the EU, 130 GW of RES and 78 GW of conventional generation have been added to the system while only 44 GW of conventional generation has been

[20] This CO_2 switching price value is slightly higher than the one that can be found in the CCS literature. This gap can mainly be explained by the fact that very recent studies (e.g., DECC, 2013 [35]) - which gives higher CCS costs due to the delay in CCS deployment -, are taken into account as well as the normalised set of techno-economic assumptions, particularly fuel prices.

retired (World Economic Forum, 2015 [139]). A few years before the 2009 economic slowdown, strong price signals encouraged investments in conventional means of electricity production which were brought into operation at the height of the economic downturn. Additionally, the economic crisis has reduced the demand whereas uncapped renewable incentives have led to an increasing installed capacity of RES.

Designing relevant CCS support policy is a necessary, albeit not sufficient, condition to trigger CCS deployment. Ensuring the availability of appropriate CO_2 storage sites is crucial.
Although designing appropriate CCS support tools when CO_2 market prices are low is a necessary condition to trigger CCS deployment, it is not sufficient. The stakeholders of CCS projects will also have to ensure the availability of appropriate storage sites near the capture units. Nevertheless, as underlined by Chapter 1, the next step in CCS commercial deployment is to increase efforts characterising and identifying appropriate geological storage sites around the world. Indeed, until now, only a limited number of countries/CCS actors have tried to establish a carbon storage atlas. In the EU, the European project Geocapacity (2008, [51]) has assessed that the European storage capacity could range from 117 to 252 GtCO_2. This storage capacity would enable large emitters[21] to store their CO_2 emissions for 60-130 years.
However, these first estimates correspond to theoretical storage capacities. When considering effective storage capacities, *i.e.* when taking into account "a number of capacity coefficients representing mobility, buoyancy, heterogeneity, water saturation and aquifer length, respectively and all reducing the storage capacity" (ZEP, 2011 [144]), the capacity would be equal to 2-30% of the theoretical capacity. By assuming the low range (2%) except for the UK[22], the EU would have a global storage capacity of almost 150 GtCO_2. However, saline aquifers, which may represent 90% of the EU storage capacity, remain poorly characterised. This reinforces the uncertainty about the real storage capacities of the EU.
Furthermore, these 150 GtCO_2 correspond to a global storage capacity. It is thus necessary to assess the balance between the needs in terms of storage capacities and their geographical distribution within the EU. According to the European project Geocapacity (2008, [51]), a few European countries might have enough storage capacities enabling them to store their emissions from several investment cycles in thermal plants (with respect to the energy mixes described in the EU's roadmap; European Commission, 2050 [54]). In addition, as shown by Chapter 3 of this thesis, social acceptance issues crystallise mostly around onshore T&S infrastructures. And social acceptance has become a prerequisite for the successful deployment of CCS techniques (IPCC, 2014 [87]). Offshore infrastructures are significantly less controversial. Thus, if onshore storage was not socially accepted in the EU, all the offshore storage capacities would be required. The UK, Norway and to a lesser extent Denmark have the largest offshore storage capacities. As a consequence, the non acceptance of onshore storage would require the development of trans-European carbon transport and storage infrastructures. Although not impossible, a trans-European carbon network would raise different issues, notably political (e.g.: coordination of the energy policy of the Member States, regulatory aspects) and economic issues.

For the moment, we shall assume that one CCS project has received the relevant supports to trigger its launch, and that there is a storage site near the capture unit. The success of this single CCS project depends on whether it is socially optimal. Chapter 3 of this thesis has

[21]More than 100 MtCO_2/yr.
[22]The UK Storage Appraisal Project estimated that the UK has a total storage capacity of 50 GtCO_2.

emphasised that to ensure that the use of CCS techniques is socially optimal (*i.e.* enables an increase in social welfare), policy-makers need to adopt a global approach. To achieve this, policy-makers need to consider a third source of marginal disutility in addition to the two sources of marginal disutiliy which are usually modelled. Straightforwardly, the use of CCS techniques creates a globally positive externality by reducing the atmospheric CO_2 concentration, and also introduces a locally negative externality due to the geological storage of carbon. However, in addition to these two sources of marginal disutiliy - the marginal disutility caused by the atmospheric pollution and the marginal disutility caused by carbon storage -, CCS use introduces also a third source of marginal disutility which is due to the simultaneous presence of CO_2 in the atmosphere and in underground storage sites. Indeed, considering each source of disutility separately, individuals might not be concerned by climate change issues, or by living nearby carbon storage sites. However, individuals might be reluctant to have CO_2 both above their head and under their feet. Thus, considering the problem as a whole enables policy-makers to avoid deploying CCS when it is not socially optimal, notably avoiding stranded costs due to the failure of advanced CCS projects.
When the use of CCS techniques is technically possible (available storage site) and effectively socially optimal, Chapter 3 of this thesis has also emphasised that policy-makers should implement a subsidy dedicated to carbon storage provided that the carbon-intensive input is taxed. This result has considerable policy implications since a subsidy to carbon storage would increase the absolute profitability of CCS plants with respect to non CCS plants. Consequently, transitional support measures to encourage CCS deployment could be reduced, thereby decreasing the related windfall effects and inefficiencies. Note that in February 2015, the United States Secretary of Energy, Ernest Moniz proposed the setting up of a subsidy of $50/t for each tonne of CO_2 stored underground.

How can Decision-Makers deal with ambiguity when deciding the CCS installed capacity in the 2050 electricity mix?
As previously shown, it is required to take into account social preferences to determine to what extent CCS is socially optimal. It gives to decision-makers/investors an upper limit not to be exceeded. As previously emphasised, this upper limit also needs to be consistent with the availability of appropriate underground storage sites. However, public decision-makers (DMs) still face the following issue: which CCS installed capacity should be put in the 2050 electricity mix? When facing these kinds of issues, decision-makers may seek the advice of experts who, nonetheless, often provide conflicting and ambiguous information. Consequently, public decision-makers know neither the CCS installed capacity they should put in their electricity mix (and therefore the investments they should proceed with), nor the related policy support measures they should implement. A few empirical papers suggest that taking into account ambiguity is relevant for public-decisions in mitigation and adaptation (Fontini et al., 2010 [58]; Alpizar et al., 2011 [7]). Nonetheless, a few articles deal with ambiguity and investment decisions in capital intensive mitigation technologies. Chapter 4 of this thesis fills this gap and provides to DMs a criterion helping them to choose the CCS installed capacity in 2050 on the basis of imprecise/ambiguous information coming from several experts with divergent opinions. One interesting result is that contrary to casual intuition, more ambiguity aversion will not necessarily reduce the CCS installed capacity in 2050; it emphasises the importance of considering it in the decision-making process and it can be interpreted as a precautionary effect.

This idea of investing in CCS techniques as a precautionary effect, notably to avoid carbon lock-ins of medium carbon intensive technology and insure against the risk of one or more technologies being more expensive than expected, is one of the main arguments advanced by the UK to justify its support to CCS commercial deployment.

For the UK Government, CCS has the potential to be one of the most cost-effective technologies to achieve its 2050 climate change targets[23]. CCS could represent 14% of the 2035-2036 power generation output (scenario Gone Green; National Grid, 2014 [109]).

But the UK policy is guided by a liberal approach: the purpose is to allow a range of low carbon technologies to compete in the 2020s with the market deciding which of the competing technologies delivers the most cost effective mix of supply and ensures a balanced electricity system. The objective of the UK policy is not dictated by CCS being in its mix: CCS will only be part of the mix if its cost-competitiveness can be demonstrated.

Therefore, to ensure that CCS will be an option to consider, the UK has designed and implemented specific tools to support CCS deployment, particularly feed-in-tariffs and CCS purchase contracts, capital grants and Emission Performance Standards. The capacity market and the carbon price floor should also encourage CCS demonstration projects and thus commercial deployment (please refer to Chapter 1 for more details). Two CCS power plant projects have recently received £1 billion capital funding from the UK government: White Rose and Peterhead. Thus the UK may have become an exception in the European Union.

The UK wants to create the right market conditions for CCS deployment, because CCS is seen as having several significant advantages. Over the next decade, on- and off-shore wind farms are likely to be the main new technology installed to meet RES and GHG emission reduction targets. To compensate for the intermittency of wind and the relative inflexibility of nuclear, dispatchable low carbon electricity sources will be required. As CCS power plants are potentially able to operate in a flexible mode (Chapter 2), they could represent an interesting option. In addition, contrary to continental Europe, a majority of the current UK base-load generation fleet will need to be replaced before 2030. And CCS is seen as a technology that could contribute to diversity and security of electricity supply. In addition, the UK presents some key advantages making it particularly suited for the deployment of CCS. First of all, the UK has one of the widest numbers of suitable off-shore storage sites in the European Union which could considerably reduce social acceptance issues (Chapter 3). Henceforth, its expertise in the offshore oil and gas industry could be transferred to the business of CO_2 transport and storage. Furthermore, the captured CO_2 might be used for enhanced gas and oil recovery, thereby improving the economics of the whole CCS chain (but then the risk is to worsen climate change issues, see below). If the captured CO_2 becomes a valuable commodity, it could reduce social acceptance issues and accelerate CCS deployment. Additionally, to justify the high costs of CCS support policies, CCS is presented as a potential green growth opportunity, creating jobs and markets. If CCS opportunities develop as anticipated, benefits for UK-based firms have been estimated to exceed £3 billion a year by the late 2020s. Furthermore, since CCS has not yet been deployed commercially in the power sector, the UK could take the lead in CCS technologies, that could thereby be exported as goods and services.

[23] The UK set a legally binding GHG emission reduction target of at least 80% by 2050. Therefore, the UK needs to considerably decarbonise its electricity system by 2030, all the more so as it has been promoting a large electrification of final uses, particularly mobility (ultra low carbon vehicles) and heat (gas generates approximately 85% of heat).

How can CCS be best deployed in the perspective of a least-cost portfolio approach to decarbonise the power sector?
But CCS support policies will have a significant cost. In the UK, the Electricity Market reform and the specific support measures for the CCS deployment are already criticised for their high burden on public finance. The DECC (2013, [36]) estimates that the investments required to decarbonise the power sector will be up to £110bn from now until 2020.
More broadly, whatever the combination of support tools chosen to encourage CCS deployment, the public cost will be significant for every country (IPCC, 2014 [87]; IEA, 2012 [116]). Based on this evidence, Chapter 2 of this thesis has provided recommendations on how CCS can be best deployed in the perspective of a least-cost portfolio approach to decarbonise the power sector.
Particularly, when countries such as the UK want to make CCS a technology to export, partial capture may be an interesting option. Indeed, when CO_2 prices are low, partial capture allows improving the economics of CCS plants which could accelerate the demonstration phase. CCS being mature more quickly, the overall cost of a carbon neutral power sector, might be reduced.
For countries which intend to use CCS in the long-term to decarbonise their power sectors but which do not intend to take the lead in the CCS field, Chapter 2 has shown that they should take advantage of the geographical differentiation of costs. Indeed, due to the prospective evolution of carbon/fuel/cost prices, CCS power plants might be close to absolute competitiveness in China by 2030[24] (refer to Chapter 1 and Chapter 2 for more details). CCS techniques will thus not require significant support measures in contrast to the EU. Within the framework of climate change negotiations, the EU and more broadly developed countries could thus consider the option of supporting CCS deployment in a low building/operating cost country such as China. Such support from the EU to China could include monetary/technology transfers or R&D agreements like the "US-China Joint agreement on climate change", signed in April 2013 between China and the United States. Such collaborative efforts are advantageous for both countries: developing CCS technology at the lowest cost will reduce the burden for developing countries and will enable developed countries to use the technology when mature (and thus less expensive). Note that in this geographical perspective, partial capture is also an interesting option to consider: it could reduce even further the cost of CCS commercial deployment and thus the overall cost of the power sector decarbonisation.

Some new research opportunities deserve to be explored.
During this thesis, other interesting issues were raised but are not addressed here, due to the lack of available data or because there are not directly covered by the scope of the researches.
As previously underlined, energy scenarios with ambitious climatic goals rely on CCS to significantly reduce global CO_2 emissions in the coming decades. As noted in Chapter 1, CCS may play an important decarbonisation role both in the power sector and in energy-intensive industries[25]: hence, in the IEA's 2°C scenario, half of the total emission reductions due to CCS globally through to 2050 comes from the power sector and the other half from industry. Indeed, CCS may play a key role in the decarbonisation of industry because many industrial processes

[24]The CO_2 price necessary to switch from classic to CCS power plants is considerably lower in China than in the EU. This result is mainly due to lower investment and O&M costs in China than in the EU, and to a lesser extent, cheaper raw materials and fuel prices. Note that in the EU, CCS gas plants might be more attractive than CCS coal plants in liberalised electricity markets, whereas in China, CCS coal plants seem to be more attractive than CCS gas plants.

[25]Biomass conversion; cement; iron and steel; refineries; and high-purity CO_2 sources.

emit large CO_2 amounts which are not related to energy but are due to raw material conversion. The potential for further energy efficiency gains to cut CO_2 emissions is thus reduced and CCS is most often the unique mitigating option. In addition, in the iron and steel sector, CCS could be a very interesting option since the technology could increase performances of blast furnaces and reduce the coke consumption. The issue is thus the following:
In which sector CCS will be widely deployed first in the 2020s? Will it be in the power sector or in industry?
Indeed, although CCS is the only available option to deeply cut CO_2 emissions, the power sector has other cost-effective alternatives; particularly nuclear and RES could help delay CCS deployment until its maturity. Consequently, CCS might commercially be deployed more quickly in industrial sectors than in the power sector which may postpone the use of this option. Thereby, the power sector could benefit from CCS deployment in industrial applications: learning-by-doing effects in carbon transport and storage infrastructures, existing carbon T&S networks (clusters) and also social acceptance lessons and experiences.
Assessing the potential spillover effects of a large-scale CCS deployment in industry on the power sector and vice versa might be interesting. Such analysis would notably require an objective overview of CCS costs in industry. But because of the lack of available data, it was not possible to make this overview. However, several LSIPs are planned or under construction. One can refer, for instance, to the world's first LSIP in the iron and steel sector which is under construction in the United Arab Emirates and is expected to be operational in 2016 (GCCSI, 2014 [63]). These techno-economic and then sectoral analyses might thus be possible in the short-term.

The semantic shift from Carbon Capture transport and Storage to Carbon Capture transport Utilisation and Storage
A semantic shift from CCS to CCUS, U standing for Utilisation has been observed. First of all, one can notice that over the 13 LSIPs in operation around the world, eight projects use anthropogenic CO_2 for Enhanced Oil Recovery (EOR). Second, most future LSIPs are also driven by CO_2 utilisation: for fuel production (e.g.: methanol), EOR or enhanced water recovery like the LSIP financed by the United States and China.
Indeed, these different CO_2 utilisations represent a direct near-term potential to produce additional revenues that partially offset CCS costs. The economic utilisation of the captured CO_2 for commercial purposes provides additional business and market case which may drive the interest of private investors in CCS techniques. Additionally, as the captured CO_2 becomes a commodity instead of a waste, it might help addressing public acceptance issues related to CCS projects. This willingness to use the CO_2 as a commodity raises several questions that would deserve further researches or studies.
Currently, the world annual consumption of CO_2 is approximately 200 Mt[26]. As an order of magnitude, this amount represents the CO_2 emitted by a 745 MW coal plant operating at base-load (7,884 hours per year) for 40 years with a net efficiency of 41%. Half of 200 MtCO_2 is currently used by the chemical industry, mainly for urea production, 80 Mt of CO_2 are used for EOR, the remaining 20 Mt being used for other industrial applications such as water treatment, solvent, as well as food and drinks (e.g.: sodas). According to the IEA's 2°C scenario (IEA, 2013 [118]), in 2050, 7,000 MtCO_2 should be annually captured. One can currently observe emerging

[26]To note, in 2010 49 Gt of CO_2eq were emitted in the atmosphere (IPCC, 2014 [87]). 25% of CO_2eq emissions were released by the electricity and heat production sector, and 21% by industry.

CO_2 uses, for instance in plastics production or in building materials. But the question is: in the long-term, will the utilisation of CO_2 be a niche market? Another question is to what extend this CO_2 utilisation can offset the extra-cost due to CCS devices and facilitate their commercial deployment? Furthermore, will the CO_2 utilisation effectively contribute to reduce global CO_2 emissions? Indeed, only used for EOR purposes, CCS might lose sight of its primary goal *i.e.* might worsen climate change: 40% to 70% of the amount of injected CO_2 does not come back to the production wheel, and EOR increases the amount of available fossil fuel resources. To ensure that CCS-EOR contributes to reduce GHG emissions, monitoring techniques are required to assess the volume of CO_2 which is effectively stored and to optimise the flow rate injection to maximise the amount of CO_2 naturally trapped underground. In other words, one will need to ensure that the amount of CO_2 which is effectively stored underground is at least equal to the amount of CO_2 needed for the capture process (efficiency penalties) plus the amount of CO_2 emitted when using the fossil fuels obtained with the EOR process. Consequently, substitutes to carbon storage in geological formations will need to be carefully assessed to make sure that they really help to reduce global GHG emissions.

This last point raises another larger issue. Giving a carbon value is a necessary, albeit not sufficient, condition to solve all the environmental issues. One can notably think of the CO_2 use for Enhanced Water Recovery like the LSPI between the United States and China (Chapter 2). To encourage producers to take into account all the externalities affecting the ecosystems and their regulatory functions (particularly with respect to exhaustible resources), integrating these external effects in the cost of production through environmental taxation may be required (De Perthuis and Jouvet, 2013 [31]).

Appendix A

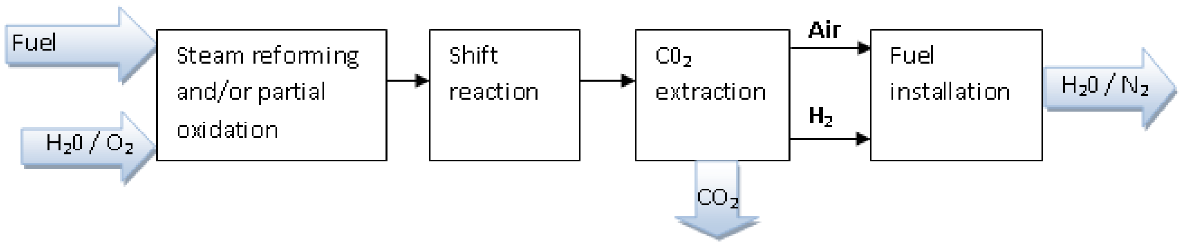
Carbon Capture techniques

A.1 Pre-combustion carbon capture

A.1.1 General principles

The carbon contained in the fossil fuel is removed before the combustion process. The problem is tackled at its root (Figure A.1). This capture process can be used with several solid or liquid fuels.

Figure A.1: Pre-combustion carbon capture.



It is the most complex carbon capture process.
The main steps of this capture process are as follows:

- The feedstock is partially oxidised with oxygen or air (gasification of coal, petroleum coke and heavy oils) or reacts with water (natural gas reforming) to be turned into a synthesis gas, mixture of hydrogen H_2 and carbon monoxide CO. The advantage of H_2 is that its combustion does not produce CO_2 but H_2O.

- Then, this synthesis gas or syngas undergoes the water-gas shift reaction to produce a CO_2 rich gas mixture. The CO_2 concentration can range from 15 to 50%.

- Then, the CO_2 is separated from H_2 in a similar way as in the post-combustion process[1]. H_2 can be used directly (e.g., in refineries) or as a fuel in combined-cycle gas plant (elec-

[1]In the post-combustion process, the flue gas stream is at low pressure and with a low CO_2 content (5-15%). In the pre-combustion process, the shifted synthesis gas stream is rich in CO_2 and at higher pressure; the CO_2 removal is thus easier.

tricity or heat without CO_2), be directly injected in gas networks (until 20%) or also be combined with CO_2 to produce methane (CH_4) and water (methanation) to be injected in the gas network (power to gas).

Pre-combustion capture technology is only applicable to new fossil fuel power plants: Integrated coal Gasification Combined Cycle (IGCC). Indeed, the capture process requires significant modifications of the power plant design.

A.1.2 Current state of the art

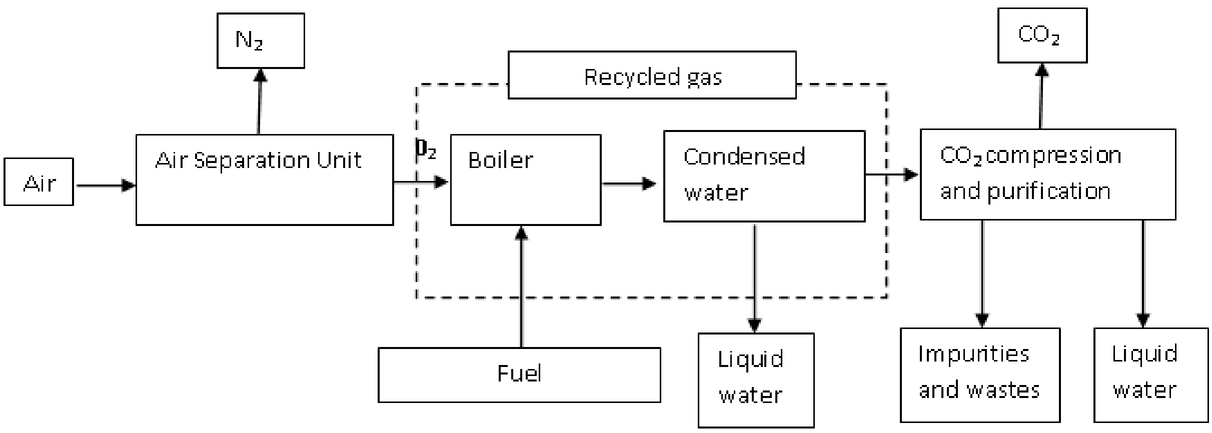
This pre-combustion capture process is already used at an industrial scale. It is less energy intensive than the post-combustion capture process but leads to higher efficiency penalties due to the shift reaction.
This capture process is particularly adapted for IGCCs (electricity generation), large-scale upgrading of asphalt sands or extra-heavy oil resources, as well as the production of petrochemical intermediates (NH_3, CH_3OH, liquid fuels).
IGCCs have higher CAPEX than traditional coal plants; consequently, the IGCC sector has struggled to develop. However, there is one IGCC with CCS under construction worldwide: Kemper County (Mississippi). This LSIP should be complete in 2015.
Poly-generation (electricity, heat, hydrogen and synthetic fuel production) schemes could have more potential than IGCCs. It can be referred to the Sino-European project COACH (partially funded by the EU under the 6^{th} Framework Program) which aims to prepare the ground for implementing large-scale poly-generation energy facilities in China.

A.2 Oxy-combustion carbon capture

A.2.1 General principles

In traditional fossil fuelled power plants, combustion is carried out with air; the flue gas has a low CO_2 content so it is costly to separate it.
In the oxyfuel process, the combustion is performed with enriched or high purity oxygen streams (Figure A.2); as a result, the flue gas contains only steam and CO_2 with a high concentration (greater than 90% by volume). These two components are then easily separated through cooling; the water condenses and a CO_2 rich gas-stream is formed.

Figure A.2: Oxy-combustion carbon capture[a].



[a] N_2 stands for nitrogen, and O_2 for dioxygen.

This capture process can be used with existing Combined Cycle Gas Plants and pulverised coal plants. However significant and thus costly modifications of the boilers are required.

A.2.2 Current state of the art

Oxy-combustion is sometimes presented as the most promising carbon capture process. However, contrary to post-combustion capture, oxy-combustion capture is still at the demonstration stage. This capture process would be more interesting than the other processes because it is less energy intensive and costly. However, one issue needs to be overcome: the continuous production of pure oxygen.

Indeed, extracting pure oxygen from air requires a large amount of energy. This extraction, required at the beginning of the process, is often got by cryogenic distillation. For a 500 MW coal plant operating 8,000 hours per year, the production of pure oxygen can represent almost 15% of its annual electricity generation.

Innovations are expected to reduce the cost of pure oxygen production. Among them, the chemical looping combustion is an interesting and promising option. This chemical looping system produces oxygen internal to the process; it thus eliminates the large capital, operating and energy costs related to the separation of oxygen from air. The chemical looping process splits combustion into separate oxidation and reduction reactions. More precisely, two chambers are linked. In the first chamber, the oxidation chamber, a metal (e.g., iron, nickel, copper or manganese) is oxidised. This metal oxide is then injected into the second chamber, the combustion chamber, that contains the fuel. This metal oxide is used as an oxygen carrier: it releases the oxygen in a reducing atmosphere and the oxygen reacts with the fuel, producing CO_2 and H_2O that can be separated easily. The advantage of using two chambers for the combustion process is that once the water is removed, the CO_2 is concentrated and not diluted with nitrogen gas. The metal is then recycled back to the oxidation chamber where the metal oxide is regenerated by contact with air: a new cycle can begin. This chemical looping is still at the R&D stage.

Large scale projects with oxy-combustion capture are required. There are some projects, such as the Callide oxyfuel Project in central Queensland (Australia). This project aims to retrofit a decommissioned pulverised coal unit at the Callide A power plant. With 30 MWe, this is the largest demonstration of oxy-combustion capture applied to a power plant.

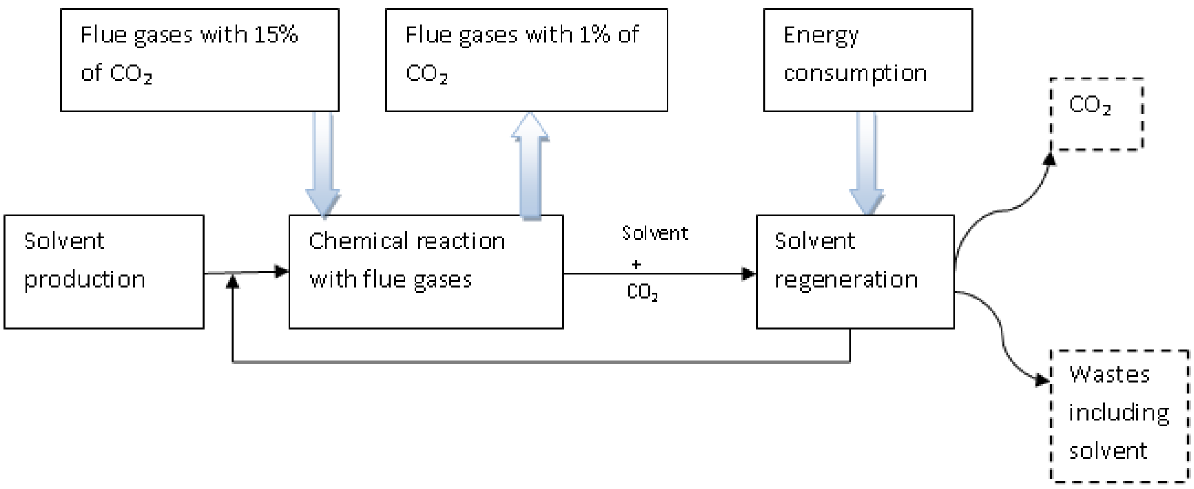
A.3 Post-combustion carbon capture

A.3.1 General principles

The process consists in separating and removing the CO_2 diluted in the flue gas produced by the combustion of a fossil fuel. Several options are available.

The most common process is absorption which is based on a chemical reaction between the CO_2 contained in the flue gas and a suitable chemical: the absorbent. Typical absorbents are amines and carbonates. The capture process happens in a scrubber column where the flue gas from the power plant is brought into contact with an absorbent dissolved in water. Then, the absorbed CO_2 is separated from the absorbent in the regeneration column. This solvent regeneration step is energy-intensive. There are two streams: one with pure CO_2 and one with the absorbent that can be recycled to the scrubber column (new cycle) (Figure A.3).

Figure A.3: Post-combustion carbon capture.



Positioned downstream, this capture process can be added to existing coal or gas power plants, blast furnaces, cement kilns or factories that emit large CO_2 amounts.

The capture of CO_2 can also be performed thanks to cryogenic separation, calcium looping and adsorption.
In the adsorption process, the CO_2 is attached to the surface of a chemical, often solid, which is called adsorbent. As in the absorption process, the adsorbent regeneration step (due to higher temperatures or lower pressure) is energy intensive. One solution could be variable electric adsorption with carbon fibres. The CO_2 desorption would be caused by an electric current: pressure decrease or temperature increase would not be required. The energy intensity of the

capture process would be significantly reduced. The capture of CO_2 could also be done with a membrane separation based on selective dense membrane and on a pressure gradient throughout the membrane. Membranes, usually micro-porous, hydrophobic and non-selective, are used as a fixed interface for CO_2 transfers. However, membranes with adequate physical properties are not commercially available.
The calcium looping cycle relies on the ability of CaO from natural limestone ($CaCO_3$) to reversibly react with CO_2 in the flue gas again to produce a pure stream of CO_2. Carbonate looping is thus an adsorption process in which calcium oxide is brought into contact with the flue gas containing CO_2 to produce calcium carbonate.
Cryogenic separation relies on the principle of separation based on cooling and condensation. This process is currently applied to flue gases with high CO_2 concentration, not to flue gases from classic power plants. CO_2 separation consumes large amounts of energy.

A.3.2 Current state of the art

Post-combustion carbon capture, with absorption, is the most mature and widely used process. Indeed, this capture process has been used for several decades, and at an industrial scale, by the oil and gas industry to separate the CO_2 naturally contained in natural gas (Sleipner and Snøhvit projects). However, this process was used to treat clean gas mixtures containing few quantities of impurity. Flue gases from power plants contains higher quantity of impurities; the capture process is thus more difficult and requires adjustments.
The main issues to overcome are: the solvent regeneration at an economically and energetically acceptable cost, and the degradation of the absorbent by the impurities contained in the exhaust gases to be treated.

Appendix B

Calculation cost file

B.1 Carbon cost

It is calculated as follows:
$Cost\ of\ emitted\ CO_2\ (€/MWh) = CO_2\ price\ (€/t) \times Emission\ Factor\ (t/MWh) \times (1 - Capture\ rate\ (\%))$

B.2 Constant Investment annuity

An annuity is the amount of money dedicated to the annual reimbursement of debt and interests. A constant annuity means that the total amount paid out annually remains the same over the lifetime of the project. The mathematical formula is from Park Chan (2003, [121]).
$Constant\ Annuity = \dfrac{Investment}{\sum_{k=1}^{n} 1/(1 + discount\ rate)^k}$
Which gives:
$Constant\ Annuity = \dfrac{Total\ Plant\ Cost\ (€/kW) \times 1000}{8760\ (hours)\ \times\ Capacity\ Factor\ (\%)\ \sum_{k=1}^{n} 1/(1 + discount\ rate)^k}$

B.3 Discount rate

A sum available today can be used to seize new investment opportunities and immediate benefits. Consequently, this sum represents an amount objectively higher than the same amount available at a later date. Bringing future sums back to today's equivalent value is called discounting. The discount rate indicates which penalty to apply to future flows in order to bring them back to a present value comparable with that of today's flow.
Each economic agent has its own degree of preference for the present which is subjective. The higher the discount rate, the higher the preference for the present.
In theory, the firm's discount rate is constructed as a weighted average cost of capital (WACC*): $WACC = \alpha \times e + (1 - \alpha)C_p$, where α represents the share of debt in the capital available, e the debt cost and C_p the equity cost.
When fiscal taxation is introduced, the calculus becomes:
$WACC = (1 - t)\alpha \times e + (1 - \alpha)C_p$, where t is the tax rate. Taking into account taxation is therefore equivalent to decreasing the discount rate.

B.4 Emission factor

The emission factor of a power plant is the ratio of the CO_2 amount which is emitted (in tons) by the hourly electricity production (MWh).
It depends on the carbon content of the fossil fuel used by the power plant as well as its efficiency.
$Emission\ factor\ = Carbon\ content\ (tCO_2/MWh) \setminus\ Effiency\ (LHV)$.
For natural gas, the following value is used: 0.20196 tCO_2/MWh (IPCC 2005 [84]).
For hard coal, the following value is used: 0.33478 tCO_2/MWh (RWE, 2012 [130]).

B.5 Fuel cost

The fuel cost (€/MWh respectively \$/MWh) can be computed with a fuel price expressed in €/t or €/GJ (respectively \$/t or \$/GJ).
$Fuel\ cost\ (LHV) = \frac{Fuel\ price\ (€/t) \times 3.6\ (GJ/MWh)}{Fuel\ heating\ value\ (t/GJ) \times LHV\ eff.} = \frac{Fuel\ price\ (€/GJ) \times 3.6}{LHV\ efficiency}$

B.6 Investment cost

It corresponds to the overnight cost plus the owner's costs.
The overnight cost is the cost of a power plant constructed in a single day to reflect technological and engineering costs in a given country. Interests during construction (IDC) and owner's cost are excluded.
Owners' costs include the costs related to: land, project management, administration and associated buildings, site works, etc.

B.7 Load factor

The load factor of a power plant indicates the ratio of the electricity produced by this plant and the theoretical maximum that could be produced at non interrupted power generation. The load factor is of considerable importance for the economics of power generation, since it defines the amount of the electricity produced per unit of generating capacity that will earn revenues to cover both the capital and the operating costs of a power plant.
A load factor of 85% (respectively 42%) means that power plants operate in base-load (respectively in mid-load).

B.8 LCoE

The Levelised Cost of Electricity (LCoE) indicates the minimum selling price of electricity below which carrying out the project would occur losses for the investor. When the selling price is equal to the LCoE, the project's Net Present Value is zero.
The LCoE is equal to the ratio of the sum of discounted expenditure by the sum of discounted production:
$LCoE = \frac{\sum_t (Investment_t\ +\ O\&M_t\ + Fuel_t\ +\ Carbon\ cost_t) \times (1+r)^{-t}}{\sum_t Quantity\ of\ electricity_t \times (1+r)^{-t}}$ with r the discount rate.

The IEA (2010, [113]) underlines the limits of this indicator: the LCoE "would correspond to the cost of an investor assuming the certainty of production costs and the stability of electricity prices. In other words, the discount rate used in LCoE calculations reflects the return on capital for an investor in the absence of specific market or technology risks. Given that such specific market and technology risks frequently exist, a gap between the LCoE and true financial costs of an investor operating on real electricity markets with their specific uncertainties is usually verified. For the same reason, LCoE is also closer to the real cost of investment in electricity production in regulated monopoly electricity markets with loan guarantees and regulated prices rather than the real costs of investments in competitive markets with variable prices". In spite of these shortcomings, the IEA emphasises that "LCoE remains the most transparent consensus measure of generating costs and remains a widely used tool for comparing the costs of different power generation technologies in modelling and policy discussions".

B.9 Low Heating Value (LHV) efficiency

Every public study about CCS costs uses LHV* efficiency values, except the two American studies: DoE-NETL (2010 [40], 2010 [39]) and WorleyParsons (2009 [141], 2011 [140]).
On the contrary to LHV values, HHV* values take into account the energy released by the condensation of water.
To turn HHV values into LHV, ZEP (2011, [143]) uses the following calculation:
$Efficiency\,(LHV) = Efficiency\,(HHV) \times \frac{HHV}{LHV}$. For hard coal cases, ZEP uses a coefficient (HHV/LHV) of 1.037 (Illinois 6) and for natural gas cases, ZEP uses a ratio of 1.108.
These ratios were used to compare sets of cost data from public studies before the standardisation process (see Part 1.3).

Appendix C

Proofs of propositions 1 and 2 from Chapter 4

C.1 Proof of proposition 1: the effects of introducing ambiguity on the investment decision

Proof. We would like to characterise the conditions under which an ambiguity averse DM chooses a higher CCS installed capacity when uncertainty arises. Denoting respectively $\overline{X}$ and X^* the optimal decision for DM under certainty and ambiguity, $X^* > \overline{X}$ if and only if:

$$\int_\Theta \phi'(W(\overline{X},\theta)) \times \frac{\partial W(\overline{X},\theta)}{\partial X} dF(\theta) > 0 \tag{C.1}$$

We have:

$$\begin{aligned} \int_\Theta \phi'(W(\overline{X},\theta)) \times \frac{\partial W(\overline{X},\theta)}{\partial X} dF(\theta) &= \\ \int_\Theta \phi'(W(\overline{X},\theta)) dF(\theta) \int_\Theta \frac{\partial W(\overline{X},\theta)}{\partial X} dF(\theta) &+ cov_\theta \left(\phi'(W(\overline{X},\theta)), \frac{\partial W(\overline{X},\theta)}{\partial X} \right) \end{aligned} \tag{C.2}$$

Let us study the sign of the covariance.

(a) Monotony of $\frac{\partial W}{\partial X}$ with respect to θ.

$$\frac{\partial^2 W}{\partial X \partial \theta} = \int_{\underline{x}}^{\bar{x}} 2(x - \overline{X}) \frac{\partial g(x,\theta)}{\partial \theta} dx \tag{C.3}$$

With an integration by parts, it comes[1]:

$$\frac{\partial^2 W}{\partial X \partial \theta} = -2 \int_{\underline{x}}^{\bar{x}} \frac{\partial G(x,\theta)}{\partial \theta} dx \tag{C.4}$$

The sign depends on the monotony of G with respect to θ.

[1] $\frac{\partial G(\bar{x},\theta)}{\partial \theta} = 0$ and $\frac{\partial G(\underline{x},\theta)}{\partial \theta} = 0$

(b) Monotony of W with respect to θ.

$$\frac{\partial W}{\partial \theta} = -\int_{\underline{x}}^{\bar{x}} (x-\overline{X})^2 \frac{\partial g(x,\theta)}{\partial \theta} dx \tag{C.5}$$

With an integration by parts, it comes:

$$\frac{\partial W}{\partial \theta} = \int_{\underline{x}}^{\bar{x}} 2(x-\overline{X}) \frac{\partial G(x,\theta)}{\partial \theta} dx \tag{C.6}$$

The sign of this expression depends on the value of the optimal level of investment, $\overline{X}$. Consider that $\frac{\partial W}{\partial \theta}$ is a function of $\overline{X}$, denoted by H_θ:

$$H_\theta(\overline{X}) = \int_{\underline{x}}^{\bar{x}} (x-\overline{X}) \frac{\partial G(x,\theta)}{\partial \theta} dx$$

This function is differentiable and:

$$H'_\theta(\overline{X}) = -\int_{\underline{x}}^{\bar{x}} \frac{\partial G(x,\theta)}{\partial \theta} dx$$

In addition, we know that $H_\theta(\bar{x}) < 0$ and $H_\theta(\underline{x}) > 0$ when $\frac{\partial g}{\partial \theta} > 0$ (conversely, $H_\theta(\bar{x}) > 0$ and $H_\theta(\underline{x}) < 0$ when $\frac{\partial g}{\partial \theta} < 0$). We deduce that, for each θ, there is a value of $\overline{X}$, denoted by $\widehat{X}_\theta$, such that $H_\theta(\widehat{X}_\theta) = 0$.
$\widehat{X}_\theta$ is thus the CCS installed capacity that should be chosen for a particular scenario θ[2].

In our case, it simply comes that:

$$H_\theta(\widehat{X}_\theta) = \int_{\underline{x}}^{\bar{x}} (x-\widehat{X}_\theta) \frac{\partial G(x,\theta)}{\partial \theta} dx = 0$$

$$\Leftrightarrow \widehat{X}_\theta = \frac{\int_{\underline{x}}^{\bar{x}} x \times \frac{\partial G(x,\theta)}{\partial \theta} dx}{\int_{\underline{x}}^{\bar{x}} \frac{\partial G(x,\theta)}{\partial \theta} dx}$$

Once again, the monotony of W depends on the monotony of G with respect to θ.

First, suppose that $G(x,\theta)$ is an increasing function of θ.
(i) The sign of $\frac{\partial^2 W}{\partial X \partial \theta}$ is negative and $\frac{\partial W}{\partial X}$ is a decreasing function of θ.
(ii) $H'_\theta(X)$ is negative. Consequently, W is an increasing function of θ if and only if $\overline{X} < \widehat{X}_\theta$ for all θ.
And as ϕ is concave, ϕ' is a decreasing function of θ if and only if $\overline{X} < \widehat{X}_\theta$ for all θ.
Consequently, the covariance is positive iff $\overline{X} < \widehat{X}_\theta$ for all θ.

Second, suppose that $G(x,\theta)$ is a decreasing function of θ.
(i) The sign of $\frac{\partial^2 W}{\partial X \partial \theta}$ is positive and $\frac{\partial W}{\partial X}$ is an increasing function of θ.
(ii) $H'_\theta(X)$ is positive and W is a decreasing function of θ if and only if $\overline{X} < \widehat{X}_\theta$ for all θ.

[2] Note the absence of ϕ-weighting.

As ϕ is concave, ϕ' is an increasing function of θ if and only if $\overline{X} < \widehat{X}_\theta$ for all θ and the covariance is again positive.

Consequently, we obtain that
$\int_\Theta \phi'(W(\overline{X},\theta)) \times \dfrac{\partial W(\overline{X},\theta)}{\partial X} dF(\theta) > \int_\Theta \phi'(W(\overline{X},\theta))dF(\theta) \int_\Theta \dfrac{\partial W(\overline{X},\theta)}{\partial X} dF(\theta)$ iff $\overline{X} < \widehat{X}_\theta$ for all θ.

Let us study the sign of $\int_\Theta \dfrac{\partial W(\overline{X},\theta)}{\partial X} dF(\theta)$.
Suppose that, in certainty, the scenario $\widehat{\theta}$ is the expected $\int_\Theta dF(\theta) = E\tilde{\theta}$, we have:

$$\frac{\partial W(\overline{X},\widehat{\theta})}{\partial X} = 0.$$

Following the Jensen inequality, we know that
$\int_\Theta \dfrac{\partial W(\overline{X},\theta)}{\partial X} dF(\theta) \leq (\geq) \dfrac{\partial W(\overline{X}, \int_\Theta \theta dF(\theta))}{\partial X}$ if $\dfrac{\partial W(\overline{X},\theta)}{\partial X}$ is concave (convex) with respect to θ.
Let us denote by J the function $J(\theta) = \dfrac{\partial W(\overline{X},\theta)}{\partial X}$. We obtain:

$$J''(\theta) = -2 \int_{\underline{x}}^{\bar{x}} \frac{\partial^2 G(x,\theta)}{\partial \theta^2} dx$$

Consequently, if G is linear with respect to θ, $\int_\Theta \dfrac{\partial W(\overline{X},\theta)}{\partial X} dF(\theta) = \dfrac{\partial W(\overline{X}, \int_\Theta \theta dF(\theta))}{\partial X} = 0$.
Moreover, if G is convex with respect to θ, $\int_\Theta \dfrac{\partial W(\overline{X},\theta)}{\partial X} dF(\theta) > 0$. And, $\int_\Theta \phi'(W(\overline{X},\theta)) \times \dfrac{\partial W(\overline{X},\theta)}{\partial X} dF(\theta) > 0$ if $\overline{X} < \widehat{X}_\theta$ for all θ.
If G is concave with respect to θ, $\int_\Theta \dfrac{\partial W(\overline{X},\theta)}{\partial X} dF(\theta) < 0$. And, $\int_\Theta \phi'(W(\overline{X},\theta)) \times \dfrac{\partial W(\overline{X},\theta)}{\partial X} dF(\theta) < 0$ if $\overline{X} > \widehat{X}_\theta$ for all θ.

□

C.2 Proof of proposition 2: the effects of an increase of ambiguity aversion on the investment decision

Proof. We would like to characterise the conditions under which the more ambiguity averse DM2 chooses a higher CCS installed capacity than DM1. Denoting respectively X_1 and X_2 the optimal decision for DM1 and DM2, by the concavity of ϕ_2, $X_2 > X_1$ if and only if:

$$\int_\Theta \phi_2'(W(X_1,\theta)) \times \frac{\partial W(X_1,\theta)}{\partial X} dF(\theta) > 0 \qquad \text{(C.7)}$$

With $\int_\Theta \phi_2'(W(X_1,\theta)) \times \dfrac{\partial W(X_1,\theta)}{\partial X} dF(\theta) = \int_\Theta \phi_1'(W(X_1,\theta)) \times k'(\phi_1[W(X_1,\theta)]) \dfrac{\partial W(X_1,\theta)}{\partial X} dF(\theta)$

Similarly to the proof of Proposition 1, $\frac{\partial W(X_1,\theta)}{\partial X}$ can be positive or negative for some values of θ.

(i) **Suppose that** $G(x,\theta)$ **is an increasing function of** θ, the sign of $\dfrac{\partial^2 W}{\partial X \partial \theta}$ is negative and $\dfrac{\partial W}{\partial X}$ is a decreasing function of θ. In addition, let us consider the function H_θ:

$$H_\theta(X^*) = \int_{\underline{x}}^{\bar{x}} (x - X^*) \frac{\partial G(x,\theta)}{\partial \theta} dx$$

and the value of X^*, denoted by $\widehat{X}_\theta$, such that $H_\theta(\widehat{X}_\theta) = 0$.
As previously, we obtain that W is an increasing function of θ if and only if $X^* < \widehat{X}_\theta$ for all θ.

(a) Consider the case where W is an increasing function of θ.
Thus, $k'(\phi_1[W(X_1,\theta)])$ is a decreasing function of θ.
We assume that there is a $\hat{\theta}$ such as: $\dfrac{\partial W(X_1,\hat{\theta})}{\partial X} = 0$.

For $\theta < \hat{\theta}$:

$k'(\phi_1[W(X_1,\theta)]) > k'(\phi_1[W(X_1,\hat{\theta})])$ and $\dfrac{\partial W(X_1,\theta)}{\partial X} > \dfrac{\partial W(X_1,\hat{\theta})}{\partial X} = 0$.

Thus, $k'(\phi_1[W(X_1,\theta)]) \times \dfrac{\partial W(X_1,\theta)}{\partial X} > k'(\phi_1[W(X_1,\hat{\theta})]) \times \dfrac{\partial W(X_1,\theta)}{\partial X}$

In the same way, for $\theta > \hat{\theta}$:

$k'(\phi_1[W(X_1,\theta)]) < k'(\phi_1[W(X_1,\hat{\theta})])$ and $\dfrac{\partial W(X_1,\theta)}{\partial X} < 0$.

Thus, $k'(\phi_1[W(X_1,\theta)]) \times \dfrac{\partial W(X_1,\theta)}{\partial X} > k'(\phi_1[W(X_1,\hat{\theta})]) \times \dfrac{\partial W(X_1,\theta)}{\partial X}$

We deduce that:

$\int_\Theta \phi_1'(W(X_1,\theta)) \times k'(\phi_1[W(X_1,\theta)]) \dfrac{\partial W(X_1,\theta)}{\partial X} dF(\theta) > 0$ and $X_2 > X_1$.

(b) It is exactly the opposite when W is a decreasing function of θ.

(ii) Suppose now that $G(x,\theta)$ **is a decreasing function of** θ, the sign of $\dfrac{\partial^2 W}{\partial X \partial \theta}$ is positive and $\dfrac{\partial W}{\partial X}$ is an increasing function of θ. Once again, let us consider the function H_θ and $\widehat{X}_\theta$, such that $H_\theta(\widehat{X}_\theta) = 0$.
As previously, we obtain that W is a decreasing function of θ if and only if $X^* < \widehat{X}_\theta$ for all θ.

(a) Consider the case where W is a decreasing function of θ.
Thus, $k'(\phi_1[W(X_1,\theta)])$ is an increasing function of θ.
We assume that there is a $\hat{\theta}$ such as: $\dfrac{\partial W(X_1,\hat{\theta})}{\partial X} = 0$.

For $\theta < \hat{\theta}$:

$k'(\phi_1[W(X_1,\theta)]) < k'(\phi_1[W(X_1,\hat{\theta})])$ and $\dfrac{\partial W(X_1,\theta)}{\partial X} < \dfrac{\partial W(X_1,\hat{\theta})}{\partial X} = 0$.

Thus, $k'(\phi_1[W(X_1,\theta)]) \times \dfrac{\partial W(X_1,\theta)}{\partial X} > k'(\phi_1[W(X_1,\hat{\theta})]) \times \dfrac{\partial W(X_1,\theta)}{\partial X}$

In the same way, for $\theta > \hat{\theta}$:

$k'(\phi_1[W(X_1,\theta)]) > k'(\phi_1[W(X_1,\hat{\theta})])$ and $\dfrac{\partial W(X_1,\theta)}{\partial X} > 0$.

Thus, $k'(\phi_1[W(X_1,\theta)]) \times \dfrac{\partial W(X_1,\theta)}{\partial X} > k'(\phi_1[W(X_1,\hat{\theta})]) \times \dfrac{\partial W(X_1,\theta)}{\partial X}$

We deduce that:

$$\int_\Theta \phi_1'(W(X_1,\theta)) \times k'(\phi_1[W(X_1,\theta)])\frac{\partial W(X_1,\theta)}{\partial X}dF(\theta) > 0 \text{ and } X_2 > X_1.$$

(b) It is exactly the opposite when W is an increasing function of θ.

□

According to the above proof, we know that W is an increasing function of θ if and only if $X^* < \widehat{X}_\theta$ for all θ.

In the discrete case, as $\dfrac{\partial W(X,\theta)}{\partial \theta} = -\sum_{j=1}^S A_j(x_j - X)^2 p_j^{'}(\theta)$ we have two thresholds[3]:

$\widehat{X}_{\theta,1} = \dfrac{2\sum_{j=1}^S A_j x_j p_j^{'}(\theta) - \sqrt{\triangle}}{2\sum_{j=1}^S A_j p_j^{'}(\theta)}$ and $\widehat{X}_{\theta,2} = \dfrac{2\sum_{j=1}^S A_j x_j p_j^{'}(\theta) + \sqrt{\triangle}}{2\sum_{j=1}^S A_j p_j^{'}(\theta)}$

with $\triangle = 4(\sum_{j=1}^S A_j x_j p_j^{'})^2 - 4\sum_{j=1}^S A_j p_j^{'}(\theta) \times \sum_{j=1}^S A_j x_j^2 p_j^{'}(\theta)$

It means that when, $\forall\theta \in [\underline{\theta};\overline{\theta}]$, $X \in [\widehat{X}_{\theta,1};\widehat{X}_{\theta,2}]$, W is an increasing function of θ, *i.e.* the DM increases the CCS installed capacity when ambiguity aversion increases.

$\forall\theta \in [\underline{\theta};\overline{\theta}]$ $\widehat{X}_{\theta,1} < 0$.

Consequently, when $\forall\theta \in [\underline{\theta};\overline{\theta}]$, $X < \widehat{X}_{\theta,2}$ the DM increases the CCS installed capacity when ambiguity aversion increases.

To simplify, we denoted $\widehat{X}_{\theta,2}$ by $\widehat{X}_\theta$.

[3]Second order polynomial in X.

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List of abbreviations and acronyms

CH_3OH Methanol.

CO Carbon monoxide.

CO_2 Carbon dioxide.

$CaCO_3$ Calcium carbonate.

CaO Carbonate.

H_2 Dihydrogen.

H_2O Water.

MWe Megawatt electrical.

$MWth$ Megawatt thermal.

NH_3 Ammonia.

N_2 Nitrogen.

O_2 Dioxygen.

RMB Renminbi (China).

2DS IEA's 2°C scenario.

ASU Air Separation Unit.

CAPEX Capital Expenditure.

CCG Combined Cycle Gas.

CCGT Combined Cycle Gas Turbine.

CCS Carbon Capture, Transport and Storage.

CDM Clean Development Mechanism.

CfD Contract for Difference.

CPF Carbon Price Floor.

CR Capture Rate.

DECC Department of Energy and Climate Change (United Kingdom).

DM Decision-Maker.

DoE Department of Energy (United States).

EOR Enhanced Oil Recovery.

EU European Union.

EUA Emission Unit Allowances.

EU-ETS European Union Emission Trading Scheme.

FG Flue Gas.

FIP Feed-in Premium.

FIT Feed-in Tariff.

FOAK First of a Kind.

FOC First order condition.

GCCSI Global CCS Institute.

GHG Greenhouse gas.

HHV High Heating Value.

IAM Integrated Assessment Models.

IDC Interest during Construction.

IEA International Energy Agency.

IGCC Integrated coal Gasification Combined Cycle.

IPCC Intergovernmental Panel on Climate Change.

LCoE Levelised Cost of Electricity.

LHV Low Heating Value.

LSIP Large Scale Integrated Project.

MIT Massachusetts Institute of Technology.

MOU Memorandum of Understanding.

NER New Entrance Reserve.

NETL National Energy Technology Laboratory.

NGCC Natural Gas Combined Cycle.

NGP Natural Gas Processing.

NIMBY Not In My Back Yard.

NOAK Nth Of A Kind.

NZEC Near Zero Emission Coal.

O&M Operating and Maintenance.

OECD Organisation for Economic Co-operation and Development.

OPEX Operating and Maintenance.

PC Pulverised Coal.

R&D Research and Development.

RD&D Research, Development and Diffusion.

RES Renewable Energy Sources.

SC Super Critical.

SEU Subjective Expected Utility.

SRMC Short Run Marginal Cost.

T&S Transport and Storage.

tCO_2 tonne of carbon dioxide.

UK United Kindgom.

w/ with.

w/o without.

WACC Weighted Average Cost of Capital.

ZEP Zero Emissions Platform.