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COMMISSION STAFF WORKING DOCUMENT

Accompanying document to the

Proposal for a

DIRECTIVE OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL

on the geological storage of carbon dioxide

IMPACT ASSESSMENT

{COM(2008) 18 final}
{SEC(2008) 55}

Executive summary

Problem and objectives

(1) The central problem is to reconcile the need for urgent action to tackle climate change with the need to ensure security of energy supply. In the context of a global reduction of CO2 emissions of 50% by 2050 needed to meet the 2°C target, a reduction in emissions of 30 % in the developed world by 2020 is required, rising to 60-80% by 2050. This reduction is technically feasible and the benefits far outweigh the costs, but to achieve it all mitigation options must be harnessed, among them carbon capture and storage.

(2) To enable the use of carbon capture and storage, two problems must be solved. The first is to manage the environmental risks of the technology, in order to ensure that CO2 captured and stored remains isolated from the atmosphere and biosphere, and so is environmentally secure and effective as a climate change mitigation option.

(3) The second is to address commercial barriers to the deployment of CCS. If left to the market investments in CCS technology development may be insufficient for six reasons:

- First, currently the positive CO2 reductions from CCS are not rewarded since CCS is not enabled as part of the EU-ETS nor the Clean Development Mechanism. If included, the CO2 reduction through CCS would be valued at the carbon price.
- Second, the positive impacts from developing the technology on the costs and its efficiency (so called learning-by-doing effects based on adoption) are not captured by the market (positive externalities).
- Third, potential positive externalities relating to security of supply would not be captured by the market.
- Fourth, potential positive externalities relating to export potential would not be captured
- Fifth, potential positive impacts on achievement of global climate objectives from deployment in the EU would not be internalised.
- Sixth, any positive reductions in traditional air pollutants from deployment of CCS are not internalised.

Impact assessment of a framework to manage environmental risks

(4) The three components of CCS – capture, transport and storage – were considered separately. A conservative approach was taken, in the sense that the default option for regulating a CCS component was taken to be the existing legal framework that regulates activities of a similar risk (if one exists).

(5) Capture presents similar risks to those of the chemical/power generation sector, and so it was concluded that Directive 96/61/EC (the IPPC Directive) is also the appropriate

regulatory framework for it. CO2 transport presents similar risks to natural gas transport and so will be regulated in the same way. Pipelines of diameter greater than 800mm and length greater than 40km will require environmental impact assessment under Directive 85/337/EC, and further regulation will be for Member States.

(6) For storage, existing legal frameworks were also examined (IPPC and the waste legislation) but were found not to be well adapted to regulating the risks. The kind of controls required differ from those under the IPPC Directive, which mainly deals with emission limit values for industrial installations. Many parts of the waste legislation potentially apply to CO2 storage, but they do so in a fragmented way and are not designed to cover the particular risks in question. Neither framework could be adapted to regulate CO2 storage without substantial and fairly complicated amendment. Thus it was decided to develop a free-standing legal framework for CO2 storage in the form of a draft Directive, and remove CCS as regulated above from the scope of the waste legislation.

(7) Some issues concerning the content of the draft Directive were subject to additional analysis. The first is the issue of how best to ensure sound implementation of the risk management framework in the early phase of storage, where it was decided to propose Commission review of draft permits, but with the final permitting decision remaining with the competent authority. The second is how to deal with liability, and in particular to assess the implications of requiring a financial security to cover obligations in case of operator insolvency, any corrective measures required, and liability for surrender of Emissions Trading Scheme allowances for any leakage. Based on previous experience and consultation with insurers, it was concluded that it is reasonable to require such a security. Other issues covered are composition of the CO2 stream, access to the transport and storage networks, and the administrative implications of the enabling legal framework for storage.

Impact assessment of options to internalise externalities

(8) Four options were considered:

- Option 0: No enabling policy for CCS at EU level, including no inclusion of CCS in the EU ETS (that is, achievement of climate objectives without CCS).
- **Option 1**: Enable CCS under the EU Emissions Trading Scheme.
- **Option 2**: In addition to enabling under the ETS, impose an obligation to apply CCS from 2020 onwards and assess the impact on the potential positive externalities not captured by the carbon market. Four principal sub-options were considered:

(a) Making CCS mandatory for new coal-fired power from 2020 onwards

(b) Making CCS mandatory for new coal- and gas-fired power from 2020 onwards

(c) Making CCS mandatory for new coal-fired power from 2020 onwards, together with retrofit of existing plants (built between 2015 and 2020) from 2020

(d) Making CCS mandatory for new coal- and gas-fired power from 2020 onwards, together with retrofit of existing plants (built between 2015 and 2020) from 2020.

- **Option 3**: In addition to enabling under the ETS, apply a subsidy so as to internalise the positive externalities not captured by the market.

(9) These were assessed using the PRIMES[1] model which simulates the European energy system and markets on a country-by-country basis and provides detailed results about energy balances, CO2 emissions, investment, energy technology penetration, prices and costs by 5-years intervals over a time period from 2000 to 2030. While the modelling provides useful quantitative indications of the scale of potential impacts, predictions of the behaviour of a complex system decades in advance are inevitably uncertain, and the main uncertainties and sensitivities are identified. The employment impacts were assessed by PRIMES and the air quality impacts by IIASA and a source-sink matching exercise was done by TNO to determine the transport and storage network that would result from the main deployment scenarios (market-based and mandatory). The non air quality environmental impacts of deployment were assessed by ECN and ERM.

(10) Analysis of Option 0 showed that without CCS the costs of meeting a reduction in the region of 30% GHG in 2030 in the EU could be up to 40% higher than with CCS[2]. Thus not enabling CCS would have substantial negative impacts on Europe's capacity to meet the 2 degrees Celsius target and on competitiveness, and also for employment, and would have a slight negative impact on security of supply.

(11) On the understanding that the ETS is implemented so as to deliver the EU's climate objectives, Option 1 (enabling under the market) internalises positive climate externalities of CCS deployment. With the carbon price resulting from the efforts required to meet the 20% reduction in greenhouse gas emissions by 2020, CCS becomes a significant part of the energy mix, but not before 2030. Because this option leads to a significant reduction in fossil fuel use, all the environmental impacts associated with fossil fuel use decline relative to the baseline. There would be offsetting impacts from the transport and storage infrastructure but at these modest deployment levels the impacts are not significant. Similarly, the CO2 storage requirement is well within the capacity of projected EU storage capacity: the significant uncertainties in projected capacity do not even begin to have an impact at this storage level.

(12) The additional cost of Option 2 (making CCS mandatory) compared with Option 1 (around €6bn/year in 2030) must be justified by additional non-climate benefits. The additional impact on learning compared with Option 1 may lead to around 10% reduction in the additional resource costs of CCS. It is hard to quantify what difference this would make to export potential and the ability to meet global climate objectives, and thus hard to distinguish between Option 2 and Option 1 on these counts. The

1 P. Capros et al (2007) Energy systems analysis of CCS Technology; PRIMES model scenarios, E3ME-lab/ICCS/National Technical University of Athens, Draft Report 29 August 2007, Athens (available upon request).

2 Capros, P and L. Mantzos (2007) Final report SERVICE CONTRACT TO EXPLOIT SYNERGIES BETWEEN AIR QUALITY AND CLIMATE CHANGE POLICIES AND REVIEWING THE METHODOLOGY OF COST-BENEFIT ANALYSIS, Contract No 070501/2004/382805/MAR/C1, Final Report to DG Environment

variant whereby CCS is made mandatory for coal and gas has a positive effect on security of supply, but the remaining options have a negative impact (by increasing gas use and hence imports).

(13) For the extreme mandatory Option (coal plus gas, new plus retrofit) the societal risk, from asphyxiation as a result of CO2 leakage, is around 5 people per year in 2030 assuming a fatal concentration of 10% CO2. Note in this context that the Thematic Strategy on Air Pollution estimated the annual premature fatalities from air pollution in 2005 at 390 000.3 Because there is a further reduction in fossil fuel use over the baseline, there is a further reduction in the related environmental impacts. Against this must be set the correspondingly greater burden on the environment posed by the transport network, estimated at just over 30,000 km. (As a reference, this can be compared with the natural gas pipeline length of 110 000 km in 2001). While the land take associated with this deployment may be relatively small, the major impact on biodiversity would come from land fragmentation. This impact would be subject to assessment in the Environmental Impact Assessments that are proposed to be required for CO2 pipelines, and appropriate measures taken, for instance using existing pipeline rights of way where possible.

(14) The CO2 to be captured would put a greater strain on EU storage capacity, but there is some evidence that it can be accommodated. While the storage scenarios provided are purely indicative and do not provide a realistic estimate of what a practical CO2 transport and storage network would look like, they show that broadly speaking, there is enough storage capacity for each Member State to store its own emissions, provided that the optimistic estimates that have been made regarding aquifer storage potential are borne out. However, it is clear that even without aquifer storage potential, the emissions on an extreme deployment scenario can probably be accommodated in Europe in high-security sites. There would be substantial storage under the North Sea, and the transport infrastructure required would increase the transport and storage cost to between €5 and €10/t CO2 avoided. These costs are still reasonable (the assumptions made in assessing deployment assumed marginal costs rising to €20/t in some cases).

(15) The impact of mandatory CCS would fall mainly on a small number of Member States. For the extreme mandatory scenario (Option 2d above), three-quarters of the CO2 capture would happen in four Member States (in descending order, Germany, Poland, UK and Belgium) with 35% of the effort in Germany alone. Employment impacts are negative, an increase in employment in the coal industry being offset by negative effects resulting from the increased energy costs.

(16) The impacts of Option 3 (subsidy for post-demonstration CCS) showed that by 2030 a 10% investment subsidy leads to 50% higher deployment (and hence total investment) than would be the case under Option 1, at small resource cost (i.e. a subsidy of €5.5bn stimulates €27bn additional investment). However, the impact on learning of the additional deployment is small and impacts on achievement of global climate objectives and export potential would be correspondingly low. The impacts on air quality, employment and security of supply relative to the market-based option are also slight.

3 Thematic Strategy on Air Pollution, p3: 3.6 million life years lost annually, equivalent to 390 000 premature deaths.

(17) On this basis, there is little evidence justifying going beyond the carbon market. For mandatory CCS, the additional learning resulting from the increased deployment does not compensate for the cost of the policy, and the impact on other externalities is also not significant. For subsidy, although substantial extra investment would be leveraged, the impact on positive externalities seems not to match the level of the subsidy. For this reason, the Commission recommends to enable CCS under the ETS, but not to make CCS mandatory or consider subsidy for the technology in the post-demonstration phase. Subsidy for the demonstration phase itself is a different matter, and that is dealt with separately under the Communication on Supporting Early Demonstration of Sustainable Power Generation from Fossil Fuels.

Consultation

(18) Consultation was conducted mainly via meetings with stakeholders. The European Climate Change Programme Working Group III on CCS met four times during the first half of 2006. An internet consultation "Capturing and storing CO2 underground - should we be concerned?" was conducted which received 787 responses. A large-scale stakeholder meeting was held on 8 May 2007 where the Commission presented an outline of its intended regulatory framework and gave the opportunity to comment. Further ad-hoc meetings with smaller groups were held on particular aspects of the proposal. Discussions with the Technology Platform on Zero Emissions Power from Fossil Fuels (TP-ZEP) were particularly useful.

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1. PROCEDURAL ISSUES AND CONSULTATION OF INTERESTED PARTIES

1.1. Organisation and timing

(19) This document summarises the impact assessment for item 2007/ENV/004 of the Commission Legislative Work Programme on developing an enabling legal framework for carbon capture and storage (CCS). In conjunction, the impact assessment also assessed the impact of measures at EU level to promote deployment of CCS. These are the two main issues covered in this impact assessment.

(20) The Impact Assessment built on earlier work, including in particular the work of the 2nd European Climate Change Programme (ECCPII) – Working Group III (WG III) on CCS; the impact assessment prepared for Commission Communication 'Limiting Global Climate Change to 2 degrees Celsius'4; and the impact assessment prepared for Commission Communication 'Sustainable Power Generation from Fossil Fuels'5.

(21) An interservice group was established on 17 November 2006 and met for the first time on 15 December 2006. It then met a further four times with the latest meeting on 6 September 2007. The DGs invited were SG, SJ, TREN, ECFIN, ENTR, JRC, RTD, COMP, FISH (including the Maritime Affairs Task Force), TAXUD, ELARG, SANCO, RELEX and DEV. The impact assessment began in December 2006 and was completed in September 2007.

1.2. Consultation and expertise

(22) The impact assessment was supported by three studies: "Technical support for an enabling policy framework for carbon capture and geological storage", with the Energy research Centre of the Netherlands (ECN) and ERM Ltd; "Impacts of options for CCS incentivisation" with ENTEC UK Limited; and "Scenarios for implementing CCS in the European Union" with TNO. ECN and ERM were responsible for assessment of the options for developing an enabling legal framework for carbon capture and storage. All three contractors were involved in assessing the options for promoting deployment of CCS, as follows. ENTEC UK was responsible for projecting CCS deployment under certain scenarios and assessing the resulting economic impacts. TNO was responsible for developing transport and storage networks based on the ENTEC deployment data. ECN and ERM were responsible for assessing the broad environmental and social impacts of CCS deployment, including transport and storage, based on the work of ENTEC and TNO. DG JRC of the Commission provided valuable assistance in assessing the capture-ready issue.

(23) Discussion with, and the responses of, the European Technology Platform for Zero-Emission Fossil Fuel Power Plants (TP-ZEP) an industry initiative supported by the Commission, provided a vital source of information and external expertise.

(24) Consultation was conducted mainly via meetings with stakeholders. The first set of stakeholder meetings, the European Climate Change Programme Working Group III on

4 COM(2007) 2.

5 COM(2006) 843.

CCS6, made a series of recommendations for the scope of the work on an enabling legal framework, inviting the Commission to address:

- Permitting of geological storage sites, including risk management, site selection, operation, monitoring, reporting, verification, closure and post-closure;
- Liability for leakage from storage sites during operation and post-closure;
- Clarification of the role of CCS under EU legislation, in particular concerning waste and water, and propose appropriate amendments;
- The recognition of CCS projects in the EU Emissions Trading Scheme;
- The need and possible options for promoting CCS deployment in a transitional period;
- The status of CCS projects under rules and guidelines for State Aid.

(25) This impact assessment covers the first four issues and part of the fifth. The remainder of the fifth, and the last, are covered in the accompanying Communication on CCS demonstration [forthcoming, DG TREN chef de file].

(26) An internet consultation ”Capturing and storing CO2 underground – should we be concerned?” was conducted which received 787 responses. The internet consultation showed broad support for the four main objectives set out in the Communication on Sustainable Power Generation from Fossil Fuels, namely that:

- The EC should support the development of up to 12 large-scale demonstration projects by 2015
- From 2020 onwards, all new coal-fired plants should be built with CCS
- Before 2020, all new fossil-fuel power plants should be "capture-ready", and
- All these "capture-ready" plants should be retrofitted soon after 2020.

(27) Stakeholders were most concerned about the potential diversion of effort away from energy efficiency and renewables, and about ensuring that stored CO2 remains underground. The targets for a 20% improvement in energy efficiency by 2020 and for a 20% share of renewables in final energy demand will ensure that those intiatives remain at the centre of climate and energy policy. The focus of the enabling legal framework is on the security of storage, which is the major stakeholder safety concern.

(28) A large-scale stakeholder meeting was held on 8 May 2007 where the Commission presented an outline of its intended regulatory framework and gave the opportunity to comment. Member State representatives, environmental NGOs and representatives of the main affected industrial sectors (equipment manufacturers, electricity generators and fuel

6 The Working Group brought together experts from Member States, various energy industries (coal, oil, gas, electricity), energy intensive industries, NGOs, research institutes and relevant Commission services. The Working Group had four meetings in the first half of 2006 under the Chairmanship of the Commission and delivered its final, unanimously approved, report on the 1st June 2006. More information on the Working Group and the report on CCS is available from: http://forum.europa.eu.int/Public/irc/env/eccp_2/home.

producers) were invited and attended. Written contributions were received from the Member States and organisations listed in Annex 1. The following main issues were raised:

- Concerns were expressed on the proposal that contaminants in the CO2 stream should be limited to levels currently prescribed for emissions to atmosphere. Concern was based on the grounds that those requirements are based on atmospheric risk and not transport or storage risk. This has been addressed by using criteria that are linked to transport and storage risk (Section 6.3) and that have also been endorsed by the Contracting Parties to the OSPAR Convention[7].

- There was also concern, on subsidiarity and proportionality grounds, regarding proposed powers for the Commission to accept or reject draft permitting decisions made by national competent authorities. This has been addressed by providing for review at EU level but retaining the final say for the national competent authority (Section 6.1).

- The original suggestion that ETS allowances should be surrendered provisionally for a certain percentage of stored emissions, to cover potential leakage, was criticised on the grounds that it might be interpreted as an expectation of a certain level of leakage, while in fact the expectation should be for no leakage. This has been addressed by extending the proposed provision covering decommissioning costs to cover also future liabilities. (Section 6.2)

- It was proposed to treat CCS in Phase III of the emissions trading scheme by enhanced opt-in to ensure that appropriate monitoring and reporting was developed for each variant of CCS in turn. However, this was criticised on the grounds that it would provide insufficient certainty for future operators. Following an assessment verifying that each variant could be covered by the same monitoring and reporting guidelines, and so the environmental integrity of the ETS would not be put at risk, it was decided to include CO2 capture, transport and storage explicitly in Annex I of the revised ETD. (Covered in the Impact Assessment for the revision of Directive 2003/87/EC.)

- The requirement for mandatory CCS from a specific date was welcomed by some respondents (principally NGOs) and objected to by others. The objectors claimed that the technology was insufficiently mature to be mandated, and that the implications of doing so were unclear. The main technical risk of CCS concerns the availability of adequate storage capacity, and this was addressed in the TNO study. The economic, social and environmental implications of mandatory CCS were addressed in the PRIMES and other studies. The main results are presented below (Section 7).

- Some respondents expressed concern that equal access to transport and storage should be ensured. This issue is addressed below (Section 6.4)

(29) Further ad-hoc meetings with smaller groups of industry, NGOs and Member States were held on particular aspects of the proposal, and presentations were made to the Coal Working Party of the Commission's Fossil Fuels 'Berlin' Forum and the Forum itself[8].

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7 The OSPAR Convention (1992) is the current instrument guiding cooperation on the protection of the marine environment of the North-East Atlantic, to which the European Community, represented by the European Commission, is a Contracting Party.

8 The Berlin Forum comprises over 100 representatives of European energy corporations, industry associations, energy-related national administrations of Member States, and members of civil society (non-governmental organisations). Further details can be obtained on the website http://ec.europa.eu/energy/oil/berlin/index_en.htm.

1.3. Response to the Opinion of the Impact Assessment Board

(30) The Impact Assessment Board's opinion requested that:

- Any market failure obstructing CCS deployment be better explained. This is covered in paragraph (51) and Sections 2.2.2 and 3.2 below.
- The range of policy options be widened. The request was in particular to assess the impacts on the above-mentioned market failure of a subsidy rather than a mandatory requirement. These were assessed by introducing an additional Option 3 in Section 7 and analysing its impacts using the PRIMES model.
- The uncertainties of the analysis be described. This was principally addressed by further developing Section 7.5.5 below to outline the major assumptions, uncertainties and sensitivities.
- The relation to renewable energy sources be clarified. This is covered in Section 7.5.5.
- Social impacts in the regional context be assessed. A new section has been added on employment impacts (Section 7.5.4). While it is not possible to assess employment impacts on a regional scale, these are likely to be concentrated in the Member States where CCS effort is greatest, which are identified in Section. 7.4.1.
- Some legal aspects be clarified. This related in particular to Section 6.4 on access to transport and storage which has been expanded.
- A forecast for future global market demand be added. Export potential in the context of projected future global market demand is assessed under Section 7.5.3.3.
- Some elements of the impact analysis be clarified. Costs and environmental benefits are monetised as far as possible, and a substantial description of the PRIMES model has been added (Section 7.3) confirming that it includes transport and storage costs.

2. CONTEXT AND PROBLEM DEFINITION

2.1. Context

2.1.1. The need for an economic and sustainable electricity supply for Europe

(31) The central problem is to reconcile the need for urgent action to tackle climate change with the need to ensure security of energy supply. This was analysed in detail in the Commission's Energy and Climate package of January 2007, and in particular in the Communications on Limiting climate change to 2 degrees Celsius ('the 2°C Communication'), and on Sustainable Power Generation from Fossil Fuels ('the SPGFF Communication').

(32) In its Spring 2007 Conclusions[9], the European Council recognised that urgent action is needed to limit climate change to a manageable level. In order to do this, it is committed to adopt the necessary domestic actions and take the lead internationally to ensure that global average temperatures do not exceed pre-industrial levels by 2ºC. It has proposed that the EU pursues in the context of international negotiations the objective of a 30% reduction in greenhouse gas (GHG) emissions by developed countries by 2020 (compared to 1990 levels) in order to stay within the 2ºC limit. In addition, the EU has taken on a firm independent commitment to achieve at least a 20% reduction in GHG emissions by 2020 using a range of policy instruments (the EU Emissions Trading Scheme (the EU ETS) and other measures including through energy policy)[10]. The Commission Communication on limiting climate change to 2°C (COM(2007)2) showed that significant further reductions are required in the longer term. In the context of the global reduction of 50% by 2050, a reduction in emissions of 60-80% by 2050 is required of the developed world. The impact assessment showed that this reduction is technically feasible and that the benefits far outweigh the costs. However, to achieve it, all mitigation options must be harnessed.

(33) The Communication and impact assessment on sustainable power generation from fossil fuels[11] further highlights that:

- Fossil fuels in general will continue to be an important source of energy for electricity generation in the future. Coal plays a role particularly for ensuring a diverse energy mix which can contribute towards supply reliability;

- The construction of new and upgraded coal-fired plant in the EU will only be acceptable if technologies that are able to significantly reduce emissions of CO_2 are developed and widely deployed;

- Clean coal technologies (improvements in conversion efficiency) can help to reduce emissions, but are insufficient on their own to meet the CO_2 reduction demands of climate change;

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9 7224/1/07 REV.

10 Limiting Global Climate Change to 2 degrees Celsius: The way ahead for 2020 and beyond. Communication from the Commission to the Council, the European Parliament, The European Economic and Social Committee and the Committee of the Regions (SEC(2007) 7, 10.1.2007).

11 Commission Staff Working Document: Accompanying document to the Communication from the Commission to the Council and the European Parliament. Sustainable power generation from fossil fuels: aiming for near-zero emissions from coal after 2020. Impact Assessment (SEC(2006) 1722).

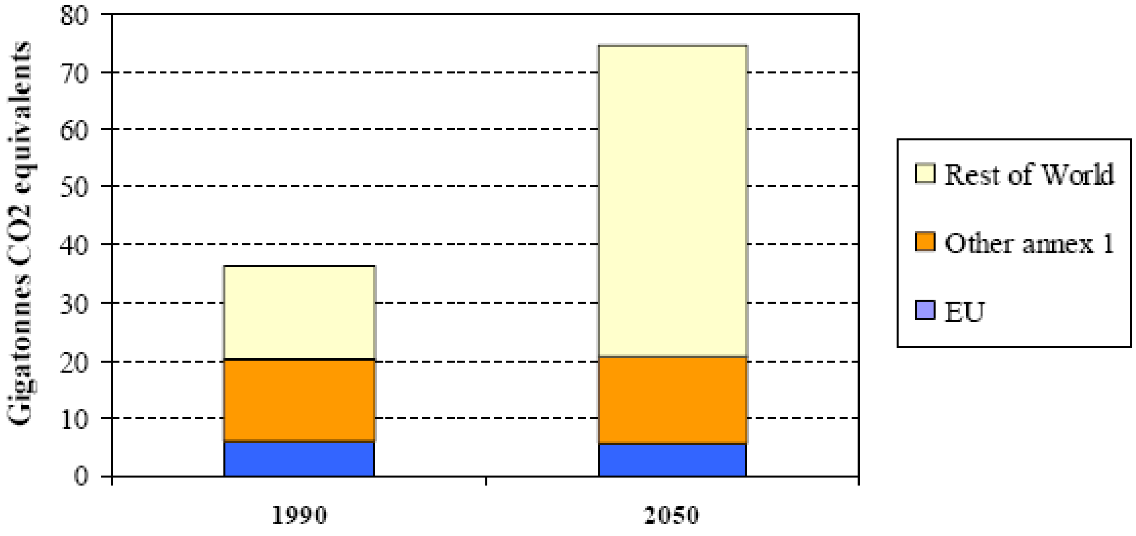
- Thus CCS will be a critical technology amongst the EU's portfolio of measures in delivering on the joint objectives of secure and economic electricity supplies and facing up to the climate change challenge.

2.1.2. The need for CCS internationally

(34) In its Fourth Assessment Report, the Intergovernmental Panel on Climate Change (IPCC) concluded that the fastest rate of emissions growth over the next 20 years will be in the rapidly industrialising nations of the world – e.g. China, India, Brazil, Mexico (Figure 1). For those countries, coal is likely to form the cornerstone of the energy system as in most cases it is the most abundant, cheap and secure form of primary energy available.

(35) Recent studies12 indicate that the world is not simply consuming more energy, but it is also generating it in a less climate-compatible way. While in the 1990s worldwide emissions had been growing by 1.1% a year, between 2000 and 2004 global emissions grew by more than 3% a year – faster than the most pessimistic projections of the UN's Intergovernmental Panel on Climate Change (IPCC) and also faster than economic growth, implying constant or slightly increasing trends in the carbon intensity of energy worldwide.

Figure 1. Projected Emissions of Greenhouse Gases in different Regions of the World



Source: Greenhouse gas reduction pathways in the UNFCCC process up to 2025, CNRS/LEPII-EPE, RIVM/MNP, ICCS-NTUA, CES-KUL (2003).

Source: Battling global climate change – the EU's Perspective (Part I) Presentation to the Second Session of the Ad hoc working Group on Further Commitments for Annex I Parties under the Kyoto Protocol, Artur Runge-Metzger, 6-14 November, 2006. UN HQ, Nairobi.

(36) In this context, the Stern Report concluded that CCS is a key technology for contributing to the global effort to combat climate change:

'The forecast growth in emissions from coal, especially in China and India, means CCS technology has particular importance. Failure to develop viable CCS technology, while traditional fossil fuel generation is deployed across the globe, risks locking-in a high

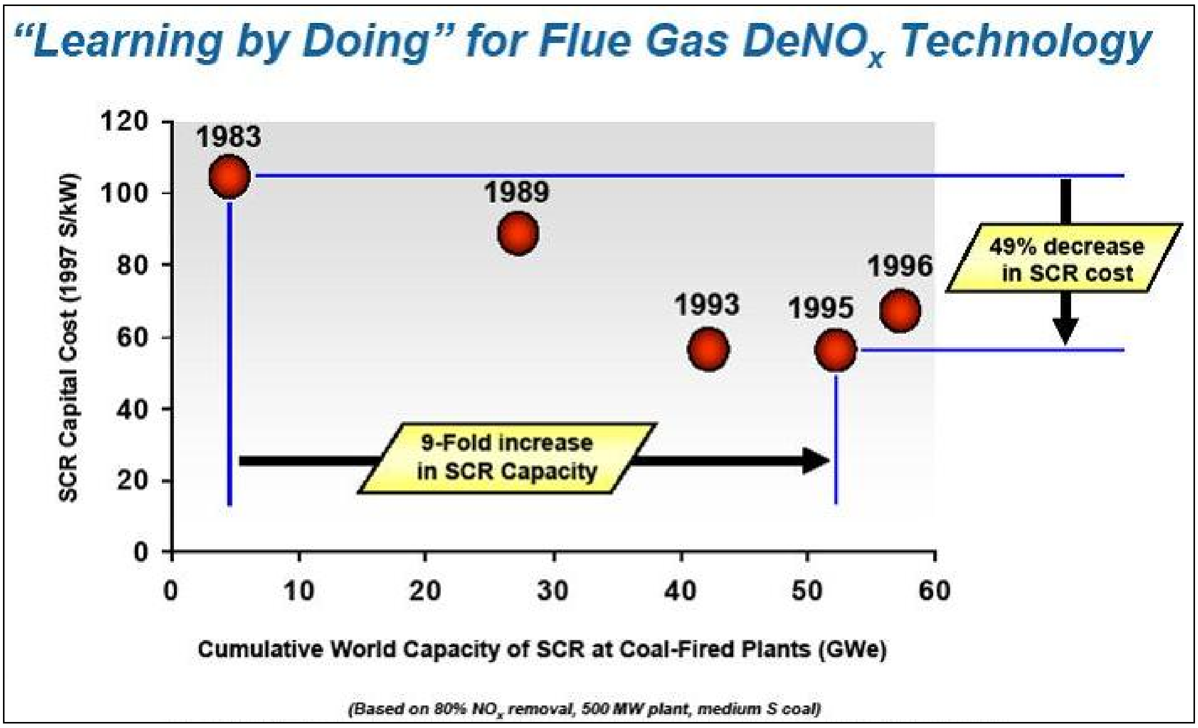
12 Raupach, M. et al. (2007) Global and regional drivers of accelerating CO2 emissions. Proceedings of the National Academy of Science, NAS – USA.

emissions trajectory. … Stabilising emissions below 550ppm CO2e will require reducing emissions from electricity generation by about 60%. Without CCS that would require a dramatic shift away from existing fossil-fuel technologies.'13

(37) Experience from previous technology deployment shows that costs reduce substantially with increased deployment. Figure 2 shows the learning achieved for flue gas NOx removal in the period since first deployment. This learning is particularly relevant for a technology with a potential global role such as CCS.

13 Stern Review on the Economics of Climate Change, Chapter 16 p368.

Figure 2. Cost development versus deployment for flue gas DeNOx technology



Source: Rubin et al; Experience Curves for Power Plant Emission Control Technologies, 2004

2.1.3. The competitiveness dimension of CCS

(38) The recent endorsement by the Heads of State of an independent GHG target of 20%, a 20% target for renewables and the development of the Strategic Energy Technology Plan indicate a strategic preference that the EU should lead the development and deployment of new energy technologies, in line with the vision for a common European energy policy set out in the Commission Green Paper A European Strategy for Sustainable, Competitive and Secure Energy (COM(2006) 105 final). The competitive advantage on CCS resulting from large-scale deployment in Europe is a collateral benefit of the enabling policy framework. The inclusion of CCS as part of the package to reduce greenhouse gas emissions to stabilize concentrations typically reduce costs by more than 30% (IPPC report on CCS, Metz et al, 2007, p. 12 SPM).

(39) It would allow European industry to become leading players in a potentially burgeoning global market for CCS technology. Other developed nations, especially the USA and Australia, are vigorously pursuing clean coal and CCS technology development and deployment. Thus the enabling policy framework can contribute to the Lisbon Agenda objective of making Europe the most competitive and dynamic knowledge-driven economy in the world by 2010, and the further objective of strengthening European enterprise in the field of environmental technologies (e.g. via the Environmental Technologies Action Plan (ETAP)14).

14 Stimulating Technologies for Sustainable Development: An Environmental Technologies Action Plan for the European Union. COM(2004) 38.

2.2. Problem definition

(40) There is a trend of increasing coal use supported by two key factors. Firstly, coal is the most abundant fossil fuel in terms of known reserves (around 150-250 years at current production rates). Secondly, coal provides strong security of supply for countries with significant domestic reserves e.g. China, India and America (key coal suppliers such as Australia are a more diverse group than the key oil and gas producing nations). Coal produces roughly twice the amount of carbon as natural gas when used for power generation, and if greenhouse gas emissions are to be stabilised globally, carbon emissions need to be taken out of coal-fired power generation.

(41) The Spring Council underlined the importance of substantial improvements in generation efficiency and clean fossil fuel technologies, and urged Member States and the Commission to work towards strengthening R & D and developing the necessary technical, economic and regulatory framework to bring environmentally safe carbon capture and sequestration (CCS) to deployment with new fossil-fuel power plants, if possible by 2020.

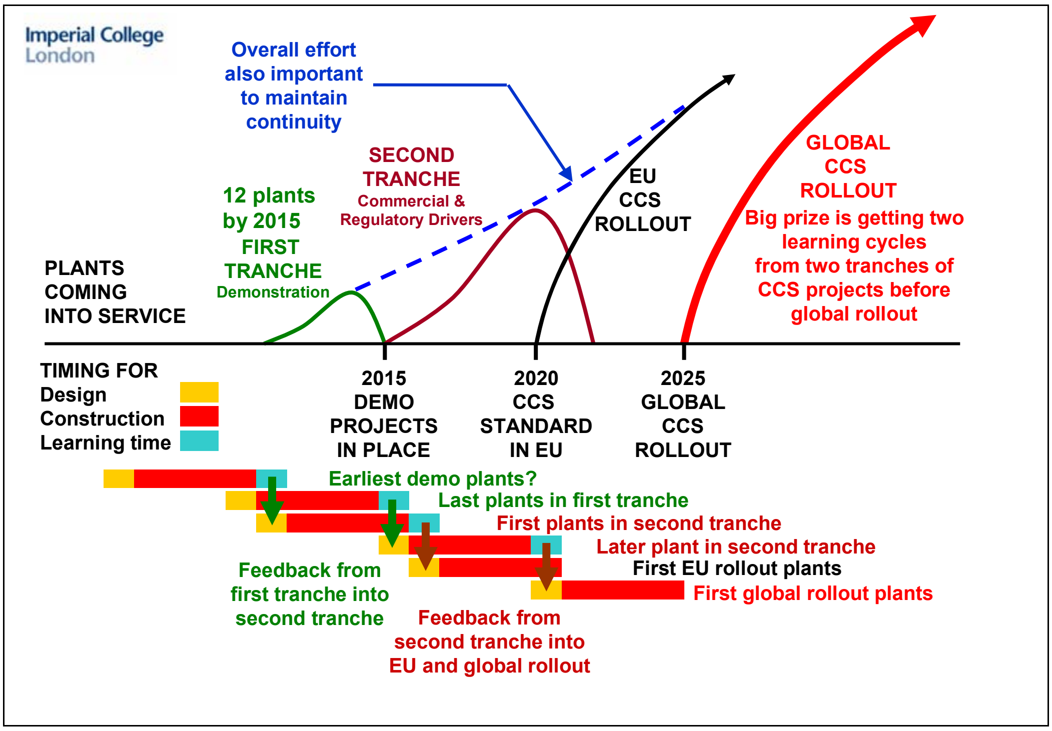
(42) The costs of CCS are one of the principal barriers to uptake, both in Europe and internationally. However, as discussed above, these can be expected to decrease with increased uptake. Although there are differences in learning potential from technology to technology, a similar development to that of flue gas denox is likely to be experienced with CCS.[15]

(43) Assessments have been made that if widespread global deployment of CCS is required from a particular date (say 2025 onwards), two generations of learning are required prior to that in order to progress along the initially steep learning curve and reduce the costs of the global rollout.[16] This is shown in schematic terms in Figure 3 below, which also shows the timeline for development of the projects and the timing of learning feedback from one tranche to the next:

Figure 3. Two tranches of deployment before rollout of CCS

15 See IEA report 'Estimating the future trends in the cost of CO2 capture technologies' (IEA 2006) for a detailed analysis.

16 Gibbins, Chalmers Imperial College London (pre-publication).



Source: J Gibbins, Imperial College London

(44) The first tranche would comprise commercial scale plants for initial demonstration. Previous experience with other technologies has indicated that these early plants are crucial in understanding many aspects of technology performance that cannot be analysed at lab and pilot scale. For example, overall plant operability can depend on feedbacks that will not be identified by desk-based studies. In addition, CCS projects are likely to include a large number of construction and operating partners and public confidence must be established. Finally, it is important to note that real costs will not be established until real plants are built and that in the early stages of new technology deployment costs tend to decrease rapidly as engineers (and others) learn from their experience.

(45) Once these plants are established, best use must be made of lessons learned for further deployment projects. On the above scenario, if first-of-type plants are built from around 2012 onwards then some real operating experience should be available by around 2015 which could be used to shape priorities and targets for these 'second tranche' plants. Although it is theoretically possible for second generation plants to reach minimum cost values, it is highly unlikely for CCS deployment according to this model since there will not be adequate time to feed back lessons learned. Thus, second tranche plants should allow many of the problems identified by initial plants to be resolved, but are also likely to identify further areas where significant improvements can be made to standard plant designs to be used for full rollout. Meanwhile, continued operation of first tranche plants will gather additional information that can be added to lessons learned from second tranche plant when plans are made for full, commercial rollout.

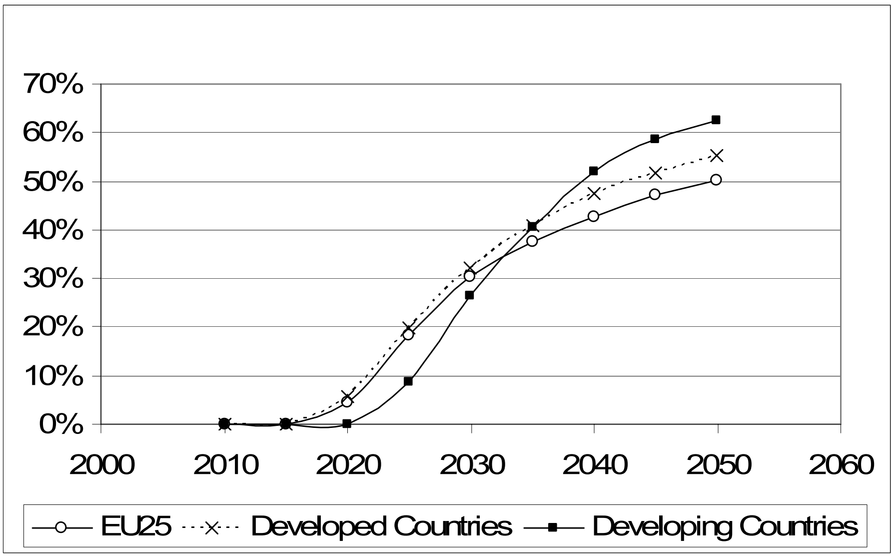
(46) Although this scenario is set out in terms of separate tranches of deployment, in reality it can and should be expected that these would overlap. For any significant degree of learning from a particular project there must be time to observe results of earlier plants and feed experience into later designs. Build times are long and technology decisions have to be finalised well before commissioning, maybe 3-5 years for main features to be fixed with perhaps a year less for some details. Then a couple of years of operation are required to

settle down and learn what the apparatus can really do. As discussed above, it is expected that many 'tranche 2' plants will not wait for all of the lessons learned from 'tranche 1' plants before they get off the drawing board. In fact, it is critical that continuity is maintained between tranches so that design and manufacturing teams can grow and develop.

(47) The essential role of CCS deployment in developing and developed countries to meet the 2°C Celsius target in a cost-effective way is illustrated in the 2°C Communication. Based on the cost-efficient reduction scenario to meet the greenhouse gas reductions outlined in the 2°C Communication17, the projections shown in Figure 4 below show the potential global importance of CCS. The projections suggest that CCS will first need to be deployed in developed countries. Soon after, from 2020 onwards, it will be rapidly deployed in developing countries that have ample coal reserves, such as China and countries in South Asia. In China, almost 40 % of total emissions from the power sector are projected to be captured by 2030, rising to two thirds in 2050. The IPCC report on CCS confirms that 50 to 90% of the global CO2 emission reductions needed over the period up to 2100 to stabilize concentration at 450 ppm (consistent with 2 degrees Celsius) come from CCS. 18

(48) However, these scenarios for global uptake depend on international agreement on reducing GHG emissions in line with the 2˚C target. China and India have also been clear in negotiations on climate and CCS that CCS would have to be proved elsewhere and have moved down the cost curves before they would consider using it.

Figure 4. Share of Power Sector Emissions Captured (JRC-IPTS, POLES)



(49) The Commission in the Communication on Sustainable Power Generation from Fossil Fuels made the following two commitments:

- 'the Commission will determine the most suitable way to support the design, construction and operation by 2015 of up to 12 large-scale demonstrations of Sustainable Fossil Fuels technologies in commercial power generation'19

17 Impact assessment for 2°C Communication, SEC(2007) 8.

18 Metz et al (eds)(2005) IPPC Special Report on Carbon Dioxide Capture and Storage, Cambridge University Press, page 354.

19 COM(2006) 843, p7, 2nd Commission action.

- '…the Commission considers that a clear and predictable long-term framework is necessary to facilitate a smooth and rapid transition to a CCS-equipped power generation from coal…On the basis of the information currently available, the Commission believes that by 2020 all new coal-fired power plants should be built with CCS. Existing plants should then progressively follow the same approach. In order to make a decision, in terms both of the timing of any CCS obligation and the most appropriate form and nature of the requirement, the Commission will undertake in 2007 an analysis including a wide-ranging public consultation on the issue. On the basis of this analysis, the Commission will evaluate what is the optimal retrofitting schedule for fossil fuel power plants for the period after the commercial viability of Sustainable Coal technologies is demonstrated.'[20]

(50) The 2020 date balanced a range of concerns. These included the need to plan now for the deep cuts in CO2 emissions needed for the mid-century (and in particular to promote the availability of a technology which will be important not only in Europe but also globally); and the need to allow the technology to mature before its widespread application. At this stage it is hard to say with any certainty what the impacts of delaying widespread European deployment to a later date would be. (Earlier deployment is probably not realistic.) Intuitively, later deployment in Europe will delay the commercial availability of the technology, which in turn may mean either that the mid-century climate goals are missed (with the attendant consequences, see e.g. the Stern Report) or that the required abatement has to be done at higher cost due to the more limited learning and hence limited cost reduction. But there are many uncertainties here: for instance, it is not clear to what extent CCS would be developed internationally if not in Europe (there are embryonic demonstration initiatives in the US and Australia).

(51) It is clear that if left to the market investments in CCS technology development may be insufficient for six reasons:

- First, currently the positive CO2 reductions from CCS are not rewarded since CCS is not enabled as part of the EU_ETS nor the Clean Development Mechanism. If included the CO2 reduction through CCS would be valued at the carbon price.

- Second, the positive impacts from developing the technology on the costs and its efficiency (so called learning-by-doing effects based on adoption) are not captured by the market (positive externalities).[21]

- Third, potential positive externalities relating to security of supply would not be captured by the market.

- Fourth, potential positive externalities relating to export potential would not be captured

- Fifth, potential positive impacts on achievement of global climate objectives from deployment in the EU would not be internalised.

- Sixth, any positive reductions in traditional air pollutants from deployment of CCS are not internalised.

20 COM(2006) 843, p10, 8th Commission action.

21 Jaffe.A, R. Newell and R. Stavins (2005) A tale of two market failures: technology and environmental policy, Ecological Economics, 54, pp 164-174.

(52) In the context of the analysis conducted for the 2°C Communication, the Sustainable Fossil Fuels Communication, and in the related Impact Assessments22, this Impact Assessment focuses on the two major issues relevant to CCS deployment identified by the Sustainable Fossil Fuels Communication:

- The environment, health and safety (EHS) risks from CCS deployment. This involves both minimising risks from CCS deployment, and ensuring that it is effective as a climate change mitigation measure.

- Commercial barriers to CCS deployment as outlined in paragraph (51).

2.2.1. Environment, health and safety (EHS) risks from CCS deployment

(53) The climate benefits of CCS must be assessed in the context of the potential risks it presents to the environment and human health as follows:

- The global risk – namely, that the transported and stored CO2 is re-emitted to the atmosphere, thus reducing the efficacy of the technology to mitigate climate change;

- Local environment, health and safety (EHS) risks, associated with the impacts and effects of CO2 capture, transport and storage, including impacts of construction, materials consumption, and the hazard posed by un-planned losses of containment, which may be augmented by the presence of certain toxic impurities in the captured CO2.

- Upstream risks related to the continued use of fossil fuels (landscape damage, discharges to water, emissions to air, solid waste generation etc.).

(54) More detailed specification of the risks is provided at Annex II. The first major problem to be addressed is to ensure that these risks are minimised in the course of CCS deployment.

(55) Note also that once the environmental integrity of CCS is ensured and legal protection provided at least equal to that governing similar activities, legal barriers to CCS deployment in current EU legislation can be removed. The principle barriers in EU legislation are in the Water Framework Directive 2000/60/EC, whose Article 11.3.j prohibits injection into saline aquifers except in certain cases, and in the Landfill Directive 1999/31/EC whose Article 5.3 prohibition on injection of liquid waste could be interpreted as prohibiting CO2 injection into geological formations (CO2 is injected as a supercritical liquid).

(56) Removing these barriers will complement similar work in the international context, in particular the Protocol to the London Convention (on dumping of wastes and other material in the marine area) and the OSPAR Convention on the protection of the North East Atlantic. The London Convention was amended in November 2006 to allow CO2 storage offshore, and the EC was actively involved in securing an amendment to the OSPAR Convention also to allow CO2 storage offshore, in conjunction with the adoption of a risk management framework which has been one of the key reference points for preparing the EU approach.

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22 See COM(2007) 2, COM(2006) 843 and related impact assessments.

2.2.2. *Commercial barriers to CCS deployment*

(57) Application of CCS leads to increased cost of electricity generation due to the added capital and operating costs of the capture, transportation and storage installations compared to conventional power plants, as well as the additional cost of the extra fuel consumed by the process. The second major problem is to assess how to overcome these barriers by internalising the positive externalities of CCS deployment identified in paragraph (51) above.

(58) The principal positive externality is the climate benefit from CO2 reduction, which is not internalised since emissions captured and safely stored are currently not recognised as not emitted under the EU Emissions Trading Scheme (ETS). The Emissions Trading Directive is in the process of revision and will revise the ETS as necessary in order to meet the climate change objectives of the Community (in particular the commitment for a reduction of 20% GHG by 2020 and any additional reductions). Thus the ETS as revised will internalise the climate change externality for all installations within its scope.

(59) There remain the five other potential positive externalities of CCS deployment, which would not be internalised by the ETS. These are: any positive impact from learning by doing, any benefits for security of supply, any benefits for technology export, any benefits for promoting achievement of global (as opposed to European) climate change objectives, and any positive reduction of traditional air pollution.

2.3. Basis for Community level action to regulate and incentivise CCS

(60) The EU has the right to act to regulate the environmental, health and safety risks represented by CCS deployment, under Article 175(1) of the Treaty. The question to be addressed in this impact assessment is to what extent safe, secure and reliable deployment of CCS on an equal basis across Europe requires action at Community level, and to what extent action can be left to Member States or the market.

(61) With regard to promoting deployment of CCS, public policy is essential to ensure CCS deployment because it is a technology that is almost exclusively driven by political concerns over climate change and diversification of energy supply (that is, it has no separate commercial rationale). As outlined in Section 2.3.2, the EU ETS forms the point of departure for promoting CCS deployment in the EU[23]. There is no presumption that further measures at EU level are appropriate, but the options should be considered.

23 Inclusion of the technology under the EU Emissions Trading Scheme also presents supportive elements for regulating environmental risks related to capturing, transporting and storing CO2 through (i) creation of an obligation to purchase EU Allowances for any accidental CO2 releases, and (ii) the creation of monitoring and reporting obligations, thus creating a chain of custody for CO2 from capture to long-term storage.

3. OBJECTIVES

3.1. To manage CCS environment, health and safety (EHS) risks

(62) The first objective is to ensure that a regulatory framework is in place that will ensure that the risks outlined in Section 2.2.1 are properly managed. The framework must be proportionate, and must be enacted at the appropriate level.

(63) All the components of CCS must be considered, namely capture, transport, injection and storage. However, it is likely that CO2 storage sites will present the greatest regulatory challenge because of the novel nature of the activity. On condition that a proper risk management framework is in place that secures at least equivalent levels of environmental protection as those applied to analogous activities, known barriers to CCS deployment in existing legislation should be identified and removed as described in section 2.2.1.

(64) The impact assessment for this issue is covered in sections 4 to 6 below.

3.2. To internalise the positive externalities of CCS deployment

(65) The Commission's proposals to achieve a first generation of CCS deployment are set out in the Commission communication [forthcoming] on establishing a Flagship Network of up to 10-12 CCS demonstration plants in Europe and internationally. The Communication assesses the logistics of the network and the incentives needed to overcome the commercial barriers to deployment. The decisive importance of CCS technologies is recognised in the new EU Strategic Energy Technology Plan (SET-Plan) which recognises the initiative of advancing CCS to enable its use in power generation from fossil fuels as one of the 'Major European Industrial Projects' within its European Mission 'Decarbonising the base-load power'.

(66) This assessment will analyse the effectiveness of options to integrate the positive externalities of CCS identified in paragraph (51) and section 2.2.2 above, so that the future energy mix contains the socially optimal proportions of CCS.

(67) The main option is recognition of CCS under the Emissions Trading Scheme, which will internalise the major positive externality of CCS deployment, its reduction of CO2 emissions. There remain the five potential externalities that would not be internalised by inclusion in the Emissions Trading Scheme. The assessment also examines options additional to inclusion in the ETS (and thus probably imposing additional costs), and assesses whether they produce additional benefits that are commensurate with the costs (an indication that the externalities are effectively internalised). It must also be borne in mind that some mechanisms for internalising externalities may be more distorting than others.

(68) The 8th Commission action of the Communication on Sustainable Fossil Fuels mentions inclusion in the ETS, support for infrastructure development, and 'adopting legally binding measures to regulate maximum allowed CO2 emissions per kWh after 2020 and/or introduce a timed phase-out (for instance by 2050 of all high CO2 emitting (i.e. non-CCS) electricity generation' as possible options. The question of whether a transport infrastructure in particular would need to be supported at EU level will be addressed in a separate assessment [scheduled by DG TREN]. This assessment will encompass at least the other options identified: deployment on the basis of the EU ETS, and deployment on the basis of

imposition of legally-binding measures at EU level. The impact assessment for this issue is covered in section 7 and 8 below.

4. ANALYSIS OF OPTIONS FOR REGULATING CO2 CAPTURE AND TRANSPORT

4.1. Principle of conservatism

(69) In the interests of proportionate assessment, a principle of conservatism was applied in assessing the appropriate regulatory framework for capture and pipeline transport. The principle is that if the risk profile of a new activity (A) is comparable to that of an existing activity (B) already covered by a risk management framework, then that risk management framework is also adequate, effective and proportionate for managing the risks of activity A, and no consideration of further options is necessary.

(70) The risk profiles of two activities A and B are comparable if activity A does not present new risks that activity B does not, and it does not present significantly greater or lesser risks than does activity B.

4.2. CO2 capture

4.2.1. Risks

(71) There are many outlines of CO2 capture technology24. The main elements of a CO2 capture process (solvent stripping of CO2, air separation for oxyfuel combustion, and gasification for pre-combustion capture) are already conducted in industrial installations for which regulatory regimes exist (power plants or chemical plants).

(72) The risk profile presented by CO2 capture is comparable to those of existing power generation and chemical activities, with one possible exception. The outstanding issue is whether the activity of CO2 compression and the presence of compressed CO2 in quantity give rise to an accident hazard warranting application of the Seveso II Directive.[25]

4.2.2. Options

(73) These existing installations are mainly controlled by the Integrated Pollution Prevention and Control Directive 96/61/EC and the Environmental Impact Assessment Directive (85/337/EC). For installations that present an elevated accident hazard risk the Seveso II Directive is conferred in addition.

(74) Using the principle of conservatism outlined above, the assessment is that the IPPC and EIA Directives are adequate to regulate CO2 capture. However, the application of the Seveso II Directive to capture is an outstanding issue which is currently under examination.

4.3. Transport

(75) There are two main kinds of technology that are likely to be used in the EU for transport of CO2: pipeline transport and shipping.

24 See for example Annex I of the Impact Assessment for the SPGFF Communication - SEC(2007) 1722.

25 Note that accident hazards can arise from the presence of solvent for stripping, from the presence of oxygen in oxyfuel combustion, and from the presence of hydrogen in pre-combustion, but these hazards are already caught under the existing Seveso framework. The risk from compressed CO2 is not.

4.3.1. Pipeline transport

4.3.1.1. Risks

(76) Pipeline transport of CO2 is analogous to natural gas transport by pipeline. Records maintained by the regulatory authorities in the USA of incidents involving CO2 pipelines in the USA indicate that whilst the frequency of incidents is similar to that of natural gas pipelines, the degree of incidental damage caused as a result of any incident is significantly lower than that for natural gas pipelines. In addition, there are no records of serious injuries or fatalities associated with incidents involving CO2 pipelines from records dating back to the mid-1970s. The principal causes of incidents involving CO2 pipelines, based on US experience, have been outside intervention and corrosion. Further information on CO2 pipeline accidents in the USA and the treatment of pipeline infrastructure by the US legal system can be found in Gale, J. and Davidson, J. "Transmission of CO2 - safety and economic considerations", Energy 29(2004) 1319-1328.

(77) Reported rates of incidents of failure for natural gas pipelines are relatively small. Data suggest that between 1972 and 2002, incidents of failure fell from 0.0010 km-1 per year to 0.0002 km-1 per year[26]. For US CO2 pipelines, around 10 incidents have been reported between 1990 and 2002, with total property damages amounting to $469 000, zero injuries or fatalities, and giving an incident rate of 0.00032 km-1 per year. Incidents mainly related to technical component failures, whereas for gas pipelines the most common form of incident is damage by external factors (e.g. excavators).

4.3.1.2. Options

(78) Natural gas transport is covered under the EIA Directive for pipelines of diameter greater than 800mm and a length more than 40 km. There are also standards for the materials to be used to transport gas at various pressures under the Pressurised Vessels Directive, which controls the build quality of imported products to be used for containing pressurised fluids. Natural gas transport by pipeline is not further regulated at EU level, but regulation is rather left to the national level.

(79) Since potential hazards posed by CO2 transport are broadly comparable to those of natural gas transport (albeit without the added risk of explosion posed by natural gas), there is good reason to believe that the risk framework applied to natural gas transport by pipeline is adequate to regulate CO2 transport. Thus no other options have been considered.

4.3.2. Shipping transport

4.3.2.1. Logistics and risks of shipping transport

(80) A carbon dioxide (CO2) leak could have consequences on humans and the environment, as outlined in previous sections of this report. The effect on the climate caused by a CO2 leak from a ship is difficult to quantify. For any significant effect to take place it is likely that a large part of the ship inventory would have to be released over a short period of time.

(81) A release of CO2 from a ship during transport would impact on the surrounding ocean. The CO2 would dissolve in the water, forming carbonic acid (H2CO3). This would acidify the

26 IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change [Metz, B., O. Davidson, H. C. de Coninck, M. Loos, and L. A. Meyer (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 442 pp.

water, improving its ability to solubilise sources of calcium carbonate present in the form of coral and the carbonaceous shells of clams and other shellfish. However, impacts of an individual release are likely to be limited to the pelagic zone, and will disperse rapidly.

(82) During loading or unloading operations a leak of CO2 would pose a significant hazard to people in the immediate vicinity of any release. Populations further afield may also be at risk since it is possible the cloud may disperse inland due to the effects of weather. It has been shown in the DNV risk report27 that a catastrophic failure of a tanker containing an inventory of around 18000 tonnes of CO2 (assuming it is stored just below its boiling point) can cause hazardous concentrations at large distances. For example, a release onto water can cause concentration levels of 15000 ppm at a distance of 925 metres. Such concentrations would not be lethal to healthy populations, although closer to the release, fatal concentrations would be expected.

4.3.2.2. Likelihood of accidents involving CO2 Tankers

(83) The closest analogy to ship transport of CO2 is the transport of liquefied gas by ship. This is an increasingly widespread practice with the rapid growth in the market for Liquefied Natural Gas (LNG). LNG transportation has been established for over forty years with almost fifty thousand cargoes delivered28. Additionally, Liquefied Petroleum Gas (LPG) is routinely transported throughout the world. For CO2 itself, a small amount is already transported by ship to service the food and drink industry. Large scale transport of CO2 is anticipated to employ similar technologies to LPG, operating at around -55°C and 6bar29.

(84) Transportation of liquefied gases by sea has a very good safety record. Despite the number of cargoes carried, LNG carriers have not suffered any significant losses. Due to the nature of the cargo, LNG and possibly LPG tankers are afforded special consideration when approaching and departing their berth. Often, other movements in the vicinity will be suspended and a tug escort will be provided from or to open water. The nature and extent of such measures are dependent on the layout of the harbour and also the type and quantity of nearby shipping.

Table 1. Incidents involving gas carriers and other cargo ships

Ship type	Number of ships2000	Serious incidents 1978-2000	Frequency (incidents/ship year)
LPG tankers	982	20	0.00091
LNG tankers	121	1	0.00037
Oil tankers	9678	314	0.00144
Cargo/bulk carriers	21407	1203	0.00250
Source: IPCC 2005 op cit. Table 4.2			

27 Vendrig M, Spouge J, Bird A, Daycock J and Johnsen O (2003), 'Risk Analysis of the Geological Sequestration of Carbon Dioxide', DNV Consulting.

28 http://www.lngworldshipping.com/content/news/compNews224.htm

29 http://www.ieagreen.org.uk/oceanrep.pdf

4.3.2.3. Options

(85) If CO_2 were to be regulated in analogy with LNG and LPG transport, regulation of CO_2 transportation by ship would be carried out at a number of levels.

(86) The EU Directive on Maritime Safety (95/21/EC) requires member states to put in place controls on various types of marine vessel (including gas and chemical tankers) over 500 tonnes. An obligation is placed on the Member States to ensure that any deficiencies revealed in the course of the inspection are rectified. Conditions warranting detention of the ship are laid down. For the most part EU shipping law (e.g. Council Directive 93/75/EEC) enforces obligations under the International Convention for the Prevention of Marine Pollution from Ships (MARPOL) and the International Maritime Dangerous Goods (IMDG) Code. Various other elements serve to enhance the protection of the environment and maintain safety in marine shipping, including the Committee on Safe Seas and the Prevention of Marine Pollution (COSS; established under Regulation 2099/2002).

(87) The International Maritime Organization (IMO) has adopted the International Gas Carrier Code for the design of hull and tank structure of liquid gas transport ships, such as LPG carriers and LNG carriers. CO_2 tankers are currently designed and constructed under this code.

(88) International transport codes and agreements applying to CO_2 adhere to the UN Recommendations on the Transport of Dangerous Goods: Model Regulations published by the United Nations in 2001. CO_2 in gaseous and refrigerated liquid states is considered a non-flammable, non-toxic substance. Any transportation of CO_2 adhering to the UN recommendations can be expected to meet all relevant agreements and conventions covering transportation by whatever means. Transportation of CO_2 by ship is also governed by various international legal conventions[30]. Best practice in LNG & LPG operations is also promoted by the Society of International Gas Tanker and Terminal Operators (SIGTTO), a non-profit company that functions as the trade body for the industry.

(89) Although national codes and standards can vary, international bodies such as ISO and CEN are working towards the unification of these. It is possible that due to public concern over the transportation of CO_2 that standards may be changed or new ones introduced to address these concerns.

(90) Further measures may be required at the local level. Depending on the local configuration of the harbour, it may be necessary to introduce specific arrangements for the handling of CO_2 cargoes. Such measures might include special escort arrangements, suspension of other shipping activities, restriction on shipping lanes etc. These measures would normally be agreed between the harbour authorities, national Marine Agency and Shipping operator.

(91) Since potential hazards posed by CO_2 transport by ship are broadly comparable to those of LNG and LPG transport (albeit without the added risk of explosion posed by natural gas), there is good reason to believe that the regulatory framework applied to LNG and LPG transport by ship is adequate to regulate also CO_2 transport, as outlined above. Thus no other options were considered.

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30 IPPC (2005), 'Carbon Capture and Storage', p181-193, Cambridge University Press

5. ANALYSIS OF OPTIONS FOR THE REGULATING FRAMEWORK FOR CO2 STORAGE

5.1. Risks and regulatory needs

(92) The risks associated with CO2 storage were identified briefly in section 2.2.1 and are specified in more detail at Annex II. On the basis of stakeholder consultation (see Section 1.2), the main issues to be addressed were identified and are outlined in Box 1 below:

(93) Main requirements of a free-standing regulatory framework for CO2 storage

- Requiring storage sites to be permitted, based on an assessment of the characteristics of the geological storage site, and its suitability for long-term storage of CO2 based on appropriate risk assessment procedures
- Imposing conditions on the safe use and selection of a site
- Ensuring that the assessment of whether the above conditions are met is robust. The main way of achieving this is via competent authority approval but other options may also be considered
- Imposing conditions on the composition of CO2 accepted for storage
- Imposing monitoring requirements
- Imposing verification/inspection requirements
- Requiring corrective measures in the case of CO2 leakage
- Establishing measures for dealing with liability, including possible insurance
- Establishing closure and after-care procedures for the storage site, including provisions on transfer to the state
- Ensuring equal access to the transport and storage network

5.2. Options for treating CCS under the EU ETS

(94) One particular issue which arises is the question of how to include (elements of) carbon capture and storage in the EU Emissions Trading Scheme. This should be dealt with first, since the approach decided on will have implications for the choices for regulating CO2 storage.

(95) CCS as a whole can be included in the EU ETS from Phase II (via Article 24 of the Emissions Trading Directive), although modifications for Phase III (2012) to allow each element of the CCS chain (source, transport, injection and storage) to be designated as separate installations in their own right have been assessed separately under the Impact Assessment for the revision of Directive 2003/87.

(96) Under the present Directive, Art. 24 opt-in would require the whole chain of CO2 source, capture, transport, injection and storage to be included in the ETS as one installation, and

appropriate monitoring and reporting guidelines (MRG) to be established. This approach allocates all the risk and liability for emissions on the one installation.

(97) For the post-2012 framework it is in principle possible to separate combustion+capture from transport and storage, and so the question arises how best to treat the various components under the ETS. The key issue is that the quantity of emissions safely isolated from the atmosphere is not necessarily equal to the quantity of emissions passed from the capture plant to the storage plant. This is because emissions may leak from the transport and storage network, and because power is used (and hence emissions caused) for the compression and injection of the transported CO2. There are four options for handling this:

- Option 1: Regulate CO2 emissions from transport and storage outside the ETS only
- Option 2: Include CO2 emissions from transport and storage within the ETS, but do not regulate otherwise
- Option 3: Combine (1) and (2)
- Option 4: Combine (1) with another means of compensating for CO2 emissions from capture and storage.

5.2.1. Consequences of Option 1

(98) Storage would be regulated as proposed in the draft Directive, including measures designed to minimise leakage, and requirements for rectification of any leakage that does occur. Transport would be regulated at Member State level to similar effect. Thus leaks would have to be rectified, but any emissions that occurred during leakage would not have to be accounted for under the ETS, resulting in effective overcompensation of the combustion installation.

(99) Also, neither emissions from injection facilities at the storage site, nor emissions from booster stations on the pipelines, would fall under the ETS unless the installations concerned had a power rating exceeding 20MW (i.e., fell under the combustion plants threshold of Annex I of the ETD). Even in that case, free allocation would be allowed for the installations concerned (in so far as consistent with the general ETS rules). Thus either the emissions would not fall under the ETS at all, and so the actual net abatement could be considerably less than the original 'source' installation had been given credit for; or a free allocation would be given for additional emissions resulting from CCS, again resulting in an unwarranted benefit.

5.2.2. Consequences of Option 2

(100) Allowances would have to be surrendered for any emissions from transport and storage, thus preventing any overcompensation of the combustion installation. The better the management of the pipeline and intermediate systems, the lower emissions should be, and thus inclusion in the ETS would act as an incentive to better management. The expected case is that the carbon price would be high enough to provide an incentive to minimise leakage, since CCS would in the normal situation only occur if the cost of capture, transport and storage was at or below the carbon price, and transport and storage currently represent a relatively small proportion of the overall cost (of the order of 25%).

(101) However, there would be no regulation of the selection and management of storage sites such as to minimise leakage, and no requirements to rectify leakage if it occurred. In the unlikely situation where the carbon price fell too low to incentivise the minimisation of leakage, unrestricted emissions could arise and would be entirely legitimate. Such emissions could cause significant other health or environmental damage, but their restriction on those grounds would not be required by ETS inclusion.

5.2.3. Consequences of Option 3

(102) Option 3 would combine the advantages of Options 1 and 2. It would provide regulation on the selection and management of storage sites so as to minimise leakage, and requirements to rectify leakage if it occurred. Inclusion under the ETS would ensure that ancillary emissions from transport and storage, including those from injection and from booster stations, were properly accounted for, and would provide an incentive to reduce them. Finally, any leakage that did occur would have to be accounted for under the ETS, thus avoiding any overcompensation for CCS installations.

(103) The application of both regulatory frameworks does not comprise double regulation, which is the case where two frameworks are applied to achieve the same end. Here, there is a range of policy desiderata that neither framework can achieve alone.

5.2.4. Consequences of Option 4

(104) There are two alternative possibilities under Option 4.

- Option 4a: To try to establish default values for the emissions from transport and storage, and reduce the amount of emissions from the combustion installation that are treated as non-emitted accordingly. The question of default values was considered by the IPCC31. There are default values available for natural gas transport from empirical data, and a rough-and-ready means of converting these into emission factors for CO2 (based on the difference in density of the gases). However, there are some technical questions on the applicability of these factors for CO2 (the natural gas data is based on throughput, which is reasonable for natural gas but might not be for CO2; and there are some questions on the conversion methodology). These factors are not currently at a state where they can be used to adjust the combustion installation surrender. The same is the case for CO2 storage: the IPCC states that no emission factors are available. Thus this alternative is not practicable.

- Option 4b: Tto attempt to reconcile actual emissions from transport and storage back to the combustion and capture installation, with only the latter being under the EU ETS.

(105) The EU ETS monitoring and reporting guidelines or a licensing or permitting regime would include provisions for pipeline and storage site operators to monitor and report emissions back to the transferring installation in order that they reconcile these emission against their inventory of exported CO2 (i.e. creation of a “chain of custody” for CO2 via the EU ETS monitoring and reporting guidelines). Risk and liability for reconciling emissions would probably need to be spread amongst operators through private contracts between exporting installations, pipeline operators and storage site operators. This would be an entirely commercial matter. In essence this is a less transparent and certain way of achieving the

31 IPCC 2006 Guidelines for National Greenhouse Gas Inventories, volume 2 Chapter 5.

same thing as Option 3, relying on private contracts which could be open to dispute, litigation and lack of transparency.

5.2.5. Conclusion

(106) Option 3 remedies the defects of Options 1 and 2 and is more transparent and legally certain than Option 4b. As such, it was decided on as the preferred policy option for the EU beyond Phase II (beyond 2012).

5.3. Options for the regulating framework

(107) CO2 storage is the significant novel element of CCS. While there are activities with some similarities (in particular natural gas storage and enhanced oil recovery, but also to a certain extent landfill), there is no single system of regulation easily adaptable to CO2 storage in the way that there is for capture and transport. On the contrary, there is a complicated range of potentially applicable legislation (depending for instance on whether CO2 storage is characterised as a waste disposal activity) which was analysed in detail[32.]

(108) Thus the task of identifying the regulatory options is significantly more complicated than for capture and transport. Simplifying assumptions were necessary, and following detailed analysis[33] the following main options were outlined:

Option 1: Use the EU Emissions Trading Directive for risk management. The EU ETD must be conferred on CCS for incentive reasons in any case (see Section 5.4.1 below) and will bring with it certain management requirements.

Option 2: Confer other elements of existing non-waste environmental legislation.

Option 3: Confer existing waste management legislation.

Option 4: Develop a free-standing framework in the form of a (draft) Directive.

(109) In line with the conclusion of Section 5.2, all options assume that CO2 storage would in any case be regulated under the ETS.

5.4. Analysis of the options

(110) The conservative approach is to use existing legislation to regulate CO2 storage, and thus a step-wise procedure was developed to ensure that the possibilities of existing legislation were fully exploited before a new stand-alone framework was considered. A detailed review of the process undertaken has been presented previously 13.

5.4.1. Option 1: Effect of inclusion of CCS in the EU ETS

(111) Under the current EU ETS system, appropriate monitoring and reporting guidelines (MRGs) would be established for each element (excluding the CO2 source which is already subject to MRG provisions). Inclusion in the EU ETS would have the following regulatory effect:

- Recognition of non-emitted CO2 in emissions trading.

32 Identification of Gaps and Obstacles for CCS in existing legislation (Norton Rose, ERM, ECN, 2007).

33 Choices for Regulating CO2 capture and storage in the EU (Norton Rose, ERM, ECN, 2007).

- A requirement to design a monitoring scheme to calculate emissions of CO2 and monitoring and reporting obligations, including partial risk assessment.

- Monitoring CO2 purity (partial).

- Monitoring post-closure.

- Liability obligations (partial) in respect of emissions of CO2 to the atmosphere (global risks), in that allowances would have to be surrendered for any leakage.

Regulatory gaps

(112) Under such as scheme, a number of regulatory gaps and ambiguities would persist, in particular in relation to:

- Risk assessment and management – basic characterization, selection and risk management for the site are not covered (despite the requirement for determination and approval of a monitoring plan). There is no requirement for control on impurities in the CO2.

- Permitting requirements – no standards or permitting requirements are applicable to the above.

- Site closure – Enforced closure is not possible, and no conditions are specified on closure requirements.

- Liability – there is no coverage of liability for local environmental damage, no provisions on transfer of liability to the state, and no requirement for a financial provision to cover future liabilities.

5.4.2. Option 2: Effect of applying existing environmental legislation

(113) The EIA, IPPC, the Environmental Liability Directive, and potentially the Seveso II Directive requirements could serve to close these gaps as follows:

- Risk assessment and management – EIA, IPPC and Seveso II Directives all require prior demonstration of the environmental and human health risks posed by major development projects, which could include CCS activities through appropriate amendment of the legislation.

- Permitting requirements – EIA, IPPC and Seveso II Directives all require consideration to be made of the risks of a project by competent authorities in Member States. It is questionable whether the regime would provide a consistent regulatory approval approach, and may need to be complemented by either guidance documents or new legislation laying down more prescriptive approaches.

- Site closure – conferring IPPC Directive requirements onto CO2 storage sites would provide the basis for forced cessation of operations. These conditions would also apply for CO2 plants employed at IPPC qualifying installations. However, no detail on conditions of closure would be specified.

- Liability – conferring IPPC Directive requirements would trigger the Environmental Liability Directive requirements in respect of any damages arising for local environmental damage. However, it does not create obligations for upfront financial provisions to be made by the operator in the event of insolvency, and does not provide for transfer of responsibility and hence also of liability to the state.

(114) However, there are a number of further considerations bearing on the choice between EIA, IPPC and Seveso II, as discussed below.

(115) The EIA Directive would require a prior impact assessment of any CCS project, on the basis of general provisions laid down in the Directive. Requirements for public consultation are specified, and the assessment must be taken into account when permitting the project. The Directive stipulates a permitting procedure without, however, specifying any substantial permitting requirements, and so will not on its own provide sufficient regulatory certainty on site selection and characterisation, monitoring and closure. Also, it would not provide a suitable framework for regulating the outstanding liability issues. However, it would provide useful public consultation requirements, and thus conferring on CO2 storage would be useful in that regard.

(116) The IPPC Directive comprises a regulatory and permitting framework applied mainly to industrial installations, although it also covers landfill sites. Its permitting regime contains elements that could be applied to CO2 storage, but in the existing Directive 96/61/EC, these requirements are specified only in framework terms for all installations, and more detail for a particular category of installation can only be provided under the BAT Reference Documents (BREFs). Reliance on a BREF document under the IPPC Directive is unlikely to be a sufficiently robust regulatory instrument to lay down technical standards for CO2 storage site selection, characterisation, construction, operation, monitoring, closure and post-closure provisions. The BREF documents do not have any legal status under the current Directive, and even if this were given, certain of the requirements are such that they should be specified in primary legal obligations. This is true in particular for requirements on site selection and on closure and post-closure, as these are the crucial phases in which the future security of the site is ensured and (for closure) the conditions for transfer of responsibility to the state are determined (see section 6.2.2 below).

(117) A second issue is whether IPPC would provide a suitable framework for regulating liability issues. As stated above, conferring the Directive would trigger the Environmental Liability Directive requirements, but there is currently no provision in IPPC for legal obligations for operators to take out financial securities for operations to cover closure, decommissioning and stewardship costs in the event of insolvency.

(118) It was also examined whether the proposal for a revision to the IPPC Directive [forthcoming] could be used to remedy these defects. The revision will incorporate three existing Directives: the Large Combustion Plants Directive (2001/80/EC), the Waste Incineration Directive (2000/76/EC) and the Solvent Emissions Directive (1999/13/EC). Each will have a separate chapter within the revised IPPC specifying legal requirements applying to that activity in particular, and Annexes specifying emission limit values for the activities in question. One possibility would be to take a similar approach to regulating CO2 storage.

(119) However, the nature of the conditions to be imposed for storage differs substantially from those being set for IPPC installations, and so there is clear technical justification for proceeding with different instruments. It should also be noted in this respect that the Landfill

Directive is not included in the draft revision, and that landfills are in fact deleted from its Annex. In addition, integrating the instruments would entail that, both in Commission and in Council and Parliament, nothing could be adopted until everything was agreed. In the stakeholder meeting of 8 May the Commission consulted on inclusion in IPPC, and for the last-mentioned reason, the majority of respondents supported a free-standing framework.

(120) The Seveso II Directive, as mentioned above, imposes safety management requirements on installations that present an elevated accident hazard risk. It was considered whether the accident hazard risk represented by injection and geological storage is such as to warrant application of Seveso II in addition to the general regulatory framework applied. If the storage site is properly regulated under a separate legal framework, it was not considered that Seveso would add any significant regulatory certainty. However, application of Seveso to CO2 injection is an outstanding issue to be further considered.

5.4.3. Option 3: Application of community waste management legislation

(121) A range of regulatory instruments would apply to CCS if CO2 is classified as a waste or CO2 storage is classified as a waste management activity. The principle instruments are the Waste Framework Directive (2006/12/EC), the Landfill Directive (1999/31/EC) and the Transfrontier Shipment of Waste Regulation (EEC/259/93).

(122) Based on analysis conducted within the Commission, it was concluded that the existing waste legislation was not well-adapted to regulating CCS. A number of instruments may apply, but the scope of application is not clear and would have to be clarified, and the obligations triggered by any application are not tailored to regulating the risks of CO2 capture, transport and storage, but would rather apply a risk management framework (such as the landfill rules) that was developed for a different purpose. Thus the following options were proposed:

- To amend the relevant parts of the waste legislation to adapt them to the requirements of CCS
- To regulate CCS risks in some other way (either by using existing legislation or by creating a free-standing framework) and to remove them, as regulated elsewhere, from the scope of the waste legislation.

(123) Clearly the key criteria are whether application of Community waste management legislation would provide additional regulatory certainty, and whether it can be easily adapted and would provide a transparent regulatory framework. It was concluded that application of the waste legislation would be unlikely to add much additional regulatory certainty, and would require significant amendments to the existing regime for it to be applicable. Notwithstanding this conclusion, the Landfill Directive was considered to provide a useful template for stand alone legislation for CO2 storage, in so far as it includes provisions for site selection, site design, waste acceptance criteria (including sampling obligations), provision of a financial security, closure procedures, technical standards for closure, after-care considerations, and technical committee review.

5.4.4. Option 4: Development of a free-standing legal framework

(124) A stand-alone legal framework provides the opportunity to tailor a risk management framework to the requirements of CO2 storage so as to cover all regulatory issues in an appropriate way. However, as stated above, the EIA Directive provides useful impact

assessment and public consultation requirements, and for that reason it would be useful also to confer it on CO2 storage.

5.5. Summary of analysis, and comparison of options

(125) In addition to the above, the following criteria were used to check the above step-wise assessment of options:

- Effectiveness and comprehensiveness. This is a measure of how completely the option covered the identified regulatory requirements so as to achieve the policy objective of secure CO2 storage.

- Legal practicality, simplicity and consistency. This is a measure of how quickly and easily the regulatory option could be brought into the EU law, how easy to understand the proposed measures would be for interested parties, and whether they would be able to comply. Parameters for consideration included: how many modifications would be required to EU law to allow application; how many different instruments would be involved in regulating; and how far the regulatory approach would differ from legislation covering similar activities.

- Ease of application (regulators). Ease of application was an assessment of how easily it would be for competent authorities to transpose, and to understand and enforce the option under consideration. It takes into consideration issues such as whether it would span existing competencies, or whether they were being asked to make judgements on difficult to assess parameters beyond their typical duties.

- Ease of application (operators). This was an assessment of how difficult it would be for potential operators to adapt their existing systems and skills in negotiating regulatory approvals procedures to fit to the regulatory framework.

(126) The principles of subsidiarity (i.e. the need for Community level action) and proportionality have been addressed in previous sections, and based on the information presented therein, Community-level action is considered necessary. A summary of the assessment is provided below (Table 2).

Table 2. Multi-criteria analysis of regulatory options

Option	Criteria: Efficacy and comprehensiveness	Legal practicability, simplicity and Consistency	Ease of application (regulators)	Ease of application (operators)	Overall score
(i) ETS alone	---	+	+	+	-3
(ii) ETS+ existing non-waste environmental legislation	--	0	0	0	-2
(iii) ETS+existing waste management legislation	+	-	-	-	-2
(iv) ETS+EIA +stand alone for storage site	++	+	+	0	3

\+ Positive result on criterion

\- Negative result on criterion

0 Positive nor negative result on criterion (indifferent)

(127) Because the ETS requires no legislative change either at EU or at national level, it would be the simplest option for legislators, regulators and operators. However, these advantages are completely outweighed by its lack of effectiveness in managing the risks. Addition of existing environmental legislation would still leave gaps in effectiveness, and would complicate the legislative framework, thus increasing the difficulty of transposition and application for regulators and operators. Applying the waste legislation may in principle allow a framework that would comprehensively cover the risks, but only at the cost of significant complication of the applicable legal framework.

(128) A free-standing legal framework, together with application of the EIA Directive to ensure public consultation, provides complete regulatory coverage tailored to the needs of CCS. It is simpler to legislate than either options 2 or 3, and is simpler to transpose and more comprehensible for regulators and operators, since all the regulatory requirements are gathered in one place.

(129) Based on the analysis presented above, the most effective option for CCS regulation will be Option 4: application of the ETD combined with the EIA Directive to ensure environmental impact assessment and public consultation, and the use of a new stand-alone legal document to cover all other aspects of CCS regulatory needs. Other existing legislation may also need

to be conferred, arising from examination of the content of the regulatory framework, which is addressed in the next section.

6. CONTENT OF THE REGULATORY FRAMEWORK FOR CO2 STORAGE

(130) Some issues regarding the content of the regulatory framework deserve specific consideration, namely how best to ensure the safety and security of CO2 storage; how to manage liability issues; requirements on the composition of the CO2 stream; and provisions for equal access to the transport and storage network.

6.1. Safety and security of CO2 storage

(131) The first of these issues is ensuring safety and security of the CO2 storage. This is the key objective of the regulatory regime, and is important both intrinsically and to ensure public confidence in CCS as a climate mitigation option.

(132) The provisions required are: provisions on characterisation of the site, including assessment of the expected permanence of storage; a condition that the site can only be used if, under the conditions of use, it is expected that the injected CO2 will be permanently contained; and appropriate requirements on operation, monitoring, site closure and post-closure obligations. There should also be comitology provisions allowing for updating of the Annexes on the basis of experience with implementation. These items are an essential component of any option to regulate the safety and security of storage, and are specified in the draft Directive as conditions on whether a storage permit can be issued. The Commission has always the option of adopting more detailed guidelines on the basis of the Annexes.

(133) The objective of the management regime is consistent application across the EU of the specified provisions so as to achieve in practice a high degree of safety and security of the storage site, and so increased confidence, both of regulators and of the public, in CCS as a sound climate mitigation option. However, CO2 storage is a relatively novel technology, and many requirements are highly site-specific. For this reason, it is, at least at the moment, only possible to specify fairly general ‘framework’ requirements in the Directive and its technical Annexes.

6.1.1. Description of options

(134) The question then arises how best to ensure uniform implementation of the framework requirements across the EU. The following options have been identified:

- Option 1: The competent authority would be responsible for the issuing of a permit. There would be a provision for further detailed guidance on the requirements of site assessment etc provided for in technical Annexes to the Directive.

- Option 2: As in Option 1, except that the competent authority would submit the draft permit decision to the Commission, which would refer it to a Scientific Panel which would assess whether the obligations of the Directive had been complied with. The Commission would then accept or reject the draft permit.

- Option 3: As in Option 2, except that following the Scientific Panel's opinion, the Commission would issue an opinion on the draft permit, which the draft Directive would require the competent authority to take into account when making the permitting decision.

(135) Under Option 1, implementation of the Directive's provisions would be the responsibility of a competent authority in the Member States. Where framework provisions are specified at EU level which leave a lot of discretion in implementation, as is the case here, consistent application can normally be ensured by developing detailed guidance on particular aspects of the framework, and the proposal allows for this. However, an initial learning period will be necessary in order to gain experience with CO2 storage, before detailed guidance appropriate to the range of potential sites can be developed. Thus in the interim before this guidance can be developed, it would be useful to have another mechanism available to ensure consistent application.

(136) These considerations underlie the concept of verification at EU level of which Option 2 and Option 3 are variants. While it is not possible to establish detailed general provisions applicable to the range of potential CO2 storage sites, it is possible for a group of experts to follow through the process of applying the Directive's framework requirements to a particular case, and assess whether the application is sound. This will involve a range of assessments, such as that all relevant data have been collected, that the data concerned are robust, that all the available options have been properly considered and that the conclusions arrived at are reasonable on the basis of the available evidence.

6.1.1.1. The role and logistics of the Scientific Panel

(137) The Scientific Panel is an essential component of Options 2 and 3 and a detailed description of its logistics is provided at Annex III. This section considers the tasks, timing, role in harmonizing Member State evaluations, and financial implications of the SC.

(138) Tasks - The SP will review the permits for an initial period, after which the need for further SP review will be assessed. (For the purposes of this assessment, a total of 30 permit reviews are assumed.) It will meet whenever a draft decision on a permit is submitted to the Commission and a request for advice on a storage permit is submitted to it by the Commission. Its tasks would be:

- to assess whether the information on the basis of which the permit decision is to be taken is comprehensive and reliable. The request for advice should contain all the information collected by the operator, i.e. the results from the initial site characterisation, the result from the static and dynamic modelling, the risk assessment, and the risk management plan. The SP may commission assistance in any aspect of this verification

- to provide a reasoned opinion as to whether the information presented is sufficient to demonstrate that all permit requirements are met. The opinion shall be provided within three months of submission of the request for advice.

(139) In conducting the verification outlined under point 1 above, the SP will assess whether comprehensiveness and reliability of the information is sufficient to form an opinion, and will commission any additional assessment required to evaluate the information provided. If results have already been verified at national level (for instance in the course of application for a site investigation license, a drilling license or the permit itself) the SP shall take this into account. The SP would perform a proportionate check on all studies, simulations, assessments and data collected. It will not redo all the work involved in the permitting

decision. It would review the documentation and check relevance of assumptions, calculations and results. Where doubts exist, additional documentation and/or runs may be asked for. This would be a reasonably robust approach, particularly once verification becomes more standardized. It would require man-months of work34.

(140) Timing - Requiring a SP assessment of Member State draft decisions on storage applications will put an additional time pressure on the permit application procedure (Figure 5). However, by using external assistance or otherwise, elements of the evaluation may run in parallel, and should take no more than three months. The Commission would examine the Scientific Panel's opinion, and when confident of the basis on which it was reached, would issue an opinion on the draft permit.

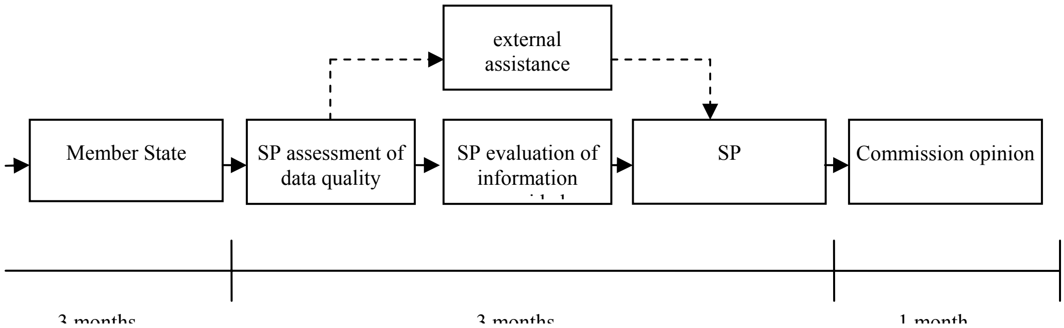


Figure 5. Timeline CO2 storage permit application

(141) Harmonization of Member State evaluations beyond 2020 - The review of the Commission will very probably result in a more uniform evaluation of storage permit applications in the EU in the initial period of deployment. Ideally, the work would contribute to building up a sizeable body of expertise with respect to the safety of underground storage of CO2, and will provide the basis for any amendment of the Annexes of the Directive, and for any guidance produced under Article 19. Nevertheless, the member state will remain the competent authority for granting the storage permit and a mechanism should be adopted to disseminate the experience gained during the Commission review. The Commission will establish annual meetings involving SP members and competent Member State authorities, using existing structures where appropriate.

(142) Financial implications – The financial implications of the Scientific Panel for the evaluation of permit applications will depend on its annual activity and on the need for external assistance in carrying out the SP's tasks. Estimating the total number of applications to be reviewed per year as on the order of 4 to 5, the annual costs of the Scientific Panel are projected to be in the region of €600 000, as outlined in Table 3.

Table 3. Annual cost projections of a Scientific Panel (assuming 2 assessments per year)

	Meetings on permit applications	Annual harmonization meetings	External assistance contracts	Total cost

34 DNV, oral communication.

Number p.a.	3	1	2	
Unit cost (k€)	3	20	300	
Total cost	9	20	600	629

6.1.2. Analysis of options

(143) Both Option 2 and Option 3 would provide additional confidence, in particular to the public, that the early phase of implementation of CCS will be sound. This is of benefit also to the operators themselves, as any negative experience in the early phase of deployment will severely damage confidence in the technology, to the detriment of all projects. Both options also provide an excellent mechanism for accumulating experience with implementation of the Directive, which can be used to develop guidance and where necessary to revise the Annexes of the Directive. Thus Option 1 is rejected.

(144) However, during the course of consultation, many respondents commented that Option 2 has a substantial subsidiarity disadvantage, in that it arrogates to the Commission the responsibility for permitting an installation. This is indeed an unnecessary encroachment on national sovereignty, in that the advantages of centralised verification can be ensured equally well without the Commission adopting the role of permitting authority.

(145) Option 3 comprises review by the Commission with the help of a Scientific Panel, a Commission opinion on the draft permit decision and permitting by the Member States, and would provide very substantial advantages in terms of confidence in the robustness of the initial set of assessments. It would also provide an excellent mechanism for exchange of information and best practice on the key elements of the permitting process. This comes at a cost of around €600 000 a year, the vast majority of which will be costs for external assistance in processing the material submitted. The delay induced in the permitting process would be of the order of 6 months. On this basis, the implications are reasonable and this option is preferred. Thus Option 2 is rejected in favour of Option 3.

6.2. Liability

(146) The main types of risk presented by CCS operations were outlined previously (Section 2.2.1). In order to manage the potential liabilities posed, several issues must be considered.

6.2.1. General liability issues

(147) Liability for local damage to health or property is not covered by the Environmental Liability Directive (ELD) for any existing industrial activity. It is rather subject to the national laws of individual Member States. There is no evidence suggesting a need for a different approach for CO2 storage, and so liability for local damage to health or property will not be dealt with at EU level.

(148) Liability for damage to the local environment from CCS activities is covered in the same way as for many industrial activities under the Environmental Liability Directive (ELD). That Directive also contains requirements on financial provision for the liabilities in question under its Article 14. The conservative approach to dealing with local environmental liability for CO2 storage sites is to confer the ELD on CO2 storage.

(149) Liability for damage to the global environment is automatically covered by inclusion of the storage site within the EU ETS, requiring surrender of allowances for any leaked emissions from the site.

6.2.2. Transfer of responsibility for the site to the state

(150) The long-term nature of CO_2 storage is such that both for public safety and for investor confidence, there must be provision for transfer of responsibility for the site to the state at some point. The lifetime of a typical commercial entity is much shorter than the time period for which CO_2 must be stored in the sites, and in the interests of public safety there should be clear provision on responsibility for the sites in the long term. Also, commercial operators are unlikely to take on responsibility for storage sites unless there is a clear provision to the effect that their liability for the storage site will end at some point.

(151) There are three main options for transfer of responsibility to the state:

- Option 1: date of transfer at the discretion of the Member State
- Option 2: transfer a fixed time after closure and decommissioning of the site
- Option 3: transfer at the point where the site has been safely closed and decommissioned and it has been demonstrated that the risk of future leakage is low.

(152) The first option would risk competitive distortion, since accepting responsibility for the liabilities of a site is an effective state aid. If different Member States were to accept liability under different conditions, the CO_2 storage market would be distorted. The second option would also risk competitive distortion, as different sites may present different risks and liabilities at a fixed time interval after closure. Thus Member States would be accepting liability on different bases.

(153) The third option would minimise competitive distortion, by ensuring that all Member States accept liability on the same performance basis: effectively that it has been demonstrated that future liabilities are likely to be low. It is also consistent with the polluter pays principle: effectively, the operator retains liability for the site in so far as it represents a significant risk, but when the operator has demonstrated that the risk is low, responsibility for the site is transferred to the state.

(154) Thus the option chosen for transfer to the state is Option 3. Since at the point of transfer the risk is demonstrated to be low, no financial provision is deemed necessary to cover the period after transfer.

6.2.3. Corrective measures for leakage

(155) The Environmental Liability Directive provides detailed provisions on the measures to be taken in case of events causing local environmental damage. Thus the default option for imposing corrective measures is to leave them to the Environmental Liability Directive. Any leakage incident that caused local environmental damage would be caught by the ELD and appropriate measures would be required.

(156) However, there is in theory the possibility that an event would cause global environmental damage (emissions to the atmosphere) without causing local environmental damage that would trigger ELD requirements (for instance, the contamination and damage to the local

environment may fall below a de minimis threshold even though the cumulative quantity of leakage to the atmosphere was still significant). The Commission has thus decided to include in the enabling legal framework for CO2 storage additional provisions on corrective measures to be taken in the case of leakage. These are modelled on those of the ELD but apply without prejudice to the ELD requirements.

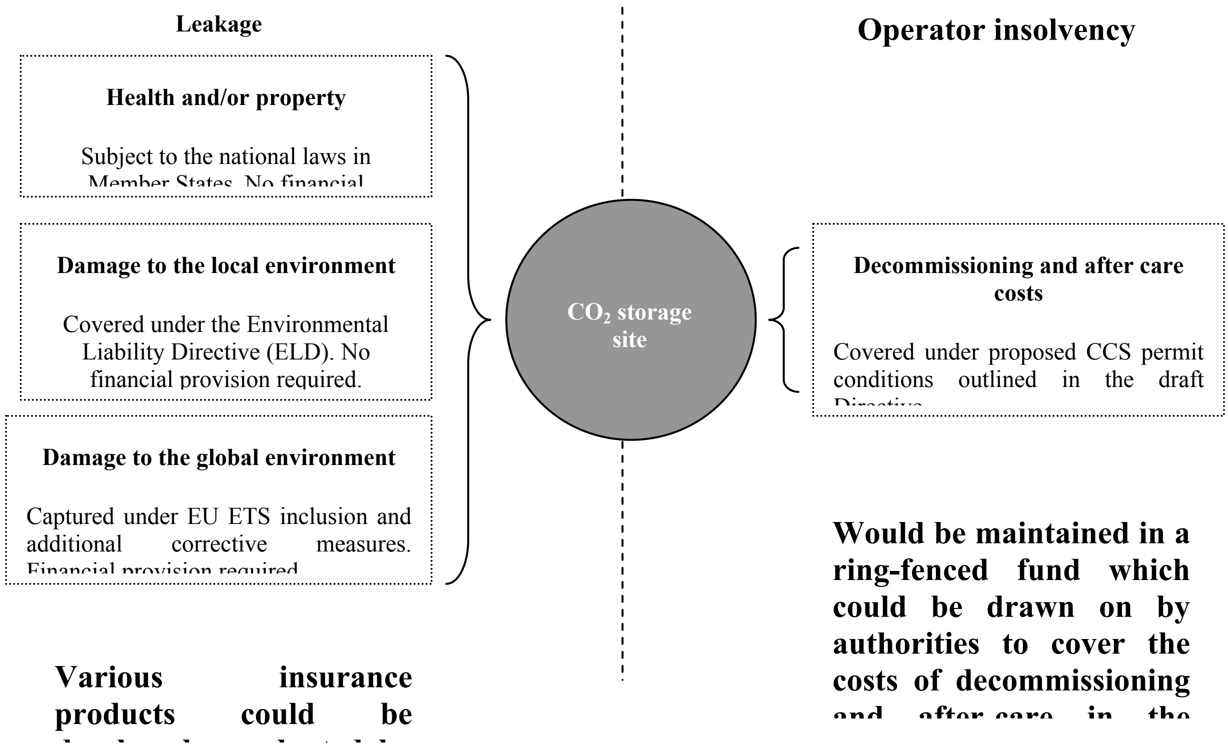
6.2.4. Financial provisions

(157) There would be an advantage in requiring operators to establish financial arrangements to ensure that sufficient funds are available to cover certain responsibilities under the Directive in the event that the operator becomes insolvent during the operational or after-care phase of a CO2 storage site, namely:

- Responsibility for closure and after-care procedures for the storage site.
- Responsibility for corrective measures required specifically under the enabling legal framework (e.g. capping blown wells, depressurising the storage site.
- Responsibility for any liabilities arising from inclusion under the ETD (that is, surrender of allowances for any leaked emissions).

(158) Note that the financial arrangement would not cover liability for local environmental damage, which is covered by the provisions of the ELD, nor liability for local damage to health and property, as the latter is regulated at Member State level. A summary of the liability situation and the relevant cost implications is provided in Figure 6 below.

Figure 6. Overview of CO2 storage site financial liabilities and options for their management



6.2.5. *Impacts of requiring Financial Provisions for closure and after care costs*

6.2.5.1. Experience with similar requirements in existing legislation

(159) A similar financial provision requirement is already present in EU law under Art. 8(a)(iv) of the Landfill Directive, requiring operators to make financial provisions such that the operator or a competent authority would be in a position to discharge the obligations of the landfill permit (in particular closure and aftercare obligations) in the event of operator insolvency. The Directive on the management of waste from extractive industries (2006/21/EC) also includes a similar requirement (Article 14).

(160) Typical financial security mechanisms used to secure landfill sites include cash accounts, bonds, insurance, mutual funds, and others (more detail is provided at Annex III). An example for a bond (covering financial provisions for CCS closure and aftercare monitoring costs for a depleted gas field) has been prepared to estimate total premiums payable. A typical bond sum schedule for a landfill, where the bond value diminishes over time, was used to calculate the premiums. Estimates were made assuming a 2% interest rate on bonded value and a 6% interest rate. Rates used here are typical for landfill sites, but are applicable for large landfill operators (with over 100 sites). Premiums can vary significantly depending on the financial standing of the operator and the type of the bond. Estimation of bond premiums associated with financial provision requirements (in million euros) are outlined below (Table 4).

Table 4. Estimated costs for financial securities for a 40 MtCO2 storage site

Depleted gas field scenario	Injection (2010 - 2050)	Closure (2050)	Aftercare (2050 - 2075)
Monitoring costs	N/A	N/A	€7.5m
Well plugging costs/site	N/A	€1m	€0.25m
Total Provisions Required	€8.75m		
Bond Premium	Annual	Total over 65 years (non discounted)	
At 2%	€80k	€5.3m	
At 6%	€242k	€15.8m	

Note: Assumes 3-D time-lapse seismic measurements would be taken at five-year intervals during the 25-year after care phase. Seismic costs approximately €1.5 million per shot. An additional amount of €250,000 per year has been budgeted for other monitoring costs that could be required in the aftercare phase. Closure costs in this scenario include only incremental costs for well plugging (i.e. different cement) compared to plugging a standard gas well. Under this context it has been assumed that overall decommissioning costs have been provisioned from the gas/oil field operator linked to the extraction phase of the field.

(161) It is also useful to compare with current practice for decommissioning of offshore oil and gas platforms. In the UK, for instance, current permit requirements include an obligation on the operator to produce a decommissioning program (outlining the estimated cost of decommissioning, a timetable, and maintenance provisions). At the moment, "hard" financial securities (i.e. bonds) are not required35, but a recent UK department of Trade and Industry (DTI) consultation has outlined the UK Government's intention to require some form of financial security in the future when the level of risk is judged to be high. The costs associated with individual decommissioning programmes can vary from £5 million pounds for a small sub-sea development with equipment only on the seabed, to £500 million pounds for a full scale decommissioning project involving large steel or concrete platforms and other facilities such as pipelines, loading systems, seabed templates and manifolds. However, while existing infrastructure may be used for CO2 storage projects, the decommissioning costs of the infrastructure would not be covered by the enabling legal framework, which would rather focus on the obligations required to make the storage site safe. These latter costs are likely to be significantly in excess of anything arising for CO2 storage projects.

(162) Art. 8(a)(iv) of the Landfill Directive was not uniformly transposed across member states and different practices have developed regarding which types of financial securities are acceptable. Additionally, varying requirements for landfill closure and aftercare management and the associated methodologies for estimating necessary financial provisions have evolved across the EU, and in many cases within a single country due to subjective

35 UK Petroleum Act 1998 Part IV – Abandonment Of Offshore Installations

estimations by the different competent authorities[36]. The above issues have, in some cases, resulted in differential estimation of the risks posed by sites and the associated financial provisions required therefore a similar situation might potentially impact bond premiums.

6.2.6. Impacts of requiring financial provision for ETS liabilities and corrective measures

6.2.6.1. Liabilities to be covered and quantification of potential scale:

(163) The financial provision would also need to cover the cost of corrective measures linked to sudden an accidental events, as outlined in the permit requirement in the draft Directive. This essentially consists of two elements: the cost of remediating a leak (e.g. replugging a leaking well; see Table 4 above), and the cost of offsetting the mass of CO2 released from a storage site. This would be additional to the decommissioning and after-care cost element described above, which would only cover the cost of site closure and monitoring absent of a sudden and accidental events occurring. These liabilities are different in character from decommissioning liabilities, since they cover fortuitous rather than certain events. They are thus more likely to be covered by insurance provisions, rather than assurance.

(164) An example of the potential cost to operators as a result of a 1% and 5% release of stored CO2 is shown below. Basic assumptions include: commencement of operations at 2010, injection rates at 0.5MtCO2/yr. for aquifer/depleted oil fields and 1MtCO2/yr for depleted gas fields; and a CO2 market price of €44.5/tonne in 2020, €50.5/tonne in 2030 and €56.5/tonne in 2040. The cost of plugging a well have been described previously (Table 4), and can be expected to be similar for remediating a leaking well.

Table 5. Damages associated with allowance surrender (in million euros)

Site Type	5% Release Scenario			1% Release Scenario		
	2020	2030	2040	2020	2030	2040
Aquifer / Depleted Oil field	€11.1m	€25.3m	€42.4m	€2.2m	€5.1m	€8.5m
Depleted gas field	€22.3m	€50.5m	€84.8m	€4.5m	€10.1m	€17.0m

(165) The risk of such an event occurring, the risk around the future price of carbon, coupled with the risk of an operator actually going insolvent would all need to be factored into the premium payable on an appropriate insurance product.

6.2.7. Implications for CCS

6.2.7.1. Decommissioning provision

(166) To prevent distortion of competition it will be important to try to avoid the kind of differential costing experienced during implementation of the Landfill Directive. A uniform procedure for defining closure and aftercare requirements and calculating associated

36 Topic Centre on Resource and Waste Management (ETC-RWM), Country fact sheets, September 2006, http://eea.eionet.europa.eu/Public/irc/eionet-circle/etc_waste/library?l=/country_fact_sheets

financial security provisions is thus required. The centralised verification discussed in Section 6.1 will help to bring about convergence in cost estimation for decommissioning in the early phases of deployment. The Commission will make a priority of following the implementation of this requirement in order to determine whether the required convergence is occurring in practice. If not, the Commission will propose additional measures.

(167) In the case of landfill, markets were able to develop solutions for assessing risk and long-term time scope issues. Therefore it is reasonable to conclude that financial security requirements should not present particular problems. However, measures to promote uniformity of assessment should be ensured. This can be covered by exchange of information on the implementation of the Directive, together with guidance issued under Art 22, but the effectiveness of these will be closely followed in the implementation phase.

6.2.7.2. Insurance for corrective measures and leakage

(168) Insurance providers are considering ways of developing products to cover CCS. In all likelihood there will be a need for negotiations between an operator and potential insurers in order to establish a level of assurance on an operator's competence in selecting, operating and closing a CO2 storage site such that a view can be taken on the risk of a leakage event occurring. The proposed regulatory framework will facilitate such a negotiation by laying down mandatory requirements to collect information on the security of containment, and subject these to a risk assessment. Although not overly prescriptive, due to the embryonic nature of the technology, it will provide a framework for assessment, and guidance developed as experience is gained will provide further help. The centralised verification procedure discussed in Section 6.1 will go some way to providing an additional level of assurance over the probability of a sudden and accidental leak event occurring. However, it has not been possible to provide quantitative estimate of the potential cost of an insurance premium to cover such a risk at this stage.

(169) However, two further factors will influence the way in which bond premiums and insurance policies for CCS could be priced, as follows:

- Mutuality – the capacity of the insurance or bond provider to pool the risk across a number of projects. This could present a challenge in early phases of CCS deployment or on low deployment scenarios. It is important that CCS moves fast from a demonstration to a wide-spread deployment stage to minimise these problems.

- Time scope – how long the liability coverage would need to be taken out for.

(170) In considering mutuality, it is too early to say how this may affect the capacity of operators to underwrite risk at stage. It may be that in the CCS demonstration phase, for instance, government-backed insurance pools are needed to secure risks. That would have state aid implications. For the full deployment phase, there is appetite amongst industry and operators to ensure that coverage is developed that reflects the nature of the risk posed. Significant development on this matter can be expected during the next few years.

(171) With regards to the time-scope issue, as presently proposed, operator liability transfer is based on storage site performance assessment, rather than fixed time periods, which could create difficulties for underwriters. However, time scope issues could be managed by taking out insurance policies for shorter timeframes with renewal on a rolling basis.

(172) Some elements of the proposed scope for insurance are covered under existing arrangements. For instance, insurance for blow-outs of wells is available for oil and gas operations. The relatively novel element is CO2 storage. Some existing projects are covered under the general insurance arrangements for the activity concerned (for instance, the Sleipner project was not excluded from the general insurance coverage for Statoil's operations). Analogous activities such as natural gas storage are in general covered within the overall portfolio protection for the company in question.

(173) The central insurance issue with CO2 storage – the absence of empirical data on which to base risk evaluations – is an issue also for other activities (e.g. geothermal). The approach that must be taken in such cases is to model the individual case in order to determine risk of leakage. (As stated above, this kind of modelling is required in any case for site selection under the enabling legal framework.) Based on experience in developing suitable models to sustain insurance products in analogous cases, the prospects for being able to insure against CO2 leakage are reasonable.[37]

(174) On the whole, the regulatory framework mandates an effective risk management process and framework applicable to the technology at its present stage of development. This will support the market in developing and pricing appropriate products which should allow for coverage of the risk of insolvency and costs of accidental events. A negotiation between a potential operator and insurance provider, guided by the mandatory assessment obligations presented in the draft Directive, and also the opinion of the centralised verification panel, will help insurance service providers to better assess risk, and facilitate the development of markets for financial products in this area.

6.3. Composition of the CO2 stream

(175) CO2 purity is desirable both to minimize transport and storage risk and to establish public confidence that CCS is not being used as a pretext to dispose of waste. It is thus necessary to impose conditions on the composition of CO2 to be accepted for storage. A requirement that no wastes or other material can be added to the stream for the purposes of disposal is widely accepted. However, a certain level of contamination, for instance by materials involved in the capture process (such as the capture solvents) is almost inevitable and should be allowed for.

(176) The main point of issue is to what extent the stream is allowed to be contaminated by air pollutants also present in the combustion exhaust, and in particular sulphur and nitrogen oxides (SOx and NOx). The Commission consulted on a position whereby the same level of denitrification and desulphurization would be required for the captured and stored exhaust as would be required under current air pollution legislation if the exhaust were vented to the air.

(177) However, respondents stressed that the current air pollution requirements are based on potential risk from venting to the atmosphere, and not on the potential risk from transport and geological storage. This is correct, and so the requirements for the composition of the CO2 stream are now to be set so as to ensure the integrity of the transport and storage network, and consequences on the environment in the case of leakage. This is in line with the approach adopted in international conventions (OSPAR and the London Convention).

37 We are grateful to a major reinsurer for informal discussion of the issues in this and the previous paragraph.

6.4. Access to the transport network and to storage sites

(178) A number of respondents to consultation on the enabling legal framework commented that a principle of equal access to transport and storage would be important to ensure operator confidence that CO_2 captured could in fact be transported and stored at reasonable cost. This is particularly the case if CCS is made mandatory. There are two options:

- Option 1: A basic approach requiring access to networks as well as to storage sites to be granted on a non-discriminatory basis, subject to limitations on access for reasons justified by public interest pursuant to Articles 46 and 55 EC.

- Option 2: A more elaborate approach imposing specific rules for achieving equal access (such as those in Directive 2003/54 for electricity, Directive 2003/55 for gas, or Regulation 1775/2005 specifically on access to gas transport, which is currently under revision), including unbundling provisions if required.

(179) The market for CCS is at an early stage and current indications are that there will in practice be separate operators for the combustion plus capture phase, on the one hand, and transport and storage on the other. For instance, of the declared potential projects in the UK in the context of the UK's demonstration project details (around 11), only one project was single ownership.

(180) Based on present evidence, a substantial procedure is not proportionate at this stage, although it will be necessary to track the development of CO_2 transport infrastructure to confirm that ownership structures liable to lead to competitive distortion do not occur. Thus Option 1 has been chosen.

6.5. Capture-readiness

6.5.1. Problem definition

(181) While minimal capture-ready pre-investments are expected to have low costs and high potential benefits (IEA-GHG, 2007; MIT, 2007), in practice it is expected that many operators will fail to make such pre-investments due to

- uncertainty regarding future climate regulation and future ETS prices, and

- economic discounting, by which individual operators attach less weight to a benefit or a cost in the future than they do to a benefit or cost occurring at present.

(182) Two main options have been identified:

- Option a: Adopt no measure to address the described failure to invest, or

- Option b: Require operators of new plant built after the Directive comes into force to fulfil de minimis criteria that would facilitate application of CO_2 capture technologies at a later stage

(183) Option b applies only to new plant because existing plant have already made all the relevant siting and technology decisions.

6.5.2. *Impact of Option a: Adopt no measures to address the described failure to invest*

(184) The above-mentioned 'failure to act' entails a high risk of stranded assets, whereby the resulting costs would be passed on to consumers in the form of higher electricity prices. In addition, not only will the described failure render later investments in CCS technologies more expensive, but it may allow lock-in of CCS-incompatible technology that could delay CCS uptake and that could ultimately increase the cost of meeting the EU target of 20% GHG reduction by 2020.

6.5.3. *Impact of Option b: Require operators to fulfil de minimis criteria that would facilitate application of CO2 capture technologies at a later stage*

(185) The following two requirements have been identified as de minimis criteria to facilitate retrofitting CO2 capture to power plants constructed initially without this feature:

- conduct a feasibility study of how capture will be added later to the plant, in conjunction with assessment of availability of suitable storage sites and of transport facilities, and

- include sufficient space and access requirements in the original plant, to allow capture-related equipment to be retrofitted (Gibbins, 2006; MIT, 2007).

(186) In order to meet the first criteria operators can use studies on capture ready power plant considerations38, reports that assess the options for capture ready pre-investments at power plants39, and studies on the availability of geological storage sites and potential transport routes for CO2 in the EU.40 Such information is easily accessible. For this reason it has been assumed that the cost for an operator associated with the fulfilment of the first criteria corresponds to the time spent collecting and processing the relevant information, and drafting the assessment report for the competent authority.

(187) Satisfying the requirements for space and for access for additional facilities is the key minimal technical requirement to ensure that power plants can be retrofitted at a later stage. Space should be available for addition of plant items (CO2-capture equipment, CO2 compression station), access to existing plant items, storage of equipment during retrofit, etc.

(188) Depending on the selected CO2 capture technology, a 400 MWe coal-fired power plant requires, on average, between 5000 and 7500 square meters of additional space for the equipment expected to be required for a capture retrofit. The average cost of securing this area is very low in comparison to the total investment costs for the plant (Table 1). As shown in the table below, at an average investment cost of circa 1 mln EUR per MWe of capacity installed41, the cost incurring to an operator of a 400 MWe coal-fired power plant for securing the additional land surface in view of later retrofit will be marginal, varying between 0.003 and 0.066% of his total investment cost. Further evidence that this is so is the fact that certain operators such as E.ON are planning to make all new coal-fired plants capture-ready.42

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38 MIT (2007) The Future of Coal; IPCC (2006) Special Report on Carbon Capture and Storage.

39 For instance, IEA GHG (2007). CO2 capture ready plants; MIT (2007) The Future of Coal.

40 TNO Report (2007) on source-sink matching for carbon capture and storage.

41 Average total investment cost per MWe for coal-fired power pants. MIT (2007) The Future of Coal, pp. 19.

42 See Outcome of the 42nd Annual EEI Finance Conference of E.ON, November 6th, 2007: http://www.eei.org/meetings/nonav_2007-11-04-dh/EONAG.pd

Table 6 Costs of additional surface as required for 'capture-readiness' for a 400 MWe coal-fired power plant

<table>
<tr><td rowspan="2">Total investment cost</td><td rowspan="2" colspan="2">Surface capture + compression plant (m2)</td><td colspan="3">Average EU cost of additional surface for CCS components</td><td colspan="3">Cost of additional surface as % of total investment costs</td></tr>
<tr><td>Bare soil</td><td>Outside city</td><td>City area</td><td>Bare soil</td><td>Outside city</td><td>City area</td></tr>
<tr><td>400,000,000 €</td><td>min.</td><td>5000</td><td>12,500 €</td><td>100,000 €</td><td>175,000 €</td><td>0.003</td><td>0.025</td><td>0.044</td></tr>
<tr><td></td><td>max.</td><td>7500</td><td>18,750 €</td><td>150,000 €</td><td>262,500 €</td><td>0.005</td><td>0.038</td><td>0.066</td></tr>
</table>

Average total investment cost for coal-fired power plants: € 1000/KWe (MIT, 2007) Assumed average prices for industrial sites: EUR2.50/m2 for bare soil; EUR20/m2 for outside city area; EUR35/m2 for city area

(189) By assessing the feasibility of CCS retrofit, the operator hedges against the possibility that the future carbon price will exceed the cost of CCS. The modelling done for this impact assessment predicts a carbon price of around €40/t in 2020 and a CCS price in the same range, and on this basis it is not economically sensible to retrofit for CCS. However, if the carbon price were higher than this value, inability to retrofit would impose a cost on the operator. To provide some idea of the risk that is being avoided, Table 2 below assumes that there is a 5% likelihood of a carbon price 30% greater than that derived from the PRIMES modelling. On this basis, the avoided cost from being able to retrofit is in the range of 10 to 100 times greater than the cost of the capture-ready requirement.

Table 7: Avoided risk of inability to refrofit in cases of higher carbon price

<table>
<tr><td rowspan="2">Year</td><td rowspan="2">Cost of additional surface for CCS components, 400 MW (€/year)</td><td colspan="2">Savings, for an assumed 30% higher CO2 price than assumed in PRIMES (€/year; probability: 5%)</td></tr>
<tr><td>200 MW</td><td>400 MW</td></tr>
<tr><td>2020</td><td rowspan="2">13,125</td><td>118,476</td><td>236,952</td></tr>
<tr><td>2030</td><td>520,862</td><td>1,041,725</td></tr>
</table>

(190) A capacity of 200 MWe and above has been identified as being the relevant threshold for such a capture-ready provision. In 2005, coal and lignite plants of 200 MW and above generated more than 80% of all coal and lignite-related CO2 emissions in the power sector. A similar calculation found that all coal, lignite and gas power plants with gross capacity of 200 MW and larger are responsible for 72% of all 2005 emissions in the power sector.43

43 JRC Netherlands.

6.5.4. *Conclusions*

(191) Option (a) involves substantial risk of stranded assets and technological lock-in that could hamper future deployment of CCS and the EU's capacity to meet its climate goals. These risks can be avoided by taking precautionary measures at present and at very limited cost for operators as outlined under Option (b). For this reason, Option (b) has been chosen.

6.6. Administrative impacts

(192) The administrative impacts for CO2 capture will be the standard impacts of the IPPC Directive and the Emissions Trading Directive. Transport is regulated at Member State level but will also fall under the Emissions Trading Directive, thus incurring the relevant administrative impacts.

(193) The administrative impacts for the proposed approach to CO2 storage were calculated using the European Standard Cost Model (see Annex XI) and assuming two deployment scenarios which are assessed in more detail in Section 7. The first is market-based deployment resulting from enabling CCS under the Emissions Trading Scheme (Option 1 in Section 7) and a maximal deployment based on making CCS mandatory for both coal and gas from 2020 onwards, with retrofit of existing plants from 2020 (Option 2d of Section 7). The total administrative impacts for both maximal deployment (mandatory CCS) and market-based deployment are shown in Table 8 below.

Table 8: Administrative costs of policy for regulating CO2 storage (€million)

CO2 storage deployment scenario	Market-based CCS (Option 1)	Mandatory CCS (Option 2d)
Costs for Operators	12.3	39.2
Costs for Member States	4.7	14.7
Costs for Commission	0.8	0.8
Total administrative costs	17.8	54.7

7. ANALYSIS OF IMPACTS OF OPTIONS FOR INTERNALISING THE POSITIVE EXTERNALITIES OF CCS

7.1. Options for internalising the positive externalities of CCS

(194) All the options to be considered are based on meeting the EU's agreed climate objective of 20% GHG reduction by 2020 plus a 20% share of renewables by 2020. The options considered are the following:

- Option 0: No enabling policy for CCS at EU level, including no inclusion of CCS in the EU ETS (that is, achievement of climate objectives without CCS).
- Option 1: Enable CCS under the EU Emissions Trading Scheme.
- Option 2: In addition to enabling under the ETS, impose an obligation to apply CCS from 2020 onwards and assess the impact on the potential positive externalities not captured by the carbon market. Four principal sub-options were considered:

(a) Making CCS mandatory for new coal-fired power from 2020 onwards

(b) Making CCS mandatory for new coal- and gas-fired power from 2020 onwards

(c) Making CCS mandatory for new coal-fired power from 2020 onwards, together with retrofit of existing plants (built between 2015 and 2020) from 2020

(d) Making CCS mandatory for new coal- and gas-fired power from 2020 onwards, together with retrofit of existing plants (built between 2015 and 2020) from 2020.

- Option 3: In addition to enabling under the ETS, apply a subsidy so as to internalise the positive externalities not captured by the market.

(195) Option 0 was examined in depth in the Impact Assessment for the Sustainable Fossil Fuels Communication. It will result in no CCS uptake, because legislative barriers to CCS deployment will remain in place (in particular Directives 2000/60/EC and 1999/31/EC) and there will be no incentive to pay the additional generation cost entailed by CCS, since no credit for the associated reductions will be given under the EU ETS. Its main use in this context is to provide an indication of the viability of CCS by allowing an assessment of how much more expensive it would be, under the carbon market, to achieve our climate objectives with CCS (Option 1) versus without it (Option 0). Its other implications are not assessed in detail.

(196) Assuming that the ETS is designed and implemented so as to deliver the EU’s climate objectives, Option 1 fully integrates the positive climate externality of CCS. Options 2 and 3 will be more expensive ways of meeting the 20% GHG reduction target than Option 1, and the additional expense can only be justified by an additional impact (relative to Option 1) on the potential additional positive externalities of CCS. These are learning-by-doing, security of supply, any positive impact on global market share for CCS technology, any positive impact on achieving global climate objectives, and air pollution reduction.

(197) Option 3 is based on a subsidy which should in theory reflect all the positive (external) effects of CCS deployment in addition to the climate benefit – that is, cost reducing

innovation resulting from learning-by-doing, security of supply, export potential, impact on achieving global climate objectives, and air pollution reduction. In economic theory, subsidy should be a more efficient means of internalising these externalities than mandating CCS.[44] Subsidies could be given for the investment or operating costs. Operating subsidies for additional fuel, storage and capture costs are difficult to measure and monitor. Such costs can make up roughly half of the additional cost (25 to 45€/tCO2) of CCS. Including CCS in the EU-ETS (current Phase II price €23/tCO2) would cover these costs. A subsidy on investment would cope with the additional capital costs. As a first approximation the innovation benefit from the mandatory scenario was used to set the subsidy level. The innovation benefit is estimated at around 10% reduction in investment costs (see section 7.5.3.1), and so for the analysis a subsidy of 10% of the investment cost is used. This level might not reflect any positive (external) effects on the other externalities not captured by the market.

7.2. Options considered but discarded at an early stage

(198) Making CCS mandatory for new coal and gas fired power earlier than 2020. Under this option, new coal and gas power stations planned for 2010-2020 would face high additional costs from CCS which is not yet commercially developed. This would be likely to lead to substitutions of new coal and gas power stations with other forms of, more expensive, power generating plant, or delays to construction of new coal and gas plant with potential shortfalls in generation capacity in Europe.

7.3. Methodology

(199) In order to provide a quantitative assessment of the potential impacts in so far as possible, modelling was used to simulate the behaviour of the energy market under each of the above options. The modelling approaches are explained below. However, while the quantitative outputs can provide some indication of the orders of magnitude of potential effects, there is inevitably a large uncertainty associated with predicting behaviour of a complex system 20 years in the future, and the results should be used with appropriate caution. The main assumptions are identified, and a sensitivity analysis provided, in Section 7.5.5

(200) For the economic assessment, all the options were assessed, including all the variants of Option 2 (mandatory CCS). However, for assessing the environmental and societal risk it was not possible in resource terms to assess all options, and so only Option 1 and Option 2d were assessed for everything, although option 3 was also assessed for air quality. The environmental assessment focuses on the year 2030. This approach was regarded as reasonable given that Option 2d in 2030 represents the most extreme deployment scenario, and so the environmental and societal impacts for that circumstance will represent a conservative estimate of the likely impacts of mature CCS deployment in Europe.

(201) Deployment scenarios were run for each of the above options using the PRIMES model.[45] PRIMES simulates the European energy system and markets on a country-by-country basis and provides detailed results about energy balances, CO2 emissions, investment, energy technology penetration, prices and costs by 5-years intervals over a time period from 2000 to 2030. The model includes power generation technologies including future power plants

44 See footnote 19.

45 P. Capros, L. Mantzos, V.Papandreou, N.Tasios and A.Mantzara (2007) Energy systems analysis of CCS Technology; PRIMES model scenarios, E3ME-lab/ICCS/National Technical University of Athens, December 2007, Athens (available upon request).

enabled with carbon capture processing. In addition, the costs of transporting and storing CO_2 are modelled. PRIMES assesses the direct and indirect impact of policy options by simulating the impacts of the market thus taking into account the reaction of market agents such as power plants operators. The model establishes a complete linkage between supply and demand for energy which takes account of impacts of CCS policies on market prices (electricity, carbon). PRIMES can reflect alternative policies and regulations that promote CCS deployment.

(202) The model is designed to assess the impacts of specific climate change targets and renewable policies and to provide impact assessment of CCS deployment within this context. Technical and economic data have been recently updated and revised. The revised data reflect new information generated from the EC Technology Platforms (CCS data reflect the "Zero Emission Platform"). The decision on whether to deploy CCS is part of the economic model which simulates the investment and plant operation behaviour of power producers within the electricity market, in interaction with demand behaviour and with upstream suppliers of fuels.

(203) Power operators are assumed to maximize profits over time which drives plant investment and operation. The optimisation is constrained by existing capacities, technical restrictions and policy obligations when these are integrated into the model. The optimisation takes into account cost supply curves of resources, for example fuels, renewables, sites for nuclear investment, cost of storage of CO_2 captured, etc. These cost supply curves incorporate information about the maximum potential of the resources and their decreasing returns of scale associated with their rate of use. The dynamics of investment are flexible and the model provides multiple alternatives, as for example the retrofitting of old plants, the replacement of an old plant on an existing site, the extension of old plants, and of course the possibility to build new plants in new sites. The model represents more than 200 typical alternative technologies for power generation.

(204) Power system decisions are followed by computation of electricity, steam and heat tariffs which influence energy demand. Thus a closed loop is established between demand for energy and supply of energy, which clears the market as a result of adjusting energy prices. Hence, a multitude of factors influences directly or indirectly CCS deployment in the PRIMES model: fuel prices and price-volume relationships, cost and potential of renewable energy, cost-potential curves of CO_2 storage, old capacities and investment commitments, potential of developments in existing sites, current and future costs of candidate power technologies (including learning effects) and government policies (e.g. on nuclear power plants).

(205) The 'PRIMES baseline (version July 2007) without additional climate policy' projects the trends in energy markets and technologies without assuming any new policy beyond those put in place in the past (and thus in particular without the 2020 GHG or renewables targets). It assumes gradually increasing carbon prices in the EU-ETS market reaching 22 €/tCO_2 in 2020. In the baseline CCS would not be employed if left to the EU-ETS market since carbon prices are insufficiently high. However, in accordance with the options outlined in Section 7.1, the Council Conclusions objectives of 20% reduction in GHGs and a 20% share of renewables in 2020 are taken as the reference case for assessing the CCS policies.

(206) The CCS deployment estimated by PRIMES was then used to develop indicative transport and storage networks across Europe, yielding information on the total length of the pipeline network, the proportion of the network that is onshore versus offshore, and the number, type

and location of storage sites used. This information was then input into the environmental impact assessment to calculate impacts for the CCS deployment scenarios in 2030.

7.4. Deployment scenarios

(207) Options 0 to 3 are all characterised by building the Community's objectives of a 20% reduction in GHG emissions and a 20% renewable target (both in 2020) onto the PRIMES baseline described above. This reference scenario assumes that the targets will be met across the EU-27 in a cost-effective way by a combination of increasing carbon prices (up to 40€/t CO2 in 2020) and renewable support schemes (around 40 €/MWh).

7.4.1. Deployment of CCS for the policy options

(208) Table 9 summarises the modelled results (under our set of assumptions) of the impact on CO2 captured of the policy options. If enabled under the EU-ETS (option 1) CCS would be gradually picked up by the market in the reference case since a price of €40/tCO2 in 2020 (increasing to around €45 in 2030) would be enough for some (coal-based) CCS to be deployed by the market. The volume of CO2 captured would increase from 7 MtCO2 in 2020 to 160 MtCO2 in 2030 in line with the increase in carbon price over time. Under this EU-ETS market 13% of CO2 emissions from power and steam production would be captured in 2030 (equal to 5% of total CO2 emissions from energy).

(209) Under option 3 a subsidy would be given equal to 10% of the investment costs for new plants. The subsidy would induce power plant operators to invest in CCS on new coal fired plants at the expense of investing in CCS (in 2020) for existing coal fired plants. Hence CCS would be stimulated but with a time delay (related to construction of new plants). Making CCS mandatory for new coal fired plants only from 2020 onwards (option 2a) initially only slightly increases the amount of carbon captured since power operators would shift to existing coal fired plants by extending their lifetime and operating hours in 2020, and later (2025-2030) shift to natural gas. In 2030 the volume of CO2 captured is more significant although power operators do shift power generation from coal to gas. Making CCS mandatory also for new gas fired plants (option 2b) does not allow this shift and results in a higher volume of CO2 captured from 2025 onward. Making CCS mandatory for new and existing coal plants (2c) will further increase the amount captured since a shift of power generation to existing coal plants is no longer possible. Power generation by gas increases considerably as a result. Making CCS mandatory for new and existing coal and gas (2d) initially leads to shift to power generation from gas and renewables (2020-2025) but in 2030 coal generation has a higher market share than under the EU-ETS option 1.

(210) Option 2a and 2b hardly have an impact on the carbon price initially but require a somewhat higher carbon price in 2030 to meet the same reduction in CO2 emissions in 2030. Option 2c and 2d lower the carbon price because of the mandatory abatement. A significant part of the coal- and gas fired capacity has CCS auxiliary equipment in place (sunk costs) and given the carbon price it makes sense to use these plants to produce electricity and reduce carbon emissions. Hence carbon emissions would be lower than needed and the carbon price is adjusted downwards to accommodate this.

Table 9. Impacts of options in terms CO2 captured by CCS (in Mt CO2)

	Option 0.	Option1: ETS	Option 2: ETS+mandatory				Option 3: ETS +
			New coal	New coal+gas	New+old coal	New+old coal+gas	

	No CCS		2a	2b	2c	2d	subsidy
2020	0	7	7	7	37	75.	0
2025	0	20	20.6	26.5	118.	177	22
2030	0	161	267	391	326	517	211

(211) Table 10 summarises the impact on CCS deployment of the options. There is little difference from the ETS option in 2020 if CCS is made mandatory only for new plants (options 2a and 2b), but a more substantial difference by 2030. However, if retrofit is required there is a significant change in the 2020 deployment. Most of the CCS capacity is for coal-fired plants except in case 2d. The investment cost subsidy of 10% would increase CCS capacity by 50% in 2030 (Option 3 versus Option 1). The total public costs of the subsidy would be 5.5 billion € and the additional private investment in CCS induced would be around 27 billion €.

Table 10. Impacts in terms of CCS deployed capacity (in GW)

	Option 1 ETS	Option 2: ETS+mandatory				Option 3: ETS + subsidy
		New coal	New coal+gas	New+old coal	New+old coal+gas	
		2a	2b	2c	2d	
2020	1	1	1	6	16	0
2025	2	3	4	19	42	3
2030	21	40	68	53	109	32

(212) The assessments for the mandatory and subsidy cases all assume that the carbon price is affected by the mandatory CCS requirement and is adjusted to ensure that both the 20% reduction in GHG emissions and the 20% renewables target are met. Due to rounding there might still be minor differences in the amount of CO2 reduced between the cases.

Distribution of efforts over the member states.

(213) In case CCS would be enabled in the EU-ETS market (option 1) more than half of the carbon captured would take place in Poland in 2030. Note that this result depends on a predicted low cost of carbon storage in Poland. Making CCS mandatory for new coal plants (option 2a) would imply that Germany and Poland would together account for 2/3 of the carbon captured. The rest would be split over Belgium, the UK, Spain and Italy in addition to Slovenia, the Czech Republic, Slovakia, Hungary, Romania and Bulgaria. Option 2c (making CCS mandatory also for existing coal plants) would add all other countries except Luxembourg, Sweden, Latvia, Lithuania, Cyprus and Malta to the list. The options (2b and 2d) involving CCS for gas-fired plants would lead to a slightly more even distribution.

Table 11.Distribution of Mt CO2 captured by Member State in 2030

Mt of CO2 Captured in 2030	Option 1	Option 2				Option 3
		2a	2b	2c	2d	
Ireland			2		5	2
United Kingdom		1	57	4	62	10
Belgium		17	27	22	50	
Luxembourg					1	
Netherlands			5	3	14	
Germany		74	115	135	186	56
France				3	3	
Spain		9	9	11	13	1
Portugal				2	2	
Denmark						
Sweden						
Finland				1	1	
Austria			7	1	11	
Italy		4	4	8	10	
Slovenia	5	5	5	5	5	5
Czech Republic	16	16	16	18	18	18
Slovakia	6	6	7	7	9	7
Poland	91	92	89	72	78	94
Hungary	8	8	9	7	12	8
Latvia						
Estonia					1	
Lithuania						

Romania	19	18	20	12	17	7
Bulgaria	15	15	15	14	16	3
Greece		1	3		3	1
Cyprus						
Malta						
EU27	161	267	391	326	517	211

7.5. Economic impacts of CCS deployment

7.5.1. Resource cost

(214) Total resource costs to the energy sector were based on the PRIMES model. These exclude costs incurred for purchase of CO2 allowances (since this is not a cost to society as a whole but a transfer payment). These costs include the costs for the energy system as a whole. They include costs for CCS (investment, operating costs, transport of CO2 and storage) as well as the indirect impact on costs of other power plants (e.g. making CCS mandatory for coal plants will increase electricity production from gas-fired plants and their costs). Costs are the sum of all changes in the energy system (including impact of increased electricity prices on demand). In all cases costs are given as additional costs to option 1 (CCS included in ETS). Costs are not discounted but a private discount rate of around 9% is assumed in the power sector to annualize investment costs and simulate the markets.

(215) Under option 1 (CCS is enabled but only used if the ETS market decides it to be cost-effective), CCS would be employed to meet the 20% reduction in GHG and the 20% renewable target. It would then be part of a package of measures such as additional renewables (e.g. wind turbines and biomass), energy efficiency measures and reductions in non_CO2 Greenhouse Gases. If CCS were not enabled (Option 0) the costs of further reductions in line with the 20% GHG and 20% renewable package (c 30% GHG reduction in 2030) would be 60 billion or 40% higher in 2030 since CCS would need to be replaced by other, more expensive technologies (e.g. solar PV or more expensive biomass options). Option 3 would cost slightly more. The additional costs of mandatory CCS clearly depend substantially on the variant chosen. For the variant on which CCS is made mandatory for new coal alone from 2020, with no retrofit obligation, there is some change over Option 1 (see

(216) Table 12). Where CCS is made mandatory for coal and gas (2b), costs increase slightly in 2020. However, for the variant where CCS is made mandatory for coal and with retrofit required (2c) costs are significantly higher (€6 billion/year in 2030) than for Option 1. This cost is doubled (12 billion) in 2030 if CCS is made mandatory for existing gas fired plants also (2d). The timing of the costs depends on when new (coal) capacity comes on line.

Table 12. Additional costs (€billion/year)

	Option 0: disallow CCS	Option 1: ETS	Option 2: ETS+mandatory				Option 3: ETS+subsidy
			New coal	New coal+gas	New+old coal	New+old coal+gas	
			2a	2b	2c	2d	
2020	2.2	0	0.8	2.4	1.9	4.9	-0.2
2025	5.2	0	2.1	3.3	4.8	10.0	-0.1
2030	59.5	0	6.7	9.8	6.7	12.6	2.1

(217) As described above, the modelling was adjusted to simultaneously satisfy, to the extent possible, the 20% GHG reduction target and the mandatory CCS obligations, and so a reduction in the carbon price will in general result from making CCS mandatory. However, the treatment of this feedback process is imperfect, and as a result option 2c and 2d are shown as still leading to some overall reduction in CO2 emission from energy (around 5% in 2030). These minor differences occur because a lower carbon price has an impact on meeting the renewables target, requiring adjustment of the subsidy for renewables which in turn impacts on the CO2 reductions making it difficult to find a (market) equilibrium. This difficulty may also be experienced in practice, and so is highlighted here. Another aspect of this phenomenon is that it distorts comparison between the options, since the costs for Option 2d (for instance) include the costs of the extra 5% reduction. To enable a comparison of the options the additional costs of the extra reduction have been valued at the average reduction costs (see Table 14). Thus it should be borne in mind (for example) that of the additional cost of option 2d in 2030 (shown as €12.6bn in

(218) Table 12 above) €6.7bn relates to an additional CO2 reduction over and above the 20% GHG reduction target.

Table 13 Additional CO2 emission reduction from energy in EU27(in MtCO2, in % in brackets)

	Option 1 ETS	Option 2: ETS+mandatory				Option 3: ETS+subsidy
		New coal	New coal+gas	New+old coal	New+old coal+gas	
		2a	2b	2c	2d	
2020	0	5 (0%)	-6 (0%)	-20 (-1%)	-20 (-1%)	6 (0%)
2025	0	-48 (-1%)	-43(-1%)	-118 (-4%)	-130 (-4%)	+1 (0%)
2030	0	-27 (-1%)	-94 (-3%)	-63 (-2%)	-157 (-5%)	-51 (-2%)

Table 14 Additional costs (bn €/year) due to CO2 reduction exceeding the 20% GHG target

	Option 1: ETS	Option 2: ETS+mandatory				Option 3: ETS+subsidy
		New coal	New coal+gas	New+old coal	New+old coal+gas	
		2a	2b	2c	2d	
2020	0	-0.2	0.3	0.8	0.8	-0.2
2025	0	2.1	1.8	4.8	5.2	0
2030	0	1.2	4.3	2.7	6.7	2.0

7.5.2. Impact on average generation cost and electricity price

(219) The impact of the options on the average generation cost of electricity was assessed by the PRIMES model (see Annex II). Option 3 (subsidy+ETS) would not change electricity generation costs. Options 2a and 2b lead to only minor differences in electricity prices compared to Option 1 in 2020. However, the mandatory application of CCS on coal and gas fired plants would leave little flexibility to generate electricity in 2020 and would lead to additional increases, particularly significant for Option 2d initially. In 2030 the impacts of the mandatory cases are less pronounced since they lead to a shift in generation from coal to gas or the other way around. Case 2b leads to less gas and relatively more coal use in 2030 for power generation. Since the coal price is relatively low in 2030 versus the gas price overall generation costs in 2030 can be lower. Up-front costs (in 2020) are higher since investments have to be made early and coal/gas price ratio differ in 2020.

Table 15. Impacts on average generation costs (%-point change compared to option 1)

	Option 2: ETS+mandatory				Option 3: ETS+subsidy
	2a	2b	2c	2d	
2020	0.2%	0.6%	0.9%	1.9%	0.0
2025	0.6%	1.0%	0.7%	1.8%	0.0
2030	-0.1%	-0.1%	-0.2%	0.0%	0.0

7.5.3. Impact of options on non-ETS externalities

7.5.3.1. Innovation (dynamic efficiency)

(220) As suggested in section 2.2, a potentially positive impact of mandatory CCS requirements is the additional learning-by-doing from the early deployment thus stimulated. Greater deployment might lead to additional reductions in costs where those reductions are dependent on the cumulative capacity build.[46] Learning will also depend on a time interval

46 Note that there is some debate over the direction of causation in the relation between cost and deployment scale. The Stern Review puts it as follows: 'There is a question of causation since cost reductions may lead to greater deployment; so attempts to force the reverse may lead to disappointing learning rates. [The available] data shows technologies starting from different points and achieving very different learning rates. The increasing returns from scale shown in these curves can be used to justify

between deployment phases in order to absorb the lessons of previous effort, but a provisional estimate of the benefits of learning can be made assuming that cost reductions are sensitive only to the cumulative capacity. (All other things being equal, this will overestimate the learning benefits.)

(221) For these purposes, we have assumed that for each doubling of installed capacity a cost reduction occurs. The model assumes cost reductions based on common agreement by major experts on the development of the costs. Components of CCS are well known. Cost savings are possibly only in the assembly of them and the optimization of the performance of the system as a whole and scaling up the dimension. For CCS these cost reductions are expected to be limited to 3% for each doubling of capacity.[47] Thus we assume that cost reduction occur after a minimum amount of capacity (2 GW each of coal and gas, in line with 10 to 12 demonstration plants) is installed to close the R&D phase, and that for every doubling of capacity beyond 2 GW a reduction in costs of 3% is entailed. The table below shows that the options 2a to 2d might lead to slightly higher cost reductions (for coal) than assumed in the model. For gas-CCS this is only the case for option 2d. For each of the options, the extra reduction in costs (over and above that assumed in the model) is calculated and multiplied by the relevant investment cost (797€/KW for coal (IGCC-coal post combustion) and 500€/KW for gas (gas combined cycle post-combustion)). This is then multiplied by the deployment in 2030 to give the total investment cost reduction, which is then annualized over the lifetime of the plant (20 years for coal, 10 years for gas). (See

deployment support, but the potential of the technologies must be evaluated and compared with the costs of development.' (Chapter 16 p 362.) This section of the Impact Assessment attempts the analysis required by the last sentence.

47 IEA (2006) Estimating the future trends in the costs of CO2 capture technologies, Technical Study, Report Nr. 2006/6, IEA Greenhouse Gas R&D program, Paris.

Table 12.) The difference between Option 1 and Option 2d is around €0.8bn/year in 2030, compared with the additional resource costs (net of additional CO2 reduction) of around €6bn. In conclusion, learning effects might lead to bigger cost reductions than assumed for the mandatory cases but including these cost reduction will lower the additional resource costs by a maximum of around 10%. An additional subsidy of 10% (Option 3) would have only a marginal impact on learning.

Table 16. Possible innovation impacts on investment costs in 2030 (% reduction in investment costs to 2020)

SOLID FUEL (Coal+Lignite)	Option1 : ETS	Option 2: ETS+mandatory				Option 3: ETS plus subsidy
		2a	2b	2c	2d	
GW CCS installed	21	40	58	49	69	31
Number of capacity doublings	4.30	5.30	5.90	5.60	6.00	5.00
Cost reduction (% of 2020)	13	16	18	17	18	15
Additional cost reduction cf PRIMES (%)	6	9	11	10	11	8
Investment costs savings (€/KW)	53	80	96	88	98	71
Total investment cost savings (bn€)	1.1	3.2	5.5	4.3	6.8	2.2
Annualized investment cost savings (bn€)	0.1	0.3	0.5	0.4	0.6	0.2
GAS	Option 1: ETS	Option 2: ETS+mandatory				Option 3: ETS plus subsidy
		2a	2b	2c	2d	
GW CSS installed	0	0	10	0	35	0
number of capacity doubling	0.00	0.00	3.30	0.00	5.12	0.00
Cost reduction (% of 2020)	0	0	10	0	15	0
Additional cost reduction cf PRIMES (%)	0	-3	7	-3	12	0
Investment costs savings (€/KW)	0	-16	36	-16	64	-0
Total investment cost savings (bn€)	0.0	0.0	0.4	0.0	2.2	0.0
Annualized investment cost savings (bn€)	0.0	0.0	0.0	0.0	0.2	0.0
Solid&GAS: SUM annualized investment cost savings (bn€)	0.1	0.3	0.6	0.4	0.9	0.2

7.5.3.2. Security of supply

(222) Insecurity of energy supply can be regarded as the exposure to interruption of imports of energy or strong fluctuations in energy prices due to the fact that supply is concentrated in a few countries with relatively high geopolitical risk. For the EU it concerns mainly reliance on gas and oil, and hence CCS policies could affect energy supply security by shifting fuel use to those fuels. Oil is of little relevance since the quantities are small, and hence the main impact of relevance is the impact on gas consumption. As a very rough rule of thumb, if gas consumption (and hence imports) increases, then security of supply decreases.

(223) Table 17 shows the impact of the options 0, 2 and 3 on fuel consumption relative to Option 1 (enabling CCS in the ETS). Remarkably the extreme mandatory option (Option 2d) increases both the use of solids and gas in the power sector. In relative terms import dependency decreases, but in absolute terms more gas is imported. This happens because the policy requires CCS on all coal and gas fired plants (new or old) which comes with a loss of efficiency (more fuel needed for same electricity output). The nature of the policy is such that there is no flexibility to shift to other alternatives.

(224) Making CCS mandatory for new coal and gas plants only (Option 2b) would increase energy supply security since the use of solids fuels would increase at the expense of gas in order to meet the GHG-reduction targets of the EU. The subsidy case would not affect energy supply security since gas consumption is not affected (CCS being mostly on coal-fired plants). Note that not enabling CCS under the EU-ETS at all would shift fuel use to imported gas mainly at the expense of coal. In conclusion, on this rough analysis Option 2b increases energy supply security, 2a and 2c have a negative impact and 2d a marginal negative impact, and Option 3 is neutral compared to Option 1.

Table 17. Change in fuel consumption in the power sector over option 1 (% in 2030)

	Policy Option					
	0	2a	2b	2c	2d	3
Solids	-38%	-6%	8%	-6%	12%	1%
Oil	-19%	4%	-3%	4%	0%	-3%
Gas	7%	15%	-6%	25%	4%	0%

7.5.3.3. Export potential

(225) Additional cost reductions achieved by learning might open opportunities for exporting the technologies to markets that are expected to expand in the future (China and USA) (c.f. experience with stimulating wind turbines in the EU in the past). The impact of such cost reductions on export opportunities is difficult to quantify since those opportunities will depend on future international agreement on reducing greenhouse gas emissions, the cost of other GHG technologies in other countries and the extent to which other countries can produce CCS technologies domestically. There is a wide range of estimate of the potential

global market for CCS in 2030 assuming that the 2°C target is translated into a binding international agreement including major developing countries. Some estimates put the potential as high as 600-700 GW (half of which coal) with more than 1/3 of the market in China and 10% in Europe.48 But there are other estimates that the market could be lower (around 300 GW) (based on IPCC scenarios that stabilise GHG concentrations while making different assumptions on energy prices, energy efficiency improvements and penetration for gas). If 20-40% of the global market (ex EU) could be captured by European companies, exports would increase by 0.2 to 0.6 billion €/year.49 The case where the potential for coal-based CCS is low is due to the fact that coal is assumed to be replaced by gas and energy consumption is lower. In that case the prospects for gas-based CCS are bigger and might range from 40 to 300 GW in 2030 depending on the scenario.

(226) A proper comparison between the options on this count would require a quantitative assessment of the effect of the differential learning between Options 1, 2 and 3 on the share of the global market the EU could capture, which is very difficult to do with any confidence. In the context also of the uncertainty about the scale of the market, it is hard to differentiate meaningfully between the options with regard to their impact on export potential.

7.5.3.4. Impacts on achievement of global climate objectives

(227) Any such impact would comprise a greater reduction in GHG emissions outside the EU than would otherwise be achieved for the same cost (or equivalently, a reduction in the cost of the same GHG emissions reduction that would otherwise be achieved). Such an additional benefit would not be reflected by the EU carbon market. Again the benefit would be a result of any accelerated reduction in the cost of CCS. Quantifying the impact that a particular option would have relative to the others is again very difficult. One way to quantify the impact of (say) the mandatory scenario would be to assess it at 10% of the investment costs of CCS deployment, but it is perhaps more sensible to consider the impact on the overall cost of meeting the climate change objectives. This is likely to be a difference of a few per cent of the total cost of meeting the climate objectives, given that the difference in technology cost is 10% and CCS effort would comprise only a proportion of the overall cost. Again, it is hard to differentiate meaningfully between the options with regard to their impact on this externality.

7.5.3.5. Impacts on reduction in traditional air pollutants

(228) Applying CCS may have direct and indirect impacts on air pollution (sulphur dioxide, nitrogen oxide and particulate matter). Directly, adding CCS to existing coal fired plants would lead to similar or lower concentration of most impurities in the flue gas of CCS-equipped plants, than in the case of plants without CO2 capture. Overall, direct impacts would result in reductions in sulphur dioxide emissions and in minor increases in nitrogen oxide emissions in CCS plants by 2020, compared to coal fired plants without CCS.50 Indirect impacts arise as a consequence of the combustion of fossil fuels in the extraction, processing and transport to the point of use, as well as emissions of dust from mining operations. When considering both direct and indirect impacts, thepolicy options (1, 2d and 3) have comparable air pollution effects by 2020, with Option 2d being slightly more costly than Option 1 and 3.

48 Result POLES model IPTS for degrees Celsius communication plus personal communication K. Riahi (IIASA) on IPPC scenarios B1+B2 with 480 ppmv.

49 Personal communication F Bauer (VGB Powertech), October 2007.

50 Cofala,J., P. Rafal, W. Schoepp and M. Amann (2007) Impacts of options of CCS incentivisation. IIASA. Laxenburg. Final report to DGENV. Monetary benefits based on standard estimates for the revision of the NEC Directive.

Table 18. Air pollution control costs of policy options in 2020 for the EU27

SCENARIO	Option 1	Option 2d	Option 3
	CCS-ETS	CCS on coal & gas + retrofit	CCS-ETS+subsidy
Air pollution control costs (bn€/year)	74.3	74.5	74.4
Monetary damage health impacts (bn€/year). Low estimate	7.2	7.2	7.2
Monetary damage health impacts (bn€/year). High estimate	16.6	16.7	16.6
Change Air pollution control costs compared to Option 1 (bn€/year)	-	0.2	0.1

(229) Indirectly, a policy that reduces greenhouse gases emissions by 20% compared to 1990 (while increasing the share of renewables in final energy consumption to 20%) would reduce fuel use and prompt a shift towards less carbon-intensive fuels, resulting in a corresponding reduction in air pollution. Table 19 compares the impacts of the mandatory plus retrofitting policy option and the EU-ETS option on the emissions of SO2, NOx and PM10 in 2030. As shown in section 7.4.1, making CCS mandatory for coal only would increase the use of gas (and to a minor extent renewables) and would reduce SO2 and increase NOx. Making CCS mandatory for both coal and gas and imposing a retrofitting obligation for existing plants (2d) would eliminate the possibility of operators to fall back either on existing coal plants, or on new gas plants without CCS. For this reason this option would lead to more CO2 being captured in the power sector than if CCS were left alone to the market (EU-ETS).

(230) A comparison of the two extreme policy options (1 and 2d) indicates that by 2030 Option 2d would achieve slightly better air pollution effects than Option 1. The mandatory plus retrofitting policy option (2d) would perform better in terms of reduced SOx, NOx and PM2.5 emissions. This is a consequence of faster learning processes for CO2 capture technologies under the stringent CCS policy scenario (2d), which in turn would be conducive to a higher overall reduction of the energy penalty and emissions associated with CCS processes than under Option 1. Impacts for Option 3 are in between option 1 and 2d.

Table 19. Air pollution impacts of policy options in 2030 for the EU27

SCENARIO	Option 1	Option 2d	O
	CCS-ETS	CCS2R	C E
CO2 emissions -energy (MtCO2)	3471	3333	34
SO2 (Kton)	2990	2890	2
NOx (Kton)	5381	5312	5
PM2.5 (Kton)	1102	1089	1
Health impacts (mln life years lost)	133.0	131.2	1
Forest Ecosystems with nitrogen above critical loads (1000 km2)	844.1	841.5	84
Forest Ecosystems with acidification above critical loads (1000 km2)	82.4	76.6	8
Air pollution control costs (bn€/year)	79.6	77.9	7
Change Air pollution control costs compared to option 1 (EU-ETS) (bn€/year)	-	-1.6	-
Monetary damage health impacts (bn€/year). Low estimate	6.9	6.8	6
Change air pollution health damage compared to Option1 (bn€/yr)	-	-0.1	-
Monetary damage health impacts (bn€/year). High estimate	16.0	15.7	1
Change air pollution health damage compared to Option1 (bn€/yr)	-	-0.2	-
Change in pollution control and (monetized part of) health damage costs compared to option 1 (bn€/year)	-	-1.7 to -1.8	- -

Note: Monetary damage

estimates for health do not include morbidity impacts but only mortality. Low
estimate

based on lower value of life year lost and value of statistical life.

(231) In brief, reducing CO2 emissions by enabling CCS (either through Option 1, 2d or Option 3) to meet the 20% GHG reduction target would have a positive effect in terms of significantly reduced air pollution control costs. Although it would lead to an additional reduction in non-CO2 harmful substances, making CCS mandatory for existing plants through Option 2d would only decrease the air pollution control costs by circa 1.6 bn€ (2%) by 2030, as compared to incentivising CCS deployment only through the EU-ETS. The net health effects of Option 2d over Option 1 for 2030 are positive (between -0.1 and -0.2 bn€). Option 3 would also reduce health and air pollution control costs but to a smaller degree.

7.5.4. Impact on employment

(232) The expected impacts on employment and GDP of Option 1 are covered in the impact assessment on effort sharing for meeting the 20% GHG and 20% renewables targets. In general these impacts are expected to be small (+/- 0.1% of total employment) and either negative or positive depending on whether revenues of auctioning allowances exist and are appropriately recycled. They are expected to be negative for coal mining because of the shift towards renewables and reduced energy demand. 51

(233) Here we compare the additional impact on employment compared to Option 1 of the mandatory options (Option 2) and the subsidy option (Option 3)52. The following effects on employment were considered:

- direct effects on coal mining
- effects from reducing the energy bill
- effects from increasing total energy costs
- effects from direct energy investment and
- other effects through competitiveness.

(234) Option 1 (allowing CCS in the EU-ETS) is the most cost-effective scenario. As a result the mandatory cases (2) and the subsidy case (3) increase overall energy costs. The additional costs for energy partially replace spending on other (more labour intensive) commodities and services, thus reducing employment. In addition energy investments are related employment are lower. These negative effects might be partially offset by decreased spending on energy imports (Option 2b, Option 3) and thus increased spending and employment within the EU. The mandatory cases and the subsidy all show a reduction in total employment in 2030 compared to the EU-ETS cases, while employment in coal and lignite mining goes up or down depending on the particular option. Making CCS mandatory for new coal and new-and-existing coal will lead to an increase in gas-based power production and a smaller number of jobs in coal mining. Making CCS mandatory for coal and gas increases employment in coal mining since this increases cost of gas-based

51 See study Cambridge Econometrics with the E3ME for the impact assessment for the EU-ETS review.

52 The analysis is based on Capros et al (2007) Energy systems analysis of CCS technology: PRIMES model scenarios. 10 October 2007. ICCS/NTUA, Athens.

electricity production relative to coal, but has a net negative impact due to the additional energy costs. Adding a subsidy for CCS has a small positive impact on coal mining employment and small negative total impacts.

(235) Note that a policy of not enabling CCS in the EU-ETS is the worst case. In that case 50 000 jobs would be lost in coal mining and over 300 000 jobs would be lost in total, because the overall energy costs of meeting the 20% GHG and renewable targets would increase by 40%.

(236) No information is available on the distribution of employment effects, but they are likely to be concentrated in those countries in which the effort is concentrated (Germany and Poland predominantly).

Table 20 Employment impact in 2030 (1000 jobs) compared to Option 1 (Enable CCS in ETS)

	Option 0: No CCS in ETS	Option 2: ETS+mandatory				Option 3: ETS + subsidy
		New coal	New coal+gas	New+old coal	New+old coal+gas	
	0	2a	2b	2c	2d	3
Coal and lignite mining	-52	-7	+10	-8	+15	+1
Other sectors	-270	-52	-70	-62	-102	-12
Total	-322	-59	-60	-70	-87	-13

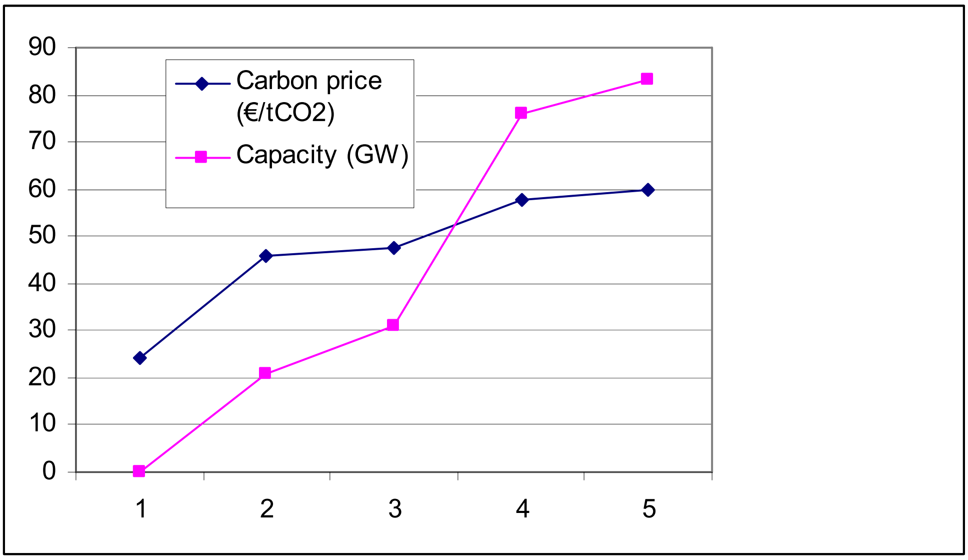
7.5.5. Major assumptions, uncertainty and sensitivities

(237) A number of assumptions are critical for the analysis: the assumed greenhouse and climate policy in 2020 and beyond (including the scope of JI/CDM), the carbon price, fuel prices, and the costs of CCS including the costs of storage vis a vis other technologies (e.g. renewables and nuclear). In particular it is assumed that a policy is put in place to allow the EU to efficiently meet a 20% reduction in GHG emissions and a 20% renewable target. This baseline assumes that the (opportunity) costs of CO2 allowances are fully reflected in the electricity price and that there is a uniform carbon price (around €40/t CO2 in 2020) across the EU-27 and all sectors. It also assumes financial support (some €40/MWh in 2020) for renewable energy produced. The baseline (option 1) across the EU assumes no further change in energy taxation above current national policies. The policy scenarios also assume a gradual further decrease in GHG emissions beyond 2020 (25% below 1990 in 2030) and a further increases in the share of renewables (25% in 2030) implying a gradual increase in carbon prices and financial support for renewables over time.

(238) A number of sensitivities are crucial. Without additional climate and renewables policy, carbon prices (assumed to be 22 €/tCO2 in 2020 in the EU-ETS) would not be high enough to lead to the employment of CCS that is predicted under option 1 (See Figure below, case 1). With a 20% GHG policy but without the renewable target, deployment of CCS (under option 1) would be higher in 2020 under EU-ETS market. This is so since carbon prices would need to be higher (in the absence of the renewable support) to meet the GHG target (a

price of around €50/tCO2). With the renewables support, the policy on CCS has minimal effect on renewables deployment, which is maintained at the 20% level. The dependence of the CCS capacity installed as function of the carbon price in 2030 is depicted in Figure 7. With JI/CDM allowed the carbon price will be lower (perhaps €30 to €35/tCO2) and CCS will enter the market later. The impact of higher oil prices than assumed is not straightforward. If higher oil prices brought higher gas prices, coal consumption in the power sector might increase. Given the limited allocation for the EU-ETS sector this will tend to increase the carbon price and lead to more CCS.

Figure 7. Capacity of CCS installed in 2030 (GW) in relation to the Carbon price in 2030



(239) The impacts are also sensitive to assumptions concerning capture costs and availability of storage, the latter of which is one of the key determinants of CCS deployment. The costs for storage determine where and to what extent CCS will take place in Europe. Sensitivity analysis (for case 2b) indicates that an increase in the CCS storage costs for the new Member States substantially decreases deployment (capture down by over half in Poland, for instance) and this sensitivity to the cost of CCS in general is likely to be replicated across the EU. Sensitivity analysis analyzing the impact of lifetime expansion of existing nuclear plants reduces the contribution of CCS somewhat but not significantly in the long run (down to 61GW from 68GW for case 2b).

7.6. Non-air quality environmental impacts of CCS deployment

7.6.1. Introduction and methodology

(240) The environmental impacts of Options 1 and 2 are here assessed against the baseline for the range of environmental hazards set out in Annex II. For Option 2, the most extreme scenario in terms of CCS deployment was chosen to provide a limiting case (Option 2d, comprising mandatory CCS on coal and gas from 2020, and mandatory retrofit for all plant before 2020) The methodology and scope of the assessment is presented in Figure 12 in Annex V. The following environmental impacts of CCS deployment have been assessed:

- accidental risk to people (referred to as societal risk)
- greenhouse gas (GHG) emissions;
- other emissions to atmosphere (NOX, SO2, etc);
- wastes and effluents;
- geology and hydrogeology;
- biodiversity; and

- cultural (landuse, landscape, heritage).

7.6.2. Construction of base data for each scenario

(241) The base data for power generation and capture plant deployment are derived from the PRIMES scenarios. Data on the length of pipeline and on CO2 storage were developed in a separate study using a tool developed under the FP6 CASTOR project. This was done using the PRIMES figures for CO2 captured, and matching these to maps of available storage sites. This gave data on the length of pipeline network, storage gaps, the proportion of storage sites of different kinds that are used, and the proportion of storage that is land-based versus sea-based. Matching the parameters of the CASTOR tool to the PRIMES output required a number of assumptions, and these are outlined at Annex V. The headline summary data for deployment for each scenario based on the above studies is summarised at Annex VI. These data provide the basis for estimating the attendant environmental impacts and societal risks linked to CCS deployment under policy Options 1 and 2 described in Section 7.2.

7.6.3. Societal risks and impacts of CCS deployment

(242) Societal risk is a measure of the impact of accidental events on the population in the vicinity of hazardous installations. Only those impacts that would cause fatalities amongst offsite populations have been considered, as it is assumed onsite risks would managed under present prevailing community occupational health & safety laws. Two measures of societal risk have been calculated for this assessment.

- Risk.Area is the product of the area that could be affected by potentially fatal concentrations of CO2, and the likelihood that such concentrations will be present. The units adopted for this measure is m2.cpm, where cpm is 'chances per million' that a fatality will occur. One chance per million means that a fatality will occur, on average, once in one million years.

- The average annual number of fatalities is obtained by multiplying Risk.Area by an assumed population density.

(243) The mass of CO2 released under each scenario has also been calculated and fed into the EIA outlined in the next section. This has been weighted by the frequency of the event to give an average annual mass released. The following assumptions have been made in developing this assessment.

- It has been assumed that there will be no significant additional societal risk from power station technology (e.g. syngas, oxyfuel etc). All elements of these technologies are well understood and many have been in use for many years. These will be controlled using existing regulatory controls (e.g. Seveso II) if hazardous materials such as hydrogen or carbon monoxide are present in sufficient quantities. A recent review of Health & Safety Aspects of CCS[53] did not identify these technologies as presenting a significantly enhanced risk to the public.

53 The Health and Safety Risks and Regulatory Strategy Related to Energy Developments - An expert report by the Health and Safety Executive contributing to the UK Government's Energy Review, 2006 para 122 ff.

- A concentration of 10% CO2 in air is assumed to cause 100% fatalities amongst the exposed population and no fatalities amongst the population outside this concentration. This is irrespective of the duration of release.54

- The pressure of the CO2 pipeline is 100bar and the pipeline diameter is 30”. It has also been assumed that the hazards associated with accidental pipeline releases are not greatly affected by the flow rate through the line. The hazard ranges arising from initial depressurisation are assumed to dominate the risks.

- Dispersion analysis has been carried out using typical weather conditions and assuming level terrain. Local hollows or confined areas could lead to more onerous conditions, but it is assumed that these will be avoided where possible when the pipeline route is defined.

- Except for pipelines, it is assumed that where the hazard range from a release is less than 50m, this will be contained within the site boundary and will not affect members of the public. All releases from onshore pipelines are assumed to be able to affect the public.

- When reservoirs are still receiving CO2 for storage, it is considered that the primary leakage route will be via the wells themselves rather than via a ‘geological’ route.55 Only releases from the wells have been considered.

- Offshore releases are assumed not to impose any risks on members of the public. There will be risks to personnel working on the riser platform and injection plant, but it is assumed that these will be managed under existing health & safety legislation.

- The behaviour of accidental releases of super-critical CO2 is not well understood and requires further research work to develop suitable consequence models.56 For the current study, the consequence analysis has been undertaken using the PHAST software which makes simplifying assumptions about the behaviour of supercritical CO2.

(244) Various other assumptions regarding the technical configuration of the CCS plant have been made, involving capture plant configuration, the presence of booster stations on pipelines, the number of junctions and connectors present on pipelines, the nature of injection facilities, the number of wells present at a geological storage site, and the range of different accidental release events that could occur at different elements of the CO2 containment scheme (i.e. full bore rupture, large release, medium release, small release). The primary data source for estimating the risk presented by different release scenarios is Vendrig et al (2003, op cit.).

(245) For non-engineered system components (i.e. the geological storage site excluding wells), no risk assessment has been possible because of the lack of empirical evidence on which to base the probability of release of CO2 from this part of the system. This view is supported by the IPCC57, which concluded that: the small number of monitored storage sites means that there is insufficient empirical evidence to produce emission factors that could be applied

54 A CO2 concentration of 10% is expected to cause a fatality in a few minutes.

55 Vendrig, M, et al "Leak Frequencies from CO2 Sequestration" Report R246 for DTI, Annex II.

56 Heath & Safety Executive op cit para 149.

57 IPCC 2006 Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter 5 (CCS).

to leakage from geological storage reservoirs implying that it is not possible to estimate leakage rates without a site specific approach.

(246) The approach taken in the enabling legal framework to regulating CO2 storage is to require an initial assessment of the potential security of storage which is then robustly assessed by a Scientific Committee at EU level. A site cannot be used unless this initial assessment concludes that there is no significant risk of leakage. Although it cannot be excluded that adverse events will occur despite all precautions taken under the legal framework, it is not possible to estimate the frequency of such events or their potential scale.

7.6.4. Societal risk assessment for Options 1 and 2

(247) Table 21 summarises the societal risks associated with the Option 1 and Option 2. The results are also illustrated in Figure 9.1 and Figure 9.2 of Annex VII. The average annual amount of CO2 released by such accidents is estimated to be just over 0.8 MtCO2 in 2030 for the Option 2. This represents less than a fifth of one percent of the annual capture rate of 517 MtCO2. The most readily understandable measure of risk is the average annual number of fatalities amongst members of the public that would be caused by accidental releases. For Option 2 (which is the most ambitious), by 2030 it is estimated that an average of around four fatalities per year would be caused by accidental releases of CO2. It must be emphasised that the number of fatalities is based on an average population density for each Member State of the EU. In reality, pipelines will be routed to avoid centres of population and individual dwellings where possible. For any given incident, therefore, the actual number of fatalities is likely to be considerably less than estimated in the following table.

Table 21. Risks Associated with Accidental Releases of CO2

	2015		2020		2025		2030	
	Op 1	OP 2	Op1	Op2	Op1	Op2	Op1	Op2
Fatalities (person/yr)	-	-	-	0.60	0.08	1.80	0.66	4.44
Accidental releases of CO2 (Mt CO2 /yr)	-	-	-	0.13	0.02	0.29	0.14	0.83
% of total captured	-	-	-	0.17	0.1	0.17	0.1	0.16

7.6.4.1. Sensitivity of results

(248) The results presented have assumed that a concentration of 10% CO2 will cause 100% fatalities among the exposed population. More vulnerable population groups, such as the elderly, infirm or infants, would be more susceptible to the effects of CO2. Table 22 shows how the number of fatalities would increase if a fatal concentration of 7% were assumed. For a given release, the area where the concentration is 7% or greater will be significantly larger (up to three times larger) than for a concentration of 10%.

Table 22. Sensitivity of results to a reduced fatal concentration of CO2

Fatalities (person/yr)		2015		2020		2025		2030	
		Op1	Op2	Op1	Op2	Op1	Op2	Op1	Op2
Fatal CO_2 concentration assumed to be	10%	-	-	0.6	0.60	0.08	1.80	0.66	4.44
	7%	-	-	-	1.5	0.21	4.6	1.69	11.3

7.6.4.2. Comparison with risks from natural gas facilities

Pipelines

(249) The risks associated with releases of CO_2 from pipelines are likely to be broadly similar to natural gas at a similar pressure, although assuming that the likelihood of pipeline failure is similar for both materials, the hazards from a release of natural gas will be generally less onerous than for CO_2. There are a number of reasons for this (Table 23).

Table 23. Comparison of the risks posed by natural gas and CO_2

CH4 (methane/natural gas)	CO2
Methane is buoyant and will naturally tend to disperse upwards in the event of an accidental release.	CO2 is heavier than air and will tend to slump, spreading horizontally at ground level. Releases will be greatly affected by the terrain and will accumulate in hollows, whilst not affecting higher elevations.
Not all accidental releases will be ignited; some will simply disperse without causing a fire.	All releases will have the potential for asphyxiation of exposed individuals.
If a large release is ignited, the subsequent flame will normally be vertically orientated, reducing the 'footprint' compared with a horizontal release.	Even if a release from a pipeline is vertically orientated, the CO2 plume will sink back to ground level.

(250) It should be noted, however, that risk assessment studies of natural gas pipelines tend to focus on the risk of ignition and resultant exposures to lethal doses of thermal radiation from jet fires. Natural gas leaks will also pose the risk of displacing oxygen in confined spaces, leading to asphyxiation, as well as additional risk linked to flash fires[58]. Usually these factors are not considered in assessing risk from natural gas pipelines. Consequently, direct comparison of the risks of natural gas with those of CO2 is difficult. Regulation of natural gas pipelines to reduce risks to adjacent populations is well established in the member states of the EU. It is anticipated that appropriate regulation of CO2 pipelines will also be required.

(251) A review of a proposed LNG project in Ireland[59] presented a risk profile for a high pressure (120barg) gas pipeline. The maximum hazard range (to fatal levels of thermal radiation) for large releases from this pipeline was of the order of 160m. For a CO2 pipeline, this distance is of the order of 250m, assuming flat terrain.[60] On this basis, applying the same probability for pipeline failure to natural gas pipelines as used in the risk assessment for CO2 pipelines would lead to a lower fatality rate, as the hazard area would be proportionally lower. However, as outlined above, this only considers the risk of jet fires, rather than additional risk of asphyxiation from natural gas.

(252) On the other hand, the overall natural gas pipeline network is much larger than that proposed under any of the deployment scenarios considered for either incentive option 1 or 2. A report on risks from European pipelines[61] gave a total pipeline length for participating organisations of over 110,000km in 2001, compared with a maximum CO2 pipeline deployment of just over 30,000 km in 2030 for the option with deepest deployment of CCS in Europe. As such, the overall risks can be considered to be proportionally lower.

Storage

58 A flash-fire is caused by a delayed ignition of a flammable gas cloud. Immediate ignition of a release would lead to a jet-fire.

59 "Independent Safety Review Of The Onshore Section Of The Proposed Corrib Gas Pipeline"Advantica Report R8391 17 Jan 2006.

60 Vendrig Op Cit Table IV.14

61 "Gas Pipeline Incidents" 5th Report of European Gas Pipeline Incident Data Group EGIG.02.R.0058 Dec 2002

(253) The use of natural or man-made cavities for the storage of natural gas is well established and increasingly used to provide a buffering capacity for national gas supply systems. Historically, a number of incidents have occurred involving releases of stored gas from underground storage. The vast majority of these incidents have involved releases from the wellheads or above ground facilities. A number of incidents were caused by leakage though pathways caused by unrecorded or erroneous drilling activities. Generally, the risks associated with underground gas storage are well understood and the lessons learned from previous incidents have been incorporated into best practice. Volume 2, Chapter 4 of the 2006 IPPC Guidelines for National Greenhouse Gas Inventories gives values of CH4 emission factors from natural gas storage of 2.5x10-4 Gg per year per 106 m3 of marketable gas.

7.6.5. Environmental impacts of CCS

(254) Environmental impacts have been assessed on the basis of a high-level, comparative approach in order to assist in decision-making on measures for promoting deployment of CCS (summary of impacts provided in Annex IX). Impacts have been quantified where this is practicable and reasonable but the extent of this is limited as many will be highly project-related and site-specific. Analysis has been undertaken using the base data described in Annex VII and sub-models to calculate attendant emissions to various media, as described in Section 7.4.1. The analysis presented here is confined to assessing the impacts linked only to thermal power generation, and indirect and second order effects – as generated in PRIMES – have been excluded from the analysis. The rationale for this is that the CCS options consider only application to thermal power plants, and the sub-models developed for this analysis account for second order effects directly linked to applying CCS both inside and outside of the EU linked only to thermal power plants (e.g. from mining in other parts of the world). See Annex V.

(255) Different sources have been used in the sub-models which quantify environmental impacts for the Baseline, Option 1 and Option 2 as described in section 7.3 above. Data sources include the IPCC Special Report on CCS, UK National Emissions Inventory and other literature sources identified in Annex VI.

(256) It is difficult to place significant confidence in many of the quantitative predictions that are made given the high level of uncertainty in defining future deployment scenarios, and the inherent uncertainty attached to the emission factors employed in making the assessment. Wherever it is appropriate, qualitative descriptions, ranges of credible values, quantification in terms of percentage or based on average emission factors are employed. Specific assumptions used to facilitate the assessment are identified, as appropriate, in later sections.

7.6.5.1. Waste and effluents generation of CCS

(257) The extraction, processing and transport of fossil fuels all generate a variety of solid and liquid wastes. As for other environmental impacts, the net reductions of fossil fuel consumptions forecast by PRIMES for delivering policy Options 1 and 2 will lead to an overall decline in the amounts of these wastes produced at the point of fuel production and processing. This is shown in Table 24 below.

(258) Wastes and effluents from onshore/offshore gas extraction activities, such as drill cuttings and produced water from drilling and deck drainage operations are usually disposed of onshore or subjected to treatment to reduce contaminants to below regulatory levels before disposal into the sea (e.g. under the OPSPAR Convention rules). As there are regulations

addressing the issue of waste and effluent handling, and the magnitude of the waste/ effluent generation decreases in the options including CCS deployment compared against the baseline scenario, environmental impacts are expected to be positive on the upstream (indirect) impacts from CCS.

(259) For coal and LNG shipping, generation and handling of waste and effluents from ocean vessels are governed by the MARPOL Convention[62]. Therefore, wastes and effluents such as ballast water, sewage and garbage are expected to be managed appropriately so as to minimise environmental impact. On land, wastes and effluents generated by road and rail transport are also expected to be handled according to local regulations. The reduction in transport frequencies due to decreased coal demand is therefore expected to present a positive environmental impact. For gas transport via pipeline, reduction in waste and effluent generation due to decreased natural gas usage is anticipated to have negligible impacts for the environment as pipelines will still be in place.

(260) Additional waste and effluents are also generated during operation of CO_2 capture systems, relative to conventional thermal power plants without CO_2 capture. These include slag and ash from increased coal, residues from FGD systems[63], recovered sulphur[64], spent sorbents etc. Reduced fossil fuel consumption relative to the baseline under both Option 1 and Option 2 will result in a decrease in the generation of waste associated with power plant operation. During operation, amines used in the pre- and post-combustion CO_2 capture technologies become contaminated with degradation products, heat stable salts, heavy hydrocarbons, particulates and eventually need replacement and treatment. Using the deployment figures under Option 2, total spent absorbents from these operations would total around 555kt/year by 2030, which would be hazardous waste which need to be treated[65]. This would represent approximately 0.9% of all hazardous waste generated in EU-25 in 2002 (58.4 Mt).[66] The typical and rather expensive treatment option for spent solvents is incineration, however amine degradation is an area of ongoing research and new novel recovery techniques such as electrodialysis, steam stripping and vacuum distillation are being developed.[67] As a result of increasing solvent disposal costs to plant operators it is reasonable to expect that improved recovery efficiencies will be forthcoming which serve to improve recovery rates, reduce overall cost and reduce environmental impacts. Recovery of some waste, e.g. ash, for other uses may be feasible and will further reduce the environmental impact.

(261) Effluents from transporting and storing CO_2 will include spoil from pipeline trenches, and drill cuttings from prospecting and constructing CO_2 storage facilities. Typically spoil material is inert and possibly suitable for re-use, giving rise to minimal environmental impacts from waste. During the prospecting and development of the CO_2 storage sites, wastes and effluents will be produced as a by-product of well drilling, e.g. drilling muds and cuttings. Quantities will depend on many factors, including the geology of the drilled area, drilling depth and method and their impact will depend on the particular disposal location and method. Disposal of these wastes will be subject to the same controls for gas extraction activities described previously. During operations, production of wastes and effluents is

62 The International Convention for the Prevention of Pollution from Ships (MARPOL) was adopted in 1973 at the International Marine Organisation (IMO) and covered pollution by oil, chemicals, harmful substances in packaged form, sewage and garbage.

63 FGD residues are produced when SO_2 is removed from gases produced during the combustion of coal. FGD residues are composed mainly of gypsum.

64 In coal gasifiers, sulphur impurities from the coal are converted to hydrogen sulphide and carbonyl sulphide from which sulphur is then recovered.

65 Amine waste from CO_2 capture would likely be classified as Hazardous Waste in accordance with Annex I.B (29) “Scrubber Waste” of the EU Hazardous Waste Directive (91/689/EC).

66 Waste generated and treated in Europe, Eurostat, 2005, http://epp.eurostat.cec.eu.int/cache/ITY_OFFPUB/KS-69-05-755/EN/KS-69-05-755-EN.PDF.

67 Amine Degradation: Problems, Review of Research Achievements, Recovery Techniques By M. Abedinzadegan Abdi, A. Meisen.

expected to be minimal, mostly associated with maintenance of pipeline equipment such as booster pumps.

Table 24. Summary of waste and effluent generation linked to CCS deployment in 2030

Policy option	Baseline	Option 1: CCS-ETS	Option 2d: CCS mandatory
Upstream (indirect) impacts			
Coal mining effluents (kt)	462	280	311
Coal mining effluents (%)	100	61	67
Coal mining solid waste (kt)	3,401	2,601	2,290
Coal mining solid waste (%)	100	76	67
Coal mining dust (kt)	23	14	15
Coal mining dust (%)	100	61	65
Direct impacts			
Ash/slag (Mt)	27	17	23
Ash/slag (%)	100	63	85
Flue Gas Desulphurisation (FGD) residue (Mt)	48	22	16
Flue Gas Desulphurisation (FGD) residue (%)	100	46	33
Sulphur (Mt)	NA	1	3
Spent CO2 sorbents (Mt)	NA	0.1	0.6
Downstream impacts			
Pipeline construction spoil	NA	NQ	NQ
Drill cuttings	NA	NQ	NQ

NA = not applicable; NQ = not quantified

7.6.5.2. Hydrogeology and Geology

(262) When compared against the baseline, Options 1 and 2 would result in a net decrease in the consumption of fossil fuels. Therefore, the level of activity and the rate of new mining/gas extraction developments might be expected to decrease, giving rise to positive impacts on natural geology and hydrogeology.

(263) Fuel transport networks are already in place and well established, and a decrease in fossil fuel consumption due to mandatory CCS deployment would not be expected to cause any geological and hydrogeological impacts in this respect.

(264) As CO2 capture occurs above ground with no need for any geological or hydrogeological contribution to its construction/ operation, no impacts on geology or hydrogeology are expected to arise.

(265) Construction of onshore CO2 pipelines will have impacts on the topsoil and subsoil (assuming that the pipelines are trenched below surface) where the pipelines will be built and should have little or no impact on groundwater. Construction of offshore CO2 pipelines will have limited impact on vulnerable geology or hydrogeology as the pipelines are laid on the seabed. During pipeline operation, large releases of CO2 into the soil from accidental events on buried onshore pipelines could result in formation of carbonic acid through solution in soil water. There is a small risk that this could lead to dissolution of limestone formations, if present in the area. This would require deep penetration and long contact times.

(266) In the event of loss of containment of underground reservoirs, geological and hydrogeological impacts could result from CO2 storage. However, geological and hydrogeological conditions vary widely and the small number of monitored storage sites means that there is insufficient empirical evidence to produce emission factors that could be applied to calculate CO2 leakage from geological storage reservoirs. The 2006 IPCC Guidelines for National Greenhouse Gas Inventories provides no Tier 1 or Tier 2 methodology. Tier 3 monitoring technologies are outlined, meaning that quantification of geological and hydrogeological risks are evaluated on a site-specific basis. A brief review of leakage incidents from natural gas geological storage facilities suggest the incidence and rate of leakage can be very low for analogue activities. For gas storage activities, the IPCC have developed emission factors for estimating leakage rates of methane for these types of installations. Volume 2, Chapter 4 of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories gives values of CH4 emission factors from natural gas storage of 2.5x10-4 Gg per year per 106 m3 of marketable gas, suggesting very low leakage rates from underground stores.

(267) In saline formations, injected CO2 in supercritical phase will be lighter than brine and vertical migration of leaking CO2 could occur, which might be accompanied by dissolution in shallower aquifer waters, forming carbonic acid. This could chemically react with and reduce the integrity of the caprock material, leading to changes in geochemistry and hydrogeology.68 Storage of CO2 could also possibly be affected by regional groundwater flow. In comparison with depleted oil/ gas wells and EOR facilities, the characteristics of which are well understood by their operators, there is a lack of seismic data to accurately map most saline aquifers. Hydraulic continuity may continue tens of kilometres away, and at such distances, the probability is high that fractures or fault lines could exist, with possible connection to underground sources of drinking water and surface waters.69 The geological and hydrogeological setting of storage sites will therefore need to be carefully evaluated on a case-by-case basis to ensure that cumulative and instantaneous releases of CO2 to the environment would not compromise the effectiveness of the storage. The proposed

68 Chemical reaction of stored CO2 is a long term issue. Although it could possibly lead to caprock weakening, it would lead to permanent capture of the reacted CO2 within the geological matrix of the aquifer.

69 Vendrig et al. (2003) Risk Analysis of the Geological Sequestration of Carbon Dioxide, Report No. R246 for UK Department of Trade and Industry (DTI).

regulatory framework has been designed to account of these potential factors as far as reasonably practicable.

(268) Upon the start of injection, appropriate survey methods will need to be used at regular intervals to monitor the movement of the injected CO2 plume to ensure that plume behaviour is as expected and, if not, to plan remediation options. Consideration of all these aspects of CO2 storage will be mandatory for potential storage site operators under the proposed regulatory framework for CCS under development.

7.6.5.3. Biodiversity and cultural impacts (land use, landscape, heritage)

(269) When compared against the baseline, Options 1 and 2 would result in a net decrease in the consumption of fossil fuels. Therefore, the level of activity and the rate of new mining/gas extraction developments might be expected to decrease, giving rise to positive biodiversity and cultural heritage impacts.

(270) The construction of CO2 capture facilities may impact on biodiversity and cultural resources where it involves development of greenfield sites. The risk can be assessed for comparative purposes in terms of the landtake needed to install the capture equipment. It is understood that capture equipment landtake is typically small and impacts are therefore expected to be minimal. As the overall fleet of fossil fuel-fired power plants will be reduced under the CCS deployment scenarios, then there will be an overall decrease in these impacts. Impacts arising from greater renewables deployment forecast under Options 1 and 2 are beyond the scope of this assessment.

(271) Development of several thousand of kilometres of new CO2 pipelines is likely to result in some impacts on biodiversity and cultural heritage, both permanently where routes cross sensitive areas or sever routes, and temporarily when construction activities lead to dust, noise and other disturbance. A pipeline right-of-way (ROW) typically occupies 15 to 30 metres in width and is required to protect the public and the security of the pipeline. Occupation of the ROW can result in restrictions on some activities including future development, mining, and construction.

(272) During operation of CO2 pipelines, impacts on cultural heritage are unlikely, but accidental releases could lead to adverse effects on neighbouring species and ecosystems. If a rupture occurs, wildlife trapped within the released plume could possibly be subject to asphyxiation. Chronic fugitive leaks from pipelines could alter the chemistry of surrounding groundwater, seawater and/or soil through acidification, for example having adverse effects on benthic marine ecosystems or soil micro-organisms. Acidification of soils could trigger increased leaching of certain minerals with long term affects on soil quality. These impacts will be regulated under existing regimes but new impacts on biodiversity are likely to occur given the extent of the required network on and off shore.

(273) Depending on the mass of CO2 released, biodiversity impacts from ocean acidification may arise due to CO2 leakage occurring as a catastrophic release or slow bubbling releases. Much of the current understanding of ocean acidification focuses on atmospheric CO2 being absorbed by seawater, although impacts of ocean acidification based on CO2 leakage could be similar. When CO2 is absorbed by the ocean, it dissolves in seawater to form carbonic acid, which is a weak acid. As a result, pH of the seawater is lowered.

(274) A decrease in pH will have negative consequences, especially for calcifying organisms, which use calcium carbonate to construct skeletons. As the ocean acidifies, structures made

of calcium carbonate may dissolve. Research has already found that corals, coccolithophore algae, shellfish and pteropods experience reduce calcification of enhanced dissolution when exposed to elevated CO2. This may affect other marine organisms such as corals, benthic fauna, phytoplankton, zooplankton and fish are also expected to experience impacts. The magnitude of these impacts, however, is largely unknown. Most studies carried out to date have relied on short-term CO2 perturbations, leaving the potential for adaptive responsive unaddressed.70 71 72 Studies are currently underway to investigate the effects of CO2 releases from sub-sea storage site.73 Individual projects would need to evaluate the risk and consequences of leakage upon the marine environment to satisfy the competent authorities before a permit to store CO2 could be issued.

(275) Whilst CO2 leakage from geological reservoirs could lead to local acidification of marine waters, the increase in marine CO2 content following such CO2 leakage events would be negligible in comparison to the inevitable increase in CO2 content arising as a consequence of elevated atmospheric CO2 concentrations in coming decades. The increase in atmospheric CO2 concentrations due to past anthropogenic emissions has resulted in the oceans taking up CO2 at a rate of about 7 Gt CO2/yr. Over the past 200 years the oceans have taken up 500 Gt CO2 from the atmosphere out of 1300 Gt CO2 total anthropogenic emissions. Anthropogenic CO2 resides primarily in the upper ocean and has thus far resulted in a decrease of pH of about 0.1 at the ocean surface with virtually no change in pH deep in the oceans.74

(276) Stabilization of CO2 at 450 ppmv, associated with the EU target of limiting global mean temperature increase to 2 C, would lead to a total amount of CO2 stored in the ocean on the order 4500 Gt CO2 via dissolution from the air into sea water. Under a stringent regime with a capture obligation for coal and gas capacity, including both new and existing plants, 21 Gt CO2 would have been captured by 2030 and 2.3 Gt CO2 stored offshore. Even if all of this volume injected offshore would leak, on the whole the resulting pH change will most likely be much smaller than the change triggered by the increase in atmospheric CO2.

(277) Moreover, since the primary objective of this work programme is to develop and mandate effective site selection and good regulatory control of operational practices, the risk of CO2 release from the storage sites should be minimised. Moreover, the impact of inaction may be greater, i.e. elevated atmospheric levels of CO2 and resultant ocean acidification could lead to bigger impacts upon marine organisms. Studies are currently underway to investigate the effects of CO2 releases from sub-sea storage site.75 Individual projects would need to evaluate the risk and consequences of leakage upon the marine environment to satisfy the competent authorities before a permit to store CO2 could be issued.

70 Royal Society (2005). Ocean Acidification due to Increasing Atmospheric Carbon Dioxide.http://globalecology.stanford.edu/DGE/CIWDGE/home/main%20page/People/Caldeira/Caldeira%20downloads/RoyalSociety_OceanAcidification.pdf

71 Turley, C. (2006). Impacts of Climate Change on Ocean Acidification. http://www.mccip.org.uk/arc/acidification1.htm

72 OSPAR Commission (2006). Effects on the Marine Environment of Ocean Acidification Resulting from Elevated Levels of CO2 in the Atmosphere. http://www.ospar.org/eng/doc/Ocean%20acidification.doc

73 Riley (2006). European Research Network of Excellence on the Geological Storage of CO2. http://www.rite.or.jp/English/lab/geological/geowse/21-1-3_Nick%20Riley.pdf

74 Caldeira, K., M. Akai et al (2005). Ocean storage. Chapter 5 in B. Metz et al (eds) IPCC Special Report on Carbon dioxide capture and storage, Cambridge University Press, Cambridge.

75 Riley (2006). European Research Network of Excellence on the Geological Storage of CO2. http://www.rite.or.jp/English/lab/geological/geowse/21-1-3_Nick%20Riley.pdf

(278) No cultural heritage impacts are expected from CO_2 storage, as the regulatory framework has been prepared with the objective of rejecting sites where sensitive receptors could potentially be affected by any leaking CO_2.

(279) The environmental impacts are summarised at Annex IX.

7.7. Availability of sufficient storage capacity

7.7.1. Member States scenario

(280) Availability of sufficient storage capacity to accommodate the CO_2 to be captured is one of the key determinants of CCS deployment. Transport and storage costs were included in the PRIMES modelling described above, based on the latest available cost estimates, but PRIMES provides no information on the actual source-sink matching that would occur in practice and the potential shape of the resulting transport and storage network. This task was thus the subject of a specific study under this impact assessment, conducted by TNO and using the model for source-sink matching developed in the FP6 CASTOR project. The latest available information on the available storage was used, both for hydrocarbon reservoirs and aquifers, but there are inevitable data gaps and uncertainties which are described below.

(281) The outcome for the most extreme deployment scenario (Option 2d) was particularly examined, as it provides the best test of whether European storage capacity could cope with widespread CCS deployment. The initial assumption made was that storage would take place on a national basis (that is, that each Member State would store its own emissions) as is the assumption under PRIMES (called the 'Member States scenario'). A detailed map of the resulting transport and storage network is shown at Annex XII. Results for the injection volume and the injection gap (the difference between CO_2 to be stored, and identified storage capacity) on a country by country basis are shown in Figure 8 below.

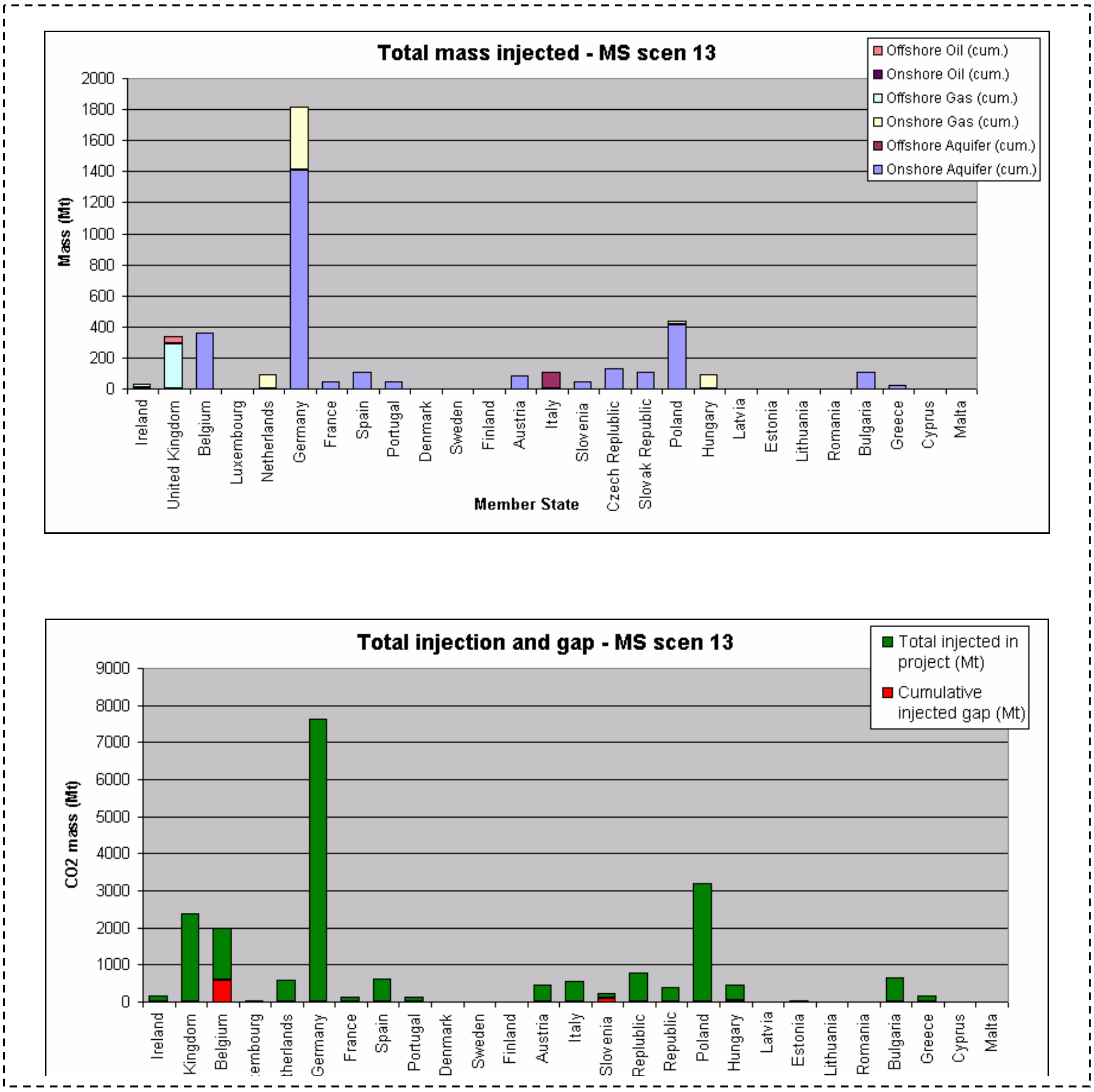


Figure 8. Injection volume by storage site type (top) and injection gap (bottom), Member State storage scenario

(282) For Belgium (and marginally for Slovenia) there is a shortfall of injection capacity. The major uncertainty for the storage deployment under the Member State scenario is related to the storage potential of aquifers, both in terms of injectivity, capacity and integrity. The numbers might be to optimistic and it is not excluded that the actual storage capacity may be one order of magnitude lower than that assumed here. The uncertainty of the storage potential of gas fields is smaller. The main uncertainty of storage capacity of gas fields is in their availability in time. In particular the very huge gas fields of 1 Gt or more will have long lifetimes, which may imply that they are not yet available as assumed in the model (i.e. at 2020).

7.7.2. European scenario

(283) In order to fill any storage gaps a different scenario was conducted, removing the requirement that each Member State store its own emissions. The scenario also aimed to increase the security of storage by substituting aquifer storage by storage in natural gas reservoirs. The storage security of gas fields is considered to be higher than that of aquifers because of their proven capability of containing gas, their high level of characterization both

of the geology and the dynamic behaviour during production, and the low initial pressure in many depleted gas reservoirs. Only where no such reservoirs were available was aquifer storage used, and the scenario incorporated a 90% reduction in estimated aquifer storage potential in accordance with the uncertainty described above. The most important remaining uncertainty is the relating to the gas and oil fields is their timely availability, but it was not possible simultaneously to adjust for the availability of hydrocarbon fields in the model.

(284) The results of the European scenario are shown in Figure 9 below and mapped at Annex XIII. All countries or groups of countries meet the required targets for storage potential. This is an encouraging result, since despite the very conservative assumption about the storage potential of aquifers, the required storage can be found even on an extreme deployment scenario. A considerable proportion of the storage potential in aquifers has been replaced by storage potential of gas fields, thus increasing the storage security. However, the above-mentioned uncertainty in the availability of the hydrocarbon fields must be borne in mind.

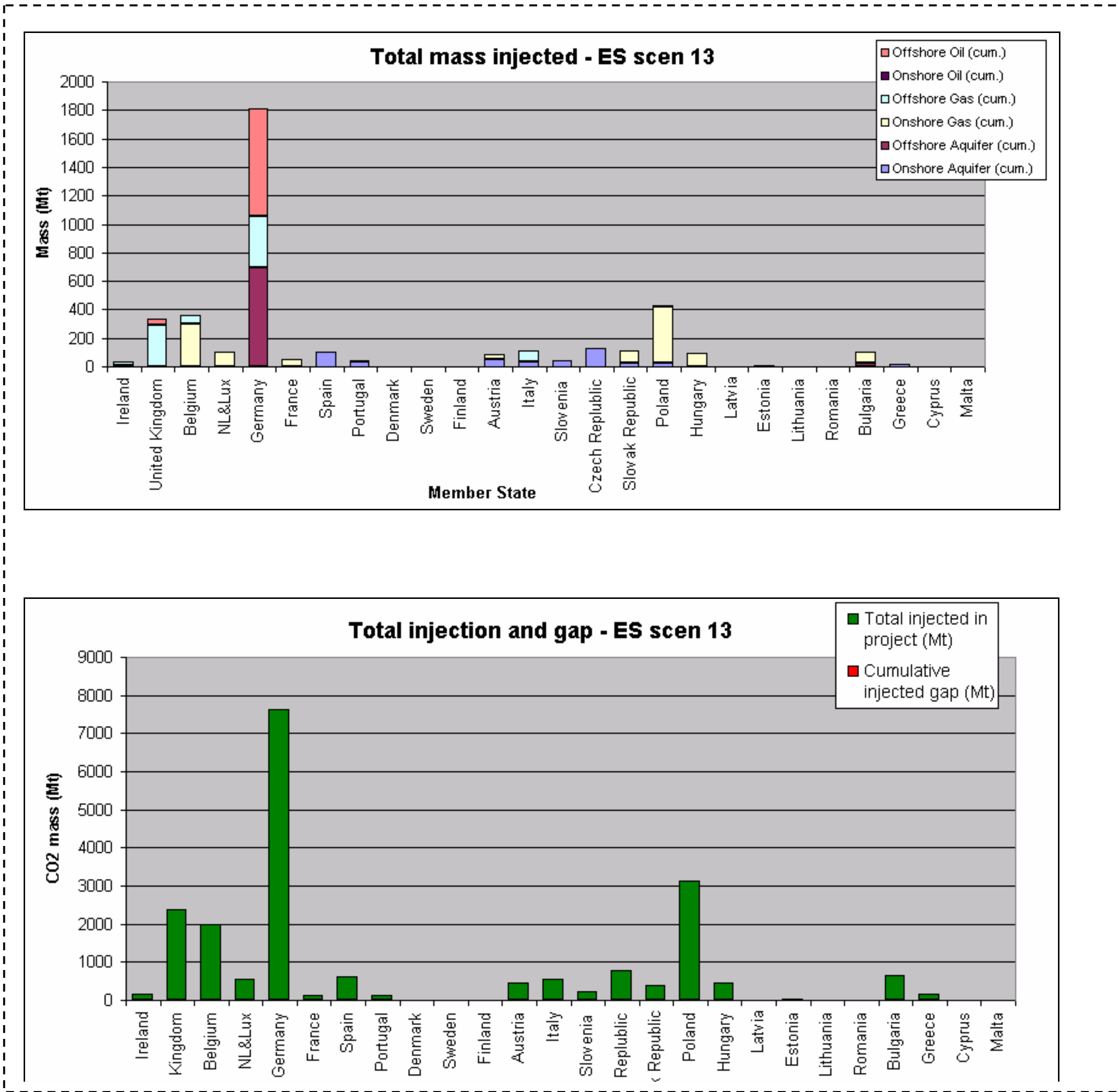


Figure 9. Injection volume by storage site type (top) and injection gap (bottom), European scenario

(285) However, the security comes at a cost. Reducing the storage shortfall and increasing the storage security in the European scenario leads to a significantly larger transport infrastructure. Both the larger transport distances to the North Sea gas fields and the more

extensive infrastructure needed for aquifer storage lead to the distinct increase in pipeline length. Also the proportion of offshore transport infrastructure increases, as a large part of the storage capacity is found in the North Sea.

(286) The offshore component and the increased length lead to an increase in the costs of the transport infrastructure, as can be seen in Figure 10. The costs of transport are often above €3/t CO2 avoided, with maximum values of around €10/t CO2 avoided (Estonia). (In the MS scenario the costs of transport are generally lower than €3/t, and never exceed €5/t). Note that these transport and storage costs are generally lower than the ranges used in the PRIMES model, which starts at €6/t and rises to €20/t when approaching the maximum storage potential. On the basis of the source-sink matching exercise, €20/t is a distinctly conservative estimate of transport and storage costs.

(287) Optimisation of the European transport infrastructure would lead to a more cost effective transport system but would probably not completely compensate for the increase in cost with respect to the MS scenario.

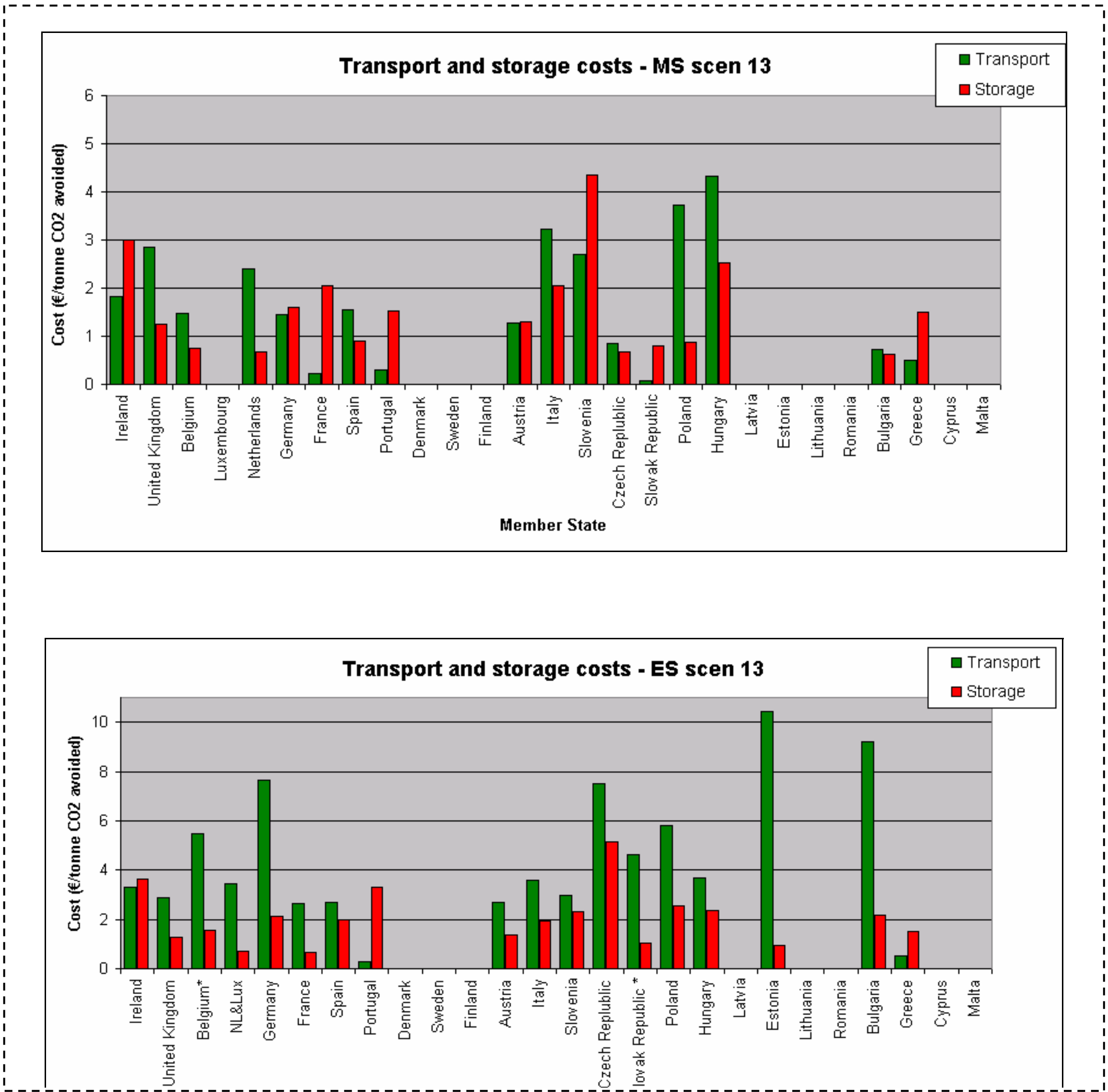


Figure 10. Transport and storage costs for Member State scenario (top) and European scenario (bottom)

(288) The storage scenarios provided are purely indicative and are based on the CCS deployment in 2030 from the PRIMES runs. While they do not provide a realistic estimate of what a practical CO2 transport and storage network would look like, they provide useful information of a more general nature. First, it seems that broadly speaking, there is enough storage capacity for each Member State to store its own emissions, provided that the optimistic estimates that have been made regarding aquifer storage potential are borne out. Second, it is clear that even without aquifer storage potential, the emissions on an extreme deployment scenario can probably be accommodated in Europe in high-security sites. This involves a substantial amount of storage in the North Sea, and the transport infrastructure required to sustain it presents a real cost, but still one which is substantially lower than the maximum marginal costs assumed in the PRIMES model.

(289) The optimal storage scenario may well be between these extremes. Aquifer capacity will be overestimated and in order to ensure integrity of storage, transport over longer distances to safer fields will be required. However, it is unlikely to be required to the full extent, and with the full cost implications, shown in the European scenario. It is clear that in any case substantially more work is required to develop realistic median options and to provide for economic optimisation of the transport network between sites.

8. COMPARING THE OPTIONS FOR PROMOTING CCS DEPLOYMENT

Table 25. Summary of modelled implications of options

Indicators			Option 0	Option 1	Option 2				Option 3
			CCS not enabled (climate objectives achieved without CCS)	Enable CCS under the EU-ETS (Baseline)	Enable CCS under the EU-ETS and impose an obligation to apply CCS from 2020 onwards				Enable CCS under the EU-ETS + 10% subsidy
					2a. CCS mandatory for new coal plants	2b. CCS mandatory for new coal&gas plants	2c. CCS mandatory for new coal + retrofitting	2d. CCS mandatory for new coal&gas + retrofitting	
ECONOMIC									
1	Additional costs (bn€/year)	2020	2.2	0	0.8	2.4	1.9	4.9	-0.2
		2030	59.5	0	6.7	9.8	6.7	12.6	2.1
2	Additional costs due to CO2 reduction exceeding the GHG target[76]	2020	na	0	-0.2	0.3	0.8	0.8	-0.2
		2030	na	0	1.2	4.3	2.7	6.7	2.1
3	Impacts on electricity	2020	na	0.0%	0.2%	0.6%	0.9%	1.9%	0.0%

76 As described in Section 7.4, the mandatory policy option (2) has lead to minor CO2 reductions from energy exceeding the assumed GHG reduction targets. For 2030 the reductions are as follows (MtCO2, in % in brackets): Option 2a: -27 (-1%); Option 2b: -94 (-3%); Option 2c: -63 (-2%); Option 2d: -157 (-5%); Option 3: -51 (-2%).

	generation costs as % of Option 1	2030	na	0.0%	-0.1%	-0.1%	-0.2%	0.0%	0.0%
4	Innovation as annualized investment cost savings (bn€, 2030)	Solid + Gas annualized	0	0.1	0.3	0.6	0.4	0.9	0.2
5	Export potential (bn€/year)	2030	-	< 0.6	< 0.6	< 0.6	< 0.6	< 0.6	< 0.6
SOCIAL									
6	Employment impacts compared to Option 1	Total	-322	-	-59	-60	-70	-87	-13
		of which: coal and lignite mining	-52	-	-7	10	-8	15	1
7	Distributional effects as % of all CO2 captured by 2030		no implication	66% in 3 countries	62% in 2 countries	67% in 3 countries	63% in 2 countries	73% in 4 countries	80% in 3 countries
8	Energy security: change in fuel consumption in the power sector over Option 1 (2030)	Solids	na	-	-6%	+8%	-6%	+12%	+1%
		Gas	na	-	+15%	-6%	+25%	+4%	+0%
ENVIRONMENTAL									
9	Risks associated with — Fatalities* (person/yr)	2020	0	0.06	0.06	0.06	0.35	0.00	na
		2030	0	1.49	2.48	3.64	3.03	0.00	na

	accidental releases of CO2	Accidental releases of CO2 (MtCO2 /yr)	2020	0	0.0	0.0	0.0	0.1	0.0	na
			2030	0	0.2	0.4	0.6	0.5	0.0	na
10	Air pollution impacts as compared to Option 1 (bn€,2030)	Air pollution control costs		na	0	na	na	na	-1.7	na
		Monetary damage health impacts: low-high estimates		na	0	na	na	na	-0.1 - 0.3	na

Note: na = Not available

* Fatal concentration assumed at 10% CO2

A summary of the modelled implications of the options is provided in Table 25 above. Further discussion is provided below.

8.1. Impacts of Option 0: CCS not enabled

(290) One of the principal questions for this impact assessment is whether under market conditions an enabled CCS could make a substantial contribution towards the EU's climate objectives. To assess this, we examined what the costs would be of meeting the EU's climate objectives under the ETS without CCS enabled (Option 0) and compared with the costs under the ETS with CCS enabled (Option 1). The result is that without CCS the costs of meeting a reduction in the region of 30% GHG in 2030 in the EU could be up to 40% higher than with CCS.[77] Thus not enabling CCS would have substantial negative impacts on Europe's capacity to meet the 2 degrees C target and on competitiveness. Option 0 would also have very substantial negative implications for employment. It has a slight negative impact on security of supply but this is unlikely to be significant.

8.2. Impacts of Option 1: EU ETS deployment based on 20% GHG reduction carbon value

(291) Option 1, defined as allowing deployment decisions on CCS to be taken according to economic decisions in the carbon market, results in low CCS deployment by 2020, although deployment rises to around 20 GW in 2030 (all in coal). Thus with the carbon price resulting from the efforts required to meet the 20% reduction in greenhouse gas emissions by 2020, CCS becomes a significant part of the energy mix, but not before 2030. By definition, there are no economic implications over and above the implications of meeting the Community's 20% greenhouse gas reduction target by 2020 and the 20% renewables target by 2020.

(292) Because Option 1 leads to a significant reduction in fossil fuel use, all the environmental impacts associated with fossil fuel use decline relative to the baseline. There would be offsetting impacts from the transport and storage infrastructure for CCS, but at such modest deployment levels these are not significant. Similarly, the CO2 storage requirement is well within the capacity of projected EU storage capacity. The significant uncertainties in projected capacity do not even begin to have an impact at this storage level.

8.3. Impacts of Option 2: Mandatory CCS

(293) Since the climate implications of Option 2 should be the same as those of Option 1, the additional cost of the Option (around €6bn/year in 2030) must be justified by additional benefits relating to additional externalities. The additional impact on learning compared with Option 1 is around 10% of the additional resource costs. It is hard to quantify what difference this would make to export potential and the ability to meet global climate objectives, and thus hard to distinguish between Option 2 and Option 1 on these counts. The variant whereby CCS is made mandatory for coal and gas has a positive effect on security of supply, but the remaining options have a negative impact relative to Option 1 (by increasing gas use and hence imports). The air quality implications are positive but minor.

(294) For the extreme mandatory Option (coal plus gas, new plus retrofit) the societal risk, from asphyxiation as a result of CO2 leakage, is around 5 people per year in 2030 assuming a fatal concentration of 10% CO2. Note in this context that the Thematic Strategy on Air Pollution estimated the annual premature fatalities from air pollution in 2005 at 390 000.[78]

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77 Capros, P and L. Mantzos (2007) Final report SERVICE CONTRACT TO EXPLOIT SYNERGIES BETWEEN AIR QUALITY AND CLIMATE CHANGE POLICIES AND REVIEWING THE METHODOLOGY OF COST-BENEFIT ANALYSIS, Contract No 070501/2004/382805/MAR/C1, Final Report to DG Environment

78 Thematic Strategy on Air Pollution, p3: 3.6 million life years lost annually, equivalent to 390 000 premature deaths.

Because there is a further reduction in fossil fuel use over the baseline, there is a further reduction in the related environmental impacts. Against this must be set the correspondingly greater burden on the environment posed by the transport network, estimated at just over 30,000 km. (As a reference, this can be compared with the natural gas pipeline length of 110 000 km in 2001). While the land take associated with this deployment may be relatively small, the major impact on biodiversity would come from land fragmentation. This impact would be subject to assessment in the Environmental Impact Assessments that are proposed to be required for CO2 pipelines, and appropriate measures taken, for instance using existing pipeline rights of way where possible.

(295) The CO2 to be captured would put a greater strain on EU storage capacity, but there is some evidence that it can be accommodated. While the storage scenarios provided are purely indicative and do not provide a realistic estimate of what a practical CO2 transport and storage network would look like, they show that broadly speaking, there is enough storage capacity for each Member State to store its own emissions, provided that the optimistic estimates that have been made regarding aquifer storage potential are borne out. However, it is clear that even without aquifer storage potential, the emissions on an extreme deployment scenario can probably be accommodated in Europe in high-security sites. There would be substantial storage under the North Sea, and the transport infrastructure required would increase the transport and storage cost to between €5 and €10/t CO2 avoided. These costs are still reasonable (the assumptions made in assessing deployment assumed marginal costs rising to €20/t in some cases).

(296) The impact of mandatory CCS would fall largely on a small number of Member States. For the extreme mandatory scenario, three-quarters of the CO2 capture would happen in four Member States (in descending order, Germany, Poland, UK and Belgium) with 35% of the effort in Germany alone. Employment impacts are negative: employment increases in the coal industry but this is more than offset by losses elsewhere due to increased energy costs.

8.4. Impacts of Option 3: Investment subsidy

(297) Using Option 3 the potential impacts of subsidising CCS deployment were assessed. The optimum level of the subsidy is that which would match the positive externalities of the increased deployment over and above what would occur under market conditions. To explore the issue, an investment subsidy of 10% was assumed running from 2020 onwards for all deployment.

(298) A 10% investment subsidy leads to 50% higher deployment (and hence total investment) in 2030 than would otherwise be the case, at small resource cost. However, it is not clear that the impact on positive externalities matches the subsidy level. The further impact on learning of the additional deployment is of the order of 2 or 3%, and impacts on achievement of global climate objectives and export potential would be correspondingly small. The impacts on air quality, employment and security of supply relative to the market-based option are also negligible. It is theoretically possible that with a higher subsidy the externality benefits of the increased deployment would match the subsidy rate, but only if the externality benefits increase non-linearly with the increasing subsidy.

8.5. Conclusion

(299) Option 0 provides strong evidence that enabling CCS under the carbon market is worthwhile, as the costs of meeting substantial reductions in EU emissions of CO2 are significantly lower with CCS enabled than without.

(300) However, there is little evidence justifying going beyond the carbon market. The additional learning resulting from the increased deployment stimulated by making CCS mandatory does not compensate for the cost of the policy. The impacts on other externalities such as security of supply, air quality, export potential and the achievement of global climate objectives also do not provide grounds for favouring mandatory CCS over the market-based approach. Furthermore, the impact of mandatory CCS would be concentrated on a small number of Member States.

(301) A subsidy of 10% would leverage additional investment from the private sector of around 50% and the resource cost would be small. However, the impact on positive externalities seems not to match the level of the subsidy, and unless the relation between the level of subsidy and the externality benefits is substantially non-linear, this is unlikely to change with higher subsidy levels than the 10% investigated here.

(302) For this reason, the Commission recommends to enable CCS under the ETS, but not to make CCS mandatory or consider any form of subsidy for the technology in the post-demonstration phase. Subsidy for the demonstration phase itself is a different matter, and that is dealt with separately under the Communication on Supporting Early Demonstration of Sustainable Power Generation from Fossil Fuels.

9. MONITORING AND EVALUATION

(303) The Directive shall be implemented by the Member States within two years after its entry into force (Article 23). Member States shall inform the Commission thereof and communicate relevant texts of national law.

(304) Measurement of progress on the application of the Directive is regulated in Article 21 of the Directive, which in its first paragraph requires Member States to submit to the Commission a report on application of the Directive every three years. This report shall pay particular attention to the issuing of permits, the selection and operation of the storage sites and the application of the Annex. The report shall be drawn up on the basis of a questionnaire or outline that shall be sent to Member States at least six months before the deadline for the submission of the first report. This questionnaire may focus inter alia on permit applications received, as well as on granted permits and the conditions under which permits have been granted (Art 7), the Commission's opinion (Art 8), and plans for monitoring, mitigation and closure (Art 11-15).

(305) Furthermore, Article 21.2 requires that on the basis of the Member State reports the Commission will publish a report on the application of this Directive within three months of receiving the reports from the Member States. In addition, the Commission shall organize an exchange of information between the competent authorities of the Member States concerning permitting, storage operation, monitoring, reporting, verification and overall compliance (Art 21.3).

(306) The outcome of the latter process and the Commission reports, issued every three years and based on the Member State reports, shall form the basis for an evaluation of the Directive.

ANNEX I: LIST OF RESPONDENTS TO STAKEHOLDER PRESENTATION OF 8 MAY

Member States

- UK
- Germany
- Italy
- Belgium

Industrial organisations and companies

- Eurelectric
- Euracoal
- General Electric
- Iberdrola
- The Carbon Capture and Storage Association (CCSA)
- E.ON UK plc
- Scottish and Southern Energy
- Vattenfall

NGOs

- WWF

ANNEX II: POTENTIAL HAZARDS TO THE ENVIRONMENT AND HUMAN HEALTH FROM CCS DEPLOYMENT

The potential hazards of CCS to the environment and human health are as follows:

- The global risk of re-emitting the transported and stored CO2 to the atmosphere;
- Upstream hazards related to the increased and continued use of fossil fuels;
- Local risks for environment, health and safety.

Global risk

Accidental releases and fugitive emissions -The global risk of re-emitting transported and stored CO2 will depend on the likelihood of leakages to occur along the CCS chain, and of the mass of CO2 released. The risk of an accidental release will be relatively small for power stations, since the technologies deployed here are well understood and may be controlled using existing regulatory controls. It is considered that the primary leakage route will be via the wells rather than via some geological route. Apart from accidental releases of CO2 fugitive emissions may occur along the entire CCS chain, in particular in compressor stations and from the injection plant.

Greenhouse gas emissions from CCS operations will occur not only as fugitive emissions or accidental releases, but also as a consequence of the increased fossil fuel combustion needed for the capture process – the energy penalty. The supply and transport of this additional fuel will result in emissions of GHG in the upstream phase of a CCS scheme.

Upstream impacts

Solid wastes and liquid effluent - Amounts of solid waste during coal mining could present significant localized impacts, but waste and effluents from transport of additional fuel is probably minimal.

Other emissions to air - The additional fuel requirement will also give rise to other emissions to the atmosphere (NOx, SO2, NH3 etc) during the production of the additional fuel. Other emissions from gas transport through pipelines are expected to be minimal, but CO2 emissions from fuel transport by road, rail and ocean transport could be significant, depending on the distance travelled between the sources of supply and the combustion plant, the types of vehicles, their fuel source, the speed travelled etc.

Biodiversity and cultural heritage - The supply of additional fuel required by CCS is not expected to lead to significant biodiversity or cultural impacts as this is assumed to occur at existing coal mines and oil/ gas fields and using existing transport routes.

Geological and hydrogeological impacts during the extraction of coal and natural gas may result from the additional fuel needed for the energy penalty associated with CCS activities. If the coal mine is located in a region of overlying aquifers, it may experience groundwater inflows/ outflows with surrounding aquifers. Mine-induced fracturing could cause hydraulic property changes, thereby changing groundwater behaviour. Some illustrative geological and hydrogeological impacts include:

- Change of geological features of the surrounding area of the mine due to intrusive mining extraction methods.

- Inflow of unconfined groundwater from siltstones/ sandstones to the coal mines from fissures/ fractures.

- Outflow of deep groundwater from the coal seams and associated sediments into the near-surface aquifers.

- Outflow of spoil dump water from the coal mines to the surrounding groundwater.

The changes in hydraulic flow patterns could result in impacts such as dry water wells, contaminated groundwater and contaminated surface water. The details of these impacts will depend on the specific conditions at individual mines but it is possible that some small increases in localised adverse effects could result form additional mining required by CCS.

Local risks

Human health and safety - This risk depends not only on the likelihood of leakages and the mass of CO2 released, but also on the population density in the vicinity of CCS operations. A concentration of 10% CO2 in air is assumed to cause 100% fatalities amongst the exposed population. Offshore releases will not impose any risks on members of the public. There will be risks to personnel working on the riser platform and injection plant, but it is assumed that these will be managed under existing health & safety legislation.

Other emissions to air include NOx, SO2 and NH3 and will occur following the combustion of additional fossil fuel. These emissions have the potential to contribute to localized impacts on health, crops and materials and to acidification and eutrophication, but will be controlled in accordance with current regulatory standards requiring BAT. Furthermore, the captured CO2 stream may contain impurities, meaning that the net atmospheric emissions of these impurities will be reduced, although this will be highly dependent on the permitted levels of impurities in injected CO2 streams. In general, it is not expected that non-GHG air emissions from operation of post-combustion capture equipment will present any significant additional environmental impacts for local air quality, as air emissions from combustion sources are strictly governed under EU law.

Waste and effluents - Waste generated during operation of CO2 capture systems include slag and ash from increase coal usage, residues from flue gas desulphurization systems, recovered sulphur, spent sorbents etc. However, it is evident that significant amounts of waste will be generated from post-combustion plants in the EU although this will be subject to strict regulation controlling its impact on the environment. During the construction of the CO2 injection facilities, significant quantities of wastes and effluents may be produced as a by-product of well drilling. This will include drilling muds and cuttings. Quantities will depend on many factors, including the geology of the drilled area, drilling depth and method and their impact will depend on the particular disposal location and method. Well drilling is well-established technology in the oil and gas industry, and there are strict controls on the management of wastes from these sectors which can be applied here to minimize impacts.

Geological and hydrogeological impacts - During pipeline operation, large releases of CO2 into the soil from accidental events on buried onshore pipelines could result in formation of carbonic acid through solution in soil water. There is a small risk that this could dissolve limestone formations if present in the area although this would require deep penetration and long contact times. In the event of loss of containment of underground reservoirs geological and hydrogeological impacts could result from CO_2 storage. These risks will be highly site-specific and cannot be assessed without detailed modelling. In saline reservoirs, injected CO_2 at supercritical phase will be lighter than brine and vertical migration of leaking CO_2 could be accompanied by dissolution in shallow aquifer waters, forming carbonic acid. This could chemically react with and stress the caprock material, leading to changes in geochemistry and hydrogeology[79]. Storage of CO_2 could also possibly be affected by regional groundwater flow. In comparison with depleted oil/ gas wells and EOR facilities, the characteristics of which are well understood by their operators there is a lack of seismic data to accurately map most saline aquifers. Hydraulic continuity may continue tens of kilometres away, and at such distances, the probability is high that fractures or fault lines could exist, with possible connection to surface waters and underground sources of drinking water.[80] The geological and hydrogeological setting of storage sites will therefore need to be carefully evaluated on a case-by-case basis to ensure that cumulative and instantaneous releases of CO_2 to the environment would not compromise the effectiveness of the storage. Upon the start of injection, appropriate survey methods will need to be used at regular intervals to monitor the movement of the injected CO_2 plume to ensure that plume behaviour is as expected and if not to plan remediation options. It is assumed that effective site selection and good regulatory control of operational practices will ensure the risk is acceptable.

Biodiversity and cultural heritage may be affected significantly by the development of new pipelines, both permanently where routes cross sensitive areas or sever routes and temporarily when construction activities lead to dust, noise and other disturbance. A pipeline right-of-way (ROW), typically occupies 15 to 30 metres in width and is required to protect the public and the security of the pipeline. Occupation of the ROW can result in restrictions on some activities including future development, mining, and construction. Other less intrusive activities such as livestock grazing and crop raising may be permitted but subject to restrictions which may affect the livelihood and economy of neighbouring communities.

During pipeline operation impacts on cultural heritage are unlikely but accidental releases could lead to adverse effects on neighbouring species and ecosystems through toxic effects. If a rupture occurs, wildlife trapped within the released plume could possibly be subject to asphyxiation. Long term fugitive releases could alter the chemistry of surrounding groundwater, seawater and/or soil through acidification, for example having adverse effects on benthic marine ecosystems or soil micro-organisms. Acidification of soils could trigger increased leaching of certain minerals with long term affects on soil quality. These impacts will be regulated under existing regimes but some significant impacts on biodiversity are likely to occur given the extent of the required network on and off shore. Accidental and fugitive releases could also impact on biodiversity at injection and storage facilities in the same way as releases from transport. It is assumed that these risks will therefore be taken into account in site selection and licensing of operations such that major impacts are avoided.

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79 Chemical reaction of stored CO_2 is a long term issue. Although it could possibly lead to caprock weakening, it would lead to permanent capture of the reacted CO_2 within the geological matrix of the aquifer.

80 Risk Analysis of the Geological Sequestration of Carbon Dioxide, Report No. R246, DTI/

ANNEX III: ROLE AND LOGISTICS OF THE SCIENTIFIC PANEL

An overall procedure for selecting a CO2 storage site is presented in Figure 11 below. In summary, an operator will perform an initial site characterization while screening various candidate sites, mostly based on existing literature and datasets. Further site investigation, including seismic surveys, may then be carried out to assess in more detail geological, geochemical and geophysical characteristics of the site. The results from the site investigation will then feed into static and dynamic models of the reservoirs. The results from drilling and well testing will help to improve the reservoir simulations, to carry out a risk assessment and to pull together a risk management plan. A number of elements will be involved in investigating potential sites, for example, licenses for drilling, seismic surveys etc. Once an application for a CO2 storage permit has been submitted to the competent authority, a draft decision may be prepared. Under Option 3, this would be submitted to a Scientific Committee (SC) at EU level, which will review the decision.

Terms of reference - The Scientific Panel (SP) shall provide an opinion on whether the assessment of the security of the storage site is robust, and whether also all other relevant permit requirements specified in Art 7.1 of the Directive are met. Thus, the SP will consider the site selection, the proposed operation, monitoring and control plan, the proposed plan for closure and after-care, the adequacy of financial securities, and the competency and reliability of the storage site management. Based on its assessment, the Commission will issue an opinion to the member state that is to permit the CO2 storage operation, which shall be taken into account in making the permitting decision. The SP will base its recommendation on extensive site information provided by the operator to the member state, and on a check of the permitting procedure followed by the responsible member state.

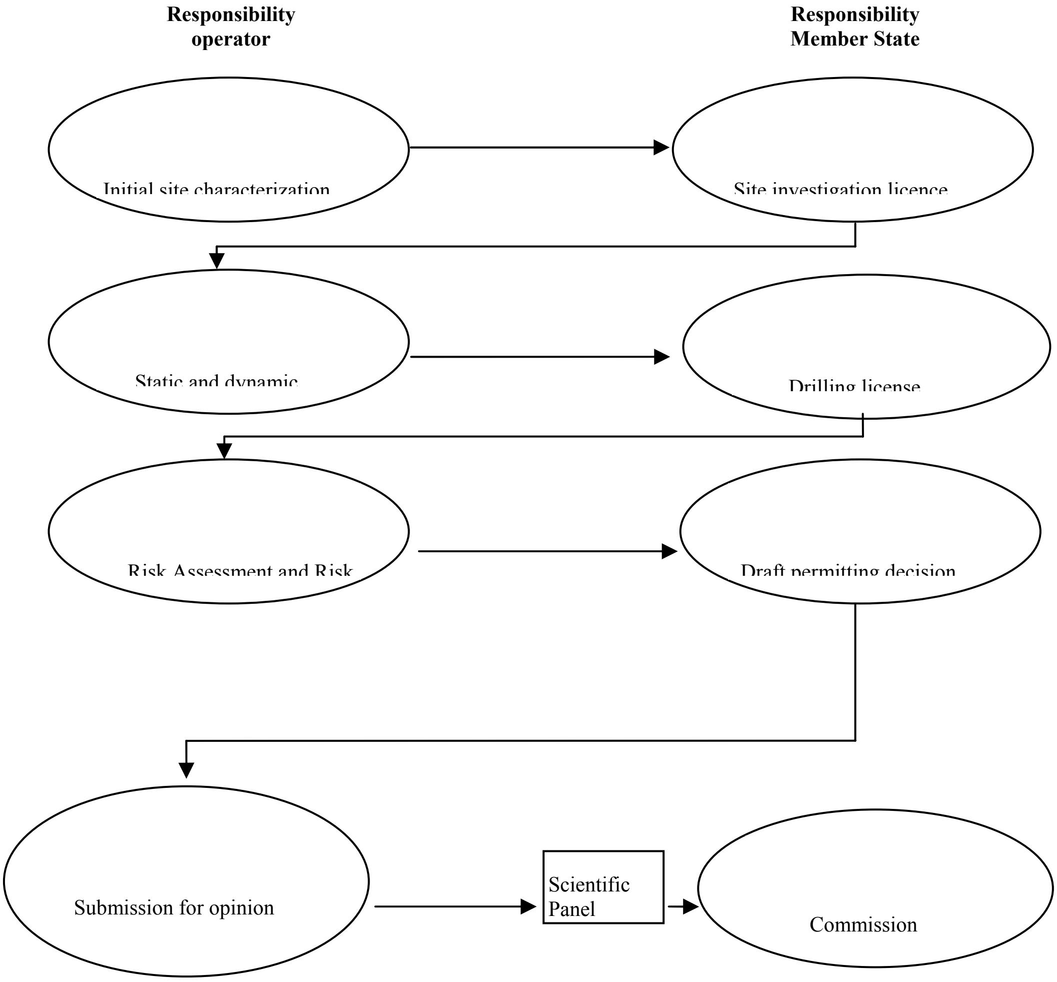


Figure 11 Possible procedure for CO2 storage site selection

Composition and recruitment -The SP is intended to have 8 permanent and 2 associated members and would include geological experts, as well as people with experience in permitting analogous activities (for instance landfills, natural gas storage and mining). Associated members would be experts who are specialized in the relevant geology of specific parts of the European continent and may be appointed on a temporary basis to assist in the evaluation of individual sites. Associate members would have the same right of participation in the discussions and responsibilities as full members, including voting rights. Members of the SP would be recruited and appointed by the Commission on the basis of (scientific) excellence following publication of an open call for expressions of interest. Candidates who have met the requirements for membership but who are not nominated, will be invited to be included in a reserve list which will be published. The list will be used when the Commission needs to replace a member who is unable to continue. Associated members may be scientists on the reserve list mentioned above or be selected in an open procedure.

Annex IV: Financial security mechanisms

The following main mechanisms have been identified:

- Cash Accounts –the permit holder provides an agreed cash amount representing the value of the estimated financial provision, which is held by the regulatory authority (e.g. a national environmental protection agency). Cash accounts represent an established financial security mechanism. However, they are considered expensive as they tie-up capital in an inefficient way.

- Bonds - Bonds are a form of surety maintained by a bank or similar institution, paid into by an operator, which allows a regulatory authority to call in monies to cover decommissioning and after care costs. Although also a costly option, bonds could be applied to ensure permit conditions are met in CCS activities.

- Insurance - Traditional insurance as a stand-alone solution is generally unsuited to meet the requirements of financial provision as it is intended in the permit requirements. Traditional insurance provides security to fortuitous events on an indemnity basis which is contrary to the nature of the predictable closure and after-care costs that will incur in case of insolvency. Nonetheless specialised (re)insurance companies in some cases have offered policies for the decommissioning and after care phases of landfill sites and have been looking at developing methodologies and models to underwrite policies for CCS storage sites.

- Mutual Funds - A mutual fund, whether voluntary or compulsory, if allowed can be used by landfill operators that agree to pool their risk exposure and provide support if a member becomes insolvent. A statutory aftercare fund is a form of a compulsory fund, usually managed by the regulatory authority and which can be raised through direct financial contributions, maybe partly covered by insurance, backed by levies or taxes from CCS operators or a combination of all the above. One of the benefits of a mutual fund is that it could provide participants with an acceptable level of cover at a lower cost. However, by definition, mutual funds only work when a relative large number of operators come together to share the risk.

- Other financial guarantees - Other financial guarantees exist in the form of letters of credit, hybrid products where insolvency requirements are covered in the form of a bond with an element of insurance protection, treasury bonds, certificates of deposit, balance sheet provisions or other forms of liquid assets that can provide financial security and assurance on the CCS operator's performance to complete the project as outlined in the permit.

ANNEX V: METHODOLOGY FOR ENVIRONMENTAL IMPACT ASSESSMENT

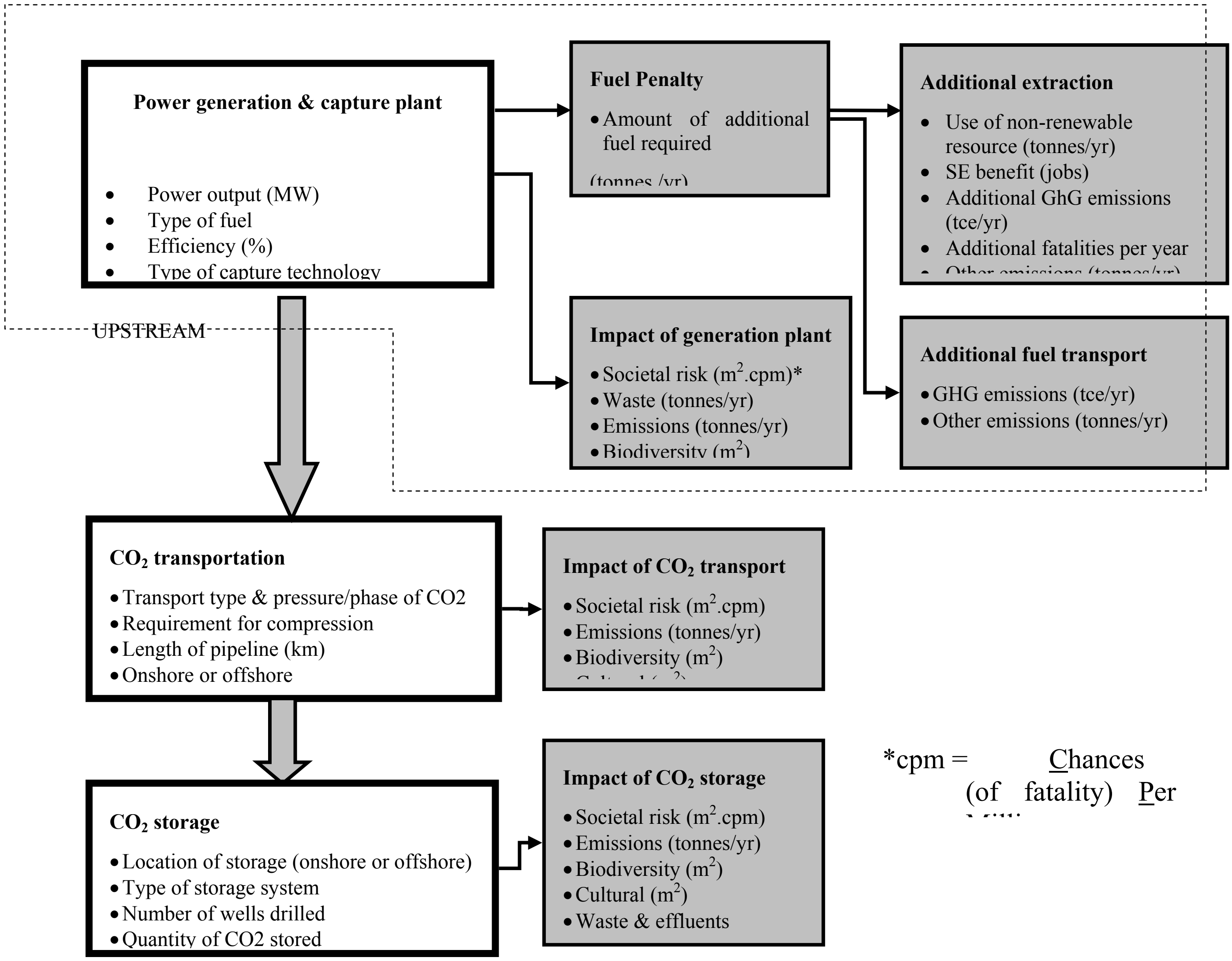


Figure 12. Systemic overview

ANNEX VI: METHODOLOGY FOR LINKING PRIMES/CASTOR MODELS

The PRIMES output of CO2 captured per country for 2020, 2025 and 2030, together with a split in the CCS power generation between coal and gas for each of the three years, was the basis of the analysis. The assumptions made in generating transport and storage scenarios were as follows:

- The data for sources and sinks were derived from the source-sink GIS database that is being built up in a succession of linked projects funded under the Framework Programmes for Research. The main projects are GESTCO (on storage capacity), CASTOR (on source-sink matching) and GEOCAPACITY (updating storage capacity data).

- The source data is for 2005, and comprises location, installed capacity and year of start-up (from which expected replacement date can be calculated). Load hours of the initial capacity were calculated using the annual CO2 emissions, the capacity and emission factors for CO2 per unit energy generated. In some cases installed capacity was not available, in which case it was calculated from the annual CO2 emissions (indicated by PRIMES) using the average load hours from the above calculation and the emission factor.

- Sources and sinks were clustered geographically, and individual source clusters matched with individual sink clusters so that there was a global match of emissions and required storage potential. The total storage potential was estimated assuming a 40 year lifetime for the CCS installations in the source cluster.

- CCS sources were deployed on the GIS by assuming that current capacity is replaced by CCS capacity as it goes out of commission. The deployment was constrained to meet the CO2 captured levels required by PRIMES in 2030 on a country-by-country basis, and to match as far as possible the gas/coal split of PRIMES.[81]

- The load hours of the CCS capacity were derived by dividing the CCS power generation figures from PRIMES by the CCS installed capacity figures from PRIMES, averaged over coal and gas.

- If the PRIMES target for CO2 capture was not met by replacing existing capacity with CCS, new capacity was added sufficient to meet the CO2 capture target. For the extreme deployment scenario, this was done for Austria, Belgium, France, Germany, Hungary, Ireland, Italy, the Netherlands and the UK.

- The well injection capacity of the sinks depends on the sink permeability, but this information is not available for all sinks. Injection capacity was therefore estimated at 1 Mt/yr for gas fields and 0.5 Mt/yr for oil fields and aquifers.

- The number of wells in a sink cluster was adjusted to accommodate the annual CO2 injected from PRIMES for the associated source cluster. (Thus if PRIMES showed 15 Mt/yr injected, and the sink cluster comprises gas fields, 15 wells were required.) A

81 PRIMES has different splits for different reference years (2020, 2025 and 2030), but the CASTOR tool can only accommodate a single split. This was calculated as the ratio of the average coal power generation to the average gas power generation provided by PRIMES.

constraint was that the resulting injectivity was not allowed to exceed the estimated maximum injectivity for the sinks.

With these inputs the CASTOR tool was run to develop transport and storage scenarios. The variable parameters in the tool were the number and lifetime of the initial sources, and the number of hydrocarbon sinks/aquifers to be used. They were used in a trial-and-error procedure designed to approach the CO2 capture targets of the PRIMES scenarios, where those targets are considered as minimum values (thus the tool may in some cases yield higher capture figures than PRIMES). It is not possible to match separately for 2020, 2025 and 2030, so the CO2 was matched for 2030.

The analysis yielded the following key parameters for the impact assessment:

- Pipeline lengths
- Number of injection locations
- Annual and cumulative injection volumes and injection gap (amount generated minus amount stored)
- Number of wells per reservoir type

ANNEX VII: BASELINE DEPLOYMENT DATA

Table 26. CCS Deployment Scenarios: summary data based on output of PRIMES and CASTOR

CCS Element	Baseline			Option 1(b)			Option 2(b)		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
CO2 Emissions									
CO2 emissions for thermal power plants (Mt)(a)	1,743	1,848	1,878	846	869	829	779	724	537
Net Electricity Generation by Fuel Type (Plants with No CCS)									
Coal and lignite (GWh)	1,132,990	1,224,473	1,275,496	658,708	654,995	733,946	669,526	675,125	819,507
Natural gas (GWh)	1,016,376	1,054,091	1,040,519	809,163	913,277	930,164	806,843	891,094	859,613
Net Electricity Generation by Fuel Type (Plants with CCS)(c)									
Oxyfuel (coal) (GWh)	NA	NA	NA	-	849	7,408	3,510	7,887	22,499
Oxyfuel (natural gas) (GWh)	NA	NA	NA	-	-	-	8,534	19,185	45,099
Post-combustion (coal) (GWh)	NA	NA	NA	-	3,517	30,689	14,543	32,674	93,209
Post-combustion (natural gas) (GWh)	NA	NA	NA	-	-	-	35,357	79,481	186,841

	Baseline			Option 1(b)			Option 2(b)		
Pre-combustion (coal) (GWh)	NA	NA	NA	-	15,522	135,456	64,189	144,215	411,405
Total (coal) (GWh)	NA	NA	NA	-	19,888	173,553	82,243	184,776	527,112
Total (natural gas) (GWh)	NA	NA	NA	-	-	-	43,892	98,667	231,940
Fuel Input									
Hard coal and lignite (ktoe)	260,098	271,479	266,148	151,008	144,389	161,306	155,806	153,761	179,225
Natural gas (ktoe)	179,777	182,563	176,946	141,861	155,686	153,546	146,269	159,618	154,114
CO2 Transport Pipeline									
Onshore length (km)	NA	NA	NA	-	557	5,944	5,417	13,244	37,149
Offshore length (km)	NA	NA	NA	-	-	-	2,662	5,454	8,432
CO2 Capture									
CO2 captured (Mt/yr)	NA	NA	NA	7	19.6	161	75	176	517
CO2 Injection									
Total volume of CO2 injected (Mt/yr)	NA	NA	NA	-	16	143	84	189	521

Baseline	Option 1(b)	Option 2(b)

Note:

(a) Calculated by ERM based on IPCC emission factors. For coal, lignite and natural gas-fired thermal power plants only.

(b) CO2 emissions from oxyfuel technology have not been accounted due to absence of IPCC emission factors.

(c) Technology breakdown for CO2 capture assumed by ERM, based on the following:

- 7% oxyfuel (3.5% coal-based plants, 3.5% natural gas-based plants)

- 29% post-combustion (14.5% coal-based plants, 14.5% natural gas-based plants)

- 64% pre-combustion (64% coal-based plants)

Source: Data from the Primes Version 3 Energy Model, generated by the National Technical University of Athens, and source-sink matching work undertaken by TNO Netherlands, unless otherwise stated.

ANNEX VIII: SOCIETAL RISK FROM CO2 LEAKAGE

Figure 9.1. Average Annual Fatalities for Option 1 and 2

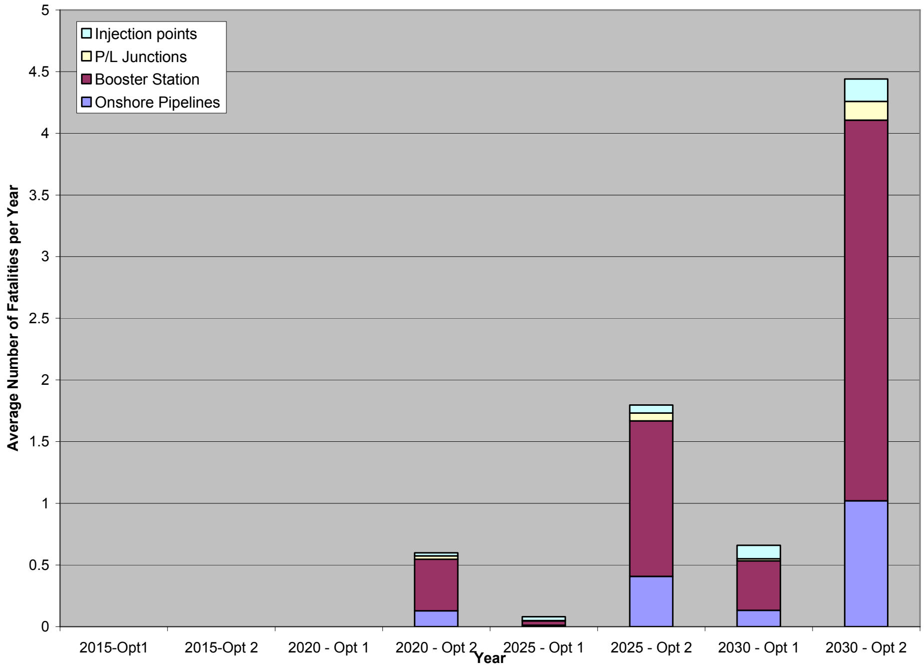
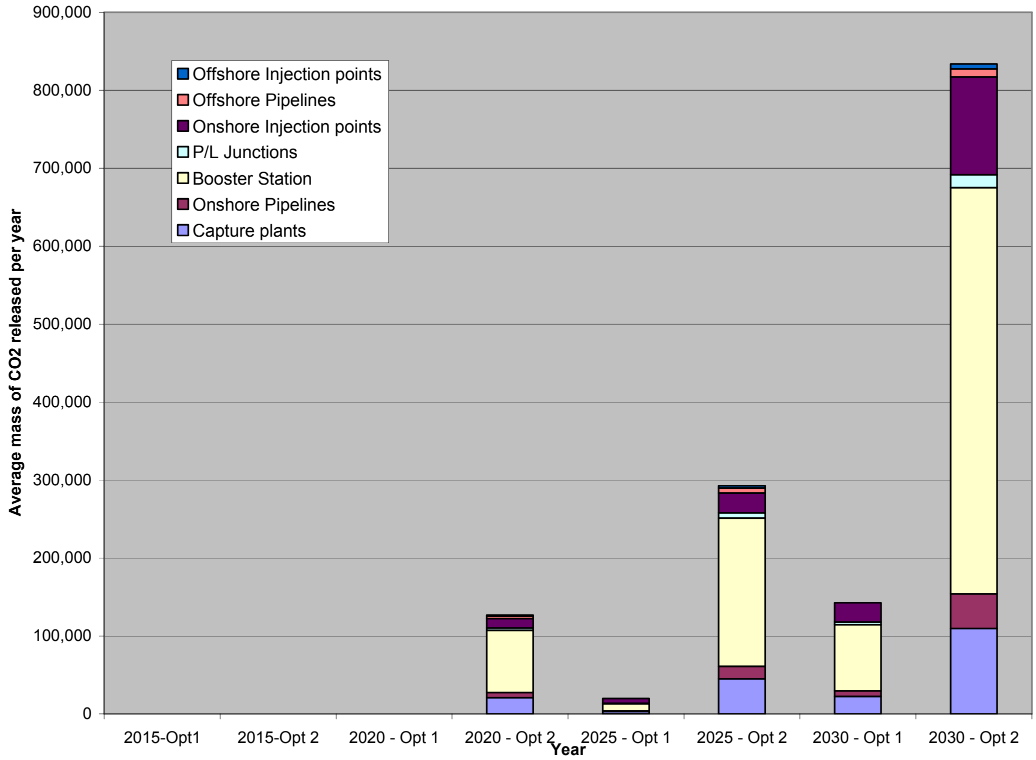


Figure 9.2. Average Annual Mass of CO2 released for Options 1 and 2



ANNEX IX: SUMMARY OF ENVIRONMENTAL IMPACTS

Table 27. Summary Table of Environmental Impacts

CCS Element	GHG Emissions			Other Emissions to Air			Wastes and Effluents			Geology and Hydrogeology			Biodiversity Cultural Heritage		
	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2	Baseline	Option 1	Opt 2
2020															
Fuel Supply (Mt)	202	133	138	0.66 (NOX) 0.53 (SO2) 0.049 (PM10)	0.42 (NOX) 0.34 (SO2) 0.030 (PM10)	0.43 (NOX) 0.36 (SO2) 0.031 (PM10)	0.45a 3.3b 0.022c	0.26a 1.9b 0.013c	0.27a 2.0b 0.013c	NA	+	+	NA	+	+
Fuel Transport	Incorporated into Fuel Supply			NA	+	+	NA	+	+	NA	+	+	NA	+	+
CO2 Capture Plant	1,743	846	779	0.76 (NOX)	0.46 (NOX)	0.44 (NOX) 0.19 (SO2)	24d	14d	15d	NA	0	0	NA	0	0

CCS Element	GHG Emissions			Other Emissions to Air			Wastes and Effluents			Geology and Hydrogeology			Biodiversity Cultural Heritage		
	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2
(Mt)				0.33 (SO2) 0.011 (NH3) 0.066(PM10)	0.19 (SO2) 0.007 (NH3) 0.038(PM10)	0.009 (NH3) 0.035(PM10)	42e	25e	23e 0.48f 0.092g						
CO2 Transport (t/yr)	NA	-	758 – 75,844	NA	0	0	NA	0	0	NA	0	0	NA	-	-
CO2 Storage	NA	0	0	NA	NA	NA	NA	0	0	NA	0	0	NA	0	0
2025															
Fuel Supply (Mt)	208	136	142	0.69 (NOX) 0.55 (SO2) 0.051 (PM10)	0.42 (NOX) 0.35 (SO2) 0.030 (PM10)	0.44 (NOX) 0.37 (SO2) 0.031 (PM10)	0.47a 3.5b 0.023c	0.25a 1.8b 0.012c	0.27a 2.0b 0.013c	NA	+	+	NA	+	+
Fuel Transport	Incorporated into Fuel Supply			NA	+	+	NA	+	+	NA	+	+	NA	+	+

CCS Element	GHG Emissions			Other Emissions to Air			Wastes and Effluents			Geology and Hydrogeology			Biodiversity Cultural Heritage		
	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2	Baseline	Option 1	Opt 2
CO2 Capture Plant (Mt)	1,848	869	724	0.82 (NOX) 0.36 (SO2) 0.012 (NH3) 0.071(PM10)	0.46 (NOX) 0.19 (SO2) 0.007 (NH3) 0.037(PM10)	0.41 (NOX) 0.19 (SO2) 0.012 (NH3) 0.030(PM10)	26d 46e	14d 24e 0.12f 0.014g	16d 20e 1.1f 0.21g	NA	0	0	NA	0	0
CO2 Transport	NA	78 – 7,791	1,854 – 185,408	NA	0	0	NA	0	0	NA	0	0	NA	-	-
CO2 Storage	NA	0	0	NA	NA	NA	NA	0	0	NA	0	0	NA	0	0
2030															
Fuel Supply (Mt)	203	143	152	0.67 (NOX) 0.54 (SO2) 0.050 (PM10)	0.45 (NOX) 0.37 (SO2) 0.032 (PM10)	0.48 (NOX) 0.40 (SO2) 0.035 (PM10)	0.46a 3.4b 0.023c	0.28a 2.1b 0.014c	0.31a 2.3b 0.015c	NA	+	+	NA	+	+

CCS Element	GHG Emissions			Other Emissions to Air			Wastes and Effluents			Geology and Hydrogeology			Biodiversity Cultural Heritage		
	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2	Baseline	Option 1	Opt 2
Fuel Transport	Incorporated into Fuel Supply			NA	+	+	NA	+	+	NA	+	+	NA	+	+
CO2 Capture Plant (Mt)	1,878	829	537	0.85 (NOX) 0.37 (SO2) 0.013 (NH3) 0.074 (PM10)	0.45 (NOX) 0.21 (SO2) 0.013 (NH3) 0.034 (PM10)	0.36 (NOX) 0.22 (SO2) 0.025 (NH3) 0.021 (PM10)	27d 48e	17d 22e 1.0f 0.12g	23d 16e 3.1f 0.56g	NA	0	0	NA	0	0
CO2 Transport	NA	832 – 83,217	5,201 – 520,089	NA	0	0	NA	0	0	NA	0	0	NA	-	-
CO2 Storage	NA	0	0	NA	NA	NA	NA	0	0	NA	0	0	NA	0	0

CCS Element	GHG Emissions			Other Emissions to Air			Wastes and Effluents			Geology and Hydrogeology			Biodiversity Cultural Heritage		
	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2	Baseline	Option 1	Option 2	Baseline	Option 1	Opt 2

Footnotes: a Coal mining effluents; b Coal mining solid waste; c Coal mining dust; d Ash/ slag; e FGD Residues; f Sulphur; g CCS Sorbents

+ denotes ‘positive impact expected, although magnitude not determined’

0 denotes ‘non-significant impact expected, although magnitude not determined’

- denotes ‘negative impact expected, although magnitude not determined’

NA denotes ‘not applicable’

ANNEX X: KEY ASSUMPTIONS AND SUMMARY DATA FOR ENVIRONMENTAL IMPACTS AND SOCIETAL RISK ESTIMATES

Section 1 – Data for assessment of societal risk

Table 28. Summary of Module Risks

Module	Unit	Size	Max. Hazard range	Area of hazard	Frequency	Risk . Area	Total risk area
			m	m2	per unit.yr	cpm.m2 per unit.yr	cpm.m2 per unit.yr
Onshore Pipeline	km	Rupture	250	16067	8.50E-06	1.37E+05	1.85E+05
		Large	240	13733	2.00E-06	2.75E+04	
		Medium	95	2200	9.50E-06	2.09E+04	
		Small	13	33	1.40E-05	4.67E+02	
Booster Station	per 50km of pipeline	Rupture	250	16067	8.80E-04	1.41E+07	2.78E+07
		Large	240	13733	3.00E-04	4.12E+06	
		Medium	95	2200	3.80E-03	8.36E+06	
		Small	13	33	3.50E-02	1.17E+06	
Converging Pipeline	Per junction	Rupture	250	16067	1.50E-04	2.41E+06	5.84E+06

Module	Unit	Size	Max. Hazard range	Area of hazard	Frequency	Risk . Area	Total risk area
		Large	240	13733	1.00E-04	1.37E+06	
		Medium	95	2200	8.80E-04	1.94E+06	
		Small	13	33	3.50E-03	1.17E+05	
Injection line (onshore)	well	Blowout	250	16067	2.10E-04	3.37E+06	3.37E+06
Capture	module	Hazard ranges not considered to present an offsite risk					
Offshore Pipeline	km	No risk to general public for offshore components					
Injection Plant	module	Hazard ranges not considered to present an offsite risk					
Offshore Riser Platform	module	No risk to general public for offshore components					
Injection line (offshore)	well	No risk to general public for offshore components					

Table 29. Mass of CO_2 Released in Accident Scenarios Associated with Each Component

Module	Unit	Average annual release mass tonne CO_2/unit.yr
Capture	Module	836
Onshore Pipeline	Km	1.2
Converging Pipeline	per junction	124
Booster Station	per 50km of pipeline	695
Offshore Pipeline	Km	1.2
Injection Plant	Module	871
Offshore Riser Platform	Module	17
Injection line	well	11
Injection line	well	11

Table 30. Population Density (people per km2)

Country	Population Density	Country	Population Density		
Austria	95	Germany	230.3	Netherlands	470.1

Country	Population Density	Country	Population Density		
Belgium	335.9	Greece	80.2	Poland	123.6
Bulgaria	69	Hungary	109.8	Portugal	111.3
Cyprus	117.1	Ireland	54.1	Romania	94
Czech Republic	130.3	Italy	191.7	Slovakia	109.9
Denmark	123.9	Latvia	36.7	Slovenia	98.1
Estonia	30.3	Lithuania	53.6	Spain	79.1
Finland	17	Luxembourg	169.2	Sweden	21.6
France	108.3	Malta	1220.9	UK	245

Table 31. Risks Associated with Accidental Releases of CO2

Emission source	Accidental CO2 releases in 2030 / tCO2 yr−1		% of total captured in 2030	
	Option 1	Option 2	Option 1	Option 2
Capture plants	22,572	109,516	0.01%	0.02%
Onshore pipelines	7,133	44,579	0.00%	0.01%
Booster station	84,790	521,250	0.05%	0.10%

	Accidental CO_2 releases in 2030 / $tCO_2\ yr^{-1}$		% of total captured in 2030	
P/L junctions	3,348	16,244	0.00%	0.00%
Onshore injection points	24,844	125,620	0.02%	0.02%
Offshore pipelines	-	10,119	-	0.00%
Offshore injection points	-	6,342	-	0.00%
Total	142,687	833,670	0.09%	0.16%

Section 2 – Data for assessment of environmental impacts

Calculation of GHG Emission from Fuel Supply

GHG emissions from fuel supply are calculated by multiplying the emission factors in Table 32 with the fuel input into the power plants. The fuel input into the power plants has been given in Table 26 in units of kilotonnes of oil equivalent (ktoe). This has been converted to kg of coal and m3 of natural gas, based on the conversion in Table 32.

Table 32. Fuel Input

CCS Element	Baseline			Option 1			Option 2		
	2020	2025	2030	2020	2025	2030	2020	2025	2030
Fuel Input									
Hard coal and lignite (ktoe)	260,098	271,479	266,148	151,008	144,389	161,306	155,806	153,761	179,225
Natural gas (ktoe)	179,777	182,563	176,946	141,861	155,686	153,546	146,269	159,618	154,114
Fuel Input									
Hard coal and lignite (Mt)	437	456	448	254	243	271	262	259	301
Natural gas (Mm3)	211,430	214,707	208,101	166,838	183,098	180,581	172,022	187,721	181,249

Conversion: 1 toe = 1.68 tonnes of coal; 1 toe = 1176 m3 of natural gas

Calculation of Wastes/ Effluents from Coal Mining

The amount of wastes/ effluents from coal mining is calculated by multiplying the coal fuel input in Table 32 with the emission factors in

Table 33. It is assumed that 60% of coal production is surface mining and 40% underground mining. Within surface mining, it is assumed 50% is contour mining and 50% area mining. Within underground mining, it is assumed 50% is conventional mining and 50% is longwall mining.

Table 33. Wastes and Effluents Produced by Coal Mining

	Surface Mining (Tonnes/ 1000 Tonnes of Coal Produced)		Underground Mining (Tonnes/ 1000 Tonnes of Coal Produced)	
Waste Characteristic	Contour	Area	Conventional	Longwall
Liquid Effluent	0.24	1.2	1	1.6
Solid Waste	10	10	3	5
Dust	0.1	0.06	0.006	0.01

Source: Edgar T.F. (1983). Coal Processing and Pollution Control. Houston, Texas. Gulf Publishing.

Calculation of Waste/ Effluents Generated from Power Plant without and with CO2 Capture

The waste/ effluents generated from power without CO2 capture and with CO2 capture is calculated by multiplying the net electricity generated presented in Table 26 with emission factors in Table 34

Table 34. Waste/ Effluent Generation Rates for Power Plant Systems

Capture Plant	PC Plant			IGCC Plant			NGCC Plant		
Parameter	Ref Plant	Capture Plant	% +/-	Ref Plant	Capture Plant	% +/-	Ref Plant	Capture Plant	% +/-
Ash/ slag (kg MWh-1)	21.4	28.1	+31%	29.5	34.2	+16%	-	-	-

Capture Plant	PC Plant			IGCC Plant			NGCC Plant		
Parameter	Ref Plant	Capture Plant	% +/-	Ref Plant	Capture Plant	% +/-	Ref Plant	Capture Plant	% +/-
FGD residues (kg MWh-1)	37.4	49.6	+33%	-	-	-	-	-	-
Sulphur (kg MWh-1)	-	-	-	6.49	7.53	+16%	-	-	-

Source: 2005 IPCC Special Report on Carbon Dioxide Capture and Storage (SRCCS), Table 3.5. Details of the power plant design are available in this table.

Calculation of Fugitive Emissions from CO_2 Transport

Fugitive emissions to the atmosphere from CO_2 transport by pipeline have been calculated by multiplying the onshore pipeline length in Table 26 with the emission factor in Table 35.

Table 35. Fugitive Emission Factor from CO_2 Transport by Pipeline

Emission Source	Value	Comments
Fugitive emissions from CO_2 transportation by pipeline	0.00014 – 0.014 Gg per year per km of transmission pipeline	Uncertainty is ± a factor of 2

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Table 5.2.

ANNEX XI: ADMINISTRATIVE COSTS IMPOSED BY LEGISLATION

Key assumptions - case A:

- Policy option 1: enable CCS under the EU-ETS and allow the market to determine CCS deployment
- total number of permitted sites by 2030: 279 (based on Member State scenario from the TNO Report (2007) CO2 Capture and Storage Scenarios in the European Union)
- single operator for each individual storage site
- European Commission to review draft permitting decisions only for the first 20 permitted storage sites

Results:

- Total administrative costs (€): 17,841,745, of which:
- Total administrative costs for operators (€): 12,368,070
- Total administrative costs for Member States (€): 4,660,695

Proposal for a Directive of the European Parliament and of the Council concerning carbon capture and storage					Tariff (€ per hour)		Time (hour)		Price (per action or equip)	Freq (per year)	Nbr of entities	Total nbr of actions	Total cost
No	Type of obligation	Referring to	Description of required action(s)	Target group	i	e	i	e					

1	Application for individual authorisation	Exploration permit	Producing the required information	Operators	65		40.00		2,600.0	0.03	279	279	725,400
2	Application for individual authorisation	Exploration permit	Administrative efforts related to permit application	Member States	65		24.00		1,560.0	0.03	279	279	435,240
3	Application for individual authorisation	Storage permit	Producing the required information	Operators	65		308.00		20,020.0	0.03	279	279	5,585,580
4	Application for individual authorisation	Storage permit	Administrative efforts related to permit application	Member States	65		145.00		9,425.0	0.03	279	279	2,629,575
5	Application for individual authorisation	Change, review and update of storage permit	Producing new data	Operators	65		100.00		6,500.0	0.20	279	279	1,813,500
6	Application for individual authorisation	Change, review and update of storage permit	Review of updated permit	Member States	65		40.00		2,600.0	0.20	279	279	725,400
7	Submission of (recurring) reports	Monitoring and reporting	Producing new data and submitting information to recipient	Operators	65		90.00		5,850.0	0.33	279	279	1,632,150
8	Inspection	Inspection	Inspecting and checking (including	Member States	65		24.00		1,560.0	0.50	279	279	435,240

			assistance to inspection by public authorities										
9	Inspection	Inspection	Inspecting and checking (including assistance to inspection by public authorities	Operators	65		4.00		260.0	0.50	279	279	72,540
10	Reporting obligation	Member States reporting obligation	Reporting every three years	Member States	65		24.00		1,560.0	0.33	279	279	435,240
11	Application for individual authorisation	Closure of storage site	Revision of the closure plan	Operators	65		40.00		2,600.0	0.03	279	279	725,400
12	Application for individual authorisation	Transfer of obligation	Report on Transfer of obligation to MS	Operators	65		100.00		6,500.0	0.03	279	279	1,813,500

13	Application for individual authorisation	Review of draft permit	Meetings on permit applications	Commission	65		46.00		2,990.0	1.00	2	2	5,980
14	Application for individual authorisation	Review of draft permit	Annual harmonization meetings	Commission	65		300.00		19,500.0	1.00	2	2	39,000
15	Application for	Review of draft	External assistance	Commission	300*		1,280.00		384,000.0	1.00	2	2	768,000

	individual authorisation	permit	contracts										

* Tariffs and hours from DNV estimates includes commercial software licenses for seismic data interpretation and visualization, geologic mapping and reservoir flow modelling

Key assumptions - case B:

- Policy option 2d: Making CCS mandatory for new coal- and gas-fired power from 2020 onwards, together with retrofit of existing plants (built between 2015 and 2020) from 2020.
- total number of permitted sites by 2030: 883 (based on Member State scenario from the TNO Report (2007) CO2 Capture and Storage Scenarios in the European Union)
- single operator for each individual storage site

Results:

- Total administrative costs (€): 54,706,885, of which:
- Total administrative costs for operators (€):39,143,390
- Total administrative costs for Member States (€):14,750,515