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Report on "Technology: bridging the gap"

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1. Executive summary

The report presents the work carried out in WP4 – Technology Assessment II. The work is based on technology assessments with the aim to analyze the possible contribution from near- and medium-term technological options in energy scenario modeling, considering the limitations and possibilities imposed by the present energy system. The focus is on CO2 capture and storage (CCS) technologies and biomass conversion technologies. This, since these are subject to intensive research and development and because these two groups of technologies are associated with different uncertainties.

CCS is believed to contribute to large cuts in emissions of CO2 until year 2050 and beyond. Yet, CCS has not been applied at scale and depends on successful development of the capture technologies as well as successful ramp-up of the transportation and storage infrastructure. Bioenergy is the only renewable energy form that inherently generates carbon-based fuels, which is the basis for much of present-day energy technology. This makes biomass very suitable for use in both heat and power production and in the transport sector, where it is presently the major renewable alternative to gasoline and diesel. Yet, biomassis associated with several uncertainties. Firstly, cost efficient introduction of biomass must take advantage of the existing energy infrastructure such as in various co-firing schemes. This will also depend on the biomass supply infrastructure. However, the existing energy infrastructure could be used as an advantage with respect to that it could facilitate a low risk and low cost option for establish a market for biomass. Secondly, there is an uncertainty in the climate benefit of biomass and thirdly, there are a large number of possible biomass conversion schemes which have different characteristics both with respect to cost and efficiency but also with respect to the size of the plants. These uncertainties are discussed and assessed in this report. The output is recommendation on modelling parameters of the modelling work carried out in WP5 and WP6.

From the assessment made of CCS it can be concluded that at this point in time it is not meaningful to associate the different capture technologies with different cost. In fact, this is misleading considering small difference in costs but also that there are differences in complexity and maturity between the technologies. The recommendation is that in energy systems modelling only to separate costs of capture with respect to fuel (hard coal, lignite and natural gas).

Although the cost for transport and storage is much lower than the capture cost, the initial projects will be subject to significantly higher costs and, thus, the ramp-up of a CCS infrastructure is crucial and CCS scenarios should reflect such an elevated initial cost for transport and storage as well as the capture processes. Based on the assessment, this work proposes six different CCS scenarios as input to energy systems modelling.

As for biomass co-firing it is on one hand shown that this can offer a low cost and low risk option for introducing biomass at scale in the energy system. Yet, it is not straight forward on how to include this in energy systems modelling. This has to be discussed further. An interesting question which the modelling could help answer is to what extent biomass demand for co-firing could bridge to lignocellulose based bioenergy such as 2nd generation biofuels by stimulating a substantial development of lignocellulosic supply systems. One additional question concerns the value of biofuel preparation technologies that allow for higher biofuel shares in the fuel mix.

With respect to land use options for climate change mitigation and the uncertainty in climate benefits of bioenergy it is proposed that a starting point for modelling can be taken in the notion

that biomass that substitutes for fossil fuels (especially coal) in heat and electricity generation in general provides larger and less costly CO2 emissions reduction per unit of biomass than substituting biofuels for gasoline or diesel in transport. Different modeling questions are discussed such as to investigate how various levels of GHG emissions reduction linked to substituting fossil fuels with different types of solid and fluid biofuels will impact on the attractiveness of these fuels in the model runs, possibly while combining energy security targets with climate targets. The implications of drastically reduced mitigation benefit due to land use change emissions might also be subject to model based investigations. In this context, the alternative use of land to produce carbon sinks instead of bioenergy is discussed as possibly an additional issue that might be addressed with some of the models in PLANETS.

The assessment of thermal systems for biomass conversion shows a large span in costs as well as in thermal efficiencies. Also, the different processes yield different size (installed capacity). Thus, it is problematic to compare such processes if comparison is only made on a cost basis since the different processes are suitable for different markets. Comparing these generally smaller processes with the large base load plants for CCS (as well as for co-firing biomass in such plants) points to a general problem in having costs as the main parameter for comparison of different technologies since technologies do not compete on the same markets. This should have implications on interpretation of results from energy systems modelling.

2. Introduction

The work in WP4 is based on technology assessments with the aim to analyze the possible contribution from near- and medium-term technological options in energy scenario modeling, considering the limitations and possibilities imposed by the present energy system.

One rationale behind WP4 is the observation that the current energy system will play an important role for several decades to come and that technological options can be identified which can take advantage of the existing system by means of offering cost efficient options which can be integrated in the existing power plant infrastructure. The hypothesis is that bridging technologies under certain conditions can have a decisive influence on the longer-term development of the energy system as a whole. If so, this should also have important implications on energy systems modelling and analysis. In more general terms, we need technologies which can make large reductions in CO2 emissions over the coming decades. A substantial portion of these technologies must (i) fit into the existing energy infrastructure; (ii) help maintaining security of supply; and (iii) be competitive. A bridging technology should fulfil these three criteria.

Several bridging technologies are using biomass as a fuel. This since biomass is considered a key near-term renewable source in the EU energy policy as well as in national policies of many EU Member States as well as in other regions around the world. At the same time, biomass based options are debated regarding their true climate change mitigation benefits and there are arguments that land would be better used for carbon sequestration if the aim is to maximize the contribution to reducing atmospheric CO2 levels.

Also CO2 Capture and Storage (CCS) can be seen as a technology that will benefit from the existing structure of the energy system (centralized production). Whereas biomass fuelled bridging technologies can be implemented in the short term, CCS is likely not to be commercially available until year 2020, although this year is a first estimate. As biomass, CCS options face challenges connected to other aspects than technical ones, such as public acceptance and uncertainties regarding implementation potential.

Based on initial assessments and discussions within the PLANETS consortium, it was decided to focus WP4 activities on an assessment of CCS and biomass based technologies, including an assessment of the use of biomass from a climate benefit perspective. The research group has a long experience from these two groups of technologies such as involvement in technical projects with industry. Thus, this experience is used as input to the assessment.

To serve as input to the stochastic modelling work, the focused options are assessed with respect to costs and possible scale, but also maturity, uncertainty and risk. As for CCS, the “debut” year and the ramp-up speed are discussed as well.

The aim of the work carried out in WP4 has been to provide insights that are complementary to those presented by the modelling groups in the PLANETS consortium. The WP4 output also serves as basis for scenario work by the modelling groups by identifying which parameters for CCS and biomass should be varied (and how) in the stochastic modelling work.

3. Methodology

The work carried out in this WP is based on technology assessment of thermal processes, systems studies on climate benefit of biomass as well as database analysis on possibilities and limitations imposed by the energy infrastructure (i.e. how CCS and biomass technologies can fit into the existing energy system). As for the latter, Europe has been in focus since the research group have access to databases of the European energy infrastructure (Kjärstad and Johnsson, 2007) but the aim has been to also provide general conclusions to support energy systems modelling on a global scale.

The technology assessment is based on various process analyses of CO2 capture processes as well as biomass based processes. In addition, the large range of biomass conversion processes has been assessed by a component by component analysis to identify the range in cost and sizes for different biomass conversion processes. The work has benefited from long term cooperation with key industrial players developing CCS and biomass technologies (technology providers as well as utilities).

4. CO2 Capture and Storage (CCS)

Fossil fuels dominate global as well as European energy supply, with the transportation sector dominated by oil. In Europe 50 percent of the electricity generation comes from coal and natural gas and coal accounts for approximately 70 percent of the CO2 emissions from the European power generation. At the same time large cuts in CO2 emissions are required to meet emission reductions which, according to IPCC, are required to limit a temperature increase between 2.0 and 2.4ºC (IPCC, 2007). Typically, this would require CO2 reductions between 50 and 85 percent globally by 2050. Considering this, and the abundant resources of fossil fuels, it seems crucial that CO2 Capture and Storage (CCS) will be successfully developed and applied if to meet emission caps. A failure of CCS would require a global agreement on quickly abandoning fossil fuels, i.e. to phase out those in spite of them being cost efficient – a scenario which hardly seems realistic especially not for developing economies with access to large coal reserves such as China.

In a recent work, Kjärstad and Johnsson (2009a) show that, applying available cost estimates, it is possible to build up a transport and storage infrastructure at a cost of less than 10 €/ton CO2 (see also Odenberger and Johnsson, 2009). Yet, the analysis by Kjärstad and Johnsson assumes well defined storage sites and that all actors agree on a concerted action to establish a large coordinated network sufficient to meet the maximum CO2 flow over the period studied (2020 to 2050). It is concluded that the ramp-up of a CCS infrastructure is crucial and depends on several factors such as establishment of legal framework, possibility to establish public-private partnership or other appropriate business regimes and acceptance issues. In addition, there may be limitations in coal supply to meet an increased use of coal corresponding to increased use of CCS. In this perspective it seems obvious to have the début year of CCS as a parameter to vary in energy systems modelling.

4.1 CCS – state of the art

Based on the recent years of research and development of CCS, the following observations can be made:

- In most scenarios (from international organizations, research institutions and political organizations) on how to meet GHG emission caps, CCS is taking a significant share of CO2 reductions from the stationary energy system (mainly electricity generation).

- It seems as if there is a growing faith in CCS as a technology having the potential to make significant reduction in anthropogenic CO2 emissions.

- If development follows current plans and targets, roll out cost for CCS – capture, transport and storage – is estimated to be in the order of 25 €/ton CO2 avoided. In Europe, this would make coal fired base load with little or no CO2 emissions competitive, considering expected price for CO2 allowances as a result from the EU Emission Trading Scheme (EU-ETS).

- It seems unlikely that CCS will be commercially implemented at large scale before 2020.

- Although the entire CCS chain (capture, transport and storage) is not yet applied each step has been demonstrated at technical scale.

- The capture part is generally considered most critical when it comes to cost. Yet, cost estimates of transport and storage assume an integrated wide distributed network implying that the ramp-up of a CCS infrastructure will be critical (since costs for smaller transport and storage network is considerably higher).

- There are capture technologies for which all components have been tried in industrial applications, but at smaller scale than required in CCS applications.

- The different capture technologies proposed are similar in estimated costs but differ in complexity and maturity of components included. Thus, it is premature to pick a winner at this point in time (2009). It seems, however, reasonable to assume that those capture technologies which to the largest extent are based on existing/proved technology will have an advantage in the development. This, since there is always a risk in changing technology.

- There are a number of projects for demonstrating the CCS technology. These projects concern different capture technologies (pre-, post and oxyfuel) and are at different stage of development; from plans on paper to concrete pilot plants already in operation. As for electricity generation, pilot projects are typically of some 10 MW, demonstration plants 100 MW and commercial project above 500 MW. For lignite plants, the commercial scale should be around 1000MW. In 2009, only (a few) pilot plants are in a start up phase or in operation. Demonstration projects are in an engineering phase whereas projects of commercial size are in an early planning phase. Yet, development is fast and EU targets

some 12 large demonstration projects to be up and running in year 2015 (ZEP, 2008).

- Up to and post year 2020, a great challenge should be to introduce and ramp-up CCS in a cost efficient way, i.e. in addition to the challenge to develop the technology itself. The challenge is to find coordinated actions for implementing CCS which typically would involve several countries and companies in a coordinated action/cooperation. This, to facilitate the ramp-up of the entire chain: capture, transport and storage in an integrated and cost efficient way.

4.2 Basis for CCS scenarios

The aim is here to arrive at a proposal for some principal CCS scenarios which can contribute to an assessment of the CCS as a CO2 mitigation option by use of energy systems models as the one used in the PLANETS project. Or, in other worlds, what is given below should serve as a basis for modelling the uncertainty of CCS. The exact implementation of the CCS scenarios will differ between models, depending on how technologies are described. Also, it is likely that not all scenarios can be implemented in all models. Based on the assessment carried out in the present work, the following have been identified as main uncertainties in the development and diffusion of CCS as a CO2 mitigation option[1]:

CCS-cost development. Obviously, costs for CCS will go down with increased amount of installed capacity. Yet, this is not straight forward as discussed below and it is therefore not straight forward how to apply the concept of technological learning for CCS.

Ramp-up of the entire CCS system (capture-transport-storage). Based on what is listed above it can be concluded that, if assuming that the cost for CCS will become according to estimates and that there will be a cost to emit CO2 high enough to meet emission caps (e.g. 50 to 85% reduction in CO2 emissions until 2050), it seems as if the timing of when CCS becomes available is not so much due to difference in cost between the different capture technologies but more due to the possibility to ramp-up the entire chain capture, transport and storage in a sufficiently coordinated way in order to limit costs. Thus, in en energy systems modelling exercise, both the year of CCS debut and the rate of increase in investments from that year and on, are crucial parameters to study. This is further discussed below.

Lock-in prevention. This refers to measures which have the aim to prevent lock-in in new fossil plants (especially coal plants), before CCS has reached commercial status (and before cost to emit CO2 is high enough for CCS to be implemented). There is currently an uncertainty in such measures and in the possible effect of these. As for CCS there are two measures of relevance; so called capture readiness and policy measures hindering the building of new coal plants without capture such as Emission Performance Standards (EPS). In addition, there is an uncertainty in that even without such measures, local and political opposition towards new coal plants is increasing and, thus, it is not known to what extent coal plants can be built, even in the case where such are planned to be implemented.

Innovations. Innovations may very well take place which will change the picture of CCS, making it more competitive. This could either result in an entirely new capture technology (possible based on some of the novel concepts currently at a research stage) or as a result of a breakthrough in

[1] This is a further development of the proposal discussed with the PLANET consortium in the Amsterdam meeting on 4th of December, 2008.

the development of key (energy consuming) components in one of the capture technologies currently under industrial development.
The basis for the above listed uncertainties is further discussed in next section followed by a proposed strategy for CCS scenarios in energy systems modelling. *With a CCS scenario is here meant the input and restrictions with respect to CCS in energy systems modelling.*

4.3 CCS – general on costs

As indicated above, the main cost for CCS lies in the capture step. Compared with a plant without CO2 capture, the cost for CCS is due to the following:

- An increase in investment costs
- Energy required for capture, i.e. a CCS plant has lower efficiency (consumes more fuel)
- Increased maintenance cost
- Cost for transport
- Cost for storage

In principle, there are three different capture technologies under development; pre combustion, post combustion and oxyfuel combustion. As seen from Figure 1, technology development is being carried out for all of these three capture technologies.

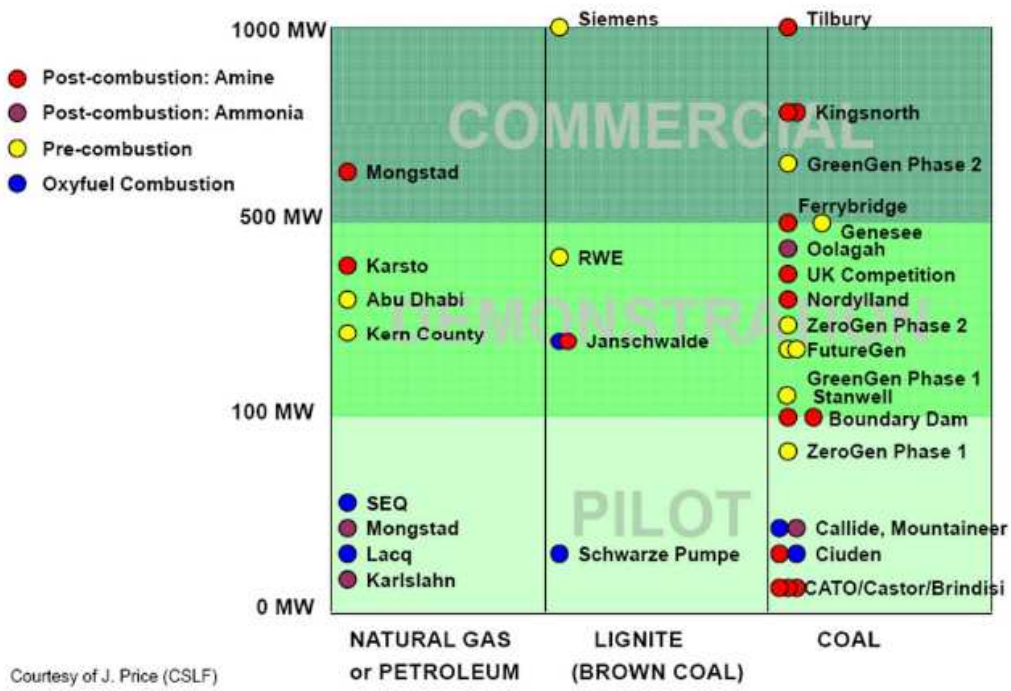


Figure 1. CCS projects divided into pilot, demonstration and commercial size/status. From Price (2008).

From available information it can be concluded that, at present (2009), it is not possible to foresee any significant difference in cost between the capture technologies (e.g. ENCAP, 2006b). At least not in the context of the energy systems modelling of PLANETS, i.e. differences between capture technologies are small and associated with uncertainties. This is especially true when considering other variations in costs which occur for large scale industrial projects such as building power plants. Yet, there is a significant learning to be expected, i.e. the cost will be reduced with number of plants built and mainly due to economy of scale, as discussed below. With cost is meant investment cost and fuel cost (i.e. including energy penalty due to decreased efficiency compared to plant without capture).

In a recently completed large EU funded project Enhanced CO2 Capture (ENCAP), a detailed assessment of the cost for various capture technologies was carried out (based on significant information from industry). These costs (ENCAP, 2006a, 2006b) have been compared with cost estimates carried out in the present work, and it can be concluded that these costs are still good estimates (or that there is no fundamental knowledge which would change costs). As for one of the capture technologies (oxyfuel) the ENCAP costs agree well with estimates a detailed technology assessment carried out by the research group of this workpackage (Andersson and Johnsson, 2006). Since there are generally little differences in costs between capture technologies, the cost obtained from the above technology assessment work in ENCAP is used here. The costs are based on a rather detailed assessment of power plants of commercial size (and carried out by industry as well as academia). Thus, the size differs between technologies and fuels, but generally large plants are required for CCS to reach costs given in various sources in literature. Typically, hard coal CCS plant would have an installed capacity of at least 600 MW and lignite fired CCS plant a capacity of around 1 GW.

Considering that there are other differences between different capture technologies (e.g. complexity, maturity) further points to that in energy systems modelling of the future it seems meaningless to divide costs between different technologies (post combustion, IGCC and oxyfuel) – in fact misleading. Only the difference between coal based CCS and natural gas CCS should be of relevance at this point in time. Table 1 gives an overview of proposed costs for coal and natural gas plants with and without CCS (Odenberget et al., 2009, ENCAP 2006a, b). Typical fuel costs are given in Table 2 together with IPCC emission factors. The exact costs are of less importance and the costs in Table 1 should therefore be seen as an example of possible reference costs from which variations can be carried out in a sensitivity analysis or in a stochastic modelling exercise. Table 1 also includes assumptions on technical life times and typical load factors. As can be seen from the load factors, CCS will be applied to base load plants.

Table 1. Assumed technical lifetimes, investment costs, O&M costs and maximum load factors for power plants with and without CCS. Costs in €-2003. Costs from ENCAP (2006a, b) and assessments from this work.

Generation technology	Technical lifetimes [years]	Investment cost [€/kWe]	Fix O&M cost [€/kWe, year]	Var O&M cost[€/MWhe]	Maximum Load Factor [percent]
Hard coal	40	1023	26.3	1	85
Hard coal CCS	40	1614	39.7	1.1	85
Lignite (Germany)	40	1337	29.3	1.1	90
Lignite CCS (Germany)	40	1960	42.7	1.1	90
Oil	30	630	26.4	0.3	85
Natural gas	30	630	26.4	0.3	85
Natural gas CCS	30	1080	32.4	0.4	85

Table 2. Fuel price projections (in €-2003) and emission factors for fossil fuels

	Assumed fuel prices [€/MWh$_{fuel}$]					Emission factors(4)
Generation technology:	2000	2010	2020	2030	2050(2)	[kg C/GJ$_{fuel}$]
Hard coal(1)	4.32	6.42	7.25	7.66	8.60	25.9
Lignite (Germany)(3)	3.96	3.96	3.96	3.96	3.96	30.4
Oil (Crude oil)(1)	16.09	22.94	24.73	29.61	42.48	20.0
Natural gas(1)	8.64	17.43	19.02	22.98	33.56	15.7

(1) (EC, 2007)
(2) values extrapolated from 2030
(3) (ENCAP, 2006a)
(4) (IPCC, 2008)

The CCS cost calculations are further described below. Firstly, the basis for modeling costs for capture is described on the form applied in Table 1 (electricity generation cost) which is the cost typically applied in energy systems modelling. Then, estimates of the so called CO2 avoidance costs, often given in literature, are given. Finally, costs for transport and storage are given which are obviously related to the amount of CO2 captured and, therefore expressed in €/ton CO2.
All costs given are costs for society, i.e. there are no "transaction costs" included.

4.4 CCS – calculations of costs for capture in energy systems modeling

The costs in Table 1 are given on the form which is typically used in models which have an objective function which is the sum of discounted annual (or other period) costs for the electricity generated during the time period investigated. Thus, the costs are on the form expressed by Equation (2) below. An example of such a model is the MARKAL model which is described in the MARKAL handbook (Loulou et al, 2004). Another model is the ELIN model developed recently by Odenberger et al. (2009) and which has been used to investigate the role of CCS for the European electricity generation system (e.g. Odenberger et al., 2008, Odenberger and Johnsson, 2009). The objective function for these ("bottom up") models can be written on the form:

$$NPV(r) = \sum_{t=start}^{t=end} (1+d)^{start-t} \bullet ANNCOST(r,t) \qquad (1)$$

where:
NPV(r) is the net present value of all costs associated with meeting electricity generation demand in the region

***ANNCOST*(*r,t*)** is the annual costs of electricity (including costs for CHP/BP heat) generation in region *r* for year *t*.
d is the general discount rate.
start is the initial year for which the CEI db provides a system description.
end is the final year within the analysis (e.g. 2050).
The annual costs *ANNCOST*(*r,t*) is the sum of all costs associated with electricity generation over all fuels *f*, technologies *k*. This includes costs for annualized investments, fixed and variable operation and maintenance costs. The term for the annual cost can be expressed as:

$$\begin{aligned} ANNCOST(r,t) = \sum_k \{ & AnInvCost(r,t,k) \bullet INV(r,t,k) \\ & + FixOM(r,t,k) \bullet CAP(r,t,k) \\ & + VarOM(r,t,k) \bullet GEN(r,t,k)\} \\ + \sum_f \{ & FuelCost(r,t,f) \bullet FUEL(r,t,f)\} \end{aligned} \quad (2),$$

Where (taking the ELIN model as an example):
***AnInvCost*(*r,t,k*)** is the investment cost annualized to a stream of equal payments throughout the physical lifetime of the investment, which discounted to the investment year is equivalent to the actual lump sum of the investment.
INV*(*r,t,k*)** is the investments in region ***r in technology ***k*** at year ***t***, which consists of new investments to meet policy and new investments to cover any shortfall in generation and in the ELIN model, this is a variable which is optimized.
FixOM*(*r,t,k*)** is the fixed operation and maintenance costs for maintaining the generation capacity in the system in region ***r in technology ***k*** at year ***t***.
CAP*(*r,t,k*)** is the sum of active generation capacity in region ***r in technology ***k*** at year ***t***. Hence, this variable consists of residual capacities at year ***t*** from the present system, new investments to meet policy and new investments to cover any shortfall in generation. In the ELIN model, *CAP*(*r,t,k*) is a variable which is optimized.
VarOM*(*r,t,k*)** is the variable operation and maintenance costs for utilizing the generation capacity in the system in region ***r in technology ***k*** at year ***t***.
GEN*(*r,t,k*)** is the sum of electricity generation in region ***r in technology ***k*** at year ***t*** and in the ELIN model this is a variable which is optimized by relation to ***CAP*(*r,t,k*)**.
FuelCost*(*r,t,k*)** is the fuel costs in region ***r in technology ***k*** at year ***t***.
FUEL*(*r,t,k*)** is the total fuel consumption in region ***r in technology ***k*** at year ***t*** and a variable optimized by the model by relation to ***GEN*(*r,t,k*)**.

4.5 CCS – estimates of CO2 avoidance cost (capture step)

As indicated above, literature on CCS often gives the cost expressed as a so called CO2 avoidance cost, i.e. as the cost of avoiding one tonne of CO_2 [€/ton CO_2]. For a power plant, this cost is normally obtained as follows: If the electricity generation cost is the total annualized cost (€/year) divided by the annual electricity production (kWh/year), the avoidance cost [€/ton CO_2] is calculated according to:

$$\frac{(€/MWh)_w - (€/MWh)_{w/o}}{(tCO_2/MWh_{w/o} - tCO_2/MWh_w)} \quad (3)$$

where indexes *w* and *w/o* denote a power plant with and without CO_2 capture, respectively. Equation (3) typically refers to plants with and without capture with the same net electric output. Thus, the net electricity output is kept the same as in the reference plant without capture. This results in an increased boiler power of the capture plant which has implications on energy systems analysis and when discussing the economic and environmental implications of the capture plant. See Andersson et al. (2006) for a discussion. Also, Equation (3) is typically used so it compares the same technology and fuel with and without capture (e.g. a pulverized coal fired plant using lignite as fuel with and without capture).

A problem with a definition according to Equation (3) is that in reality, the real CO2 avoidance cost will depend on the whole energy system and is not necessarily a comparison between a plant with capture and one without applying the same technology. Instead, the cost of avoiding CO2 for an energy system should be as obtained from modelling the development of an entire system with costs according to previous section applying a cap of CO2 emissions which gives a shadow price of the CO2 emissions which then would be the CO2 avoidance cost. Yet, the cost obtained from Equation (3) is important for plant owners when estimating what it will cost them to remove CO2 from a specific plant.

Some reports also presents CO2 avoidance cost curves (marginal cost curves in [€/ton CO_2 vs ton CO_2 avoided]) such as the one given by McKinsey (2009). The curve by McKinsey is based on estimates of emissions and abatement potential by sector and region (presented as a global curve). The curve is based the difference in emissions and costs between a baseline without any measures and a case with abatement applied. The calculations are for a specific year (year 2030 in the McKinsey case). For each measure costs are calculated as in Equation (3). The results can be used as an estimate and comparison between technologies and sectors with respect to potential for CO2 emission reductions and costs for these reductions.

4.6 CCS – estimates of costs for transport and storage

As for transport and storage, cost will obviously vary with distance and other regional conditions for capture. On the other hand, except for initial projects, CCS is hardly an alternative if costs for transport and storage exceeds 10€/ton CO2 (perhaps except for some niche markets). If no other information is available an average cost for transport and storage of 7.5€/ton CO2 can be applied as a first estimate (Odenberger and Johnsson, 2008), i.e. equal to roll-out cost for the intermediate category (Catergory 2) in Table 3. In order to refine costs a regional assessment must be carried out with respect to conditions for a CCS infrastructure such as average distance to storage sites and storage capacity. Table 3 summarizes the results of such an assessment made for EU27. Obviously, there will be countries/regions for which CCS is not an option (e.g. due to too long transport distances or lack of large fossil fuelled power plants).

Table 3. Estimates of member state specific costs for transportation and storage of CO2 captured in CCS technologies. Costs estimates in each category based on known national storage potentials and locations of present point sources (power plants) as described by Kjärstad and Johnsson (2009a). Costs in 2005 €.

Category 1 (5 €/ton CO_2)	Category 2 (7.5 €/ton CO_2)	Category 3 (10 €/ton CO_2)
Belgium, Bulgaria, Czech Rep., Denmark, Germany, Greece, Hungary, Ireland, Italy Latvia, Netherlands, Norway, Poland, Romania, Slovakia, Slovenia	Austria, France, Luxembourg, Spain, UK	Cyprus, Estonia, Finland, Lithuania, Luxembourg, Malta, Portugal, Sweden

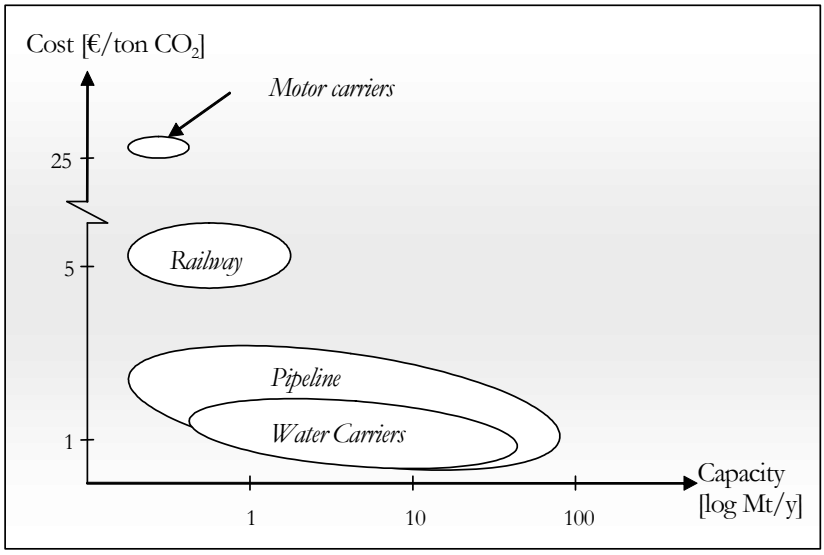
4.7 CCS – uncertainties in costs and implementation

As indicated above this section gives basis for the CCS scenarios proposed in Section 4.8.

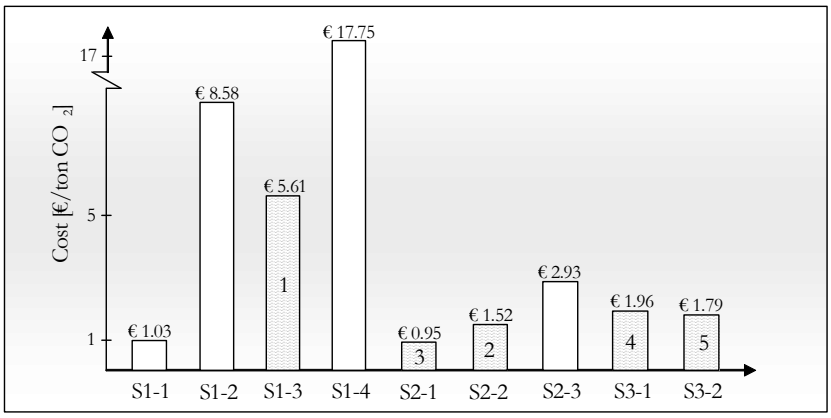
CCS-cost development. Little is known on what learning to be expected for CCS in terms of the slope of a learning curve. Riahi et al. (2004), and more recently Rubin et al. (2007), discuss learning for CCS using historical experience curves as the basis for estimating future cost trends. Thus, their work is mainly focussed on the capture process, although they give costs which include both transport and storage. Rubin et al. (2007) do not include learning for the transport and storage part, observing that these costs are generally low relative to the cost of the plant with capture. In line with what is mentioned above, this should be true for a fully developed CCS system with an integrated transportation and storage system (serving several power plants). However, initial costs for transport and storage may be high and there should be significant reduction in costs but then mainly due to economy of scale. Especially for the transport part, initial projects will give significantly higher transportation costs, i.e. in case a transportation system is built for only one utility (or for one or a few power plants). Thus, the rather low costs for transport often used in economical calculations (some 2-3€/tonne CO_2) assume an integrated transportation network. This can be seen from Figure 2 which shows estimates of transportation costs for various CO2 transportation modes (Figure 2a) and systems (Figure 2b and 2c). Figure 2b shows the transportation costs for a number of transportation systems, illustrated in Figur 2c with the systems specified in Table 4. As can be seen, costs range from a few €/tonne CO2 transported to almost 20 €/tonne CO2 transported. Similar variations should hold for the storage part, since costs for prospecting, developing and maintaining the storage site should depend on the amount of CO2 to be stored. Also for storage the main reduction in cost should be due to scale and not so much due to learning in a strict sense. This, since storage technology is similar to what has been used in oil industry.

Table 4. Combinations of CO2 transportation systems as investigated by Svensson et al. (2004).

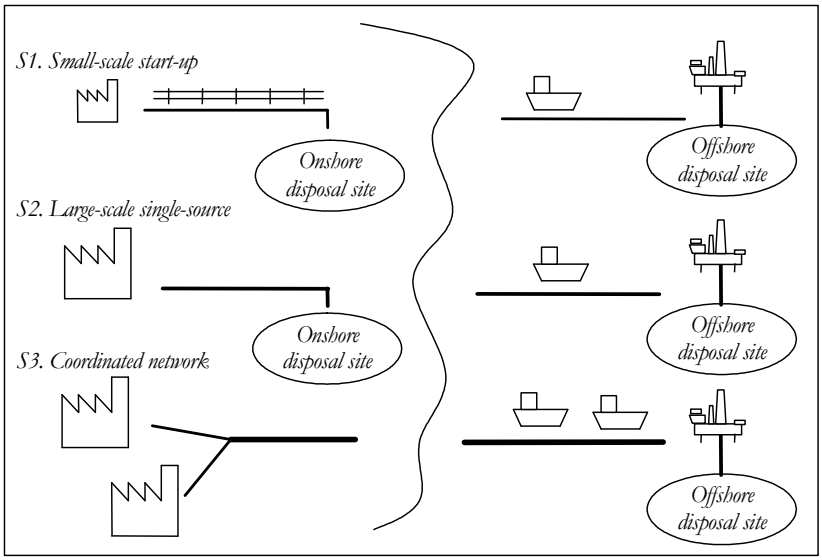
System	Module combinations	Distance [km]	Amount [Mt/y of CO_2]
S1-1	Pipeline onshore	110	1.0
S1-2	Railway Intermediate storage Water carrier	100 500	1.0
S1-3	Pipeline onshore Intermediate storage Water carriers	100 500	1.0
S1-4	Pipeline onshore Pipeline offshore	100 500	1.0
S2-1	Pipeline onshore	110	10.0
S2-2	Pipeline onshore Intermediate storage Water carriers	100 500	10.0
S2-3	Pipeline onshore Pipeline offshore	100 500	10.0
S3-1	Pipeline network onshore Pipeline network offshore	230 550	40.0
S3-2	Pipeline network onshore Intermediate storage Water carriers	230 500	40.0


Cost [€/ton CO2]
Motor carriers
25
5
Railway
Pipeline
Water Carriers
1
Capacity
[log Mt/y]
1
10
100

a.


Cost [€/ton CO 2]
17
5
1
€ 1.03
€ 8.58
€ 5.61
€ 17.75
€ 0.95
€ 1.52
€ 2.93
€ 1.96
€ 1.79
1
3
2
4
5
S1-1
S1-2
S1-3
S1-4
S2-1
S2-2
S2-3
S3-1
S3-2

b.


S1. Small-scale start-up
Onshore disposal site
Offshore disposal site
S2. Large-scale single-source
Onshore disposal site
Offshore disposal site
S3. Coordinated network
Offshore disposal site

c.

Figure 2. Cost and capacity for transportation of CO2, **a.** Cost for transportation alternatives assuming 250 km transportation distance. **b.** Specific cost comparisons for the transportation systems outlined in c and specified in Table 4. **c.** Transportation systems investigated. From Svensson et al. (2004).

In summary, for both transport and storage, establishment of an integrated infrastructure seems crucial in order to bring costs down whereas technological learning[2] can be expected to have less influence. It should, however, be stressed that since neither transport nor storage of CO2 have been implemented at the scale required for large scale CCS, there is obviously little experience to use as basis for en estimate of what learning can be expected. It can only be concluded that both transport and storage is based on less complex technologies than the capture process and, therefore, learning can be expected to be of less significance. Economy of scale on the other hand should be significant and, thus, the ramp-up of the entire CCS system is critical and failure to obtain coordinated actions may delay the début and ramp-up of CCS.

Ramp-up of entire CCS systems (capture-transport-storage). The ability for the society to establish coordinated transportation network and coordinate storage obviously depends on several factors, such as international agreements, agreements between companies and development of required institutional frameworks (e.g. national environmental laws and permitting processes) as well as how storage sites can be allocated nationally and as coordinated allocation for several countries. Thus, it is important that clusters of emission sources (power plants and industries with large CO2 emissions) can build a coordinated transport and storage infrastructure. Although this should be rather straight forward from a technology point of view this is not obvious from an institutional point of view (possibilities to reach public private partnerships, competition issues etc).

Although storage potential is large, most figures available builds on rather rough estimates and site specific investigations are required in order to arrive at actual storage capacity (see Kjärstad and Johnsson, 2007, Kjärstad and Johnsson, 2009a, and references in these for a discussion). There is a great need for a detailed assessment of storage capacity which links emission sources with storage locations and on a level which is detailed enough, but not too detailed to provide input (boundaries) to energy systems modelling. A too detailed analysis will obviously be limited in geographical scope whereas rough estimates on global storage capacity without any connection to emission sources will be of limited use as basis for boundaries in energy systems modelling of the role of CCS.

A limited number of studies which specifically investigate CCS from an energy systems perspective can be found in literature. Wise et al. (2007) Rafaj and Kypreos (2007) investigate the role of CCS by applying scenario analysis in energy systems modelling. Other studies have a more general scope investigating the development of the entire energy system, including estimates on the possible role of CCS applying a variety of methods and models (Pacala and Socolow, 2004; Eurelectric, 2007; EC, 2007; Stangeland, 2007; Capros et al, 2008; OECD/IEA, 2008). In addition, there are studies on transportation infrastructures for captured CO2 from a technical and economical point of view (GESTCO, 2004; IEA, 2005; Middleton and Bielicki, 2009). The main conclusion drawn in the above studies is that, provided that there will be a cost of emitting CO2, CCS can contribute to reduce CO2 emissions substantially from power generation although other options are needed as well. Yet, there is a lack of studies which include

[2] One may of course include economy of scale as part of learning.

information on the energy infrastructure on a level of detail which make it possible to match centralised CO2 emission sources and CO2 storage capacity on an intermediate level of detail, appropriate for energy systems modelling. The research group of this work have performed such studies, but so far only for Europe (*e.g.* Kjärstad and Johnsson, 2009a, Odenberger et al, 2009). Work has been initiated to make global estimates on source sink matching, considering power pant infrastructure (Kjärstad and Johnsson, 2009b). Yet, such work is rather comprehensive, involving collection and analysis of both energy systems data and geological data. As for the latter there is a problem in that site specific investigations on storage capacity is often lacking leaving analysis to rest on rough estimates of storage potential.

In all, the above points to that an assessment of CCS using energy systems modelling should include a scenario for which the commercialization of CCS is delayed, compared to what is generally expected. As indicated above such delay is not necessarily due to problems with the development of the capture technology, but could be due to problem in the ability of society to ramp-up CCS infrastructure in a coordinated way. Thus, from an uncertainty point of view one could see two possible scenarios for the ramp-up of CCS: A "*coordinated-action scenario*" and a "*slow-start scenario*". In the coordinated-action scenario, agreements are reached both with respect to international climate treaties and between companies and countries with respect to coordinated actions for establishment of a CCS infrastructure. Thus, it is assumed that strong international climate policies are required in order to establish efficient introduction of CCS. Costs would then soon reach CCS reference cost estimates (such as those presented in Table 1). For the transport and storage network national and regional agreements considering the area covered by the CCS infrastructure is the most crucial for efficient ramp-up of CCS infrastructure.

In a slow-start scenario, diffusion of CCS is lower because of lack of concerted actions for CCS introduction rather than failure or delays in the development of the CCS capture technology as such. In this case, the initial period with higher costs for CCS will last longer.

<u>Lock-in prevention.</u> Although not linked to the CCS technology itself, the prospects of coal power from now and until CCS becomes commercially available should have implications on parameter variation in energy systems modelling. There is both in the US and in Europe a growing public and political opposition to new coal fired power plants and several coal fired projects have recently been shelved, mainly due to local opposition (Kjärstad and Johnsson, 2009c). Figure 3 shows an example from North America. As can be seen a significant number of planned plants have been shelved (red bullets in the figure), often due to local and/or political opposition. In addition, both in the US and in EU, there have been proposals to enforce so called Emission Performance Standards (EPS). Such standards define maximum thresholds for the emission-intensity of power generation (e.g. in gCO2/kWh). Any emission level below 500gCO2/KWh will make it impossible to run a coal plant or to build new ones. Schemes which enforce such emission limits are discussed in Europe, such as applying EPS on new plants from year 2010 and on existing plants from year 2015 and on, as an example of a strict case (e.g. Ecofys, 2008). EPS is already in place in some states in the US and have recently been proposed on a national level in the US (US Clean Energy and Security Act, 2009).

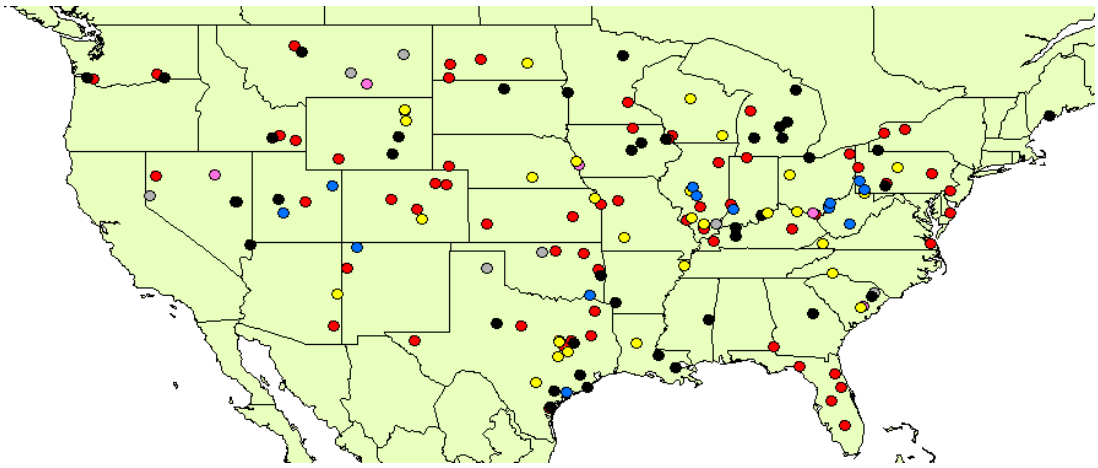


Figure 3. Coal plants under various stages of development in USA (collected between January 2007 and July 31, 2008). Red circles illustrate plants that have been rejected or abandoned, pink circles plants that came online, yellow circles plants that are under construction, blue circles plants that have been approved, black circles show plants that are under various stages of planning while grey circles show plants that have been proposed (see Kjärstad and Johnsson, 2009c for sources).

It is not clear how to combine an EPS with an emission trading scheme such as the European Emission Trading Scheme (EU-ETS). There is, of course, an obvious inherent contradiction with such a plant emission limit and the EU ETS since the whole idea with EU-ETS is to obtain a market based policy measure with the aim to reduce emissions at lowest cost.
Although EPS is meant to avoid lock-in effects it may in some regions instead enhance lock-in effects such as excessive use of natural gas in electricity generation (installations of natural gas combined cycles). Thus, this would result in short term reduction but then make it more difficult to achieve deeper cuts in CO2 emissions and to enhance security of supply on a longer time scale (e.g. natural gas dependency in Europe will be enhanced and prolonged). Thus, EPS may indeed give initial reductions in CO2 but will then leave less room for CCS when available (most likely over the first decades from introduction, CCS will be cost efficient on coal plants whereas not for natural gas fired plants, especially not for existing natural gas fired plants, *cf.* Table 1). It should be mentioned that also emission trading has been criticised for mainly promoting short term actions (*e.g.* Grübler et al., 1998), although this is disputed and long term effects from emission trading may promote technology shift and development of new technologies (Criqui and Viguier, 2000). See also Metz et al. (2001) for a discussion.
In summary, a scenario which assumes no coal fired power plants to be built from say, 2010 and on, together with an early retirement of existing plants would be of interest (especially to be applied in North America and Europe). Such an "EPS scenario" is proposed in next section and would make it possible to study if implementation of EPS (or other effects hindering the building of new coal fired plants) could lead to the above mentioned lock-in effects compared to a scenario without restrictions on technology but with a cost to emit CO2, such as a result from an emission trading system.

Related issue are retrofitting and capture readiness. As for retrofitting, this is believed[3] to have marginal importance. Retrofitting would in principle mean application of post combustion technology[4]. Since capture is associated with an energy penalty, it is important to apply capture to high efficient power plants if to arrive at competitive electricity production. It seems unlikely that there will be retrofitting of plants with lower efficiencies than 43%, since this would result in a plant with very low efficiency and, thus, increase the cost for electricity generation. In Europe (within EU) the Large Combustion Plant Directive (LCPD) may facilitate a driving force to replace old coal plant with new plants and, thus, there will not be any old inefficient plants left.
In EU as well as in individual member states, it has been discussed that coal plants should be capture ready. Yet, there is at present no definition on capture readiness or rather, there are several definitions proposed, as discussed by Markusson and Haszeldine (2008). Capture readiness is a range of possible investments that a plant owner might undertake during the design and construction of the plant (Bohm et al., 2007). A low cost capture readiness alternative is simply to ensure that there is enough space for future post combustion capture equipment. One may also argue that in principle all fossil fuel plants are capture ready since unless the site of the power plant is very tight, there is always the possibility to apply post combustion. It seems unlikely that utilities would make significant investments in capture readiness, more than guarantee that there is space allocated for installation of capture provided this will be commercially competitive (*i.e.* a rather weak condition). As stated by Bohm et al. (2007), the longer the delay in establishing a CO2 price after a plant is built, the higher the CO2 price needs to be to justify a capture ready plant.
From a modelling perspective it seems reasonable to assume:

- Retrofitting capture on existing plants will not be an option if plant efficiency is lower than 43%. A 43% efficiency means reasonable high steam data and this is a typical efficiency for state of the art plants built around year 2000 (cf. Andersson and Johnsson, 2006). Based on a first assessment and discussions with industry a first estimate is that retrofitting will have an investment cost around the same as a new plant, due to the reasons explained below. O&M costs (after retrofitting) can be assumed similar to a new CCS plant. As for fuel cost efficiency can be assumed same as for new CCS plant (or original efficiency subtracted by available figure on post combustion energy penalty).

- Capture readiness for new plants could be an option from year 2010, but it is hardly meaningful to define a cost for such option. At least this has to be further discussed if finding a modelling strategy which includes capture readiness.

The reason why investment cost for capture retrofitting is similar to a new CCS plant is due to the following:

[3] According to the authors, this is the general view in industry and from an assessment of the requirements for a capture cycle to be cost efficient. There are no specific references in literature which can back-up this conclusion – it is a conclusion drawn from cooperation with industry.

[4] Here, retrofitting assumes that most of the original power plant is kept. Since the value of an existing power plant site is high, one may denote a complete replacement of a boiler on a site (possible keeping cooling towers and other infrastructure) retrofitting. However, this would mean costs similar to a new CCS plant.

- *Incompatibility problem*. Retrofitting a power plant would yield less electricity since process heat is required for the scrubbing process (post combustion).

- *Turbine reinvestment*. Related to the above point, there is a possible reinvestment required for the steam turbine (accelerated depreciation for existing turbine).

- *Extra cooling tower*. Increased cooling efficiency is required to cool the excess heat from capture process. This means that a new cooling tower must be built and these are costly.

- *Reduced depreciation time*. The depreciation time will be more or less reduced for the capture investment (i.e. can only be depreciated during remaining life time of original plant).

For capture readiness it follows from the above that it is difficult to know what costs to apply, i.e. since this depend on what is meant by capture readiness. The paper by Bohm et al. (2007) may give some guidance to capture readiness. In all, both retrofitting and capture readiness are believed to be of minor importance and it seems reasonable to assume that there will be no large investments in capture readiness.

CCS failure. There is of course the risk that there will be a major hurdle in the development of the CCS technology such as a result of an initial accident (e.g. sudden leakage, other accident or political opposition) or failure to reach agreement on institutional or legal framework required to establish a cost efficient ramp-up of CCS. Although at present there seems to be a strong will to develop CCS as well as development seems to follow plans, an energy systems modelling exercise should include a scenario with a significant show-stopper for CCS. Thus, a scenario for which CCS is not an option should be investigated. A stochastic modelling could include a scenario with an initial breakthrough of CCS followed by a more or less sudden phase out of CCS (to simulate a sudden discovery of CO2 leakage or other problem with the CCS technology).

Innovations (technological breakthrough). There are some novel CCS technologies under development as well as development of key components in the above mentioned CCS technologies which, if successful, would result in a significant reduction in cost for CCS. The chemical looping technology is an example of a capture technology which is currently under development with promising results so far (chemical looping has no inherent energy penalty). There may also be a breakthrough in separation technologies (e.g. for oxygen production for oxyfuel combustion or for post combustion capture) which may lower capture costs. Thus, in a modelling exercise it should be of interest to include a “positive” jump, representing technological breakthrough for the CCS technology. Thus, at a specific year (or a random year), this would mean that zero emitting (or near zero emitting) fossil fuel technologies will be available at a cost only somewhat higher than a plant without capture with respect to running (fuel) cost whereas investment costs can be assumed similar. Also the cost for compressing CO2 to required state for transportation and storage will remain. For simplicity, the running CCS cost in such scenario may be set equal to a plant without capture (i.e. same efficiency). Yet, transport technology will most likely remain the same (as indicated above, transport is standard technology with little room for technology breakthrough) although storage technology may develop in similar way as oil extraction technology.

Other CCS options. In addition to the difference between different capture technologies, there will probably be different niche markets for the different capture technologies (rather that that there is a clear "winner"). An interesting niche market is CO2 capture in combined heat and power plants. Here, the revenue from the heat sales will offset some of the capture costs. In addition, some of the capture technologies (such as oxyfuel fired fluidized beds and chemical looping combustion) may be possible to build at smaller scales (without higher costs) than what is envisioned for the oxyfuel and post combustion technologies applied to pulverized coal fired power plants. There is, however, currently too little information as basis for a meaningful assumption on costs for such smaller capture plants (say 100-200 MW electric power).
CCS may be applied to polygeneration schemes and in co-firing of biomass. Producing heat, electricity and transportation fuel may yield a different cost picture and higher revenues for the plant owner. A future with an increased electrification of the transport sector may also shift the plant owner revenue.
These system effects are difficult to incorporate in an energy systems modelling exercise, due to limitations in technology descriptions in the models. Yet, this should be discussed, especially if there are modelling outputs which yield high electrification of the transportation sector (or, possible the other way around, the models may miss supply side opportunities associated with integration of the stationary and transport sector with respect to electrification of transport sector). Co-firing of biomass makes it possible to reach "zero emission" type or below zero emission" type plants. Co-firing should also be straight forward to include in energy systems modelling.
More work is required in order for a meaningful implementation of such processes in energy systems modeling.

4.8 CCS – proposal of scenarios for PLANETS modelling

Based on the above, CCS scenarios are proposed below. As mentioned above, CCS scenarios refer to the way CCS is defined in the various models, not the overall scenarios. Thus, conditions and boundaries for other technologies and measures should be defined separately, for each model. Also, it is the principal variations of costs and conditions for CCS technologies which should be in focus and not the absolute values. The figures given here should be seen as indications. Costs are given on the form expressed in Sections 4.3 and 4.4, i.e. cost for electricity generation. In addition, next section gives some estimates of CO2 avoidance costs as defined by Equation (3).
Reference scenario (CCS-1). This will represent a "*Coordinated action scenario*" applying the costs given in Table 1 (capture) and Table 3 (transport and storage). As for transport and storage 7€/tonCO2 can be assumed if no other information is available. Thus, the assumption is full scale CCS with integrated transportation and storage network, from year 2020 (or from when CCS is assumed available) an onwards. It should be noted that thermal efficiencies should be increased over the period studied.
Cost development (CCS-2). In line with discussions above this scenario will include cost development for the capture as well as for transport and storage to reflect that initial cost will be higher than roll-out costs. Thus, this will exemplify the above mentioned "*Slow-start scenario*". It is assumed that the major development will take part over the first 15 years after implementation of CCS, i.e. roll out costs are reached in year 2035. Additional development would be due to improvements in thermal efficiency (if included in modelling).

Table 5 presents a CCS cost-development scenario for the capture part in line with discussions given above. Obviously, such a scenario has to be implemented in different ways, depending on the characteristics and features of the model used and Table 5 should thus only be seen as an indication of cost levels to be applied. Models with endogenous learning may use the year 2020 cost as initial costs and apply learning rates as given by Rubin et al. (2007).

Table 5. Proposed cost-development scenario for capture technologies (Investment costs, O&M costs and efficiencies). Load factors assumed same as without CCS (Table 1). Roll-out costs same as in Table 1.

Generation technology	Year	Investment cost [€/kWe]	Fix O&M cost [€/kWe, year]	Var O&M cost [€/MWhe]	Efficiency [%]
Hard coal CCS	2020	3000	80	2	40
	2025	2500	60	1.5	
	2030	2000	50	1.3	
	2035/Roll out	1614	39.7	1.1	43
Lignite CCS	2020	4000	80	2	40
	2025	3500	60	1.5	
	2030	3000	50	1.3	
	2035/Roll out	1960	42.7	1.1	43
Natural gas CCS	2020	2000	60	0.8	47
	2025	1700	50	0.6	
	2030	1400	40	0.5	
	2035/Roll out	1080	32.4	0.4	53

Corresponding costs for transport and storage are given in Table 6 for a global estimate and in Table 6 to be used in models which can regionalize EU member states. As for the global estimate the high and low estimates can also be seen as offshore (high) vs onshore (low) storage. As indicated above, the assumption is made that there is higher uncertainties in transport costs than in storage costs. Therefore, transport costs are given as a high and a low cost range. Table 7 proposes corresponding cost-development scenarios for the three cost categories in Table 3.

Table 6. Proposed cost-development scenario for transport and storage in case national estimates are not available.

Year	Transport (high/low) [€/tonCO2]	Storage [€/tonCO2]
2020	20/15	10
2025	10/7	7
2030	5/5	5
2035	3.5/3	3.5

Table 7. Proposed cost-development scenario for transport and storage for the three cost category countries of EU27. Cost categories according to Table 3.

Year	Category 1 [€/tonCO2]	Categroy 2 [€/tonCO2]	Category 3 [€/tonCO2]
2020	15	17.5	20
2025	10	12	15
2030	7.5	9.5	12.5
2035	5	7.5	10

Ramp-up of entire CCS systems (CCS-3). This will correspond to the above given cost-development scenario, but it is assumed that CCS will not be commercially available until year 2030. The same data as given in Tables 5 to 7, but with year shifted 10 years further into future.
Lock-in prevention (CCS-4). Two scenarios are proposed:
CCS-4a. New coal plants (hard coal and lignite) without CCS are not allowed to be built from year 2010 and on. CCS assumed commercially available from year 2020. Thus, this means no investments in coal between 2010 and 2020.

A more general formulation is: Investments in plants which emits more than 500gCO2/kWh are not allowed from year 2010 and on.
CCS-4b. As CCS-4a, but after 2020, coal plants without CCS (or which emits more than 500gCO2/kWh) have either to be turned down or retrofitted with capture (plants with efficiency less than 43% will not be retrofitted and, thus, have to be turned down).
The results of these scenarios should be compared with CCS-1 in order to discuss possible lock-in effects.
CCS failure (CCS-5). Two scenarios could be investigated:
CCS-5a. CCS is not an option.
CCS-5b. An initial breakthrough of CCS and then in 2025 a phase out of CCS until 2030. Stored CO2 is assumed to leak at a yearly rate of 0.1% (which is a rather high leakage). The obvious question is then what will happen to global fossil fuel resources.
Costs as for CCS-1.
Innovations (CCS-6). At year 2025 (or a random year) zero emitting (or near zero emitting) fossil fuel technologies are assumed available with an efficiency of a plant without capture (possibly

subtracted by 2% to account for CO2 compression). If model only uses fuel cost as input, this one could be taken same as for a plant without capture for simplicity. It should be noted that cost for transport and storage remains (i.e. same as in CCS-1 scenario).
The result from this scenario should give information on how much development of CCS should be valued. A question is how far non-fossil fuel technologies and efficiency measures have reached by this year.
Costs until year 2025 as for CCS-1 (or CCS-2).

4.9 CCS – estimates of CO2 avoidance costs

Below are some estimates of CO2 avoidance costs on the form explained in Section 4.5, i.e. as given by Equation (3). Thus, figures are for the capture step and costs for transport and storage can be taken from the estimates given in Tables 6 and 7. Costs are from various estimates (e.g. ENCAP 2006a, 2006b, Andersson and Johnsson, 2006) and agree well with a recent report by McKinsey on costs for CCS (McKinsey 2008).
Thus, the following range for capture can be applied (year: total cost):

<u>High</u>
2015: 100 €/ton CO_2 (demonstration phase)
2020: 50 €/ton CO_2 (early market intro)
2025: 40 €/ton CO_2 but target is less which may be possible
2030: 37.5 €/ton CO_2
2035: 35 €/ton CO_2 (roll out)

<u>Low</u>
2015: 60 €/ton CO_2 (demonstration phase)
2020: 25 €/ton CO_2 (early market intro)
2025: 20 €/ton CO_2 - but target is less which may be possible
2030: 17.5 €/ton CO_2
2035: 15 €/ton CO_2 (roll out)

5. Biomass

5.1 Introduction

Bioenergy is the only renewable energy form that inherently generates carbon-based fuels, which is the basis for much of present-day energy technology. This makes biomass very suitable for use in both heat and power production and in the transport sector, where it is presently the major renewable alternative to gasoline and diesel. The respective bioenergy uses have different implications in term of, e.g., climate and energy security benefits. Consequently, different objectives and related policies lead to different prioritisation of bioenergy options, including the biofuel chain configuration.

The socioeconomic context and the already established energy, industry and transport systems are also strong – and geographically varying – determinants of the technology response to policies put in place. Technologies that can be integrated with the existing systems and do not require drastic changes in consumer behavior have a clear advantage: the blending strategy for biofuels in transport is one example of this and the substitution of biomass for fossil fuels in the forest industry is another. A third contrasting example, biomass based DME may become an important substitute for traditional biomass and LPG in developing countries and thereby reduce environmental pollution and health problems, while also increasing the efficiency of the biomass use in these countries.

In addition to already built energy infrastructure, the present construction and planning is important – not the least since new power plants, pipelines, etc. will stay in operation for many decades. For example:

- The large installed – and further growing – capacity of coal based power makes biomass co-firing with coal an important near term option. Globally, about 5000 PJ of biomass/waste could in theory presently be burned in coal power plants every year, assuming that biomass could be co-fired all coal-fired power plants at a 10% fuel share (on energy basis) (NETBIOCOF, 2006). The longer term prospects for biomass co-firing with coal depends on whether carbon capture and storage and/or high biomass shares in the fuel mix can allow for competitive power also under stringent climate targets (Figure 4).

- The availability of large installed capacity of natural gas based power with long remaining lifespan, and distributed grid of natural gas in domestic areas for heating, warm water and cooking, will make bio-methane production with upgrading to sufficiently high standard an option with substantial deployment potential. The buildup of a biogas refueling infrastructure for the transport sector can also rely on already existing natural gas pipelines. A clear illustration of this can be found in Sweden, where biogas refueling stations are concentrated along the west coast where the natural gas pipelines exist. On the other hand, further extension of natural gas pipelines in Sweden has been objected based on it competing with solid biofuel use in industry and CHP.

- District heating systems represent a possibly important sink for surplus heat that could make biomass gasification with subsequent biofuel synthesis more competitive. But heat

sink competition may arise due to the large existing surplus heat generation in the present energy and industry systems. In this perspective, ethanol production may instead obtain a competitive advantage by representing a heat sink suitable for co-siting with energy plants and industries generating surplus heat.

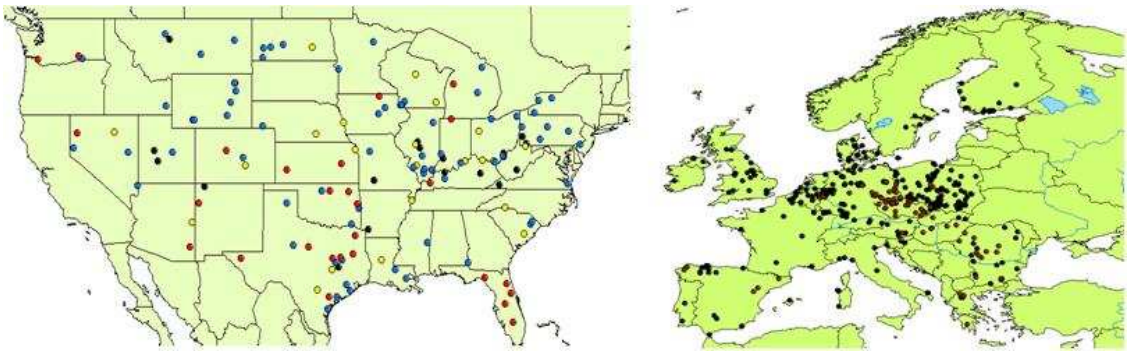


Figure 4. Right map: Coal fired power plants in EU (from Kjärstad and Johnsson, 2009c). Black and red dots represent hard coal and lignite plants, respectively. If the fuel mix used in existing plants less than 40 years old included 10-15% biomass, roughly 900 PJ of biomass could provide about 90 TWh, or almost 20% of 2005 RES-E generation. Left map: Future biomass co-firing opportunities in the US (same as Figure 3). Yellow dots represents coal power plants under construction (15 GW in total), Red dots = projects cancelled in 2007 (22 GW), Blue = plants under planning/proposed (50 GW) and Black = approved projects (12 GW). In total, roughly 1500 coal-powered units across the US (total nominal capacity of 335.8 GW in 2006[5]) presently account for roughly half of the electricity production in the US.

The development of bioenergy will also be shaped by the presence of competing energy resources and technologies for meeting policies. Illustrative of this, model-based energy system studies report diverging findings about whether biomass should be used for transport of stationary energy. The most basic explanation is that how biomass is used is to a large degree determined by availability of carbon neutral transportation that does not rely on biomass. If hydrogen or electric vehicles show themselves to be technically complicated, expensive or just incapable of satisfying the demands for technical performance which we want from our vehicles – and at the same time we want to achieve very low emissions of CO2 due to the climate problem – the only remaining option is to rely on biofuels for transport. The stationary sector in contrast can rely on a range of different low carbon options.
Another example – derived from WP4 modeling using Chalmers Energy Infrastructure Database and illustrative of the connections between the two major focus areas in WP4; biomass and CCS – the diagrams in Figure 5 show the development of electricity generation in Europe under a carbon cap, given contrasting development pathways for CCS. As can be seen, if CCS becomes established as an option and grows fast much less biomass will be required for heat and power production compared to a situation where CCS does not become established.

[5] http://www.eia.doe.gov/cneaf/electricity/page/capacity/capacity.html

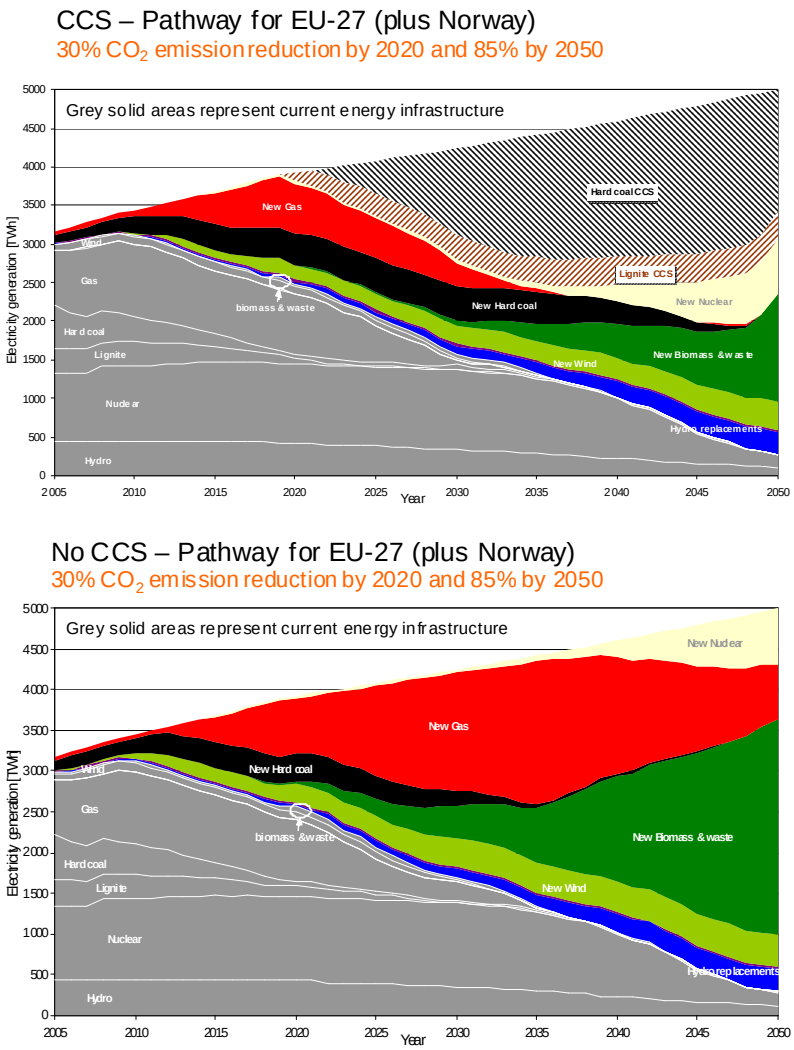


Figure 5. Contrasting bioenergy futures – the diagrams show the development of electricity generation in Europe under a carbon cap, given contrasting development pathways for carbon capture and storage (CCS) with upper plot representing a scenario with successful implementation of CCS (CCS-1) and lower plot a scenario for which CCS fails (CCS-5a). The grey area represents the existing power generation capacity, which is phased out over time due to age, and the coloured area represents the new generation capacity, which is added in response to increasing demand and the need to replace aged capacity. The diagrams are illustrative of the fact that the prospects for other technologies than those directly related to bioenergy can strongly determine how the demand for biomass develops. From Odenberger (2009, unpublished data).

Since individual countries differ in their existing energy infrastructure – and also in the prospects for other energy options than bioenergy – they will likely prioritize the biomass use differently. However, while region-specific preconditions consequently influence energy technology development in diverging directions, there are also conforming drivers: global companies compete based on own knowledge and technological capital (e.g., patents) and see advantages

in deploying the same technology platforms worldwide. Also standards drive development towards uniform systems.

The extensive modeling capacity in the PLANETS consortium provides unique opportunities to increase our understanding of how climate and energy policy drivers shape bioenergy development on the global (and large regional) scale. Model based explorations into the complexities of biomass use for energy – or even wider into land use strategies in response to climate and energy policy objectives – can provide important insights connecting to the present European energy policy context. Not only are there questions with respect to how biomass can be supplied in a sustainable way but there are also many questions related to the numerous ways and processes through which the biomass can be converted to heat, electricity or transportation fuel or combinations of these. Biomass is a limited resource and provided there will be a cost to emit CO2 (as in the climate scenarios of PLANETS) it is important to identify and assess cost efficient ways to convert biomass to electricity, heat or transportation fuels, or combinations of those.

The following focus areas are studied:

1. Ramp-up of biomass co-firing with coal in Europe
2. Uncertainties about the climate benefit of using bioenergy
3. Uncertainties regarding efficiency and cost of thermal systems for biomass conversion

Although the co-firing ramp-up is made on Europe, the experiences made should be applicable for other regions as well.

5.2 Ramp-up of biomass co-firing with coal in Europe

5.2.1 Biomass co-firing with coal – state of the art

Co-firing is the simultaneous combustion of two or more fuels in the same plant in order to produce one or more energy carriers. Co-firing biomass with coal in existing boilers to generate electricity has been proposed as a near-term, low-cost way to use biomass (e.g., lignocellulosic feedstocks) for reducing carbon dioxide (CO2) emissions (e.g., Baxter and Koppejan, 2004; Johnsson et al., 2006). Globally, experience with biomass (or waste) co-firing with coal comes from about 150 power plants, either as pilot tests or in commercial use (IEA Bioenergy, 2007). About 100 of these are in Europe, mainly in Germany, Finland, and the UK. A wide variety of biomass materials, including herbaceous and woody materials, wet and dry agricultural residues and energy crops are used (van Loo and Koppejan, 2008).

Currently, the typical conversion efficiency for a dedicated biomass-fired power plant is 25% (van Loo and Koppejan, 2008). The average conversion efficiency for conventional coal-fired power plants (so-called subcritical pulverised plants) is around 36% in OECD countries (Wicks and Keay, 2005), with new state of the art plants reaching at least 43% (Beér, 2007). Since the impact on conversion efficiency from low levels of biomass co-firing is judged to be modest (e.g., Hughes and Tillman, 1998; NETBIOCOF, 2006), biomass co-firing with coal represents a way to convert biomass with a high electric efficiency. Furthermore, experience show that moderate biomass levels can be co-fired without any major problems of alkali related high temperature corrosion, slagging and fouling (e.g., Davidsson et al., 2007; NETBIOCOF, 2006; Tillman, 2000).

In addition to offering high conversion efficiency, biomass co-firing with coal requires relatively small changes at the power plants. As a consequence, it costs less to implement than other biomass-based electricity generating options (see Box below). It also holds the advantage of

uncertain biomass supplies not uncertain biomass supplies do not jeopardize the fuel supply for power plant owners, who can manage a temporary loss on the biomass supply side (or short-term biomass price volatility) by increasing the share of coal in the fuel mix. This fuel flexibility also works the other way around: plant owners can increase the share of biomass in the fuel mix (up to technically defined limits) in response to low biomass prices and/or high RES-E prices.
Despite the substantial number of biomass co-firing installations, there are few cost estimates for implementing biomass co-firing with coal given in the literature. IEA/OECD (2006) reports costs at about 1000 USD/kW compared to 2500-5000 USD/kW for stand-alone biomass-based electricity. Lower values at about 50-300 USD/kW of biomass capacity is reported by NETBIOCOF (2006). These costs are in the lower cost range compared to other RES-E options, e.g., hydropower, at roughly 2500 USD/kW and onshore wind power at roughly 1000 USD/kW (OECD/IEA, 2006).
The large number of coal-fired power plants in Europe implies that biomass co-firing should have a substantial potential and studies also conclude that biomass co-firing can play a valuable role in these countries when meeting RES-E targets and reducing CO2 emissions from electricity generation (Perry and Rosillo-Calle 2006; Berggren et al. 2008). Yet, there is no detailed and consistent assessment of the potential for co-firing in Europe as a whole.

5.2.2 Assessment of the potential for biomass co-firing in the existing and planned coal power plants infrastructure in Europe

Below we present such an assessment for the EU similar to the assessment for Poland made by Berggren et al (2008). The purpose has been to assess the near-term (about 2010-15) technical potential for biomass co-firing with coal in the existing coal-fired power plant infrastructure in the EU27 Member States (MS). The main focus is on the power plant infrastructure, i.e. the assessment mainly pertains to the technical possibility for biomass co-firing, but we also determine the technical potential for biomass co-firing with coal for EU27 plants under construction or planned.

Assessment approach

The technical potential for biomass co-firing with coal – i.e., the ability of the power plants to burn biomass – is presented in terms of (i) the maximum amount of biomass-based electricity that can be produced from biomass co-firing in the existing coal-fired power plant infrastructure; and (ii) the corresponding amount of biomass required, applying previous co-firing experience from various power plant types.
The assessment has used the CPPD (described above), which contains information about all plants in EU (plus Norway and Switzerland) with a capacity generally exceeding 10 MWe, covering 97% of the total net capacity of plants in operation in the region as given by Eurostat (2005). It includes the name, position, fuel type, net power capacity, and age of power plants.
The possibility for meeting the assessed biomass demand for co-firing domestically is indicated and also the possibility for biomass imports by sea, based on mapping of the European waterway infrastructure. The importance of RES-E from co-firing when meeting future RES-E targets is also presented. Finally, we briefly discuss additional factors influencing near and long-term levels of biomass co-firing with coal in the EU27, as well as relevant policy considerations.
We assume that all types of coal-fired boilers in operation are in principle available for co-firing, which is a fair assumption according to OECD/IEA (2006). However, the power plant age is assumed to influence the availability for co-firing since old boilers in general have lower

efficiency, are likely to remain in operation a shorter time and therefore are less interesting for upgrading to support co-firing. The reference year is set to 2007, and two cases are considered:

- Case 1, where boilers commissioned in 1967 or later (i.e., those ≤40 years old) are assumed to be available for co-firing,

- Case 2 where boilers commissioned in 1977 or later (i.e., those ≤30 years old) are assumed to be available for co-firing.

Case 1 is designed to include the major part of the capacity of the existing EU27 coal-fired power plant infrastructure (about 90%, see Section 3). Case 2 represents a less optimistic scenario for co-firing (assuming the use of about 50% of the installed capacity).
The technical biomass co-firing potential depends on the capacity for burning biomass in available boilers, i.e., on the possible share of biomass in the fuel mix. In this study we use two different biomass fuel shares in order to reflect that there is a difference in the possible co-firing share between fluidised bed (FB) boilers and pulverized coal-fired (PC) and grate-fired (GF) boilers, where the former generally allows a higher share of biomass than the latter (Berggren et al., 2008; Leckner, 2007). We assume that biomass can replace 15% of coal (in terms of energy) in FB boilers and 10% of coal in PC and GF boilers.
These assumed biomass fuel shares are based on the technical assessment of co-firing possibilities for different boiler types made by Berggren et al. (2008). Their assessment is based on co-firing in Europe and the US, with special attention to the Swedish experience (since co-firing has a relatively long history in Sweden and since this information was easily accessible). It should be noted that there are commercial co-firing applications with higher co-firing shares than those suggested by Berggren et al (2008); e.g., a 20% biomass fuel share (energy terms) is applied in plants in Denmark (IEA Bioenergy, 2007). Thus, future co-firing levels might be higher, but the chosen values are judged as representative of the present levels and are considered low-risk, i.e. do not pose significant problems with corrosion, slagging and fouling, fuel handling, and fuel feeding. Also, the current paper aims at estimating the technical biomass co-firing potential rather than projecting biomass volumes going to co-firing (or corresponding amount of RES-E), which will depend on many other factors, not the least the cost and availability of biomass.
Regarding conversion efficiency, we make the following assumptions:

- Due to the relatively low share of biomass in the fuel mix the introduction of biomass is not assumed to change the efficiency (or the capacity) of the plants.

- All coal plants are assumed to have the following age-dependent electricity conversion efficiencies: 31-40 years, 30%; 21-30 years, 35%; 11-20 years, 37%; 0-10 years, 40% and plants under construction and planning, 45% .

The CPPD includes slightly more than 1 000 coal-fired power plants in EU27 when each boiler is treated separately. The number of plants and installed net power capacity for coal-fired power plants per boiler type are given for each country in total and for the two analysed cases in Table 8. The net power capacities reported in the CPPD are converted to gross power capacities by assuming that losses and energy for internal use correspond to 5% of the gross capacity.
The annual technical biomass co-firing potential also depends on the operating time or load factor of the plants. The load factor was estimated on a nation by nation basis and for plants using

lignite and hard coal separately. This was done by using the 2004 annual national power generation by fuel (Eurostat, 2006) and the national total power capacity (except reserve and peak capacity) for the two kinds of coal, from CPPD. The calculated average load factors are included in Table 8. Future load factors will mainly be determined by energy prices (i.e., coal prices as well as prices of substitutes). The estimate here is based on the present cost-effectiveness of the included coal-fired power plants.

Table 8. Estimated average national load factors for coal fired power plants in the MS having such plants. Also given is the capacity per boiler type and the number of plants (each boiler is treated separately).

	Load factor (hours per year) [a]		Net power capacity (GW) and number of coal-fired power plants in paranthesis	
	Hard coal	Lignite	fluidised bed boilers	pulverised coal boilers and grate-fired boilers
Austria (A)	4707	2529	0.08 (3)	1.79 (8)
Belgium (B)	3416	-	-	2.68 (15)
Bulgaria (BU)	1780	4545	-	5.51 (38)
Czech Republic[b] (CZ)	4693	4693	1.04 (13)	9.54 (79)
Denmark (DK)	3542	-	0.02 (1)	5.25 (19)
Estonia (EE)	-	3175	0.20 (1)	2.80 (8)
Finland (FIN)	4751	-	0.18 (2)	3.57 (18)
France (F)	3433	-	0.40 (4)	7.11 (24)
Germany (D)	4860	7740	0.94 (12)	47.3 (163)
Greece (EL)	-	7263	-	4.87 (21)
Hungary (HU)	-	5640	-	1.37 (20)
Ireland (IRL)	7285	-	-	0.86 (3)
Italy (I)	6341	-	0.32 (1)	6.86 (24)
Netherlands (NL)	5410	-	-	4.17 (8)
Poland (PL)	4208	6553	1.96 (14)	26.9 (341)
Portugal (P)	8366	-	-	1.78 (6)
Romania[b] (RO)	3344	3344	-	6.42 (31)
Slovakia (SK)	4279	4515	0.27 (4)	1.03 (10)
Slovenia (SI)	2392	6832	-	0.90 (7)
Spain (E)	7253	3018	0.05 (1)	12.0 (41)
Sweden (S)	1667	-	0.23 (1)	0.37 (7)
United Kingdom (UK)	4540	-	-	29.1 (64)

[a] The load factors are in many cases surprisingly low but depend on the large amount of relatively old boilers, especially in the Eastern Europe, requiring more maintenance. Note also that for some countries (Austria, Finland, Ireland, and Spain) the load factors for hard coal is higher than for lignite contrary to what is expected. The reason can be the use of different sources (Eurostat, 2006 for the national electricity production and CPPD for the total national capacity for the fuels), which might not include the exact corresponding information. See also [16].
[b] The same load factor is used for lignite and hard coal in both the Czech Republic and Romania, due to differences in the reporting of coal use in the sources.

The technical potential for RES-E generation from co-firing biomass with coal in existing power plants is calculated for each EU27 MS using the available boiler capacity for co-firing, the estimated load factor, and the assumed maximum biomass share in the fuel mix for the different boiler types included in the database. This RES-E production is compared to the total gross national electricity production in 2005 as reported by Eurostat (2007a). It is also compared to the remaining amount of RES-E needed to meet the RES-E targets for 2010. The RES-E production in 2005 is taken from Eurostat (2007b) and the RES-E targets are calculated in absolute terms by defining the gross national electricity consumption in 2010 as the sum of the electricity generation and net import of electricity for 2010 as given by EC (2006b).
The amount of biomass required for meeting the estimated technical biomass co-firing potential is obtained by using the conversion efficiencies defined for the plants.

Results of the assessment

Technical potential for biomass co-firing with coal. There is a technical potential for biomass co-firing with coal in 22 of the EU27 MS (and in 20 MS for Case 2). Cyprus, Latvia, Lithuania, Luxembourg, and Malta lack coal-fired electricity. Poland and Germany have in total the largest number of coal-fired power plants (more than 50% of the total number) but the Czech Republic, the UK, and Spain also have relatively many plants. Germany followed by the UK and Poland, has the largest installed coal-fired power capacity. Together, these countries have about 55% of the total net power capacity in EU27 (at about 190 GW).
For the boilers included in this study the total installed net power capacity in EU27 is 167 GW and 91 GW for Case 1 and 2, respectively (i.e., for boilers less than 40 and 30 years old). The majority of the plants have PC boilers with the other two types being GF boilers and FB boilers. The latter are reported separately since they can co-fire higher shares of biomass. In the CPPD the PC and GF boilers are not reported separately. About 70% of the total installed coal-fired net power capacity in EU27 uses hard coal as main fuel (71 and 66% for Case 1 and 2, respectively) while the remaining share uses lignite. The age structure of the coal-fired plants (all boilers included in the CPPD) and their net power capacity is described in Figure 6.

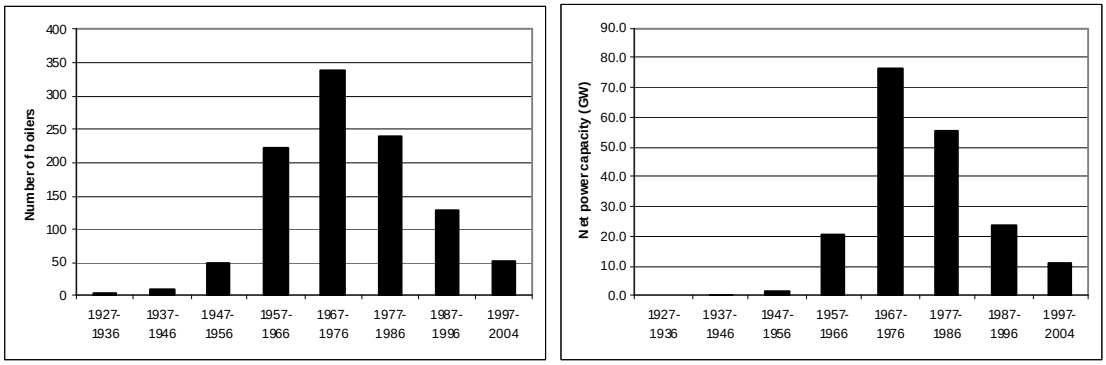


Figure 6. Age structure of coal-fired power plants (left) and the corresponding net power capacity (right). Case 1 and 2 are represented by the four (Case 1) and three (Case 2) bars from the right, respectively.

The technical potential for RES-E production from biomass co-firing with coal amounts to 87 and 52 TWh per year in EU27 for Case 1 and 2, respectively, or about 2.5% and 1.5% of the total gross electricity generation in EU27. Table 9 presents the 2010 RES-E percentage targets for the

EU27 MS and also the estimated RES-E generation required for reaching the targets, calculated based on projections of electricity generation in 2010 (EC, 2006b). It also shows the RES-E production in 2005 (in total about 15% of the total gross electricity production) and the size of the technical potential for RES-E from co-firing for the two analysed cases. The 2010 RES-E target for EU27 is 21% of the gross electricity consumption and the estimated technical potential for RES-E from co-firing corresponds to 2.4% and 1.4% of the projected gross electricity consumption in EU27 in 2010 for Case 1 and 2, respectively. The technical potential for RES-E from co-firing corresponds to roughly 10% of the RES-E required to reach the EU27 RES-E target for 2010.

The size of the technical potential for RES-E from co-firing varies substantially among the EU27 MS, but the possible role in the national electricity systems is similar: in all countries the technical potential for RES-E from co-firing corresponds to less than 10% of the total national gross electricity production in 2005 and less than 5% in most countries. The technical potential for RES-E from co-firing in Case 1 is roughly as large as the total biomass-based electricity production in EU27 in 2005 (Eurostat, 2007b).

The estimated technical potential for RES-E from co-firing is of course sensitive for the assumptions made. Besides the assumptions on power plant age, the share of biomass in the fuel mix and the load factors are the most critical determinants. For instance, if the load factors are set to 7500 and 7000 hours per year for all plants using lignite and hard coal respectively the RES-E potential from co-firing increases with 40 and 30 % for Case 1 and 2 respectively and amounts to about 25-45% of the estimated gap in EU27 between the 2005 RES-E level and the estimated 2010 RES-E target (instead of 20-33%). The assumption that biomass co-firing does not influence the conversion efficiency of the plant has a minor impact on the estimated technical biomass co-firing potential compared to other assumptions.

The EU also aims at a 20% reduction of greenhouse gases by 2020 compared to 1990 levels (EC, 2007). The contribution from the estimated RES-E from biomass co-firing with coal (when assuming that biomass is climate neutral and replaces coal with a carbon content of about 25 g C/MJ) corresponds to approximately 5 % of the required emission reduction in EU27 estimated using (EC, 2006c).

Table 9. The technical potential for RES-E production from biomass co-firing with coal for the two analysed cases. Also given are the RES-E production in 2005 (Eurostat, 2007b) and the estimated RES-E production required for reaching the RES-E targets for 2010 (EP&C, 2001; EC, 2003; CEU, 2006) using (EC, 2006b). CY, LV, LT, L and MT refer to Cyprus, Latvia, Lithuania, Luxembourg and Malta.

	RES-E production in 2005 (TWh)					Estimated RES-E target 2010	Technical potential for RES-E from co-firing (TWh)	
Member State	Hydro	Wind	Geo + Solar[1]	Bio-mass	Total (%)[2]	TWh (%)[3]	Case 1 (≤40 years)	Case 2 (≤30 years)
A	38.6	1.3	0.01	2.4	42 (64)	65 (78)	0.81	0.79
B	1.6	0.2	0.001	2.1	4 (5)	6 (6)	0.79	0.10
BU	4.7	0.002	-	-	5 (11)	4 (11)	1.58	0.86
CZ	3.0	0.02	-	0.7	4 (5)	6 (8)	4.33	2.25
DK	0.02	6.6	-	4.0	11 (29)	11 (29)	1.86	1.50
EE	0.02	0.1	-	0.02	0.1 (1)	1 (5)	0.57	-
FIN	13.8	0.2	0.003	9.6	24 (33)	31 (32)	1.71	0.94
F	56.9	1.0	0.02	5.1	63 (11)	114 (21)	2.63	1.24
D	26.7	27.2	1.3	16.6	72 (12)	78 (13)	22.8	18.2
EL	5.6	1.3	0.001	0.1	7 (12)	15 (20)	3.47	2.44
HU	0.2	0.01	-	1.7	2 (5)	2 (4)	0.64	-
IRL	1.0	1.1	-	0.1	2 (9)	4 (13)	0.66	0.66
I	42.9	2.3	5.4	6.0	57 (19)	97 (25)	4.49	2.67
NL	0.1	2.1	0.03	6.7	9 (9)	12 (9)	2.47	1.62
PL	3.8	0.1	-	1.8	6 (4)	12 (8)	12.5	8.1
P	5.1	1.8	0.1	2.0	9 (19)	25 (39)	1.56	1.56
RO	20.2	-	-	0.01	20 (34)	25 (33)	2.17	1.56
SK	4.7	0.01	-	-	5 (15)	11 (31)	0.28	0.07
SI	3.5	-	-	0.1	4 (24)	6 (34)	0.46	0.23
E	23.0	21.2	0.1	3.1	47 (16)	100 (29)	7.91	5.76
S	72.9	0.9	-	8.3	82 (52)	94 (60)	0.11	0.03
UK	7.9	2.9	0.01	9.6	20 (5)	45 (10)	13.3	1.80
CY	-	-	-	-	-	0.3 (6)	-	-
LV	3.3	0.05	-	0.04	3 (70)	5 (49)	-	-
LT	0.8	-	-	0.01	1 (6)	1 (7)	-	-
L	0.9	0.1	0.02	0.1	1 (25)	0.4 (6)	-	-
MT	-	-	-	-	-	0.1 (5)	-	-
EU27	340	70	7	80	498(15)	760 (21)	87	52

[1] Geothermal energy and solar photovoltaics
[2] The total RES-E generation as share of total gross electricity generation in 2005 (Eurostat, 2007b) is given in parenthesis
[3] The RES-E target in percentage is given in parenthesis

Co-firing potential in relation to biomass supply prospects. In order to better understand the implications of increasing biomass demand for co-firing for the development in the biomass

supply side (we come back to this later when discussing the bridging function of biomass co-firing), the technical potential demand for biomass is estimated and put in relation to the present national primary production of biomass (as reported in Eurostat, 2007b) and estimates of national biomass supply potentials for 2010, in order to provide a first estimate of the efforts required and possibilities to fulfil the near-term technical biomass co-firing potential. The national biomass supply potential for 2010 is set based on EEA (2006) (except for Bulgaria and Romania), which assesses how much biomass could technically be available for energy production within Europe without increased pressure on the environment. The biomass supply potentials for Bulgaria and Romania (which are not included in EEA, 2006) are collected from Scenario 1 in Ericsson and Nilsson (2006), which represents the short-term biomass production potential for Europe.
The technical potential demand for biomass from co-firing with coal is estimated to about 940 and 520 PJ per year in Case 1 and 2, respectively. Figure 7 presents the technical potential demand for biomass from co-firing for the different EU27 MS. For Case 1, a comparison is also made with the national biomass production for energy in 2005 (Eurostat, 2007b). As can be seen in Figure 7, there is a substantial variation among the countries both regarding the absolute size of the technical potential biomass demand from co-firing and what regards the size in relation to the national primary biomass production. For several countries the technical potential demand for biomass from co-firing is substantial in relation to the present primary production of biomass.

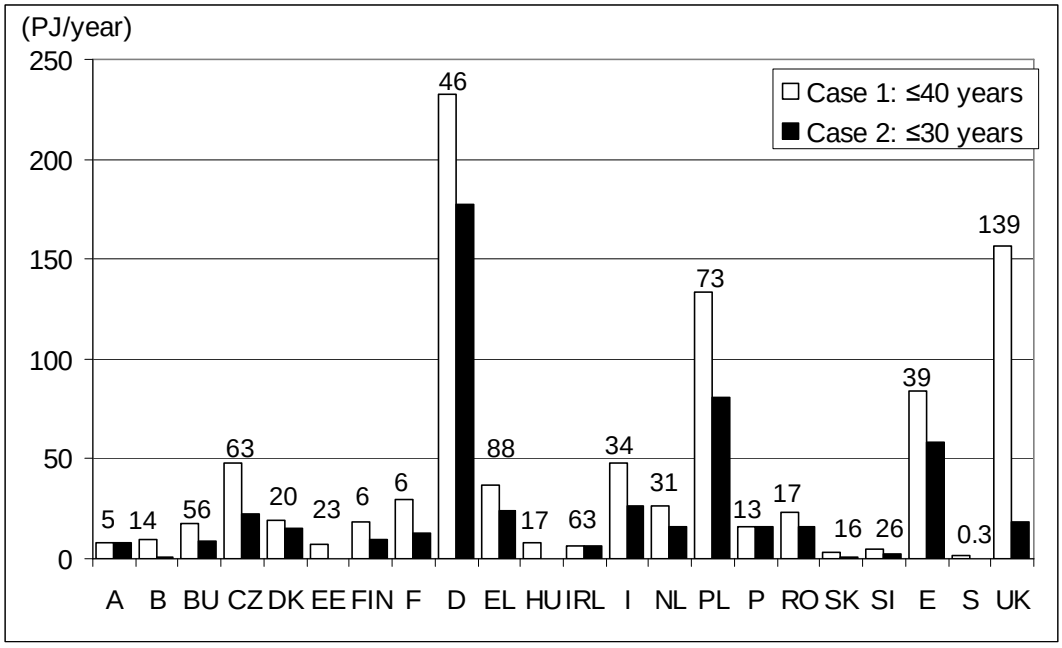


Figure 7. The technical potential demand for biomass from co-firing in the existing coal-fired power plants (in PJ of biomass). Above the bars, the potential for Case 1 is given as percentage of the national primary energy production of biomass in 2005 (Eurostat, 2007b).

The estimated technical potential demand for biomass from co-firing with coal in EU27 (presented in Figure 7) corresponds to about 10% of the estimated biomass supply potential in EU27 for 2010 (Figure 8). There is a large variation between the different countries but all have an estimated biomass supply potential that is larger than the estimated technical potential biomass demand from co-firing. However, as was shown in Figure 7, meeting the prospective biomass

demand from co-firing will require a substantial increase compared to the present primary production of biomass for energy in many EU27 MS.
Different types of organic waste and residue flows in agriculture and forestry represents one possible source of biomass for co-firing. For instance, more than half of the biomass used for co-firing with coal in the UK in 2005 consisted of vegetable oil waste products such as palm, olive and sunflower (Perry and Rosillo-Calle; 2006). In all the EU27 MS (except Romania and Bulgaria where information is missing), the national supply potential for waste and residues in 2010 (as reported in EEA, 2006) – including e.g., agricultural residues such as straw and manure as well as wood processing residues but not residues from fellings – is larger than the estimated technical potential demand for biomass from co-firing. For EU27, the technical potential demand for biomass from co-firing corresponds to about 20% and 10% of the supply potential for waste for Case 1 and 2, respectively and an even smaller percentage if also all forest sector residues are included. However, co-firing is not the only possible use of these biomass sources and competition for the biomass may arise in some countries if also other uses (e.g., burning for heat and conversion to biofuels for transport) expand.

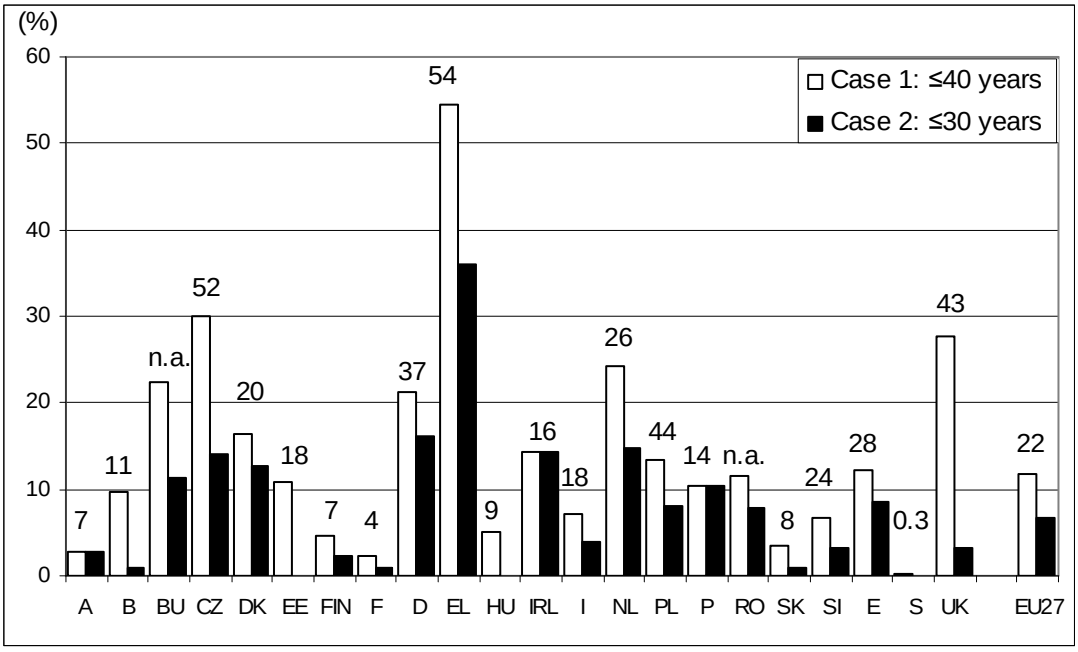


Figure 8. The estimated technical potential demand for biomass from co-firing expressed as share (as percentage) of the estimated national biomass supply potential, set based on EEA (2006) and Ericsson and Nilsson (2006). The numbers above the bars, show for Case 1, the technical potential biomass demand from co-firing expressed as share (as percentage) of the national biomass supply for waste (EEA, 2006).

The location of a power plant will influence the power plants' access to biomass and will thus influence the introduction of co-firing. Power plants close to the sea or near rivers supporting boat transport of relevant size may import biomass from long distances, increasing the access of biomass and possibly at lower costs than for domestic biomass. Sea transport has low variable costs and a low energy use per ton kilometre compared to other transport means and is competitive for long distance transportation (e.g., Hamelinck et al., 2005). Studies also indicate that the climate benefit of substituting fossil fuels with biomass is maintained also when the

biofuels are transported over long distances (e.g., Hamelinck et al., 2003). The international bioenergy trade has also increased substantially in recent years, and includes biomass for co-firing (Junginger et al., 2008).

It can be noted that most of the hard coal used in the EU is imported, with the exception of the Czech Republic and Poland (based on EC/Eurostat, 2007) where domestic resources are available. Thus, there is a considerable fuel import to many of the power plants already today and shifting from importing coal to importing biomass should not be a difficult, at least from a logistic capacity point of view.

In order to assess the possibility for biomass transport by sea and inland waterways, information about the geographic location of the coal-fired power plants in the form of coordinates (based on the CPPD) is combined with GIS-based information about waterways in EU27 (Vladimirova, 2008). The geographic location in the CPPD was for this reason updated for the majority of the plants using EPER (2008). The watercourses considered are the navigable waterways of class I-VII as defined in (ECMC, 1992), including main inland waterways of international and regional importance, where the largest are capable of handling transport up to 27000 ton. The plants located in the vicinity of the coast are identified, by a complementary visual inspection of maps (generated for this analysis) showing the coal-fired power plants as well as the main waterways on a national level.

Figure 9 shows the share of the estimated potential biomass demand from co-firing that is represented by power plants located close to the sea or near main navigable rivers, which indicates the amount that would be possible to import by sea transport. It is found that about 20% of the total potential biomass demand from co-firing in EU27 is located by the sea. About 25 % is located within a distance of 3 km from main waterways (about 15% within 1 km) and about 30 % within a distance of 10 km (for both analysed cases). In Germany and Poland, with high potential biomass demand from co-firing, a relatively small share of the power plants assessed to have a co-firing capacity are located by the sea. If also the main waterways are included about 40 % and 30-35% of the estimated biomass demand for co-firing Germany and Poland is located close to water. Countries where the major share of the coal-fired power capacity is located close to coastal areas and navigable rivers are Belgium, Denmark, Finland, Italy, the Netherlands, and Portugal (when including plants ≤40 years old), and, when assuming the use of plants ≤30 years old, also the UK, and Sweden.

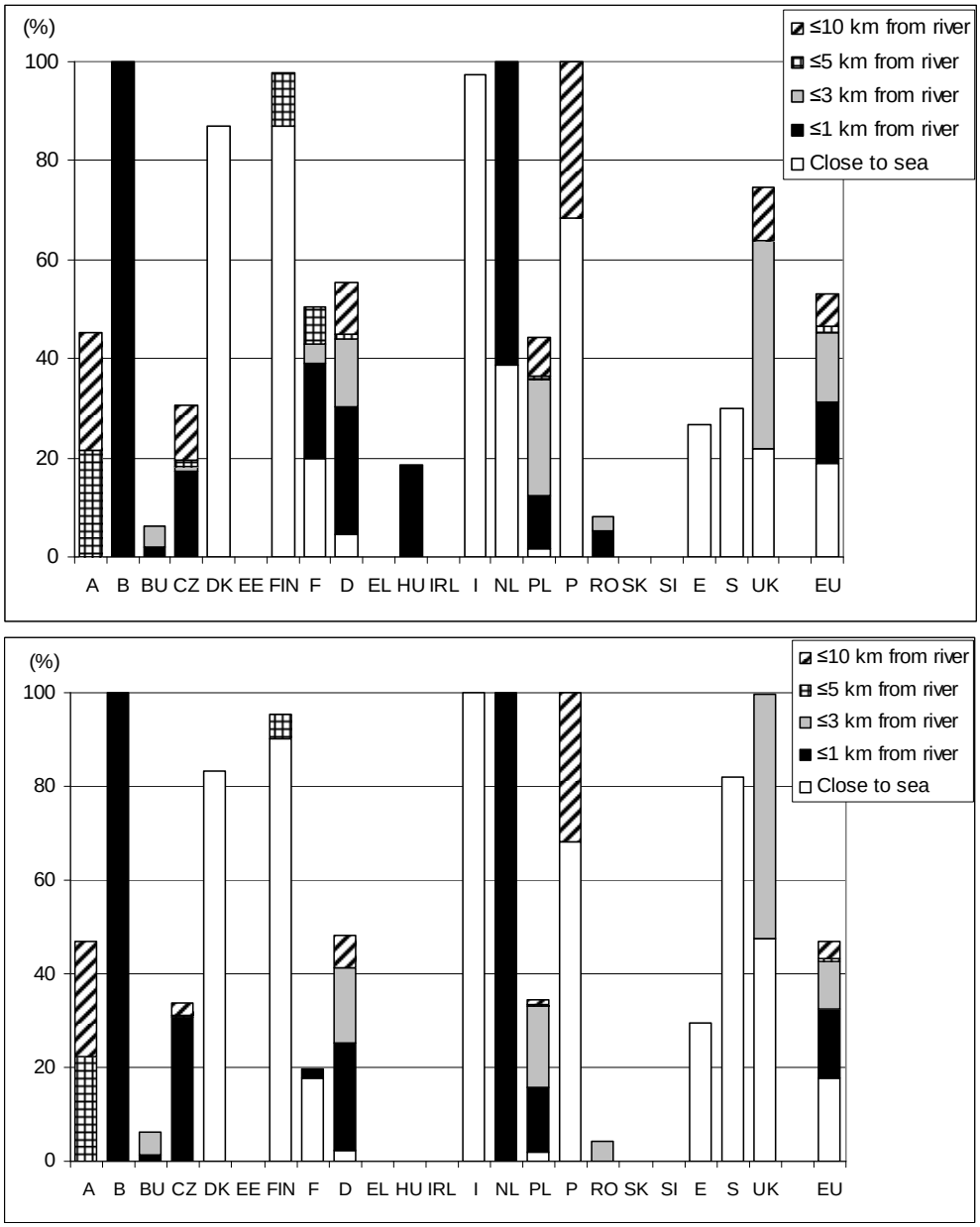


Figure 9. The share (as percentage) of the estimated technical potential demand for biomass from co-firing that is located by the sea and also close to navigable waterways. The upper figure shows Case 1 and the lower figure Case 2.

5.2.3 Bioenergy development and co-firing as a bridging option towards lignocellulose based bioenergy options

When looking at longer term biomass demand/supply prospects in Europe it becomes clear that lignocellulosic supply systems and especially lignocellulosic crops might need to provide a major part of the supply – especially in a prospective situation where much biomass is used for heat and power and at the same time 2nd generation biofuels (using lignocellulosic feedstocks) are playing a more prominent role in the EU's transport sector. Studies have also found a substantial potential for lignocellulosic crops on agricultural areas in EU, including lands not suitable for the

cultivation of conventional food/feed crops (primarily pastures and grasslands) due to that this would lead to significant soil carbon losses and also risk causing other negative environmental impacts. Studies also report that the production cost for lignocellulosic crops can go down substantially over time due to learning and benefits of large scale establishment.

At the same time, lignocellulosic supply systems are not much developed presently. In countries having large forestry sectors there is a wood supply infrastructure in place. In a few countries such as Sweden and Finland the use of forest wood for energy has grown to a substantial activity and this has influenced the wood supply infrastructure. But in most countries in Europe, the wood supply infrastructure has still to develop in response to changing demand patterns, as bioenergy becomes an increasingly important end use. This development does not only concern technology and economics of logistical systems, but also institutional development: regulations need to reflect the new situation and ensure that the increased forest biomass output respects sustainability restrictions (which in many instances need to be understood first). One example is the increased utilization of residues in forests, including stumps, that require regulation and compensating measures to maintain nutrient balances. Also, the increased forest wood demand in general can be expected to stimulate measures to intensify forestry, e.g., by forest fertilization. This intensification needs to be managed in a responsible way.

In the agricultural sector, the lignocellulosic output so far mainly consists of fibre crops for non-energy purposes and harvest residues in conventional food/feed crop production, straw being the most common residue. The harvest residues are mainly collected for non-energy purposes such as animal feeding and bedding but in a few EU countries also for energy purposes (heat and power). Willow has been grown commercially for heat and power in Sweden since the beginning of the 1990s, and the plantations now amount to some 14 thousand hectares, or about 0.5% of the Swedish arable land. Thus, despite this experience of soon 20 years of cultivation, forest supplies dominate in biomass based heat and power and willow production is still an emerging agricultural activity with a small land claim. A very limited cultivation of lignocellulosic crops for energy exists in a few other countries in Europe.

From the perspective of absolute size biomass co-firing with coal clearly qualifies as a potentially important near term biomass demand source in many MS: if biomass co-firing expands strongly in response to policy targets and other stimulating mechanisms biomass output for energy would have to increase substantially in many MS. Mobilization of residues and waste for energy use may be the most cost effective response to increasing biomass demand for energy in the near term – and from the assessment presented above we can conclude that there is low risk that biomass demand for co-firing would deplete biomass markets (unless strong institutional or other supply side barriers prevent a supply side response to increasing biomass demand). In fact, the estimates indicate that the potential biomass demand for co-firing could be met using only residues in agriculture and forestry, and when the import opportunities are also considered the supply situation appear non-problematic.

At the same time, policymakers contemplate the possibility of stimulating the domestic production of lignocellulosic crops by introducing specific policies linking co-firing with such biomass sources (e.g., by requiring that a certain share of the co-fired biomass is from lignocellulosic crops). In fact this approach has already been used in e.g., UK. The increased costs of requiring use of presently more costly biomass sources is motivated by the expectation that these sources will become cheaper in the future and possibly provide a substantial share of the total supply.

Figure 10 gives an illustration of how the potential biomass demand for co-firing with coal in existing power plants (and those under construction) decreases over time due to power plant age.

Thus, co-firing in existing power plants can bridge to prospective bioenergy options as the major subsequent use of the lignocellulosic biomass – benefitting from the already established biomass supply infrastructure. Possible alternatives include new advanced multi-fuel power plants, plants producing so-called 2nd generation biofuels, or maybe new types of plants that co-generate fuels, power and heat from biomass, coal and gas. The essence of the bridging function is that it starts up biomass supply chains, and leaves their long-term application open to future investment decisions.

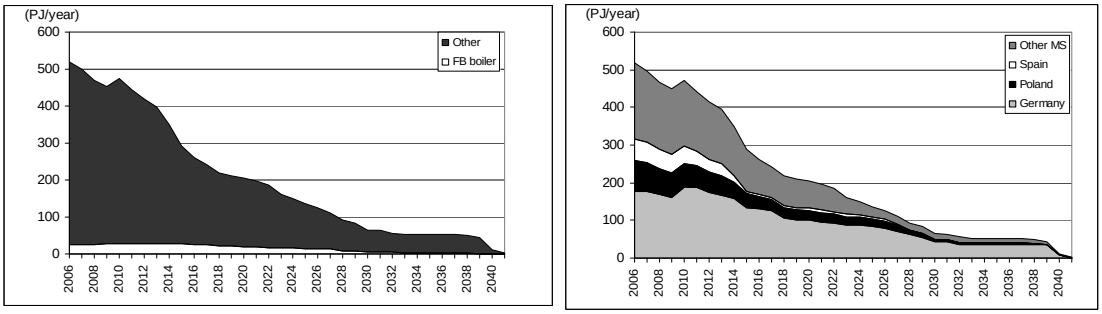


Figure 10. Illustration of how the potential biomass demand for co-firing with coal in existing power plants (and those under construction) decreases over time due to power plant age. The diagrams represent a situation where: (i) co-firing is implemented promptly in all power plants ≤30 years old; (ii) co-firing is implemented in all plants under construction according to plan; and (iii) all power plants are shut down due to age when reaching 30 years. Left: per boiler type ("FB boilers" = fluidised bed boilers, "Other" = pulverized coal-fired and grate-fired boilers). Right: per nation as specified.

The analyses presented here that primarily focused on the existing coal fired power plant infrastructure meet the criterion of being a near term bridging option that will not compete for biomass on the longer term, since the power plants will eventually be shut down due to high age. However, to the extent that new coal-fired power plants are built (possibly prepared for co-firing from the start) this option might prevail as a competing biomass use also on the longer term.
The CPPD also contains information on power plants under construction and planning (for the period 2007-2015). The technical potential for RES-E from co-firing (and the corresponding biomass demand) for the plants under construction and planning is shown in Table 10, estimated using the same assumptions as for the existing power plant infrastructure. The additional RES-E from the plants under construction is about 8 TWh/year, with an additional biomass demand at almost 70 PJ/year. If also planned plants are included the corresponding values are about 30 TWh/year and 230 PJ/year. Compared to the estimated technical potential demand for biomass from co-firing in the existing infrastructure the additional potential for plants under construction is considerable in the Netherlands and Italy, as well as in Belgium for Case 2. Note that these estimates are highly uncertain; only reported plans for some countries are included, new projects arise and some of the planned plants will not be built. Yet, the numbers give an indication of the current trend for coal-fired power generation, with possible implications for biomass co-firing.
New technology development may make biomass co-firing with coal competitive also in a future climate regime with high CO2 prices (arising e.g. from the EU-Emission trading scheme). For instance, if carbon capture and storage becomes widely available, biomass co-firing with coal may become a long-term option for low-CO2 power (possibly even providing power associated

with negative CO2 emissions). This can also be the case if biomass preparation technologies allow for substantially higher biomass shares in the fuel mix. For instance, a combination of torrefaction with washing out the mineral salts might produce fuels that can be co-fired in high percentages with coal without causing the problems associated with burning biofuels with high alkali content.

From the perspective of biomass co-firing paving the way for 2nd generation biofuels for transport, a steady growing biomass demand for co-firing may be considered a lock-in risk preventing the advancement of more climate friendly vehicle transport. But if biomass co-firing grows steadily in the context of a carbon cap complying with an ambitious climate target (and the transport sector contributes substantially), co-firing may just represent a cost-effective use of biomass resources. The transport systems may then have evolved to a state where climate compatible technologies other than those based on biofuels are dominant.

Table 10. The estimated technical potential demand for biomass from co-firing for the coal-fired electricity generation capacity under construction and planning (as reported in the CPPD) and the corresponding RES-E production. For the EU27 MS not included in the table, there is no information available on plants under construction and planning.

	Biomass demand (PJ/year)		**RES-E production (TWh/year)**	
Member State	under construction	planned	under construction	planned
B	1.0	-	0.1	-
BU	2.8	2.4	0.3	0.3
CZ	-	10.9	-	1.4
FIN	0.3	-	0.04	-
D	35.2	77.6	4.4	9.7
EL	-	11.0	-	1.4
HU	-	3.3	-	0.4
I	13.6	2.2	1.3	0.3
NL	8.7	12.8	1.1	1.6
PL	5.0	14.4	0.6	1.8
RO	-	1.1	-	0.1
E	-	0.1	-	0.02
UK	-	29.9	-	3.7
SUM	66.5	165.6	7.9	20.7

5.3 Uncertainties about the climate change mitigation benefit of using bioenergy

Several studies have over the past few years highlighted environmental and socioeconomic concerns associated with bioenergy, stressing both negative effects already associated with the conventional agriculture and forestry systems (e.g., biodiversity losses, eutrophication and soil degradation) and new types of impact specific for bioenergy including spread of alien invasive species and not the least rising food commodity prices due to increasing land use competition.

The use of biomass for bioenergy – and especially the use of conventional food/feed crops to produce biofuels for transport – has come under serious criticism, with some analysts questioning

whether biofuels at all deliver any benefits (JRC 2008, Farrell et al 2006; Hill et al. 2006; Keeney and Muller 2006; Tilman et al. 2006; WWI 2006; Pimental et al 2007; Bringezu et al. 2007; Crutzen et al. 2007; Martinelli and Filoso 2007; Scharlemann and Laurence 2008; Donner and Kucharik 2008; Searchinger et al. 2008; Simpson et al. 2008; Gallagher 2008; Keeney 2009. Howarth 2009; OECD 2007; Royal Society 2007; Doornbosch and Steenblik 2007; von Blottnitz and Curran 2006; Rajagopal and Zilberman 2007; Rowe et al 2008).
Uncertainties about climate change mitigation benefit of bioenergy was during project meetings discussed and found a suitable topic for the model based probabilistic assessments in PLANETS. The judgement is also that it can contribute with new insights for the continuous discussion in science and policy, since the tools available in the PLANETS consortium have rarely been used to address this issue. In WP4 we have made an extensive meta-analysis of literature and developed an assessment framework with the ambition to provide a basis for the modelling groups to explore the issue in other WPs.
One conclusion from the WP4 analyses is that in many instances, the analysis of the mitigation benefit (and of environmental implications in general) has remained speculative, uncertain, and often controversial. Given the multitude of existing and rapidly evolving bioenergy sources, complexities of physical, chemical, and biological conversion processes, and variability in site specific environmental conditions, few universal conclusions can currently be drawn. The impacts are a function of (i) the socioeconomic and institutional situation where the feedstocks and bioenergy outputs are produced and utilized; (ii) types of lands used (forest land, cropland, marginal or degraded lands); (iii) feedstock type (annual crops, perennial grasses, woody plants, crop residues) and production practice employed; and (iv) conversion processes utilized including type of process energy used. It is also recognized that the rate of implementation matters (IGRC 2005; Royal Society 2007; Firbank 2008; Convention on Biodiversity 2008; Gallagher 2008; Howarth et al. 2009; Kartha 2006; Purdon et al. 2009; Rowe et al 2008; OECD 2008).
This is further elaborated below but it can be noted that this conclusion was expected and confirmed that this topic could benefit from the probabilistic model based assessments in PLANETS.

5.3.1 Assessment of climate change mitigation benefits of using bioenergy

Some notions on methodological and empirical difficulties

Production and use of bioenergy influences global warming through:

- GHG emissions related to changes in biospheric carbon stocks often – but not always – casued by induced land use change (LUC);

- Emissions from the bioenergy chain including non-CO2 GHG emissions and fossil CO2 emissions from auxiliary energy use in the biofuel chain;

- Other non-GHG related climatic forcers including changes in surface albedo; particulate and black carbon emissions from small-scale bioenergy use that e.g. reduce the snow cover albedo in the Arctic; and aerosol emissions associated with forests.

The climate change mitigation benefit of bioenergy systems is determined by the net change in radiative forcing resulting from the replacement of another – commonly fossil – energy system.
In addition to comprehensive LCA:s that look at wider environmental impacts of bioenergy systems there are many studies with LCA-type approaches that focus on energy balances and GHG emissions balances (readable recent examples include Fleming et al. 2006, Larson 2006, von Blottnitz and Curran 2006, Zah 2007, OECD 2008, Rowe et al 2008, Menichetti and Otto 2009). Most assumptions and data used in LCA studies are so far primarily related to conditions and practices in Europe or USA, but studies are becoming available for countries such as Brazil.
Most studies have concerned biofuels for transport, especially those that are produced based on conventional food/feed crops. Limited attention has been directed towards the environmental implications of prospective bioenergy options (e.g., lignocellulosic ethanol and options using the biomass gasification route) and their assessment via the LCA process is by definition speculative since the technologies are not yet available.
Despite that studies commonly follow ISO standards a wide range of results has often been reported for the same fuel pathway, sometimes even when holding temporal and spatial considerations constant (Fava 2005). The ranges in results may, in some cases, be attributed to actual differences in the systems being modelled but are also due to differences in method interpretation, assumptions and data issues. The ISO standards were developed with consumer products as the main targets and for bioenergy LCAs there are several issues that make the methodology less applicable in its present form.
Key issues in bioenergy LCAs are system definition including the definition of both spatial and dynamic system boundary and the selection of allocation methods for energy and material flows over the system boundary. Disparities in the treatment of co-products have had major impact on results of LCA studies (Kim and Dale 2002, Larson 2006, Farrell et al. 2006, Börjesson 2009, Rowe et al 2008). Furthermore, the handling of uncertainties and sensitivities related to the data for parameter sets used may have significant impact on the results (Larson 2006. von Blottnitz and Curran 2006, OECD 2008, Rowe et al 2008).
Many biofuel production processes produce several products and bioenergy systems can be part of biomass cascading cycles, where the biomass is first used for the production of biomaterials, while the co-products and biomaterial itself after its useful life are cycled to bioenergy. This introduces significant data and methodological challenges, including also consideration of space and time aspects since the environmental effects can be distributed over several decades and occurs at different geographical locations.
There are in addition gaps in scientific knowledge surrounding key variables, including implications of LUC, N2O emissions related to feedstock production, and nutrient depletion and soil erosion due to too high rates of agricultural residue removal: these processes cause soil and vegetation degradation involving carbon losses to the atmosphere and also reduced productivity which means that the CO2 assimilation of re-growing vegetation is decreased.
The influence of LUC on the mitigation benefits of bioenergy has received considerable attention recently, although has been subject to analyses for many years. For example, using an integrated energy-land use model Leemans et al. (1996) analyzed the land use and carbon cycle consequences of realizing the biomass intensive LESS scenario developed for the Second Assessment Report of IPCC and found that carbon emissions linked to LUC can significantly reduce the mitigation benefits of large scale bioenergy expansion. Other studies (e.g., Schlamadinger et al. 2001; Berndes and Börjesson 2002) have conversely pointed to the possibility of increasing biospheric carbon sinks when expanding bioenergy systems.

The incorporation of LUC effects into LCA type studies has so far relied on either analyzing prescribed LUC patterns (Marland and Schlamadinger 1997; Fargione et al. 2008; Hill et al. 2008) or have used equilibrium land use models that are linked with less detailed characterization of the systems not covered by the equilibrium model (Searchinger et al. 2008). Further methodology development is needed to improve the confidence of quantifications made using these approaches. Besides that empirical data on carbon flows linked to land use and LUC in different parts of the world is uncertain, the causal chains proposed to link specific bioenergy projects with specific LUCs taking place in distant locations – and being driven by a range of additional factors – are yet poorly understood. Critical aspects include the land use evolution as influenced by the combined food, feed, fiber and bioenergy demand, availability of new types of energy crops, new cropping patterns, and policies influencing the land use directly or indirectly, including possible pricing of biospheric carbon flows and other instruments such as REDD. Additional uncertain factors influential on the outcomes include assumptions concerning drivers for technological development and productivity growth in agriculture (Gallagher 2008; Kim et al. 2009; Kløverpris et al. 2008a,b).

As noted above mitigation benefits of bioenergy systems must be evaluated based on comparing their influence on impact categories with the influence of the energy systems they replace. For the case of evaluating climate impacts, a standard methodology has been established and continously developed since the 1990s (Schlamadinger et al. 1997). One difficulty experienced is that it has proven to be difficult to obtain comparable LCA data for the reference energy system replaced – ideally these LCA data should come from studies with consistent methodologies, scope, level of detail, and country representativeness. Reasons include:

- The impacts of bioenergy products are often characteristic of the agriculture sector and by extension, are difficult to compare to other elements of the reference energy system i.e. oil and coal exploration, mining / refining, storage transportation and spills; and,

- There is an identified lack of updated LCA studies on fossil fuels assessing recent and emerging trends in extraction and use of oil, (microbial enhanced oil recovery, deep sea drilling, use of oil sands etc.) (See Fava 2005, von Blottnitz and Curran 2006 and OECD 2008)

The reference energy system can also cause indirect emissions linked to LUC or other activities and these can be difficult to quantify. Examples include (i) surface mining of coal that destroys soils and eliminates existing vegetation leading to displacement or destruction of habitats and wildlife; (ii) oil and gas projects causing deforestation for access roads, drilling platforms, and pipelines; (iii) oil shale production where surface mining, processing and disposal requires extensive areas; (iv) oil sand production that is requiring removal of vegetation as well as the topsoil and subsurface layers atop the oil sands deposit. Indirect LUC can also arise from the easy access to previously remote primary forest provided by new roads and pipeline routes, causing increased logging, hunting, and deforestation from human settlement. A portion of military expenditures and associated GHG emissions are related to the geopolitical considerations and energy security. Preliminary estimates for the case of U.S. military security associated with the acquisition of Middle Eastern petroleum indicate that this indirect source of emissions might be similar in size as the emissions usually linked to Middle Eastern petroleum (Liska and Perrin 2009).

Albedo changes, so far little analysed in connection to bioenergy expansion, might be an important variable. If the land is darkened (lower albedo) more solar energy is absorbed leading to increased warming. Since the albedo of a forested landscape is generally lower than that of cultivated land, especially when snow is lying, planting of coniferous forests in areas with snow can significantly increase the radiative forcing offsetting the negative forcing expected from the obtained carbon sequestration in the forest.

Conversely, if the land becomes lighter there is cooling. The cooling due to albedo change from deforestation was found of the same order of magnitude as the increased radiative forcing from CO2 emissions and model based analyses show that a global-scale deforestation event could even have a net cooling influence on the Earth's climate. Different types of drivers of LUC can influence albedo and climate change differently. For instance, modeling studies found that the decrease in precipitation after a soybean expansion in the Amazon area was significantly higher when compared to the change after a pastureland extension, a consequence of the very high albedo of the soybean[6].

Incorporation of albedo effects in analyses of the mitigation benefits of bioenergy systems show (tentatively, see Figure 11) that in both regions with snow and regions with drought the influence of albedo changes can be so large that some strategies for bioenergy production may need to be reconsidered.

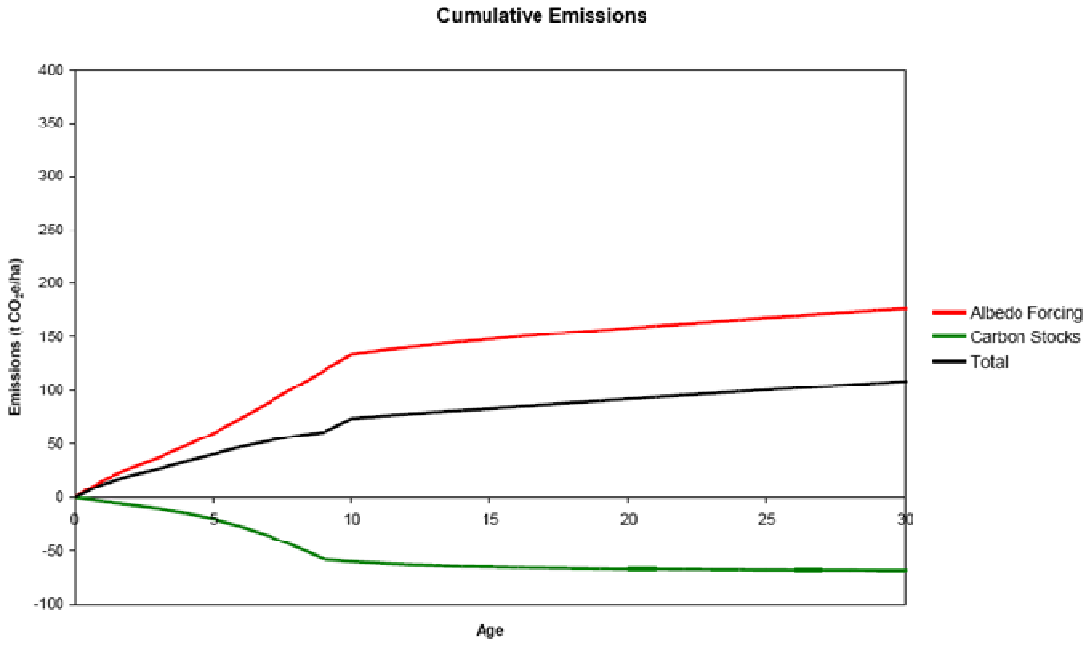


Figure 11. Tentative diagram from Neil Bird (Task leader, IEA Bioenergy Task 38) showing the effect of albedo for the case of Jatropha in South Africa.

[6] Selected references treating albedo: Nature 408:187-90; PNAS 104:6550-55; Science 320:1444 – 49; PNAS 105:19336-41; Geophys. Res. Lett. 35:L09706; Geophys. Res. Lett.:34, L07706

Results – mitigation benefit when LUC is not considered

Since PLANETS models do not focus on the transformation of traditional energy uses in developing countries focus here is placed on so-called modern bioenergy comprising burning/gasification of biofuels in heat and power in more advanced installations and various types of biofuels suitable for use in the transport sector.

As noted above, the wide multitude of existing and rapidly evolving bioenergy sources, complexities of physical, chemical, and biological conversion processes, feedstock diversity and variability in site specific environmental conditions – together with inconsistent use of methodology – prevent meta-analysis of large number of studies to produce generally valid quantification of the influence of bioenergy systems on climate.

Figure 12, showing the ranges in net GHG emission reductions from replacing petroleum fuels with biofuels found in a review of about 60 recent LCA studies, is illustrative of that the assessed mitigation benefit of a given bioenergy systems can vary significantly due to varying feedstock growing conditions and agronomic practices, conversion process configuration, differences in substitution effects of bioenergy and co-product use – and not the least due to differences in on how these effects are considered in the analysis.

Figure 13 exemplifies this for the case of U.S. maize ethanol and also shows how GHG emissions can vary depending on process configuration and process fuel use. As can be seen in Figure 13 choice of fuel for the conversion process is one major reason for this difference. If biomass (e.g., bagasse, straw, or wood chips) is used GHG emissions from the conversion can be very low (although the marginal benefit of shifting to biomass depends on how this biomass would otherwise be used). Co-siting of biofuel plants to exploit surplus heat from other energy plants or industrial activities can also be very beneficial, which is exemplified by the case of wheat ethanol in Sweden reaching about 80% GHG savings (Börjesson 2008). If instead coal is used in less efficient plants the mitigation benefits might be completely lost.

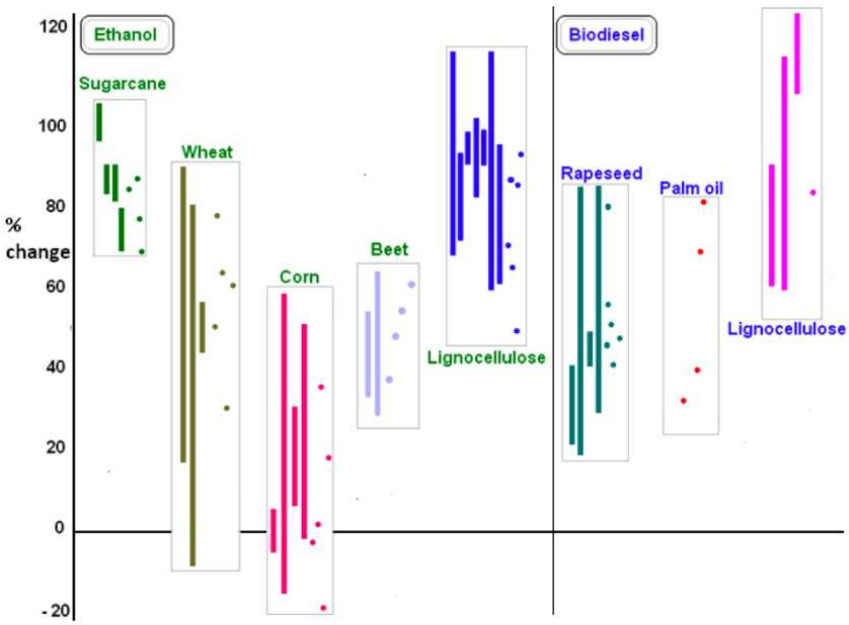


Figure 12. Net reductions in GHG emissions for a range of biofuels replacing gasoline or mineral diesel (excluding LUC). Negative net reductions indicate that the biofuel options have higher W-t-W emissions than the fossil alternative it replaces. When reductions are above 100% additional

GHG savings are obtained from fossil fuel substitution elsewhere than in the transport sector. For instance, when bagasse from sugarcane ethanol production is used for electricity generation that replaces fossil electricity additional GHG benefits are obtained. Source: IEA (2008).

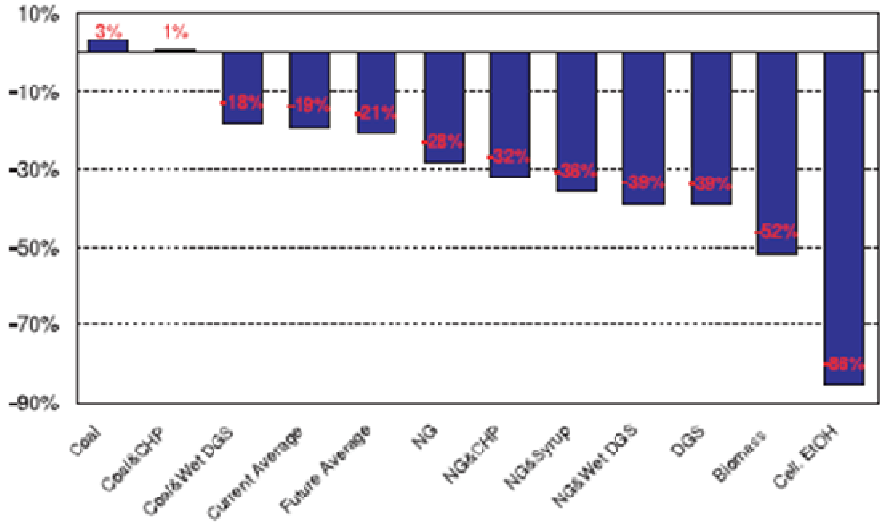


Figure 13. Well-to-Wheel GHG emission for maize etanol compared to gasoline, given different etanol process configuration and process fuel use (Wang et al. 2007). The highest and second emissions reduction is acheived for cellulosic etanol and for corn etanol using biomass as process fuel, respectively. The use of coal as process fuel leads to higher emissions from etanol than from gasoline. Recent analyses (Liska et al, 2009) found emissions reductions of roughly 50-60% for maize ethanol in USA, while earlier studies have reported significantly less reduction (see, e.g., Farrel et al. 2006).

High mitigation benefit further requires good land management and especially for grain or seed-based biofuels that require relatively high rates of fertilizer input mitigation benefits can be significantly improved through minimization of nitrous oxide emissions (one of the most important and uncertain parameters) by means of efficient fertilization strategies using nitrogen fertilizer produced in plants that have nitrous oxide gas cleaning. High yields reduce agricultural GHG emissions per unit biofuel produced, which can be seen, e.g., for sugarcane and sugar beet that reach high biofuel output per hectare. Lignocellulosic crops (both herbaceous and woody) generally require less agronomic inputs, which has a positive effect on GHG emissions (and overall environmental performance).

It is certainly not so, that biofuel plant modification per definition leads to improvements in GHG performance over time. This depends on how economic drivers are viewed in strategic planning situations For instance, increasing natural gas prices may shift process fuel use towards more coal unless the cost of increased CO2 emissions outweigh the economic benefit of this process fuel shift. If liquid biofuel output per unit land is high priority – possibly because they are high in demand and consequently price due to compulsory policy targets – high yielding options with higher GHG emissions per litre biofuel may be favoured.

Important for modelling is also to know that the use of by-products such as animal feed – which can lead to great GHG reductions especially when the by-product is assumed to replace soy protein imports from deforesting land use activities in the Amazon – is limited by the relatively small size of this by-product market (corresponding to a few percent of the transport fuel

demand). Thus, it can be risky to assign a generally valid high climate benefit to a biofuel option based on LCA studies pointing to good GHG performance thanks to such by-product use.
Thus, biofuels for transport can perform very differently – and this is also the case for bioelectricity and bioheat. But it can anyhow be concluded that biomass that substitutes for fossil fuels (especially coal) in heat and electricity generation as a rule provides larger and less costly CO2 emissions reduction per unit of biomass than substituting biofuels for gasoline or diesel in transport.
The major reasons for this are (i) the lower conversion efficiency, compared to the fossil alternative, when biomass is processed into biofuels and used for transport; and (ii) the higher energy inputs in the production and conversion of biomass into biofuels for transport, especially when based on conventional arable crops.

Results – The impact of LUC

The possible emissions from converting land to bioenergy use can substantially influence the climate benefit of expanding bioenergy systems. In some cases the conversion of land to bioenergy use will simultaneously enhance the biospheric carbon stocks, such as when perennial grasses or short rotation woody crops are established on carbon-depleted lands. In other cases it can lead to lower biospheric carbon stocks, such as when a forest is clear-cut to make place for the cultivation of soybean for biodiesel or when pastures with high soil carbon content are ploughed and cultivated with cereals for ethanol. Also sustainable biomass production systems can temporarily involve substantial decreases in biospheric carbon stocks, management of boreal forests being an illustrative example. C hanged forest management regime towards intensification – shorter rotations, forest residue removal, and fertilization – leads to larger output but smaller forest C stock, thus a change that is maintained over time rather than a consequence of the long rotations.
Figure 14 shows the Carbon Payback Time for a range of biofuel-LUC combinations and Figure 15 illustrates how LUC patterns may impact the carbon payback time. As can be seen, there are very large differences in how biofuel options perform depending on LUC effects.

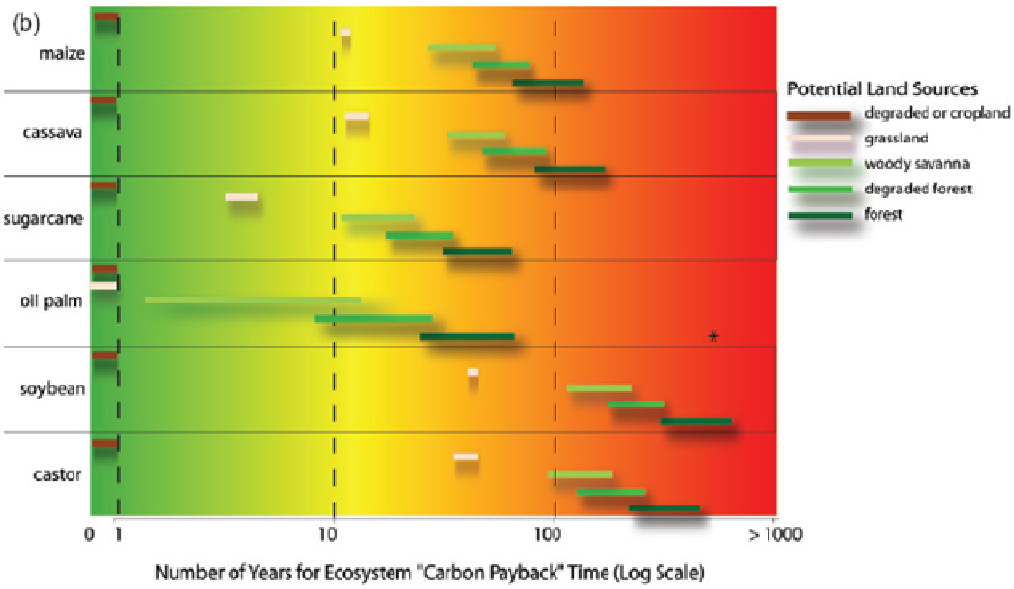


Figure 14. The 'carbon payback' time for potential biofuel crop expansion pathways across the tropics. The bars represent the range across the humid, seasonal and dry tropics for different combinations of land sources and biofuel feedstock crops across the tropics. The payback period is calculated based on that biofuels replace conventional petroleum sources and assuming that all crops achieved the top 10% global yields, which resulted in largest improvements for crops such as maize, castor and rice because these crops were substantially below global 90th percentile yields, while sugarcane, soybeans and oil palm were already high yielding so the change has a smaller impact. '∗' indicates the 587 year payback time if oil palm expands into peat forests. Payback times would be reduced by about 25% if petroleum derived from tar sands were replaced by the biofuels.

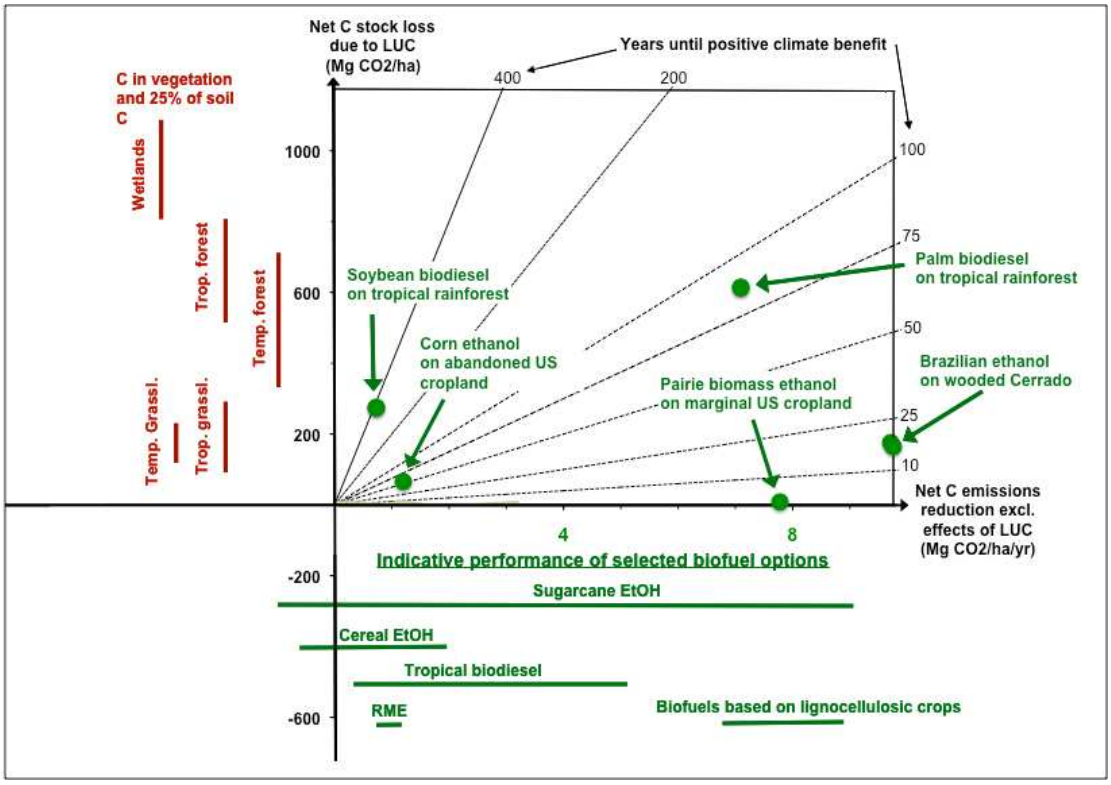


Figure 15. Illustration of how LUC emissions can influence the climate benefit of biofuels. The x-axis shows the net GHG emissions reduction (CO2eq.) of using biofuels (excluding LUC effects), with typical performance (green bars) indicated based on biofuel output per hectare in IEA Bioenergy (2008c) and GHG emissions reduction in Gallagher (2008). Different use of process fuel is one major explanation for the range for the sugar cane and cereal ethanol cases, for tropical biodiesel the specific crop causes the range, with palm biodiesel performing better than soybean biodiesel. The y-axis shows the net loss of carbon in soils and vegetation when different ecosystem types are converted to bioenergy plantations: the bars to the left of the y-axis indicate the ranges for C content in different ecosystem types (IPCC 2001; Searchinger 2008). The dashed lines indicate how many years of biofuels production and use that is required to fully compensate for the C emissions due to land conversion to bioenergy plantations. The dots represent specific cases reported in Fargione et al. (2008).

As discussed above, the quantifications of these aspects reported so far involve a significant degree of uncertainty, for example the linkage between statistical relationships and causal effects, and in relation to causal chains and the carbon stock changes linked to LUC. The effects are complex and difficult to quantify in relation to a specific bioenergy project and the reference energy system substituted may also cause LUC. For example:

- Brazilian sugarcane plantations are commonly expanding on pastures, displacing cattle ranching (Sparovek et al. 2008; Walter et al. 2008; Zuurbier and van de Vooren 2008). This may lead to intensified cattle production on existing pastures or establishment of new pastures elsewhere. If a substantial part of the pasture expansion was induced by the biofuels and required the clearing of new lands (e.g. in the Amazon region), CO2 emissions from deforestation would severely reduce the climate benefits of Brazilian ethanol. Biofuel policies, on the other hand, may influence the industry to improve compliance with long-standing environmental regulations that consider forest reserves and riparian buffers; this is one explanation for the increased forest cover observed concurrent with sugarcane expansion in the primary ethanol production zone (state of Sao Paulo). And biofuels contribute to international scrutiny, certification schemes and other actions by governments and civil society to protect the Amazon forests. There are also options for integrating sugarcane production with cattle production, inducing productivity improvements of the present low-intensive cattle production (Sparovek et al. 2007)

- If European biofuel demand leads to pastures and grasslands being converted to croplands for rape seed (or other annual crops), soil C emissions from these lands may be high. But even if biodiesel comes from rape seed cultivated on the present cropland, rising demand for this feedstock may lead to increasing prices, which may in turn lead to increased palm oil production (and possibly deforestation) for rape seed oil substitution in the food sector. Another illustrative example is the shift from soy to corn cultivation in response to increasing ethanol demand in the US, which has induced increased expansion of soy cultivation in Brazil and other countries (Laurance 2007).

Yet, despite the substantial degree of uncertainty, it can be concluded that if the expansion of crops for 1st generation biofuels results directly or indirectly in the loss of permanent grasslands and forests it is likely to have negative impacts on GHG emissions. There can be a net acumulation of carbon in soils and standing biomass when lignocellulosic crops are established on land with sparse vegetation and moderate/low soil carbon content. But all bioenergy options will face large upfront net GHG emissison if the biomass production is established based on the conversion of land high in soil/aboveground carbon (notably dense forests). In such cases it can take many years (up to centuries) before the production and use of bioenergy to substitute fossil fuels will make a positive net contribution to climate change mitigation.

5.3.2 Bioenergy vs. carbon sinks

Land can be used for climate change mitigation in two principal ways:

- by increasing the biospheric carbon stocks in soils and standing biomass and thereby

withdrawing CO2 from the atmosphere[7] (carbon sink option)

- by supplying biomass for energy substituting fossil fuels and thereby reducing the emissions of CO2 to the atmosphere (bioenergy option)

These two options are not mutually exclusive: as has been discussed above the establishment of bioenergy systems in themselves often leads to changes in the biospheric carbon stocks. Conversely, reforestation can enhance carbon stocks in plants and soils, while at the same time contributing to a future biomass resource.
Both the bioenergy and the carbon sink option can also induce indirect LUC when they are implemented. Thus, the possible emissions from direct and indirect LUC can substantially influence the climate benefit also for carbon sinks projects. Figure 16 below shows two illustrative bioenergy cases where the relative importance of fossil fuel substitution and increases in carbon stocks differ. Obviously, the climatic benefit is greater when biomass replaces coal for heat production, than when natural gas is replaced for electricity production. It is also clear from the diagrams that the climatic benefit of fossil-fuel substitution dominates in the long run, but the contribution from carbon binding in land, stems, and standing biomass is substantial, especially at the beginning.

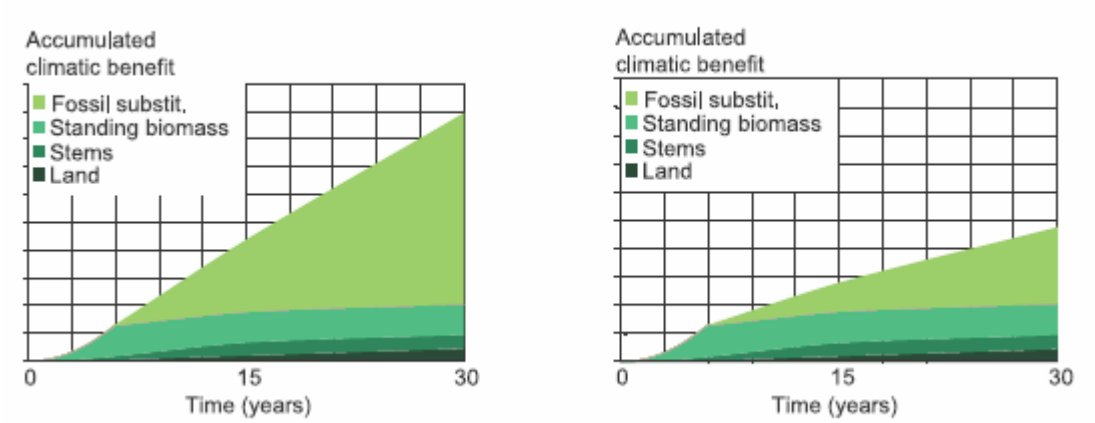


Figure 16. Illustration of the accumulated climatic benefit when lignocellulosic energy crops are cultivated on previous cereal lands (i.e., where soil carbon levels are rather low) and are used as fuel. The left diagram could represent the case where the heat and electricity from modern biomass-fired combined heat and power plants substitute heat from a coal-fired boiler and electricity from a coal-fired condensing plant. The right diagram could represent the case where instead the fossil alternative would be a modern natural gas based CHP plant. The diagrams were produced using the GORCAM model (Marland and Schlamadinger 1997) and do not consider possible indirect effects.

[7] Preservation of existing biospheric C stores can be regarded a third option as it leads to a deviation from trends in atmospheric CO2 accumulation (due to biospheric C losses) in the same way as bioenergy substituting fossil fuel use reduces the rate of atmospheric CO2 accumulation (due to reduced fossil C emissions). Preservation of biospheric C stores differs from bioenergy in the same way as C sinks creation: it does not require any energy system changes. It represents an alternative to bioenergy in the sense that land owners can choose whether to keep the land forested or to convert it to bioenergy plantations – and loose some biospheric C in the land conversion process.

The question whether land should be used for biomass production for fossil fuel substitution or for the creation of biospheric carbon stores has been subject to substantial debate and scientific effort[8]. The lack of uniform and comprehensive evaluation standards and varying limitations in scope for studies (e.g. studies commonly disregard the effects of indirect LUC) have resulted in a diverse set of studies that are difficult to compare and whose comparison does not provide clear answers.

Ranking of land use options based on their contribution to climate change mitigation is complicated by lack of solid empirical data (as already discussed for biofuels and valid notion also for carbon sinks: maintenance of large biospheric carbon stocks (typically forests) as an alternative use of land can have additional advantages in relation to, e.g., biodiversity, but it also faces significant challenges related to that the biospheric carbon dynamics are poorly known, difficult to monitor and control, and expected to be influenced by climate change in ways not yet well understood.

First of all, increased atmospheric CO2 concentration in itself induces re-allocation of carbon from the atmosphere to the biosphere through the CO2 fertilization effect. Increasing atmospheric CO2 concentrations also influence the balance between net primary productivity and soil respiration, which are critical determinants of the net carbon exchange between the biosphere and the atmosphere. Processes that destabilize organic matter in response to disturbances such as warming or LUC are poorly understood and the longer term influence of increased atmospheric C levels on biospheric C levels is uncertain, with climate-C cycle models indicating that the fertilization effect can become weaker in the future. Even small changes in flux rates into or out of the biospheric pools could have a strong influence on atmospheric CO2 concentrations. Natural disturbances such as forest fires can lead to large losses of biospheric carbon to the atmosphere without benefits of replacing fossil fuels and studies indicate that climatic changes may increase the risk of such events.

Nevertheless, some general conclusions can be made about the more critical parameters and how they influence the relative attractiveness of these two land use options:

- biomass productivity and efficiency with which the harvested material is used are critical parameters – high productivity and efficiency in use favour the bioenergy option. Low productive land may be better used as carbon sinks, given that it can be accomplished without displacing land users to other areas where their activities lead to indirect CO_2 emissions. Local acceptance is also a prerequisite for the long term integrity of sinks projects.
- fossil fuel system to be displaced – the GHG emissions reduction is obviously higher when bioenergy replaces coal that is used with low efficiency and lower when it replaces efficient natural gas based electricity or gasoline/diesel for transport.
- the initial state of the land converted to carbon sinks or bioenergy plantations (and of land elsewhere possibly indirectly impacted) – conversion of land with large carbon stocks in soils and vegetation can fully negate the climate benefit of the sink/bioenergy establishment

The relative attractiveness of the bioenergy and carbon sink options is also dependent on the time scale that is used for the evaluation: a short timeframe (a few decades) tends to favour the

[8] IEA Bioenergy Task 38 is one example of thematic research networks involved with these issues.

sink option while a longer timeframe favours the bioenergy option. The reason is that the accumulation of carbon in forests and soils cannot continue endlessly: the forest eventually matures and reaches a steady state condition. This is also the case for soils. In contrast, bioenergy can be produced repeatedly and continue to deliver greenhouse gas emissions reduction by substituting fossil fuels.

Figure 17 shows the difference after 40 years between a scenario where land is reforested with fast growing species to produce biomass for energy (fossil fuel substitution), and a scenario where land is reforested with the main purpose of storing carbon (carbon sequestration). As can be seen, a combination of high yielding species and efficient use of the biomass to replace fossil fuels makes substitution management the preferable option over sequestration management. In the back right corner of the diagram the benefits of substitution management exceed those of sequestration management by almost 250 tons carbon / ha after 40 years. On the other hand, low-efficiency biomass use, independent of growth rate, means that the land is better used for carbon sequestration. Where biomass is used efficiently, but growth rates are low, the relative merits of substitution management are limited.

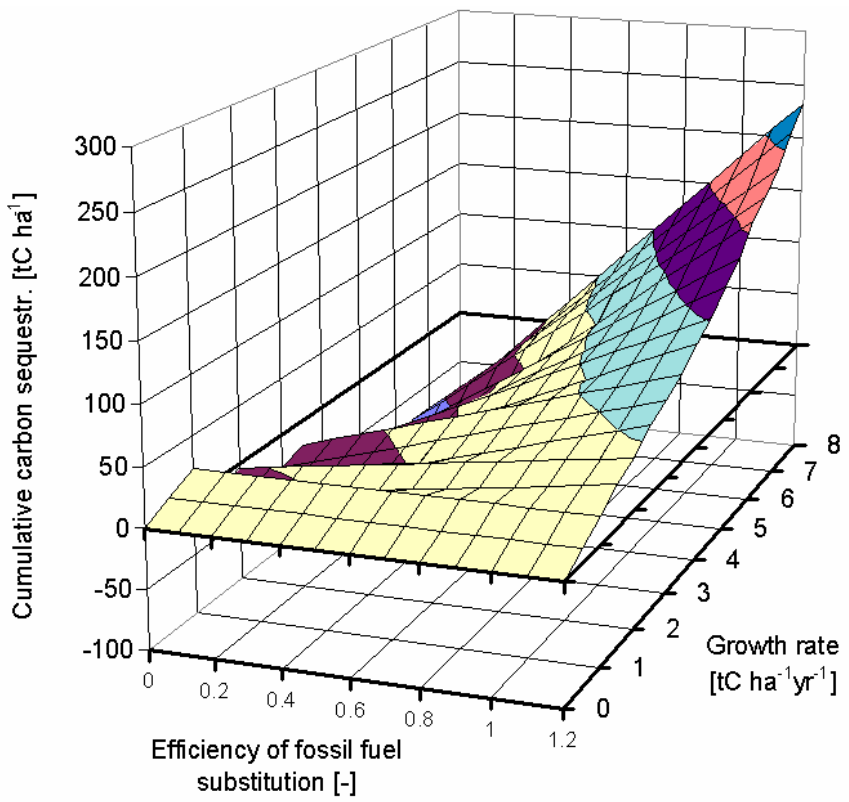


Figure 17. The difference after 40 years between a scenario where land is reforested with fast growing species to produce biomass energy, and a scenario where land is reforested with the main purpose of storing carbon. The coloured surface (vertical axis) depicts cumulative carbon benefits of substitution over sequestration as a function of the efficiency of bioenergy use, and the growth rate. Positive values indicate that management for biomass energy is the better choice (Marland and Schlamadinger 1997).

The bioenergy and C sink options obviously differ in their influence on the energy and transport systems. Bioenergy promotion induces systems changes as biofuels use for heat, power and transport increases. In contrast, the C sink option reduces the need for systems change in relation to a given climate target since it has the same function as shifting to a less ambitious climate target. The lock-in character of C sinks is one additional disadvantage for this option: mature forests that have ceased to serve as C sinks can in principle be converted to biomass production systems (or to food production), but this would involve the release of at least part of the C store created. On the other hand, C sinks can be viewed as a way to buy time for the advancement of other climate friendly energy technologies than bioenergy. Thus, from an energy and transport systems transformation perspective, the merits of the two options are highly dependent on expectations about other energy technologies.

5.4 Probability distributions of efficiency and cost in thermal systems

Another difficult problem with introduction of biomass is the large number of possible processes which could be used to convert biomass to heat, electricity or transportation fuels, or more likely, to a combination of two or three of these energy carriers. Firstly, there are many processes which are known on paper but which have not yet been applied in reality. Second, the processes differ considerably in efficiencies and costs and the definition of efficiency is not straightforward but depends on which is the main product. Thus, it is reasonable to apply a marginal view on the efficiency for production of an energy carrier if it can be produced as marginal product on an existing base load of, for example electricity (marginal efficiency will be decisive). This means a more cost efficient way of introducing biomass derived gas (SNG) or transportation fuel.

Based on a technology assessment, this work provides a range of basic cost and efficiency numbers for a wide range of biomass conversion processes for production of heat, electricity and transportation fuels and combinations of these. This range of costs and efficiencies can serve as probability distributions of inputs that can be used for sensitivity analyses by the models of the consortium, using some reference cost as the baseline case.

The hypothesis is that successful implementation of biomass technologies will depend on the access to near- and medium-term technological options. Chalmers will map such options both by means of the above-mentioned identification of a range of costs and efficiencies and by means of a more specific case study from which general conclusions can be drawn.

In addition, the complexity and maturity of the different processes should be of importance: an idea is to classify the processes with respect complexity/maturity. This information can be valuable regardless of whether such information can be made useful in the modelling.

The processes investigated are linked to production of

- Bio pellets (or lignin pellets), dried, grinded and compressed biomass (or lignin)
- Ethanol via hydrolysis (process where the biomass is divided into sugars and lignin) followed by fermentation
- Methane via hydrolysis and fermentation
- Methane via indirect or entrain flow gasification

- DME (dimethyl ether) via indirect or entrain flow gasification
- Methanol via indirect or entrain flow gasification
- DME and methanol via methane produced via indirect gasification

Lignocellulosic biomasses are, for example, forest residues or biomass that can be cultivated on degraded lands. The result from the assessment made in this work package shows that it is only the production of bio pellets that is fully commercially available today. For the other technologies one or several components are still not commercialized.
For the evaluation, each process has been analyzed component per component with the details given elsewhere (Thunman et al., 2008, 2009). The energy flows connected to each component has been identified and integrated within the process to optimize the production of the biofuel and electricity. The cost for each component has also been estimated from literature sources, direct contacts with industry and from involvement in erection of demonstration plants.
Summarizing the efficiencies for the different processes, the processes that produce biofuels for stationary applications, e.g. bio pellets show the highest efficiencies. Accounted for the cogenerated power, efficiencies up to 90 % based on ingoing lower heating values of the dry substance fed to the process could be achieved. For the processes that produce biofuels suitable for the transport sector, e.g. methanol or DME, efficiencies between 45 and 55 % can be reached, independent of product. However, there is one exception, which is methane produced via gasification that can reach efficiencies between 70 and 75 %. What differs more between the biofuel producing processes for the transport sector is the amount of biofuel that is possible to get out from the ingoing biomass, which can be anything between 20 and 70 %. Here, ethanol gives the lowest values and methane via gasification the highest values.
With respect to the costs to produce the different products the lowest costs are obviously related to the production of biofuels to be used in the stationary energy system. The total production cost of these products is between 40 and 90 % higher than the cost for biomass feedstock (Swedish forest residues). The production cost for the other biofuels is 2.5 to 3.5 times higher than the cost for the feedstock (Swedish forest residues), independent of product. However, some polygeneration schemes show very high cost, up to 9 times the cost for the feedstock. The uncertainty in these figures is, nevertheless, high and the real costs are dependent on if there are any supplier of the technology, which availability that is possible to achieve and the costs for the operation and maintenance. Until now the interest from the technology supplier to develop and market suitable technologies for larger units has been rather limited and at present there is no producer that are willing to offer a turn key project with a full guarantee responsibility for this type of processes (except for biopellet production). During the last year (2008) there has, however, been a change among producers and the technology supplier has started to show a growing interest. This makes it reasonable to expect that a number of full scale pilot plants can be up and running before 2015 and if these are successful a larger expansion can be expected after 2018-2020. Thus, our analysis indicates rather long lead times until these processes can be expected to be available on a commercial scale.
Figure 18 shows investment costs assuming a developed market for the technologies and feedstock/fuel costs (O&M excluded in this figure) for different cases of production of refined solid, liquid and gaseous biofuels. The fuel selected for this estimates are Swedish forest residue, which should be kept in mind if comparing these with costs, for example, ethanol and methane

from sugar canes respective sewage water, which are substantially different. The fuel related cost in the upper figure is a measure of the efficiency of the various processes. Here, the ethanol production via fermentation, shows the greatest variation, further the ethanol is divided into two areas dependent on if the process is incorporated with electrical production or not. The reason for this is the large demand of low value heat for the distillation process, which can be used as a heat sink when connected to electrical production and, thereby, significantly reduce the efficiency loss of the ethanol process. For the other processes this effect is not as pronounced even if the lower regions of each of the fuel related costs is related to combined biofuel and electrical production.

Figure 18 also shows the relative investment costs for the various products. It can be seen that the relative investment cost varies over a rather limited range for ethanol and methane via fermentation and for wood pellets. For production related to gasification the variation is greater, which is due to the preferred choose of different technologies for different unit sizes. Smaller units would most likely be based fluidized bed technologies, whereas larger units will be based on the more costly entrain flow technology.

The difference in preferred sizes for the different technologies and the related investment cost for the products are shown in the lower figure. It can be seen that for the preferred sizes for the two gasification technologies the investment related cost for the end product will end up in typically the same range. Noticeable in the lower figure is that the investment cost for methanisation in connection to fluidized bed gasification is lower than for DME and methanol production. This is due to a simpler technology and higher efficiency. For suspension gasification this difference is not as significant. The reason for this is that in a fluidized bed one has the possibility to take advantage of that methane is naturally produced in the gasification process, which is not the case for the entrain flow gasification process operating at higher temperatures. On the other side the methanisation process for the entrained flow is proven for large scale units using coal, a technology that most likely would work also for biomass. For fluidized bed gasifiers the metanisation process on large scale (above typically 20 MWproduct) yet have to be proven.

In addition, the work has investigated options for substitution of natural gas with biomass in a combined cycle plant (CCGT) with supplementary firing, operated in combined heat and power (CHP) mode. Such options should be of interest, since there have been large investments in CCGT units over the last decades and it is likely that there will be a need to reduce CO_2 emissions from these units. From an energy systems perspective, it is of interest to understand what opportunities are available for low risk and low cost introduction of biomass in line with what has been discussed above. This is also the case for natural gas fired systems.

The options investigated are indirect atmospheric and oxygen-blown pressurized gasification of biomass to Synthetic Natural Gas (SNG) for firing in the CCGT, biomass firing in a stand-alone boiler (CHP) and integration of a solid fuel combustion unit in a biomass/natural gas hybrid combined cycle. These options were compared to an existing 600 MW_{fuel} CCGT reference plant by means of simulations. The comparison was made quantitatively (thermal efficiencies) and qualitatively (risk and flexibility of the options).

The simulations show that the hybrid scheme will have significantly higher (41.7%/97.9% electric/total) efficiency than both the gasification option (26.0%/91.9% electric/total) and the stand-alone biomass boiler (32.4%/98.6% electric/total). The gasification scheme offers the highest load factor and flexibility (in fuel and energy carrier), but suffers from lower efficiency and higher risks compared to the hybrid scheme. The biomass boiler option is a low-risk technology with high total efficiency, but with lower flexibility than gasification and lower electric performance

than the hybrid option. Choice of the most suitable option is dependent on factors such as risk willingness, fuel access and the revenue from selling heat, power and gas. Applying the results on the Göteborg case study, it is concluded that options based on solid combustion (Bio, BioHyb) are more attractive (due to higher efficiency, lower risks and better compliance with local district heating demand) than a gasifier solution (Gasif). For other energy systems the conclusion may differ, i.e. local conditions should be considered when evaluating various options.
In summary, different processes for conversion of biomass yield substantial differences in costs as well as in efficiency. In addition, the processes have different ranges of size (installed capacity). Thus, comparing the processes with cost as the only parameter can be misleading since they have rather different niche markets and the conditions for market entrance ("room" in the energy system) vary between the processes.
PLANETS modelling should consider the large variations in a stochastic modelling exercise. This has to be discussed further and will depend on the possibilities in the different energy systems models as well as what technologies can be included in the modeling. In summary, there are two important issues with respect to biomass conversion technologies:

- The possibility to convert biomass to different products (electricity, transportation fuels and combinations of these).

- There are considerable variations in fuel as well as in investment costs both between the groups of conversion technologies and within each group of technology. The variations are due to technical parameters (difference between different technologies) and due to size of plants.

Thus, an issue is if and how these variations can be handled in a modelling exercise.

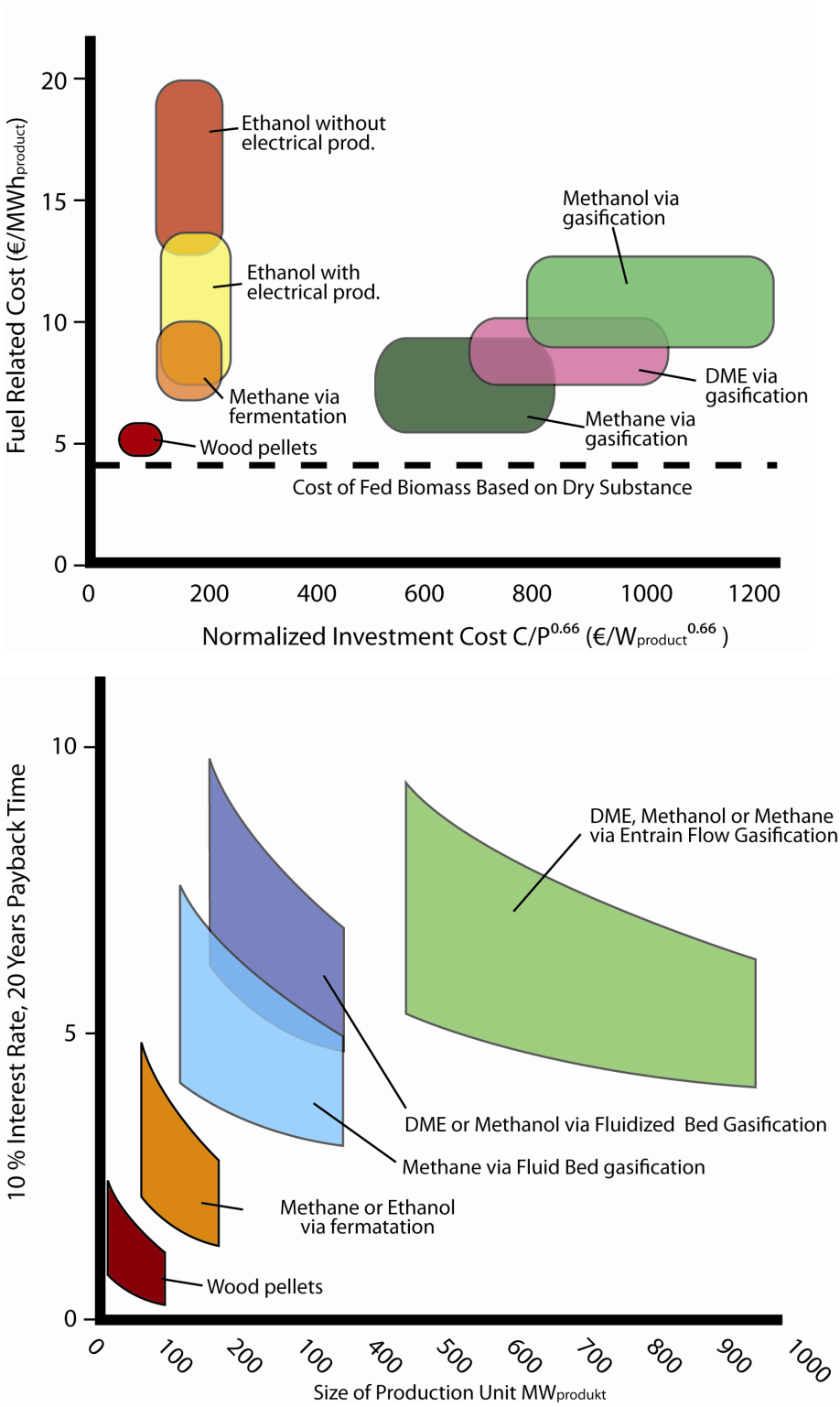


Figure 18. Upper figure, fuel related cost for production of various biofuels as function of normalized investment cost. Lower figure, investment related cost for the various biofuels vs expected size of production unit.

5.5 Biomass – proposals for PLANETS modelling

5.5.1 Bioenergy development and co-firing as a bridging option

It is not obvious how to introduce biomass co-firing in energy systems modelling. This, since co-firing is linked to existing (and possibly new) coal fired power plants. Although co-firing is cost efficient its implementation will probably be governed by other factors than the cost, such as access to existing power plants and biomass supply infrastructure. This means that a certain maximum ramp-up of co-firing needs to be defined. The quantification presented above could be a basis for setting a maximum rate of co-firing expansion for the near to medium term in Europe.
Besides using the results from the assessment above for introducing co-firing in the modelling, the PLANETS modelling groups could also contribute to insights in relation to issues coming up when biomass co-firing is discussed as a bridging option and also in relation to the possible character of bioenergy demand/supply development and, especially, from the perspective of learning the energy models may provide information on the importance of learning for new bioenergy options.
One possible question to address based on PLANETS modelling:

> *Could a prospective biomass demand for co-firing bridge to lignocellulose based bioenergy such as 2nd generation biofuels by representing a near term market for lignocellulosic biomass and this way stimulating a substantial development of lignocellulosic supply systems?*

PLANETS modelling might investigate the value of inducing early development and learning for lignocellulosic supply systems. One interesting question is whether this approach to stimulating the longer term development of 2nd generation biofuels is less costly than introducing specific economic incentives in the form of investment subsidies for 2nd generation biofuel production plants or tax exemptions for 2nd generation biofuels.
One additional question concerns the value of biofuel preparation technologies that allow for higher biofuel shares in the fuel mix (such as reducing salt content and obtain mechanical qualities more similar to those of coal) – for instance, what biofuel price increase would be acceptable if the biofuel share in the fuel mix could be increased from 10-20 percent to 50 percent?

5.5.2 Uncertainties about the climate change mitigation benefit of using bioenergy

As described earlier Bioenergy can have varying mitigation benefits depending on (i) character of inputs (i.e. GHG emissions) in feedstock production and conversion to biofuel/electricity; (ii) LUC emissions arising directly or indirectly as a result of the bioenergy expansion; and (iii) substitution pattern when used for energy, but this last aspect is taken care of in the modeling.
An original idea for PLANETS modelling was to investigate how various levels of GHG emissions reduction linked to substituting fossil fuels with different types of solid and fluid biofuels will impact on the attractiveness of these fuels in the model runs. A distinction would then be made between biofuel use in the transport sector on the one hand and biofuel use in the stationary sector on the other hand, and the relative climate benefit of these two principal options could be varied referring to higher expected climate benefit of bioenergy use in stationary sector.

However, to the extent that (endo-/exogenously defined) energy demand includes the energy sectors' own energy use as a small part of the total energy demand, it might be strange to assign GHG emissions only to bioenergy with reference to energy inputs in the biomass production and conversion to biofuel/electricity while not at the same time assign GHG emissions to e.g., PV production and tropical hydro (CH4 from anaerobic breakdown of organic matter in dams).
An alternative for the modelling could be that all bioenergy options are defined to have their production emissions already included implicitly via energy demand in models. In other words bioenergy expansion is assumed not to result in any deviation in internal energy use within the energy sector.
The bioenergy options could be assigned a certain level of GHG emissions refering to LUC emissions caused by converting land to bioenergy use. Possibly one could also include a factor reflecting lower average conversion efficiency for transport sector bioenergy compared to stationary sector bioenergy: lower conversion efficiency means lower benefit (in terms of energy service delivery) per unit of LUC caused by the biomass production.
Tentative proposition for discussion within the PLANETS consortium:

- 0-50 EJ/yr (the 50 number should be varied): zero LUC GHG emissions assuming these volumes could be met based on using residues and organic waste. If wanting to include time aspects, could model this as bioenergy use causing immediate emissions instead of the gradual decomposing emissions existing if not used for bioenergy

- Above 50 EJ/yr (assumed to be dedicated feedstock production systems): LUC GHG emission level is varied depending in pace of bioenergy expansion. Rationale is that productivity increase provides much of the supply increase in a BAU agricultural development but drastically increased demand (caused by the energy sector requiring biomass for energy) probably leads to that a relatively larger share of the supply response comes from cropland area expansion leading to LUC emissions.

In a model this approach might be implemented by using a type of cost-supply curve, where the cost in this case is LUC GHG emissions. As shown in an earlier section the LUC emissions can be very different depending on which lands are converted to bioenergy plantations. Figure 15 could be a starting point for developing LUC GHG emission scenarios.
PLANETS modelling may also contribute to the ongoing discussion about GHG benefits observed on bioenergy system level vs. more strategic energy system considerations where also prospects for other energy technologies are included. If possible, climate targets could be complemented with certain energy security targets (e.g., maximum level of oil/gas import dependency), which could be varied to see if this influences how the models prioritize the bioenergy use.
While biomass uses for heat and electricity as a rule provide higher mitigation benefit, arguments for using biomass for the production of transport fuels is that the stationary sector can rely on a range of different low carbon options. In contrast, biofuels may be the major option for climate change mitigation and energy security improvement in the transport sector, at least in the near to medium term. Future fossil fuels in the transport sector may also yield higher GHG emissions, and improve the case for biofuels: transport fuels from less conventional oil resources and coal based Fischer-Tropsch diesel both have higher lifecycle GHG emissions than the gasoline and diesel used today.
This discussion is complicated also by the possible longer term development of technologies for hydrogen and electric vehicle propulsion (hybrid, plug-in hybrid and electric vehicles) may make it

possible to support road transport using a range of renewable energy sources on the longer term. Given such a development bioelectricity powering electric vehicles can offer higher mileage per unit area than when liquid biofuels such as ethanol are used in a conventional internal combustion engine (Campbell et al. Science 324:1055). However, the higher area efficiency is mainly due to higher efficiency of electric vehicle propulsion and ethanol or other biofuels (including biomass derived hydrogen) can also be used in hybrid cars and plug-in hybrids. Whether bioelectricity or gaseous/liquid biofuels will be the preferred option for biomass based transport in such a future will depend on a range of aspects, not the least economic factors.

5.5.3 Bioenergy vs. carbon sinks

In addition to the above proposed model based analyses of the implications of uncertainty regarding climate benefits of bioenergy, PLANETS modellers could investigate the attractiveness of the carbon sinks option as an alternative to bioenergy.

By including the C sink option, the modelling groups in PLANETS could contribute to the bioenergy vs. C sinks debate based on an energy system perspective. For instance, Persson and Azar[9] found that the net present value of forest clearing for palm oil bioenergy plantations is positive, even in the face of a price on the carbon emissions from deforestation. Climate policy, in the form of a uniform carbon price, may therefore not suffice as protection for the world's tropical forests. In other words, clearing of forests to make place for bioenergy cultivations can in some instances (high-yielding plantations) be rational from the perspective of cost effective climate change mitigation.

[9] M Persson, PhD thesis 2008 (ISBN/ISSN 978-91-7385-196-1).

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