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Vienna International Centre, P.O. Box 300, 1400 Vienna, Austria
Tel: (+43-1) 26026-0 · www.unido.org · unido@unido.org

Global Technology Roadmap for CCS in Industry

Biomass-based industrial CO_2 sources: biofuels production with CCS

Michiel Carbo

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Acknowledgments

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1. Introduction

The biomass industry involves a range of processes that convert a raw biomass feedstock into products such as pulp and paper, sugar, timber and final energy products. Biomass conversion combined with Carbon Capture and Storage (CCS) has the potential to generate useful energy products such as electricity, bioethanol, Fischer-Tropsch diesel, substitute natural gas (biomethane) and hydrogen, while removing CO_2 from the natural carbon cycle for geological timescales (Rhodes and Keith, 2003).

Under the most stringent climate change mitigation scenarios, an average minimum temperature increase of 1.4 °C is likely to occur during the 21st century (Van Vuuren et al., 2008). This corresponds to an increase of approximately 2.0 °C in comparison with preindustrial levels. Mitigation scenarios incorporate forcing targets below 3.5 Watt per m^2, which indicate that CO_2 emissions in 2100 should be lowered by 20-60% with respect to 2000. Modelling suggests that the application of bioenergy with CCS (BECCS) is indispensable to in order to achieve deep emission reductions in the longer term, in particular under the most stringent climate change mitigation scenarios (Fischer et al., 2007). The use of CO_2 neutral biomass has the potential to achieve net removal of CO_2 from the atmosphere when used in combination with CCS. This is important as it allows offsetting historic CO_2 emissions and emissions from dispersed sources. Fossil fuel conversion with CCS typically only mitigates 80 to 90% of the original CO_2 emissions of a source (IPCC, 2005). BECCS technologies involve the use CCS with the conversion of biomass to electricity or biofuels, or hybrid concepts that can produce both.

BECCS could also facilitate a further reduction of the net present value cost for meeting relatively low atmospheric CO_2 concentration stabilization targets, when compared with CCS from fossil fuels only (Azar et al, 2006). The reduction of added costs appears to become more significant with ambitious atmospheric CO_2 concentration stabilization targets. A general tendency that can be observed from various stabilization scenarios is that the CO_2 emission abatement through the use of biomass grows relatively slowly during the first half of the century, with projected mitigation potentials of up to 7,000 million tonnes CO_2 per year by 2050. While the abatement is expected to increase more rapidly during the second half of the century, with projected mitigation potentials of up to 27,000 million tonnes CO_2 per year by 2100 (Fischer et al., 2007).

The scope of this assessment initially focuses on the conversion of biomass with CCS in the manufacturing industry and biofuels production; not taking into account electricity generation. Recent projections for 2020 and 2050 (IEA 2009b; IEA, 2010) indicate that the contribution of biofuels production with CCS to the combined share of biomass-based CCS in the manufacturing industry and biofuels production is by far the most significant. Therefore a number of concepts for the production of biofuels with CCS will be discussed more in-depth later during this assessment.

2. Current and projected CO_2 emissions

The direct CO_2 emissions in industry amounted to approximately 7,600 million tonnes CO_2 in 2007, this figure involves both process related and fuel combustion emissions (IEA, 2010). The total CO_2 emissions in the OECD countries are slightly lower than China; while the iron and steel, cement and chemicals sectors almost emit three-quarters of the total direct industrial CO_2 emissions. The IEA BLUE Map low-demand scenario projects a significant increase of biomass use in particular for transportation fuels and power generation, which is displayed in Figure 2.1. The scenario also projects a large contribution for transportation biofuels combined with CCS.

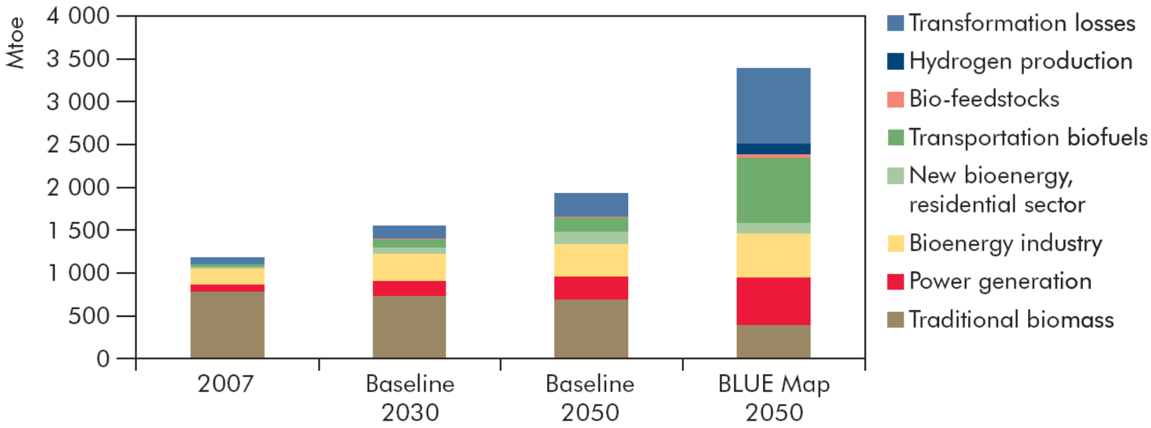

Figure 2.1 *World biomass use for different scenarios (1 Mtoe = 0.041868 EJ)*

The global deployment of CCS is projected to increase from a capture rate of 161 million tonnes CO_2 per year in 2020 to 4,032 million tonnes CO_2 per year in 2050 (IEA, 2010). As depicted by Figure 2, biomass-based production of synthetic fuels and hydrogen with CCS covers 26.3% of the total CCS deployment in the manufacturing industry and biofuel production by 2020 and 52.3% by 2050, in accordance with the BLUE Map low-demand scenario. Please note that Figure 2.2 displays the distribution of CCS deployment for both the manufacturing industry and biofuels production sector.

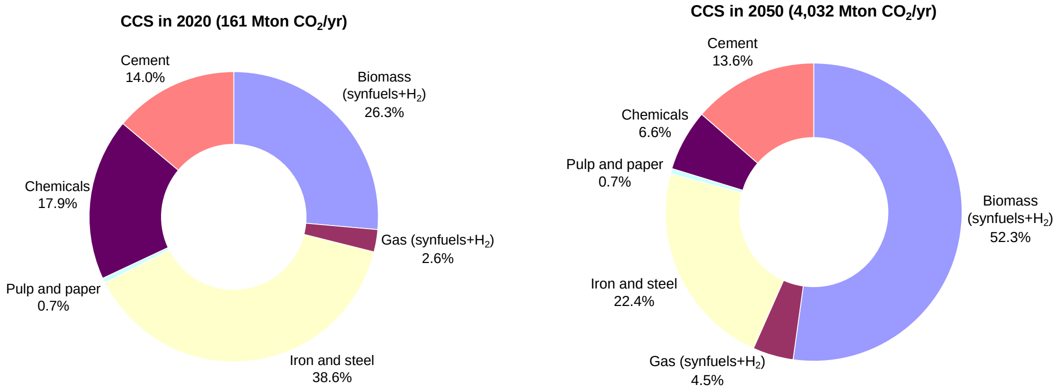

Figure 2.2 *Global deployment of CCS in industry and biofuels production in 2020 and 2050, based on data obtained from (IEA, 2010)*

Figure 2.2 illustrates that the contribution of CCS in the pulp and paper industry only covers a small share of the total projected CCS deployment by 2050. It must be noted that the pulp and paper industry currently consumes the largest biomass share in industry, 55 out of a total energy use of 190 Mtoe (IEA, 2010), which does not account for biomass use as process feedstock. The total direct and indirect CO_2 emissions for the pulp and paper industry amounted 405 million tonnes CO_2 per year in 2007, and in accordance with the BLUE Map low-demand scenario these are projected to decrease to 175 million tonnes CO_2 per year by 2050 (IEA, 2010). The most important contributions to this reduction are energy efficiency improvements, fuel switching and the use of decarbonised electricity.

One of the most important by-products in this industry is black liquor, which is an aqueous solution of lignin, hemicellulose and the spent pulping chemicals used during digestion of wood into paper pulp. Black liquor typically contains roughly half of the energy of the wood going into the digester. The black liquor stream is usually concentrated and is burned in a recovery boiler to generate steam and reclaim the pulping chemicals. The total global black liquor production amounted approximately 215 million tonnes (dry basis) in 2007, which corresponds to roughly 60 Mtoe (Naqvi et al., 2010).

Numerous studies illustrated that black liquor gasification combined with synthesis of transportation fuels could be very suitable for integration with CCS, both from a technological and economical perspective (Möllersten et al., 2003; Larsson et al., 2006; Naqvi et al., 2010; Petterson and Harvey, 2010). The projected total contribution of CCS combined with black liquor Integrated Gasification Combined Cycle (IGCC) power plants is relatively small at 30 million tonnes CO_2 per year in 2050 (IEA, 2010). The costs for CCS appear similar to coal-fired IGCC with CCS. However, black liquor gasification with synthesis of transportation fuels and CCS has not been taken into account in the latter reference. It is recognized that the pulp and paper industry could be an early mover for large-scale biofuels production with CCS in the EU and North America; and therefore a cost-effective contributor to emission reductions through the implementation of BECCS.

Figure 2.3 and Figure 2.4 illustrate the global deployment of CCS per industrial and biofuels production sector and feedstock in 2020 and 2050, respectively. These figures were compiled under the assumption that the fraction of biomass use as function of the total fuel consumption in a specific industrial sector can projected at the deployment of CCS in that sector. This approach results in an estimate of both the biomass-based and fossil fuel-based share of CCS deployment. The projected contribution of biomass-based CCS amounts 30.6% in 2020, of which

26.3% accounts for synfuels and H_2. The projected contribution of biomass-based CCS is expected to increase to 58.8% in 2050, of which 52.3% accounts for synfuels and H_2. The cement (4.5%), iron and steel (1.1%), chemicals (0.5%) and pulp and paper (0.4%) industries will cover a much smaller share of the global CCS deployment, therefore only the production of biomass-based transportation fuels in combination with CCS will be taken into account during this sectoral assessment.

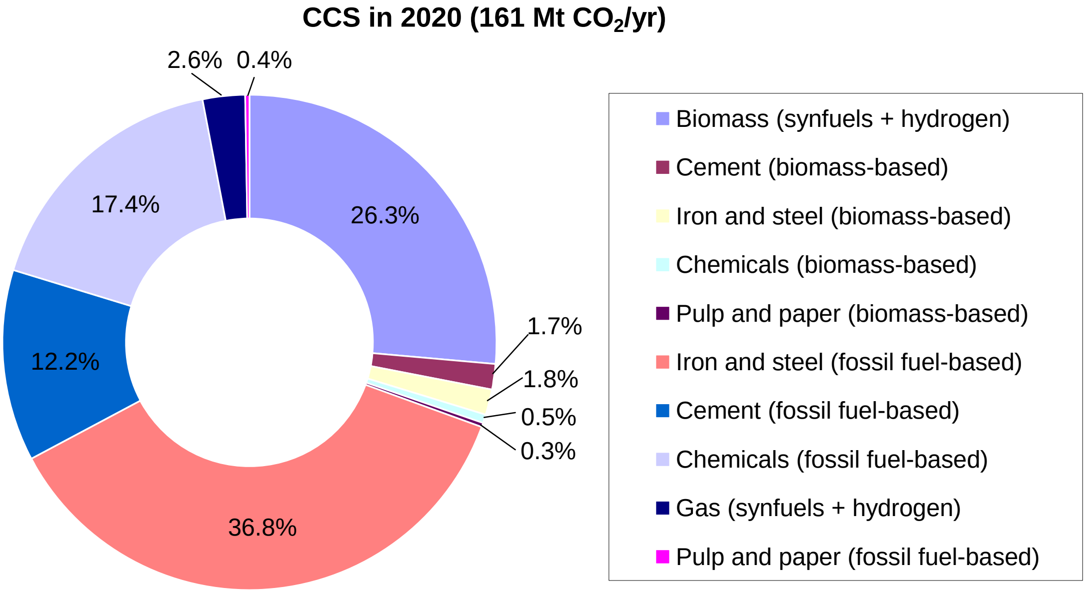

Figure 2.3 *Global deployment of CCS per industrial sector and feedstock in 2020, based on data obtained from (IEA, 2010)*

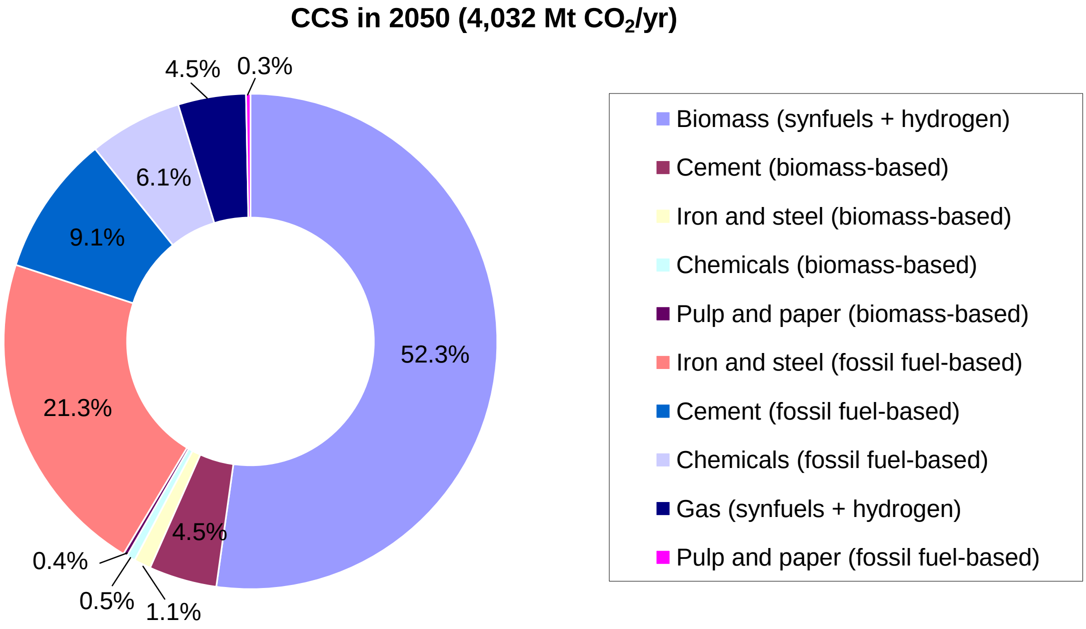

Figure 2.4 *Global deployment of CCS per industrial sector and feedstock in 2050, based on data obtained from (IEA, 2010)*

The increase in biomass use will largely depend on the decarbonisation of the biofuels production sector, with a transition from fossil fuels to biofuels. The replacement of natural gas with biomass-derived substitute natural gas (SNG), and an increase demand of hydrogen for heat and power may also stimulate a growth of the biomass use. In the pulp and paper industry black liquor is a biomass derived residue that is locally available at relatively large quantities, and could be deployed -through gasification- for synthesis of biofuels in combination with CCS.

3. Industry characteristics

3.1 Pulp and paper industry

The production of pulp and paper involves different technologies that are able to convert wood in to pulp; these can be roughly divided in to chemical and mechanical pulping, and combinations of both. Kraft mills use chemicals to degrade the lignin that binds the cellulose fibers; combustion of the lignin compounds (called black liquor) in a recovery boiler allows reuse of these chemicals. Mechanical mills use grinding and –at some point in the process– steam treatment, this typically results in products that are less sturdy. Paper mills can use a combination of virgin and recycled pulp to produce paper.

Table 3.1 illustrates that for Kraft over 90% of the CO_2 is of biogenic origin, for mechanical approximately 50% and for paper mills less than 20%. The average European Kraft integrated pulp and paper mill emitted 1.2 million tonnes CO_2, the average mechanical pulp and paper mill 0.23 million tonne CO_2 per year, and the average paper mill 0.17 million tonne CO_2 per year.

Table 3.1 *Capacities and CO_2 emissions of European pulp and paper mills (Jönsson and Berntsson, 2010)*

Mill type	Kraft pulp	Kraft integrated pulp & paper	Mechanical pulp & paper	Paper[1]
Mills [no.]	21	29	45	76
Pulp capacity [kADt/year][2]	9,955	12,320	12,095	14,775
Paper capacity [tonnes/year]	-	16,131	22,132	27,169
CO_2 emissions [thousand tonnes/year]				
Mills [no.]	21	29	43	70
Fossil	1,391	3,164	4,759	9,420
Biogenic	24,308	30,775	5,524	2,217
Total	25,699	33,940	10,283	11,637

[1] Paper mills with capacity above 200 thousand tonnes paper per year were included

[2] kilo air dried tonnes (90% dry solids)

The total global CO_2 emissions in the pulp and paper industry are estimated to amount to 405 million tonnes per year (IEA, 2010). Roughly two third of these emissions originate from Kraft pulp and integrated pulp mills (Jönsson and Berntsson, 2010), and therefore approximately 60% of the CO_2 emissions of total pulp and paper industry are biogenic. During recent years the global Kraft pulp production capacity has been growing at a relatively slow rate. The global potential for CO_2 capture is estimated to be 300 to 350 million tonnes at present.

Off gases of pulp and paper mills can typically contain up to 13-14% CO_2, and for Kraft mills most of this CO_2 is biogenic by origin. For Kraft mills retrofit of CO_2 capture could be an option, using chemical absorption similar to post-combustion CO_2 capture. Drastic process integration could potentially reduce the specific energy consumption for CCS and the associated capture costs substantially (Möllersten et al., 2003; Jönsson and Algehed, 2010). For mechanical pulp and stand-alone paper plants integration of CCS appears less viable due to the relatively high cost of capturing small volumes of CO_2.

The estimated global black liquor production obtained from Kraft mills equaled approximately 60 Mtoe in 2007 (Naqvi et al., 2010), while a typical Kraft mill produces 250 to 300 MW_{th} of black liquor (Landälv, 2009). The fleet of recovery boilers is aging and a large number of boilers are expected to be replaced in the coming decade. This could open a window of opportunity for the gasification of black liquor; the latter would allow the synthesis of transportation fuels that have more added value than the production of heat or electricity.

3.2 Biofuels production

The current cumulative biofuel production mainly involves the production of bioethanol from sugar cane and grains, and biodiesel from oil seeds. The cumulative global production of these first generation biofuels amounted approximately 2.0 EJ in 2008 (REN21, 2009), as displayed in Figure 5. The production of bioethanol is a well-established industry, particularly in Brazil and the USA with 90% of the global bioethanol production using sugar cane and corn (respectively) as feedstock. Roughly two-thirds of the global biodiesel production stems from the European Union, with Germany and France being the largest producers. The feedstock is usually vegetable oil, such as rapeseed or soybean oil.

The 2020 and 2050 projections for the global biofuels production in accordance with the IEA BLUE Map low-demand scenario (IEA, 2010) are also displayed in Figure 3.1. The total biofuels production is projected to increase to 3.2 EJ in 2020, with a slight increase for bioethanol from sugar cane and the introduction of ligno-cellulosic bioethanol and Fischer-Tropsch diesel. The total biofuels production is projected to further increase to 35.2 EJ in 2050. According to the IEA BLUE Map scenario the production of bioethanol from grains and biodiesel from oil seeds are potentially abandoned, while large increases are projected for bioethanol from sugar cane and ligno-cellulosic material, Fischer-Tropsch diesel. It also foresees in the deployment of gaseous energy carriers from biomass, being biogas, BioSNG and hydrogen.

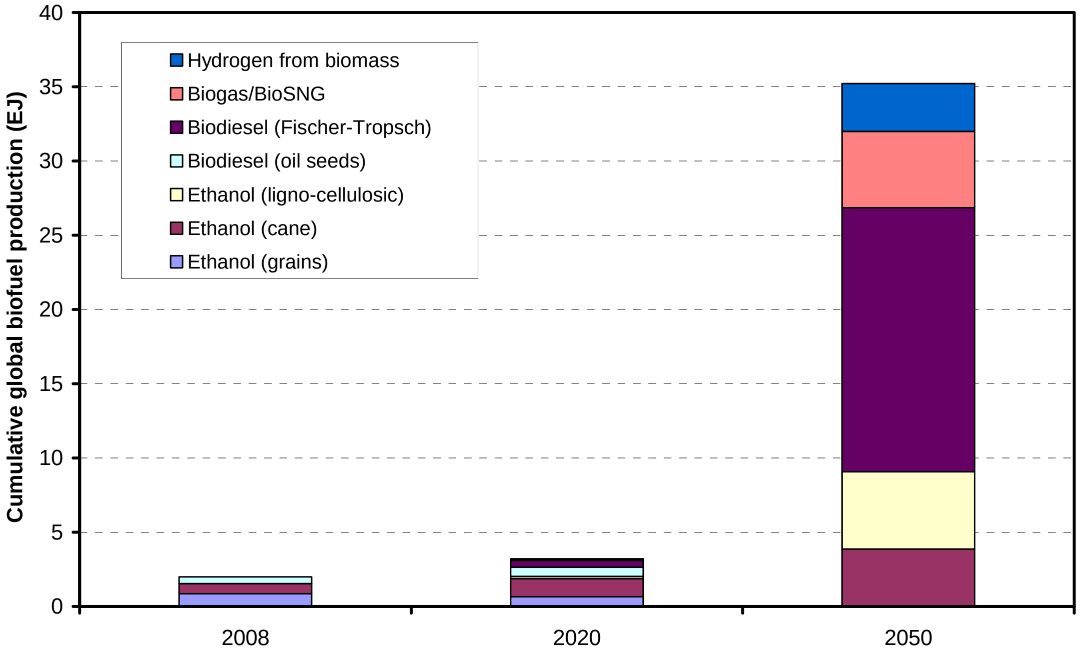

Figure 3.1 *Current (converted from: REN21, 2009) and future cumulative global biofuel production according IEA Blue Map low-demand scenario (IEA, 2010)*

Figure 3.2 displays the cumulative capacity of currently known planned second generation biofuel projects; this survey was conducted by IEA Bioenergy Task 39 (Bacovsky, 2010). Thermochemical, bio-chemical and hybrid conversion cover approximately 60%, 30% and 10%, respectively, of the global second generation biofuel production capacity in 2016. The total foreseen production of second generation biofuels in 2016 is roughly 3% of the total biofuels production in 2008.

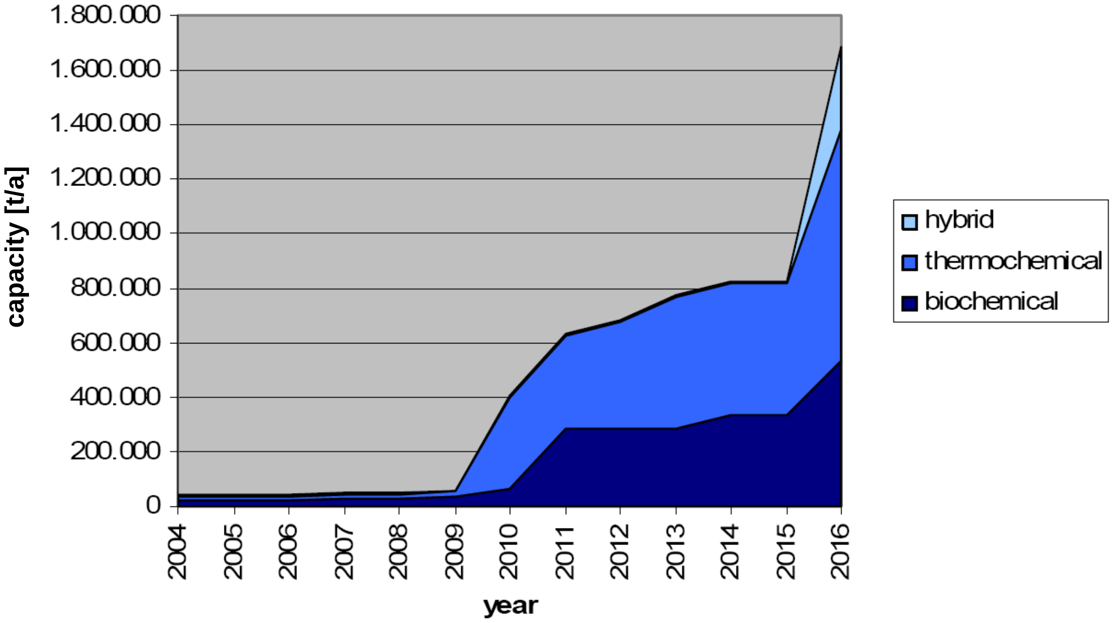

Figure 3.2 *Cumulative capacities of planned second generation biofuel projects (Bacovsky et al., 2010)*

The IEA BLUE Map low-demand scenario (IEA, 2010) foresees a contribution of 80% thermochemical and 20% bio-chemical conversion for second generation biofuels production in 2020. The total foreseen production of second generation biofuels in 2020 is approximately 35% of the total biofuels production in 2008. This appears to be a fairly large discrepancy to be covered in just four years; a reason for this could be that the IEA Bioenergy Task 39 survey only includes projects from the respondents to a voluntary questionnaire. Furthermore a significant amount of demonstration projects are commissioned in the coming two to three years, which potentially could result commercial-scale facilities during the second half of this decade. It is also important to realize that the BLUE Map scenario envisions a certain global energy demand and CO_2 emissions in 2050, which determines what the deployment of biofuels should be in 2020 to achieve the long-term target.

4. Technical overview of capture options

There are a number of routes to convert biomass into final energy products (see Figure 4.1). For this roadmap, because of the focus on CCS applications in biofuels production, only the gasification and biological processing routes will be covered.

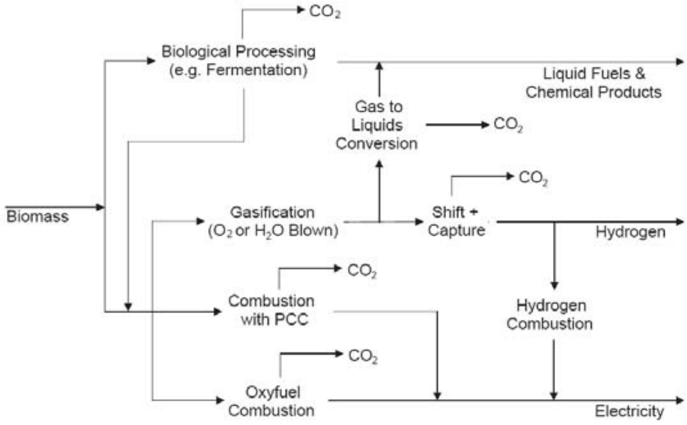

Figure 4.1 *Routes to biomass with CO_2 capture and storage (Rhodes and Keith, 2003)*

The replacement of fossil fuels with synthetic fuels that are produced from sustainable biomass readily provides a CO_2 mitigation option. The use of biomass in biofuel production processes typically also results in high-purity CO_2 by-product streams. In that case the combination of CO_2-neutral biomass and CO_2 capture and permanent storage potentially leads to a net CO_2 uptake from the atmosphere, i.e. negative lifecycle emissions.

Bio-chemical biomass conversion processes, for example fermentation, uses living microorganisms to breakdown the feedstock and produce liquid and gaseous fuels. A common 1st generation process to produce bioethanol, is the fermentation of sugar cane, sugar beet or corn starch, where a by-product of the reaction is a relatively pure stream of CO_2. The production of liquid ethanol and gaseous CO_2 is almost equal on mass basis. The separation of both compounds is straightforward since both compounds are present in different phases; hence no additional separation equipment is required. The CO_2-rich off-gases from the fermentation tanks are dried and compressed to facilitate transport and storage. On a bio-ethanol plant with a net output of 235 million litres per year, the addition of compression equipment only leads to a 0.9% increase in capital costs (Rhodes and Keith, 2003).

Thermo-chemical biomass conversion, or gasification, is a thermal treatment that results in the production of gaseous products and a small amount of char and/or ash (Demirbas, 2002). During gasification, the biomass or black liquor is converted into gases by means of pyrolysis, which occurs at high temperatures of 875-1275 K. To reach these temperatures an oxidizing agent is needed. This can be air or oxygen (Gao et al., 2008). For synthesis of liquid or gaseous fuels it is essential that only a minimum amount of nitrogen is present during the synthesis. This reduces equipment sizes and cost, and increases the partial pressures of the reactants, which typically improves the product yield. This implies that relatively pure oxygen must be employed, typically obtained via cryogenic distillation of air, at significant thermodynamic and economic penalties.

Depending on a number of variables such as feedstock characteristics, temperature and gasifying agent, the gas composition consists of carbon monoxide, carbon dioxide, hydrogen, methane, nitrogen, as well as non-gaseous by-products such as char and tars. At gasification temperatures above 1275 K the resulting gas stream consists primarily of hydrogen and carbon monoxide, called synthesis gas or syngas. At relatively lower gasification temperatures, other components such as methane and higher hydrocarbons (tars) are also present in the resulting gas stream, and this is often referred to as producer gas.

The gasification of biomass can lead to a number of products, most suitably represented in Figure 4.2, derived from (Smit, 2009). Carbon dioxide is a by-product during all the represented synthesis processes. The employed CO_2 separation technologies are the same as those that are foreseen for pre-combustion CO_2 capture at power plants.

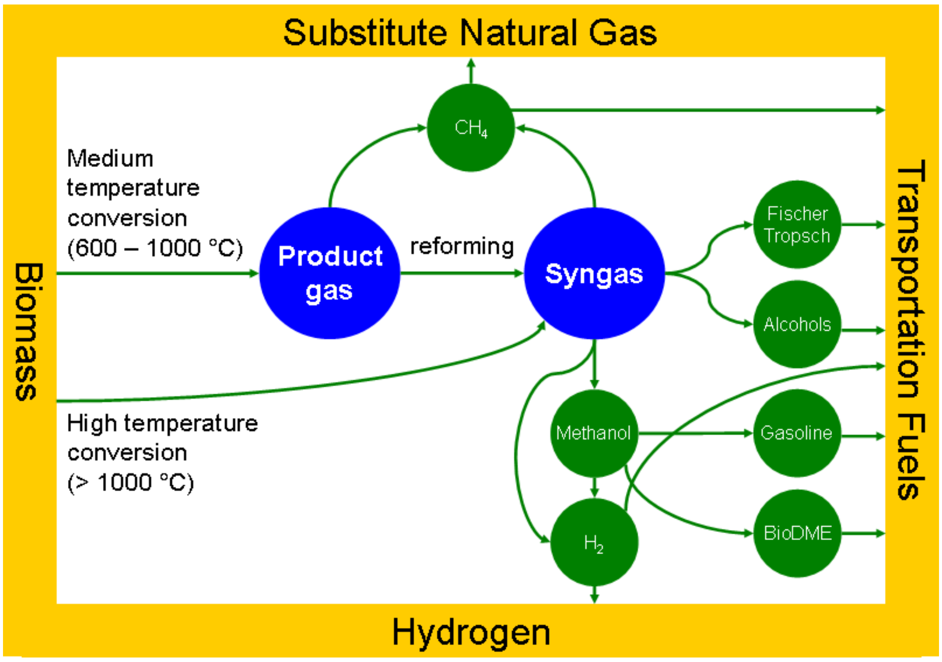

Figure 4.2 *Products from the gasification of biomass (Smit, 2009)*

Integration of additional separation equipment to facilitate CCS is typically not necessary during conversion of biomass to biofuels, either because gaseous CO_2 can be readily separated from the liquid product, or because CO_2 separation equipment is already in place to comply with required product specifications (Carbo et al., 2010a). The CO_2 product stream needs to be dried and compressed to facilitate transport and storage. For both bio-chemical and thermo-chemical biomass conversion routes the additional CO_2 capture costs for dehydration and compression and are estimated to amount 6-12 $ per tonne CO_2 (Dahowski and Dooley, 2008).

The different routes for CCS during biofuel production vary significantly in terms of characteristics and estimated costs. Only capture of process-related CO_2 emissions has been taken into account, since these provide high-purity and often also high-pressure CO_2 streams. Capture from diluted sources, such as an on-site Combined Heat and Power (CHP) unit is financially less interesting, due to the limited scale of the CO_2 source and the heavily diluted flue gas stream. For this matter four different biofuel conversion routes are described in more depth: bioethanol through biomass fermentation, as well as Fischer-Tropsch liquids, BioSNG, and hydrogen through biomass gasification and subsequent synthesis. Table 4.1 summarizes indicative CO_2 capture rates and CO_2 product stream concentration per CO_2 source.

Table 4.1 *Indicative CO_2 capture rates and CO_2 concentrations per source*

CO_2 source	Carbon in captured high-purity CO_2 stream/ Carbon in feed stream [mol%]	CO_2 concentration in high-purity CO_2 stream[1] [mol%]
Ethanol	15-35%	~99%
FT diesel	~50%	>95%
BioSNG	40-45%	>95%
BioDME	~50%	>95%
Hydrogen	>90%	>95%

4.1 Ethanol

Ethanol is currently produced through the bio-chemical conversion of mainly agricultural crops, which contain either sugar (sugar cane, sugar beet, molasses and sorghum) or starch (potato, corn, barley and wheat). The starch in the latter crops should be converted to sugars prior to further conversion.

The predominant conversion technology is biomass fermentation followed by a series of distillation and dehydration steps, which are needed to increase the ethanol concentration. Sucrose is extracted from sugar-rich agricultural crops by mechanically pressing the cooked biomass and a subsequent fractionation. Yeast converts the sucrose which results in ethanol and carbon dioxide as waste products of the metabolism. The ethanol product obtained from the fermentation is diluted with water, which could be removed through distillation up to ethanol purities of approximately 96 wt%. The formation of a low-boiling water-ethanol azeotrope prevents further purification through distillation. This so-called hydrated ethanol is suitable to use as fuel, although not for blends with gasoline. Further purification to anhydrous ethanol –which allows blending with gasoline– is established by using molecular sieves that absorb the remaining water content.

The use of starch-based crops requires grain milling or grinding followed by liquefaction and fractionation. The latter steps take place simultaneously during cooking after the addition of water. Either enzymatic or acidic hydrolysis is used to convert starch to hexose, which can be fermented to produce ethanol and CO_2 as described above. The combined amount of ethanol produced in the US and Brazil was approximately 42 billion liters in 2007 (IEA Bioenergy, 2008). This corresponds to a CO_2 release during the fermentation of 32 million tonnes CO_2 per year in both countries. In the USA the average plant size is about 200 million liters of ethanol per year, which translates to 140 thousand tonnes high-purity CO_2 that could be captured and stored.

Significant R&D efforts are dedicated to the conversion of lignocellulosic feedstock into ethanol through fermentation. These types of feedstock are typically cheaper and more abundantly available than food crops, although the molecular structure –and therefore the conversion in to ethanol– is more complex. Lignocellulose consists of cellulose, hemicellulose and lignin; the first two can be converted to sugars and subsequently fermented, although hydrolysis of these compounds typically is more complex than of starch. Lignin is an aromatic polymer that can not be fermented and is typically combusted to generate heat and/or electricity.

Based on the initial carbon content of the sugars that are fermented in a bioethanol plant 67% of the carbon leaves as ethanol, and 33% as high-purity CO_2 that could be captured and stored. It must be noted that the distribution of carbon in the outlet streams of the entire plant can vary significantly with different feedstocks and plant configurations, for example by combustion of lignin in a combined heat and power unit in a lignocellulosic bioethanol plant.

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[1] After dehydration

One of the first commercially operated ethanol plants integrated with CCS, and thus biomass-based industrial CO_2 capture and storage project, started operation in the U.S.A. during the third quarter of 2009 (Chaparral Energy, 2010). At present approximately 60% (170-180 thousand tonnes CO_2 per year) of the total produced CO_2 is captured at the Arkalon bioethanol plant in Liberal, Kansas, and transported to an oil field near Booker, Texas, for enhanced oil recovery.

A similar pilot project in the U.S.A. is managed by the Midwest Geological Survey Consortium and started operation early 2010 (MGSC, 2010). This project foresees the injection of 1.0 million tonnes CO_2 over three years in the Mt. Simon Sandstone saline formation. The CO_2 is obtained from the Archer Daniels Midland Company (ADM) bioethanol plant in Decatur, Illinois.

The Global Environment Facility (GEF) of the United Nations Development Programme (UNDP) awarded a grant for implementation of CCS at a sugar fermentation-based ethanol plant in Sao Paolo state, Brazil (GEF, 2010). For a typical sugar mill size in Sao Paolo state of 25 million liters of ethanol per year, this implies that 20 thousand tonnes of CO_2 per year will be stored in a local saline formation. Implementation is foreseen in early 2012.

4.2 Fischer-Tropsch Liquids

The production of Fischer-Tropsch liquids involves the thermo-chemical conversion of lignocellulosic biomass into synthesis gas, followed by gas cleaning, Fischer-Tropsch synthesis and refining to the final product. Typical Fischer-Tropsch liquid products are diesel and kerosene.

High-temperature biomass gasification technologies result in a synthesis gas that primarily consists of hydrogen and carbon monoxide, which are two primary reactants in Fischer-Tropsch synthesis. Furthermore, high temperatures reduce the tar concentration in the produced synthesis gas. Two types of gasifiers that are suitable for synthesis gas production with high H_2 and CO concentration can be distinguished: pressurized fluidized bed and entrained flow gasifiers (Higman and van der Burgt, 2008). Both use oxygen obtained from an Air Separation Unit (ASU), to minimize the nitrogen concentration in the synthesis gas.

After fluidized bed gasification roughly 5% of the carbon ends up in the ash, while the synthesis gas contains a moderate amount of tar that requires conversion or removal prior to further synthesis. Entrained flow gasification requires biomass pre-treatment to allow high-temperature gasification. Pre-treatment can occur through torrefaction, which involves biomass upgrading though a mild heat treatment (250-300 °C) that increases the heating value, reduces the moisture content and eases milling (Gerhauser et al., 2010). Another pre-treatment method involves biomass pyrolysis, which involves a moderate heat treatment (450-550 °C) that results in a pyrolysis oil slurry and char. The Carbo-V concept by Choren is commercially available and includes pyrolysis of biomass at moderate temperature and subsequently high-temperature (> 1300 °C) conversion of the pyrolysis oil to synthesis gas, while the char is added and converted in a secondary quench step (Rudloff, 2010).

Two types of catalyst are commercially used for the Fischer-Tropsch synthesis: iron- and cobalt-based catalysts. Unlike iron-based catalysts, cobalt-based catalysts display no activity for the water-gas reaction and therefore the H_2/CO-ratio should be corrected upfront by a separate water-gas shift reactor. Before the Fischer-Tropsch synthesis, CO_2 and other trace impurities are selectively removed in the acid gas removal section. The absence of CO_2 during the Fischer-Tropsch synthesis improves the yield. CO_2 is separated using commercially available absorption technologies, and upon regeneration of the liquid solvent a high-purity CO_2 stream is available for capture and storage.

Fischer-Tropsch synthesis produces a range of products, which depending on the operating conditions and catalyst, range from methane to heavy waxes. The process is also highly exothermic and adequate heat removal is required to control the desired product specification. Cobalt-based catalysts are commonly used in fixed reactors, while iron-based catalysts are commonly used in slurry reactors. Saturated steam is generated in the reactor to maintain appropriate temperature levels. After the Fischer-Tropsch synthesis the gaseous products are separated and either used to generate electricity, or these are fed to an autothermal reformer to produce synthesis gas that is fed back to the gasification outlet stream. The liquid products are distilled to produce the final products and a heavy fraction; the latter undergoes an additional hydrocracking step to increase the final product yield.

A Fischer-Tropsch liquids plant based on an oxygen-blown CFB gasifier emits roughly 5% of the initial carbon input as CO_2 in the flue gas of the combined heat and power unit, 6% in the char, 37% in Fischer-Tropsch liquids and 52% as high-purity CO_2 that could be captured and stored (Carbo et al., 2010a).

The first commercial biomass-to-liquids plant is the Choren Beta plant in Freiberg, Germany, (Rudloff, 2010) with an input of 45 MW_{th} and an output of 18 million liter fuel. Wood chips are converted in the Carbo-V gasifier; the synthesis gas is cleaned, conditioned and led to the Fischer-Tropsch synthesis. Commercial operation is expected to start late 2010.

4.3 Substitute Natural Gas (BioSNG)

BioSNG is produced through the thermo-chemical conversion of lignocellulosic biomass, followed by gas cleaning and methanation. After compression, the methane-rich product stream could be injected in any existing natural gas grid.

One of the most important aspects during the design of a bioSNG plant is the selection of the appropriate gasification technology. A nitrogen-lean producer gas should be obtained from the gasifier, since the absence of nitrogen facilitates compliance with specifications for injection in high-pressure natural gas grids. This requirement leaves three possible biomass gasification technologies: oxygen-blown pressurised Entrained Flow (EF), oxygen-blown pressurised fluidised bed (both BFB and CFB) and steam/air-blown indirect gasification at atmospheric pressure. The net biomass-to-bioSNG efficiency on LHV-basis for these technologies amount 54.3%, 58.1% and 66.8%, respectively (van der Meijden et al., 2010). The net efficiency for indirect gasification based bioSNG plants is significantly higher since this configuration does not require a capital and energy-intensive Air Separation Unit (ASU). Oxygen-blown BFB and CFB biomass gasification are more developed than indirect gasification at present. However, for BioSNG production the focus will be on indirect gasification, since this technology has a significantly higher yield and is expected to mature during the next decade.

Indirect gasification concepts typically consist of two reactors: Biomass pyrolysis takes place in the first reactor by heated bed material obtained from the second combustion reactor (Bengtsson, 2007). The first reactor uses steam for fluidisation and typically yields high initial methane concentrations in the producer gas stream, due to the moderate gasification temperatures (800 – 900°C). The carbon conversion in the first reactor is typically 80 – 90%; the unconverted fraction is combusted in the second air-blown fluidised bed combustion reactor, to pre-heat the bed material prior to feeding it back to the pyrolysis reactor. The use of bed material for heat transfer between both reactors limits the operating pressure to approximately 7 bara (van der Meijden et al., 2010). At significantly higher pressures the gaseous volume becomes too small to provide sufficient transport of bed material for heat transfer.

An important disadvantage of gasification at moderate temperatures is the formation of tars (Milne et al., 1998). Tars are higher aromatic hydrocarbons that typically condense at temperatures below 400°C, and cause equipment fouling and plugging. The carcinogenic nature of tars also poses strict handling implications from a safety and environmental point of view. Thermal or catalytic cracking of tars is undesirable, since these technologies are expected to reform a significant part of the methane content in the producer gas. Oil-based scrubbing appears more appropriate since tars are removed above the water dew point temperature, which avoids contamination of water with tar compounds. After regeneration of the scrubbing oil these tars can be fed back to the combustion reactor of the indirect gasifier.

After tar removal, unsaturated hydrocarbons are hydrogenated, sulphurous and chlorine components are removed and CO_2 is separated. The latter takes place using commercially available natural gas sweetening technologies (absorption), to provide a product gas with the appropriate stoichiometric composition of H_2, CO and CO_2. A near pure CO_2 stream will be available upon regeneration of the absorption liquid, which can be compressed to facilitate transport to the CO_2 storage site. Traces of CO_2 that are not separated will be converted to methane in the methanation section. Commercially offered methanation processes are based on a sequence of fixed-bed reactors with intermediate cooling; the catalyst is nickel-based.

Gasification in indirect gasifiers typically takes place at relatively low pressure; hence the cleaned producer gas is compressed to increase the methane yield in the methanation section. Downstream of the methanation reactors, the product stream primarily consists of methane and water with traces of hydrogen and carbon monoxide. An interesting feature of a bioSNG plant is the net production of water, in contrast to fossil fuel power plants with CCS. The produced water is removed during bioSNG upgrading, and is therefore relatively clean which eases waste water treatment.

Dedicated biomass gasification and gas cleaning technologies are still under development at this stage (Kopyscinski et al., 2010), while water-gas shift, CO_2 separation and methanation technologies are commercially available and have been proven downstream of coal gasification applications. A BioSNG plant based on indirect gasification emits roughly 20% of the initial carbon input as CO_2 in flue gas, 40% as methane in BioSNG and 40% as high-purity CO_2 that could be captured and stored (Carbo et al., 2010a).

The largest commercial BioSNG project is the Göteburg Biomass Gasification Project, GoBiGas, which was initiated by Göteborg Energy and E.ON. The first phase comprises a 20 MW_{th} bioSNG plant to be operational in 2012; it will be constructed in Göteborg, Sweden. For this plant an indirect FICFB gasifier will be deployed with Haldor Topsøe's TREMP fixed bed methanation technology downstream (Mastrup, 2010). The second phase involves an 80 MW_{th} SNG plant, which is scheduled to be operational by 2016.

4.4 Methanol to BioDME

The methanol to BioDME synthesis is typically positioned downstream of the same gasification technologies as described under the Fischer-Tropsch liquids section of this assessment. The H_2/CO-ratio is adjusted in a water-gas shift reactor, with H_2S and CO_2 removal positioned downstream. The methanol yield in a single reactor can be relatively high, although a recycle or a second reactor is required to further increase the yield and reduce by-product formation. Any remaining by-products will be separated prior to the DME synthesis, which converts two ethanol molecules to one molecule dimethyl ether and one molecule water (Landälv, 2009). Any unconverted methanol is recycled or sold as by-product.

An interesting feature of a BioDME plant is the opportunity for co-production of methanol and DME, which could be used to bridge the gap to a more mature market for DME as transportation fuel (Clausen et al., 2010).

Chemrec has operated a 3 MW_{th} oxygen blown black liquor gasifier at Piteå, Sweden (Landälv, 2009). This pilot facility was started up in 2005 and operates at a pressure of 30 bar. From 2010 to 2012 a BioDME pilot plant will be operated downstream of the gasifier as part of the EU FP7 BioDME project. This project foresees the production of 4 tonnes DME per day, which will be used for field tests with 14 trucks. This project is coordinated by Volvo.

A larger commercial project is foreseen in Domsjö, Sweden. This project involves a 200 MW_{th} Chemrec oxygen blown black liquor gasifier, and the downstream synthesis of 450 tonnes methanol per day or 300 tonnes DME per day. The final investment decision for this project will be made late 2011, while start-up is scheduled in 2013.

In parallel to the above mentioned methanol to BioDME projects, the U.S. Department of Energy awarded a 25 million USD grant for a methanol to gasoline project (Mastrup, 2010). This pilot plant will be installed downstream of the Carbona gasifier at GTI in Des Plaines, Illinois, which processes 20 tonnes of wood per day corresponding to an input of roughly 5 MW_{th}.

4.5 Hydrogen

The hydrogen production in principal uses the same gasification technologies as described under the Fischer-Tropsch liquids section of this assessment. The water-gas shift reaction however, likely takes place in a sequence of reactors with intermediate cooling, to maximize the carbon monoxide conversion to hydrogen. CO_2 and trace impurities will be selectively removed in the acid gas removal section, using commercially available absorption technologies. The resulting hydrogen-rich stream still contains traces of CO and CO_2, therefore this stream is further purified in a Pressure Swing Adsorption (PSA) unit. The bulk of the initial carbon input can be captured as pressurized high-purity CO_2, being roughly 80 t0 90%. Part of the carbon is captured in the char or slag (depending on the gasifier type) and the PSA off-gases.

To the knowledge of the author no commercial demonstration plants for the production of bio-based hydrogen are either in operation or planned at present.

5. Estimated costs

Cost data for biomass-to-biofuel conversion processes are scarce, in particular for conversion processes combined with CCS. The most important reason for this is that BECCS forms a relatively new field in research and development. Plants for the production of second generation biofuels are still relatively small in size, up to the commercial demonstration phase, which could result in less accurate cost figures.

Typically the capital investment of biomass conversion plants is higher than for fossil fuel conversion plants. This is mainly attributable to the nature of biomass: the energy density is usually lower than for instance coal, the moisture content higher and the composition of biomass is less homogenous and more fibrous. Therefore more equipment for biomass pretreatment is required in comparison with coal and natural gas. Large-scale import of biomass is expected to result in higher prices on an energy basis than for fossil fuels, which also contributes to higher prices for biofuels.

These phenomena can also be observed in Figure 5.1. This figure displays the incremental cost and lifetime well-to-wheel CO_2 savings for various synthetic fuels and biofuels using conventional gasoline as a reference (without accounting for negative CO_2 emission reduction through BECCS). The incremental cost for biomass-to-liquids (BTL) in comparison with gasoline is roughly zero, while the cost significantly decreases for CTL despite of the relatively high CO_2 emissions.

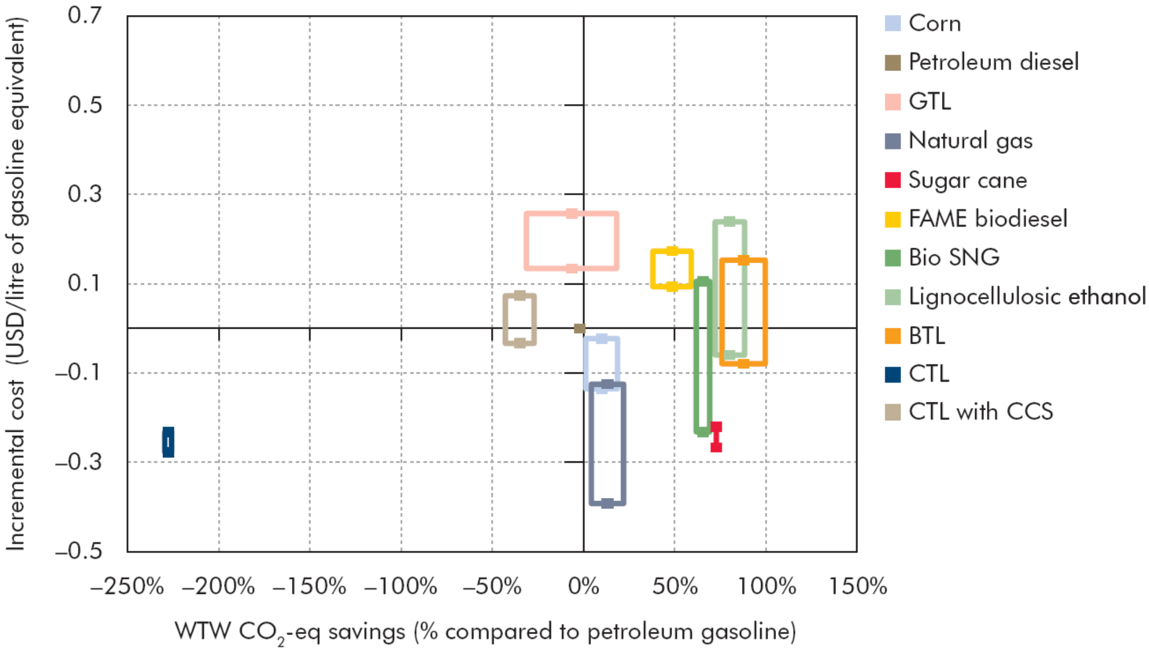

Figure 5.1 *Incremental cost of alternative fuels as a function of their CO_2-equivalent saving potentials at USD 120/bbl (IEA, 2010)*

Note 1: Negative CO_2-eq savings means the use of the fuel results in higher WTW CO_2-eq emissions than using gasoline.

Note 2: Assumes oil priced at USD 120/bbl. Costs reflect a bottom-up technology cost analysis of making each fuel, including feedstock production, transport, conversion to fuel, fuel transport, storage and retail supply to vehicles.

Note 3: Natural gas and BioSNG are assumed to be widely used in different end uses, sharing the costs of the transmission and distribution infrastructure required.

An overview of reported biofuel production plant capacities and associated biomass and biofuel production costs is provided in Table 5.1. A large share of the production cost comprises the biomass cost. It must be noted that the reported figures should be divided by the plant efficiency to provide the actual share of biomass cost as part of the production cost. An additional complication is that only a few studies report the integration opportunities for CCS, although these are often not substantiated by cost figures, such as CO_2 capture or avoidance cost.

Table 5.1 *Plant capacity, biomass and production cost for different biofuels*

Ethanol (from woody biomass)	Hamelinck & Faaij	Solomon et al.	Eriksson & Kjellström		Range
	2006	2007	2010		
Plant capacity ($MW_{th,in}$)	400	Not specified	295		295-400
Biomass cost (€/GJ)	3.0	Not specified	3.5		3.0-3.5
Ethanol cost (€/GJ)[2]	22.0	18.7	19.7-21.5		18.7-22.0

Fischer-Tropsch	Yamashita et al.	Hamelinck & Faaij	Kreutz et al.	Van Vliet et al.	Range
	2004	2006	2008	2009	
Plant capacity ($MW_{th,in}$)	430	400	660	400	400-660
Biomass cost (€/GJ)	1.5	3.0	3.8	1.8-4.6	1.5-4.6
FTL cost (€/GJ)[2]	13.8-20.8	18.0	21.5	18.0-48.5	13.8-48.5

BioSNG	Gassner & Maréchal	Åhman	Carbo et al.	Hacatoglu et al.	Range
	2009	2010	2010b	2010	
Plant capacity ($MW_{th,in}$)	150	100	500	400	100-500
Biomass cost (€/GJ)	9.2	4.5	4.0	2.8	2.8-9.2
BioSNG cost (€/GJ)[2]	16.4-26.9	20.0	13.3	13.1	13.1-26.9

BioDME	RENEW	Larsson et al.	Clausen et al.		Range
	2008	2008	2010		
Plant capacity ($MW_{th,in}$)[3]	500	479-601	2,302		479-2,302
Biomass cost (€/GJ)	5.1-7.8	0.9-1.9	4.6		0.9-7.8
BioDME cost (€/GJ)[2]	16.1-21.0	7.6-12.8	11.9		7.6-21.0

Hydrogen	Hamelinck & Faaij	Sarkar & Kumar			Range
	2006	2010			
Plant capacity ($MW_{th,in}$)	400	456			400-456
Biomass cost (€/GJ)	3.0	2.2			2.2-3.0
H_2 cost (€/GJ)[2]	16.0	7.5			7.5-16.0

[1] Exchange rates: EUR/USD: 1.0:1.3; EUR/SEK: 1.0:9.5

[2] Production cost

The incremental cost of CO_2 capture in case of biomass-to-biofuel conversion processes is generally low, since a high-purity CO_2 stream is readily available for capture. The incremental capture costs are therefore limited to CO_2 dehydration and compression, and typically only amount 6-12 $ per tonne CO_2, mainly depending on the CO_2 transportation pressure.

During the calculation of the total CO_2 avoidance cost, the price difference between a biofuel and its fossil fuel counterpart is also taken into account. The IEA Blue Map low-demand scenario foresees gradually decreasing fossil fuel commodity prices in the long-term as a result of reduced demand; since a significant part of the demand will be fulfilled with biofuels. This scenario also foresees much higher effective commodity prices due to the inclusion of a CO_2 price of 175 USD per tonne CO_2 in 2050.

The production of BioSNG illustrates what the effect would be of the inclusion of negative emission accounting for the synthesis of biofuels with CO_2 capture and storage. During the production of BioSNG through indirect gasification the total carbon content of the inlet stream is distributed over the following outlet streams: 40% as BioSNG, 40% in high-purity CO_2 stream and 20% as flue gas which is vented. The net greenhouse gas emissions on plant level are presumably almost zero.

Figure 5.2 demonstrates the effect of the inclusion of negative emission accounting for BioSNG. Starting points are the lower and upper boundary of BioSNG production cost with no CO_2 price in place, representing an N^{th} plant and a first-of-a-kind plant, respectively. A natural gas commodity price of 7.5 € per GJ was assumed, while the combustion of natural gas results in a CO_2 emission of approximately 55 kg CO_2 per GJ if life cycle CO_2 emissions are omitted for the sake of simplicity.

The inclusion of negative emission accounting results in decreasing BioSNG production cost at increasing CO_2 prices, and provides an incentive to implement CCS. The use of natural gas is also expected to result in increasing costs when CO_2 prices increase. This further reduces the price gap between natural gas and BioSNG. The total CO_2 avoidance cost for an N^{th} BioSNG plant with CCS and inclusion of negative emission accounting therefore amounts approximately 60 € per tonne CO_2, and 205 € per tonne CO_2 for a first-of-a-kind plant with CCS.

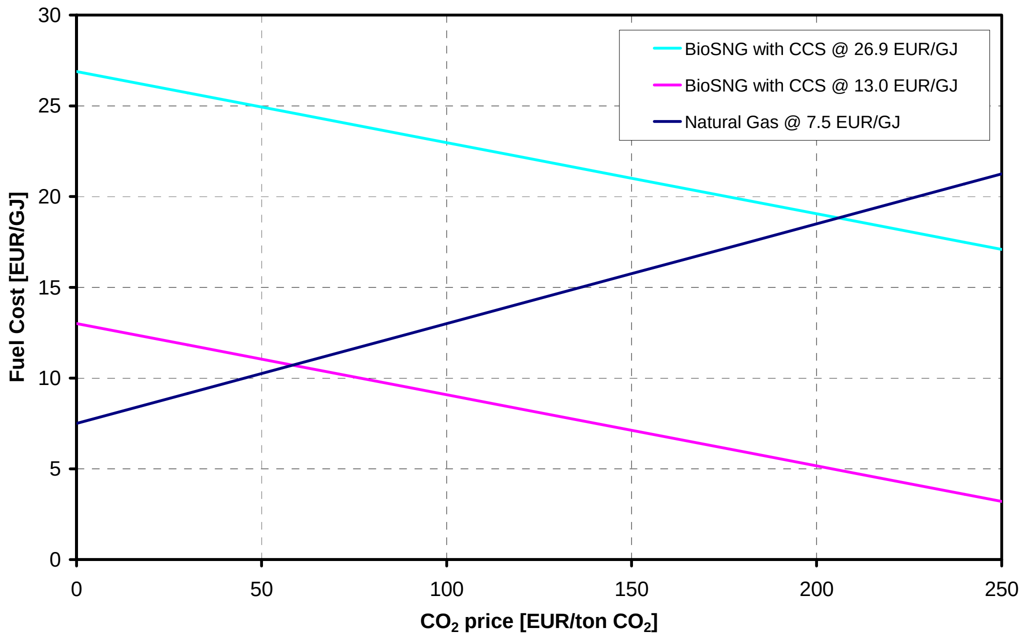

Figure 5.2 *The effect of negative emission accounting on total production cost for BioSNG (range 13.0-26.9 EUR/GJ according to Table 3), at a natural gas commodity price of 7.5 €/GJ*

It is apparent that the total CO_2 avoidance costs will increase at lower natural gas commodity prices. If the CO_2 price gradually increases to 175 USD per tonne CO_2 in 2050 (CO_2 price as suggested by the IEA Blue Map scenario) and negative emissions would not be accounted for, the broad implementation of BioSNG to replace natural gas will take place much slower. The latter would imply that the total CO_2 avoidance cost for an N^{th} BioSNG plant with CCS would amount approximately 100 € per tonne CO_2. The total CO_2 avoidance costs associated with other biofuel types display similar tendencies when it comes to the inclusion of negative emission accounting.

6. Current environmental legislation and pressures

The production of biofuels is inherently dependent on the demand for biofuels. For environmental and energy security reasons, several countries around the world have implemented policies and measures to enhance the use of biofuels. Initial biofuel policies mainly pursued blending of bioethanol and biodiesel with their fossil equivalents (IEA Bioenergy, 2009a). These policies mainly involved obligatory measures as well as tax breaks and subsidies. Since then policies gradually expanded towards flexible vehicles that are able to run on a range of fossil/biofuel blends, and the introduction of fuel standards for bioethanol and biodiesel. Moreover, overall biofuel targets and minimum annually required volumes were set.

There are a number of regions in the world that have taken steps to encourage the use of biofuels in transportation fuels, primarily through mandating a certain percentage of biomass-derived fuel to be blended with conventional fossil fuels. Policies which mandate ethanol blending, currently in Brazil and the US, have been designed for the purposes of energy security rather than efforts to reduce CO_2 emissions from transport. Policies primarily involve promoting 1st generation biofuels, which in addition to exhibiting variable greenhouse gas emission savings of between 20% to 70%, (Concave, 2008), have been criticized on various aspects from effecting grain and livestock prices, to the greenhouse gas emissions stemming from land-use change for biomass cultivation.

Table 6.1 provides an overview of blending mandates, biofuel targets and required volumes per country. The non-OECD nations that have established biofuel policies are generally countries that either produce biofuels or biofuel feedstock. The main driver for developing these policies is usually energy security as opposed to climate change mitigation. Other countries did not mandate blends; define targets or required volumes, but created incentives to increase the biofuel production, such as Mexico, Guatemala, El Salvador Malaysia and Indonesia.

Table 6.1 *Overview per country of blending mandates, biofuels targets and volumes required (Jank et al., 2007; Bringezu et al., 2009; Jumbe et al., 2009; Eisentraut, 2010)*

	Blending mandates		Biofuel targets	Volumes required per year	
	Bioethanol	Biodiesel	Biofuels total	Bioethanol	Biodiesel
Argentina	E5	B5			
Australia					
Belgium			5.75%		
Bolivia		B20 (2015)			
Brazil	E22-E25	B5 (2013)			
Canada	E5	B2 (2012)			
China	E10 (9 provinces)			13 bl (2020)	
Columbia	E10	B5			2.5 bl (2013)
Croatia			5.75%		
Dominican Rep.	E15 (2015)	B2 (2015)			
EU Total			10% (2020)		
France			10% (2015)		
Germany			12-15% (2020)	1.45 (2020)	8.3 (2020)
Ghana		20% (2015)			
India	E10 (13 states)	B5 (10 states)			2.3 bl (2020)
Italy	E1	B1			
Japan			5% (2030)	6 bl (2030)	
Malaysia		B5			
New Zealand			3.4% (2012)		
Paraguay		B5			
Peru	E7.8	B5			
Philippines	E10 (2011)	B2 (2011)			
Portugal			10%		
South Africa			4.5% (2013)		
Thailand	E10	B5 (2011)	10% (2012)		
UK	E5	B5			
Uruguay	E5 (2014)	B5 (2012)			
USA			20% (2022)	130 bl (2022)	

Brazil is the country with the most long-standing biofuel policy, aimed at mainly producing bioethanol from sugarcane, for which the country has excellent climatic conditions. The rationale was mainly energy security and foreign currency concerns in the 1970s, when petroleum prices soared (IEA Bioenergy, 2009b). The policy employed was a combination of public (including World Bank) and private investment in the sugarcane plantation area and a subsidy on the use of bioethanol. The subsidy, which reached 2 billion USD in 1996/1997, was complemented by a renewable fuel standard of ethanol in petrol (and more recently of biodiesel in diesel, based on soybean as a feedstock). Already in the 1980s, a significant number of vehicles produced in Brazil ran on pure ethanol. Starting in 2003, the favourable market conditions for biofuels led to the adaptation of vehicles that are suitable for both fossil- and bio-based fuels, the so called flexcars (Pelkmans et al., 2008).

Brazil is also the world's largest exporter of biofuels, mostly to the United States, Europe, Korea and Japan. While export markets are still growing, Brazilian companies continue to build new ethanol plants. With an almost 25,000 million litre production of bioethanol in 2008, the high-purity CO_2 emissions of these ethanol plants could amount to an estimated 19 million tonnes CO_2 per year.

Accepting the limitations of 1st generation biofuels, the US Renewable Fuels Standard (RFS) has mandated the blending of 2nd generation biofuels from 2010 onwards. The US has previously had strong policies to support ethanol production from corn, but with the enactment of the RFS, further increases in biofuel production in the next decade is expected occur through the use of 2nd generation biofuels. Production of 2nd generation biofuels in the use are expected to increase from current negligible amounts to 60.6 billion liters per year in 2020, out of a total predicted biofuel production of 136 billion liters per year.

An alternative for the policy measures addressed in Table 4 is the introduction of low-carbon fuel standards. These standards aim at the reduction of the overall lifecycle CO_2 emissions of transportation fuels. A reduction target is defined and fuel providers can choose their preferred method to reduce CO_2 emissions, such as biofuel blending, increase refinery efficiencies, capture and storage of CO_2 during production, and buying credits from other parties. Low carbon fuel standards are seen as more flexible than most of the other policy measures at moderate abatement costs. However, an important disadvantage is that fuels could be obtained from unregulated markets or the fuel production could be shifted, which subsequently could hamper the energy security and result in CO_2 leakage (Yeh and Sperling, 2010).

Low-carbon fuel standards are being employed in the US RFS and the European Union Renewable Energy Directive (EU RED) and involve the establishment of a minimum GHG emissions saving of a biofuel compared to its fossil fuel equivalent. The EU Directive mandates member states to enact policies that ensure that second generation biofuels account for a 10% share in gasoline and diesel consumption by 2020. This mandate is supplemented by the introduction of a biofuel ‘sustainability criteria’. Part of the sustainability criteria, covers the minimum emissions saving to be achieved by biofuels, compared to the gasoline or diesel fuel it replaces. The minimum requirement for emissions savings is 35% from 2013, rising to 50% by 2017 and 60% by 2018. These mandated emissions savings are comparable to the requirements under the US RFS, which states that lifecycle GHG emission savings for 2nd generation (cellulosic) biofuels must be 60%, and 50% for biomass-derived diesel[2].

Of particular interest to the incentives for application of CCS in biofuel production, in the EU RED calculation methodology for the GHG emissions from the production and use of biofuels and bioliquids, the emissions saving through CCS can be subtracted from the total emissions from the use of the fuel. The typical and default greenhouse gas emission savings for various biofuel production pathways are presented in Table 6.2. However, given that the future 2nd generation biofuels are expected to be able to reach GHG emissions savings of up to 95% compared to fossil fuels, it is unclear whether the minimum emissions savings requirements set by the US and EU legislation will warrant the application of CCS for compliance purposes.

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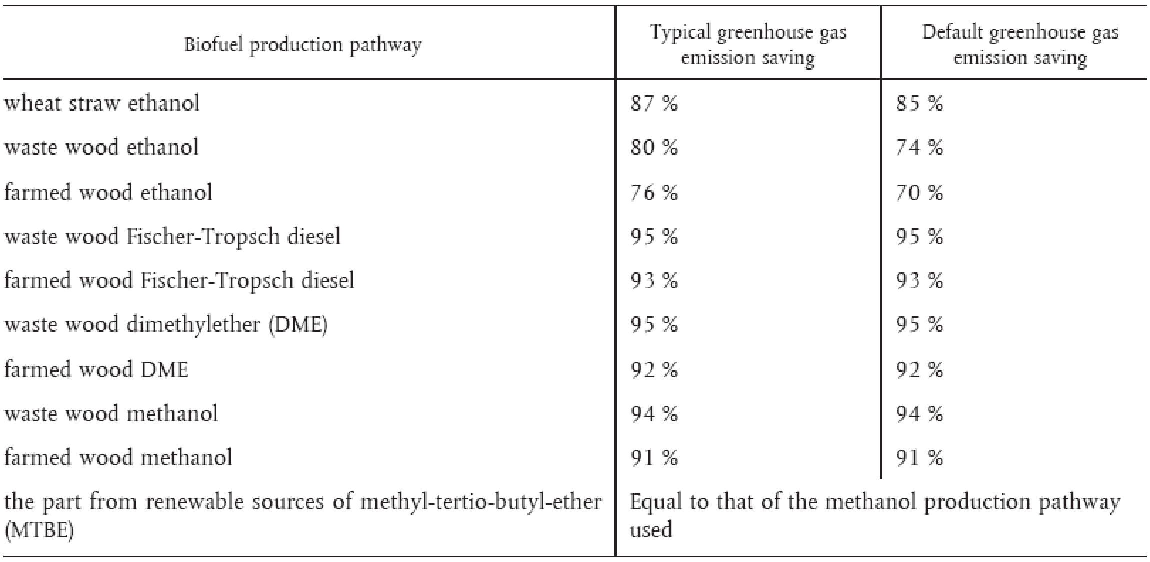
[2] Compared to the average baseline emissions of gasoline and diesel in 2005.

Table 6.2 *Estimated typical and default values for future biofuels*[3] *(EU, 2009)*



Biofuel production pathway	Typical greenhouse gas emission saving	Default greenhouse gas emission saving
wheat straw ethanol	87 %	85 %
waste wood ethanol	80 %	74 %
farmed wood ethanol	76 %	70 %
waste wood Fischer-Tropsch diesel	95 %	95 %
farmed wood Fischer-Tropsch diesel	93 %	93 %
waste wood dimethylether (DME)	95 %	95 %
farmed wood DME	92 %	92 %
waste wood methanol	94 %	94 %
farmed wood methanol	91 %	91 %
the part from renewable sources of methyl-tertio-butyl-ether (MTBE)	Equal to that of the methanol production pathway used	

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[3] Not net carbon emissions from land-use change

7. Major gaps and barriers to implementation

CO_2 capture and storage from biomass-based industrial sources is a mitigation technology that only receives little interest at present. The 4th assessment report of the IPCC (Fischer et al., 2007) recognized BECCS as a technology that could potentially be the key in pursuit of low atmospheric CO_2 concentration stabilization levels. However, the combination of biomass conversion with CCS generally tends to be overlooked by the biomass-based industry, biofuels production sector and CCS communities. From the perspective of the biomass community the acceptance of CCS is generally low, while the focus of the CCS community is on the use of fossil fuels specifically tailored for electricity generation with CCS. Consequently, the number of research papers on biomass conversion with CCS to date only amount approximately one hundred. Furthermore, the technology lacks industrial supports to pursue broad implementation, while there is a lack of awareness amongst policy makers.

Even though the 2006 IPCC Guidelines for National Greenhouse Gas Inventories allow for negative emissions to be allocated in national GHG inventories (IPCC, 2006), the concept has yet to be transposed into current policy frameworks (IEA, 2009b). An example of that is the third phase of the EU Emission Trading System, where the potential inclusion of biomass conversion only involves biomass co-firing during electricity production. Installations that exclusively[4] use biomass as process input stream are excluded from the system. This allows the emission of CO_2 without fiscal penalties, although it does not result in financial benefits since CO_2 credits are not allocated to these installations. The exclusion from the EU ETS has the potential to encourage bio-based industries; however the policy does not recognize the potential of achieving ‘negative emissions’ through combination of CCS with biomass conversion processes. In order to incentivize CCS in biomass-based industries, operators that capture and store CO_2 must be effectively credited for doing so.

Currently CO_2 capture and storage in general is not creditable under the Kyoto Protocol’s Clean Development Mechanism (CDM) due to issues around certainty of storage in a temporally constrained crediting mechanism. This has the consequence that the CO_2 capture and storage from biofuel production also cannot benefit from the carbon price in the CDM. An additional gap for developing nations could be that the subsurface CO_2 storage potential is generally mapped to a lesser extent in comparison with developed nations.

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[4] 97%

8. Actions and milestones

The actions necessary to improve the deployment of CCS with biofuels production must be viewed from a broader perspective of demand for alternative transport fuels and energy carriers. In distinction between the other sectors covered in the UNIDO Global Technology Roadmap for CCS in Industry, the biomass-based sector is small and underdeveloped. Demand for biofuels, biogas and other biomass derived products is currently slight, effectively suppressed by conventional fuels such as gasoline, diesel and natural gas which still dominate the market. Furthermore, the technologies to produce biofuels from biotic feedstocks that are less likely to compete with food supply, termed 2nd generation biofuels, are at present in development and demonstration stages. Nevertheless, the IEA BLUE Map scenario states that reducing global CO_2 emissions by 50% by 2050 will require an intensification of biofuel production, and substantial application of CCS within this emerging sector. An overview of actions is provided in Table 8.1.

Table 8.1 *Summary of actions for CCS deployment with biofuels production*

ACTIONS

Research

- Research conducted to develop methods for the inclusion of negative emissions in existing policy mechanisms, such as the EU ETS
- Research conducted to analyze the impact that negative emissions could have on the global carbon market
- Continued research into biomass-to-liquid technologies, the gasification of biomass for the production of 2nd generation biofuels
- Research networks established

Technological development

- Demonstration activities and scale-up of biomass gasification to continue
- Demonstration plant for gasification of biomass with CCS by 2015
- Expansion of demonstration plants for bioethanol production with CCS

Policy

- Policies that increase the demand for biomass-based products must continue to by implemented in developed and developing countries
- Biomass with CCS must be recognized by governments as a potential cost-effective abatement option, and incorporated into future policies relating to CCS deployment in general
- A BECCS stakeholder network should be formed, to facilitate more effective lobbying for the technology

One of the first actions to be undertaken in the near future is the formation of a BECCS stakeholder network. This requires mobilization of all relevant entities: policy makers, NGO's, scientific community and industry champions. The involvement of bodies such as the IEA, UNIDO and GCCSI is considered to be essential in the formation of such a network. Other early movers are nations that could have a short-term interest in application, such as Brazil, Sweden, the USA and Indonesia. This network increases awareness amongst stakeholders and potentially facilitates the establishment of policies aiming at BECCS deployment.

Meanwhile, more detailed scientific studies are needed on costs, long-term contribution on GHG reduction and early opportunities. Furthermore a dedicated BECCS pilot and demonstration programme should be facilitated by policy makers. All the above measures are required to achieve a substantial contribution of biomass-based industrial CO_2 capture and storage by 2050.

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