Combining BIO-ENERGY and CCS in Northwestern Europe

Master Thesis

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Content

Abstract

In this thesis we researched under which conditions bio-energy technologies with carbon capture and storage can be competitive with conventional fossil fuel powered technologies for the production of electricity and transport fuels in northwestern Europe in the year 2030. In the power sector the options of combustion, gasification and co-firing are researched. The results show that gasification has the highest mitigation potential, and can compete with the fossil reference technologies at a CO_2 credit price of 44 €$_{2010}$/tonne CO_2. When CO_2 credit prices do not compensate negative biogenic emissions, BECCS cannot compete with the fossil fueled technologies. The results also show that at CO_2 credit prices above 70 €$_{2010}$/tonne CO_2, and biomass prices below 6 €$_{2010}$/GJ, the CO_2 credit price outweighs the biomass price. This means that technologies with lower efficiencies, such as dedicated biomass combustion with CCS have lower cost of electricity than gasification. The total negative emissions for dedicated biomass combustion with CCS are -929 kg CO_2/MWh, for gasification with CCS -789 kg CO_2/MWh and for co-firing with CCS -175 kg CO_2/MWh. The results for the liquid fuel sector show that the Fischer-Tropsch diesel and DME technologies are able to compete with diesel and gasoline without the introduction of a CO_2 price. The emission reduction potential for the liquid fuel technologies are -97 kg CO_2/GJ for Fischer-Tropsch diesel and -69 kg CO_2/GJ for DME production. DME has lower production cost than FT, which makes DME the best option in the liquid transport fuel sector. In the gaseous fuel sector we see that Substitute natural gas is dependent on compensation of at least 53.3 €$_{2010}$/tonne CO_2 for stored emissions to be able to compete with natural gas. The emission reduction potential of SNG is -59 kg CO_2/GJ. The conclusion of this research is that BECCS technologies are highly dependent on low biomass prices, and compensation of negative biogenic emission by means of the introduction of sellable CO_2 credits of at least 44 €$_{2010}$/tonne CO_2 in the electricity sector, and 68 €$_{2010}$/tonne CO_2 in the gaseous fuel sector. The liquid fuel sector is not dependent on introduction of sellable CO_2 credits.

Keywords

Bio-energy, CCS, BECCS

Abbreviations

BE	Bio-energy
BECCS	Bio-energy Carbon Capture and Storage
BFB	Bubbling Fluidized Bed
BIGCC	Biomass Integrated Gasification Combined Cycle
CCS	Carbon Capture and Storage
CFB	Circulating Fluidized Bed
DME	Dimethyl ether
EF	Entrained Flow
FB	Fluidized Bed
FT	Fischer-Tropsch
GJ	Giga Joule
IEA	International Energy Agency
Kg	Kilogram
kW	Kilo Watt
MW	Mega Watt
MW_h	Mega Watt Hour
NGCC	Natural Gas Combined Cycle plant
NPS	New Policy Scenario
O&M	Operations & Maintenance
PC	Pulverized Coal
PFC	Pulverized Fuel Combustion
SNG	Substitute Natural Gas
TJ	Tera Joule
TOPS	Torrified wood pellets
Yr	Year

1. Introduction

The increased use of fossil fuels over the last centuries has led to increased greenhouse gas emissions to the atmosphere, which causes climate change. The combination of the damage done to the environment and decreasing supplies of fossil resources has led us to the point where a transition towards cleaner and more efficient technologies is necessary (IEA, 2012b).

In order to limit the increase in global temperature over future years, it was agreed during the 2009 UN conference on climate change in Copenhagen to limit the increase in global average surface temperature to a maximum of 2 degrees Celsius (IEA, 2010b). *As a result of this agreement the European Commission has set targets for all its member states for the year 2020. These targets oblige them to 1) reduce their greenhouse gas emissions in 2020 by 20% compared to 1990 and by 80% in 2050, 2) increase the percentage of energy from renewable sources to 20% of national production and 3) improve the energy efficiency by 20% by the year 2020 (European Commission, 2013).*

In order to keep global warming below 2 degrees Celsius, more powerful technologies are necessary than currently available (ZEP, 2012). There is an urgent need for carbon negative solutions, i.e. systems that remove CO_2 from the atmosphere (ZEP, 2012). Bio-Energy (BE) combined with Carbon Capture and Storage (CCS) is the only large scale technique that is able to achieve net negative emissions (ZEP, 2012). The IPCC state that BECCS technologies could be essential in the stabilization of the global average temperature. BECCS has also been appointed as a rapid-response prevention strategy for abrupt climate change (Rao et al., 2007). Abandoning CCS as a mitigation option would significantly increase the cost to achieve the 2 degree target (IEA, 2012a), or makes it impossible to achieve the target at all (Rogelj, McCollum, Reisinger, Meinshausen, & Riahi, 2013). When combining CCS with Bio-Energy the emission reduction will be greater than combining CCS with fossil fuel combustion. This is due to the biogenic carbon content of the bio-energy fuel.

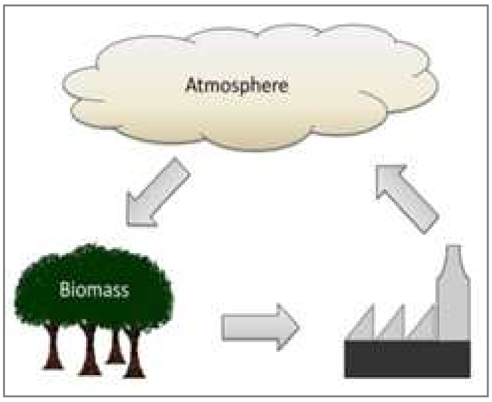


Figure 1: Short carbon cycle (Global CCS Institute, 2010)

As biomass grows, CO_2 is absorbed from the atmosphere. Through photosynthesis, carbon is incorporated into organic molecules, while the oxygen from the decomposed CO_2 molecule is released. When the biomass is eventually broken down (e.g. by the process of combustion), the carbon stored in the fibers reacts with oxygen to form CO_2 and is released into the atmosphere. The CO_2 produced during combustion is approximately the same quantity as consumed during biomass growth; therefore emissions from biomass combustion are considered to be CO_2 neutral (Figure 1) (Global CCS Institute, 2010; Koornneef et al., 2011).

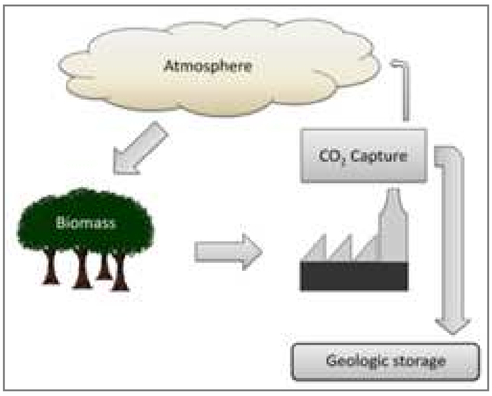


Figure 2 bio-energy with CCS (Global CCS Institute, 2010)

When combining bio-energy with CCS, the CO_2 from the biomass is captured, and subsequently stored in the bedrock. In this way, BECCS (Bio-Energy Carbon Capture and storage) systems withdraws carbon from the short term carbon cycle, which is stored into the underground (Global CCS Institute, 2010). As such, BECCS systems deliver "negative CO_2 emissions" (ZEP, 2012).

There have been several publications on Bio-Energy and CCS. In 2011 Ecofys conducted research commissioned by the International Energy Agency (IEA) on the worldwide potential for bio-energy combined with Carbon Capture and Storage (Koornneef et al., 2011). The study determined the realizable, economic and technical potential of six conversion pathways for the year 2030 and 2050. The selected conversion technologies are shown in Figure 3. The study concluded that the dedicated circulating fluidized bed combustion power plant and the dedicated biomass integrated gasification combined cycle plant are the technologies with the highest potential for negative emissions when equipped with CCS. The potential for negative emissions in biofuel production are low, since a significant portion of the carbon remains in the biofuel and is later emitted into the atmosphere.

Only a selection of BECCS technologies was subjected to a techno economic analysis by Ecofys. In the combustion and gasification section the choice was made based on the current technical states of the technologies. However, other types of configurations are also possible depending on the feedstock and the desired output such as Biomass based Dimethyl ether (DME) and Substitute Natural Gas (SNG).

Route name	Technology description	Feedstock and CO_2 capture principle
Electricity production		
PC-CCS co-firing	Pulverized Coal fired power plant with direct biomass co-firing	Co-firing share[1] is 30% in 2030 and 50% in 2050. *Post-combustion*
CFB-CCS dedicated	Circulating Fluidised Bed combustion power plant	100% biomass share. *Post-combustion*
IGCC-CCS co-firing	Integrated Gasification Combined Cycle with co-gasification of biomass	Co-firing share[1] is 30% in 2030 and 50% in 2050. *Pre-combustion*
BIGCC-CCS dedicated	Biomass Integrated Gasification Combined Cycle	100% biomass share. *Pre-combustion*
Biofuel production		
Bio-ethanol-advanced generation	Advanced production of Bio-ethanol through hydrolysis + fermentation	100% biomass share *Nearly pure CO_2; only drying and compression.*
FT biodiesel	Biodiesel based on gasification and Fischer Tropsch-synthesis	100% biomass share *Nearly pure CO_2 from Pre-combustion; only compression*

[1]Share of biomass on a primary energy basis.

Figure 3: BECCS technologies assessed in (Koornneef et al., 2011)

The European Biofuel Technology Platform has set up a joint task force with the Zero Emission Platform, in order to guide, accelerate and ensure the place of BECCS within EU policy and R&D priorities. Together they have published a report on the implementation of BECCS in Europe (ZEP, 2012). The report focuses on the BECCS potential in Europe and the actions that are required for a quick implementation of BECCS.

Van Vliet et al. published an assessment of different Fischer-Tropsch (FT) diesel production technologies (van Vliet, Faaij, & Turkenburg, 2009). Multiple plant configurations are discussed in this study, which differ in terms of conversion technologies and feedstock. The authors compared these plant configurations based on the carbon emissions, energy flow and cost.

The report by the Global CCS Institute, describes the BECCS projects planned for the coming years, and projects that are currently in use. Also a case study of BECCS in Sweden by Biorecro is presented in the report, identifying the potential of BECCS to reduce CO_2 emissions (Global CCS Institute, 2010).

Since the combination of bio-energy with CCS is relatively new, and not researched that often, this thesis aims to contribute to a more complete understanding of the possibilities of BECCS technologies. The aim of this thesis is to determine under which conditions BECCS technologies are able to compete with conventional fossil fuelled power plants with and without CCS. The focus is on the northwestern part of Europe in the year 2030. The research question of this thesis is the following:

Under which conditions are bio-energy technologies with carbon capture and storage competitive with alternatives based on conventional fossil fuels in northwestern Europe in the year 2030?

This research question will be answered by performing a literature review followed by a techno-economic assessment and comparison of a selection of BECCS and conventional technologies. The geographical scope is chosen to create a regional assessment of suitable BECCS technologies with feedstock that can be grown in this region. The year 2030 is chosen under the assumption that BE technologies that currently in a pilot phase are commercially available, and CCS is widely deployed by then (IEA, 2013).

2. Methodology

The research is divided in 6 steps which are shown in Figure 4. In the next paragraph all of the research steps are explained.

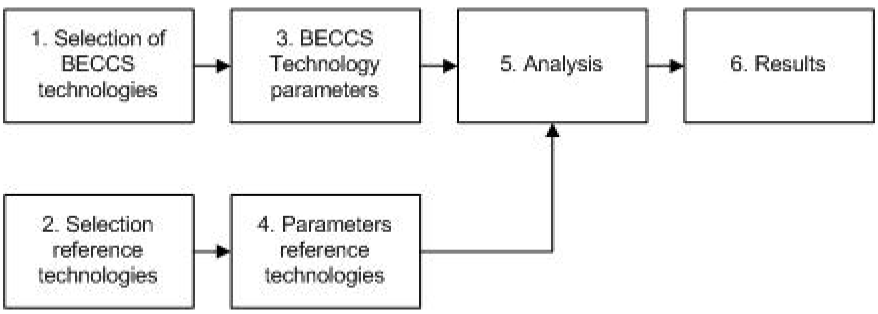


Figure 4: Research steps

2.1 Research steps

In order to answer the research question the following 6 research steps are taken:

1. *Selection of BECCS technologies.*

A selection of BECCS technologies is made for this analysis. This selection is based on a preliminary cost inventory, the scale of the technology, the technology readiness level, the features of the installation and compatibility with the chosen feedstock.

- The preliminary cost data expressed in €$_{2010}$/kW are used to make a selection from technologies within the same category (e.g. different boiler design within the biomass combustion category).

- The scale of the installation has to be 10 MW or higher, because we consider installations at a centralized level.

- The Technology Readiness Level (TRL) is a measurement of the maturity of technologies. The selected level for the selection of technologies has to be at least level 5. At this level, the components of the installation are validated in a relevant environment, and the technology is in the demonstration phase. Although the R&D cost are likely to be equal or greater than the investment cost at first, we expect that these technologies reach higher levels of maturity and become closer to commercialization by the year 2030. To reach these higher TRL, R&D of this technology is dependent on some form of formal sponsorship (e.g. through government or industry) (Mankins, 2009). The full TRL scale can be found in Annex II.

- The features of the installation are reviewed in order to determine the suitability of the installation with the selected feedstock, desired output and possibilities to combine the installation with CCS. Furthermore the characteristics such as the conversion efficiency and production cost are used to compare different plant set-ups or designs within the same category.

- The selected feedstock for the BECCS technologies is willow. Research by RENEW shows that willow is a suitable crop for the use of biofuel production, and can be grown in the northwestern part of Europe. Willow has a higher production potential in the northwestern part of Europe than miscanthus or poplar. In order to increase the energy density and regulate the size, which is necessary for gasification, willow can be toriffied. The torrefied biomass is called TOPS. Today the price of willow is estimated at 4.4 – 6.4 €$_{2010}$/GJ (RENEW, 2008), and the cost for TOPS are at 6.5 €$_{2010}$/GJ (H. Meerman, 2012). In 2030 the cost of willow are expected to decrease to 3.6 – 4.1 €$_{2010}$/GJ (RENEW, 2008), and the cost of TOPS to 5.0 €$_{2010}$/GJ. The decrease of the price is contributed to the assumption that towards 2030 more land becomes available as a result of on-going agriculture intensification in the EU (RENEW, 2008). The prices of TOPS used as input in the analysis are 6.1 €$_{2010}$/GJ in the 2010 calculation and 5.0 €$_{2010}$/GJ in 2030.

- The CCS technologies included in the analysis are post combustion and pre-combustion CCS. The assumption is made that the captured CO_2 is stored in offshore depleted oil and gas fields. At a transport cost of 9.5 €$_{2010}$/tonne CO_2 and a storage cost of 6.2 €$_{2010}$/tonne CO_2 (ZEP, 2011) for the year 2030.

2. *Selection of reference technologies and fuels.*

The cost of electricity and mitigation cost of BECCS technologies are compared to four reference technologies with and without CCS. The *New Policies Scenario (NPS),* and the *450 ppm scenario (450 ppm)* of the World Energy Outlook (IEA, 2012b) are used in order to determine which feedstock and conversion processes are likely to be used in the future. These scenarios are used to determine the conversion technologies that are used in the future electricity mix for northwestern Europe. The liquid biofuel technologies are compared to the current standard technologies: gasoline and diesel, and substitute natural gas (SNG) is compared to natural gas (NG)

3. *Inventory of the techno-economic parameters of the selected BECCS technologies.*

The parameters necessary to calculate the cost of energy of BECCS technologies are presented in Table 1. These parameters will be quantified based on previous estimates from literature. These are collected by performing a literature review. For some technologies, we expect that cost data are hard to find, because they are not yet applied at a commercial scale. If data are unavailable, the fossil fuel based process will be examined instead of the biomass-based process, since biomass has many similarities with fossil fuels and uses the same conversion technologies for power production (e.g. combustion or gasification). The parameters are calculated for the years 2010 and 2030. The year 2030 is used in the analysis, where the 2010 data are used to place the future data in context.

All costs are harmonized to 2010 Euro's using the CPI index from Eurostat (Eurostat, 2013). The following calculation method is used:

$$Cost\ in\ year\ 2010 = Cost\ in\ year\ X * \frac{Cost\ index\ in\ year\ 2010}{Cost\ index\ in\ year\ X}$$

The historical exchange rates are used for the conversion from Dollar to Euro$_{2010}$ (OANDA, 2013).

Table 1: Parameters BECCS

Parameters Technologies		
I	Investment cost	€$_{2010}$/kW
t	Lifetime	Yr
D	Discount rate	%
O&M Fixed	Fixed annual O&M costs	€$_{2010}$/kW or €$_{2010}$/GJ
F	Annual feedstock costs	€$_{2010}$/kW or €$_{2010}$/GJ
E_e	Annual energy production	kWh/yr
E_f	Annual fuel production	GJ/yr
η	Conversion efficiency	%
L	Load factor	%

Parameters Feedstock	
Pre-treatment cost	€$_{2010}$/GJ
Energy content	GJ/tonne feedstock
Carbon content	Tonne CO_2/tonne feedstock

4. *Techno-economic parameters of reference technologies.*

The parameters presented in Table 1 are also relevant for reference technologies, that are used for comparison. The Energy Technology Perspective report is used as a starting point for the parameters (IEA, 2010a).

5. *Analysis: How do the BECCS options compare to the reference options for the considered cases.*

The technologies are compared based on the cost of energy and the CO_2 mitigation costs.

The Cost of Energy is calculated based on the methodology proposed by Blok (Blok, 2009). Also, the CO_2 avoidance cost of the BECCS technologies is determined in comparison to the reference technology. This value reflects an average cost of reducing atmospheric CO_2 mass emissions by one unit, while providing the same amount of useful products as a 'reference plant' without CCS. (Xu, Jin, Yang, & Xu, 2010)

Table 2: the methodological approaches

Cost of Energy	$\text{COE}=\frac{\text{(CRF)*(Initial investment)+(Annual O\&M cost)+(Annual fuel cost)}}{\text{Annual energy production}}$	COE [€/GJ or €/MWh] Source: (Blok, 2009)
CO_2 mitigation costs	$\text{CO}_2\text{ mitigation costs}=\frac{\text{COE}_{\text{ccs}}\text{- COE}_{\text{ref}}}{CO_2\ flow\ ref\text{- CO}_2\ flow\ BECCS}$	CO_2 flow [kg CO_2/MWh or kg CO_2/GJ] COE [€/MWh or €/GJ] Source: (Damen, van Troost, Faaij, & Turkenburg, 2007)

The CO_2 flow in the CO_2 mitigation costs calculation, consists of the emitted and stored emissions. The emitted biogenic emissions are considered to be neutral as well as the stored emissions from fossil resources. The stored biogenic emissions are considered negative.

6. *Results: Which parameters are decisive for the moment when BECCS becomes competitive with a fossil reference?*

In the results of the analysis, we focus on the cost of electricity or cost of fuel and the CO_2 mitigation costs of BECCS technologies compared to the reference technologies for the year 2030. Parameters such as feedstock prices and CO_2 credit price are varied to measure the impact on the cost of energy and mitigation costs, and to determine which parameters are decisive for the competitiveness of BECCS technologies.

7. *Sensitivity analysis*

A sensitivity analysis will be conducted to determine which parameters have the greatest impact on the results.

2.2 Boundaries

- This research project will focus on the year 2030.
- The scope of the research is northwestern Europe. This Area is selected to be able to estimate the CO_2 storage and transport cost, feedstock price and investment cost.
- This research focuses on the conversion of lignocellulosic biomass which could be produced for bio-energy purposes without affecting food production in northwestern Europe (RENEW, 2008).
- All installations are centralized and industrial scale.
- Based on a first screening we limited the selection to thermochemical biomass conversion for direct electricity production and the conversion of biomass to liquid and gaseous transport fuels. This technologies are screened by their feedstock, size and compatibility with CCS. The screening is presented in Annex I.
- The Carbon Capture and Storage methods that will be researched are pre-combustion and Post-combustion. Oxy-fuel combustion is less mature than pre- and post-combustion and more expensive. (MacDowell et al., 2010), and is therefore excluded.
- This research focusses on the direct emissions.

3. Selection of biomass conversion technologies which can be combined with Carbon capture technologies

This chapter is divided into four parts. These sections consist of the biomass to power section, the biomass to liquid fuel section, the biomass to gaseous fuel section and the selection of the reference technologies. In these sections the available technologies are described, and compared with the criteria set in the methodology and each other.

3.1 Biomass to power

Dedicated biomass combustion and co-firing of biomass in fossil fired power plants are currently the most applied biomass conversion routes for the generation of heat and power, and are commercially available (van Loo & Koppejan, 2008). Gasification technologies are less mature, but are able to convert the syngas in to transport fuels. Since both technologies are at least early commercial, both combustion and gasification technologies are included in the analysis. Based on the Investment cost, TRL, scale shown in Table 3 and technology features, a selection is made for a plant design within the combustion and gasification technologies.

Table 3: TRL, scale and investment cost of biomass conversion technologies (Bauen, Berndes, Junginger, Londo, & Vuille, 2009; E4Tech, 2009; Faaij, 2006; Gerssen-Gondelach, Saygin, Wicke, Patel, & Faaij, 2013; IEA GHG, 2009; IEA, 2007; H. Meerman, 2012; Rhodes & Keith, 2005; The International Renewable Energy Agency, 2012; van Loo & Koppejan, 2008; Yeh, 2011)

Dedicated Biomass Combustion		Bauen	IRENA	IEA GHG	Faaij	Gerssen-Gondelach	van Loo & Koppejan
FB	TRL	9	9				
	Investment cost [€2010/kWe]		1419 - 3215				
	Scale [MWe]		4-300				
BFB	TRL	9	9				
	Investment cost [€2010/kWe]		3395 - 1637	2497	2734 - 1750		
	Scale [MWe]		<300	76	20-100s		
CFB	TRL	9	9				
	Investment cost [€2010/kWe]		3395 - 1637	1385	2734 - 1750	2430	
	Scale [MWe]		<300	273	20-100s	100	
PFC	TRL						2-8
	Investment cost [€2010/kWe]						
	Scale [MWe]						

Biomass Co-firing		Bauen	IRENA	IEA GHG	Faaij	Gerssen-Gondelach	IEA 2007
Direct co-firing	TRL	9	9				
	Investment cost [€2010/kWe]	1131-103 [a]		1293	273 [a]	166-224 [a]	959-1133
	Scale [MWe]	5-100		519	5-20		10-50
Indirect co-firing [f]	TRL	7					
	Investment cost [€2010/kWe]					811-933 [a]	
	Scale [MWe]						
Parallel co-firing	TRL	5	5				
	Investment cost [€2010/kWe]	308-823 [a]				684-810 [a]	
	Scale [MWe]	<10					

Dedicated Biomass Gasification		Bauen	Yeh	Rhodes	E4Tech	Meerman	Gerssen-Gondelach
BIGCC	TRL	5					
	Investment cost [€2010/kWe]	5297-2212		1125			
	Scale [MWe]	5-10		149			
CFB	TRL		4-5				
	Investment cost [€2010/kWe]				2807-3981 [b]		1080-1710
	Scale [MWe]				3-4,5		250
BFB	TRL		5				
	Investment cost [€2010/kWe]				1101-1468 [c]		
	Scale [MWe]				7		
EF	TRL		4-5				
	Investment cost [€2010/kWe]				2582 [d]	2520	
	Scale [MWe]				10	289	
Dual Fluidised bed	TRL		4-5				
	Investment cost [€2010/kWe]				1100 [e]		
	Scale [MWe]				-		

[a]Investment cost exclude the cost for the fossil fired plant.
[b] Technology provider Fraunhofer UMSICHT
[c] Technology provider Enerkem technologies Inc.
[d] Technology provider CHOREN industries GMBH
[e] Technology provider Tayler Biomass Energy LLC
[f] Database of IEA Bioenergy Task 32 shows that indirect co-firing is not frequently applied. (IEA Bioenergy Task 32, 2009)
FB: fluidized bed, BFB: Bubbling Fluidized Bed, CFB: Circulating Fluidized Bed, PFC: Pulverized Fuel Combustion, BIGCC: Biomass Integrated Gasification Combined Cycle, EF: Entrained Flow, 100s: hundreds.

3.1.1 Dedicated biomass combustion for electricity production:

Technologies for dedicated biomass firing are fluidized bed (FB) combustion (both circulating fluidized bed combustion (CFB) as bubbling fluidized bed combustion (BFB)), various types of fixed bed technologies (e.g. grate firing) and pulverized fuel combustion.

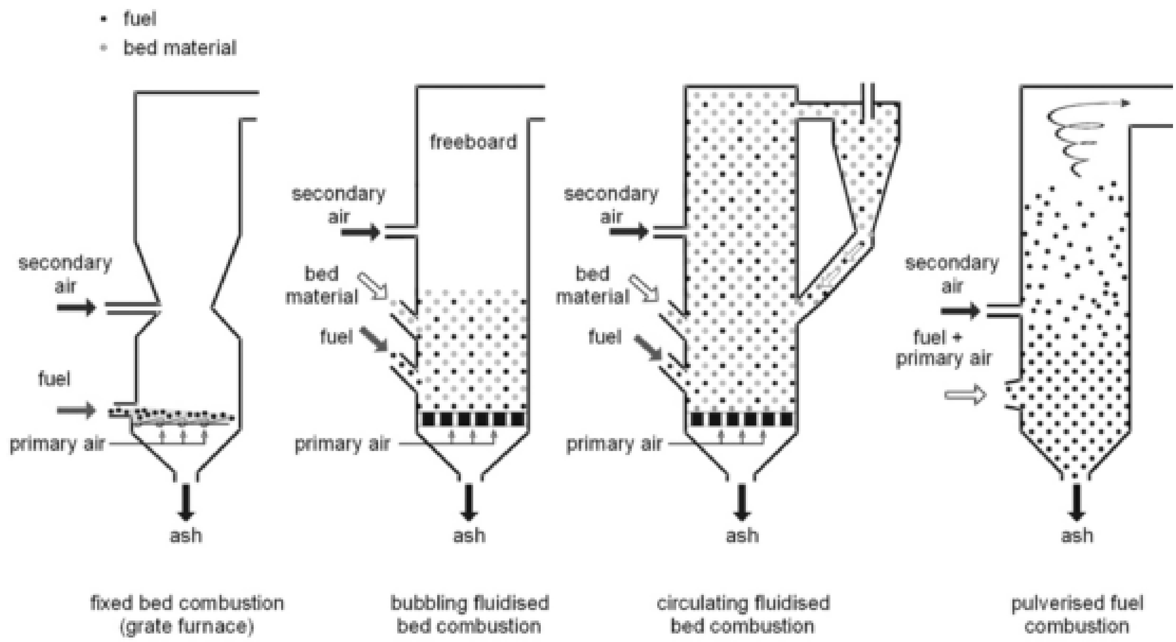


Figure 5: Principal combustion technologies for biomass (van Loo & Koppejan, 2008)

Figure 5 shows the principals of the combustion technologies. "*In the grate furnace, the primary air passes through a fixed bed in which drying, gasification and charcoal combustion take place. The combustible gases are burned after secondary air addition has taken place, usually in a combustion zone separated from the fuel bed*" (van Loo & Koppejan, 2008). Various grate furnace design are possible: fixed grate, moving grates, traveling grates, rotating grate and vibrating grate. All of these technologies have different advantages and disadvantages, depending on the fuel properties, but all designs are focused on a homogeneous distribution of fuel to the bed. The combustion process is similar in all designs.

"*In the fluidized bed furnaces, the biomass fuel is burned in a self-mixing suspension of gas and solid-bed material into which combustion air enters from below. Depending on the fluidization velocity, bubbling fluidized bed (BFB) and circulating fluidized bed (CFB) combustion can be distinguished*" (van Loo & Koppejan, 2008). In BFB combustion the fluidization velocity varies between 1 and 2 meter per second, and in CFB 5 to 10 meter per second. The higher fluidization velocity leads to a better heat transfer and a very homogeneous temperature distribution in the bed. The CFB uses smaller bed material which is suspended with the flue gasses. The bed material is separated from the flue gas and fed back into the combustion chamber (van Loo & Koppejan, 2008).

"Pulverized fuel (PF) combustion is suitable for fuels available as small particles (average diameter smaller than 2 mm) e.g. sawdust. A mixture of fuel and primary combustion air is injected into the combustion chamber. Combustion takes place while the fuel is in suspension and gas burnout is achieved after secondary air addition" (van Loo & Koppejan, 2008).

Selection of technology

The grate furnace is the most applied and mature technology. The investment and operation cost are lower compared to the fluidized bed furnaces. Disadvantages of the grate furnace are that mixing of fuels such as wood fuels and straw, cereals and grass is not possible, and that the excess amount of oxygen decreases the efficiency. The advantages of fluidized bed and pulverized fuel furnaces is that there are no moving parts in the hot combustion chamber and can achieve higher efficiencies than the grate furnaces. Also the high flexibility concerning the moisture content and kind of biomass is an advantage of fluidized bed technologies (van Loo & Koppejan, 2008).

Disadvantages of fluidized bed technologies are the investment and operation costs. Also the requirement for particle size is a disadvantage. In CFB the particle size needs to be below 40 mm and in BFB below 80 mm, this means that pretreatment of biomass is necessary (van Loo & Koppejan, 2008). Despite these disadvantages fluidized bed combustion has been indicated as one of the most promising techniques, because of its flexibility, high combustion efficiency and low environmental impact (Khan, de Jong, Jansens, & Spliethoff, 2009).

The fixed grate furnaces and fluidized bed technologies are applied at large scales in the range of tens to hundreds MW_e. This is not the case for the dedicated biomass combustion in pulverized fuel variant, which has not yet been deployed in large scales and is therefore excluded. However pulverized biomass is used in co-firing in pulverized coal plants.

The selected technology for dedicated biomass firing in this thesis is the CFB furnace because of the higher combustion efficiencies in comparison with the grate furnace. The CFB has lower capital cost than the BFB furnace at a scale >30 MW_{input} and lower flue gas production (IEA GHG, 2009). Therefore the CFB preferred over the BFB.

Circulating fluidized bed combustion with CCS

The two CCS technologies that can be applied in combination with CFB biomass combustion are similar as those applied in coal fired power plants, being post-combustion and oxy-fuel combustion.

In post combustion, the CO_2 is removed after the combustion process. The most applied method of post-combustion capture of CO_2 is solvent scrubbing. In solvent scrubbing the flue gas is first cleaned from sulphur and nitrogen oxides, followed by the absorption of CO_2 by the solvents, such as Selexol, Rectisol or MEA (methanolamine). The "rich" solvent is led to the solvent regeneration process, consisting of the reboiler, desorber and condenser. The reboiler heats the incoming liquid stream to a suitable temperature in order to break the chemical bonds formed in the absorber, so that pure CO_2 is released. The separation of CO_2 and solvent takes place in the desorber. The condenser returns the 'lean' solvent to the absorber (MacDowell et al., 2010). Post-combustion capture using solvents such as methanolamine (MEA) is commercially available and has been used for various industrial applications.

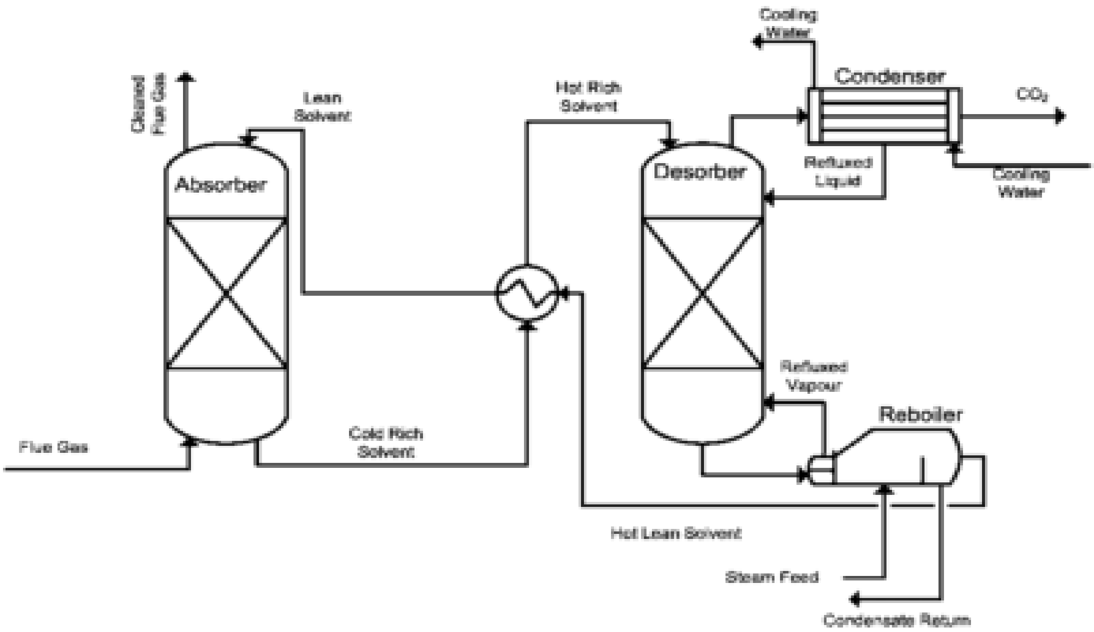


Figure 6: Schematic of a basic chemical absorption process for amine based CO2 capture (MacDowell et al., 2010)

Advantages of post-combustion technologies are that they are applicable to the majority of new and existing installations and the ongoing R&D to improve the sorbents and capture equipment. Disadvantages of using post-combustion technologies are the parasitic load of the technology which decreases the plants efficiency, that the pressure of the flue gas is lower than required for CO_2 transport and the need for cleaned flue gas to minimize sorbent usage and cost (Mills, 2012).

3.1.2. Co-Firing of biomass for electricity production:

Biomass co-firing is already applied on a large scale, mostly in pulverized coal fired power plants (IEA Bioenergy Task 32, 2009). Co-firing is identified as the most efficient, least expensive, lowest risk and shortest term option for renewable based electrical power generation (Khan et al., 2009). The co-firing concept can be classified under three types:

- Direct co-firing
- Indirect co-firing
- Parallel co-firing

In all types the use of biomass replaces an equivalent amount of energy produced by fossil fuels, which results in a decrease in CO_2 and NO_x emissions. In direct co-firing the biomass is mixed with the coal before it is fired. Indirect co-firing (or gasification co-firing) involves the gasification of solid biomass and the combustion of the gasification gasses in the coal fired boiler. Parallel combustion fires the biomass in a separate combustor and boiler and utilizes the produced steam in the coal plant's steam and power generation system. (Basu, Butler, & Leon, 2011; van Loo & Koppejan, 2008)

Constraints related to the co-firing of biomass can include fuel preparation, handling and storage, milling and feeding problems, different combustion behavior, possible decreases in overall efficiency, deposit formation (slagging and fouling), agglomeration, corrosion and/or erosion, and ash utilization (Maciejewska, Veringa, Sanders, & Peteves, 2006). These constraints are dependent on the type, quality, pre-treatment and the percentage at which the biomass is co-fired.

The database for co-firing technologies of EIA bioenergy task 32 state that the experience with indirect and parallel co-firing is very limited, this explains the limited amount of data of the scale and investment cost in Table 3 (IEA Bioenergy Task 32, 2009).

Selection of co-firing technology

The cost for the co-firing technologies is summarized in Table 3. Direct co-firing is already applied in pulverized coal plants, and is more mature than the other two options. In Table 3 can be seen that direct co-firing is also the only option that is applied in the range of tens to hundreds $MW_{e.}$ The cost of direct co-firing is also lower than parallel co-firing. Therefore direct co-firing is selected.

Co-Firing with CCS

Carbon capture and storage in combination with direct co-firing is very similar as for dedicated biomass combustion, and the same technology and selection applies for direct co-firing.

3.1.3. dedicated biomass gasification

Gasification of biomass is a thermochemical transformation at high temperature in the presence of a restricted supply of oxygen, air or steam. The product of gasification process is called syngas and consists of carbon monoxide, hydrogen and methane. Syngas is a gaseous mixture which can be used in electric power generation, manufacturing of liquid and gaseous fuels or bio based chemicals.

All designs consist of four main stages (Baskar, Baskar, & Dhillon, 2012) and are shown in Figure 7:

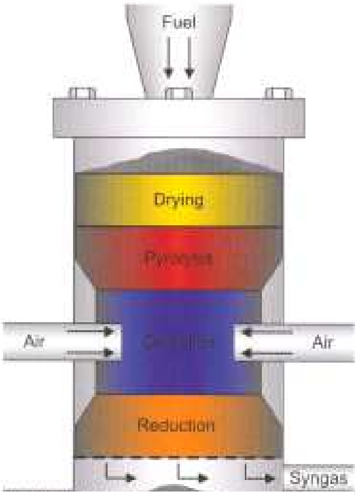
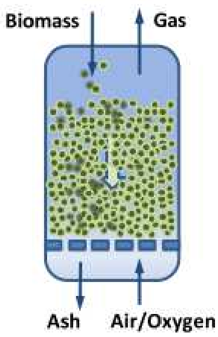


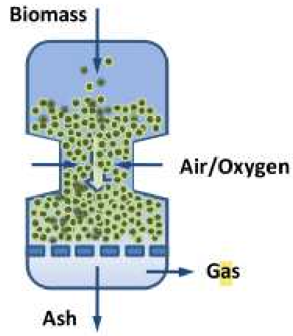
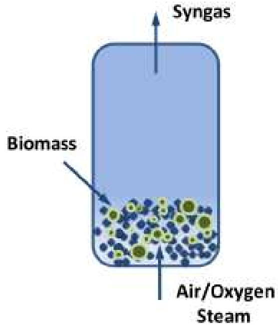
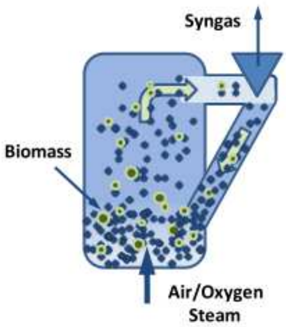
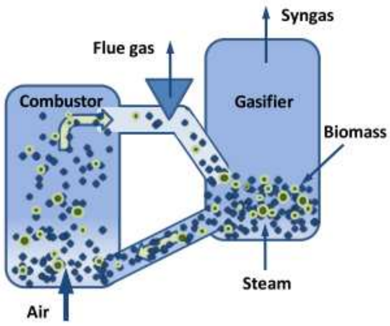
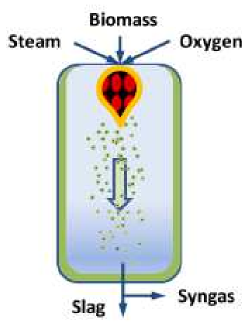
Figure 7: The 4 steps in gasification (Knoef, 2005)

1) preheating and drying to reduce the moisture content of the biomass.
2) Thermal decomposition to break down the biomass into gas, carbon char and tars/oils (pyrolysis). This process is endothermic and does not involve reactions with oxygen or any other medium.
3) The thermal decomposition process is followed by a number of reactions with oxygen, air or steam to produce the syngas consisting of CO, CO_2, H_2, H_2O, and CH_4. The carbon char is further gasified in presence of restricted air, oxygen or steam to produce the syngas.
4) the combustion of char produces extra CO and provides heat for the process.

The most used feedstock in gasification processes is woody biomass (Baskar et al., 2012; Koornneef et al., 2011). The fluidized bed gasifier and entrained flow gasifiers are the most applied designs (E4Tech, 2009). Six different gasification designs are possible. Similar as to the combustion reactor design the fixed bed and fluidized bed gasifiers can be distinguished. The differences between designs are shown in Table 4.

Table 4: Gasification designs, description and pictures taken from E4Tech (E4Tech, 2009)

	**Updraft Fixed bed** In fixed bed gasifiers two different design are possible. The first one is the updraft fixed bed gasifier in which the biomass is fed in at the top of the gasifier, and the oxygen/air intake is at the bottom, hence the biomass and the gasses move in opposite directions. The syngas contains high levels of tars and methane. The updraft fixed bed gasifier operates at 200 to 400 °C.

	**Downdraft Fixed bed** The second design is the downdraft fixed bed reactor in which both the biomass and oxygen/air is fed in at the top (or the side) of the reactor, and move in the same direction. The downdraft fixed bed gasifier operates at temperatures of 700 °C.
	**Bubbling fluidized bed** In fluidized bed gasification both bubbling fluidized bed as circulating fluidized bed is possible. in bubbling fluidized bed the biomass is fed in from the side and sits at the bottom of the gasifier, with air, oxygen or steam being blown upwards trough the bed. All fluidized bed configuration operate at temperatures of around 900 °C.
	**Circulating fluidized bed** The circulating fluidized the biomass is also fed in from the side, and the air/oxygen or steam from the bottom which suspends the biomass. The mixture of syngas and particles are separated using a cyclone to return the material to the bottom of the gasifier.
	**Dual fluidized bed** The last fluidized bed variant is the dual fluidized bed gasifier. This system has two chambers: a combustor and a gasifier. The char is burnt in the combustor to heat the bed material, which is fed into the gasifier. The preheated bed material provides indirect reaction heat so that the biomass can be converted into syngas.
	**Entrained flow** Next to these technologies there is the entrained flow design in which powdered biomass is fed into the gasifier with pressurized oxygen and/or steam. a turbulent flame at the top of the gasifier burns some of the biomass providing large amounts of heat for fast conversion in high quality syngas. EF gasification operates at temperatures of around 1200-1500°C.

The designs in Table 4 are the most common design, some other designs are possible such as plasma gasification. These technologies are not included because of the high capital cost and low TRL, but can be found in the E4Tech report (E4Tech, 2009).

In dedicated biomass gasification the syngas can be fired in gas turbines for electricity generation. A promising improvement is the integration of an extra thermodynamic cycle which uses the heat from the exhaust gas to power an extra cycle to extract extra energy from the excess heat of the process, increasing the efficiency and electricity output. This combination of gasification with the steam cycle is called an Integrated Gasification Combined Cycle (IGCC) and has already been applied in several pilot plants in combination with coal (Mills, 2012). In case this plant is operated fully on biomass, it is called a Biomass Integrated Gasification Combined Cycle (BIGCC).

Selection of technology

Gasification with fossil fuels is a mature technology, but not with biomass as a feedstock. In Table 5, the TRL is shown by technology provider for biomass gasification.

Table 5: TRL of gasification technologies by technology provider (Yeh, 2011)

Technology Provider	Gasifier Type	TRL
Choren	Entrained Flow	5.75
Clearfuels/Rentech	Entrained Flow	4
CUTEC	CFB	4.44
GTI/UPM-Kymmene/Carbona	BFB	5.5
Red Lion Bio-energy/Pacific Renewable Fuels/REII	BFB	5.63
RTI	Dual Fluidized bed	4
Stora Enso/Neste Oil/VTT	CFB	5.69
TRI	BFB	5.19
TUV	Dual Fluidized bed	5.56
Velocys	Dual Fluidized bed	-

E4tech has researched the different gasification design, and has identified the entrained flow gasifier as the preferred design for the biomass gasification process. Entrained flow gasifiers uses oxygen instead of air, which reduces the formation of methane and tars, resulting in a high quality syngas (E4Tech, 2009). Therefore there is no need for a tar cracker and cyclone to filter out the unconverted carbon particles, which is necessary in fixed and fluidized gasifiers (H. Meerman, 2013). Both the Yeh as the E4Tech research state that the dedicated biomass Entrained Flow gasifier is closest to commercialization (E4Tech, 2009; Yeh, 2011).

As can be seen from Table 5, Choren is one of the leading companies in the field of biomass gasification. Choren has built multiple pilot plants. The first was the Alpha plant which had a capacity of 3 oven dried tonnes per day (odt/day). The second plant was called Beta and had a capacity of 198 odt/day. The latest test plant is called Sigma 1, with a capacity of 3040 odt/day and was planned for 2013. In 2011 Choren filed for insolvency, and was bought by Linde Engineering Dresden in 2012 (European Biofuel Technology Platform, 2013).

Gasification technologies with CCS

Pre-combustion carbon capture is a proven technology and commercially available technology, in which the CO_2 is separated prior to the combustion or further processing of the syngas. The syngas from the gasification process is cleaned and then fed to the water gas shift unit, in which the ratio between hydrogen and carbon monoxide is optimized, yielding heat and a gas stream with high CO_2 and H_2 concentrations. Potential technical options for the separation of CO_2 are chemical and physical solvents, adsorbents and membranes (Koornneef et al., 2011; Rhodes & Keith, 2005). The selected method for pre-combustion capture is by the use of solvents, similar to the post-combustion process.

3.2 Biomass to fuel technologies:

Based on the TRL level and cost and scale, a selection of liquid and gaseous biofuel technologies is made. The criteria of scale and the aim for the biofuels to be competitive with their fossil equivalent make second generation biofuels more attractive than the first generation biofuels. Liquid biofuels can be produced from a range of feedstock and conversion technologies. The two main end products are ethanol and biodiesel. In ethanol production the main technology is fermentation, and for biodiesel production gasification technologies in combination with processes as Fischer-Tropsch synthesis, methanol and hydrogen synthesis. For gaseous fuels the use of BioSNG is the main technology. The overview of technologies is given in Table 6.

Table 6:Overview of cost for biofuel technologies. Taken form (Carbo, 2011) with added sources (Åhman, 2010; Bauen et al., 2009; Clausen, Elmegaard, & Houbak, 2010; Eriksson & Kjellström, 2010; Gassner & Maréchal, 2009; Hacatoglu, McLellan, & Layzell, 2010; Hamelinck & Faaij, 2006; Hannula & Kurkela, 2013; Low Carbon Innovation Coordination Group, 2012; RENEW, 2008; Sarkar & Kumar, 2010; Solomon, Barnes, & Halvorsen, 2007; van Vliet et al., 2009; Williams, Larson, Liu, & Kreutz, 2009)**.**

Ethanol production (ligno.)	Hamelinck & Faaij	solomon et al.	Eriksson & Kjellström	TINA	Bauen
Plant capacity (MWth,in)	400	-	295	-	
Biomass cost (€2010/GJ)	3.0	-	3.5	3.0	
Production cost (€2010/GJ)	24.6	18.7	19.7-21.5	40.8	
TRL					3-4

FT production	Yamashita et al.	Hamelinck & Faaij	Kreutz er al.	van vliet et al.	TINA	Hannula et al.	Bauen
Plant capacity (MWth,in)	430	400	548	400	-	300	
biomass cost (€2010/GJ)	1.5	3	3.8	4.6	3.0	4.6	
Production cost (€2010/GJ)	13.8-20.8	21.7	21.5	29	38.4	17.1-20.8	
TRL							5

BioSNG production	Gassner & Marechal	Ahman	Carbo et al.	Hacatoglu et al.	TINA	Bauen
Plant capacity (MWth,in)	150	100	500	400	-	
biomass cost (€2010/GJ)	9.2	4.5	4	2.8	3.0	
Production cost (€2010/GJ)	16.4-26.9	20	13.3	13.1	24.5	
TRL						4

BioDME production	Larsson et al.	RENEW	Clausen et al.	TINA	Hannula et al.	Bauen
Plant capacity (MWth,in)	479-601	500	2302	-	300	
biomass cost (€2010/GJ)	1.5	5.1-7.8	3.5	3	4.6	
Production cost (€2010/GJ)	7.6-12.8	16.1-21.0	9.2	43.1	16.1-18.3	
TRL						5

Hydrogen production	Hamelick & Faaij	Sarkar & Kumar	Bauen
Plant capacity (MWth,in)	400	456	
biomass cost (€/GJ)	3	2.2	
Production cost (€2010/GJ)	18.8	7.5	
TRL			3-4

Although Fischer-Tropsch diesel and BioDME may not be the cheapest technologies, they are identified as the most promising liquid fuels for the transport because of their fuel characteristics (E4Tech, 2009; RENEW, 2008). RENEW state that DME and FT have high emission reduction potential and are closest to commercialization. The technology readiness level of FT and BioDME are higher than the TRL of ethanol and hydrogen production from lignocellulosic biomass. Therefore these technologies are selected for the liquid fuel technologies. For the gaseous fuels the BioSNG is selected.

3.2.1. Liquid fuel technologies

The selected liquid fuel technologies are based on the process of gasification, which is explained in the section "gasification technologies for biomass to power". The biomass is converted to syngas with the same process as in the biomass to power section, with the added step of FT and DME synthesis.

3.2.1.1. Gasification with Fischer-Tropsch for liquid fuel production.

Fischer-Tropsch (FT) is a process in which the syngas from the gasification process is converted to hydrocarbon chains of different lengths. Next, these hydrocarbons can be hydrocracked to biodiesel.

After the gasification process, the syngas needs to be cleaned and processed to make it suitable for FT synthesis. The processing technology depends on the feedstock, in the biomass variant a water-gas shift unit is used to optimize the H_2/CO ratio. The optimal ratio between H_2 and CO is different for each conversion process, the optimal H_2/CO ratio for FT synthesis is 1.2:1. After the water-gas shift reaction the CO_2 is removed from the syngas in the Acid Gas Removal unit (AGR), where solvents are used to absorb the CO_2, which is similar as in post combustion technologies. In the FT reactor the syngas is converted by the use of a catalyst, which produces paraffinic hydrocarbons (van Vliet et al., 2009). This reaction is highly exothermic. Next to the desired diesel and gasoline, FT synthesis also yields wax and gas. To maximize the output, the wax can be cracked in a hydrocracker to produce extra diesel and gasoline, and the gas are recycled to a gas turbine (H. Meerman, 2012).

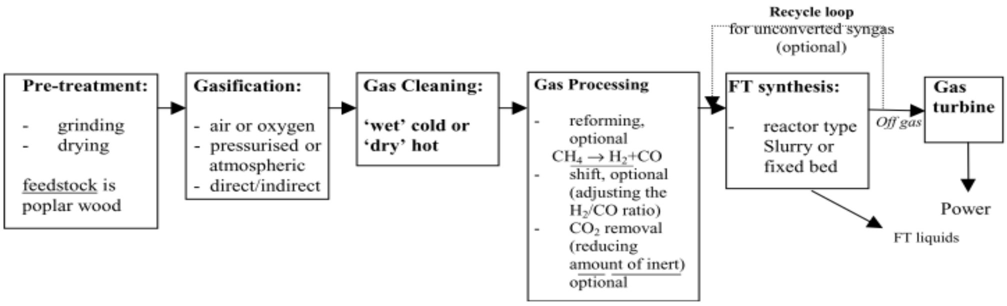


Figure 8: Basic schematic view of the key components of the FT process (Faaij, Hamelinck, & Hardeveld, 2002)

Research by E4Tech shows that entrained flow gasifiers is the most suitable for FT production despite their low feedstock tolerance and high pre-treatment cost. The entrained flow gasifier uses oxygen in a pressurized environment which increases the quality of the syngas. Cost data of EF with FT are available in the paper by E4Tech, Meerman and van Vliet et al. (E4Tech, 2009; H. Meerman, 2012; van Vliet et al., 2009).

Multiple reactor designs are possible for FT synthesis. The most common FT reactor design are the slurry reactor and the multi tubular fixed-bed reactors. In the slurry reactor design, the syngas is contacted with slurry that consists of fine catalyst suspended in liquid, the slurry and syngas are cooled by pipes submerged in the slurry. The multi tubular fixed bed design is equipped with sets of concentric tubes, in which the catalyst occupies the annular space, and is surrounded by boiling water (see Figure 9). (Krishna & Sie, 2000; Sie & Krishna, 1999)

The slurry reactor has multiple advantages over the fixed bed reactors, such as lower unit cost, lower pressures, lower catalyst consumption and higher conversion rates. On the downside, if any catalyst poison would enter the reactor the catalyst could deactivate, therefore syngas cleaning is crucial (Dry, 2002). The FT reactor of choice is the slurry reactor combined with a hydrocracking unit to convert waxes into extra fuel.

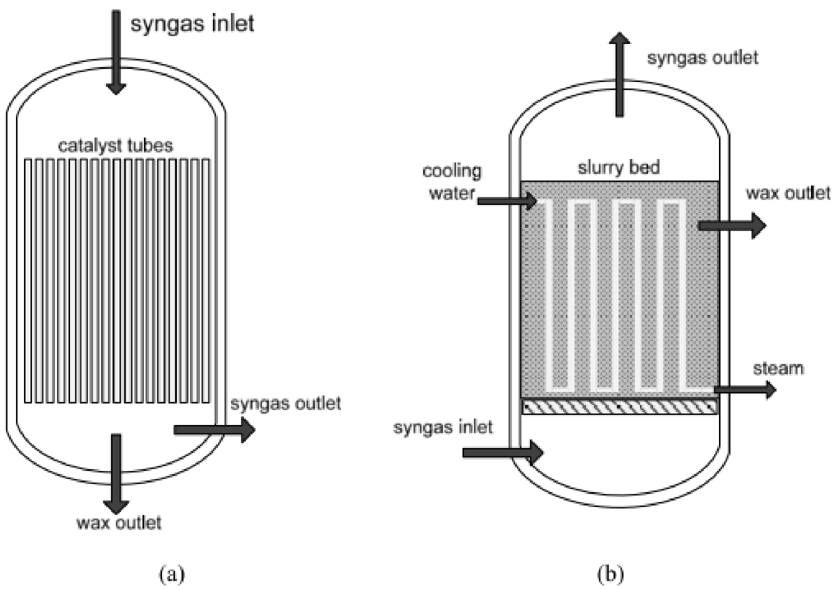


Figure 9: Fischer-Tropsch reactor types (a) multi-tubular fixed bad and (b) slurry bed (Swanson, Satrio, Brown, & Hsu, 2010)

Selection Fischer-Tropsch for liquid fuel production.

Yeh published an assessment of the TRL of gasification technologies with Fischer-Tropsch diesel (see Table 7) (Yeh, 2011).

Table 7: TRL of gasification technologies with FT by technology provider (Yeh, 2011)

Technology Provider	FT Reactor Type	TRL
Choren	Multi-tubular Fixed bed	4.88
Clearfuels/Rentech	Slurry reactor	4.38
CUTEC	Multi-tubular Fixed bed	4.06
TRI	Multi-tubular Fixed bed	-
TUV	Slurry reactor	4.94

The two relevant technologies that were researched in the assessment by van Vliet are the combinations of the Carbo-V gasifier from Choren with the advanced FT process which combines the slurry reactor with the wax hydrocracker, and the Shell EF gasifier with advanced FT (van Vliet et al., 2009). Meerman uses the Shell EF gasifier with a slurry FT reactor and hydrocracker to convert waxes to fuel in his dissertation (H. Meerman, 2012).

The FT chain that is used in this thesis is a pressurized entrained flow gasifier followed by gas cleaning unit and water gas shift unit and the advanced FT process which contains a slurry reactor with a hydrocracking unit to convert waxes into extra fuel.

Fischer-Tropsch synthesis with CCS

The Fischer-Tropsch uses a pre-combustion capture technology. After the water gas shift reaction which optimizes the syngas, the syngas is cleaned in the AGR, in which solvents are used to remove the CO_2 from the syngas.

3.2.1.2. Gasification with BioDME for liquid fuel production

Dimethyl ether (DME) is diesel-like fuel that can be produced by a very similar process as Fischer-Tropsch synthesis. The use of BioDME in the transport sector can significantly decrease the NO_x and SO_x emissions in reference to the traditional diesel (Clausen et al., 2010). A drawback of DME is the need for compression to keep the DME in liquid state. It is possible to mix DME with conventional diesel fuel in regular diesel engines, but the need for compression and the ignition of the fuel make dedicated DME-fuelled engines a better option. (RENEW, 2008)

As said the process steps are similar as for the Fischer-Tropsch synthesis process. The biomass is first gasified in the entrained flow gasifier (same configuration as in FT is chosen), followed by gas cleaning to remove CO_2 and sulfur followed by the water-gas shift reaction.

In order to produce DME from syngas, the syngas need to be converted into methanol followed by dehydration. This can be done in separate steps, or in a single reactor in which the catalyst for both processes is present. Typical catalysts for the conversion of syngas to methanol are copper oxide, zinc oxide or chromium oxide. The most applied reactor design for direct conversion of syngas to DME is a fixed bed or slurry reactor.

Before the syngas enters the reactor, the syngas is compressed to 60 bar and cooled by a water jacketed cooler. The product gas generated by the reactor is cooled further to separate DME, methanol and water by condensation. The unconverted syngas can be recycled to the synthesis reactor. By recycling the unconverted syngas in the process, it is possible to achieve a conversion efficiency of 66%. The methanol formed in the reactor can be converted to DME by dehydration (Clausen et al., 2010; Hannula & Kurkela, 2013).

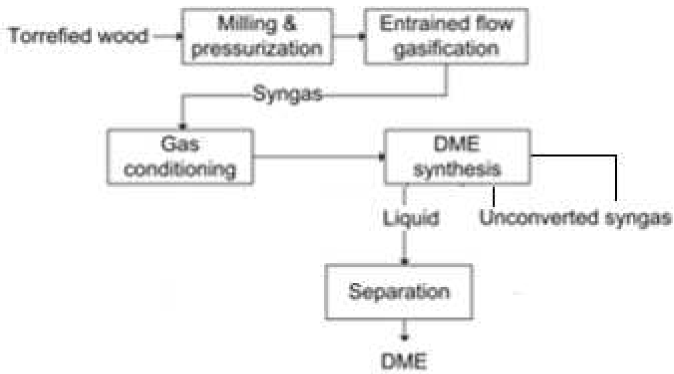


Figure 10: Simplified flow sheet of the DME plant models (Clausen et al., 2010)

Selection of BioDME

The selected process for BioDME production is slurry phase reactor in which the unconverted syngas is recycled back into the system. The model of the DME plant with syngas recycling that is described in the paper by Clausen et al. and shown in Figure 10 is used as a guideline. The current DME plants run on black liquor from the paper industry (Clausen et al., 2010).

BioDME with CCS

As in the FT process, the BioDME process makes use of the pre-combustion capture method, where solvents are used to separate the CO_2 from the syngas.

3.2.2. Biomass to gaseous fuel:

3.2.2.1. BioSNG

BioSNG stands for biomass based substitute natural gas. The process is similar to the FT and BioDME synthesis process, instead of the shift towards hydrogen, the syngas is shifted to methane. A simplified scheme of the process is given in the Figure 11.

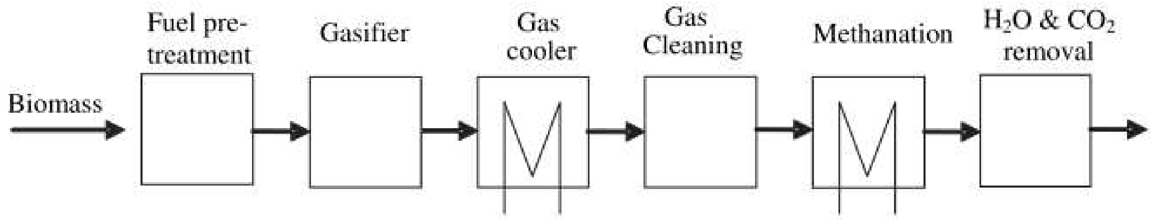


Figure 11: Simplified scheme of biomass to SNG configuration (van der Meijden, Veringa, & Rabou, 2010)

BioSNG can be produced by a number of different gasifier designs. In contrast to the gasifier in FT and DME production, the entrained flow gasifier is less suitable for BioSNG. This is due to the high temperature of 1200 to 1500°C during entrained flow gasification. The syngas in high temperature gasification consists mostly out of CO, H_2, CO_2 and H_2O. Options as fluidized bed gasification and indirect gasification are able to operate at temperature of 900°C, which produces methane directly (Carbo, 2011; van der Meijden et al., 2010). This produced methane can be converted into SNG directly. A disadvantage of gasification at moderate temperatures are the formation of tars which can cause fouling and plugging of the equipment. Thermal or catalytic cracking of these tars are undesirable since these technologies are expected to reform part of the methane in the syngas. ECN is working on an oil-based tar removal technology called OLGA, where the tars can be fed back to the gasifier. (Carbo, Smit, van der Drift, & Jansen, 2011)

The steps in the BioSNG process are a little different compared to the other biomass to fuel cases. The syngas is produced by gasification, and then cooled. After cooling the syngas, the syngas needs to be cleaned. Tar removal is important, which is a risk of gasification at moderate temperatures. The cleaned gas is sent to the methanation unit where CO and H2 are converted into CH4 and CO2. After CO2 removal and drying, the gas is ready for injection into the natural gas grid. (van der Meijden et al., 2010)

BioSNG with CCS

As in Fischer-Tropsch and BioDME synthesis the CO_2 capture process of choice is pre-combustion. The technology of physical absorption is selected for the removal of CO_2 from the BioSNG, which is explained in the gasification section.

3.3 Reference technologies

The reference technologies used in the analysis are based on the *New policy scenario* and the *450 ppm scenario* of the world energy outlook 2012 report. The definition of the these scenarios are the following:

"New Policy Scenario: Existing policies are maintained and recently announced commitments and plans, including those yet to be formally adopted, are implemented in a cautious manner

450 ppm: Policies are adopted that put the world on a pathway that is consistent with having around a 50% chance of limiting the global increase in average temperature to 2 °C in the long term, compared with pre-industrial levels." (IEA, 2012b)

The scenarios have significant influence on the projected electricity mix of countries. Due to the policy measures to reduce emissions (e.g. CO_2 pricing), it is expected that the electricity mix will shift towards more sustainable and low carbon technologies. This shift has an impact on demand and the feedstock prices. The demand for coal in the 450 scenario decreases due to policy actions to reduce CO_2 emissions, which results in a low coal price. The expected prices and share in the electricity mix are given in Table 8.

Table 8: Cost data for reference cases (IEA, 2010a)

OECD Europe	2010	2011	2030 (New Policy)	Percentage of total generation	2030 (450)	Percentage of total generation
Total Electricity Generation [TWh]	2683		4243	-	3972	-
Electricity from Coal [TWh]	1040		597	14%	272	7%
Electricity from Gas [TWh]	168		1062	25%	598	15%
Coal Price [€2010/GJ]		€3.17	€2.93		€2.00	
Gas Price [€2010/GJ]		€7.06	€8.97		€7.36	
Crude Oil Price [€2010/GJ]		€11.45	€13.16		€11.14	
Gasoline Price [€2010/GJ]		€16.43	€18.66		€16.02	
Diesel Price [€2010/GJ]		€17.81	€20.55		€17.31	
CO_2 Price [€2010/tonnes CO_2]			€27.88		€66.32	

Based on these two scenarios, the reference technologies are chosen. As can be seen in Table 8, the amount of electricity produced from coal decreases in both scenarios, while the electricity produced in gas fired power plants increase. The 450 ppm scenario includes a large share of nuclear energy. With the nuclear disaster in Fukushima in March 2011, it is unlikely that in the coming years a drastic shift towards nuclear energy is made. Therefore we expect that a larger share of renewable energy technologies such as BECCS are needed to fulfill the 450 ppm target. The selected technologies for the reference scenarios are an NGCC and a pulverized coal (PC) plant with and without CCS.

The fuel prices for the future scenarios are derived from the crude oil price using a regression analysis with the following equation (EPA United States Environmental Protection Agency, 2010).

$$(1)\quad Wholesale\ price\ Gasoline\ [\$c/gal] = crude\ oil\ price\ [\$/bbl] * 2.65 + 27.0$$
$$(2)\quad Wholesale\ price\ Diesel\ \ [\$c/gal] = crude\ oil\ price\ [\$/bbl] *\ 3.38 - 11.7$$

The numbers represent the historical relation between the crude oil price and gasoline and diesel price. The data are taken from EPA's Renewable Fuel Standard Program (EPA United States Environmental Protection Agency, 2010).

4. Parameters

This chapter explains the parameters that are chosen for the analysis. An overview of the selected parameters is provided in Table 15. In the following paragraphs the selection of these parameters are explained. The 2010 data are used to place the 2030 values in perspective.

4.1 Biomass to power parameters

For all cases it assumed that willow is used and pretreated by torrefaction in order to reduce the moisture content, and increase the energy density of the biomass (H. Meerman, 2012). It is expected that due to larger production the price of biomass decreases towards the year 2030 (RENEW, 2008). The pretreatment cost of willow to torrified pellets and transport are included in the biomass price.

For all the cases, we used a lifetime of 30 years, and a discount rate of 10%. The O&M cost are set at 4% of the investment costs (H. Meerman, 2012).

4.1.1. Combustion

The combustion case is based on a dedicated biomass CFB boiler in which torrified wood pellets are fired. Post-combustion is applied in order to capture the CO_2 from the flue gasses. First the data for the 2010 case are discussed, followed by the data for the 2030 case.

The capital cost data for the 2010 dedicated biomass case are retrieved from the papers by Gerssen-Gondelach, IEA ETSAP, IEA GHG and Bain (Bain, Amos, Downing, & Oak, 2003; Gerssen-Gondelach et al., 2013; IEA ETSAP, 2010; IEA GHG, 2009). The IEA GHG has researched the possibilities for Biomass in combination with CCS where the others have not. Gerssen-Gondelach, Bain and the IEA ETSAP estimate the cost for a dedicated CFB biomass boiler at 2197 – 2641 $€_{2010}$/kW for a scale to 50-100 MW. The capital cost data found in the paper by The IEA GHG estimate the cost at 1385 $€_{2010}$/kW for a 273 MW CFB plant. All excluding CCS. The investment cost used in the calculation are the investment cost taken from Gerssen-Gondelach, Bain and IEA ETSAP, scaled to the same level as the IEA GHG paper, resulting in a range of 1692 – 1872 $€_{2010}$/kW with an average investment cost of 1754 $€_{2010}$/kW which is used in this thesis. The used scaling factor of 0.74 is taken from Faaij and Hamelinck (Faaij et al., 2002). The capital cost include flue gas cleaning and conversion to electricity. We see that the investment cost by Gerssen-Gondelach, IEA ETSAP and Bain are in the same range, and the IEA GHG data are lower. Therefore we assume that the capital cost without CCS are in the range mentioned above, and is the IEA GHG capital cost not included.

Table 9: Capital cost of dedicated biomass combustion in a CFB combustion plant for 2010 (left) and 2030 (right) (Bain et al., 2003; Gerssen-Gondelach et al., 2013; IEA ETSAP, 2010; IEA GHG, 2009; Koornneef et al., 2011)

Investment Cost CFB combustion plant 2010	Cost [€2010/kWe]	Scale [Mwe]	Efficiency	With CCS	Investment Cost CFB combustion plant 2030	Cost [€2010/kWe]	Scale [Mwe]	Efficiency	With CCS
IEA GHG 2009	1385	273	41.7%	No	IEA ETSAP 2010	1574	500	38.0%	No
	3141	169	25.8%	Yes	Koornneef et al. 2011	1614	500	47.0%	No
Gerssen Gondelach 2013	1872	273	28.0%	No		3039	500	37.0%	Yes
IEA ETSAP 2010	1699	273	32.0%	No					
Bain 2003	1692	273	-	No					
this thesis 2010	1754	273	32.0%	No	**this thesis 2030**	1594	500	42.5%	No
	3979	273	19.8%	**Yes**		3002	500	33.6%	**Yes**

The additional cost for post combustion CCS is added to the capital cost. The capital cost of the IEA GHG case for the CFB boiler with CCS is used as a reference, since they assume lower cost for the CFB boiler without CCS. The study by Finkenrath analyses multiple reports on CCS in the fossil fuel market, for different plant designs (pulverized coal, NGCC, CFB) (Finkenrath, 2011). The report provides an overview of the cost increase and energy penalty. The CCS technology used in coal fired power plants is the same as in biomass fired power plants. There is a difference in flue gas flows: due to lower energy content of biomass, higher volumes of biomass are necessary to produce the same output, which result is higher flue gas flows (IEA GHG, 2009). When comparing the additional cost for CCS, the IEA GHG state that the capital cost increase with 127% for dedicated biomass CFB plants with CCS where Finkenrath state that the capital cost will increase with 82% for fossil fired CFB plant. The additional cost for CCS are taken from the IEA GHG report since these account for the higher flue gas flows of biomass combustion, resulting in a capital cost of 3979 €$_{2010}$/kW$_e$. (Finkenrath, 2011; IEA GHG, 2009)

The use of post combustion comes with an energy penalty due to the need for extra energy consuming equipment which decreases the efficiency. Finkenrath states an energy penalty of 27% for fossil fueled plants, where IEA GHG state a 38% energy penalty for dedicated biomass plant. The IEA GHG energy penalty is taken for the analysis, since these account for the higher flue gas flows of biomass combustion, causing a higher parasitic load. The efficiency of the plant including the penalty is 19.8%.

In the 2030 plant it is expected that the scale of the plant increases to 500 MW. The R&D of post combustion technologies focusses on new and adaptation of solvents, to reduce the energy consumption of the CCS equipment, resulting in a lower energy penalty (Koornneef et al., 2011).

The capital cost of the plant are calculated in the same way as the current technology plant and are shown in Table 9. The capital cost data are based on the papers by Koornneef and the IEA ETSAP (IEA ETSAP, 2010; Koornneef et al., 2011). Koornneef et al. state a capital cost of 1613 €$_{2010}$/kW for 500 MW$_e$ plant, with an efficiency of 47% excluding CCS. Their estimate for a plant including CCS at the same scale is 3038 €$_{2010}$/kW with an efficiency of 37%. The IEA ETSAP estimate the cost for a dedicated CFB plant at 1937 €$_{2010}$/kW for a 50 MW$_e$ plant with an efficiency of 38%. The cost of the plant are scaled to a plant of 500 MW$_e$ resulting in an investment cost of 1574 €$_{2010}$/kW excluding CCS. The scaling factor used is 0.91 for technologies beyond 400 MW, according to Faaij and Hamelinck (Faaij et al., 2002).

Koornneef et al. estimate that additional cost for CCS in a dedicated CFB plant will increase with 88% (Koornneef et al., 2011). This value is used for the analysis. The energy penalty is expected to decrease due to the improvement of the solvents used for CO_2 capture. Koornneef et al. state that the energy penalty will decrease with 21% resulting in an efficiency of 33% (Koornneef et al., 2011).

4.1.2. Co-firing

In the co-firing scenario, the biomass is directly co-fired in a pulverized coal plant. In the 2010 scenario, the co-firing percentage is 10%, which increases to 30% in 2030. The investment cost consist of the PC plant cost, the additional cost of biomass co-firing and the additional cost for CCS.

The capital cost data for the 2010 scenario are taken from the papers by the IEA GHG, Gerssen-Gondelach et al., IEA ETSAP, IRENA, and Uslu et al. (Gerssen-Gondelach et al., 2013; IEA ETSAP, 2010; IEA GHG, 2009; The International Renewable Energy Agency, 2012; Uslu, van Stralen, Beurskens, & Dalla Longa, 2012).

The IEA GHG and IRENA state the cost for the complete PC plant with biomass co-firing. The IEA GHG state a capital cost of 1292 $€_{2010}$/kW for 518 MW_e PC plant with an efficiency of 44.8%, and 10% biomass co-firing. Their PC plant with CCS has a capital cost of 2109 $€_{2010}$/kW with an efficiency of 34.5%. IRENA state a range of the capital cost of 1584 to 2339 $€_{2010}$ /kW for PC plant with 10% co-firing excluding CCS.

Gerssen-Gondelach, IEA ETSAP, and Uslu et al. state the additional cost for co-firing in a PC plant. Gerssen-Gondelach states a range 176 to 317 $€_{2010}$/$kW_{biomass\ capacity}$ up to 100 MW_e of biomass capacity with efficiencies ranging from 36 to 44%. Uslu state capital cost of 168 $€_{2010}$/$kW_{biomass\ capacity}$ up to 70 MWe biomass capacity with an efficiency of 44%. These cost are added to the initial investment cost for a PC plant taken from the IEA Energy Technology Perspective (IEA, 2010a).

The addition of CCS to the PC plant has a lower energy penalty and lower additional investment cost in reference to the dedicated combustion plant. The decrease in efficiency is 25% and an increase of the capital cost of 82% (Finkenrath, 2011). We expect that the size of the plant remains the same in 2030.

The investment cost for co-firing are added to the costs of a PC plant without CCS, resulting in a range of 1800 – 2018 $€_{2010}$/kW. When we compare this range to the range that is stated by the IRENA report, we see that our prices are in range. Again the reported cost data by the IEA GHG are lower. An average value is taken resulting in an investment cost of 1957 $€_{2010}$/kW excluding CCS. For the Investment cost for the co-firing plant with CCS, we used the expected capital increase by Finkenrath, together with the investment cost for a PC plant with CCS and the additional capital cost for co-firing, resulting in an investment cost of 3316 $€_{2010}$/kW.

The IEA GHG state lower capital cost for a PC co-firing plant with CCS than Finkenrath does for a PC plant with CCS without co-firing. We therefore have not incorporated the capital cost by the IEA GHG.

The 2030 scenario is based on the on the cost data retrieved from Koornneef et al., IEA energy technology perspective and Uslu et al. (IEA, 2010a; Koornneef et al., 2011; Uslu et al., 2012) and shown in Table 10. The percentage of co-fired biomass is expected to increase from 10% to 30%. (Koornneef et al., 2011). Uslu et al. state that the additional cost for co-firing remains similar to the 2010 scenario, while the efficiency increases to 51%. The estimated cost by Uslu et al. are added to the cost of a pulverized coal plant with CCS. Cost data for that plant are taken from the IEA energy technology perspective report (IEA, 2010a), resulting in an investment cost of 2548 €$_{2010}$/kW. Koornneef et al. state a capital cost of 1507 €$_{2010}$/kW for a PC plant with an efficiency of 51% excluding CCS, and 2339 €$_{2010}$/kW for a post combustion PC plant with an efficiency of 41%. We used the value of the Koornneef and the IEA with Uslu et al., resulting in an investment of 2372 €$_{2010}$/kW

Table 10: Investment cost of biomass Co-Firing in a PC plant in 2010 (left) and 2030 (right) (Finkenrath, 2011; Gerssen-Gondelach et al., 2013; IEA ETSAP & IRENA, 2013; IEA ETSAP, 2010; IEA GHG, 2009; IEA, 2010a; Koornneef et al., 2011; Uslu et al., 2012).

Investment cost 10% Co-Firing 2010	cost [€2010/kW]	scale [MW]	efficiency	With ccs	Investment cost 30% Co-Firing 2030	cost [€2010/kW]	scale [MW]	efficiency	With ccs
PC+co-firing cost									
IEA GHG 2009	1293	519	45%	No	Koornneef 2011	1508		51%	No
	2109	396	35%	Yes		2197		41%	Yes
	1385	521	45%	No					
	2401	391	34%	Yes					
IRENA	1585			No					
to	2339			No					
PC cost									
Finkenrath	2874	500	31%	Yes	IEA 2010a	2380	500	44%	Yes
	1631	500	41%	No					
Additional Co-firing cost									
Gerssen Gondelach 2013	387	100	36%	No	Uslu 2011	169	70	46%	No
IEA ETSAP 2010	176	100	36%	No					
to	317	100	44%	No					
Uslu 2011	169	70	38%	No					
This thesis	**1957**	**500**	**44%**	**No**	**This thesis**	**2372**	**500**	**41%**	**Yes**
	3316	**500**	**33%**	**Yes**					

4.1.3. Gasification

The chosen gasifier design is the entrained flow gasifier because of the high quality syngas. The gasification process is followed by acid gas removal unit which removes the CO_2 from the syngas, followed by the gas turbines for power production.

The cost for the 2010 scenario are taken from the dissertation of Meerman (H. Meerman, 2012). The chain contains a 289 MW$_e$ entrained flow gasifier with a combined cycle for optimal electricity production. The capital cost for the BIGCC plant are estimated at 2520 €$_{2010}$/kW and has an efficiency of 34%. This includes the AGR in which the CO_2 is removed from die syngas, using Rectisol as a solvent.

All other sources use a CFB gasifier design. For comparison, Rhodes state a capital cost of 2374 €$_{2010}$/kW, for 123 MW$_e$ CFB gasifier with CCS with an efficiency of 28%. And for the plant excluding CCS, Rhodes state a capital cost 1715 €$_{2010}$/kW and an efficiency of 34% (Rhodes & Keith, 2005). Gerssen-Gondelach et al. state a capital cost of 1080 to 1980 €$_{2010}$/kW for a 250 MW_e plant with capacity factors of 68 to 80%. The plant has an efficiency of 44.6% and excludes CCS (Gerssen-Gondelach et al., 2013). Cormos is the only other source that uses entrained flow gasifiers, although these gasifiers are coal fired, prices are in the same range. (Cormos, 2012)

Table 11: Investment cost of gasification with electricity production in 2010 (left) and 2030 (right) (Cormos, 2012; Gerssen-Gondelach et al., 2013; Koornneef et al., 2011; Larson, Jin, & Celik, 2005; Luckow, Dooley, Kim, & Wise, 2010; H. Meerman, 2012; Rhodes & Keith, 2005)

Investment cost gasification 2010	Cost [€2010 /kW]	scale [Mwe]	Efficiency	Gasifier design	With CCS	Investment cost gasification 2030	Cost [€2010 /kW]	Scale [Mwe]	Efficiency	Gasifier design	With CCS
Gerssen Gondelach et al. 2013	1980	250	45%	CFB	No	Gerssen Gondelach et al. 2013	1710	250	42%	CFB	No
Larson 2005	1129	400	49%	CFB	No	Meerman 2012	2154	334	39%	EF	Yes
	1663	354	38%	CFB	Yes	Koornneef et al. 2011	2277		43%	CFB	Yes
Rhodes 2005	1715	149	34%	CFB	No	Luckow 2010	1571		42%	CFB	No
	2374	123	28%	CFB	Yes		2023		36%	CFB	Yes
Meerman 2012	2520	289	34%	EF	Yes						
Coal fired											
Cormos 2012	1875	485	47%	EF (shell)	No						
	2556	432	37%	EF (Shell)	Yes						
	1982	448	43%	EF (Siemens)	No						
	2622	420	36%	EF (Siemens)	Yes						
This thesis	**2520**	**289**	**34%**		**Yes**	**This Thesis**	**2154**	**334**	**39%**	**EF**	**Yes**

The energy penalty and additional cost for pre-combustion CCS are significantly lower than for post-combustion CCS. Finkenrath state an increase of capital cost of 44% and a decrease in net efficiency of 20% for fossil fueled IGCC's (Finkenrath, 2011). Meerman state a decrease in net efficiency of 20% and a capital increase of 40% (H. Meerman, 2012).

In 2030 it is expected that several new technologies improve the performance of the process. The improvement of the air separation unit, feed system and turbine design will improve the systems efficiency (H. Meerman, 2012). The plant size is expected to increase to 334 MW_e, and the capital cost are expected to decrease to 2154 €$_{2010}$/kW. The lifetime, discount rate and O&M percentage are similar to the 2010 scenario. (H. Meerman, 2012)

4.2 Biomass to liquid fuel

4.2.1. Fischer-Tropsch

The Fischer-Tropsch case consists of the same entrained flow gasifier used in the gasification section, followed by the AGR to remove CO_2 from the syngas and the water gas shift unit to optimize the H_2/CO ratio for FT-liquid production.

The cost data are taken from Meerman and compared with the technologies in the paper by van Vliet et al.. Both cases use TOPS as a feedstock since it increases the performance of the gasification process. In both cases the gasifier design is an EF gasifier, produced by Shell and van Vliet incorporated the Carbo-V design by Choren (H. Meerman, 2012; van Vliet et al., 2009). Meerman state a capital cost of 1600 €$_{2010}$/kW$_{output}$ for 848 MW$_{input}$ plant that uses torrified wood pellets as a feedstock. The total conversion efficiency is 56.3%. Van Vliet has multiple technology variants in which he varies the feedstock, and gasifier design. The first variant is a 300 MW$_{input}$ plant that is fired on eucalyptus. The gasifier design is a BFB gasifier from the company IGT. The capital cost are 1958 €$_{2010}$/kW$_{output}$ and has an total conversion efficiency of 52% and does not include CCS. The second and third variant by Van Vliet et al. is based on the Carbo-V design by Choren, both have 2000 MW$_{input}$ wood pellets as input. Only the second variant has CCS incorporated. The capital cost for the second design are estimated at 1575 €$_{2010}$/kW$_{output}$ and the third design is estimated at 1533 €$_{2010}$/kW$_{output}$. The fourth design is similar to the technology described in the dissertation by Meerman (H. Meerman, 2012). The design is based on a Shell EF gasifier and has a 2000 MW$_{input}$ torrified wood pellets as input. The capital cost are estimated at 1511 €$_{2010}$/kW$_{output}$ including CCS. In order to compare the data we scaled the cost data from Meerman to the output level of van Vliet resulting in 1497 €2010/kW$_{output}$ with a scaling factor of 0.91 as proposed in the paper by Hamelinck (Hamelinck & Faaij, 2006). In order to harmonize the data we decided to use the cost data and output level of Meerman in the analysis.

Table 12: Investment cost of gasification with FT in 2010 (left) and 2030 (right) (Hamelinck & Faaij, 2006; Hannula & Kurkela, 2013; Koornneef et al., 2011; H. Meerman, 2012; RENEW, 2008; Swanson et al., 2010; van Vliet et al., 2009)**.**

Investment cost FT 2010	Cost [€2010/ kWoutput]	Scale [MW output]	Efficiency	With CCS	Investment cost FT 2030	Cost [€2010/ kWoutput]	Scale [MW output]	Efficiency	With CCS
Hamelinck & Faaij 2006	2030	168	42%	No	Hamelinck & Faaij 2006	1634	168	42%	No
Hanulla 2013	2350	157		Yes	Koornneef 2011	1616	200	42%	Yes
RENEW 2008	1676		53%		Swanson 2010	1686	529	53%	No
van Vliet 2009	1958	156	52%	No	Meerman 2012	1389	499	59%	Yes
	1576	1020	51%	Yes					
	1534	1020	51%	No					
	1512	1000	50%	Yes					
Meerman 2012	1600	477	56%	Yes					
This thesis	**1600**	**477**	**56%**	**Yes**	**This Thesis**	**1389**	**499**	**59%**	**Yes**

The 2030 scenario is based on the data retrieved from Koornneef et al., Swanson and Meerman et al. (Koornneef et al., 2011; H. Meerman, 2012; Swanson et al., 2010). Koorneef et al. estimate the capital cost at 1616 €$_{2010}$/kW$_{output}$ for a 200 MW$_{th\ input}$ plant. Swanson state a capital cost of 1686 €$_{2010}$/kW$_{output}$ for a 529 MW$_{th\ input}$ plant, with an efficiency of 52%. Meerman state a capital cost of 1389 €$_{2010}$/kW$_{output}$ with an efficiency of 58,9%. The value calculated by Meerman is used in the analysis.

We assume that 33% of the carbon remains in the fuel, 60% of the carbon is captured, and that 7% of the carbon is emitted (H. Meerman, 2012).

4.2.2. DME

The DME pathway consists of the Shell EF gasifier used in the gasification to power and FT section. The gasification is followed by the AGR to remove CO_2 from the syngas and the water gas shift unit to optimize the H_2/CO ratio for DME production. The conversion of syngas to DME takes place in a single step reactor which converts syngas directly into DME.

Cost data for biomass gasification in EF gasifiers to DME production are hard to find. In order to harmonize the data, cost data are taken from Meerman. Meerman has included a TOPS to methanol scenario. The cost of the methanol conversion are subtracted from the investment cost, and the cost of a single step DME reactor are added. Data for the DME reactor are found in the paper Hannula, which has The combination of a CFB boiler with DME production (Hannula & Kurkela, 2013). The DME reactor is scaled to the same syngas flows, and capital cost are added. The calculated capital cost are 1537 $€_{2010}/kW_{output}$ for a 1600 MW_{input} plant. Huisman at al. estimate the capital cost at 1706 $€_{2010}/kW_{output}$, for a 230 $MW_{th\ input}$ plant, with an 55.6% conversion efficiency(Huisman, Van Rens, De Lathouder, & Cornelissen, 2011; Van Rens, Huisman, De Lathouder, & Cornelissen, 2011). Larson has researched the possibilities for the implementation of DME in the paper sector, at which black liquor is converted to DME. Larson state a capital cost of 1025 $€_{2010}/kW_{output}$, for a 514 MW_{input} plant. The value used for the analysis is the constructed value of Meerman and Hannula.

Table 13: Investment cost DME 2010

Investment cost DME 2010	Cost [€2010/kw output]	Scale [MW output]	efficiency	With CCS
Hamelinck & Faaij 2006	1544	232	58,0%	No
RENEW	829	500		
Hanulla 2013	1993	179	56,1%	Yes
Larson 2006	1025	365	71,0%	Yes
Clausen 2010	1141	944	59,0%	Yes
Meerman ADAPTED FROM MeOH to DME	1537	928	58,0%	Yes
Huisman 2011	1707	128	55,6%	Yes
This thesis	**1537**	**100**	**58,0%**	Yes

The 2030 scenario is based on the cost data retrieved from Huisman et al. the estimated capital cost are 1289 $€_{2010}/kW_{output}$, with an efficiency of 69% and scaled at 200 MW output.

We assume that 50% of the carbon is captured after the gasification process, 47% of the carbon remains in the fuel and 3% of the emissions are emitted (Clausen et al., 2010).

4.3 Biomass to gaseous fuel

4.3.1. SNG

The SNG scenario is different in setting than the DME and FT scenario. SNG is a gaseous fuel. The case consist of a CFB gasifier, followed by the methanation unit to convert the syngas in to methane, followed by the AGR to remove CO_2.

The capital cost found for the SNG scenario are retrieved from Rönsch & Kaltschmitt, Gassner, and Cozens (Cozens & Manson-Whitton, 2010; Gassner & Maréchal, 2009; Rönsch & Kaltschmitt, 2012). Rönsch & Kaltschmitt have researched multiple plant setups for SNG production with the addition of steam cycle, organic rankine cycle, gas turbine and gas engine. Rönsch & Kaltschmitt conclude that the SNG production with steam cycle is the lowest cost option, and has the lowest greenhouse gas emissions. Rönsch & Kaltschmitt state capital cost of 1134 $€_{2010}/kW_{output}$ for a 95 MW_{input} plant, with an efficiency of 64.5%. Gassner & Maréchal estimate the capital cost at 1205 $€_{2010}/kW_{output}$ for a 20 MW_{input} plant with an efficiency of 75%

based on pressurized steam-oxygen blown gasifier. Cozens researched the possibilities for a Bio-SNG plant in the UK. Cozens state a capital cost of 1323 €$_{2010}$/kW$_{output}$ for a 300 MW$_{th}$ plant with an efficiency of 65%. The 2010 scenario is based on the cost data of Cozens because of the detailed economic data.

Table 14: Investment cost of gasification with SNG production in 2010 (left) and 2030 (right) (Carbo et al., 2011; Cozens & Manson-Whitton, 2010; Gassner & Maréchal, 2009; Rönsch & Kaltschmitt, 2012)

Investment Cost CFB + SNG plant 2010	Cost [€2010/ kW output]	Scale [MW output]	Efficiency	Investment Cost CFB + SNG plant 2030	Cost [€2010/kW output]	Scale [MW output]	Efficiency
Cozens 2010	1323	195	65%	Rönch 2012	1123	62	65%
Gassner 2009	1205	15	75%	Carbo 2011	1100	334	67%
Rönch 2012	1134	62	65%	Uslu 2012	1070	167	65%
This thesis	**1323**	**200**	**64%**	**This Thesis**	**1030**	**300**	**65%**

The future scenario is based on the cost data from the paper by Carbo, Rönsch & Kaltschmitt, and Uslu et al. (Carbo et al., 2011; Rönsch & Kaltschmitt, 2012; Uslu et al., 2012). Carbo state a capital cost of 1100 €$_{2010}$/kW$_{output}$, for a 500 MW$_{th}$ plant with an efficiency of 66,8% based on the CFB gasifier of the ECN. Rönsch estimate the capital cost at 1123 €$_{2010}$/kW$_{output}$ for a 95 MW$_{input}$ plant with a steam cycle. Uslu estimate the cost at 1070 €$_{2010}$/kW$_{output}$ for a 168 MW output plant with an efficiency of 65%. The cost are scaled to 300 MW output, and an average investment cost is taken. The scaled cost data are 975 €$_{2010}$/kW$_{output}$ for Rönsch & Kaltschmitt, 1015 €$_{2010}$/kW$_{output}$ for Uslu et al., and 1100 €$_{2010}$/kW$_{output}$ for Carbo. The investment cost used in the 2030 case is 1030 €$_{2010}$/kW$_{output}$.

We assume that 40% of the carbon remains in the fuel, 40% is captured after the gasification process, and 20% of the carbon is emitted (Carbo, Smit, Drift, & Jansen, 2010).

4.4 Reference cases

The cost data for the reference technologies for electricity production are based on the data of the Energy Technology Perspectives 2010 report by the IEA and the report by Finkenrath (Finkenrath, 2011; IEA, 2010a). The data for the 2010 cases are taken from Finkenrath, and the 2030 data are retrieved from the ETP 2010 report. The cost data can be found in Table 15.

The cost data for the reference fuel technologies are based on the future crude oil price, and are calculated in chapter 3.4.

Table 15: Input and output of the analysis

	Reference scenarios								Biomass to Power						
	NGCC		NGCC+CCS		PC		PC + CCS		CFB+CCS		Co-firing+CCS		BIGCC		
	2010	2030	2010	2030	2010	2030	2010	2030	2010	2030	2010	2030	2010	2030	
Output MW	500	500	546	546	500	500	500	500	273	500	500	500	289	334	Mwe
Output TJ	13403	13403	14636	14636	13403	13403	13403	13403	7748	14191	13403	13403	7291	8426	TJ
Investment cost	724	623	1294	962	2310	1415	2874	2380	3979	3002	3591	2373	2520	2154	€2010/kW
O&M fixed	20.3	17.1	72.4	55.8	82.3	70.5	77.0	66.8	139.3	120.1	143.6	94.9	100.8	86.2	€2010/(kW yr)
Efficiency (elect)	58%	63%	49%	56%	46%	52%	31%	44%	20%	33%	33%	41%	34%	39%	-
Capture efficiency	-	-	90%	90%	-	-	90%	90%	90%	90%	90%	90%	90%	90%	-
Capacity factor	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.90	0.90	0.85	0.85	0.80	0.80	-
Lifetime	30	30	30	30	30	30	30	30	30	30	30	30	30	30	yr
Discount rate	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	-
CRF	0.106	0.106	0.106	0.106	0.106	0.106	0.106	0.106	0.106	0.106	0.106	0.106	0.106	0.106	-
Cost of Electricity	54.8	60.4	71.8	72.1	57.3	41.4	76.6	58.8	181.4	109.2	105.9	80.7	115.7	90.4	€2010/MWh
Emission fossil vented	0.448	0.412	0.053	0.046	0.674	0.596	0.100	0.070	-	-	0.053	0.053	-	-	tCO2/MWh
Emission biogenic vented	-	-	-	-	-	-	-	-	0.175	0.103	0.010	0.025	0.101	0.088	tCO2/MWh
Emission fossil stored	-	-	0.477	0.418	-	-	0.903	0.634	-	-	0.754	0.476	-	-	tCO2/MWh
Emission biogenic stored	-	-	-	-	-	-	-	-	1.571	0.929	0.093	0.228	0.912	0.789	tCO2/MWh

	Biomass to Fuels						
	FT		DME		SNG		
	2010	2030	2010	2030	2010	2030	
Output MW	477	499	100	200	200	200	Mwe
Output TJ	13689	14320	2870	5740	5740	5740	TJ
Investment cost	1600	1389	1537	1289	1323	1030	€2010/kW
O&M fixed	64	56	61	52	53	41	€2010/(kW yr)
Efficiency (elect)	56%	59%	58%	69%	64%	65%	-
Capture Efficiency	60%	60%	50%	50%	40%	40%	-
Carbon in fuel	33%	33%	47%	47%	20%	20%	-
Capacity factor	91%	91%	91%	91%	91%	91%	-
Lifetime	30	30	30	30	30	30	yr
Discount rate	10%	10%	10%	10%	10%	10%	-
Capital recovery factor	0,11	0,11	0,11	0,11	0,11	0,11	-
Cost of fuel	18,91	15,52	18,13	13,73	16,18	12,95	€2010/GJ
Emission biogenic vented	0,012	0,011	0,005	0,004	0,030	0,030	ton CO2/GJ
Emission biogenic stored	0,102	0,098	0,083	0,069	0,060	0,059	ton CO2/GJ

5. Results

In this chapter the results of the analysis are presented. The chapter is divided in two parts: the biomass to power section and the biomass to fuel section.

5.1 Results biomass to power

The results are divided in three parts. Frist we compared the cost of electricity for the BECCS technologies with the reference cases, with variations in the biomass cost and CO_2 credit price. Then we compared the mitigation costs and emission balance of the BECCS technologies.

Cost of electricity

The cost of electricity in presented in Table 15 of the previous chapter. The introduction of CO_2 pricing in the form of CO_2 credits has great influence on the cost of electricity of all future technologies, as can be seen in Figure 12. A CO_2 credit is a tradable permit, presenting the right to emit one tonne of CO_2.

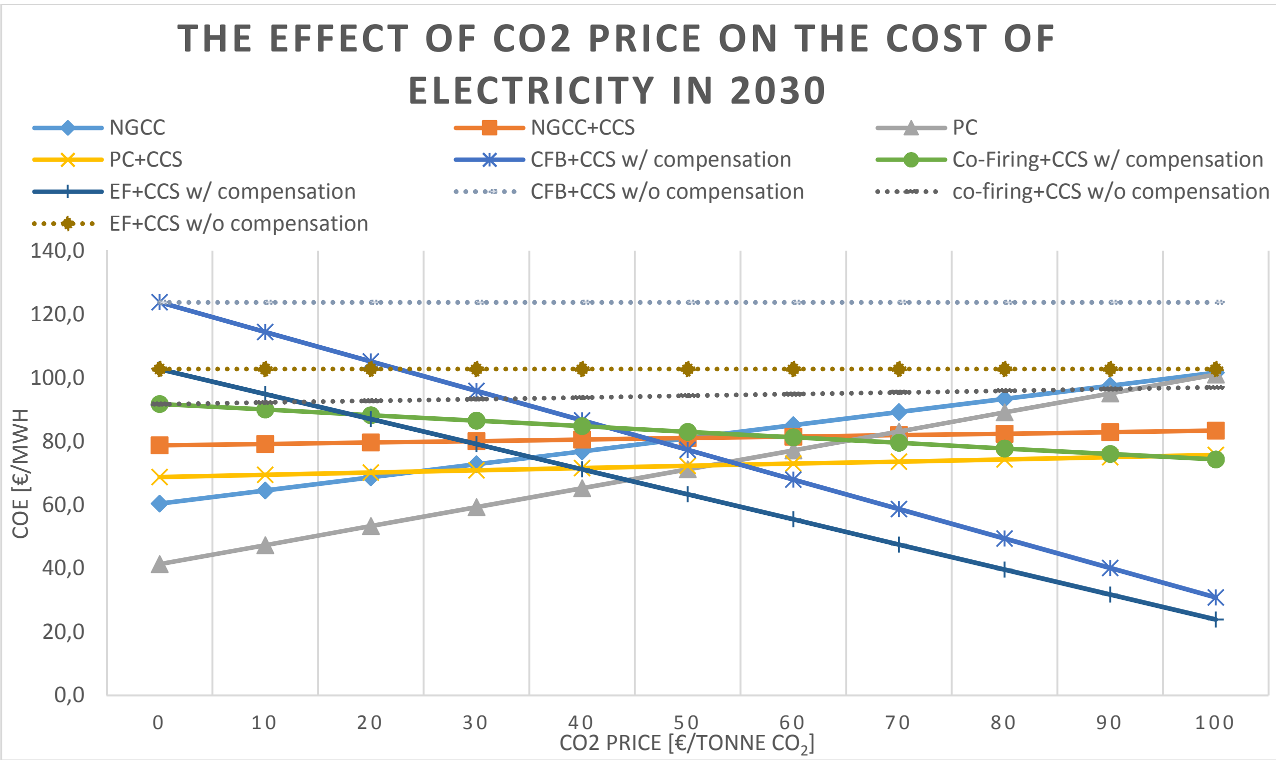


Figure 12: The effect of CO_2 pricing on the cost of electricity at a biomass price of 5€/GJ. The dashed lines represent the case where stored biogenic emissions are not compensated.

Starting with the NGCC and PC plants, we see that cost of energy increase rapidly for both technologies because of the increasing cost for their emitted CO_2. This is increase is less steep if the plant is equipped with CCS. In the fossil CCS scenarios, the carbon credits are bought for the emitted fossil emissions, and the stored emissions are considered neutral.

We see a decrease in cost of electricity for all BECCS cases as the CO_2 credit price increase. This is due to their possibilities to generate extra revenue by selling the CO_2 credits for stored biogenic CO_2 emissions (Domenichini, Gasparini, Cotone, & Santos, 2011). The biogenic emissions that are emitted are considered to be neutral, and does not have to be paid for. In the co-firing scenario, the biogenic emissions that are stored receive sellable CO_2 credits, and the stored fossil emissions are considered neutral, and therefore do not receive or cost credits. The emitted emissions from fossil fuels must be paid for, where the emitted biogenic emissions are neutral. Therefore the cost of the co-firing scenario does not decrease as rapidly as gasification and dedicated combustion.

An important finding is that when the stored biogenic emissions do not generate extra revenue in the form of sellable CO_2 credits, the cost of energy remains the same. Meaning that the BECCS technologies will not become cheaper than the fossil fueled technologies see Figure 12. Which means that the BECCS technologies are fully dependent on the introduction of sellable CO_2 credits for stored biogenic emissions.

A second parameter that has influence on the cost of electricity is the biomass price. The changes in cost of electricity at variations of the biomass price are shown in Figure 13. The green line represents the cost of electricity at a CO_2 credit price of 66 €/tonne CO_2 which is proposed in the 450ppm scenario of the IPCC, and is favorable for the BECCS technologies. The grey line represents a CO_2 credit price of 28 €/tonne CO_2 which is proposed in the NPS (IEA, 2012b). The biggest change in cost of electricity can be seen in the dedicated biomass combustion, due to the relatively low efficiency in reference to gasification and co-firing, high volumes of biomass are necessary for combustion.

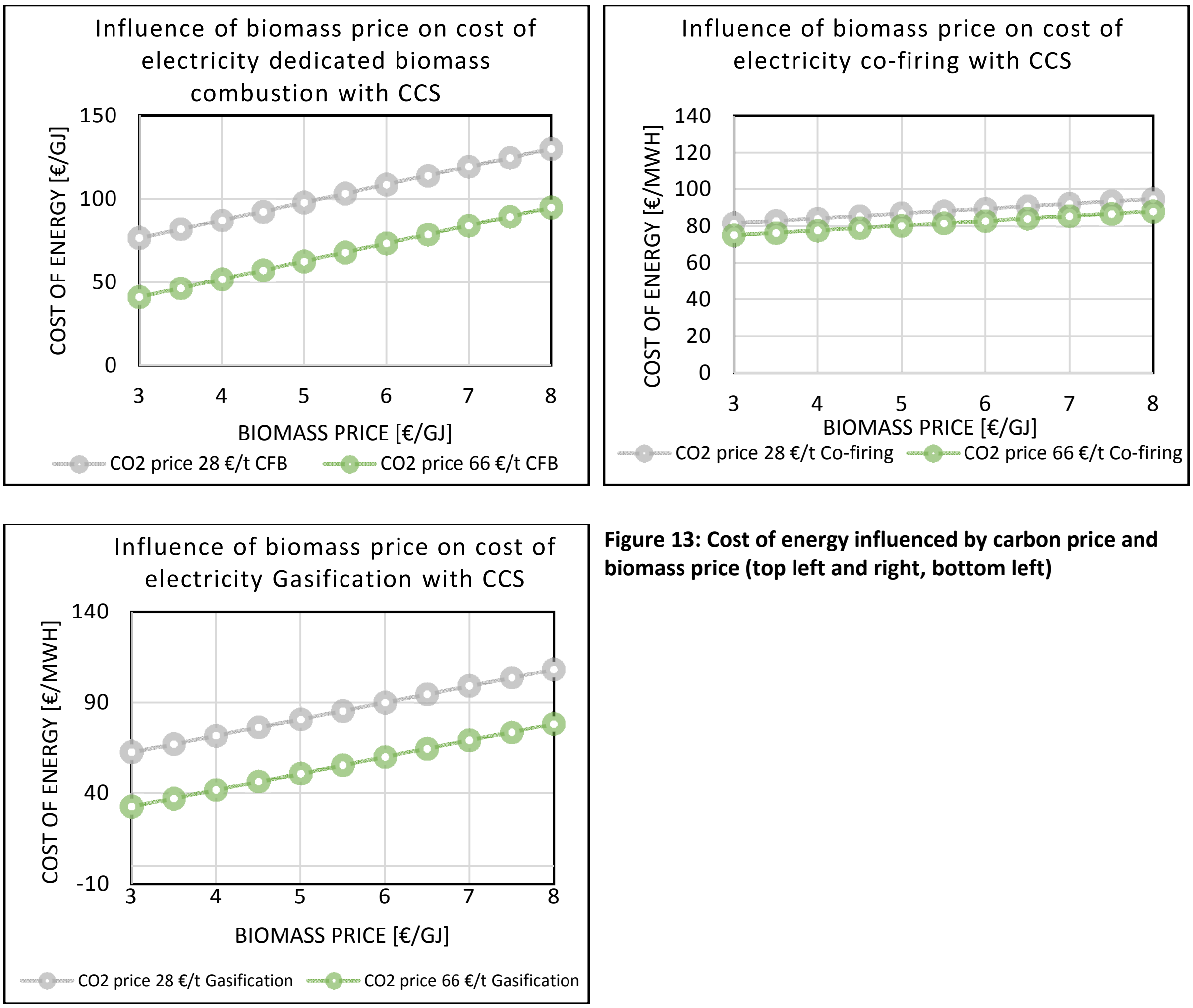


Figure 13: Cost of energy influenced by carbon price and biomass price (top left and right, bottom left)

In Figure 14 we assessed the lowest cost option for all BECCS and reference technologies at different CO_2 credit and biomass prices. The lowest cost BECCS technology is gasification. We also see that even with the lower efficiency and higher investment costs, dedicated biomass combustion is cheaper than the other BECCS technologies at low biomass prices and high CO_2 prices. This indicates that there is a point where the benefits of the sellable CO_2 credits are greater than the cost of biomass and therefore promotes low efficiencies. This occurs at CO_2 credit prices above 70 €$_{2010}$/tonne CO_2, and biomass prices below 6 €$_{2010}$/GJ. This is undesirable because it means that it could become more profitable to produce high amounts of CO_2 instead of reducing CO_2.

At higher biomass prices we see that PC with CCS takes over. Due to the low emissions of PC with CCS in reference with PC without CCS, it is able to compete with the BECCS technologies when the biomass prices increase. Even with high CO_2 prices, PC with CCS can produce electricity at the lowest cost.

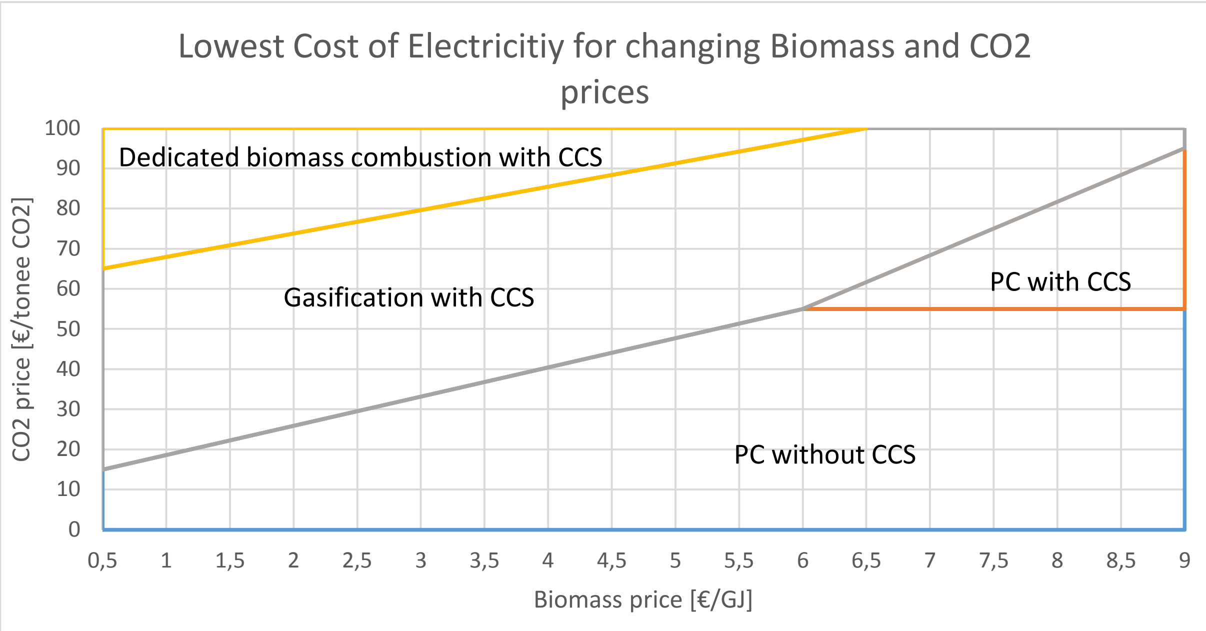


Figure 14: Lowest cost of electricity at changing biomass and CO_2 credit prices. All technologies are included.

Emission balance

The emission balance in Figure 15 show large reductions in emission for dedicated biomass combustion and for gasification. This gives a distorted image of the abilities of BECCS. The dedicated biomass option, has relatively low efficiency in reference to gasification, which means high amounts of CO_2 per MWh are produced. The goal of BECCS technologies is to reduce emissions, therefore lower emission flows with CCS are a better option than high emissions flows with CCS. As can be seen in Figure 15, the emission reduction of co-firing is very small in reference to gasification and combustion, this is due to the fact that only 30% of the stored emissions are biogenic, and can be accounted as negative. Co-firing also emits fossil emissions, which are subtracted of the stored biogenic emissions. The total negative emissions for dedicated biomass combustion with CCS are -929 kg/MWh, for gasification with CCS -789 kg/MWh and for co-firing with CCS -175 kg/MWh.

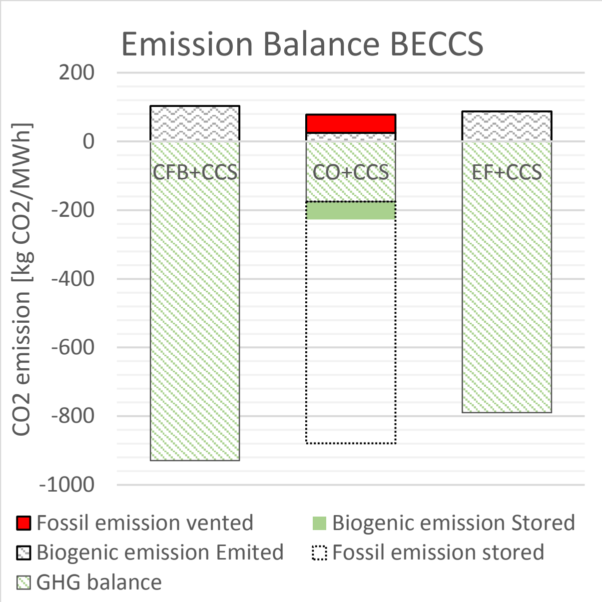


Figure 15: Emission balance BECCS scenarios

Mitigation costs of BECCS technologies

The third performance indicator are the CO_2 mitigation costs of the BECCS technologies in comparison with the reference technologies. The CO_2 mitigation cost for the biomass to power cases are presented in Figure 16.

The level of the CO_2 credit price is dependent on the policy makers. The proposed levels in the scenarios in the World Energy Outlook of the IEA are 28 $€_{2010}$/tonne CO_2 for the New Policy Scenario, and 66 $€_{2010}$/tonne CO_2 in the 450 ppm scenario. Figure 16 shows the influence of the introduction of a CO_2 credit price, on the mitigation cost under the new policy and the 450 ppm scenarios. We see that the mitigation cost decrease as CO_2 credit price increases. Gasification is the most cost efficient carbon mitigation option in all three scenarios, due to relatively low investment cost and high rewards for carbon storage. In Figure 16 we see that Co-firing is the least effective BECCS technology. This is due to the small amount of biogenic emissions that create extra revenue.

Figure 16: CO_2 mitigation costs with and without the influence of CO_2 pricing in the year 2030

This calculation is made with a fixed feedstock prices of 5 €/GJ. The calculation show us that at CO_2 credit price of 29 €/tonne CO_2, the mitigation costs of gasification are equal to the cost of a NGCC with CCS. It is more costly to mitigate the CO_2 emissions of the PC plant due to the low cost of electricity. The calculations show that a CO_2 credit price of 44 €/tonne CO_2 would make the mitigation cost equal for gasification.

Figure 17, Figure 18 and Figure 19 show how the biomass price influences the cost of electricity, and therefore the mitigation costs of the BECCS technologies. A complete sensitivity analysis of the used parameters can be found in the next chapter.

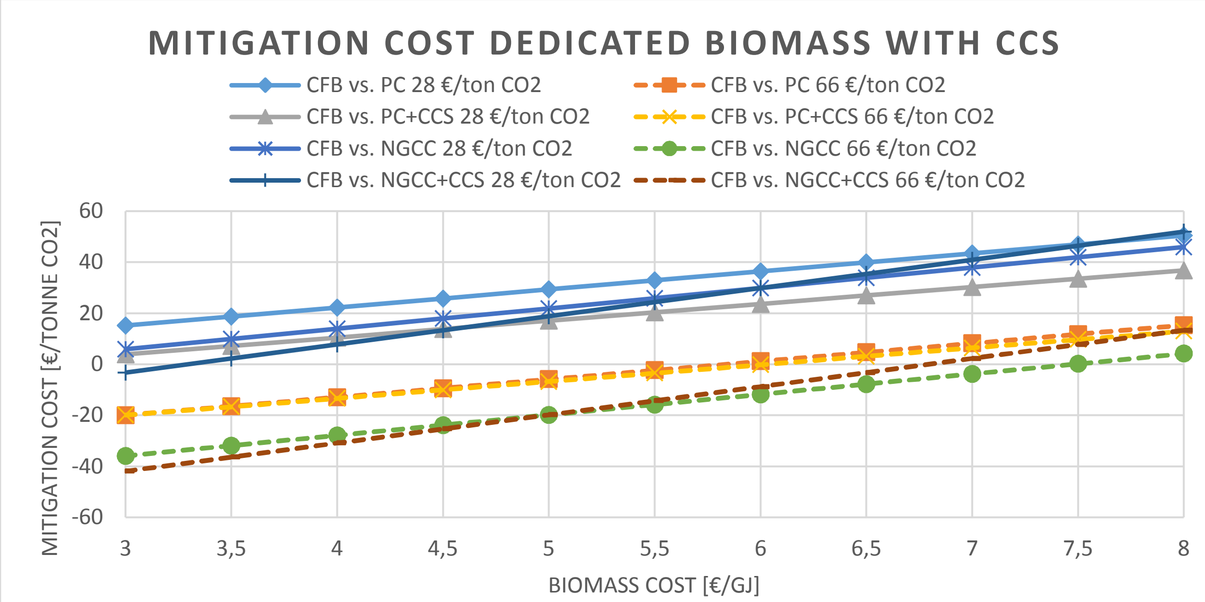


Figure 17: Mitigation cost under different biomass prices for dedicated biomass combustion

Figure 17 shows the impact of different biomass prices on the mitigation cost. The dashed lines represent the 450 ppm scenario where the CO_2 credit price increases to 66 €$_{2010}$/tonne CO_2. The solid line represent the NPS with a CO_2 credit price of 28 €$_{2010}$/tonne CO2. We can see that the dedicated biomass combustion is the cheaper technology at a biomass price of 3.3 €$_{2010}$/GJ in the NPS scenario. In the 450 scenario, this is the case for biomass prices below 6.8 €$_{2010}$/GJ.

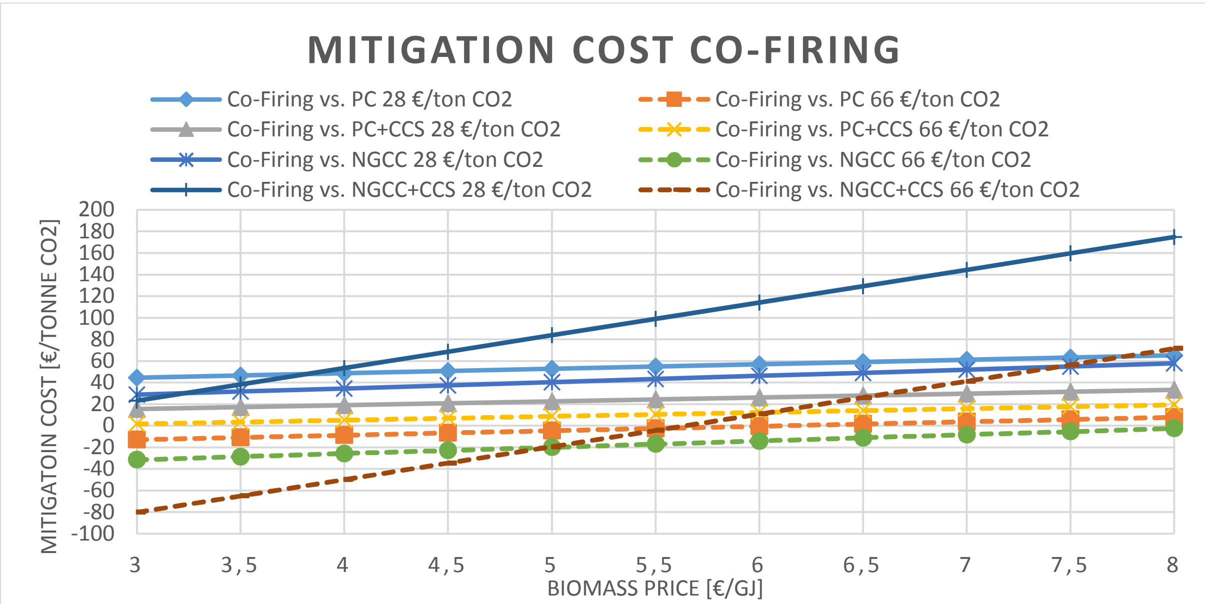


Figure 18: Mitigation cost under different biomass prices for co-firing

Figure 18 shows the impact for the co-firing scenario. In reference to the NGCC with CCS, we see that the mitigation cost increase steeply. With increasing biomass cost, the cost of electricity of co-firing increases. The high caloric value of natural gas in combination with the high efficiency of the NGCC, and the addition of CCS result in low emissions. In the mitigation cost calculation we see that the small difference in emissions and cost of electricity result in high abatement cost. The negative emissions of co-firing are small, since the co-firing plant also emits fossil emission. We also see that PC with CCS is a better option even with the CO_2 credit price of 66 €$_{2010}$/tonne CO_2, which can be contributed to the slightly higher efficiencies (3%-point).

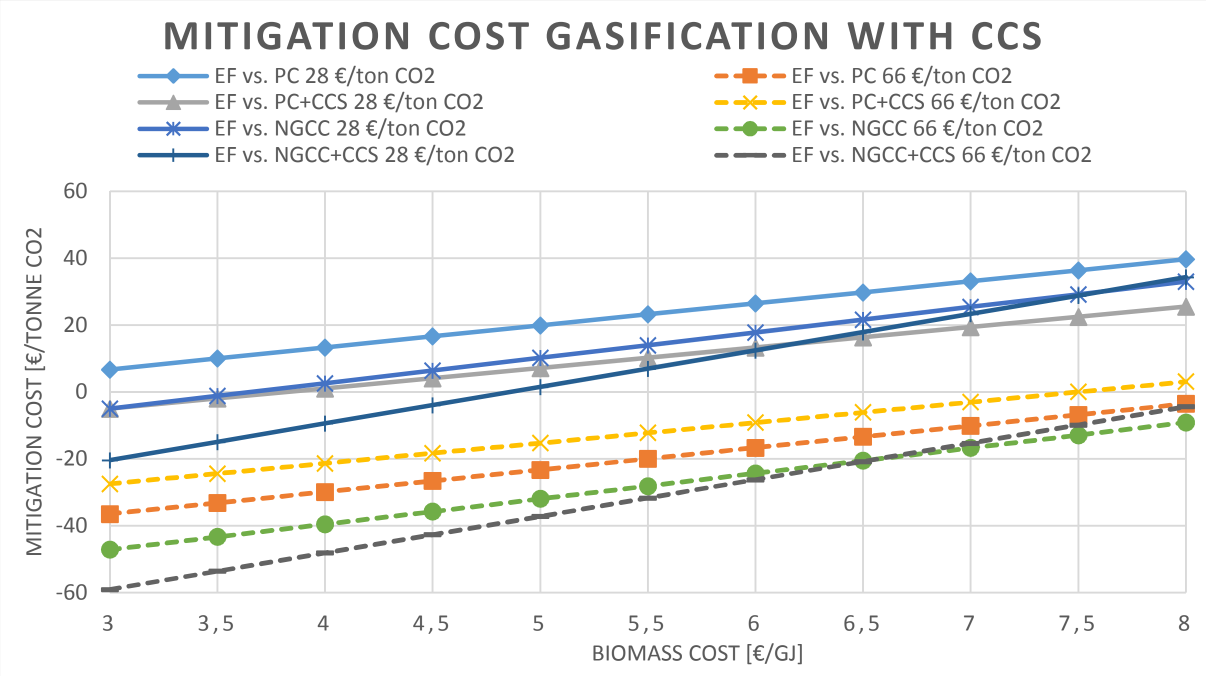


Figure 19: Mitigation cost under different biomass prices for gasification

As can be seen from Figure 19, gasification as a mitigation option in the NP scenario is cheaper than the reference technologies at biomass prices below 4.9 €/GJ. In the 450 ppm scenario we see that gasification has lower mitigation cost than all the reference technologies up to biomass prices of 7.5 €/GJ.

5.2 Results biomass to liquid fuel

Cost of fuel

The crude oil price is expected to increase towards the year 2030 in both the NPS and the 450 ppm scenario. This has a direct effect on the production cost of the traditional fuels, and is shown in Table 8. When looking at Figure 20 we see that due to the increase in crude oil prices under the NPS, conventional fuels are no longer competitive with biofuels. When a carbon credit price is introduced, this gap will increase even further. We therefore can conclude that the biofuel cases are not dependent in the implementation of a CO_2 credit price. The 450 ppm scenario assumes that the demand for crude oil decreases towards 2030, and therefore the price decreases. As can be seen from Figure 20, the difference between biofuels and gasoline and diesel are small. DME has a lower cost of fuel in reference to both diesel and gasoline. FT is cheaper than diesel and gasoline in the NPS. In the 450ppm scenario, we see that gasoline is cheaper than FT up to a CO_2 credit price 5.5 €$_{2010}$/tonne CO_2. At a CO_2 credit price of 78 €$_{2010}$/tonne CO_2, FT becomes cheaper than DME.

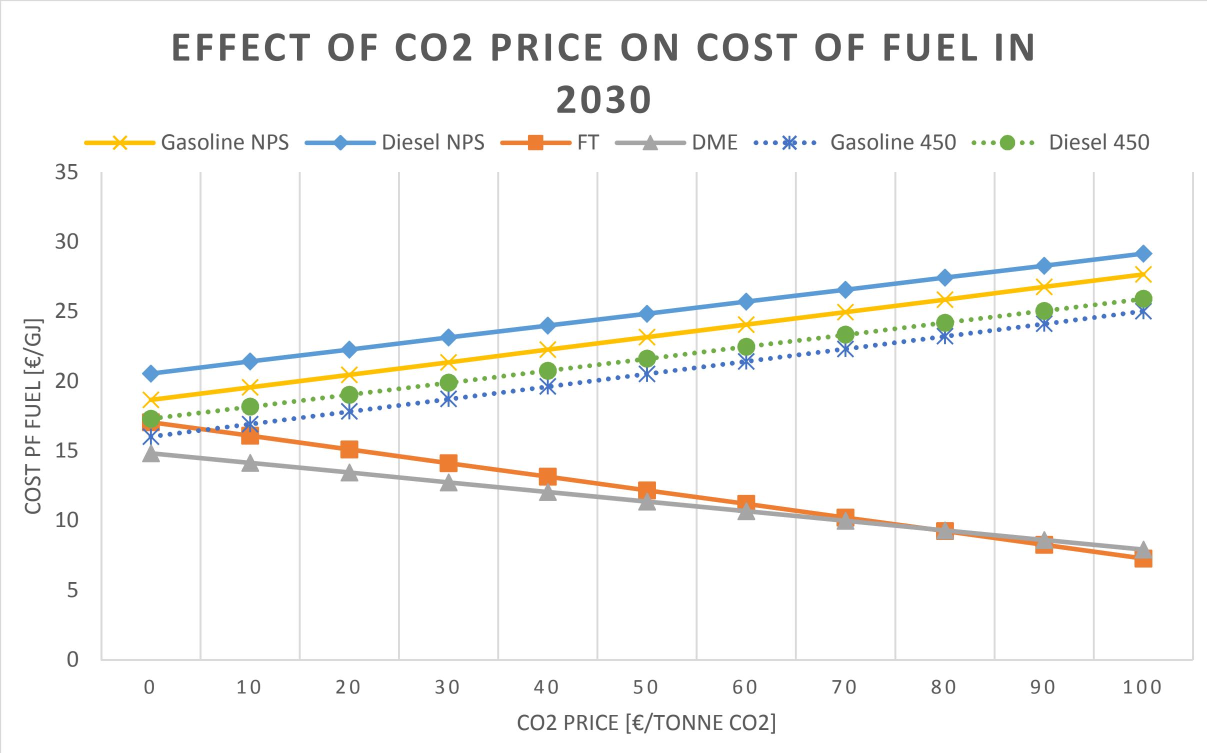


Figure 20: Influence CO2 price on cost of fuel

Figure 21 shows the cost of fuel for Fischer-Tropsch and DME under different biomass prices. The two lines indicate the carbon tax levels set by the policies scenarios. As can be seen, both fuels are close together in terms of their production price. The grey line shows the cost of fuel at 28 €/tonne CO_2 as proposed in the NPS scenario, and the red line presents the 450 scenario with a CO_2 price of 66 €/tonne CO_2.

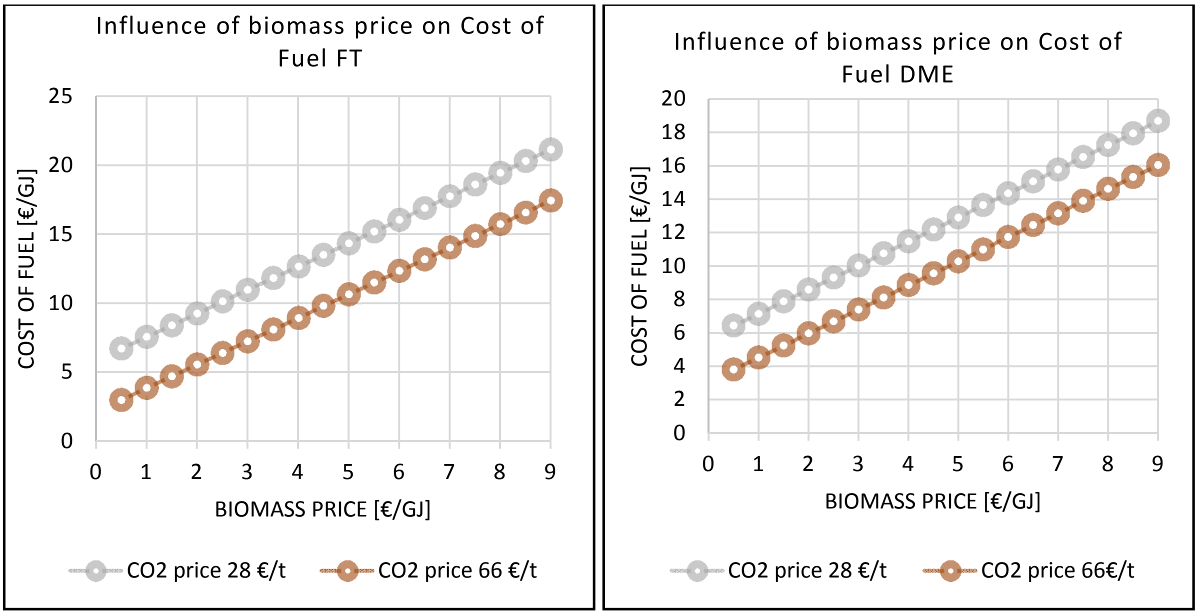


Figure 21: influence of biomass and CO2 price on COF for FT and DME

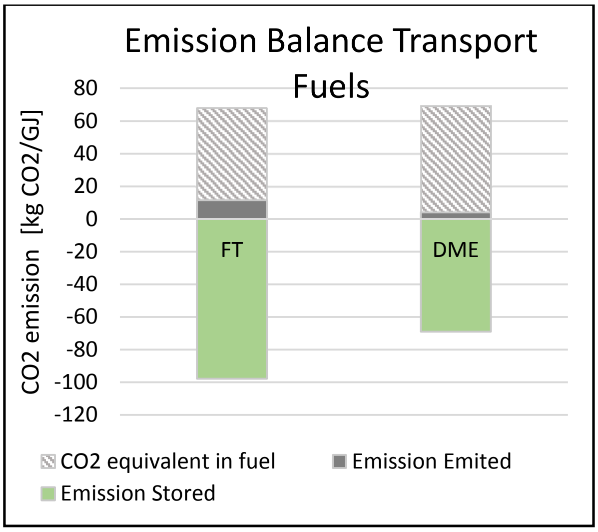


Figure 22: Emission Balance fuels

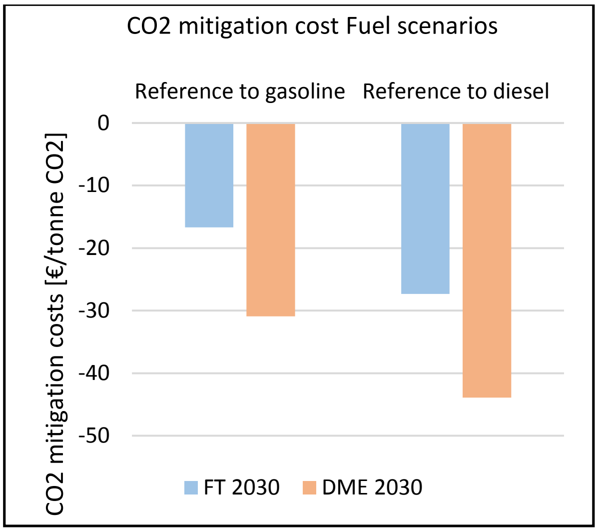


Figure 23: Mitigation cost

Emission balance

Figure 22 shows the emission reduction potential of the fuel technologies. In DME production, 47% of the carbon remains in the fuel. In FT production this share is 33%. The remaining carbon in the fuel is neutral since it is from a biogenic source. FT has a higher capture rate (60%), resulting in a higher emission reduction. The total emission reduction for FT are -98 kg CO_2/GJ and for DME -69 kg CO_2/GJ

Mitigation costs of fuel technologies

Figure 23 shows the mitigation cost of the fuel technologies. As can be seen the mitigation potential for DME is the greatest. This is due to the higher conversion efficiencies of DME, and the lower cost of fuel. Therefore there is less biomass needed, to produce the same output. These mitigation cost are excluding the extra benefits of the introduction of a CO_2 price, since this would decrease the mitigation cost even further.

5.3 Biomass to gaseous fuel

Cost of fuel

The natural gas price is expected to increase towards the year 2030, in the NPS to 8.97 €/GJ and 7.36 €/GJ in the 450 ppm scenario. Figure 24 shows the influence of the CO_2 price on the cost of fuel for SNG. As can be seen SNG is dependent on the introduction of a CO_2 price to be competitive with natural gas. At a CO_2 price of 53.4 €/tonne CO_2 SNG production is cheaper than NG production in the NPS scenario, and a CO_2 price of 68.1 €/tonne CO_2 in the 450 ppm scenario.

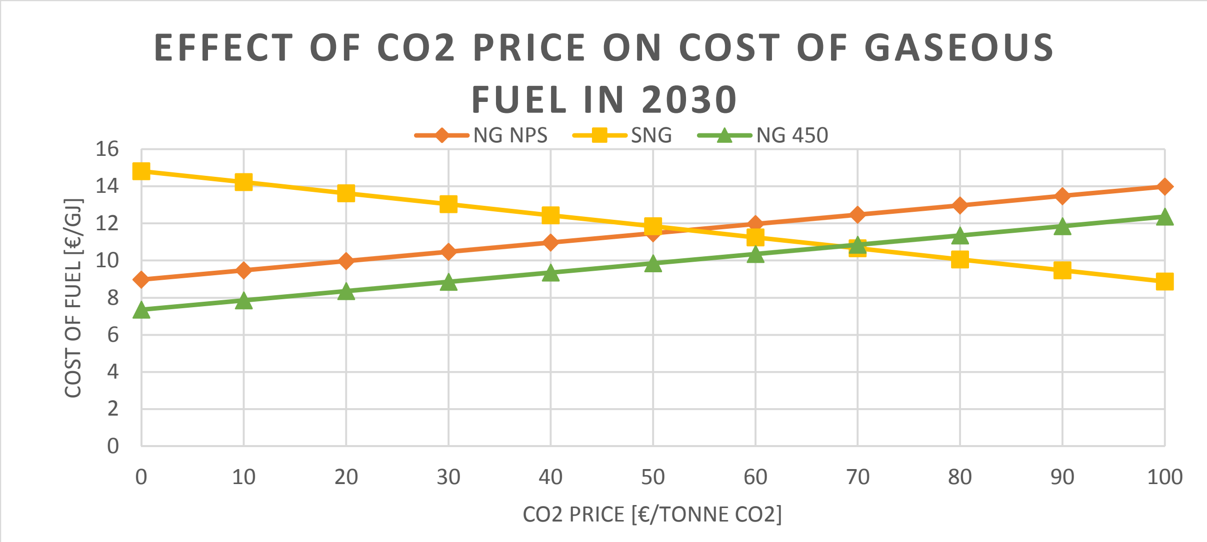
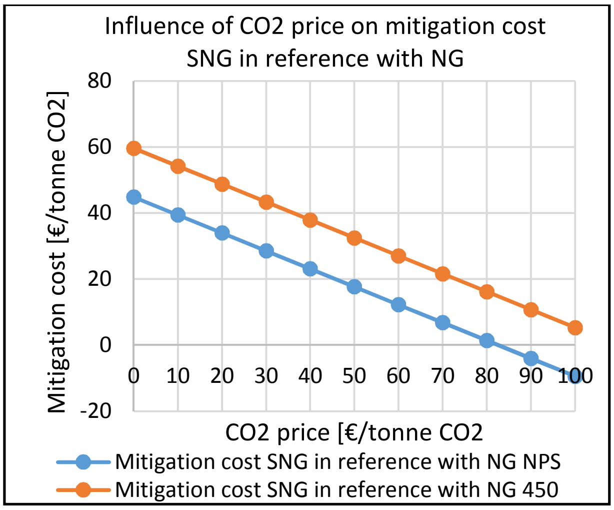


Figure 24: effect of CO2 price on SNG and NG

Mitigation costs SNG

The effect of a change in biomass price is similar as in the FT and DME scenarios. When looking at the mitigation cost SNG in reference with NG, we see that the mitigation cost without the introduction of a CO_2 price are at 53.4 €$_{2010}$/tonne CO_2 for the NPS, and at 68.2 €$_{2010}$/tonne CO_2 for the 450 ppm scenario. SNG becomes the cheaper option at a CO_2 price of 82.6 €$_{2010}$/tonne CO_2 in the NPS and 109.8 €$_{2010}$/tonne CO_2 in the 450 ppm scenario. This means that the CO_2 price of 66 €/tonne CO_2 proposed in the 450 ppm scenario is not sufficient to make SNG competitive with NG.



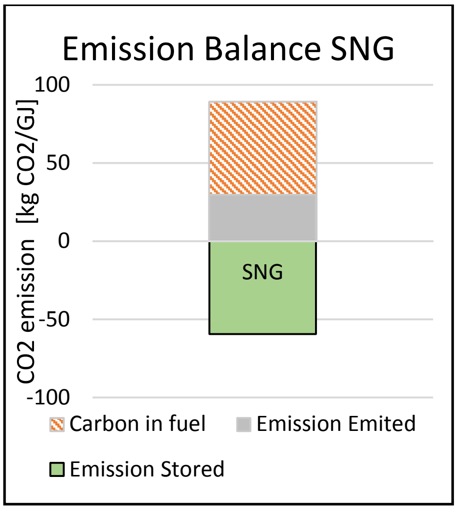


Figure 25: Influence of CO_2 price on the mitigation cost of SNG

Figure 26: emissions balance SNG

Emission balance SNG

Figure 25 shows the emission balance of SNG. 40% of the carbon remains in the fuel, and with an emission of 20%, the reduction is the smallest of the fuel technologies with 40% (Carbo et al., 2010).

6. Sensitivity Analysis

In order to determine the influence of the parameters on the cost of energy, a sensitivity analysis is performed. The parameters that are selected for the sensitivity of the biomass price, investment cost, discount rate, capacity factor and the conversion efficiency. Table 15 shows the variation of the parameters in the sensitivity analysis. Revenue and costs for emissions are excluded from the sensitivity since their influence is shown in the results.

Table 16: Variation in parameters in the sensitivity analysis

Biomass price	50%	100%	200%	Investment cost	70%	100%	150%
Biomass price [€/GJ]	2.5	5	10				
CFB+CCS	37.48	44.92	59.79		41.55	44.92	50.53
Co-firing+CCS	31.64	33.46	37.11		30.65	33.46	38.16
EF+CCS	31.18	37.50	50.13		34.78	37.50	42.03
FT+CCS	12.83	17.06	25.51		15.52	17.06	19.62
DME+CCS	11.23	14.82	21.99		13.39	14.82	17.20
SNG+CCS	10.03	13.88	21.59		12.74	13.88	15.79
Discount rate	**50%**	**100%**	**150%**	**Capacity factor**	**80%**	**100%**	**110%**
Discount rate [%]	5%	10%	15%	[1]			
CFB+CCS	40.58	44.92	49.80		48.29	44.92	42.16
Co-firing+CCS	29.83	33.46	37.55		35.95	33.46	31.43
EF+CCS	33.99	37.50	41.45		43.78	37.50	35.22
FT+CCS	15.07	17.06	19.29		18.78	17.06	15.77
DME+CCS	12.98	14.82	16.90		16.35	14.82	13.69
SNG+CCS	12.41	13.88	15.54		15.32	13.88	12.81
Conversion efficiency	**80%**	**100%**	**110%**	**O&M**	**60%**	**100%**	**140%**
				O&M [% of investment]	2.4%	4%	5.6%
CFB+CCS	48.64	44.92	42.44		43.22	44.92	46.61
Co-firing+CCS	35.83	33.46	32.60		32.05	33.46	34.88
EF+CCS	40.66	37.50	36.35		36.13	37.50	38.86
FT+CCS	19.17	17.06	16.29		16.28	17.06	17.83
DME+CCS	16.61	14.82	14.17		14.10	14.82	15.54
SNG+CCS	15.81	13.88	13.18		13.31	13.88	14.46
CO_2 storage cost	**60%**	**100%**	**140%**	**CO_2 transport cost**	**60%**	**100%**	**140%**
Storage cost [€/tonne CO_2]	3.72	6.2	8.68	Transport cost [€/tonne CO_2]	5.7	9.5	13.3
CFB+CCS	40.92	44.92	48.91		39.69	44.92	50.14
Co-firing+CCS	31.72	33.46	35.21		30.79	33.46	36.14
EF+CCS	35.54	37.50	39.46		34.50	37.50	40.50
FT+CCS	16.81	17.06	17.30		16.68	17.06	17.43
DME+CCS	14.65	14.82	14.99		14.56	14.82	15.08
SNG+CCS	13.73	13.88	14.03		13.66	13.88	14.11
Coal cost	**50%**	**100%**	**200%**				
Coal cost [€/GJ]	1.71	3.42	6.84				
Co-firing+CCS	30.54	33.46	39.30				

[1] capacity factor is different for the technologies; for fuel technologies 91% (Hannula & Kurkela, 2013)**, for CFB 90%** (IEA GHG, 2009)**, EF 80%** (H. Meerman, 2012)**, co-firing has the same capacity factor as PC plant: 85%** (Finkenrath, 2011)**.**

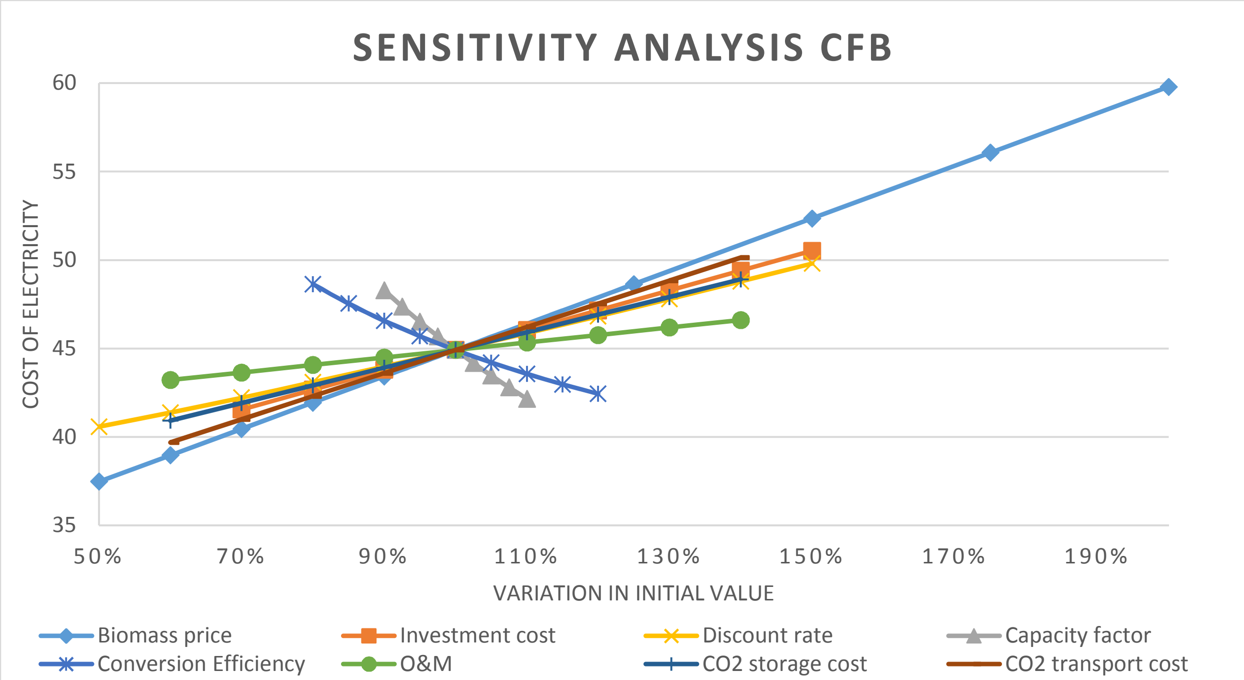


Figure 27: sensitivity analysis CFB

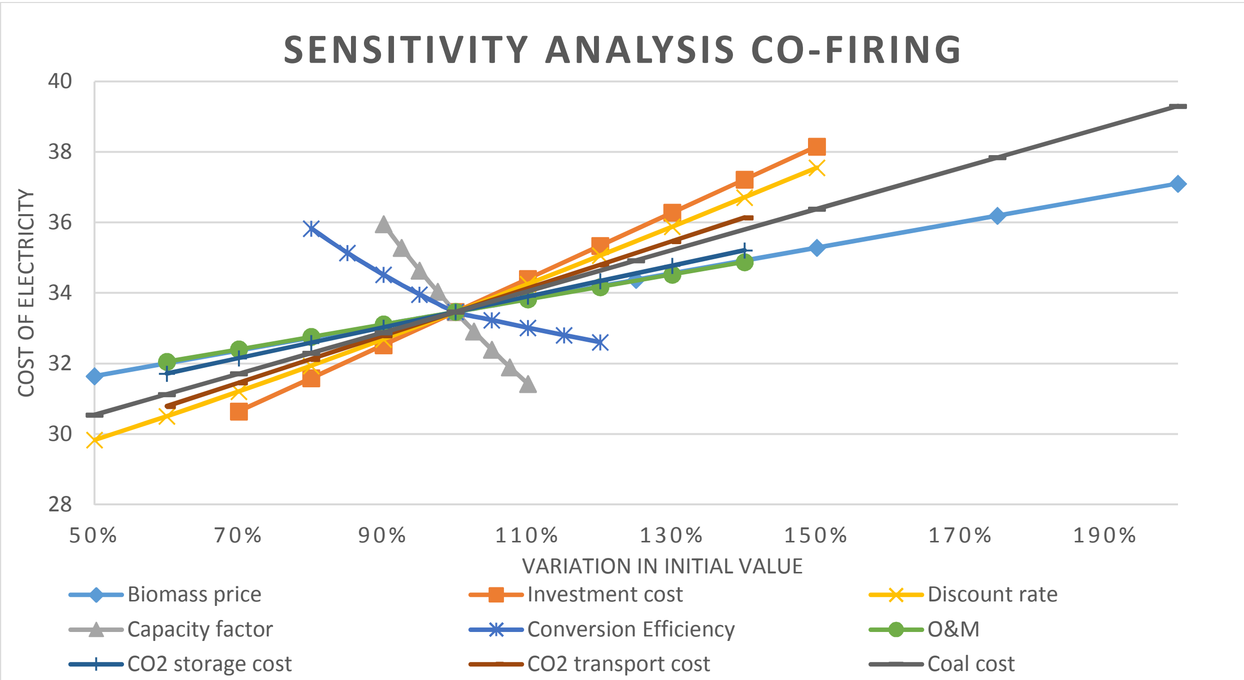


Figure 28: Sensitivity analysis Co-firing

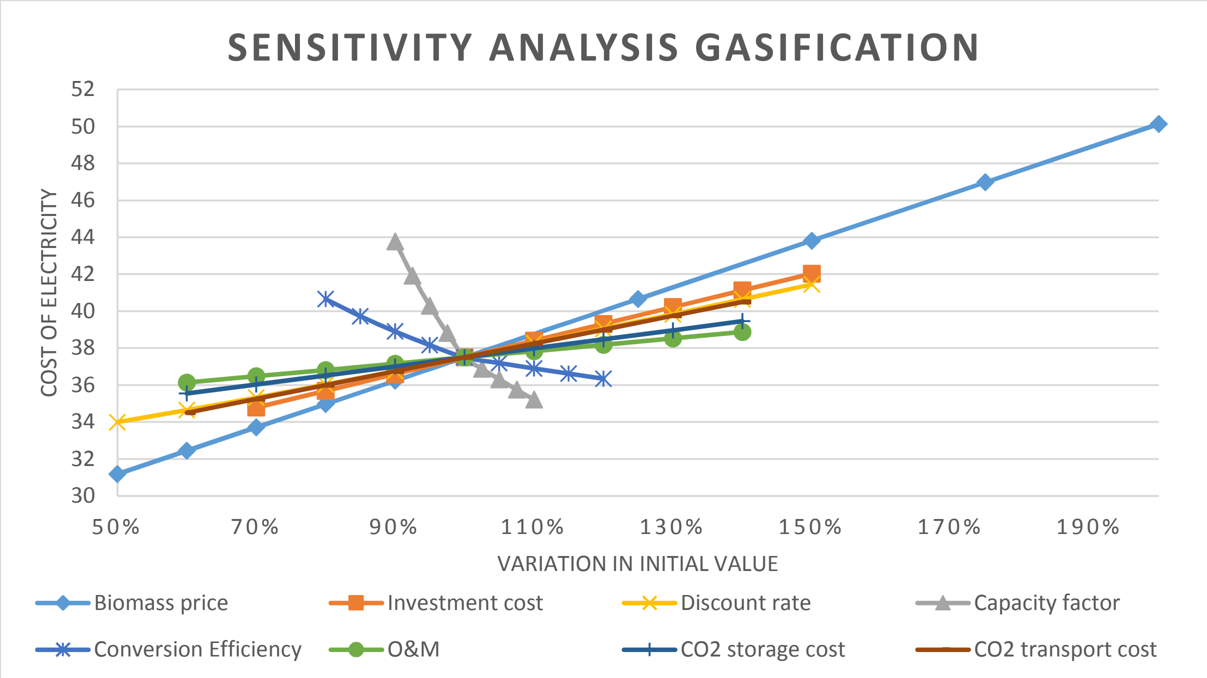


Figure 29: Sensitivity analysis gasification

The most important parameters in the gasification and dedicated biomass scenarios are the feedstock price. Feedstock prices are uncertain towards the year 2030. It is expected that a transition will take place from fossil powered energy towards more sustainable technologies such as BECCS. This transition will have its effect on the feedstock prices. For the analysis a biomass price of 5 €$_{2010}$/GJ is used. However, higher feedstock demand will increase the feedstock prices. Both the investment cost as the feedstock cost account for the biggest share in the cost of electricity and as can be seen, both have a significant influence on the cost of electricity in both cases. We also see that improvements in the capacity factor of the biomass to electricity technologies, would reduce the cost of electricity in all cases. A variation in the O&M costs has the least effect on the cost of electricity. The CO_2 transport and storage costs, have the largest influence for dedicated combustion (in reference to co-firing and gasification), because it has the highest flue gas flows.

The co-firing case is less sensitive for variations in biomass price, due to the small part of biomass being co-fired. As can be seen in Figure 28, the capital cost and coal cost have greater influence on the cost of electricity.

In the fuel scenarios we see similar values as in the biomass to power technologies. Again the biomass price, investment cost and capacity factor are of influence on cost of fuel.

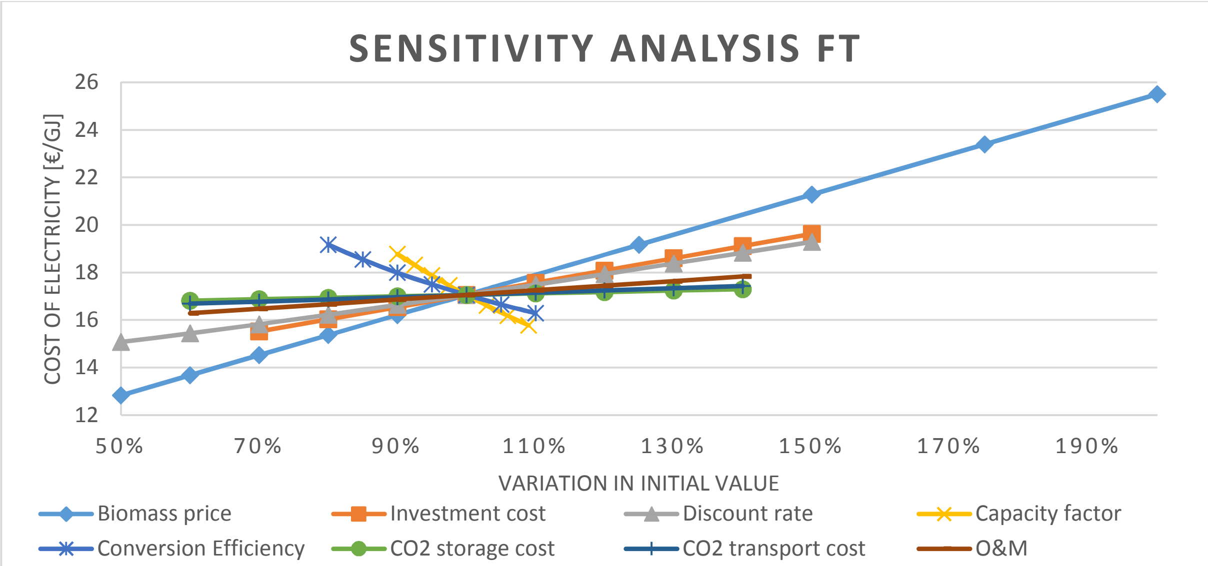


Figure 30: Sensitivity analysis FT

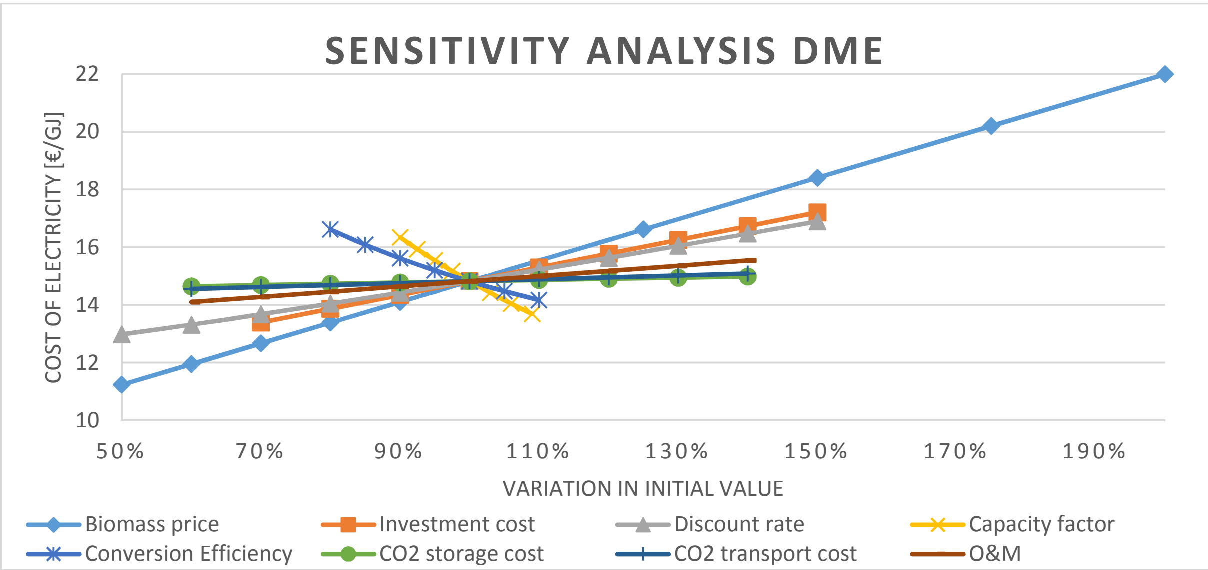


Figure 31: Sensitivity analysis DME

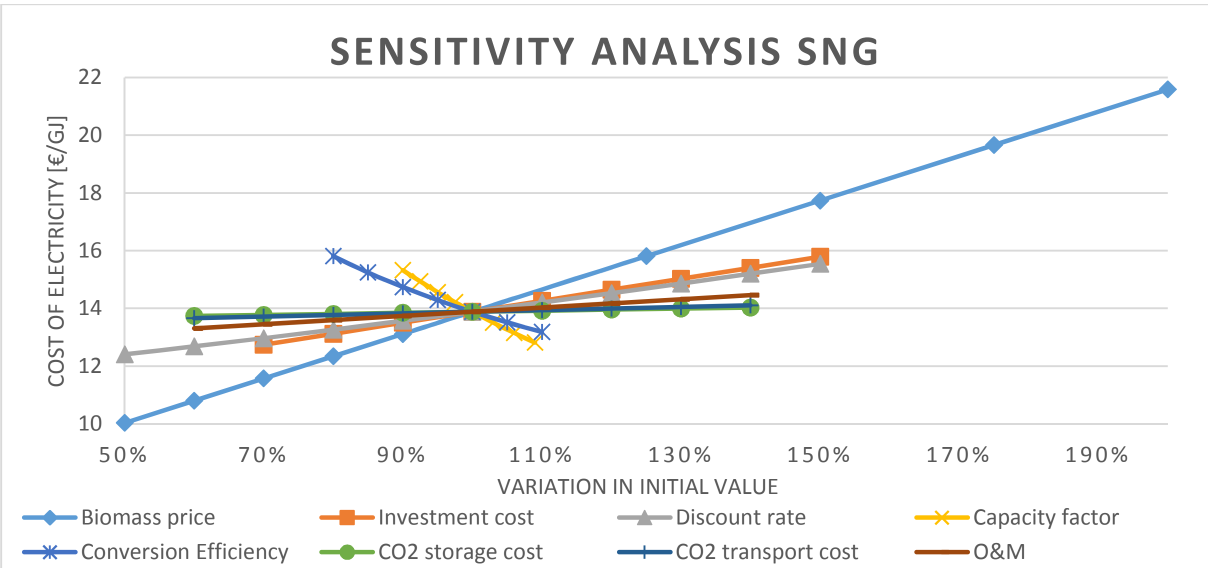


Figure 32: Sensitivity analysis SNG

7. Discussion

The capital cost of all the cases are based on a literature review. We see that in some scenarios such as DME and SNG specific data are hard to find for 2030. These technologies are not broadly applied yet or applied in other fields. For instance DME is applied in the paper sector to produce DME from black liquor, and not yet in a dedicated biomass installation. In all cases, the 2010 investment costs are used as a benchmark for the 2030 data. With some lack of data in the 2030 scenario, an estimation is made based on the 2010 cost data.

In the literature we found that the investment cost for gasification with CCS will be lower in 2030 than the investment cost of dedicated biomass combustion with CCS. This contributes to the result of gasification being the best option. Koornneef also state higher cost for dedicated combustion than for gasification (Koornneef et al., 2011).

The research focusses on a small range of technologies, where more options are available. An option would be to research other technologies that are now ruled out by the criteria set in the methodology such as ethanol production from lignocellulosic biomass.

Furthermore the O&M costs of all technologies are now calculated as a percentage of the investment cost. Other sources, such as the IEA GHG and the dissertation of Meerman also apply this method, which is not the most accurate one (IEA GHG, 2009; H. Meerman, 2012). Improvement could be the implementation of variable O&M costs. However, the uncertainty analysis has shown us that the O&M costs have the least influence on the cost of electricity.

This research focusses on the year 2030, and does not incorporate the time in between. An interesting addition would be the years in between, or after 2030. The IPCC expects that the cost of some key bioenergy technologies such as lignocellulosic syngas-based biofuels will decrease in the near term due to R&D and market support, which could allow their commercialization around 2020 (IPCC, 2012).

As shown in the results the biomass price has a large impact on the cost of energy. This thesis used energy crops as willow that is produced in northwestern Europe. The willow is torrified and pelletized to improve the heating value and reduce the moisture content. Other pre-treatment processes and feedstock are possible. Pre-treatment technologies such as direct pelletization show lower improvement in heating value and have higher moisture content (J. C. Meerman, Ramírez, Turkenburg, & Faaij, 2012). Feedstock such as miscanthus or poplar are also an option, but are less suitable to grow in the northwestern part of Europe (RENEW, 2008).

The CCS transport and storage cost are now incorporated as a fixed price per MWh or GJ. This of course is site specific and dependent on the location of the reservoir. This research assumes that the storage location is off shore in depleted oil and gas fields, where other reservoir types are also possible. The sensitivity analysis has shown us that the CO_2 storage and transport costs account for 33% of the total cost of electricity in the dedicated biomass combustion case which has the highest flue gas flows.

When comparing the results with the research by Koornneef et al. we see that the conclusion is the same: high CO_2 prices and low biomass prices are the most important drivers for the competitiveness of BECCS technologies. Furthermore without the financial compensation of negative emissions, BECCS technologies are uncompetitive. Koornneef concluded that for 2030, BIGCC has the lowest cost of electricity, which corresponds to our findings. Koornneef state that CO_2 prices of 50 €/tonne CO_2 and above are necessary to provide enough economic potential for BECCS technologies. Our results show that gasification has lower cost of electricity at a CO_2 credit price of 44.3 $€_{2010}$/tonne CO_2. The difference can be contributed to the lower cost of biomass we used in the analysis of the lowest cost of electricity. This thesis used a biomass price of 5 $€_{2010}$/GJ, where Koornneef et al. used a biomass price of 5.2 $€_{2010}$/GJ. Also the investment cost used in this thesis are lower. Koornneef state the capital costs of a BIGCC with CCS at 3039 $€_{2010}$/kWe, this thesis used the capital cost data from Meerman which states a capital cost of 2154 $€_{2010}$/kWe. We used the capital costs from Meerman, because it uses the EF gasifier design, where Koornneef et al. used the CFB gasifier.

When comparing the results with van Vliet et al., we see similar emission reduction for FT production form TOPS in an EF gasifier (van Vliet et al., 2009). Van Vliet state an emissions reduction of -88 kg/GJ were we found an emission reduction of -97 kg/GJ. The difference can be contributed to different assumptions in the carbon content of the biomass.

The Research by Hannula & Kurkela, show the cost of fuel for DME and FT in the present time. The cost of fuel for FT is around 69.9 $€_{2010}$/MWh, and for DME 63.6 $€_{2010}$/MWh. The cost of fuel in this thesis are at 61.5 $€_{2010}$/MWh for FT and 53.5 $€_{2010}$/MWh for DME in 2030. The production cost of the 2010 cases in this thesis are 67 $€_{2010}$/MWh fot FT, and 63.8 $€_{2010}$/MWh for DME. This shows that the calculation method is in line with the method used by Hannula.

8. Conclusion

A techno-economic analysis has been performed to study under which conditions BECCS options become competitive with their fossil fuel equivalent in northwestern Europe. The most important conditions to increase competitiveness of BECCS are the introduction of a CO_2 credit price, low feedstock prices and low investment cost. The introduction of a CO_2 credit price works in two ways: as a punishment for the polluter and as a reward for plants that store biogenic emissions. The second condition are low biomass prices. In the analysis a biomass price of 5 €$_{2010}$/GJ including pre-treatment cost is assumed. The results and sensitivity analysis show that the cost of energy and therefore the mitigation cost are heavily dependent on a low biomass cost.

In the biomass to power cases, we see that under the assumption of a biomass price of 5 €$_{2010}$/GJ, gasification with CCS is the most promising technology. Gasification is competitive with PC without CCS at a CO_2 credit price of 44.3 €$_{2010}$/tonne CO_2, and with PC with CCS at a price of 39.6 €$_{2010}$/tonne CO_2. This shows that the introduction of a CO_2 price at 28 €$_{2010}$/tonne CO_2 as proposed in the new policies scenario, is too low to make BECCS competitive with fossil fueled technologies. The CO_2 credit price set in the 450 ppm scenario which has the goal to limit the global increase in average temperature to 2 degrees Celsius, would be sufficient for BECCS technologies to compete with fossil fueled technologies in 2030. An important finding is that when the stored biogenic emissions do not generate extra revenue in the form of sellable CO_2 credits, the cost of energy remains the same. Meaning that the BECCS technologies will not become cheaper than the fossil fueled technologies. Which means that the BECCS technologies are fully dependent on the introduction of sellable CO_2 credits for stored biogenic emissions.

The results show that the benefits of the sellable CO_2 credits for stored biogenic emissions can outweigh the cost of biomass in the cost of electricity calculation. In this case we see that the dedicated biomass combustion becomes cheaper than gasification while having a lower conversion efficiency and higher investment costs. This occurs at CO_2 credit prices above 70 €$_{2010}$/tonne CO_2, and biomass prices below 6 €$_{2010}$/GJ. This result is not favorable because it promotes high biomass use to create high emission flows, instead of reducing emissions.

For co-firing we see that prices of around 60 €$_{2010}$/tonne CO_2 are needed to compete with the current technologies, and prices of 93 €$_{2010}$/tonne CO_2 in order to compete with PC with CCS. This would mean that dedicated biomass technologies as gasification and combustion are better options than co-firing in 2030. However until a CO_2 price is introduced of 18 €/tonne CO_2, co-firing is a cheaper option and therefore a good short-term possibility considering investment cost and TRL.

The CO_2 mitigation costs calculation also show that gasification is the best option to mitigate CO_2 emissions. The mitigation costs are the highest for PC, due to low cost of electricity for PC and high emissions.

The emission balance shows that the largest CO_2 reduction can be achieved with dedicated biomass combustion. This gives a distorted image of the abilities of BECCS. The dedicated biomass option, has a lower efficiency than gasification, which means higher amounts of CO_2

per kWh are produced. The goal of BECCS technologies is to reduce emissions, therefore lower emission flows with CCS are a better option than high emissions flows with CCS. The emission reduction of co-firing is very small in reference to gasification and combustion, this is due to the fact that only 30% of the stored emissions are biogenic, and can be accounted as negative. Co-firing also emits fossil emissions, which are subtracted of the stored biogenic emissions. The total negative emissions for dedicated biomass combustion with CCS are -929 kg CO_2/MWh, for gasification with CCS -789 kg CO_2/MWh and for co-firing with CCS -175 kg CO_2/MWh.

In biomass to fuel scenarios we see that these are less dependent on the introduction of a CO_2 price. Even without the a CO_2 price, the cost of fuel for diesel and gasoline is higher than the cost for Fischer-Tropsch diesel and DME in the New Policy Scenario. When looking at the fuel prices of the 450 ppm scenario, a CO_2 price of 5.5 €$_{2010}$/tonne CO_2 would make both technologies cheaper than the production of diesel and gasoline. However, SNG is dependent on a CO_2 price of 53.4 €$_{2010}$/tonne CO_2 with a natural gas price of 9 €/GJ which is expected in the new policy scenario, and 68.2 €$_{2010}$/tonne CO_2 with a natural gas price of 7.4 €$_{2010}$/GJ as is expected in the 450 ppm scenario.

The emission balance of the fuel cases show emission reductions of -97 kg CO_2/GJ for Fischer-Tropsch diesel, -69 kg CO_2/GJ for DME production, and -59 kg CO_2/GJ for SNG production.

DME shows the highest potential for the fuel technologies. With lower production costs, and slightly lower emission reduction, mitigation costs are the lowest in reference to conventional diesel and gasoline.

We can conclude that BECCS technologies are highly dependent on low biomass prices, and compensation of negative biogenic emission by means of the introduction of sellable CO_2 credits of at least 44 €$_{2010}$/tonne CO_2 in the electricity sector, and 68 €$_{2010}$/tonne CO_2 in the gaseous fuel sector. The liquid fuel sector is not dependent on introduction of sellable CO_2 credits.

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Annex I: overview of BECCS conversion technologies

Type	Process	Technology (source: Baskar)	Feedstock (source: Koornneef)	process/ output	Capture Technology	Sources
Thermochemical	Combustion	Fixed bed combustion	Coal, Woody biomass (wood chips, wood pellets, sawdust, bark from forestry operations and processing) Agricultural residues (straw, sugar bagasse, palm kernel shells) Energy crops (short rotation coppice or forestry (willow, poplar, eucalyptus), miscanthus, switchgrass) Waste related streams (RDF, municipal waste, and demolition wood)	electricity	**Post combustion**, Oxyfuel	(Baskar et al., 2012; van Loo & Koppejan, 2008)
		Fluidized bed combustion		electricity	**Post combustion**, Oxyfuel	(Baskar et al., 2012; IEA GHG, 2009; Koornneef et al., 2011; van Loo & Koppejan, 2008)
	Pyrolysis	Slow pyrolysis		high % of C in the char	Mostly used as a pre-treatment step for other processes. Most carbon remains in the char/ pyrolysis oil. Pre-combustion seems possible in some options with the produced syngas	(Baskar et al., 2012; Bauen et al., 2009)
		Torrefaction		followed by entrained flow gasifier		
		Carbonization				
		Fast pyrolysis		(followed by indirect gasifier)		
		Flash pyrolysis				
		Utra-rapid pyrolysis				
		Hydrouspyrlysis (liquefaction)				
		Hydropyrolysis (H2)				
		vacuumpyrolysis				
	Gasification	Fixed bed gasifier	Coal, Woody biomass (wood chips, wood pellets, sawdust, bark from forestry operations and processing) Agricultural residues (straw, sugar bagasse, palm kernel shells) Energy crops (short rotation coppice or forestry (willow, poplar, eucalyptus), miscanthus, switchgrass) Waste streams (RDF36, municipal waste, and demolition wood)		Pre combustion	(Baskar et al., 2012; E4Tech, 2009; Koornneef et al., 2011; van Vliet et al., 2009)
		Updraft gasifier			Pre combustion	
		Fluidized bed gasifier		FT, DME, BioSNG, electricity	Pre combustion, post combustion	
		Bubbling fluidized bed gasifier		FT, DME, SNG, electricity	Pre combustion	
		Entrained flow gasifier		FT, DME, electricity	Pre combustion, post combustion	
		Top-feed entrained flow gasifier			Pre combustion	
		Direct-gasifier			Pre combustion	
		Indirect gasifier		BioSNG, electricity	Pre combustion	

		Char indirect gasifier			Pre combustion	
		gas indirect gasifier			Pre combustion	
		Multistage gasifier (Entrained Flow)		FT	Pre combustion	
Biochemical	Aerobic fermentation			biogas	CO2 seperation or post combustion	(Carbo, 2011)
	Anaerobic digestion	Continuous stirred tank reactor	livestock manure, food processing wastes (fruit and vegetable waste), municipal solid wastes, crop residues (corn stover and wheat straw) and energy crops (sugar beet and grass silage)			
		Mixed plug flow loop reactor				
		Anaerobic filter reactor				
		Upflow anaerobic sludge blanket reactor		Methane + CO2	Pre combustion	(Baskar et al., 2012; Zhang & Zhang, 1999)
		Anaerobic baffled reactor				
		Expanded granular sludge blanket reactor				
		Internal circulation reactor				
		Anaerobic sequencing batch reactor		Methane + CO2	Pre combustion	(Baskar et al., 2012; Zhang & Zhang, 1999)
		Covered lagoon digester				
		Dry anaerobic digestion technology				
		Two-stage digester				
		Temperature-phased anaerobic digester				
	Alcoholic fermentation	**Ethanol fermentation**	Starch and sugars (e.g. cereal crops, maize, sugarcane, sugar beet, potato, sorghum, cassava, wheat) Ligno-cellulosic (e.g. straw, wood pellets, bagasse)	ethanol	CO2 seperation or post combustion	(Baskar et al., 2012; Bauen et al., 2009; Carbo, 2011; Koornneef et al., 2011)

	pre-treatment
	Most applied
	not compatible with chosen feedstock
	decentralized scale

Fischer-Tropsch and BioSNG (Bauen et al., 2009; Carbo, 2011; van Vliet et al., 2009)

Type	Reacto design	Gasifier type	Treatment after gasification	Gas conditioning	Product upgrading
Fischer-Tropsch	**fixed bed reactor**	Entrained flow or circulating fluidised bed	tar cracking and conventional wet gas cleaning; tar scrubbing and conventional wet gas cleaning; Tar cracking and dry gas cleaning	Water Gas Shift reaction to alter H2/CO ratio and CO2 removal	FT poduct upgraiding by: hydrotreating and hydrocracking unit, Heavy paraffin converter
	fluidised bed reactor				
	slurry phase reactor				
BioSNG	-	oxygen-blown pressurised Entrained Flow (EF), oxygen-blown pressurised fluid- ised bed (BFB or CFB), steam/air-blown **indirect gasification at atmospheric pressure (two reactors 1st pyrolysis 2nd FB combustion)**	oil-based scrubbing	natural gas sweetening technologies (removal of sulfer and CO2) most used is amine process	-
BioDME	-	Entrained flow or circulating fluidised bed	tar cracking and conventional wet gas cleaning; tar scrubbing and conventional wet gas cleaning; Tar cracking and dry gas cleaning	Water Gas Shift reaction to alter H2/CO ratio and CO2 removal	

Annex II: Technology Readiness Level scale

TRL	Description
1	Basic principles observed and reported
2	Technology concept and/or application formulated
3	Analytical and experimental critical function and/or characteristic proof of concept
4	Component and/or system validation in laboratory environment
5	Laboratory scale, similar system validation in relevant environment
6	Engineering/pi lot-scale, similar (prototypical) system validation in relevant environment
7	Full-scale, similar (prototypical) system demonstrated in relevant environment
8	Actual system completed and qualified through test and demonstration
9	Actual system operated over the full range of expected mission conditions

Table 17: TRL (U.S. Department of Energy, 2011)