



IEAGHG Technical Report
2021-01
March 2021

Biorefineries with CCS

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ACKNOWLEDGEMENTS AND CITATIONS

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The report should be cited in literature as follows: 'IEAGHG, "Biorefineries with CCS", 2021-01, March 2021.'

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BIOREFINERIES WITH CARBON CAPTURE AND STORAGE (CCS)

The aim of this study is to provide a techno-economic assessment of biorefinery concepts with and without carbon capture and storage (CCS) as well as a comparative assessment of 1st generation and 2nd generation biorefineries. The results of this study will be of interest to developers of biorefinery and CCS projects and policy makers.

Key Messages

- The cost of adding CCS on the high-concentration streams of biorefineries varies between 22 and 24 \$/tCO₂. If CCS is extended also to flue gas streams, the cost of CCS varies between 27 and 66 \$/tCO₂. The wider range of cost is explained by differences between biorefineries in the share of CO₂ that needs to be captured from low-concentration streams.
- The lowest cost of CCS is achieved with gasification-based configurations using base case CCS design (22 \$/tCO₂) followed closely by ethanol plants with base case CCS design (24-25 \$/tCO₂).
- Several of the cost estimates are developed for first-of-a-kind commercial plants and contain a lot of uncertainty as they are derived from a small handful of demonstration projects. Cost reductions could be achieved over the coming decades through learning from these technologies at relevant scale.
- Biorefineries with CCS show potential for negative emissions. First generation corn ethanol plants with CCS can only produce carbon negative fuels if natural gas inputs are switched to a low-carbon energy source. For second generation biorefineries with CCS, based on woody biomass, emissions range between -59 gCO_{2eq}/MJ and -164 gCO_{2eq}/MJ. The deepest emissions reductions in comparison to the fossil reference are associated with second generation wheat straw plants with CCS, which can achieve -274 gCO_{2eq}/MJ in the maximum capture configuration.
- Biorefineries with CCS seem very attractive, especially for decarbonising the hard-to-abate transport sector. On the other hand, the cost of biofuel is currently too high to compete with petroleum fuels and out of the examined configurations only two have currently been demonstrated at commercial scale.
- Recommendations for further work include:
 - Implementation of large-scale demonstration projects in order to reduce risk and increase investor confidence.
 - More data should be made available from projects in order to refine the techno-economic assessment of biorefineries with CCS and reduce uncertainties.

Background to the Study

Negative emissions technologies (NETs) feature in many climate models that comply with 2°C scenarios; and efforts to aim towards a 1.5°C target, as outlined in the Paris Accord, have drawn further attention to the need for options that reduce the overall stock of emissions in the atmosphere. Negative emissions are also an important tool for offsetting residual emissions from the hard-to-abate sectors like aviation, cement and steel industry, as well as agriculture to achieve overall carbon-neutrality.

A range of plausible NETs have been proposed, and some of them are currently more developed than others, in terms of both technological maturity and the amount of CO₂ removal that could potentially be offered. As NETs are growing in prominence in energy planning, better understanding is needed of the many trade-offs that achieving negative emissions have on cost, emissions and the required resources.

Bioenergy with Carbon Capture and Storage (BECCS or Bio-CCS) is a NET that receives most attention in integrated assessment model studies and in the latest IPCC reports. A key difference between BECCS and fossil-based CCS technologies is that when CO₂ produced as a by-product from biomass processing is captured and securely stored in geological formations, the generated energy could be characterised by negative net greenhouse gas (GHG) emissions, because of the storage of biogenic CO₂. However, the overall climate change mitigation potential of BECCS depends on a number of factors (land use aspects, biomass procurement, performance of processing, share of CO₂ capture, transportation of CO₂ and the permanence of storage).

A closely related concept to BECCS is so-called Bioenergy with Carbon Capture and Utilisation (BECCU). Here CO₂ produced as a by-product from biomass processing is captured, but instead of permanent storage, the CO₂ is used as a feedstock in a way that produces value for the plant operator. In most of these CCU applications, the CO₂ is released into the atmosphere fairly quickly after its utilisation, and therefore its climate change mitigation potential can be significantly lower than that of CCS. However, possible displacement of fossil fuels and carbon intensity of the energy used to run the CCU process can also play a decisive role in the overall climate impact. CCS technologies have been used industrially over several decades for example in oil refining, and they can be considered relatively mature.

Currently, the only large-scale BECCS process is the Illinois Industrial CCS facility that captures annually up to 1 Mt of CO₂ from the fermentation process of a Decatur corn ethanol plant and injects it into a geological storage beneath the facility. The remaining four BECCS facilities operating today are small-scale ethanol production plants that use most of the captured CO₂ for enhanced oil recovery (EOR).

Modern bioenergy plays an essential role in the International Energy Agency (IEA) 2°C Scenario (2DS) providing nearly 17% of final energy demand in 2060 compared to 4.5% in 2015. Bioenergy is important especially in sectors for which other decarbonisation options are not available.

Technologies for producing so called “first generation” crop-based biofuels like ethanol from sugar and starch-based feedstocks, and FAME (fatty acid methyl ester) biodiesel from vegetable oils and other lipid feedstocks (including wastes and by-products) are well-established, and provide most of today’s transport biofuels.

In recent years, technology to produce HVO (hydrotreated vegetable oil), also known as *renewable diesel* (including advanced biodiesel, naphtha and aviation fuels), has been successfully commercialised. About 5 Mt/yr of HVO was produced globally in 2017 and production is expected to increase to 6-7 Mt/yr by 2020 and continue to increase thereafter. HVO production is increasingly based on waste and residue oil and animal fat feedstocks rather than oil crops. HVO has advantageous

fuel characteristics compared to FAME, and can be used to produce so-called *drop-in fuels*, i.e. fuels that can be used unblended in the existing vehicle fleet or distribution infrastructure.

The longer-term growth of transport biofuels in the IEA’s 2DS relies on the widespread supply of novel *advanced biofuels* produced by processes that are generally not yet mature. Advanced biofuels are sustainable fuels produced from non-food crop feedstocks that are capable of delivering significant life-cycle GHG emissions savings without competing with food and feed crops for agricultural land use. Advanced biofuels can also be called “second generation” (2G) biofuels, to differentiate them from first generation crop-based biofuels.

The development and commercialisation of advanced biofuel technologies has been slow, however, and most commercial-scale projects are currently on hold due to the high investment cost of pioneer process plants combined with the lack of funding instruments that share the risk of scale-up.

The sustainable conversion of biomass feedstocks to biomass-derived fuels and chemicals are often referred to as “biorefining”. In addition to biofuel, such “biorefineries” typically produce also by-products and CO₂ (see Figure 1). The CO₂ from biomass processing is normally vented to atmosphere, but if it were captured and securely sequestered in geological formations, the produced biofuel could be characterised by net negative GHG emissions because of the storage of biogenic CO₂.

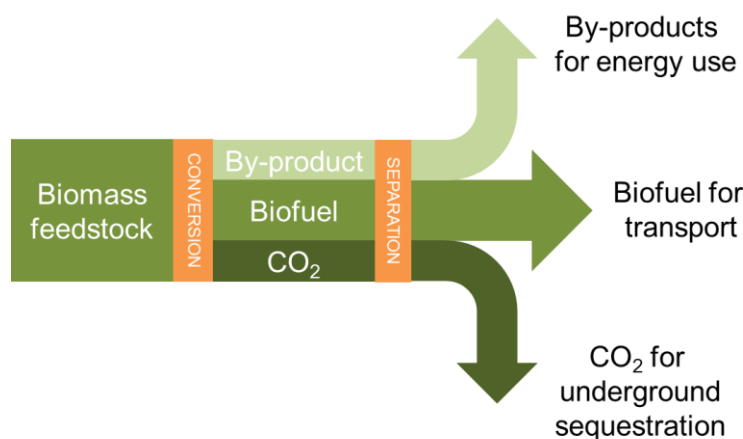


Figure 1: Conceptual representation of a biorefinery coupled with CCS.

Scope of Work

IEAGHG commissioned VTT Technical Research Centre of Finland to carry out a techno-economic assessment of different biorefinery concepts with and without CCS.

The scope of work comprises the following tasks:

1. A techno-economic assessment of 2nd generation biorefineries with and without CCS for a select number of different feedstocks;
2. An estimation of the potential for negative emissions of such biorefinery with CCS concepts; and
3. A comparison of a 2nd generation bioethanol plant with and without CCS to 1st generation bioethanol plant with and without CCS.

Findings of the Study

Methods and approach

Several technological pathways are available for converting lignocellulosic feedstocks to biofuels (see Figure 2). Gasification represents a thermochemical processing route where the feedstock is first converted to gas at elevated temperatures (800 – 1,200°C) and in the presence of an oxidising agent (air, oxygen and/or steam). The gas is then cleaned and conditioned, and catalytically converted either to hydrocarbon fuels (e.g. Fischer-Tropsch diesel or methane) or to fuel alcohol (e.g. methanol). Alternatively, pure hydrogen can be produced by separation from synthesis gas using pressure swing adsorption (PSA).

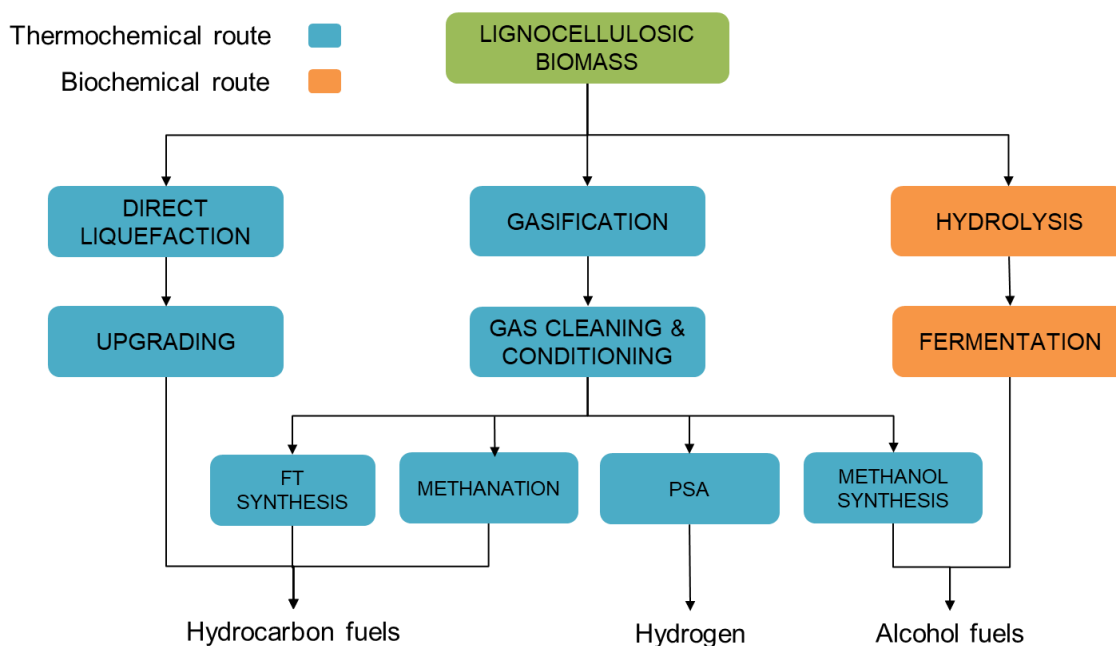


Figure 2. Schematic of possible processing pathways to second generation biofuels from lignocellulosic biomass.

Another main thermochemical option is the direct liquefaction of biomass into bio-oil, using e.g. fast pyrolysis process where solid biomass is heated up rapidly at around 500°C and the formed product is recovered as bio-oil by condensation. The production of bio-oil for use in transport applications (such as diesel and/or petrol/gasoline) requires significant upgrading by hydrogenation.

The main biochemical pathway involves the hydrolysis of biomass into sugars, followed by fermentation into bioethanol. The bioethanol is separated from the fermented solution by distillation. In addition, a lignin-rich by-product is obtained from the process.

Reference plants

The prospective cost and performance of advanced biofuels have been extensively investigated in a series of “scoping studies”. However, results from these past studies are heterogeneous, and a wide range of values has been proposed. In addition, scoping studies typically evaluate costs at some future date based on the assumption of mature technology. Such Nth-of-a-kind (NOAK) cost estimates are valuable for outlining the prospective long-term cost potential of biofuels, but are less useful in assessing costs of first-of-a-kind (FOAK) plants, as conventional cost estimation methods are found to routinely understate the costs of pioneering FOAK technologies.

In recent years, however, a small amount of actual data on demonstration projects has surfaced, allowing indicative cost and performance estimates to be derived for different emerging biofuel technologies from empirical evidence. The following projects have been used to derive the reference cases for this study:

- ADM corn ethanol plant, Decatur, Illinois, USA
- Inbicon demonstration plant, Kalundborg, Denmark,
- Fortum pyrolysis plant, Joensuu, Finland
- GoBiGas gasification plant, Gothenburg, Sweden

Performance analysis

The study analyses and compares the performance of different biorefinery configurations based on mass and energy flows simulated with Aspen Plus®. Following helpful metrics are calculated to assist the investigation. Fuel yield:

$$Y_{fuel}(\frac{bbl}{t}) = \frac{\dot{m}_{biof} * H_{biof}}{H_{petrol} * \dot{m}_{biom} * 159} \quad (1)$$

where \dot{m}_{biof} is output massflow of biofuel (kg/s), H_{biof} is lower heating value of biofuel (MJ/s), H_{petrol} is lower heating value of petrol (MJ/l), \dot{m}_{biom} is input massflow of dry biomass (kg/tonne) and 159 stands for litres per barrel; and CO₂ capture yield:

$$Y_{CO_2} = \frac{\dot{m}_{CO_2}}{\dot{m}_{biom}}, \quad (2)$$

where \dot{m}_{CO_2} is massflow of captured CO₂.

GHG emissions analysis

Total emission from biofuel production are defined as a sum of upstream emissions ($E_{upstream}$) caused by feedstock harvesting and transport, and nitrogen fertilisation to replace nutrients removed within the feedstock; and process emissions ($E_{process}$) caused by the possible use of fossil fuels during processing. $E_{upstream}$ values are taken from the literature and $E_{process}$ values are based on our process simulation results. Emissions caused by manufacturing of the biofuel plants or other needed infrastructure are excluded from the calculation. We also exclude emissions from producing the catalyst needed in some configurations as they are found to represent less than a 0.1 % of total emissions and thus have insignificant contribution to the overall results.

Table 1. Emission calculation parameters.

FOSSIL FUEL CARBON INTENSITIES, GCO_{2EQ}/MJ	
Natural gas	65.9
Fossil petrol/diesel	94
Fossil hydrogen	93
DIRECT UPSTREAM EMISSIONS, GCO_{2EQ}/MJ	
Corn ethanol	25.5
Wheat ethanol	1.8
Delivered waste wood	2.4

*calculated from natural gas emissions by dividing with thermal efficiency of steam reforming of 71 % (lhv).

**upstream emissions for the delivered waste wood are converted to upstream biofuel emissions by dividing with thermal efficiency of biomass to biofuel (lhv).

***values from RED II (Edwards et al. 2019); values for wheat and wood are lower due to being 2G residue feedstocks.

The functional unit under study is one megajoule (MJ) of biofuel produced, and emissions are expressed as gCO_{2eq}/MJ. All emissions are allocated to the main biofuel product, and electricity used by some configurations is assumed to be procured from zero-carbon sources. CO₂ emissions relative to the fossil fuel comparator are calculated using the following equation:

$$R(\%) = \frac{E_{upstream} + E_{process}}{E_{fos}}, \quad (3)$$

where E_{fos} is emissions from fossil fuel comparator. Fossil fuel carbon intensities and upstream emissions used in the calculations are summarised in Table 1.

Cost analysis

The prospective costs of advanced biofuels have been investigated extensively in a series of scoping studies. However, results from past studies are heterogeneous and a wide range of values have been proposed. In recent years, however, a small amount of actual data on demonstration projects has surfaced, allowing indicative cost and performance estimates to be derived for emerging biofuel technologies from empirical evidence. Here, publicly available information from reference and demonstration biofuel plants (see Table 2) are used to develop total capital investment (TCI) estimates individually for each configuration examined. Exchange rates and Chemical Engineer magazine's Plant Cost Index (CEPCI) are used to escalate all demonstration plant costs to 2018 US dollars.

Table 2: Reference plant cost data.

REFERENCE PLANT TYPE	CORN ETOH	CELLULOSIC ETOH	PYROLYSIS OIL	SYNTHETIC BIOFUELS
Reference plant name	ADM Decatur	Inbicon Demo plant	Fortum Joensuu pyrolysis plant	GoBiGas
Location	Illinois, USA	Kalundborg, Denmark	Joensuu, Finland	Gothenburg, Sweden
Biomass input, MW	371.8	16	50	30
Biofuel output, MW	278.5	4.6	30	20
Commissioning year	2011	2010	2012	2014
Total capital investment	127 M\$	180 M\$*	27 M€	1375 MSEK
Adjusted TCI (m\$2018)	131	216	36	210

*) Newer estimate to give more accurate estimate for near future 2G ethanol plants according to e4Tech

To minimise distortion caused by scale benefits in the cost results, the same biofuel output should be used for all plants. However, as existing corn-based biofuel plants are much bigger than existing cellulosic biofuel plants, a choice was made to set the scale of corn fed plants to 5,000 bbl_{pe}/d (petrol equivalent barrels per day), and set the scale of lignocellulosic feedstock plants to 1,000 bbl_{pe}/d.

A cost-scaling exponent (k) was used to scale reference plant capital costs (C_0) to a commercial scale capacity (S) using the following relation:

$$C = C_0 * \left(\frac{S}{S_0}\right)^k, \quad (4)$$

where S_0 is the scale of the reference plant and C the TCI of a FOAK plant at commercial scale.

The choice of capital investment scaling function and scaling parameter has a significant impact on the estimated process economics. If the selected scaling exponent is small, it suggests that the optimum plant size is very large and vice versa. An average value of 0.67 is used for k in this work. Previous research indicates that the investment for biomass-based plants, especially for the

biochemical route, could scale with higher values than this, but some ambiguity still remains regarding capital investment scaling exponent for biorefineries.

For a summary of financial parameters, see Table 3.

Table 3: Financial parameters used in the work.

Weighted avg. cost of capital (WACC)	8	%
Economic lifetime	20	years
Capital charge rate (CCR)	0.10	-
Annual operating and maintenance	4	% of TCI
Annual runtime	8,000	h/yr
	333	days/yr
Corn price	150	\$/tonne
Biomass price	60	\$/tonne
Electricity price	50	\$/MWh
Natural gas price	30	\$/MWh
Value of DDGS as animal feed	75	\$/tonne
CO₂ transport and injection/storage costs	15	\$/tCO ₂

LCOF (levelised cost of fuel) production is evaluated according to the following equation:

$$LCOF \left(\frac{\$}{GJ} \right) = \frac{F+E+C+O+R}{P}, \quad (5)$$

where

- F is the annual cost of biomass feedstock,
- E is the annual cost of electricity,
- C is the annualised capital charge, including return on equity and interest on debt,
- O is the annual operating and maintenance costs, and
- R is the annual revenue from selling by-product fuel gas.

The sum of these annual costs (\$/yr) is divided by P , which is the annual output of fuel (GJ/yr) from the plants. When defined in this way, LCOF (\$/GJ) indicates the product sale price needed to break-even under the technical and economic parameters assumed.

Summary of process configurations

Five different biofuel technologies are examined in detail, representing different approaches, feedstocks, end-products and technological maturities, namely:

- 1st generation ethanol via fermentation of corn,
- 2nd generation ethanol via biochemical conversion of wheat straw,
- bio-oil via thermal fast pyrolysis of forest residues,
- Fisher-Tropsch liquids (FTL) via thermal gasification of forest residues, and
- hydrogen via thermal gasification of forest residues.

Each basic configuration is investigated with and without carbon capture and storage (CCS). Two different CCS approaches are considered for plants that have more than one stream that contains CO₂. The base case approach is to capture carbon only from high CO₂ concentration streams, while an alternative configuration CCS-MAX is developed for maximal CO₂ capture (including also low concentration streams). Combination of these designs results in thirteen configurations (see Table 4),

each characterised by distinctive plant designs. These configurations are identified by acronyms that identify both the biofuel production approach and the treatment of CO₂:

- ETOH = Ethanol from corn,
- CE = Ethanol from lignocellulosic biomass,
- PO = Pyrolysis oil from lignocellulosic biomass,
- FTL = Fischer-Tropsch liquids from lignocellulosic biomass,
- H₂ = Hydrogen from lignocellulosic biomass;
- V = Vent of biogenic-CO₂ to atmosphere,
- CCS = Capture and underground storage of carbon from high concentration CO₂ streams,
- CCS-MAX = Capture and underground storage of carbon from all streams that contain CO₂.

Following capture efficiencies are assumed for different capture processes, depending on the CO₂:

- 100% direct capture of CO₂ from fermentation by drying;
- 97% capture of CO₂ (and 100% co-capture of H₂S) from synthesis gas by scrubbing with chilled methanol;
- 90% capture of CO₂ from flue gas by scrubbing with amine solution (30% MEA).

Three different feedstocks are considered in this work:

- Corn for ETOH-V and ETOH-CCS,
- Wheat straw for CE-V, CE-CCS and CE-CCS-MAX, and
- Forest residues for FTL-V, FTL-CCS, FTL-CCS-MAX, H₂-V, H₂-CCS and H₂-CCS-MAX.

All examined plant configurations are designed to be self-sufficient in terms of heat and steam (by recovering heat from hot process streams), while electricity is balanced from the grid. Process models are developed using Aspen Plus® process simulation software and used as a tool for carrying out performance analyses.

Table 4: Summary of examined process configurations.

CASE	FEEDSTOCK	CONVERSION TECHNOLOGY	END PRODUCT	CO₂ CAPTURE TECHNOLOGY
ETOH-V	Corn	Fermentation	Fuel ethanol	-
ETOH-CCS	Corn	Fermentation	Fuel ethanol	Chemical absorption
CE-V	Lignocell. residues	Biochemical conversion	Fuel ethanol	-
CE-CCS	Lignocell. residues	Biochemical conversion	Fuel ethanol	Drying
CE-CCS-MAX	Lignocell. residues	Biochemical conversion	Fuel ethanol	Drying and chemical absorption
PO-V	Lignocell. residues	Fast pyrolysis (+ HDO)	Bio-oil	-
PO-CCS	Lignocell. residues	Fast pyrolysis (+ HDO)	Bio-oil	Chemical absorption
FTL-V	Lignocell. residues	Fluidised-bed gasification	FT-liquids	-
FTL-CCS	Lignocell. residues	Fluidised-bed gasification	FT-liquids	Chemical absorption
FTL-CCS-MAX	Lignocell. residues	Fluidised-bed gasification	FT-liquids	Physical and chemical absorption
H₂-V	Lignocell. residues	Fluidised-bed gasification	Hydrogen	-
H₂-CCS	Lignocell. residues	Fluidised-bed gasification	Hydrogen	Physical absorption
H₂-CCS-MAX	Lignocell. residues	Fluidised-bed gasification	Hydrogen	Physical and chemical absorption

Process emissions

Mass and energy flows were simulated with Aspen Plus® for plants that produced either 5,000 bbl_{pe}/d (from corn) or 1,000 bbl_{pe}/d (from lignocellulosic feedstocks) of biofuel. The carbon flows are summarised in Table 5, together with calculated results for the upstream, conversion and total biofuel emissions (gCO₂eq/MJ) and *R*. The H₂-CCS configuration captures the highest share of input carbon to a concentrated stream of CO₂ (97% and 90%), followed by CE-CCS-MAX (74%), FTLs (66% and 54%), PO-CCS (36%), ETOH-CCS (21%) and finally CE-CCS (10%).

Relative emissions (*R*) from the plants are negative for almost all examined configurations featuring CCS due to the storage of the biogenic-CO₂. ETOH-CCS is an exception due to the high upstream emission, the use of natural gas as an energy source, and to the small share of CO₂ being captured.

Table 5: Carbon distributions and biofuel emissions. *R* is relative biofuel emissions in comparison to the fossil fuel reference. This study uses 94 gCO₂/MJ for petroleum-derived diesel/petrol and 93 gCO₂/MJ for fossil hydrogen produced via steam reforming of natural gas.

OF FEEDSTOCK CARBON THAT ENDS UP

	vented	in fuel	stored as CO ₂	Direct upstream emissions gCO ₂ /MJ	Direct process emissions gCO ₂ /MJ	Total direct emissions gCO ₂ /MJ	<i>R</i>
ETOH-V	0.0	41.9	0.0	25.5	26	51	54 %
ETOH-CCS	0.0	41.9	21.0	25.5	-10	16	16 %
CE-V	81.0	19.0	0.0	1.8	0	2	2 %
CE-CCS	71.0	19.0	10.0	1.8	-37	-36	-38 %
CE-CCS-MAX	7.1	19.0	73.9	1.8	-276	-274	-291 %
PO-V	40.0	60.0	0.0	4.2	0	4	4 %
PO-CCS	4.0	60.0	36.0	4.2	-63	-59	-63 %
FTL-V	69.4	30.6	0.0	5.4	0	5	6 %
FTL-CCS	15.5	30.6	53.9	5.4	-122	-117	-124 %
FTL-CCS-MAX	3.1	30.6	66.4	5.4	-151	-145	-154 %
H₂-V	100.0	0.0	0.0	4.1	0	4	4 %
H₂-CCS	10.1	0.0	89.9	4.1	-156	-152	-163 %
H₂-CCS-MAX	3.5	0.0	96.5	4.1	-168	-164	-175 %

Wheat ethanol with maximal CO₂ capture is the most carbon negative product having emissions of -291% relative to fossil petrol. This is caused by both the large share of CO₂ being captured and the relatively low conversion efficiency to ethanol. CE-CCS-MAX is followed by hydrogen plants having emissions ranging from -175% to -163% relative to fossil hydrogen, followed by FT liquids from 154% to 124%, thermal bio-oil (-63%) and 2G ethanol with base case CO₂ capture design (-38%).

Natural gas is one of the main process utilities used in corn based ethanol plant and replacing it with a low-carbon alternative such as biogas, electricity etc. would lower the total biofuel emissions for ETOH-V from 51 to 26 gCO₂/MJ and for ETOH-CCS from 16 to -10 gCO₂/MJ. In the latter case, the switch from natural gas to a non-fossil energy source together with CCS would therefore negate direct upstream emissions for the corn ethanol plant, making it a negative emissions technology.

Between 1,881 and 1,753 kg of CO₂ is captured for every tonne of biomass (dry) by H₂ configurations featuring CCS. This is followed by FT-liquids with capture rate from 1,294 to 1,052 kgCO₂/t_{biom}, CE-ETOH with capture rate from 1,240 to 1,168 kgCO₂/t_{biom}, thermal bio-oil with 702 kgCO₂/t_{biom} capture rate and 1G ethanol with 342 kgCO₂/t_{biom}.

Ethanol configurations that feature base case CCS designs have the smallest CO₂ capture rates as most of the biomass carbon will end up in the by-products, either distiller's dried grain solids (from corn) or combustion feedstock (from lignocellulosic biomass). When CO₂ from the by-product biomass is also captured (CE-CCS-MAX), a substantial increase in capture rate is achieved. For thermochemical configurations, base case CCS designs already capture most of the available CO₂ from the process and maximal capture designs contribute only a small addition to the total capture. Highest capture rates are achieved with hydrogen configurations as all carbon from the process is in the form of CO₂ and therefore available for capture.

Process economics

Finally, the contribution of different cost categories on the total cost of fuel (\$/GJ_{LHV}) and the cost of CCS (\$/tCO₂) are presented in Table 6. Cost of carbon capture and sequestration ranges from 22 to 66 \$/tCO₂ depending on the examined configuration. Lowest costs are associated with ethanol and gasification-based plants that feature CO₂ separation already in the base (vent) configuration and the cost of adding CCS is only 22 – 25 \$/tCO₂. A clear jump in cost can be seen for plants that incorporate post-combustion capture design, being 66 \$/tCO₂ for pyrolysis where all CO₂ is captured from flue gas, and 50 \$/tCO₂ for CE-CCS-MAX, where part of the CO₂ is captured at a lower cost from fermentation. For the CCS-MAX configurations, the costs increase more moderately for gasification-based configurations where only a small part of the overall CO₂ is captured from flue gas.

Table 6: Cost comparison of examined process configurations. Results are given as \$/GJ_{LHV}, if not otherwise noted.

CONFIG.	CAPITAL	O&M	FEED STOCK	NG	DDGS	CO ₂ DISPOSAL	ELECTRICITY	TOTAL (\$/GJ)	COST OF CCS (\$/TCO ₂)
ETOH-V	1.6	0.6	15.6	3.2	-2.6		0.5	19.0	
ETOH-CCS	1.7	0.7	15.6	3.2	-2.6	0.5	0.7	19.8	24
CE-V	15.1	5.9	13.3				-7.0	27.5	
CE-CCS	15.3	6.0	13.3			0.6	-6.8	28.4	25
CE-CCS-MAX	20.1	7.9	13.3			4.1	-5.0	40.4	47
PO-V	3.4	1.3	5.4				-1.1	9.0	
PO-CCS	5.4	2.1	5.4			0.9	-0.6	13.2	66
FTL-V	26.0	10.2	7.0				-0.8	42.3	
FTL-CCS	26.2	10.3	7.0			1.8	-0.2	45.0	22
FTL-CCS-MAX	27.3	10.7	7.0			2.3	0.0	47.2	33
H2-V	26.0	10.2	5.4				0.8	42.3	
H2-CCS	26.2	10.3	5.4			2.3	1.6	45.8	22
H2-CCS-MAX	26.8	10.5	5.4			2.5	1.7	46.9	27

The main cost results (the levelised cost of fuel and the cost of CCS) are also visualised in Figure 3 for all examined plant configurations.

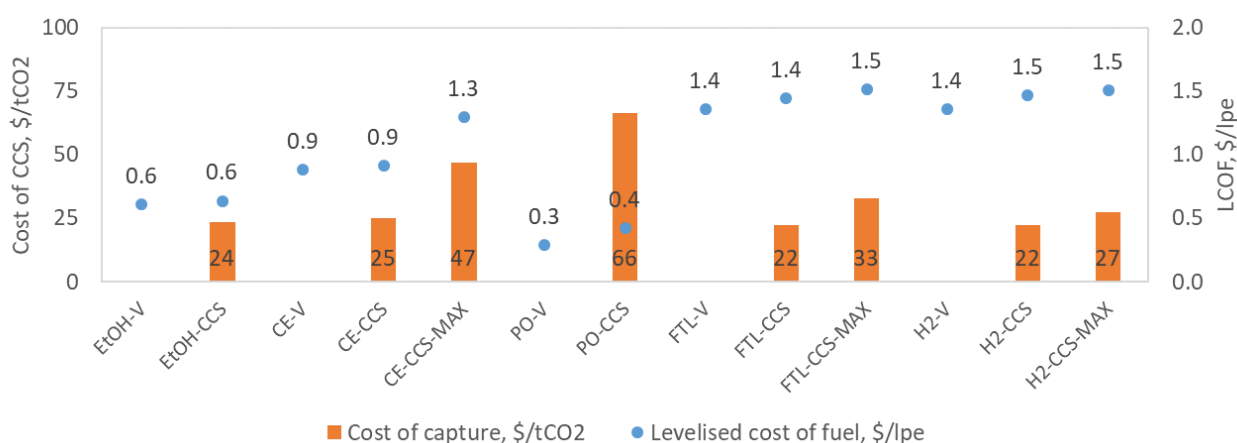


Figure 3: Levelised cost of fuels (dollars per petrol equivalent litres of biofuel) and cost of CCS (US dollars per tonne of sequestered CO₂) for all examined plant configurations.

The levelised cost of biofuel ranges from 0.3 to 1.5 dollars per petrol equivalent litre being lowest for thermal bio-oil from pyrolysis and second lowest for corn ethanol. The low LCOF of pyrolysis plants is mainly due to the general low investment, operating and feedstock costs of these plants. A clear jump in costs can be seen when transitioning to other technologies. LCOF for wheat ethanol is between 0.9 and 1.3 \$/lpe (dollars per petrol equivalent litres) depending on the CCS design whereas gasification based configuration has biofuel cost between 1.4 and 1.5 \$/lpe.

Sensitivity analysis

We then investigate the impact of plant scale on process economics. Chemical process technologies are usually expected to benefit from a large scale, as doubling the plant output less than doubles the capital investment cost. Biomass-based technologies are, however, limited in their scale by the availability of biomass, which is a geographically dispersed resource that cannot usually be economically transported more than 100 km. In Figure 4, the impact of plant scale on the cost of CCS and levelised cost of fuel is examined for plants that process woody biomass (corn ethanol plants were excluded from this analysis as they are operating at a much larger scales).

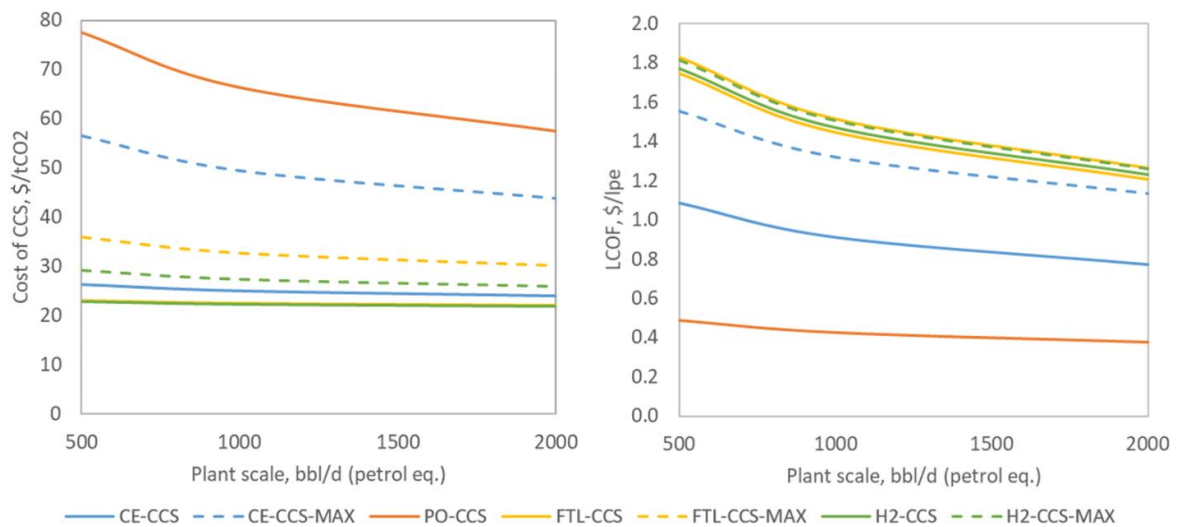


Figure 4: Impact of plant scale on the cost of CCS and on the levelised cost of biofuel.

According to the results, the plant size has modest impact on the cost of CCS for plants that incorporate capture from fermentation and from synthesis gas, as the costs are associated only for the compression and are therefore relatively low. For plants where most of the CO₂ is captured from flue gases by scrubbing with amine, the size of the plant has higher impact on costs. For example, for pyrolysis plants the cost of CCS reduces from 78 \$/tCO₂ to 58 \$/tCO₂ when the scale of plant increases from 500 to 2,000 bbl/d. The plant scale has a much more pronounced impact on the levelised cost of fuel. For example, for gasification based configurations the cost of biofuel reduces from about 1.8 \$/lpe to 1.3 \$/lpe when plant scale increase from 500 to 2,000 bbl/d level.

In Figure 5, the impact of feedstock cost on the biofuel production cost is shown. Here the corn ethanol configurations are also excluded from the comparison as they are governed by different feedstocks characteristics (both in terms for cost and availability) than plants operating on lignocellulosic feedstocks.

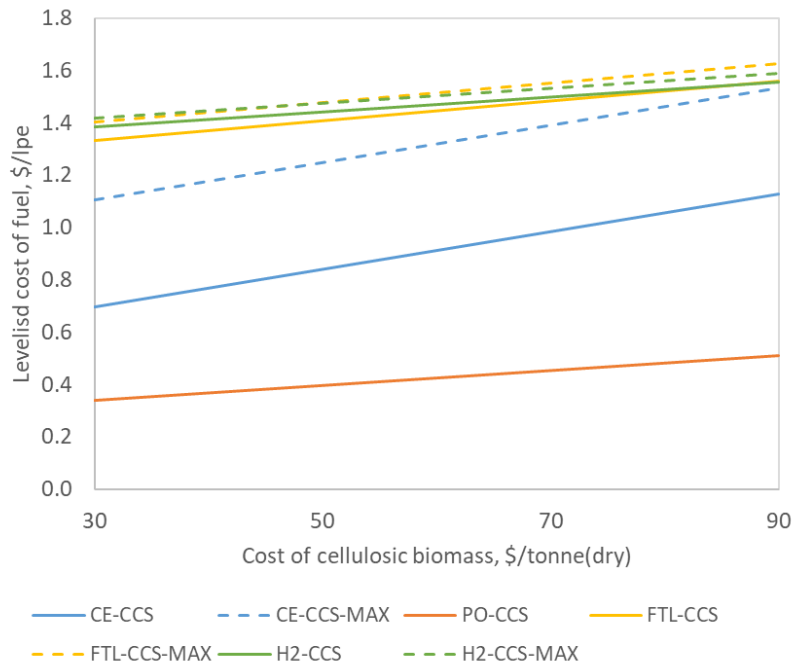


Figure 1. Impact of cellulosic biomass cost on the levelised cost of fuel.

Based on the results, the feedstock cost has lowest impact on the biofuel production cost for the gasification-based configurations, and highest for the PO-CCS and CE-CCS configurations. This is probably explained by the higher share of CapEx in the cost of gasification-based plants. For example, an increase in the cost of biomass feedstock from 30 to 90 \$/tonne increases the biofuel production cost by 61% (from 0.7 to 1.1 \$/lpe) for the CE-CCS plant, but only by 12% (1.4 – 1.6 \$/lpe) for the H2-CCS-MAX.

Expert Review Comments

Four reviewers from industry, academia and IGOs provided comments on the draft report. The majority of the comments have been addressed by the contractor, including but not limited to:

- Restructuring of the report to allow better flow of reading and improve clarity (e.g. underlying modelling assumptions have mainly been moved to an annex)
- Addition of an executive summary upfront in the report
- Addition of further references and contextualisation
- Addition of new illustrations and tables to better support the discussion
- Discussion of pulp mills has been shortened to only present information relevant to the report
- Removal/correction of inconsistencies

Conclusions

Five different biorefinery technologies have been examined and compared, representing different technological approaches, feedstocks, end-products and commercial maturities. The base case capture designs in this study capture CO₂ only from high-concentration streams, while MAX designs feature additional capture from low-concentration streams, i.e. flue gases.

The cost of adding CCS on the high-concentration streams of biorefineries varies between 22 and 24 \$/tCO₂. If CCS is extended also to flue gas streams, the cost of CCS varies between 27 and 66 \$/tCO₂. The wider range of cost is explained by differences between biorefineries in the share of CO₂ that needs to be captured from low-concentration streams. The lowest cost of CCS is achieved with

gasification-based configurations using base case CCS design (22 \$/tCO₂) followed closely by ethanol plants with base case CCS design (24-25 \$/tCO₂). However, up to ten times more CO₂ (1,052 – 1,753 kgCO₂/t_{biom}) is captured from the same amount of biomass by gasification configurations than by base case ethanol configurations (168 – 342 kgCO₂/t_{biom}). Only when the by-product lignin is fully combusted and captured (CE-CCS-MAX) can similar capture rates be achieved for the biochemical plants. However, this will significantly increase the cost of CCS to 47 \$/tCO₂.

Due to the capture and sequestration of biogenic CO₂, biorefineries show potential for negative emissions. The corn ethanol design ETOH-CCS is a notable exception to this rule, due to high upstream emissions of corn and the use of natural gas as additional energy source in the process. However, if natural gas would be switched to a low-carbon energy source, corn ethanol plants with CCS would also produce carbon negative fuels. For biorefineries based on lignocellulosic biomass, emissions range between -36 gCO_{2eq}/MJ and -274 gCO_{2eq}/MJ. The deepest emissions reductions in comparison to fossil petrol are associated with CE-CCS-MAX, as it combines a large capture rate with relatively small biofuel output, therefore leading to highly negative emissions per MJ of biofuel produced.

On paper, biorefineries with CCS seem very attractive. They would contribute to decarbonising the hard-to-abate transport sector, provide much-needed negative emissions at scale, and the cost of CCS would be only a fraction of that when applied to traditional power plants. On the other hand, the cost of biofuel is currently too high to compete with petroleum fuels, the location of a geological storage formation does not always coincide with good availability of biomass, and out of the examined configurations only ETOH-V and ETOH-CCS have been currently demonstrated at commercial scale. However, responding to the Paris Agreement will ultimately require deploying negative emissions at scale.

Recommendations

Based on the results and conclusions of this study it is suggested that future work should focus on:

- Implementation of large-scale demonstration projects in order to reduce risk and increase investor confidence
- More data should be made available from projects in order to refine the techno-economic assessment of biorefineries with CCS and reduce uncertainties

Biorefineries with CCS

Report for IEAGHG

September 2020

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VTT Technical Research Centre of Finland

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Executive summary

We investigate the techno-economic feasibility of providing negative emissions from “biorefineries”, i.e. from processes that convert solid biomass feedstocks into gaseous or liquid biofuels. Some CO₂ is formed as a by-product of biofuel production, and it is normally vented to atmosphere. However, if it were captured and securely sequestered in geological formations, the produced biofuel could be characterised by net negative greenhouse gas emissions because of the storage of biogenic CO₂.

Four different biorefinery technologies (corn ethanol, cellulosic ethanol, biomass fast pyrolysis and biomass gasification) are examined and compared against each other in terms of performance, emissions and costs. These technologies were chosen on the basis of adequate maturity, i.e. each technology has been demonstrated at multi-megawatt scale, and sufficient amount of information is publicly available from these projects allowing to derive performance and cost estimates at commercial-scale. Three of the chosen technologies are considered “advanced” i.e. they use non-edible lignocellulosic feedstocks, while the production of ethanol from corn was chosen as a reference case as it is widely applied today in the US and as there already exists CCS (carbon capture and storage) experience from a large-scale ADM Decatur plant located in Illinois.

Concerning end-products, following alternatives were included in the analysis: fuel ethanol, pyrolysis oil, Fischer-Tropsch fuels and hydrogen. Together they span a wide variety of different biofuel options with different characteristics and end-use sectors. To remove differences caused by varying heating values (e.g. 27 MJ/kg for fuel ethanol, 120 MJ/kg for hydrogen), all results are reported on a petrol equivalent (43 MJ/kg) basis.

Some biorefinery concepts, like those involving fermentation, feature high-concentration CO₂ streams that could be captured and prepared for transport at a low cost. Some concepts feature both high and low-concentration CO₂ streams, and therefore pursuing more extensive capture also increases the total cost of CCS. Our base case CCS designs capture CO₂ only from these “low-hanging” high-concentration streams, while CCS-MAX designs are developed to capture carbon from all available CO₂-containing streams.

The lowest cost of CCS was achieved with gasification-based biorefineries featuring base case CCS design (22 \$/tCO₂), followed closely by ethanol plants (both corn and cellulosic) with base case CCS design (24-25 \$/tCO₂). However, from three to up to ten times more CO₂ (1052-1753 kgCO₂/t_{biom}) is captured from the same amount of biomass by gasification-based biorefineries than by comparable ethanol plants (168-342 kgCO₂/t_{biom}). Only when the by-product lignin is fully combusted and captured (CE-CCS-MAX), can similar capture rates be achieved for the cellulosic ethanol plant. However, this will increase the total cost of CCS to 47 \$/tCO₂.

Due to the capture and sequestration of biogenic CO₂, biorefineries show deeply negative emissions. The corn ethanol plant with a base case CCS design is a notable exception to this rule due to high upstream emissions of corn and the use of natural gas as additional energy source in the process. However, if natural gas would be switched to a low-carbon energy source, corn ethanol plants with CCS would also produce carbon negative fuels. For biorefineries based on woody biomass, emissions range between -36 gCO_{2eq}/MJ and -274 gCO_{2eq}/MJ. The deepest emissions reductions in comparison to fossil petrol are associated with cellulosic ethanol plant featuring a CCS-MAX design as it combines a large capture rate with relatively small biofuel output, therefore leading to highly negative emissions per megajoule of biofuel produced.

Gasification-based biorefineries seem to be striking the best balance in terms of cost (22 \$/tCO₂), CO₂ capture rate (1052 kgCO₂/t_{biomass}) and biofuel yield (268 litres/t_{biomass}). Unfortunately, gasification-based biorefineries are also associated with the highest levelised cost of biofuel (1.4 \$/litre). However, any attempt to estimate the realistic cost of advanced biofuels is inevitably limited by the small handful of actual projects, and so, more operational plants will be needed to

reduce uncertainties. Our cost estimates are also developed for first-of-a-kind commercial-scale plants and significant cost reductions could be achieved over the coming decades through learning from these technologies at relevant scale.

Table 1. Summary of abbreviations used in the work.

IPCC = Intergovernmental Panel on Climate Change
NET = Negative Emissions Technology
GHG = Greenhouse Gas
CCS = Carbon capture and storage
BECCS = Bioenergy with Carbon Capture and Storage
BECCU = Bioenergy with Carbon Capture and Utilisation
ETS = Emissions Trading System
RED2 = EU directive (2018 recast) on the promotion of the use of energy from renewable sources
RD&D = Research, Development and Demonstration
HVO = Hydrotreated Vegetable Oils
RD&D = Research, Development & Demonstration
2G = Second generation biofuel
TRL = Technical Readiness Level
FT = Fischer-Tropsch
PSA = Pressure Swing Adsorption

1 Background

In the latest Special report on the impacts of global warming of 1.5°C the Intergovernmental Panel on Climate Change (IPCC) highlights the urgent need to reduce the atmospheric CO₂ emissions.¹ The report also identifies the importance of negative emissions, i.e. removing CO₂ already emitted to the atmosphere, in order to limit the rise in global surface temperatures and to reach the emissions reduction targets of the Paris Agreement.

Negative emissions technologies (NETs) feature in many climate models that comply with 2°C scenarios;² and efforts to aim towards a 1.5°C target as outlined in the Paris Accord, have drawn further attention to the need for options that reduce the overall stock of emissions in the atmosphere. Negative emissions are also an important tool for offsetting residual emissions from the hard-to-abate sectors like aviation, cement and steel industry, as well as agriculture to achieve overall carbon-neutrality.

Some authors have voiced their concern that emissions reduction strategies that place extensive emphasis on NETs contain significant risks. Relying too much on negative emissions technologies to meet emission targets may create a moral hazard problem, i.e., “why should we go through the effort to reduce emissions now when we can deal with the problem later just by using NETs”?³ However, given the current trajectory of emissions and the remaining carbon budget, it is becoming increasingly clear that NETs are not a substitute to defossilisation measures, but instead both approaches need to be aggressively pursued. However, to satisfy the growing demands for food,

¹ Summary for Policymakers. In: *Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty* (IPCC, 2018)

² Smith, P., Davis, S., Creutzig, F. et al. Biophysical and economic limits to negative CO₂ emissions. *Nature Clim Change* **6**, 42–50 (2016). <https://doi.org/10.1038/nclimate2870>

³ Anderson K. and Peters, G. The trouble with negative emissions. *Science* **354**(6309), 182–183 (2016).

wood products, energy, climate mitigation and biodiversity conservation — all of which compete for increasingly limited quantities of biomass and land — the deployment of mitigation strategies must be driven by sustainable and integrated land management.⁴

A range of plausible negative emissions technologies have been proposed, spanning from dedicated processes (capture of CO₂ from bioenergy conversion, mineral carbonation) to land management (afforestation/reforestation, soil organic carbon sequestration and biochar) and further to different geoengineering solutions (ocean fertilisation, cloud treatment). Some NETs are currently more developed than others, in terms of both technological maturity and the amount of carbon dioxide removal that could potentially be offered. As NETs are growing in prominence in energy planning, better understanding is needed of the many trade-offs that achieving negative emissions have on cost, emissions and the required resources.⁵

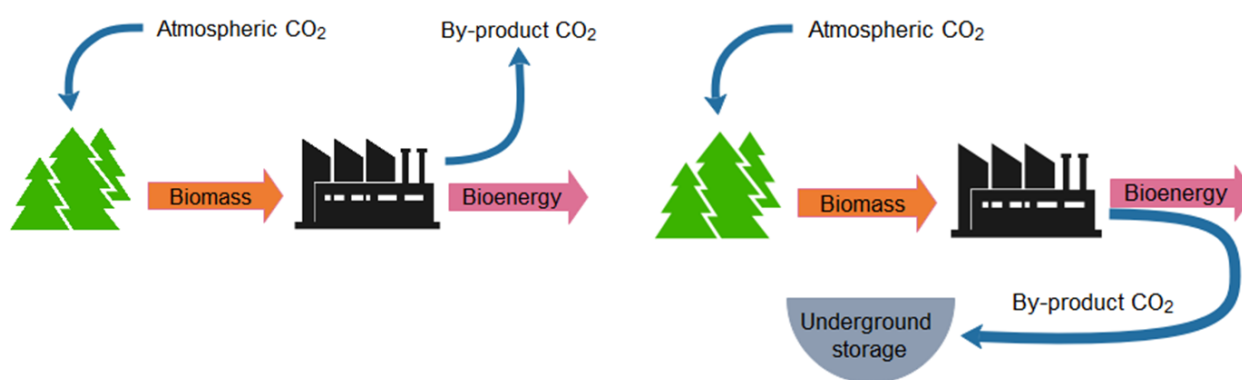


Figure 1. Two scenarios for the by-product CO₂ formed during biomass processing. In the base case (BEVENT) scenario, by-product CO₂ is vented to atmosphere. In the BECCS scenario, CO₂ is captured and safely sequestered to geological formations.

Bioenergy with Carbon Capture and Storage (BECCS or Bio-CCS) is a NET that receives most attention in integrated assessment model studies and in the latest IPCC reports.⁶ A key difference between BECCS and fossil-based CCS technologies is that when by-product CO₂ from biomass processing is captured and securely stored in geological formations, the generated energy could be characterised by negative net greenhouse gas (GHG) emissions, because of the storage of biogenic CO₂ (see **Error! Reference source not found.** for illustration).^{7,8} However, the overall climate change mitigation potential of BECCS depends on a number of factors, spanning from land use aspects and biomass procurement to performance of processing, share of carbon capture,

⁴ Canadell, J., Schulze, E. Global potential of biospheric carbon management for climate mitigation. *Nat Commun* **5**, 5282 (2014). DOI:10.1038/ncomms6282

⁵ van Vuuren, D.P., Hof, A.F., van Sluisveld, M.A.E, and Riahi, K. Open discussion of negative emissions is urgently needed. *Nature Energy* **2**, 902-904 (2017).

⁶ Torvanger, A. Governance of bioenergy with carbon capture and storage (BECCS): accounting, rewarding, and the Paris agreement. *Climate Policy* **19** (2018). DOI:10.1080/14693062.2018.1509044.

⁷ Sanchez, D.L. and Kammen, D.M. A commercialization strategy for carbon-negative energy. *Nature Energy* **1**, 15002 (2016).

⁸ Liu, G., Larson, E.D., Williams, R.H., Kreutz, T.G. and Guo, X. Making Fischer-Tropsch fuels and electricity from coal and biomass: Performance and cost analysis. *Energy Fuel* **25**, 415-437 (2011).

transportation of CO₂ and the permanence of storage. Therefore, a comprehensive life-cycle analysis is required to ensure carbon negativity. In addition, many low-carbon policies and associated GHG accounting frameworks (e.g. EU ETS, California ETS) do not currently appropriately recognise, attribute or reward negative emissions from Bio-CCS.⁹

A closely related concept to BECCS is so-called Bioenergy with Carbon Capture and Utilisation (BECCU). Here by-product CO₂ from biomass processing is captured, but instead of permanent storage, the CO₂ is used as a feedstock in a way that produces value for the plant operator. Possible applications of CO₂ utilisation include enhanced oil recovery, carbonation of beverages, CO₂ fertilisation in greenhouses, and various industrial approaches for the production of fuels, chemicals, plastics and building materials.¹⁰ In most of these CCU applications, the CO₂ is released into the atmosphere fairly quickly after its utilisation, and therefore its climate change mitigation potential can be significantly lower than that of CCS. However, focussing only on the fate of CO₂ in the overall concept can lead to incomplete understanding of CCU's climate impacts, as possible displacement of fossil fuels and carbon intensity of the energy used to run the CCU process often have a decisive role in the overall climate impact.¹¹

CCS technologies have been used industrially over several decades for example in oil refining, and they can be considered relatively mature. This goes not only for the capture part, but also for CO₂ transport and storage. CO₂ is removed from gas streams using commercial technologies such as physical (e.g. Rectisol[®], Selexol[®], etc.), or chemical absorption (e.g. amine) scrubbing systems. Regarding transport, CO₂ has been shipped regionally for over 20 years, while a 5,000 km pipeline network has been operating in the USA for over 30 years for Enhanced Oil Recovery (EOR). CO₂ storage projects have been operating successfully now for over two decades, e.g. at Sleipner (Norway). However, despite these experiences, the deployment of fully integrated CCS projects have stalled, and fallen considerably behind from levels originally set by ambitious technology roadmaps.¹²

Currently, the only large-scale BECCS process is the Illinois Industrial CCS facility that captures annually up to 1 Mt of CO₂ from the fermentation process of a Decatur corn ethanol plant and injects it into a geological storage beneath the facility. According to a recent report by the Global CCS Institute,¹³ The remaining four BECCS facilities operating today are small-scale ethanol production plants that use most of the captured CO₂ for enhanced oil recovery (EOR); including:

- Plane Kansas Arkalon
 - Location: USA
 - Size: 200,000 tonnes per year
 - Transport method: compressed and piped.
- Bonanza CCS
 - Location: USA
 - Size: 100,000 tonnes per year
 - Transport method: compressed and piped.

⁹ Kemper, J. Biomass and carbon dioxide capture and storage: A review. *International Journal of Greenhouse Gas Control* **40**, 401-430 (2015). DOI:10.1016/j.ijggc.2015.06.012.

¹⁰ Naims, H., Olfe-Kräutlein, B., Lafuente, AML. and Bruhn, T. *CO₂ Recycling – An Option for Policymaking and Society? Twelve theses on the societal and political significance of carbon capture and utilisation (CCU) technologies* (Institute for Advanced Sustainability Studies, 2015).

¹¹ Koponen, K. and Hannula, I. GHG emission balances and prospects of hydrogen enhanced synthetic biofuels from solid biomass in the European context, *Applied Energy* **200**, 106-118 (2017). DOI: 10.1016/j.apenergy.2017.05.014

¹² Reiner, D.M. Learning through a portfolio of carbon capture and storage demonstration projects. *Nature Energy* **1**, 1-7 (2014). DOI: 10.1038/NENERGY.2015.11

¹³ Consoli, C. Bioenergy and carbon capture and storage (Global CCS Institute, 2019). https://www.globalccsinstitute.com/wp-content/uploads/2019/03/BECCS-Perspective_FINAL_18-March.pdf

- Husky Energy CO₂ Injection
 - Location: Canada
 - Size: 250 tonnes per day
 - Transport method: compressed and trucked
- Farnsworth
 - Location: USA
 - Size: Over 600,000 tonnes of CO₂ (injection now ceased)
 - Transport method: compressed and piped.

2 Introduction

Bioenergy is the main source of renewable energy today, providing five times the contribution of wind and solar to global final energy consumption, when traditional use of biomass is excluded.¹⁴ In addition to electricity, bioenergy provides heat for industry and buildings, and fuels for transport.

Modern bioenergy plays an essential role in the International Energy Agency (IEA) 2°C Scenario (2DS) providing nearly 17% of final energy demand in 2060 compared to 4.5% in 2015.¹⁵ Bioenergy is important especially in sectors for which other decarbonisation options are not available. For example, in the transport sector bioenergy complements improved efficiency and electrification, and is particularly important in aviation and shipping. According to the IEA, its contribution to the transport sector should grow ten-fold between 2015 and 2060.¹⁵

Technologies for producing so called “first generation” crop-based biofuels like ethanol from sugar and starch-based feedstocks, and FAME (fatty acid methyl ester) biodiesel from vegetable oils and other lipid feedstocks (including wastes and by-products) are well-established, and provide most of today’s transport biofuels. In the short-term, the deployment of first generation biofuels could be boosted by RD&D focussed on improving conversion rates, costs and life-cycle GHG emission savings, improving the production of co-products such as animal feed, and widening the feedstock base to include those with limited land-use implications. The share of bioethanol could be further increased either by adopting higher blend levels with petrol, or by promoting unblended use to maximise GHG emission reduction¹⁶.

In recent years, technology to produce HVO (Hydrotreated Vegetable Oil), also known as *renewable diesel* (including advanced biodiesel, naphtha and aviation fuels), has been successfully commercialised. About 5 Mt/yr of HVO was produced globally in 2017 and production is expected to increase to 6-7 Mt/yr by 2020 and continue to increase thereafter.¹⁷ HVO production is increasingly based on waste and residue oil and animal fat feedstocks rather than oil crops. HVO has advantageous fuel characteristics compared to FAME, and can be used to produce so-called *drop-in fuels*, i.e. fuels that can be used unblended in the existing vehicle fleet or distribution infrastructure.

The longer-term growth of transport biofuels in the IEA’s 2DS relies on the widespread supply of novel *advanced biofuels* produced by processes that are generally not yet mature. Advanced biofuels are sustainable fuels produced from non-food crop feedstocks that are capable of delivering significant life-cycle GHG emissions savings without competing with food and feed crops for

¹⁴ IEA Renewables Information: Overview (IEA/OECD, 2020) <https://www.iea.org/reports/renewables-information-overview>

¹⁵ IEA Technology Roadmap – Delivering Sustainable Bioenergy (IEA/OECD, 2017).

¹⁶ IEA Technology Roadmap – Delivering Sustainable Bioenergy (IEA/OECD, 2017)

¹⁷ Landälv, I., Waldheim, L. and Maniatis, K. (Eds.) *Technology status and reliability of the value chains: 2018 Update* (ART Fuels Forum, Continuing the work of the Sub Group on Advanced Biofuels for the RED II market deployment for Advanced Biofuels)

agricultural land use. Advanced biofuels can also be called “second generation” (2G) biofuels, to differentiate them from first generation crop-based biofuels.

The development and commercialisation of advanced biofuel technologies has been slow, however, and most commercial-scale projects are currently on hold due to the high investment cost of pioneer process plants combined with the lack of funding instruments that share the risk of scale-up. Nevertheless, policy interest remains strong, notably in Europe (RED2 sets a 3.5% target for advanced biofuels by 2030),¹⁸ and in the United States (Renewable Fuel Standard, California Low-Carbon Fuel Standard).^{19,20}

The sustainable conversion of biomass feedstocks to biomass-derived fuels and chemicals are often referred to as “biorefining”. In addition to biofuel, such “biorefineries” typically produce also by-products and CO₂ (see Figure 2). The CO₂ from biomass processing is normally vented to atmosphere, but if it were captured and securely sequestered in geological formations, the produced biofuel could be characterised by net negative GHG emissions because of the storage of biogenic CO₂.

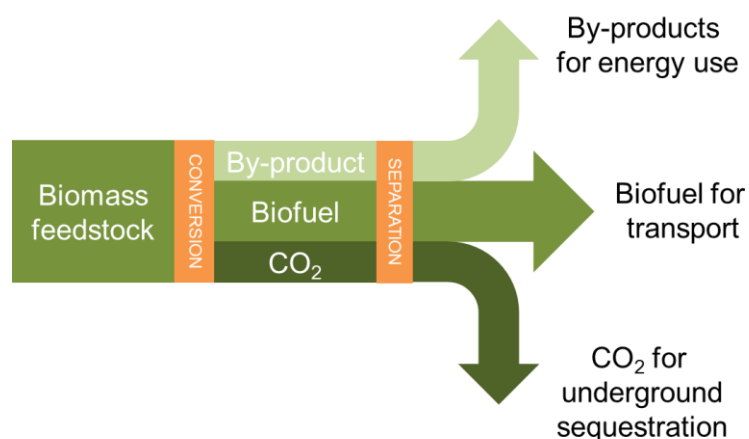


Figure 2: Conceptual representation of a biorefinery coupled with CCS.

As already mentioned, the coupling of biomass conversion with CCS has been promoted as one of the most promising candidates for a large-scale NET.²¹ Globally, Bio-CCS could potentially remove 10 billion tonnes of CO₂ from the atmosphere annually by 2050— equivalent to a third of all current global energy-related emissions.²² Given the relative difficulty of mitigating CO₂ emissions in the

¹⁸ EU. Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources (recast). 2018.

¹⁹ <https://www.epa.gov/renewable-fuel-standard-program>

²⁰ <https://www2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard>

²¹ Johnson, N., Parker, N. and Ogden, J. How negative can biofuels with CCS take us and at what cost? Refining the economic potential of biofuel production with CCS using spatially-explicit modeling. *Energy Procedia* **63**, 6770-6791 (2014). DOI:10.1016/j.egypro.2014.11.712.

²² Koornneef, J., van Breevoort, P., Hamelinck, C., Hendriks, C., Hoogwijk, M., Koop, K., Koper, M., Dixon, T. and Camps, A. Global potential for biomass and carbon dioxide capture, transport and storage up to 2050, *International Journal of Greenhouse Gas Control* **11**, 117-132 (2012). DOI: 10.1016/j.ijggc.2012.07.027.

transport sector, biofuel production with CCS is expected to play a significant role in reducing the carbon intensity of liquid transport fuels in 2 °C scenarios.²³

As existing CCS technologies have been developed largely around the combustion of fossil fuels, they may need to be adapted for use with biomass feedstocks. This is due to the different characteristics of biomass feedstocks (e.g. high oxygen content, high amount of volatiles, low volumetric energy density and fibrous structure),²⁴ and because biomass-processing plants are usually an order of magnitude smaller than comparable plants based on fossil fuels.

Capturing CO₂ from bioethanol production has been studied by Laude et al. for midsize plants.²⁵ They found that GHG emission of CCS retrofit on fermentation and natural gas fired cogeneration could be decreased by 115 % compared to the case without CCS. Later both the GHG emissions and economics of CCS connected to US corn ethanol production have been investigated by McCoy.^{26,27} Also, the coupling of CSS to sugar cane based bioethanol production has been investigated.^{28,29}

Sanchez et al. (2018)³⁰ estimated that 60 percent of all CO₂ emitted annually through the production of ethanol at the US 216 biofuel plants (about 1 percent of all CO₂ emissions from the U.S.) could be captured at low cost, under \$25 per metric tonne of CO₂. If credits for captured CO₂ were set at \$60 per metric ton, it would incentivise the sequestration of 30 MtCO₂/yr that would otherwise be vented into the atmosphere.

Liu et al.³¹ examined various system configurations that involve gasification-based coproduction of Fischer-Tropsch liquid (FTL) fuels and electricity from coal and/or biomass, both with and without capture and storage of by-product CO₂. This was followed by later studies,^{32,33} where similar approach was extended to cover synthetic petrol (gasoline). Highly carbon-negative fuels (specific emissions of -123 gCO₂/MJ_{LHV}) were produced when biomass was the only feedstock, although this meant significant constraints on the scale of the fuel production plants and resulted in higher

²³ Muratori, M., Kheshgi, H., Mignone, B., Clarke, L., McJeon, H. and Edmonds, J. Carbon capture and storage across fuels and sectors in energy system transformation pathways, *International Journal of Greenhouse Gas Control* **57**, 34-41 (2017). DOI: 10.1016/j.ijggc.2016.11.026.

²⁴ Wilen, C., Moilanen, A. and Kurkela, E. *Biomass feedstock analyses* (VTT Publications 282, 1996).

²⁵ Laude, Audrey & Ricci, Olivia & Bureau, G. & Royer-Adnot, J. & Fabbri, Antonin. CO₂ capture and storage from a bioethanol plant: Carbon and energy footprint and economic assessment. *International Journal of Greenhouse Gas Control* **5**, 1220-1231 (2011). 10.1016/j.ijggc.2011.06.004.

²⁶ McCoy S., The bioeconomy through the lens of carbon management, US Department of Energy DOE, 2017 https://www.energy.gov/sites/prod/files/2017/10/f37/mccoy_bioeconomy_2017.pdf

²⁷ McCoy S., The Value Proposition for Combining CCS and Ethanol Production, 2017, Betterenergy.org https://www.betterenergy.org/wp-content/uploads/2018/03/McCoy-Ethanol-and-CCS_v1.pdf

²⁸ Hudson Bolsoni Carminati; Raquel de Freitas D. Milão; José Luiz de Medeiros; Ofélia de Queiroz F. Araújo, Bioenergy and full carbon dioxide sinking in sugarcane-biorefinery with post-combustion capture and storage: Techno-economic feasibility, *Applied Energy*, 254, 2019, 113633

²⁹ Restrepo-Valencia S, Walter A., Techno-Economic Assessment of Bio-Energy with Carbon Capture and Storage Systems in a Typical Sugarcane Mill in Brazil, *Energies* **2019**, 12, 1129; doi:10.3390/en12061129

³⁰ Sanchez, D.L., Johnson, N., McCoy, S.T., Turner, P.A and Mach, K.J. Near-term deployment of carbon capture and sequestration from biorefineries in the United States. *Proceedings of the National Academy of Sciences* **115**(19), 4875-4880 (2018). DOI:10.1073/pnas.1719695115

³¹ Liu, G. et al. Making Fischer-Tropsch Fuels and Electricity from Coal and Biomass: Performance and Cost Analysis. *Energy Fuels* **25**, 415–437 (2011). DOI:10.1021/ef101184e

³² Liu et al. Gasoline from Coal and/or Biomass with CO₂ Capture and Storage. 1. Process Designs and Performance Analysis. *Energy Fuels* **29**, 1830–1844, (2015). DOI:10.1021/ef502667d

³³ Liu et al. Gasoline from Coal and/or Biomass with CO₂ Capture and Storage. 2. Economic Analysis and Strategic Context. *Energy Fuels* **29**, 1845–1859 (2015). DOI:10.1021/ef502668n

production costs (due to lesser scale benefits) than for plants that co-processed also fossil feedstocks.

Van Álamo et al.³⁴ studied the potential to apply CCS in biomass and waste gasification-based routes. A considerable impact on the reduction of GHG emissions was observed, doubling the amount of CO₂ avoided for both routes, but leading to 10-14% increase in the cost of biofuel.

Storing carbon from pyrolysis as biochar to improve soil properties in agriculture has been studied, as is the use of bio-oil as asphalt binder and as an additive to concrete and other building materials³⁵. However, carbon capture from flue gas of the fast pyrolysis process has not been previously evaluated.

CO₂ can be also captured from pulp mills from various flue gases using standard post-combustion capture technologies, Recent estimates for CO₂ avoidance cost in kraft pulp mills range between 52 – 66 €/tCO₂.³⁶ In the IPCC 1.5° special report, the role of BECCS varies between 0 to 16 GtCO₂/yr by 2050.³⁷ Current CO₂ emissions from chemical pulp production are roughly 350 MtCO₂/yr. By 2050, the BECCS potential from the pulping sector could be in the range of 200-400 MtCO₂/yr and could play an important role in providing negative emissions needed to achieve overall carbon neutrality targets.

Some studies also exist about the application of CCU to the production of biofuels. Hannula examined the “enhancement” of biofuels manufacture with additional hydrogen, and found that up to 2.6 or 3.1-fold increase in biofuel output could be attained for enhanced plant configurations over reference designs.^{38,39} In a follow-up study, Koponen and Hannula⁴⁰ found that the emissions of BECCU are largely governed by the specific carbon emissions of the used electricity and needs to remain below 84–110 gCO₂/kWh for the fuels to achieve more than 70% emission saving compared to fossil fuels. Onarheim et al.⁴¹ studied the possibility to add CCU to pyrolysis-based biofuel production. Their results indicated that utilising pyrolysis process off-gases to produce synthetic natural gas could provide up to 48%-61% savings in biomass use when fully enhanced with an external hydrogen source.

In this work, we investigate the techno-economic feasibility of coupling CCS with the production of biofuels. In section 3, we summarise publicly available information from relevant biofuel demonstration plants that we use to develop Total Capital Investment (TCI) estimates for our biorefinery configurations, and discuss methods used to carry out our analysis. In section 4, the basic principles of capturing CO₂ from biorefineries are discussed and the examined biorefinery configurations are presented. In section 5, we present our simulation results, discuss the economic

³⁴ Álamo, G. et al. *Implementation of bio-CCS in biofuels production*. (IEA Bioenergy Task 33, 2018)

³⁵ Schmidt H-, Anca-Couce A., Hagemann N., Werner C., Gerten D., Lucht W., Kammann C., 2019, Pyrogenic carbon capture and storage, *Bioenergy*, 11, 573–591, DOI: 10.1111/gcbb.12553

³⁶ Onarheim, K., Santos, S., Kangas, P. and Hankalin, V. Performance and cost of CCS in the pulp and paper industry part 2: Economic feasibility of amine-based post-combustion CO₂ capture. *International Journal of Greenhouse Gas Control* (2017).

³⁷ *Global Warming of 1.5 OC: An IPCC Special Report on the Impacts of Global Warming of 1.5° C Above Pre-industrial Levels and Related Global Greenhouse Gas Emission Pathways, in the Context of Strengthening the Global Response to the Threat of Climate Change, Sustainable Development, and Efforts to Eradicate Poverty* (IPCC, 2018).

³⁸ Hannula, I. Co-production of synthetic fuels and district heat from biomass residues, carbon dioxide and electricity: Performance and cost analysis, *Biomass and Bioenergy* **74**, 26-46 (2015). DOI: 10.1016/j.biombioe.2015.01.006

³⁹ Hannula, I. Hydrogen enhancement potential of synthetic biofuels manufacture in the European context: A techno-economic assessment. *Energy* **104**, 199-212 (2016). DOI: 10.1016/j.energy.2016.03.119

⁴⁰ Koponen, K. and Hannula, I. GHG emission balances and prospects of hydrogen enhanced synthetic biofuels from solid biomass in the European context, *Applied Energy* **200**, 106-118 (2017). DOI: 10.1016/j.apenergy.2017.05.014

⁴¹ Onarheim, K., Hannula, I. and Solantausta, Y. Hydrogen enhanced biofuels for transport via fast pyrolysis of biomass: A conceptual assessment. *Energy* **199** (2020). DOI: 10.1016/j.energy.2020.117337

feasibility of capturing CO₂ from biorefineries, and carry out sensitivity studies for key input parameters. Finally in section 6, we derive conclusions based on our results, and propose directions for future work.

3 Materials and methods

Several technological pathways are available for converting lignocellulosic feedstocks to biofuels (see Figure 3). Gasification represents a thermochemical processing route where the feedstock is first converted to gas at elevated temperatures (800 – 1200°C) and in the presence of an oxidising agent (air, oxygen and/or steam). The gas is then cleaned and conditioned, and catalytically converted either to hydrocarbon fuels (e.g. Fischer-Tropsch diesel or methane) or to fuel alcohol (e.g. methanol). Alternatively, pure hydrogen can be produced by separation from synthesis gas using Pressure Swing Adsorption (PSA).

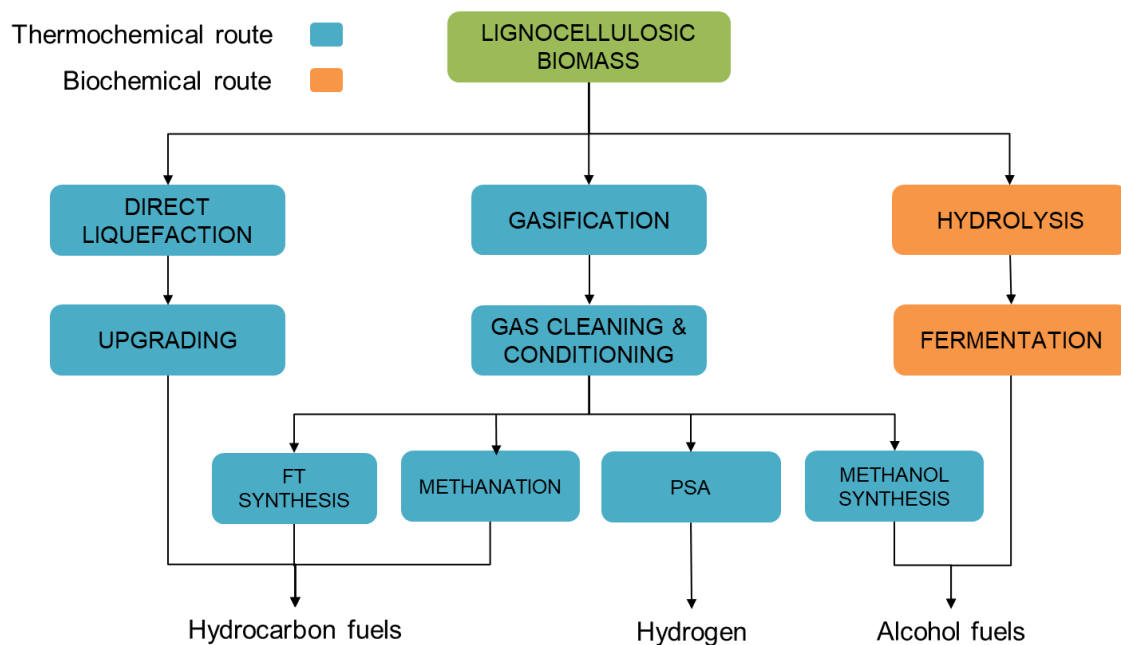


Figure 3. Schematic of possible processing pathways to second generation biofuels from lignocellulosic biomass.

Another main thermochemical option is the direct liquefaction of biomass into bio-oil, using e.g. fast pyrolysis process where solid biomass is heated up rapidly at around 500°C and the formed product is recovered as bio-oil by condensation. For use in transport applications (as diesel and/or petrol), the produced bio-oil requires significant upgrading by hydrogenation.

The main biochemical pathway involves the hydrolysis of biomass into sugars, followed by fermentation into bioethanol. The bioethanol is separated from the fermented solution by distillation. In addition, a lignin-rich by-product is obtained from the process.

3.1 Reference plants

The prospective cost and performance of advanced biofuels have been extensively investigated in a series of “scoping studies”. However, results from these past studies are heterogeneous, and a wide range of values has been proposed.⁴² In addition, scoping studies typically evaluate costs at some future date based on the assumption of mature technology. Such Nth-of-a-kind (NOAK) cost estimates are valuable for outlining the prospective long-term cost potential of biofuels, but are less useful in assessing costs of first-of-a-kind (FOAK) plants, as conventional cost estimation methods are found to routinely understate the costs of pioneering FOAK technologies.^{43,44}

In recent years, however, a small amount of actual data on demonstration projects has surfaced, allowing indicative cost and performance estimates to be derived for different emerging biofuel technologies from empirical evidence. In the following paragraphs, we present a selection of demonstration plants that we use later to derive cost estimates for different FOAK plants at commercial scale.

3.1.1 ADM Decatur, Illinois, USA

The ADM Decatur plant produces fuel ethanol from corn. The plant is large, processing 600,000 bushels of corn per day (~21,100 m³/d). Fuel ethanol is produced via the saccharification and fermentation route based on enzymes and yeast. In this process, corn is milled into meal and mixed with water and enzymes to produce a liquid mixture called mash. The mash is heated in order to liquefy the cornstarch, and more enzymes are added to convert it to light sugars during saccharification. The sugar-rich mash is cooled down and sent to fermentation where yeast processes sugars in the mash. Fermentation products include heat, ethanol and CO₂. The CO₂ is separated from the fermentation step while the mash, now called beer, is distilled to separate ethanol from non-fermentable solids. The CO₂ resulting from the fermentation is relatively pure and will only need to go through a dehydration and compression process in order to meet the quality requirements for delivery to the wellhead as supercritical CO₂.

In 2011, construction begun for a full-scale commercial CCS unit at the Decatur plant. The initial plan was to capture and store 2 500 tons of CO₂/day to the nearby 7,000 feet deep saline Mount Simon Sandstone formation. The first three years of operation, led by the Midwest Geological Sequestration Consortium of which ADM is part of, captured and stored around 1 Mt CO₂. In 2017, ADM took a step further from the 2011-2014 one-off project by starting operation of the USDOE funded ~1 Mt CO₂/yr Illinois Carbon Capture and Storage (ICCS) project. The project holds an operating permit for five years, totalling a capture rate of up to 5.5 Mt CO₂. The ADM facility is the 12th large-scale CCS facility to go online in North America, and the first in the world to apply CCS on biofuels production.⁴⁵

3.1.2 Inbicon demonstration plant

The production of cellulosic ethanol has been demonstrated at the Inbicon plant at the port of Kalundborg, Denmark, where 4 t/h of wheat straw is converted into ethanol, lignin pellets and C5 molasses. The demonstration plant was commissioned at the end of 2010 and the produced cellulosic ethanol is currently distributed to 100 filling stations in Denmark as “Bio95 2G” petrol. Lignin pellets are sold to DONG Energy for use in power plant, and the C5 molasses are sold as biogas

⁴² Haarlemmer, G., Boissonnet, G., Peduzzi, E. and Setier, P. Investment and production costs of synthetic fuels – a literature survey. *Energy* **66**, 667–676 (2014).

⁴³ Merrow, E., Phillips, K., and Myers, C. (1981). Understanding Cost Growth and Performance Shortfalls in Pioneer Process Plants (RAND).

⁴⁴ Ansar, A., Flyvbjerg, B., Budzier, A., and Lunn, D. Should we build more large dams? The actual costs of hydropower megaproject development. *Energ. Pol.* **69**, 43–56 (2014).

⁴⁵ Gollakota S. , McDonald S., Commercial-Scale CCS Project in Decatur, Illinois –Construction Status and Operational Plans for Demonstration, *Energy Procedia* 63 (2014) 5986 – 5993

boosters in local biogas plants. Continuous operation from straw bales to fermentation has been demonstrated achieving a yield above 198 litres of ethanol per tonne of dry straw.

3.1.3 Fortum Joensuu pyrolysis plant

Direct liquefaction of wood by fast pyrolysis has been demonstrated by several companies such as Fortum and BTL-BTG, and commercial scale plants are currently being built. Fast pyrolysis oil can be used as such to replace heavy fuel oil in the production of district heat or steam, but use as a transport fuel requires significant upgrading by hydrogenation.

Our process design is inspired by the Fortum pyrolysis plant, located in Joensuu Finland. Start-up of the plant was in 2013 and it produces 30 MW of pyrolysis oil (50 kt/yr) from 50 MW of lignocellulosic residues.⁴⁶ The pyrolysis plant is integrated with a co-located fluidised-bed boiler for the extraction of hot bed material for the pyrolysis reactor. Downstream of the pyrolysis unit, the vapours are separated and condensed while the sand and the by-products (char and permanent gases) are returned as fuel to the fluidised-bed boiler.

The plant has been operated as a demonstration unit, using different kind of raw materials and production parameters in order to develop and optimise the process. Final product has been used for replacing Heavy Fuel Oil (HFO) and tested with several sizes of boilers, from 1MW to 300MW. Hydrothermal liquefaction is another possible technology for direct liquefaction of biomass, but it was not considered in this work due to lower TRL and therefore lack of information from demonstration plants.

3.1.4 GoBiGas gasification plant

The production of synthetic biofuels from solid biomass residues has been demonstrated in Varkaus, Finland (by Neste, Stora Enso and VTT); Chicago, USA (UPM, Haldor Topsoe and GTI); and in Gothenburg, Sweden (GoBiGas). The Varkaus plant demonstrated the production of Fischer-Tropsch fuels, while the production of synthetic petrol was demonstrated in Chicago and the production of biomethane in Gothenburg. However, no commercial scale plants have yet been built.

The GoBiGas plant has been the biggest demonstration plant to date that represents gasification-based 2nd generation biofuel technology. The plant was commissioned in 2014 by Göteborg Energi in Gothenburg, Sweden; and features a 30 MW_{th} dual fluidised-bed biomass gasifier that converts pellets to raw synthesis gas. The syngas is purified with scrubbers and filters, and converted to synthetic methane over a nickel catalyst at elevated temperature and pressure. The methane output is 20 MW, suggesting about 67% (LHV) overall efficiency.⁴⁷

3.2 Performance analysis

We analyse and compare the performance of different biorefinery configurations based on mass and energy flows simulated with Aspen. Following helpful metrics are calculated to assist the investigation. Fuel yield:

$$Y_{fuel} \left(\frac{bbl}{t} \right) = \frac{\dot{m}_{biof} * H_{biof}}{H_{petrol} * m_{biom} * 159} \quad (1)$$

⁴⁶ Siikanen L. <https://www.cif-ifc.org/wp-content/uploads/2016/10/First-Commercial-Pyrolysis-Oil-Plant- -DEMO-2016 -Siikanen.pdf>, 2016

⁴⁷ Thunman H, Gustavsson C, Larsson A, Gunnarsson I, Tengberg F. (2019) Economic assessment of advanced biofuel production via gasification using cost data from the GoBiGas plant. *Energy Sci Eng.* 2019;1-13. <https://doi.org/10.1002/ese3.271>

where \dot{m}_{biof} is output massflow of biofuel (kg/s), H_{biof} is lower heating value of biofuel (MJ/s), H_{petrol} is lower heating value of petrol (MJ/l), \dot{m}_{biom} is input massflow of dry biomass (kg/tonne) and 159 stands for litres per barrel; and CO₂ capture yield:

$$Y_{CO_2} = \frac{\dot{m}_{CO_2}}{\dot{m}_{biom}}, \quad (2)$$

where \dot{m}_{CO_2} is massflow of captured CO₂.

3.3 GHG emissions analysis

We define total emission from biofuel production as a sum of upstream emissions ($E_{upstream}$) caused by feedstock harvesting and transport, and nitrogen fertilisation to replace nutrients removed within the feedstock; and process emissions ($E_{process}$) caused by the possible use of fossil fuels during processing. $E_{upstream}$ values are taken from the literature and $E_{process}$ values are based on our process simulation results. Emissions caused by manufacturing of the biofuel plants or other needed infrastructure are excluded from the calculation. We also exclude emissions from producing the catalyst needed in some configurations as they are found to represent less than a 0.1 % of total emissions and thus have insignificant contribution to the overall results.⁴⁰

Table 2. Emission calculation parameters.

Fossil fuel carbon intensities, gCO_{2eq}/MJ	
Natural gas ⁴⁸	65.9
Fossil petrol/diesel ⁴⁸	94
Fossil hydrogen ⁴⁸	93
Direct upstream emissions, gCO_{2eq}/MJ	
Corn ethanol ⁴⁸	25.5
Wheat ethanol ⁴⁸	1.8
Delivered waste wood ^{49,**}	2.4

*Calculated from natural gas emissions by dividing with thermal efficiency of steam reforming of 71 % (LHV).

**Upstream emissions for the delivered waste wood are converted to upstream biofuel emissions by dividing with thermal efficiency of biomass to biofuel (LHV).

The functional unit under study is one megajoule (MJ) of biofuel produced, and emissions are expressed as gCO_{2eq}/MJ. We allocate all emissions to the main biofuel product, and electricity used by some (ETOH and H₂) configurations is assumed to be procured from zero-carbon sources. We calculate CO₂ emissions relative to fossil fuel comparator using the following equation:

⁴⁸ Edwards, R Definition of input data to assess GHG default emissions from biofuels in EU legislation. (2019) JRC115952, DOI: 10.2760/69179

⁴⁹ Jäppinen, E., Korpinen, O., Laitila, J. and Ranta, T. Greenhouse gas emissions of forest bioenergy supply and utilization in Finland, *Renewable and Sustainable Energy Reviews* **29**, 369-382 (2014). DOI: 10.1016/j.rser.2013.08.101.

$$R(\%) = \frac{E_{upstream} + E_{process}}{E_{fos}}, \quad (3)$$

where E_{fos} is emissions from fossil fuel comparator. Fossil fuel carbon intensities and upstream emissions used in the calculations are summarised in Table 2.

3.4 Cost analysis

The prospective costs of advanced biofuels have been investigated extensively in a series of “scoping” studies intended to inform public policy discussions on their use. However, results from past studies are heterogeneous and wide range of values have been proposed.⁵⁰

In recent years, however, a small amount of actual data on demonstration projects has surfaced, allowing indicative cost and performance estimates to be derived for emerging biofuel technologies from empirical evidence. We use publicly available information from reference and demonstration biofuel plants (see Table 3) to develop Total Capital Investment (TCI) estimates individually for each configuration examined in this work. We use exchange rates and Chemical Engineer magazine’s Plant Cost Index (CEPCI) to escalate all demonstration plant costs to 2018 US dollars. For a description of reference plants, see section 3.1.

Table 3: Reference plant cost data.

Reference plant type	Corn ETOH	Cellulosic ETOH	Pyrolysis oil	Synthetic biofuels
Reference plant name	ADM Decatur	Inbicon Demo plant	Fortum Joensuu pyrolysis plant	GoBiGas
Location	Illinois, USA	Kalundborg, Denmark	Joensuu, Finland	Gothenburg, Sweden
Biomass input, MW	371.8	16	50	30
Biofuel output, MW	278.5	4.6	30	20
Commissioning year	2011	2010	2012	2014
Total Capital Investment	127 M\$	180 M\$*	27 M€	1375 MSEK
Adjusted TCI (M\$2018)	131	216	36	210

*) We used a newer estimate to give more accurate estimate for near future 2G ethanol plants according to e4Tech⁵¹.

To minimise distortion caused by scale benefits in the cost results, same biofuel output should be used for all plants. However, as existing corn-based biofuel plants are much bigger than existing cellulosic biofuel plants, a choice was made to set the scale of corn fed ETOH and ETOH-CCS plants to 5000 bbl_{pe}/d (petrol equivalent barrels per day), and set the scale of lignocellulosic feedstock plants to 1000 bbl_{pe}/d.

We use cost-scaling exponent (k) to scale reference plant capital costs (C_0) to a commercial scale capacity (S) using the following relation:

⁵¹ Chudziak C., Alberts G. and Bauen A., Ramp up of lignocellulosic ethanol in Europe to 2030, E4Tech, 6th International Conference on Lignocellulosic Ethanol, 2017.

$$C = C_0 * \left(\frac{S}{S_0}\right)^k, \quad (4)$$

where S_0 is the scale of the reference plant and C the TCI of a FOAK plant at commercial scale.

The choice of capital investment scaling function and scaling parameter has a significant impact on the estimated process economics. If the used scaling exponent is small, it suggests that the optimum plant size is very large and vice versa. An average value of 0.67 is used for k in this work.⁵² Previous research indicates that the investment for biomass-based plants, especially for the biochemical route, could scale with higher values than this, but some ambiguity still remains regarding capital investment scaling exponent for biorefineries.⁵³

We calculate annual capital charges from the TCI using 0.12 capital charge rate, which is based on 10% WACC (weighted average cost of capital) and 20-year economic life for the biorefinery. The yearly operating and maintenance (O&M) costs are assumed to be 4% of the TCI, and plants are expected to run 8000 h per year (91% availability factor). The cost of feedstocks and electricity varies greatly across time and geographic location. For the purpose of our cost analysis, following representative values are used: 150 \$/tonne for corn, \$60/tonne (dry) for biomass and 50 \$/MWh for electricity. For designs incorporating CCS, CO₂ is available at 150 bar at the plant gate. We assume that the CO₂ is transported 100 km from the conversion facility, and stored 2 km underground in geological formations. The cost of transport and injection/storage of supercritical CO₂ is valued at 15 \$/tCO₂.³¹ For a summary of financial parameters, see Table 4.

Table 4: Financial parameters used in the work.

WACC	8	%
Economic lifetime	20	years
Capital charge rate (CCR)	0.10	-
Annual operating and maintenance	4	% of TCI
Annual runtime	8000	h/yr
	333	days/yr
Corn price	150	\$/tonne
Biomass price	60	\$/tonne
Electricity price	50	\$/MWh
Natural gas price	30	\$/MWh
Value of DDGS as animal feed	75	\$/tonne
CO₂ transport and injection/storage costs	15	\$/tCO ₂

We evaluate the LCOF (levelised cost of fuel) production according to the following equation:

$$LCOF \left(\frac{\$}{GJ}\right) = \frac{F+E+C+O+R}{P}, \quad (5)$$

⁵² Remer, D.S. and Chai, L.H. Estimate costs of scaled-up process plants. *Chemical Engineering* **97**(4), 138, (1990).

⁵³ Leboreiro, J. and Hilaly, A.K. Analysis of supply chain, scale factor, and optimum plant capacity for the production of ethanol from corn stover, *Biomass and Bioenergy* **54**, 158-169 (2013). DOI: 10.1016/j.biombioe.2013.03.021.

where

- F is the annual cost of biomass feedstock,
- E is the annual cost of electricity,
- C is the annualised capital charge, including return on equity and interest on debt,
- O is the annual operating and maintenance costs, and
- R is the annual revenue from selling by-product fuel gas.

The sum of these annual costs (\$/yr) is divided by P , which is the annual output of fuel (GJ/yr) from the plants. When defined in this way, LCOF (\$/GJ) indicates the product sale price needed to break-even under the technical and economic parameters assumed.

4 Process configurations

We examine five different biofuel technologies in detail, representing different approaches, feedstocks, end-products and technological maturities, namely:

- 1st generation ethanol via fermentation of corn,
- 2nd generation ethanol via biochemical conversion of wheat straw,
- bio-oil via thermal fast pyrolysis of forest residues,
- Fisher-Tropsch liquids (FTL) via thermal gasification of forest residues, and
- hydrogen via thermal gasification of forest residues.

Each basic configuration is investigated with and without carbon capture and storage (CCS). Two different CCS approaches are considered for plants that have more than one stream that contains CO₂. Our base case approach is to capture carbon only from high CO₂ concentration streams, while an alternative configuration CCS-MAX is developed for maximal CO₂ capture (including also low concentration streams). Combination of these designs results in thirteen configurations (see Table 5), each characterised by distinctive plant designs. These configurations are identified by acronyms that identify both the biofuel production approach:

- ETOH = Ethanol from corn,
- CE = Ethanol from lignocellulosic biomass,
- PO = Pyrolysis oil from lignocellulosic biomass,
- FTL = Fischer-Tropsch liquids from lignocellulosic biomass,
- H2 = Hydrogen from lignocellulosic biomass;

and the treatment of carbon dioxide:

- V = Vent of biogenic-CO₂ to atmosphere,
- CCS = Capture and underground storage of carbon from high concentration CO₂ streams,
- CCS-MAX = Capture and underground storage of carbon from all streams that contain CO₂.

Following capture efficiencies are assumed for different capture processes, depending on the CO₂ source:

- 100% direct capture of CO₂ from fermentation by drying;
- 97% capture of CO₂ (and 100% co-capture of H₂S) from synthesis gas by scrubbing with chilled methanol;
- 90% capture of CO₂ from flue gas by scrubbing with amine solution.

Table 5: Summary of examined process configurations.

CASE	FEEDSTOCK	CONVERSION TECHNOLOGY	END PRODUCT	CO ₂ CAPTURE TECHNOLOGY
ETOH-V	Corn	Fermentation	Fuel ethanol	-
ETOH-CCS	Corn	Fermentation	Fuel ethanol	Chemical absorption
CE-V	Lignocell. residues	Biochemical conversion	Fuel ethanol	-
CE-CCS	Lignocell. residues	Biochemical conversion	Fuel ethanol	Drying
CE-CCS-MAX	Lignocell. residues	Biochemical conversion	Fuel ethanol	Drying and chemical absorption
PO-V	Lignocell. residues	Fast pyrolysis (+ HDO)	Bio-oil	-
PO-CCS	Lignocell. residues	Fast pyrolysis (+ HDO)	Bio-oil	Chemical absorption
FTL-V	Lignocell. residues	Fluidised-bed gasification	FT-liquids	-
FTL-CCS	Lignocell. residues	Fluidised-bed gasification	FT-liquids	Chemical absorption
FTL-CCS-MAX	Lignocell. residues	Fluidised-bed gasification	FT-liquids	Physical and chemical absorption
H2-V	Lignocell. residues	Fluidised-bed gasification	Hydrogen	-
H2-CCS	Lignocell. residues	Fluidised-bed gasification	Hydrogen	Physical absorption
H2-CCS-MAX	Lignocell. residues	Fluidised-bed gasification	Hydrogen	Physical and chemical absorption

Three different feedstocks are considered in this work:

- Corn for ETOH-V and ETOH-CCS,
- Wheat straw for CE-V, CE-CCS and CE-CCS-MAX, and
- Forest residues for FTL-V, FTL-CCS, FTL-CCS-MAX, H2-V, H2-CCS and H2-CCS-MAX.

Feedstock properties for corn, wheat straw and forest residues are given in the appendix.

All examined plant configurations are designed self-sufficient in terms of heat and steam (by recovering heat from hot process streams), while electricity is balanced from the grid. Process models are developed using ASPEN Plus (Aspen) process simulation software and used as a tool for carrying out performance analyses. The examined configurations are discussed in the following sections, while main design parameters are summarised in the appendix.

4.1 Ethanol from corn (ETOH)

Bioethanol production from corn is a mature technology and mostly produced in the US. Between 2004 and 2014, US corn ethanol production increased from 13 to 54 billion litres per year.⁵⁴ Production of bioethanol from corn or other starch-containing feedstocks involves a straightforward and relatively low-CapEx process that achieves high yield to biofuel.

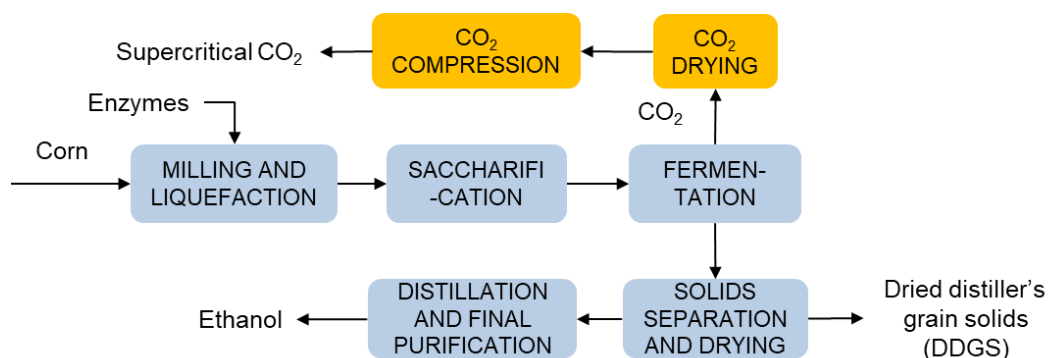


Figure 4: Block diagram of the ETOH-CCS process design.

In our 1st generation ethanol plant design (see Figure 4), the first step is milling of corn kernels to flour needed to solubilise the polysaccharides in corn starch. If wet milling process is used, gluten meal is often obtained as by-product. Water, enzymes, possibly lime to adjust pH and urea as nutrients are added and the mixture is heated up to 88°C; the slurry is solubilised by cooking. After cooling in the saccharification step the mixture is heated to 110°C for 20 minutes and then cooled to 60°C, pH is adjusted and enzymes are added to convert polysaccharides typically during 6 hours into fermentable monosugars. The aqueous solution of monosugars are cooled and then fermented at 34°C during 46 hours to produce ethanol and CO₂. The ethanol is separated by distillation at elevated temperatures and subsequent water removal with molecular sieves⁵⁵. The solution from ethanol removal is evaporated and dried, while Distiller's Dried Grain Solids (DDGSs) are separated and typically used as feed for animals. The CO₂ that is obtained from fermentation is washed with water in order to remove traces of ethanol, and washed with glycol to remove residual water. Finally, CO₂ is compressed to supercritical 150 bar pressure for transport.

4.2 Ethanol from lignocellulosic biomass (CE)

During the past 10 years, seven large-scale 2nd generation bioethanol plants have been commissioned with design capacities between 10 and 114 million litres of fuel ethanol per year. Two of these plants are integrated into or co-located with 1st generation ethanol plants, using corn and sugarcane as raw material. The remaining five plants are stand-alone plants using different biomass sources.

⁵⁴ Jan Lewandrowski, Jeffrey Rosenfeld, Diana Pape, Tommy Hendrickson, Kirsten Jaglo & Katrin Moffroid (2019) The greenhouse gas benefits of corn ethanol – assessing recent evidence, *Biofuels*, DOI: [10.1080/17597269.2018.1546488](https://doi.org/10.1080/17597269.2018.1546488)

⁵⁵ McAloon A., Taylor F., Yee W, Ibsen K. Wooley R., 2000, Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks, National Renewable Energy Laboratory, NREL/TP-580-28893, <https://www.nrel.gov/docs/fy01osti/28893.pdf>

The most recent plant, the St1 Cellunolix™ facility in Finland, uses only wood processing side-stream as raw material.^{56,57} The main pre-treatment technology in use is steam explosion or hydrothermal pre-treatment, while other pre-treatment technologies are in development phase. We use publicly available information from Inbicon demonstration plant producing bioethanol from wheat straw to develop realistic mass and energy balances for our biochemical ethanol production route.⁵⁸

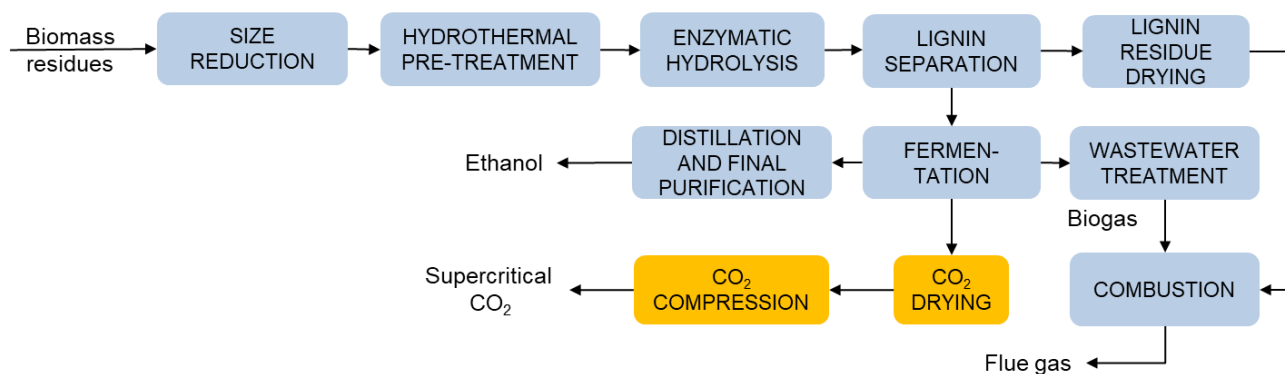


Figure 5: Block diagram of the CE-CCS base case process design.

In our 2nd generation ethanol plant design (see Figure 5), wheat straw bales are cut into pieces and the dry matter content of the feed is adjusted by recycling acetic acid containing condensate recovered after the pre-treatment. Subsequently the biomass is kept at 180-200°C for 10-20 minutes with steam.⁵⁹ In aqueous solution at elevated temperatures and pressure, some of the hemicelluloses are solubilised and after cooling, the solid residue can be converted into sugars more easily in the enzymatic hydrolysis. The breaking down of the cellulose into fermentable sugars by enzymes can take several days. The solid residue that contains mainly lignin is separated, dried and combusted in a CHP plant to produce heat and power. The solution is subsequently fermented at approximately 33°C and the formed ethanol is separated by distillation and further by dewatering using molecular sieves. The fermentation gases containing mainly CO₂ are washed to remove ethanol and dried with glycol.

Finally, the pure CO₂ is compressed to supercritical 150 bar pressure for transport. During fermentation, especially C5 sugars remain partly unfermented (typically 0-20wt-%) and are processed with anaerobic digestion to produce biogas. The biogas is burned together with lignin in the CHP to heat and power.

⁵⁶ Lynd, L.R.; Liand, X.; Bidy, M.J.; Allee, A.; Cai, H.; Foust, T.; Himmel, M.E.; Laser, M.S.; Wang, M. and Wyman, C.E. 2017. *Cellulosic ethanol: status and innovation*. Current Opinion in Biotechnology, 45, pp. 202-211. DOI: 10.1016/j.copbio.2017.03.008.

⁵⁷ Yamamoto, M. 2018. *St1 Cellunolix® process - Lignocellulosic bioethanol production and value chain upgrading*. Bio4Fuels Days, 12 October 2018, Oslo, Norway.

⁵⁸ https://www.eia.gov/biofuels/workshop/pdf/paul_kamp.pdf, US energy Administration, 2012 accessed 29.4.2020

⁵⁹ Larsen J., Østergaard M. H, Thirup L., 2012, Inbicon makes lignocellulosic ethanol a commercial reality, Biomass Bioenergy 46, 36-45

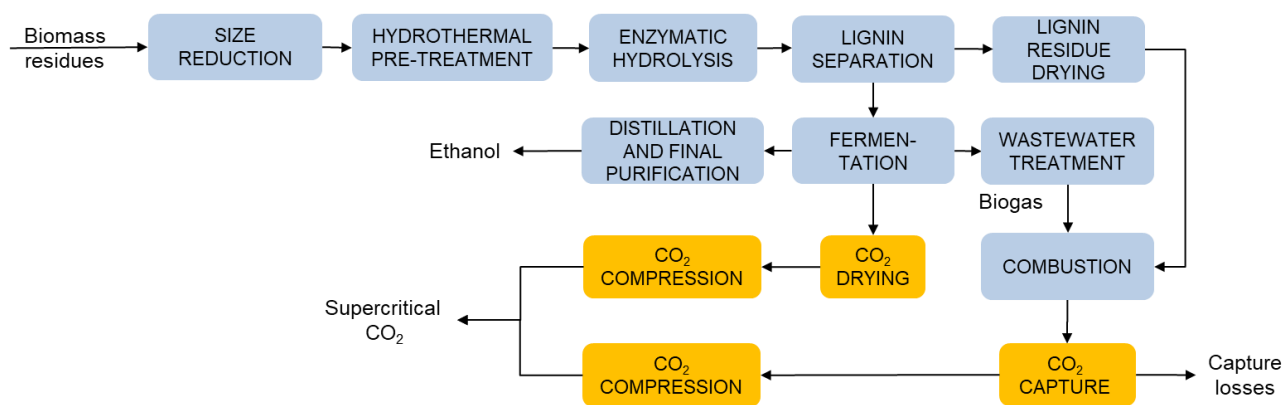


Figure 6: Block diagram of the CE-CCS-MAX process design.

An alternative capture design CE-CCS-MAX is also examined (see Figure 6). The configuration is otherwise similar to CE-CCS, but now CO₂ from the combustion of by-products (lignin and biogas) is also captured by scrubbing with amine wash. As the major part of feedstock carbon ends up in lignin and biogas, significantly more CO₂ can be captured by this design.

4.3 Pyrolysis oil from lignocellulosic biomass (PO)

Interest towards producing bio-oil (pyrolysis liquids) from biomass using fast pyrolysis process has sustained already for several decades.⁶⁰ Fast pyrolysis bio-oil (FPBO) is a complex mixture of oxygenated hydrocarbons and contains around 20 - 30wt-% water, depending on the feedstock type and pre-treatment approach. Consequently, FPBO is not directly compatible with current transport fuel systems, but can be used to replace heavy fuel oil in boilers and kilns. Bio-oil can be further refined to hydrocarbons via catalytic processing with hydrogen (hydro-deoxygenation, HDO) and further distilled into diesel and petrol fractions that can replace petroleum distillates in transport use.⁶¹

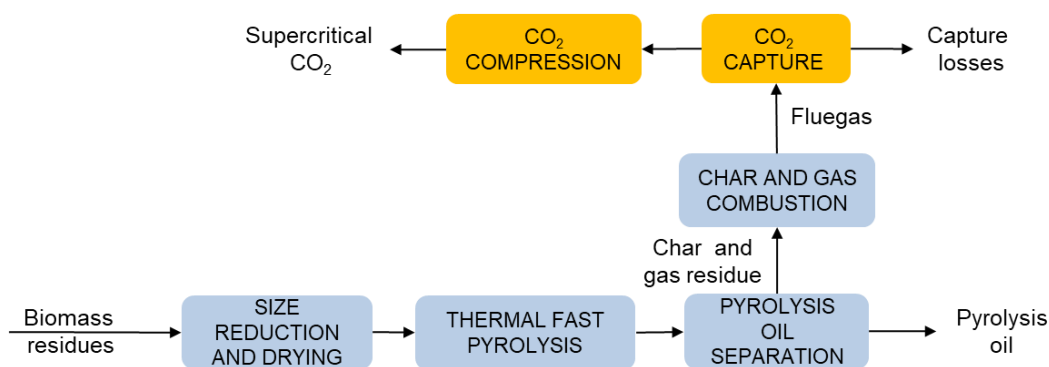


Figure 7: Block diagram of the PO-CCS process design.

In our pyrolysis plant design (see Figure 7), processing starts with drying and pretreatment of forest residues into small particles. Biomass is then fed to a thermal fast pyrolysis reactor where it is heated rapidly to around 500°C typically in a fluidised bed. Major part of biomass (~80wt%) is vaporised and recovered by quick cooling. The rest of the biomass is converted to char. The part of the vapour that

⁶⁰ Oasmaa, A., Solantausta, Y., Arpiainen, V., Kuoppala, E., and Sipilä, K. Fast pyrolysis bio-oils from wood and agricultural residues. *Energy & Fuels* **24**, 1380–1388 (2010).

⁶¹ Elliott, D.C. Transportation fuels from biomass via fast pyrolysis and hydroprocessing. *WIREs Energy Environ.*, 2, pp. 525-533 (2013). DOI: 10.1002/wene.74.

condenses at approximately 30°C is called pyrolysis oil, while uncondensed gases are combusted together with the char to produce heat. The generated heat is typically used internally in the process and any excess is used to generate electricity. From flue gas, the CO₂ is separated by scrubbing with amines and the recovered CO₂ is compressed to supercritical 150 bar pressure for transport. The pyrolysis oil can be transported to an oil refinery where it is upgraded by hydrogenation into transport fuels. Upgrading typically features several steps, and upgraded pyrolysis oil is usually co-processed with petroleum fuels into transport fuels with a biofuel component.

Fast pyrolysis oil is not stable if stored at ambient or higher temperatures, as the share of water-insoluble compounds, average molecular weight, and viscosity of bio-oil will increase over time. This will also worsen bio-oil's suitability for further upgrading, and imposes restrictions on the distance between the pyrolysis plant and the refinery. However, aging can be slowed down by storing in cold conditions, or with stabilisation methods like dilution, removing of alkali metals that catalyse aging reactions, or adding antioxidants to stabilise reactive specimens.⁶²

4.4 Fischer-Tropsch liquids from lignocellulosic biomass (FTL)

Gasification is a thermochemical conversion process that turns carbonaceous feedstocks into a gas mixture rich in carbon monoxide and hydrogen, called product gas or synthesis gas depending on the end-use application. Other major compounds include carbon dioxide, nitrogen, water, methane and a rich spectrum of hydrocarbons and tars. A general objective of gasification is to maximise the yields of light combustible gases and minimise the amounts of condensable hydrocarbons and unreacted char. The exact composition of product gas depends on the type of process feeds, their feed ratios, process parameters and the type of gasification reactor used. In contrast to coal gasification, where char gasification reactions determine the overall yield, in biomass gasification the devolatilisation stage of the feedstock and secondary reactions of primary pyrolysis products play the major role.⁶³ Once the feedstock has been converted to raw gas, it needs to be purified and conditioned to meet the strict requirements of the downstream catalytic synthesis, which then converts the gas to desired fuel depending on the choice of pressure, temperature and catalyst.

⁶² Oasmaa, A. Bio-oil stabilization, in *Fast Pyrolysis of Biomass: Advances in Science and Technology*. Royal Society of Chemistry RSC, p. 138-159 (2017).

⁶³ E. Kurkela, Formation and removal of biomass-derived contaminants in fluidized-bed gasification processes, VTT Publications Vol.287, Technical Research Centre of Finland, VTT (1996).

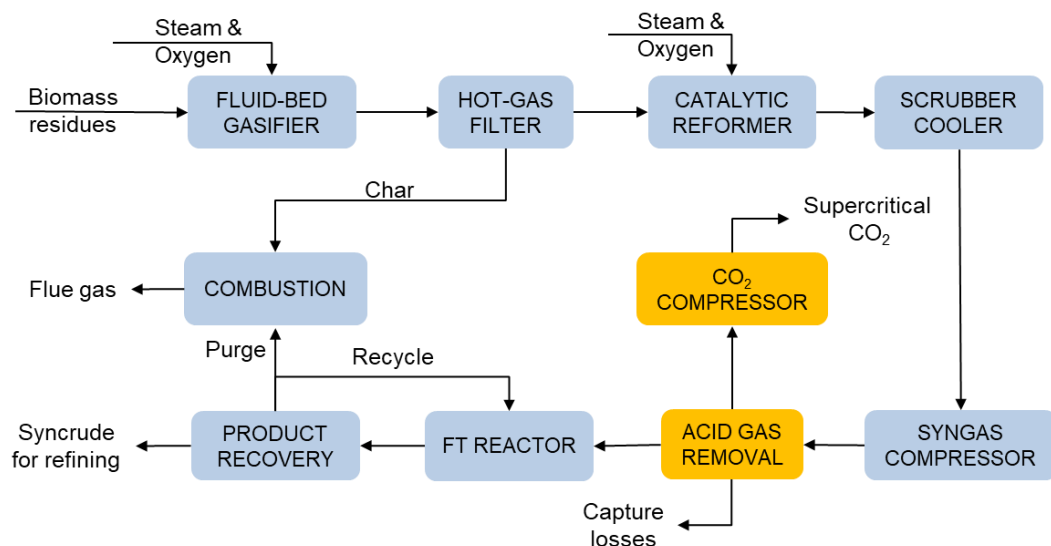


Figure 8: Block diagram of the FTL-CCS process design.

Our gasification process design and the associated simulation model is validated with experimental data derived from a 0.5 MW_{th} PDU (process development unit) run circa 4000 hours in pressurised oxygen-blown mode using various wood residues as feedstock.⁶⁴ The model itself is described in detail in Refs. [65,66]. The process (see Figure 8) begins with the drying of forest residues from their initial moisture of 50 wt-% to 15wt-% with a belt dryer and fed to a fluidised-bed gasification reactor operated at 880°C and 4 bar with a mixture of steam and oxygen (from a cryogenic air separation unit, ASU). During gasification, the residues are converted to product gas containing CO, H₂, CO₂, H₂O, CH₄, small amount of higher hydrocarbons and tars.⁶⁷ The gas is cooled down to 820°C to facilitate removal of entrained dust by ceramic filter elements.⁶⁸ Gas then enters a catalytic reformer, where tars and hydrocarbons are converted to light gases.⁶⁹ The tar-less gas exits the reformer at around 950°C and is cooled down to 200-300°C while recovering sensible heat to generate steam. The stoichiometry of the syngas (i.e. its molar H₂/CO ratio, modulus) is then adjusted by feeding a portion of the gas into a sour shift reactor where water-gas shift reaction is catalysed. The outlet temperature of the adiabatic reactor is set to 400°C and minimum steam/CO ratio of 1.8 is maintained with steam inputs located upstream from the reactor. The share of by-pass gas flow is set to achieve a modulus of 2.1 for the combined stream. The shifted gas is then cooled

⁶⁴ Kurkela E, Simell P, McKeough P, Kurkela M. Production of synthesis gas and clean fuel gas [Synteesikaasun ja puhtaan polttokaasun valmistus]. VTT Publications 682, Technical Research Centre of Finland, VTT. 2008.

⁶⁵ Hannula I, Kurkela E. A parametric modelling study for pressurised steam/O₂-blown fluidised-bed gasification of wood with catalytic reforming. *Biomass and Bioenergy* 2012;38:58-67. <http://dx.doi.org/10.1016/j.biombioe.2011.02.045>.

Overcoming Barriers to Bioenergy: Outcomes of the Bioenergy Network of Excellence 2003-2009.

⁶⁶ Hannula I, Kurkela E. Liquid transportation fuels via large-scale fluidised-bed gasification of lignocellulosic biomass. VTT Technology 91, Technical Research Centre of Finland. 2013.

⁶⁷ Kurkela E, Kurkela M, Hiltunen I. The effects of wood particle size and different process variables on the performance of steam-oxygen blown circulating fluidized-bed gasifier. *Environ Prog Sustain Energy* 2014;33(3):681-7. <http://dx.doi.org/10.1002/ep.12003>.

⁶⁸ Simell P, Hannula I, Tuomi S, Nieminen M, Kurkela E, Hiltunen I, et al. Clean syngas from biomass e process development and concept assessment. *Biomass Convers Biorefinery* 2014:1-14. <http://dx.doi.org/10.1007/s13399-014-0121-y>.

⁶⁹ Kaisalo N, Kihlman J, Hannula I, Simell P. Reforming solutions for biomass-derived gasification gas experimental results and concept assessment. *Fuel* 2015;147:208-20. <http://dx.doi.org/10.1016/j.fuel.2015.01.056>.

to 200°C with heat recovery and fed to a two-stage water scrubber where it cools down to 60°C while recovering sensible heat for feedstock drying. Finally, the gas is cooled down to 30°C to remove syngas moisture. The dried gas is compressed and cooled down to enable removal of acid gases (CO₂ and sulphur species) from syngas by scrubbing with chilled methanol. The separated stream of CO₂ is compressed to supercritical 150 bar pressure for transport.

The ultra-clean synthesis gas is converted to Fischer-Tropsch syncrude using cobalt-based catalysts in a boiling-water reactor. The reactor is operated at 200 °C and 25 bar and reaction exotherm is recovered as saturated steam. The alpha value is set to 0.90 and selectivity to C₅₊ is 92%.⁷⁰ The pressure drop over the reactor is set to 1 bar. Input HO, CO, N as well as unreformed methane, ethane and longer hydrocarbons are considered inert.

The C₅₊ and heavier oil fractions are recovered while lighter products (C₁-C₄) together with unconverted syngas are recycled back to the synthesis reactor. A small amount of the recycle flow is continuously purged to prevent accumulation of inerts and sent for combustion. The oil fraction and wax (syncrude) is sent for refining to fuel-related products and the aqueous product (reaction water) is treated as waste water.

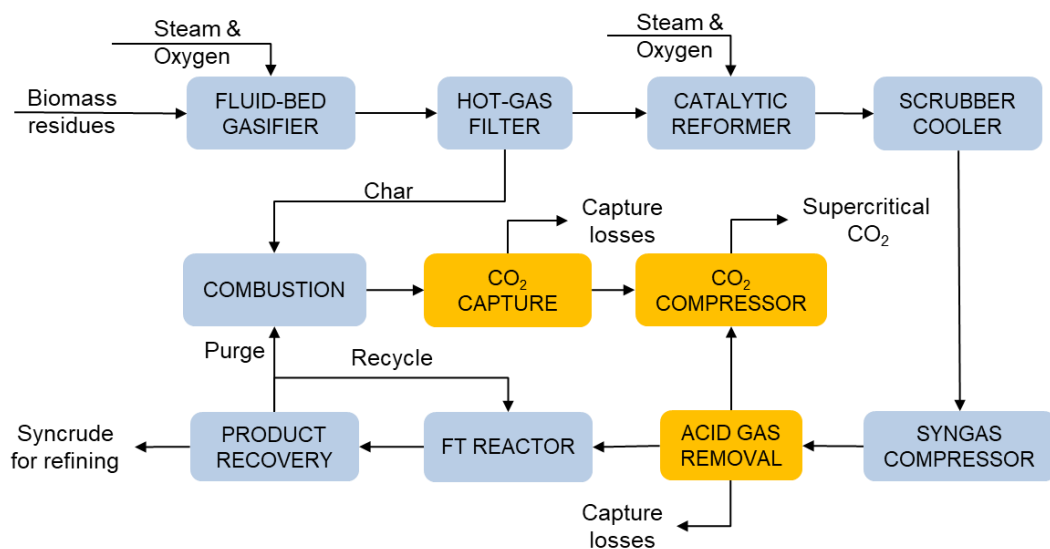


Figure 9: Block diagram of the FTL-CCS-MAX process design.

Similarly to CE-CCS-MAX we also examine a maximal capture desing for the FTL technology. Here additional carbon is captured from flue gas that originates from the combustion of purge from FT synthesis and char from the fluidised-bed gasifier. Capture from flue gas is achieved by scrubbing with amine. The combined stream of captured CO₂ is then compressed to supercritical 150 bar pressure for transport.

4.5 Hydrogen from lignocellulosic biomass (H₂)

Hydrogen is one possible product from synthesis gas. In our hydrogen plant design (Figure 10), forest residues are dried from their initial moisture of 50wt-% to 15wt-% with a belt dryer and fed to a fluidised-bed gasification reactor operated at 880°C and 4 bar with a mixture of steam and oxygen. The gas is then cooled down to 820°C to facilitate removal of entrained dust by ceramic filter elements. Gas then enters a catalytic reformer, where tars and hydrocarbons are converted to light gases. The tar-less gas exits the reformer at around 950°C, and is cooled down to 350°C with heat

⁷⁰ Hargreaves, N. (2013). Velocys, Inc., Personal communication in February.

recovery. Syngas modulus (H_2/CO ratio) is then maximised by two adiabatic sour shift reactors with intermediate cooling. The maximum exit temperature from both reactors is set to $400^\circ C$ and minimum steam/ CO ratio of 1.8 is maintained with steam inputs located upstream from the reactors.

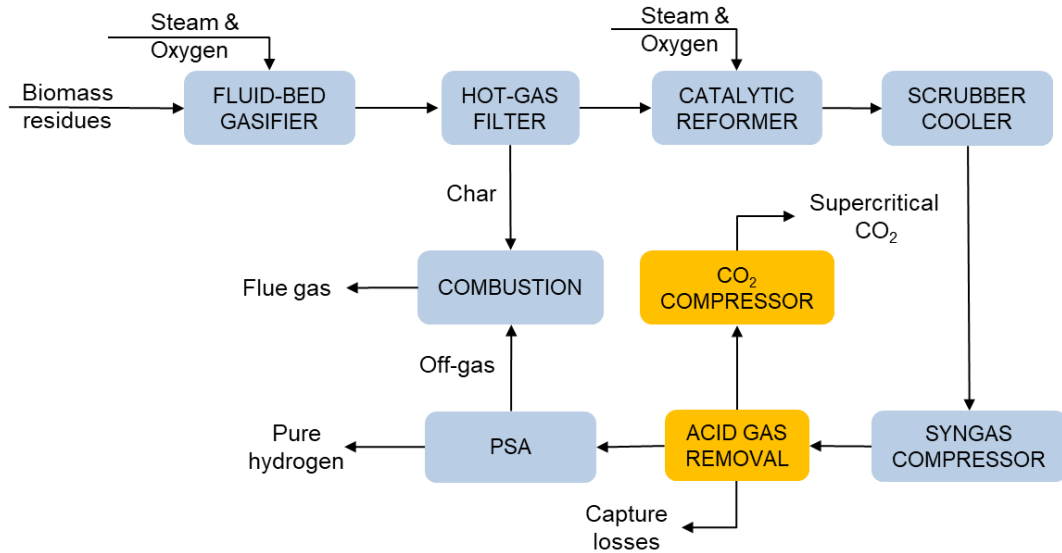


Figure 10: Block diagram of the H_2 -CCS process design.

The shifted gas is then cooled down with heat recovery to $200^\circ C$ and further to $60^\circ C$ using two-stage water scrubber that in the first stage recovers sensible heat for feedstock drying and in the second stage further down to $30^\circ C$ to remove syngas moisture. The dried gas is compressed to 20 bar and fed to an acid gas removal unit where CO_2 and sulphur species are removed by washing with chilled methanol. The separated stream of CO_2 is compressed to supercritical 150 bar pressure for transport. The ultra-clean synthesis gas is then fed to a pressure swing adsorber (PSA) that separates 86% of syngas hydrogen to a dedicated hydrogen stream with a hydrogen purity of 99.999vol%. Rest of the gas exits the PSA at an atmospheric pressure as off-gas. The off-gas is combusted along with char from the gasifier in an auxiliary boiler.

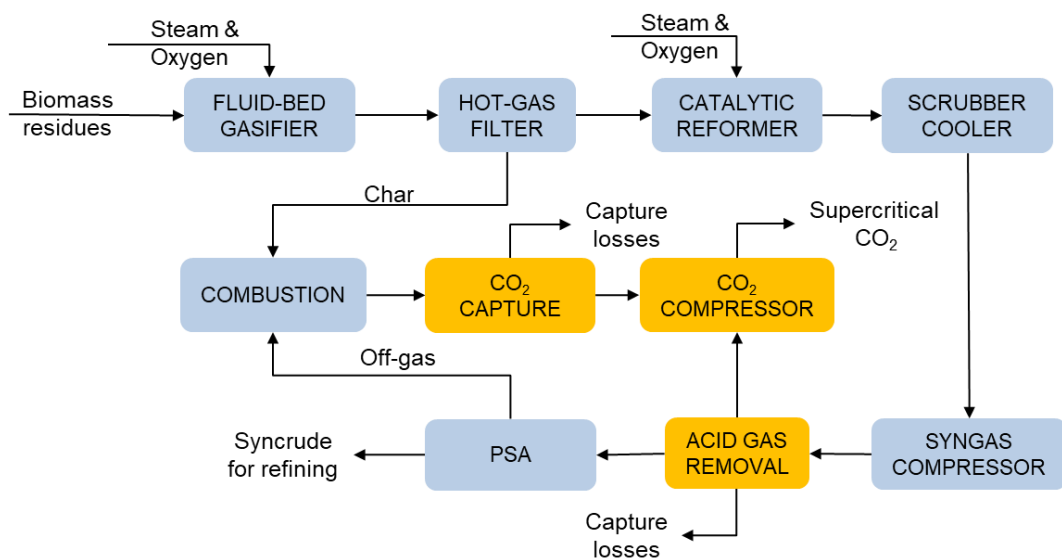


Figure 11: Block diagram of the H_2 -CCS-MAX process design.

As an alternative to H₂-CCS, we also examine a maximal CO₂ capture design for the hydrogen process H₂-CCS-MAX. In addition to CO₂ that is removed from pressurised syngas by scrubbing with chilled methanol, additional CO₂ from the combustion of PSA off-gas and char is captured from flue gas by scrubbing with amine solution.

5 Results

5.1 Mass and energy flows

Mass and energy flows were simulated with Aspen for plants that produced either 5000 bbl_{pe}/d (from corn) or 1000 bbl_{pe}/d (from lignocellulosic feedstocks) of biofuel. Main results are summarised in Table 6. The highest fuel yield Y_{fuel} (measured as petrol equivalent barrels per tonne of dry biomass) is achieved with PO and H₂ configurations (2.2 bbl_{pe}/t), followed by ETOHs (1.9 bbl_{pe}/t), FTLs (1.7 bbl_{pe}/t) and finally CEs (0.9 bbl_{pe}/t).

Table 6: Simulated annual mass and energy flows for the examined plant configurations.

Configuration	Biomass, t/yr (dry)	Electricity, MWh/yr	Fuel, MWh/yr	CO ₂ captured, tCO ₂ /yr	Y_{fuel} (bbl/tonne)
ETOH-V	885 573	-84307	2 362 917	0	1.9
ETOH-CCS	885 573	-116077	2 362 917	302 576	1.9
CE-V	378 298	236679	472 583	0	0.9
CE-CCS	378 298	230329	472 583	63 490	0.9
CE-CSS-MAX	378 298	170359	472 583	469 193	0.9
PO-V	153 436	36825	472 583	0	2.2
PO-CCS	153 436	19919	472 583	107 684	2.2
FTL-V	197 982	28597	472 583	0	1.7
FTL-CCS	197 982	6735	472 583	208 207	1.7
FTL-CCS-MAX	197 982	1691	472 583	256 252	1.7
H ₂ -V	151 856	-26210	472 583	0	2.2
H ₂ -CCS	151 856	-54155	472 583	266 141	2.2
H ₂ -CCS-MAX	151 856	-56202	472 583	285 643	2.2

Based on the simulated mass and energy flows, carbon flows are illustrated separately to all CCS-configurations using Sankey diagrams. Easy comparison across different configurations has been facilitated by normalising biomass input to 100 units of carbon for each process.

For ETOH-CCS (see Figure 12), 42 units of carbon end up in fuel ethanol while 37 C ends up in Distiller's Dried Grain Solids (DDGSs). The remaining 21 C of concentrated CO₂ is captured at 100% efficiency and compressed at the plant to 150 bar for transport.

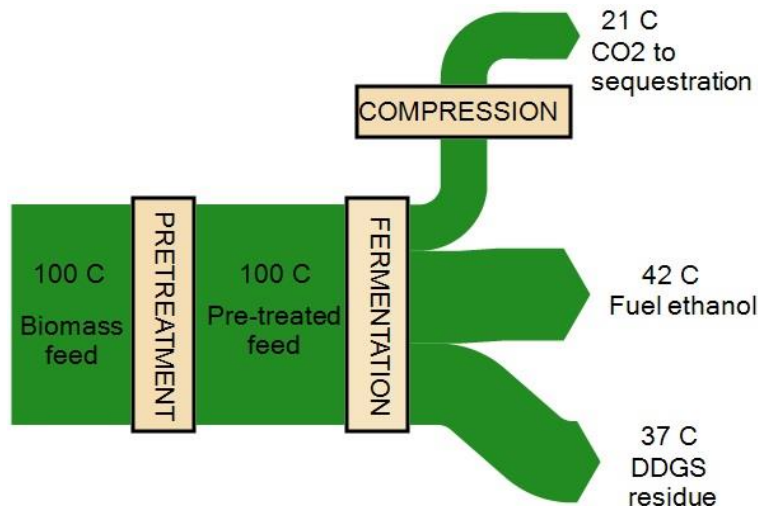


Figure 12: Simulated carbon flows for plant producing ethanol from corn (ETOH-CCS). Some natural gas is used in this configuration to regenerate glycol drying agent under high temperature. These fossil carbon flows are not illustrated here, but have been included in the emissions calculations.

For CE-CCS (see Figure 13) 41 units of carbon continue with the pre-treated feed to fermentation while 59 C end up in the solid residue stream. From fermentation 19 C end up into biofuel while 12 C go to combustion together with the solid residue from pre-treatment as biogas. The remaining 10 C of concentrated CO₂ from fermentation is captured at 100% efficiency and compressed at the plant to 150 bar for transport.

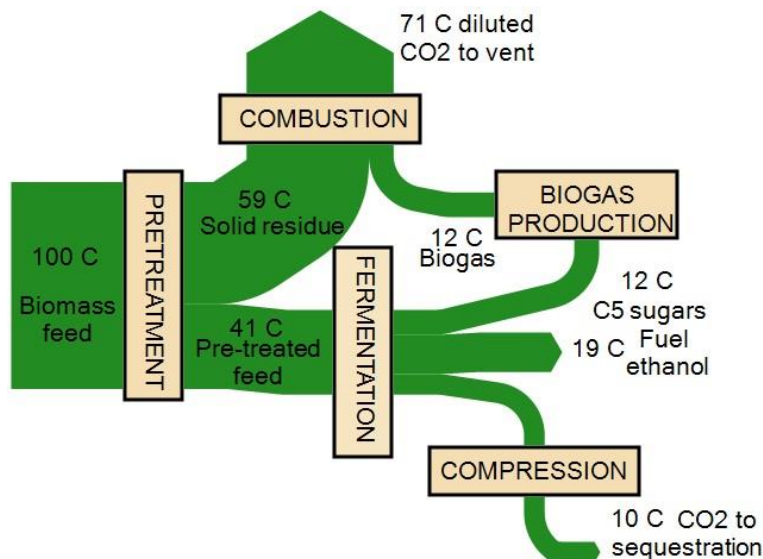


Figure 13: Simulated carbon flows for ethanol from lignocellulosic biomass (CE-CCS) configuration.

For CE-CCS-MAX, CO₂ from the combustion of by-products is also captured by using amine wash with 90% capture efficiency. The carbon flows are the same as in the case of CE-CCS, however instead of 71 C only 7 C are now vented. A small residual part of carbon remains in the liquid phase

after digestion. The feed to digestion is highly digestible and only a negligible amount (few percent) of the carbon in the feedstock goes to the digestate. Therefore it has not been considered here.

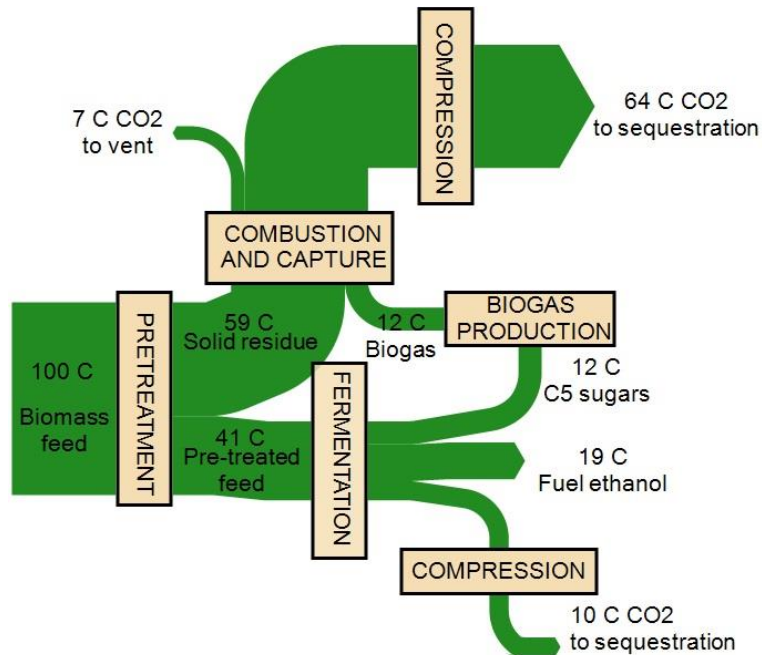


Figure 14: Simulated carbon flows for ethanol from lignocellulosic biomass (CE-CCS-MAX) configuration featuring both CO₂ capture from fermentation and from flue gas.

For PO-CCS (See Figure 15) 60 units of carbon end up in thermal bio-oil during pyrolysis while 40 C will end up to combustion as char and purge gas. The formed CO₂ is then captured with 90% efficiency and compressed to 150 bar for transport.

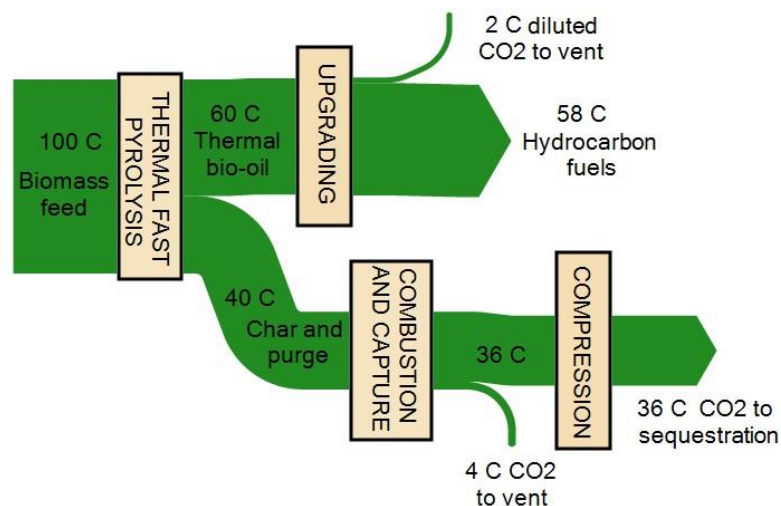


Figure 15: Simulated carbon flows for fast pyrolysis oil from lignocellulosic biomass (PO-CCS) configuration.

For FTL-CCS (See Figure 16), 97 units of carbon are converted to gas and tars and 3 C to solid char. From carbon contained in the synthesis gas, 41 units are fed to the FT unit where 31 C is converted to FT liquids (syncrude) and 11 C to purge gas. The purge gas is combusted together with

char to form a stream of diluted CO₂ for venting to atmosphere. Separation of CO₂ by scrubbing with chilled methanol captures 54 units of carbon (capture losses 2C) that are compressed to 150 bar for transport.

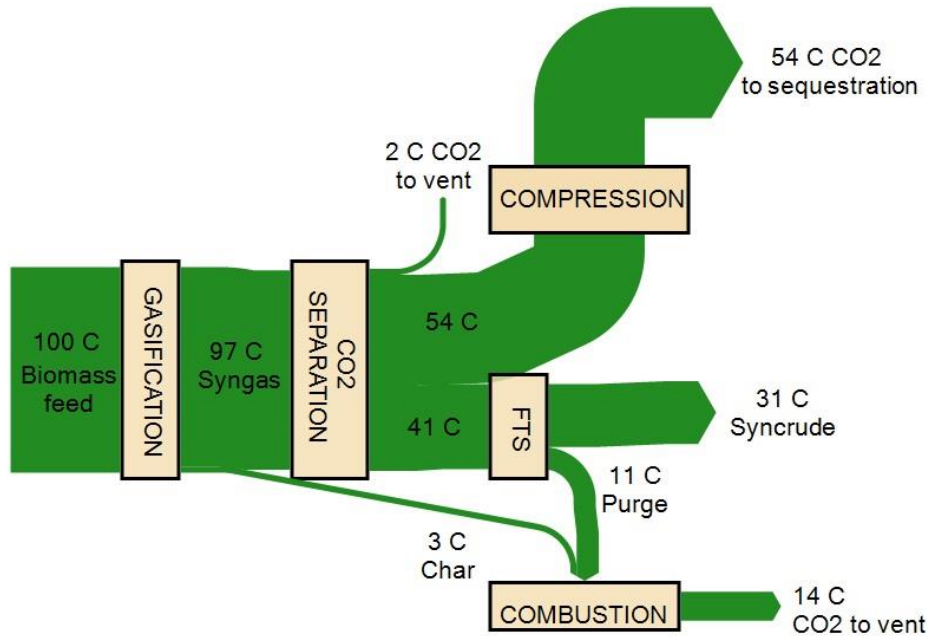


Figure 16: Simulated carbon flows for Fischer-Tropsch liquids from lignocellulosic biomass (FTL-CCS) configuration.

For FTL-CCS-MAX (Figure 17) additional 12 C from the combustion of char and FT purge is captured increasing the total capture share to 66 C. Combined capture losses are 3 C for this maximal capture design.

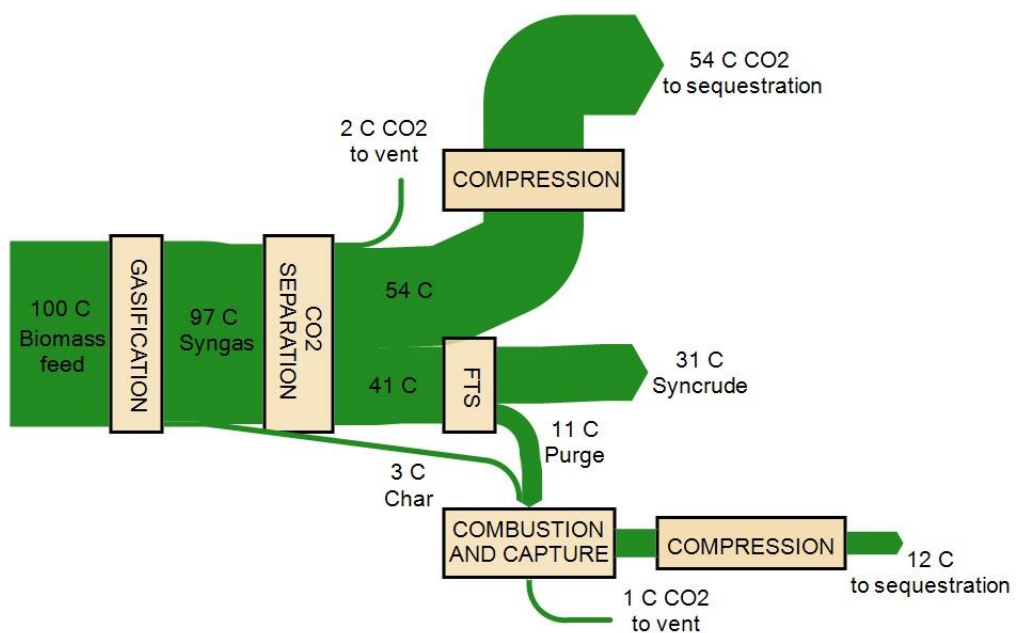


Figure 17: Simulated carbon flows for FTL-CCS-MAX configuration.

For H2-CCS (see Figure 18), 97 units of carbon are converted to gas and tars and 3 C to solid char. After maximal shifting, the gas now contains essentially only hydrogen and CO₂ with some residual methane and carbon monoxide. Almost all carbon (90 C) is separated by washing with chilled methanol (capture losses 3 C). Synthesis gas is then fed to a PSA unit where most of the hydrogen is removed to a separate stream. The remaining off-gas (4 C) is combusted with char (3 C) from the gasifier in an auxiliary boiler to form a diluted stream of CO₂ with 7 C. The concentrated stream of CO₂ from PSA is compressed to 150 bar for transport.

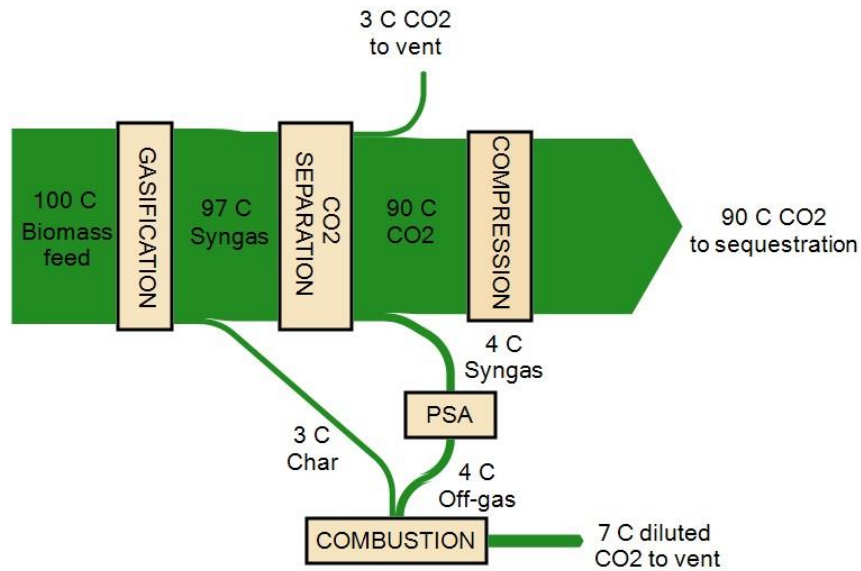


Figure 18: Simulated carbon flows H2-CCS configuration.

For H2-CCS-MAX (Figure 19), additional 7 C following combustion of char and PSA off-gas is captured by washing with amine. This increases the total capture share to 97 C. Combined capture losses are 4 C for this maximal capture design (deviations from 100 caused by rounding).

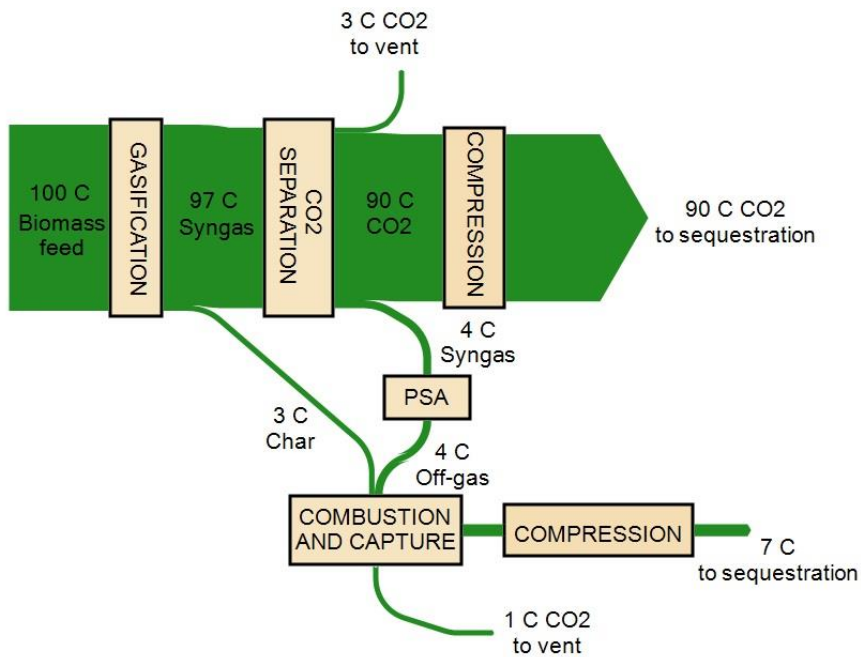


Figure 19: Simulated carbon flows for H2-CCS-MAX configuration.

The carbon flows discussed above are summarised in Table 7, together with calculated results for the upstream, conversion and total biofuel emissions (gCO₂eq/MJ) and *R*. The H₂-CCS configuration captures the highest share of input carbon to a concentrated stream of CO₂ (97% and 90%), followed by CE-CCS-MAX (74%), FTLs (66% and 54%), PO-CCS (36%), ETOH-CCS (21%) and finally CE-CCS (10%).

Relative emissions (*R*) from the plants are negative for almost all examined configurations featuring CCS due to the storage of the biogenic-CO₂. ETOH-CCS is an exception due to the high upstream emission, the use of natural gas as an energy source, and to the small share of CO₂ being captured.

Table 7: Carbon distributions and biofuel emissions. R is relative biofuel emissions in comparison to the fossil fuel reference. We use 94 gCO₂/MJ for petroleum-derived diesel/petrol and 93 gCO₂/MJ for fossil hydrogen produced via steam reforming of natural gas.

**OF FEEDSTOCK CARBON
THAT ENDS UP**

	vented	in fuel	stored as CO ₂	Direct upstream emissions gCO ₂ /MJ	Direct process emissions gCO ₂ /MJ	Total direct emissions gCO ₂ /MJ	<i>R</i>
ETOH-V	0.0	41.9	0.0	25.5	26	51	54 %
ETOH-CCS	0.0	41.9	21.0	25.5	-10	16	16 %
CE-V	81.0	19.0	0.0	1.8	0	2	2 %
CE-CCS	71.0	19.0	10.0	1.8	-37	-36	-38 %
CE-CCS-MAX	7.1	19.0	73.9	1.8	-276	-274	-291 %
PO-V	40.0	60.0	0.0	4.2	0	4	4 %
PO-CCS	4.0	60.0	36.0	4.2	-63	-59	-63 %
FTL-V	69.4	30.6	0.0	5.4	0	5	6 %
FTL-CCS	15.5	30.6	53.9	5.4	-122	-117	-124 %
FTL-CCS-MAX	3.1	30.6	66.4	5.4	-151	-145	-154 %
H ₂ -V	100.0	0.0	0.0	4.1	0	4	4 %
H ₂ -CCS	10.1	0.0	89.9	4.1	-156	-152	-163 %
H ₂ -CCS-MAX	3.5	0.0	96.5	4.1	-168	-164	-175 %

Wheat ethanol with maximal CO₂ capture is the most carbon negative product having emissions of -291% relative to fossil petrol. This is caused by both the large share of CO₂ being captured and the relatively low conversion efficiency to ethanol. ETOH-CCS-MAX is followed by hydrogen plants having emissions ranging from -175% to -163% relative to fossil hydrogen, followed by FT liquids from 154% to 124%, thermal bio-oil (-63%) and 2G ethanol with base case CO₂ capture design (-38%).

Natural gas is one of the main process utilities used in corn based ethanol plant and replacing it with a low-carbon alternative such as biogas, electricity etc. would lower the total biofuel emissions for ETOH-V from 51 to 26 gCO₂/MJ and for ETOH-CCS from 16 to -10 gCO₂/MJ. In the latter case, the

switch from natural gas to a non-fossil energy source together with CCS would therefore negate direct upstream emissions for the corn ethanol plant, making it a negative emissions technology.

The calculated biofuel emissions are also illustrated in Figure 20 together with biofuel yields and CO₂ capture rates for configurations featuring CCS. The biofuel yields are calculated as petrol equivalent litres per tonne of dry biomass input, and the CO₂ capture rates are calculated as stored kilograms of CO₂ per tonne of dry biomass input.

Between 1881 and 1753 kg of CO₂ is captured for every tonne of biomass (dry) by H₂ configurations featuring CCS. This is followed by FT-liquids with capture rate from 1294 to 1052 kgCO₂/t_{biom}, CE-ETOH with capture rate from 1240 to 168 kgCO₂/t_{biom}, thermal bio-oil with 702 kgCO₂/t_{biom} capture rate and 1G ethanol with 342 kgCO₂/t_{biom}.

Ethanol configurations that feature base case CCS designs have the smallest CO₂ capture rates as most of the biomass carbon will end up in the by-products, either distiller's dried grain solids (from corn) or combustion feedstock (from lignocellulosic biomass). When CO₂ from the by-product biomass is also captured (CE-CCS-MAX), a substantial increase in capture rate is achieved.

For thermochemical configurations, base case CCS designs already capture most of the available CO₂ from the process and maximal capture designs contribute only a small addition to the total capture. Highest capture rates are achieved with hydrogen configurations as all carbon from the process is in the form of CO₂ and therefore available for capture.

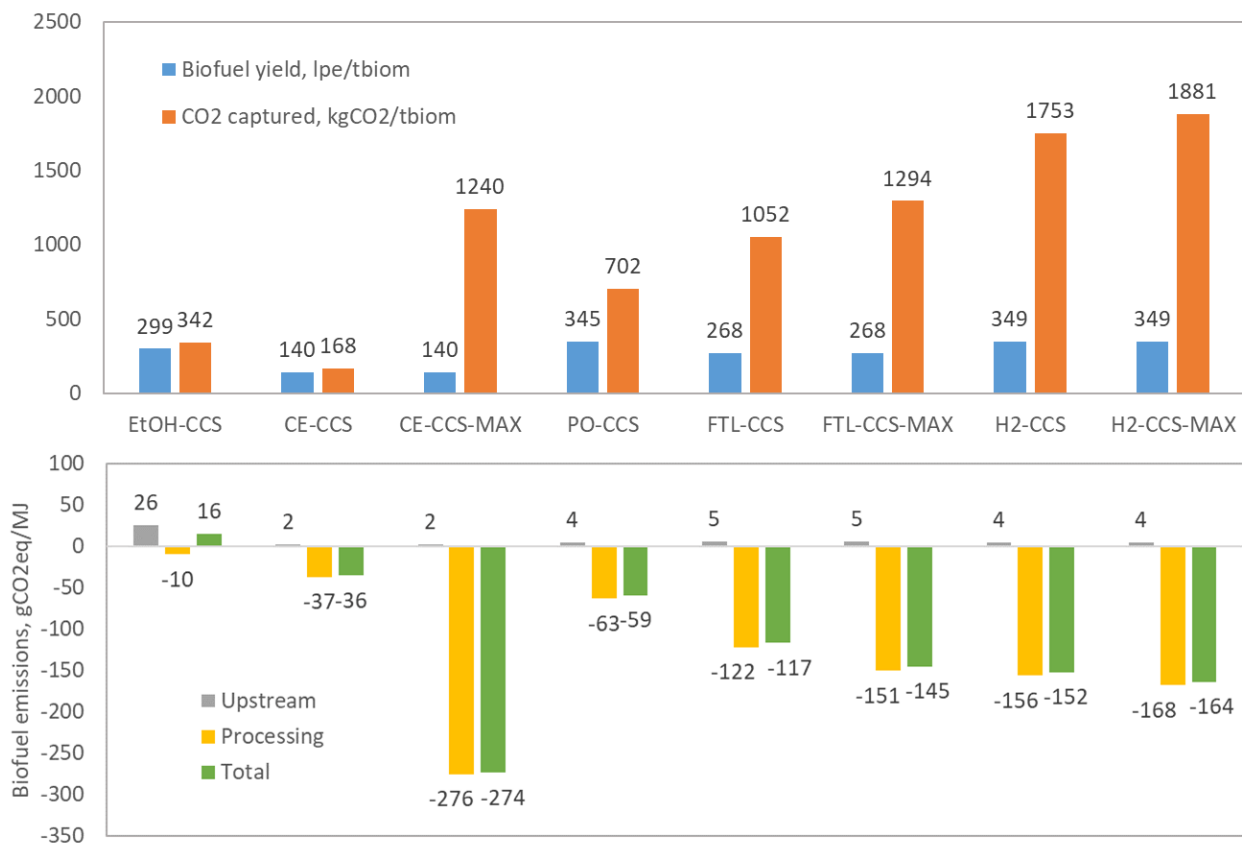


Figure 20: Biofuel yields, the amount of CO₂ captured and biofuel emissions for the examined biorefinery configurations that feature carbon capture and storage.

5.2 Process economics

Our FOAK estimates are summarised in Table 8 for each process configuration. The estimated carbon capture and compression (CCC) investments are presented separately and added to Vent configurations to arrive at an estimate on the TCI of CCS configurations. As separation of CO₂ is already included in the ethanol and gasification configurations, the additional investment needed to realise a CCS configuration comprises only of the compression system to pressurise CO₂ to 150 bar for transport..

The cost for CO₂ compression to supercritical pressure is based on Kreutz, et al.,⁷¹ who give a cost of \$14.8 million (\$2002) for a CO₂ dehydration and compression system (to 150 bar) at a scale of 13 MW_e. Of this total, 36% is due to the dehydration equipment, which is not required in biomass gasification based designs, as the CO₂ emerges dry from the Rectisol process. Kreutz's cost includes BOP, indirect costs (15%), and contingencies (15%).

The investment cost of post-combustion capture plant is estimated according to Jones et al.⁷² The total fixed investment cost for a 30 % Monoethanolamine (MEA) capturing 0.91 million tonne/annum CO₂ capture plant was \$134.4 year 2011. All investment costs are given as 2018 costs.

Table 8: Investment cost (TCI) estimates

Configuration	CCC, M\$	TCI, M\$
ETOH-V		136
ETOH-CCS	7	143
CE-V		253
CE-CCS	2	255
CE-CCS-MAX	83	335
PO-V		56
PO-CCS	33	89
FTL-V		434
FTL-CCS	3	437
FTL-CCS-MAX	22	456
H2-V		434
H2-CCS	4	437
H2-CCS-MAX	14	448

Using total capital investment estimates from Table 8 and financial parameters from Table 4, we calculate annual cash flows for the examined configurations as shown in Table 9.

⁷¹ Kreutz, T., Williams, R., Consonni, S., and Chiesa, P. Co-production of hydrogen, electricity and CO₂ from coal with commercially ready technology. Part B: Economic analysis. *International Journal of Hydrogen Energy* **30**, 769-784 (2005).

⁷² D. A. Jones, T. McVey, S. J. Friedmann, 2013 Technoeconomic Evaluation of MEA versus Mixed Amines for CO₂ Removal at Near-Commercial Scale at Duke Energy Gibson 3 Plant, Lawrence Livermore National Laboratory, <https://pdfs.semanticscholar.org/16fb/87f2ea4136441baafa23c56a9aa375634922.pdf>

Table 9: Annual cash flows for the examined plant configurations as M\$(2018)/yr.

CONFIGURATION	CAPITAL	O&M	CORN	BIOMASS	NG	DDGS	CO ₂ DISPOSAL	ELECTR. REVENUE	TOTAL
ETOH-V	13.9	5.4	132.8		27	-22		4.2	162
ETOH-CCS	14.5	5.7	132.8		28	-22	4.5	5.8	169
CE-V	25.8	10.1		22.7				-11.8	47
CE-CCS	26.0	10.2		22.7			1.0	-11.5	48
CE-CCS-MAX	34.2	13.4		22.7			7.0	-8.5	69
PO-V	5.7	2.3		9.2				-1.8	15
PO-CCS	9.1	3.6		9.2			1.6	-1.0	23
FTL-V	44.2	17.3		11.9				-1.4	72
FTL-CCS	44.5	17.5		11.9			3.1	-0.3	77
FTL-CCS-MAX	46.5	18.2		11.9			3.8	-0.1	80
H2-V	44.2	17.3		9.1				1.3	72
H2-CCS	44.6	17.5		9.1			4.0	2.7	78
H2-CCS-MAX	45.6	17.9		9.1			4.3	2.8	80

Finally, the contribution of different cost categories on the total cost of fuel (\$/GJ_{LHV}) and the cost of CCS (\$/tCO₂) are presented in

Table 10. Cost of carbon capture and sequestration ranges from 22 \$/tCO₂ to 66 \$/tCO₂ depending on the examined configuration. Lowest costs are associated with ethanol and gasification-based plants that feature CO₂ separation already in the base (vent) configuration and the cost of adding CCS is only 22 – 25 \$/tCO₂. A clear jump in cost can be seen for plants that incorporate post-combustion capture design, being 66 \$/tCO₂ for pyrolysis where all CO₂ is captured from flue gas, and 50 \$/tCO₂ for CE-CCS-MAX, where part of the CO₂ is captured at a lower cost from fermentation. For the CCS-MAX configurations, the costs increase more moderately for gasification-based configurations where only a small part of the overall CO₂ is captured from flue gas.

Table 10: Cost comparison of examined process configurations. Results are given as $\$/GJ_{LHV}$, if not otherwise noted.

CONFIG.	CAPITAL	O&M	FEED STOCK	NG	DDGS	CO ₂ DISPOSAL	ELECTR.	TOTAL (\$/GJ)	COST OF CCS (\$/TCO ₂)
ETOH-V	1.6	0.6	15.6	3.2	-2.6		0.5	19.0	
ETOH-CCS	1.7	0.7	15.6	3.2	-2.6	0.5	0.7	19.8	24
CE-V	15.1	5.9	13.3				-7.0	27.5	
CE-CCS	15.3	6.0	13.3			0.6	-6.8	28.4	25
CE-CCS-MAX	20.1	7.9	13.3			4.1	-5.0	40.4	47
PO-V	3.4	1.3	5.4				-1.1	9.0	
PO-CCS	5.4	2.1	5.4			0.9	-0.6	13.2	66
FTL-V	26.0	10.2	7.0				-0.8	42.3	
FTL-CCS	26.2	10.3	7.0			1.8	-0.2	45.0	22
FTL-CCS-MAX	27.3	10.7	7.0			2.3	0.0	47.2	33
H2-V	26.0	10.2	5.4				0.8	42.3	
H2-CCS	26.2	10.3	5.4			2.3	1.6	45.8	22
H2-CCS-MAX	26.8	10.5	5.4			2.5	1.7	46.9	27

The main cost results (the levelised cost of fuel and the cost of CCS) are also visualised in Figure 21 for all examined plant configurations.

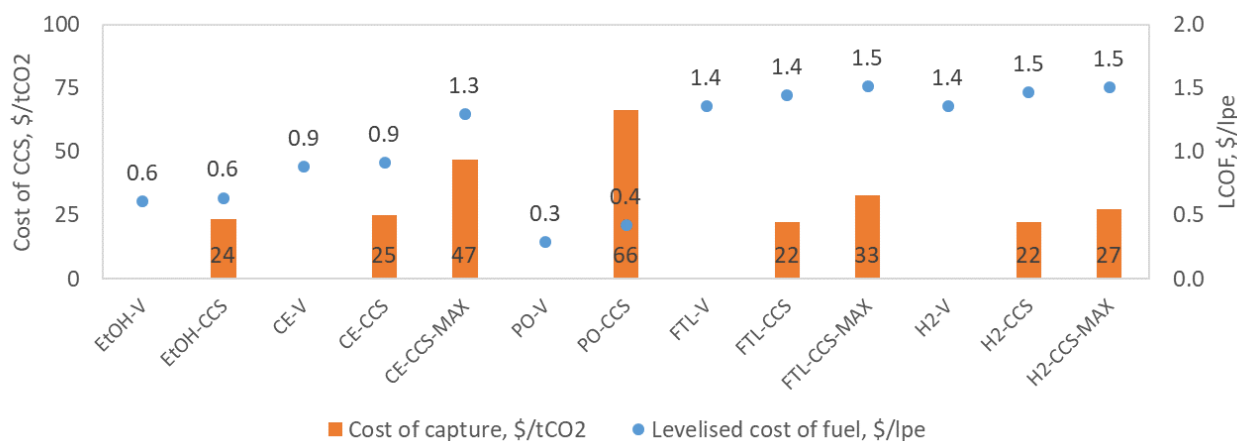


Figure 21: Levelised cost of fuels (dollars per petrol equivalent litres of biofuel) and cost of CCS (US dollars per tonne of sequestered CO₂) for all examined plant configurations.

The levelised cost of biofuel ranges from 0.3 to 1.5 dollars per petrol equivalent litre being lowest for thermal bio-oil from pyrolysis and second lowest for corn ethanol. A clear jump in costs can be seen when transitioning to other technologies. LCOF for wheat ethanol is between 0.9 and 1.3 \$/lpe (dollars per petrol equivalent litres) depending on the CCS design whereas gasification based configuration has biofuel cost between 1.4 and 1.5 \$/lpe.

5.3 Sensitivity to plant scale

We then investigate the impact of plant scale on process economics. Chemical process technologies are usually expected to benefit from a large scale, as doubling the plant output less than doubles the capital investment cost. Biomass-based technologies are, however, limited in their scale by the availability of biomass, which is a geographically dispersed resource that cannot usually be economically transported more than 100 km. In Figure 22, the impact of plant scale on the cost of CCS and levelised cost of fuel is examined for plants that process woody biomass (we exclude corn ethanol plants from this analysis as they are operating at a much larger scales).

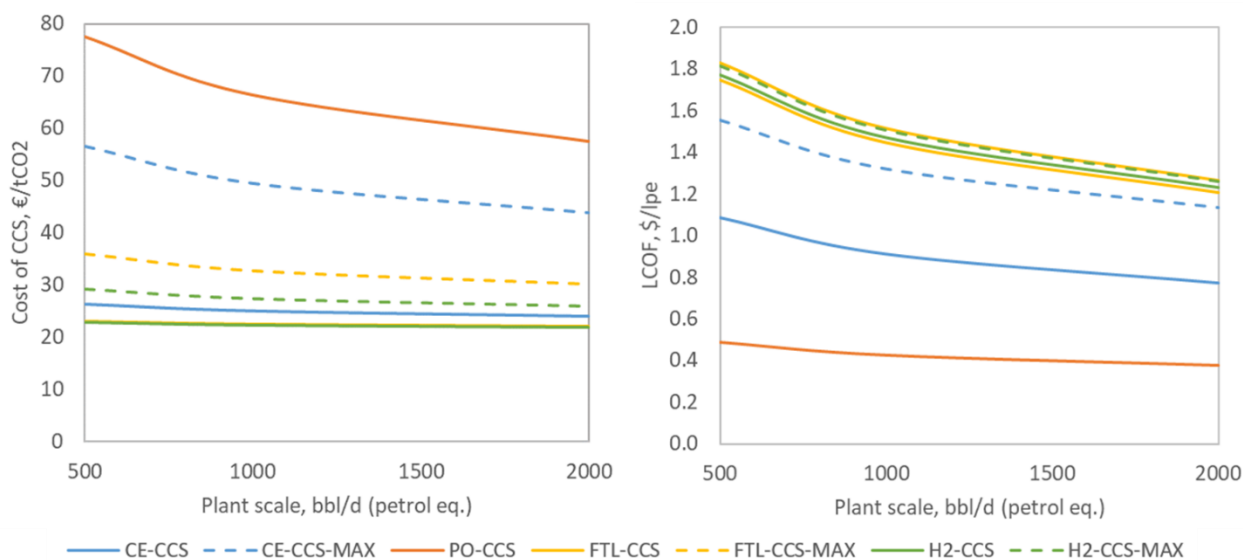


Figure 22: Impact of plant scale on the cost of CCS and on the levelised cost of biofuel.

According to the results, the plant size has modest impact on the cost of CCS for plants that incorporate capture from fermentation and from synthesis gas, as the costs are associated only for the compression and are therefore relatively low. For plants where most of the CO₂ is captured from flue gases by scrubbing with amine, the size of the plant has higher impact on costs. For example, for pyrolysis plants the cost of CCS reduces from 78 \$/tCO₂ to 58 \$/tCO₂ when the scale of plant increases from 500 to 2000 bbl/d. The plant scale has a much more pronounced impact on the levelised cost of fuel. For example, for gasification based configurations the cost of biofuel reduces from about 1.8 \$/lpe to 1.3 \$/lpe when plant scale increase from 500 to 2000 bbl/d level.

In Figure 23, we examine the impact of feedstock cost on the biofuel production cost. Here the corn ethanol configurations are also excluded from the comparison as they are governed by different feedstocks characteristics (both in terms for cost and availability) than plants operating on lignocellulosic feedstocks.

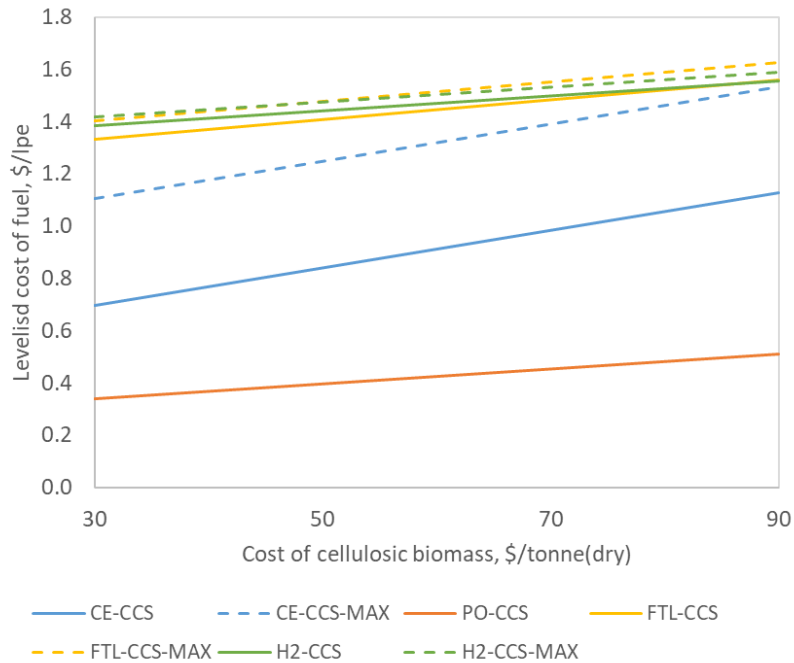


Figure 23. Impact of cellulosic biomass cost on the levelised cost of fuel.

Based on the results, the feedstock cost has lowest impact on the biofuel production cost for the gasification-based configurations, and highest for the PO-CCS and CE-CCS configurations. This is probably explained by the higher share of CapEx in the cost of gasification-based plants. For example, an increase in the cost of biomass feedstock from 30 to 90 \$/tonne increases the biofuel production cost by 61% (from 0.7 to 1.1 \$/lpe) for the CE-CCS plant, but only by 12% (1.4 – 1.6 \$/lpe) for the H2-CCS-MAX.

6 Discussion and recommendations

CCS technologies have for long been considered as an essential tool to meet climate mitigation targets in the power and industrial sectors. In recent years, however, as the need to remove substantial amounts of carbon dioxide from the atmosphere has become imminent, the prospect of coupling CCS with bioenergy has regained interest.

Five different biorefinery technologies have been examined and compared, representing different technological approaches, feedstocks, end-products and commercial maturities. Some process configurations, like those involving fermentation, feature high-concentration CO₂ streams that could be captured and prepared for transport at a low cost. Some concepts feature both high and low concentration CO₂ streams, and therefore a higher share of capture would also lead to higher cost of CCS. In the present work, our base case capture designs capture CO₂ only from high-concentration streams, while MAX designs feature additional capture from low-concentration streams, i.e. flue gases. Here, our pyrolysis design represents an exception, as CO₂ is only available in flue gas, and therefore the base case capture design is also the MAX design.

Based on our results, the cost of adding CCS on the high-concentration streams of biorefineries varies between 22 and 24 \$/tCO₂. If CCS is extended also to flue gas streams, the cost of CCS varies between 27 and 66 \$/tCO₂. The wider range of cost is explained by differences between biorefineries in the share of CO₂ that needs to be captured from low-concentration streams. The lowest cost of CCS is achieved with gasification-based configurations using base case CCS design (22 \$/tCO₂) followed closely by ethanol plants with base case CCS design (24-25 \$/tCO₂). However,

up to ten times more CO₂ (1052 – 1753 kgCO₂/t_{biom}) is captured from the same amount of biomass by gasification configurations than by base case ethanol configurations (168 – 342 kgCO₂/t_{biom}). Only when the by-product lignin is fully combusted and captured (CE-CCS-MAX) can similar capture rates be achieved for the biochemical plants. However, this will significantly increase the cost of CCS to 47 \$/tCO₂.

Due to the capture and sequestration of biogenic CO₂, biorefineries show deeply negative emissions. The corn ethanol design ETOH-CCS is a notable exception to this rule, due to high upstream emissions of corn and the use of natural gas as additional energy source in the process. However, if natural gas would be switched to a low-carbon energy source, corn ethanol plants with CCS would also produce carbon negative fuels. For biorefineries based on woody biomass, emissions range between -36 gCO_{2eq}/MJ and -274 gCO_{2eq}/MJ. The deepest emissions reductions in comparison to fossil petrol are associated with CE-CCS-MAX as it combines a large capture rate with relatively small biofuel output, therefore leading to highly negative emissions per megajoule of biofuel produced.

On paper, biorefineries with CCS seem very attractive. They would contribute to decarbonising the hard-to-abate transport sector, provide much-needed negative emissions at scale, and the cost of CCS would be only a fraction of that when applied to traditional power plants. On the other hand, the cost of biofuel is currently too high to compete with petroleum fuels, the location of a geological storage formation does not always coincide with good availability of biomass, and out of the 13 examined configurations only ETOH-V and ETOH-CCS have been currently demonstrated at commercial scale.

However, responding to the Paris Agreement will ultimately require deploying negative emissions at scale. Given the current slow progress in deploying both biorefineries and CCS, the main goal in the near term should be to develop successful large-scale demonstration projects that reduce risk and increase investor confidence towards these emerging technologies. Any assessment of the prospective performance and cost of biorefineries with CCS is inevitably limited by the small handful of actual projects, and so, more operational plants will be needed to reduce uncertainties and to start learning from these technologies at relevant scale.

Annex I:
Summary of process design parameters and feedstock
properties

All process design parameters used in the Aspen simulation models are listed separately for biochemical, fast pyrolysis, and gasification configurations in *Table 11*. In addition, equipment common to all designs are described at the end of the table.

Table 11: Summary of design parameters used in simulation models.

Item	Design parameters
<i>Biochemical configurations</i>	
Corn to Ethanol	Equal molar amount of CO ₂ and ethanol are produced, corresponding to a mass ratio of 1.054 between ethanol and CO ₂ . Ethanol yield = 452 litres (357 kg) of ethanol per metric tonne dry matter of corn feedstock.
Ethanol from lignocellulosic biomass	Equal molar amount of CO ₂ and ethanol are produced, corresponding to a mass ratio of 1.054 between ethanol and CO ₂ . Mass yield of ethanol assumed to be 16.7 wt-% according to data reported in the Inbicon demo plant. ⁷³ Lignin residue and produced biogas are combusted at a nearby CHP plant.
<i>Fast pyrolysis configurations</i>	
	Mass yield of pyrolysis oil based wood dry matter 77 wt-%, based on experimental pilot test at VTT in the 4REFINERY project. Mass of CO ₂ produced in combustion of char and gases in pyrolysis process 79 wt% of the dry biomass feed.
<i>Gasification configurations</i>	
Pressurised steam/O ₂ -blown fluidised-bed gasifier	Heat loss = 1 % of biomass LHV. $\Delta p = -0.2$ bar. Carbon conversion: 97 %. Modelled in two steps with RStoic and RGibbs using Redlich-Kwong-Soave equation of state with Boston-Mathias modification (RKS-BM). Hydrocarbon formation (kmol/kg of fuel volatiles): CH ₄ = 6.7826, C ₂ H ₄ = 0.4743, C ₂ H ₆ = 0.2265, C ₆ H ₆ = 0.2764. Tars modelled as naphthalene: C ₁₀ H ₈ = 0.0671, All fuel nitrogen converted to NH ₃ . All other components assumed to be in simultaneous phase and chemical equilibrium. Inlet pressure 4 bar, outlet temperature 880°C.
Ceramic hot-gas filter	$\Delta p = -0.05$ bar. Inlet temperature 820 °C.
Catalytic autothermal partial oxidation reformer	Modelled as RGibbs using Redlich-Kwong-Soave equation of state with Boston-Mathias modification (RKS-BM). Phase and chemical equilibrium conversion for C ₂₊ and tar. Ammonia conversion restricted to 50 %. Outlet temperature 957°C, CH ₄ conversion 95 %. $\Delta p = -0.4$ bar
Sour-shift reactor(s)	Steam/CO = 1.8 mol/mol, $\Delta p = -0.2$ bar. Modelled as REquil using Redlich-Kwong-Soave equation of state with Boston-Mathias modification (RKS-BM). Equilibrium reactions: CO + H ₂ O = CO ₂ + H ₂ , T _{appr} = 10 K. COS + H ₂ O = CO ₂ + H ₂ S, T _{appr} = 0 K. HCN + H ₂ O = CO + NH ₃ , T _{appr} = 10 K. FTL designs: one adiabatic WGS reactor, T _{out} = 400°C, bypass adjusted to achieve H ₂ /CO = 2.1 (mol/mol). H ₂ designs: two adiabatic WGS reactors. T _{1out} =400°C and CO conversion 75%, T _{2out} =250°C and CO conversion 79%; combined CO conversion 95%.
Syngas scrubber cooler	Scrubbing liquid: water. T _{inlet} 200 °C. Two-step cooling: T ₁ = 60 °C, T ₂ = 30 °C. Complete ammonia removal. Modelled as Flash using Soave-Redlich-Kwong (SRK) equation of state model.
Acid gas removal (pre-combustion capture)	97 % capture of CO ₂ , 100% capture of H ₂ S. Utilities: Electricity (other than for refrigeration) =1900 kJ/kmol(CO ₂ +H ₂ S); Refrigeration 3 x duty needed to cause -12 K temperature change in the syngas; 5 bar steam = 6.97 kg/kmol (H ₂ S+CO ₂).
Low-temperature Fischer-Tropsch synthesis	T _{reaction} = 200°C, P _{fresh feed} = 25 bar, $\Delta p = -1$ bar, Boiling-water reactor using cobalt catalysts modelled with REquil using Redlich-Kwong-Soave equation of state with Boston-Mathias modification (RKS-BM). Per-pass CO conversion depending on the configuration. 0.90 α value and 92 % C ₅₊ selectivity. Input H ₂ O, CO ₂ , N ₂ as well as unreformed methane, ethane and longer hydrocarbons considered inert.

⁷³ Larsen J., Østergaard M., H. , Thirup L., Inbicon makes lignocellulosic ethanol a commercial reality, Biomass and bio energy, 46 (2 0 1 2) 3 6 -4 5

Pressure Swing Adsorption	Inlet: 25°C and 20 bar. Pressure drop 0.2 bar for product stream, off-gas at ambient pressure. Hydrogen separation efficiency 86%.
<i>Common equipment</i>	
Post-combustion capture	Regeneration of 30 wt-% MEA CO ₂ absorption solvent is assumed to require 3.9 GJ/tCO ₂ absorbed, thus appr. 31.9 MW of heat is needed for regeneration. When 3.9 MW of heat is supplied as 4.5 bar steam instead of 2 bar district heat, the estimated reduction in power production for case ETOH-CCS-MAX is 1.0 MW based on process simulation. When 3.9 MW of heat is supplied as 4.5 bar steam instead of 2 bar district heat, the estimated reduction in power production for case PO-CCS is 0.2 MW based on process simulation.
CO ₂ compression	The outlet pressure of each compression stage is specified (polytropic efficiencies in parentheses) as follows: compression stage 1: 4.35 bar (80 %) stage 2: 18.65 bar (80 %) and stage 3: 80 bar (75 %). After the third stage, the supercritical CO ₂ is pumped to the suggested final pressure of 150 bar. All compressor drivers have an efficiency of 95 % giving specific electricity requirement of 0.36 MJ/kgCO ₂ for the pressurisation of CO ₂ from near atmospheric level to 150 bar.
Heat exchangers ⁷⁴	$\Delta p/p = 2 \%$; $\Delta T_{\min} = 15^{\circ}\text{C}$ (gas-liq), 30°C (gas-gas). Heat loss = 1 % of heat transferred.
Compressors ⁷⁵	Stage pressure ratio <2, $\eta_{\text{polytropic}} = 0.85$, $\eta_{\text{driver}} = 0.92$, $\eta_{\text{mechanical}} = 0.98$.
Multistage compressors (>4.5 kg/s) ⁷⁶	Stage pressure ratio <2, $\eta_{\text{polytropic}} = 0.87$, $\eta_{\text{driver}} = 0.92$, $\eta_{\text{mechanical}} = 0.98$, $T_{\text{intercooler}} = 35^{\circ}\text{C}$, $\Delta p/p$ intercooler = 1%.
Multistage compressors (<4.5 kg/s) <small>ERROR! BOOKMARK NOT DEFINED.</small>	Stage pressure ratio <2, $\eta_{\text{polytropic}} = 0.85$, $\eta_{\text{driver}} = 0.90$, $\eta_{\text{mechanical}} = 0.98$, $T_{\text{intercooler}} = 35^{\circ}\text{C}$, $\Delta p/p$ intercooler = 1 %.
Pumps <small>ERROR! BOOKMARK NOT DEFINED.</small>	$\eta_{\text{hydraulic}} = 0.75$, $\eta_{\text{driver}} = 0.90$.

⁷⁴ G. Liu, E. D. Larson, R. H. Williams, T. G. Kreutz, X. Guo, Supporting information for making Fischer-Tropsch fuels and electricity from coal and biomass: Performance and cost analysis, Energy & Fuels 25 (1). doi:10.1021/ef101184e.

⁷⁵ P. Chiesa, S. Consonni, T. Kreutz, R. Williams, Co-production of hydrogen, electricity and CO₂ from coal with commercially ready technology. Part A: Performance and emissions, International Journal of Hydrogen Energy 30 (7) (2005) 747–767. doi:10.1016/j.ijhydene.2004.08.002.

⁷⁶ A. Glassman, Users manual for updated computer code for axial-flow compressor conceptual design, Tech. rep., University of Toledo, Toledo, Ohio (1992).

Table 12: Properties of the biorefinery feedstocks used in this work.

	Corn	Wheat straw	Forest residues ⁷⁷
Proximate analysis, wt%, d.b.*			
Fixed carbon	18.84 ⁷⁸	18 ⁷⁹	25.3
Volatile matter	70.89 _a	74.89 _a	70.8
Ash content	1.27 _a	7.1 _a	3.9
Ultimate analysis, wt%, d.b.			
Ash	1.27 _a	7.1 _a	3.9
C	44.44 ₈₀	45.8 _a	53.2
H	6.22 _a	5.96 _a	5.5
N	0	0.16 _a	0.3
S	0	0.45 _a	0.04
O (difference)	49.34 ^a	40.13 _a	37.06
Other properties			
Composition analysis wt% d.b.*			Not needed for thermochemical process calculations
Starch	72.0⁸¹		
Hemicellulose/	totally	26.5 ⁸²	
Cellulose	10.0_a	37.8 _a	
Protein	9.5_a	4.3 _a	
Oil	4.5_a		
Sugars	2.0_a		
Lignin		17.5 _a	
HHV, MJ/kg	16.6 ⁸⁷	18.49 ⁸⁸	20.67
Moisture (in to process), wt%	9	11.1	15
*wt% d.b. = weight percent dry basis.			
a) same source as above			

⁷⁷ Wilen C, Moilanen A, Kurkela E. Biomass feedstock analyses. VTT Publications 282, (VTT, 1996).

⁷⁸ Phyllis 2 - ECN Phyllis classification, 2020, <https://phyllis.nl/> corn shelled (#1973), accessed 31.08.2020

⁷⁹ Phyllis 2 - ECN Phyllis classification, 2020, <https://phyllis.nl/> wheat straw (Danish) (#1302), accessed 31.08.2020

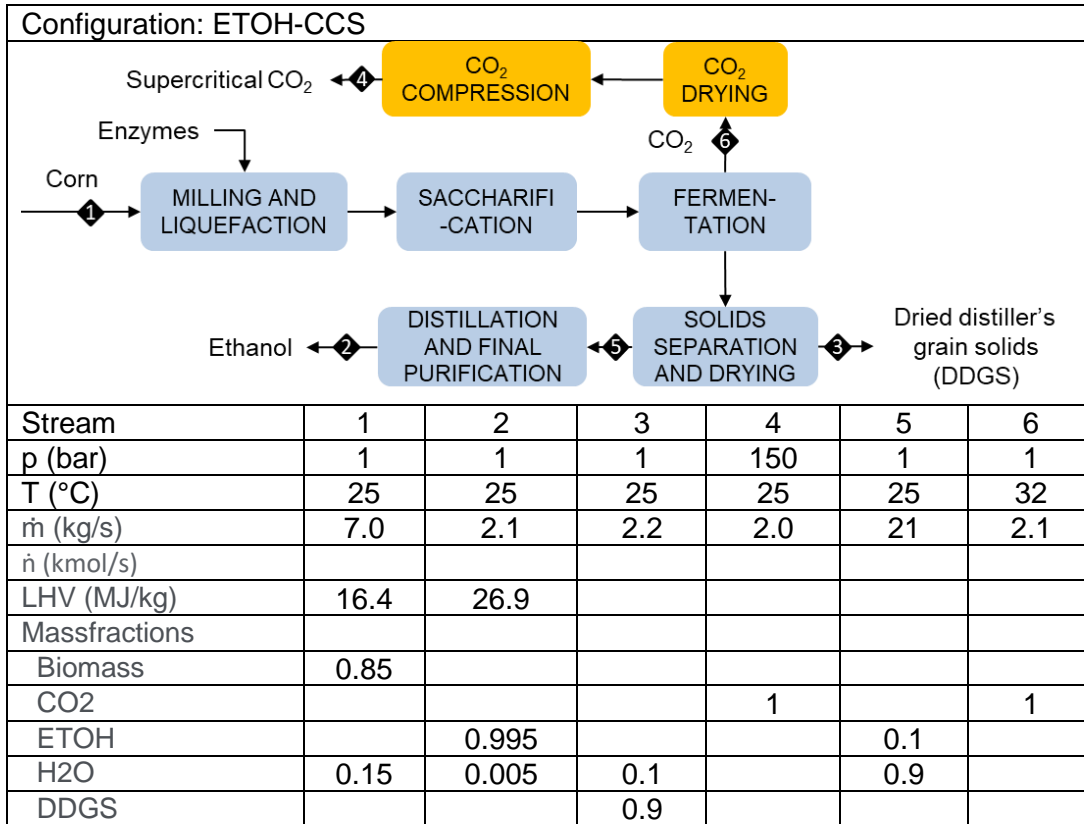
⁸⁰ <https://phyllis.nl/Browse/Standard/ECN-Phyllis#corn>, corn strach #2793 , accessed 31.08.2020

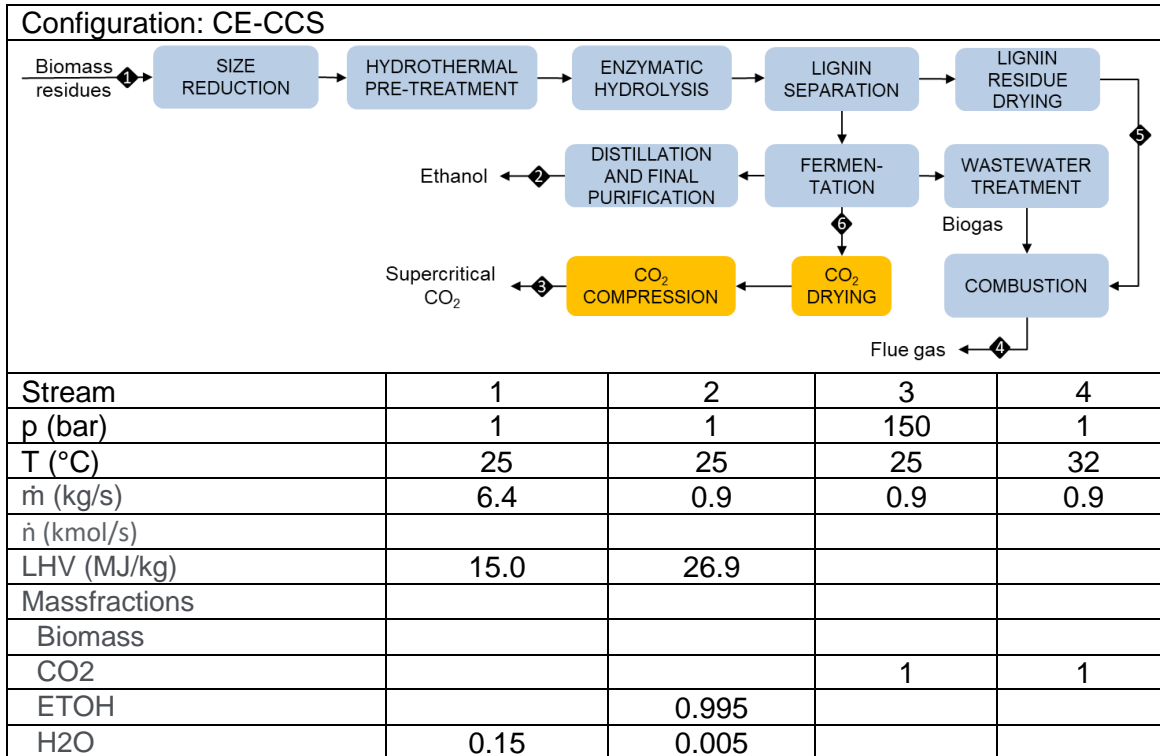
⁸¹ Andrew McAloon, Frank Taylor, and Winnie Yee, Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks, U.S. Department of Agriculture, 2000

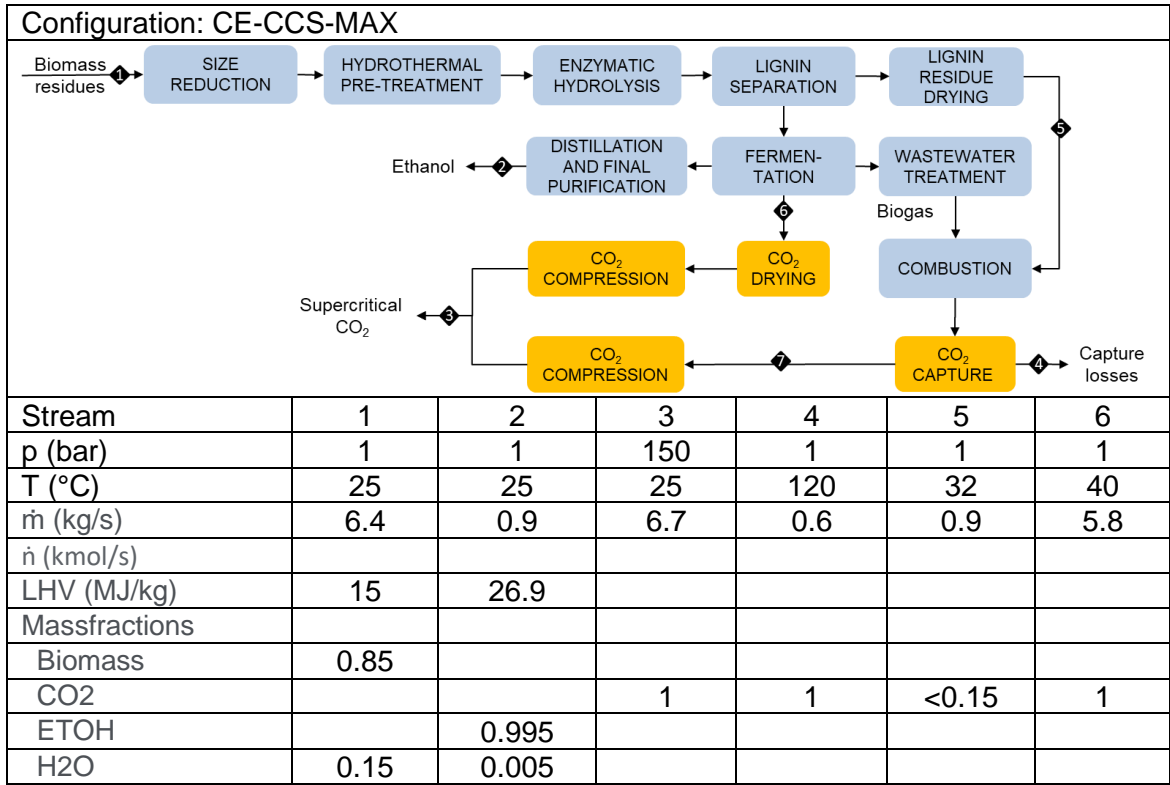
⁸² Rob Bakker, Wolter Elbersen, Ronald Poppens, Jan Peter Lesschen, Rice straw and Wheat straw Potential feedstocks for the Biobased Economy , 2013

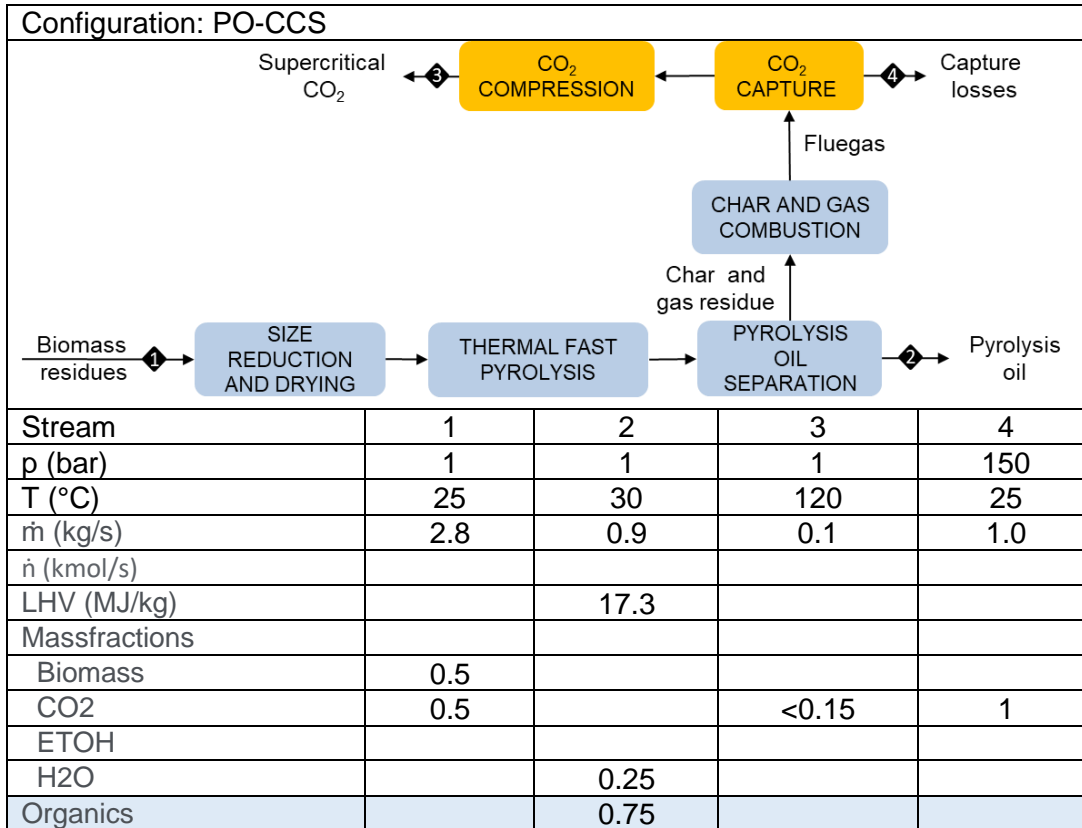
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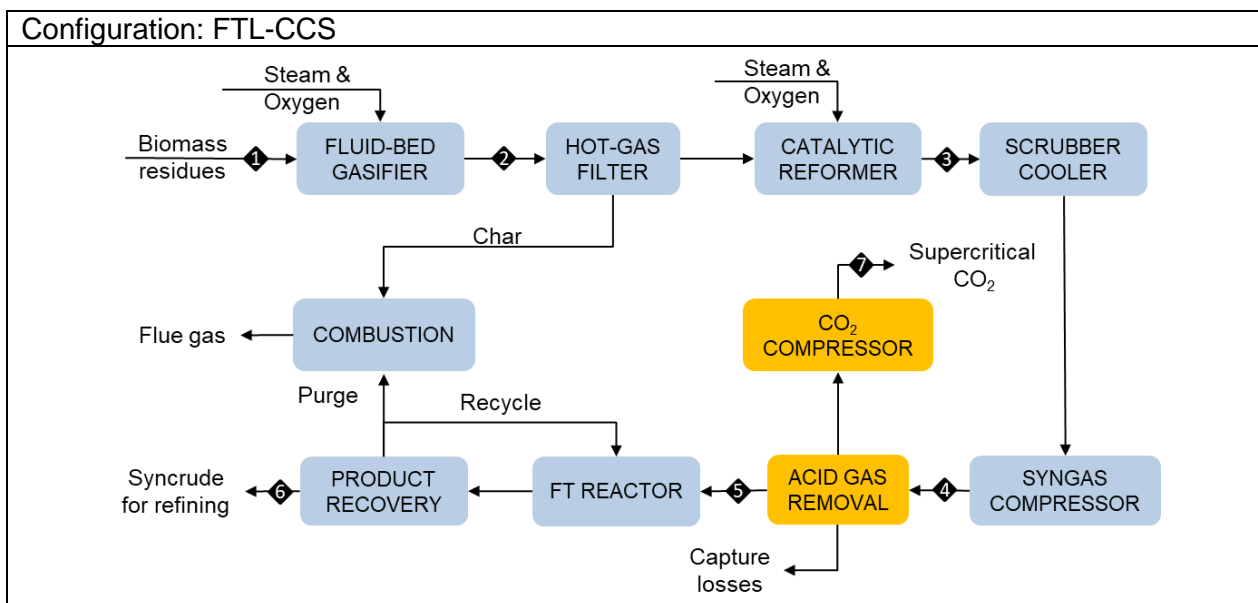
Annex II:
Block diagrams for examined process configurations with
simulated stream data





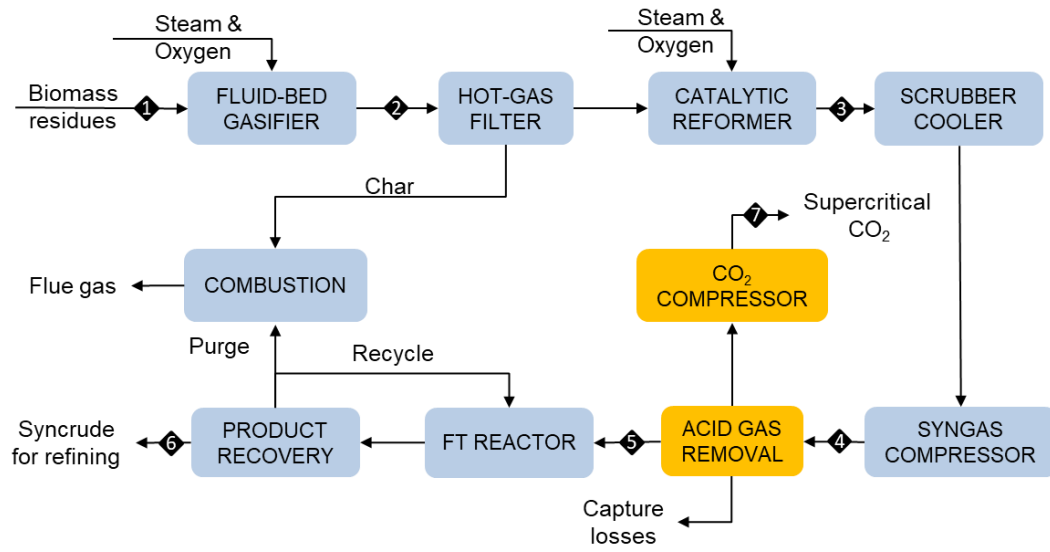






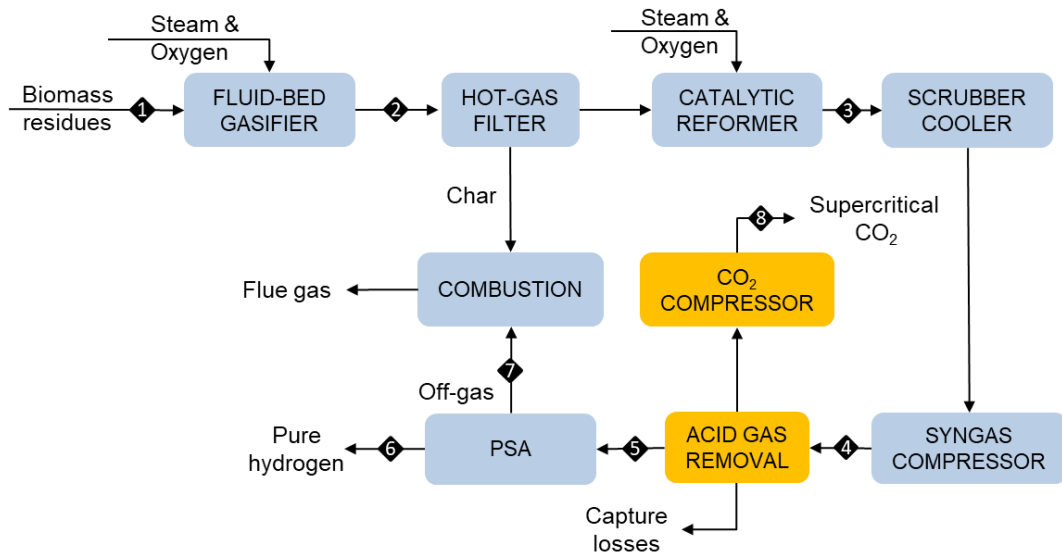
Stream	1	2	3	4	5	6	7
T (°C)	25	880	957	35	200	40	25
p (bar)	4	4	3	26	25	1	150
\dot{m} (kg/s)	1000	1927	2169	1711	926	199	1083
\dot{n} (kmol/s)		85	106	81	71	1	25
LHV (MJ/kg)	19.6	8.5	6.7	8.3	22.3	44.0	0.0
Molefractions							
CO		0.214	0.234	0.218	0.291		
H2		0.242	0.283	0.457	0.574		
CO2		0.199	0.169	0.309	0.027		1.000
CH4		0.054	0.002	0.003	0.055		
C2H4		0.007					
C2H6		0.002			0.005		
C6H6		0.002					
C10H8		0.001					
NH3		0.002					
H2O		0.268	0.302	0.002	0.000		
N2		0.009	0.008	0.011	0.041		
H2S		0.00014	0.00011	0.00015			
COS		0.00001	0.00000	0.00000			
C5+						1	

Configuration: FTL-CCS-MAX



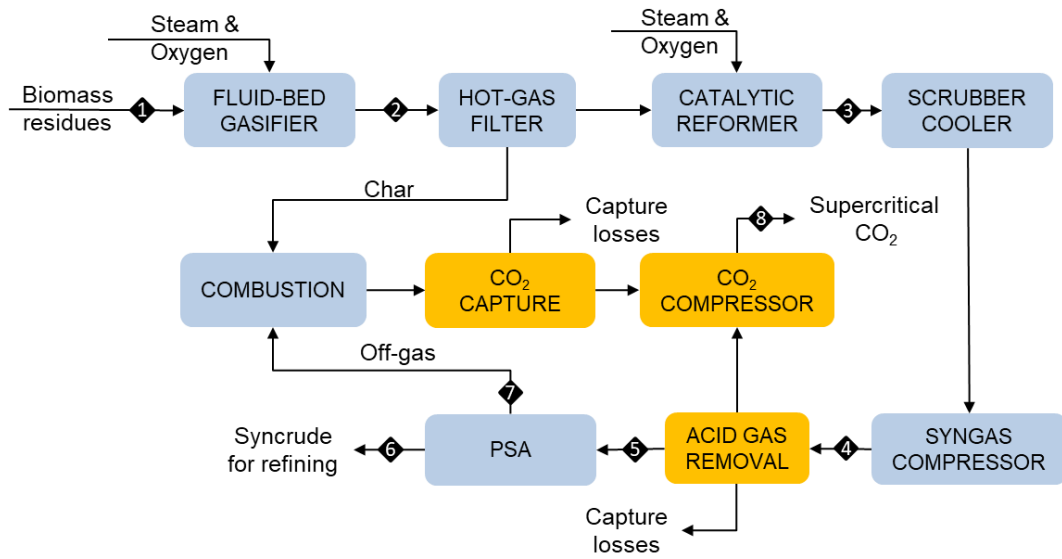
Stream	1	2	3	4	5	6	7
T (°C)	25	880	957	35	200	40	25
p (bar)	4	4	3	26	25	1	150
\dot{m} (kg/s)	1000	1927	2169	1711	926	199	1351
\dot{n} (kmol/s)		85	106	81	71	1	31
LHV (MJ/kg)	19.6	8.5	6.7	8.3	22.3	44.0	0.0
Molefractions							
CO		0.214	0.234	0.218	0.291		
H2		0.242	0.283	0.457	0.574		
CO2		0.199	0.169	0.309	0.027		1.000
CH4		0.054	0.002	0.003	0.055		
C2H4		0.007					
C2H6		0.002			0.005		
C6H6		0.002					
C10H8		0.001					
NH3		0.002					
H2O		0.268	0.302	0.002	0.000		
N2		0.009	0.008	0.011	0.041		
H2S		0.00014	0.00011	0.00015			
COS		0.00001	0.00000	0.00000			
C5+						1	

Configuration: H2-CCS



Stream	1	2	3	4	5	6	7	8
T (°C)	25	880	957	35	40	35	40	25
p (bar)	4	4	3	21	20	30	1	150
\dot{m} (kg/s)	1000	1926	2168	2008	198	93	105	1805
\dot{n} (kmol/s)	0	85	106	98	57	46	10	41
LHV (MJ/kg)	19.6	8.5	6.7	6.8	68.3	120.0	22.6	0.0
Molefractions								
CO		0.214	0.234	0.013	0.023		0.125	
H2		0.242	0.283	0.548	0.947	1.000	0.716	
CO2		0.199	0.169	0.424	0.010		0.054	1.000
CH4		0.054	0.002	0.002	0.004		0.022	
C2H4		0.007						
C2H6		0.002						
C6H6		0.002						
C10H8		0.001						
NH3		0.002						
H2O		0.267	0.301	0.002				
N2		0.009	0.008	0.009	0.015		0.083	
H2S		0.00014	0.00011	0.00015				
COS		0.00001	0.00000	0.00000				

Configuration: H2-CCS-MAX



Stream	1	2	3	4	5	6	7	8
T (°C)	25	880	957	35	40	35	40	25
p (bar)	4	4	3	21	20	30	1	150
\dot{m} (kg/s)	1000	1926	2168	2008	198	93	105	1937
\dot{n} (kmol/s)	0	85	106	98	57	46	10	44
LHV (MJ/kg)	19.6	8.5	6.7	6.8	68.3	120.0	22.6	0.0
Molefractions								
CO		0.214	0.234	0.013	0.023		0.125	
H2		0.242	0.283	0.548	0.947	1.000	0.716	
CO2		0.199	0.169	0.424	0.010		0.054	1.000
CH4		0.054	0.002	0.002	0.004		0.022	
C2H4		0.007						
C2H6		0.002						
C6H6		0.002						
C10H8		0.001						
NH3		0.002						
H2O		0.267	0.301	0.002				
N2		0.009	0.008	0.009	0.015		0.083	
H2S		0.00014	0.00011	0.00015				
COS		0.00001	0.00000	0.00000				



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