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FUTURE-PROOF BIOFUELS THROUGH IMPROVED UTILIZATION OF BIOGENIC CARBON

Carbon, Climate and Cost Efficiency (K3)

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PREFACE

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The Swedish Energy Agency is a government agency subordinate to the Ministry of Infrastructure. The Swedish Energy Agency is leading the energy transition into a modern and sustainable, fossil free welfare society and supports research on renewable energy sources, the energy system, and future transportation fuels production and use.

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SUMMARY

With competition for clean carbon intensifying as the energy transition accelerates, the biofuel industry must prepare for two likely future developments: (1) increasing demand for sustainable biomass assortments in multiple sectors will require careful balancing of commercial and societal priorities, and (2) wastage of biogenic carbon will be undesirable. The push for biofuels in Sweden is centered on the use of forest residues as the principal feedstock base. The conversion of biomass to biofuel typically generates residual carbon flows (often as CO_2), the extent of which depends on the choice of conversion technologies. Capturing residual carbon streams and upgrading them to biofuels with the help of electricity is an example of bioenergy carbon capture and utilization (BECCU), that can improve carbon utilization and boost production. Sequestering the same carbon in permanent storage (BECCS) can instead achieve biofuels with negative CO_2 emission footprints. In this study we examined the potentials of combining biofuel production with CCS and CCU. We used process-level carbon and energy balance models to estimate the performance in terms of carbon efficiency, greenhouse gas (GHG) footprint, biofuel production cost, biomass feedstock potential in Sweden, and technological maturity. A total of 14 different biofuel production pathways were examined, for (1) a *base* option without CO_2 capture, (2) a *CCS* option with capture and permanent sequestering of CO_2, and (3) a *CCU* option with upgrading of the captured CO_2 to additional biofuel using hydrogen from electrolysis. Both commercially widespread and emerging pathways (technically demonstrated but still under development) were included.

The full benefits of BECCS and BECCU in the biofuel sector were concluded to be best unlocked by deploying emerging pathways. While the emerging pathways do not offer the lowest GHG reduction costs, they do offer the largest relative improvements in carbon efficiency and GHG reductions under the CCS option. From a combined carbon, cost and climate perspective, the overall best performing pathways were based on gasification or hydrotreatment of forest residues.

BECCS and BECCU are of more limited value in commercial biofuel pathways. *Biogas pathways* have high CO_2 transport costs due to small and relatively dispersed plants, and commercial *hydrotreatment* already uses their feedstock carbon efficiently. For both of those, as well as for *ethanol from wheat grain*, significant biogenic carbon quantities also end up in commercially important by-products, while the Swedish feedstock potentials are relatively limited.

Using BECCU to produce more biofuels from captured carbon may be economically competitive, and can offer a viable solution for a biomass-constrained future. The increased biofuel production capacity would, however, come with a corresponding increased electricity demand, which would in turn require an extensive scale-up of renewable electricity production.

Sequestering CO_2 through BECCS generates biofuels with very good climate performance, but at higher cost. The cost for carbon efficient biofuels with negative GHG footprints may, however, be reduced significantly if markets and/or support schemes for negative emission credits were to emerge. Credits around 100 EUR per ton of CO_2 could make the best BECCS biofuel production pathways cost-competitive in relation to the base and the CCU options.

In summary, we conclude that integration of BECCS and BECCU with current commercial biofuel production pathways offers limited value. The full benefits are contingent on the timely deployment of biofuel pathways that are not currently in commercial operation.

SAMMANFATTNING

När konkurrensen om förnybart kol hårdnar i takt med att energiomställningen accelererar behöver biodrivmedelssektorn förbereda sig för att: (1) ökad efterfrågan på hållbara biomassasortiment kommer kräva noggrann balansering av kommersiella och samhälleliga prioriteringar, och (2) ”slöseri” av biogent kol kommer vara oönskat. I Sverige inriktas framtidens biodrivmedel mot rester från bland annat skogen som huvudsaklig råvara. Omvandlingen av biomassa till drivmedel orsakar vanligtvis att en icke försumbar av råvarans biogena kol hamnar i olika reströmmar (ofta som CO_2). Infångning av dessa kol-reströmmar och uppgradering till biodrivmedel med hjälp av elektricitet är ett exempel på BECCU (bioenergy carbon capture and utilisation), som kan förbättra kolutnyttjandet och öka utbytet till drivmedel. Genom att i stället lagra kolet permanent (BECCS, carbon capture and storage) kan i stället biodrivmedel med negativa CO_2-utsläpp åstadkommas.

I detta projekt har vi undersökt möjligheter att kombinera biodrivmedelsproduktion med BECCS och BECCU. Processmodeller användes för att uppskatta prestandan vad gäller koldioxideffektivitet, växthusgasfotavtryck, produktionskostnad för biodrivmedel, potential för biomassaråvara i Sverige och teknikmognad. Totalt undersöktes 14 olika teknikspår, utifrån (1) basfallet utan CO_2-avskiljning, (2) CCS med avskiljning och permanent lagring av CO_2, och (3) CCU med uppgradering av infångad CO_2 till ytterligare biodrivmedel med hjälp av vätgas från elektrolys.

Resultaten visade att **för att uppnå störst nytta med biodrivmedelsproduktion med BECCS och BECCU är nyckeln de framväxande teknikspåren** (tekniker som fortfarande är under utveckling). Även om de framväxande teknikspåren inte uppvisade lägst kostnader för minskning av växthusgasutsläpp, uppvisade de både störst relativ förbättring av koleffektivitet och störst minskning av växthusgaser, med CCS. Ur ett kombinerat kol-, kostnads- och klimatperspektiv presterade teknikspår baserat på förgasning eller hydrogenering av skogsrester bäst.

BECCS och BECCU är av mer begränsat värde för de kommersiella teknikspåren. Biogasspåren har höga transportkostnader för CO_2 pga. små och relativt utspridda anläggningar, och kommersiella spår för hydrogenering har redan effektivt kolutnyttjande. För dessa spår, liksom för etanol från vete, hamnar också betydande mängder biogent kol i kommersiellt viktiga biprodukter, samtidigt som den svenska råvarupotentialen är relativt begränsad.

Att använda BECCU för att producera mer biodrivmedel kan vara ekonomiskt konkurrenskraftigt och kan erbjuda en hållbar lösning för en framtid med begränsade biomassatillgångar. Den ökade produktionskapaciteten för biodrivmedel skulle dock komma med ett motsvarande ökat elbehov, vilket i sin tur skulle kräva uppskalning av förnybar elproduktion.

Att binda CO_2 genom BECCS ger biodrivmedel med mycket god klimatprestanda, men till högre kostnad. Kostnaden för koleffektiva biobränslen med negativa växthusgasfotavtryck kan dock minska avsevärt om marknader och/eller stödsystem för negativa utsläppskrediter skulle uppstå. Utsläppskrediter på 100 EUR per ton CO_2 skulle kunna göra de bästa biodrivmedelsspåren med BECCS kostnadsmässigt konkurrenskraftiga i förhållande till bas- och BECCU-alternativen.

Sammanfattningsvis drar vi slutsatsen att integration av BECCS och BECCU med nuvarande kommersiella biodrivmedelstekniker endast erbjuder begränsat värde, jämfört med möjligheterna som de framväxande teknikspåren erbjuder.

NOMENCLATURE/ABBREVIATIONS

Abbreviation	Definition
AD	Anaerobic Digestion
BECCS	Bioenergy Carbon Capture and Storage
BECCU	Bioenergy Carbon Capture and Utilization
BL	Black Liquor
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CCU	Carbon Capture & Utilization*
CTO	Crude Tall Oil
DFB	Dual fluidized bed
FOAK	First of a kind
FT	Fischer-Tropsch
GHG	Green-House Gases
HDO	Hydrodeoxygenation
HTL	Hydrothermal Liquefaction
IPCC	International Panel on Climate Change
LCOP	Levelized cost of production
LPG	Liquefied Petroleum Gas
MTG	Methanol-to-Gasoline
OPEX	Operational Expenditure
RED II	European Renewable Energy Directive

* Utilization is defined narrowly in the present study as conversion to drop-in gasoline or LPG or to bio-methane.

CONTENTS

1 INTRODUCTION

1.1 BACKGROUND

With competition for clean carbon intensifying as the energy transition accelerates, the biofuel industry must prepare for two likely future developments. Increasing demand for sustainable biomass feedstock in multiple sectors will require careful balancing of commercial and societal priorities. Wastage of biogenic carbon will be undesirable.

Gaseous and liquid biofuels that are not considered to have a detrimental effect on the environment are expected to play an important role in meeting Swedish climate targets for the transport sector within the backdrop of net-zero by 2045 [1]. The push for biofuels in Sweden is centered on the use of forest residues as the principal feedstock base. The conversion of biomass to various types of biofuel typically generates residual carbon streams. CO_2 is present in off-gas streams in all thermochemical conversion processes for biofuel production [2]. The extent of carbon loss depends on the choice of conversion technologies. Promising future biofuel pathways based on technologies such as gasification and hydrotreatment typically generate significant streams of CO_2. In the case of the former and in technologies that are commercial today, e.g. anaerobic digestion and fermentation, CO_2 is released in a high purity streams that can be captured at low energetic cost. Another common by-product of biomass conversion is process heat, which is generated in excess in several biofuel pathways and can be used to reduce the operating expense of post-combustion carbon capture

Capturing residual carbon streams and upgrading them to biofuels with the help of electricity is an example of a bio-energy carbon capture and utilization (BECCU) concept that can significantly improve utilization efficiencies and production potentials. Sequestering the same carbon in permanent storage (BECCS) can potentially deliver biofuels with large negative footprints. Captured biogenic CO_2 can be converted to biofuels with the help of renewable (electrolysis-based hydrogen) in so-called electricity-biomass hybrid or Power-to-X concepts [3]. Several technology tracks are available. Examples include the production of bio-methane via the Sabatier process [4] and the synthesis of methanol [5] from CO_2 and hydrogen, with subsequent conversion to bio-gasoline through the MTG (methanol-to-gasoline) process [6].

Permanent storage of CO_2 emissions from biomass conversion processes lowers the GHG concentration in the atmosphere; the emissions can thus be considered to be negative. Realizing the potential of BECCS requires new policy instruments. Implementation of BECCS is challenging and is unlikely to be achieved widely before 2030 [7]. The possibility of including BECCS in the EU Emissions Trading System is being considered. A goal for the European Union is to be climate-neutral by 2050 and BECCS can be an important element in the realization of the goal.

Sweden is at the forefront of pioneering BECCS policy design [8]. The Swedish Energy Agency recently decided to recommend the use of reverse auctions following an investigation into the relative merits of different support schemes [9]. However, BECCS is a relatively new field of study and concrete infrastructure development plans have only started to emerge. Thus, uncertainty regarding costs and unavailability of useful literature have been identified as a hindrance by both industrial actors and academic researchers [8,10]. There is a large gap in the research literature on the relative merits of combining BECCS and BECCU with the various pathways – particularly those that are emerging – for biofuel production relevant in a Swedish context.

1.2 PROJECT OBJECTIVES

The overall aim of the 'carbon, climate and cost efficiency (k3)' project has been to compile a knowledge base as decision-making aid for setting long-term transport sector priorities, particularly for R&D and commercial deployment of carbon-efficient and cost-effective biofuel production. The area has been highlighted as being in pronounced need of an expanded knowledge base, since wide-spread deployment of biofuels has been identified as important for the timely attainment of Sweden's climate goals [11].

This report summarizes the results of the mentioned project concerning the following specific objectives:

1) Estimate and compile carbon, climate and cost efficiencies for existing and emerging biofuel production pathways with and without modifications for CO_2 capture.
2) Analyze technical solutions and quantify CO_2 capture costs for each of the studied pathways. Separately evaluate the options of directing the captured CO_2 to permanent storage (BECCS) or to upgrading it to biofuels with electrolysis-based hydrogen to increase biofuel yields (BECCU/electrofuels).
3) Perform an overall comparative assessment of the carbon efficiencies, climate performance, biofuel production costs and GHG reductions costs of the studied biofuel production pathways under the BECCS and BECCU options.
4) Perform an overall comparative assessment of the contributory potential of the studied pathways to the transport sector transition with respect to non-technical barriers, technology readiness and feedstock potential.

1.3 REPORT OUTLINE

This report is organized into four chapters. Chapter 1 serves as a general introduction. Chapter 2 contains a summary of the results and a description of methods related to specific objectives 1-3. Chapter 3 provide the same information for specific objective 4. The overall results and conclusions of the project are summarized in Chapter 4.

1.4 BIOFUEL PATHWAYS

The 14 biofuel pathways appraised are listed in Table 1. The feedstock base covers a majority of biomass fraction that are topical to biofuel production in Sweden. With one exception, namely, wheat grain, all other pathways are based upon feedstocks that are classified as residues or wastes. Ethanol from wheat grain is currently manufactured commercially in Sweden and is primarily included for completeness and as a point of reference.

Table 1. List of examined biofuel production pathways.

Abbreviation	Pathway	Development Status
	Fermentation and anaerobic digestion pathways	
EtSdFr	Ethanol from sawdust by hydrolysis & fermentation	Emerging
EtWgFr	Ethanol from wheat grain by fermentation	Commercial
MeFmAd	Bio-methane from food waste & manure by anaerobic co-digestion (AD)	Commercial
MeSsAd	Bio-methane from sewage sludge by anaerobic digestion (AD)	Commercial
	Hydrotreatment pathways	
DrFrHt	Drop-in biofuels from forest residues by hydrothermal liquefaction (HTL)	Emerging
DrLiHd	Drop-in biofuels from lignin by hydrodeoxygenation (HDO)	Emerging
DrFrFp	Drop-in biofuels from forest residues by fast pyrolysis & hydrodeoxygenation (HDO)	Emerging
DrFrHp	Drop-in biofuels from forest residues by hydropyrolysis	Emerging
DrToHd	Drop-in biofuels from crude tall oil by distillation & hydrodeoxygenation (HDO)	Commercial
DrTaHd	Drop-in biofuels from meat industry by-products (tallow) by hydrodeoxygenation	Commercial
	Gasification pathways	
DrBlGm	Drop-in biofuels from black liquor (BL) by entrained- flow gasification & methanol synthesis	Emerging
DrBlGf	Drop-in biofuels from black liquor by entrained-flow gasification & FT synthesis	Emerging
MeBaGm	Bio-methane from bark by dual fluidized-bed gasification & catalytic methanation	Emerging
DrBaGf	Drop-in Biofuels from bark by dual fluidized-bed gasification & FT synthesis	Emerging

A full listing of the feedstocks, biofuel products and tradable by-products is given in Table 2. Only biofuel fractions intended for the road transport market are treated as 'biofuel products' for the purpose of this report. Biofuels are also expected to play a significant role in the aviation and shipping markets [12][13]. A knowledge base on the production of carbon and climate-efficient biofuels for aviation through the implementation of BECCS and BECCU has been put together in a sister project 'climate positive and carbon efficient bio-jet fuels'[14].

Pathways are generally referred to by their designated abbreviations. Letters 1 & 2 in each abbreviation indicate the principal biofuel product(s), namely, bio-**m**ethane, **e**thanol and **d**rop-in biofuels (one or more of LPG, diesel & petrol). Letters 3 & 4 indicate the feedstock – **ba**rk, **bl**ack liquor**,** **f**ood waste & **m**anure, **f**orest **r**esidues, **l**ignin, **w**heat **g**rain, saw**d**ust, crude tall **o**il, **ta**llow (meat industry residue). Letters 5 & 6 indicate the principal conversion technologies – **fer**mentation, **a**naerobic **d**igestion, **f**ast **p**yrolysis, **g**asification, **m**ethanol synthesis, **m**ethane synthesis, **F**ischer-Tropsch synthesis, **h**ydro**t**hermal liquefaction, **h**ydro**d**eoxygenation and **h**ydro**p**yrolysis. The last three are also collectively referred to as **h**ydrotreatment.

Table 2. Overview of feedstocks, tradable by-products and biofuel products.

Pathway	Feedstock(s)	Other biogenic carbon inputs	Tradable by-products	Biofuel Product(s)
EtSdFr	Sawdust	Molasses	Lignin pellets	Ethanol, Bio-methane
EtWgFr	Wheat grain	Woodchips [a] Molasses	DDGS	Ethanol
MeFmAd	Food waste & manure	Biocoal [a]		Bio-methane
MeSsAd	Sewage sludge		Biocoal [b]	Bio-methane
DrFrHt	Forest residue		Marine fuel	Drop-in petrol & diesel
DrLiHd	Black liquor lignin	Forest residue [a]		Drop-in petrol & diesel
DrFrFp	Forest residue			Drop-in petrol & diesel
DrFrHp	Forest residue	Forest residue [a]		Drop-in petrol & diesel
DrToHd	Raw tall oil	Biocoal [a]	Tall oil pitch	Drop-in petrol & diesel
DrTaHd	Meat industry by-products	Biogas [a]	Meat & bone meal	Drop-in petrol & diesel LPG
DrBlGm	Black liquor			Drop-in petrol, LPG
DrBlGf	Black liquor			Drop-in petrol & diesel
MeBaGm	Bark	Rapeseed Methyl Ester		Bio-methane
DrBaGf	Bark			Drop-in petrol & diesel

[a] For meeting the process heating demand.
[b] Under the CCU option only.

2 TECHNO-ENVIRO-ECONOMIC ASSESSMENT OF BIOFUELS WITH BECCS AND BECCU

This chapter covers the following project objectives:

1) Estimate and compile carbon, climate and cost efficiencies for existing and emerging biofuel production pathways with and without modifications for CO_2 capture.
2) Analyze technical solutions and quantify CO_2 capture costs for each of the studied pathways. Separately evaluate the options of directing the captured CO_2 to permanent storage (BECCS) and of upgrading it to biofuels with electrolysis-based hydrogen to increase biofuel yields (BECCU/electrofuels).
3) Perform an overall comparative assessment of the carbon efficiencies, climate performance, biofuel production costs and GHG reductions costs of the studied biofuel production pathways under the BECCS and BECCU options.

2.1 METHODS AND DATA FOR TECHNO-ENVIRO-ECONOMIC ASSESSMENT

The description of methods that follows is a summarized version of the text included in [15].

Three configuration options for the treatment of residual carbon streams were defined for each of the biofuel pathways under evaluation: *base*, *CCS*, and *CCU*. The base option refers to the production of biofuels without carbon capture and was used as baseline comparison for the CCS and CCU options. The CCS option considers the capture of carbon in the form of CO_2 with subsequent transport to a permanent storage location by ship and truck or by ship. Under the CCU option the carbon captured in the form of CO_2 was assumed to be upgraded to either bio-methane or to drop-in gasoline and LPG. Feedstock throughput was kept the same under all three options.

Key design parameters under the base, CCS & CCU options are summarized in Table 3.

The performance indicators used in the carbon, cost and climate evaluations are listed and defined in section 2.1.5.

Table 3. Key design parameters for base, CCS & CCU options. For pathway nomenclature, see Table 1.

Pathway	Plant Type	Plant Size [MW]	Captured CO_2 Streams Yes/No (Quantity)		Captured CO_2 Transport		CCU Product	Reference Studies
			Concentrated	Dilute	Truck	Ship		
EtSdFr	Stand-alone	132	Yes (2)	Yes (1)	Yes	Yes	Bio-methane	[16]
EtWgFr	Stand-alone	240	Yes (1)	Yes (1)	Yes	Yes	Bio-methane	[17]
MeFmAd	Stand-alone	3.4	Yes (1)[a]	No	Yes	Yes	Bio-methane	[a][18,19]
MeSsAd	Integrated (Wastewater Treatment Plant) [b]	4.5	Yes (1)[b]	No	Yes	Yes	Bio-methane	[19]
DrFrHt	Stand-alone	162	No	Yes (1)	No	Yes	Drop-in petrol & LPG	[20,21]
DrLiHd	Integrated (Pulp Mill, Oil Refinery)	101	No	Yes (1)	No	Yes	Drop-in petrol & LPG	[22]
DrFrFp	Integrated (Oil Refinery)	25.6	No	Yes (2)	Yes	Yes	Drop-in petrol & LPG	[c][23–25]
DrFrHp	Integrated (Oil Refinery)	25.6	No	Yes (1)	Yes	Yes	Drop-in petrol & LPG	[d][26,27]
DrToHd	Integrated (Oil Refinery)	578	No	Yes (1)	No	Yes	Drop-in petrol & LPG	[e][28,29]
DrTaHd	Integrated (Rendering Plants, Oil Refinery)	1144	No	Yes (1)	No	Yes	Drop-in petrol & LPG	[30]
DrBlGm	Integrated (Pulp Mill, Oil Refinery)	92.8	Yes (1)	No	No	Yes	Drop-in petrol & LPG	[22]
DrBlGf	Integrate (Pulp Mill)	92.8	Yes (1)	Yes (1)	No	Yes	Drop-in petrol & LPG	[22,31]
MeBaGm	Stand-alone	359	Yes (1)	Yes (1)	No	Yes	Bio-methane	[f][32]
DrBaGf	Stand-alone	533	Yes (1)	Yes (1)	No	Yes	Drop-in petrol & LPG	[g][31,32]

[a] Feedstock and digestate compositions and bio-methane yields from [18], data on energy demand and bio-methane leakage from [19]. Biogas is assumed to be composed of 60% bio-methane and 40% CO_2 on molar basis.
[b] Sewage sludge is the only stream exchanged between the wastewater treatment plant and the biofuel plant.
[c] [27] is used as the principal reference but the balances are modified to reflect the standalone nature of the pyrolysis plant in the present study. [24] is the original reference for the fast pyrolysis step and [25] for the pyrolysis oil hydrotreatment step.
[d] [27] is used as the principal reference. [26] is the original reference.
[e] [28] for the yields and energy requirements in tall oil distillation and for the yields in the hydrotreatment step and [29] for the hydrogen demand in the hydrotreatment step.
[f] Data for bark gasification and syngas cleaning is taken from [32] and data for Fischer-Tropsch synthesis is provided by RISE Research Institutes of Sweden AB [31].
[g] Data for black liquor gasification is taken from [27] and data for Fischer-Tropsch synthesis is taken from [31].

2.1.1 Biofuel Pathway Process Models

A literature review was carried out to identify representative process configurations and plant sizes for each of the biofuel pathways under evaluation. Schematic overviews of base process configurations are provided in Appendix A. Detailed process models were developed following the principle of using publically available studies as primary references. An annotated list of reference studies used for compiling the carbon and energy balances for the base option is provided in Table 3.

Where possible, the same study was used for modelling all process steps in a given biofuel pathway. Inconsistencies associated with the use of different heating values and carbon contents by different sources for the same biomass material were reduced by standardizing compositional and thermochemical data. Two plant types were defined: integrated and stand-alone. The integrated plants were characterized by having some degree of material and/or energy integration with existing industrial facilities, e.g., pulp mills and crude oil refineries. The stand-alone plants were not assumed to have material or energy integration with existing industrial facilities. The choice of plant sizes for commercial pathways was based on an analysis of existing and prospective industrial facilities. Plant sizes for emerging pathways were primarily based on previous techno-economic studies. See [15] for further details on sizing assumptions. Note that the choice of scale in the reference studies did not take into account suitability for CCU, and was not always intended to maximize economies-of-scale. Some of the plant sizes, such as for instance those for the pyrolysis pathways, are likely not feasible at the chosen scale, and results should be interpreted bearing in mind the possibility of cost improvements linked to economies-of-scale under both the CCS and the CCU options. A detailed feasibility assessment with focus on applicability to CCS and CCU is recommended as future work.

2.1.2 CO_2 Capture, Transport & Upgrading Models

Depending on their CO_2 concentration, residual streams intended for carbon capture were categorized into two types. High purity CO_2 streams generated during fermentation or during the conditioning of syngas for biofuel synthesis were classified as *concentrated streams* and were assumed to contain CO_2 only. For estimating utility consumption, low purity or dilute CO_2 streams were classified as *dilute streams* and were sub-divided into flue gas from (a) biomass boilers, (b) methane reforming units, and (c) multifuel boilers at crude oil refineries, see Table 4. The concentrations of CO_2 in (a), (b) and (c) were assumed to be 15.5 mol% [33], 8 mol% [34]and 24 mol% [34], respectively. The capture of CO_2 from dilute streams was assumed to be carried out with monoethanolamine (MEA) as solvent.

Under the CCS option, the transport of the captured CO_2 was assumed to take place in liquefied form at medium pressure conditions with liquefaction being carried out using a propane-base refrigeration unit conditions (-30°C, 15 bar(g)) [35]. The production pathways were divided into two categories for the purpose of CO_2 transport. The first category consists of the two ethanol pathways (sawdust ethanol, EtSdFr; wheat grain ethanol, EtWgFr), the two anaerobic digestion pathways (food waste and manure, MeFmAd; sewage sludge, MeSsAd) and the two pyrolysis & hydrotreatment pathways (forest residues fast pyrolysis, DrFrFp; forest residues hydropyrolysis DrFrHp). The biofuel plants for these pathways were assumed to be located inland, 50 km from a harbor facility capable of handling CO_2 transport by ship. The captured CO_2 was assumed to be transported to the harbor facility by trucks with 40 t capacity and stored temporarily in tanks (4500 t capacity) prior to transshipment to the storage site. The biofuel plants for the remaining pathways were assumed to be located in the immediate vicinity of a harbor facility capable of handling CO_2 transport by ship.

The required sizes of the ships used for transporting CO_2 to the final storage site varied between 2000 t and 20,000t. The transport distance was set at 1200 km for all pathways. The total time at sea was calculated to be 128 h. The magnitude of the CO_2 captured from different pathways varied greatly – from 2-4 kt/y for the anaerobic digestion pathways to 0.6-0.9 Mt/y for the bark gasification pathways. It was assumed that small plants that did not generate enough CO_2 to enable the smallest sized ship of 2000 t to be utilized for at least 4000 h/y or more shared the capital cost of transport with same-sized plants. Larger plants that were able to exceed ship utilization rates of 4000 h/y were assumed to have their own dedicated ships for CO_2 transport.

Following a survey of the literature, the storage site was defined as an 80% depleted offshore gas field with storage taking place at a depth of 1000 m [36]. Upon arrival at the storage site, CO_2 was assumed to be offloaded into storage tanks with a capacity of 40 000 t moored adjacent to the storage well.

Table 4. Utility demand for dilute CO_2 capture.

Stream Type	Electricity [MJ/kg CO_2]	Heat [MJ/kg CO_2]	Capture Rate [%]	Notes (Reference)
Biomass boiler	0.0870 [37]	3.76 [33,34]	85 [34]	Post-combustion [33,34,37]
Refinery fuel gas	0.341 [38]	4.00 [34]	85	Post-combustion [34,38,39]
Methane reforming	0.126 [38]	3.60 [34]	85	Mixed [34,38]

Two separate process yielding different biofuel products were used to upgrade the captured CO_2 under the CCU option. Bio-methane produced through catalytic methanation of the captured CO_2 with electrolysis H_2 [40] was the biofuel product considered under the CCU option in pathways that had either bio-methane or ethanol as the main biofuel product under the base option, namely, MeFmAd (methane from food waste and manure via anaerobic digestion), MeSsAd (methane from sewage sludge via anaerobic digestion), MeBaGm (bio-methane via bark gasification), EtSdFr (ethanol from sawdust) and EtWgFr (ethanol from wheat grain). In all other pathways, drop-in petrol and LPG were assumed to be produced under the CCU option by first catalytically upgrading the captured CO_2 to chemical-grade methanol with the addition of electrolysis H_2 and then upgrading the methanol to the required hydrocarbon products through the methanol-to-gasoline (MTG) process. Notably, other CCU options also exist, e.g., including Fischer-Tropsch (FT) synthesis, but in order to limit the number of cases for this study, methanation and MTG were selected.

For more information on the assumptions and data behind the CO_2 capture, transport and upgrading models, see 'CO_2 Capture, Transport & Upgrading Model' Part 2 of the Supplementary Material to [15].

2.1.3 GHG Footprint Assessment

Climate performance from a well-to-wheel perspective was examined by estimating GHG footprints following the procedure laid-out in the Renewable Energy Directive (RED II) [41]. The allocation of emissions was carried out on an energy basis. Emissions associated with a given process step or series of steps were allocated equally but only to biofuel products produced in the steps concerned. A similar approach was applied to emissions associated with the final distribution of different products. This meant that emissions associated with the electrolysis H_2 used for upgrading CO_2 were only allocated to CCU biofuel products, and the emissions associated with the electricity used for the base process were only allocated to the base biofuel products. An exception was made for negative emissions under the CCS option, which were allocated on an energy basis to all biofuel products. A complete listing of the GHG footprints of the biofuel products under the base, CCS & CCU options in all 14 pathways can be found in the Supplementary Material to [15]. For ease of understanding, the GHG footprints associated with each pathway in this report represent an average of individual biofuel product footprints.

An annotated list of GHG emissions is provided in Table 11 in section 2.2.2.

Table 5. Listing of emission factors used for estimating GHG footprints.

		Unit	Reference [Notes]
Electricity	46.8	kg CO_2eq/MWh	[41] [Swedish mix]
Diesel	335	kg CO_2eq/MWh	[42] [Fossil]
Petrol	342	kg CO_2eq/MWh	[42] [Fossil]
Natural gas	224	kg CO_2eq/MWh	[42] [Fossil]
GWP methane	32	g CO_2eq/g CH_4	[43]
Forest biomass outtake	1.03	kg CO_2eq/MWh	[44]
Forest biomass transport	0.02	kg CO_2eq/MWh,km	Network for Transport and Environment (2010)
Methanol distribution	1.18	kg CO_2eq/MWh	[45]
Bio-Methane distribution	2.49	kg CO_2eq/MWh	[45]
Ethanol distribution	0.9	kg CO_2eq/MWh	[45]
Petrol distribution	1.55	kg CO_2eq/MWh	[45]
Diesel distribution	1.45	kg CO_2eq/MWh	[45]
CO_2 distribution truck	108	g CO_2eq/ton*km	[46]
CO_2 distribution ship (LNG fuel)	38	g CO_2eq/ton*km	[47]
Wheat cultivation	50.4	kg CO_2eq/MWh	[48] [EtWgFr only]
Average fossil fuel footprint	333	kg CO_2eq/MWh	Used for estimating GHG reduction costs (see text)

2.1.4 Economic Assessment

With biofuel CCS & CCU concepts not expected to enter commercial operation much before the end of the current decade, the economic assessment was focused on an energy market scenario for the year 2030. The prices of energy carriers in the target year were estimated with the energy price and carbon balance scenario (ENPAC) tool [49], as described below. An annotated listing of the references used for estimating capital expenditure (CAPEX) is provided in Table 6. It is worth noting that the CAPEX estimates for different pathways differ greatly in granularity and quality even where it was possible to use the same study for both CAPEX estimation and process modelling. Given the coarseness of some of the estimates, it was not always possible to accurately identify and adjust scaling factors for process equipment such as compressors, heat exchangers and pumps. With the large number of sources involved and the opacity of the underlying assumptions, the magnitude and direction of the resulting uncertainty were hard to estimate with any degree of accuracy. Cost estimates are therefore best interpreted as indicative and are not intended to be compared directly.

Where the necessary costing information was missing, investment costs were scaled with the biofuel throughput following eq. 1 [50]:

$$C = C_0 * \frac{P_0}{P}^{SF} \qquad \text{(Eq. 1)}$$

where C is the cost of the process or specific unit operation, C_0 the base cost, P_0 the base scale, and P the scale. SF is the scaling factor, which was set to 0.67 unless otherwise specified in the literature. All capital cost estimates were recalculated to 2020 monetary value with the help of the chemical engineering plant cost index. The currency exchange rates used for price conversions were 0.88 EUR/USD, 0.095 EUR/SEK and 1.13 EUR/GBP.

Table 6. Annotated listing of CAPEX references.

Pathways [a]	CAPEX Refs.	Process Modelling Refs.	Comments
EtSdFr Ethanol: sawdust, hydrolys+ferment.	[51]	[16]	[16] is partly based on [51].
EtWgFr Ethanol: wheat grain, fermentation	[17]	[17]	
MeFmAd Methane: food waste+manure, AD	[52,53]	[18,19]	[52] for anaerobic digestion and [53] for biogas up-grading.
MeSsAd Methane: sewage sludge, AD	[53,54]	[19]	[54] for anaerobic digestion and [53] for biogas up-grading.
DrFrHt Dropin: forest residues, HTL	[55][22]	[20,21]	[55] is based on [56]. Process configurations in [56] and [20,21] are relatively similar, but differences exist. PEM investment costs [1000 EUR/kW in USD_{2018}] are based on [22] in conjunction with an updated literature survey.
DrLiHd Dropin: lignin, HDO	[22]	[22]	PEM investment costs [1000 EUR/kW] were already included in the CAPEX estimates in the principal reference.
DrFrFp Dropin: forest res., fast pyr+HDO	[57][22]	[24,25,27]	PEM investment costs [1000 EUR/kW in 2018 USD] are based on [22] in conjunction with an updated survey of the literature.
DrFrHp Dropin: forest residues, hydropyr.	[58][22]	[26,27]	The H_2 quantities required for saturating the diesel fraction are so small relative to the H_2 throughput of any commercial crude oil refinery that capital investment in a corresponding PEM electrolyzer would be unrealistic. It is instead assumed that the H_2 quantities required would be taken from the refinery's (electrolysis) hydrogen pool.
DrToHd Dropin: tall oil, distillation+HDO	[29]	[28,29]	
DrTaHd Dropin: tallow, HDO	[30]	[30]	PEM investment costs [1000 EUR/kW in 2018 USD] are based on [22] in conjunction with an updated survey of the literature.
DrBlGm Dropin: BL, gasific.+methanol+MTG	[22]	[22]	The oxygen required as oxidant is either purchased on the market (base, CCS options) or produced by PEM electrolysis (CCU option).
DrBlGf Dropin: BL, gasific.+FT	[22,31]	[22,31]	The oxygen required as oxidant is either purchased on the market (base, CCS options) or produced by PEM electrolysis (CCU option).
MeBaGm Methane: bark, gasific.+methanation	[59]	[32]	
DrBaGf Dropin: bark, gasific.+FT	[31,59]	[31,32]	

[a] Dropin = drop-in biofuels; AD = Anaerobic Digestion; BL = Black Liquor; FT = Fischer-Tropsch; HDO = Hydrodeoxy-genation; HTL = Hydrothermal Liquefaction; MTG = methanol-to-gasoline.

Operational expenditure (OPEX) was divided into two components: $OPEX_{Materials\ \&\ Energy}$ and $OPEX_{O\&M}$, with the latter covering fixed operational costs. The prices of various biomass fractions and other important energy carriers were estimated using the ENPAC tool, which takes user-defined inputs and assumptions to generate scenarios consisting of sets of future energy prices. ENPAC handles the uncertainty in future energy market conditions by generating scenarios consisting of sets of future energy prices based on user-defined input and key assumptions. The resulting energy market scenarios consist of consistent sets of data that capture expected interrelations between different parameters given certain scenario conditions. The input data for the present study was based on the Sustainable Development (SD) scenario for 2030 from the IEA's World Energy Outlook (WEO) 2017 [60]. Inputs included representative CO_2 emission charges for Northern Europe as well as prices for crude oil, natural gas and coal. Assumptions on the technological availability of new grid capacity, renewable energy and various connected aspects were in accordance with [61]. More information on the ENPAC tool and its limits and opportunities can be found in [49,62,63].

A selection of the energy and material prices used in the economic assessment are presented in Table 7 and Table 8. More information on ENPAC assumptions and outputs can be found in Appendix D. A full listing of the OPEX flows included in the cost estimates can be found in the Supplementary Material to [15]. The focus was primarily on energy carriers and costs of chemicals and catalysts were generally not included except in the case of the fermentation pathways for which data of good quality was available in the source references. Water and wastewater costs were not included. Electricity prices were taken to be a representative average for all hours of the year and the impact of fluctuations was not considered. It was assumed that the electricity market in 2030 will be able to handle the coupling of fluctuating renewable sources with the operation of electrolyzers at steady-state.

Table 7. Prices for energy and material streams for the year 2030 generated with or based on data from ENPAC.

	Prices		Notes
	[EUR/kg]	[EUR/MWh]	
Electricity [Buy]	-	49	A network charge is included in the price.
Electricity [Sell]	-	50	Plants exporting renewable electricity were assumed to be eligible for support and the corresponding support level (5 EUR/MWh) was included in the price.
Pellets [Buy]	-	43	Pellets from lignin and other forestry assortments.
Pellets [Sell]	-	32	Pellets from lignin and other forestry assortments.
Bio-Methane [For Industrial Heating, Producer gate price]	-	43	Based on an alternative cost to the consumer, where the biogas was exempted from the energy tax according to current Swedish tax levels and avoided the EU ETS allowances at the cost level of the CO_2 emissions charge. Gate prices were calculated assuming the same distribution costs for natural gas and biogas.
Woodchips [Buy]	-	29	Based on historical price relation between wood chips and by-products the last decade.
Forest Residue [Buy]	-	30	Forest residue include tops and branches, bark, hog fuel, saw dust etc. Price of wood chips was based on the price relation between wood chips and by-products the last decade.
District Heating Water	-	28	Assuming heat replaces existing Bio-CHP
Natural Gas	-	51	Including CO_2 charge.
Fossil gasoline [Sell]	-	47	Producer gate price.
Fossil diesel [Sell]		54	Producer gate price.
Bark	-	30	Bark is a forestry by-product and the price was assumed to shadow the price of forestry residue in ENPAC.
Sawdust	-	30	Sawdust is a forestry by-product and the price was assumed to shadow the price of forestry residue in ENPAC.

Table 8. Prices for energy and material streams for year 2030 generated outside ENPAC.

	Prices		Assumptions
	[EUR/kg]	[EUR/MWh]	
Wheat Grain	0.167	-	December 2020 price for the wheat used for ethanol production in Sweden [64,65].
Sewage Sludge	0	-	The procurement of sewage sludge by the WWTP hosting the biofuel plant was assumed to be cost neutral, likely an optimistic assumption.
Manure	0	-	The co-digestion plant for food waste & manure was assumed to be situated adjacent to a farm with relatively high farm and population density to minimize the costs associated with the transport of the feeds and the digestate, which was returned to the farms for use as fertilizer, following [19]. Feed and fertilizer costs were not priced explicitly and were assumed to cancel each other out.
Food Waste	0	-	Same assumptions as for manure concerning feed cost and digestate value. Collection of food waste as a separate stream varies greatly between different regions in Sweden. It was further assumed that the co-digestion plant does not receive an income for treating and sorting foodwaste [66]. The allocation of costs for the transport of food waste is impacted by whether the facility is owned by the municipality or by private actors. Costs for transporting the food waste are primarily financed by the households and/or the organisations producing the waste [66].
Crude Tall Oil	0.474	-	Based on the average historical crude tall oil (CTO) price in the period 2006-2016 (400 EUR/t) [67]. CTO is used in both the energy (biofuels) and the biochemicals market. Adjusted for inflation using the EU producer price index C201.
Meat Industry By-Products	0.300	-	AO2 carcass price was chosen as an indicative reference price for tallow feedstock [68,69]

2.1.5 Performance Indicators

Mapping carbon flows to generate consistent carbon balances and using these to examine the impact of CCS & CCU on carbon utilization from different perspectives was an important aim of the project. The principal measure of carbon utilization is *carbon efficiency*, η_{Carbon}, which is defined in eq. 2 as the share of the carbon in the biomass feedstock that ends up in either biofuel products or in permanent storage.

$$\eta_{Carbon} = \frac{C_{Biofuel\ Product(s)} + C_{Permanent\ Storage}}{C_{Feedstock(s)}} \qquad \text{(Eq. 2)}$$

Despite the above definition, it is worth bearing in mind that the relevant timeframe for the carbon that is upgraded to biofuel products is different from that for the carbon that is deposited in permanent geological storage. In the former case, the biofuels are used to replace fossil equivalents and thereby contribute to reduction in GHG emissions. In the latter case, the carbon that is stored is essentially removed from the carbon cycle for millennia.

Feedstock carbon was the predominant carbon inflow in all pathways. Non-feedstock biomass inputs for primarily heating applications were nevertheless present in several pathways. Following eq. 3, the *carbon system efficiency*, $\eta_{Carbon\text{-}System}$, was defined as the share of a pathway's total biogenic carbon input that ends up in biofuel product(s), tradable by-product(s) and permanent CO_2

storage, to capture the contribution of secondary biomass inputs and of the share of feedstock carbon that ended up in non-biofuel by-products with economic value.

$$\eta_{Carbon-System} = \frac{C_{Biofuel\ Product(s)} + C_{Tradable\ by-products} + C_{Permanent\ Storage}}{C_{Feedstock(s)} + C_{Other\ Biomass\ Inputs}} \quad \text{(Eq. 3)}$$

As noted in previous sections, climate performance was quantified by allocating emissions based on the energy content of the biofuel products. The emissions included in the calculation are given in eq. 4:

$$E = e_{ec} + e_p + e_{td} - e_{ccs} \quad \text{(Eq.4)}$$

Where *E* denotes the total value-chain emissions from the production and use of the biofuel (in g CO_2eq./MJ), e_{ec} emissions from extraction and cultivation of feedstock(s), e_p emissions from processing the feedstock(s), e_{td} transport and distribution emissions, and e_{CCS} emissions savings from CO_2 capture and geological storage.

The economic performance of the biofuel pathways concerning their primary purpose – biofuel production – was evaluated by calculating levelized costs of production according to eq. 5:

$$LCOP = \frac{CRF * CAPEX_{Total} + OPEX_{Materials\ \&\ Energy} + OPEX_{O\&M} - Revenue_{By-products}}{P * h} \quad \text{(Eq.5)}$$

where *CRF* is the capital recovery factor, $CAPEX_{Total}$ the total capital investment, $OPEX_{Material\ \&\ Energy}$ the annual operational expenditure on energy and material streams, $OPEX_{O\&M}$ the annual operational expenditure on operational personnel and maintenance, $Revenue_{By\text{-}products}$ the annual revenue from by-product sales, *P* the biofuel production capacity in MW_{th} LHV with all road biofuel products aggregated together, and *h* the annual plant operating hours, set at 8000 for all pathways under all options.

CRF was calculated according to eq. 6:

$$CRF = \frac{i\,((1+i)^n}{(1+i)^n - 1} \quad \text{(Eq. 6)}$$

where *i* is the real discount rate and *n* the economic lifetime of the investment. *i* and *n* were set to 11% and 20 years, respectively. Since several pathways are based on emerging technologies, a relatively high discount rate typical of investments with relatively high economic risk was used in the evaluations.

Proposals for Bio-CCS support schemes have been formulated in Sweden [9]. Creation of a market for the trade of CO_2 emission credits between companies is also being discussed on the European level. The European Commission is preparing an initiative for certifying carbon removal that will propose common EU rules on monitoring, reporting and verifying the authenticity of CO_2 removal actions [70]. Another initiative under preparation is intended to support the development of sustainable carbon removal solutions by proposing an action plan for the promotion of carbon farming and the development of a regulatory framework for the certification of carbon removals [71]. The LCOP calculations treated as the default option in this report do not include potential revenues from CO_2 sequestration. However, the impact on LCOPs of introducing a sequestration revenue equal to 50 and 100 EUR/t CO_2, respectively, was assessed in a sensitivity analysis. Furthermore, as a contribution to the policy discussion on future Bio-CCS subsidy levels, the sequestration costs for CO_2 as estimated in the project are discussed separately in the results.

The combined outcome of climate and cost performance was quantified by estimating GHG reduction costs as defined in eq. 7:

$$GHG\ Reduction\ Cost = \frac{(Annual\ Production\ Cost_{Biofuel} - Annual\ Production\ Cost_{Fossil})}{GHG\ Footprint_{Fossil} - GHG\ Footprint_{Biofuel}} \qquad \text{(Eq. 7)}$$

where *Annual Production Cost*$_{Biofuel}$ is the combined annual biofuel CAPEX and OPEX, *Annual Production Cost*$_{Fossil}$ the reference fossil equivalent, calculated by multiplying the annual biofuel production capacity with the average of fossil gasoline and diesel gate prices for the year 2030 (50.2 EUR/MWh) in the applied ENPAC scenario, *GHG Footprint*$_{Biofuel}$ the average biofuel GHG footprint calculated according to eq. 4, and *GHG Footprint*$_{Fossil}$ the reference fossil fuel GHG footprint (92.5 g CO_2eq./MJ). The relatively small difference in the distribution costs of biofuels and fossil fuels was not considered when calculating the *Annual Production Cost*$_{Fossil}$.

2.2 TECHNO-ENVIRO-ECONOMIC PERFORMANCE

The results presented here are a condensed version of the results from [15].

2.2.1 Carbon and Climate performance

The resulting carbon efficiencies of biofuel pathways under the base, CCS and CCU options are given in Table 9. Detailed carbon and energy balances can be found in Appendices B & C. The share of feedstock carbon that ends up in biofuel products under the base option is typically around 30-40%, and CCS & CCU increase the share to 90% and greater for the best performing pathways.

Without carbon capture, drop-in biofuel from meat processing by-products (DrTaHd) is the only pathway able to deliver a carbon efficiency in excess of 50%. Bio-methane from sewage sludge (MeFmAd) has the lowest carbon efficiency. Only 14% of the feedstock carbon is converted to bio-methane. The majority ends up in the digestate product. The base and CCS options assume that the digestate can be used as fertilizer. Note that the question of whether the digestate product from the anaerobic digestion of sewage sludge will continue to be used as a fertilizer in Sweden is as yet not fully settled. An alternative option is explored under the CCU option, in which the digestate is assumed to be carbonized to biocoal. Some of the biocoal is combusted for the generation of process heat and the rest is exported as a tradable by-product. A part of the carbon released in the process is captured and upgraded to bio-methane, resulting in an increase in carbon efficiency by 20 percentage points.

The generation of significant quantities of tradable by-products is a feature common to all commercial pathways. This is well illustrated by comparing the values of η_{Carbon} with those of $\eta_{Carbon\text{-}System}$ in Table 9. The fraction of feedstock carbon available for capture is therefore comparatively small. In emerging pathways based on pyrolysis, hydrotreatment and gasification technologies, nearly all of the carbon that is not converted to biofuel products is released to the atmosphere in the form of CO_2. These pathways are accordingly good contenders for the application of CCS and CCU concepts. The drastic improvement in carbon utilization is well illustrated by a comparison of the carbon efficiencies of the four gasification pathways under the base option (27-33%) with those under the CCS (87-96%) and CCU (86-96%).

With relatively high feedstock-to-biofuel conversion rates, and with significant by-product but modest capturable carbon flows, the relative increase in carbon efficiency achieved under the CCS and CCU options is minimal for drop-in biofuels from crude tall oil (DrToHd) and meat processing by-products (DrTaHd). The explanation for this can be found in that the oxygen content in oil and fat feedstocks is relatively low (~11 wt%), with the majority of the oxygen removed as water, thus resulting in a high hydrocarbon and carbon yields in the hydrotreatment step. Conversely, the feedstocks for the emerging pathways (woody and residual biomass) have high oxygen content (30-40 wt%) with the majority of the oxygen removed as CO_2, which results in relatively lower hydrocarbon and carbon yields.

Note that the numbers presented above do not take into account the possibility of carbon leakage during the liquefaction, transport and sequestration of the captured CO_2.

Table 9. Carbon efficiencies under the base, CCS & CCU options.

Pathway [a]	Carbon Efficiencies [%] [b]			Carbon System Efficiencies [%] [c]		
	Base	CCS	CCU	Base	CCS	CCU
EtSdFr Ethanol: sawdust, hydrolys+ferment.	32	73	73	55	84	96
EtWgFr Ethanol: wheat grain, fermentation	42	85	85	63	97	97
MeFmAd Methane: food waste+manure, AD	34	53	65	55	68	99
MeSsAd Methane: sewage sludge, AD	14	23	44	79	88	85
DrFrHt Dropin: forest residues, HTL	38	64	64	67	75	75
DrLiHd Dropin: lignin, HDO	57	91	94	49	80	81
DrFrFp Dropin: forest res., fast pyr+HDO	39	91	90	39	91	90
DrFrHp Dropin: forest residues, hydropyr.	47	97	96	45	77	76
DrToHd Dropin: tall oil, distillation+HDO	48	55	55	84	91	91
DrTaHd Dropin: tallow, HDO	67	67	68	89	90	90
DrBlGm Dropin: BL, gasific.+methanol+MTG	33	87	86	44	96	95
DrBlGf Dropin: BL, gasific.+FT	27	87	86	36	97	96
MeBaGm Methane: bark, gasific.+methanation	31	96	96	30	93	93
DrBaGf Dropin: bark, gasific.+FT	30	91	90	29	88	87

[a] Dropin = drop-in biofuels; AD = Anaerobic Digestion; BL = Black Liquor; FT = Fischer-Tropsch; HDO = Hydrodeoxygenation; HTL = Hydrothermal Liquefaction; MTG = methanol-to-gasoline.
[b] Carbon efficiency is defined as the share of feedstock carbon that ends up in either biofuel products or in permanent storage (only applicable under the CCS option), see eq. 2.
[c] Carbon system efficiency is defined as the share of all biogenic carbon input that ends up in either biofuel products and tradable by-products (see Table 2 for a listing), or in permanent storage (only applicable under the CCS option), see eq. 3.

The favorable impact of CCS and CCU on climate performance is well in evidence in the compilation of GHG footprints in Table 10. Several emerging pathways, most notably those belonging to the gasification track, are able to deliver large negative emissions under the CCS option. Drop-in biofuel lignin hydrotreatment (DrLiHd) is notable in being the only pathway that can also deliver negative emissions under the base and CCU options. The hydrotreatment of lignin releases large amounts of energy gases, which can provide significant GHG savings by substituting for fossil heat sources at a crude oil refinery. The beneficial placement of DrLiHd is therefore contingent upon crude oil refineries relying on fossil sources such as natural gas for process heat, which may not be the cases in the medium-to-long term.

Compared with emerging pathways, commercial pathways that use their feedstock carbon more efficiently and therefore generate comparatively small capturable carbon outflows deliver relatively modest improvements in climate performance under the CCU option. This is particularly apparent for drop-in biofuels from meat processing by-products (DrTaHd), which shows minimal differences in GHG footprints for the base, CCS and CCU options.

GHG footprints under the CCU option are broadly similar to those under the base option. This analysis assumes the use of a Swedish electricity mix, which with its low emission factor is less penalizing to substantial electricity consumption than more fossil-dominated national electricity mixes. The GHG footprint of bio-methane via gasification of bark (MeBaGm) – in which the CO_2 captured is upgraded to bio-methane – is similar to that of drop-in biofuels via gasification of bark and Fischer-Tropsch synthesis (DrBaGf) – in which CO_2 is upgraded to drop-in petrol and LPG. Although the hydrogen consumption and consequently the electricity use in two CCU tracks differs somewhat, the quantity of electricity required to convert one unit of CO_2 product is broadly the same.

Table 10. GHG footprints under the base, CCS & CCU options.

Pathway [a]	GHG Footprints [g CO_2eq./MJ]		
	Base	CCS	CCU
EtSdFr Ethanol: sawdust, hydrolys+ferment.	5	-62	19
EtWgFr Ethanol: wheat grain, fermentation	17	-28	24
MeFmAd Methane: food waste+manure, AD	3	-11	6
MeSsAd Methane: sewage sludge, AD	8	-11	20
DrFrHt Dropin: forest residues, HTL	1	-4	15
DrLiHd Dropin: lignin, HDO	-19	-39	-7
DrFrFp Dropin: forest res., fast pyr+HDO	-23	-109	4
DrFrHp Dropin: forest residues, hydropyr.	4	-85	9
DrToHd Dropin: tall oil, distillation+HDO	8	2	10
DrTaHd Dropin: tallow, HDO	14	13	14
DrBlGm Dropin: BL, gasific.+methanol+MTG	11	-99	18
DrBlGf Dropin: BL, gasific.+FT	10	-134	19
MeBaGm Methane: bark, gasific.+methanation	7	-97	19
DrBaGf Dropin: bark, gasific.+FT	7	-131	19

[a] Dropin = drop-in biofuels; AD = Anaerobic Digestion; BL = Black Liquor; FT = Fischer-Tropsch; HDO = Hydrodeoxygenation; HTL = Hydrothermal Liquefaction; MTG = methanol-to-gasoline.

The impact of capturing residual CO_2 for sequestration or biofuel manufacture on the carbon and climate performance of biofuel pathways is illustrated in Figure 1. The CCS option and both the alternatives for CO_2 upgrading under the CCU option offer comparable improvements in carbon efficiencies (under the definition used in this study). Moreover, the CCS option can help pathways that are profligate with feedstock carbon to achieve large negative emission.

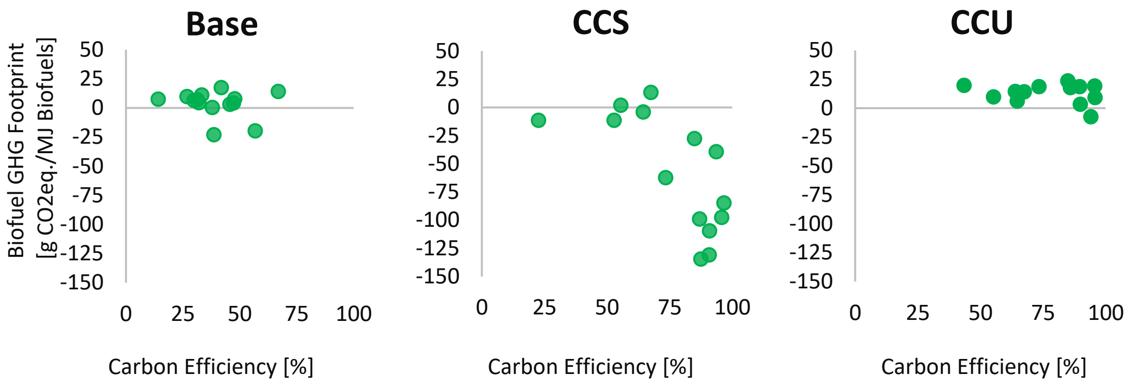

Figure 1. Impact of CO_2 capture on carbon and climate performance. Each dot represents one of the fourteen pathways examined in this study.

2.2.2 Climate and cost performance

The levelized costs of biofuel production (LCOPs) under the base, CCS & CCU options are tabulated in Table 11. Note that potential revenue from credits for CO_2 sequestration under the CCS option is not included. Hence, as expected, LCOPs under the CCS option are on average significantly higher than those under the base and CCU options. Bio-methane from anaerobic co-digestion of food waste & manure (MeFmAd) and bio-methane from anaerobic digestion of sewage sludge (MeSsAd) are the lowest cost alternatives under the base option. Drop-in biofuels from tall oil (DrToHd) also offers low LCOPs. Capital cost and energy balance data for DrToHd was partly obtained from two different sources.Commercial considerations limit the availability of high quality data on industrial hydrotreatment of biomass fraction. The costs are therefore subject to a high degree of uncertainty and should be interpreted with care. The product yields and energy balances for DrTaHd are for instance based on a generic case of a hydrotreatment plant for oils and fats with the carbon released in the energy gases being estimated by difference. Care is advised when interpreting the results, which are intended to be compared first and foremost between the different CO_2 options. LCOPs under the CCU option are comparable or lower to those under the base option for several pathways. The CCU option can be viewed as a hybrid between a pure electrofuel and a pure biofuel option.

It should be noted that our framework of reference is a 2030 energy market where we have implicitly assumed that additional renewable electricity production capacity has been brought online. The dynamics of the electricity market have not been possible to assess within the scope of the project; rather, the results can be seen to provide a snapshot of an (on average) steady-state operation. Under these considerations, the results show an indication that production costs for forest residue-based biofuels and transportation electrofuels may be broadly comparable under the chosen energy market assumptions.

Table 11. Cost of biofuel production in EUR/MWh and annual capital expenditure in MEUR/y under the base, CCS & CCU options. Credits for CO_2 sequestration are not included.

Pathway [a]	Levelized Cost of Biofuel Production [EUR/MWh]			Total CAPEX [MEUR/y] [b]		
	Base	CCS	CCU	Base	CCS	CCU
EtSdFr Ethanol: sawdust, hydrolys+ferment.	143	182	124	23.0	31.6	31.0
EtWgFr Ethanol: wheat grain, fermentation	67	102	95	23.4	37.2	40.3
MeFmAd Methane: food waste+manure, AD	31	68	68	0.6	1.4	1.3
MeSsAd Methane: sewage sludge, AD	42	123	128	0.1	0.5	2.1
DrFrHt Dropin: forest residues, HTL	73	90	91	26.9	32.6	33.5
DrLiHd Dropin: lignin, HDO	81	108	100	8.0	14.8	17.2
DrFrFp Dropin: forest res., fast pyr+HDO	126	201	141	8.0	11.7	11.9
DrFrHp Dropin: forest residues, hydropyr.	113	158	117	6.8	9.6	9.8
DrToHd Dropin: tall oil, distillation+HDO	62	65	74	26.4	33.0	35.0
DrTaHd Dropin: tallow, HDO	120	121	121	71.3	73.0	75.4
DrBlGm Dropin: BL, gasific.+methanol+MTG	124	162	99	18.3	25.7	27.5
DrBlGf Dropin: BL, gasific.+FT	94	143	100	7.4	15.5	17.5
MeBaGm Methane: bark, gasific.+methanation	115	151	110	65.3	88.6	92.3
DrBaGf Dropin: bark, gasific.+FT	129	146	121	103.0	125.4	142.1

[a] Dropin = drop-in biofuels; AD = Anaerobic Digestion; BL = Black Liquor; FT = Fischer-Tropsch; HDO = Hydrodeoxygenation; HTL = Hydrothermal Liquefaction; MTG = methanol-to-gasoline.

[b] For further details see the Supplementary Material to [15].

The GHG footprints and LCOPs in the majority of pathways are similar under the base and CCU options, which means that costs for reducing 1 kg CO_2eq. of GHG emissions relative to a fossil reference of 92.5 g CO_2eq. and 50.2 EUR/MWh are also similar, as can be seen in Figure 2 and Table 12. The GHG reduction cost span extends from -0.06 EUR/kgCO_2 for the anaerobic digestion-based MeFmAd (bio-methane from food waste and manure) under the base option to 0.30 EUR/kgCO_2 for the anaerobic digestion-based MeSsAd (bio-methane from sewage sludge) under the CCU option. The good economic performance of the anaerobic digestion pathways under the base option is offset by their comparatively poor carbon performance, as discussed in the previous section.

The quantities of CO_2 available for capture in MeFmAd and MeSsAd are small relative to those on offer in some of the other pathways. They are therefore particularly sensitive to economy-of-scale effects and transport cost distribution assumptions under the CCS option. An MeFmAd plant carries ~6% of the capital cost of the ship transporting its captured CO_2. Under the assumption of a dedicated ship for transporting the CO_2 captured from a typical plant, the GHG reduction cost would be higher by a factor of ~3. With the largest plants in the gasification pathways expected to be large enough to fill up a small dedicated ship, there is greater robustness with respect to cost assumptions. Adding a CCS option to a co-digestion plant thus appears to be economically attractive option particularly if the infrastructure cost of transporting CO_2 can be shared with other CO_2-generating sources, a possibility that is not available currently.

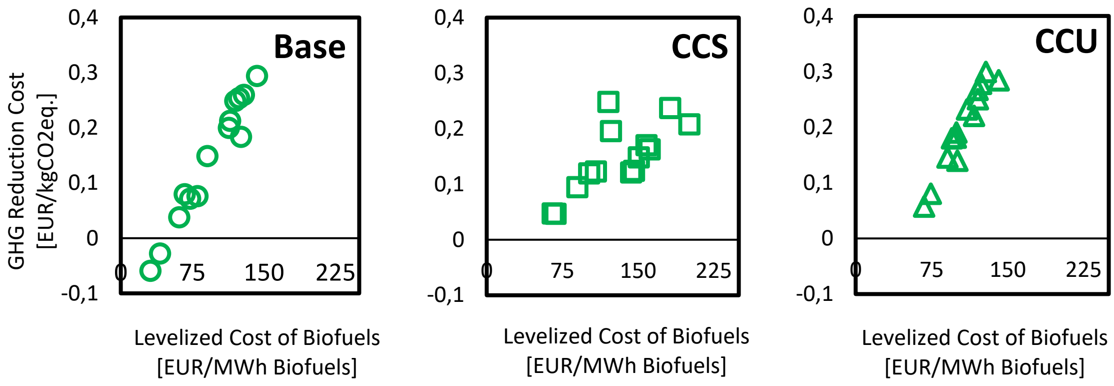

Figure 2. Comparison of GHG reduction and biofuel production costs under the base, CCS & CCU options. Each dot represents one of the fourteen pathways examined in this study.

Adding a CCS option to gasification pathways results in some of the largest relative drops in GHG reductions costs (23-111%) relative to the base option. Together with drop-in biofuels from lignin hydrotreatment (DrLiHd – 0.093 EUR/kg CO_2) and drop-in biofuels from forest residue hydrothermal liquefaction (DrFrHt – 0.12 EUR/kg CO_2), the black liquor (DrBlGf) and bark (DrBaGf) FT pathways (0.12 EUR/kg CO_2) have the lowest GHG reduction costs among the emerging pathways. The commercially important pathway drop-in biofuels from meat processing by-products (DrTaHd) does not offer low GHG reduction costs and is not a suitable candidate for reducing climate impact in a cost and carbon-efficient manner.

Table 12. Cost of reducing 1 kg CO_2eq. of GHG emissions under the base, CCS & CCU options.

Pathway [a]	Carbon Reduction Costs [EUR/kg CO_2eq.]		
	Base	CCS	CCU
EtSdFr Ethanol: sawdust, hydrolys+ferment.	0.294	0.237	0.277
EtWgFr Ethanol: wheat grain, fermentation	0.079	0.119	0.180
MeFmAd Methane: food waste+manure, AD	-0.060	0.046	0.057
MeSsAd Methane: sewage sludge, AD	-0.029	0.195	0.299
DrFrHt Dropin: forest residues, HTL	0.071	0.094	0.145
DrLiHd Dropin: lignin, HDO	0.076	0.122	0.140
DrFrFp Dropin: forest res., fast pyr+HDO	0.183	0.207	0.284
DrFrHp Dropin: forest residues, hydropyr.	0.199	0.170	0.220
DrToHd Dropin: tall oil, distillation+HDO	0.038	0.047	0.080
DrTaHd Dropin: tallow, HDO	0.248	0.247	0.250
DrBlGm Dropin: BL, gasific.+methanol+MTG	0.253	0.162	0.181
DrBlGf Dropin: BL, gasific.+FT	0.148	0.121	0.190
MeBaGm Methane: bark, gasific.+methanation	0.212	0.148	0.231
EtSdFr Ethanol: sawdust, hydrolys+ferment.	0.259	0.124	0.269

[a] Dropin = drop-in biofuels; AD = Anaerobic Digestion; BL = Black Liquor; FT = Fischer-Tropsch; HDO = Hydrodeoxygenation; HTL = Hydrothermal Liquefaction; MTG = methanol-to-gasoline.

2.2.3 Cost of sequestering CO_2 under the BECCS option

An estimation of carbon sequestration costs under the CCS option is provided in Figure 3. A detailed breakdown is given in the Supplementary Material to [15]. The estimates indicate order of magnitude and are primarily intended as a guide to the ratio between the cost of capture and the cost of transport & injection. The cost of capturing, transporting and storing 1 ton of CO_2 is lowest for gasification pathways but, with the exception of the two anaerobic digestion pathways (MeFmAd & MeSsAd) and drop-in biofuels from meat processing by-products (DrTaHd), which in a realistic implementation would benefit from economies-of-scale associated with the refinery integration, all estimates fall in or below the range mooted in recent literature (100-200 EUR/t CO_2) [8,9]. For the anaerobic digestion pathways, the quantities of CO_2 available for capture in absolute terms are not large enough to mitigate the cost of transport even under favorable cost-sharing arrangements (see section 2.1.2).

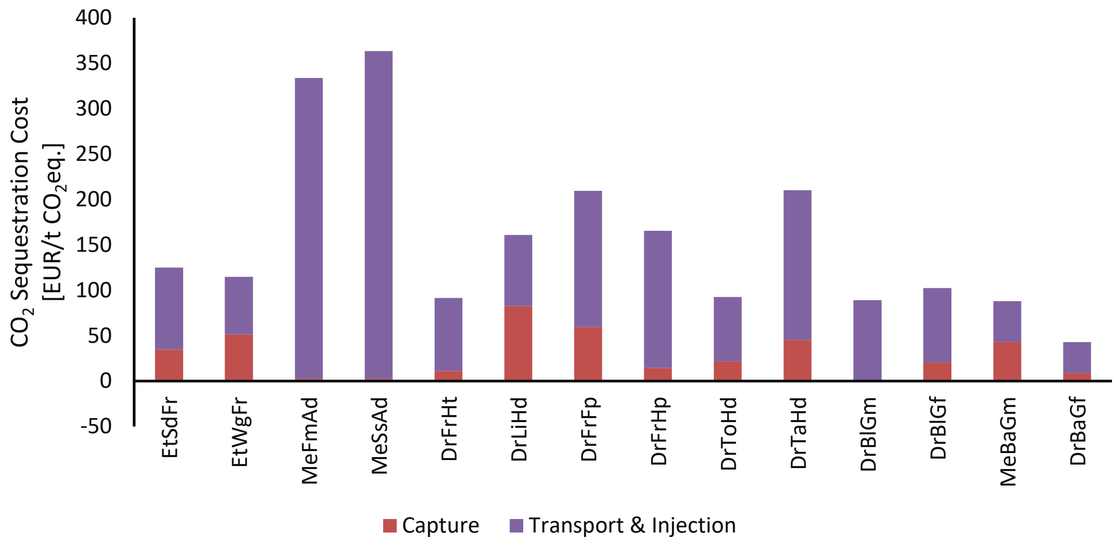

Figure 3. Cost of capturing, transporting and storing 1 ton of CO_2 under the CCS option. For pathway nomenclature, see Table 1.

2.2.4 Impact of Future Carbon Sequestration credits

The comparison of the LCOPs under the CCS and CCU options in Section 2.2.2 shows that the deployment of emerging biofuel pathways with CCS is not a commercially viable prospect without the introduction of a support scheme designed to relieve the considerable costs of capturing, transporting and storing CO_2. Under the methodology outlined in Section 2.1 and presented in more detail in [15], the resulting carbon sequestration costs for 11 out of the 14 biofuel pathways evaluated were estimated to range between 50 and 200 EUR/t CO_2. A recent study found large variations between key Swedish BECCS actors' own expectations of likely sequestration costs, with estimates ranging from 100 EUR/t to 200 EUR/t and with large uncertainty around transport and storage costs [8]. The Swedish Energy Agency has released its own recent investigation into BECCS support schemes and settled on 100-200 EUR/t as the most likely range, subject, however, to large uncertainties [8]. FOAK (first of a kind) plants may have costs exceeding this range.

It can be seen from Figure 4 that CO_2 credits for sequestration with values around 50 EUR/tCO_2 could already bring parity to base and CCS LCOPs for the best performing pathways. Levels around 100 EUR/tCO_2 would turn biofuels with CCS competitive against the base and CCU options for several pathways.

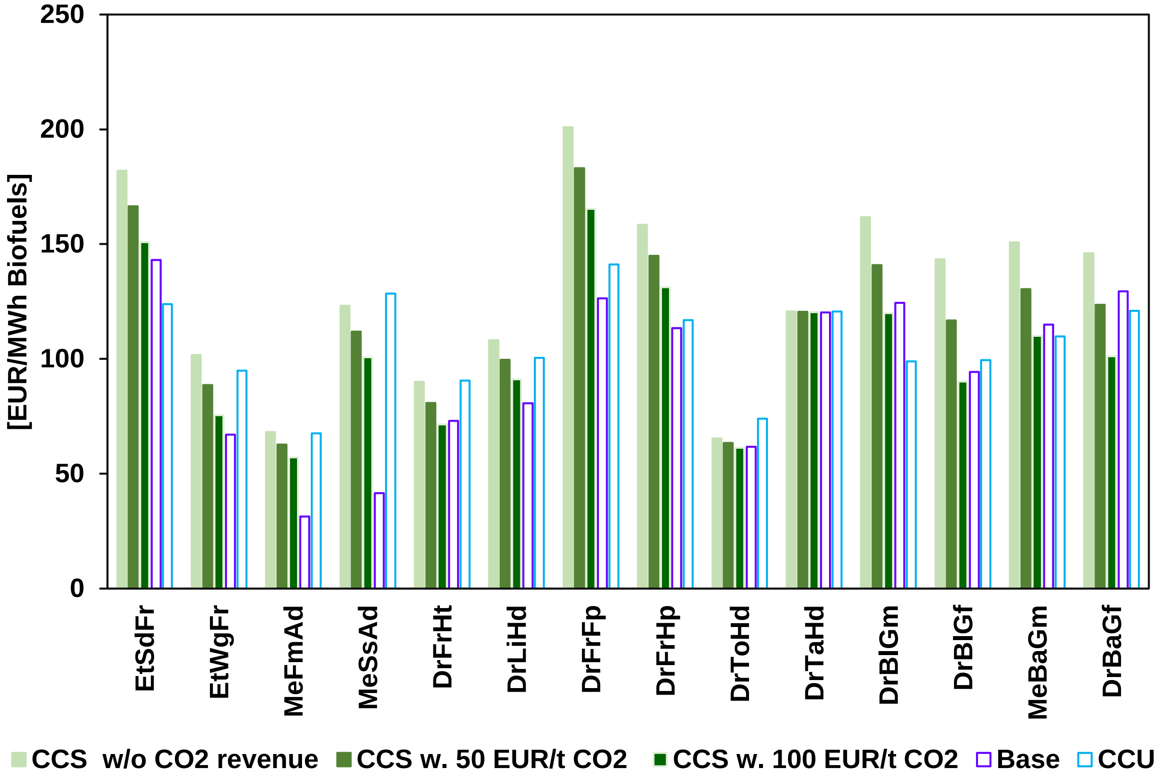

Figure 4. Impact of potential carbon sequestration credits (0, 50 and 100 EUR/t CO_2, respectively) on biofuel production costs with CCS, compared to biofuel production costs of the base and CCU options. For pathway nomenclature, see Table 1.

2.2.5 Increased Biofuel Production with BECCU

Table 13 shows biofuel production under the base and CCU options. The increased biofuel production levels that can be achieved with CCU are substantial. With the exception of drop-in biofuels from either meat processing by-products (DrTaHd) or tall oil (DrToHd), all other pathways can increase the biofuel production by 50% or more without needing to import additional biomass feedstock. The large capacity increase on offer can significantly enhance biomass resource utilization in the transport sector within the backdrop of increasing competition for various biomass assortments. It should be noted, however, that the increased biofuel production capacity comes with a corresponding increased electricity demand. In order to meet this demand, an extensive scale-up of different renewable electricity production technologies, such as wind power, would be required. The availability as well as security of supply for renewable electricity is likely to require developments and also investments from local power suppliers and electricity grid infrastructure operators. A closer examination of the actions required is outside the scope of this report but an idea of the scale of electricity requirement for each pathway can be gleaned from the energy balances for the CCU options, which are presented in Appendix C.

Table 13. Biofuel production under BECCU compared to under the base option

Pathway [a]	Biofuel Products [MW]	
	Base	CCU
EtSdFr Ethanol: sawdust, hydrolys+ferment.	62.2	160
EtWgFr Ethanol: wheat grain, fermentation	147	341
MeFmAd Methane: food waste+manure, AD	4.33	6.75
MeSsAd Methane: sewage sludge, AD	1.14	4.02
DrFrHt Dropin: forest residues, HTL	76.8	132
DrLiHd Dropin: lignin, HDO	84.0	140
DrFrFp Dropin: forest res., fast pyr+HDO	13.2	31.6
DrFrHp Dropin: forest residues, hydropyr.	16.4	33.6
DrToHd Dropin: tall oil, distillation+HDO	304	352
DrTaHd Dropin: tallow, HDO	816	822
DrBlGm Dropin: BL, gasific.+methanol+MTG	45.6	120
DrBlGf Dropin: BL, gasific.+FT	40.5	125
MeBaGm Methane: bark, gasific.+methanation	200	612
EtSdFr Ethanol: sawdust, hydrolys+ferment.	254	697

[a] Dropin = drop-in biofuels; AD = Anaerobic Digestion; BL = Black Liquor; FT = Fischer-Tropsch; HDO = Hydrodeoxygenation; HTL = Hydrothermal Liquefaction; MTG = methanol-to-gasoline.

3 NON-TECHNICAL CONSIDERATIONS, TECHNOLOGY READINESS & FEEDSTOCK POTENTIALS

This chapter covers the following project objective:

4) Perform an overall comparative assessment of the contributory potential of the studied pathways to the transport sector transition with respect to non-technical barriers, technology readiness and feedstock potential.

3.1 METHODS FOR ASSESSING NON-TECHNICAL ASPECTS, TECHNOLOGY READINESS & FEEDSTOCK POTENTIALS

3.1.1 Assessment of Non-technical BECCS/U Drivers and Barriers

The investigation of non-technical drivers and barriers that impact upon technical development and diffusion was carried out with the aid of the Technological Innovation Systems (TIS) framework. TIS is part of a wider theoretical model called innovative system approach, a term originally coined by Lundvall (see e.g. [72]). The essential feature of the TIS framework is its definition and delineation of different structural components that can inhibit or facilitate innovation, as shown in Figure 5. By studying the links between different structure components and the manner in which they facilitate or inhibit the emergence, development and dissemination of new technology, it is possible to identify useful insights that can aid both technology developers and policy decision-makers. It is also possible to identify system weaknesses, which may be influenced by actors in the system but might also require specific policy attention.

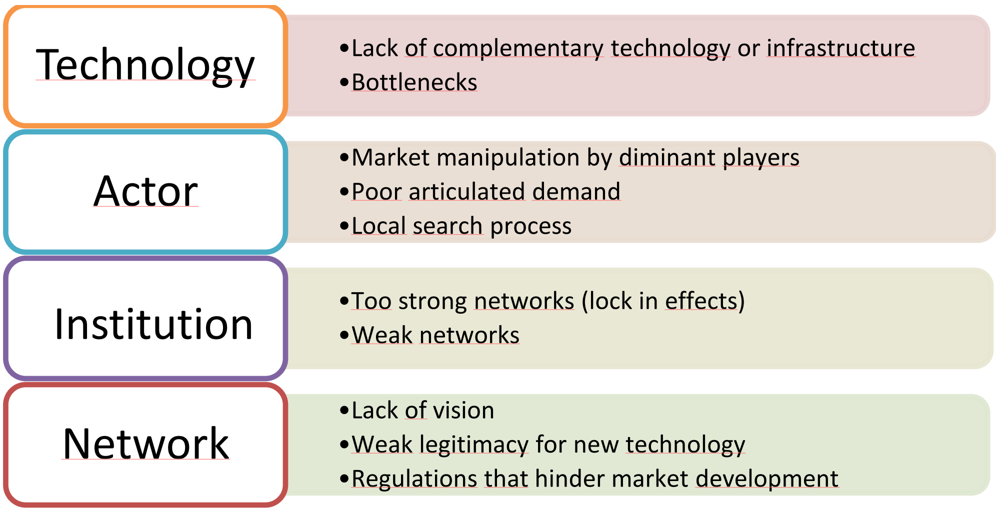

Figure 5. Structural components of the technology innovation system method.

Hellsmark et al. identified several system strengths that have spurred the development of the Swedish biorefinery TIS, e.g. strong actor networks, the existence of research infrastructure and long-term funding initiatives [73]. System weaknesses, e.g. weak coordination among ministries, unclear roles and lack of absorptive capacity (expert-level mastery of pertinent technological domains) were also pointed out.

It was highlighted that these weaknesses can be addressed with the help of four specific policy measures: (1) the implementation of a deployment policy for creating domestic niche markets, (2) an improvement in timing the introduction of new policies through better and more structured coordination among different governmental agencies, (3) the provision of stronger incentives that spur established industries to invest in R&D and improve their absorptive capacity; and (4) improved organization and financing of existing research infrastructure. Giurca and Späth investigated the strength, weaknesses and policy options for lignocellulosic biorefineries in Germany. They identified a number of internal and external weaknesses, including fragmented policies, undeveloped market formation, technological immaturity and incomplete market networks [74]. Their analysis presented a number of policy options for supporting the construction of biorefineries in Germany and also emphasized the need for better policy coordination.

A full TIS analysis is time-consuming and outside the scope of this work. A workshop supported by a simplified and shortened version of the TIS framework was conducted to identify key non-technical barriers and drivers pertaining to the deployment of BECCS and BECCU in the Swedish biofuel sector. The following structural components that potentially inhibit innovation in different ways (see Figure 5) were selected as the basis for the discussion:

- Technology (artefacts, codified knowledge)
- Actors (universities, businesses, individuals, other organizations)
- Networks (political networks, social networks, learning networks)
- Institutions (norms and values, standards, laws and regulations, routines)

Participants in the workshop included representatives from the fuel industry (refineries, biofuel producers and forest companies), academic researchers within biofuel development and energy systems analysis, and governmental policymaking units (the Swedish Energy Agency). The aim of the workshop was to supplement the technical focus of the techno-enviro-economic assessment with an assessment of non-technical barriers and drivers that Swedish BECCS and BECCU actors themselves identified as key to technical development and deployment. The participants were introduced to the TIS framework at the beginning of the workshop after which they were divided into small working groups. The discussions in the groups were summarized at the end and were examined to identify the most important structural components.

3.1.2 Assessment of Technology Maturity & Feedstock Potential

Technology maturity was scored on the TRL scale with definitions from the European Commission [75] and the US Department of Energy as guidelines [76]. Several of the emerging pathways that were investigated are under active development. The evaluation of technology maturity built upon work conducted in previous studies [22,27]. The TRL scores were assembled from different source studies with their own scoring approaches, not all of which considered the effect of raw material stream systematically and explicitly. Since the main aim of the assessment was to capture the differences in technology readiness between the different base biofuel pathways, only the TRL of the base option was assessed. The technology readiness of the steps common to all pathways, such as the capture, transport and storage of CO_2 was not assessed more closely. It should be noted that the TRL of the CCS and CCU options are in general lower than that of the base option.

The availability of biomass assortments in Sweden as feedstock for biofuel production was examined through a survey of recent literature. The scope was limited to latest estimates of the technical potential of residual biomass fractions. As discussed in section 2.2.5, the pathways with CCU would also require significant volumes of renewable electricity. The potential for additional renewable electricity production has, however, not been assessed within the scope of this project.

3.2 SUMMARY OF WORKSHOP ON DRIVERS & BARRIERS

The most important drivers and barriers relating to the technical development of biofuels with CCS and CCU as identified by workshop participants are presented in Figure 6 and Figure 7. It is evident from the comparison of the two figures that the numbers of barriers significantly outweighed the drivers in the opinions of the workshop participants. Both the barriers and drivers identified in the workshop correlate rather well with the system strengths and weaknesses identified in broad evaluations of Swedish and German bio-refinery TIS by [73] and [74]. This is particularly true for institutions and networks.

Several participants focused on policy issues and time horizons for investments. It was clear from the discussion that industrial actors were frustrated with what they identified as the impermanence of policy support mechanisms. There was a strong demand for the development of policies with a long-term time horizon to aid decision-making. Participants also expressed the need of further technology development in order to mitigate technology risks. Specific technological barriers that were highlighted included, e.g., limitations to the transport and storage of H_2, the emerging nature of CCU technologies, and limitation to electrification and grid capacity. Another critical aspect that was raised was that, despite there being a tradition of co-operating across the supply chain for Swedish industries, particularly the forest sector, allocating value between actors remains a challenge.

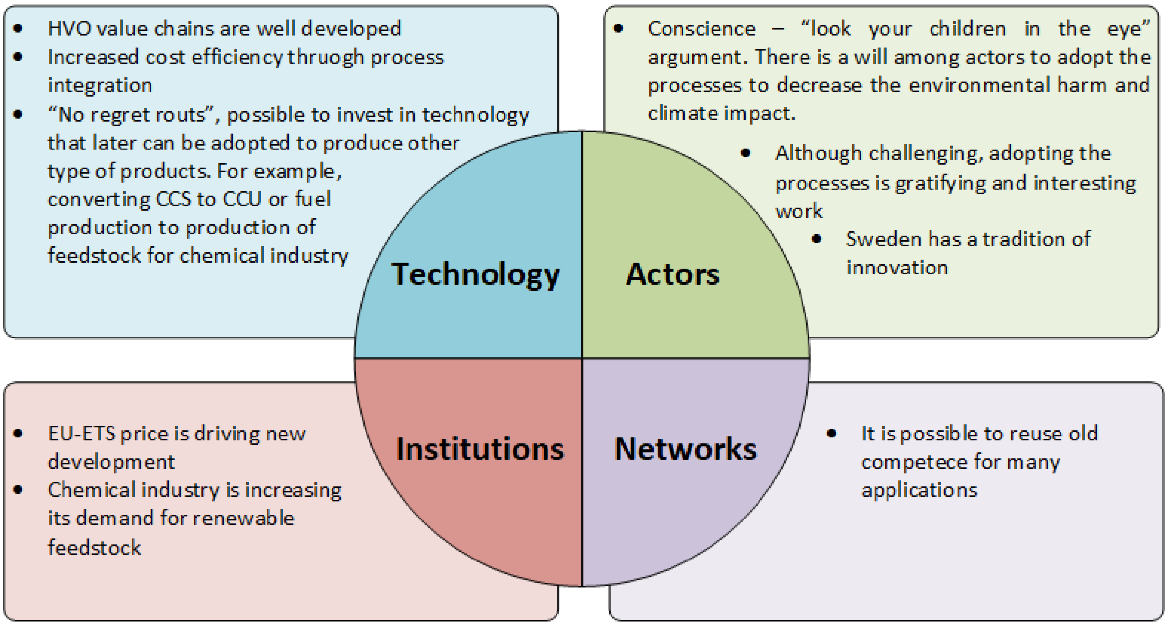

Figure 6. Non-technical drivers that can assist BECCS and BECCU development as identified by Swedish actors in the technology innovation system workshop.

Overall, particularly for the industry participants, the biggest drivers were in the technology and actor components, while the biggest barriers were institutional in nature. Some participants also identified lack of local networks as a hindrance to collaboration.

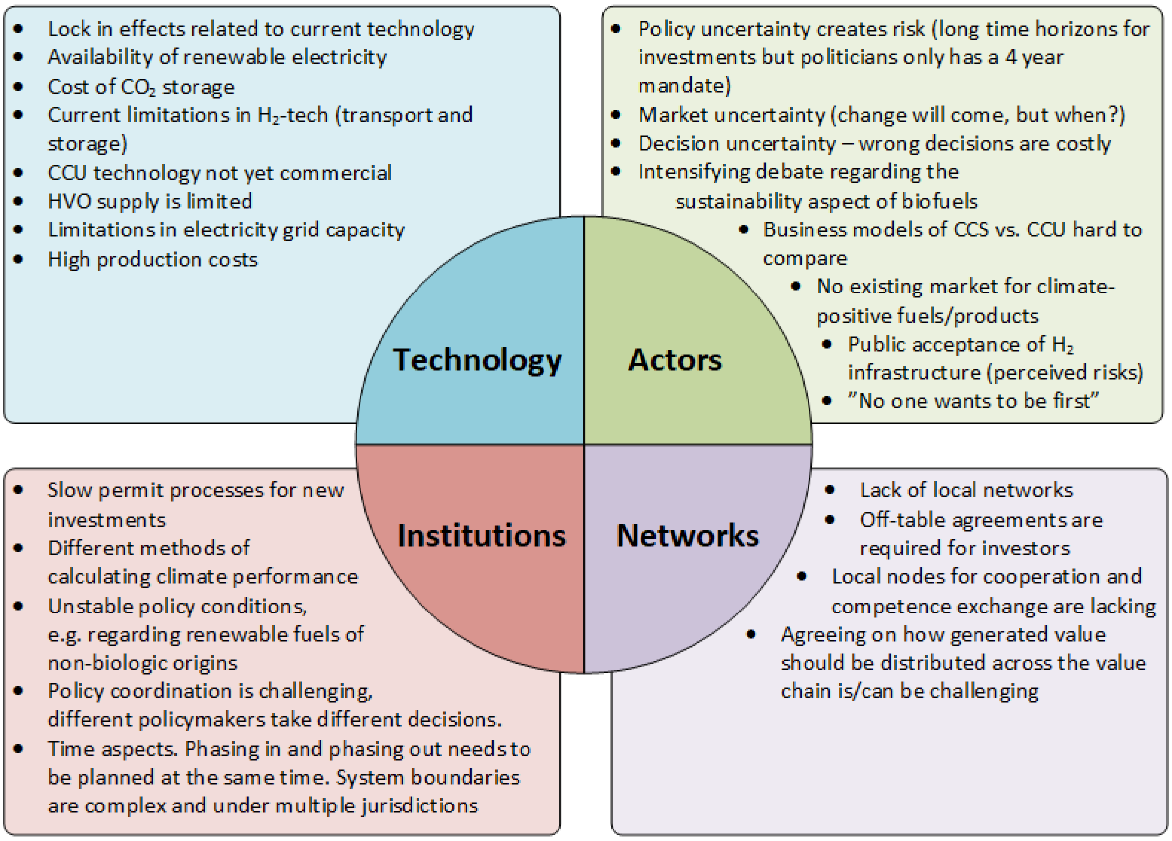

Figure 7. Non-technical barriers to BECCS and BECCU development as identified by Swedish actors in the technology innovation system workshop.

3.3 TECHNOLOGY READINESS ASSESSMENT

The results of the technology readiness assessment are summarized in Table 14. Five of the fourteen pathways are currently in commercial use. Among emerging pathways, gasification-based alternatives remain at a slightly higher degree of technology development than hydrotreatment-based alternatives, as has been discussed previously [22]. Technologies belonging to both tracks are currently under development and testing.

Table 14. Technology readiness level (TRL) assessment of the biofuel pathways under examination.

Pathway [a]	TRL	Reference	Comment
EtSdFr Ethanol: sawdust, hydrolys+ferment.	7	[77]	
EtWgFr Ethanol: wheat grain, fermentation	9	[78]	Commercial.
MeFmAd Methane: food waste+manure, AD	9	[79]	Commercial.
MeSsAd Methane: sewage sludge, AD	9	[79]	Commercial.
DrFrHt Dropin: forest residues, HTL	5	[80,81]	
DrLiHd Dropin: lignin, HDO	6-7	[82]	Applies to the development status of the RenFuel technology. The techno-economic evaluation of DrLiHd in this study is based on the SunCarbon technology [83].
DrFrFp Dropin: forest res., fast pyr+HDO	6	[27]	
DrFrHp Dropin: forest residues, hydropyr.	5	[27]	The latest development status of the IH_2 demonstration unit is difficult to ascertain from public literature and the TRL level may have advanced to 6.
DrToHd Dropin: tall oil, distillation+HDO	9		Commercial.
DrTaHd Dropin: tallow, HDO	9		Commercial.
DrBlGm Dropin: BL, gasific.+methanol+MTG	7	[22]	
DrBlGf Dropin: BL, gasific.+FT	7	[22]	Own assessment based on separate demonstration of the entrained-flow black liquor gasification technology and FT projects under commissioning. Fulcrum Bioenergy is in the process of constructing a biofuel plant based on gasification and FT plant with municipal solid waste as the primary feedstock. The plant is currently being commissioned and will produce approximately 35 kt/y of biofuel once fully commissioned.
MeBaGm Methane: bark, gasific.+methanation	8	[84]	
EtSdFr Ethanol: sawdust, hydrolys+ferment.	8	[84]	Own assessment based on the demonstration of GoBiGas gasification technology and upcoming FT biofuel projects. Red Rock biofuels is currently constructing a gasification and FT-based biofuel plant in Arizona in the United States that will produce 45 kt/y of biofuels from forest-based residues.

[a] Dropin = drop-in biofuels; AD = Anaerobic Digestion; BL = Black Liquor; FT = Fischer-Tropsch; HDO = Hydrodeoxygenation; HTL = Hydrothermal Liquefaction; MTG = methanol-to-gasoline.

3.4 FEEDSTOCK POTENTIAL ASSESSMENT

The results of the survey of Swedish feedstock potentials are presented in Table 15. When taken in aggregate, forest residues (branches & tops) and black liquor offer the largest feedstock potential, followed by bark and lignin. The pathways that utilize these feedstocks are not currently in commercial operation. In comparison, currently commercial pathways based on anaerobic digestion and hydrotreatment of tall oil and animal fats have very limited feedstock potentials.

Table 15. Assessment of the feedstock potential of relevant biomass assortments.

Feedstock	Range (TWh/y)	Reference	Comment
Bark	12.5	[85]	Estimate does not include current use.
Black liquor	24-54	[23]	The upper limit denotes the entire Swedish BL throughput under an annual production increase of 1.3% between 2018 and 2030 in the reference study, while the lower limit denotes BL from mills with recovery boilers built before 1995. It is assumed that these indicative estimates of technical potential remain broadly applicable.
Food Waste	⍰0.16	[79]	Sweden produced 2.16 TWh/y of biogas in 2020 and 65% of that amount was upgraded to bio-methane [79]. Food waste had a feedstock share of 21%. Given these numbers, assuming that the feedstock bases for the biogas that is and is not upgraded to bio-methane are the same, the maximum technical potential for bio-methane from food waste is ⍰0.16 TWh/y.
Forest residues (branches & tops)	32	[85]	Current use is not included. Ecological restrictions on removal of branches & tops are taken into account.
Lignin	9.9	[85]	Estimate does not include current use, currently insignificant.
Manure	⍰0.08	[79]	Sweden produced 2.16 TWh/y of biogas in 2020 and 65% of that amount was upgraded to bio-methane [79]. Manure had a feedstock share of 11%. Given these numbers, assuming that the feedstock bases for the biogas that is and is not upgraded to bio-methane are the same, the maximum technical potential for bio-methane from food waste is ⍰0.08 TWh/y.
Sawdust	10.2	[85]	Estimate does not include current use, currently insignificant.
Sewage Sludge	⍰0.24	[79]	Sweden produced 2.16 TWh/y of biogas in 2020 and 65% of that amount was upgraded to bio-methane [79]. Sewage sludge was the dominant feedstock with a share of 32%. Given these numbers, assuming that the feedstock bases for the biogas that is and is not upgraded to bio-methane are the same, the maximum technical potential for bio-methane from sewage is ⍰0.24 TWh/y.
Crude tall oil (CTO) [a]	1.92	[86]	Estimated by taking the average value of the technical potentials of tall oil in 2020 (1.85 TWh/y) and 2030 (1.33-2.64 TWh/y).
Meat industry by-products ("waste animal fats")	0.55	[86]	Estimated by taking the average value of the technical potentials of waste animal fats in 2020 (0.54 TWh/y) and 2050 (0.56 TWh/y).
Wheat Grain	n.a.	n.a.	Ethanol from wheat grain is currently produced commercially by Lantmännen Agroetanol AB [87]. The feedstock potential of wheat grain was not assessed as the focus of this project was principally on biomass residues.

[a] Since crude tall oil is traded globally on both the biofuel and biochemical markets, some information on the European situation is also provided for reference. A 2021 review of the crude tall oil market [88]provides an analysis of recent trade figures to argue that the European supply of CTO will become constrained from 2022 onwards, with increasing competition between end-use applications and demand continuously outstripping supply. The review forecasts that the demand for crude tall oil-based biofuels for transportation will increase from 320,000 t/y to 880,000 t/y by 2030 and projects a crude tall oil availability deficit of 180,000 t/y by 2030.

4 OVERALL RESULTS & CONCLUSIONS

This chapter contains a tabulated summary of the project results and a thesis of the principal conclusions.

The overall aim was to assemble a knowledge base as decision-making aid for setting long-term transport sector priorities, particularly for R&D and commercial deployment of carbon-efficient and cost-effective biofuel production. Carbon and energy balance models for 14 biofuel production pathways were compiled with data primarily from the open literature and used to calculate carbon utilization efficiencies and greenhouse gas (GHG) footprints, estimate biofuel production costs, and identify pathways that can achieve GHG reductions cost-effectively with CCS and CCU in a 2030 energy market scenario.

4.1 SUMMARY OF OVERALL RESULTS

The techno-economic and the enviro-economic performance of the biofuel production pathways was assessed with the help of several performance indicators. Related aspects such as technology maturity, feedstock potentials and non-technical barriers were also taken into account. A summary of the overall results is presented in Table 16.

The best-performing commercial pathways offer lower biofuel production and GHG reduction costs than the best-performing emerging pathways under both the BECCS options (65 EUR/MWh, 0.045–0.046 EUR/kg CO_2eq. vs. 90 EUR/MWh, 0.093 EUR/kg CO_2eq.) and the BECCU options (68 EUR/MWh, 0.057 EUR/kg CO_2eq. vs. 90 EUR/MWh, 0.14 EUR/kg CO_2eq.).

With a CO_2 sequestration credit of 100 EUR/t CO_2, the costs of biofuel production are significantly lower for several pathways, e.g. the gasification pathways decrease from 143-162 EUR/MWh to 90-120 EUR/MWh. These costs are competitive compared with the base (91-120 EUR/MWh) and the CCU options (99-120 EUR/MWh). The study's own estimation of carbon sequestration costs found 11 out of the 14 biofuel pathways to be in the range between 50 and 200 EUR/t CO_2.

However, with significantly lower carbon efficiencies than the best emerging pathways (~50–55% compared to ~85–95%) and with modest feedstock potentials (not estimated in the present study), the commercial pathways do not offer the same improvement in carbon utilization.

Concerning non-technical barriers, particularly for the industry participants, the biggest drivers were in the technology and actor components, while the biggest barriers were institutional in nature. Some participants also identified lack of local networks as a hindrance to collaboration.

Covering a broad array of residual biomass assortments, the feedstock potentials for the biofuel pathways under examination showed large variations. Generally, the technical potentials of emerging pathways based on residual biomass assortments was medium-to-high, while the technical potentials of currently commercial pathways based on meat processing residues, tall oil, sewage sludge and food waste were low to poor.

Among emerging pathways, gasification-based alternatives remain at a slightly higher degree of technology development than hydrotreatment-based alternatives, as has been discussed previously [22]. Technologies belonging to both tracks are currently under development and testing.

Table 16. Overall assessment of road biofuels under the base, CCS & CCU options.

Pathway [a]	All options		Base Option			CCS Option				CCU Option		
	Swedish Feedstock Potential [b] [TWh/y]	Technology readiness (TRL) [c] [1-9]	Carbon efficiency [d] [% Feed-to-Biofuels]	Biofuel Cost [e] [EUR/MWh]	GHG Footprint [f] [g CO_2eq./MJ Biofuels]	Carbon efficiency [d] [% Feed-to-Biofuels]	Biofuel Cost [e] [EUR/MWh] 100 EUR/t CO_2 credit	Biofuel Cost [e] [EUR/MWh] w/o CO_2 credit	GHG Footprint [f] [g CO_2eq./MJ Biofuels]	Carbon efficiency [d] [% Feed-to-Biofuels]	Biofuel Cost [e] [EUR/MWh]	GHG Footprint [f] [g CO_2eq./MJ Biofuels]
EtSdFr Ethanol: sawdust, hydrolys+ferment.	10.2	7	32	143	5	73	151	182	-62	73	124	19
EtWgFr Ethanol: wheat grain, fermentation	n.a.	9	42	67	17	85	76	102	-28	85	95	24
MeFmAd Methane: food waste+manure, AD	~0.24	9	34	31	3	53	57	68	-11	53	68	6
MeSsAd Methane: sewage sludge, AD	~0.24	9	14	42	8	23	101	123	-11	43	128	20
DrFrHt Dropin: forest residues, HTL	32	5	38	73	1	64	72	90	-4	64	91	15
DrLiHd Dropin: lignin, HDO	9.9	6-7	57	81	-19	91	91	108	-39	94	100	-7
DrFrFp Dropin: forest res., fast pyr+HDO	32	6	39	126	-23	91	165	201	-109	90	141	4
DrFrHp Dropin: forest residues, hydropyr.	32	5	47	113	4	97	131	158	-85	96	117	9
DrToHd Dropin: tall oil, distillation+HDO	1.92	9	48	62	8	55	61	65	2	55	74	10
DrTaHd Dropin: tallow, HDO	0.55	9	67	120	14	67	120	121	13	68	121	14
DrBlGm Dropin: BL, gasific.+methanol+MTG	24-54	7	33	124	11	87	120	162	-99	86	99	18
DrBlGf Dropin: BL, gasific.+FT	24-54	7	27	94	10	87	90	143	-134	86	100	19
MeBaGm Methane: bark, gasific.+methanation	12.5	8	31	115	7	96	110	151	-97	96	110	19
DrBaGf Dropin: bark, gasific.+FT	12.5	8	30	129	7	91	101	146	-131	90	120	19

[a] Dropin = drop-in biofuels; AD = Anaerobic Digestion; BL = Black Liquor; FT = Fischer-Tropsch; HDO = Hydrodeoxygenation; HTL = Hydrothermal Liquefaction; MTG = methanol-to-gasoline.

[b] < 10 TWh, 10 – 20 TWh, > 20 TWh. Potentials rounded to two significant figures for classification assignment.

[c] TRL 4 – 5, TRL 6 – 7, TRL 8 – 9.

[d] < 33%, 33 – 66%, >66%. Efficiencies rounded to two significant figures for classification assignment.

[e] > 115 EUR/MWh, 75 – 115 EUR/MWh, < 75 EUR/MWh. Represents the levelized cost of biofuel production.

[f] > 103 g CO_2eq./MJ, 103 – 0 g CO_2eq./MJ, < 0 g CO_2eq./MJ. Represents the average value of the footprints of all individual biofuel products. Classification based on a 65% reduction relative to a fossil reference of 92.5 g CO_2eq./MJ.

4.2 CONCLUSIONS

The full benefits of BECCS and BECCU in the biofuel sector are best unlocked by the emerging pathways. Integrating CCS and CCU with commercial biofuel pathways offers limited value for reasons that differ between technology tracks. Biogas pathways release a significant share of their feedstock carbon in concentrated CO_2 streams that can be captured easily and offer low GHG reduction and biofuel product costs. However, feedstock potentials are limited, and the costs of transporting CO_2 from small and relatively geographically dispersed biogas plants to offshore storage facilities are high and associated with large uncertainties. It is however unlikely that biogas pathways would lead the deployment of BECCS in the biofuel sectors.

Commercial hydrotreatment pathways based on tall oil and particularly meat processing residues use their feedstock carbon relatively efficiently. Significant quantities of the biogenic carbon input end up in commercially significant by-products, which is also the case for the ethanol and biogas pathways. Swedish feedstock potential and capturable carbon quantities are nevertheless limited and GHG reduction costs for meat processing residues are relatively high. Although dominant in the biofuel market, drop-in biofuels from meat processing residues and tall oil are not the most suitable candidates for BECCS and BECCU.

Emerging biofuel pathways do not offer the lowest GHG reduction costs but do offer the largest relative improvements in carbon efficiency and GHG reductions under the CCS option. Depending on the biomass fraction, Swedish feedstock potentials vary from moderate to large. Biofuel costs can be competitive against the base and CCU options with CO_2 sequestration credits in excess of 100 EUR/t CO_2**. The merit orders of emerging and commercial pathways on the carbon efficiency and GHG reduction cost metrics suggest that increasing the production of carbon efficient biofuels with negative GHG footprints will require the emergence of markets and/or support schemes for negative emission credits.** An example of such that is starting to happen is the recent Swedish proposal advocating the use of reverse auctions in a BECCS deployment program for which funds were reserved in the 2022/2023 Swedish budget proposal. The lack of long-term policy support is a commonly heard investor-lament. Institutional barriers such as unstable policy conditions were highlighted as key barriers to technical development.

Emerging pathways based on the gasification or hydrotreatment of forest residues typically have modest carbon efficiencies, around 30-40%, due to the high feedstock oxygen content, which is removed mainly as CO_2. BECCS can double the efficiency numbers and deliver negative emission biofuels, with GHG footprints below -50 g CO_2eq./MJ for several pathways. BECCU can also double the carbon efficiencies while offering similar production costs and GHG footprints under the assumption of a Swedish electricity mix in a 2030 energy market scenario. Upgrading captured CO_2 to bio-methane or to drop-in petrol & LPG can therefore be economically competitive with biofuels without CO_2 capture, while offering the added benefit of increasing biofuel production potentials without impacting on biogenic feedstock use. **If competition for biogenic feedstock in a future energy market was to increase, a CCU option for biofuel from gasification and hydrotreatment of forest residues would likely be an economically and societally attractive option.**

With transport costs for CO_2 rendering commercial investments in biofuel BECCS untenable until a support scheme for BECCS or a market for negative emission credits with attendant

regulatory framework for e.g. certification is in place, there is a risk that the priorities of investors, interested in low production costs, and those of policymakers, concerned with maximizing climate and carbon performance in furtherance of national climate goals, will not fully align.

Biofuel pathways vent CO_2 in both concentrated and dilute streams. Capturing and upgrading or storing both provides the best environomic outcomes. Differences in their respective specific costs appear to be relatively marginal. Cost estimates and process data is uneven in quantity. The results presented in this report are intended for facilitating indicative comparisons firstly between the CO_2 options and secondly between the different pathways.

In summary, our headline conclusion is that integration of CCS and CCU with current commercial biofuel production pathways offers limited value, due to already high carbon efficiencies and limited feedstock potential. The full benefits are contingent on the timely deployment of biofuel pathways that are not currently in commercial operation, and that are based on residual woody feedstocks. Successful industrial transformation is, however, dependent not only on continued techno-economic development, but also on the creation of a market for climate-positive fuels and products and a policy landscape perceived as stable by relevant stakeholders.

Finally, we hope that the results and the knowledge base we have compiled can aid future researchers, policy makers, and industrial business developers in their investigations into BECCS and BECCU concepts for the biofuel sector.

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APPENDIX A – SCHEMATIC OVERVIEWS OF BASE PROCESS CONFIGURATIONS

FERMENTATION PATHWAYS

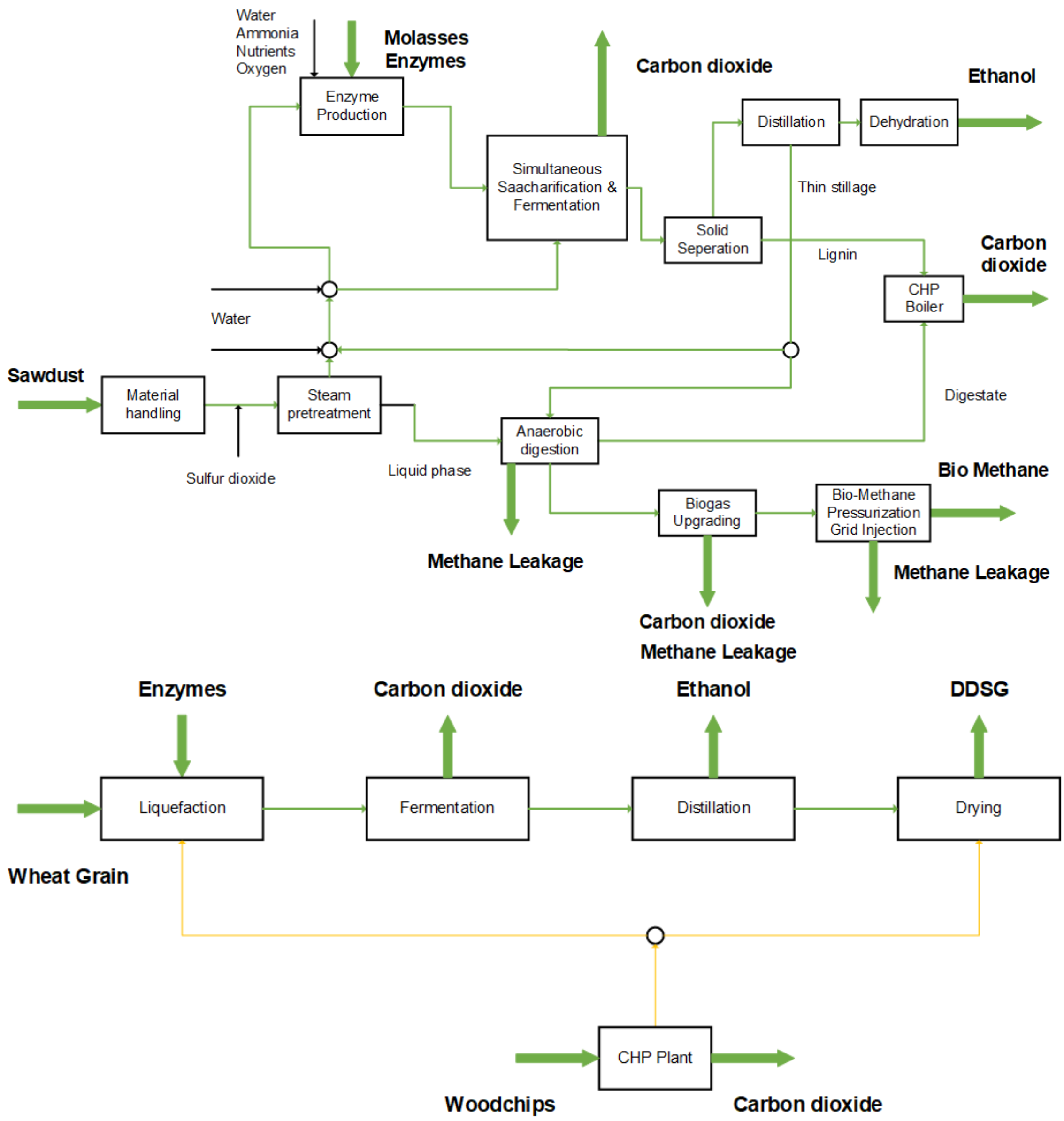


Figure A 1. Base process configurations for ethanol from sawdust by hydrolysis & fermentation, EtSdFr (top) and ethanol from wheat grain by fermentation, EtWgFr (bottom). Biogenic carbon, electricity and heat flows are indicated by green, blue and mustard arrows, respectively.

ANAEROBIC DIGESTION PATHWAYS

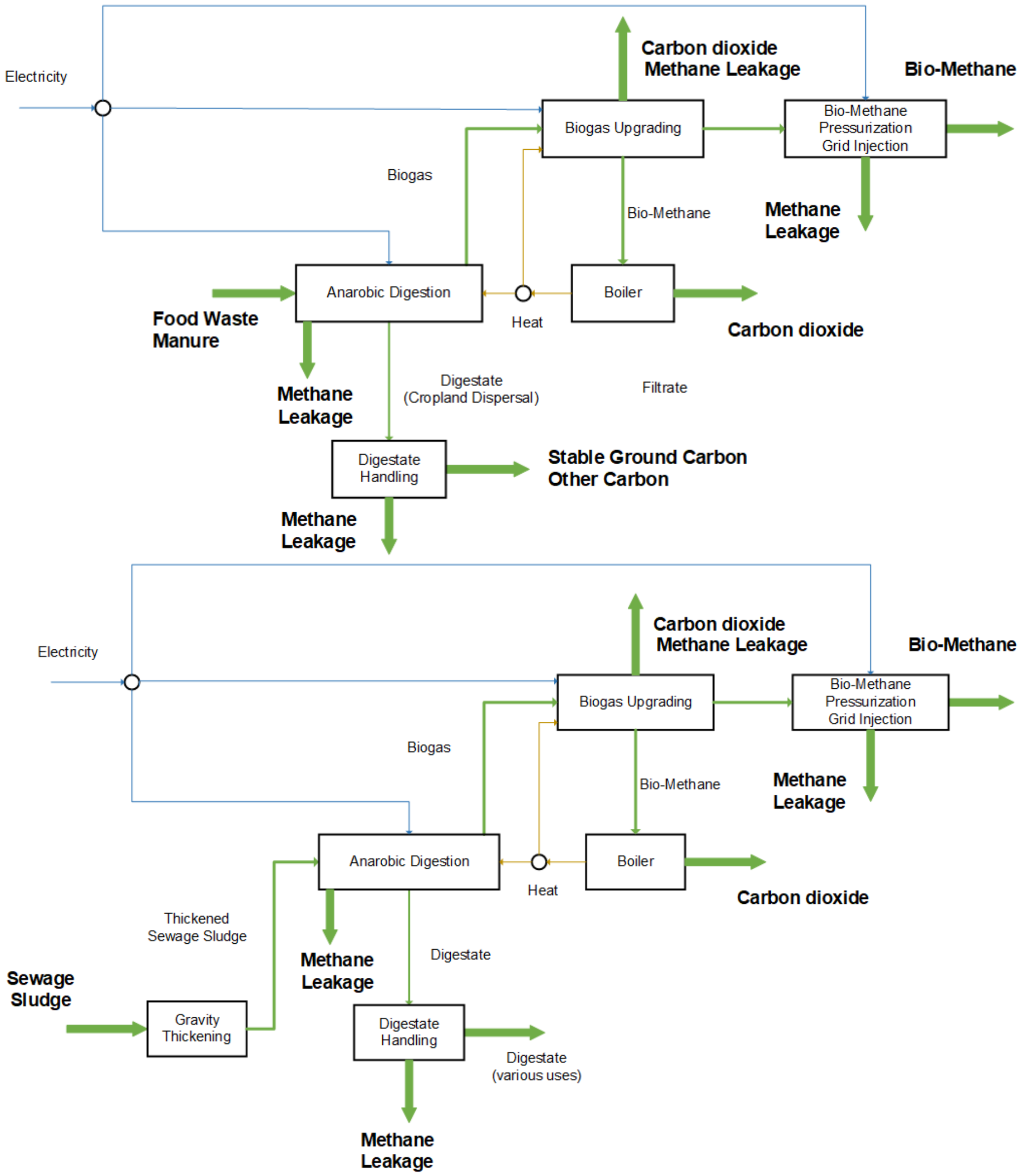


Figure A 2. Base process configurations for bio-methane from food waste & manure by anaerobic co-digestion, MeFmAd (top) and bio-methane from sewage sludge by anaerobic digestion, MeSsAd (bottom). Biogenic carbon, electricity and heat flows are indicated by green, blue and mustard arrows, respectively.

HYDROTREATMENT PATHWAYS

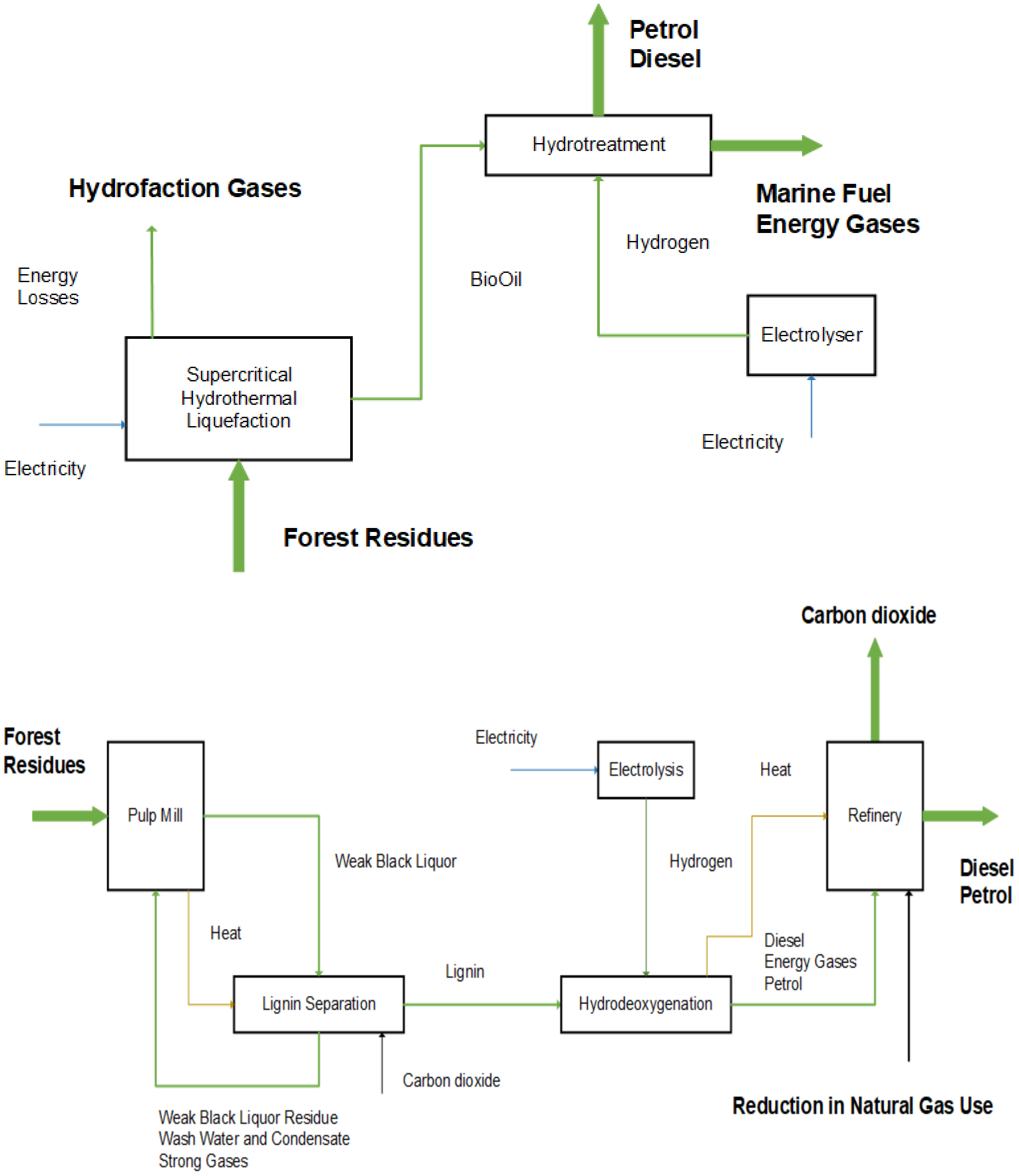


Figure A 3. Base process configurations for drop-in biofuels from forest residues by hydrothermal liquefaction, DrFrHt (top) and drop-in biofuels from lignin by hydrodeoxygenation, DrLiHd (bottom). Biogenic carbon, electricity and heat flows are indicated by green, blue and mustard arrows, respectively.

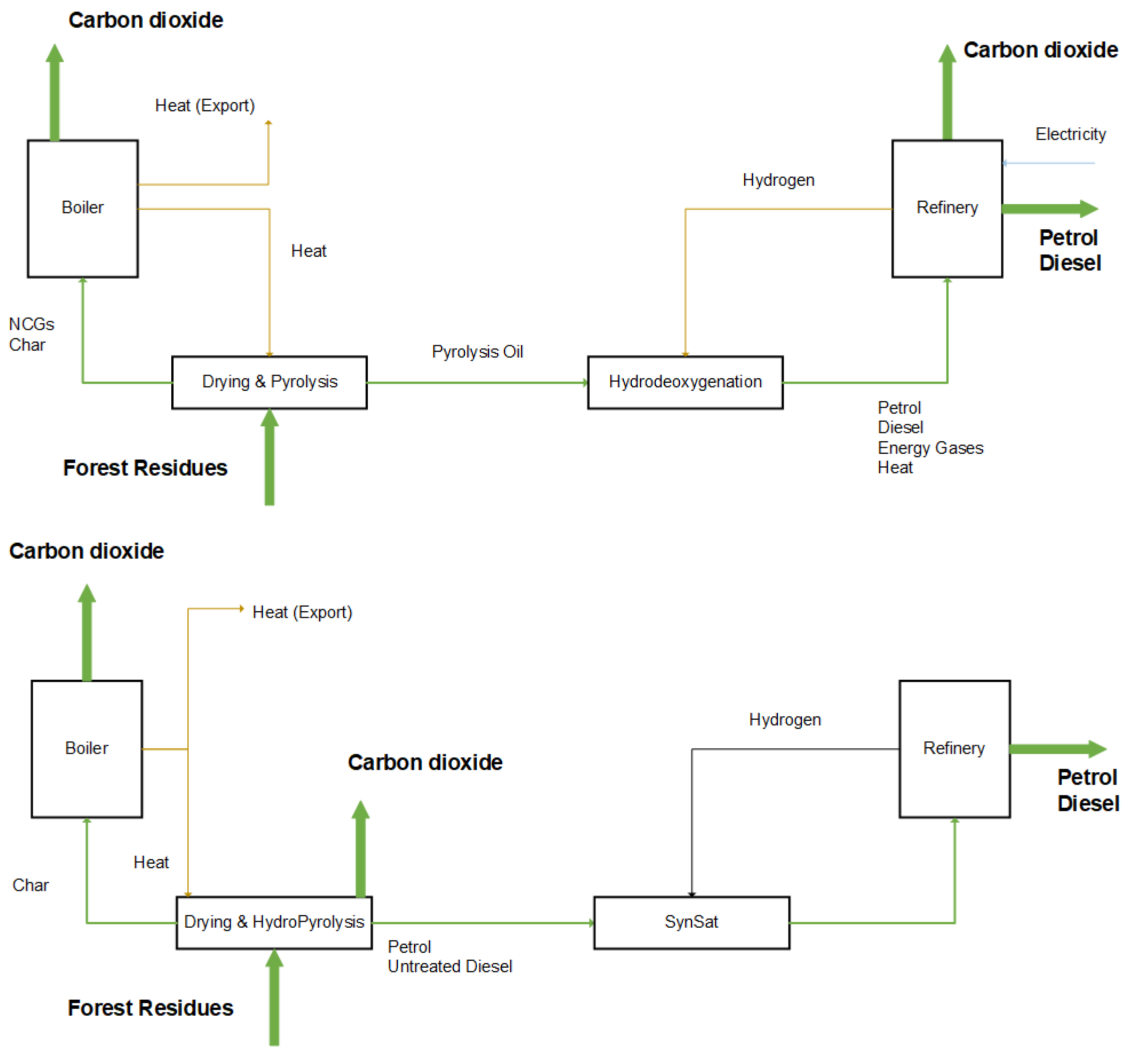


Figure A 4. Base process configurations for drop-in biofuels from forest residues by fast pyrolysis & hydrodeoxygenation, DrFrFp (top) and drop-in biofuels from forest residues by hydropyrolysis, DrFrHp (bottom). Biogenic carbon, electricity and heat flows are indicated by green, blue and mustard arrows, respectively.

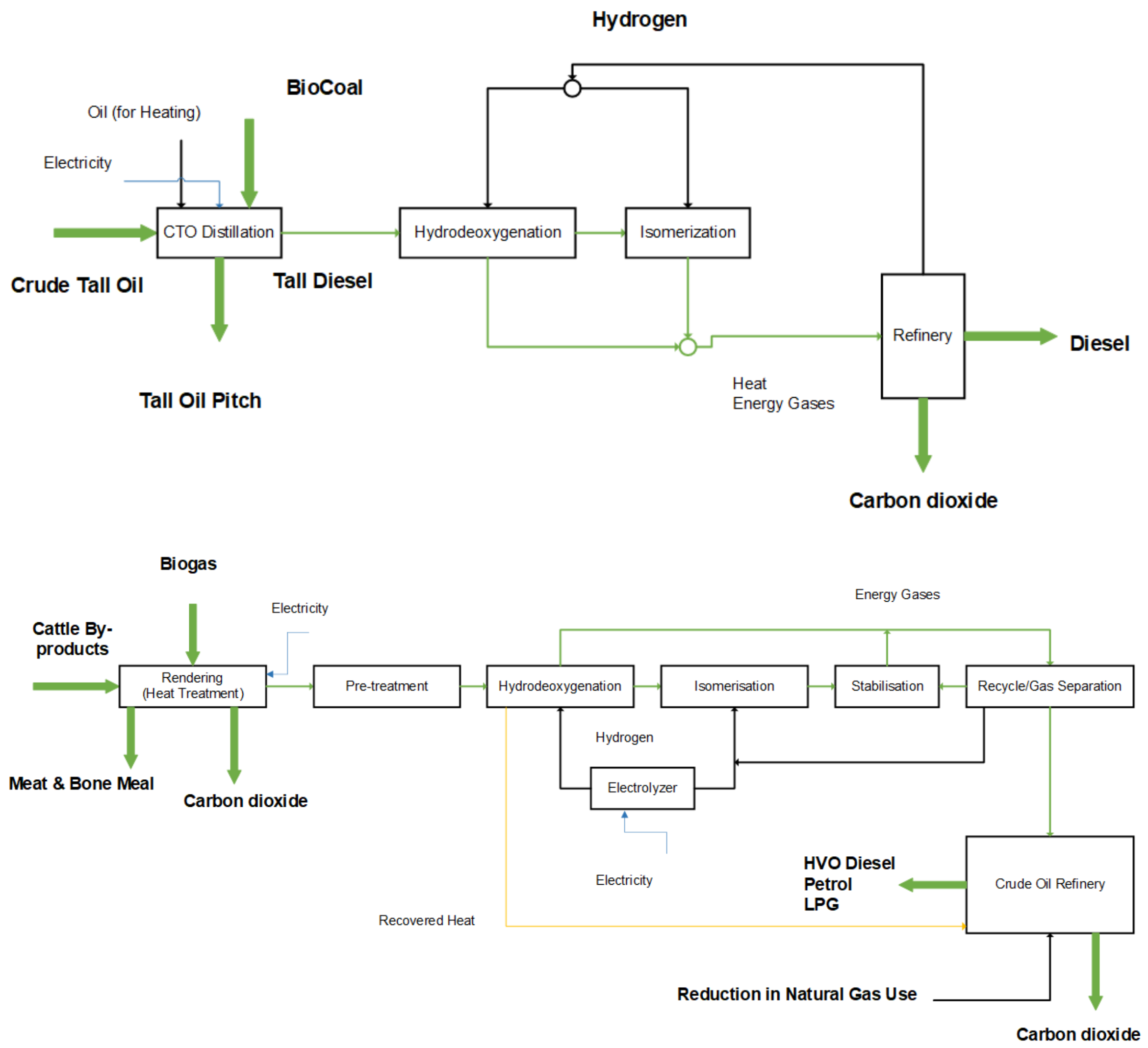


Figure A 5. Base process configurations for drop-in biofuels from crude tall oil by distillation & hydro-deoxygenation, DrToHd (top) and drop-in biofuels from meat industry by-products (tallow) by hydro-deoxygenation, DrTaHd (bottom). Biogenic carbon, electricity and heat flows are indicated by green, blue and mustard arrows, respectively.

GASIFICATION PATHWAYS

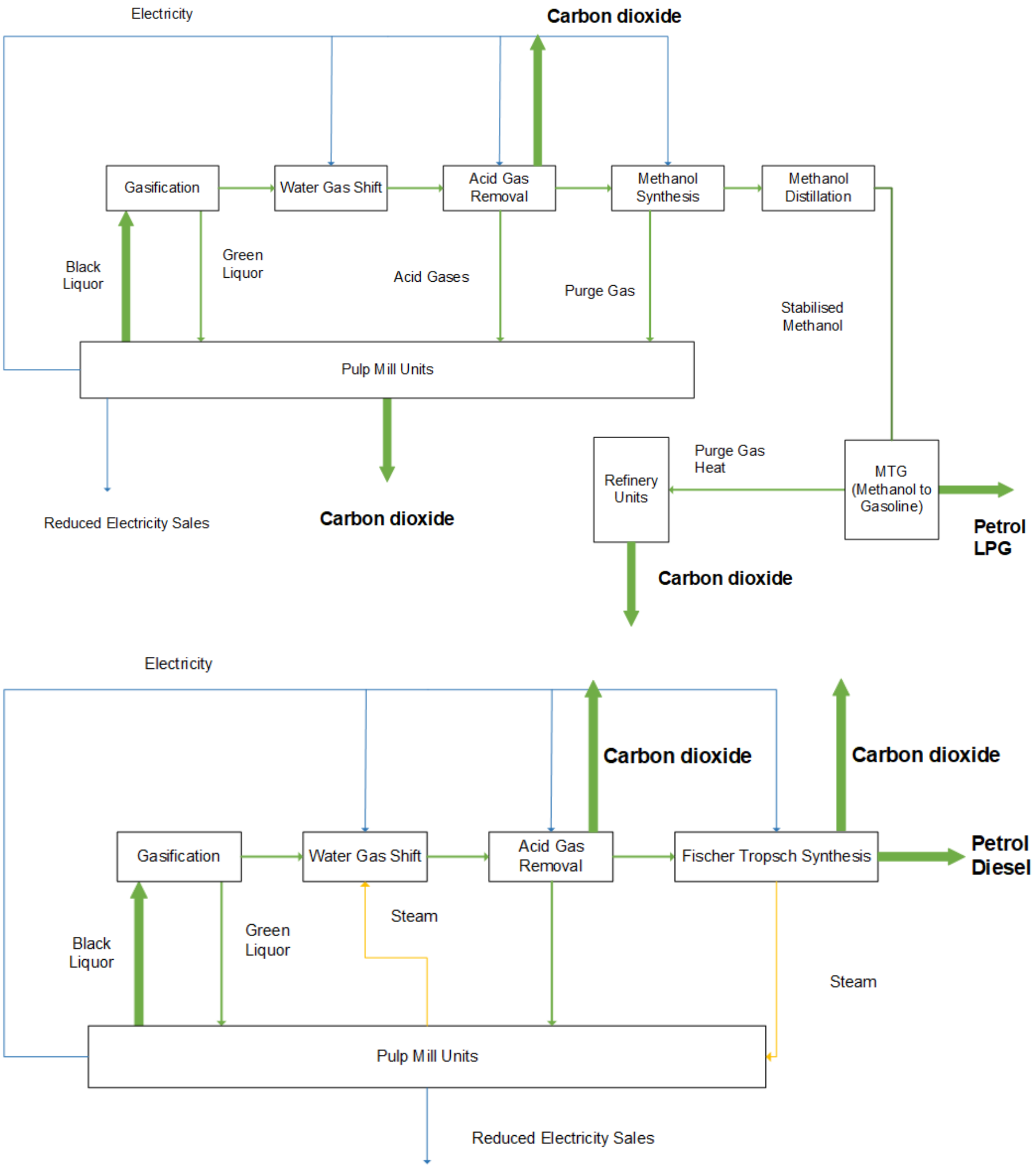
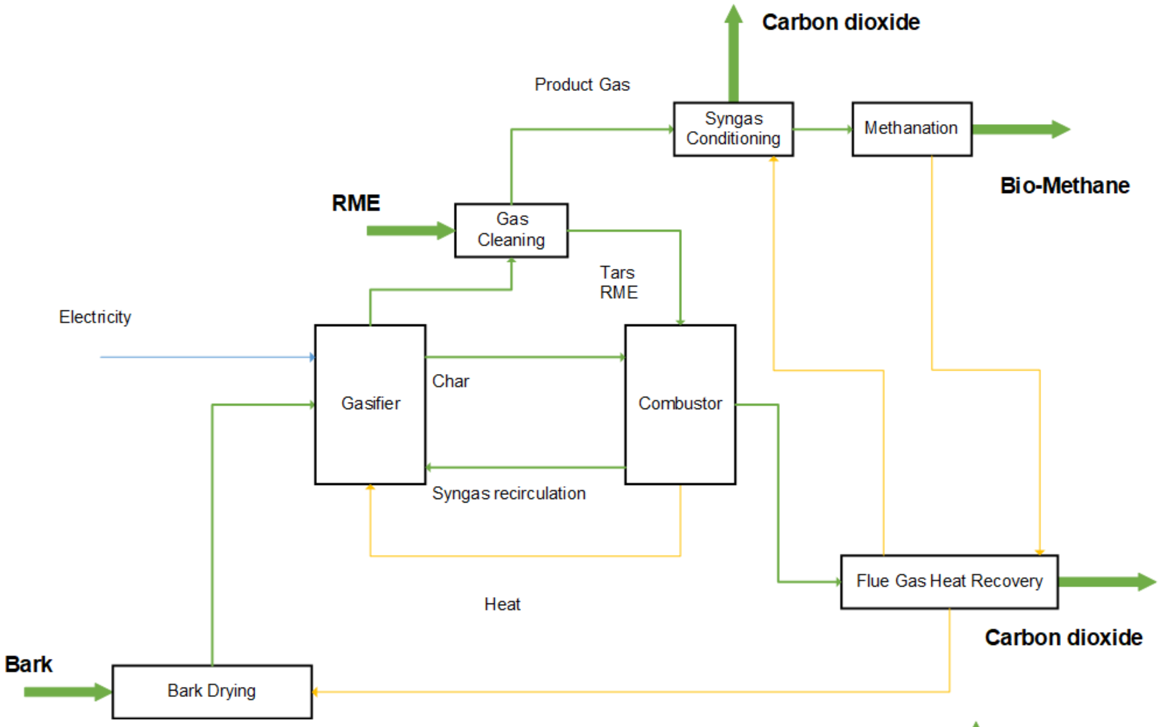


Figure A 6. Base process configurations for drop-in biofuels from black liquor by entrained- flow gasification & methanol synthesis, DrBlGm (top) and drop-in biofuels from black liquor by entrained-flow gasification & FT synthesis, DrBlGf (bottom). Biogenic carbon, electricity and heat flows are indicated by green, blue and mustard arrows, respectively.



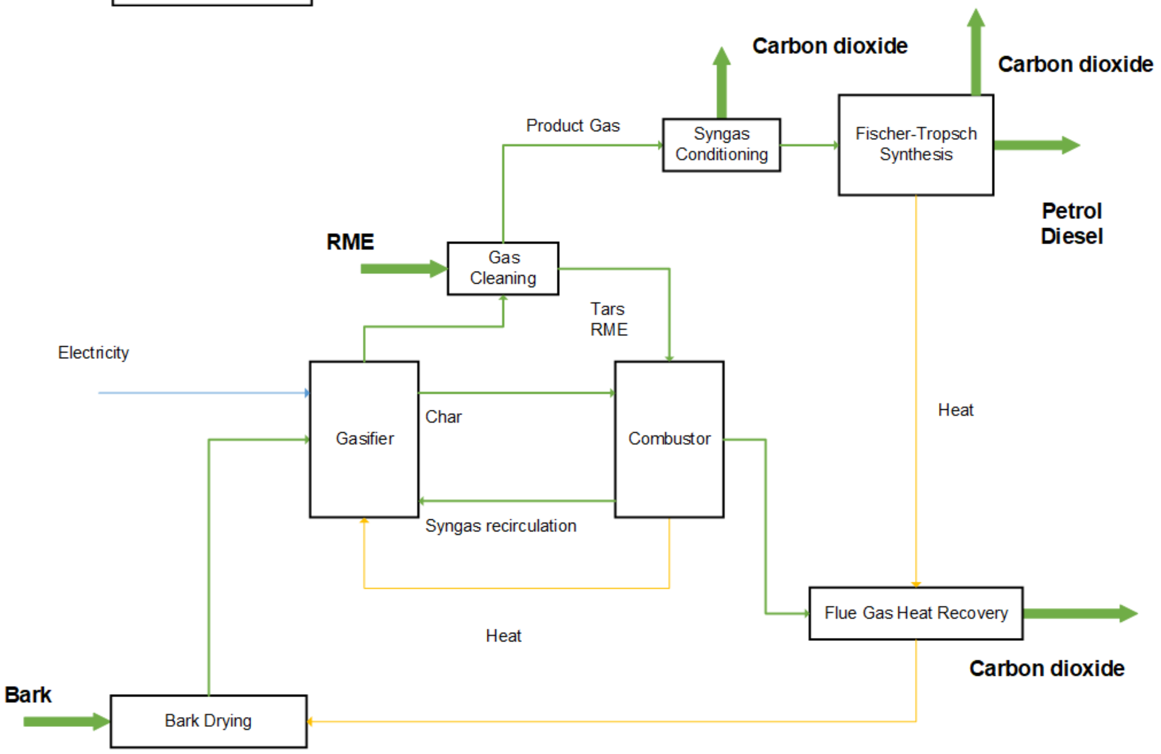


Figure A 7. Base process configurations for bio-methane from bark by dual fluidized-bed gasification & catalytic methanation, MeBaGm (top) and drop-in Biofuels from bark by dual fluidized-bed gasification & FT synthesis, DrBaGf (bottom). Biogenic carbon, electricity and heat flows are indicated by green, blue and mustard arrows, respectively.

APPENDIX B – CARBON BALANCES UNDER BASE, CCS & CCU OPTIONS

Table B 1. Carbon balances for ethanol from sawdust by hydrolysis & fermentation (EtSdFr) & ethanol from wheat grain by fermentation (EtWgFr)

	EtSdFr			EtWgFr		
	Base	**CCS**	**CCU**	**Base**	**CCS**	**CCU**
Input(s) [t/h]						
Feedstock(s)	12.8	12.8	12.8	24.4	24.4	24.4
Other biomass feed(s)	0.200	0.200	0.200	5.92	5.92	5.92
Output(s) [t/h]						
Biofuel product(s)	4.09	4.09	9.36	10.23	10.23	20.70
Tradeable by-product(s)	3.01	1.46	3.01	8.72	8.72	8.72
Atmosphere (concentrated)	2.06	0.01	0.01	5.46	0.00	0.00
Atmosphere (dilute)	3.79	2.11	0.57	5.89	0.884	0.884
Underground CO_2 Storage	0.00	5.27	0.00	0.00	10.47	0.00
Other flows/Loss	0.00	0.00	0.00	0.00	0.00	0.00

Table B 2. Carbon balances for bio-methane from food waste & manure by anaerobic co-digestion (MeFmAd) & bio-methane from sewage sludge by anaerobic digestion (MeSsAd)

	MeFmAd			MeSsAd		
	Base	**CCS**	**CCU**	**Base**	**CCS**	**CCU**
Input(s) [t/h]						
Feedstock(s)	0.690	0.690	0.690	0.581	0.581	0.581
Other biomass feed(s)	0.314	0.314	0.000	0.000	0.000	0.000
Output(s) [t/h]						
Biofuel product(s)	0.234	0.234	0.365	0.082	0.062	0.253
Tradeable by-product(s)	0.317	0.317	0.317	0.379	0.379	0.239
Atmosphere (concentrated)	0.140	0.010	0.010	0.074	0.004	0.002
Atmosphere (dilute)	0.314	0.314	0.000	0.046	0.046	0.054
Underground CO_2 Storage	0.000	0.130	0.000	0.000	0.070	0.000
Other flows/Loss	0.000	0.000	0.000	0.000	0.021	0.033

Table B 3. Carbon balances for drop-in biofuels from forest residues by hydrothermal liquefaction (DrFrHt) and drop-in biofuels from lignin by hydrodeoxygenation (DrLiHd)

	DrFrHt			DrLiHd		
	Base	**CCS**	**CCU**	**Base**	**CCS**	**CCU**
Input(s) [t/h]						
Feedstock(s)	14.7	14.7	14.7	10.6	10.6	10.6
Other biomass feed(s)	0.00	3.73	3.73	1.73	1.46	1.73
Output(s) [t/h]						
Biofuel product(s)	5.57	5.57	9.38	6.04	6.04	10.01
Tradeable by-product(s)	4.34	4.34	4.34	0.00	0.00	0.00
Atmosphere (concentrated)	0.00	0.00	0.00	0.00	0.00	0.00
Atmosphere (dilute)	4.56	4.41	4.48	6.06	2.15	2.09
Underground CO_2 Storage	0.00	3.88	0.00	0.00	3.64	0.00
Other flows/Loss	0.216	0.216	0.216	0.273	0.273	0.273

Table B 4. Carbon balances for drop-in biofuels from forest residues by fast pyrolysis & hydrodeoxygenation (DrFrFp) & drop-in biofuels from forest residues by hydropyrolysis (DrFrHp)

	DrFrFp			DrFrHp		
	Base	**CCS**	**CCU**	**Base**	**CCS**	**CCU**
Input(s) [t/h]						
Feedstock(s)	2.47	2.47	2.47	2.47	2.47	2.47
Other biomass feed(s)	0.00	0.000	0.000	0.130	0.635	0.635
Output(s) [t/h]						
Biofuel product(s)	0.953	0.953	2.22	1.16	1.16	2.36
Tradeable by-product(s)	0.00	0.00	0.00	0.00	0.00	0.00
Atmosphere (concentrated)	0.00	0.00	0.00	0.00	0.00	0.00
Atmosphere (dilute)	1.51	0.227	0.249	1.43	0.719	0.740
Underground CO_2 Storage	0.00	1.29	0.00	0.00	1.22	0.00
Other flows/Loss	0.00	0.00	0.00	0.00	0.00	0.00

Table B 5. Carbon balances for drop-in biofuels from crude tall oil by distillation & hydrodeoxygenation (DrToHd) & drop-in biofuels from meat industry by-products (tallow) by hydrodeoxygenation (DrTaHd)

	DrToHd			DrTaHd		
	Base	**CCS**	**CCU**	**Base**	**CCS**	**CCU**
Input(s) [t/h]						
Feedstock(s)	44.8	44.8	44.8	84.3	84.3	84.3
Other biomass feed(s)	3.68	3.68	3.68	9.30	9.30	9.30
Output(s) [t/h]						
Biofuel product(s)	21.4	21.4	24.8	56.4	56.4	56.9
Tradeable by-product(s)	19.4	19.4	19.4	27.4	27.4	27.4
Atmosphere (concentrated)	0	0	0	0	0	0
Atmosphere (dilute)	7.65	4.28	4.34	9.86	9.38	9.34
Underground CO_2 Storage	0.00	3.37	0.00	0.00	0.475	0.00
Other flows/Loss	0	0	0	0	0	0

Table B 6. Carbon balances for drop-in biofuels from black liquor by entrained- flow gasification & methanol synthesis (DrBlGm) & drop-in biofuels from black liquor by entrained-flow gasification & FT synthesis (DrBlGf)

Pathway	DrBlGm			DrBlGf		
	Base	**CCS**	**CCU**	**Base**	**CCS**	**CCU**
Input(s) [t/h]						
Feedstock(s)	9.74	9.74	9.74	9.74	9.74	9.74
Other biomass feed(s)	0.00	0.00	0.00	0.00	0.00	0.000
Output(s) [t/h]						
Biofuel product(s)	3.25	3.25	8.37	2.61	2.61	8.41
Tradeable by-product(s)	0.890	0.890	0.890	0.890	0.890	0.890
Atmosphere (concentrated)	5.21	0.00	0.00	5.30	0.00	0.00
Atmosphere (dilute)	0.234	0.234	0.322	0.705	0.106	0.206
Underground CO_2 Storage	0.00	5.21	0.00	0.00	5.90	0.00
Other flows/Loss	0.157	0.157	0.157	0.230	0.230	0.230

Table B 7. Carbon balances for bio-methane from bark by dual fluidized-bed gasification & catalytic methanation (MeBaGm) & drop-in Biofuels from bark by dual fluidized-bed gasification & FT synthesis (MeBaGf).

Pathway	MeBaGm			MeBaGf		
	Base	CCS	CCU	Base	CCS	CCU
Input(s) [t/h]						
Feedstock(s)	34.5	34.5	34.5	51.2	51.2	51.2
Other biomass feed(s)	0.924	0.924	0.924	1.371	1.371	1.371
Output(s) [t/h]						
Biofuel product(s)	10.8	10.8	33.0	15.4	15.4	45.9
Tradeable by-product(s)	0	0	0	0	0	0
Atmosphere (concentrated)	8.53	0	0	10.8	0	0
Atmosphere (dilute)	16.1	2.42	2.42	26.5	6.15	6.67
Underground CO_2 Storage	0	22.2	0	0	31.1	0
Other flows/Loss	0	0	0	0	0	0

APPENDIX C – CARBON & ENERGY BALANCES

The following figures show the carbon & energy balances for 1 kg C and 1 MW_{LHV} feedstock energy input.

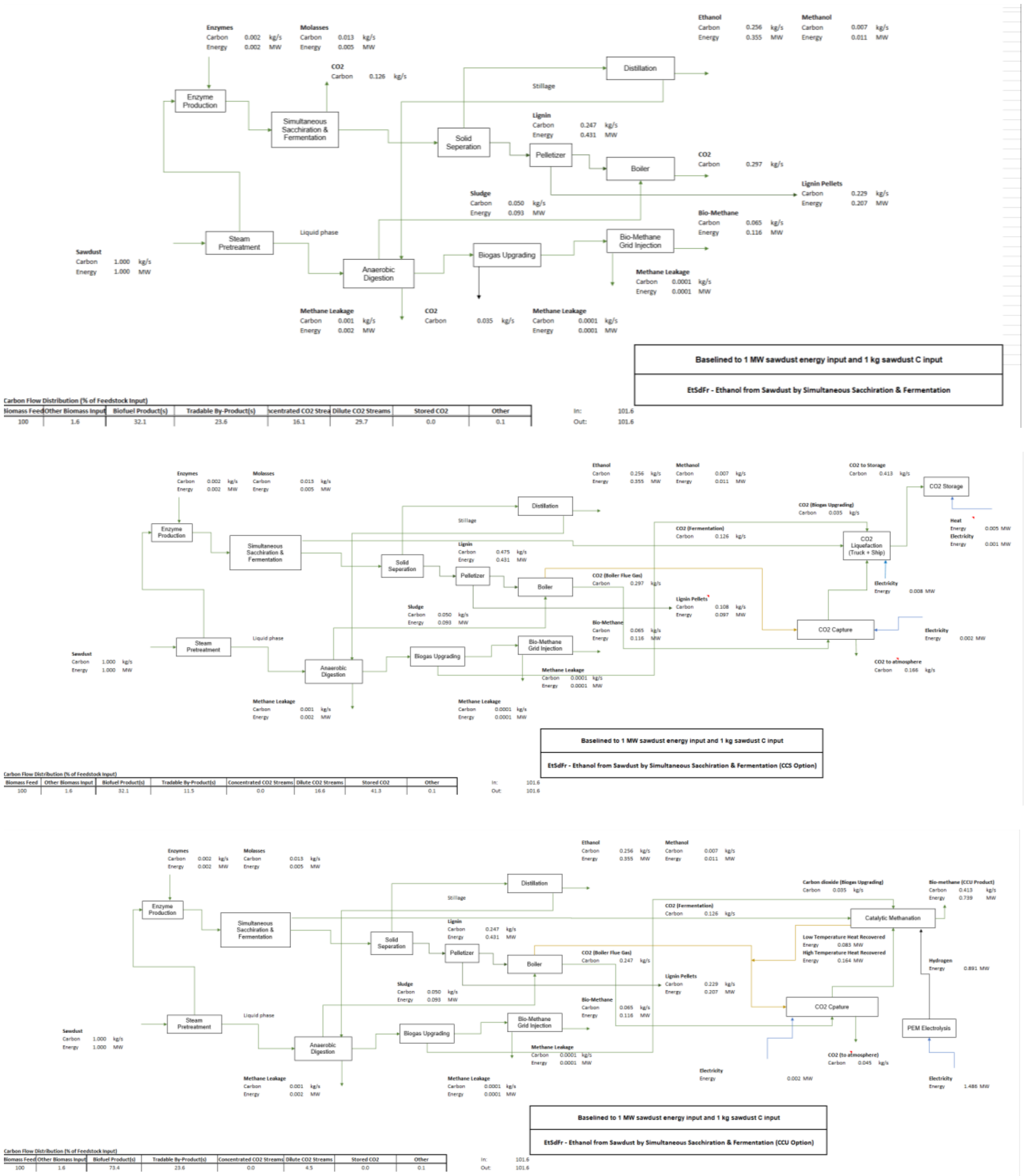
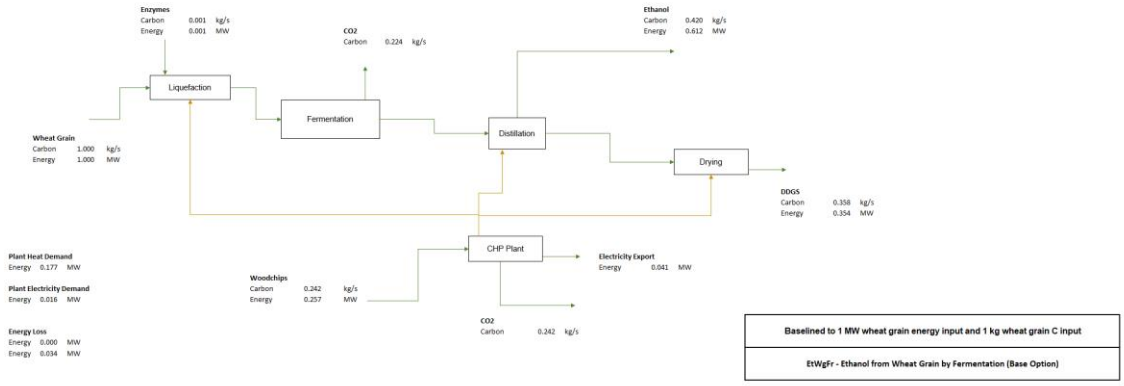


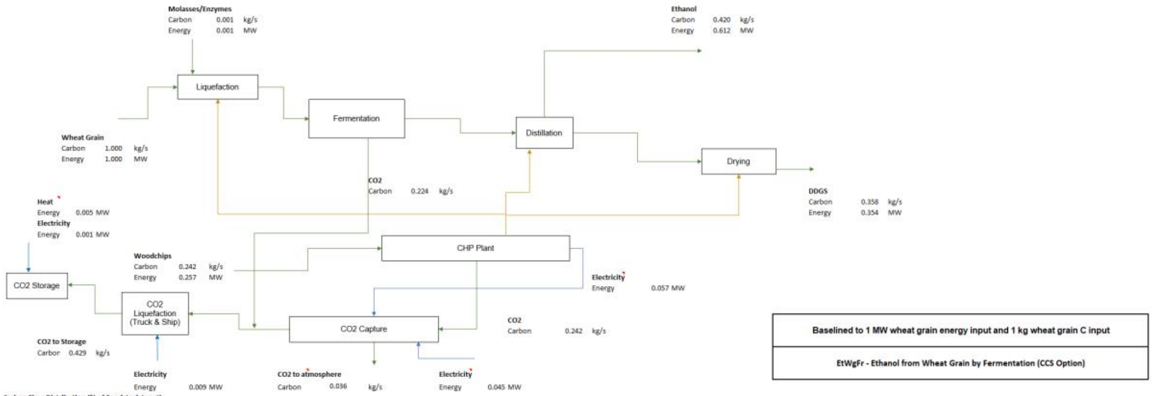
Figure C 1. EtSdFr – base option (top), CCS option (middle) & CCU option (bottom).



Carbon Flow Distribution (% of Feedstock Input)

Biomass Feed	Other Biomass Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other
100	24.3	42.0	35.8	22.4	24.2	0.0	0.0

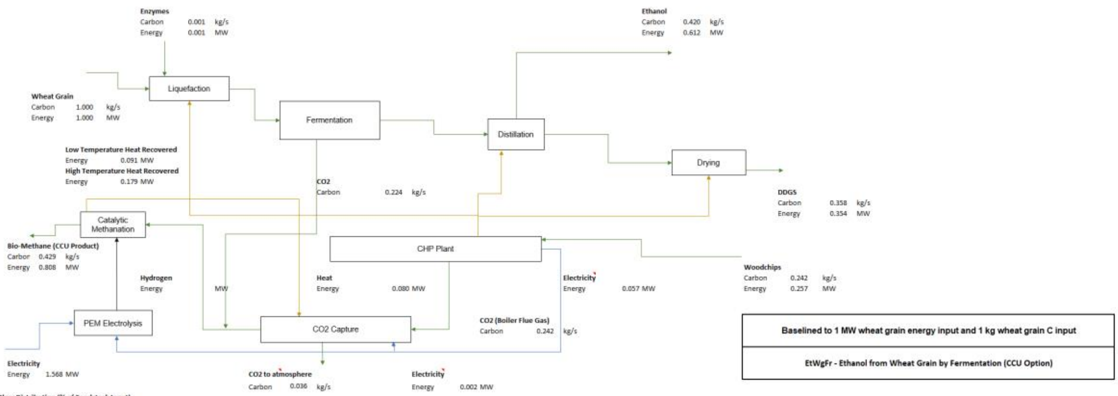
In: 124.3
Out: 124.3



Carbon Flow Distribution (% of Feedstock Input)

Biomass Feed	Other Biomass Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other
100	24.3	42.0	35.8	0.0	3.6	42.9	0.0

In: 124.3
Out: 124.3

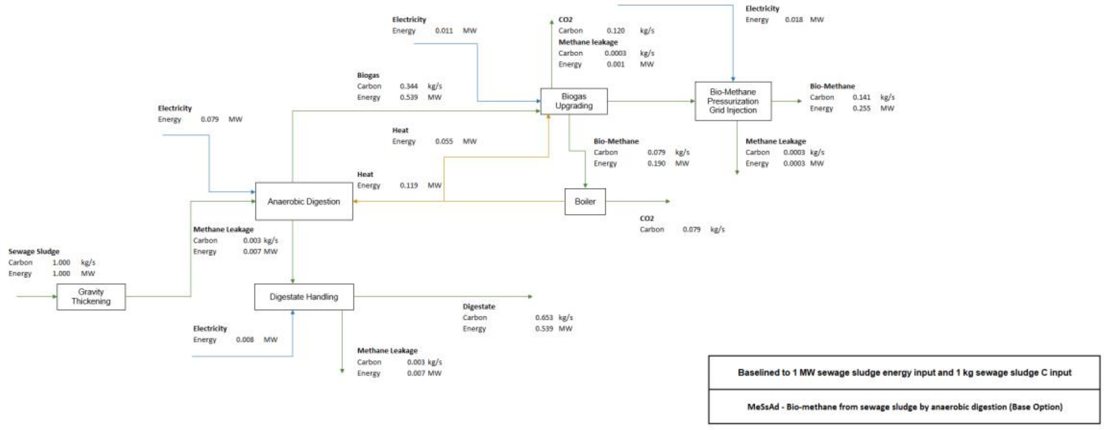


Carbon Flow Distribution (% of Feedstock Input)

Biomass Feed	Other Biomass Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other
100	24.3	84.9	35.8	0.0	3.6	0.0	0.0

In: 124.3
Out: 124.3

Figure C 2. EtWgFr– base option (top), CCS option (middle) & CCU option (bottom).

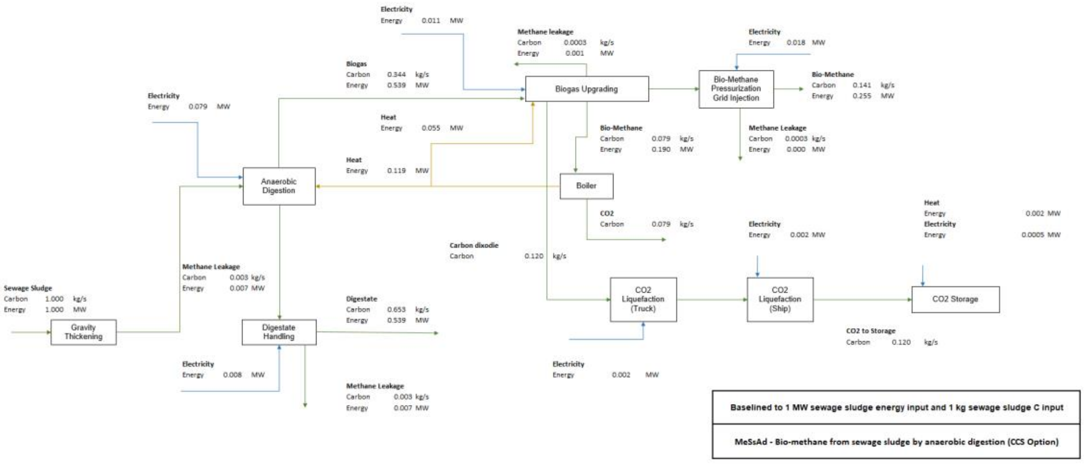


Carbon Flow Distribution (% of Feedstock Input)

Biomass Feed	Other Biomass Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other
100	0.0	14.1	65.3	12.0	7.9	0.0	0.6

In: 100.0
Out: 100.0

Baselined to 1 MW sewage sludge energy input and 1 kg sewage sludge C input

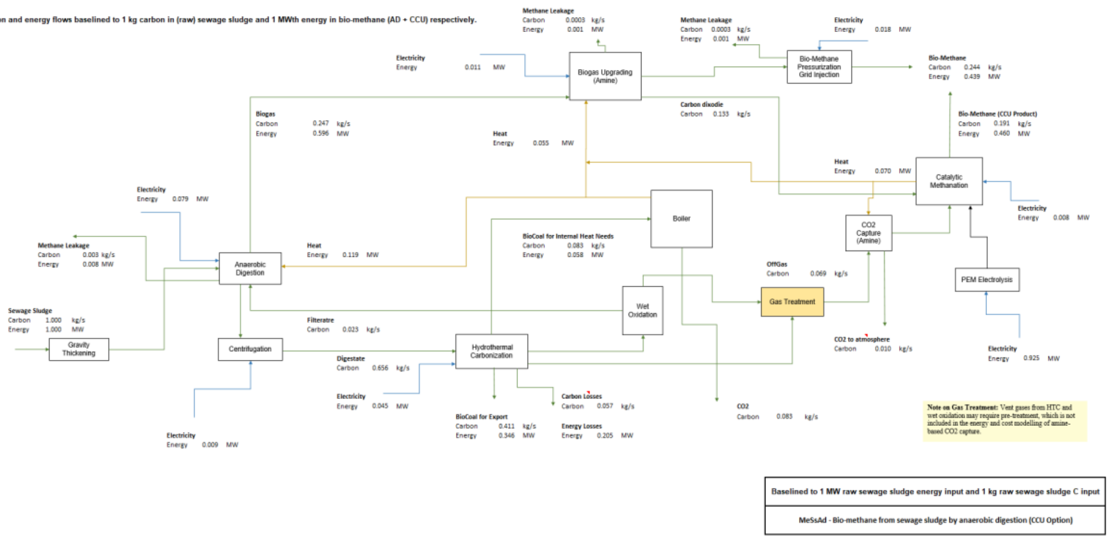


Carbon Flow Distribution (% of Feedstock Input)

Biomass Feed	Other Biomass Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other
100	0.0	14.1	65.3	0.0	7.9	12.0	0.6

In: 100.0
Out: 100.0

Carbon and energy flows baselined to 1 kg carbon in (raw) sewage sludge and 1 MWth energy in bio-methane (AD + CCU) respectively.

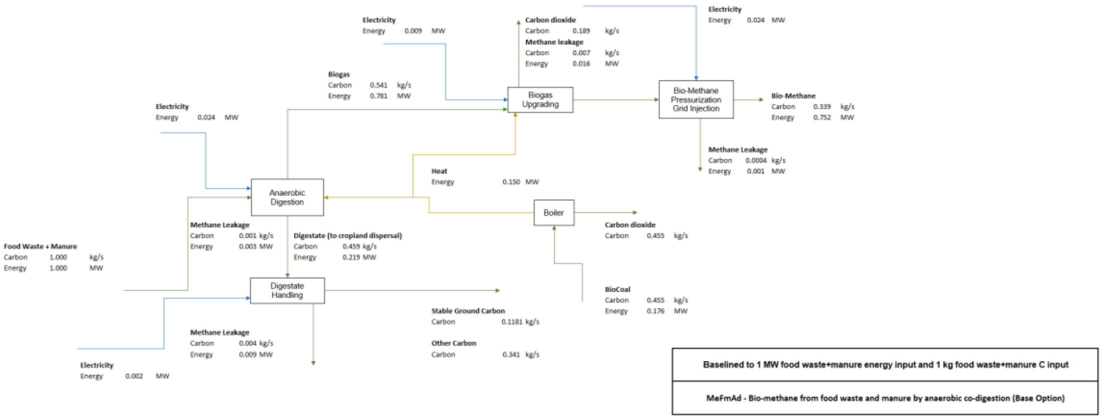


Carbon Flow Distribution (% of Feedstock Input)

Biomass Feed	Other Biomass Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other
100	0.0	43.5	41.1	0.0	9.3	0.0	6.1

In: 100.0
Out: 100.0

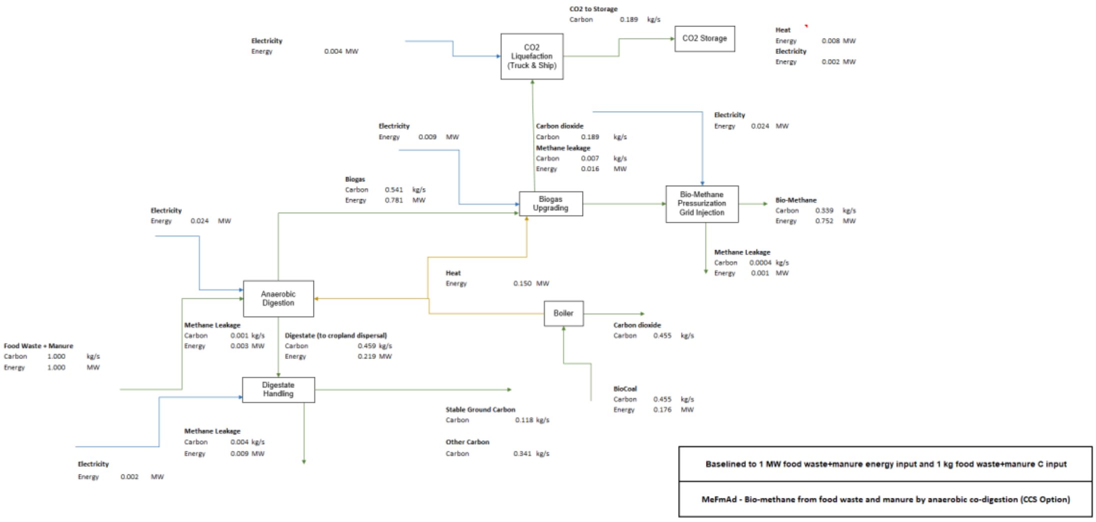
Figure C 3. MeSsAd– base option (top), CCS option (middle) & CCU option (bottom).



Carbon Flow Distribution (% of Feedstock Input)

Biomass Feed	Other Biomass Input	Biofuel Product(s)	Tradable By-Product(s)	ncentrated CO2 Strea	Dilute CO2 Streams	Stored CO2	Other
100	45.5	33.9	45.9	18.9	45.5	1.3	0.0

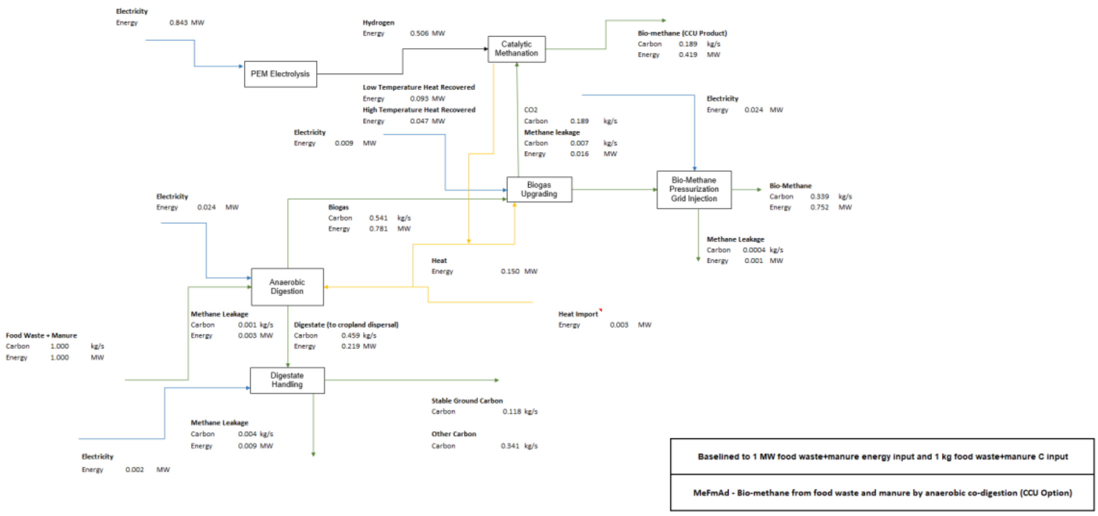
In: 145.5
Out: 145.5



Carbon Flow Distribution (% of Feedstock Input)

Biomass Feed	Other Biomass Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other
100	45.5	33.9	45.9	0.0	45.5	18.9	1.3

In: 145.5
Out: 145.5

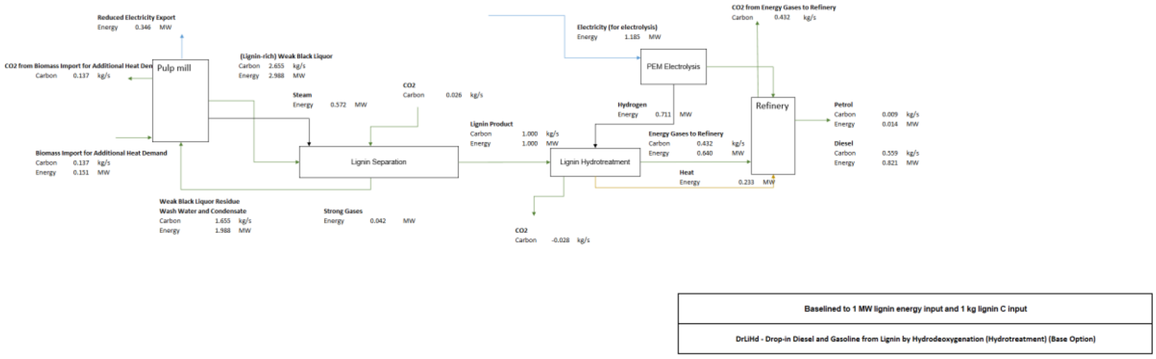


Carbon Flow Distribution (% of Feedstock Input)

Biomass Feed	Other Biomass Input	Biofuel Product(s)	Tradable By-Product(s)	ncentrated CO2 Strea	Dilute CO2 Streams	Stored CO2	Other
100	0.0	52.8	45.9	0.0	0.0	0.0	1.3

In: 100.0
Out: 100.0

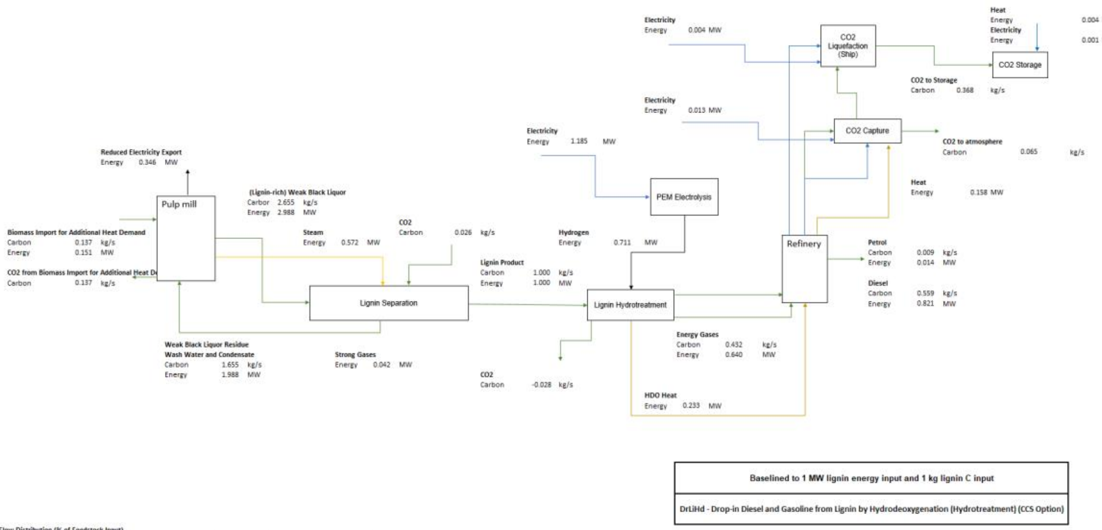
Figure C 4. MeFmAd– base option (top), CCS option (middle) & CCU option (bottom).



Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Expanded System Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other	Expanded System Output
100	2.6	13.7	56.8	0.0	0.0	43.2	0.0	2.6	56.8

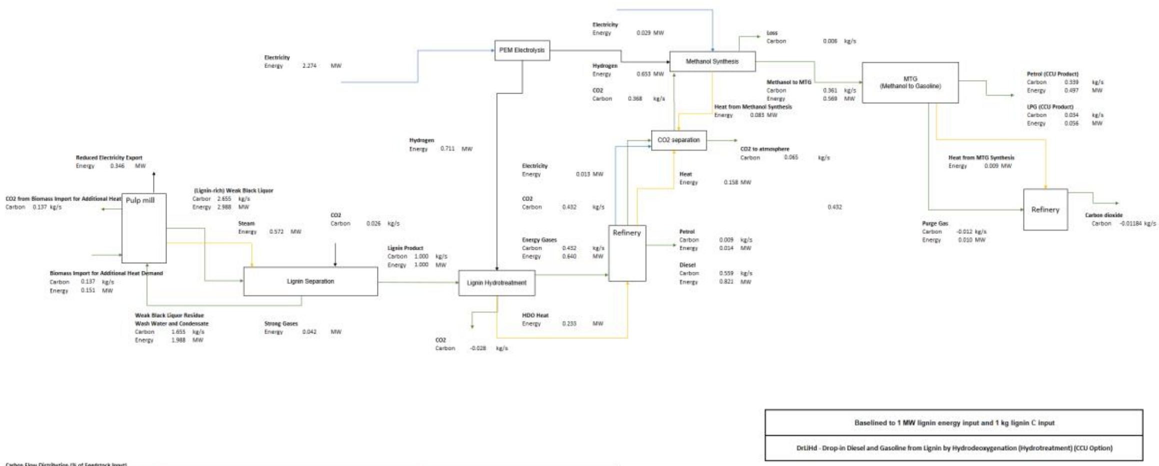
In: 102.6
Out: 102.6



Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Expanded System Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other	Expanded System Output
100	0.0	13.7	56.8	0.0	0.0	6.5	36.8	0.0	13.7

In: 100.0
Out: 100.0

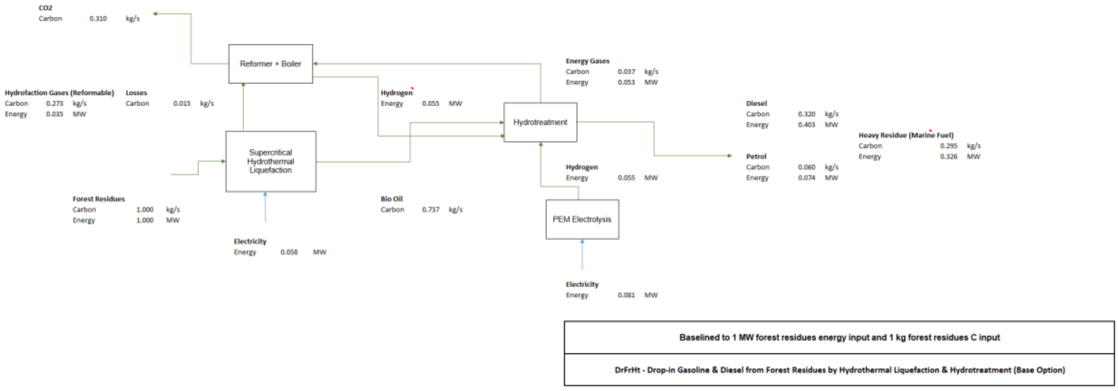


Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Expanded System Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other	Expanded System Output
100	100.0	13.7	94.1	0.0	0.0	6.5	0.0	-0.6	13.7

In: 100.0
Out: 100.0

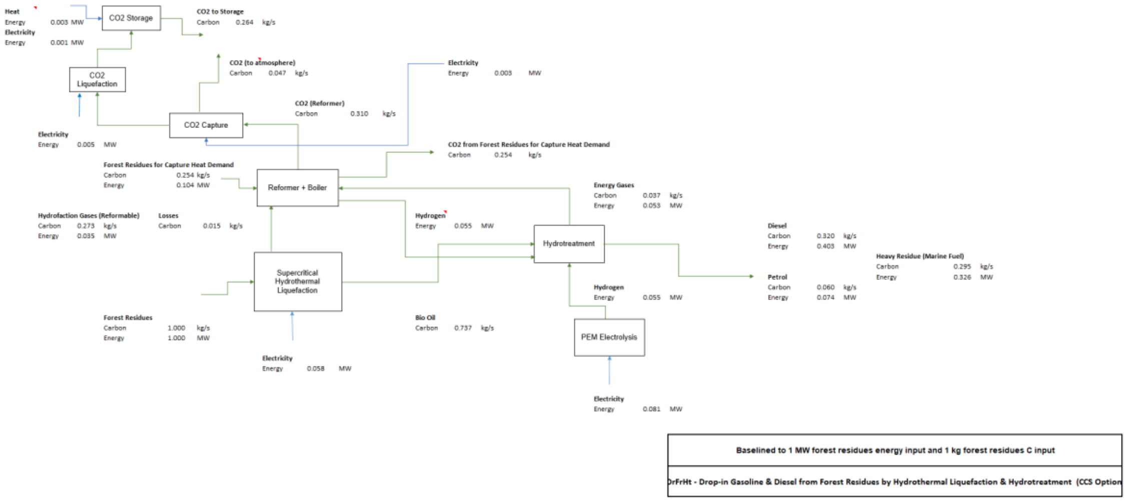
Figure C 5. DrLiHd– base option (top), CCS option (middle) & CCU option (bottom).



Carbon Flow Distribution (% of Feedstock Input)

Biomass Feed	Other Biomass Input	Biofuel Product(s)	Tradable By-Product(s)	oncentrated CO2 Stream	Dilute CO2 Streams	Stored CO2	Other
100	0.0	38.0	29.5	0.0	31.0	0.0	1.5

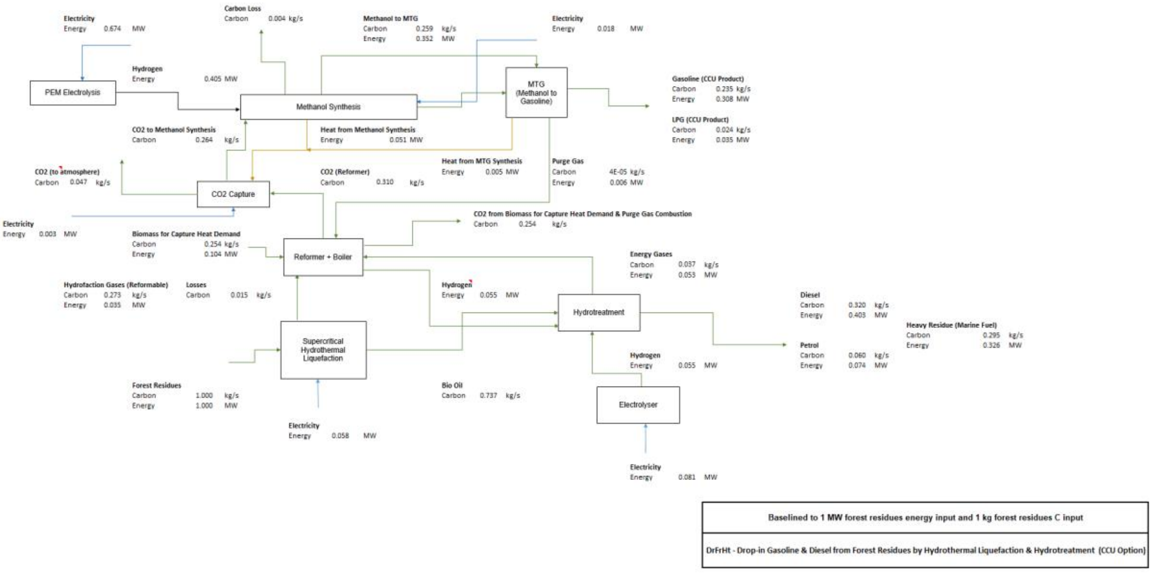
In: 100.0
Out: 100.0



Carbon Flow Distribution (% of Feedstock Input)

Biomass Feed	Other Biomass Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other
100	25.4	38.0	29.5	0.0	30.0	26.4	1.5

In: 125.4
Out: 125.4

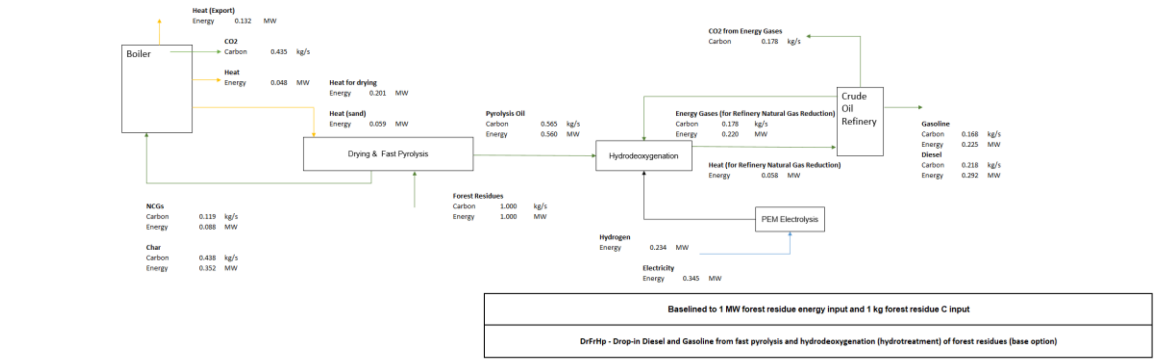


Carbon Flow Distribution (% of Feedstock Input)

Biomass Feed	Other Biomass Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other
100	25.4	63.9	29.5	0.0	30.0	0.0	1.9

In: 125.4
Out: 125.4

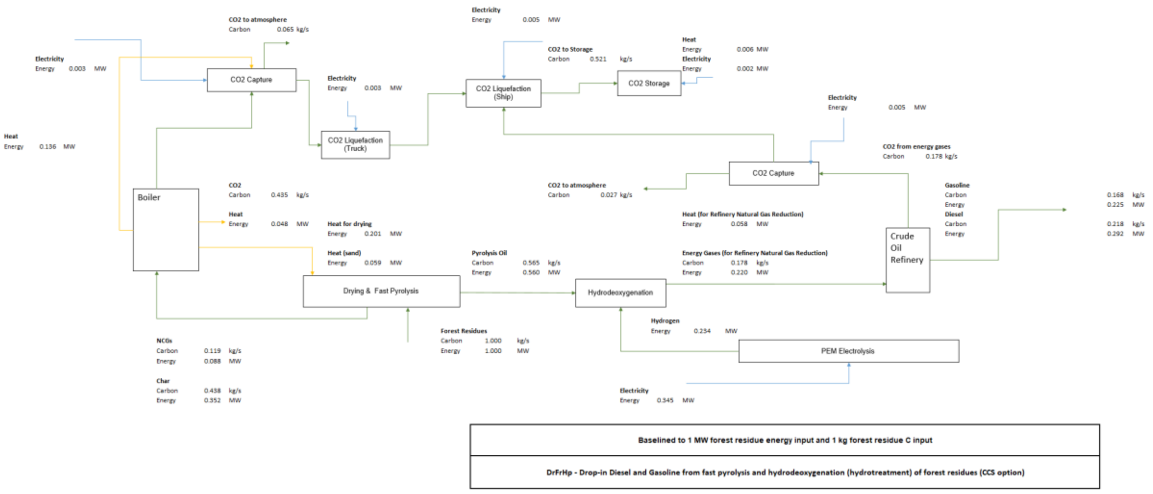
Figure C 6. DrFrHt – base option (top), CCS option (middle) & CCU option (bottom).



Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Expanded System Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other	Expanded System Output
100.0	0.0	0.0	38.7	0.0	0.0	61.3	0.0	0.0	0.0

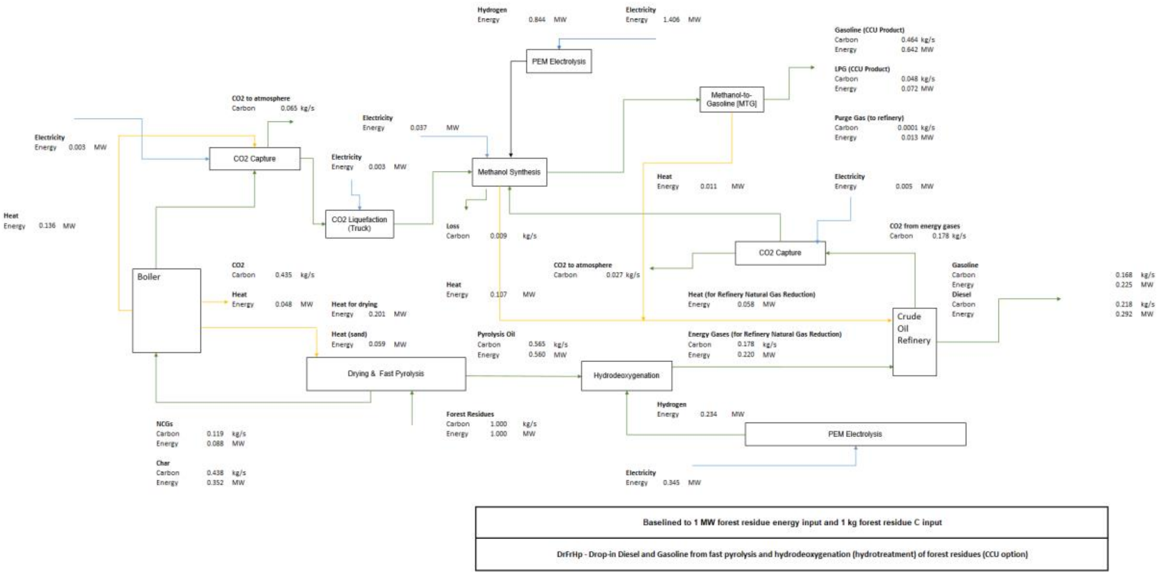
In: 100.0
Out: 100.0



Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Expanded System Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other	Expanded System Output
100.0	0.0	0.0	38.7	0.0	0.0	9.2	52.1	0.0	0.0

In: 100.0
Out: 100.0

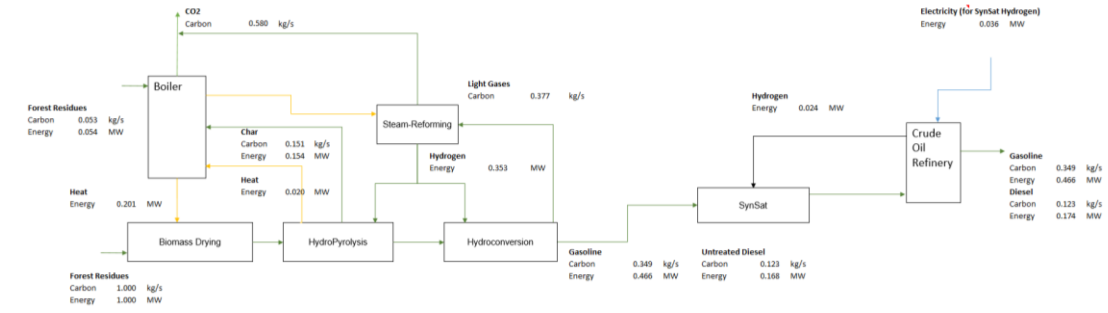


Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Expanded System Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other	Expanded System Output
100.0	0.0	0.0	89.9	0.0	0.0	10.1	0.0	0.0	0.0

In: 100.0
Out: 100.0

Figure C 7. DrFrFp – base option (top), CCS option (middle) & CCU option (bottom).



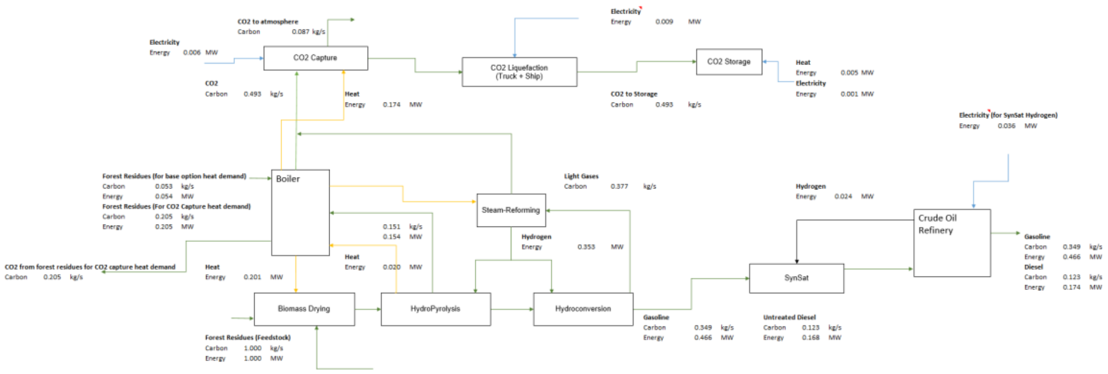
Baselined to 1 MW forest residue energy input and 1 kg forest residue C input

DrFrHp - Drop-in Diesel and Gasoline from hydropyrolysis of forest residues (base option)

Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Expanded System Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other	Expanded System Output
100.0	5.3	0.0	47.2	0.0	0.0	58.0	0.0	0.0	0.0

In: 105.3
Out: 105.3



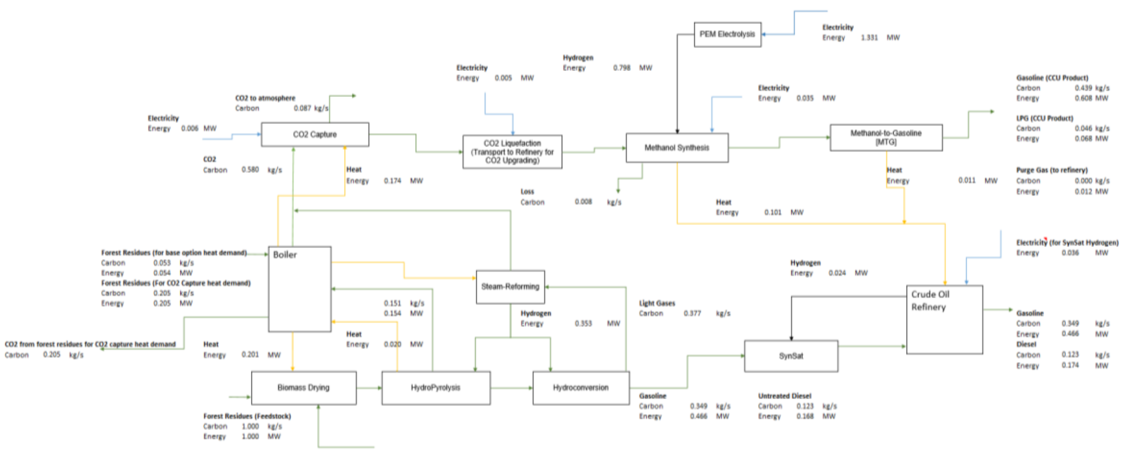
Baselined to 1 MW forest residue energy input and 1 kg forest residue C input

DrFrHp - Drop-in Diesel and Gasoline from hydropyrolysis of forest residues (CCS option)

Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Expanded System Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other	Expanded System Output
100.0	25.7	0.0	47.2	0.0	0.0	29.2	49.3	0.0	0.0

In: 125.7
Out: 125.7



Baselined to 1 MW forest residue energy input and 1 kg forest residue C input

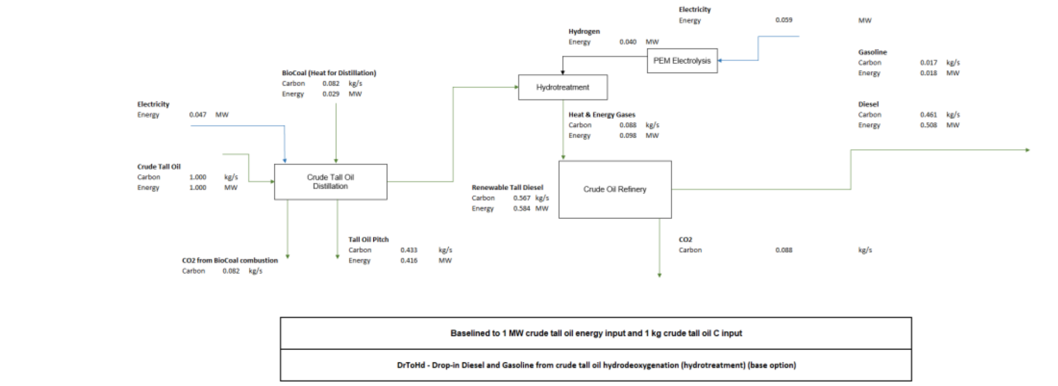
DrFrHp - Drop-in Diesel and Gasoline from hydropyrolysis of forest residues (CCU option)

Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Expanded System Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other	Expanded System Output
100.0	25.7	0.0	95.7	0.0	0.0	30.0	0.0	0.0	0.0

In: 125.7
Out: 125.7

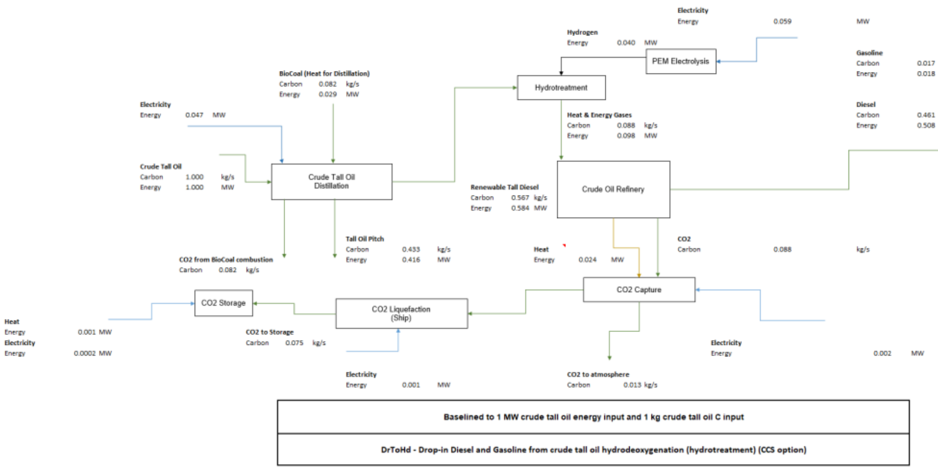
Figure C 8. DrFrHp – base option (top), CCS option (middle) & CCU option (bottom).



Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Expanded System Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other	Expanded System Output
100	8.2	0.0	47.9	43.3	0.0	17.1	0.0	0.0	0.0

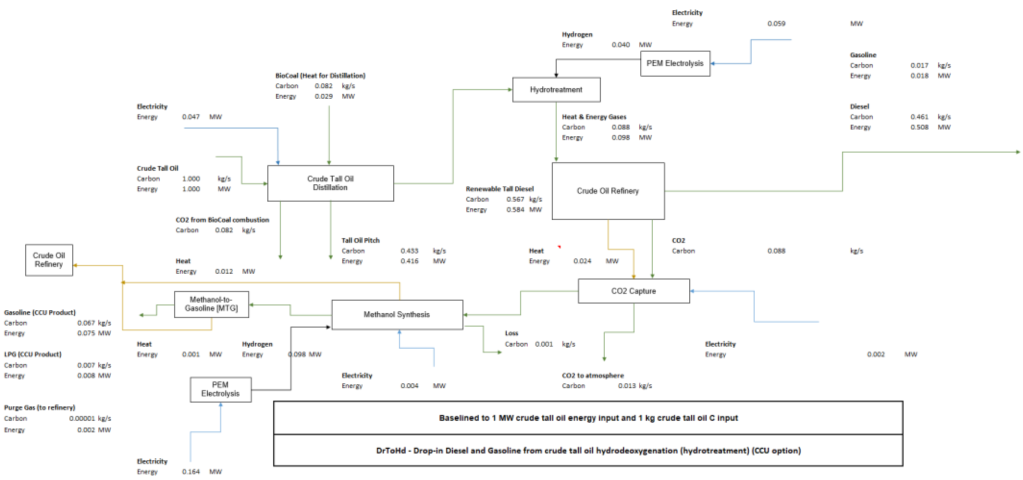
In: 108.2
Out: 108.2



Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Expanded System Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other	Expanded System Output
100	8.2	0.0	47.9	43.3	0.0	9.5	7.5	0.0	0.0

In: 108.2
Out: 108.2

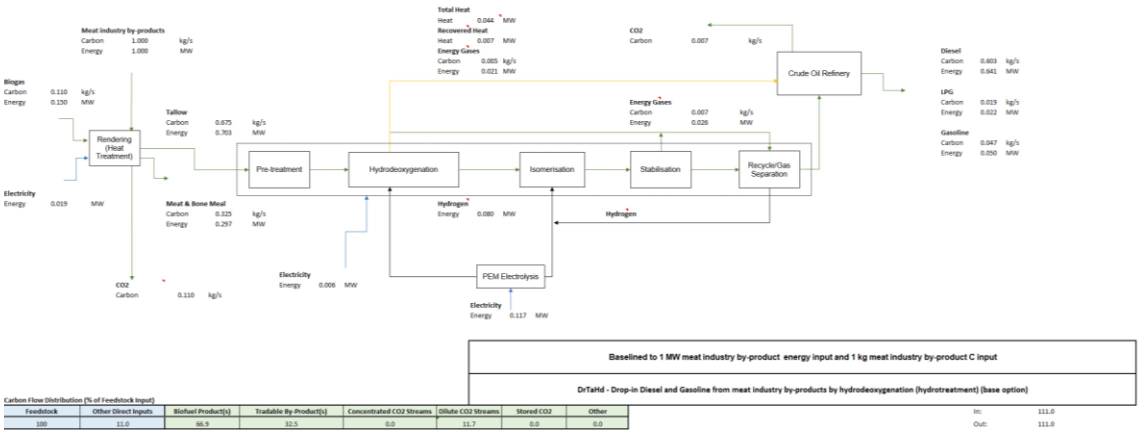


Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Expanded System Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other	Expanded System Output
100	8.2	0.0	55.2	43.3	0.0	9.7	0.0	0.0	0.0

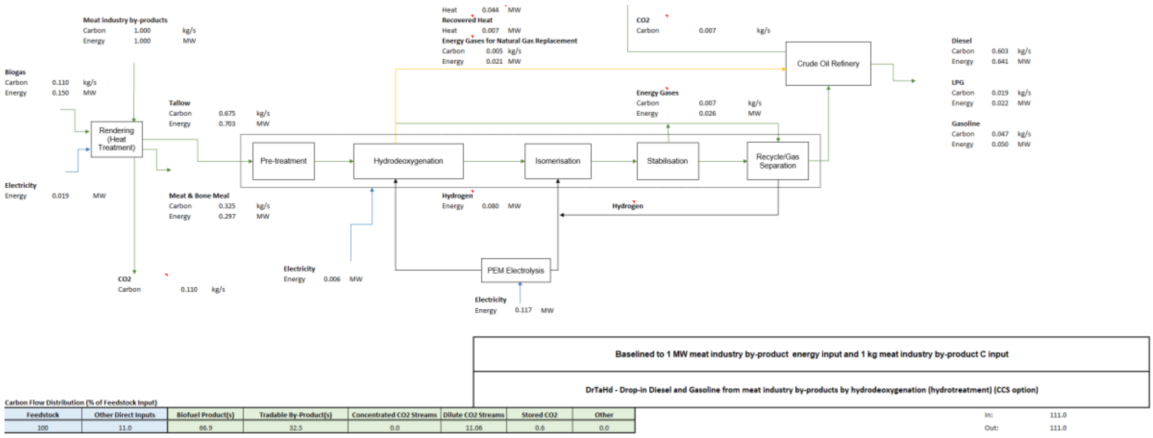
In: 108.2
Out: 108.2

Figure C 9. DrToHd – base option (top), CCS option (middle) & CCU option (bottom).



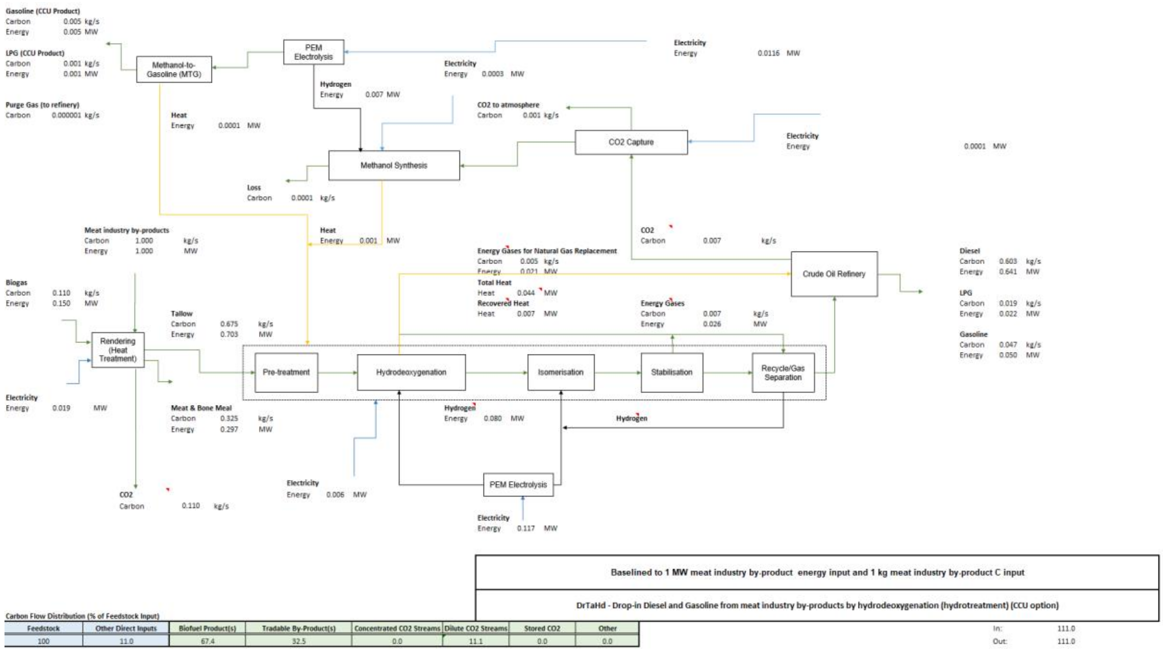
Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other
100	11.0	66.9	32.5	0.0	11.7	0.0	0.0



Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other
100	11.0	66.9	32.5	0.0	11.06	0.6	0.0



Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other
100	11.0	67.4	32.5	0.0	11.1	0.0	0.0

Figure C 10. DrTaHd – base option (top), CCS option (middle) & CCU option (bottom).

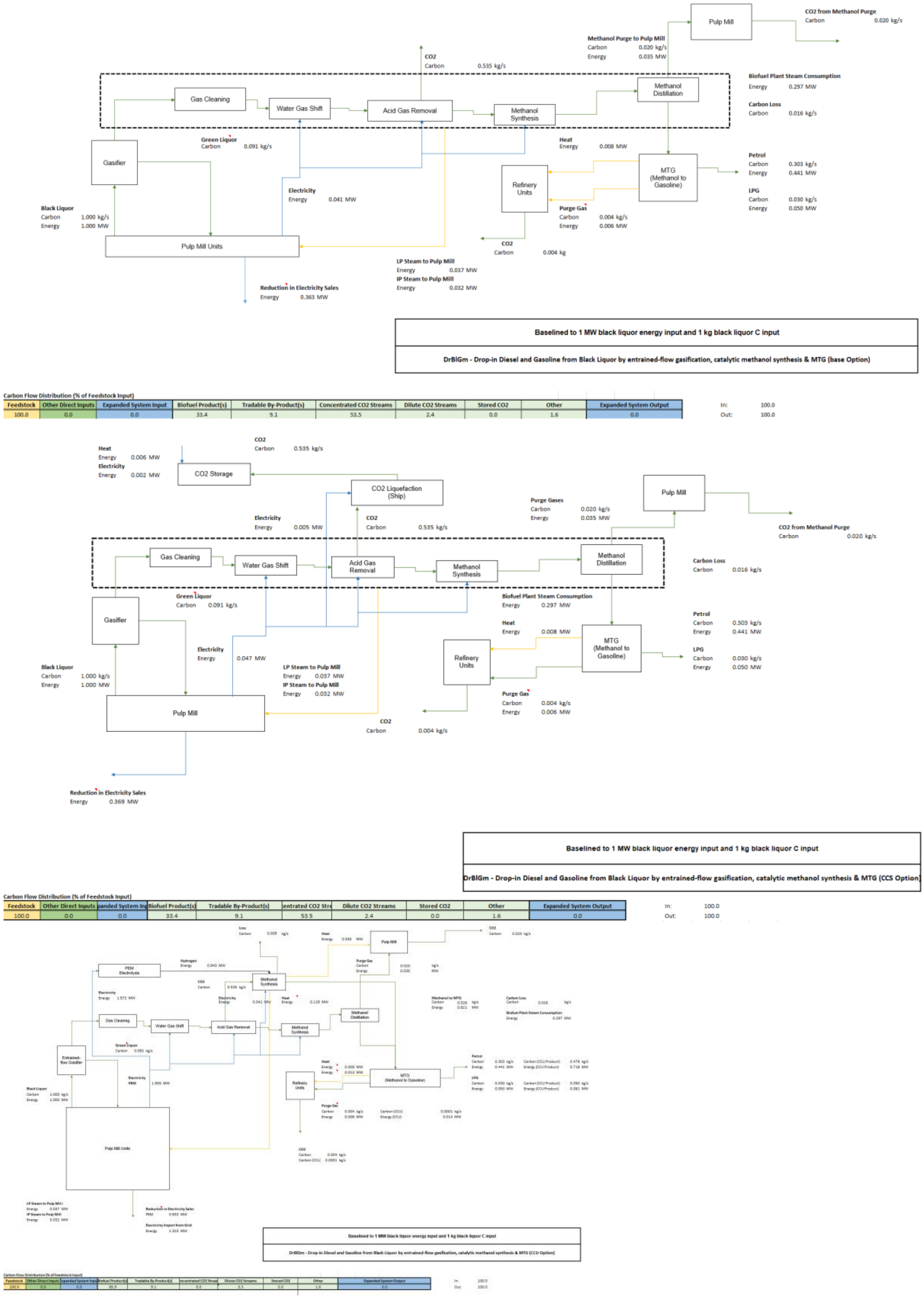
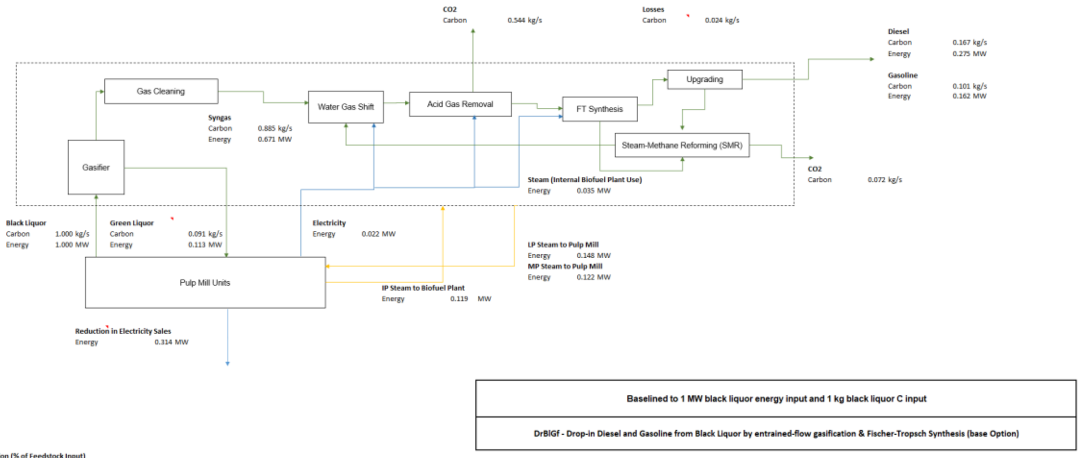
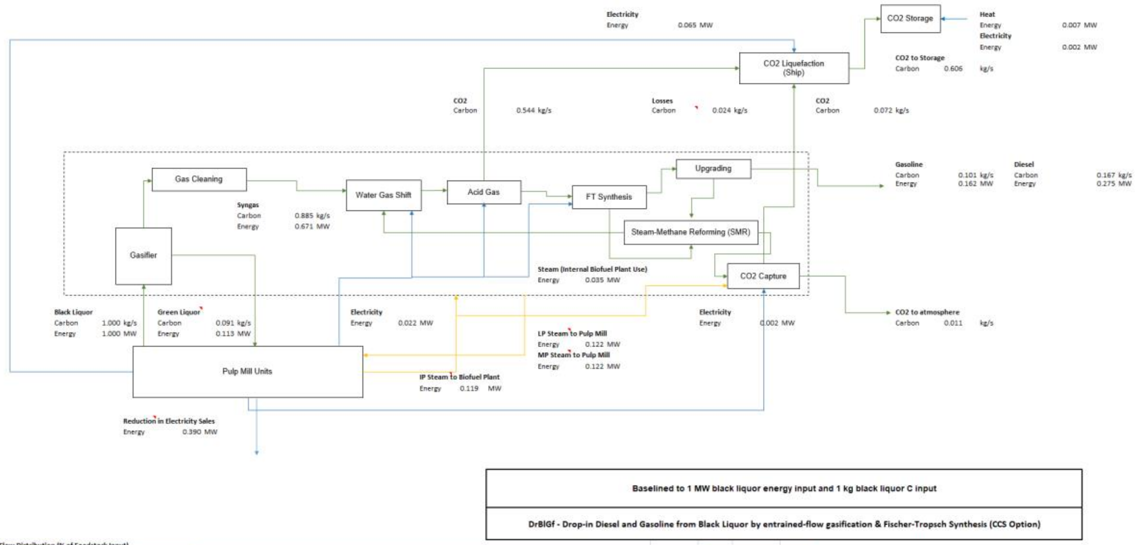


Figure C 11. DrBlGm – base option (top), CCS option (middle) & CCU option (bottom).



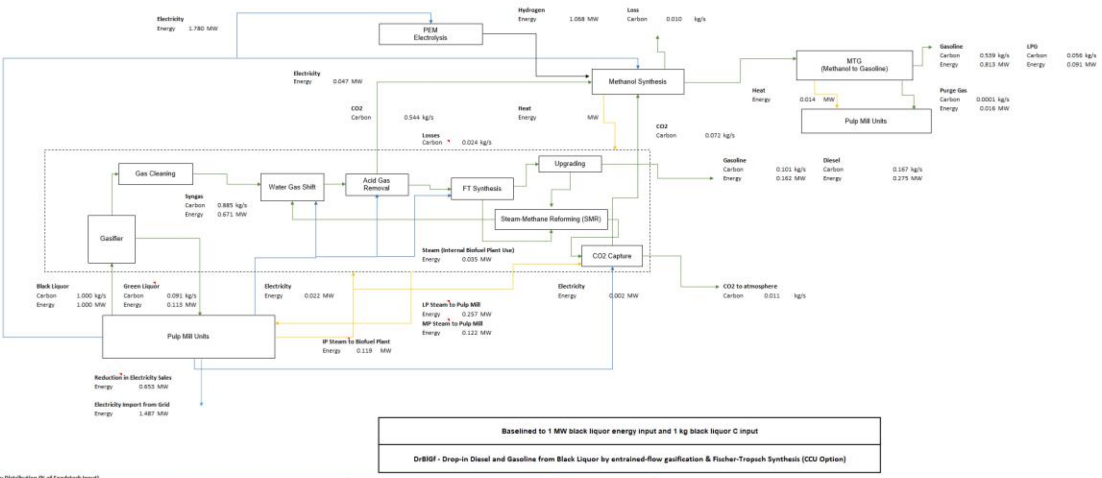
Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Expanded System Input	Biofuel Product(s)	Tradable By-Product(s)	Concentrated CO2 Streams	Dilute CO2 Streams	Stored CO2	Other	Expanded System Output		
100.0	0.0	0.0	26.9	9.1	54.4	7.2	0.0	2.4	0.0	In:	100.0
										Out:	100.0



Carbon Flow Distribution (% of Feedstock Input)

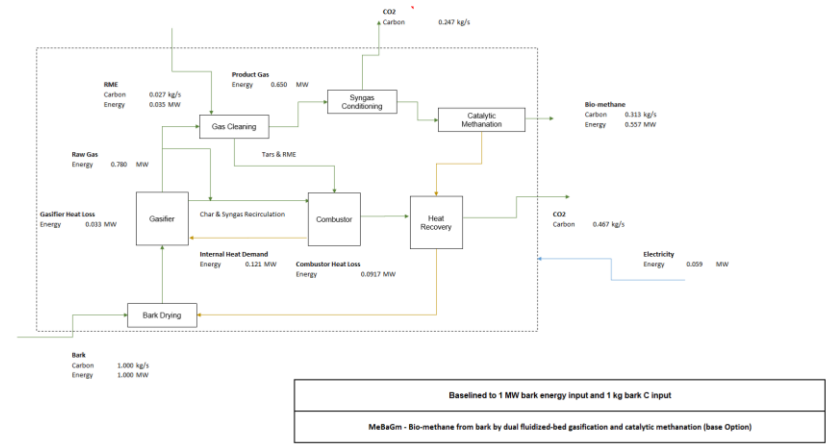
Feedstock	Other Direct Inputs	Expanded System Input	Biofuel Product(s)	Tradable By-Product(s)	ncentrated CO2 Strea	Dilute CO2 Streams	Stored CO2	Other	Expanded System Output		
100.0	0.0	0.0	26.9	9.1	0.0	1.1	60.6	2.4	0.0	In:	100.0
										Out:	100.0



Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	xpanded System Inpu	Biofuel Product(s)	Tradable By-Product(s)	ncentrated CO2 Strea	Dilute CO2 Streams	Stored CO2	Other	Expanded System Output		
100.0	0.0	0.0	86.4	9.1	0.0	1.1	0.0	3.4	0.0	In:	100.0
										Out:	100.0

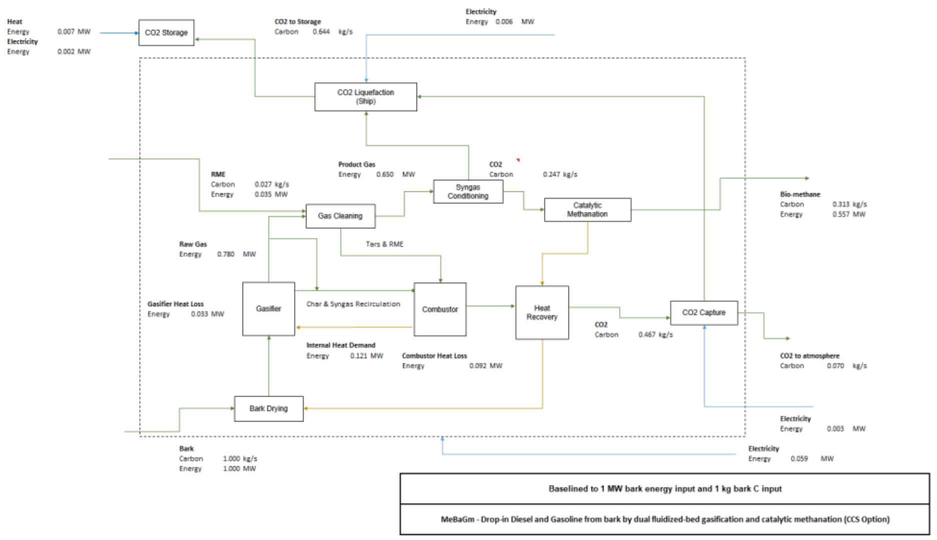
Figure C 12. DrBlGf – base option (top), CCS option (middle) & CCU option (bottom).



Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Biofuel Product(s)	Tradable By-Product(s)	ncentrated CO2 Strea	Dilute CO2 Streams	Stored CO2	Other
100	2.7	31.3	0.0	24.7	46.7	0.0	0.0

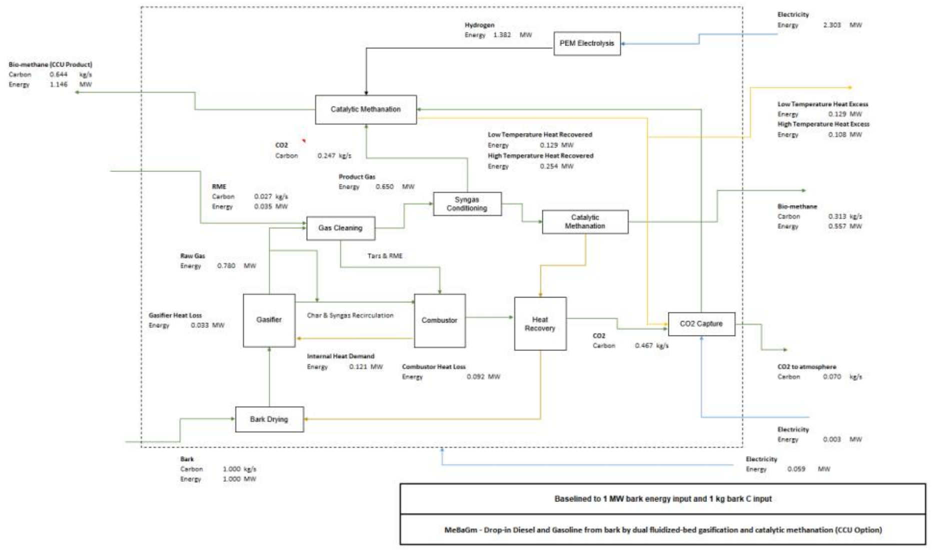
In: 102.7
Out: 102.7



Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Biofuel Product(s)	Tradable By-Product(s)	ncentrated CO2 Strea	Dilute CO2 Streams	Stored CO2	Other
100	2.7	31.3	0.0	0.0	7.0	64.4	0.0

In: 102.7
Out: 102.7

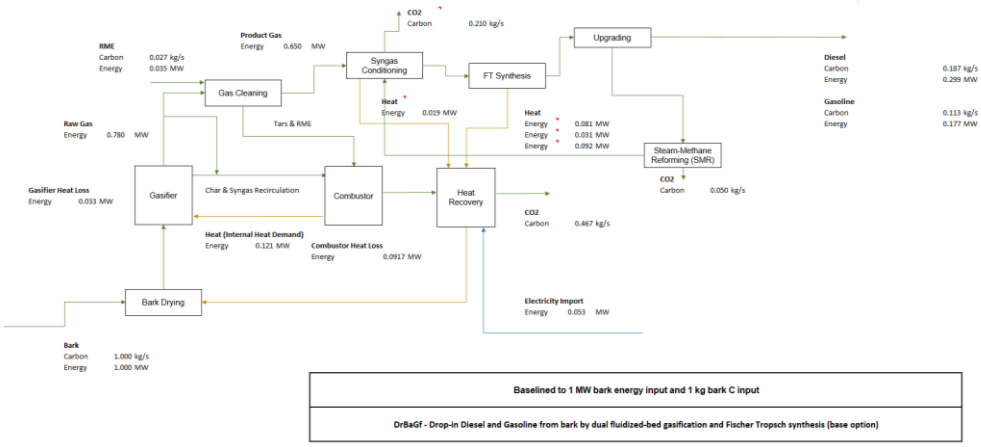


Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Biofuel Product(s)	Tradable By-Product(s)	ncentrated CO2 Strea	Dilute CO2 Streams	Stored CO2	Other
100	2.7	95.7	0.0	0.0	7.0	0.0	0.0

In: 102.7
Out: 102.7

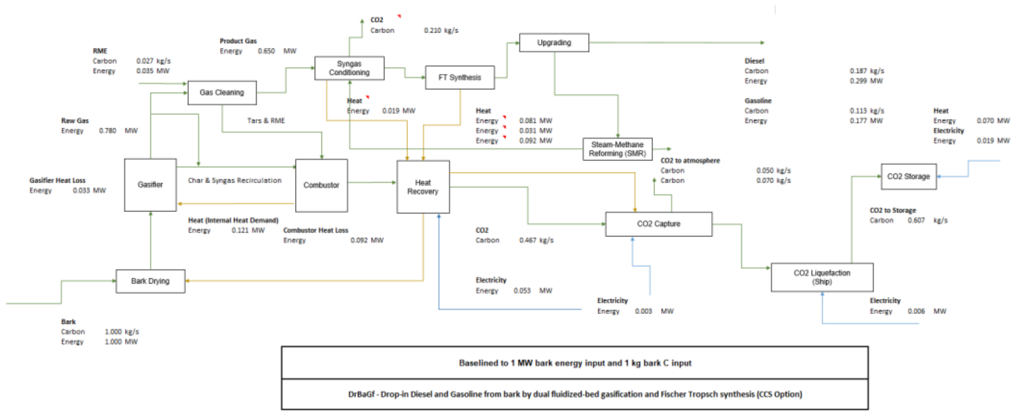
Figure C 13. MeBaGm – base option (top), CCS option (middle) & CCU option (bottom).



Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Biofuel Product(s)	Tradable By-Product(s)	ncentrated CO2 Strea	Dilute CO2 Streams	Stored CO2	Other
100	2.7	30.0	0.0	21.0	51.7	0.0	0.0

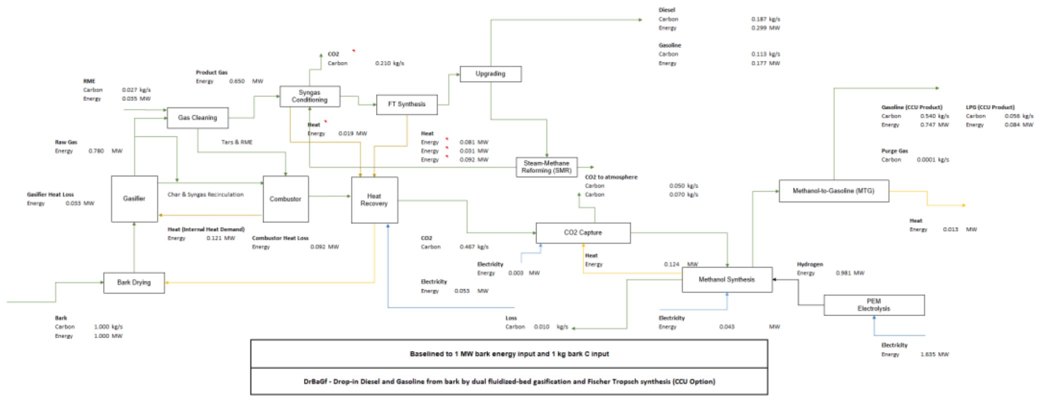
In: 102.7
Out: 102.7



Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Biofuel Product(s)	Tradable By-Product(s)	ncentrated CO2 Strea	Dilute CO2 Streams	Stored CO2	Other
100	2.7	30.0	0.0	0.0	12.0	60.7	0.0

In: 102.7
Out: 102.7



Carbon Flow Distribution (% of Feedstock Input)

Feedstock	Other Direct Inputs	Biofuel Product(s)	Tradable By-Product(s)	ncentrated CO2 Strea	Dilute CO2 Streams	Stored CO2	Other
100	2.7	89.6	0.0	0.0	12.0	0.0	1.0

In: 102.7
Out: 102.7

Figure C 14. DrBaGf – base option (top), CCS option (middle) & CCU option (bottom).

APPENDIX D – ENPAC INPUT DATA

Table D 1. ENPAC SD (Sustainable Development) 2030 Scenario Input Data

Fossil fuel prices		**SD2030**
Crude oil Brent	USD/barrel	74
Natural gas (EU import)	USD/Mbtu	8
OECD steam coal import	USD/tonne	70
Technology choices		
Carbon capture and storage (CCS) available for potential fuel-based build margin technologies in the power sector		no
Nuclear power available as potential build margin in the power sector		yes
Wind power available as potential build margin in the power sector		yes
Biomass considered as limited resource		yes
Policy instruments/taxes		
CO_2 emissions charge, EU ETS	EUR/tonne	85
CO_2 emissions charge, diesel (CO_2 tax)	EUR/tonne	111
CO_2 emissions charge, petrol (CO_2 tax)	EUR/tonne	100
CO_2 emissions charge, gas as transportation fuel (CO_2 tax)	EUR/MWh	21.6
Green electricity premium	EUR/MWh	5
Biofuel premium, "diesel fuels" (exemption from energy tax)	EUR/MWh	25
Biofuel premium, "petrol fuels" (exemption from energy tax)	EUR/MWh	43
Biofuel premium, biogas (exemption from energy tax)	EUR/MWh	8.4
Other settings and inputs		
Type of biofuel determining the willingness-to-pay for biomass as a biofuel feedstock		FT
Distribution cost petrol fuels	EUR/MWh	14.7
Distribution cost diesel fuels	EUR/MWh	12.7
Transport cost low-grade wood fuel	EUR/MWh	5.3
Transport cost refined wood fuel (e.g. pellets)	EUR/MWh	10,8
Distribution cost gas grid	EUR/MWh	8
ENPAC scenario output		SD
Build margin electricity		Wind
Marginal use of wood fuel		Pellets

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