Green Horizons

On the production costs, climate impact and future supply of renewable jet fuels

Sierk de Jong

Green Horizons
On the production costs, climate impact and future supply of renewable jet fuels

Sierk de Jong, June 2018
Copernicus Institute of Sustainable Development, Utrecht University

ISBN: 978-90-8672-081-1

Cover: Sunrise mid-air between Boston and Amsterdam
Layout and Printing: Ridderprint BV

Green Horizons

On the production costs, climate impact and future supply of renewable jet fuels

Groene Vergezichten

Over de productiekosten, klimaatimpact en toekomstige beschikbaarheid van hernieuwbare vliegtuigbrandstoffen

(met een samenvatting in het Nederlands)

Proefschrift

ter verkrijging van de graad van doctor aan de Universiteit Utrecht
op gezag van de rector magnificus, prof.dr. H.R.B.M. Kummeling,
ingevolge het besluit van het college voor promoties
in het openbaar te verdedigen
op vrijdag 15 juni 2018 des middags te 4.15 uur

door

Sierk Arne de Jong

geboren op 18 september 1991 te Wageningen

Promotoren: Prof. dr. H.M. Junginger

Prof. dr. A.P.C. Faaij

Copromotor: dr. E.T.A. Hoefnagels

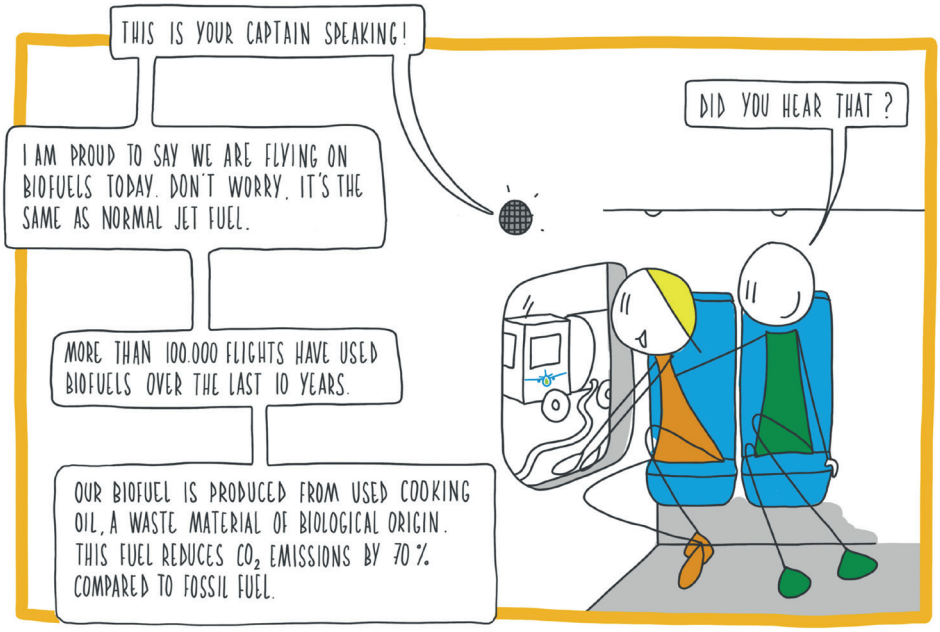
This research was conducted in the context of the Renewable Jet Fuel Supply Chain Development and Flight Operations (RENJET) project. The author would like to acknowledge the funding and support from Climate-KIC in carrying out this research. Climate-KIC is supported by the European Institute of Innovation and Technology (EIT), a body of the European Union.

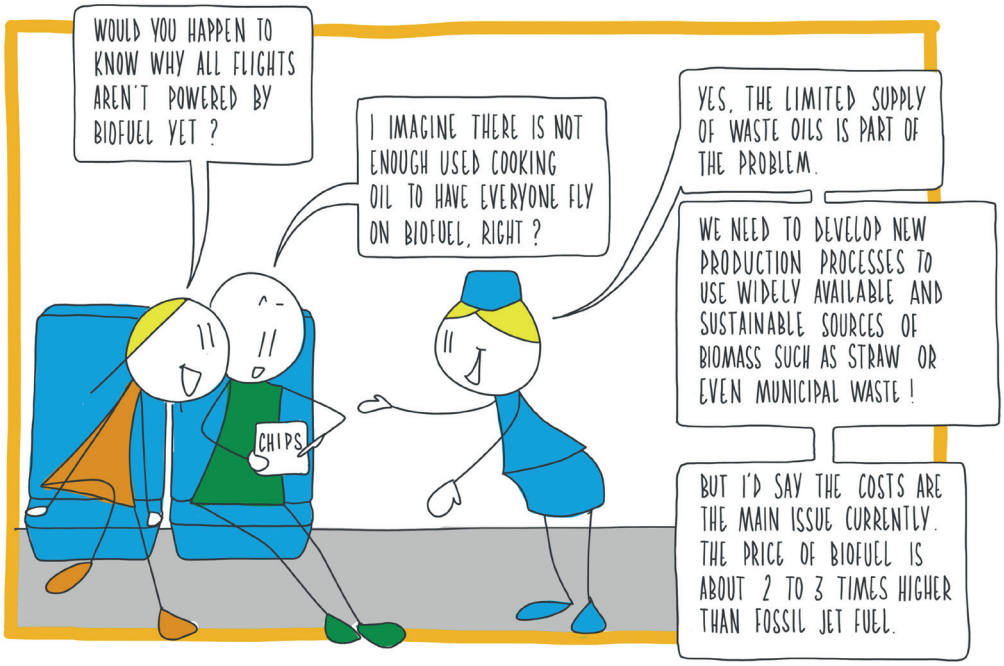
De dag heeft mooie plannen

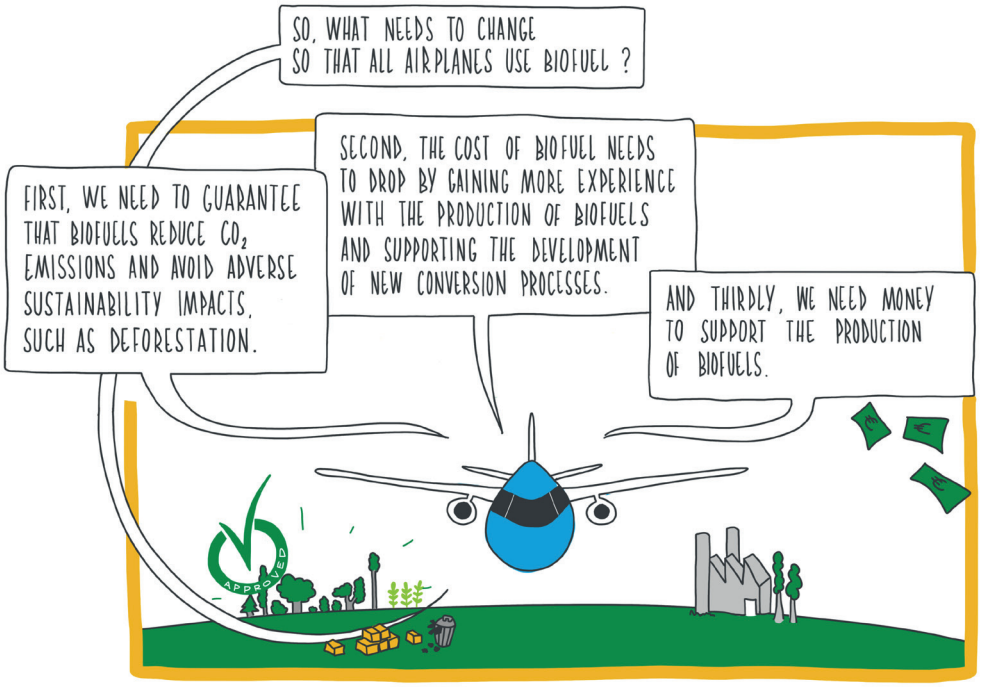
SUSTAINABLE FLYING?

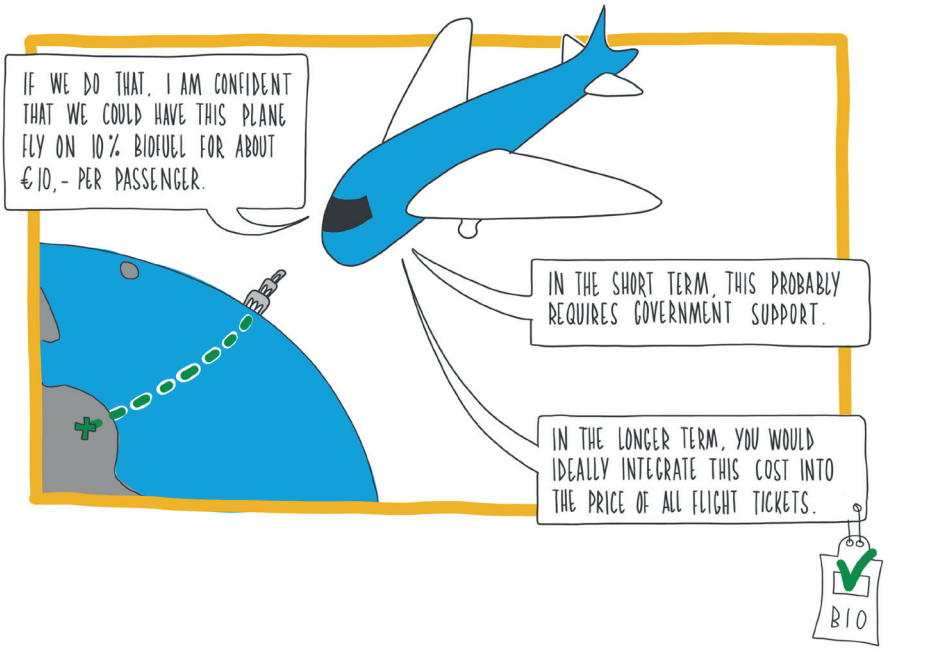
HOW BIOFUELS CAN REDUCE CO_2 EMISSIONS FROM FLYING

Summary for lazy executives




WOULD YOU HAPPEN TO KNOW WHY ALL FLIGHTS AREN'T POWERED BY BIOFUEL YET ?
I IMAGINE THERE IS NOT ENOUGH USED COOKING OIL TO HAVE EVERYONE FLY ON BIOFUEL, RIGHT ?
YES, THE LIMITED SUPPLY OF WASTE OILS IS PART OF THE PROBLEM.
WE NEED TO DEVELOP NEW PRODUCTION PROCESSES TO USE WIDELY AVAILABLE AND SUSTAINABLE SOURCES OF BIOMASS SUCH AS STRAW OR EVEN MUNICIPAL WASTE !
CHIPS
BUT I'D SAY THE COSTS ARE THE MAIN ISSUE CURRENTLY. THE PRICE OF BIOFUEL IS ABOUT 2 TO 3 TIMES HIGHER THAN FOSSIL JET FUEL.


SO, WHAT NEEDS TO CHANGE SO THAT ALL AIRPLANES USE BIOFUEL ?
FIRST, WE NEED TO GUARANTEE THAT BIOFUELS REDUCE CO_2 EMISSIONS AND AVOID ADVERSE SUSTAINABILITY IMPACTS, SUCH AS DEFORESTATION.
SECOND, THE COST OF BIOFUEL NEEDS TO DROP BY GAINING MORE EXPERIENCE WITH THE PRODUCTION OF BIOFUELS AND SUPPORTING THE DEVELOPMENT OF NEW CONVERSION PROCESSES.
AND THIRDLY, WE NEED MONEY TO SUPPORT THE PRODUCTION OF BIOFUELS.
APPROVED



selma koopman

TABLE OF CONTENTS

1

Introduction

1. INTRODUCTION

1.1 The necessity of climate change mitigation

Anthropogenic greenhouse gas (GHG) emissions are extremely likely to be the dominant cause of the observed warming of the climate since the mid-20th century.[1] Current atmospheric concentrations of carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) are the highest in at least 800,000 years. Emissions of GHG species increase their atmospheric concentration, which affects the energy balance of the earth system ('radiative forcing') and changes the global mean surface temperature.[2] Continued GHG emissions will instigate further warming, increasing the likelihood of "severe, pervasive and irreversible impacts" on natural and human systems, such as ice and permafrost melt, heat waves, floods, droughts, wildfire, extreme precipitation, and sea level rise.[1] The parties to the United Nations Framework Convention on Climate Change (UNFCCC) agreed in the 2015 Paris Agreement (COP21) to limit average global temperature increase to well below 2°C above pre-industrial levels to significantly reduce the risk of the aforementioned impacts of climate change.[3] Figure 1-1 shows four Representative Concentration Pathways (RCP), which represent a range of possible GHG emission pathways in the future. The RCP 2.6 scenario, leading to a temperature rise ranging from 0.9 to 2.3 °C (mean 1.6 °C) in 2100, is the only scenario consistent with the Paris Agreement.[4] This scenario implies a 40-70% reduction of GHG emission by 2050 (relative to 2010) and net-negative GHG emissions at the end of the century, which requires strong mitigation efforts across all sectors.[1,5]

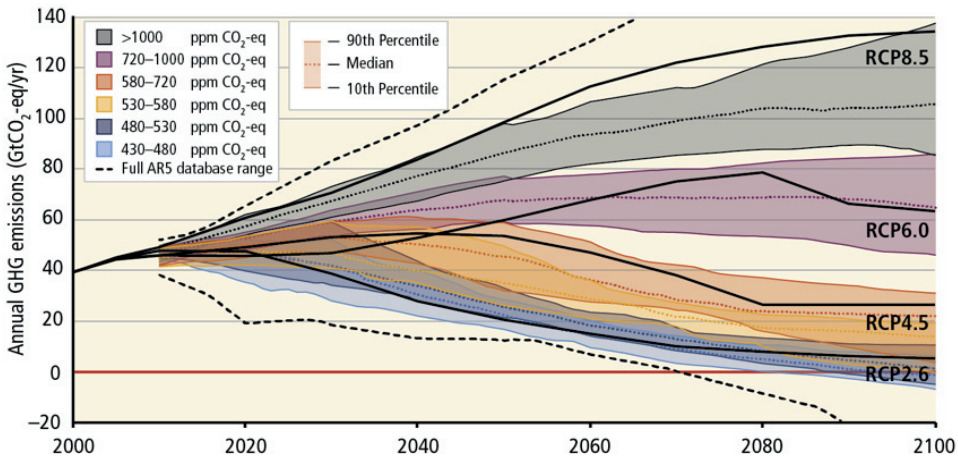


FIGURE 1-1: Emission pathways until 2100, based on the fifth assessment report of the IPCC.[1]

1.2 The climate impact of aviation and mitigation measures

The latest IPCC report estimates global annual anthropogenic GHG emissions at 49 Gt CO_2-equivalents (CO_2-eq) yr^{-1} in 2010.[6] A more recent estimate shows that GHG emissions have increased to 53.4 Gt CO_2-eq yr^{-1} in 2017.[7] The scope of GHG emissions included in these estimates follow the Kyoto protocol, which covers emissions from CO_2, CH_4, N_2O and several fluorinated gases. In 2010, these emissions comprised 76%, 16%, 6% and 2% of total GHG emissions (in CO_2-eq), respectively.[6]

Figure 1-2 shows that the transport sector accounted for 7.0 Gt CO_2-eq in 2010. International and domestic aviation emitted 0.46 Gt and 0.29 Gt CO_2-eq yr^{-1} in 2010, representing 1.5% of global GHG emissions.[8] The GHG emissions allocated to the aviation industry mainly include CO_2 emissions from the combustion of jet fuel, particularly because upstream emissions from oil extraction and jet fuel production are allocated to the energy sector. Although short-lived emission species are not covered by the Kyoto Protocol (particularly aerosols, water vapor, and NO_x), their share in the overall climate impact of aviation is estimated to be 2-5 times larger than CO_2 combustion emissions.[9,10] The share of anthropogenic radiative forcing attributed to the aviation industry in 2005 was estimated at 3.5% (1.3-10%, 5-95th percentile) or 4.9% (2-14%, 5-95th percentile) if cirrus cloud enhancement effects are included.[9]

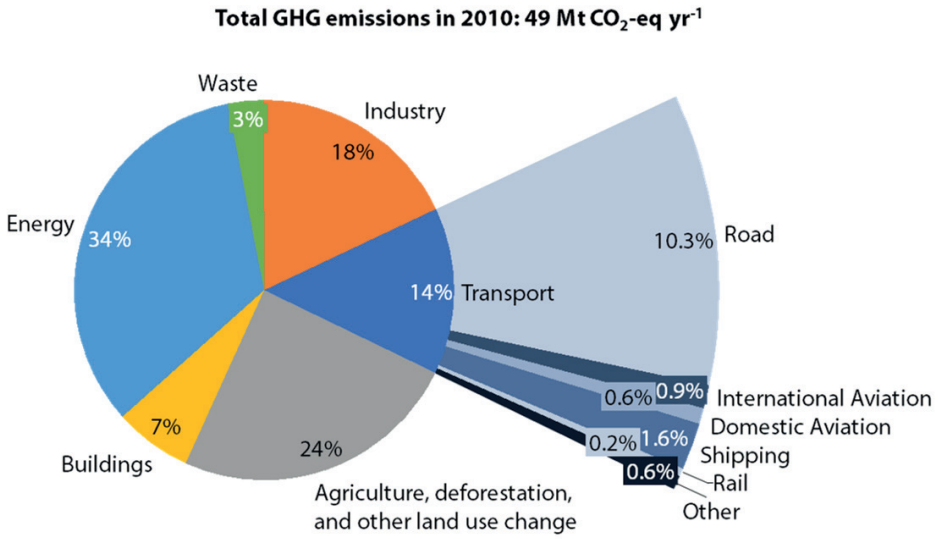


FIGURE 1-2: Global GHG emission in 2010 by sector, based on the fifth assessment report of the IPCC. [6,8]

Due to rapid growth of the aviation industry, GHG emissions are projected to increase 3.6- to 6.2-fold by 2050 relative to 2010 (Figure 1-3). These growth rates substantially exceed the 1.7-fold increase expected for the transport sector as a whole.[8,11] Nonetheless, international aviation was not included in the Paris Agreement, because its emissions are not attributed to any nation. Instead, the aviation industry, represented by airlines, manufacturers, air navigation service providers and airports, proposed a voluntary industry target to cap emissions by 2020 ('carbon-neutral growth') and halve emissions by 2050 relative to 2005.[12] The 2050 target is approximately in line with the RCP 2.6 emission pathway in which aviation's share in global GHG emissions remains constant from 2015 onwards. However, the RCP 2.6 emission pathway requires that emissions start declining in the coming decade.

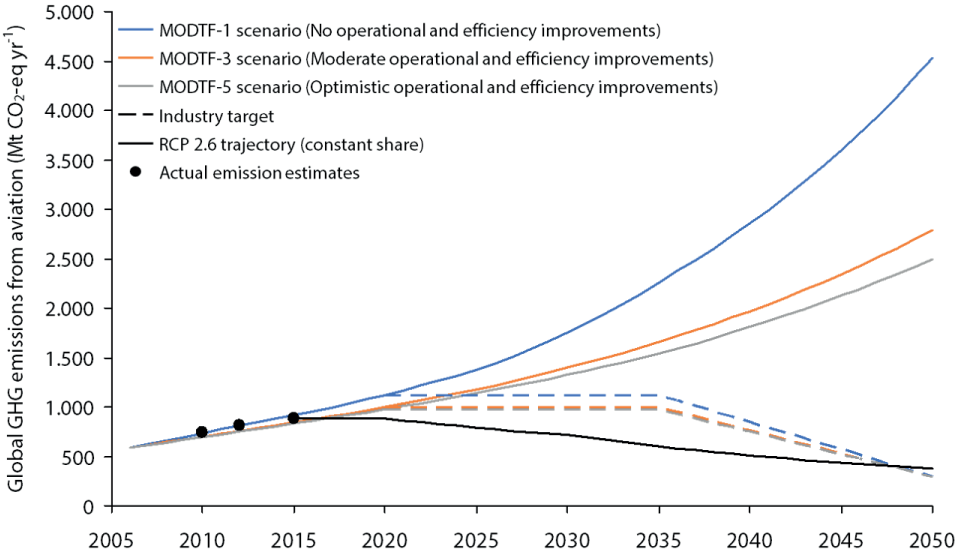


FIGURE 1-3: Projection of combustion emissions from the global aviation industry, based on projections of the Group on International Aviation and Climate Change (GIACC).[11] The Modelling and Database Task Force (MODTF) scenarios use a central traffic forecast and vary in the extent of operational and fuel efficiency improvements. The actual emission estimates for 2010 were taken from the fifth assessment report of the IPCC[8]. Others were calculated based on reported global jet fuel use in 2012[13] and 2015[14]. The RCP 2.6 trajectory describes a constant share of global aviation emissions in 2015 (1.9%) in an RCP 2.6 emission pathway.[15]

Although efficiency gains and operational improvements are estimated to reduce GHG emissions significantly, the emission gap between projected and targeted CO_2 emissions grows to 2.2-2.5 Gt CO_2-eq yr^{-1} by 2050 (Figure 1-3). The advent of propulsion methods with a lower carbon intensity should cover the remaining emission gap. However, the

aviation industry has limited options to decarbonize its activities compared to other sectors such as road transport or the power sector. To avoid a costly global transition, sustainable alternatives should be compatible with current aircraft design and fueling infrastructure, which is tailored to hydrocarbon fuels from fossil origin. Moreover, the urgency of the climate change mitigation requires a readily available alternative.

Renewable jet fuel (RJF), a liquid hydrocarbon fuel produced from renewable resources, is considered the only low-carbon alternative which complies with these criteria.[16–18] The development of electric or hybrid aircraft has potential to provide a low-cost solution to environmental and noise concerns (especially for short-haul flights). However, these solutions have limited short-term potential to reduce GHG emissions of the aviation industry, as the technology is still in its infancy and depends on advancements in electric engines, battery power storage, and fast-charging technologies.[19]

The general assembly of the International Civil Aviation Organization (ICAO) recently agreed to implement a Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA).[20] CORSIA requires airlines to purchase carbon offsets from 2020 onwards to comply with the industry target of carbon-neutral growth. Despite its potential to achieve short-term emission reductions, it is commonly acknowledged that CORSIA is a temporary gap filler and should not come at the expense of structural solutions, such as the introduction of RJF.[17,20–23]

1.3 Renewable jet fuel as a means to reduce the climate impact of aviation

RJF can be produced from biomass or CO_2. Although the production of RJF from CO_2 is promising, the technology is still relatively immature compared to bio-based RJF and depends on abundant supply of cheap renewable electricity.[24] As this thesis focuses on short-term options, 'RJF' thus refers to bio-based RJF.

The dominant fossil jet fuel used in the aviation industry is Jet A/A-1, a mixture of petroleum-derived hydrocarbons with stringent requirements on, amongst others, volumetric energy density, thermal stability, freeze point and viscosity.[25] As a full substitute for Jet A/A-1, RJF is subject to more stringent quality criteria than biofuels produced for the road transport sector (e.g. ethanol or esterified biodiesel) to ensure compatibility with existing infrastructure and adequate performance in extreme conditions (e.g. high altitudes). To guarantee the performance of RJF, a comprehensive certification procedure, facilitated by the American Society for Testing and Materials (ASTM), is mandatory before new conversion pathways (feedstock-technology combinations) for RJF production can be used in commercial aircraft. ASTM certification

is a lengthy process, which may take several years to complete. Various RJF conversion pathways are approved by ASTM, while several others are currently being reviewed (section 1.4.1).[12,17]

Since the first type of RJF was certified in 2009, the technical feasibility of using RJF in aircraft and airport infrastructure has been demonstrated on numerous occasions.[12,17] There is an increasing number of airlines and airports expressing interest in RJF in the form of engagement in supply chain projects, long-term off-take agreements with RJF producers and/or equity investments in technology providers.[12,17] Moreover, several airlines have become a member of the Sustainable Aviation Fuel Users Group (SAFUG), which commits itself to using RJFs which do not compete with food supply, positively affect socio-economic conditions, and significantly reduce GHG emissions.[26] The first and only factory to date producing RJF on a continuous basis was commissioned in 2016 in the US, producing roughly 5 PJ yr^{-1} (120 kt yr^{-1}) of RJF and renewable diesel.[27] Although the commissioning of this facility is a clear milestone for the RJF industry, it represents a tiny share of the current global annual jet fuel consumption of 12 EJ yr^{-1} (280 Mt yr^{-1}).[14]

1.4 Research gaps

Despite the proven technical feasibility of RJF production and use, the market for RJF is yet to take off. The climate change mitigation value of RJF for the aviation industry is the product of its supply potential and climate impact relative to fossil jet fuel. At this moment, the supply potential of RJF is largely constrained by high production costs and the absence of adequate incentives. At present, production costs of RJF are 2-3 times higher than fossil jet fuel.[21] This price gap poses a barrier to the commercialization of RJF, as airlines lack the financial resources or appetite to cover it, while current government incentives are either absent or inadequate.[18,28,29] Moreover, individual airlines or national governments are hesitant to act due to the international and competitive character of the sector.

This thesis addresses the production cost, climate impact and future supply of RJF, which will largely determine the contribution of RJF to reducing the climate impact of the aviation industry. The following subsections outline the status of knowledge on these topics and discuss the research gaps which this thesis intends to cover.

1.4.1 The production costs of renewable jet fuels

Multiple conversion technologies can convert biomass to RJF (Box 1). Current production of RJF is dominated by the Hydroprocessed Esters and Fatty Acids (HEFA) technology, which converts oils and fats into diesel, naphtha, and, optionally, jet fuel.[30]

Figure 1-4 shows the HEFA technology is currently the only technology with a Fuel Readiness Level (FRL) 9, meaning it is commercialized and ASTM certified. However, its potential is constrained by the supply of sustainable oils and fats. Technologies able to produce RJF from sustainable, more abundantly available (lignocellulosic) feedstocks include Fischer-Tropsch (FT), direct sugars to hydrocarbons (DSHC)[a], Alcohol-to-Jet (ATJ), pyrolysis and hydrothermal liquefaction (HTL). FT, DSHC and ATJ are ASTM certified (FRL 7), but have not reached the commercialization stage yet. HTL and pyrolysis are currently at pilot/demonstration scale (FRL 4-6) and are yet to obtain ASTM certification.

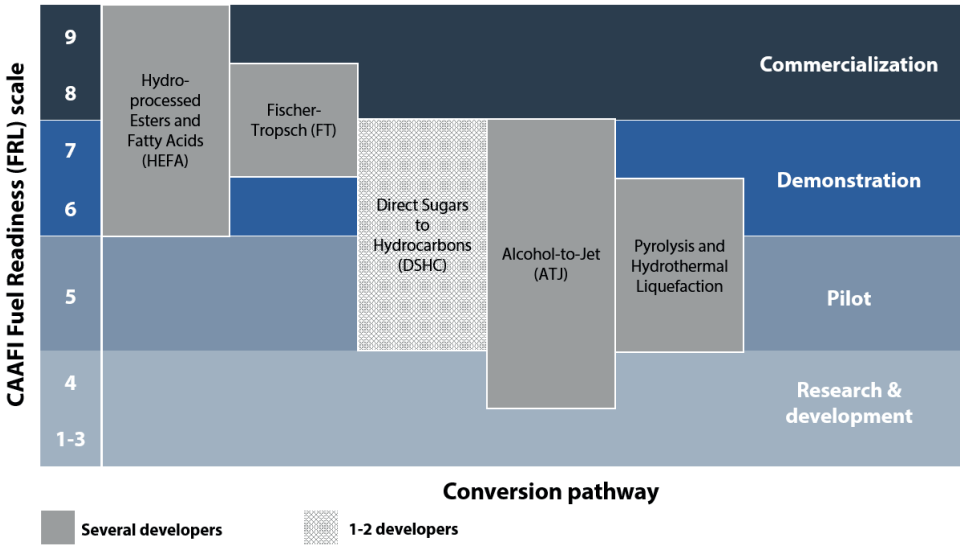


FIGURE 1-4: Renewable jet fuel conversion pathways on the CAAFI Fuel Readiness Level (FRL) scale, adapted from Mawhood et al.[28]

BOX 1: Overview of RJF conversion pathways.

RJF conversion pathways, adapted from De Jong et al.[31]

Biomass-based RJF can be produced from any carbon-rich feedstock, including oils (e.g. vegetable oil crops and waste oils), lignocellulosic feedstocks (e.g. agricultural and forestry residues), and sugar/starch crops (Figure 1-5). The conversion pathways can be subdivided into thermochemical and biochemical pathways, or a combination of both. Thermochemical pathways comprise, inter

a DSHC is also referred to as synthesized iso-paraffinic (SIP) fuels.

alia, Fischer-Tropsch (FT) synthesis, Hydroprocessed Esters and Fatty Acids (HEFA), pyrolysis and hydrothermal liquefaction (HTL). These technologies employ elevated temperatures and/or pressures to convert biomass to a mixture of paraffinic and/or aromatic hydrocarbons. Biochemical pathways utilize micro-organisms, enzymes or bacteria to convert biomass to specific molecules, such as ethanol, butanol or farnesene. Biochemical pathways often require further (thermochemical) processing steps to produce RJF. Most RJF types do not contain the entire range of chemical compounds present in fossil jet fuel and require blending with fossil fuels to meet all quality requirements (e.g. HEFA jet fuel can be blended up to 50%). The figure below is not exhaustive; RJF can also be produced using other feedstock-technology combinations, such as aqueous phase reforming or pathways producing synthetic RJF from CO_2, H_2 and (renewable) electricity.

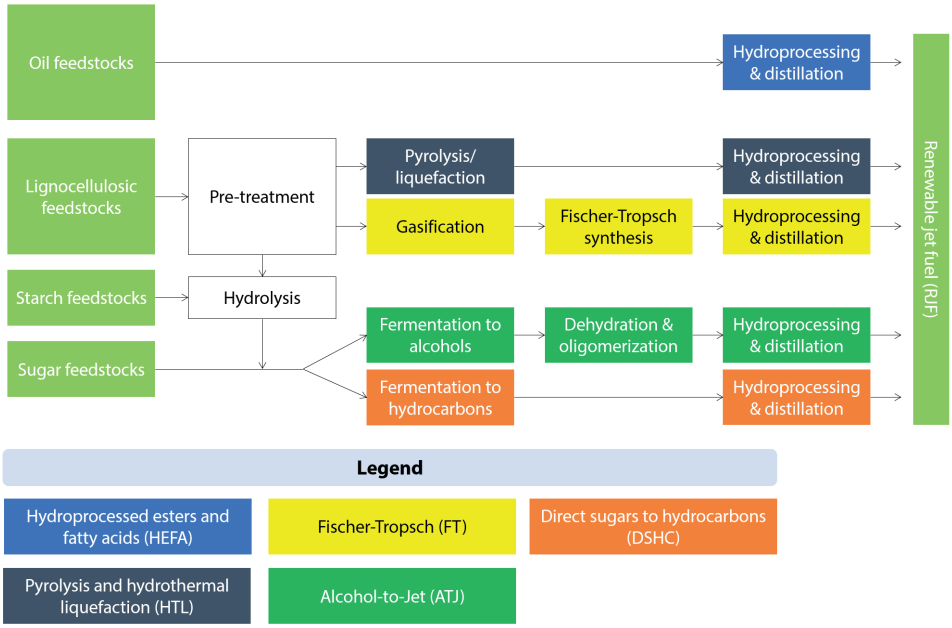


FIGURE 1-5: Overview of RJF conversion pathways.[31]

Over the recent years, various studies have analyzed the techno-economic performance of RJF conversion pathways (particularly focused on HEFA).[30,32–36] However, several factors impede a clear view on the current and future production costs of RJF production. First, an inter-study comparison of RJF production systems is a delicate exercise due to diverging methods, input data, and temporal and geographical scope. Second, current analyses generally rely on n^{th} plant estimates (i.e. as if the technology were

already mature and deployed at commercial scale), whereas RJF production systems vary widely in terms of technology maturity level. Third, there is limited knowledge on how production costs for the various RJF conversion pathways may develop over time, especially in relation to their technological learning potential, the scope for cost reduction by optimizing supply chain design, and the impact of competing demand for biomass from other sectors (e.g. road transport biofuels or the forestry industry).

This thesis aims to fill these research gaps by conducting multiple analyses. First, it uses established methods to quantify and consistently compare the techno-economic performance of RJF conversion technologies. This thesis primarily focuses on technologies which were certified or under review by the ASTM in 2014, which include HEFA, FT, pyrolysis, HTL, ATJ and DSHC (Box 1). These methods were adjusted to incorporate technological immaturity and estimate the merits of co-production strategies with other sectors. Second, a cost optimization model was developed to show how optimizing supply chain design may reduce production costs. Third, it integrates RJF production technologies in a European bioenergy system model to analyze how production costs may develop over time when explicitly considering technological learning and the interaction with other bioenergy sectors. As such, this thesis intends to be the first to give a broad view on the production costs of RJF in the short (2020) and medium term (2030).

1.4.2 The climate impact of renewable jet fuels

The climate impact of RJF in this thesis is confined to the climate impact from well-mixed GHGs (CO_2, CH_4 and N_2O), as the primary rationale for RJF relies on reducing GHG emissions. The scope of this thesis thus excludes other climate forcers which may alter to climate impact of RJF relative to fossil jet fuel, including surface albedo, surface roughness and evapotranspiration (associated with feedstock cultivation), as well as additional emissions species such as sulfates, soot, NO_x and H_2O emissions (associated with jet fuel combustion).[37–41] It also excludes other environmental and socio-economic sustainability indicators that may apply to RJF production, such local air quality, eutrophication, ozone depletion, land use, food security, human rights, etc.[24]

The climate impact of RJF is often quantified based on a GHG life-cycle assessment (GHG-LCA), which systematically sums GHG emissions during the production life-cycle including feedstock cultivation, upstream and downstream logistics, conversion and jet fuel combustion.[39,42,43] The feedstock cultivation stage is an important determinant of GHG-LCA results. Whereas carbon sequestration during biomass growth provides net negative GHG emissions, biomass cultivation may also cause direct land use change (LUC) emissions due to vegetation clearing, reduction of carbon storage in

carbon pools or indirect emissions through market-mediated mechanisms.[44–47] Indirect LUC is a prominent example of a market-mediated effect, whereby biomass cultivation induces direct LUC emissions elsewhere (e.g. by increasing commodity prices). The contribution of emissions from logistics is usually low, especially when the biomass is locally sourced. GHG emissions in the production stage are generally positive, due to the use of utilities (e.g. electricity, hydrogen, steam) and carbon losses in the production process (often emitted as biogenic CO_2). A notable exception includes the use of carbon capture and storage during the conversion stage, which stores produced CO_2 in the ground. GHG emissions from combustion are significant and mainly involve CO_2 emissions. The sum of biogenic CO_2 emissions from biomass/biofuel combustion and carbon loss is often equated to sequestered CO_2 emissions during feedstock growth under the assumption of 'carbon neutrality' over the life-cycle of the project. However, this assumption is widely debated as there may be a time lag between the emission and sequestration of carbon ('carbon debt'), especially for long-rotational feedstock such as forestry biomass.[48]

Several studies have addressed the life-cycle GHG reduction of RJF production systems[34,39,43,49–53] A comparison of the results is challenging due to diverging methods and input data, while system comparison is inherently affected by the choice of co-product allocation procedure.[44,49,54,55] This thesis quantifies and consistently compares the GHG emission performance of the RJF production systems mentioned in section 1.4.1. It further analyzes the impact of different allocation procedures and identifies measures to improve the GHG emission performance of RJF.

GHG-LCA is a useful tool to quantify life-cycle GHG reductions of bioenergy processes and identify opportunities for process improvement. However, the approach is not suited to incorporate the time-dependent character of emissions associated with LUC and carbon debt. The timing of GHG emissions and sequestration is important because the climate impact of GHGs increases with the atmospheric residence time.[56–61] Moreover, the climate impact of GHG emissions is affected by the choice of climate impact category, as the impact categories GHG concentration, radiative forcing and temperature change exhibit different temporal responses to GHG emissions and GHG species.[59–62] In this thesis, a dynamic performance indicator, the Relative Climate Impact (RCI), is defined to better quantify and compare the climate impact of bioenergy production systems. To the best of our knowledge, the RCI is the first performance indicator that incorporates time-dependent emission profiles, while offering the flexibility to compare the performance of systems for different impact categories.

1.4.3 The future supply of renewable jet fuels

The future supply of RJF depends on a combination of internal factors, associated with the production costs and climate impact of RJF, and external factors, such as the availability of (low-cost) sustainable feedstocks, the commercialization of new conversion technologies, policy developments and oil price dynamics.[18,28] Vice versa, increasing RJF volumes will also impact other bio-based sectors, which compete over the same feedstock base, production capacity and policy incentives.

The theoretical potential of biomass is limited by biophysical conditions such as climate, soil type and solar irradiation. The technical potential is further constrained by technical limits on biomass collection, competing demand for food, fiber, fodder and forest products, and land area required for human infrastructure.[24] The sustainable potential also considers restrictions associated with nature conservation and soil, water and biodiversity preservation.[24] The sustainable biomass potential is subject to large uncertainties and depends on social, political and economic developments.[63] Global biomass use equals approximately 50 $EJ_{primary}$ yr^{-1} in 2010. It was estimated that the sustainable technical biomass potential in 2050 ranges between 100 and 300 $EJ_{primary}$ yr^{-1}, depending on different views on sustainability and socio-ecological constraints.[63] The consumption of biomass for energy purposes was projected at 40-55 EJ_{final} yr^{-1} by 2050 and mainly depends on biomass cost, biomass supply and the climate change mitigation ambition. Moreover, the availability of bioenergy technologies able to convert the diverse types of biomass is key to unlock the full biomass potential. The biomass resource is not only exclusively available to the aviation industry, whose combined final energy use was projected to increase from 12 EJ_{final} yr^{-1} in 2015 to 31 EJ_{final} yr^{-1} in 2050[11]; the resource will need to be shared with other end-use sectors, such as road transport, marine transport, power, heat and chemicals. Unlike aviation, many of these sectors have alternative climate change mitigation options. However, the ability of aviation to secure biomass feedstocks, its impact on other sectors, and the desirability thereof will be important determinants for the future role of RJF.

Besides biomass supply, the future deployment of RJF highly depends on the mechanisms to cover the cost differential between RJF and fossil jet fuel.[18] Given the limited ability or willingness of the aviation industry to cover the differential, policy incentives will be essential for the future supply of RJF in the short and medium term. Most jurisdictions currently do not have specific policy instruments to incentivize RJF. The EU Renewable Energy Directive I (RED-I)[64] and US Renewable Fuel Standard 2 (RFS2)[65], two important renewable energy policies, allow RJF to be counted towards biofuel targets for the road transport sector (Box 2). Although this voluntary opt-in for aviation creates a level playing field for road and aviation biofuels, it has not led to a significant increase in RJF production. This is presumably caused by the fact that

RJF is associated with smaller production scales, higher quality requirements and fewer additional (tax) incentives, compared to road transport biofuels. The additional incentives for RJF in the proposed RED-II (the successor of the RED-I) will likely change the attractiveness of RJF production.

BOX 2: Policy incentives for RJF in the EU and US

The EU Renewable Energy Directive (RED) and US Renewable Fuel Standard (RFS)

The EU RED and US RFS are two important regional renewable energy policies using targets or mandates to establish a guaranteed demand for biofuels. The US RFS2 requires the use of 136 billion L yr^{-1} of renewable fuels in transport by 2022, of which lignocellulosic biofuels comprise 61 billion L. Although RJF can count towards the biofuel mandate, the incentive has led to limited RJF consumption to date (5.9 kt in 2016 and 5.2 kt in 2017).[66] The RED-I establishes a target of 20% renewable energy in the EU in 2020, of which half should be used in the transport sector.[67] Since 2015[64], member states are allowed to count RJF towards the renewable energy targets (although aviation is not an obligated party). However, few member states have explicitly adopted this in national legislation.[29] Recently, the European Commission published a proposal for the successor of the RED-I, the 'RED-II', which aims to increase the share of renewable energy sources to 27% by 2030.[68] The RED-II establishes targets for renewable transport fuels (excluding food-based biofuels) of 6.8% of total energy use in the road and rail sector by 2030. It also contains a sub-target for advanced biofuels, which should represent 3.6% of total energy use in the road and rail sector by 2030. Whereas aviation is not an obliged party, it is proposed that RJF may count 1.2 times its energy content towards the biofuel targets. This multiplier mechanism creates a 'tilted' playing field (as opposed to a level playing field) aiming to stimulate biofuel uptake in sectors which lack clear renewable options and cover higher production costs that may exist in these sectors. Final approval of the RED-II is expected in late 2018.

Several authors have estimated the future supply of RJF based on biomass supply[69], production cost developments[25], and planned production capacity[70,71]. However, few studies have quantified the future supply of RJF in explicit recognition of the context in which RJF is embedded. This thesis uses an integrated bioenergy system model to provide quantified projections of the future supply of RJF in the EU, given the

anticipated regulatory context, availability of biomass and conversion technologies, and competing biomass demand from other sectors (i.e. transport, heat, power and chemicals). It further models the impact of RJF production on other bioenergy sectors. As such, this thesis intends to present an integrated view on the pre-conditions and implications of the emergence of RJF.

1.5 Thesis objectives and research questions

The first objective of this thesis is to quantify the cost and climate impact relative to fossil jet fuel for a wide range of RJF conversion pathways. The second objective of this thesis is to quantify the supply of RJF and the associated GHG emission reductions in the EU towards 2030. These objectives are addressed by the following research questions:

I. What are the production costs of renewable jet fuels compared to fossil jet fuel in the short (2020) and medium term (2030)?

II. What is the climate impact from CO_2, CH_4 and N_2O emissions of renewable jet fuel production systems compared to fossil jet fuel and how can it be improved?

III. What is the contribution of renewable jet fuel to reducing aviation-related greenhouse gas emissions in the EU towards 2030 and how is its contribution affected by policy incentives, technological progress, biomass supply and competing biomass demand?

These questions will be addressed in the various chapters of this thesis (Table 1-1) within a confined geographical and temporal scope. The geographical scope of this thesis is primarily constrained to the EU, but also evaluates the performance of production systems in the US and Brazil, as these are important production locations of and markets for biofuels.[72] The temporal scope of this thesis is confined to the short (2020) and medium term (2030). This implies that the scope of conversion pathways contains feedstocks that are currently available (e.g. excluding algae) and technologies which were certified or under review by the ASTM in 2014 (see Box 1).

TABLE 1-1: Overview of the thesis chapters and their relation to the research questions.

Chapter		Research question		
		I	II	III
2	The feasibility of short-term production strategies for renewable jet fuels – A comprehensive techno-economic comparison	•		
3	Cost optimization of biofuel production – The impact of scale, integration, transport and supply chain configurations	•		
4	Life-cycle analysis of greenhouse gas emissions from renewable jet fuel production		•	•
5	Using the Relative Climate Impact performance indicator to quantify the climate impact of bioenergy production systems		•	•
6	Renewable jet fuel supply scenarios in the European Union in 2021-2030 in the context of proposed biofuel policy and competing biomass demand	•		•

1.6 Thesis outline

Chapter 2 examines the techno-economic performance of various RJF conversion pathways. The assessment compares the cost of an nth plant and a first-of-a-kind plant. Furthermore, a new approach is introduced to quantify the merits of co-production strategies, which is applied to RJF production alongside existing supply chains in the pulp, wheat ethanol, and beet sugar industries in Europe. A sensitivity analysis was performed to explore the impact of uncertainties in investment cost, yield, feedstock price and hydrogen consumption.

Chapter 3 introduces a geographically-explicit cost optimization model to analyze the impact of and interrelation between four cost reduction strategies for biofuel production: economies of scale, intermodal transport, integration with existing industries, and distributed supply chain configurations (i.e. supply chains with an intermediate pre-treatment step to reduce biomass transport cost). The model was applied to a biofuel supply chain based on HTL in the context of the existing Swedish forestry industry.

Chapter 4 presents a life-cycle assessment of the well-to-wake GHG emissions of various RJF conversion pathways using the Greenhouse gases, Regulated Emissions and Energy use in Transportation (GREET) tool. The analysis examines the impact of key uncertainties and alternative hydrogen production methods. Furthermore, it explores how different co-product allocation methods affect the results. The findings of this study are related to the calculation of GHG emission reductions of RJF in CORSIA, as such scheme will require a global meta-standard to quantify the life-cycle GHG emissions of RJF conversion pathways.

Chapter 5 expands on Chapter 4 by introducing a novel time-dependent performance indicator, the Relative Climate Impact (RCI), to quantify and compare the climate impact of bioenergy systems relative to their fossil counterpart. The RCI incorporates the impact of emission timing while offering the flexibility to alter the climate impact category, time horizon and equivalency metric. The RCI is calculated for various bioenergy production contexts to examine the interaction between emission profiles and the choice of impact category.

Chapter 6 incorporates RJF in the RESolve-Biomass model to study its emergence in the context of competing biomass demand from the power, heat, transport fuels (road and marine) and chemicals sector. Scenario analysis and sensitivity analyses are used to study the effect of biomass supply, technology development, fossil jet fuel prices and biofuel policies on the supply of RJF in the EU towards 2030. It also explores the associated feedstock-technology portfolio, system cost, GHG emission reductions and impact on the wider bio-based economy.

Chapter 7 synthesizes the main findings from Chapter 2-6 and provides answers to the research questions.

Chapter 8 presents the conclusions of this thesis and lists key pre-conditions for the widespread use of RJF. It also provides recommendations for policy makers, the aviation industry and further research.

2

The feasibility of short-term production strategies for renewable jet fuels – A comprehensive techno-economic comparison

Sierk de Jong[1], Ric Hoefnagels[1], André Faaij[2], Raphael Slade[3], Rebecca Mawhood[3], Martin Junginger[1]

1. Copernicus Institute of Sustainable Development, Utrecht University, The Netherlands.
2. Energy and Sustainability Research Institute, Rijksuniversiteit Groningen, The Netherlands.
3. Energy Engineering, Centre for Environmental Policy, Imperial College London, United Kingdom.

Published in Biofuel, Bioproducts & Biorefining. 9:778–800 (2015)

ABSTRACT

This study compares the short-term economic feasibility of six conversion pathways for renewable jet fuel (RJF) production. The assessment combines i) a harmonized techno-economic analysis of conversion pathways expected to be certified for use in commercial aviation by 2020, ii) a pioneer plant analysis taking into account technological immaturity, and iii) a quantified assessment of the merits of co-producing RJF alongside existing European supply chains in the pulp, wheat ethanol and beet sugar industries. None of the pathways assessed are able to reach price parity with petroleum-derived jet fuel in the short term. The pioneer plant analysis suggests that the Hydroprocessed Esters and Fatty Acids (HEFA) pathway is currently the best option; the technology achieves the lowest minimum fuel selling price (MFSP) of 29.3 € GJ^{-1} (1289 € t^{-1}) and the technology is deployed on commercial scale already. In the short term, n^{th} plant analysis shows Hydrothermal liquefaction (HTL) and Pyrolysis emerging as promising alternatives, yielding MFSPs of 21.4 € GJ^{-1} (939 € t^{-1}) and 30.2 € GJ^{-1} (1326 € t^{-1}) respectively. The pioneer plant analysis shows considerable MFSP increases for producing drop-in fuels using HTL and pyrolysis as both technologies are relatively immature. Hence, further RD&D efforts into these pathways are recommended. Co-production strategies decrease the MFSP by 4-8% compared to greenfield production. Integration of process units and material and energy flows is expected to lead to further cost reductions. As such, co-production can be a particularly useful strategy to get emerging technologies to commercial scale.

2.1 Introduction

The aviation industry is responsible for 2-3% of global anthropogenic greenhouse gas (GHG) emissions.[29,73,74] To lower the industry's environmental impact, the Air Transport Action Group (ATAG) has set targets to cap net emissions from 2020 onwards and reduce net carbon emissions by 50% by 2050 (relative to 2005 levels).[75] The introduction of renewable jet fuel (RJF), a drop-in alternative to fossil jet fuel derived from biomass, is expected to make the most important contribution to reaching this target.[75]

To date production volumes of RJF have been negligible, owing to low demand as a result of high prices. In 2013, batches of RJF were about two to three times as expensive as petroleum-derived jet fuel.[21] Most commercial flights on RJF have been powered by fuels produced using the Hydroprocessed Esters and Fatty Acids (HEFA) technology, which converts oils and fats to hydrocarbons in the jet and diesel range. This technology has been demonstrated on a commercial scale, primarily for diesel production.[30] However, the high price and limited availability of sustainable oil feedstocks are major challenges that constrain the ramp-up of HEFA RJF production volumes.[76,77] Therefore, there is a need to develop new RJF conversion pathways that can bridge the existing price premium and enable large-scale production. These pathways should make use of feedstocks that are abundantly available, have a low economic value, and do not compete with food production, such as forestry residues, agricultural residues or municipal solid waste. A comparative techno-economic analysis of such emerging pathways can aid in formulating a strategy for the development of RJF.

Techno-economic analyses of RJF conversion pathways are widely available.[16,30,32–36,78–82] However, several factors impede a comprehensive assessment of the short-term economic feasibility of RJF production. First, the majority of existing analyses are limited to conversion pathways that have already received the mandatory technical certification from the American Society for Testing and Materials (ASTM), thus omitting the technologies that are expected to receive certification in the coming years. Second, fair comparison of techno-economic studies is a delicate exercise due to different input assumptions, economic evaluation metrics, temporal scales and geographical locations. Third, current analyses generally rely on n^{th} plant estimates, which present techno-economic performance as if the technology were already mature and deployed at commercial scale. Historically, n^{th} plant estimates have tended to underestimate capital cost and overestimate plant performance as compared to actual values observed for first-of-a-kind plants.[83,84] Since RJF production is a nascent industry and many first commercials of the respective technologies still need to be built, a pioneer (i.e. first-of-a-kind) plant estimate seems more appropriate to assess the current economic feasibility of RJF production pathways. Last, most analyses evaluate

greenfield production only, while co-production strategies (e.g. adding 'bolt-on' units or co-locating additional units adjacent to existing production plants) have been argued to yield cost reductions and reduce investment risks, particularly for emerging technologies in cellulosic biofuel production (e.g. the plants operated by POET-DSM (Emmetsburg) and Raizen (Costa Pinto)).[83,85–89]

This paper aims to assess the short-term economic feasibility of RJF production. Therefore, it presents i) a harmonized techno-economic comparison of conversion pathways which are expected to be ASTM certified for use in aviation before 2020, ii) a pioneer plant analysis to translate the nth plant results to pioneer plant results in order to reflect the current state of play, and iii) a quantified assessment of the potential economic merits of co-production strategies for RJF production in the EU-28.

2.2 Methods and data collection

This study employs a harmonized techno-economic framework based on existing process modelling data to compare RJF conversion pathways. The following sections provide an overview of the conversion pathway scoping procedure (section 2.2.1), a literature survey (section 2.2.2), the techno-economic framework and data collection process (section 2.2.3), and the adjustments made to the base model to assess pioneer plants and co-production strategies (section 2.2.5 and 2.2.6). More information regarding methods and input assumptions can be found in the supplementary information.

2.2.1 Conversion pathway selection

For the purpose of this analysis, the term 'conversion pathway' describes a technology and feedstock combination, which is further characterized by its 'degree of integration' with existing plants (hereafter referred to as 'incubator facilities'). Since ASTM certification is mandatory before fuel can be used in commercial aircraft and the certification process takes several years to complete, the current scope only includes certified technologies or technologies under review, namely: Hydroprocessed Esters and Fatty Acids (HEFA), Fischer-Tropsch (FT), Hydrothermal Liquefaction (HTL), pyrolysis, Alcohol-to-Jet (ATJ) and Direct Sugars to Hydrocarbons (DSHC).[90 b]

In line with the aviation industry's commitment to use non-food feedstocks only, wheat straw and forestry residues were considered for FT, HTL, pyrolysis, ATJ and DSHC; used cooking oil was used for HEFA.[26] Existing plants in the pulp and paper, wheat ethanol and beet sugar industries were selected as incubator facilities, since these industries

b RJF produced by the HEFA pathway are also commonly referred to as Hydrotreated Renewable Jet (HRJ). Fuels produced by the DSHC pathway are also commonly referred to as Synthesized Iso-Paraffinic (SIP) fuels.

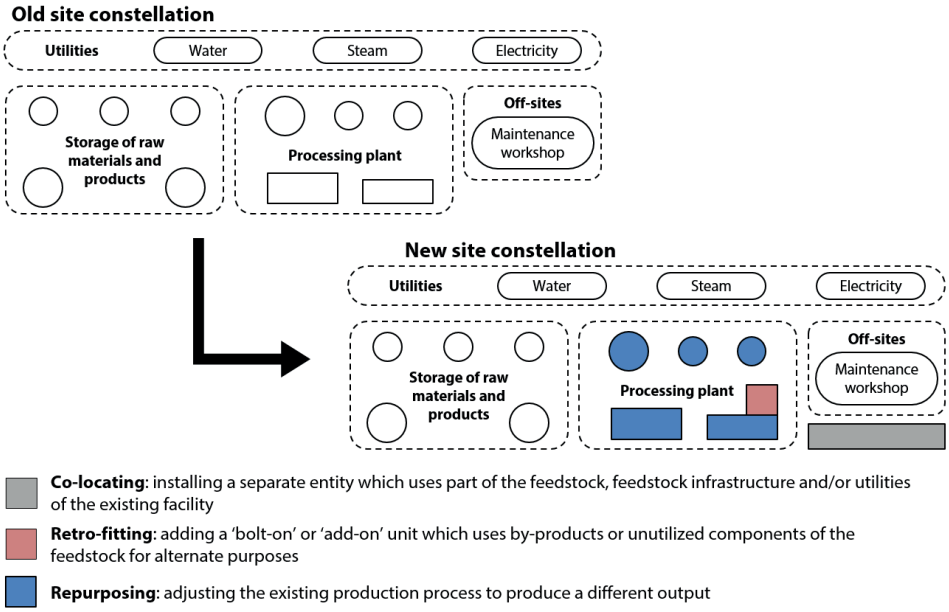


FIGURE 2-1: A visualization of different degrees of integration. This image serves as a schematic example of possible co-production strategies. In some cases a co-production strategy might, for example, also require additional service or storage facilities (adapted from Ereev & Patel[102]).

show substantial accumulation of residues along their supply chain and have a wealth of experience with biomass logistics and conversion. Residues produced in the beet sugar industry (i.e. A-molasses and unpressed beet pulp) and pulp and paper industry (i.e. black liquor and hog fuel) were also included as feedstocks for the conversion pathways involving co-production.

Four 'degrees of integration' between industrial processes can be discerned in the literature: *greenfield*, *co-locating, retro-fitting* and *repurposing*. The latter three are referred to as examples of 'co-production strategies' (Figure 2-1). As these terms are often used interchangeably, definitions are provided below:

- *Greenfield* strategies involve building a stand-alone facility at a new industrial site.
- *Co-locating* strategies involve installing a separate entity adjacent to an existing facility which uses part of the feedstock, feedstock infrastructure and/or utilities of the existing facility (i.e. producing B alongside A without changing the existing production line).[91–93]
- *Retro-fitting* strategies involves altering the current production line of an existing facility (e.g. adding a 'bolt-on' unit), such that by-products or unutilized components

of the feedstock can be used for alternative purposes (i.e. producing B alongside A by altering the existing production line);[93–99]

- *Repurposing* strategies involve adjusting the production process of an existing (mothballed) facility to produce a different output (i.e. producing B instead of A).[85,100,101]

Based on these definitions and possible feedstock-technology combinations, ten greenfield, three retro-fitting and nine co-locating strategies were selected (Figure 2-2). All the *co-locating* strategies were also evaluated on a greenfield basis. The *retro-fitting* strategies were not evaluated on a greenfield basis, as these strategies require integration by definition. No repurposing strategies were considered.

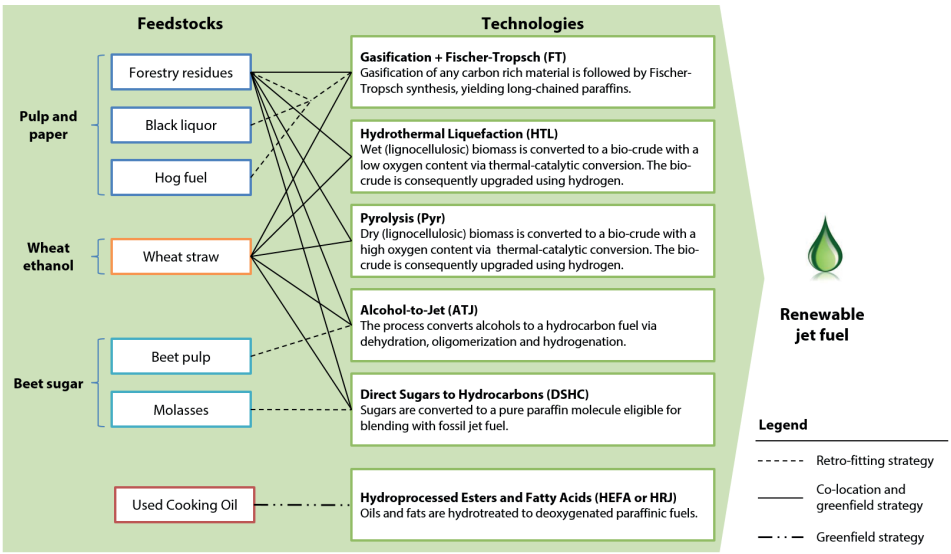


FIGURE 2-2: Feedstock-technology combinations in the current scope.

2.2.2 Literature survey

A literature survey was conducted to investigate the ranges of key technology-specific assumptions for RJF production pathways. The survey compared estimates of total capital investment (TCI) and yield from techno-economic studies of RJF production, published between 2005 and 2015. Studies examining drop-in diesel production were also included, because of the limited availability of RJF studies and specifications of both products being reasonably similar. Also, data from three operational HEFA plants and one lignocellulosic ethanol plant were included.

The TCI was normalized to $€_{2013}$ or $US\$_{2013}$ using the Chemical Engineering Plant Cost Index (CEPCI).[103,104] $US\$_{2013}$ were converted to $€_{2013}$ using the average euro-dollar exchange rate in 2013 (0.753 € $\$^{-1}$). To allow for a comparison across conversion pathways, output capacities were normalized to 500 or 1000 t (metric tonne) hydrocarbon product output per day (hydrocarbon products include jet fuel, diesel, naphtha, gasoline, liquefied petroleum gas (LPG) and propane).[c] The following general scaling equation was used with a scaling factor of 0.6.[102,105,106]

$$(Cost\ of\ equipment)_X = (Cost\ of\ equipment)_{base} * \left(\frac{Capacity\ X}{Capacity\ base}\right)^{scaling\ factor}$$

Table 2-1 shows a considerable range in TCI and yield estimates for the pathways in scope, particularly for HEFA, FT and pyrolysis. It also illustrates the uncertainty regarding process performance and cost estimates. Furthermore, the survey showed that data availability for black liquor gasification (BLG), HTL, ATJ, sugar extraction and DSHC is relatively limited. This impedes a solid comparison and increases the uncertainty surrounding the performance of these technologies.

Variation in TCI and yield originated primarily from differences in process design and uncertainties in parameter estimates. For most pathways, the largest yields variations were caused by different process designs. For instance, yields for pyrolysis were considerably lower when biomass or part of the intermediate product (bio-crude) was used for hydrogen production.[112,118] Modest yield reductions for fermentation pathways including on-site enzyme production were caused by partial diversion of the hydrolysate to the seed reactor.[122,125] For HEFA, the Ecofining process utilizes increased cracking requirements to produce RJF, thereby also producing more lighter components.[30] A broader range of FT yields was observed amongst the sample (Δ = 0.09 t t^{-1}) than within individual comparative studies with different gasifier designs (Δ = 0.04 t t^{-1}), suggesting study assumptions have a larger impact on the yield than gasifier type.

On-site production of hydrogen or enzymes (for fermentation) and bio-crude upgrading (for pyrolysis and HTL) all lead to TCI increases, but also reduce operational expenditure (OPEX). Zhu et al. calculated that on-site hydrogen production is economically favorable when prices are above 1.39 $€_{2013}$ kg^{-1} hydrogen.[107] FT process designs including an entrained flow gasifier were generally associated with higher TCI than those assuming a fluidized bed gasifier. A clear relation between feedstock type and yield did not emerge from this survey.

c It must be noted that scaling based on output instead of input favors the TCI of studies reporting high yields. In addition, the choice of scaling factor and normalized capacity size affects the TCI range.

TABLE 2-1: Process characterization for each conversion pathway including reported TCI and yield ranges (see S2.7).

	Key process design variations	Hydrogen for upgrading required	Non-hydrocarbon co-products	Yield		Normalized *output* capacity[i]	TCI at normalized capacity	Ref.
				Energy[ii]	Mass[iii]			
Unit				**GJ GJ^{-1}**	**t t^{-1} (dm)**	**t day^{-1} fuel product (MW_{output})**	**M€$_{2013}$**	
Gasification + FT	Gasifier type, syngas cleaning technology	No	Electricity	0.40-0.53	0.13 - 0.22	500 (254)	327 – 1186	[36,80,107–113]
Black liquor gasification + FT	Gasifier type, syngas cleaning technology	No	Electricity/steam	0.65-0.70	0.13	500 (254)	330 – 722	[114,115]
HTL	On/ex-site upgrading, on/ex-site hydrogen generation	Yes		0.64	0.18 - 0.36	500 (254)	273 – 513	[107,116]
Pyrolysis	On/ex-site upgrading, on/ex-site hydrogen generation	Yes		0.63-0.77	0.16 - 0.36	500 (254)	156 – 482	[107,112,117–120]
ATJ		Yes		0.91[v]	0.56[121]	500 (254)	68 – 72[36,121]	
Fermentation (dilute acid)	Separate/simultaneous saccharification, on/ex-site enzyme production	No	Electricity	0.49	0.20 - 0.33	500 (156)	215 – 426	[89,112,122–125]
DSHC		Yes		0.50[v]	0.17	500 (254)	292	[35]
Sugar extraction		No	Electricity	0.51	0.59	1000 (165)	206	[123]
HEFA	Ecofining/Neste process[iv]	Yes		0.92[v]	0.75 - 0.83	1000 (254)	200 - 644	[30,33,35,126–128]

i. The capacities were normalized to 500 or 1000 t day^{-1} output to avoid excessive scaling. As sugar extraction and HEFA have high mass yields, these were scaled to a higher output capacity. The energy output (in MW) is calculated based on an average (non-weighted) energy density for gasoline, naphtha, diesel and jet fuel (43.85 GJ t^{-1}). Energy densities for ethanol and sugars are listed in S2.8. Additional useful outputs (e.g. electricity, steam, etc.) are not included in the output capacity.

ii. When reported in the reference study, the efficiency from biomass and other inputs (e.g. hydrogen, natural gas) to fuel outputs and electricity was tabulated. Only efficiencies estimated on lower heating value (LHV) basis were included.

iii. The mass yield is defined as tonne (fuel) product output (i.e. jet fuel, diesel, gasoline and/or naphtha) per tonne dry matter (dm) feedstock input.

iv. The processes differ in process design (UOP's Ecofining process also includes isomerization besides hydrotreatment) and production flexibility to alter the RJF/diesel ratio in the product slate.

v. No energy yield data for these conversion pathways were available. Estimates are based on dividing the energy input from feedstock and additional hydrogen inputs by the energy output.

Uncertainty in the yield and TCI estimates also contributes to the observed ranges. Due to limited publicly available data from commercial plants, the majority of yield and total purchased equipment costs (TPEC) estimates in the literature are derived from process modeling tools, pilot test data or cost curves from comparable industries (e.g. petroleum industry) and, hence, come with uncertainties. Furthermore, the translation from TPEC to TCI introduces additional uncertainties inherent to the factorial estimation methods that are often employed to estimate costs for installation, piping, buildings, service facilities, etc.[109] As cost estimation methods are dissimilar in terms of cost items and cost factors, different methods can arrive at other TCI estimates while starting from the same TPEC. Moreover, ambiguity about what is included in reported TPEC and consequent cost items impedes a transparent comparison.

2.2.3 Techno-economic model structure

The model structure as discussed in this section was used to assess the greenfield n^{th} plant performance for all conversion pathways. N^{th} plant economics are to be interpreted as the (future) cost of the technology after several commercial plants have been commissioned and the technology can be considered mature.[120,123] The alterations made to the base model to assess pioneer plants and co-production strategies are discussed in sections 2.2.4 and 2.2.5.

2.2.3.1 Techno-economic framework

The techno-economic model was constructed according to the Standardized Cost Estimation for New Technologies (SCENT) method developed by Ereev & Patel (see S2.1).[102] This method was preferred over others as it provides a transparent factorial method to estimate full OPEX and total capital investment (TCI) by combining cost estimation methods of, amongst others, Peters, Timmerhaus and West, Couper, and Towler and Sinnott.[105,106,129] This method has a claimed accuracy of ±30%.[102]

The fixed capital investment (FCI) was estimated from total purchased equipment cost (TPEC)[d] using Lang factors (i.e. the ratio between TPEC and FCI) of 4.69, 4.77 and 4.86 for high (>76M€), medium (8-76 M€) and low (<8M€) TPEC respectively. These Lang factors are higher compared to the 4.28 as reported for solid-fluid plants in Peters, Timmerhaus and West.[106] The total capital investment (TCI) was computed by adding the required working capital (assumed to be 5% of FCI) to the FCI. The OPEX was calculated from mass balances and utility requirements, complemented with reported factors for other OPEX cost items, such as maintenance and repairs (6% of FCI), local taxes (1.5% of FCI) and insurance (1% of FCI).

d In the literature, the term Total Purchased Equipment Cost (TPEC) is used ambiguously. Whereas delivery charges are excluded from the TPEC in the SCENT method, Peters, Timmerhaus and West's[106] mehod includes delivery charges in TPEC. As both methods estimate delivery charges at 10% of bare equipment costs, TPEC in one method could easily be converted to the other method.

Production and financing assumptions were harmonized across all technologies (Table 2-2). A 80:20 debt-to-equity ratio was assumed with a discount rate of 10%. The average EU corporate tax rate (22%) was used.[130] Towler & Sinnott's production start-up schedule was deemed most appropriate for novel technologies (Table 2-3).[105]

TABLE 2-2: Financing and production assumptions.

Financing assumptions		
Parameter	**Value**	**Unit**
Plant lifetime	25	yr
Depreciation period	10	yr
Rate of principal payments	15	yr
Debt-to-equity ratio	80:20	
Interest rate on debt	8%	
Corporate tax rate	22%	
Discount rate[35,107,117,123]	10%	
Depreciation schedule	Straight line	
Production assumptions		
Capacity factor	90%	

TABLE 2-3: Plant start-up schedule, adopted from Towler & Sinnott.[105]

Year	**TCI schedule**	**Plant availability**
-1	30% of fixed capital	0
0	50% of fixed capital	0
1	20% of fixed capital + working capital	30%
2		70%
3		100%

2.2.3.2 Data selection

Technology-specific mass balances, utility requirements and TPEC were retrieved from reference process modelling studies focusing on RJF production. No studies targeting RJF production could be identified for the FT, BLG, HTL and pyrolysis pathways. Instead, studies tailored to diesel production were used, assuming that 25% of the produced diesel consists of jet fuel-ranged hydrocarbons. As all process designs already include a distillation column to separate the hydrocarbon products, no additional costs were taken into account.

Table 2-4 shows the values for TPEC, TCI, yield and input capacity used in this study. The selection of reference studies was based on i) the match with conversion pathway configurations in the current scope and consistency in process design and ii) moderate TCI and yield estimates relative to other studies where possible. More practically, the source should have complete disclosure of TPEC, mass balances and utility requirements to allow reproduction. The modelled HTL, pyrolysis and fermentation pathways all include on-site hydrogen or enzyme production. The TCI estimate for HEFA was based on the FCI from a commercial facility (Neste Oil's Rotterdam plant) as this was deemed more accurate. For ATJ, fermentation and sugar extraction, yield and TPEC data were obtained from multiple sources to complete the dataset or allow for feedstock flexibility. A sensitivity analysis was performed to quantify the impact of TCI and yield ranges observed in the literature survey (section 2.4.1).

The TPEC was obtained from the reference studies or deduced from aggregate cost items by subtracting the included cost components using the respective factors for these as described in SCENT. Costs for general service facilities (e.g. wastewater treatment) were systematically omitted from the TPEC, as these components are already included in the SCENT framework.

Costs were actualized to $€_{2013}$ using the same procedure as discussed in section 2.2.2. In most cases the capacity of the reference study was used and no scaling was applied. For beet pulp and molasses conversion, however, the input scale of all conversion units was adjusted to fit the production of these feedstocks at the incubator facility. The equipment for lignocellulosic sugar extraction was scaled to fit the fermentation unit in the DSHC facility. The input of the ATJ conversion unit was scaled to fit the output from the fermentation island. The input capacity of the black liquor gasification (BLG) conversion facility was scaled to the capacity of the other thermochemical conversion pathways (i.e. 454 MW), corresponding to a large European pulp mill (approximately 0.3 million tonne annual pulp production).[136] Specific scaling factors were applied for individual pieces of equipment when reported in the literature. Where no specific scaling factors could be obtained, a scaling factor of 0.6 was used.[102,105,106]

2.2.3.3 Variable costs and revenues from by-products

Variable costs and revenues were determined by the quantities and prices of the materials and utilities involved. Quantities were obtained from reported mass and energy balances; prices were based on reported prices for feedstocks and quoted prices for other raw materials (Table 2-5 and S2.3). No price was assumed for hydrocarbon products (i.e. RJF, diesel, gasoline, naphtha, LPG and propane) as their cost price is the

TABLE 2-4: Capacity, TPEC, TCI and yield values used in this study (see S2.2).

Technology	Key process design assumptions	Feedstock input(s)[i]	Product output(s)[ii]	Reference *input* capacity[iii]	TPEC (TCI[iv])	Yield[v]	Ref.
Unit				**t (dm) day^{-1} (MW)**	**M€$_{2013}$**	**t t^{-1} (dm)**	
Gasification + FT	Directly heated, oxygen-blown, pressurized, fluidized bed gasifier	FR	J, D, N	2000 (454)	96 (471)	0.17	[107]
		WS	J, D, N	2178 (454)	96 (471)	0.16[vi]	
Black liquor gasification + FT	BLG in a Chemrec gasifier and biomass gasification (fluidized bed), rectisol cleaning.	BL	J, D, G	2991 (454)	95 (384-394)[vii]	0.11[viii]	[114,131]
HTL	On-site upgrading, on-site hydrogen generation	FR	J, D, G	2000 (454)	89 (436)	0.36	[107]
		WS	J, D, G	2178 (454)	89 (436)	0.33[vi]	
Pyrolysis	On-site upgrading, on-site hydrogen generation	FR	J, D, G	2000 (454)	102 (504)	0.27	[120]
		WS	J, D, G	2178 (454)	102 (504)	0.25[vi]	
ATJ[ix]		EtOH	J, G	482 (150)	10 (48)	0.56	[36,81,121]
Fermentation[x,xii]	Separate saccharification, on-site enzyme production	FR	EtOH	2000 (454)	71 (350)	0.24	[123,132]
		WS	EtOH	2000 (417)	74 (365)	0.22	
		BP	EtOH	2000 (288)	46 (186-191)[vii]	0.40	
DSHC		Sug	J, D, N	1420 (262)	42 (205)	0.17	[35]
		Mol[xi]	J, D, N	1420 (153)	42 (169-174)[vii]	0.09	
Sugar extraction[xii]		FR	Sug	2000 (454)	69 (337)	0.52	[123,124]
		WS	Sug	2000 (417)	69 (337)	0.48	
HEFA[30,128]	Ecofining & Neste process[xiii]	UCO	J, D, N, LPG, P	2500 (1042)	133 (657)	0.83	

i. BL = Black liquor, hog fuel and forestry residues, BP = Beet pulp, EtOH = Ethanol, FR = Forestry residues, Mol = A-molasses, Sug = C5 and C6 sugars, UCO = Used cooking oil, WS = Wheat straw.
ii. D = Diesel, EtOH = Ethanol, G = gasoline, J = jet fuel, LPG = Liquefied Petroleum Gas, N = Naphtha, P = Propane.
iii. Unlike Table 2-1, the reference capacity is based on feedstock *input*.
iv. The TPEC was retrieved from the indicated reference; the TCI is calculated from the TPEC using the SCENT method.
v. The mass yield is defined as tonne product output (i.e. jet fuel, diesel, gasoline, naphtha, LPG and/or propane) per tonne dry feedstock input.
vi. The yields of hydrocarbon products were adjusted on the basis of the lower heating value (LHV) of the feedstocks with respect to the feedstock used in the source. See S2.8 for feedstock characteristics.
vii. The range in TCI for retro-fit strategies is caused by the variation in construction labor costs in the country of production. In addition, the TCI was calculated using a lower Lang factor because these are retro-fit strategies and therefore have a reduction in capital cost, see also section 2.2.5.
viii. The yield to FT liquids (0.13 t t^{-1} (dm)) was based on Consonni et al. (2009). It was assumed that the produced FT liquids were upgraded in an existing refinery, yielding 0.62 tonne diesel and 0.22 tonne gasoline per tonne of FT liquids.[131] The 2014 average of the NW European 2:1:1 crack spread (0.053 € L^{-1} crude oil) was taken as a measure of the refiner's profit margin for upgrading the FT liquid in an existing refinery.[133]
ix. The TPEC was retrieved from Atsonios et al.[36] The yields were taken from Crawford[121] due to limited data disclosure in Atsonios et al. Hydrogen requirements were based on Pham et al.[81]
x. TPEC were obtained from Humbird et al.[123] As beet pulp has a low lignin content, no boiler was installed and a lower sulfuric acid loading to break the lignin was assumed.[134] Feedstock-specific sugar and ethanol yields were calculated based on the glucan, xylan, arabinan, galactan and mannan content of forestry residues, straw and beet pulp. See the S2.8 for feedstock characteristics. Conversion yields were based on the reported yields for dilute acid pretreatment of lignocellulosic feedstocks and beet pulp.[124,132] Moreover, feedstock-specific lignin contents were used as an approximation of electricity production from the burnable components.[135]
xi. It is assumed A molasses has a 55% sugar content.[35]
xii. Concentrations of produced ethanol and sugar solutions were adjusted to fit the input requirements of ATJ and DSHC conversion, also accounting for increased gas usage as a result of additional concentration activities.
xiii. The FCI was based on the Rotterdam Neste facility.[128] Although hydrocarbon yields of the Ecofining and Neste process are quite similar, Pearlson et al.'s study (using the Ecofining process) was selected due to data disclosure.[30,126] For the HEFA pathway, it was assumed that the Soybean oil used in Pearlson et al. has similar LHV, product yields and hydrogen input requirements as filtered, de-watered used cooking oil.

targeted output of the model. Labor costs were determined using Wessel's method for well-instrumented processes.[137] Average EU prices for electricity, natural gas prices, operating and construction labor were retrieved from Eurostat.[138–141]

TABLE 2-5: Assumed feedstock prices for greenfield strategies.

	Value used in this study	**Range[i]**	**Comments**
Unit	**€ GJ^{-1} (€ t^{-1} (dm))**	**€ GJ^{-1} (€ t^{-1} (dm))**	
Forestry residues[142,143]	4.8 (95)	3.6-6.1 (70-120)	Including handling and transport
Wheat straw[142,143]	10.6 (190)	7.9-12.3 (142-222)	
Used cooking oil[144]	20.3 (730)	15.9-31.8 (573-1146)	Delivered NWE

i. The ranges are based on reported ranges for forestry residues[142], and historic price variations for wheat straw[145] and used cooking oil (historic palm oil trends were used as a proxy)[146] in the period 2010-2014. Please note these are European averages; national or local prices can be higher or lower than the reported range. National prices for forestry residues and wheat straw were taken for assessing the co-production scenarios (section 2.2.5).

2.2.3.4 Economic evaluation

A discounted cash flow rate of return (DCFROR) was used to determine for each conversion pathway the minimum fuel selling price (MFSP) of RJF and other hydrocarbon products, i.e. diesel, gasoline, naphtha, LPG and propane. The MFSP reflects the cost price at which the products need to be sold to achieve a zero equity net present value (NPV) (see S2.4). The costs of production were proportionally allocated to the outputs based on their market price per tonne (Table 2-6).[e] This approach was chosen to facilitate a fair comparison of the conversion pathways with high and low RJF yields (relative to other hydrocarbon products).

TABLE 2-6: Market prices of fuel products (2014).

Product	Price (€ t^{-1})	Comments
Jet fuel[147]	480	CIF NWE December 2014
Diesel[147]	446	
Gasoline[147]	420	
Naphtha[147]	363	
LPG/Propane[148]	288	

2.2.4 Pioneer Plant analysis

The reference studies report production costs for n^{th} plants, presuming a commercial scale facility using commercially available technologies, and thus bearing lower risk. However, n^{th} plant estimates have historically tended to underestimate capital cost and overestimate plant performance as compared to pioneer (i.e. first-of-a-kind) industrial facilities.[83,84] As the first commercial plants are still to be built for almost all conversion pathways (except HEFA), a pioneer plant estimate seems more appropriate to assess the *current* economic feasibility of RJF production pathways.

In 1981 the RAND corporation performed a multi-factor linear regression analysis on 44 production plants to identify key drivers for capital investment growth and decreased plant performance during the second six months after production start-up.[84] They formulated two equations to describe the cost growth and the plant performance of a pioneer plant as a function of certain process features (e.g. the number of commercially unproven process areas, the complexity of the process; see S2.5). Although there is little recent empirical evidence to validate the RAND method, it continues to be used in techno-economic assessments for a range of novel biofuel production technologies.[108,112,122,149] Fulton et al. found that some recently commissioned cellulosic ethanol and pyrolysis plants followed the predictions of the RAND study, showing a

e The MFSP for other products than RJF can be calculated from the MFSP of RJF using the ratio between the market prices as displayed in Table 2-6. E.g. a RJF MFSP of 480 € t^{-1} implies a diesel MFSP of 446 € t^{-1}.

higher capital investment and lower availability during operation start-up.[83] Also, plant availability in the first year of early Integrated Gasification Combined Cycle (IGCC) plants has been shown to be particularly low, ranging from 0-40% in the first year to 30-60% in the third year after formal commissioning.[150]

The RAND method was employed in this analysis to estimate the increase in MFSP for pioneer plants. It must be stressed that these estimates do not necessarily reflect the actual cost of a pioneer plant; rather they quantify the technology risk and the associated potential cost increase because of unforeseen problems in the start-up phase. The calculated cost growth factor and plant performance in the first year of production for the technologies in scope are displayed in Table 2-7. It was assumed plant availability ramps up by 20 percentage points per year in subsequent years until full nameplate capacity is reached.[112,149] The total capital investment (TCI) for the pioneer plant was calculated using the following equation:

$$TCI_{Pioneer} = \frac{TCI_{Nth}}{Cost\ \ growth\ factor}$$

TABLE 2-7: Cost growth factors and plant performance for pioneer plants (see S2.5).

Technology	FT		HTL	Pyrolysis	DSHC[i]		ATJ	HEFA
Feedstock[ii]	WS/FR	BL	WS/FR	WS/FR	Mol	WS/FR	EtOH	UCO
Cost growth factor	0.45	0.47	0.40	0.37	0.73	0.58	0.42	0.86
Plant availability year 1[iii]	32%	22%	22%	22%	78%	31%	21%	86%

i. The assessment for DSHC was made separately for molasses and cellulosic sugar as the latter requires additional pre-treatment technology.

ii. BL = Black liquor, hog fuel and forestry residues, EtOH = Ethanol, FR = Forestry residues, Mol = A Molasses, UCO = Used cooking oil, WS = Wheat straw.

iii. The techno-economic model runs with timesteps of one year. It was therefore assumed that the plant availability in the first six months after start-up is equal to the availability in the second six months.

2.2.5 Assessing co-production strategies

Two aspects were added to greenfield calculations in the base model to evaluate co-production strategies at the location of incubator facilities: local parameters and the quantified benefits of co-production (Figure 2-3). Since the difference in MFSP of greenfield (using EU averages) and co-production strategies (using local parameters) is affected by both aspects, a 'localized' greenfield facility was introduced to isolate the effect of co-production benefits. The fictional localized greenfield facility is situated next to an incubator facility but not integrated with it. It shares the incubator facility's local parameters, but does not experience the merits of co-production. As such, localized greenfield facilities also give an indication as to how production costs vary across the EU-28. The following sub-sections describe how local parameters and the benefits of co-production were incorporated in the greenfield model.

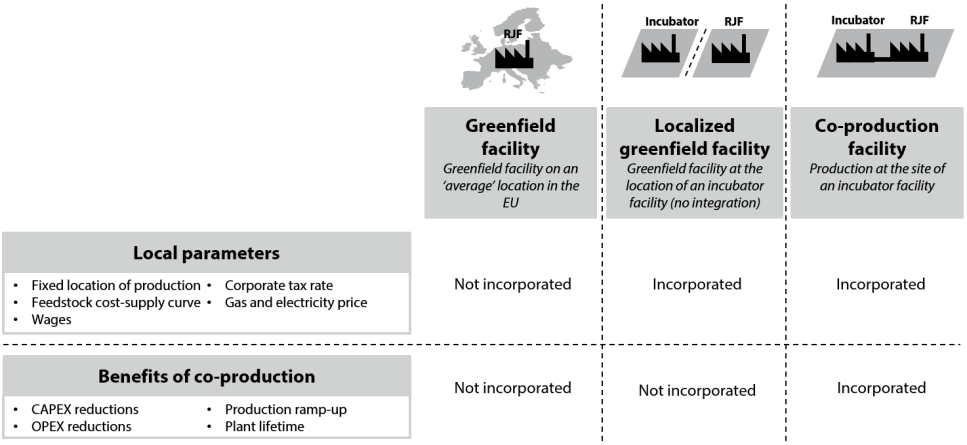


FIGURE 2-3: Comparison between the inputs of greenfield, 'localized' greenfield and co-production facilities.

2.2.5.1 Local parameters

Co-production strategies were evaluated at potential incubator facilities in the pulp and paper, wheat ethanol and beet sugar industries. A detailed survey identified 290 potential incubator facilities in the EU-28: 150 pulp mills, 40 wheat ethanol facilities and 100 beet sugar mills.[151–153] At each incubator facility, cost supply curves for forestry residues and wheat straw at NUTS-3 (i.e. sub-regional) level were constructed based on local feedstock prices and transport costs (Table 2-8).[142,143] Nation-specific hourly wages for construction and industrial labor, corporate tax rates and gas and electricity prices were used.[102,130,138–141]

TABLE 2-8: Assumed feedstock prices for co-production strategies (see S2.6).

Feedstock	Value	Unit
Forestry residues	Local cost-supply curve (see S2.6)	
Wheat straw	Local cost-supply curve (see S2.6)	
Black liquor	34.3	€ t^{-1} (80% solids content)[114]
Hog fuel	28.3	€ t^{-1} (50% moisture content)[114]
Beet pulp	16.3	€ t^{-1} (22% dry matter)[154]
A-molasses	144	€ t^{-1} (55% sucrose content)[35]

2.2.5.2 Quantifying the economic merits of co-production – a novel approach

Co-production strategies aid producers in gaining experience in the handling and conversion of cellulosic feedstocks whilst benefiting from shared supply chain

infrastructure, distribution networks, chemical and energy recovery facilities and an experienced existing workforce – thus reducing costs and investment risks. General methodologies to quantify these benefits could not be identified in the literature; most studies either qualitatively describe the benefits or quantify these by performing process optimization for specific processes or locations.[155–161] Based on such studies, the benefits of co-production were generalized, quantified, and added to the greenfield model. Depending on the degree of integration, several parameters were adjusted in the greenfield calculations to account for co-production benefits (Table 2-9).

Capital expenditure factors for buildings, service facilities, land and yard works were decreased because these are usually available at an existing site.[85,91,102,159,162] The contingency on a repurposed plant was lowered because the existing production line likely consists of units that have proven robustness.[85]

For repurposing scenarios, the bare equipment cost items to be excluded from the TPEC should be assessed on a case-by-case basis.[85] Furthermore, remuneration to the (former) owner of the facility should be included for repurposing or retro-fitting strategies, preferably using the book value of the piece of equipment (the initial cost of the asset minus the accrued depreciation). For repurposing strategies, the residual value should be compared to the costs of dismantling the facility and environmental remediation costs. For simplicity, these costs are often assumed to be equal, such that the costs of repurposed assets amount to zero.[85,101] In this study, it was assumed that retro-fitted equipment has been fully depreciated and that the shutdown of the incubator facility for retro-fitting can take place during its usual maintenance cycle.[f]

It was assumed that labor costs are reduced because the work force can be shared between facilities.[91,98] Also local property taxes were reduced based on the assumption that (part of) the land is shared. The production ramp-up for greenfield and co-located factories was defined according to Towler & Sinnott; ramp-up values for the repurposing and retro-fitting scenarios were taken from Gonzalez et al.[85,105]

In case of repurposing or replacing existing equipment, the plant lifetime depends on the remaining lifetime of the repurposed equipment or the lifetime of the retro-fitted incubator facility. In this study it was assumed that all incubator facilities will continue to operate for at least 25 years.

f A first approximation of the remuneration costs for a 10-year old Tomlinson boiler, assuming initial capital cost of 91-182 M_{2013}[114] and a useful economic lifetime of 25 years, showed an increase of roughly 30% in the MFSP for Black Liquor Gasification. It is therefore plausible to assume that implementing retro-fitting and repurposing strategies will only be worthwhile at the end of the equipment's lifetime.

TABLE 2-9: Quantified benefits of co-production for all three degrees of integration with respect to greenfield projects.

	Unit	Repurposing	Retro-fitting	Co-locating	Greenfield[i]
Capital expenditures					
Buildings	% of TPEC	7%	7%	29%	47%
Service facilities	% of TDEC[ii]	0%	45%	45%	55%
Land[iii]	% of TDEC[ii]	0%	0%	6%	6%
Yard works	% of TDEC[ii]	0%	0%	12%	12%
Contingency	% of TDEC[ii]	10%	37%	37%	37%
TPEC		New + repurposed equipment	New + retro-fitted equipment	Only new equipment	Only new equipment
OPEX reductions					
Operating labor cost[iv]	% reduction w.r.t. greenfield	0%	41%	41%	0%
Local taxes	% of Fixed Capital Investment	1.5%	0%	1%	1.5%
Production ramp-up					
Production year 1	% of nominal capacity	50%	50%	30%	30%
Production year 2	% of nominal capacity	80%	80%	70%	70%
Production year 3	% of nominal capacity	100%	100%	100%	100%
Plant lifetime					
Plant lifetime		Residual lifetime of repurposed asset	Residual lifetime of the incubator facility	New equipment lifetime	New equipment lifetime

i. The greenfield values for capital expenditures and OPEX are based on the SCENT model
ii. Total delivered equipment cost (TDEC) represents TPEC including delivery charges.
iii. It is assumed that the co-located facility requires about two-thirds of the land of the incubator facility. It is assumed that retro-fitted equipment is bolted-on to the incubator facility and therefore does not require additional land.
iv. The reduction of 41% is based on the reduction in labor costs per processing step according to Wessel's method[137] when comparing two separate facilities to one joint facility. It was assumed that the incubator facility's capacity is twice that of the co-located facility.

2.3 Results

2.3.1 Nth plant greenfield production results

Figure 2-4 illustrates a cost breakdown for greenfield n^{th} plants. The costs are subdivided in feedstock, capital expenditures (CAPEX; including debt principle payments and interest), maintenance and repairs, other OPEX (including amongst others corporate taxes, labor costs, fixed production costs), utilities and raw materials, and non-hydrocarbon co-products (e.g. electricity).

The results show a clear preference towards HTL, pyrolysis and HEFA, which yield minimum fuel selling prices of 21-29, 29-41 and 30 € GJ^{-1}. None of the nth plant MFSPs reaches the top tenth percentile of petroleum-derived jet prices over the last decade. The low MFSP for HTL and pyrolysis is caused by relatively high conversion yields and modest TPEC. Pyrolysis has a slightly higher MFSP compared to HTL because of its increased TPEC due to higher bio-crude upgrading requirements and a lower yield. HEFA performs well due to an exceptionally high yield since only few chemical transformations are required to convert oil feedstocks to RJF. Biochemical pathways (i.e. ATJ and DSHC) show relatively higher MFSPs, largely due to the lower conversion yields (on a dry matter basis) and the high capital cost of lignocellulosic sugar extraction and fermentation. Forestry residues are generally preferred over wheat straw due to their lower price.

Based on Figure 2-4, the conversion pathways can be roughly characterized according to their determining cost components: i) capital expenditures, ii) feedstock and iii) OPEX. FT and ATJ are the most capital-intensive conversion technologies (in terms of TPEC per tonne RJF produced). The gasification unit is the major cost component for FT, while the pre-treatment, hydrolysis and fermentation units represent the greater share of the costs for ATJ. The same holds for sugar extraction units in the DSHC pathway. Figure 2-4 shows that feedstock costs comprise 70% of the MFSP for HEFA. As such, the performance of the HEFA pathway is very dependent on the economics of sustainable oils and fats. Pyrolysis and HTL have high shares of OPEX due to their relatively high requirements for utilities and raw materials, predominantly caused by the cost of natural gas for hydrogen production in the upgrading process. Furthermore, the bio-crude

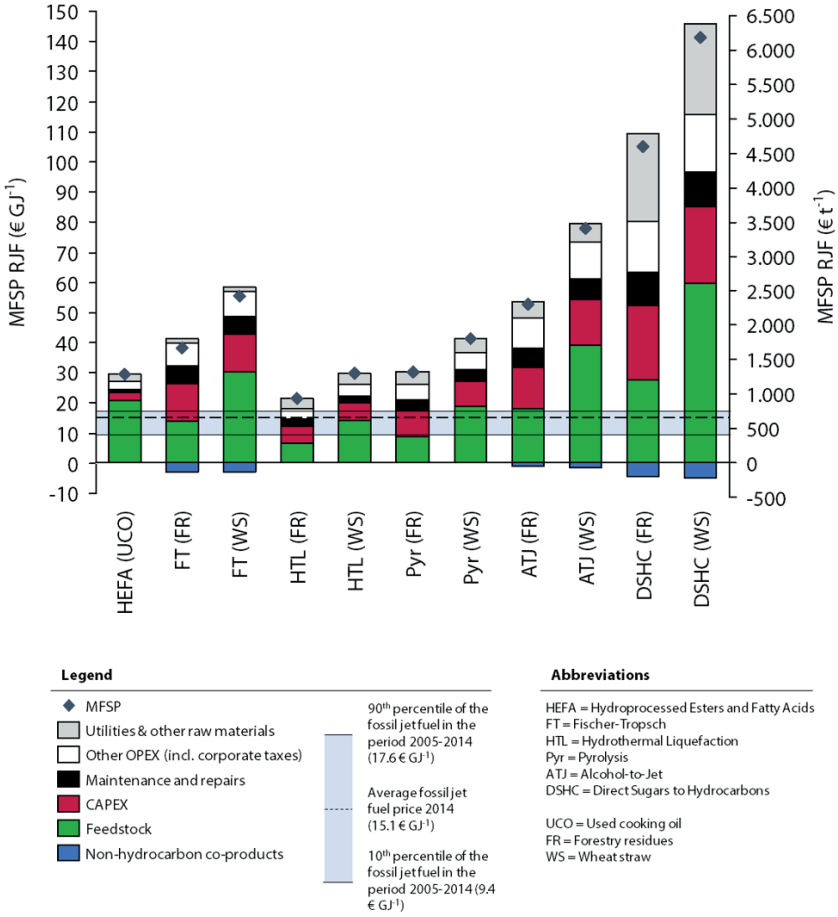


FIGURE 2-4: The cost breakdown of the MFSP for greenfield (n^{th} plant) production.

upgrading units require substantial capital investments. For DSHC the majority of the operational costs arise from natural gas (used for process heat for sugar concentration) and glucose used during the extraction of lignocellulosic sugars.

2.3.2 Pioneer plant production results

Figure 2-5 illustrates that pioneer plants show significantly higher MFSPs than n^{th} plants, both for greenfield and co-production strategies. A particularly high increase is shown by capital-intensive technologies such as FT (+57-82%) and ATJ (+64%-86%) and technologies with relatively high cost growth factors due to technological immaturity, such as HTL (+63-87%) and pyrolysis (+77-105%) or technological complexity such as BLG (+93%). The HEFA technology shows a mere 1% increase in MFSP as it has already

been employed at commercial scales. Hence, when looking at the current development status, HEFA shows the best economic performance. Although HTL and pyrolysis demonstrate considerable cost increases, they emerge as the best performing pathway in the short term.

2.3.3 Co-production results

Figure 2-5 shows that co-production strategies follow a similar trend to greenfield strategies. Due to the better performance of thermochemical pathways, pulp mills and wheat ethanol facilities prove better incubator facilities than beet sugar facilities. In addition, RJF production from beet pulp is the least economically attractive due to the limited production of beet pulp at the sugar facilities. Black liquor gasification (BLG) yields the best performance of all retro-fitting strategies, which is largely due to the relatively low price of the feedstocks used, particularly hog fuel and black liquor.
The spread between the bottom and upper MFSP (as indicated by the connector line in Figure 2-5) is caused by variation in local parameters, particularly wages and feedstock prices. MFSP variation due to feedstock prices is more profound for production involving straw, because large ranges in straw prices exist across Europe. Incubator facilities in regions such as Eastern EU and Portugal were found to have MFSPs up to 28% lower than the average MFSP, whilst MFSPs for incubator facilities located in Scandinavia showed an increase up to 39%. As the capacity of beet sugar mills varies significantly, the spread between the minimum and maximum MFSP is relatively large due to scaling effects.

Occasionally the average MFSP for co-production strategies exceeds the greenfield MFSP. This effect is ascribed to local parameters for some locations being less attractive than the average European conditions. For example, co-production strategies involving pulp mills (which are often located in Scandinavia – where labor costs are relatively high) tend to result in higher average MFSPs than greenfield production at an 'average' European location. Hence, although co-production *can* yield lower MFSPs at specific locations, it also limits the choice of location, which sometimes leads to higher production costs.

Co-locating strategies show an average reduction in MFSP of 4-8% for n^{th} plants and 5-8% for pioneer plants with respect to localized greenfield production (Figure 2-6). The reduction can largely be ascribed to a reduction of TCI and related costs (e.g. maintenance costs). Consequently, the most capital-intensive technologies (i.e. FT and ATJ) show the largest cost reductions. The reduction in MFSP for pioneer plants is on average 1.4% larger than for n^{th} plants, mainly because pioneer plants are generally more capital-intensive. In absolute terms this represents a considerable reduction, since MFSPs for pioneer plants tend to be substantially higher than those for n^{th} plants.

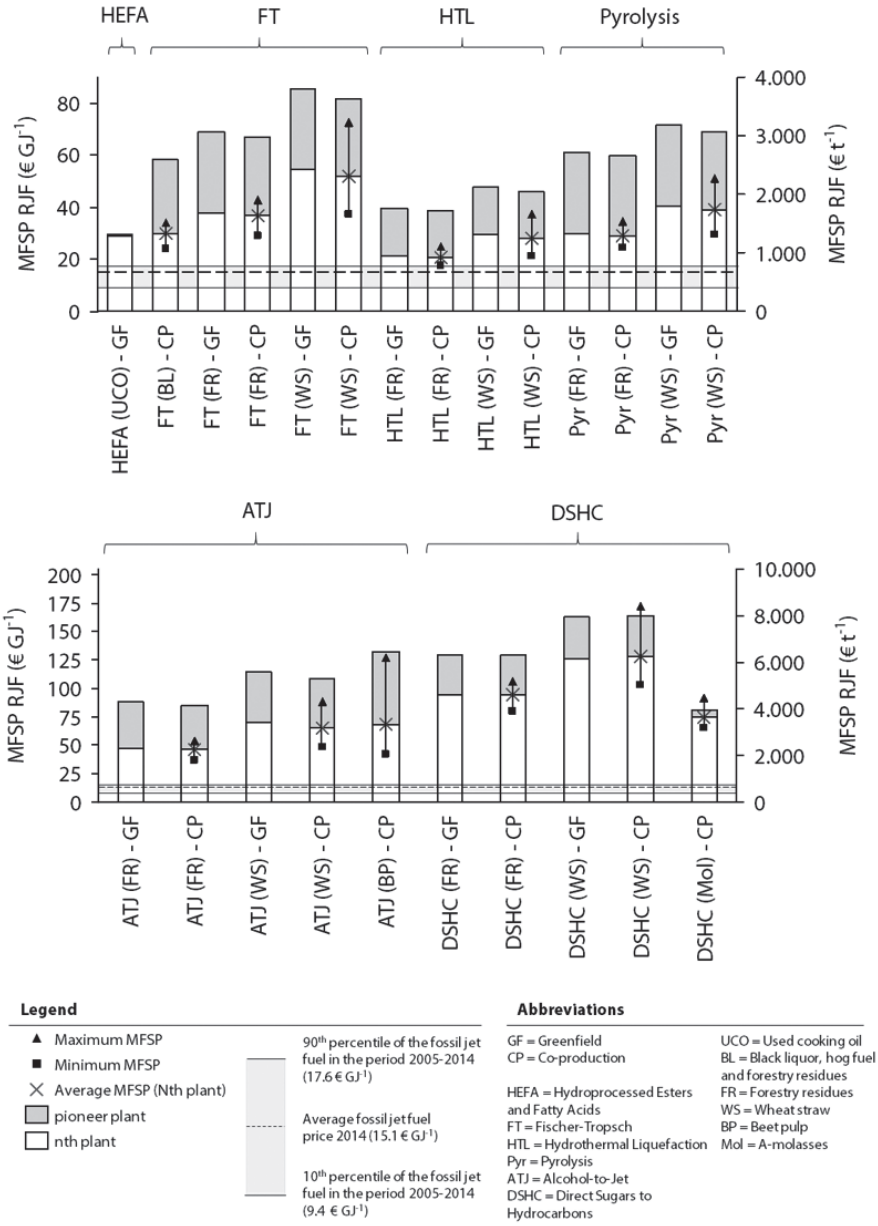


FIGURE 2-5: MFSP for all conversion pathways, both n^{th} plants and pioneer plants, greenfield and co-production. The markers indicate the spread between the minimum (square) and maximum (triangle) n^{th} plant MFSP for co-production strategies at different locations. Please note that the two vertical axes of the upper and lower panel are scaled differently.

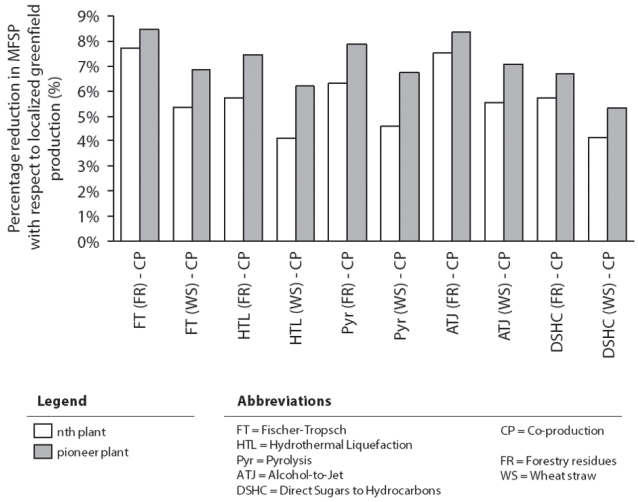


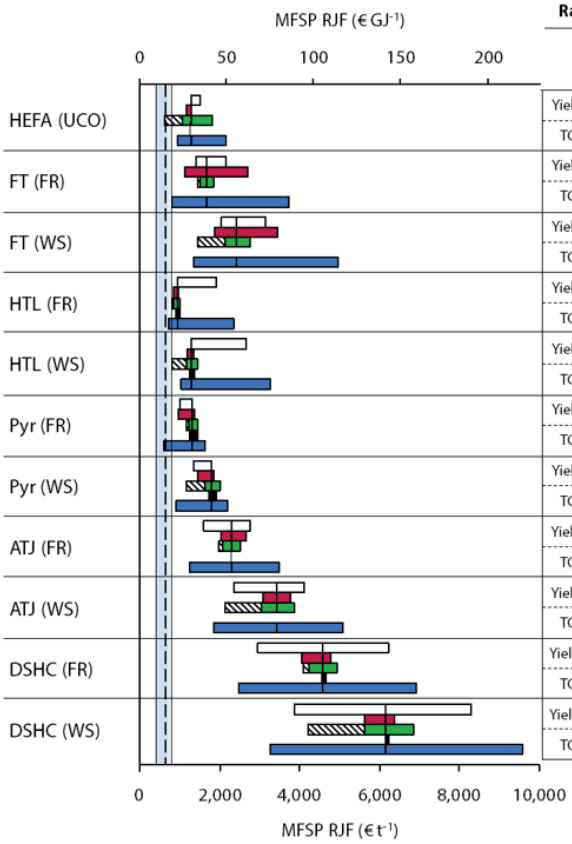
FIGURE 2-6: Reduction in MFSP of co-locating production with respect to localized greenfield production for n^{th} and pioneer plant, averaged over all production locations.

2.4 Sensitivity analysis

A sensitivity analysis was performed to examine the impact of selected inputs on the model results. Also, the opportunity costs of producing RJF (rather than biochemicals) for the ATJ and DSHC pathways were quantified. The base case is greenfield n^{th} plant production.

2.4.1 TCI, yield, feedstock price and hydrogen consumption

A sensitivity analysis was performed on the parameters TCI, yield, feedstock price and hydrogen consumption to quantify the variations and uncertainties in these parameters (section 2.2.2). Ranges for TCI and yield were determined based on lower and upper values identified in reference studies with comparable process designs (e.g. studies with ex-site hydrogen production or enzyme production were excluded), and the values used in the current study. Feedstock prices were varied across the ranges detailed in Table 2-5 and Figure 2-7. The 'future low' case for feedstock prices aims to show the impact of possible feedstock cost reductions in the medium term due to yield increases and learning effects. As such, it uses feedstock costs based on European cost-supply curves for dedicated wood, grass and oil crops in 2020, respectively.[163] It should be stressed that this case is based on production costs rather than prices (as in the base case), hence excluding profit margins and potential feedstock subsidies. As hydrogen is an important utility input for nearly all pathways (except FT), hydrogen consumption was varied between -25% and +50%. The ranges were inserted as single permutations to the base model. Simultaneous permutation of optimistic or pessimistic values in all four parameters is indicated by 'All' (hence the 'future low' case is not included in 'All').



Ranges (Yield and TCI)

	Optimistic	Base	Pessimistic
HEFA (UCO) Yield (t t^{-1})[i]	0.89	0.89	0.75[35]
HEFA (UCO) TCI (M€)	309[30]	657	657
FT (FR) Yield (t t^{-1})[i]	0.19[110]	0.17	0.13[108]
FT (FR) TCI (M€)	221[111]	518	941[109]
FT (WS) Yield (t t^{-1})[i]	0.19[110]	0.16	0.12[108]
FT (WS) TCI (M€)	221[111]	518	941[109]
HTL (FR) Yield (t t^{-1})[i]	0.36	0.36	0.17[116]
HTL (FR) TCI (M€)	338[107]	480	480
HTL (WS) Yield (t t^{-1})[i]	0.33	0.33	0.16[116]
HTL (WS) TCI (M€)	338[107]	480	480
Pyr (FR) Yield (t t^{-1})[i]	0.36[117]	0.27	0.27
Pyr (FR) TCI (M€)	246[117]	555	555
Pyr (WS) Yield (t t^{-1})[i]	0.33[117]	0.25	0.25
Pyr (WS) TCI (M€)	246[117]	555	55
ATJ (FR) Yield (t t^{-1})[ii]	0.34[122]/0.58	0.24/0.56	0.21[122]/0.53
ATJ (FR) TCI (M€)	254[125]/50[36]	385/113	416[124]/113
ATJ (WS) Yield (t t^{-1})[ii]	0.34[122]/0.58	0.24/0.56	0.21[122]/0.53
ATJ (WS) TCI (M€)	254[125]/47[36]	402/109	416[124]/109
DSHC (FR) Yield (t t^{-1})[iii]	0.61[123]/0.30	0.52/0.20	0.52/0.15
DSHC (FR) TCI (M€)	287[123]/188[35]	487/225	487/225
DSHC (WS) Yield (t t^{-1})[iii]	0.57[123]/0.30	0.48/0.20	0.48/0.15
DSHC (WS) TCI (M€)	287[123]/188[35]	487/225	487/225

Legend

- Yield
- TCI
- Future low
- Feedstock
- Hydrogen
- All

Top ten percentile of the fossil jet fuel in the period 2005-2014 (17.6 € GJ^{-1})

Average fossil jet fuel price 2014 (15.1 € GJ^{-1})

Bottom ten percentile of the fossil jet fuel in the period 2005-2014 (9.1 € GJ^{-1})

Abbreviations

HEFA = Hydroprocessed Esters and Fatty Acids
FT = Fischer-Tropsch
HTL = Hydrothermal Liquefaction
Pyr = Pyrolysis
ATJ = Alcohol-to-Jet
DSHC = Direct Sugars to Hydrocarbons

UCO = Used cooking oil
FR = Forestry residues
WS = Wheat straw

Ranges

Feedstock price	Future low	Opti-mistic	Base	Pessi-mistic
FR (€ GJ^{-1})	2.5[163]	3.6	4.8	6.1
WS (€ GJ^{-1})	3.5[163]	7.9	10.6	12.3
UCO (€ GJ^{-1})	6[163]	15.9	20.3	31.8

Hydrogen consumption[iv]	Optimistic	Pessimistic
Hydrogen consumption (t H_2 t^{-1} feed)	-25%	+50%

Tablenotes

i. The yield of FT, HTL and pyrolysis varies for forestry residues and straw due to calculation of the yield based on feedstock LHV.
ii. The TCI and yield are reported for the ethanol fermentation and ATJ unit respectively. Due to the absence of multiple references for the ATJ yield, a range of ±5% was assumed. The ATJ unit scales with the ethanol output of the fermentation unit and is thus connected to fermentation yield.
iii. The TCI and yield are reported for the sugar extraction and DSHC unit respectively. Due to the absence of multiple references for DSHC yield, the range was based on theoretical yield (0.30 t t^{-1}) and 50% of the theoretical yield.[164]
iv. The variation in hydrogen consumption is not applicable to FT.

FIGURE 2-7: A sensitivity analysis on greenfield nth plant production.

Figure 2-7 shows the result of the sensitivity analysis. HEFA is most sensitive to shocks in feedstock price. Considerable variation in MFSP was also observed for FT, ATJ and DSHC. Whereas ranges in TCI estimates predominantly cause the MFSP variation for FT (and to a lesser extent pyrolysis), ranges in yield estimates dominate for HTL, ATJ and DSHC. For FT the range originates from diverging literature estimates; the range for ATJ and DSHC can be ascribed to the wide ranges for yield estimates as a result of limited research available. The impact of variation in hydrogen consumption is particularly prominent for HTL and pyrolysis, but relatively marginal compared to feedstock price, TCI and yield variations.

The sensitivity analysis nuances the base case results; although the ranges of HEFA, HTL and pyrolysis are found on the lower side of the spectrum, the lower bound MFSPs of DSHC and ATJ fall within the uncertainty range of the other pathways. Whereas base results for HTL appear relatively optimistic, base results from pyrolysis are relatively pessimistic. In fact, using optimistic assumptions pyrolysis yields a lower MFSP than HTL and touches the average petroleum-derived jet fuel price in 2014. It is, however, questionable whether these low MFSPs for pyrolysis are feasible given that cost estimates have risen with improved knowledge in recent years.[107,112,117–120] In addition, the 'future low' scenario shows that reduction in feedstock price can have a substantial impact on the economic viability of RJF conversion pathways; the HEFA technology would even reach fossil jet fuel prices when oil based feedstocks become available at lower prices.

2.4.2 Opportunity cost involved with the ATJ and DSHC pathway

Although the airline sector provides a huge potential market for biofuel producers, RJF is a rather unattractive product in terms of selling price when compared to chemicals. The trade-off between these markets is especially significant for the ATJ and DSHC pathway which produce high-valued intermediates. Amyris, industry leader in the DSHC pathway, produces a wide range of isoprenoids, which can be used for the production of cosmetics, flavors, fragrances, lubricants and biopharmaceuticals. One of these isoprenoids, farnesene (5465 € t^{-1}) can also be upgraded to RJF.[165] The ATJ pathway utilizes either ethanol (599 € t^{-1}) or butanol (which has an even higher selling price), as a precursor for RJF.[166]

The opportunity costs of producing RJF are quantified by the NPV which can be used to compare two investment decisions. Figure 2-8 shows that a higher NPV is achieved when selling the intermediate products, leading to considerable opportunity costs, especially for DSHC. It is possible that market price for farnesene will decline in the future as DSHC technology players scale up their production, thereby also saturating

the relatively small alternative markets they target. However, it seems unlikely that DSHC and ATJ can make a sensible business case for dedicated RJF production at current production volumes and market prices. Joint production of biochemicals and biofuels in a biorefinery, however, is more robust to market volatilities as they can serve both the chemical and fuel market.[167] Moreover, such biorefinery concept can stimulate RJF development by enabling producers to gain experience with RJF production while enjoying the higher profit margins of biochemicals.

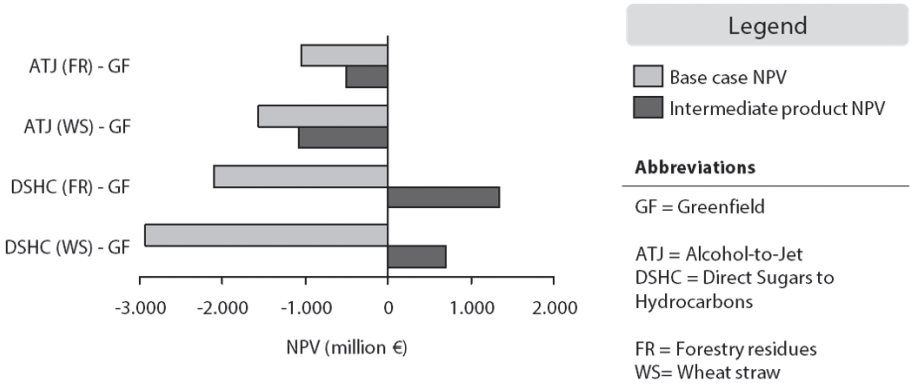


FIGURE 2-8: A comparison of the equity NPV of RJF (base case) and ethanol and farnesene (intermediate product NPV) for ATJ and DSHC. The NPV was calculated using market prices for the hydrocarbon products (based on their petroleum-derived counterparts, Table 2-6), ethanol (599 € t^{-1} (22 € GJ^{-1})) and farnesene (5465 € t^{-1}).

2.5 Discussion

The harmonized techno-economic framework allows for a fair comparison of the conversion technologies and is, as such, useful to reveal certain trends amongst the conversion pathways, identify their major cost components, and facilitate a well-informed decision about directing support or research efforts to promising conversion pathways.[102,123] However, the results should be interpreted as ranges rather than points, given the large uncertainties in feedstock prices, TCI and yield estimates in current literature that perpetuate in the model results. Taking these ranges into account, a cost preference was found for HEFA, HTL and pyrolysis out of the six conversion pathways assessed.

2.5.1 Comparison with existing literature

2.5.1.1 Greenfield production

Although the general sequence of the six conversion pathways investigated in this study is roughly similar to cost ranges in techno-economic performance found in literature, Table 2-10 shows that this study yields generally higher results than other studies, especially for Pyrolysis, ATJ and HTL. Some variation originates from different feedstock choices, process configurations and economic evaluation methods. However, the major discrepancies can be ascribed to the higher feedstock prices used in this study, especially compared to US-focused studies. This underlines the fact that feedstock prices are highly dependent on region. Most references included in the literature survey assume lignocellulosic feedstock prices ranging from 1.7-3.8 € GJ^{-1}.[36,107,108,111,112,116–121] For oil feedstocks, prices of 14-18 € GJ^{-1} were reported.[30,33] This study uses feedstock prices found for the current European context, with an average price of 4.8, 10.6 and 20.3 € GJ^{-1} for forestry residues, straw and used cooking oil respectively. Furthermore, the timeframe is important as more lower-cost sustainable feedstocks might come available in the future due to cost decreases resulting from large scale cultivation, learning effects and yield increases.[24,163,168–171] The sensitivity analysis confirms that lower feedstock prices can have a substantial impact on the MFSP, albeit not so much on the relative performance of technologies.

As shown in the sensitivity analysis, the TCI estimates used in this study are relatively conservative for pyrolysis, ATJ and sugar extraction. For pyrolysis this is due to the reference study of Jones et al. being on the high end of the TCI range. For ATJ and sugar extraction this is because of the higher Lang factor employed in the SCENT cost estimation method with respect to the reference study.[120] The SCENT method also prescribes high maintenance (6% of FCI) and fixed cost factors relative to other studies.

This comparative analysis, as well as the sensitivity analysis presented in section 2.4, underlines the uncertainty inherent to forward-looking techno-economic analyses. Transparent comparison of the results with other studies is a delicate exercise due to different economic evaluation methods, base years, capacities and input assumptions. Convergence of cost ranges is expected when assumptions can be validated with commercial plant performance data. Nonetheless, the literature is relatively consistent about the overall order of the investigated conversion pathways in terms of economic performance.

TABLE 2-10: A comparison of the study results with reported production cost ranges.

	Production cost ranges ($€_{2013}$ GJ^{-1})			
	This study[i]	**Literature survey**	**IEA[172]**	**IPCC-SRREN[ii, 24]**
Timeframe	n^{th} plant	n^{th} plant or unspecified	10th plant	2020-2030
HEFA	29	20-28[30,33]	28	13-27
FT	38-55	18-42[36,80,107–113]	35	14-27
HTL	21-29	15-16[107,116]	-	13-22
Pyrolysis	30-41	13-20[107,112,117–120]	-	13-22
ATJ	52-78	24-37[36,121]	-	-
DSHC	104-140	95[35]	-	-

i. These values are based on greenfield n^{th} plant results. Lower and upper values for all pathways except HEFA were based on forestry residues and straw, respectively.

ii. The IPCC-SRREN values are based on reported ranges for 'oil plant-based, pyrolysis-based and FT diesel or jet fuel'.

2.5.1.2 Co-production

Compared to reported reductions in MFSP resulting from co-production strategies, the methodology proposed here appears to provide a conservative estimate of potential process integration as it excludes the integration of material flows and specific process units. Jones et al. calculated a decrease of 15% in MFSP for co-locating a pyrolysis plant with a refinery, thereby leveraging existing hydrogen production and hydrocracking capacity and exchanging off-gases.[117] Purchasing hydrogen or enzymes from (co-located) ex-site sources in case of pyrolysis, HTL, sugar extraction and ethanol fermentation decrease the TCI and thus investment risk, but increases OPEX. Model calculations show ex-site purchase is favored when the hydrogen price is below 1.00-1.65 $€_{2013}$ kg^{-1} (for pyrolysis and HTL respectively) and the enzyme price is below 7.36 $€_{2013}$ kg^{-1}.[g] Ou et al. analyzed the benefits of co-locating first and second generation ethanol production plants.[161] Their results show a decrease of 44% in overall ethanol MFSP can be achieved compared to a stand-alone second generation ethanol plant because of sharing electricity and steam generation units. Also, the Italian refiner Eni reports a 80% reduction in TCI for their renewable diesel facility in Venice due to utilization of existing assets.[173] Including such TCI reduction in our model translates to an MFSP reduction of 14% for HEFA. In addition, other non-quantified merits of co-production can also accelerate the growth of novel technologies. For example, production adjacent to incubator facilities can benefit from reduced lead times due to fewer construction requirements, existing experience with biomass handling and existing links between the incubator facility and feedstock providers. The latter two factors can be particularly effective in alleviating key supply chain issues for novel technologies.[174]

g The break-even hydrogen purchase price is lower in case of pyrolysis relative to HTL as the process produces more off-gases which can be converted to hydrogen in an on-site steam reformer. It was assumed that these gases did not have economic value in a hydrogen purchase scenario.

2.5.2 The value of pioneer and nth plant analysis

The pioneer plant analysis estimates the *potential* cost increases for a first-of-a-kind commercial plant, as if it was built today. N^{th} plant results represent the (future) cost of a *currently known* technology after several commercial plants have been commissioned. However, n^{th} plant economics does not entail information about a timeframe nor a cumulative capacity required to come from a pioneer plant to an nth plant. An assessment of the technology or fuel readiness level can shed more light on the current technology status and its pace towards commercialization.[28] Furthermore, an nth plant analysis does not suffice to find the 'silver bullet' amongst conversion pathways; learning effects and technological breakthroughs can influence the development timeline and alter the merit order of the technologies over time.

2.5.3 Geographic location

The spatial analysis linked to the assessment of co-production strategies reveals lowered MFSPs for RJF production in Portugal and countries in Eastern Europe. Key differentials are labor cost and feedstock price. However, the geographical preference is likely to change when more country-specific parameters are added, such as discount rates as a proxy for investment risks or the possibility of (extra-EU) feedstock imports by ship. Moreover, the optimal production locations for RJF are not determined by MFSP only; other factors such as existing infrastructure, the interest of local airlines and the political climate can be of equal importance for the development of a RJF supply chain. A comprehensive multi-criteria analysis incorporating these factors could give a more complete answer.

2.6 Conclusion

This paper assesses the short-term economic feasibility of RJF production, calculating the MFSP for conversion pathways expected to be ASTM certified for use in aviation before 2020. This assessment can facilitate a development strategy for the short term, especially since production costs are of key importance for large scale adoption of RJF.

From an economic perspective, this analysis shows HEFA is the best short-term option with HTL and pyrolysis as the most feasible alternatives. However, none of the conversion pathways are expected to reach price parity with petroleum-derived jet fuel in the short term. The sensitivity analysis shows that large uncertainty ranges still exist in the economic performance of RJF pathways due to the nascent nature of the technologies and/or large variation in feedstock prices. Convergence of cost ranges is expected when the industry matures and assumptions can be validated with commercial plant performance data. In general, co-production can reduce the MFSP

with 4-8% for n^{th} plants and 5-8% for pioneer plants. Leveraging site- and technology-specific integration options have been reported to further reduce the MFSP.

Although HEFA, HTL and pyrolysis have emerged as best performing technologies in the short term, they are not necessarily the 'silver bullet' in the long term. Given the status of the technology, the HEFA pathway is expected be the primary accelerator for global RJF uptake in the coming years. However, 'locking-in' to this technology may not be desirable given the limited availability of sustainable oil feedstocks and the fierce competition with mandated and incentivized road fuel sectors in the EU and US. Moreover, a price premium for HEFA is likely to remain as long as oil feedstock prices stay close to the price of petroleum-derived jet fuel. The commercial performance of HTL and pyrolysis is still uncertain as a result of a lack of empirical validation.

Production costs will need to be reduced to fall within the range of petroleum-derived jet fuel prices of the last decade. In the long term, learning effects, economies of scale, technological breakthroughs, biomass price dynamics, and changing policy landscapes can have a decisive impact on the economic performance and merit order of conversion pathways for RJF production. It is of cardinal importance to start gaining experience across the entire supply chain in the short term in order to reach price parity in the long term. Bridging the valley of death of technologies in their pioneer status requires significant RD&D efforts and stable policy support in the form of grants, loan guarantees, biofuel mandates or significant carbon prices. The results of this study can provide direction to industry, research and policy efforts on the short term. However, a comprehensive long-term strategic roadmap requires more insight in the future learning potential as well as the current and future sustainability performance of RJF production pathways. The development of current and emerging technologies as well as biorefinery concepts (producing RJF alongside products for other markets such as biochemicals) should be fostered. Furthermore, optimization of feedstock logistics, yield improvements, large-scale cultivation (without jeopardizing food supply) and the commercialization of new sustainable feedstock types can boost cost reductions of RJF production in the longer term. Lastly, co-production strategies, transitional technologies (e.g. co-gasification of coal and biomass) or strategies involving existing infrastructure (e.g. co-processing oil feedstocks or bio-crude in existing refineries) should be explored further and leveraged. The aforementioned advancements will not be driven by developments in the RJF sector alone; an integral approach towards bioenergy is required to take the necessary incremental steps towards a sustainable bioeconomy.

S2. Supplementary Information

S2.1 Capital Cost Build-up

This study follows the cost element structure as proposed by Ereev and Patel (2012) in their Standardized Cost Estimation for New Technologies (SCENT). Ereev and Patel (2012) distinguish the production costs in two categories, being (semi-) variable costs and fixed cost. Variable costs are fully or partially proportional to the facility's load factor; fixed costs are independent of the load factor. Both categories consist of multiple individual cost components (see figure below).

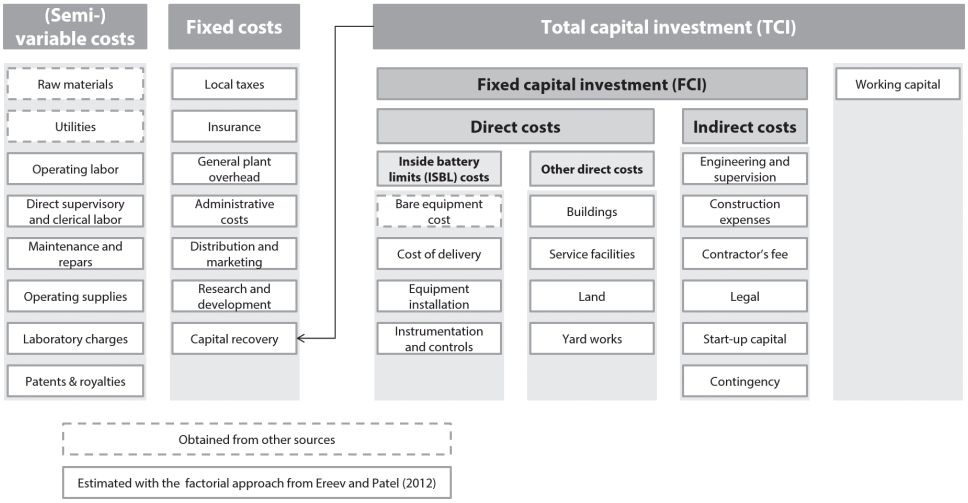


FIGURE 2-9: Cost components according to Ereev & Patel[102].

The table below lists the total capital investment (TCI) build-up for greenfield facilities assuming a solid-fluid plant, adapted from Ereev & Patel[102].

TABLE 2-11: Capital cost components build-up.

Capital cost components build-up	Value	Unit
Direct cost		
Bare equipment cost	100%	
Total purchased equipment cost (TPEC)	**100%**	
Delivery	10%	% of TPEC
Total delivered equipment cost (TDEC)	**110%**	Relative to TPEC

Equipment installation	39%[i]	% of TPEC
Instrumentation and controls	26%	% of TDEC
Buildings	47%	% of TPEC
Service facilities	55%	% of TDEC
Indirect cost		
Engineering and supervision	32%	% of TDEC
Construction expenses	34%	% of TDEC
Contractor's fee	19%	% of TDEC
Legal	4%	% of TDEC
Contingency	37%	% of TDEC
Total direct and indirect cost (TDIC)	**424%**	Relative to TPEC
Start-up capital	6-10%[ii]	% of TDIC
Depreciable Capital Investment (DCI)	**449-466%**	Relative to TPEC
Land	6%	% of TDEC
Yard Works	12%	% of TDEC
Fixed Capital Investment (FCI) (Lang factor)	**469-486%**	Relative to TPEC
Working capital	5%[iii]	% of FCI
Total Capital Investment (TCI)	**492-510%**	Relative to TPEC

i. Computed from the average construction labor coefficient in the EU and a weighted average (based on equipment cost) of the material and labor installation factor as reported in SCENT. [102]

ii. 6% when the total purchased equipment cost (TPEC) is higher than 18 M€, 8% if TPEC is between 1.8 M€ and 18 M€, 10% if TDIC is lower than 1.8 M€.

iii. Here, a more common value of 5% is taken which deviates from the 20% as mentioned in SCENT.

Most operational expenditures (indicated by solid-lined boxes) are estimated using a factorial approach. The corresponding factors as well as a more detailed description of the respective cost components are given in the table below, based on average values for solid-fluid plants as documented in Ereev and Patel (2012). The cost components in the dashed boxes were estimated using data reported in previous techno-economic studies.

TABLE 2-12: Description of cost components.

Cost component	Description	Factor	Base
(Semi-) variable costs	Costs fully or partially proportional to the facility's load factor	Sum	
Raw materials	Feedstocks, catalysts, chemicals, etc.	Obtained from technology-specific sources	
Utilities	Fuel, process steam, heating or cooling fluids, electricity, process water, nitrogen, hydrogen, natural gas, instrument air, etc.	Obtained from technology-specific sources	
Operating labor	The total labor costs of all operating staff	Wessel's method	
Direct supervisory and clerical labor	Cost for supervising and clerical activities	15%	% of operating labor cost
Maintenance and repairs – labor[i]	Labor expenses necessary for maintenance and repairs	3%	% of Fixed Capital Investment (FCI)
Maintenance and repairs - materials	Material expenses necessary for maintenance and repairs	3%	% of Fixed Capital Investment (FCI)
Operating supplies	Lubricants, spare parts, lubricants, etc.	15%	% of total maintenance and repairs
Laboratory charges	Charges for laboratory tests	15%	% of operating labor cost
Patents and royalties	Royalties paid to the technology licenser	3.5%	% of (semi-) variable costs and fixed costs
Fixed costs	All costs independent of the load factor	Sum	
Local taxes	Property taxes paid to local governments	1.5%	% of Fixed Capital Investment (FCI)
Insurance	Plant insurance	1%	% of Fixed Capital Investment (FCI)
General plant overhead	Can comprise hospital and medical services, safety services, cafeteria and recreational facilities, payroll overhead, lighting, employment offices, distribution of utilities, etc.	35%	% of total labor cost
Administrative costs	Expenses related to top-management or administrative activities	20%	% of operating labor cost
Distribution and marketing	Salaries, wages, supplies and other expenses for the sales office	2%	% of (semi-) variable costs and fixed costs
Research and development	Salaries, wages, supplies and other expenses for the R&D department	1.5%	% of Fixed Capital Investment (FCI)

i. This value is multiplied with the construction labor cost index as reported in Ereev and Patel[102].

S2.2 Model assumptions

TABLE 2-13: Model assumptions.

FT [107]			**Black liquor gasification** [114]			**HTL** [107]		
	Value	**Unit**		**Value**	**Unit**		**Value**	**Unit**
Bare equipment cost								
Air separation unit	6.9	M€$_{2013}$	Air separation unit	16.1	M€$_{2013}$	Hydrothermal liquefaction (HTL) plant	43.3	M€$_{2013}$
Feed prep and drying	8.3	M€$_{2013}$	BL gasifier and green liquor filter	13.0	M€$_{2013}$	Hydrotreating	11.3	M€$_{2013}$
Gasification with tar reforming and heat recovery	26.6	M€$_{2013}$	Nitrogen compressor	0.5	M€$_{2013}$	Hydrocracking and separation	8.5	M€$_{2013}$
Syngas cleanup and steam reforming	19.8	M€$_{2013}$	Acid gas removal and sulfur recovery	8.6	M€$_{2013}$	Hydrogen plant	25.5	M€$_{2013}$
FT synthesis	12.1	M€$_{2013}$	Synthesis island (FT synthesis)	7.9	M€$_{2013}$	Wastewater treatment	-[i]	M€$_{2013}$
Hydrocracking and product separation	14.6	M€$_{2013}$	Combined cycle power island	21.3	M€$_{2013}$	Remainder OSBL	-[i]	M€$_{2013}$
Steam system and power generation	7.3	M€$_{2013}$	Wood yard expansion	1.2	M€$_{2013}$	TPEC	88.6	M€$_{2013}$
Remainder OSBL	- [i]	M€$_{2013}$	Biomass dryer	9.3	M€$_{2013}$			
TPEC	96	M€$_{2013}$	Biomass gasifier and tar cracker	9.6	M€$_{2013}$			
			Biomass syngas cooler and wash	7.0	M€$_{2013}$			
			TPEC	94.5	M€$_{2013}$			
Outputs								
Output diesel	0.0068	t GJ^{-1} (feed)	Output FT liquids	0.40	GJ GJ^{-1} (feed)	Output diesel	0.013	t GJ^{-1} (feed)
Output naphtha	0.0020	t GJ^{-1} (feed)				Output gasoline	0.0048	t GJ^{-1} (feed)
Output waste water	0.0751	m3 GJ^{-1} (feed)				Wastewater	0.063	m^3 GJ^{-1} (feed)

Output wet ash	0.0039	t GJ^{-1} (feed)				Wet ash	0.00029	t GJ^{-1} (feed)
Utilities								
Water requirement	0.162		Lime kiln #6 fuel oil	0.0026	t GJ^{-1} (black liquor)	Natural gas requirement	4.6	m^3 GJ^{-1} (feed)
Power consumption	0.010	MWh GJ^{-1} (feed)	Electricity produced	0.025	MWh GJ^{-1} (feed)	Power consumption	0.016	MWh GJ^{-1} (feed)
Power production	0.025	MWh GJ^{-1} (feed)	Electricity produced in reference case[ii]	0.021	MWh GJ^{-1} (feed)	Power production	0.0043	MWh GJ^{-1} (feed)
						Water requirement	0.044	m^3 GJ^{-1} (feed)
Miscellaneous								
Base year reference study	2008		Base year reference study	2005		Base year reference study	2008	
Reference capacity	39.2	TJ (feed) day^{-1}	Reference capacity Black liquor	16.1	TJ (feed) day^{-1}	Reference capacity	39.2	TJ (feed) day^{-1}
Catalyst & chemicals	54.3	€ t^{-1} diesel	Reference capacity hog fuel	2.5	TJ (feed) day^{-1}	Catalyst & chemicals	31.0	€ t^{-1} diesel
Number of processing steps[108,112]	9		Reference capacity forestry residues	20.7	TJ (feed) day^{-1}	Number of processing steps	5	
			Number of processing steps[iii]	11				

i. Excluded value because the OSBL costs are also included in Ereev and Patel's SCENT method.

ii. This value was inserted to compensate for the income loss of the pulp mill owner for due to the diversion of hog fuel and black liquor from electricity production.

iii. Based on the value for FT plus an additional gasifier and syngas quench for the black liquor gasification.

(continued)

Pyrolysis[120]			**DSHC [35]**			**ATJ[36,81,121]**		
	Value	**Unit**		**Value**	**Unit**		**Value**	**Unit**
Bare equipment cost at reference capacity								
Fast pyrolysis	42.0	M€$_{2013}$	Separation[vi]	0.8	M€$_{2013}$	Dehydration, oligomerization & hydrogenation[36]	9.8	M€
Pyrolysis oil upgrading to stable oil	31.9	M€$_{2013}$	Hydrocracking[vi]	37.0	M€$_{2013}$			
Product separation and hydrocracking	4.7	M€$_{2013}$	Fermentation[vi]	3.7	M€$_{2013}$	TPEC	9.8	M€
Hydrogen plant	23.8	M€$_{2013}$	TPEC	41.5	M€$_{2013}$			
Balance of plant	-[iv]	M€$_{2013}$						
TPEC	102.4	M€$_{2013}$						
Outputs								
Output diesel	0.0077	t GJ^{-1} (feed)	Intermediate farnasene	0.20	t t^{-1} sucrose	Output jet[121]	0.130	t t^{-1} ethanol
Output gasoline	0.0063	t GJ^{-1} (feed)	Farnasene losses yeast centrifuge	1%	% of farnasene production	Output gasoline[121]	0.425	t t^{-1} ethanol
Waste water	0.024	m^3 GJ^{-1} (feed)	Farnasene losses organic centrifuge	3%	% of farnasene production			
			Output jet	0.50	t t^{-1} farnasene			
			Output diesel	0.075	t t^{-1} farnasene			
			Output naphtha	0.27	t t^{-1} farnasene			
			Waste water	6.2	t t^{-1} farnasene			
Utilities								
Natural gas requirement	2.6	m3 GJ^{-1} (feed)	Water requirement	850.3	m^3 t^{-1} farnasene	Hydrogen requirement[81]	0.008	t t^{-1} ethanol
Water requirement	0.027	m3 GJ^{-1} (feed)	Steam usage	0.00047	t t^{-1} sucrose	Steam requirement[121]	0.22	t t^{-1} ethanol
Electricity requirement	0.006	MWh GJ^{-1} (feed)	Hydrogen requirement	0.095	t t^{-1} farnasene	Electricity requirement[121]	0.22	MWh t^{-1} ethanol
			Electricity requirement	0.022	MWh t^{-1} sucrose			

Miscellaneous								
Base year reference study	2011		Base year reference study	2011		Base year reference study [36]	2011	
Reference capacity	39.2	TJ (feed) day^{-1}	Reference capacity	1420	t sucrose day^{-1}	Reference capacity[36]	482	t ethanol day^{-1}
Number of processing steps[112 v]	7		DAP	0.0027	t t^{-1} sucrose	Number of processing steps	4	
Catalyst & chemicals	1.2	€ t^{-1} feed	NH4OH	0.044	t t^{-1} sucrose			
Disposal cost	0.03	€ t^{-1} feed	NaOH	0.026	t t^{-1} farnasene			
			NaCl	0.22	t t^{-1} farnasene			
			Tergitol	0.016	t t^{-1} farnasene			
			Number of processing steps	11				

iv. Excluded value because the OSBL costs are also included in Ereev and Patel's SCENT method
v. Number based on Anex et al.[112] plus an additional hydrogen plant
vi. When scaled, a scaling factor of 0.6 was applied

(continued)

Ethanol fermentation[123]			**Sugar extraction[123]**			**HEFA[30,128]**		
	Value	**Unit**		**Value**	**Unit**		**Value**	**Unit**
Bare equipment cost at reference capacity								
Pre-treatment and conditioning[viii]	15.9	$M€_{2013}$	Pre-treatment and conditioning[viii]	15.9	$M€_{2013}$	Fixed capital investment (FCI)[128]	626	M€
Enzymatic hydrolysis & fermentation[ix]	13.7	$M€_{2013}$	Enzymatic hydrolysis & fermentation[ix]	8.6	$M€_{2013}$			
Cellulase enzyme production[x]	8.1	$M€_{2013}$	Cellulase enzyme production[x]	8.1	$M€_{2013}$			
Solids recovery[xi]	8.2	$M€_{2013}$	Solids recovery[xi]	9.2	$M€_{2013}$			
Waste water treatment	- [vii]	$M€_{2013}$	Waste water treatment	- [vii]	$M€_{2013}$			
Storage	- [vii]	$M€_{2013}$	Storage	- [vii]	$M€_{2013}$			
Boiler/ turbogenerator (lignocellulosic feedstocks) [viii]	25.3	$M€_{2013}$	Boiler/ turbogenerator (lignocellulosic feedstocks) [viii]	26.8	$M€_{2013}$			
Boiler/ turbogenerator (beet pulp)	- [vii]	$M€_{2013}$	Pre-treatment and conditioning[viii]	- [vii]	$M€_{2013}$			
Utilities	- [vii]	$M€_{2013}$	TPEC	68.8	$M€_{2013}$			

TPEC	71.1	M€$_{2013}$

Outputs

Outputs for forestry residues and wheat straw[124]			**Sugar yield for lignocellulosic feedstocks**[124]			Output jet[30]	0.128	t t^{-1} UCO
Glucose yield	0.83	t t^{-1} glucan	Glucose yield	0.83	t t^{-1} glucan	Output diesel[30]	0.681	t t^{-1} UCO
Xylose yield	0.80	t t^{-1} xylan	Xylose yield	0.80	t t^{-1} xylan	Output naphtha[30]	0.018	t t^{-1} UCO
Arabinose yield	0.80	t t^{-1} arabinan	Arabinose yield	0.80	t t^{-1} arabinan	Output LPG[30]	0.016	t t^{-1} UCO
Galactose yield	0.89	t t^{-1} galactan	Galactose yield	0.89	t t^{-1} galactan	Output propane[30]	0.042	t t^{-1} UCO
Mannose yield	0.89	t t^{-1} mannan	Mannose yield	0.89	t t^{-1} mannan			
Ethanol from glucose	0.48	t t^{-1} glucose						
Ethanol from xylose	0.44	t t^{-1} xylose						
Ethanol from arabinose	0.44	t t^{-1} arabinose						
Ethanol from galactose	0.44	t t^{-1} galactose						
Ethanol from mannose	0.44	t t^{-1} mannose						

Outputs for beet pulp[132]		
Ethanol output	0.40	t t^{-1} feed (dm)

Utilities

Makeup water requirement	1.77	m^3 t^{-1} feed (dm)	Makeup water requirement	1.77	m^3 t^{-1} feed (dm)	Water requirement[30]	-	m^3 t^{-1} UCO
Electricity production[xii]	154	kWh t^{-1} feed (dm)	Natural gas	33.3	m^3 (L kg^{-1} water reduced)$^{-1}$ t^{-1} sugar produced	Natural gas usage[30]	150	m^3 t^{-1} UCO
Electricity consumption	10.3	kWh t^{-1} feed (dm)	Electricity production	153.8	kWh t^{-1} feed (dm)	Hydrogen requirement[30]	0.027	t t^{-1} UCO

			Electricity consumption	10.3	kWh t^{-1} feed (dm)	Electricity requirement[30]	0.088	MWh t^{-1} UCO
Miscellaneous								
Base year reference study	2007		Base year reference study	2007		Base year reference study	2011	
Reference capacity plant	2000	t feed (dm) day^{-1}	Reference capacity plant	2000	t feed (dm) day^{-1}	Reference capacity plant[128]	2500	t feed day^{-1}
Reference capacity boiler	608	t lignin (dm) day^{-1}	Output sugar concentration[123]	7.85	L water kg^{-1} sugar	Number of processing steps	5	
Other chemicals	1.97	€ t^{-1} feed (dm)	Target sugar concentration for DSHC[35]	0.47	L water kg^{-1} sugar			
Sulfuric acid loading (lignocellulosic feedstocks)	0.024	t feed (dm) day	Other chemicals	0.79	€ t^{-1} feed (dm)			
Sulfuric acid loading (beet pulp)	0.0087	t feed (dm) day	Sulfuric acid loading	0.024	t t^{-1} feed (dm)			
Ammonia loading	0.014	t feed (dm) day	Ammonia loading	0.014	t t^{-1} feed (dm)			
Corn syrup loading	0.029	t feed (dm) day	Corn syrup loading	0.029	t t^{-1} feed (dm)			
DAP	0.0017	t feed (dm) day	Number of processing steps	5				
FGD Lime	0.011	t feed (dm) day						
Combustor ash[xiii]	0.069	t feed (dm) day						
Number of processing steps[112,122]	11							

vii. Excluded value because the OSBL costs are also included in Ereev and Patel's SCENT method

viii. When scaled, a scaling factor of 0.6 was applied [123]

ix. When scaled, a scaling factor of 0.9 was applied [123]

x. When scaled, a scaling factor of 1.0 was applied [123]

xi. When scaled, a scaling factor of 0.7 was applied [123]

xii. The value is based on the lignin content of corn stover. This value is adapted to the specific lignin content of the feedstocks under consideration. The value is zero for beet pulp.

xiii. Derived from Humbird et al.[123]. The value is based on the ash content of corn stover. This value is adapted to the specific ash content of the feedstocks under consideration. The value is zero for beet pulp.

S2.3 Prices raw materials and utilities

TABLE 2-14: Prices of raw materials and utilities.

Materials[i]		
Electricity[i] [141] (EU average)	0.07	€ kWh^{-1}
Natural gas[140] (EU average)	0.30	€ m^{-3}
Water[35]	0.04	€ m^{-3}
Steam[35]	9.04	€ t^{-1}
Hydrogen[117]	854	€ t^{-1}
Waste water discharge fee[107]	0.72	€ m^{-3}
Ash disposal[117]	16.8	€ t^{-1}
DAP[35]	529	€ t^{-1}
NH4OH[35]	173	€ t^{-1}
NaOH[175]	490	€ t^{-1}
NaCl[176]	136	€ t^{-1}
Tergitol[177]	2,823	€ t^{-1}
Sulfuric acid[178]	60.4	€ t^{-1}
Ammonia[178]	420	€ t^{-1}
Glucose[178]	527	€ t^{-1}
Lime[179]	85.9	€ t^{-1}
Heavy fuel oil (#5 & #6) [180]	462	€ t^{-1}

i. Costs for raw materials and utilities were normalized to 2013 values using the US Consumer Price Index (CPI) and the country specific Harmonized Index for Consumer Prices (HICP) for dollars and euros, respectively.[181,182]

ii. It was assumed that the selling price of green electricity to the grid was equal to the purchase price of electricity from the grid.

S2.4 MFSP calculation

The MFSP is the price at which the fuel products should be sold to achieve a zero equity net present value (NPV). The equity NPV is the sum of future cash flows to and from the equity holders. The MFSP was calculated using the following equation:

$$MFSP = \frac{\sum_{t=-1}^{L} \frac{I_t{*}E + D_t + T_t + COP_t}{(1+r)^t}}{\sum_i \; q_i \sum_{t=-1}^{L} \frac{P_{i,t}}{(1+r)^t}}$$

In which t = financial year, L = project lifetime, I_t = investment expenditures in year t (€), E = equity share of investment, D_t = Principle and interest payments in year t (€), T_t = Tax payments in year t (€), COP_t = cost of production in year t, minus the revenues of the non-fuel co-products (€), r = discount rate, i = fuel product (i.e. jet fuel, diesel, gasoline or naphtha), q = ratio of fuel product with respect to the jet price, $P_{i,t}$ = production of fuel product i in year t (tonne).

Please note that the tax payments are dependent on the revenues. The revenues, in turn, depend on the MFSP. Therefore, this iterative calculation was performed using Goal Seek in Excel.

S2.5 Pioneer plant analysis

A dated, but still widely used method to estimate the capital investment and plant performance of a pioneer plant from Nth plant figures is the RAND method, developed by Merrow, Phillips and Myers[84] at RAND (Research ANd Development) corporation. The study comprised a multi-factor linear regression analysis on 44 production plants to identify the major factors causing capital investment growth and decreased plant performance during the first year of production. Based on empirical data, they formulated two equations that describe the cost growth and the plant performance of a pioneer plant as a function of certain process details as outlined in the table below[84,112].

$$Cost\ growth = 1.1219 - 0.00297 * PCTNEW\text{-}0.02125 * IMPURITIES\text{-}0.01137 * COMPLEXITY + 0.00111 * INCLUSIVENESS\text{-}C_1 * PROJECT\ DEFINITION$$

$$Plant\ Performance = 85.77 - 9.69 * NEWSTEPS + 0.33 * BALEQS\text{-}4.12 * WASTE\text{-}17.19 * SOLIDS$$

Using this method, the total capital investment and plant capacity in year 1 can be calculated using the following equations:

$$TCI_{Pioneer} = \frac{TCI_{Nth}}{Cost\ \ growth\ factor}$$

$$Plant\ performance\ (year\ 1) = Nameplate\ capacity * plant\ performance\ factor$$

The plant performance is increased with 20 percent points per year in consequent years.

TABLE 2-15: Pioneer plant analysis.

Parameter	Range	Definition
Cost growth	>0	The reciprocal of cost growth equals the factorial increase of the actual capital costs with respect to the cost estimate
Plant performance	0-100	Percentage of nameplate capacity which is achieved during the first year
PCTNEW	0-100	The percentage of capital cost of commercially unproven process areas in the entire plant
IMPURITIES	0 (none) - 5 (many)	The extent to which build-up of impurities can be expected
COMPLEXITY	≥1	Number of continuously linked process steps
INCLUSIVENESS	0-100	The percentage of start-up cost (i.e. land purchase/leases/property rentals, initial plant inventory/warehouse parts/catalysts and pre-operating personnel cost included in the capital estimate
PROJECT DEFINITION	2 (maximum definition) - 8 (minimum definition)	Level of site-specific information and engineering included in the cost estimate

C_1	0.04011 for commercial or pre-commercial, -0.06361 for processes in R&D stages	The commercialization status of the technology
NEWSTEPS	≥0	The number of steps that have not been proven at commercial scales
BALEQS	0-100	The percentage of mass and energy balances that were retrieved from commercial plant data
WASTE	0 (none) to 5 (significant issues)	The extent to which waste handling issues may arise
SOLIDS	1 if it does, 0 if it does not	Whether or not the process involves solid handling

The RAND factors for each technology used in this analysis are given in the table below. It was chosen to assign particular factors to each technology separately, because each technology is in a different stage of development and is expected to have its particular scale-up problems.

TABLE 2-16: Calculation of RAND factors.

CAPEX growth	**HEFA**	**FT**	**BLG**	**HTL**	**Pyrolysis**	**ATJ**	**DSHC (mol)**	**DSHC (cell. Sug.)**
Pctnew	-	37	25	71	77	32	-	24
Impurities	-	4	4	4	4	3	3	4
Complexity	5	9	11	5	6	15	11	16
Inclusiveness	66	66	66	66	66	66	66	66
Project Definition	7	7	7	7	7	7	7	7
C_1	-0.04011	-0.06361	-0.06361	-0.06361	-0.06361	-0.06361	-0.04011	-0.04011
Cost growth factor	**0.86**	**0.45**	**0.47**	**0.40**	**0.37**	**0.42**	**0.73**	**0.58**
Plant performance								
Nwstps	0	2[i]	3[ii]	3[iii]	3[iv]	4[iv]	0	3[vi]
Baleweqs	0	0	0	0	0	0	0	0
Waste	0	4	4	4	4	2	2	2
Solids	0	1	1	1	1	1	0	1
Plant performance in year 1	**86%**	**32%**	**22%**	**22%**	**22%**	**22%**	**78%**	**40%**

i. This number includes feedstock handling and gasifier[112]
ii. This number follows the number for FT with an additional gasifier
iii. This number includes the Pretreatment, HTL and hydroprocessing
iv. This number includes the Pyrolysis reactor, hydroprocessing, combustor[112]
v. Anex et al.[112] reported 6 new units. Seeing the recent advancements in cellulosic ethanol production and large scale sugar and starch ethanol facilities, this number was reduced to only include the feeedstock handling, pretreatment, saccharification and cofermentation units. No new steps were encountered in the ATJ conversion.
vi. This number includes feedstock handling, pre-treatment and enzymatic hydrolysis area

The amount of (new) processing steps (encapsulated in the variables *Complexity* and *Newstps*) were derived from process designs as reported in the reference studies and existing pioneer plant analyses[108,112,118,122]. *Pctnew* was calculated by dividing the bare equipment cost for the new units over the total bare equipment cost. The fact that some process steps are already demonstrated on commercial scale (e.g. DSHC and HEFA) or are common chemical operations (e.g. hydrocracking, dehydration of alcohol, etc.) was taken into account. The sensitivity to *Impurities* (on a scale of 0-5) was set to 4 for thermochemical technologies involving high temperatures and pressures and 3 for biochemical pathways based on estimates for Pyrolysis, FT and Ethanol fermentation in Anex et al.[112] A similar approach was taken for *Waste*. *Inclusiveness* was set to 66% for all technologies. Although SCENT methodology includes all cost factors, these cost factors could not be validated with a commercial plant. The extent to which location specific data was taken into account (included in *Project Definition*) was set to a conservative 7 in all cases, corresponding with the high-level character of this study. C_1 was set to the maximum value (-0.06361) for technologies that are not proven for biomass at commercial scales. Following similar reasoning as Swanson et al., the percentage of mass and energy balances that were retrieved from commercial plant data, *Baleweqs*, was set to zero as none of the used data has been validated with real plant data.[108] Lastly, all technologies involving solids handling were given a value of 1 for *Solids*. DSHC based on molasses and HEFA were assigned a 0 as it only involves liquids.

S2.6 Constructing local cost-supply curves

As feedstock costs are usually location dependent and make up a large share of total raw material cost, these were subject to more detailed estimates using local cost-supply curves. Cost-supply curves for wheat straw and forestry residues were constructed by adding the feedstock price at the forest/farm site and the cost of transport at NUTS-3 (i.e. sub-regional) level.

The wheat straw and forestry residue prices at the forest/farm site on NUTS-2 (i.e. regional) level were obtained from Kühner.[142] It was assumed prices in NUTS-3 regions were similar to prices in their respective NUTS-2 regions. The feedstock price was assumed to be the average of the mentioned range for each NUTS-2 region. Wheat straw prices were updated to the most recent prices (2012) using prices and indices of agricultural products as reported by Eurostat.[145,183] Prices were consequently updated using country-specific Harmonized Index of Consumer Prices (HICP). The transport costs include both handling and storage at the forest/farm as well as the factory site. Country-specific costs for storage, handling and transport (using a telescopic handler and transport by truck and drawback trailer) were calculated using the indices for labor fuel, and vehicle investment costs as reported in Rotter & Rohrhofer[143]. The distance between the feedstock production site and the conversion site was calculated using the Origin-Destination function (part of the Network Analyst tool) in ArcMAP 10.1. It was assumed that the available biomass in a certain NUTS-3 region is located at the centroid of the region. Consequently, ArcMAP was used to compute the distance between the centroid and the incubator facility via the road transport network suitable for trucking (NAVTEQ 2012 Q1 Europe map). Forestry residue potentials were obtained from Elbersen et al.[184] Wheat straw potentials

were retrieved from Monforti et al.[185] NUTS-2 potentials were allocated to the respective NUTS-3 regions according to NUTS-3 area size. In addition, it was assumed that only 10% of the residue potential (the so-called 'participation rate') is available for biofuel production for both forestry residues and wheat straw.

In all calculations regarding co-production strategies, total feedstock costs were computed from the area under the cost-supply curve. This assumes that the factory owner pays different prices at the factory gate for batches of feedstock coming from other regions. An alternative approach (not used in this study) is to assume a market in which each feedstock seller wants the same price for every batch of feedstock, preferably the maximum (marginal) price. The increase in MFSP as a result of using the marginal price is more profound for strategies involving wheat straw (20-24%) than forestry residues as (3-7%), because the average supply density of wheat straw in the EU is about one-tenth that of forestry residues. This results in a wider biomass collection radius and hence a larger difference between the closest and the furthest collection point – with associated variation in transport costs. In practice the actual pricing structure of feedstock may lie between both approaches.

A-molasses, hog fuel, beet pulp and black liquor are produced at the incubator facility itself. It is assumed that these feedstocks are available at a constant cost price. As black liquor and hog fuel are often used for electricity and steam production, it was presumed that the pulp mill owner's loss of income from electricity sales should be fully compensated by revenue from hog fuel and black liquor sales to the biofuel plant. Beet pulp and A-molasses availability was determined from the size of the incubator facility. As sugar beet factories do not produce all year round, the beet pulp and A-molasses potential were annualized by using country specific beet campaign lengths[186] to fit the production cycle of the biofuels plant. It was presumed that excess beet pulp and A-molasses was stored during the beet campaign and used outside the beet campaign.

S2.7 Literature survey

The values retrieved from the literature for the literature survey are reported in the table below in the respective quantity they were reported. Values were converted using conversion factors and as stated in S2.8. Scaling was based on fuel output and a scaling factor of 0.6. Bare equipment costs were normalized to $US\$_{2013}$ or $€_{2013}$ using the Chemical Engineering Plant Cost Index (CEPCI).[103,104] $US\$_{2013}$ were converted to $€_{2013}$ using the average euro-dollar exchange rate in 2013 (0.753 € $\$^{-1}$).

TABLE 2-17: Literature survey.

Fischer-Tropsch					
Reference	**Technology**	**Feedstock**	**Parameter**	**Value**	**Unit**
Zhu et al.[107]	FT-directly heated gasifier/indirectly heated gasifier	Hybrid poplar wood chips	Total project investment	537/379	$M\$_{2008}$
			Feed input	2000/200	t (dm) day^{-1}
			Product yield - diesel Product yield - naphtha	28/24 9/8	MMgal $year^{-1}$ MMgal $year^{-1}$
			Production costs (MFSP)	4.6/4.3	$\$_{2008}$ gal^{-1}
			Feedstock price	60	$\$_{2008}$ t^{-1}(dm)
Ekbom et al.[80]	FT-Brista case	Wood chips	Total investment	500	$M€_{2009}$
			Feed input	108	t $hour^{-1}$
			Product yield - naphtha Product yield - jet Product yield - heavy diesel	17.9 50.0 21.4	t $year^{-1}$
			Production costs	812	€ m^{-3}
			Feedstock price	18	$€_{2009}$ MWh^{-1}
Swanson et al.[108]	FT-Low Temperature /High Temperature	Corn stover	Total investment	498/606	$M\$_{2007}$
			Feed input	2000/2000	t (dm) day^{-1}
			Product yield	47.2/61.0	GGE t^{-1} feed (dm)
			Production costs (MFSP)	4.8/4.3	$\$_{2008}$ gal GGE^{-1}
			Feedstock price	75	$\$_{2007}$ short ton^{-1}
Haarlemmer et al.[109]	FT- Fluidised bed/ Entrained flow reactor	Wood	Total investment	834/949	$M€_{2007}$
			Feed input	80	t (dm) $hour^{-1}$
			Product yield	0.17/0.17	t t^{-1} feed (dm)
			Production costs	1.16/1.14	$€_{2007}$ L^{-1}
			Feedstock price	100	$€_{2007}$ t^{-1} (dm)
Sarkar, Kumar & Sultana[111]	FT – atmospheric pressure gasifier / pressurized gasifier	Forestry residues	Total investment	298/552	$M\$_{2008}$
			Feed input	400	MWth
			Product yield	0.13/0.13	t t^{-1} feed (dm)
			Production costs	0.97/1.53	$\$_{2008}$ kg^{-1}
			Feedstock price	42	$\$_{2008}$ t^{-1} (dm)
Tuna & Hulteberg[110]	FT	Poplar	Total investment	760	$M\$_{2011}$

			Feed input	2000	t (dm) $hour^{-1}$
			Product yield- gasoline Product yield- diesel	0.0517/0.0517 0.0779/0.0779	t t^{-1} feed (dm)
			Production costs	139.6	$\$_{2011}$ MWh^{-1}
			Feedstock price	140	$\$_{2011}$ t^{-1}
Meerman et al.[113]	FT – entrained flow gasifier	Torrefied pellets/ Eucalyptus	Total investment (excl. CCS unit)	1373/1442	$M€_{2008}$
			Feed input	283/274	t (dm) $hour^{-1}$
			Product yield – FT liquids	61/48	t $hour^{-1}$
			Production costs	13-33/22-38	$€_{2008}$ GJ^{-1}
			Feedstock price	6	$€_{2008}$ GJ^{-1}
Anex et al.[112]	FT-Low Temperature /High Temperature	Corn stover	Total investment	500/610	$M\$_{2007}$
			Feed input	2000	t (dm) $hour^{-1}$
			Product yield	47.2/61.0	Gal t^{-1} feed (dm)
			Production costs (MFSP)	3.8/4.3	$\$_{2008}$ GGE^{-1}
			Feedstock price	75	$\$_{2007}$ short ton^{-1}
Atsonios et al.[36]	FT	Wood chips	Total investment	207	$M€_{2011}$
			Feed input	864	t (dm) day^{-1}
			Product yield - jet fuel Product yield - gasoline	0.097 0.076	t t^{-1} feed (dm) t t^{-1} feed (dm)
			Production costs (MFSP)	1.24	$€_{2011}$ L^{-1}
			Feedstock price	60	$€_{2011}$ t^{-1} (dm)
Consonni et al.[114]	FT - FTc case	Black liquor, hog fuel and forestry residues	Total investment	350	$M€_{2005}$
			Feed input - Black liquor Feed input - Hog fuel Feed input - Forestry residues	350.7 54.1 368.5	MW
			Product yield - FT liquids	342.7	MW
Ekbom et al.[115]	FT - FTD case	Black liquor, hog fuel and forestry residues	Total investment	580	$M€_{2005}$
			Feed input - Black liquor Feed input - Biomass	487 378	MW MW
			Product yield - diesel Product yield - naphtha	109700 56200	t diesel $year^{-1}$ t naphtha $year^{-1}$
			Production costs	12.1	€ GJ^{-1}

HTL					
Zhu et al. [187]	HTL SOT case/Goal case	Woody biomass	Total investment	512/468	$M\$_{2007}$
			Feed input	2000	t (dm) day^{-1}
			Product yield - hydrocarbon	0.22/0.36	L kg^{-1}
			Production costs (MFSP)	4.44/2.52	$\$_{2007}$ GGE^{-1}
			Feedstock price	70	$\$_{2007}$ t^{-1} (dm)
Zhu et al.[107]	HTL	Hybrid poplar wood chips	Total investment	456	$M\$_{2008}$
			Feed input	2000	t (dm) day^{-1}
			Product yield - gasoline Product yield - diesel	22 55	MMgal $year^{-1}$ MMgal $year^{-1}$
			Production costs (MFSP)	2.4	$\$_{2008}$ GGE^{-1}
			Feedstock price	60	$\$_{2008}$ t^{-1} (dm)

Pyrolysis					
Zhu et al.[107]	Fast pyrolysis	Hybrid poplar wood chips	Total investment	332	$M\$_{2008}$
			Feed input	2000	t (dm) day^{-1}
			Product yield - gasoline Product yield - diesel	34 43	MMgal $year^{-1}$ MMgal $year^{-1}$
			Production costs (MFSP)	2.4	$\$_{2008}$ gal^{-1}
			Feedstock price	60	$\$_{2008}$ t^{-1} (dm)
Jones et al. [117]	Fast Pyrolysis	Hybrid poplar wood chips	Total investment	303	$M\$_{2007}$
			Feed input	2000	t (dm) day^{-1}
			Product yield - gasoline Product yield - diesel	28555 38367	lbs $hour^{-1}$
			Production costs (MFSP)	2.04	$\$_{2007}$ gal^{-1}
			Feedstock price	80	$\$_{2007}$ short ton^{-1} (dm)
Wright et al.[118]	Fast Pyrolysis H_2 purchase/H_2 production	Corn stover	Total investment	200/267	$M\$_{2009}$
			Feed input	2000	t day^{-1}
			Product yield - fuel yield	220/134	ML $year^{-1}$
			Production costs (MFSP)	2.11/3.09	$\$_{2009}$ GGE^{-1}
			Feedstock price	83	$\$_{2008}$ t^{-1} (dm)
Anex et al.[112]	Fast Pyrolysis H_2 purchase/H_2 production	Corn stover	Total investment	200/280	$M\$_{2007}$
			Feed input	2000	t day^{-1}
			Product yield - fuel yield	88.2/53.6	Gal t^{-1}
			Production costs (MFSP)	2.11/3.09	$\$_{2007}$ GGE^{-1}
			Feedstock price	75	$\$_{2007}$ short ton^{-1} (dm)

Brown et al.[188]	Fast Pyrolysis	Corn stover	Total investment	429	M$$_{2011}$
			Feed input	2000	t (dm) day^{-1}
			Product yield - fuel yield	57.4	MMgal year^{-1}
			Production costs (MFSP)	2.57	$$_{2011}$ gal^{-1}
			Feedstock price	83	$$_{2011}$ t^{-1} (dm)
Jones et al.[120]	Fast Pyrolysis	Woody biomass	Total investment	700.6	M$$_{2011}$
			Feed input	2000	t (dm) day^{-1}
			Product yield - gasoline Product yield - diesel	40 44	Gal (short ton)$^{-1}$ feed (dm)
			Production costs (MFSP)	3.39	$$_{2011}$ GGE^{-1}
			Feedstock price	51	$$_{2011}$ t^{-1} (dm)

HEFA					
Pearlson et al.[30,189]	HEFA	Soybean oil	Total investment	224.87	M$$_{2010}$
			Feed input	747338	klbs year^{-1}
			Product yield - jet Product yield - diesel Product yield - naphtha	0.128 0.681 0.018	t t^{-1} feed t t^{-1} feed t t^{-1} feed
			Production costs (MFSP)	1.01	$$_{2010}$ L^{-1}
			Feedstock price	0.7	$$_{2010}$ L^{-1}
Seber et al.[33]	HEFA	Yellow grease and tallow	Analysis based on Pearlson et al. (see previous entry) [30,189]		
Klein-Marcuschamer et al.[35]	HEFA	Pongamia seeds	Total investment HEFA unit	365	M$$_{2011}$
			Feed input	12.05	t hour^{-1}
			Product yield - jet Product yield - diesel Product yield - naphtha	0.44 0.07 0.24	kg kg^{-1} feed
			Production costs (MFSP)	5.54	$$_{2011}$ kg^{-1}
Neste Oil[128,190]	HEFA (NEXBTL) Rotterdam/ Singapore	Palm, Rapeseed oil, waste fat	Total investment	670/550	M€$_{2011}$/M€$_{2010}$
			Product yield – diesel	800000	t year^{-1}
Diamond green diesel[127]	UOP/Eni Ecofining	Animal fats, used cooking oil and vegetable oils	Total investment	368	M$$_{2011}$
			Product yield – diesel	500000	t year^{-1}

ATJ					
Crawford[121]	ATJ	Ethanol	Total investment ATJ unit	113	$M\$_{2011}$
			Feed input	450000	t ethanol $year^{-1}$
			Product yield - jet	0.56	t t^{-1} ethanol
			Production costs	1.08	$\$_{2011}$ L^{-1}
			Feedstock price	70	$\$_{2011}$ t^{-1}
Atsonios et al.[36]	ATJ	Ethanol	Total installed cost ATJ unit	23.445	$M€_{2011}$
			Feed input	472	t ethanol day^{-1}
			Production costs (MFSP)	1.27	$€_{2011}$ L^{-1}
			Feedstock price	60	$€_{2013}$ t^{-1}

DSHC					
Klein-Marcuschamer et al.[35]	DSHC	Sugarcane A-molasses	Total investment DSHC unit	258.7	$M\$_{2011}$
			Feed input	1419.6	t sucrose day^{-1}
			Product yield - jet	0.17	t t^{-1} feed (dm)
			Production costs (MFSP)	301.35	$\$_{2011}$ bbl_{eq}^{-1}

Sugar extraction					
Humbird et al.[123]	Dilute Acid Prehydrolysis with Enzymatic Saccharification	Corn stover	Total investment	279.9	$M\$_{2007}$
			Feed input	2000	t (dm) day^{-1}
			Product yield - sugar	1179	lb short ton^{-1}
			Production costs (MFSP)	0.1158	$\$_{2007}$ lb^{-1}
			Feedstock price	58.5	$\$_{2007}$ short ton^{-1} (dm)

Fermentation					
Anex et al.[112]	Dilute acid base/ high solids	Corn stover	Total investment	380/390	$M\$_{2007}$
			Feed input	2000	t day^{-1}
			Product yield - ethanol	74.9/76.0	gal t^{-1} feed (dm)
			Production costs (MFSP)	3.4/3.6	$\$_{2007}$ gal^{-1}
			Feedstock price	75	$\$_{2007}$ short ton^{-1}
Kabir Kazi et al.[122]	Dilute acid base/ high solids/two stage dilute acid	Corn stover	Total investment	376/389/391	$M\$_{2007}$
			Feed input	2000	t (dm) day^{-1}
			Product yield - ethanol	76.3/72.5/46.8	gal t^{-1} feed

			Production costs (MFSP)	3.4/3.6/4.38	$\$_{2007}$ gal^{-1}
			Feedstock price	83	$\$_{2007}$ t^{-1} dm)
Humbird et al.[123]	Dilute acid	Corn stover	Total investment	422.5	M$\$_{2007}$
			Feed input	2000	t (dm) day^{-1}
			Product yield - ethanol	79.0	gal short ton^{-1} (dm)
			Production costs (MFSP)	2.15	$\$_{2007}$ gal^{-1}
			Feedstock price	58.5	$\$_{2007}$ short ton^{-1} dm)
Hamelinck et al.[124]	Dilute acid	Forestry residues	Total investment	~295	M$€_{2003}$
			Feed input	2000	t (dm) day^{-1}
			Product yield - glucan Product yield - xylan Product yield - arabinan Product yield - galactan Product yield - mannan	0.40 0.35 0.35 0.39 0.39	t ethanol t^{-1} polysaccharide
			Production costs (MFSP)	22	$€_{2003}$ GJ^{-1}
			Feedstock price	3	$€_{2003}$ GJ^{-1}
Gnansounou & Dauriat[125]	Dilute acid	Straw/ Eucalyptus/ poplar/ switchgrass	Total investment	309/290/281/ 296	M$\$_{2007}$
			Feed input	1960/1680/ 1636/1818	t (dm) day^{-1}
			Product yield - ethanol	291.3/339.9/349.0/314.1	L t^{-1} feed (dm)
			Production costs (MFSP)	0.73/0.56/0.76/0.77	$\$_{2007}$ L^{-1}
			Feedstock price	109/62/140/131	$\$_{2007}$ t^{-1} (dm)
Raizen Costa Pinto plant[89]	Dilute acid steam explosion	Sugarcane bagasse and straw	Feed input	770	t (dm) day^{-1}
			Product yield - ethanol	20	MMgal year^{-1}

S2.8 Conversion units and physical parameters

TABLE 2-18: Densities.

Quantity	Value	Unit
Density jet fuel	0.804	kg L^{-1}
Density diesel	0.832	kg L^{-1}
Density naphtha	0.768	kg L^{-1}
Density gasoline	0.740	kg L^{-1}
Density crude oil	0.847	kg L^{-1}
Density ethanol	0.789	kg L^{-1}
Density FT wax[191]	0.774	kg L^{-1}

TABLE 2-19: Feedstock composition data.

Constituent	Unit	Wheat straw[192]	Corn stover[123]	Forestry residues[i]	Beet pulp[132]
Glucan (C6)	wt% dry weight	36%	35%	42%	23%
Xylan (C5)	wt% dry weight	19%	20%	9%	5%
Arabinan (C5)	wt% dry weight	2%	2%	1%	24%
Galactan (C6)	wt% dry weight	1%	1%	2%	6%
Mannan (C6)	wt% dry weight	1%	1%	8%	2%
Lignin	wt% dry weight	26%	16%	26%	1%
Extractives	wt% dry weight	8%	15%	2%	0%
Acids	wt% dry weight	2%	2%	2%	0%
Ash	wt% dry weight	7%	5%	0%	3%
Protein	wt% dry weight	3%	3%	0%	11%

i. According to CEPI[136], 27% of used wood in the European pulping sector is hardwood and 73% is softwood (mostly spruce and pine). Based on these shares, a weighted average of the composition of hardwood (birch)[193] and softwood species (pine[124] and spruce[193]) was taken.

TABLE 2-20: Energy content.

	Energy content	Unit
Forestry residues[184]	19.6	MJ kg^{-1} (dm)
Straw[184]	18.0	MJ kg^{-1} (dm)
Black liquor[114]	9.8	MJ kg^{-1} (80% solid content)
Hog fuel[114]	8.14	MJ kg^{-1} (50% moisture content)
Used cooking oil[184]	36.0	MJ kg^{-1}
Lime kiln #6 fuel oil [194]	39.5	MJ kg^{-1}
Fischer-Tropsch synthetic crude[114,191]	40.3	MJ kg^{-1}
Energy density renewable jet fuel[194]	44.0	MJ kg^{-1}
Energy density renewable diesel[194]	43.2	MJ kg^{-1}
Energy density renewable gasoline[194]	43.2	MJ kg^{-1}
Energy density naphtha[194]	44.9	MJ kg^{-1}
Energy density propane[194]	46.3	MJ kg^{-1}
Energy density ethanol[194]	27.0	MJ kg^{-1}

3

Cost optimization of biofuel production – The impact of scale, integration, transport and supply chain configurations

Sierk de Jong[1*], Ric Hoefnagels[1], Elisabeth Wetterlund[2,3], Karin Pettersson[4,5], André Faaij[6], Martin Junginger[1]

1. Copernicus Institute of Sustainable Development, Utrecht University, Utrecht, The Netherlands.
2. Energy Engineering, Division of Energy Science, Luleå University of Technology, Luleå, Sweden.
3. International Institute for Applied Systems Analysis (IIASA), Laxenburg, Austria.
4. SP Technical Research Institute of Sweden, Göteborg, Sweden.
5. Division of Energy Technology, Department of Energy and Environment, Chalmers University of Technology, Göteborg, Sweden.
6. Energy and Sustainability Research Institute, Rijksuniversiteit Groningen, The Netherlands.

Published in Applied Energy. 195:1055-1070 (2017)

ABSTRACT

This study uses a geographically-explicit cost optimization model to analyze the impact of and interrelation between four cost reduction strategies for biofuel production: economies of scale, intermodal transport, integration with existing industries, and distributed supply chain configurations (i.e. supply chains with an intermediate pre-treatment step to reduce biomass transport cost). The model assessed biofuel production levels ranging from 1-150 PJ yr^{-1} in the context of the existing Swedish forest industry. Biofuel was produced from forestry biomass using hydrothermal liquefaction and hydroprocessing. Simultaneous implementation of all cost reduction strategies yielded minimum biofuel production costs of 18.1-18.2 € GJ^{-1} at biofuel production levels between 10-75 PJ yr^{-1}. Limiting the economies of scale was shown to cause the largest cost increase (+0-12%, increasing with biofuel production level), followed by disabling integration benefits (+1-10%, decreasing with biofuel production level) and allowing unimodal truck transport only (+0-6%, increasing with biofuel production level). Distributed supply chain configurations were introduced once biomass supply became increasingly dispersed, but did not provide a significant cost benefit (<1%). Disabling the benefits of integration favors large-scale centralized production, while intermodal transport networks positively affect the benefits of economies of scale. As biofuel production costs still exceed the price of fossil transport fuels in Sweden after implementation of all cost reduction strategies, policy support and stimulation of further technological learning remains essential to achieve cost parity with fossil fuels for this feedstock-technology combination in this spatiotemporal context.

3.1 INTRODUCTION

Bioenergy is expected to have a significant contribution in climate change mitigation strategies, especially for electricity, liquid fuel and biochemical purposes.[195] Whereas traditional use of bioenergy mainly occurs locally, modern bioenergy use (for example large-scale power, heat, chemicals and transport fuels production) requires more complex supply chains. Besides feedstock availability and sustainability, cost-effective mobilization and conversion of biomass is a prerequisite for the large-scale deployment of bioenergy.

On a supply chain level, the economic performance of a bioenergy supply chain can be optimized by strategic choices regarding production capacity, supply chain configuration, transport modes and conversion location.[196] A key factor in cost-effective supply chain design is the trade-off between economies of scale and transport cost: whereas higher production scales allow for cost reductions due to economies of scale, it increases the need to mobilize biomass over larger distances and thus the upstream transport cost.[196–206] Distributed supply chain configurations (as opposed to centralized configurations) have also been proposed to decrease the transportation cost of biomass and allow for further upscaling.[196–204] As illustrated in Figure 3-1, distributed configurations use an intermediate densification step early in the supply chain (e.g. chipping, pelletization or liquefaction) to decrease transport cost, even though this may increase the capital or operational expenditures (CAPEX or OPEX). Additionally, intermodal transport networks based on multiple transport modes (i.e. road, rail and river/sea transport) have been examined as a means to decrease transport cost and unlock distant biomass supplies.[207–212] Furthermore, co-location of production at existing industrial sites may decrease production cost when integration benefits can be leveraged.[213,214] As all of these four cost reduction strategies (i.e. economies of scale, integration, intermodal transport and distributed supply chain configurations) are interrelated, it is important to evaluate them simultaneously to analyze the impact of and interrelations between the different options.

Mathematical optimization models are often used to find the optimal (e.g. least-cost) supply chain design. Unlike techno-economic analyses, optimization models can determine the optimal supply chain design while simultaneously considering a large array of possible supply chain configurations, production locations, biomass supply locations, production scales, transport modes or production locations.[196] Moreover, optimization models can include geographical heterogeneity in feedstock cost, demand and supply.

Various recent studies have used mathematical optimization models to determine the optimal design of bioenergy supply chains, addressing one or more of the

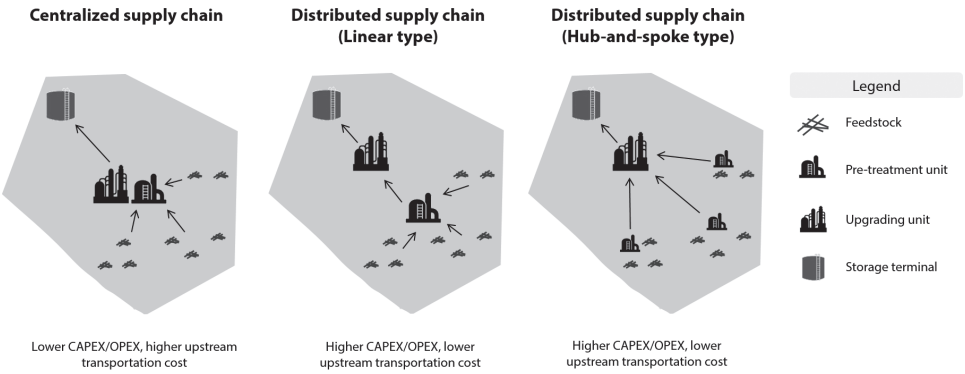


FIGURE 3-1: A schematic image of centralized and distributed supply chain configurations.

aforementioned cost reduction strategies. A large number of optimization studies have looked at the optimal network structure and the number, location and size of the conversion plants in a certain geographical context. [204,213,215–223] Most of these studies include spatially-explicit data of feedstock supply and, to a lesser extent, feedstock cost and (intermodal) transport networks (see Yue et al.[196] for an extensive review).[204,213,215–220] Only few models, however, incorporate the option of integration with existing industries[213] or different supply chain configurations[219,220], even though both could have a large impact on supply chain design. Moreover, although competition for feedstock and land resources has been discussed at length at a general level regarding crop-based biofuels [224–226] and forest-based biofuels[227,228], competing biomass demand from other industries has only been considered explicitly in a few studies.[213,221,222]

The aim of this study is to examine the impact of and interrelation between the four aforementioned cost reduction strategies in one optimization model. These strategies were applied to a case study in Sweden. Sweden was chosen because of its well-developed forest industry (creating competing biomass demand as well as integration opportunities), forestry feedstock potential and the ambitious vision to be one of the first nations to completely phase out fossil fuels for transport.[229,230] Moreover, the availability of detailed spatially-explicit data in Sweden allows for relatively detailed analysis. Although this study includes a high level of regional specificity and provides strategic insights for the development of a biofuel sector in Sweden, it was also attempted to generalize the findings within the boundaries of a case study.

A mixed-integer linear programming (MILP) model was developed to minimize the sum of biofuel production costs and feedstock procurement cost for forest industries (i.e. sawmills, stationary energy and pulp mills). Hence, unlike most other studies, this

study does not minimize biofuel costs, but optimizes for the forestry system as a whole. For biofuel production, forest biomass is converted to biocrude through hydrothermal liquefaction (HTL). The biocrude is subsequently hydroprocessed to drop-in (i.e. hydrocarbon fuels which are chemically similar to their fossil counterpart) biofuels at sites with access to natural gas (natural gas grid or LNG terminal) or hydrogen (refinery). These high-quality 'advanced' biofuels can provide high greenhouse gas emission reductions[231,232] and can be used in transport sectors for which no low-carbon alternatives other than biomass-derived fuels are readily available, such as marine, aviation and heavy trucking.[24]

Similar to pelletization or pyrolysis, HTL densifies biomass into a transportable intermediate and can hence be used in a distributed supply chain design. HTL was selected in this study based on its promising techno-economic performance and integration opportunities with existing industries due to the production of excess steam.[107,116,214,231,233,234] Furthermore, it produces a biocrude of higher quality than pyrolysis in terms of heating value, moisture content, oxygen content, and stability.[231,234]

The optimization model is spatially explicit in competing biomass demand, transportation infrastructure, feedstock cost-supply data and production locations. The optimization parameters comprised production scale, supply chain configuration, feedstock source and type, transport mode, and production location. Furthermore, the benefits of co-location with existing assets (i.e. sawmills, pulp and paper mills, district heating, forestry terminals, refineries, LNG terminals and the natural gas grid) were quantified and included in the model calculations.

3.2 METHODS

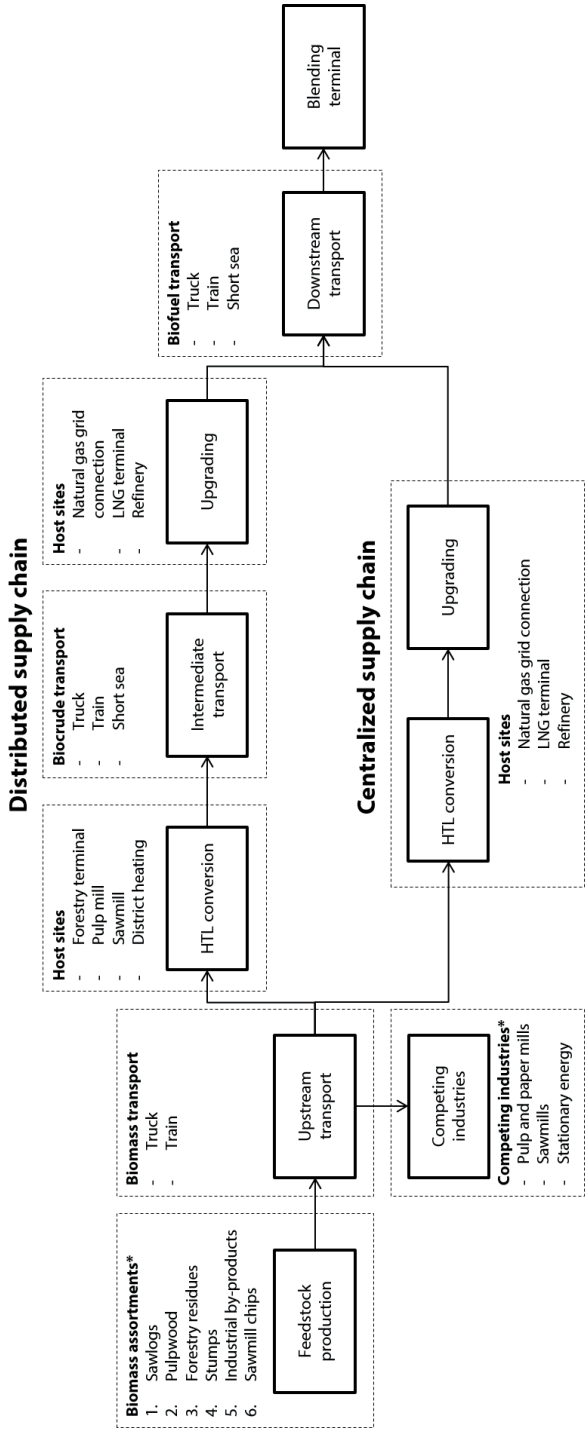
3.2.1 Geographical scope

This study focuses on feedstock supply and demand within the national boundaries of Sweden, hence excluding border effects. The Swedish forestry sector is a highly developed sector in which a large part of the biomass supply is already utilized. Sawlogs and pulpwood are almost completely utilized for materials (paper and sawn goods). By-products such as stumps and forestry residues are available, but may be restricted by mobilization constraints (e.g. by price or sustainability requirements).[228,235] In 2013, biomass contributed to almost 34% (470 PJ yr^{-1} or 130 TWh yr^{-1}) of final domestic energy use.[228,236] Liquid or gaseous biofuels in transport have grown significantly in the last decade to 12% (40 PJ yr^{-1}or 11 TWh yr^{-1}) of final energy use in the road transport sector. Although roughly 3.6 PJ (1 TWh) of forest biomass (mainly tall oil) is currently

used for biofuel production, the demand for forest biomass for biofuel production was estimated to grow by 50-97 PJ yr^{-1} (14-27 TWh yr^{-1}) in 2030.[228] A description of Swedish feedstock cost-supply, competing biomass demand, potential conversion locations and transport costs can be found in Section 3.2.4.1, 3.2.4.2, 3.2.4.3, and 3.2.4.6, respectively.

3.2.2 Supply chain scope

The scope encompasses the biofuel supply chains from feedstock production site to blending terminal (Figure 3-2). Forestry feedstocks are converted to biocrude through HTL. The biocrude is consequently upgraded to diesel, gasoline and light ends using hydroprocessing.[116] In centralized supply chains, HTL conversion and upgrading occur at the same location. In distributed supply chains HTL conversion and upgrading occurs at different locations, thus requiring intermediate transport. Feedstocks include both virgin feedstocks (sawlogs, pulpwood, primary forestry residues and stumps) and by-products from the forest industry (sawmill chips and industrial by-products from sawmills (IBS) and pulp mills (IBP)). Other by-products from the forest industry (e.g. black liquor or tall oil) were excluded from this analysis (see for example Pettersson et al.[213]). Feedstocks may be used for biofuel production or competing forest industries, i.e. sawmills, pulp mills and the stationary energy sector to produce heat and power (Section 3.2.4.2). HTL conversion may occur at sawmills, pulp and paper mills, forestry terminals or sites with access to district heating systems. Upgrading or centralized production is located at LNG terminals, refineries and sites connected to the natural gas grid. Integration benefits from for example steam sales, by-product sales, shared equipment or shared workforce were translated into a reduction of feedstock cost, OPEX and/or CAPEX (Section 3.2.4.3). Biomass, biocrude and biofuel were transported over lowest-cost intermodal routes (including road, rail and short sea transport). Petroleum storage and blending terminals were considered the end point of the supply chain.[237,238]



* Assortment 2-6 are considered for biofuel production, paper mill heat demand and stationary energy sector. Assortment 1,2 and 6 can be used by the pulp mills. Assortment 1 is used in sawmills. Industrial byproducts from sawmills are used on-site to cover sawmill heat demand.

FIGURE 3-2: Scope of the analysis.

3.2.3 Modelling framework

A MILP optimization model was adapted from Lin et al.[215] The model was written in GAMS using a CPLEX solver. For a defined demand for biofuels, the model optimized total system cost for one production year within a certain set of constraints. The total system costs were defined as the sum of the feedstock procurement cost for competing industries (i.e. feedstock and upstream transport cost) and biofuel production costs, which includes feedstock cost, transport cost for the upstream, intermediate and downstream portions, and cost of conversion (CAPEX and OPEX). Modelling parameters and constraints are given in Table 3-1. The employed model resolutions are listed in S3.1.

TABLE 3-1: Modelling parameters and constraints.

Modelling parameters	Modelling constraints
• Number, location and size of biofuel/biocrude production plants • Supply chain configuration (centralized and distributed) • Material flows (forestry feedstock, biocrude and biofuel) to biofuel production plants and competing industries • Steam and/or material transfer at a production site • Transport mode	• Biomass supply • Maximum production scale at a production site • Amount of material and steam transfer at a production site

3.2.4 Input data

This section discusses key input data. Additional input data can be found in S3.2 and S3.3. All energy quantities were based on lower heating value. Plant capacities indicate actual capacity, not nameplate capacity. A load factor of 90% was used to relate nameplate capacity and actual capacity.[116] All costs are given in $€_{2015}$. Employed conversion factors can be found in S3.4.

3.2.4.1 Feedstock supply and price distribution

The aggregated feedstock supply and cost distribution is shown in Table 3-2. A spatially-explicit bottom-up approach was applied to define the harvesting costs and theoretical supply potential for sawlogs from final felling and thinning, pulpwood from final felling and thinning, forestry residues from final felling and thinning and stumps from final felling. For harvesting residues and stumps a number of restrictions were implemented on the theoretical potentials to give the ecological potential, as described in Lundmark et al.[239] The results from Lundmark et al. were updated to 2015 using more recent scenarios[240,241], which particularly decreased the potential for stumps. The feedstock supply potential was aggregated at a half-degree spatial resolution (Figure 3-3).

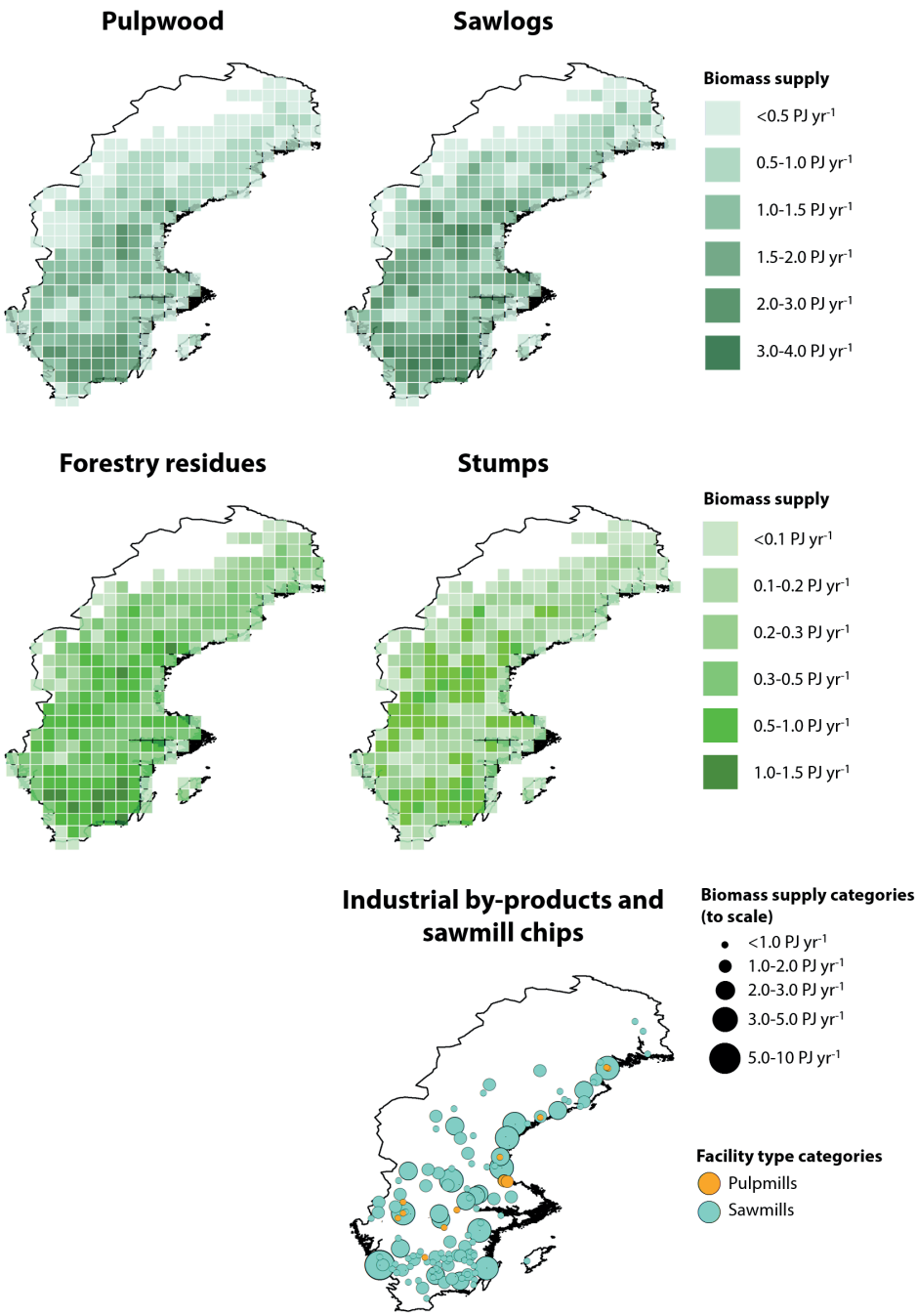


FIGURE 3-3: Supply of forest biomass, industrial by-products and sawmill chips.

Available quantities of sawmill chips, IBS and IBP were correlated to the production capacities of pulp mills and sawmills using generic yield factors.[242–247] Imports and exports of biomass were not explicitly considered in the model. Instead, the industrial wood demand was calibrated using trade statistics from the Swedish Forest Agency.[248] As the imports (of which the main part consists of pulp wood) exceed the exports, the net imports of biomass were deducted from the total wood demand, i.e. all pulp mills and sawmills were assumed to use an equal share of imported wood. The costs of virgin biomass was converted into roadside prices using a calibration factor which was determined from bioenergy and stemwood price statistics.[249,250] Prices for sawmill chips, IBS and IBP were kept constant across Sweden.[251,252] S3.5 contains a geographical distribution of the feedstock price.

TABLE 3-2: Aggregated supply and price distribution of biomass assortments.

Biomass assortments	**Total supply (PJ yr^{-1})**	**Roadside price (€ GJ^{-1})**		**Calibration factor to convert roadside cost to price**
		Average	Standard deviation	
Sawlogs	321	5.96	0.44	2.23
Pulpwood	248	4.23	0.30	1.48
Forestry residues	111	4.18	0.45	1.39
Stumps	58	5.94	1.13	1.39
Sawmill chips	87[i]	3.06	0	-
Industrial by-products from sawmills (IBS)	63[i]	2.78	0	-
Industrial by-products from pulp mills (IBP)	5[i]	2.78	0	-
Total	**893**			

i. Yield factors of 5.41 GJ sawmill chips per m^3 sawn wood and 3.93 GJ IBS per m^3 sawn wood were used.[242] The production of IBP was estimated based on information from the environmental database of the Swedish Forest Industries Federation (SFIF).[246]

3.2.4.2 Competing industrial biomass demand

Competing demand for biomass from pulp mills, sawmills and stationary energy sector were considered spatially explicitly in the model (Figure 3-4). Sawmills and pulp mills use forestry feedstocks for material and process heat purposes. The stationary energy sector utilizes forestry feedstocks to produce heat and power. The demand sectors with the respective biomass assortments they use are listed in Table 3-3. From Figure 3-3 and Figure 3-4 it can be observed that biomass supply and competing demand is particularly high in the southern part of Sweden and along the coastline. The demands are described statically on an annual basis (seasonal differences in demand

were not taken into account here), based on production and demand in the reference year 2015.[245–248,253,254] Heat demand from sawmills and pulp mills could be met in the model by integration with an HTL plant, by using (a share of) the industrial by-products available on-site or by transporting biomass to the industrial site. For sawmills and pulp mills, a boiler conversion efficiency of 80% and 90% (on energy basis) were used, respectively.

TABLE 3-3: Aggregated biomass demand for biofuel production, sawmills, pulp mills and the stationary heat sector in Sweden and the corresponding biomass assortments that are used in these sectors.

	Aggregated biomass demand (PJ yr^{-1})	**Biomass assortments**						
		Sawlogs	Pulpwood	Forestry residues	Stumps	Sawmill chips	IBS	IBP
Competing industry								
Sawmills (sawn products)	247	x						
Pulp mills (pulp)	304	x	x			x		
Stationary energy sector	103		x	x	x	x	x	x
Saw mills (heat demand)	14						x	
Pulp mills (heat demand)	28		x	x	x	x	x	x
Total	**696**							
Biofuel production	Variable		x	x	x	x	x	x

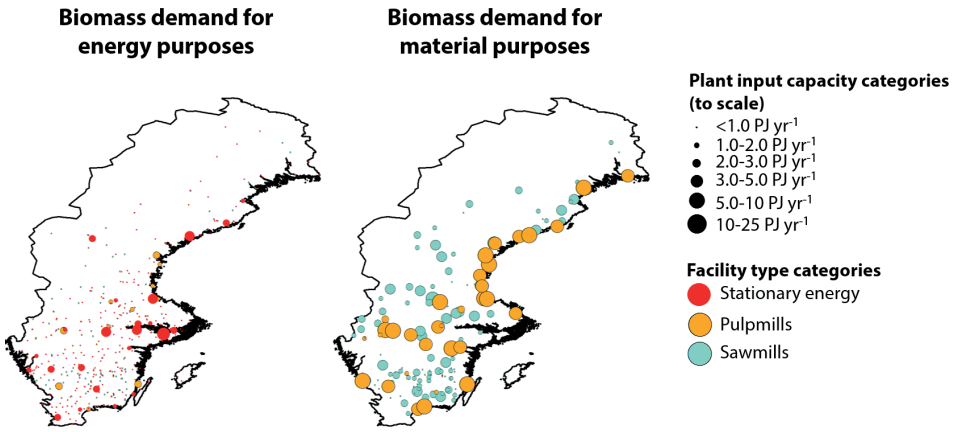


FIGURE 3-4: Biomass demand for (process) energy purposes and material purposes (pulp and sawn products) in stationary energy plants, pulp mills and sawmills.

3.2.4.3 Production locations and blending terminals

Figure 3-5 visualizes the potential production locations for HTL, upgrading and centralized plants as well as blending terminals. The production locations were selected based on the availability of essential utilities (natural gas or hydrogen) and/or integration opportunities, which may include a reduction of feedstock cost, OPEX and/or CAPEX depending on the production location (Table 3-4). Only refineries with a steam methane or catalytic reformer were included, as these are able to produce (excess) hydrogen. Production locations near a natural gas grid were localized at the center of those municipalities connected to the natural gas grid. Figure 3-5 shows HTL plants may be located throughout the country, while upgrading locations and blending terminals are confined to the southern part of the country and some sites along the coastline. Moreover, the number of included HTL conversion locations (366) considerably exceeds the number of upgrading sites (37).

Sites with storage facilities for petroleum products were used as a proxy for sites with blending capacity.[237,238] The size of the terminal was taken to be a measure of fuel demand in the region and was used as a constraint on the maximum supply to this terminal. Based on the oil handling capacity of the terminal, the maximum biofuel blending capacity of the terminal was categorized into four groups: 0.2 PJ yr^{-1} (7), 1 PJ yr^{-1} (14), 50 PJ yr^{-1} (3) and 400 PJ yr^{-1} (2). It was assumed that 50% of the storage capacity could be used for biofuel blending and storage operations.

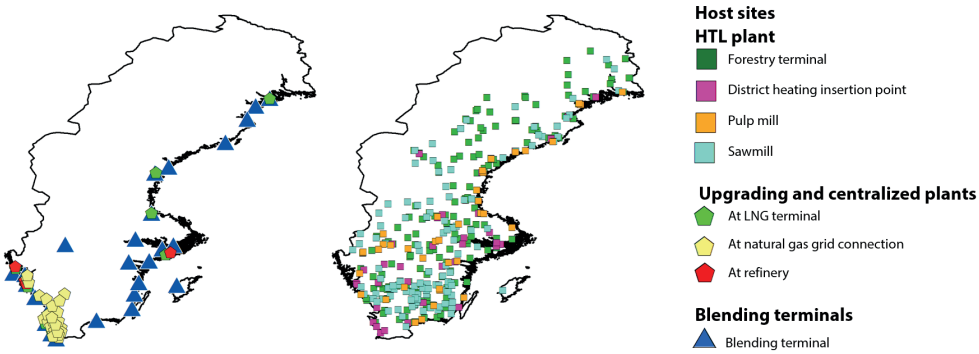


FIGURE 3-5: Production locations for upgrading (left), centralized plants (left), blending terminals (left) and HTL conversion (right).

3.2.4.4 Integration benefits

Cost benefits from integration were determined on a high-level basis and generalized for each type of production location (Table 3-4). Steam sales and by-product purchases

are cash flows between biofuel production and host industries. Whereas these transfers do not directly affect the total system costs (as the cash flows cancel each other out), they have an indirect impact since they liberate on-site low-cost by-products for biofuel production, and decrease biomass purchases or increase by-product sales for sawmills and pulp mills. Steam sales to refineries and district heating systems were deducted from the biofuel production costs. Co-location benefits (e.g. shared work force, buildings and service facilities) were calculated using the approach proposed by De Jong et al.[214] At conversion locations with feedstock handling infrastructure in place, the CAPEX for handling infrastructure was reduced by 50%. For co-location with refineries, hydrogen is assumed to be bought from the refinery, hence eliminating the need for a steam methane reformer (SMR). Offgases from upgrading were assumed not to be recycled in this case, contrary to other upgrading locations. Example site layouts for integration with a sawmill and a refinery are provided in S3.6.

Material and steam integration benefits were constrained based on the capacity of individual production locations. Steam demand was capped at the heat demand at individual production locations (Figure 3-4). Heat transfer to district heating systems was limited to a site-specific heat demand (capped at 10 MW) and load factor. [253] Refinery steam demand was estimated using the average ratio of steam use to crude oil processing capacity of US refineries over the last decade (2006-2015).[260,261] It was assumed that steam could not be valorized at forestry terminals, LNG terminals or locations connected to the natural gas grid. The transfer of by-products at sawmills and pulp mills was constrained by its availability (Section 3.2.4.2 and Figure 3-3). The maximum amount of hydrogen transferred at refineries was assumed to be 10% of the available hydrogen on-site.[256] The availability of natural gas at LNG terminals was assumed to be constrained at ten times the nominal LNG storage capacity.[255] No cap was placed on the availability of natural gas at sites connected to the natural gas grid.

3.2.4.5 Techno-economic input data and economies of scale

Data for biofuel production through HTL is based on a process design, mass and energy balances, and equipment costs provided by Zhu et al.[116] (goal case). The Standardized Cost Estimation for New Technologies (SCENT) method was used to calculate the production costs from the data provided by Zhu et al.[102] The production costs vary for each type of production location due to integration benefits (Table 3-5). The total costs in Table 3-5 are given for selected production capacities and do not include feedstock costs, transport costs and potential steam sales. A more detailed breakdown of production costs is available in S3.2.

TABLE 3-4: Material/steam exchange and CAPEX/OPEX benefits per type of production location.

	Type of production location	Ref.	Integration type			
			Material/steam exchange			CAPEX/OPEX benefits[i]
			Flow	Price[ii]	Maximum transfer quantity (range due to site-specificity)	
Unit				€ GJ^{-1}	PJ yr^{-1}	
Centralized						
HTL & Upgrading	Natural gas grid		Natural gas	8.02	Not capped	-
	LNG terminal	[255]	LNG	8.02	1.0-6.0	-
	Refinery	[237,256, iii]	Hydrogen	19.2	2.2-16	Use of existing SMR Co-location benefits[v]
Distributed						
HTL	Forestry terminal	[257,258]	-			Shared feed handling infrastructure
	Pulp and paper mill	[245,247]	IBP Steam	2.78 3.48	0-1.4 0-2.6	Shared feed handling infrastructure Co-location benefits[v]
	Sawmill	[246,254]	IBP Sawmill chips Steam	2.78 2.78 3.48	0.01-2.4 0.02-3.3 0-0.56	Shared feed handling infrastructure Co-location benefits[v]
	District heating	[253, iv]	Steam	3.48	0.16-0.29	-
Upgrading	Natural gas		Natural gas	8.02	Not capped	-
	LNG terminal	[255]	LNG	8.02	1.0-6.0	
	Refinery	[237,256, iii]	Hydrogen Steam	19.2 10.0	2.2-16 0.7-1.9	Use of existing SMR Co-location benefits[v]

i. Quantification of the CAPEX/OPEX benefits is discussed in Section 3.2.4.5 and Table 3-5.

ii. The price for steam was approximated by assuming the current value is represented by the feedstock price of industrial by-products (2.78 € GJ^{-1}) or, in case of refineries, natural gas (8.02 € GJ^{-1}) and a boiler efficiency of 0.8 GJ steam per GJ biomass. The Swedish natural gas price was taken from Eurostat.[140] The hydrogen price was calculated based on a fixed (3.37 € GJ^{-1} hydrogen) and a variable portion (1.97 € GJ^{-1}J hydrogen per € GJ^{-1} natural gas), taken from the NREL H2A study (Central Natural Gas design).[259] The LNG price is set similar to the natural gas price, as calculations of the LNG price based on either Norwegian or Henry Hub natural gas prices yielded lower prices than Swedish natural gas prices.

iii. Hydrogen production at the Gothenburg (ST1) and Nynäshamn refinery was estimated using the Gothenburg (Preem) hydrogen per barrel oil input ratio. [256]

iv. Only district heating systems with a substantial load factor (>4500 h yr^{-1}) and base heat load (>10 MW) were considered. Exchange of heat was capped at 10 MW.

v. These include benefits of a plant co-located with a processing plant (i.e. sawmill, pulp and paper mill or refinery) relative to a greenfield plant, such as reduced cost for buildings, service facilities, operating labor (shared workforce), and local taxes. These benefits reduce the CAPEX by 7.2% and labor cost by 41%, see also De Jong et al.[214] and S3.2.

TABLE 3-5: Techno-economic data at selected capacities.

Cost item	Unit	Distributed supply chain							Centralized supply chain		
		HTL conversion				Upgrading			HTL conversion and upgrading		
Reference capacity		Biomass input: 2.75 PJ yr^{-1} (87 MW, 19 t h^{-1})				Biocrude input: 2.18 PJ yr^{-1} (69 MW, 7.6 t h^{-1})			Biomass input: 2.75 PJ yr^{-1} (87 MW, 19 t h^{-1})		
Production location		Forestry terminal	Pulp mill	Sawmill	District heating	Natural gas grid	LNG terminal	Refinery	Natural gas grid	LNG terminal	Refinery
Input		Biomass	Biomass	Biomass	Biomass	Biocrude	Biocrude	Biocrude	Biomass	Biomass	Biomass
Output		Biocrude	Biocrude	Biocrude	Biocrude	Biofuel	Biofuel	Biofuel	Biofuel	Biofuel	Biofuel
Process data											
Yield	$GJ_{out}\ GJ_{in}^{-1}$	0.79	0.79	0.79	0.79	1.06	1.06	1.06	0.84	0.84	0.84
Steam production	$GJ\ GJ_{out}^{-1}$		0.10	0.10	0.10						0.09
Net electricity requirement	$GJ\ GJ_{out}^{-1}$	0.007	0.007	0.007	0.007	0.014	0.014	0.007	0.049	0.049	0.021
Natural gas requirement	$GJ\ GJ_{out}^{-1}$					0.16	0.16		0.06	0.06	
Hydrogen requirement	$GJ\ GJ_{out}^{-1}$							0.15			0.15
Total Purchased Equipment	M€	16.5	16.5	16.5	16.9	18.0	18.0	13.4	32.5	32.5	28.6
Total Capital Investment	M€	82.3	76.4	76.4	83.9	89.8	89.8	61.7	162	162	132
Annualized total Capital investment (CAPEX)	€ GJ_{out}^{-1}	4.44	4.12	4.12	4.53	4.58	4.58	3.15	8.26	8.26	6.75
Operational expenditures (OPEX)[i]	€ GJ_{out}^{-1}	6.31	5.83	5.83	6.39	6.23	6.23	6.37	11.2	11.2	11.7
Total production cost (OPEX + CAPEX)[i]	**€ GJ_{out}^{-1}**	**10.7**	**10.0**	**10.0**	**10.9**	**10.8**	**10.8**	**9.5**	**19.5**	**19.5**	**18.4**
Scale-independent conversion costs	€ GJ_{out}^{-1}	2.21	2.03	2.03	2.21	2.00	2.00	3.47	3.64	3.64	5.46
Scale-dependent conversion costs	€ GJ_{out}^{-1}	8.53	7.92	7.92	8.70	8.80	8.80	6.05	15.9	15.9	13.0

i. Excluding feedstock costs, upstream transport cost and potential steam sales, but including hydrogen and natural gas costs.

Due to synergies between the HTL and upgrading plants (i.e. exchange of offgases and shared utilities, Figure 3-6), the sum of the costs for separate plants (in case of a distributed supply chain) is larger than the total cost of a centralized facility, even when considering integration benefits. The liquefaction process and the waste water treatment produce offgases which can be used to produce electricity and (excess) steam (distributed case or centralized refinery case) or to partially fuel the SMR which produces hydrogen for the upgrading process (centralized natural gas or LNG terminal case). The excess steam produced in the former cases can be exported to host industries. Upgrading in the distributed supply chain thus requires additional natural gas input for hydrogen production, compared to the centralized scenarios which partly use HTL offgases.

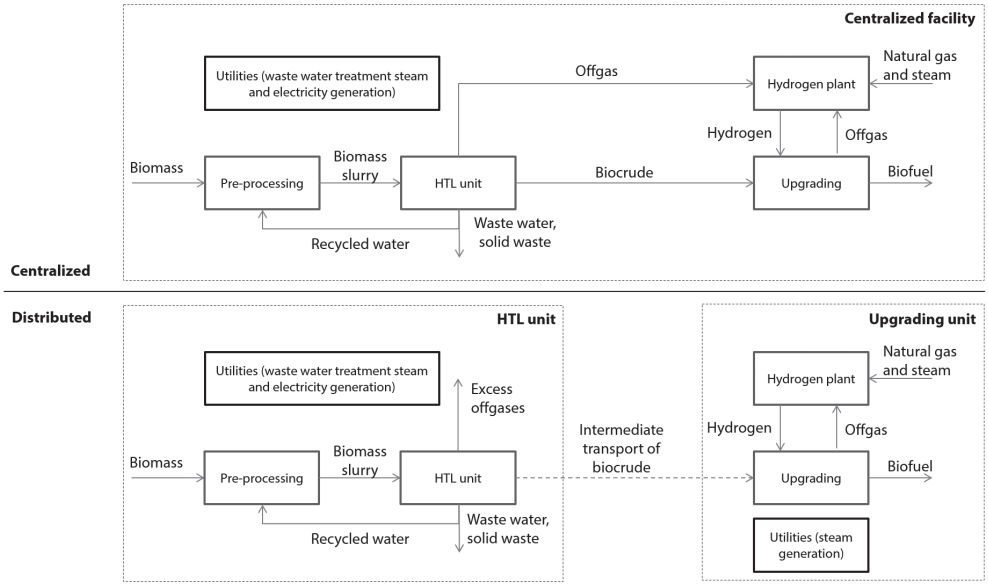


FIGURE 3-6: Process configurations for centralized and distributed production, adapted from Zhu et al.[116]

The scale-dependent behavior of conversion costs was approximated using the power law.[105] Scaling factors for process units range between 0.60-0.79 (S3.2).[105,114,116] A maximum scale was applied to the HTL reactor, SMR and hydrotreater. Multiple units were built in parallel once the maximum scale for a particular unit is reached. The maximum scales were based on previously reported limits for liquefaction units and scaling curves for SMRs and hydrotreaters.[105,231,262] For implementation in the MILP model, the non-linear power law was approximated by a piecewise linear function.[215] The power function was divided into three linear functions with breaks at the maximum input capacity of a HTL reactor (2.75 PJ yr^{-1}, 87 MW) and an SMR (39.3 PJ yr^{-1}, 1246 MW). Remaining equipment

(i.e. utilities, hydrotreater, hydrocracker, biomass conditioning and feedstock handling equipment) was scaled up to the maximum scale of production at one site, which was aligned with the maximum input scale of a hydrotreater (73.1 PJ yr^{-1}, 2318 MW). This scale is less than half the input capacity of a small oil refinery, such as the ST1 refinery in Gothenburg (174 PJ yr^{-1}), but much larger than a large Swedish pulp mill (~21 PJ yr^{-1}). Please note that the data in Table 3-5 is presented for a specific capacity; upscaling reduces the difference between distributed and centralized production, as the scale-dependent costs decrease with size. An example scaling curve is provided in S3.2.

3.2.4.6 Transport costs

Transport costs of solids (biomass) and liquids (biocrude and biofuel) were pre-optimized using geographically explicit intermodal transport model that runs in the Network Analyst extension of ESRI's ArcGIS. The geodatabase of the transport model consisted of transport network layers for road[263], rail[264] and short sea shipping[265] (S3.3). Swedish forest biomass terminals and sea ports were used as intermodal terminals.[257,265,266] For each commodity, the Network Analyst tool constructs origin-destination (OD) cost matrices for least-cost paths along the intermodal transport network between all possible supply nodes and demand nodes, based on mode- an feedstock-specific parameters shown in Table 3-6. S3.3 contains the underlying assumption regarding fuel consumption and prices, variable costs and fixed costs.

TABLE 3-6: Transport cost parameters.

Parameter	Unit	Road	Rail	Sea
Transport cost				
Forestry residues and stumps (chipped)	€ $GJ^{-1}km^{-1}$ (€ t^{-1} km^{-1})	0.0097 (0.162)	0.0008 (0.013)	0.0004 (0.006)
Industrial by-products (IBS, IBP and sawmill chips)	€ $GJ^{-1}km^{-1}$ (€ t^{-1} km^{-1})	0.0097 (0.162)	0.0008 (0.013)	0.0004 (0.006)
Sawlogs and pulpwood	€ $GJ^{-1}km^{-1}$ (€ t^{-1} km^{-1})	0.0097 (0.162)	0.0008 (0.013)	0.0004 (0.006)
Biocrude	€ $GJ^{-1}km^{-1}$ (€ t^{-1} km^{-1})	0.005 (0.162)	0.0002 (0.008)	0.0002 (0.007)
Biofuels	€ $GJ^{-1}km^{-1}$ (€ t^{-1} km^{-1})	0.004 (0.162)	0.0002 (0.008)	0.0002 (0.007)
Loading or unloading cost[i]				
Forestry residues and stumps (chipped)	€ GJ^{-1} (€ t^{-1})	0.31 (5.11)	0.53 (8.93)	0.29 (4.85)
Industrial by-products (IBS, IBP and sawmill chips)	€ GJ^{-1} (€ t^{-1})	0.16 (2.71)	0.53 (8.93)	0.39 (6.48)
Sawlogs and pulpwood	€ GJ^{-1} (€ t^{-1})	0.12 (1.99)	0.48 (8.04)	0.39 (6.48)
Biocrude	€ GJ^{-1} (€ t^{-1})	0.04 (1.39)	0.1 (3.26)	0.35 (11.53)
Biofuels	€ GJ^{-1} (€ t^{-1})	0.03 (1.31)	0.08 (3.08)	0.27 (10.89)

i. Loading and unloading cost are assumed to be similar.

3.2.5 Base scenario and alternative scenarios

The model was evaluated for a range of total biofuel production levels (1, 5, 10, 15, 30, 50, 75, 100, and 150 PJ yr^{-1}). This can be compared to current total fuel consumption for road transport in Sweden, which amounts to approximately 320 PJ yr^{-1}. Scenario VI and VII were run up to 100 PJ yr^{-1} only, as there was no feasible solution for 150 PJ yr^{-1} due to biomass supply constraints. The Base scenario run includes competing demand, centralized and distributed supply chain configurations, all integration benefits, and intermodal transport. Alternative scenarios were run to isolate the role of different cost reduction strategies and examine the impact of competing demand and biomass supply:

I. **Base scenario**.

II. **Reduced maximum capacity.** The maximum input capacity per site was set to 7.31 PJ yr^{-1} (232 MW), i.e. 10% of the initial value, to explore the impact of limiting economies of scale. This scale is roughly the size of an average Swedish pulp mill, but relatively large compared to current cellulosic ethanol plants.[267]

III. **Centralized supply chain configurations only.** Only centralized supply chain configurations were allowed in the model solution.

IV. **Distributed supply chain configurations only.** Only distributed supply chain configurations were allowed in the model solution.

V. **No integration benefits.** In this scenario all integration benefits listed in Table 3-4 were disabled, except the exchange of industrial by-products. OPEX and CAPEX profiles from district heating sites (HTL conversion), LNG terminals (upgrading) and LNG terminals (centralized facilities) were adopted for other production locations.

VI. **Low biomass supply.** Total biomass supply of virgin feedstocks (i.e. stumps, forestry residues, sawlogs, and pulpwood) was diminished by 10% to analyze a scenario in which biomass supply decreases. Supply of industrial by-products and sawmill chips remained unaltered.

VII. **High competing demand.** Competing demand and the production of industrial by-products was increased by 10% to analyze a scenario in which competing demand increases.

VIII. **Road transport only**. Only road transportation (by truck) was allowed for solid biomass and biocrude. Downstream logistics of biofuels could still occur through road, rail or short sea transport. This scenario was used to explore the impact of introducing intermodal transport.

3.3 RESULTS

3.3.1 Base scenario results

Figure 3-7 shows the cost breakdown for the Base scenario. The figure describes a sharp downward cost trend at first, which is counteracted by an upward tail after 15 PJ yr^{-1}at which the cost are lowest (18.1 € GJ^{-1}). The initial cost decrease is mainly due to a decline in CAPEX; the upward tail is mainly caused by increased feedstock costs and upstream transport cost. The upward tail is shallow; the cost difference between 15 and 150 PJ yr^{-1} is only 0.8 € GJ^{-1}. The share of upstream cost never exceeds 10% and declines after distributed supply chain designs are introduced beyond 100 PJ yr^{-1} (Figure 3-8). The contribution of downstream distribution or intermediate transport cost is negligible. Whereas feedstock procurement cost for sawmills are moderately affected in the Base scenario (+2%), procurement cost for pulp mills (+7% for pulpwood demand and +24% for heat demand) and stationary energy plants (+11%) increase significantly at 150 PJ yr^{-1} relative to the reference level with no biofuel demand, because they use the same (inexpensive) feedstocks as biofuel production. Sawmill heat demand is exclusively met by on-site sawmill by-products and do not incur a cost to the sawmill.

Figure 3-8 visualizes the production locations in the Base scenario for six different biofuel production levels. It shows that centralized production at the southwestern refineries is preferred at all levels due to high feedstock availability and significant integration benefits. The Base scenario solution does not include HTL conversion at district heating sites or forestry terminals due to lower integration benefits compared to sawmills and pulp and paper mills. The locations of the HTL plants, however, vary with the biofuel production level and cannot be explained by exceptional site-specific benefits, indicating there is no robust preference for particular HTL locations. Even though LNG terminals might be closer to HTL locations, natural gas upgrading plants are preferred over LNG terminals as the former allow for higher production scales since the supply of natural gas is constrained at LNG terminals (at 6-39 PJ yr^{-1} biofuel for upgrading plants and 17-101 PJ yr^{-1} biofuel for centralized plants). With the inclusion of a natural gas upgrading plant instead of a refinery upgrading plant at 150 PJ yr^{-1}, conversion cost increase (due to the need for an SMR), while the average cost for hydrogen/natural gas purchases decrease.

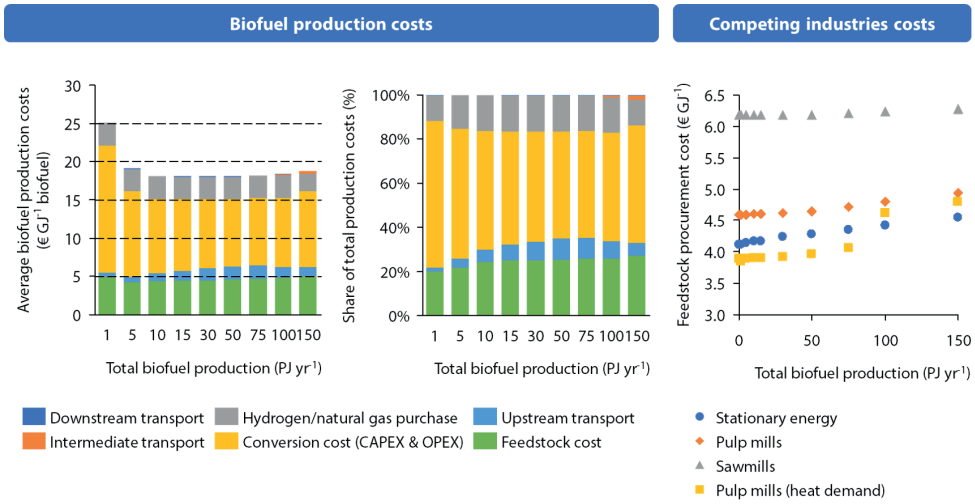


FIGURE 3-7: The biofuel production costs and feedstock procurement costs (i.e. feedstock and upstream transport costs) for competing industries for the Base scenario.

Figure 3-8 also shows a gradual expansion with rising biofuel production levels to the north of the country because of lower feedstock utilization rates. Industrial by-products and sawmill chips (not shown in Figure 3-8) are used first due to their low roadside price. From 15 PJ yr^{-1} onwards, pulpwood, forestry residues and sawmill chips are increasingly used for biofuel production because of relatively low roadside prices and moderate loading/unloading costs. This instigates a shift towards the use of more sawlogs and pulpwood in pulp mills. From 75 PJ yr^{-1} onwards, stumps are increasingly utilized, particularly for stationary energy and biofuel production. Even though the majority of unutilized feedstock supply is located in the north, it is only used at higher biofuel production levels, as the feedstock is also more expensive to mobilize and further away from locations where large-scale upgrading is possible.

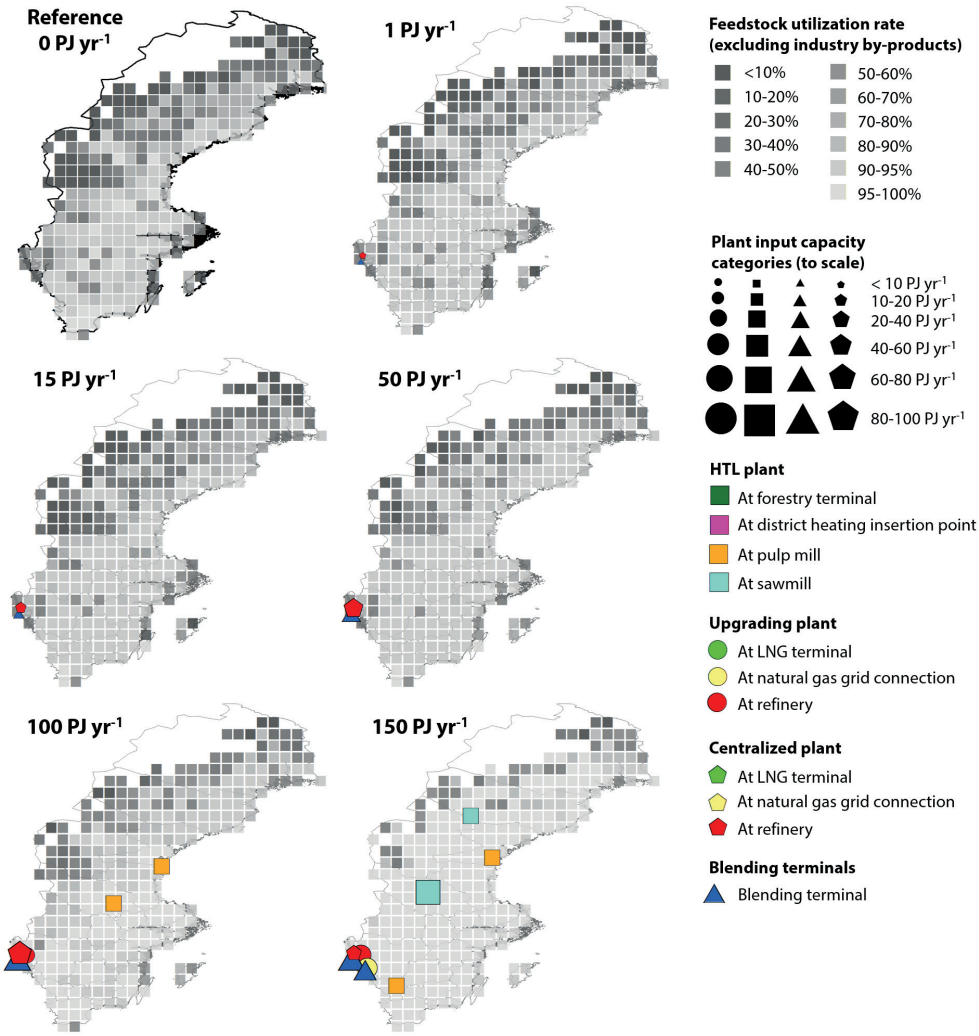
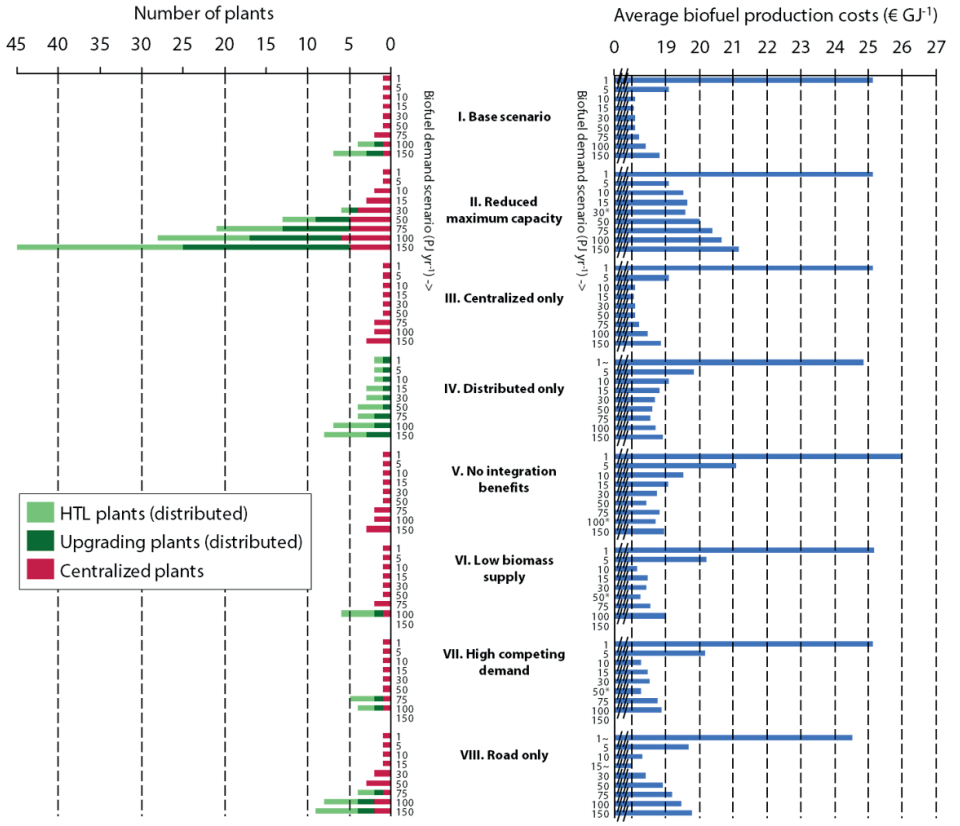


FIGURE 3-8: Production locations and feedstock use in the base scenario at different biofuel production levels.

3.3.2 Alternative scenarios

Figure 3-9 gives an overview of the number and type of plants and the average biofuel production costs for each scenario considered.



*The graph shows the biofuel production costs, while the model optimizes the total system cost (the sum of biofuel production cost and feedstock procurement costs for competing industries). For this reason the cases marked with an asterisk do not show a continuous upward trend towards higher biofuel production levels.
~Cases marked with a tilde yield lower biofuel production cost than the base scenario, but they show higher total system cost.

FIGURE 3-9: An overview of the number of plants and average biofuel production costs for different biofuel production levels.

3.3.2.1 Large scale versus small scale

All scenarios show the expected cost profile with increasing biofuel production levels; a rapid cost decline at small biofuel production levels due to economies of scale followed by an upward tail beyond the optimum. Between the optimum and the maximum plant output capacity (61.2 PJ yr^{-1}, 1941 MW), the upward tail is typically caused by increasing feedstock cost and/or upstream transport cost. Despite the upward tail, no additional plants are built before the maximum capacity is reached in the Base scenario, indicating that an optimum scale is a local optimum instead of a general optimum, depending on feedstock price, feedstock availability and integration benefits. Beyond the maximum capacity, additional (distributed) plants are built at less suitable locations which increase the CAPEX and feedstock cost while decreasing transport costs. Similar

dynamics are visible in the Centralized only and No integration benefits scenarios. In these scenarios medium-sized plants (input capacity >30 PJ yr^{-1}, 951 MW) also dominate the model solutions at higher biofuel production levels.

Scenarios in which economies of scale are restricted (Reduced maximum capacity), transport is more expensive (Road only) or distributed supply chain configurations are adopted (Distributed only) show a similar dominance of economies of scale at low production scales, but deviate from the aforementioned dynamics thereafter. Compared to the base scenario, the Reduced maximum capacity scenario shows a rise in biofuel production cost of 0-12%, with an increasing trend towards higher biofuel production levels. The upward tail in the Reduced maximum capacity scenario is mainly caused by rising feedstock cost and higher conversion cost, because less suitable sites need to be introduced as the biofuel production level increases. The Road only scenario shows a much steeper upward tail and the introduction of multiple plants at a lower biofuel production level (30 PJ yr^{-1}) due to increased transport cost. The Distributed only scenario shows a cost optimum at higher biofuel production levels (75 PJ yr^{-1}) because distributed designs temper the effect of increasing upstream transport cost; the upward tail is mainly caused by increasing feedstock cost.

3.3.2.2 Distributed versus centralized supply chains

In the Base scenario, centralized supply chain configurations prevail at biofuel production levels below 75 PJ yr^{-1}. The introduction of distributed supply chains at 100 PJ yr^{-1} is marked by lower feedstock and transport cost, but higher conversion cost. At the highest biofuel production level, almost 80% of the biofuel volumes are supplied through distributed supply chains. Centralized supply chains are preferred over distributed configurations, mainly because the latter show higher conversion cost due to the loss of synergies between the HTL plant and the upgrading plant (i.e. offgas integration and shared utilities), even including integration benefits. These additional costs outweigh the benefits of distributed configurations (i.e. lower upstream transport cost or access to lower-priced feedstocks). Distributed supply chains emerge at higher biofuel production levels, as upscaling reduces the difference between distributed and centralized production, while the share of upstream transport costs increases. Furthermore, at higher production levels well-sited locations are already taken and the biomass supply becomes increasingly dispersed and expensive. Consequently, the value of distributed configurations becomes more pronounced. Limiting economies of scale (Reduced maximum capacity) and higher transport cost (Road only scenario) leads to the introduction of distributed configurations from 30 PJ yr^{-1} and 75 PJ yr^{-1} onwards, respectively.

By allowing distributed supply chain configurations in the model solution, the Base scenario yields insignificant cost reductions (<1%) relative the Centralized only scenario. The Distributed only scenario shows 5% higher production costs compared to the Base scenario at a low biofuel production level, which fades at higher biofuel production levels. Figure 3-10 shows that upgrading remains centered in the southwest of Sweden in the Base scenario and Distributed only scenario. It is, however, only cost-effective to have multiple upgrading plants in one area (e.g. a refining cluster) if additional biomass is efficiently transported from elsewhere (e.g. by distributed supply chains). No significant variation was found in feedstock utilization rates.

Figure 3-1 shows distributed supply chains may be linear-type (i.e. one pre-treatment plant supplying one upgrading plant) or hub-and-spoke-type (i.e. multiple pre-treatment plants supplying one or more upgrading plants). Both types aim to decrease the upstream transport cost. Whereas both types incur additional cost due to the loss of synergies between the HTL and upgrading plant, the hub-and-spoke-type also experiences a loss of economies of scale. For this reason, linear-type distributed supply chains emerge at lower biofuel production levels while hub-and-spoke-type supply chains are introduced once the biofuel production level allows multiple medium-sized HTL plants (input capacity >10 PJ yr^{-1}, 317 MW) to be built.

3.3.2.3 Competing demand and the merits of integration

Biofuel production may be impeded by competition over biomass with existing forest industries, but may also profit from integration benefits with the same forest industries. The No integration scenario shows higher production costs than the Base scenario (+1-10%, decreasing with biofuel production level). As conversion costs have a higher share in the total production cost at small scales, CAPEX/OPEX benefits are particularly pronounced at smaller scales. Moreover, eliminating the integration benefits increases the additional cost for distributed relative to centralized configurations, causing centralized plants to dominate the No integration scenario. The material and energy integration benefits included in this study are valid on a small to medium scale. Cost reductions due to integrations benefits are, however, modest compared to the overall production costs and benefits of economies of scale. The production of by-products at pulp mills and sawmills provides 5.8 and 1.4 PJ yr^{-1} of by-products, respectively, at maximum. Similarly, steam integration at sawmills, district heating and pulp mills can be utilized at biomass input capacities of 7.2, 3.8 and 34 PJ yr^{-1} at maximum, but provide a marginal cost reduction (0.36 € GJ^{-1} biofuel). For refineries, steam integration can be utilized at input capacities up to 9-25 PJ $yr^{-1}$and provides a slightly higher cost reduction due to a higher heat transfer price (0.92 € GJ^{-1} biofuel).

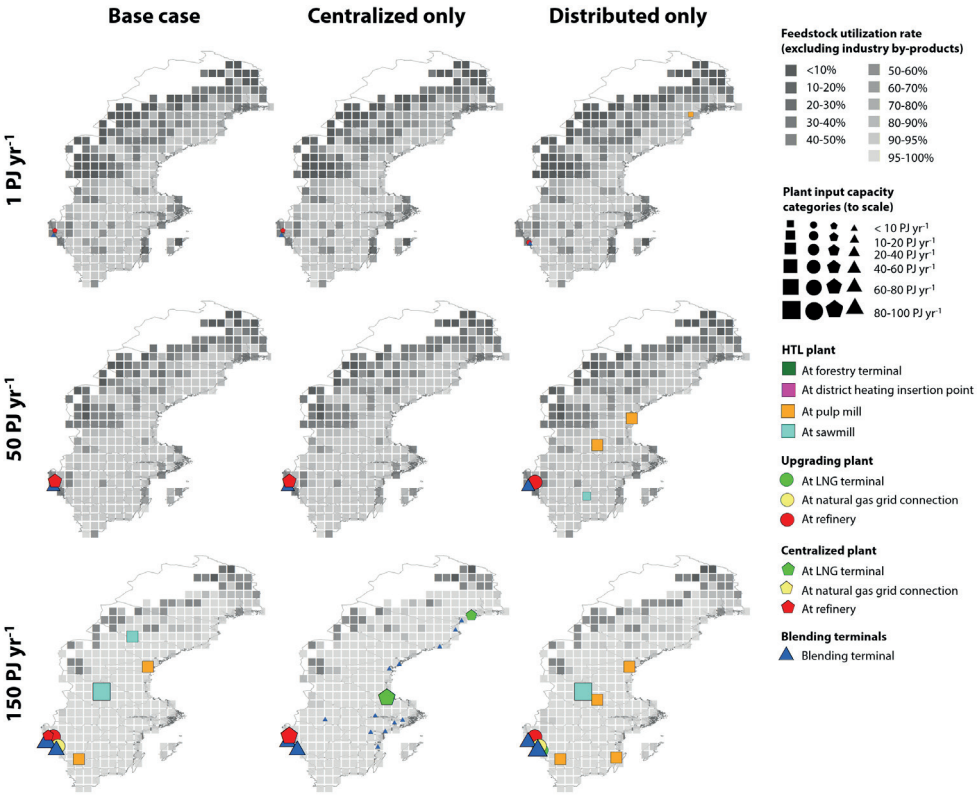


FIGURE 3-10: Production locations and feedstock utilization rate for the Base scenario, Centralized only scenario and Distributed only scenario at 1, 50 and 150 PJ yr^{-1}.

Integration benefits, if sufficiently large, may outweigh increased feedstock procurement cost at particular locations. For example, whereas the Base scenario mainly showed refinery locations, the No integration scenario strictly includes locations with a connection to the natural gas grid or LNG terminals, indicating the latter locations are better sited in terms of biomass supply.

The impact of increased competition over feedstock was tested in the High competing demand and Low biomass supply scenarios. These scenarios show marginally higher biofuel production costs (+0-6%, increasing with biofuel production level) relative to the Base scenario, because more expensive feedstocks are used and feedstocks are transported over larger distances. Feedstock procurement cost for competing industries for these two scenarios also rise by 0-18% relative to a similar biofuel production level in the Base scenario. Stationary energy plants and pulp mills (heat demand) were most affected. It is shown that the amount, type or size of plants built in both scenarios roughly represents the dynamics of the Base scenario.

3.3.2.4 Intermodal transportation networks

Intermodal transport allows for lower transportation costs over large distances, thereby providing access to cheaper feedstocks. Relative to the Base scenario, the Road only scenario is characterized by higher overall production costs (+0-6%, increasing with biofuel production level) due to higher feedstock and intermediate transport cost, but roughly similar upstream transport costs. The Road only scenario increases the cost of feedstock mobilization, which causes a switch to nearby but more expensive feedstocks (e.g. stumps). Figure 3-9 and Figure 3-11 also shows that the Road only scenario leads to a more decentralized system with more, smaller and more dispersedly located production plants.

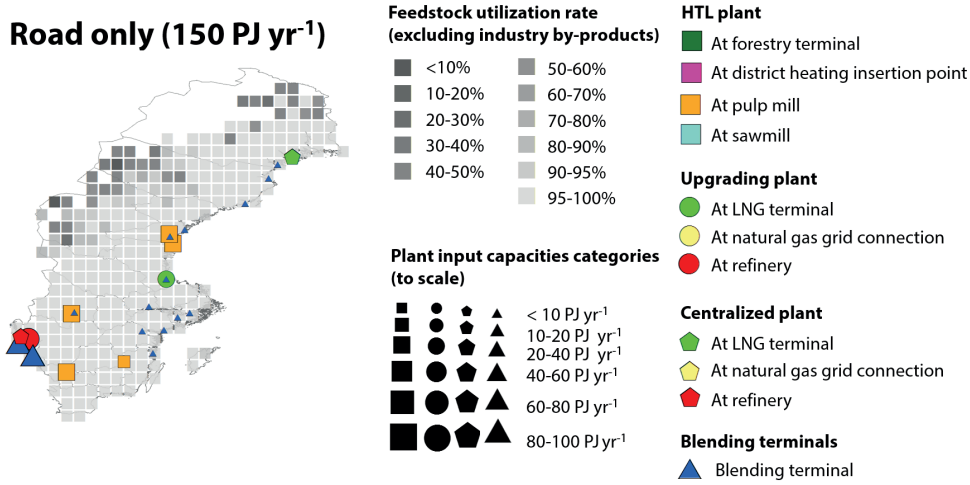


FIGURE 3-11: Production locations and feedstock utilization rate for the Road only scenario at a biofuel production level of 150 PJ yr^{-1}.

3.4 DISCUSSION

3.4.1 The impact of cost reduction strategies

This study explored the impact of economies of scale, integration, intermodal transport and distributed supply chain configurations on the cost performance of biofuel production. In the Base scenario, in which all cost reduction strategies were included, minimum biofuel production cost of 18.1-18.2 € GJ^{-1} were obtained for biofuel production levels between 10-75 PJ yr^{-1}. Both at lower and higher biofuel production levels production cost increase. Below 10 PJ yr^{-1} smaller units are built which increase conversion cost significantly. Beyond 75 PJ yr^{-1}increased feedstock and upstream transport cost are the main cause of rising cost. However, biofuel production costs rise

only modestly between biofuel production levels of 10-150 PJ yr^{-1}. Similar cost profiles were obtained in previous studies. Least-cost output capacities for various conversion technologies were found in a broad range between 4-67 PJ yr^{-1} (127-2125 MW), with an average at 21 PJ yr^{-1} (666 MW).[202,268–272,h]

The minimum cost are still higher than current (2015) fossil fuel pump prices in Sweden of 14-15 € GJ^{-1} (taxes excluded).[273] Hence, besides implementing all four cost reduction strategies, policy support and further technological learning is still required for biofuels produced from HTL to achieve cost parity with fossil fuels in this spatiotemporal context.

The impact of individual cost strategies was analyzed in alternative scenarios. Limiting the economies of scale (Reduced maximum capacity scenario) was shown to cause the largest cost increase relative to the Base scenario (+0-12%, increasing with biofuel production level), followed by disabling integration benefits (+1-10%, decreasing with biofuel production level) and allowing unimodal truck transport only (+0-6%, increasing with biofuel production level). Please note that the cost reductions cannot be added as the strategies are interrelated: disabling integration benefits favors large-scale centralized production, while intermodal transport networks positively affect the benefits of economies of scale.

Distributed supply chain configurations were introduced in the Base scenario once biomass supply became increasingly dispersed (at biofuel production levels beyond 100 PJ yr^{-1}), but did not provide a significant cost benefit (<1%) over the production costs found in the Base scenario or Centralized only scenario. Reducing the maximum production capacity (Reduced maximum capacity scenario) and increasing the cost of transport (Road only scenario) instigated a preference for distributed supply chains at biofuel production levels of 30 and 75 PJ yr^{-1}, respectively. Two previous analyses using techno-economic analyses found a similar transition point at output capacities between roughly 30-60 PJ yr^{-1}.[203,204] Hub-and-spoke-type distributed supply chains require large benefits from upstream transport cost reductions, economies of numbers, or site-specific integration benefits to offset the loss of economies of scale. Linear-type distributed supply chains may be preferred over centralized supply chains in cases where a high distance between the location of biomass supply and end use justifies additional CAPEX and/or OPEX (e.g. electricity generation in Europe using overseas (pelletized) biomass[197,199,201]).

h This range was obtained from six studies. Most of these studies assume a homogeneous feedstock density. Generally, a generic participation rate was assumed to represent competing demand for land and feedstock. A large variety in assumed feedstock densities (4-673 t km^{-2}) was found to be a main contributor to the broad range in least-cost capacities. The feedstock density used in this study ranges from 2-396 t km^{-2} (average 120 t km^{-2}). This density was calculated before competing demand was deducted (only 22 % of the total feedstock was available for biofuel production).

3.4.2 Key uncertainties

The relative differences between cost reduction strategies are small and the impact of individual strategies on the overall production costs is modest. As such, it is important to discuss the impact of key uncertainties.

The impact of economies of scale is highly dependent on the scaling factor and assumed maximum capacity. While production input scales beyond 30 PJ yr^{-1} (951 MW) dominate model solutions at higher biofuel production scales, the technical feasibility and the economic benefits of upscaling have yet to be confirmed. The input capacity of the largest Swedish pulp mill is roughly 21 PJ yr^{-1} (666 MW); the largest lignocellulosic biofuel (ethanol) plants are even smaller (~5 PJ yr^{-1}, 159 MW).[267] HTL is still in the early demonstration phase.[28,234] Given the commercialization status and the associated risk profile of HTL, investor appetite to build large-scale plants in the near future will likely be low, especially if the overall fuel costs are not substantially lower than fossil fuels. Hence, it is more likely that small-scale plants will be built in the near future before larger scales can be targeted. The Reduced maximum capacity scenario (constraining input capacity to 7.31 PJ yr^{-1} or 232 MW) shows that limits on the benefits of economies of scale may particularly increase the value of distributed configurations. Also, it is expected that integration benefits will have a large impact in the first phase. Depending on the development of biomass supply and competing demand, (policy/industry) strategies focused on further upscaling (i.e. scale-dependent learning) and the development of an intermodal transport network will likely contribute to further cost reductions. As the biomass surplus fades, the merits of distributed supply chains become more profound and may be employed to gradually scale-up existing upgrading plants.

The model contains a relatively high degree of spatially-explicit detail regarding competing demand, transport network and production locations. The spatial resolution of biomass supply and price data (half-degree) is relatively coarse and can be improved. While adding detail may instigate a clearer preference for particular production locations, which may be of interest to industry stakeholders, it is not expected to alter the merit of the cost reduction strategies. The addition of international biomass trade, however, may alter domestic cost-supply curves, likely strengthening the trend towards large-scale conversion plants, especially near sea ports. As the additional conversion cost of distributed relative to centralized configurations is decisive for the trade-off between both configurations, more detailed quantification and optimization of the cost performance of different pre-treatment technologies is recommended. Whereas integration benefits between biofuel production and existing industries were constrained on a site-specific level, the character and monetary value of integration benefits was generalized for each type of production location. As a result, a robust preference was found for the type of host site (i.e. refineries), but a low convergence was

observed for preferred production locations. Site-specific integration opportunities (e.g. bolt-on solutions, co-processing of biocrude at refineries) which can be applied at large scales may yield significant cost reductions and outweigh the potential increased cost of feedstock mobilization at that site. Conversely, site-specific safety issues, site layouts or strategic interests of the host might impede integration.

Whereas adding more detail may improve the robustness of the results, it is strongly advised to select only the most relevant modelling parameters on the basis of their expected impact (e.g. by doing a pre-analysis) to limit computation time and improve the transparency of the results. For example, eliminating conversion locations at district heating systems and forestry terminals from this study would not have an impact on the results.

3.4.3 Generalization of results

Temporal variability in competing demand, production locations, infrastructure, feedstock supply and feedstock prices was not captured in this study. In Sweden in particular, annual forestry biomass demand for energy and bio-chemicals may increase by 80-100 PJ in 2030 relative to current demand (excluding additional demand from biofuel production), particularly due to bio-chemical production.[228] Although the Swedish production of pulp, paper and sawn wood has stagnated or decreased during the last decade[248,274], the output of the Swedish forest industry is likely to grow alongside the increasing global demand for forest products.[275] Moreover, biomass demand from competing industries may become more clustered if the trend towards increasing plant scale and phasing out smaller plants continues.[276] The highest biofuel production levels examined in this study would require full utilization of all residues, including stumps. While the standing volume is projected to increase in the coming decades (hence increasing the potential supply of forest biomass for energy purposes) [239,240,277], the actual sustainable harvesting rates are subject to discussion, especially for stumps.[228,278] A lower biomass surplus (as demonstrated in the Low biomass and High competing demand scenarios) shows a mildly higher preference for smaller distributed plants; an opposite trend will likely show larger centralized plants. Moreover, this study utilizes top-down optimization of biofuel production systems for a particular biofuel demand, neglecting the fact that production systems grow organically and originate from bottom-up action of single actors.

Multi-step optimization can be used to capture time-dependent variability in competing demand, feedstock availability, production scale and technology performance.[223] Such analysis enables the user to identify lock-in effects and explore of the role and robustness of different cost reduction strategies at various development stages, both of which are important components of regional biofuel deployment strategies. Multi-

objective optimization can be used to simultaneously optimize conflicting objectives (e.g. economic and environmental indicators).[279,280]

Furthermore, the geographical characteristics of the study area and choice of feedstock-technology combination influence the results. Whereas a higher transport cost and lower feedstock density will limit the impact of economies of scale[h], more capital intensive technologies or a higher scaling factor enlarge the role of economies of scale. [202,268–272,281] As other pre-treatment processes, such as pelletization, also incur additional OPEX/CAPEX relative to a supply chain without pre-treatment, it should be examined closely under what circumstances such additional costs are justified, especially because feedstock and transport cost tend to rise only marginally with scale.

3.5 Conclusions

This study evaluated the impact of four strategies to reduce the cost of biofuel production in a Swedish context: economies of scale, intermodal transport, integration, and distributed supply chain configurations. Simultaneous implementation of all cost reduction strategies yielded minimum biofuel production costs of 18.1-18.2 € GJ^{-1} at production levels between 10-75 PJ yr^{-1}. As the minimum biofuel production costs are still higher than the current fossil fuel prices, policy support and technological learning remains essential to achieve cost parity.

Limiting the economies of scale was shown to cause the largest cost increase (+0-12%), followed by disabling integration benefits (+1-10%) and allowing unimodal truck transport only (+0-6%). Distributed supply chain configurations were introduced once biomass supply became increasingly dispersed, but did not provide a significant cost benefit (<1%). The benefits depend on the maturity of the biofuel production system: whereas the benefits of economies of scale and intermodal transport grow with increasing biofuel production level, integration benefits have a more profound impact in the early stages of biofuel deployment. These strategies are interrelated and should therefore ideally be analyzed simultaneously in optimization models. Model results show that disabling integration benefits favors large-scale centralized production, while intermodal transport networks positively affect the benefits of economies of scale. Similarly, constraints on the benefits of economies of scale particularly increase the value of distributed configurations.

The analysis may be expanded by including more geographically-explicit detail to improve the robustness of results. Multi-step optimization can be used to capture temporal variability, while multi-objective optimization allows for simultaneous optimization of conflicting objectives. At the same time, it is strongly advised to pre-select only the most relevant modelling parameters to improve the transparency of the results.

S3 SUPPLEMENTARY INFORMATION

S3.1 Model resolutions

The model resolution is defined as the proportional difference between the solution found and the best theoretical objective function.[282] The model was run at a resolution of 0.2% up to a maximum of 100 hours, after which the model was automatically terminated. Table 3-7 lists the model resolutions or all biofuel production levels. A resolution of 0% indicates the model obtained the best theoretical objective function.

TABLE 3-7: Model resolutions for all biofuel production levels.

Biofuel production level (PJ yr^{-1})	Base scenario	Reduced maximum capacity	Centralized only	Distributed only	No integration benefits	Low biomass supply	High competing demand	Road only
1	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%
10	0%	0%	0%	0%	0%	0%	0%	0%
15	0%	0%	0%	0%	0%	0%	0%	0%
30	0%	0%	0%	0%	0%	0%	0%	0%
50	0%	0%	0%	0.20%	0%	0%	0%	0.20%
75	0.17%	0.19%	0.11%	0.17%	0%	0.26%	0.27%	0.80%
100	0.23%	0.19%	0.20%	0.51%	0.20%	0.20%	0.22%	0.92%
150	0.47%	0.20%	0.18%	0.65%	0.18%			0.53%

S3.2 Techno-economic input data

Table 3-8 shows the techno-economic input data for selected input capacity. The production costs are calculated using a discount rate of 10%, plant lifetime of 20 years (annuity factor: 0.11746) and a load factor of 90%. Figure 3-12 shows the scaling curve for a centralized plant. The scaling curve was approximated by a piecewise linear function which breaks at the maximum input capacity of a HTL reactor (2.75 PJ yr^{-1}, 87 MW) and an SMR (39.3 PJ yr^{-1}, 1246 MW).

TABLE 3-8: Input data.

Cost item	Unit	Distributed supply chain							Centralized supply chain			Scaling factor	Source
		HTL conversion Reference capacity: 2.75 PJ_{in} yr^{-1} (87 MW_{in})				Upgrading Reference capacity: 2.18 PJ_{in} yr^{-1} (69 MW_{in})			Conversion and upgrading Reference capacity: 2.75 PJ_{in} yr^{-1} (87 MW_{in})				
Host site		Forestry terminal	Pulp mill	Sawmill	District heating	Natural gas grid	LNG terminal	Refinery	Natural gas grid	LNG terminal	Refinery		
Input		Biomass	Biomass	Biomass	Biomass	Biocrude	Biocrude	Biocrude	Biomass	Biomass	Biomass		
Output		Biocrude	Biocrude	Biocrude	Biocrude	Biofuel	Biofuel	Biofuel	Biofuel	Biofuel	Biofuel		
Production data													
Yield	GJ_{out} GJ_{in}^{-1}	0.79	0.79	0.79	0.79	1.06	1.06	1.06	0.84	0.84	0.84		[116]
Electricity production[i]	GJ GJ_{out}^{-1}	0.065	0.065	0.065	0.065				0.034	0.034	0.061		[116,231]
Electricity consumption[i]	GJ GJ_{out}^{-1}	0.072	0.072	0.072	0.072	0.014	0.014	0.007	0.083	0.083	0.083		[116,231]
Net electricity requirement	GJ GJ_{out}^{-1}	0.007	0.007	0.007	0.007	0.014	0.014	0.007	0.049	0.049	0.021		
Natural gas requirement	GJ GJ_{out}^{-1}					0.16	0.16		0.06	0.06			
Hydrogen requirement	GJ GJ_{out}^{-1}							0.15			0.15		
Steam production[i]	GJ GJ_{out}^{-1}		0.10	0.10	0.10						0.09		[116,231]
CAPEX													
Feedstock handling	M€	0.29	0.29	0.29	0.59				0.59	0.59	0.59	0.77	[114]
Biomass conditioning	M€	3.59	3.59	3.59	3.59				3.59	3.59	3.59	0.70	[116]
HTL reactor	M€	6.82	6.82	6.82	6.82				6.82	6.82	6.82	0.70	
Hydrotreater	M€					8.86	8.86	8.86	8.86	8.86	8.86	0.60	

Hydrocracker	M€					3.28	3.28	3.28	3.28	3.28	3.28	0.60	
Hydrogen plant	M€					3.55	3.55		3.55	3.55		0.79	
Utilities[i, v]	M€	4.32	4.32	4.32	4.32	0.72	0.72		2.88	2.88	2.88	0.70	
Missing equipment (10%)	M€	1.50	1.50	1.50	1.53	1.64	1.64	1.21	2.96	2.96	2.60		
Total purchased equipment cost (TPEC)	M€	16.53	16.53	16.53	16.85	18.05	18.05	13.35	32.52	32.52	28.62		
Lang factor[ii]		4.98	4.62	4.62	4.98	4.98	4.98	4.62	4.98	4.98	4.62		214
Total capital investment (TCI)	M€	82.3	76.4	76.4	83.9	89.8	89.8	61.7	161.9	161.9	132.3		
Total CAPEX[iv]	€ GJ_{out}^{-1}	4.44	4.12	4.12	4.53	4.58	4.58	3.15	8.26	8.26	6.75		
OPEX													
Electricity[i,v]	€ GJ_{out}^{-1}	0.09	0.09	0.09	0.09	0.17	0.17	0.09	0.59	0.59	0.26		116,141
Catalyst and chemicals[v]	€ GJ_{out}^{-1}	0.25	0.25	0.25	0.25	0.28	0.28	0.28	0.51	0.51	0.51		116
Waste disposal[v]	€ GJ_{out}^{-1}	1.34	1.34	1.34	1.34				1.26	1.26	1.26		116
Labor cost[vii]	€ GJ_{out}^{-1}	0.43	0.25	0.25	0.43	0.26	0.26	0.15	0.65	0.65	0.38		102,214
Other[ix]	€ GJ_{out}^{-1}	0.12	0.11	0.11	0.12	0.04	0.04	0.03	0.17	0.17	0.13		102,214
Hydrogen[vi]	€ GJ_{out}^{-1}							2.92			2.92		
Natural gas[vi]	€ GJ_{out}^{-1}					1.26	1.26		0.46	0.46			
CAPEX-dependent OPEX[viii]	€ GJ_{out}^{-1}	4.09	3.80	3.80	4.17	4.22	4.22	2.90	7.61	7.61	6.22		102,214
Total OPEX	€ GJ_{out}^{-1}	6.31	5.83	5.83	6.39	6.23	6.23	6.37	11.24	11.24	11.68		
Total production cost (OPEX + CAPEX)	€ GJ_{out}^{-1}	10.7	10.0	10.0	10.9	10.8	10.8	9.5	19.5	19.5	18.4		
Scale-independent production costs	€ GJ_{out}^{-1}	2.2	2.0	2.0	2.2	2.0	2.0	3.5	3.6	3.6	5.5		116
Scale-dependent production costs	€ GJ_{out}^{-1}	8.5	7.9	7.9	8.7	8.8	8.8	6.0	15.9	15.9	13.0		

i. In the reference study, which is based on a centralized supply chain, offgases from the HTL process are used as a feed for hydrogen production and anaerobic digestion (AD) is used to produce steam for electricity production (11 MW @ 2000 t biomass input per day) and heating the HTL unit, reformer and upgrading areas.[116] When the HTL conversion and upgrading are disconnected, HTL and AD offgases can be fully utilized to produce electricity and heat, which is both used to heat the process and export to host industries. Similar to the reference study, it is assumed for forestry terminals, PPM, sawmills, district heating (all distributed) and refineries (centralized only) that the AD offgas can be utilized to heat the HTL process and generate 11 MW of electricity. Based on the HTL offgas composition reported in Zhu et al.[116] and an assumed conversion rate to electricity of 30%, electricity generation from HTL offgases was approximated to be 8.9 MW. Furthermore, it was assumed that 1.5 units of exportable heat are produced per unit of electricity. Hence, for a reference HTL plant of 2000 t biomass input per day we assume 19.9 MW of electricity generation and 29.9 MW of exportable heat. As the offgases are also not used at the refinery sites (centralized supply chain design), increased electricity generation (19.9 MW) is also assumed here. Electricity consumption is distributed over the HTL conversion (22.2 MW) and upgrading (4.6 MW) according to the OPEX split reported in Tews et al.[231] (see also note v). Electricity consumption is assumed to be similar to the reference study. We assume the electricity consumption for the upgrading plant remains the same.

ii. The CAPEX for utilities for distributed supply chains (which include waste water treatment, electricity generation and steam production) was adapted from Zhu et al.[116] For HTL conversion, CAPEX was inflated by a factor 1.5 to account for the increased electricity and steam production. For natural gas sites and LNG terminals 25% of the costs was used to cover the steam generation unit. For refineries no utility costs were allocated as only the hydrotreatment occurs on-site.

iii. The Lang factor was adjusted for sites where co-location synergies exist (i.e. pulp mills, sawmills and refineries).[214]

iv. The capital recovery factor (0.118) was calculated assuming a 10% discount rate, 20 years plant lifetime and 90% load factor.

v. Allocation factors for Electricity use (83%, 9%, 8%), Waste disposal cost (100%,0%,0%) and Catalyst and chemicals (46%, 54%, 0%) cost are used to distribute the total OPEX over HTL conversion, upgrading and hydrogen plant. The allocation factors are calculated based on the OPEX distribution in Tews et al.[231]

vi. Hydrogen requirement for refinery sites (1.35 kg hydrogen per GJ biocrude) and natural gas requirement for natural gas and LNG terminal sites in centralized supply chains were taken from Zhu et al.[116] For natural gas and LNG terminal sites in distributed supply chains, the amount of natural gas (0.1649 GJ natural gas per kg hydrogen) required to satisfy the hydrogen consumption for upgrading was determined using the NREL H2A study (Central Natural Gas design).[259] In centralized supply chains part of the hydrogen is generated from offgases from HTL conversion, explaining the lower natural gas consumption relative to distributed supply chains.

vii. Labor costs were determined according to Wessel's method at a capacity of 388 MW biomass input or 307 MW biocrude input. Labor costs were reduced for sites where co-location synergies exist (i.e. pulp mills, sawmills and refineries).[214] Swedish hourly wages were taken from Eurostat.[138]

viii. The CAPEX-dependent OPEX cost items include maintenance and repairs, operating supplies, local taxes, and insurance.[102,214] This cost is calculated in the model as a factor (0.102) of TCI and thus scales with capacity.

ix. Other includes distribution and marketing and patents and royalties fees, which amount 5.5% of total OPEX.

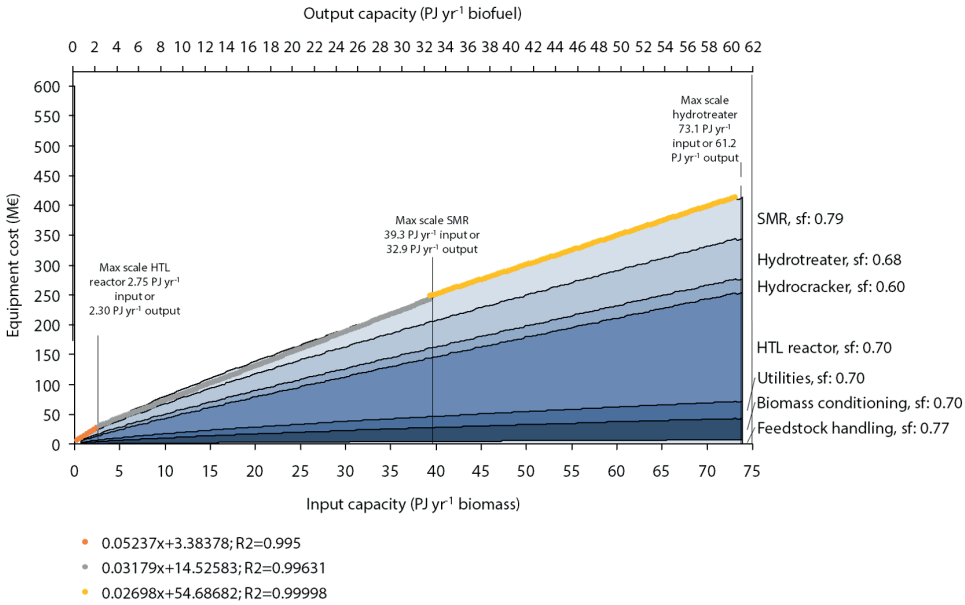


FIGURE 3-12: Equipment costs for a centralized supply chain (at natural gas pipeline and LNG terminals) at different scales. Linear lines were fitted to the non-linear scaling curve and consequently inserted in the model. The scaling factors (sf) are listed for each piece of equipment. The cost item 'missing equipment' is not shown.

S3.3 Transport cost

Table 3-9 shows the input data used to calculate the transport cost. Figure 3-13 shows the transport network and intermodal terminals in Sweden. The transhauling terminals are similar to the forestry terminals.[257,258]

TABLE 3-9: Input parameters for calculation of the transport cost.

Parameter	Unit	Road[ii]		Rail[ii]		Sea[iii,iv]	
		Solids	Liquids	Solids	Liquids	Solids	Liquids
Load capacity	t	22	22	465	864	9600	9600
Net load capacity roundtrip	%	50%	50%	75%	75%	94%	94%
Average speed	km h^{-1}	50	50	70	70	32	32
Time cost (per vehicle)	€ km^{-1}	0.63	0.63			9.39	12.36
Labor cost (per vehicle)	€ km^{-1}	1.19	1.19				
Variable cost (per vehicle)	€ km^{-1}	0.36	0.36	3.83	4.06	14.73	24.46
Fuel cost (per vehicle)	€ km^{-1}	1.37	1.37	2.26	2.91	33.54	33.54
Total transport cost (per vehicle)	€ km^{-1}	3.55	3.55	6.09	6.98	57.66	70.37
Total transport cost	€ t^{-1} km^{-1}	**0.162**	**0.162**	**0.013**	**0.008**	**0.006**	**0.007**
Transport cost							
Forestry residues and stumps (chipped)	€ GJ^{-1} km^{-1} (€ t^{-1} km^{-1})	0.0097 (0.162)		0.0008 (0.013)		0.0004 (0.006)	
Industrial by-products (IBS, IBP and sawmill chips)	€ GJ^{-1} km^{-1} (€ t^{-1} km^{-1})	0.0097 (0.162)		0.0008 (0.013)		0.0004 (0.006)	
Sawlogs and pulpwood	€ GJ^{-1} km^{-1} (€ t^{-1} km^{-1})	0.0097 (0.162)		0.0008 (0.013)		0.0004 (0.006)	
Biocrude	€ GJ^{-1} km^{-1} (€ t^{-1} km^{-1})		0.005 (0.162)		0.0002 (0.008)		0.0002 (0.007)
Biofuels	€ GJ^{-1} km^{-1} (€ t^{-1} km^{-1})		0.004 (0.162)		0.0002 (0.008)		0.0002 (0.007)
Loading/unloading[i]							
Forestry residues and stumps (chipped)	€ GJ^{-1} (€ t^{-1})	0.31 (5.11)		0.53 (8.93)		0.29 (4.85)	
Industrial by-products (IBS, IBP and sawmill chips)	€ GJ^{-1} (€ t^{-1})	0.16 (2.71)		0.53 (8.93)		0.39 (6.48)	
Sawlogs and pulpwood	€ GJ^{-1} (€ t^{-1})	0.12 (1.99)		0.48 (8.04)		0.39 (6.48)	
Biocrude	€ GJ^{-1} (€ t^{-1})		0.04 (1.39)		0.10 (3.26)		0.35 (11.53)
Biofuels	€ GJ^{-1} (€ t^{-1})		0.03 (1.31)		0.08 (3.08)		0.27 (10.89)

i. Based on Athanassiadis et al. (2009) [266], transport of wood chips. Liquid bulk assumed similar to dry bulk. Diesel cost: 0.7 € L^{-1}, excise duty: 0.46 € L^{-1}, VAT: 25%.
ii. Dry bulk rail freight rates and load based on the Heuristics Intermodal Transport Model Calculation System (Flodén 2011) [283], Medium case, electric engine. Liquid bulk calculated from dry bulk and NEA (2004) [284]. Electricity price: 0.075 € kWh^{-1}.
iii. Short sea shipping > 7500 dwt dry and wet bulk international/continental. Based on NEA (2004) [284]. Fuel oil price: 694 € t^{-1}.
iv. Loading and unloading cost are assumed to be similar.

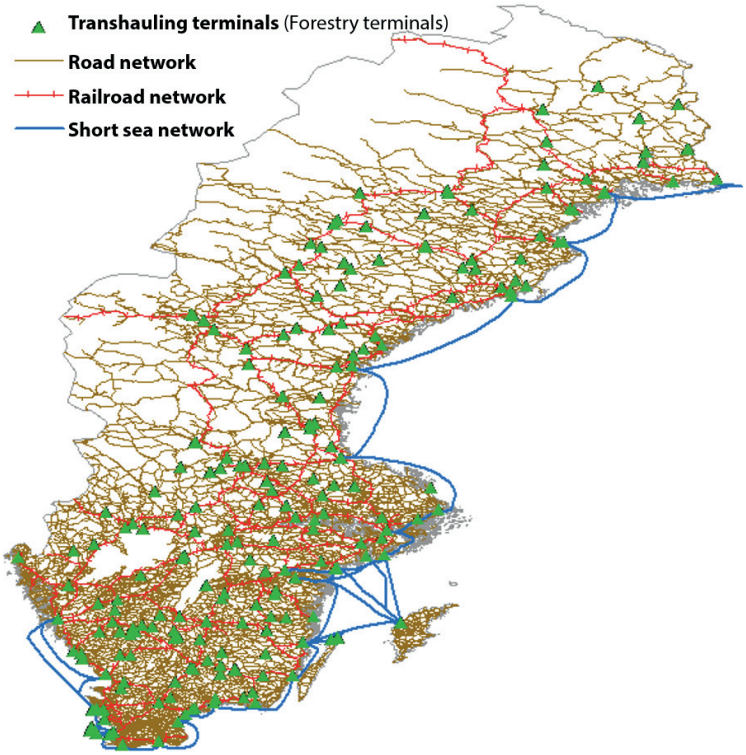


FIGURE 3-13: Transport network.

S3.4 Unit conversion

Monetary values were normalized to $€_{2015}$ using the yearly EU harmonized index of consumer prices.[285] Values in US$ were converted to € using the euro-dollar exchange rate for the respective year.[286] A similar approach was followed for the conversion of SEK to €.

Table 3-10 shows the lower heating value and density for biomass, biocrude and biofuel as employed in this study.

TABLE 3-10: Lower heating value and density for biomass, biocrude and biofuel.

	Unit	Biomass	Biocrude	Biofuel
Energy density (volume)[213]	GJ m^{-3}	7.41	-	-
Energy density (mass)[231]	GJ t^{-1} (dry)	16.7	32.7	40.3

S3.5 Feedstock price distribution

Figure 3-14 shows the feedstock price distribution for pulpwood, sawlogs and forestry residues. Industrial by-products are homogenously priced across Sweden.

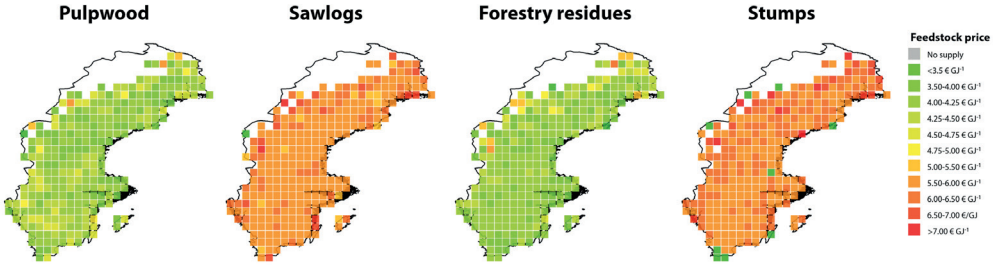
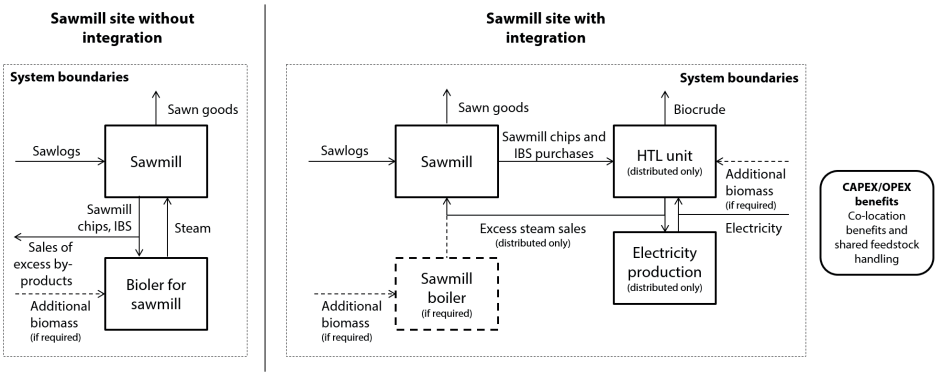


FIGURE 3-14: Feedstock price distribution.

S3.6 Examples of site layouts with and without integration

Figure 3-15 shows the site layouts for a sawmill (top) and refinery (bottom) with and without integration with biofuel production. Integration with a pulp mill is similar to the example of a sawmill.



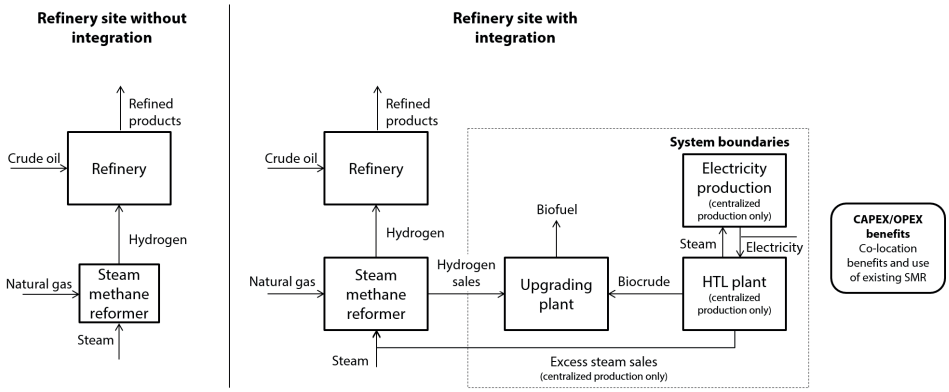


FIGURE 3-15: Example site layouts for a sawmill (top) and refinery (bottom) with and without integration with biofuel production.

4

Life-cycle analysis of greenhouse gas emissions from renewable jet fuel production

Sierk de Jong[1]*, Kay Antonissen[1], Ric Hoefnagels[1], Laura Lonza[2], Michael Wang[3], André Faaij[4], Martin Junginger[1]

1. Copernicus Institute of Sustainable Development, Utrecht University, The Netherlands.
2. European Commission – Directorate for Energy, Transport and Climate, Sustainable Transport Unit, EC-Joint Research Centre, Italy.
3. Center for Transportation Research, Argonne National Laboratory, Argonne, US.
4. Energy and Sustainability Research Institute, University of Groningen, The Netherlands.

Published in Biotechnology for Biofuels. 10:64 (2017)

4 ABSTRACT

The introduction of renewable jet fuel (RJF) is considered an important emission mitigation measure for the aviation industry. This study compares the Well-to-Wake (WtWa) greenhouse gas (GHG) emission performance of multiple RJF conversion pathways and explores the impact of different co-product allocation methods. The insights obtained in this study are of particular importance if RJF is included as an emission mitigation instrument in the global Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA). Fischer-Tropsch pathways yield the highest GHG emission reduction compared to fossil jet fuel (86-104%) of the pathways in scope, followed by Hydrothermal Liquefaction (77-80%) and sugarcane- (71-75%) and corn stover-based Alcohol-to-Jet (60-75%). Feedstock cultivation, hydrogen and conversion inputs were shown to be major contributors to the overall WtWa GHG emission performance. The choice of allocation method mainly affects pathways yielding high shares of co-products or producing co-products which effectively displace carbon intensive products (e.g. electricity). RJF can contribute to significant reduction of aviation-related GHG emissions, provided the right feedstock and conversion technology are used. The GHG emission performance of RJF may be further improved by using sustainable hydrogen sources or applying carbon capture and storage. Based on the character and impact of different co-product allocation methods, we recommend using energy and economic allocation (for non-energy co-products) at a global level, as it leverages the universal character of energy allocation while adequately valuing non-energy co-products.

4.1 BACKGROUND

The aviation industry emits roughly 2% of global anthropogenic greenhouse gas (GHG) emissions.[74] Despite a projected four-fold increase in CO_2 emissions in 2050 relative to 2010[287], aviation was excluded from the recent COP21 Paris Agreement[288]. The International Air Transport Association (IATA) has set an industry target to achieve carbon-neutral growth after 2020 and reduce emissions by 50% in 2050 (referenced to 2005). Besides efficiency improvements in technology and operations, the adoption of renewable jet fuel (RJF), a Jet A-1 substitute derived from biomass, is expected to make an important contribution.[17] The International Civil Aviation Organisation (ICAO) recently agreed to develop a Global Market-based Measure (GMBM) to achieve carbon-neutral growth after 2020.[20] In this scheme, aircraft operators should offset any annual increase in the GHG emissions beyond 2020 from international aviation between participating states using the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA). The scheme is currently approved until 2035. Consumption of RJFs may also be included as part of a basket of measures.[20]

The contribution of RJF to the emission reduction ambitions in aviation depends on the market penetration of RJF and its GHG emission reduction potential. To date, the market penetration of RJF has been negligible because of high prices and limited production capacity. Prior studies have explored the techno-economic feasibility and technology readiness of different RJF conversion pathways.[16,28,30,36,214,289] A positive GHG emission balance and sustainability impact (e.g. on water use, land use, biodiversity, etc.) is essential for RJF to contribute to a more sustainable aviation industry.

Various GHG emission performance assessments have been conducted for road biofuels, including comparisons between different conversion pathways.[24,290–292] Previous studies have shown the GHG emission performance is impacted significantly by methodological choices (especially allocation methods for co-products) and spatiotemporal variability in input data (e.g. feedstock yields or electricity mix).[44,49,54,55,293,294] Although RJF can be produced from similar feedstocks as road biofuels[i], conversion and downstream handling may deviate due to different fuel specifications and higher quality standards. These standards generally require more stringent upgrading, thus affecting yields and/or hydrogen consumption. Moreover, a thorough understanding of the impact of different methodological frameworks on the GHG emission performance of RJF is necessary, because the use of RJF in a global carbon offsetting scheme requires a global methodological meta-standard.

i To leverage the experience with biofuels in the road transport sector and avoid adverse sustainability effects, the Sustainable Aviation Fuel Users Group (SAFUG – a group of airlines representing approximately one-third of global jet fuel use), has committed to using fuels which do not compete with food supplies, significantly reduce well-to-wake GHG emissions, and have a low risk of indirect land use change (LUC) [26,455].

Prior analyses have considered the GHG emission performance of several RJF conversion pathways.[34,39,43,49–53] A comparison of the results is challenging due to diverging methodologies and input data. This study expands the comparative base by examining the GHG emission performance of six RJF conversion technologies: Hydroprocessed Esters and Fatty Acids (HEFA), Fischer-Tropsch (FT), Hydrothermal Liquefaction (HTL), pyrolysis, Alcohol-to-Jet (ATJ) and Direct Sugars to Hydrocarbons (DSHC; also commonly referred to as Synthetic Iso-paraffinic fuel, SIP). Additionally, this analysis shows the impact of different co-product allocation methods. As such, the objectives of this study are to 1) compare the GHG emission performance of RJF conversion pathways using different allocation procedures, 2) discuss potential improvements of the GHG emission performance of RJF, and 3) provide input for the development of a methodological meta-standard for the calculation of the GHG emission performance of RJF.

4.2 METHODS

4.2.1 LCA framework

A life-cycle analysis (LCA) framework can be used to assess the environmental impact across the entire product life-cycle. Methodology and default values are often standardized within a certain regulatory context, such as the EU Renewable Energy Directive (RED) and US Renewable Fuel Standard (RFS). A number of standardized approaches and respective calculation tools exist, of which prominent ones include the Greenhouse gases, Regulated Emissions and Energy use in Transportation (GREET), BioGrace, and GHGenius (used in the US, EU and Canada respectively). This study utilized the GREET model (GREET.net v1.3.0.12844, database version 12384), as it already included some RJF conversion pathways.[39,295,296] Furthermore, it gives the opportunity to compare and add pathways in a comprehensive yet transparent way. Default values for the reference year 2020 were used to assess the short-term GHG emission performance of RJF conversion pathways.

4.2.2 Functional Unit

The conversion pathways were compared on the basis of their GHG emissions in gCO_2-eq per MJ of RJF. The GHG emissions considered were CO_2, CH_4 and N_2O using their 100-year global warming potential (1, 25 and 298, respectively), in line with the United Nations Framework Convention on Climate Change reporting guidelines.[39,297]

4.2.3 System boundaries

The assessment covered Well-to-Wake (WtWa) GHG emissions, expressed as CO_2-eq, including emissions from feedstock cultivation and pre-processing, upstream logistics,

conversion to RJF, downstream distribution, and end use (Figure 4-1). Upstream transport comprises the transport from the feedstock production site or pre-processing facility to the conversion facility. Downstream distribution includes the transportation of the RJF to a blending terminal, blending operations, transportation to the airport tank farm and storage. Non-CO_2 emissions from jet fuel combustion were excluded from the analysis, as reported combustion data was only found for HEFA and FT RJF. Furthermore, as the chemical properties of RJF are by definition closely related to fossil jet fuel, it was assumed that there is no significant difference in GHG emissions from combustion, as was demonstrated for HEFA and FT RJF.[38,39,298–300] CO_2 emissions from the combustion of RJF are treated to be zero under the assumption of carbon neutrality.[44]

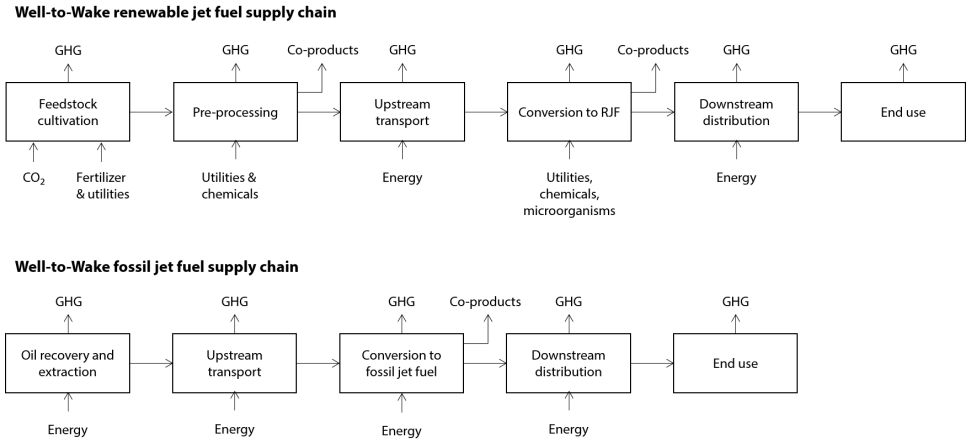


FIGURE 4-1: A schematic overview of the RJF supply chain and the system boundaries used in this study.

4.2.4 Land use change

Emissions from direct and indirect land use change (LUC) can have a large impact on the GHG emission performance of conversion pathways.[50,290] Emissions from direct LUC are caused by changes to the above- and below-ground carbon stocks as a result of changing former land use to cultivate biomass for bioenergy purposes. Changing land use for biomass cultivation or diverting existing feedstock flows for bioenergy purposes may instigate land use changes elsewhere to restore initial production level of food, feed and materials, causing indirect LUC emissions. The larger part of LUC emissions typically occur at the start of a project; as such, its impact can be affected significantly by the method used to amortize emissions over a given time period.[60 j]

Depending on the context, LUC-related GHG emissions may be positive (net emissions) or negative (net sequestration). Negative LUC-emissions may occur for highly productive

j For example, a fundamental difference between the Renewable Energy Directive (RED) and Renewable Fuel Standard (RFS) is the amortization period; whereas the RED specifies 20 years, the RFS uses 30 years.

feedstocks with a low fertilizer requirement (e.g. perennial grasses) which sequester more above- and below-ground carbon than the reference vegetation, especially when grown on degraded or marginal lands (which mitigates indirect LUC effects as well).[301–303] Conversely, conversion of large carbon stores (e.g. (tropical) forests, peatlands or prairie) into high-input croplands (e.g. palm oil or corn) may lead to high positive LUC emissions. Although important, these impacts are challenging to quantify, surrounded by considerable uncertainties and highly dependent on context-specific circumstances such as soil type, previous land use and management practices (please see Wicke et al.[304] for a comprehensive review of LUC-related GHG emissions from biofuels).[304–307] Moreover, quantification of these effects should be considered in a broader context; for example, agricultural zoning, improved management or intensification measures in agriculture may mitigate the indirect LUC GHG emissions from bioenergy.[304,308] As this analysis focused on the performance of the conversion pathway, LUC emissions were excluded from this analysis.

4.2.5 Conversion pathway scope

The scope included technologies which are or are expected to become commercially available in the near-term, namely Hydroprocessed Esters and Fatty Acids (HEFA), Fischer-Tropsch (FT), Hydrothermal Liquefaction (HTL), pyrolysis, Alcohol-to-Jet (ATJ) and Direct Sugars to Hydrocarbons (DSHC), see Figure 4-2.[k] The selected feedstocks include sugar/starch (sugarcane and corn), lignocellulosic (poplar, willow, corn stover and forest residues), and oil feedstocks (used cooking oil, jatropha and camelina), as these feedstocks are currently used or have been considered for RJF production (this is, however, not an exhaustive list).

k HEFA, FT, DSHC and ATJ (from butanol) are certified for use in commercial aviation by the American Society of Testing and Materials (ASTM). The other pathways are currently in the certification process.

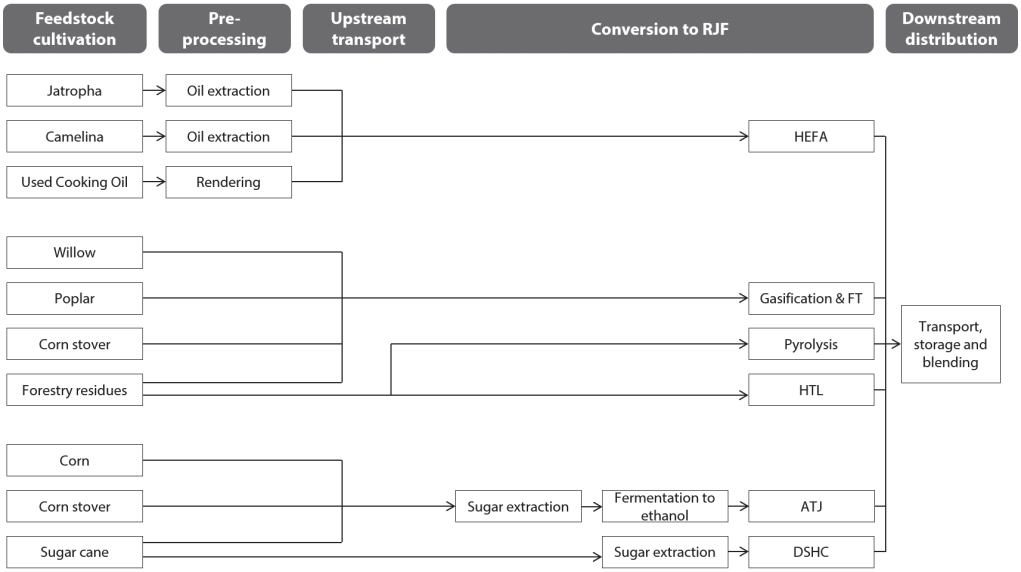


FIGURE 4-2: The scope of conversion pathways.

4.2.6 Methods to deal with co-products

The co-product allocation method in an LCA can have a profound impact on the GHG emission performance of a product[44,49,50,52,55], especially when the yield of co-products is high compared to the main product (see also S4.3). GHG emissions can be allocated to the co-products according to their energy, mass and economic value.[44,55,309,310] Alternatively, the displacement method (or system expansion) awards an emission credit to co-products based on the yield of the co-product and the GHG emission intensity of the displaced product (e.g. the fossil counterpart of the co-product). While energy allocation yields strictly positive emission intensities (except bioenergy pathways with carbon capture and storage), the displacement method may give negative emission intensities in case the emission credits exceed total system emissions.

Benefits and drawbacks exist for each method; the suitability of a particular method largely depends on the production system and the co-products. The International Standards Organisation (ISO)[310] deems the use of the displacement method most appropriate as it represent the potential GHG emission mitigation effects of producing co-products. However, it requires additional system choices regarding the displaced product and the associated avoided emissions.[55] Furthermore, when the yield of the co-products is significant compared to the main product, the choice of main product and co-product can have a decisive impact on the results.[55,311] Allocation methods are indifferent to the choice of main product. Moreover, mass and energy allocation are

based on physical properties of the co-product and are thus universally applicable and less susceptible to methodological choices and uncertainties. This is a key motivation for regulators, including the European Union, to adopt this method in a normative context.[55] However, mass allocation can only be applied to co-products having a mass and is hence unsuitable for systems producing immaterial products such as electricity. Energy allocation may not rightfully capture the value of non-energy co-products. For example, camelina meal, which can be used as an animal feed, is allocated more emissions when it is valued for its nutritional value (substituting soybean meal or corn) than when it is valued for its energy content.[52] The last method, economic allocation, captures the economic value of the co-product. However, a price ratio may be challenging to establish for novel non-commoditized products and could be highly affected by price fluctuations, geographical location or market distortions (e.g. monopolies or subsidies).[55,309] As such, economic allocation is earmarked by the International Standards Organisation (ISO) as a last-resort methodological option, when other methods prove inapt.[309,310]

In this study both energy allocation and the displacement method were used for non-energy co-products as they are employed in two prominent regulatory frameworks, the EU Renewable Energy Directive and the US Renewable Fuel Standard, respectively (Table 4-1).[65,67] Energy allocation was used for all fuel co-products (i.e. diesel, gasoline, heavy fuel oil, propane, methane and naphtha), as this is common practice for (sub-) processes which produce mainly fuels, because it captures the energy value of the product and is relatively indifferent to the choice of co-product and variations in product slate.[49,312,313] Hence, essentially, two analyses were conducted; one using solely energy allocation and one using a hybrid method, integrating the displacement method and energy allocation. An analysis using only the displacement method was not conducted, as such analysis was shown to be very sensitive to the choice of main product, especially if the yield fraction of the main product is low compared to other fuel co-products produced by the same system.[49]

4.2.7 Fossil baseline

The results were compared to the baseline WtWa emissions of fossil jet fuel. Considerable ranges for jet fuel exist depending on crude oil quality and processing technique; for the US a range between 80.7 and 109.3 gCO_2-eq MJ^{-1} was reported[42], while for the EU a range of 80.4-105.7 was found.[314] [l] The average WTWa emission intensity for conventional jet fuel (87.5 gCO_2-eq MJ^{-1}) consumed in the US was used as the fossil baseline such that it matches the geographical scope of the input data.[42] This

l As combustion emissions were excluded in the source used[314], the CO_2 emissions from the combustion of conventional jet fuel as reported in Stratton et al.[42] (73.2 gCO_2 MJ^{-1}) were added.

baseline is in between the fossil fuel baselines for transport fuels used in EU and US regulatory frameworks (Table 4-1).

4.2.8 Threshold values

The EU and US regulatory frameworks use GHG emission reduction threshold values to define which biofuels are eligible to count towards renewable fuels targets (Table 4-1). These thresholds originate from policy objectives (e.g. emissions reduction, sustainability requirements, security of supply) rather than being of technical origin. Whereas the EU Renewable Energy Directive has increasingly higher reduction thresholds over time, the US Renewable Fuel Standard has separate reduction thresholds for different categories of biofuels which are fixed in time. The biofuel categories in the US Renewable Fuel Standard are based on the feedstock-technology combination.

The results of this study were compared to the GHG emission reduction threshold as specified for biofuels in the EU Renewable Energy Directive and US Renewable Fuel Standard to provide an indication of the eligibility of the RJF conversion pathways under both regulatory schemes. It is an order-of-magnitude screening only, primarily because this assessment does not include sustainability indicators acting as exclusion criteria and LUC emissions. Also, it uses (slightly) different fossil baselines, default values and assessment methodologies, especially relative to the EU regulatory framework.

TABLE 4-1: An overview of biofuel regulation in the EU Renewable Energy Directive and US Renewable Fuel Standard.

	EU Renewable Energy Directive[i]	**US Renewable Fuel Standard**	
Co-production allocation method for non-fossil products	Energy allocation except for cogeneration of heat and (excess) power	Displacement method	
GHG reduction threshold (compared to the fossil fuel baseline)	35% for all biofuels 50% from 1 January 2017 for all existing installations 60% from 1 Jan 2018 for installations commencing production after 5 October 2015	Cellulosic biofuel: 60%	**Applicable to:** Lignocellulosic feedstocks
		Advanced biofuel: 50%	All feedstock except corn starch
		Biomass based diesel: 50%	Oil feedstocks
		Renewable fuels (conventional biofuels): 20%	Typically refers to corn ethanol
Fossil fuel baseline	83.8 gCO_2-eq MJ^{-1}	Diesel type fuels: 91.8 CO_2-eq MJ^{-1} Gasoline type fuels: 93.3 gCO_2-eq MJ^{-1}	

i. In 2015 the EU introduced a 7% cap on biofuels from crops grown on agricultural land and an indicative 0.5% target for advanced biofuels to reduce the risk of ILUC effects.

4.3 LIFE CYCLE INVENTORY

This section discusses the system configurations and most important assumptions used in this study. A full overview of the input data can be found in S4.1.

4.3.1 Geographical origin of the data

Input values may vary across different world regions due to e.g. farming practice, feedstock yield or process design. In this study, RJF was assumed to be consumed in the US. Most feedstock cultivation and RJF production was situated in the US, except for sugarcane-based DSHC and ATJ for which feedstock cultivation and conversion to RJF occurs in Brazil. In these cases, transportation of the RJF to and distribution in the US was added for consistency. Default values in GREET were used where available. The life-cycle inventory was complemented with data from recent studies for those feedstocks and technologies not available in GREET. Energy use for blending and storage was obtained from BioGrace[315], but US emission factors were used to calculate the associated emissions.

4.3.2 Conversion pathway description

This study comprises six conversion technologies:

- **Hydroprocessed Esters and Fatty Acids (HEFA)**. The HEFA technology uses hydrogen to deoxygenate and saturate the fatty acid carbon chains. Carbon chains are sized to fit the diesel and jet range using selective hydrocracking and/or isomerization. The values used in this study were taken from the GREET database, which is based on the UOP Ecofining process.[39,42,295,311]
- **Gasification and Fischer-Tropsch (FT)**. Lignocellulosic biomass is gasified to produce syngas. The syngas is converted to RJF, diesel, gasoline, propane and methane through FT synthesis. Electricity is generated from excess steam from gasification and FT synthesis. Process performance data was taken from Swanson et al.[108] As the reference study did not consider RJF production, it was assumed that the diesel output could be split in 25% RJF-ranged hydrocarbons and 75% diesel-ranged hydrocarbons. No additional emissions were taken into account as distillation was already considered in the process design.
- **Pyrolysis**. The pyrolysis process design was adopted from Tews et al.[231] In the process, feedstocks are dried (using waste heat from char combustion), ground (using electricity) and consequently converted at elevated temperatures (~500 °C) to bio-oil, gas and char.[149] The bio-oil is consequently converted to a mixture of hydrocarbons by hydrodeoxygenation. Char is combusted to produce steam. Again, a 25%-75% RJF-diesel split was applied to the diesel output.

- **Hydrothermal Liquefaction (HTL)**. The HTL process design was also based on Tews et al.[231] The HTL process converts wet feedstocks (no drying required) into a biocrude using water as a medium. Compared to pyrolysis it is operated at more modest temperatures (250 - 550°C), but elevated pressures (5 - 25 MPa).[316] As the HTL biocrude contains less oxygen than the pyrolysis bio-oil, the hydrodeoxygenation step requires less hydrogen. Again, a 25%-75% RJF-diesel split was applied to the diesel output.
- **Alcohol-to-Jet (ATJ)**. The ATJ platform converts alcohols (e.g. ethanol, butanol) to hydrocarbons. In this study, we use the ATJ pathway available in the GREET excel model. This pathway upgrades ethanol to RJF, diesel and naphtha through dehydration, oligomerization and hydroprocessing.[34,296] Data for ethanol production through fermentation of sugarcane, corn (including milling processes) and corn stover were adopted from GREET.[295]
- **Direct sugars to Hydrocarbons (DSHC)**. In the DSHC process, sugars are fermented to farnesene, a branched C-15 molecule with four double bonds. The double bonds are saturated using hydrogen to produce farnesane. We used data for the DSHC process including the sugarcane milling from Klein-Marcuschamer et al. and Cox et al., which is based on the Amyris process.[53,289] Unlike these studies, we assume both sugar and molasses were used to produce biofuels. Although farnesane is eligible for 10% blending with fossil jet fuel, Klein-Marcuschamer et al.'s process design includes additional hydrocracking and hydroisomerization, which produces an enhanced RJF with a higher blend level but also increases the hydrogen consumption. Both the 'increased blend level' and '10% blend level' cases were considered here. The former case is based on the hydrogen consumption as specified in Klein-Marcuschamer et al. The hydrogen consumption for the latter case was approximated by taking 120% of the stoichiometric hydrogen required for farnesene saturation. In this case, it was assumed that the farnesane is used as RJF only; no co-products were produced.

TABLE 4-2: Key process assumptions regarding the RJF conversion technologies.[108,231,289,295,296]

Process		**HEFA** [295]	**FT** [108]	**Pyrolysis** [231]		**HTL** [231]		**ATJ** [296]	**DSHC** [289]	
Sub-process				Ex-situ	In-situ	Ex-situ	In-situ		Increased blend level	10% blend level
Inputs	**Unit**									
Feed	MJ feed MJ^{-1} RJF	1.17	12.93	26.39	26.39	16.89	16.89	1.49[i]	6.28	3.25
Natural gas consumption[ii]	MJ MJ^{-1} RJF	0.18								
Electricity consumption	MJ MJ^{-1} RJF	0.005			1.53	0.21	0.86	0.03		
Hydrogen consumption	MJ MJ^{-1} RJF	0.15		5.44		1.31		0.08	0.52	0.12
Hydrogen feedstock		Natural gas		Natural gas	Process off-gases	Natural gas	Process off-gases and waste water	Natural gas	Natural gas	Natural gas
Outputs										
Co-product allocation ratio										
RJF	Normalized	1	1	1	1	1	1	1	1	1
Diesel	MJ co-product MJ^{-1} RJF		3.00	2.95	2.95	2.95	2.95	0.12	0.15	
Gasoline			1.69	7.88	7.88	4.57	4.57			
Heavy fuel oil				2.17	2.17	1.65	1.65			
Naphtha		0.14						0.21	0.54	
Propane		0.10	0.49							
Methane			0.24							
Electricity			0.45	0.51					0.13	0.07

i. Feedstock is ethanol.

ii. Excluding natural gas used for hydrogen generation.

The process performance indicators of the RJF conversion technologies are listed in Table 4-2 and S4.1. The reader is referred to Mawhood et al.[28] for a more elaborate description of the conversion technologies and their respective CAAFI fuel readiness level.[m]

4.3.3 Hydrogen generation

All pathways require hydrogen except FT, HTL (in-situ) and pyrolysis (in-situ). In the base case it was assumed that hydrogen was produced through steam methane reforming (SMR) of natural gas, which corresponds to the current production practice of hydrogen. For pyrolysis and HTL, ex-situ (SMR of natural gas) and in-situ hydrogen production were considered. In the pyrolysis in-situ case, hydrogen was produced through SMR of process off-gases; in the HTL in-situ case hydrogen was produced through SMR of off-gases from the process and anaerobic digestion of the waste water. Ex-situ hydrogen consumption was calculated from mass and energy balances presented in Tews et al.[231] The feeds used for hydrogen generation in the in-situ case were utilized to power the process in the ex-situ case, hence explaining the lower electricity consumption in the ex-situ case.

4.3.4 Allocation and displacement ratios

All conversion pathways produce non-fuel and/or fuel co-products. Table 4-2 shows the co-product allocation ratios for fuel co-products. Table 4-3 provides an overview of the co-product allocation ratios applied for non-energy co-products (a subgroup of non-fuel co-products) and electricity (considered an energy and non-fuel co-product) for both the energy allocation and displacement method.

m CAAFI's (Commercial Aviation Alternative Fuels Initiative) Fuel Readiness Level (FRL) methodology is based on NASA's Technology Readiness Level (TRL) scheme. The FRL scale allows users to track the progress of a RJF in terms of research, certification, and demonstration.[456]

TABLE 4-3: Allocation ratios for non-energy co-products and electricity.[35,52,231,295,296,317–320]

Supply chain component	Applicable for pathway	Main product	Co-product	Co-product allocation ratio r_A		Displaced product	Displacement ratio r_D	Emission factor	Ref.
				Co-product per main product					
Non-energy co-products				MJ MJ^{-1}	g MJ^{-1}		g displaced product g^{-1} co-product	g CO_2-eq g^{-1} displaced product	
Camelina oil extraction	HEFA	Camelina oil	Camelina meal	0.64	47.79	Soybean meal	0.77[ii]	0.53	52,317,318
Corn dry mill ethanol production w/o corn oil extraction[i]	ATJ	Ethanol	Distillers grain solubles	0.68	31.74	Corn	0.78	0.29	295
						Soybean meal	0.31	0.53	
						Urea	0.02	1.22	
Corn dry mill ethanol production w corn oil extraction[i]	ATJ	Ethanol	Distillers grain solubles	0.65	30.36	Corn	0.78	0.29	295
						Soybean meal	0.31	0.53	
						Urea	0.02	1.22	
		Ethanol	Corn Oil	0.04	1.06	Soy oil	1.00	0.53	295
Corn wet mill ethanol production[i]	ATJ	Ethanol	Corn gluten meal	0.15	6.87	Corn	1.53	0.29	295
						Urea	0.02	1.22	
		Ethanol	Corn gluten feed	0.56	29.74	Corn	1.00	0.29	295
						Urea	0.02	1.22	
		Ethanol	Corn Oil	0.21	5.52	Soy oil	1.00	0.53	295

Electricity (co-product)				MJ MJ^{-1}		MJ displaced product MJ^{-1} co-product	g CO_2-eq MJ^{-1} displaced product[iii]	
FT synthesis	FT	RJF	Electricity	0.45	US grid electricity	1.00	137.88	296
Jatropha oil extraction	HEFA	Jatropha oil	Electricity[iv]	0.34	US grid electricity	1.00	137.88	295
Pyrolysis	Pyrolysis ex-situ case	RJF	Electricity	0.51	US grid electricity	1.00	137.88	231
Ethanol from corn stover	ATJ	Ethanol	Electricity	0.10	US grid electricity	1.00	137.88	319
Ethanol from sugarcane	ATJ	Ethanol	Electricity	0.22	Brazilian Grid electricity	1.00	26.52	320
Sugarcane milling	DSHC (increased blend level)	RJF	Electricity[v]	0.13	Brazilian Grid electricity	1.00	26.52	35
Sugarcane milling	DSHC (10% blend level)	RJF	Electricity[v]	0.07	Brazilian Grid electricity	1.00	26.52	35

i. GREET uses a weighted average of three different corn ethanol technologies. Dry mill ethanol production without corn oil extraction, dry mill ethanol production with corn oil extraction, and wet mill ethanol production respectively produce 18.23%, 72.91% and 8.87% of the total produced ethanol.

ii. Based on the ratio between the average protein content of camelina (36.2%) and soybean meal (47%).

iii. For electricity production, an average emission factor without transmission and distribution losses was used. For electricity consumption, these losses were included. For pathways located in Brazil, a much lower emission factor was used due to the high diffusion of hydropower in the electricity mix.

iv. From the combustion of jatropha husks, shells and meal.

v. From the combustion of bagasse, after deduction of internal use of heat and power in the DSHC process.

4.4 RESULTS

4.4.1 Comparison between pathways

Figure 4-3 shows the WtWa GHG emissions per conversion pathway for energy allocation and the hybrid method. FT yields consistently low WtWa GHG emissions across all feedstocks and both allocation methods, mainly due to the self-sufficiency of the process and excess electricity production. Corn-based ATJ and sugarcane-based DSHC (increased blend level case) show the highest WtWa GHG emissions in both methods. For corn-based ATJ this is caused by high fossil energy use during ethanol production and high emissions from fertilizer use. For DSHC, the low conversion yield and high hydrogen consumption are the main contributors to a high GHG footprint. Jatropha and camelina-based HEFA also show particularly high cultivation emissions. While per-hectare use of fertilizer and other inputs could be small for jatropha and camelina, the oil yield is usually low, leading to high emissions per unit of oil. In almost all processes hydrogen is an important contributor to the overall WtWa GHG emissions. In-situ hydrogen production generally yields lower WtWa GHG emissions than ex-situ hydrogen production; the emissions avoided by producing hydrogen from offgas instead of natural gas offset the emissions related to increased electricity use (valid for the US electricity mix). The benefits of in-situ production are stronger for the pyrolysis process as the upgrading of pyrolysis oil requires large amounts of hydrogen and the process off-gas already contains high concentrations of hydrogen. For RJF conversion pathways situated in Brazil (sugarcane-based pathways), the emissions from downstream distribution increase slightly due to international transport while emissions from electricity use (or co-product credit) are reduced. This reduction is because Brazil's average electricity mix has a lower emission factor compared to the US, particularly due to a high share of hydropower.

Most pathways yield GHG emissions reductions exceeding 60% compared to fossil jet fuel and can therefore comply with the most stringent emission reduction thresholds of the EU Renewable Energy Directive and US Renewable Fuel Standard. Whereas DSHC (increased blend level) is above or close to the lowest thresholds for biofuels irrespective of allocation method, the performance of jatropha-based HEFA or corn-based ATJ highly depends on the allocation method used. It is worth reminding that this assessment does not include LUC emissions, and therefore could over- or underestimate the GHG emission performance of these conversion pathways for a specific context.

Residues and lignocellulosic crops generally show better emission mitigation potential than food crops, because of low emissions related to fertilizer use, feedstock cultivation

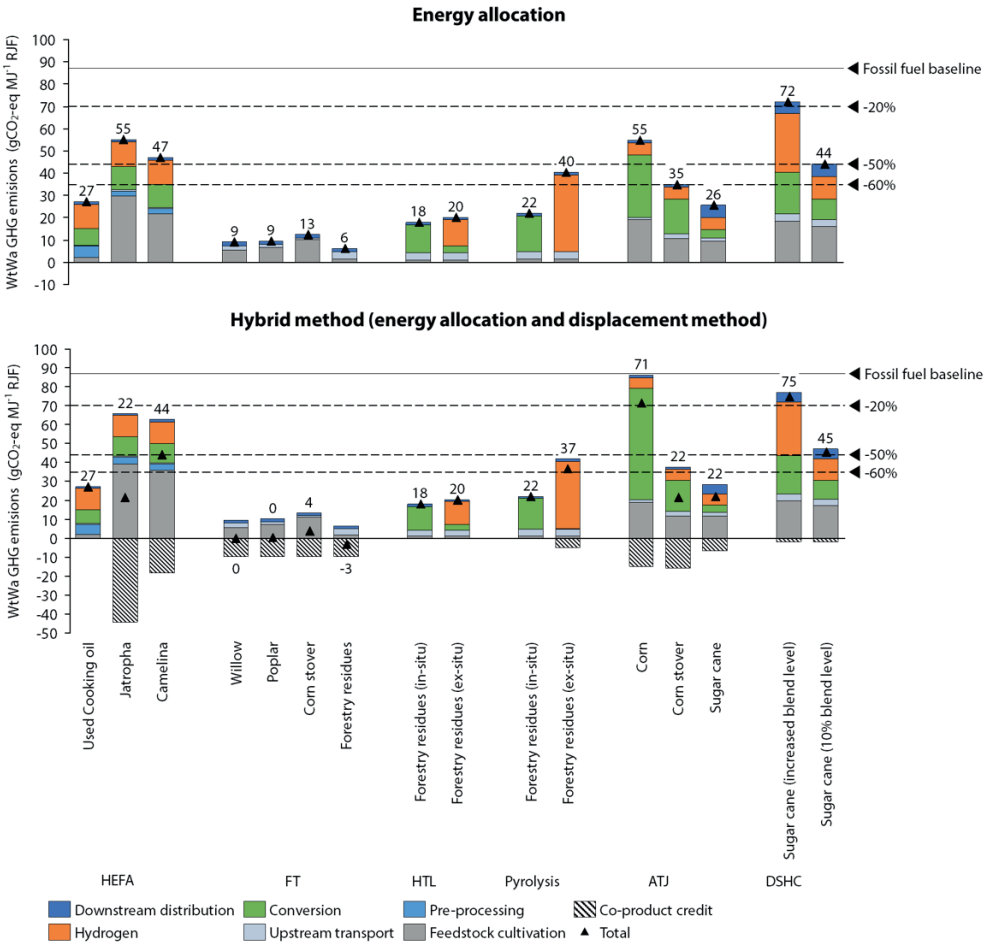


FIGURE 4-3: WtWa GHG emission performance of RJF conversion pathways.

or feedstock collection. RJF produced from highly productive food crops in combination with an efficient conversion process (i.e. sugarcane-based ATJ) is also able to meet the strictest GHG emission reduction thresholds currently applied.

4.4.2 Comparison between allocation methods

Figure 4-3 shows that the allocation method applied has a significant effect on the GHG emission performance for some pathways. As described in S4.3, the difference between energy allocation and the hybrid method increases for conversion pathways

producing large amounts of co-products. Moreover, the hybrid method tends to yield lower WtWa GHG emissions for conversion pathways producing co-products which displace products whose emission intensity exceeds the emission intensity of the system (before allocation).

Particular differences are observed for FT and jatropha-based HEFA. Although the co-product (electricity) is valued for its energy content in both methods, they still yield disparate results. In these cases, the emission intensity of the displaced product (grid electricity) far exceeds the emission intensity of the system, hence leading to the hybrid method yielding lower GHG emission results than energy allocation. Similar dynamics are at the origin of the lower emission intensity of Pyrolysis (ex-situ) and corn stover-based ATJ for the hybrid method. On the contrary, sugarcane-based DSHC yields higher emissions using the hybrid method because of the low emission intensity of Brazilian electricity combined with a high GHG emission profile of the conversion pathway. Despite a relatively high co-product allocation ratio for camelina-based HEFA, the moderate displacement ratio and low emission intensity of soy meal yields only a small decrease in WtWa GHG emissions for the hybrid method. This pathway will be examined more closely in the sensitivity analysis.

Conversely, corn ATJ shows higher emissions using the hybrid method. This is to be ascribed to its co-products (DGS, Corn oil, CGM and CGF) displacing products with low emission intensities relative to the total system, which makes energy allocation more attractive than the displacement method.

Two out of sixteen pathways change threshold category after applying a different allocation method. Whereas jatropha-based HEFA meets a lower threshold category using the hybrid method, corn-based ATJ is demoted one category.

4.5 SENSITIVITY ANALYSIS

4.5.1 Alternative allocation methods for non-energy co-products

To illustrate the impact of different allocation methods, we apply mass and economic allocation to the camelina-based HEFA pathway in which large amounts of camelina meal are produced. Similar to the base results, energy allocation was used for the remaining fuel co-products (i.e. propane and naphtha). For mass-based allocation, we used an allocation ratio of 1.78 kg camelina meal kg^{-1} camelina oil. For economic allocation, the ratio between soy oil and soy meal was used as a proxy to determine the allocation ratio, as price data for camelina meal and oil were not available. A price for camelina meal and oil was derived from this ratio using a displacement ratio of 0.77 kg camelina meal kg^{-1} soy meal and 1 kg camelina oil kg^{-1} soy oil, respectively.

A mean, minimum and maximum (0.34, 0.29 and 0.45 $ kg^{-1} camelina meal per $ kg^{-1} camelina oil) allocation ratio was found, based on a 10-year series of monthly price ratios between soy oil and soy meal.[321]

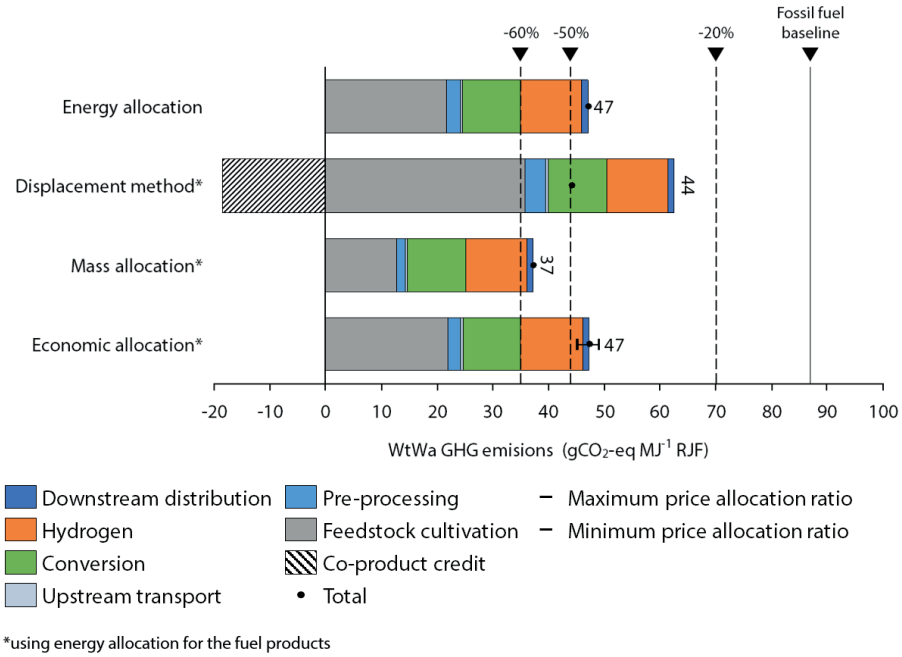


FIGURE 4-4: WtWa GHG emissions for the HEFA camelina pathway using different co-product allocation methods for camelina meal.

Figure 4-4 shows that the WtWa GHG emissions for the camelina-based HEFA pathway range between 37 and 49 gCO_2-eq MJ^{-1} RJF for different allocation methods. Whereas energy allocation assigns a relatively small share of emissions to the meal, mass allocation allocates a high share of emissions to the meal due to the large mass of meal produced. Economic allocation shows a modest range of ±5% due to variability of price ratios. Although the displacement method is shown as a point value here, different assumptions regarding displacement ratio, displaced product or emission intensity of the displaced product may change the result substantially, as was shown in other studies for e.g. camelina and jatropha-based HEFA RJF.[49,50,52]

4.5.2 Yield, fertilizer use and hydrogen use

In Figure 4-3, feedstock cultivation, hydrogen use and conversion were shown to have an important contribution to the overall WtWa GHG emissions. Therefore, a sensitivity analysis was performed to determine the impact of the hydrogen, N

fertilizer and conversion yields. Ranges for conversion yields were adopted from a survey of technology performance data (see S4.2).[214] Ranges in hydrogen emissions originate from variability in hydrogen consumption or emission intensity of hydrogen production. Emissions from N fertilizer input may vary for different management practices, cultivation locations or calculation methods (see S4.1). Both parameters were varied by ±20% to illustrate the sensitivity of the WtWa GHG emissions to variance in these parameters. The ranges were inserted as single permutations and simultaneous permutations (as indicated by 'All'). The results were calculated using energy allocation.

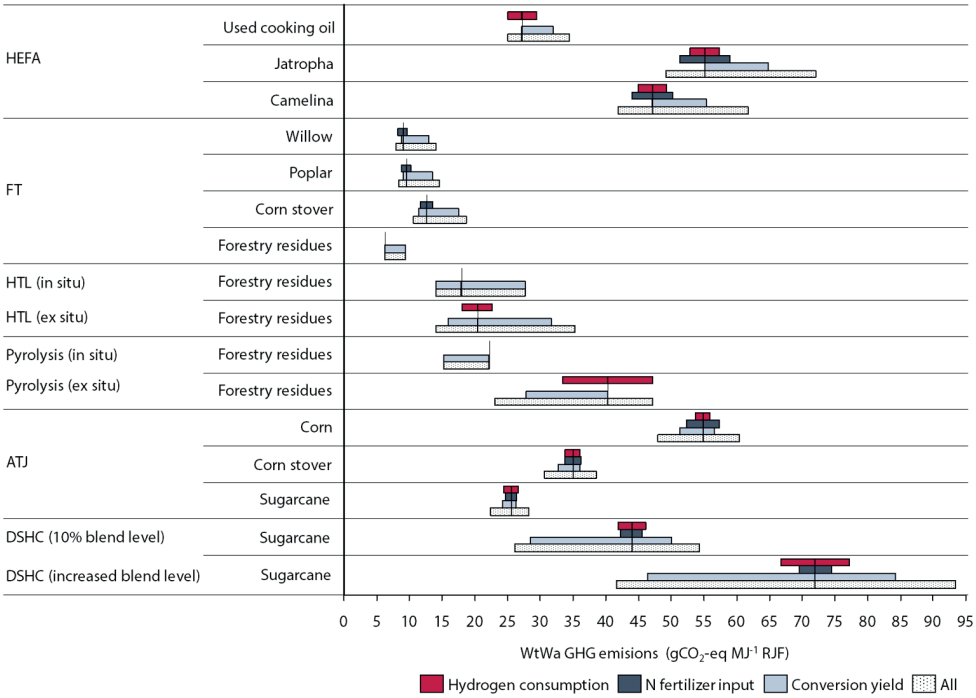


FIGURE 4-5: Sensitivity analysis on hydrogen consumption, N fertilizer input and conversion yield (energy allocation).

Figure 4-5 shows that the general merit order is retained in the sensitivity analysis. Whereas the majority of the pathways show modest ranges (<±20% for simultaneous permutations), pyrolysis (ex-situ) and DSHC (high blend level) show relatively large ranges, mainly due to hydrogen being an important determinant for the performance of these conversion pathways and the uncertainty regarding the conversion yield. Fertilizer input is shown to have a minor impact on the results. Furthermore, it is shown that the Base case considers relatively pessimistic yields for DSHC and pyrolysis, while being optimistic for HEFA, FT and HTL.

4.5.3 Hydrogen production method

The base results assume hydrogen production using SMR of natural gas. Technological advancements and a higher penetration of renewable electricity can make more sustainable hydrogen generation processes technically and economically feasible. Two other processes were assessed to show the impact of such developments: 1) electrolysis using renewable electricity from wind, solar and biogenic waste and 2) gasification of biomass (switchgrass was taken as a proxy for biomass). These pathways were adopted from GREET.[295] The results were calculated using the energy allocation method.

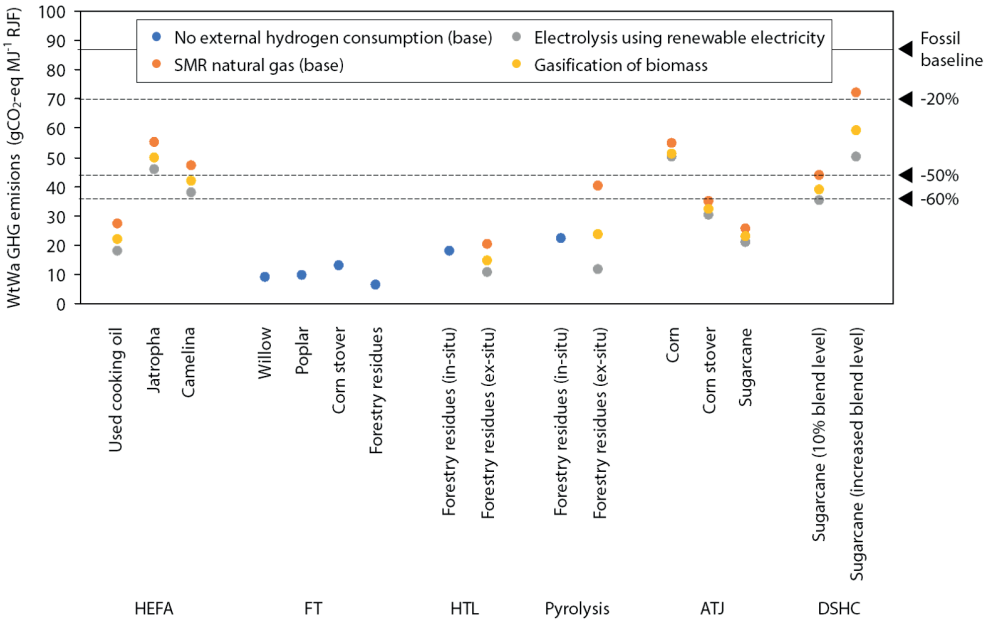


FIGURE 4-6: Sensitivity analysis on the hydrogen source (energy allocation).

Figure 4-6 illustrates that alternative hydrogen generation methods can reduce the WtWa GHG emissions significantly and shift the merit order, especially for pathways for which hydrogen consumption is responsible for a high share of the total emissions such as ex-situ pyrolysis (-71%), ex-situ HTL (-48%), DSHC (-20%/-30%) and UCO-based HEFA (-34%). For electrolysis, the majority of the conversion pathways show WtWa GHG emissions below the 50% emission reduction threshold.

4.6 DISCUSSION

4.6.1 Conversion pathway WtWa GHG emission performance

The first aim of this study was to compare the GHG emission performance of RJF conversion pathways using different allocation procedures. In terms of feedstock, it is shown that residues or lignocellulosic crops yield low WtWa GHG emissions, irrespective of conversion pathway or allocation method. The food and oil crops under consideration were generally characterized by higher feedstock cultivation emissions, which originated particularly from the high fertilizer use (except for sugarcane). In terms of technology, hydrogen consumption and conversion yield were found to be important determinants of GHG emission performance. Upstream transport and downstream distribution only contributed marginally to the overall WtWa GHG emissions. Although considerable uncertainty exists, the merit order of the pathways considered is quite robust to changes in key input parameters. Wide ranges were particularly observed for DSHC (high blend level) and pyrolysis (ex-situ) due to uncertainty regarding the conversion yield.

It is stressed that the results were obtained for a specific spatiotemporal context. The spatial component may influence emissions from feedstock cultivation and the carbon intensity of utilities and fossil jet fuel.[42,294,314,322,323] Improvements inside and outside the production system may positively affect the GHG emission performance of RJF over time (see section 4.6.2).

Table 4-4 shows a comparison of study results with existing studies using energy allocation, the displacement method, or a hybrid method. The ranges found are largely ascribed to variability in methodological approach (e.g. system boundaries or life cycle inventory elements, i.e. some include land use change emissions) or input data (e.g. co-product allocation ratios, conversion yields). Despite this variability, studies seem to agree on the superior WtWa GHG emission performance of FT RJF, irrespective of the feedstock or allocation method used. Greater methodological variability in the application of the displacement method causes wider ranges in GHG emission performance. The observed difference between results from both allocation methods concurs with existing literature, particularly for conversion pathways with high co-product allocation ratios or co-products which effectively displace emission-intensive products (e.g. electricity).[49,52,55,327]

TABLE 4-4: A comparison of study results with existing literature.[33,34,39,42,43,49,50,52,53,79,231,324]

Technology[i]	Feedstock	Energy allocation		Ref.	Displacement method		Ref.
		This study	Prior studies		This study	Prior studies	
		g CO_2-eq MJ^{-1}	g CO_2-eq MJ^{-1}		g CO_2-eq MJ^{-1}	g CO_2-eq MJ^{-1}	
HEFA	UCO	28	17-21	33	28	-	
	Jatropha	55	37-55	43,49,50	21	-134-63	42,49,50
	Camelina	47	18-47	43,52	44	-17-60	52,324
FT	Willow	9	-		-7	-17-10	39,79
	Poplar	10	-		-6	-17-10	39,79
	Corn Stover	13	8-11	43	-3	9-14[iii]	42,49,79
	Forestry residues	6	-		-10	10-12[iii]	39,42
HTL (in-situ)	Forestry residues	18	27[ii]	231	18	-	
HTL (ex-situ)	Forestry residues	21	-		21	-	
Pyrolysis (in-situ)	Forestry residues	22	34[ii]	231	22	-	
Pyrolysis (ex-situ)	Forestry residues	41	-		37	-	
ATJ	Corn	54	-		71	-	
	Corn stover	35	-		22	-	
	Sugarcane	31	-		31	-27[iv]	34
DSHC (increased blend level)	Sugarcane	76	-		79	55-100	53
DSHC (10% blend)	Sugarcane	47	-		49	-	

i. Some conversion pathways could not be compared due to lack of reference studies. It should be noted that the literature entails a much wider feedstock and technology scope than employed in this study, including a wide range of LCAs of RJF production based on algae species, edible oil crops, and herbaceous crops [325,326].

ii. Based on diesel production, not RJF. It is included in this comparison as it is used as a data source for our computations.

iii. Elgowainy et al. [39], Stratton et al. [49] and Stratton et al. [42] assume all electricity produced during FT synthesis is used internally.

iv. Relative to Staples et al. [34], this study uses lower yields and a higher electricity emission intensity.

4.6.2 Improving the GHG emission performance of RJF production

The second aim of this paper was to identify improvements inside and outside the RJF supply chain which lead to further GHG emission reductions. The GHG emission reduction performance of RJF may improve in the future by higher conversion yields, better agricultural practice and lower carbon intensity of utilities. At the same time, the emission intensity of fossil jet fuel will likely increase in the future as the trend towards the utilization of more heavy and sour (high sulfur) crude oil pursues.[42,328] Moreover, relocation of RJF production can improve the GHG emission reduction performance significantly; particularly due to the relatively high emission intensity of the US electricity mix (see Table 4-3).

The production and use of hydrogen plays a particularly important role in current and future RJF production, as it is required in almost all pathways. Hence, sustainable

hydrogen production technologies can have an important contribution towards reducing the emission intensity of RJF, especially when produced through electrolysis from renewable electricity. Furthermore, hydrogen consumption can sometimes be limited due to choice of feedstock, product slate, catalyst, organism or process conditions.

Deoxygenation remains inevitably important as oxygen is essentially the main impurity in biomass compared to RJF. In general, oxygen can be removed as water (using hydrodeoxygenation) and/or (biogenic) carbon dioxide (using decarboxylation, fermentation or gasification). Provided hydrogen can be produced sustainably, hydrodeoxygenation may be preferred from a climate change mitigation point of view as it increases conversion (carbon) yields and limits the emissions of biogenic carbon dioxide.[n] On the other hand, pathways removing oxygen through carbon dioxide (particularly FT and fermentation pathways, but also hydrogen production from biomass gasification) yield high-purity point-source CO_2 streams which can be captured against modest cost compared to lower-purity CO_2 streams from power plants (fossil and bioenergy-based).[329–331] Such bioenergy and carbon capture and storage (BECCS) options provide the opportunity to achieve negative emission performance for RJF and can contribute significantly to deep emission reductions on a global scale.[63,332,333]

4.6.3 Implications for a global meta-standard for RJF

The third aim of this study was to provide input to a global meta-standard for the calculation of the GHG emission performance of RJF. Whereas methodological differences can and should be smoothened in a global meta-standard for RJF to avoid competitive distortion or adverse sustainability effects, spatial differences are real and should ideally be addressed. Existing databases such as BioGrace, GREET, and GHGenius could be used as a starting point to determine regional default values (e.g. energy input and emission factors).

Co-product allocation is of particular importance for RJF production, as co-products are produced in almost all pathways (particularly fuel co-products in thermochemical pathways). The results of this study indicate that the choice for energy allocation or a hybrid method particularly affects pathways producing high amounts of (non-energy) co-products or co-products which effectively displace carbon intensive products (e.g. electricity in a US context).

Given the results and the trade-offs between different allocation methods (see section 4.2.6), we propose to employ energy allocation as a base in a global meta-standard,

n Life-cycle GHG emission assessments generally assume biogenic carbon dioxide emissions to be fully offset by carbon sequestration during feedstock growth. Nonetheless, such emissions do contribute to radiative forcing until they are sequestered and as such influence the timing of GHG emission savings (as captured in the carbon payback time).

supplemented with economic allocation for specific systems. Energy allocation would likely lead to easier development and implementation, due to its universal character, indifference to the choice of main product and ability to capture the value of energy products. For non-energy co-products produced in specific systems, economic allocation was deemed appropriate as it is subject to fewer methodological and circumstantial choices than the displacement method.

Such framework necessitates a threshold co-product allocation ratio after which economic allocation is to be used and an index (or regional indices) on the basis of which the co-product allocation ratio should be determined, including a defined timespan and sensible proxies for non-commoditized co-products. Moreover, it is important to be aware that this combination of allocation methods is sensitive to changes in co-product use (e.g. using naphtha as a chemical feedstock rather than using it for fuel production) or the product slate (e.g. produce more (non-energy) co-products at the expense of RJF yield).[49] As some of the conversion pathways considered are flexible in product output (e.g. FT and HEFA), further research on the impact of product slate variability is encouraged.

4.6.4 RJF as an emission mitigation instrument for aviation

The mitigation costs of RJF are high compared to other mitigation options for aviation. Combining techno-economic data from De Jong et al.[214] with the results of this study yields minimum GHG emission mitigation costs of roughly 200 \$ t^{-1} CO_2 abated, irrespective of co-product method (found for HTL at an oil price of 45 \$ bbl^{-1}). Although this figure is indicative and highly dependent on the oil price, these mitigation costs place RJF at the higher end of other biomass-based mitigation options.[334]

Other mitigation options for aviation (e.g. carbon offsets or efficiency improvements in technology and operations) yield lower mitigation costs; most efficiency improvement measures come at zero or negative mitigation costs[335], while 85% of the global carbon offsets is currently priced at less than 10 US\$ t^{-1} CO_2.[336] Although carbon prices are expected to rise, it is unlikely that carbon prices will approach the mitigation costs for RJF before 2050.[337–339]

Nonetheless, the introduction of RJF is deemed an important part of the industry's ambition to structurally reduce GHG emissions.[17] Hence, even though the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) will raise the price of fossil fuel, it is most likely that further reduction of RJF production costs (through technological learning and maturation of biomass markets) and supplementary incentives are still required in order for airlines to prefer RJF adoption over buying

emission credits to comply with the CORSIA scheme on the basis of cost. Given the substantial development efforts still required to get sufficient volumes of RJF on the market, the aviation industry cannot afford to rely solely on offsets and efficiency measures for the coming decade; it will need to continue to actively stimulate the development of RJF capacity in concurrence with the biofuel and biochemical sectors.

4.6.5 Wider sustainability considerations of RJF production

The results of this analysis alone do not fully represent the climate change mitigation potential of RJF nor give a guarantee of the overall sustainability of RJF production. Firstly, this analysis does not include direct or indirect LUC emissions. Including LUC effects would likely lead to a stronger preference for residues. The magnitude of LUC emissions may have a positive or negative impact depending on the feedstock cultivation context (see section 4.2.4). Moreover, the importance of LUC effects is likely to increase with growing demand for RJF and other biomass-derived products.[322]

Secondly, the GHG emission reduction as a result of using RJFs is not immediate. The timing of GHG emission savings (as captured in the GHG payback period) depends on the feedstock used and prior land use, since there generally exists a temporal imbalance ('carbon debt') between the time of emission and sequestration of the carbon. The GHG payback period is particularly long for feedstocks with long rotation periods and/or natural decay times, such as different types of woody biomass.[340] For the feedstocks investigated in this paper (residues, annual agricultural crops or short rotation crops), this effect is probably less relevant.

Thirdly, the system boundaries and functional unit employed in this analysis exclude the contribution to radiative forcing of other emission species than CO_2, N_2O and CH_4. For example, water vapor, NO_x, soot and sulfate aerosols, as well as contrails and contrail-induced cirrus formation emitted during fuel combustion increase the radiative forcing by a factor 2-5 relative to the impact of CO_2 emissions alone.[9] Although RJF has the potential to reduce some of these combustion emissions (particularly CO, NO_x, PM_{10} and SO_x)[39,300], the positive impact of RJF on radiative forcing is likely to be lower than the percentage reduction in life-cycle GHG emissions suggests.[38] Furthermore, other emissions during the life-cycle (e.g. black carbon or primary organic carbon) or LUC-induced surface albedo effects may also significantly impact the net radiative forcing effect of biofuels.[40,341,342]

Lastly, an assessment of the sustainability of RJF should also include other possible impacts on water use, land use, air quality, health effects, food security, and biodiversity, most of which are highly circumstantial and transcend the domain of RJF.[16,39,343,344]

4.7 CONCLUSION

This study compares the Well-to-Wake (WtWa) GHG emission performance of various RJF conversion pathways and shows the impact of different co-product allocation procedures. Conversion pathways based on residues or lignocellulosic crops yield low WtWa GHG emissions, irrespective of allocation method. The FT pathway shows the highest GHG emission savings (86-104%) of the pathways considered, followed by HTL (77-80%), pyrolysis (54-75%), UCO-based HEFA (68%), and sugarcane- (71-75%) and corn stover-based ATJ (60-75%). The largest differences between energy allocation and the hybrid method (using the displacement method for non-fuel co-products) were found for conversion pathways producing high amounts of co-products or co-products which effectively displace carbon intensive products, such as FT, jatropha-based HEFA or corn-based ATJ. This study was framed in a particular spatiotemporal context; a comparison of RJF production across regions and timeframes using different assessment frameworks is recommended to determine the impact of methodological and actual differences on the GHG emission intensity of RJF production. Also, this assessment does not include emissions from land use change and could thus over- or underestimate the GHG emission performance in specific contexts.

The GHG emission performance of RJF can be enhanced by using more sustainable sources of electricity and hydrogen (e.g. biomass or renewable electricity), improving agricultural practices and advancing RJF technologies. Also, some pathways provide the opportunity to be combined with carbon capture and storage, potentially yielding negative emissions at relatively modest cost compared to other options for carbon capture and storage. Future research should evaluate the potential of these improvement options, preferably from a broader energy systems perspective.

The inclusion of RJF in a global carbon offsetting scheme requires a harmonized methodology to assess the GHG emission performance of different RJFs. We recommend using energy allocation as a base, supplemented with economic allocation for systems yielding high shares of non-energy co-products. This combination of allocation methods leverages the universal character of energy allocation and the ability of economic allocation to properly value non-energy co-products. The allocation methodology is only one of the aspects of a global meta-standard; broad cooperation is required to develop a robust framework which needs to be flexible to account for spatial diversity yet standardized to avoid competitive distortion or adverse sustainability effects.

S4 SUPPLEMENTARY INFORMATION

S4.1 Input data

All feedstock cultivation and conversion was considered to occur in the US, except sugar cane-based ATJ and DSHC (Brazil). For sugarcane-based conversion pathways all cultivation and conversion inputs correspond to a Brazilian context. Consequent downstream transport of RJF from Brazil to the US was accounted for (see section S.4.1.5).

S4.1.1 Feedstock cultivation

The inputs for feedstock cultivation are displayed in Table 4-5. The emission factors corresponding to the inputs were obtained from GREET. Emissions for the production of residues (corn stover, forestry residues) or food by-products (used cooking oil) were considered from the time of collection. It was not chosen to allocate a portion of the cultivation emissions to the residue or by-product to avoid additional assumptions on input data and allocation methodology. Fertilizer inputs for corn stover were based on the required supplementary fertilizer to replenish soil nutrients after corn stover harvesting; no fertilizer for the production of forest residue was assumed.[345] Used cooking oil was considered a recycled product, hence emissions from used cooking oil production were excluded.[33,315,346] Emissions from residue collection were included.

Besides emissions from fertilizer production and application, N_2O emissions are also caused by direct and indirect conversion of N fertilizers in the soil [39]. Direct emissions result from nitrification and denitrification cycles. Indirect emissions are caused by nitrate leaching and volatilization of nitrates [292]. The conversion rate to calculate the N_2O emissions per unit of N fertilizer applied is highly uncertain as it depends on local factors such as soil and climate conditions, farm practices, N fertilizer type, and application rate.[42,52,290,292]

The reference studies used in this analysis utilize different conversion rates to calculate the N_2O emissions from N fertilizer. For the majority of the feedstocks (poplar, willow, forest residue, corn stover, corn and sugarcane) the conversion rates as specified in GREET were used (1.525% for poplar, willow, forestry residues, corn stover, and corn, and 1.22% for Brazilian sugarcane).[292] These factors were determined from an extensive literature survey. N_2O emissions from jatropha and camelina cultivation were calculated using the IPCC Tier 1 method[o], reporting conversion rates of 1.325% for N fertilizers and 1.225% nitrogen from crop residues.[42,52]

The conversion rates as specified in the reference study were also adopted in this study. To account for the uncertainties associated with N_2O soil emissions, the impact of fertilizer use was analyzed in the sensitivity analysis.

o More information on the IPCC Tier 1-3 methods can be found in [457].

TABLE 4-5: Input values for feedstock cultivation.

		Fertilizer					
		K_2O	P_2O_5	N	$CaCO_3$	Herbicides	Insecticides
	Product	g kg^{-1} product	g kg^{-1} product	g kg^{-1} product	g kg^{-1} product		-
Jatropha	Jatropha seeds	40.20	14.00	36.60	-	-	-
Camelina	Camelina seeds	11.60	17.40	43.00	-	-	-
UCO	UCO	-	-	-	-	-	-
Poplar	Poplar	2.02	1.01	3.02	2.38	0.15	-
Willow	Willow	-	-	2.85	-	0.03	-
Corn stover	Corn stover	15.04	8.77	8.77	-	-	-
Forestry residues	Forestry residues	-	-	-	-	-	-
Sugarcane	Sugarcane	1.00	0.30	0.80	5.20	0.05	2.50
Corn	Corn	5.39	5.20	15.09	40.98	0.28	2.36

(continued)

		Utilities					Other inputs		Geography	Source
		Diesel	Natural gas	Electricity	Gasoline	LPG				
	Product	MJ kg^{-1} product	MJ kg^{-1} product	MJ kg^{-1} product	MJ kg^{-1} product	MJ kg^{-1} product		g kg^{-1} product		
Jatropha	Jatropha seeds	1.50	-	-	-	-			US	[295]
Camelina	Camelina seeds	1.18	-	-	-	-			US	[295]
UCO	UCO	-	-	-	-	-			US	[33,347]
Poplar	Poplar	0.25	-	-	-	-			US	[295]
Willow	Willow	0.18	0.00	0.00	-	-			US	[295]
Corn stover	Corn stover	0.26	-	-	-	-			US	[295]
Forestry residues	Forestry residues	0.14	-	-	-	-			US	[295]
Sugarcane	Sugarcane	0.04	0.02	0.01	0.01	0.02	Sugarcane straw[i]	17	Brazil	[295]
Corn	Corn	0.18	0.05	0.02	0.05	0.06			US	[295]

i. The straw is assumed to be burnt on the field

S4.1.2 Feedstock pre-processing

Table 4-6 shows the assumptions for feedstock pre-processing steps.

TABLE 4-6: Input values for feedstock pre-processing.

Feedstock	Process	Yield		Other inputs			Co-product			Source
Jatropha	Oil extraction	74.36	g seed MJ^{-1} oil	Natural gas	0.049	MJ MJ^{-1} oil	Electricity	0.34	MJ MJ^{-1} oil	[42,295]
				Hexane	0.0047	MJ MJ^{-1} oil				
Camelina	Oil extraction	74.36	g seed MJ^{-1} oil	Natural gas	0.031	MJ MJ^{-1} oil	Camelina meal	47.79	g MJ^{-1} oil	[52,295]
				Hexane	0.0027	MJ MJ^{-1} oil				
				Electricity	0.0023	MJ MJ^{-1} oil				
				Diesel	0.017	MJ MJ^{-1} oil				
UCO	Rendering	1.66	kg kg^{-1} yellow grease	Natural gas	0.039	MJ MJ^{-1} oil				[33,347]
				Electricity	0.0040	MJ MJ^{-1} oil				

S4.1.3 Upstream transport

Table 4-7 shows the assumptions used for feedstock transportation. Several transportation modes are used in GREET.net. The pathways in the scope of this research include heavy-duty trucks, train and barges. Dunn et al.[348] reports assumptions for the energy intensity and emissions parameter for transportation used in GREET. The energy intensity for goods transport by rail is based on data reported to the Surface Transportation Board of the United States Department of Transportation (DOT). Emission factors are based on values from EPA. The energy intensity and emissions factors for Heavy-Duty trucks are based on EPA's Motor Vehicle Emission Simulator (MOVES) model. GREET includes a Medium Heavy-Duty Truck and a Heavy Heavy-Duty truck. The energy intensity and emission values for Barge transport is based on research by the Bureau of Transportation statistics and the Department of Energy. Transportation distances and mode shares are based on the Freight Analysis Framework (FAF) model of the DOT. The payloads and transport parameters can be found in GREET.[295]

TABLE 4-7: Upstream transport assumptions.

Transport						
Feedstock	Transport stage	Transport mode	Distance	Share	Geography	Source
			km			
Jatropha	From field to stacks	Medium Heavy-Duty Truck	16	100%	US	295
	From stacks to extraction plant	Heavy Heavy-Duty Truck	64	100%	US	
	From extraction plant to conversion plant	Barge	837	40%	US	
		Rail	1127	20%	US	
		Heavy Heavy-Duty Truck	129	40%	US	
Camelina	From field to stacks	Medium Heavy-Duty Truck	16	100%	US	295
	From stacks to extraction plant	Heavy Heavy-Duty Truck	64	100%	US	
	From extraction plant to conversion plant	Rail	1127	33%	US	
		Heavy Heavy-Duty Truck	129	67%	US	
UCO	From collection location to rendering plant	Heavy-Heavy Duty truck	156	100%	US	347
	From rendering plant to conversion facility	Heavy Heavy-Duty Truck	80	100%	US	295
Poplar	From field to conversion plant	Heavy Heavy-Duty Truck	80	100%	US	295
Willow	From field to conversion plant	Heavy Heavy-Duty Truck	80	100%	US	295

Corn stover	From field to conversion plant	Heavy Heavy-Duty Truck	153	100%	US	[295]
Forestry residues	From field to conversion plant	Heavy Heavy-Duty Truck	144	100%	US	[295]
Sugar cane	From field to conversion plant	Heavy Heavy-duty truck	19.31	100%	Brazil	[295]
Corn	From corn field to stack	Heavy Heavy-duty truck	64	100%	US	[295]
	From stacks to ethanol plant	Medium Heavy-Duty Truck	16	100%	US	

S4.1.4 Conversion to RJF

The table below provides supplementary data not tabulated in Table 4-2 and Table 4-3 in the main text. It should be noted that the level of detail varies among the reference studies. For example, whereas the catalysts are included for ATJ, they are not included for FT. Similarly, enzyme and yeast use for sugarcane ethanol production is not included in GREET as the reference study of Wang et al.[292] did not have data available and assumed that their effect on sugarcane WTWa GHG emissions are small, as is the case for corn ethanol. Based on similar reasoning we are confident that this study has included the most important inputs from a GHG point of view.

TABLE 4-8: Conversion assumptions.

Input	Unit	Value	Source
DSHC			
Yeast	g MJ^{-1} Jet	1.41E-06	[35]
Sodium chloride	g MJ^{-1} Jet	9.95	
Sodium hydroxide	g MJ^{-1} Jet	0.23	
Ammonium hydroxide	g MJ^{-1} Jet	2.59	
Diammonium phosphate	g MJ^{-1} Jet	0.63	
Glucose	g MJ^{-1} Jet	22.49	
Sulfuric acid	g MJ^{-1} Jet	11.7	
ATJ			
Catalyst for hydrotreating	g MJ^{-1} Jet	0.064	[296]
Catalyst for oligomerization	g MJ^{-1} Jet	0.043	

Corn stover to ethanol					
Corn stover	kg MJ^{-1} ethanol	0.13			295
Sulfuric acid	g MJ^{-1} ethanol	3.10			
Ammonia	g MJ^{-1} ethanol	1.77			
Yeast	g MJ^{-1} ethanol	0.35			
Cellulase	g MJ^{-1} ethanol	1.41			
Diesel	MJ MJ^{-1} ethanol	0.00			

Sugarcane to ethanol[i]					
Sugarcane	g MJ^{-1} ethanol	579.89			295
Residual oil	g MJ^{-1} ethanol	3.93E-03			

Corn to ethanol[ii]		1	2	3	
Alpha Amylase	g MJ^{-1} ethanol	0.03	0.03	0.03	295
Gluco Amylase	g MJ^{-1} ethanol	0.07	0.07	0.07	
Yeast	g MJ^{-1} ethanol	0.03	0.03	0.04	
Sulfuric Acid	g MJ^{-1} ethanol	0.22	0.22	0.23	
Ammonia	g MJ^{-1} ethanol	0.22	0.22	0.23	
Sodium hydroxide	g MJ^{-1} ethanol	0.27	0.27	0.29	
Calcium oxide	g MJ^{-1} ethanol	0.13	0.35	0.14	
Natural Gas	MJ MJ^{-1} ethanol	0.29	0.29	0.45	
Electricity	MJ MJ^{-1} ethanol	0.03	0.034	-	
Coal	MJ MJ^{-1} ethanol	2.00E-03	0.03	0.17	

vi. Sugarcane straw and sugarcane bagasse is used for internal heat and power.

vii. GREET uses a weighted average of three different corn ethanol technologies. Dry mill ethanol production without corn oil extraction (1), dry mill ethanol production with corn oil extraction (2), and wet mill ethanol production (3) respectively produce 18.23%, 72.91% and 8.87% of the total produced ethanol.

S4.1.5 Downstream distribution

Downstream distribution includes the transportation of the RJF to a blending terminal, blending operations, transportation to the airport tank farm, storage and distribution in the airport hydrant system. Input data is listed in Table 4-8 and Table 4-9. Electricity use for storage and blending was obtained from BioGrace.[315] Similar to BioGrace, variance in energy use as a result of different blend walls for each RJF type was not taken into account.

TABLE 4-9: Energy use for blending and storage.

Supply chain component	Value	Unit	Source
Blending (filling station)	0.0034	MJ electricity MJ^{-1} RJF	[315]
Storage (depot)	0.00084	MJ electricity MJ^{-1} RJF	[315]

TABLE 4-10: Transport distance downstream distribution.

Transport						
Product	Transport stage	Transport mode	Distance	Share	Geography	Source
			km			
RJF	Conversion plant to bulk terminal	Barge	837	8%	US	[295]
		Rail	1287	29%	US	[295]
		Heavy Heavy-Duty Truck	80	63%	US	[295]
RJF	Blending terminal to airport farm	Heavy Heavy-Duty Truck	48	100%	US	[295]
RJF[i]	Conversion plant to bulk terminal	Heavy Heavy-Duty Truck	692	100%	Brazil	[295]
RJF[i]	Bulk terminal Brazil to US terminal	Small Ocean Tanker	11935	100%	Brazil-US	[295]
RJF[i]	US terminal to blending terminal	Heavy Heavy-Duty Truck	48	100%	US	[295]

i. Only applicable for sugarcane-based pathways.

S4.2 Sensitivity analysis yield ranges[214]

TABLE 4-11: Sensitivity analysis yield ranges.[214]

		Base	Pessimistic	Optimistic
		kg fuel product kg^{-1} feed		
HEFA	UCO	0.88	0.75	0.89
	Camelina oil	0.88	0.75	0.89
	Jatropha oil	0.88	0.75	0.89
FT	Poplar	0.19	0.13	0.22
	Willow	0.19	0.13	0.22
	Corn stover	0.18	0.13	0.22
	Forestry residues	0.21	0.13	0.22
HTL in-situ	Forestry residues	0.27	0.17	0.36
HTL ex-situ	Forestry residues	0.27	0.17	0.36
Pyrolysis in-situ	Forestry residues	0.24	0.26	0.36
Pyrolysis ex-situ	Forestry residues	0.24	0.26	0.36
ATJ	Ethanol	0.54	0.53	0.58
DSHC increased blend wall	Sugar[i]	0.18	0.15	0.30
DSHC 10%	Sugar[i]	0.18	0.15	0.30

i. Sugar to farnasene yield.

S4.3 Energy allocation and displacement method

For a hypothetical system with one main product and one co-product, the GHG emission intensity of the main product can be calculated as follows:

$$Energy\ allocation: \varepsilon_{main\ product,EA} = \varepsilon_{system} \quad (1)$$

$$Displacement: \varepsilon_{main\ product,DM} = \frac{\varepsilon_{system} - (1-\eta_p) * r_D * \varepsilon_{displaced\ product}}{\eta_p} \quad (2)$$

In which ε is the specific GHG emission intensity for the total system (including the product and co-products) and the displaced product. The product share (η_p), co-product allocation ratio (r_A) and displacement ratio (r_D) are defined here as:

$$\eta_p = \frac{1}{1+r_A} = \frac{E_p}{E_p + E_{cp}}\ in\ which\ r_A \equiv \frac{E_{cp}}{E_p} \quad (3)$$

$$r_D \equiv \frac{E_{cp}}{E_{dp}} \quad (4)$$

In which E is the energy content of the product (p), co-product (cp) and displaced product (dp). The parameters η_p and r_D can be defined in terms of units (e.g. kg kg^{-1}, MJ MJ^{-1}). To avoid conversion, we use MJ MJ^{-1} in this example. It should be noted that η_p is inversely proportional to r_A. Furthermore, equation 1 and 2 show that while energy allocation yields strictly positive emission intensities (excluding the possibility that the total system is carbon negative due to the application of carbon capture and storage), the displacement method may give negative emission intensities.

The difference (Δ) between the GHG emission intensity of the main product using energy allocation and the displacement method is expressed as:

$$\Delta = \varepsilon_{EA} - \varepsilon_{DM} = \left(\frac{1}{\eta_p} - 1\right) * \left(r_D * \varepsilon_{displaced\ product} - \varepsilon_{system}\right) = r_A * \left(r_D * \varepsilon_{displaced\ product} - \varepsilon_{system}\right) \quad (5)$$

The sign of the difference is determined by the term $_D * \varepsilon_{displaced\ product} - \varepsilon_{system}$. Hence, energy allocation yields higher GHG emissions when:

$$r_D * \varepsilon_{displaced\ product} > \varepsilon_{system} \quad (6)$$

The displacement method yields higher GHG emissions for systems in which:

$$r_D * \varepsilon_{displaced\ product} < \varepsilon_{system} \quad (7)$$

As an illustration we take a system in which the co-product is green electricity. As electricity is often a direct substitute for grid electricity r_d is likely equal to 1. As such, inequalities 6 and 7

reduce to a comparison between the emission intensity of the displaced product (grid electricity) and the energy intensity of the system. For systems having lower specific emission intensity than grid electricity, the displacement method will always yield a lower GHG emission intensity for the main product. For systems having higher emission intensity than grid electricity, the energy allocation method will always yield lower results than the displacement method.

The size of Δ grows with higher co-product allocation ratios and increasing divergence between the terms $r_D{}^*\varepsilon_{displaced\ product}$ and ε_{system}. In other words, larger differences between the results of both methods may be expected for systems producing high amounts of co-products. Furthermore, for systems which are much less emission intensive than the system producing the displaced product (i.e. $\varepsilon_{displaced\ product} \gg \varepsilon_{system}$) larger differences between both methods occur for systems producing co-products that effectively displace emission intensive products (i.e. high r_D and $\varepsilon_{displaced\ product}$).

For systems with more co-products the general dynamics still hold, i.e. higher allocation ratios will lead to higher differences. Calculation of the sign of the difference requires, however, more parameters than postulated for the example system above.

5

Using the Relative Climate Impact performance indicator to quantify the climate impact of bioenergy production systems

Sierk de Jong[1,*], Mark Staples[2], Carla Grobler[2], Vassilis Daioglou[3], Robert Malina[2,4], Steven Barrett[2], Ric Hoefnagels[1], André Faaij[5], Martin Junginger[1]

1. Copernicus Institute of Sustainable Development, Utrecht University, Utrecht, The Netherlands.
2. Laboratory of Aviation and the Environment, Massachusetts Institute of Technology, Cambridge, United States.
3. Department of Climate, Air and Energy, PBL Netherlands Environmental Assessment Agency, The Hague, The Netherlands.
4. Center for Environmental Sciences, Hasselt University, Hasselt, Belgium.
5. Energy Academy Europe, University of Groningen, Groningen, The Netherlands.

Submitted

5 ABSTRACT

The climate impact of bioenergy is commonly quantified in terms of CO_2-equivalents, using a fixed 100-year global warming potential as an equivalency metric. This method has been criticized for the inability to appropriately address emissions timing and the focus on a single impact metric, which may lead to inaccurate or incomplete quantification of the climate impact of bioenergy production. In this study, we formulate the Relative Climate Impact (RCI), a novel time-dependent performance indicator for bioenergy systems. The RCI offers the flexibility to analyze system performance for different value judgments regarding impact categories (e.g. emissions, radiative forcing and temperature change), equivalency metrics, and analytical time horizon. It may be used by policy makers to set two-dimensional performance thresholds based on the maximum climate impact and time horizon. The application of the RCI to fourteen bioenergy systems illustrates how value judgments affect the merit order of bioenergy systems, because they alter the importance of one-time (associated with land use change emissions) versus sustained (associated with carbon debt or foregone sequestration) emission fluxes and short- versus long-lived climate forcers. Best practices for bioenergy production (irrespective of value judgments) include high feedstock yields, high conversion efficiencies and the application of carbon capture and storage. Furthermore, this study provides examples of production contexts in which the risk of LUC emissions, carbon debt or foregone sequestration can be mitigated. For example, the risk of indirect LUC emissions can be mitigated by accompanying bioenergy production with increasing agricultural yields. Moreover, production contexts in which the counterfactual scenario yields immediate or additional climate impacts can yield highly negative RCI values. The RCI can also be used to compare other energy systems, particularly those with time-dependent emission profiles, such as electric vehicles.

5.1 INTRODUCTION

Biomass is an important renewable energy source in climate change mitigation strategies, particularly for sectors relying on energy-dense liquid fuels, such as aviation, shipping and long-haul trucking.[195,349] The conventional approach to quantify the climate change mitigation value of bioenergy is based on cradle-to-grave life-cycle assessment (LCA) of greenhouse gas (GHG) emission fluxes (GHG-LCA), using the 100-year global warming potential as an equivalency metric[p] to convert non-CO_2 emissions into CO_2 equivalents. This method is widely employed to compare system performance and to determine compliance of bioenergy systems to sustainability standards or policies.

In the context of bioenergy, the conventional GHG-LCA approach is criticized for its treatment of time-dependent emission profiles and the related climate impacts.[56–61] The net emission profile of bioenergy production is determined by 1) the cradle-to-grave life-cycle production emissions, 2) the displaced (fossil) emissions, 3) direct emissions from e.g. carbon stock changes in the feedstock production area and 4) indirect emissions from market-mediated effects. Emission fluxes from the latter two effects are generally time-dependent, particularly when land clearing is involved (instigating land use change (LUC) emissions) and/or long-rotation feedstocks are used (e.g. forestry biomass).[59,350–353] These emission fluxes are measured against the initial carbon stocks or the carbon stocks in a counterfactual scenario in which no bioenergy is produced. The conventional GHG-LCA approach often employs linear amortization of carbon stock changes, measured relative to the initial carbon stocks, over an arbitrary production period.[60] Alternatively, a parity point can be calculated at which emissions of bioenergy production equal the emissions of the counterfactual scenario.[354] However, both methods neglect the fact that the climate impact of GHGs increases with the atmospheric residence time and may therefore lead to incomplete conclusions about (relative) system performance and the timing of climate mitigation benefits.[56–61] The use of discount rates[57,59,355] and time correction factors[60,62] have been proposed; however, the former does not have a physical basis in climate science, and the latter is unable to consider prolonged temporal variability of emission profiles.

Moreover, the use of a single performance indicator, as defined by the impact category, equivalency metric and analytical time horizon used in the conventional approach, does not reflect the complexity of the climate system.[37] The climate impact can be quantified according to different impact categories along the cause-effect chain (i.e. GHG emissions, radiative forcing, temperature change and climate damages) at or over different analytical time horizons for instantaneous and cumulative metrics,

p Equivalency metrics are also commonly referred to as normalized (emission) metrics or characterization factors.

repectively.[37,56,61] The impact categories exhibit different temporal responses to emission pulses, which affects the impact of emission timing.[59–62] Similarly, the choice of equivalency metric affects the relative importance of short-lived to long-lived emission species.[37] Additionally, the analytical time horizon determines the cut-off point of the analysis, thus excluding impacts beyond a certain time. The choice of performance indicator therefore contains a value judgment about the weighting of one-time versus sustained emission fluxes and short- versus long-lived climate forcers, and can thus benefit or disadvantage the evaluation of systems with a particular emission profile.[1]

Bioenergy systems demonstrate a wide variety of emission profiles, in terms of both emission species and timing. Therefore, it is necessary to consider the time-dependence and the impact of value judgments in bioenergy GHG-LCA to be able to properly quantify and compare their performance. Various authors have proposed methods to incorporate one of the aforementioned aspects in LCA. Some studies focus on dynamic performance indicators to incorporate time-dependent emission profiles, such as the Fuel Warming Potential[59], Carbon Neutrality Factor[47,356] or Carbon Balance Indicator[357]. Other authors have proposed alternative equivalency metrics, which vary in equivalency base, time horizon and type of time horizon (time-dependent or fixed).[37,57,61,350,358–361] In addition, several studies have quantified the performance of bioenergy systems for different impact categories, such as radiative forcing, temperature change and economic damages.[59,62,352,353,362,363]

Building upon prior efforts, we define a dynamic performance indicator, the Relative Climate Impact (RCI). To the best of our knowledge, the RCI is the first performance indicator that enables consistent comparison of the climate impact of bioenergy systems with different time-dependent emission profiles, while offering the flexibility to compare the effects of value judgments regarding the impact category, analytical time horizon and equivalency metric. The use of the RCI was illustrated for various bioenergy systems with different temporal emission profiles to study the impact of different emission profiles and value judgments. A reduced-order climate model was employed to translate emission profiles into impact categories and quantify the associated uncertainty.

The remainder of this chapter is structured as follows. Section 5.2 introduces a generalized approach to assess the climate impact of bioenergy systems using the RCI and demonstrates the approach for three bioenergy systems. Section 5.3 discusses the RCI results and quantifies the uncertainty associated with climate impact modeling. Section 5.4 introduces variations on the three bioenergy systems in scope to quantify the relative importance of emission sources (e.g. life-cycle emissions, LUC emissions, carbon debt and foregone sequestration) and identify best practices for

bioenergy production. Section 5.5 discusses the merits and limitations of the RCI and the implications for evaluation of bioenergy systems. Section 5.6 provides the main conclusions of this study.

5.2 METHODS

5.2.1 Bioenergy systems in scope

The three bioenergy systems in scope were selected based on their distinct emission profile (Table 5-1). The systems are stylized examples chosen to demonstrate the use of the RCI for systems with different emission profiles, and therefore may contain simplifying assumptions. The selected systems produce 10 PJ yr^{-1} middle-distillate (MD) transport fuels (gasoline, diesel and/or jet fuel) on a commercial scale destined for the US market. The HEFA-UCO system is based on full hydrodeoxygenation of used cooking oil, a residue from the food industry. The FT-DWD system employs gasification and Fischer-Tropsch synthesis based on downed woody debris (DWD) from loblolly pine. The ATJ-SC system is based on the Alcohol-to-Jet technology, which converts alcohols (in this case sugarcane ethanol) to MD fuels through dehydration, oligomerization and hydrogenation. Hydrogen consumption in the HEFA-UCO and ATJ-SC case is covered by steam methane reforming of natural gas.

TABLE 5-1: Characterization of the bioenergy systems in scope.

	Bioenergy scenario					**Counterfactual scenario**	**Fossil baseline**
System code	**Technology**	**Feedstock**	**Production Location**	**Direct emissions**	**Indirect emissions**		
HEFA-UCO	Hydroprocessed Ester and Fatty Acids	Used cooking oil	US	Not applicable (residue from food industry)	No substitution effect assumed	Burning used cooking oil without energy recovery	US diesel-type fossil fuels
FT-DWD	Gasification and Fischer-Tropsch synthesis	Downed woody debris (loblolly pine)	Eastern US	Residue removal creates a carbon debt	No indirect emissions assumed (residues were not utilized before)	Natural aerobic decay of downed woody debris	US diesel-type fossil fuels
ATJ-SC	Fermentation and Alcohol-to-Jet	Sugarcane	Brazil (grassy cerrado), imported to the US	Carbon stock change due to land clearance	None	Foregone sequestration due to growth of natural vegetation	US diesel-type fossil fuels

5.2.2 Dynamic life cycle inventory

5.2.2.1 Generalized approach

A dynamic Life Cycle Inventory (LCI) contains a time-dependent inventory of emission fluxes, grouped by emission species (denoted with subscript *i*).[57–59] A separate LCI exists for the bioenergy (*bio*) and counterfactual (*cf*) scenario, which represent alternative futures diverging from the production start year (t_0). The LCI is defined from t_0 to the LCI time horizon (TH_{LCI}).[59] If TH_{LCI} is longer than the production time horizon (TH_p), post-production emission fluxes (e.g. regrowth) should be included.

The LCI of the bioenergy scenario (*bio*) consist of life-cycle production emissions ($Elc_{bio,i}$), direct emissions in the biomass production area ($Edir_{bio,i}$), and indirect emissions from market-mediated effects ($Eind_{bio,i}$) (eq. 1). Direct emissions may include methane emissions from wetland drainage, or carbon stock changes from LUC or carbon debt. Indirect emissions may occur when increased crop production for bioenergy purposes affect global agricultural and fuel markets and give rise to additional emissions in other sectors. Indirect LUC emissions are a prominent example of a market-mediated effect, whereby bioenergy production induces land conversion elsewhere, e.g. due to increasing commodity prices. Biogenic combustion emissions in the bioenergy scenario should be included in Elc_i or be accounted for in $Edir_{bio,i}$ (i.e. adding the combustion emissions to the carbon sequestration due to feedstock growth).

The counterfactual scenario (*cf*) represents the anticipated future scenario in which no bioenergy is produced. It includes the life-cycle emissions of the main (fossil) products directly displaced by the produced quantity of bioenergy ($Edmp_{cf,i}$), direct emissions in the biomass production area ($Edir_{cf,i}$) and indirect emissions ($Eind_{cf,i}$) (eq. 2). Direct emissions in the counterfactual scenario often involve foregone sequestration, which includes the future sequestration that would have occurred in the intended biomass production area if no bioenergy was produced. If system expansion is used, emissions from displaced co-products should also be considered in the counterfactual scenario ($Edcp_{cf,i}$). If mass, energy or market value allocation is used for co-product allocation, all emission fluxes in the bioenergy and counterfactual scenarios should be allocated accordingly.[44]

System performance is often benchmarked against a fossil baseline to calculate the relative reduction and allow for comparison among systems. In biofuel regulation such as the US Renewable Fuel Standard 2 (RFS2) or EU Renewable Energy Directive (RED), the fossil baseline (or "fossil comparator") is often pre-defined based on average emission factors for a benchmark fossil product. In the current dynamic formulation,

the fossil baseline is assumed constant over time and includes life-cycle emissions of the benchmark product ($Elc_{base,i}$) (eq. 3).

$$LCI(t)_{bio,i} = Elc_{bio,i}(t) + Edir_{bio,i}(t) + Eind_{bio,i}(t) \quad (1)$$

$$LCI(t)_{cf,i} = Edmp_{cf,i}(t) + Edcp_{cf,i}(t) + Edir_{cf,i}(t) + Eind_{cf,i}(t) \quad (2)$$

$$LCI(t)_{base,i} = Elc_{base,i} \quad (3)$$

In the formulation in eq. 1-3, sequestration is considered a negative emission. Unlike customary practice to allocate the difference in carbon stock between the bioenergy and counterfactual scenario entirely to the bioenergy scenario (see e.g. Zanchi et al.'s carbon neutrality factor[356]), the dynamic LCI presented above quantifies the emission fluxes in year t relative to t-1 in both scenarios, thus tracking actual emissions to the atmosphere. This distinction is required to calculate impact categories further down the cause-effect chain, due to the non-linear relation between GHG emissions and these impacts.

5.2.2.2 Dynamic Life Cycle Inventory for the bioenergy systems in scope

Based on eq. 1-3, a dynamic LCI was constructed for the bioenergy systems in scope. The LCI comprised CO_2, CH_4 and N_2O emissions for the bioenergy and counterfactual scenarios and fossil baseline for $TH_p = TH_{LCI} = 100$ years (Figure 5-1 and Table 5-2). The emissions were summed by emission species and quantified per MJ of MD fuels. It was assumed that none of the systems cause indirect emissions, as quantifying the indirect emissions requires economic modelling (e.g. general equilibrium modeling), and involves considerable uncertainties.[304] Biogenic emissions (from e.g. biomass or biofuel combustion) were assumed equal to the carbon sequestration from feedstock growth within the same year on a landscape level and were hence omitted from the LCI.

Life-cycle emissions and displaced emissions were calculated using the Greenhouse gases, Regulated Emissions and Energy use in Transportation model (GREET.net v.1.3.0.13107), using system expansion and cradle-to-grave supply chains described in de Jong et al.[232] Life-cycle emissions were assumed constant over TH_p and TH_{LCI}. The fossil baseline was based on emission factors for diesel-type fuels as defined in the US RFS2.[364]

TABLE 5-2: LCI for CO_2, CH_4 and N_2O for three bioenergy systems.

System		HEFA-UCO		FT-DWD		ATJ-SC		Baseline
Scenario		**Bioenergy**	**Counterfactual**	**Bioenergy**	**Counterfactual**	**Bioenergy**	**Counterfactual**	
$LCI_{CO2}(t)$	$g\ MJ_{MD}^{-1}$	30	99	Time-dependent (Figure 5-1)		Time-dependent (Figure 5-1)		89
$LCI_{CH4}(t)$	$g\ MJ_{MD}^{-1}$	0.12	0.19	0.020	0.22	0.20	0.20	0.094
$LCI_{N2O}(t)$	$mg\ MJ_{MD}^{-1}$	3.4	3.1	4.1	4.6	38	3.6	2.2

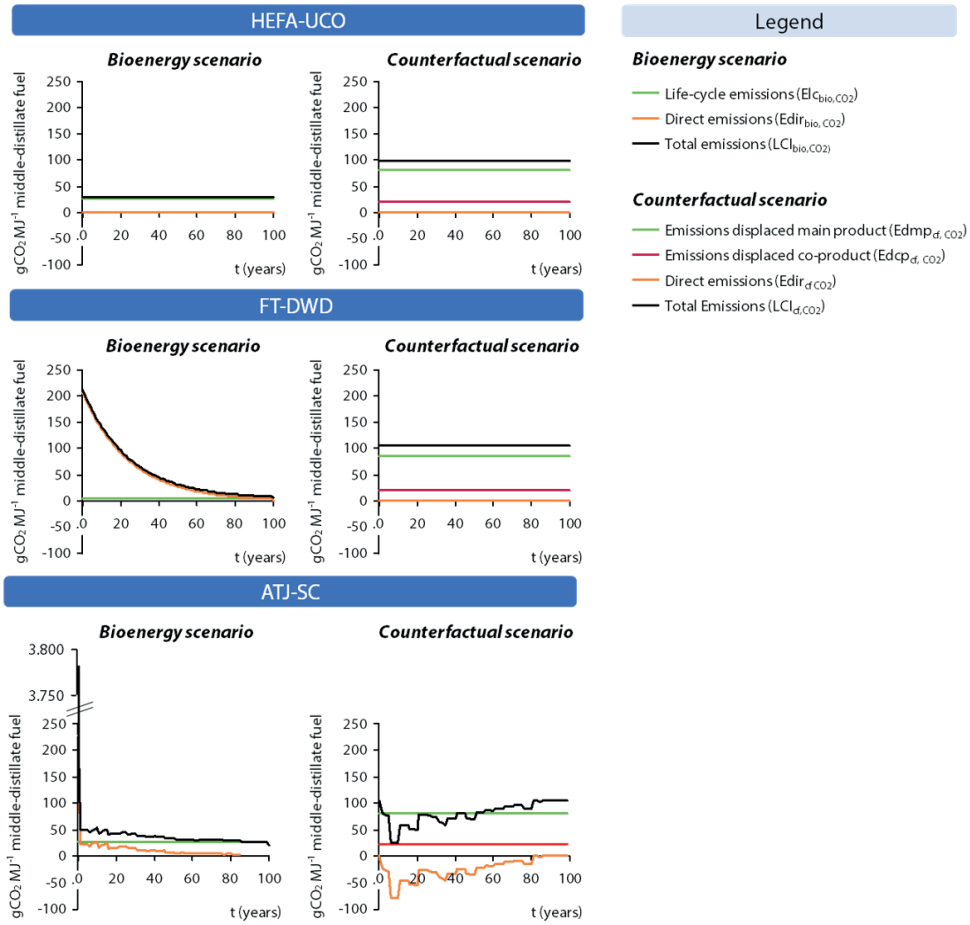


FIGURE 5-1: Dynamic LCI of three bioenergy systems in scope, showing instantaneous CO_2 emissions.

For simplicity, direct emissions were assumed to include carbon stock changes only. For the ATJ-SC system, carbon stock changes were modeled using the Lund-Potsdam-Jena with Managed Land (LPJml) model within the Integrated Model to Assess the Global

Environment (IMAGE) (S5.1).[322] The model tracks changes in above- and below-ground carbon, carbon in soil litter and soil carbon. The analysis uses the yearly average carbon stock of the grassy cerrado grid cells in Brazil. The model was run from 2020 to 2100, after which carbon stocks were assumed to stabilize. The sugarcane bagasse was used to produce electricity and heat, while sugarcane straw was assumed to be burnt in the field.[320] Sugarcane yield was obtained from the LPJml model and was kept constant at 2015 levels (199 GJ ha^{-1}).

The irregular behavior of the emission curves in Figure 5-1 is caused by the 5-year time step used in IMAGE. The initial spike in emissions in the bioenergy scenario is caused by LUC emissions from land clearing. The remainder of emissions are due to loss of soil organic carbon over time. The counterfactual scenario shows negative $Edir$ emissions due to foregone sequestration, since it was assumed that carbon stocks are not yet in equilibrium.

The FT-DWD case used DWD from a loblolly pine forest in which carbon stocks were assumed in equilibrium on a landscape level, hence no carbon stock changes were considered in the counterfactual scenario. The removal of DWD in the bioenergy scenario causes a carbon debt relative to the counterfactual in which DWD is left to decay. The portion of remaining DWD in the counterfactual scenario was approximated using a simple exponential decay function $Mass(t) = \mathrm{Mass}_0 \exp(-kt)$, in which k equals the annual decay rate (k=0.041 for loblolly pine).[365] The carbon debt over time due to continuous extraction was computed by the convolution of the yearly extraction rate and the decay function. The carbon content of DWD was assumed to be 50% of total mass and constant over time. It was further assumed that below-ground carbon was not affected by the extraction of DWD and all carbon in the biomass decays as CO_2 (no CH_4 was produced). As shown in Figure 5-1, continuous extraction of DWD in the bioenergy scenario causes a large reduction in carbon stock initially, until a new equilibrium is reached after approximately 100 years.

5.2.3 Quantifying the climate impacts

5.2.3.1 Generalized approach

The impact of GHG emissions on the earth's climate can be evaluated for different impact categories along the cause-effect chain (Figure 5-2). The emission of GHGs changes the atmospheric concentration of the respective species. GHGs are naturally removed from the atmosphere at a species-specific rate due to interactions with the atmospheric, terrestrial and oceanic system. The emission concentration in the atmosphere instigates a net change in the energy balance of the earth system ('radiative

forcing'), which consequently causes a change in global mean surface temperature ('temperature change'). The temperature response is delayed due to the inertia of the climate system (e.g. thermal inertia of oceans). Temperature change, in turn, may be related to impact categories such as sea level rise and welfare loss. Compared to other climate indicators, GHG emissions are quantified with more certainty and regulated more easily. Moving down the cause-effect chain generally increases the policy relevance, but also increases the scientific uncertainty.[61]

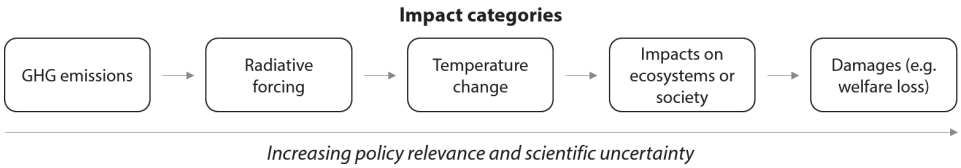


FIGURE 5-2: Cause-effect chain for GHG emissions (adapted from Cherubini et al.[61]).

Conventional GHG-LCAs and parity point analyses generally evaluate system performance at the GHG emission level. The conversion of emission profiles to other impact categories can be done using complex climate models[366], reduced-order climate impact models (e.g. MAGICC[367], ACC2[368] or APMT-IC[369,370]) or following simpler relationships between the indicators as described in various sources[59,61,363,371]. Equivalency metrics are often used to translate the impact of non-CO_2 emissions into CO_2 equivalents. Climate efficacies can be used align the temperature response of species-induced radiative forcing (S5.2).[61]

As the climate response extends beyond the time of the emission discharge, it is required to define an analytical time horizon TH_a at which the impact category is evaluated. The TH_a often exceeds the production and LCI time horizon (TH_p and TH_{LCI}).

5.2.3.2 Quantifying the climate impact of the bioenergy systems in scope

The climate module of the Aviation Environmental Portfolio Management Tool (referred to as APMT-Impacts Climate (APMT-IC)) was used to calculate impact categories from the dynamic LCIs described in section 5.2.2.2. APMT-IC is a reduced-order climate model which models the physical and monetary impacts of CO_2, CH_4, N_2O, sulfates, soot, NO_x and H_2O emissions. Although the toolset, its algorithm, and assumptions have been well-documented and used in numerous previous studies[38,362,369,370,372–375], it has recently undergone a number of updates to align to the state of the science. Therefore, the methods APMT-IC used in this study are presented in S5.3. For current purposes, the

use of APMT-IC was confined to CO_2, CH_4, and N_2O emissions. The equivalency metrics to equate CO_2, CH_4, and N_2O emissions were calculated with APMT-IC. For this study, APMT-IC applied climate efficacies from the Model for Assessment of Greenhouse Gas Induced Climate Change (MAGICC6) (S5.2).[367] The model was run using an RCP 2.6 background emission scenario. The impact of using an RCP 8.5 scenario is discussed in S5.4.

The quantification over time of climate impacts beyond GHG emissions introduces scientific uncertainty related to climate impact modeling.[37,56,61,376] APMT-IC captures this type of uncertainty using Monte Carlo simulation, in which key model parameters were varied using predefined probabilistic distributions.[370] The climate impact was calculated using the mean and 5 and 95 percentile results. For sake of clarity, only the mean values are shown in the results below; the associated uncertainty is addressed separately in section 5.3.2.

5.2.4 Introducing a flexible performance indicator

5.2.4.1 Generalized approach

In conventional GHG-LCA, the climate impact of bioenergy systems is often evaluated using the net GHG emission reduction or relative GHG emission reduction. The net GHG emission reduction is calculated by subtracting the life-cycle emissions of the bioenergy system (*bio*) by the emissions of a counterfactual scenario (*cf*), i.e. life-cycle emissions of the displaced (fossil) product(s) and, if system expansion is used, potential co-products (eq. 4). The relative GHG emission reduction performance is quantified by dividing the net GHG emission reduction by the GHG of a fossil baseline, e.g. electricity, diesel or gasoline (eq. 5).

$$Net\ GHG\ emission\ reduction = GHG_{bio}\text{-}GHG_{cf} \qquad (4)$$

$$Relative\ GHG\ emission\ reduction = \frac{GHG_{bio}\text{-}GHG_{cf}}{GHG_{base}} \qquad (5)$$

In this analysis, we introduce a time-dependent performance indicator, the relative climate impact (RCI) (eq. 6), which was defined analogous to the relative GHG emission reduction. The RCI quantifies the net climate impact of a production system relative to a fossil baseline at the analytical time horizon, TH_a.

$$RCI_{Impact\ category}(TH_A) = \frac{Impact_{Impact\ category,bio}(TH_A)\text{-}Impact_{impact\ category,cf}(TH_A)}{Impact_{impact\ category,base}(TH_A)} \qquad (6)$$

The RCI is time-dependent and offers the flexibility to alter the impact category (including the equivalency metric used) and analytical time horizon. As such, it can be used to compare systems with varying temporal emission profiles and evaluate the effect of key value judgments. A negative RCI implies that the bioenergy scenario has a climate benefit over the counterfactual scenario. For example, an RCI of -0.5 indicates a 50% reduction in a particular impact category relative to the fossil baseline.

The relative formulation was selected over the net climate impact, as a dimensionless parameter allows for comparison between RCI based on different impact categories. Moreover, the scientific uncertainty associated with climate models converges when the numerator and denominator in eq. 6 are of the same order of magnitude, since the uncertainty grows approximately proportional to the climate impact (section 5.3.2). Unlike previously proposed indicators[47,59,62,356], the RCI is defined relative to a fossil baseline instead of the counterfactual scenario to allow for comparison of production systems with different counterfactual scenarios.

The RCI is a generalized performance indicator to quantify environmental system performance, of which the relative GHG emission reduction and carbon parity point are specific examples. The relative GHG emission reduction method often employs linear amortization of initial LUC emissions over an amortization period. This approach is mathematically equivalent to evaluating the RCI for cumulative emissions at an analytical time horizon equal to the amortization period, with the relevant exception that the RCI formulation also includes emission fluxes beyond the first year of the project (e.g. from foregone sequestration). The carbon parity point is the analytical time horizon for which the RCI for cumulative emissions equals zero. The RCI can therefore be used for direct comparison between conventional performance indicators and indicators using a different point of evaluation.

5.2.4.2 Quantifying the relative climate impact of the bioenergy systems in scope

The climate impact of the bioenergy systems was evaluated for three impact categories, based on their distinct temporal response:

1. Cumulative emissions using a fixed GWP_{100} as an equivalency metric ($RCI_{Em,cum}$),
2. Instantaneous radiative forcing using climate efficacies ($RCI_{RF,inst}$),
3. Cumulative temperature change ($RCI_{\Delta T,cum}$).

Cumulative indicators generally respond more slowly to emission events compared to instantaneous indicators, because they record all impacts over the analytical time

horizon. The change in instantaneous radiative forcing is faster than cumulative emissions, as it depends emission concentrations which include emission decay mechanisms. Radiative forcing also responds faster than temperature change, as temperature response is delayed due to the inertia of the climate system.[362]

A comparison of different equivalency metrics to compute $RCI_{Em,cum}$ can be found in S5.2, as the effect on system performance was small compared to the choice of impact category and analytical time horizons.

5.3 RESULTS

5.3.1 Climate impact and analytical time horizon

Figure 5-3 shows the $RCI_{Em,cum}$, $RCI_{RF,inst}$ and $RCI_{\Delta T,cum}$ for the three bioenergy systems. The RCI curves for HEFA-UCO are relatively stable over time and across the three impact categories, due to its constant emission profile. The RCI curves for ATJ-SC start high initially ($RCI_{Em,cum}$= 39.6), but decline rapidly as the impact of upfront LUC emissions fades over time. The FT-DWD system shows a steady decline, because the emission pulses associated with carbon debt are generally less irregular over time compared to initial LUC emissions. The RCI curves start to stabilize after 100 years, as the TH_{LCI} is reached.

The choice of impact category affects observed system performance, particularly for systems with time-dependent emission profiles such as the ATJ-SC and FT-DWD systems. For example, the ATJ-SC system reduces instantaneous radiative forcing by 9% relative to the fossil baseline after 100 years, while it increases cumulative temperature change by 50% over the same analytical time horizon. Due to their distinct temporal response, the choice of impact category also alters the importance of one-time versus sustained emissions. Systems with large initial LUC emissions, such as ATJ-SC, yield lower RCI scores when evaluated based on instantaneous and rapidly responding impact categories (i.e. instantaneous radiative forcing), compared to cumulative and slowly responding impact categories (e.g. cumulative temperature change). As the selection of impact category is less important for systems with sustained emissions (e.g. FT-DWD and HEFA-UCO), the choice impacts inter-system comparison.

As stipulated in prior analyses, the choice of impact category also affects the relative importance of short- and long-lived emission species.[37,56] For example, instantaneous radiative forcing emphasizes the importance of short-lived forcers compared to cumulative emissions, especially in the first years. This effect is illustrated for FT-DWD by comparing $RCI_{Em,cum}$ and $RCI_{RF,inst}$ at TH_A=0, at which the bioenergy scenario shows

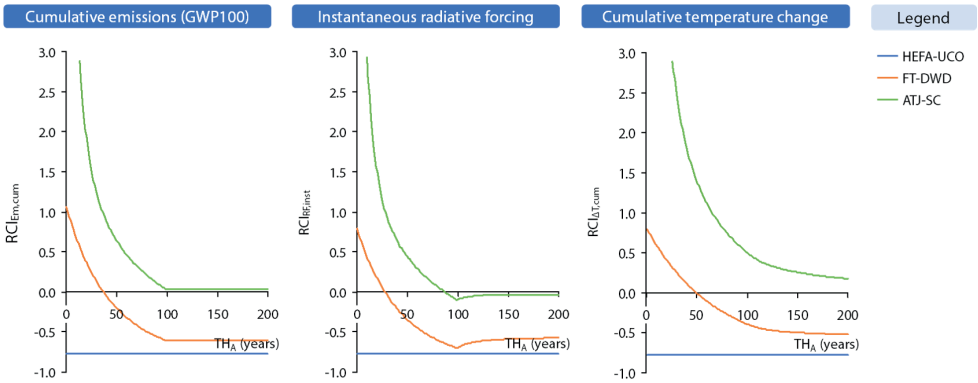


FIGURE 5-3: The RCI for three bioenergy systems for cumulative greenhouse gas emissions, instantaneous radiative forcing and cumulative temperature change as a function of the analytical time horizon, TH_A.

higher CO_2 emissions than the counterfactual, but lower CH_4 and N_2O emissions. As the $RCI_{RF,inst}$ allocates a higher weighting to CH_4 and N_2O savings than the $RCI_{Em,cum}$, the $RCI_{RF,inst}$ is lower (0.80) than the $RCI_{Em,cum}$ (1.07). This effect is less prominent for HEFA-UCO, because amplification of CH_4 and N_2O emissions savings is counteracted by a decreased impact of CO_2 savings. The choice of equivalency metric also affects the relative importance of short- versus long-lived species, but has a smaller impact on overall system performance than the impact category and time horizon (S5.2).

5.3.2 Uncertainty

Figure 5-4 shows the 5th and 95th percentile results of APMT-IC for the FT-DWD system. For absolute climate impacts, the uncertainty is substantial and grows over time; e.g. for cumulative temperature change at TH_A=100 years, the 5th and 95th percentile results range between -37% and +52% of the mean result. However, the uncertainty reduces to ±5% in the relative formulation of the RCI (i.e. relative to a fossil baseline), because the uncertainty in the numerator of the RCI is paired with the uncertainty in the denominator and increases approximately proportionally. The uncertainty in the RCI grows with increasing absolute difference between the numerator and denominator (not with time), albeit marginally.[q] Similar converging behavior has been observed for uncertainty related to background emission concentration scenarios (S5.4). The RCI can therefore be used to study the effect of bioenergy production on a wide range of impact categories (with higher policy relevance) without dramatically increasing

q A dummy run in which the numerator value was defined 100.000 times larger than the denominator value, the maximum uncertainty equaled ±10%.

the uncertainty associated with climate impact modeling and background emission concentration.

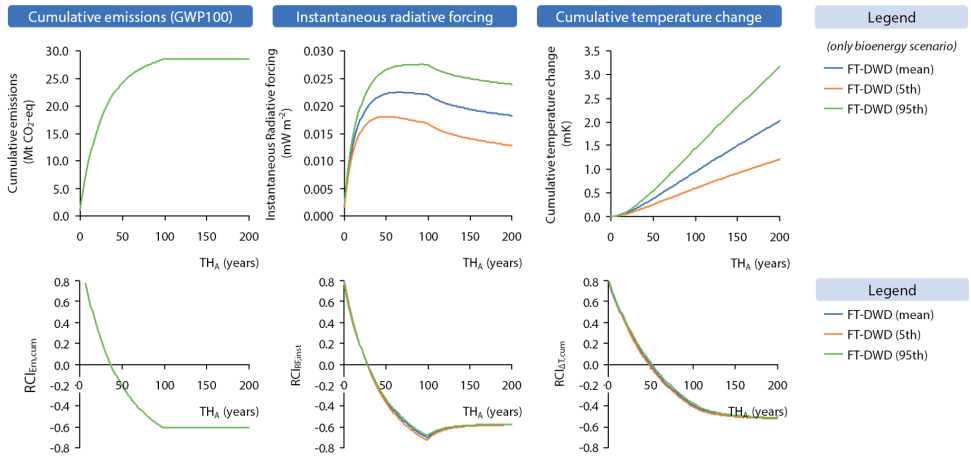


FIGURE 5-4: The uncertainty associated with climate impact modeling for the FT-DWD system.

5.4 VARIABILITY IN BIOENERGY SYSTEMS

This section evaluates alternative systems based on the FT-DWD and ATJ-SC systems to quantify the relative importance of emissions sources and identify best practices for bioenergy production. The analysis includes variations in life-cycle emissions, LUC emissions, carbon debt and foregone sequestration. The fossil baseline remained the same throughout all analyses. The various systems are discussed in more detail in S5.2.

5.4.1 FT-DWD

Four alternative systems were considered for FT-DWD:

- FT-DWD-CCS. This system applies carbon capture and storage (CCS), lowering life-cycle emissions by 108 $gCO_2\ MJ_{MD}^{-1}$.[377]
- FT-DWD-HighDecay and FT-DWD-LowDecay. These systems use DWD from tree species with the highest (k=0.076; water oak) and lowest (k=0.023; red pine) decay rates observed in Eastern US forests, which affects the overall carbon debt.[365]
- FT-DWD-CFBurn. This system assumes a counterfactual scenario in which the DWD is burnt in the forest without energy recovery, for example to prevent forest fires. No carbon debt is included in the bioenergy scenario, because the biogenic carbon of the DWD is also released immediately in the counterfactual scenario.

The results shown in Figure 5-5 indicate that the application of CCS yields the lowest RCI performance after 27-49 years (depending on the impact category), as it offsets the carbon debt with carbon storage. The impact of carbon debt would not be visible in conventional GHG-LCA, as temporal emission fluxes (apart from LUC emissions) are usually not incorporated. However, the results show that the tree species or counterfactual scenario may affect system performance considerably, especially for shorter analytical time horizons. The spread in RCI as a result of different decay rates varies between -0.70 and 0.02 for $RCI_{RF,inst}$ (TH_A=50 years) and -0.35 and 0.30 for $RCI_{\Delta T,cum}$ (TH_A=50 years). The RCI for the FT-DWD-CFBurn system is relatively constant and is less than -1 for all TH_A and RCI types, which means that it has a net negative climate impact relative to the baseline.

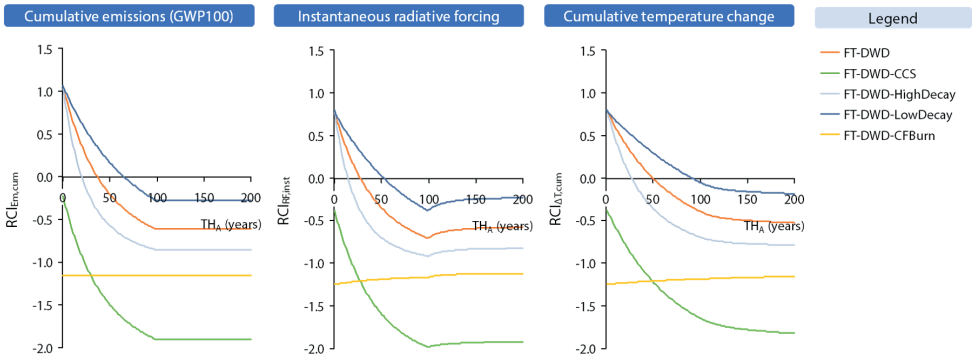


FIGURE 5-5: Alternative production systems based on FT-DWD.

5.4.2 ATJ-SC

Seven alternative production systems were considered for ATJ-SC:

- ATJ-SC-CCS. This system applies CCS to the fermentation step, lowering life-cycle emissions by 27 $gCO_2\ MJ_{MD}^{-1}$.[331]
- ATJ-SC-5th and ATJ-SC-95th. These systems cultivate sugarcane on Brazilian cerrado soils with low and high carbon stocks (the 5th and 95th percentile of the carbon stock distribution within the cerrado biome), leading to 0.1 and 2 times the LUC emissions compared to the mean (in terms of t $CO_2\ ha^{-1}$).
- ATJ-SC-TropicalForest and ATJ-SC-Abandoned. These systems assume cultivation of sugarcane on an average grid cell (in terms of carbon stock) in the tropical forests and abandoned agricultural land biomes. Whereas the former system instigates high initial LUC emissions, the latter system includes significant amounts of foregone sequestration from regrowth of natural vegetation in the counterfactual scenario.

- ATJ-SC-LUCPrevention. This system assumes bioenergy production is accompanied by measures to prevent indirect LUC emissions (e.g. by increasing agricultural yields or improving supply chain efficiencies[378]) such that additional sugarcane is produced on existing sugarcane land without increasing life-cycle emissions or causing direct or indirect LUC emissions. These measures are not implemented in the counterfactual scenario.
- ATJ-SC-ImprovedYield. This system assumes sugarcane yield on cerrado land improves to 2050 levels (266 GJ ha^{-1}), based on IMAGE-LPJml projections.[322]

The results in Figure 5-6 indicate that a profound difference exists between converting low-carbon or high-carbon cerrado, for which the RCI varies between -0.11 and 1.01 for $RCI_{RF,inst}$ (TH_A=50 years) and 0.20 and 2.85 for $RCI_{\Delta T,cum}$ (TH_A=50 years). The difference mainly originates from higher initial LUC emissions for the high-carbon cerrado case, which also explains the larger difference between the systems when evaluated using $RCI_{\Delta T,cum}$.

Sugarcane cultivation on cerrado, abandoned agricultural land or tropical forest show comparable RCI performance, because high LUC emissions are mitigated by high sugarcane yields. Furthermore, foregone sequestration creates a large carbon sink in the counterfactual scenario of the ATJ-SC-Abandoned system, leading to higher RCI scores over longer time horizons. This effect is particularly apparent for $RCI_{RF,inst}$; the ATJ-SC-Abandoned system initially has a lower RCI than ATJ-SC (base case) and ATJ-SC-TropicalForest due to low initial LUC emissions, but gradually shows a higher $RCI_{RF,inst}$ due to foregone sequestration. This example also shows how the choice of performance metric may change the merit order of systems and why foregone sequestration effects are important when assessing system performance.

If LUC emissions can be prevented, the RCI is reduced to approximately -0.7 across all impact categories and time horizons (ATJ-SC-LUCPrevention system). This underlines the importance of LUC prevention measures to achieve high climate impact reductions using bioenergy. The application of CCS shifts the $RCI_{Em,cum}$ curve of the ATJ-SC system by -0.42 for all TH_A. Improvements in sugarcane yield reduce the RCI particularly for short TH_A, as carbon stock changes (particularly initial LUC emissions) are lower because less land is required to produce the same quantity of biofuel.

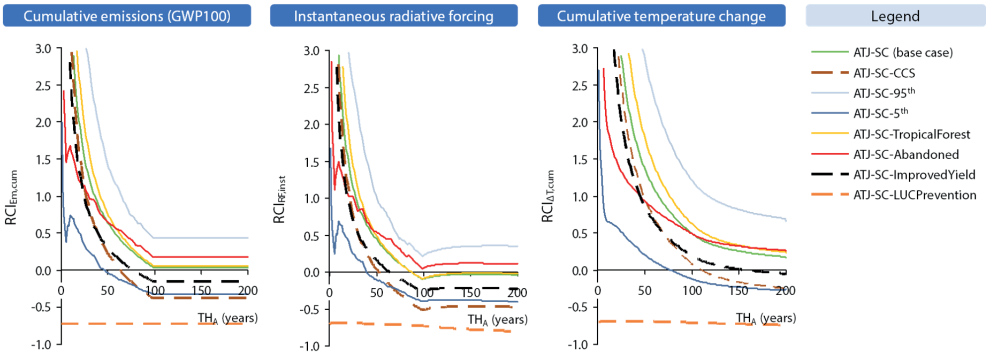


FIGURE 5-6: Alternative production systems based on ATJ-SC.

5.5 DISCUSSION

5.5.1 The use of the RCI

The RCI is a time-dependent performance indicator that is able to incorporate the temporal emission profiles associated with LUC emissions, carbon debt and foregone sequestration. Therefore, the RCI is suitable for the analysis of a wide array of bioenergy systems. It also allows for a transparent comparison of bioenergy systems using different impact categories (including equivalency metrics) and analytical time horizons. Due to its ratio formulation, it is relatively robust to uncertainties in climate impact modeling and background emission concentration scenarios.

The RCI provides more flexibility than conventional performance indicators, such as the relative GHG emission reduction and carbon parity point, which are essentially one-dimensional in terms of the point of evaluation (Figure 5-7). The RCI can be used to illustrate how the choice of impact category and analytical time horizon alters the merit order of systems. For instance, the FT-DWD-HighDecay system has a greater RCI than the HEFA-UCO system when evaluated using conventional indicators, while it has a lower $RCI_{Em,cum}$ from 78 years onwards. The ATJ-SC-CCS and FT-DWD-LowDecay systems yield similar carbon parity points (63 and 66 years, respectively), while FT-DWD-LowDecay has a lower RCI for the first 147 years in terms of cumulative temperature change.

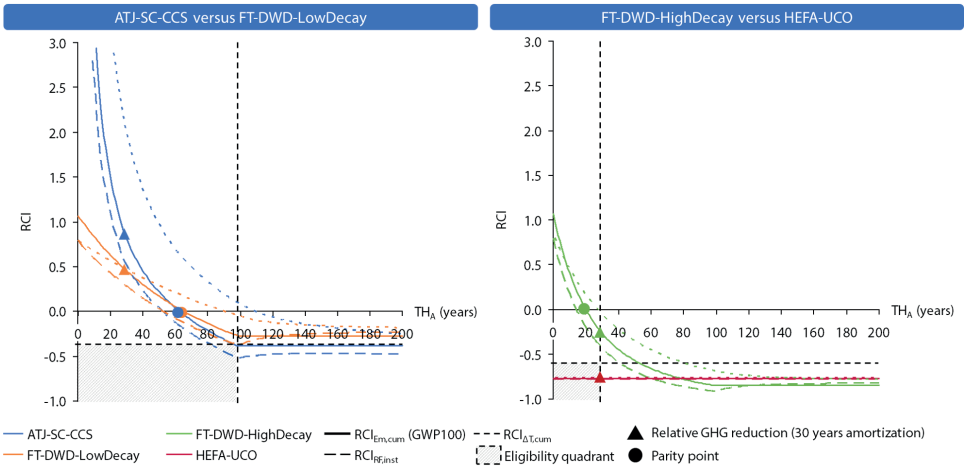


FIGURE 5-7: Comparison of the RCI with the relative GHG emission reduction (triangles; amortization period 30 years) and carbon parity point (circles). The eligibility quadrants were placed at a RCI=-0.35 and TH_A=100 years (left) and RCI=-0.60 and TH_A=30 years (right).

The RCI quantifies the climate benefits of a system over time, which enables the definition of an 'eligibility quadrant' (Figure 5-7). The eligibility quadrant is a two-dimensional threshold which can be used to determine if a bioenergy production system is below a maximum RCI before a given analytical time horizon, as defined by a policy or certification scheme of interest. The definition of these thresholds and the type of RCI they apply to has a significant impact on the eligibility of different bioenergy systems, especially those with time-dependent emission profiles. For instance, placing the eligibility quadrant at $RCI_{Em,cum}$=-0.35 and TH_A=100 years would qualify ATJ-SC-CCS as eligible, while cumulative temperature is increased by 8% relative to the baseline. Alternatively, the HEFA-UCO system is the only system meeting a RCI below -0.6 before TH_A=30 years, while the FT-DWD-HighDecay system has a lower RCI over longer analytical time horizons for all indicators.

The choice of impact category, analytical time horizon and equivalency metric is essentially a value judgement about the importance attributed to one-time versus sustained emissions and short- versus long-lived climate forcers. Similarly, the definition of the eligibility quadrant, and the type of RCI indicator required to meet the threshold, are value judgements that should be made in accordance with the objectives of the policy or certification scheme of interest. Shorter analytical time horizons allocate more weight to short-term emission events, while short analytical time horizons for equivalency metrics allocate more weight to short-lived climate forcers.[37] Longer

analytical and production time horizons will yield lower RCI values, as the climate impact of the bioenergy systems in scope generally improves over time. Cumulative impact categories keep memory of short-lived emission species and one-time emission pulses (e.g. from LUC), but are also criticized for not reflecting the actual climate response.[56,61] The choice for instantaneous impact categories can be aligned with a peaking or stabilization year of the respective impact, and may be well-suited for goal-setting.[56,358] Impact categories further down the cause-effect chain introduce a time lag in the analysis due to delayed climate response, but may be a better proxy for climate damages such as extreme weather events, sea-level rise and loss of permanent ice.[56,358] Although the current study focused on mid-point indicators, the RCI formulation may also be used for end-point impact categories such as economic damages or sea level rise.

5.5.2 The limitations of the RCI indicator

The flexibility of the RCI is a key strength of the indicator; However, similar to other performance indicators, it should be calculated and applied consistently to allow for comparison between analyses. Moreover, the RCI is a relative measure, and therefore does not provide information on the absolute climate impact of a system. Multiplication by the climate impact of the fossil baseline yields an estimate of the absolute climate impact, however this comes with greater uncertainty. The use of the RCI is particularly valuable for systems with time-dependent emission profiles. However, adequate quantification of direct and indirect emissions requires comprehensive models, which may complicate the practical implementation of the RCI approach.

The scope of climate forcers can be expanded to include surface albedo, surface roughness, evapotranspiration and additional emissions species such as sulfates, soot, NO_x and H_2O emissions.[37] The impact of these effects may be of the same order of magnitude as GHG emission fluxes, either in a positive or negative direction.[40,379] Several of these issues require climate models with higher spatial and temporal resolution than those used in this study, especially because the location and timing of direct and indirect effects may vary between the bioenergy and counterfactual scenario.

5.5.3 Implications for bioenergy production systems

The impact of LUC emissions, carbon debt and foregone sequestration on the performance of bioenergy systems is significant, and may in some cases exceed the impact of life-cycle emissions.[45,46,306] Feedstock-technology systems with high feedstock yields and conversion efficiencies mitigate the contribution of LUC emissions, carbon debt and foregone sequestration, while the application of CCS can reduce the life-cycle emissions significantly.

The occurrence of LUC emissions, carbon debt or foregone sequestration is driven by the production context rather than the feedstock-technology combination. The production contexts of the analyzed bioenergy systems were intentionally framed to contain these types of emissions for the sole purpose of demonstrating the impact of temporal emission profiles. These systems should therefore not be interpreted as typical bioenergy system with the most probable counterfactual scenario.

Direct LUC emissions can be reduced by producing bioenergy feedstocks on low carbon stock soils. The risk of indirect LUC emissions and carbon debt can be mitigated by shaping the right production context, for instance by supplementing bioenergy production with efforts to optimize land/forest management, improve agricultural yields, increase supply chain efficiencies, and integrate bioenergy, food and feed production.[304,380–384] The Shared Socio-economic Pathways 1 (SSP 1) scenario represents such a storyline, in which land use for biomass production increases alongside a reduction in land use for food production caused by high agricultural yield improvements, changing food consumption patterns and low population growth.[385] Furthermore, production contexts in which the counterfactual scenario yields immediate or additional climate impacts can yield highly negative RCI values. As the RCI incorporates these time-dependent emission fluxes, it is a valuable performance indicator to select production contexts in which bioenergy systems consistently show a climate benefit, as shown for example in the ATJ-SC-LUCPrevention and FT-DWD-CFBurn systems.

The importance of time-dependent emission fluxes and the production context suggests that bioenergy GHG-LCAs and bioenergy policy frameworks should move beyond the static characterization of the cradle-to-grave life-cycle emissions of feedstock-technology combinations towards a time-dependent characterization of the bioenergy production context, including carbon stock changes, (in)direct LUC emissions, realistic counterfactual scenario(s), and time-dependent parameters such as yield improvements or carbon intensities of fossil products. The predictive character of such analysis introduces additional uncertainties that should be addressed appropriately, e.g. by scenario analysis or using probability distributions (S5.5 discusses the issue of the potential and likelihood of bioenergy systems).

This analysis further demonstrates the importance of evaluating bioenergy system performance using different impact categories and analytical time horizons, which particularly applies to systems with time-dependent emission profiles. For example, the impact of initial LUC emissions on system performance will be greater when considering cumulative and slowly responding impact categories or shorter analytical time horizons. We found that the choice of equivalency metric did not significantly

affect the RCI value for the bioenergy systems in scope, but can be important when a large difference in non-CO_2 emissions exists between the bioenergy and counterfactual scenario (S5.2). This may apply to systems associated with high fertilizer use (emitting N_2O), methane leakage (e.g. biogas) or peatland conversion (emitting CH_4).

5.6 CONCLUSION

The RCI is a useful performance indicator to quantify the climate impact of bioenergy systems. It appropriately captures time-dependent emissions, and offers the flexibility to alter the impact category, analytical time horizon and equivalency metric, thereby addressing major shortcomings of conventional performance indicators. It is also robust to uncertainties in climate impact modeling and future background emissions.

The stylized bioenergy systems analyzed in this study show that the impact category and analytical time horizon affect absolute and relative system performance, as these value judgements alter the importance of one-time (e.g. LUC emissions) versus sustained (e.g. carbon debt or foregone sequestration) emission fluxes and short- versus long-lived climate forcers. The RCI was used to identify characteristics for bioenergy systems with climate benefits irrespective of value judgements, which include high feedstock yields, high conversion efficiencies and the application of CCS. Furthermore, this paper provides examples of production contexts which can (partially) mitigate the risk of LUC emissions, carbon debt or foregone sequestration. For example, the risk of indirect LUC emissions can be mitigated by accompanying bioenergy production with increasing agricultural yields. Moreover, production contexts in which the counterfactual scenario yields immediate or additional climate impacts (e.g. burning of forestry residues to prevent forest fires) can yield highly negative RCI values.

The RCI can be used to test the robustness of system performance to value judgments and tailor the performance indicator to the research or policy purpose. For example, the RCI approach allows providers of credits, subsidies or sustainability certification to define a two-dimensional performance threshold based on a maximum RCI to be achieved before a certain analytical time horizon. Besides bioenergy systems, the RCI can also be used to evaluate and compare other climate change mitigation measures, particularly those with time-dependent emission profiles and relatively large upfront emissions, such as electric vehicles, wind turbines or solar panels.

S5 SUPPLEMENTARY INFORMATION

S5.1 Supplementary data for the bioenergy production systems

S5.1.1 FT-DWD system

The carbon debt per tonne of extracted DWD is plotted in Figure 5-8. The decay rate of tree species was computed using a simple exponential decay function $Mass(t) = \mathrm{Mass}_0 \exp(-kt)$. This decay function describes the amount of carbon stored in DWD over time in the counterfactual scenario. In the bioenergy scenario, the the DWD are removed and converted to biofuels. The biofuels are assumed to be burned in the same year, thus releasing all carbon in the feedstock within the year. The carbon debt in the bioenergy scenario is therefore equal to the carbon stored in the counterfactual scenario (as modelled by the decay function).

The cumulative carbon debt was computed by taking the convolution of the decay function and a constant extraction rate of 1 tonne of DWD. It was assumed that 1 tonne of feedstock contains 50% carbon[386], which decays aerobically to CO_2 (3.667 tCO_2 t^{-1} C). The instantaneous carbon debt (modeled as instantaneous CO_2 emissions) was obtained by taking the time derivative of the convolution.

The decay constants were obtained from Russell et al.[365], who empirically established the decay rate and residence time of 36 tree species common to eastern US forests. For this assessment, we used loblolly pine as a base case and tree species with the highest (k=0.076; water oak) and lowest (k=0.023; red pine) decay rates observed in Eastern US forests to illustrate the range of decay rates.

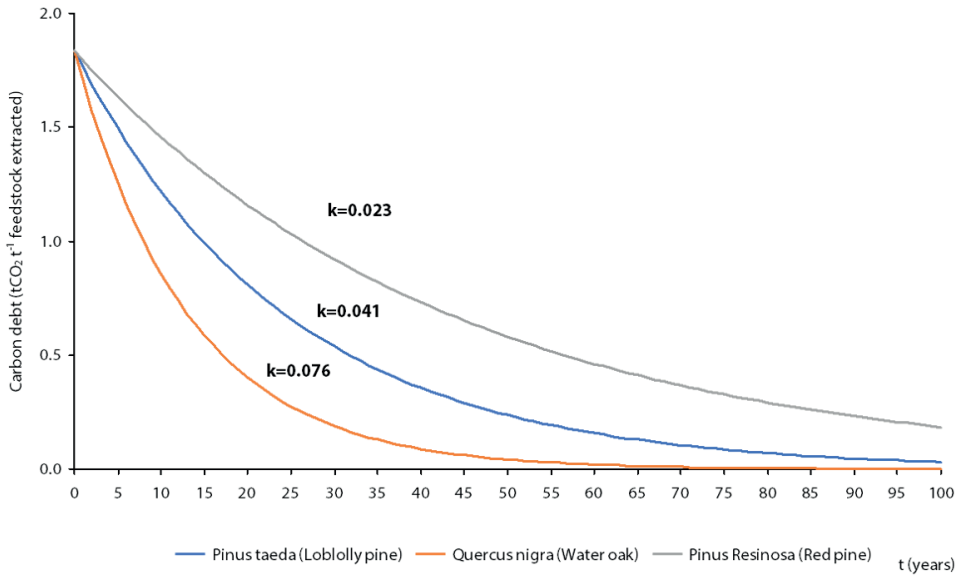


FIGURE 5-8: Carbon debt for three different tree species.

the FT-DWD-CFBurn system assumes that all DWD are burnt in the counterfactual scenario, such that all carbon is released instantaneously and no carbon debt exists in the bioenergy scenario. The CO_2 savings from CCS in the FT-DWD-CCS system are calculated based on Kreutz et al.[377], who report 0.125 tCO_2 GJ^{-1} FT liquids, 90% capture efficiency, and 91 kWh electricity use per tonne CO_2 captured.

S5.1.2 ATJ-SC system

The LPJml model tracks changes in above- and belowground carbon, carbon in soil litter and soil carbon. The model was used to construct a carbon stock curve track in the grid cells (0.5° x 0.5° spatial resolution) of the Brazilian savannah (grassy cerrado), tropical forest and abandoned agricultural lands biome. The mean, 5th and 95th percentile of the carbon stock curves for grassy cerrado grid cells are shown in Figure 5-9. The mean carbon stock curves for savannah, tropical forest and abandoned agricultural land are shown in Figure 5-10.

The model was run under the assumption of the Representative Concentration Pathway (RCP) 2.6 and Shared Socioeconomic Pathway (SSP) 2 scenario. The RCP 2.6 scenario will likely lead to a temperature rise ranging from 0.9 to 2.3 °C (mean 1.6) in 2100.[4] The SSP 2 scenario is a middle-of-the-road scenario in terms of socio-economic challenges related to climate change adaptation and mitigation.[387] The SSP scenario affects the amount and quality of grid cells. Only grid cells which remained in a particular biome throughout the entire modeling period in the counterfactual scenario were considered. The model was run from 2020 to 2100, after which carbon stocks were assumed to stabilize. Carbon stocks were interpolated in between time steps (5 years) except for the clearance of aboveground biomass in the bioenergy scenario which was assumed to occur at the outset of production. Crop productivity was modeled with the LPJml model and was kept constant over the production period for savannah (199 GJ ha^{-1}), tropical rainforest (309 GJ ha^{-1}) and abandoned agricultural land (112 GJ ha^{-1}).

The CO_2 savings from the application of CCS to the fermentation steps are calculated based on a pure CO_2 stream from fermentation (0.033 tCO_2 GJ^{-1} ethanol)[331], 90% capture efficiency[377], and 91 kWh electricity per tCO_2 captured[377].

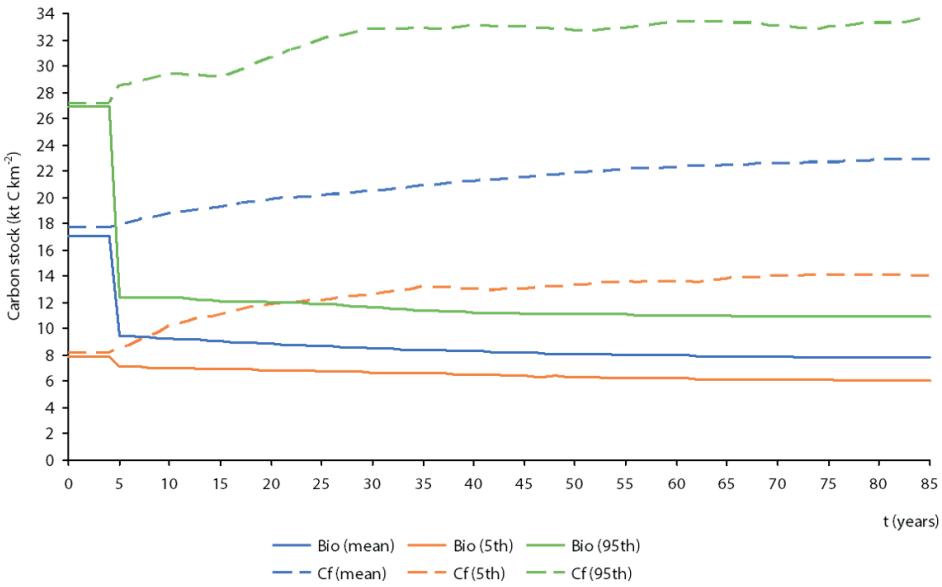


FIGURE 5-9: The mean, 5th and 95th percentile of the carbon stock curves for grassy cerrado grid cells for the bioenergy (Bio) and counterfactual (Cf) scenario.

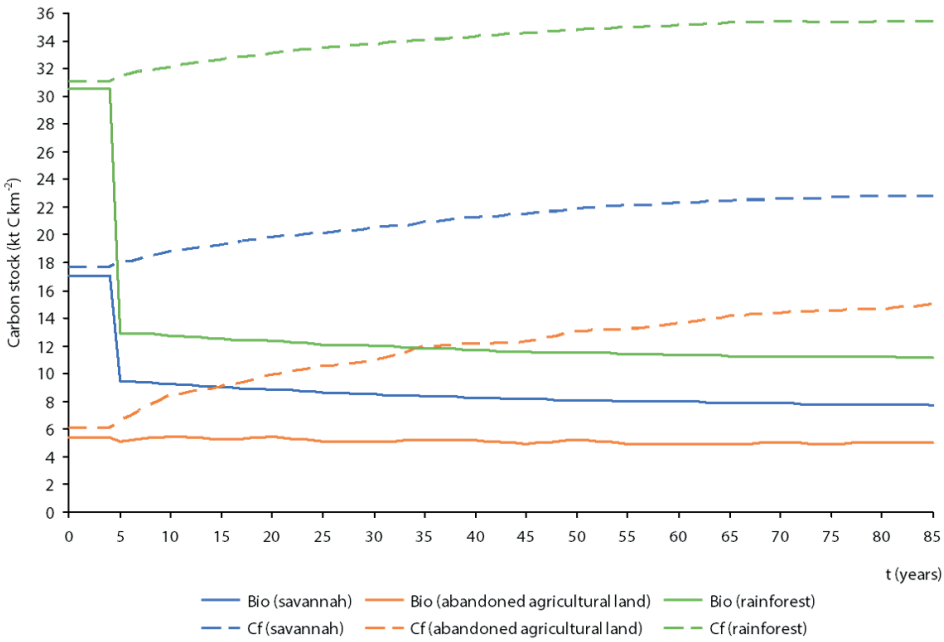


FIGURE 5-10: The mean carbon stock curves for grassy cerrado, rainforest and abandoned agricultural land for the bioenergy (Bio) and counterfactual (Cf) scenario.

S5.2 Equivalency metrics

Equivalency metrics are used to compare the impact of an emission pulse of species i to the impact of a reference gas (usually CO_2) over a fixed or time-dependent time horizon (eq. S.1 and S.2). Time-dependent time horizons for equivalency metrics have been introduced to align the time horizon of the equivalency metric to the analytical time horizon to avoid inconsistencies between the time horizon of the analysis and the definition of the equivalency metric.[57,358]

$$Fixed\ time\ horizon: Impact_{impact\ category}\ (t) = \sum^{i} Impact_{impact\ category,i}\ (t) * Equivalency\ metric_i\ (T)\ , with\ T\ constant \qquad (S.1)$$

$$Time\text{-}dependent\ time\ horizon: Impact_{impact\ category}\ (t) = \sum^{i} Impact_{impact\ catory,i}\ (t) * Equivalency\ metric_i\ (TH_A\text{-}t) \qquad (S.2)$$

The equivalency metrics for CH_4 and N_2O emissions were calculated with APMT-IC. The mean results are displayed in Figure 5-11. The GWP_{100} values used in the manuscript are 34 and 315 for CH_4 and N_2O, respectively. The GWP and GTP values are slightly higher than values reported in the IPCC AR5 report, but lower than reported by Cherubini et al.[61]

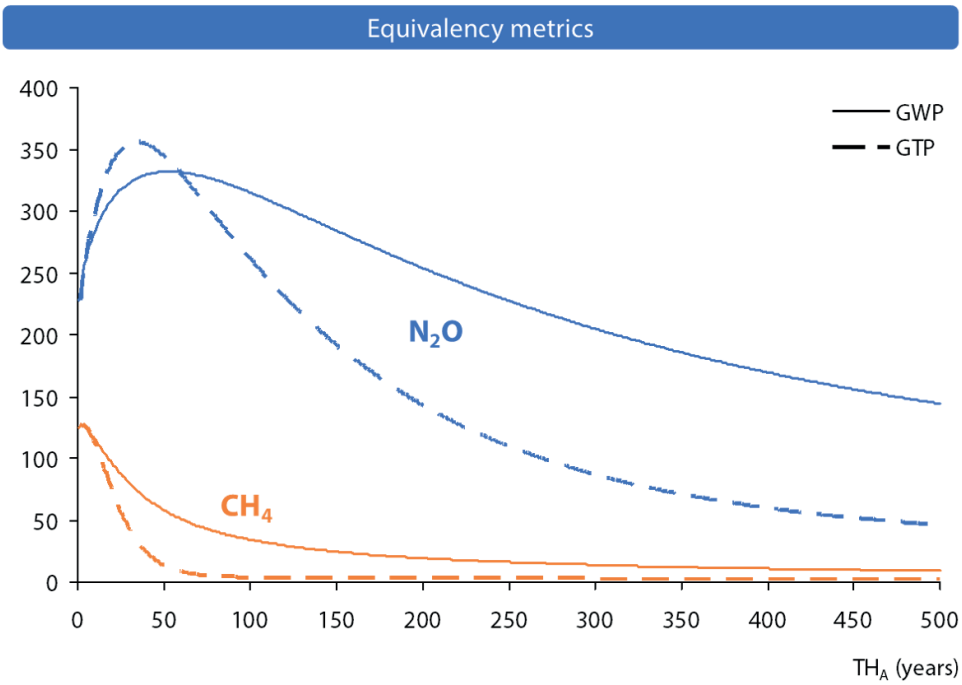


FIGURE 5-11: GWP and GTP values as computed with APMT-IC.

The choice of equivalency metric affects the importance of non-CO_2 emissions. The results in Figure 5-12 shows the results for ATJ-SC and FT-DWD systems for different equivalency metrics. The equivalency metrics were varied in terms of equivalency base (i.e. cumulative radiative forcing, instantaneous temperature change), time horizon (i.e. 20, 100, 500) and type of time horizon (i.e. fixed and time-dependent). The time-dependent time horizon was calculated based on an analytical time horizon of 200 years (see eq. SI. 2).

Equivalency metrics based on short time horizons allocate more weight to N_2O and CH_4. Similarly, GWP values are higher than GTP values for N_2O and CH_4 for time horizons exceeding 59 years (Figure 5-11). As the ATJ-SC system emits more N_2O emissions than its counterfactual, the $RCI_{Em,cum}$ is higher for short time horizons. Conversely, the FT-DWD system emits lower CH4 and N_2O emissions than its counterfactual, resulting in higher $RCI_{Em,cum}$ for longer time horizons. Due to the definition of time-dependent equivalency metrics (TH_A-t), the equivalency metrics applied to emissions occurring in the first 100 years all exceed 100 years. As such, the current use of time-dependent equivalency allocates less weight to non-CO_2 emissions compared to equivalency metrics based on a fixed time horizon of 100 years (e.g. GWP_{100} and $AGTP_{100}$). This explains a relatively low and high RCI for ATJ-SC and FT-DWD.

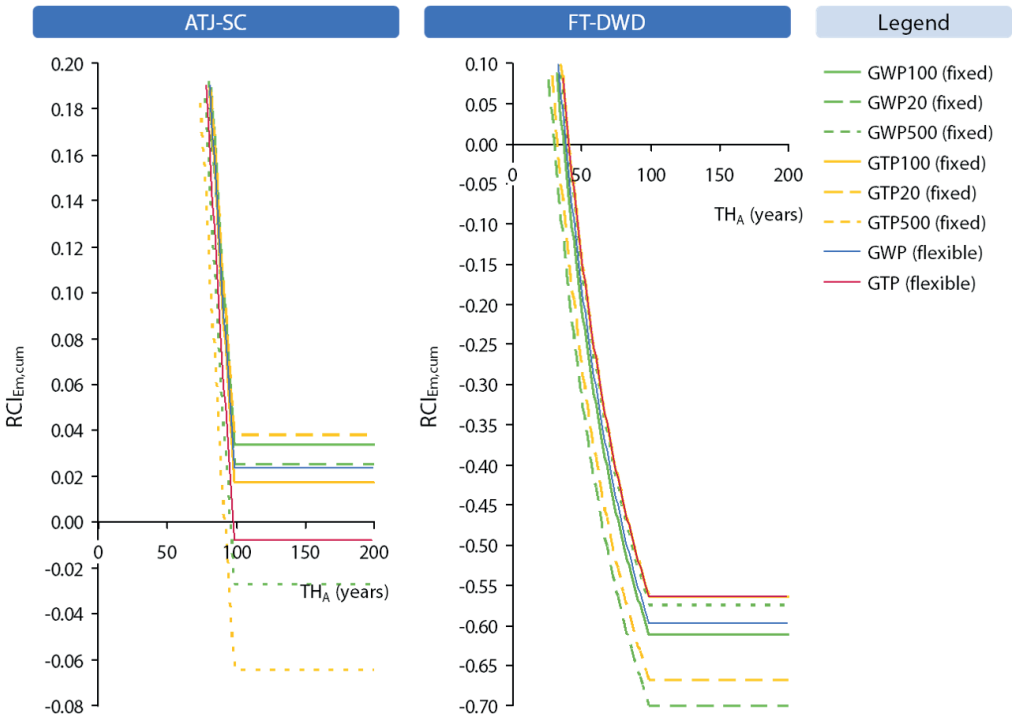


FIGURE 5-12: The $RCI_{Em,cum}$ for ATJ-SC for different equivalency metrics. Please note the different range of the y-axes.

5

The spread in $RCI_{Em,cum}$ for ATJ-SC and FT-DWD for different equivalency metrics is small (e.g. 0.10-0.15 at TH_A=100 years) compared to different impact categories (e.g. 0.30-0.56 at TH_A=100 years) and analytical time horizons (e.g. 0.39-0.58 comparing $RCI_{Em,cum}$ for TH_A=50 and 100 years), but may be significant when determining whether a system meets a certain threshold. The spread due to choice of equivalency metric grows with increasing difference in non-CO_2 emissions between the bioenergy and counterfactual scenario, which particularly applies for bioenergy systems associated with high fertilizer use (emitting N_2O), methane leakage (e.g. biogas) or peatland conversion (emitting CH_4). Conversely, the spread decreases for bioenergy systems with high CO_2 emissions compared to non-CO_2 emissions. This effect explains why the spread observed for ATJ-SC is lower than FT-DWD, despite having a higher difference in non-CO_2 emissions between the bioenergy and counterfactual scenario.

S5.3 APMT-Impacts Climate overview

APMT-IC is a reduced-order climate model which models the physical and monetary impacts of CO_2, CH_4, N_2O, sulfates, soot, NO_x and H_2O emissions. APMT-IC has a temporal resolution of one year and a relatively coarse spatial resolution at the global mean level. For the purpose of this study, the use of APMT-IC was confined to ground emissions of CO_2, CH_4, and N_2O.

The tool was recently updated to align with state of the science and therefore this section details how APMT-IC treats impact of the species CO_2, N_2O, and CH_4.

APMT-IC models the concentration, radiative forcing, and temperature response resulting from an emission by treating the emission as a marginal emission. To perform the analysis, APMT-IC models a background scenario with the emission profile of the bioenergy or counterfactual scenario or fossil baseline, as well as a background scenario without additional emission. To find the impact due to emission profile, APMT-IC takes the difference between the background scenarios with and without the emission profile.

For background emissions scenarios, APMT-IC uses concentrations values from the RCP database[388] as well as the extension from Meinshausen et al.[389] APMT-IC models the life-cycle emissions by considering the evolution of their concentration in the form of a convolution integral. It is assumed that N_2O and CH_4 decay according to a first-order exponential decay based on the perturbation lifetime 12.4 and 121 years respectively.[2] CO_2 decays according to an impulse response function approach, such as the approach outlined in Joos et al.[366], which also showed that background CO_2 concentrations have a large impact on CO_2 uptake. To capture these effects, APMT-IC uses impulse response functions generated using the Model for Greenhouse Gas Induced Climate Change (MAGICC6).[367]

Elevated concentrations of CO_2, N_2O, and CH_4, lead to a direct radiative forcing impact, while CH_4 additionally contributes to a number of indirect effects, such as elevated concentrations of tropospheric ozone, stratospheric water vapor, as well as an additional CO_2 impact.[2] The direct radiative forcings are computed using the concentration to forcing relationships reported in Etminan et al.[390], which take into account the overlapping radiative bands between CO_2, N_2O, and CH_4. The indirect forcing due to CH_4, is modeled based on the methods outlined in Meinshausen

et al.[367] Similarly APMT-IC uses climate efficacies to align species-induced radiative forcing from MAGICC6.[367]

The temperature response is modeled using a two-box model comprising the deep ocean and the atmosphere/mixed layer ocean[10], while a climate sensitivity distribution from Roe and Baker[391] was used.

APMT-Impacts can be run with deterministic or probabilistic inputs, the latter enabling a quantification of uncertainty on the results. The uncertainties are captured through a Monte Carlo simulation. For each emission profile, APMT-IC used a Monte-Carlo simulation with 10,000 runs. In this paper we report only the mean and 5th and 95th percentile climate impact for each scenario.

S5.4 The impact of background emission scenario on the absolute and relative climate impact

Future background emission concentrations are uncertain, but affect the absolute climate impact of (future) emission fluxes and the value of equivalency metrics, as the marginal impact of additional emissions fluxes decrease with increasing background emission concentration.[37,56,376] For the base case an RCP 2.6 scenario was used, which is an future emission scenario leading to a temperature rise ranging from 0.9 to 2.3 °C (mean 1.6) in 2100.[4]

Figure 5-13 shows the absolute and relative cumulative temperature change for the FT-DWD system modeled assuming an RCP 2.6 compared to a RCP 8.5 scenario, which is a future emission

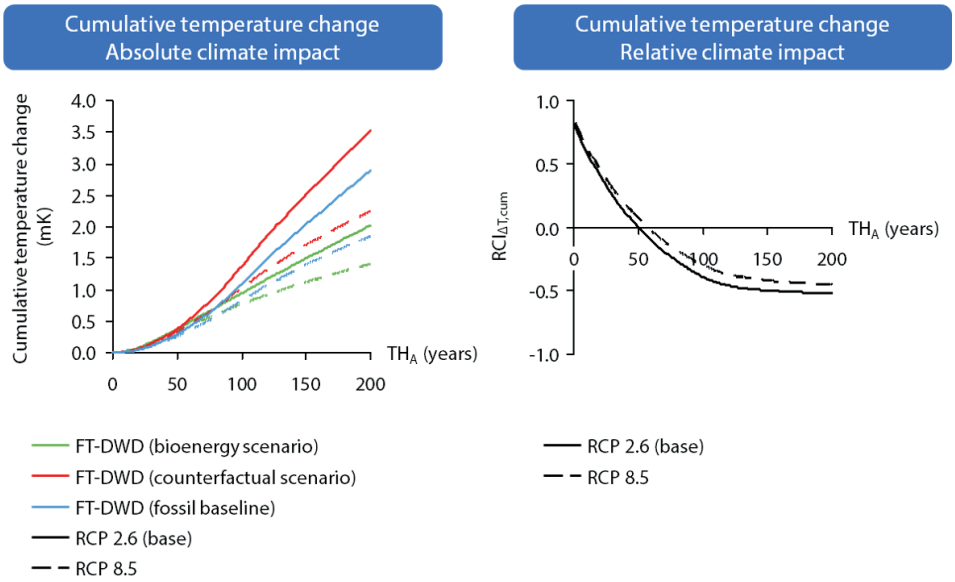


FIGURE 5-13: RCI results for the FT-DWD for different RCP scenarios.

scenario leading to a temperature rise ranging from 3.5 to 4.5 °C in 2100.[4] The results show that the difference in absolute climate impact for the RCP 8.5 and RCP 2.6 scenario is significant and grows over time. However, the difference between the RCI computed for both RCP scenarios is at maximum 0.09 and peaks around TH_p. The reason for this behavior is similar to the uncertainty related to climate impact modeling; effect of the background emission concentrations in the same for the climate impact in the numerator and denominator of the RCI. The RCI can therefore be used to study the effect of bioenergy production without significantly increasing the uncertainty associated with future background emissions, especially over long analytical time horizons.

S5.5 The potential and likelihood of bioenergy systems

The RCI shows the climate impact for various bioenergy systems. However, it does not show the potential and likelihood of a particular system. For example, this study shows that the land type and carbon content is an important determinant of system performance. The likelihood and potential of production on a particular land type highly depends on the socio-economic context. This is illustrated by comparing the land use projections of the three biomes in Brazil according to IMAGE-LPJml projections for two shared socio-economic pathway (SSP) scenarios (Figure 5-14). The SSP scenarios describe future socio-economic development storylines which vary in the challenges to mitigation and adaptation.[387] The SSP 1 scenario presents the lowest challenges to both categories as it is associated with rapid technology development, high environmental awareness, low energy demand and low global population. The SSP 2 scenario represents a middle-of-the-road scenario in which trends do not shift significantly from historical patterns. Figure 5-14 shows that the potential of abandoned agricultural land in the SSP 1 scenario is much higher than the SSP 2, due to increased agricultural yield and low population increase. Hence, it can be expected that the potential and likelihood of a production system like ATJ-SC-Abandoned is higher in an SSP 1 scenario than in an SSP 2 scenario.

As land availability, the counterfactual scenario is inherently uncertain, as a myriad of alternative futures exist for a production area.[354,380] Furthermore, the indirect effects of bioenergy production are challenging to quantify and associated with considerable uncertainty.[304,392] These sources of uncertainty require that the performance score for a particular feedstock-technology combination is ideally accompanied by a detailed description (and the likelihood) of the production context and/or uncertainty bars. Probability distributions may be used to aggregate production contexts and counterfactual scenarios into a performance score for a particular feedstock-technology combination. Impact-supply curves may also prove helpful to evaluate the supply potential of a particular production system.[322]

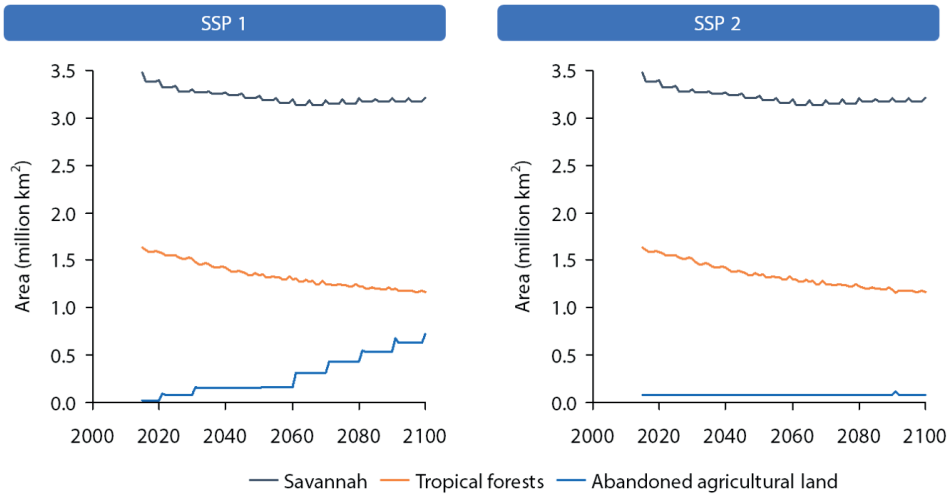


FIGURE 5-14: Land use projections for Brazil according to IMAGE-LPJml projections for the SSP 1 and 2 scenario.

6

Renewable jet fuel supply scenarios in the European Union in 2021-2030 in the context of proposed biofuel policy and competing biomass demand

Sierk de Jong[1]*, Joost van Stralen[2], Marc Londo[1,2,3], Ric Hoefnagels[1], André Faaij[4], Martin Junginger[1]

1. Copernicus Institute of Sustainable Development, Utrecht University, Utrecht, The Netherlands.
2. Energy research Centre of the Netherlands (ECN), Amsterdam, The Netherlands.
3. The Netherlands Association for Renewable Energy (NVDE), Utrecht, The Netherlands.
4. Energy Academy Europe, University of Groningen, Groningen, The Netherlands.

Published in GCB Bioenergy. (2018)

ABSTRACT

This study presents supply scenarios of non-food renewable jet fuel (RJF) in the European Union (EU) towards 2030, based on the anticipated regulatory context, availability of biomass and conversion technologies, and competing biomass demand from other sectors (i.e. transport, heat, power and chemicals). A cost optimization model was used to identify pre-conditions for increased RJF production and the associated emission reductions, costs and impact on competing sectors. Model scenarios show non-food RJF supply could increase from 1 PJ in 2021 to 165-261 PJ yr^{-1} (3.8-6.1 million tonne (Mt) yr^{-1}) by 2030, provided advanced biofuel technologies are developed and adequate (policy) incentives are present. This supply corresponds to 6-9% of jet fuel consumption and 28-41% of total non-food biofuel consumption in the EU. These results are driven by proposed policy incentives and a relatively high fossil jet fuel price compared to other fossil fuels. RJF reduces aviation-related combustion emission by 12-19 Mt yr^{-1} CO_2-eq by 2030, offsetting 53-84% of projected emission growth of the sector in the EU relative to 2020. Increased RJF supply mainly affects non-food biofuel use in road transport, which remained relatively constant during 2021-2030. The cost differential of RJF relative to fossil jet fuel declines from 40 € GJ^{-1} (1740 € t^{-1}) in 2021 to 7-13 € GJ^{-1} (280-540 € t^{-1}) in 2030, because of the introduction of advanced biofuel technologies, technological learning, increased fossil jet fuel prices, and reduced feedstock costs. The cumulative additional costs of RJF equal €7.7-11 billion over 2021-2030 or €1.0-1.4 per departing passenger (intra-EU) when allocated to the aviation sector. By 2030, 109-213 PJ yr^{-1} (2.5-4.9 Mt yr^{-1}) RJF is produced from lignocellulosic biomass using technologies which are currently not yet commercialized. Hence, (policy) mechanisms that expedite technology development are cardinal to the feasibility and affordability of increasing RJF production.

6.1 Introduction

Currently, approximately 2% of global anthropogenic greenhouse gas (GHG) emissions can be attributed to fuel combustion in aviation.[393] While global air traffic is expected to rise by 4.9% yr^{-1} up to 2040, international aviation was not covered by the Paris Agreement.[287,288] The aviation industry aims to cap net emissions by 2020 and halve emissions by 2050 relative to 2005.[12] Efficiency gains and operational improvements alone are likely insufficient to close the emission gap between projected and targeted CO_2 emissions from 2020 onwards.[287,393] The introduction of renewable jet fuel (RJF), a liquid substitute for fossil jet fuel produced from renewable resources, should contribute to further emission reductions and close the gap on the long term.[17,20–23] These measures are supplemented by the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) and the EU Emission Trading Scheme (EU ETS), which create an obligation for airlines to reduce emissions (through aforementioned measures) or surrender (purchased) emission offsets or allowances.

RJF produced from biomass (hereafter referred to as 'RJF') is currently considered the most technically feasible alternative to reduce the GHG intensity of jet fuel, as it can be produced commercially and is compatible with existing infrastructure.[394] The production, distribution and use of RJF in commercial aircraft has been demonstrated over the past decade.[17] However, the large-scale uptake of RJF has been impeded by the high cost differential between RJF and fossil jet fuel, limited number of commercialized conversion technologies, highly competitive and international character of the aviation industry, and current lack of adequate (policy) incentives.[28,29,70,214] The future role of RJF depends on contextual factors, of which the most important ones comprise the regulatory context, the availability of (low-cost) sustainable feedstocks, the commercialization of conversion technologies, and future oil price development.[18,28,31,325,394]

Previous work has estimated the bottom-up supply potential of RJF based on biomass availability[69], production cost developments[25], and planned production capacity[70,71]. Wise et al.[395] were among the first to analyze the emergence of RJF in a more holistic manner, using an integrated assessment model to quantify RJF volumes under two global emission mitigation trajectories. However, few studies explicitly consider the role of RJF in relation to the wider bioenergy system, even though aviation may become an important end-use application of biomass as the sector lacks clear alternatives to reduce its GHG emissions.[396]

To our knowledge, this analysis is the first to quantify the role of RJF in the EU until 2030, based on the anticipated regulatory context, availability of biomass and conversion technologies, and competing biomass demand from other sectors (i.e. transport, heat,

power and chemicals). The scope of RJFs considered is confined to RJFs produced from non-food biomass (i.e. advanced biofuels[r] or biofuels produced from used cooking oils and animal fats (UCOAF)), based on the general aversion of airlines to use food-based biofuels, as illustrated by the sustainability commitment of members of Sustainable Aviation Fuel Users Group "not to displace or compete with food crops".[26] Moreover, the policy trend in the EU towards phasing out food-based biofuels and stimulating the use of advanced biofuels suggests that future growth of biofuel consumption will mainly originate from increased advanced biofuel production.[64,68]

In this study, we incorporated RJF production technologies in the RESolve-Biomass model. This model is able to explicitly analyze the interaction between different end-use sectors, as it covers bio-based power, heat, transport fuels (road, marine and aviation) and chemicals. The RESolve-Biomass model was used to study the emergence of RJF supply scenarios and the associated technology portfolio, GHG emission reductions, and costs. This chapter further discusses the requirements in terms of technology development and feedstock mobilization, as well as the impact of increased RJF supply on biofuel use in other sectors, such as road and maritime transport.

6.2 Background

6.2.1 Aviation-related emission projections in the EU

Due to the projected growth of the aviation sector, GHG emissions from jet fuel combustion have been estimated to increase by 150% in the EU in 2050 relative to 2005 (Figure 6-1).[70,397] Despite anticipated efficiency gains and operational improvements, the gap between projected and targeted combustion emissions grows to 22 million tonne (Mt) CO_2-eq in 2030 and 166 Mt CO_2-eq in 2050 (S6.1 shows alternative growth scenarios). The emission gap is to be covered by carbon offsets and RJF.[12] However, current consumption of RJF in the EU is negligible, despite an aspirational target of achieving 2 Mt of RJF to be used in EU aviation in 2020 as outlined in the EU Flightpath Initiative.[21,398]

r In this context, advanced biofuels are defined as biofuels produced from feedstocks listed in Annex IX (part A) of the RED-II proposal[441], which includes feedstocks such as algae, sludges, perennial crops, and agricultural and forestry residues.

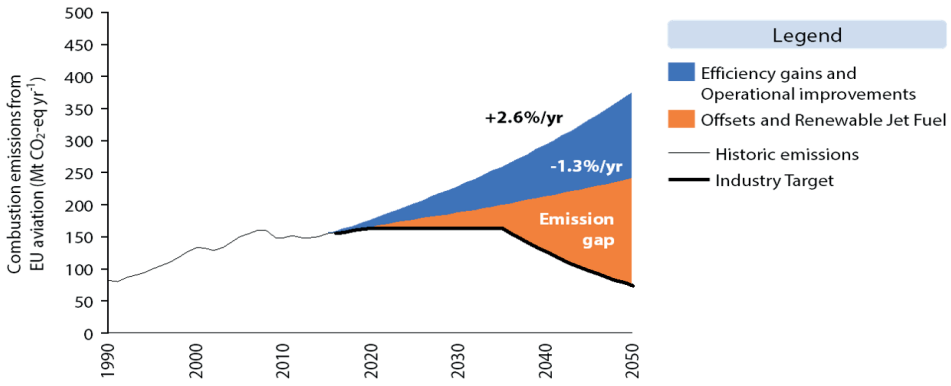


FIGURE 6-1: Combustion greenhouse gas emissions from flights departing from EU airports (intra- and extra-EU) with improvements in fuel efficiency and operations versus an industry target (S6.1).

6

6.2.2 Regulatory context

The regulatory context relevant for RJF in the EU includes the Renewable Energy Directive I (RED-I) and its successor RED-II, the EU Emission Trading Scheme (EU ETS) and the global Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA). As these schemes were awaiting definitive implementation at the time of writing, the information below may deviate from the actual content of the schemes when implemented.

6.2.2.1 The EU Renewable Energy Directive

The RED-I promotes the use of renewable energy sources in the EU. It establishes a target of 20% renewable energy in the EU in 2020, with a 10% sub-target for renewable energy in the transport sector, most of which will probably need to be met by biofuels.[67] While the aviation sector is not an obligated party, the RED-I allows RJF to be counted towards the renewable energy targets.[64] However, only few member states have explicitly adopted this in their national transposition.[29]

Recently, the European Commission proposed a recast of the RED-I for the period 2021-2030 (hereafter referred to as 'RED-II proposal').[68] The proposal is currently under review by the European Parliament and the European Council; final approval is expected in 2018, after which it will be transposed into national legislation. As it is the only comprehensive proposal at the time of writing, we base our analysis on the Commission's proposal, while evaluating alternative policy options in the sensitivity analyses.

The RED-II proposal aims to increase the share of renewable energy sources to 27% by 2030, without specifying a sub-target for neither the entire transport sector nor

specifically for the aviation sector. Instead, the proposal contains separate caps and binding targets for different renewable fuel categories to avoid adverse environmental impacts (e.g. land use change emissions) and promote the use of more advanced technologies (S6.2). Renewable fuels for transport produced from biomass (i.e. biofuels) are affected by two targets; the overall target for renewable transport fuels (1.5% in 2021 increasing to 6.8% by 2030) and a sub-target for advanced biofuels (0.5% in 2021 increasing to 3.6% by 2030). The overall target for renewable fuels may be fulfilled by advanced biofuels, biofuels produced from used cooking oil and animal fat (UCOAF), renewable electricity, waste-based fossil fuels and renewable fuels of non-biological origin (e.g. solar fuels and CO_2-based fuels). The share of UCOAF-based biofuels is capped at 1.7%. Food/feed-based biofuels are excluded from the renewable transport fuels target, but they may still contribute to the overarching 27% renewable energy target to a maximum of 3.8% of total transport fuel use by 2030.

The targets define the share of renewable transport fuels relative to the final energy consumption in the road and rail sectors. Renewable fuels supplied to the EU aviation and marine sectors may count 1.2 times their energy content towards the target. This multiplier mechanism aims to stimulate biofuel uptake in sectors which lack clear renewable options and cover higher production costs that may exist in these sectors.

6.2.2.2 EU ETS and CORSIA

The EU ETS and CORSIA address emissions from intra- and extra-EU flights, respectively. The EU ETS sets an EU-wide emission cap covering multiple, mainly industrial sectors (civil aviation was added in 2012). Under international pressure it was decided to apply EU ETS to intra-EU flights only, pending the development of a global measure by the International Civil Aviation Organization (ICAO).[399] In 2016, ICAO's general assembly decided to implement CORSIA, which is a measure prescribing aircraft operators to offset any annual increase in CO_2 emissions beyond 2020 from international aviation between participating states.[20] 72 states, including the EU member states, representing 87.7% of international aviation activity, intend to participate voluntarily from 2020 onwards.[400] The European Commission recently proposed to restrict the EU ETS scope to intra-EU flights while awaiting the development of CORSIA.[401]

The inclusion of aviation in EU ETS and CORSIA sets a price on combustion emissions from aviation. In EU ETS, fuels produced from biomass are allocated an emission factor of zero as long as they meet the RED-I sustainability criteria, thus providing a financial incentive for the use of RJF equal to the price of an emission allowance.[402,403] The role of RJF in CORSIA as well as the environmental integrity and credibility level of the offsets used (influencing their price) are still under discussion at the point of writing.

6.3 Materials and methods

6.3.1 RESolve-Biomass model

The role of RJF in the EU in 2021-2030 was assessed using the RESolve-Biomass model, developed by Energy research Centre of the Netherlands (ECN). RESolve-Biomass is a one-year myopic cost-optimization model that optimizes the feedstock-technology portfolio to fulfill a certain demand for bio-based products. The model minimizes the total additional well-to-tank system cost relative to a fossil reference. These costs comprise feedstock cultivation and transport, pre-treatment, conversion, and distribution (e.g. blending). RESolve-Biomass includes a variety of feedstocks, technologies and demand segments. It has a longstanding reputation and has been used in multiple European projects to address policy-related questions (e.g. REFUEL, Biomass Policies, Biomass Futures and S2Biom).[404] The exogenous model inputs shown in Figure 6-2 are discussed below.

RESolve-Biomass model		
System components	**Exogenous model components (input)**	**Endogenous model components (output)**
Biomass supply	• Domestic and imported biomass cost-supply curves • Key constraint: feedstock mobilization rate	• Feedstock portfolio

Energy system	• Conversion technologies
	  • Technology scope and techno-economic data
	  • Greenhouse gas performance thresholds
	  • Technological learning system and introduction year
	• Key constraint: technology deployment rate and blend wall
		• Technology portfolio
		• System cost*
		• Greenhouse gas reduction (post-analysis)
		*the model minimizes total *additional* system cost

Biomass demand	• Demand for bio-based electricity, heat, chemicals and transport fuels • Regulatory framework (biofuel targets and multiplier for aviation and marine)	• Biofuel use in aviation, marine, and road transport

FIGURE 6-2: Exogenous and endogenous model components of RESolve-Biomass.

6.3.2 Biomass demand and supply scenarios

The supply of RJF is analyzed using four scenarios varying in biomass supply and biomass demand (Figure 6-3).

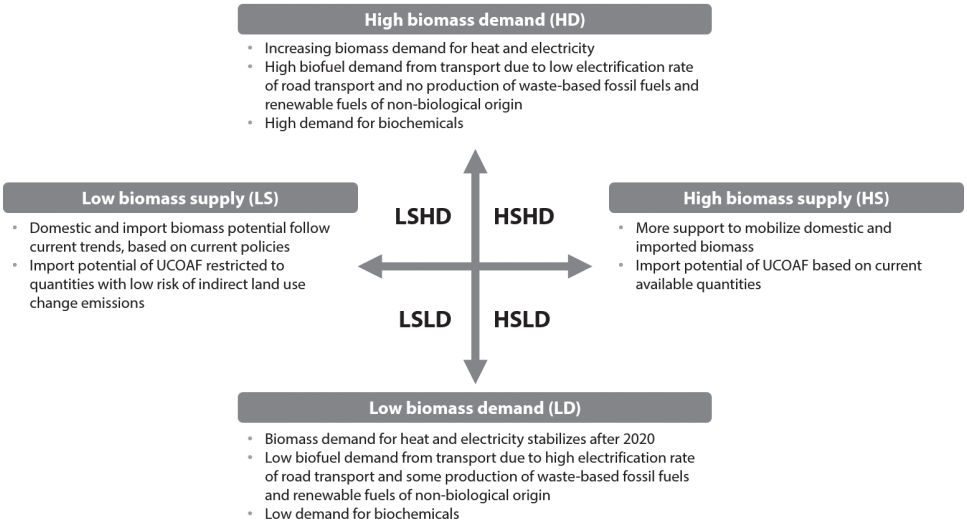


FIGURE 6-3: Four scenarios varying in biomass supply and demand.

6.3.2.1 Biomass supply

Current gross consumption of biomass for energy purposes in the EU is about 5.4 EJ, of which 4.4% is imported.[405] Various studies have quantified the future domestic biomass supply potential; however, its mobilization depends on a magnitude of social, technical and economic factors.[63] Extra-EU import potentials are possibly large, but depend on mobilization efforts and domestic consumption in the exporting countries.[406] This study attempts to capture this variation in a Low Biomass Supply (LS) and High Biomass Supply (HS) supply scenario. The supply potentials are used as a constraint on feedstock use. The mobilization of novel feedstocks was modeled as an S-curve as described in van Stralen et al. (2016).

The supply potential of biomass and biofuel in/to the EU increases from 11.4-11.8 EJ in 2021 to 13.4-16.9 EJ in 2030 in the LS and HS scenario (Figure 6-4). The potential of domestic biomass was obtained from the Biomass Policies project, which quantifies the cost-supply potential of a wide range of agricultural, forestry and waste biomass types on a member state level.[408] The supply assessment employs exclusion criteria based on sustainability considerations (e.g. soil conservation, biodiversity, erosion control) and conventional competing uses (e.g. food, feed, bedding, material). The LS scenario follows the baseline scenario used in Biomass Policies; the HS scenario follows the B2 scenario which shows higher biomass supply, particularly of manure and agricultural and forestry residues due to higher mobilization and extraction rates.[408,409] The cost for domestic biomass was based on market prices for biomass types which are already

traded and road-side costs for feedstock for which the market is not yet developed. The cost declined by 10% between 2020 and 2030 because of technological learning and efficiency improvements.[408]

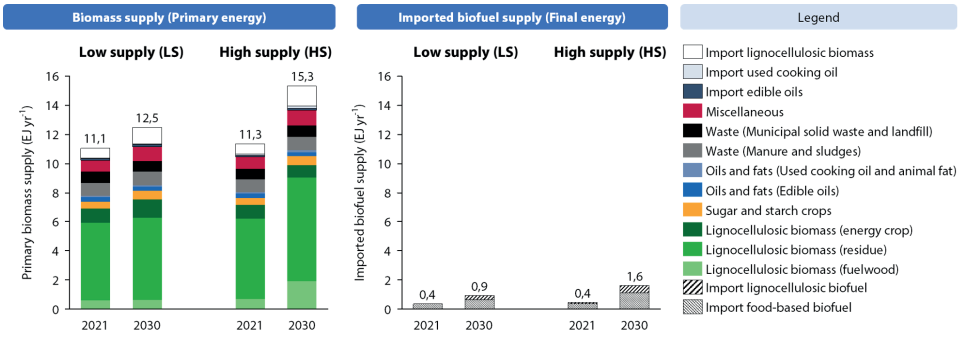


FIGURE 6-4: Sustainable biomass and imported biofuel potential in the EU.

The import potentials include liquid biofuels (food-based biodiesel, food-based ethanol and lignocellulosic bioethanol) and solid biomass (wood pellets) from countries that are or could become major export regions (e.g. Brazil, the US and Canada). The import share available for EU consumption (after deduction of local demand) was based on the population size of the EU relative to countries with similar paying capacity.[410] The costs comprise production, processing, transport and certification. These potentials were supplemented with imports of palm oil[411,412] and used cooking oil[413] . The palm oil import potential in both supply scenarios was based on current palm oil imports into the EU for bioenergy use. The HS scenario uses the collectable potential (165 PJ yr^{-1} by 2030) of used cooking oil, while the LS scenario uses the "low indirect land use change (iLUC) potential" of used cooking oil (44 PJ yr^{-1} by 2030) from which all competing uses except bioenergy and dumping were deducted. A large share (97 PJ) of the difference between of the collectable and low iLUC potential arises from used cooking oil that is allegedly used for human consumption in China. Diversion of this feedstock stream to bioenergy would likely instigate a growing demand of vegetable oils (potentially causing emissions), but would also reduce the health threat associated with used cooking oil consumption.[413] The remaining competing uses include animal feed and the oleochemical industry. The used cooking oil potential increases by 270% in the HS compared to the LS scenario, but this is likely an overestimation of the sustainable potential. S6.3 provides supplementary data on the categorization of biomass types, cost-supply curves and import regions.

6.3.2.2 Biomass demand

Biomass supply for non-food RJF production is primarily affected by non-food biomass demand for heat, electricity, biochemicals and biofuels. Demand for bio-based products in the low biomass demand (LD) and high biomass demand (HD) scenario is visualized in Figure 6-5. Biomass demand for bio-based heat and power comprises the largest share of overall biomass demand. Biomass demand for the HD scenario was obtained from the S2Biom project.[407] For the LD scenario a faster introduction of energy efficiency measures and other sources of renewable energy was assumed. Furthermore, it was assumed that demand for bio-based heat and power would stabilize after 2020 and decrease for applications where the HD scenario already showed a reduction. The demand for bio-based chemicals (ethylene, hydrogen, methanol, benzene, toluene, xylene, surfactants, solvents and polymers) in the HD and LD scenarios, obtained from the S2Biom project, show only a marginal contribution to the total biomass demand (Figure 6-5).[414]

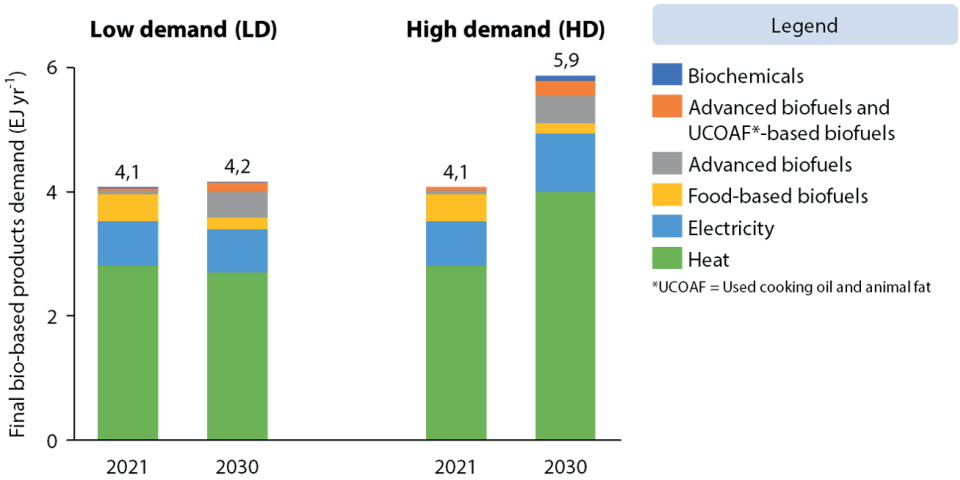


FIGURE 6-5: Final bio-based products demand in the EU.

Biomass demand from the transport sector in 2021-2030 follows the renewable energy targets for non-food biofuels as specified in the RED-II proposal where applicable. The model was forced to fulfill the targets; hence the option of non-compliance (at certain cost) was not analyzed. The demand for advanced biofuels was based on the sub-target for advanced biofuels (0.5% in 2021, increasing to 3.6% by 2030). In this study, the definition of advanced biofuels follows the RED-II proposal and include lignocellulosics-based biofuels and gaseous biofuels from sludges and landfill gas. The overall target for renewable transport fuels (1.5% in 2021 increasing to 6.8% by 2030) was disaggregated to a combined biofuel demand for advanced biofuels and biofuels

based on used cooking oil and animal fats (UCOAF) by subtracting the projected share of renewable electricity, waste-based fossil fuels and renewable fuels of non-biological origin. The maximum share of UCOAF-based fuels (1.7%) specified in the RED-II proposal was incorporated as a model constraint.

The LD and HD scenarios assume a 0.5% and 0% share of waste-based fossil fuels and renewable fuels of non-biological origin by 2030, respectively. The share of renewable electricity in the road transport sector in the HD scenarios was calculated from projections of electricity use in road transport (0.87% in the EU by 2030) and renewable electricity production in the PRIMES 2016 reference scenario.[415] In the LD scenario, the share of renewable electricity in road transport was assumed to be twice as high, anticipating on a faster electrification of the car fleet across the EU and a higher share of renewables in the electricity mix. The projected share of renewable electricity in rail transport was added to the total renewable electricity usage in transport.[416] This leads to a renewable electricity share in road and rail transport increasing from 0.5% (2021) to 0.9% (2030) in the HD scenarios and 0.6% (2021) to 1.2% (2030) in the LD scenarios.

In absence of dedicated policy targets for food-based biofuels in the RED-II proposal (it may only contribute to the overarching 27% renewable energy target), the share of food-based biofuels was assumed to decline from 3.6% in 2021 to 1.6% by 2030, based on restrictions on the import of food-based biodiesel and the construction of new edible oil-based and starch-based biofuel facilities (S6.2). Although this is much lower than the proposed cap in the RED-II proposal (7.0% in 2021 and 3.8% by 2030), this assumption has limited impact on the production of advanced biofuels and UCOAF-based biofuels, because the demand for these biofuels is established by separate targets and these biofuels are produced from other types of biomass.

6.3.3 Biofuel production technologies

The RESolve-Biomass model contains a wide range of bioenergy production technologies. This section focuses on non-food biofuel production technologies. S6.4 provides the full technology scope of RESolve-Biomass and supplementary techno-economic and greenhouse gas emissions data.

6.3.3.1 Technology scope and techno-economic data

Table 6-1 displays the scope and techno-economic data of non-food biofuel technologies. Besides technologies able to produce RJF, the table also includes production technologies for other non-food biofuels, as these are in direct competition with RJF to fulfill the renewable energy targets in transport. RESolve-Biomass includes existing technologies producing ethanol, biogas, Fatty Acid Methyl Ester (FAME) biodiesel, Hydrotreated Esters and Fatty Acids (HEFA) diesel. Technologies expected to

commercialize during 2021-2030 to be included in the model were selected based on their promising techno-economic performance[214] and fuel readiness level[28]. The data in the table represents the costs in 2021 or at technology introduction (Table 6-2 lists the introduction years). The techno-economic data was obtained from prior studies, which generally model n^{th} plant economics (as if the technology was deployed at large scale). Therefore, the CAPEX for new technologies was scaled to the initial plant capacity as outlined in Table 6-2 (using a scaling factor of 0.8) to reflect higher investment cost for the first-of-a-kind plant.

The model may use biofuels to replace conventional fuels in aviation, marine, car, bus and truck segments. The eligible biofuels and blend walls were defined per transport segment (S6.5). The model includes versions of Hydroprocessed Esters and Fatty Acids (HEFA), Fischer-Tropsch (FT), pyrolysis and Hydrothermal Liquefaction (HTL) production capacity with and without RJF co-production to incorporate the producer's flexibility to optimize their process for different end-use applications. The production of HEFA-RJF incurs additional costs relative to producing diesel only, due to lower middle-distillate yield and more stringent upgrading requirements.[30] Due to lack of information for FT, pyrolysis and HTL, it was assumed that 25% of the energy content of the produced diesel could be used as RJF without additional production costs, since all process designs already include a distillation column.[214] The model could adjust the yield of gasoline, diesel and jet fuel for FT, Pyrolysis, ATJ and HTL by ±0.1 $GJ_{product}\ GJ^{-1}_{biomass\ feed}$ (without altering the overall yield) to resemble the variance and flexibility within the technology types.

TABLE 6-1: Non-food biofuel production technologies (i.e. advanced and UCOAF-based biofuel) in the scope of RESolve-Biomass.

Technology	Feedstock	Main products[i]	Yield[ii]	Annualized CAPEX[ii,iii]	OPEX[ii,iii]	Typical GHG reduction[iv]	Ref.
			$GJ_{products}$ $GJ_{biomass\ feed}^{-1}$	$€_{2010}$ $GJ^{-1}_{product}$	$€_{2010}$ $GJ^{-1}_{product}$	% savings relative to fossil reference	
RJF production technologies							
Hydrotreated Esters and Fatty Acids (HEFA)	UCOAF	D, HEFA-RJF, P, N	1.11	1.7	2.7	77%	30,214,290
Fischer-Tropsch (FT)	Lignocellulosics	D, E, N, FT-RJF	0.45	9.6	9.1	93%	214,290
Alcohol-to-Jet (ATJ)	Lignocellulosic ethanol	G, ATJ-RJF	0.89	1.4	1.7	73%	214,232,417
Hydrothermal liquefaction (HTL) and full hydrodeoxy-genation	Woody biomass	D, G, HFO, HTL-RJF	0.56	3.4	3.0	81%	231,232
Pyrolysis and full hydrodeoxy-genation	Woody biomass	D, G, HFO, Pyrolysis-RJF	0.50	5.6	5.7	77%	231,232
Other non-food biofuel production technologies							
Fatty Acid Methyl Ester (FAME)	UCOAF	FAME, Gl	1.07	0.6-0.9	2.5-2.8	79%	290,418
Hydrotreated Esters and Fatty Acids (HEFA)	UCOAF	D, P, N	1.09	1.8	2.8	77%	30,214,290
Fermentation	Lignocellulosics	EtOH, H, E	0.61	10	9	78% - 90%	290,418
Digestion and biogas upgrading	Manure and sludges, landfill gas, and organic waste	B	0.57-0.6	2.7-12.9	1.2-4.9	50% - 179%[iv]	290,419,420
Biogas liquefaction	Biogas from manure, sludges and landfill	LNG	0.92	1.7	0[v]	60% - 163%[iv]	290,421,422
Fischer-Tropsch (FT)	Lignocellulosics	D, E, N	0.45	9.6	9.1	93%	214,290
		DME, H, E	0.55	7.4	4.1	93%	290,418
Hydrothermal liquefaction (HTL) and full hydrodeoxy-genation	Woody biomass	D, G, HFO	0.56	3.4	3.0	81%	231,232
Pyrolysis and full hydrodeoxy-genation	Woody biomass	D, G, HFO	0.50	5.6	5.7	77%	231,232

i. B=Biogas, D=Renewable diesel, DME=Renewable Dimethyl Ether, E=Renewable electricity, EtOH=bioethanol, FAME=FAME biodiesel, G=Renewable gasoline, Gl=Glycerine, H=Heat, HFO=Renewable heavy fuel oil, LNG= Renewable Liquefied natural gas, N=Renewable Naphtha, P=Renewable propane, and RJF=Renewable jet fuel.

ii. Ranges in cost and yield are due to feedstock-specific differences. Product yields may exceed unity due to the input of utilities. S6.4 shows product-specific yields.

iii. The annualized CAPEX was calculated using a discount rate of 7% and a lifetime of 20 and 12 years for biofuel and biogas installations, respectively. The OPEX listed here does not include the cost of feedstocks, utilities (i.e. hydrogen, electricity and natural gas) nor netbacks of co-products (i.e. LPG, naphtha), as these may change with model solution or modeling year. For all technologies 8000 full load hours were assumed.

iv. Ranges are due to variation in feedstock and technology design (a disaggregation can be found in S6.4). The RED-II fossil comparator for transport fuels (94 g CO_2-eq MJ^{-1} fuel) was used to calculate the GHG savings for diesel, gasoline and jet fuel substitutes. Please note that for biogas and bio-LNG, the fossil comparators of natural gas (56.2 g CO_2-eq MJ^{-1} fuel) and LNG (76.4 g CO_2-eq MJ^{-1} fuel) were used. When the RED-II fossil comparator was used, all biogas and bio-LNG pathways would achieve the 70% GHG emission savings threshold imposed by the RED-II proposal for installations commissioned from 2021 onwards.

v. The utility requirement is covered by natural gas (incorporated in the yield); other OPEX was included in the CAPEX.

6.3.3.2 Greenhouse gas performance

The reduction in life-cycle and combustion emissions was quantified based on the feedstock-technology portfolio emerging from RESolve-Biomass. The life-cycle emission reduction represents the overall GHG emission reductions from the use of non-food biofuels in EU transport. The GHG emission savings listed in Table 6-1 were obtained from Edwards et al.[290] and de Jong et al.[232] All pathways listed in Table 6-1 achieve the 70% GHG savings threshold, which is imposed on installations commissioned from 2021 onwards by the RED-II proposal.[68] The combustion emission reduction quantifies the emission reduction allocated to the aviation, marine and road transport sector. CO_2 emissions from the combustion of biofuels were assumed to be zero, in line with the IPCC Guidelines for National Greenhouse Gas Inventories emissions from biofuels.[423] The combustion emission reduction from non-food biofuels was estimated by awarding an emission credit equal to the CO_2 emission factor for fossil jet fuel (71.5 g CO_2 MJ^{-1}), gasoline (69.3 g CO_2 MJ^{-1}), diesel (74.1 g CO_2 MJ^{-1}), residual fuel oil (77.4 g CO_2 MJ^{-1}) and natural gas (56.1 g CO_2 MJ^{-1}).[423]

6.3.3.3 Capacity deployment

RESolve-Biomass was initialized in 2005 and aligned with actual production and consumption data during 2005-2016 (especially the spatial distribution of production and consumption).[424–427] Model projections were used to establish the biofuel mix for 2020. These projections show a lower renewable energy share in transport in 2020 (8.7% on an EU average, including double counting biofuels) compared to the proposed RED-I target of 10%. This is largely due to limited announced advanced biofuel capacity and the imposed restrictions on the share of food-based biofuels (S6.2).

The maximum rate at which production capacity could be deployed was constrained at +150% in the first three years and +90% thereafter to better reflect historic biofuel deployment rates in the EU.[398] Premature closure (<20 years) was allowed up to 10% of

total capacity per year. The growth potential of technologies was further constrained by their theoretical market size, which may be confined by fuel type (e.g. ethanol can only replace gasoline) or blend wall (7% for FAME biodiesel and 10% for ethanol on volumetric basis) (S6.5).

Table 6-2 lists the introduction year of the conversion technologies in scope. Fischer-Tropsch (FT) and Alcohol-to-Jet (ATJ) technology are assumed to be commercially available by 2020 (at 100 MW_{in}), as (components of) the technology have been validated for other products and feedstocks.[28] It was assumed that pyrolysis and HTL are commercialized in 2023 and 2025 (at 50 MW_{in}), respectively, as several pre-commercial pyrolysis facilities are currently in operation, while HTL is yet to be demonstrated.[28,267] Moreover, full hydrodeoxygenation of the biocrude still poses technical challenges and the jet fuel fraction is yet to be certified for use in commercial aviation.[428] The introduction year was varied in a sensitivity analysis, as these assumptions are uncertain and largely depend on future Research, Development and Demonstration (RD&D) efforts.

6.3.3.4 Technological learning

RESolve-Biomass incorporates cost reductions over time through technological learning based on scale-dependent and market-driven learning effects.[429] Scale-dependent learning includes cost reductions caused by economies of scale as plant size may increase over time. Scale-dependent learning effects were initialized once the technology was introduced in the model. These effects were modeled exogenously and were defined by the time it takes to double the plant size ('doubling time'). Market-driven learning effects include process improvements, upscaling of individual process components and increasing operation experience. It is modeled using experience curves, in which a progress ratio describes the CAPEX and OPEX reduction for every doubling in cumulative capacity. No endogenous learning was applied to feedstock cost or GHG emission reduction performance.

Table 6-2 summarizes the assumptions regarding technological learning, which were largely based on de Wit et al.[429] and van Stralen et al.[407] It was assumed that upscaling is the most important driver during early commercialization of novel technologies, for which a doubling time of 5 years was utilized.[429] A conservative scaling factor of 0.8 was assumed to account for process components which have high scaling factors (e.g. feedstock handling or steam methane reformer) or require parallel production after a certain maximum capacity.[105,430] Furthermore, a 5% maximum market share was assumed for single plants to avoid unrealistic dependencies on one plant. The initial and maximum plant capacities were set to 100 MW_{in} and 2000 MW_{in} for large-

scale technologies and 50 MW_{in} to 400 MW_{in} for small-scale technologies. For existing technologies, only market-driven learning was incorporated. The cumulative capacity was determined endogenously by the deployed capacity in the model, thereby assuming the EU is a closed learning system (or the EU share of global deployed capacity remains constant).

TABLE 6-2: Assumptions regarding capacity deployment and technological learning.

Technology	Sub process	Introduction year	Market-driven learning	Scale-driven learning			Ref.
			Progress ratio	Initial plant capacity	Maximum plant capacity	Doubling time[i]	
			%	MW_{input}	MW_{input}	Years	
Fatty Acid Methyl Ester (FAME)		2005	90%	-	-	-	429
Fermentation (Lignocellulosics)		2015	99%	100	2000	5	429
Hydrotreated Esters and Fatty Acids (HEFA)	Diesel	2007	90%	-	-	-	ii
	RJF	2016	90%	-	-	-	
Digestion and biogas upgrading		2005	100%	-	-	-	431
Biogas liquefaction		2005	100%	-	-	-	iii
Fischer-Tropsch (FT)[iv]		2020	98%	100	2000	5	429
Alcohol-to-Jet (ATJ)[iv]		2020	100%	100	2000	5	iii
Hydrothermal liquefaction (HTL)[iv]		2025	98%	50	400	5	407
Pyrolysis[iv]		2023	98%	50	400	5	ii

i. Only years in which new capacity was built were considered in the doubling time.
ii. Pyrolysis was assumed similar as HTL. HEFA was assumed similar as biodiesel.
iii. No market-driven learning was included as the components of the ATJ systems are widely used in the petrochemical industry, albeit separately.
iv. The data listed in this table were assumed equal for both versions of technologies with and without RJF co-production.

6.3.4 Fossil reference

The costs for the fossil reference products were based on price projections of crude oil, natural gas and coal, taken from the PRIMES reference 2016 scenario (S6.6).[415] Fossil fuel price projections are highly uncertain and depend on the stringency of climate policy and the production costs of different supply options. The current projections show a constantly increasing oil prices (2.3% yr^{-1}) during 2021-2030, driven by growing demand in developing countries, while production stabilizes in countries outside the Organisation of the Petroleum Exporting Countries. The average oil/product price ratio over 2007-2017 (energy basis) was used to determine the price ratio for jet fuel (1.30),

diesel (1.18), gasoline (1.24), heavy fuel oil (0.78), marine gasoil (1.24) and other fossil products, relative to crude oil (S6.6).

The electricity price was projected using the electricity market model COMPETES.[407,432] A CO_2 price was added to fossil product use in sectors included in the EU ETS (i.e. electricity, large scale heat applications and intra-EU aviation). It was assumed that extra-EU aviation will be covered under CORSIA from 2021 onwards. The CO_2 price was assumed equal for EU ETS and CORSIA and grows progressively from 9 € t^{-1} in 2021 to 27 € t^{-1} by 2030.[415] It was assumed that RJF may be counted towards proposed RED-II biofuel targets as well as CORSIA or EU ETS.

6.4 Results

6.4.1 Technology portfolio

Figure 6-6 and Figure 6-7 show the biofuel mix by conversion technology and end-use sector for the four supply-demand scenarios. The results show two trends: 1) an increase in advanced biofuel production driven by the sub-target for advanced biofuels and 2) a growing share of non-food biofuel consumption in the aviation and marine sectors driven by the multiplier for aviation and marine biofuels and the relatively high price for fossil jet fuel and marine gasoil relative to diesel and gasoline (making aviation and marine biofuels a cheaper substitute for fossil fuel).

As a result of these trends, the consumption of non-food biofuels in the aviation sector grows from 1 PJ in 2021 to 165-261 PJ yr^{-1} (3.8-6.1 Mt yr^{-1}) of RJF by 2030, representing 24-33% of total EU non-food biofuel consumption. The RJF volume is positively affected by high supply of UCOAF (HS scenarios) and high demand for advanced biofuels production, of which RJF is often a co-product (HD scenarios). Although the quantity of UCOAF-based biofuels remains roughly constant over time due to limits on feedstock supply (rather than the 1.7% cap imposed by the RED-II proposal), it is increasingly diverted to the aviation sector due to the multiplier mechanism; 41%-45% of UCOAF-based biofuels are consumed in the aviation sector by 2030. By 2030, 109-213 PJ yr^{-1} (2.5-4.9 Mt yr^{-1}) RJF is produced from lignocellulosic biomass using technologies which are currently not yet commercialized. RJF based on lignocellulosic biomass is initially produced using FT and ATJ. Pyrolysis and HTL are added to the technology portfolio upon commercialization, but their contribution is marginal due to low RJF yields.

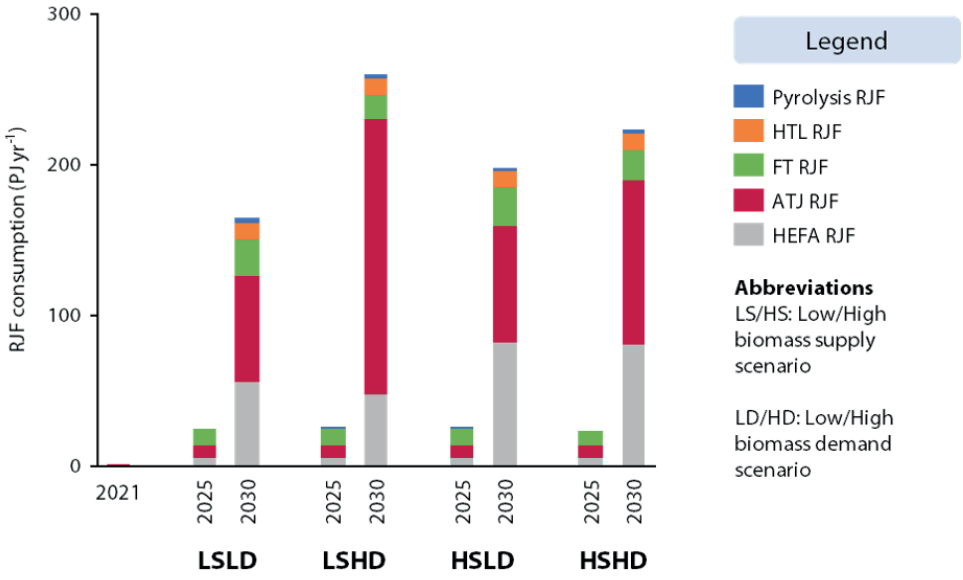


FIGURE 6-6: The mix of RJF by technology type for the four biomass supply-demand scenarios.

Figure 6-7 shows that non-food biofuel consumption in road transport remains relatively constant, while it increases sharply in the aviation and marine sectors (instigated by the multiplier). The sub-target for advanced biofuels increases overall consumption in the EU from 71 PJ yr^{-1} in 2021 to 460-515 PJ yr^{-1} by 2030. Initial volumes are supplied through biogas from digestion and lignocellulosics-based ethanol; after 2025 a more diverse technology mix with ATJ, FT, pyrolysis and HTL emerges as these technologies commercialize. 393-450 PJ yr^{-1} non-food biofuel is produced from lignocellulosic biomass by 2030. The lack of variation among scenarios (especially before 2027) indicates that new technologies not necessarily emerge because of superior economic performance, but rather because the model has few technology options to meet the biofuel targets. In the first years, non-food biofuel options are mainly limited to lignocellulosic ethanol, because other advanced biofuel technologies have not commercialized and UCOAF-based biofuels are restricted by limited feedstock supply. As a result, the E10 blend wall is reached in 2023, instigating the need for ATJ and FT technologies to produce drop-in fuels (hence boosting RJF production), despite poorer economic performance than alternative technologies. New technologies generally follow the maximum deployment rates before 2027, after which the model has more room to maneuver.

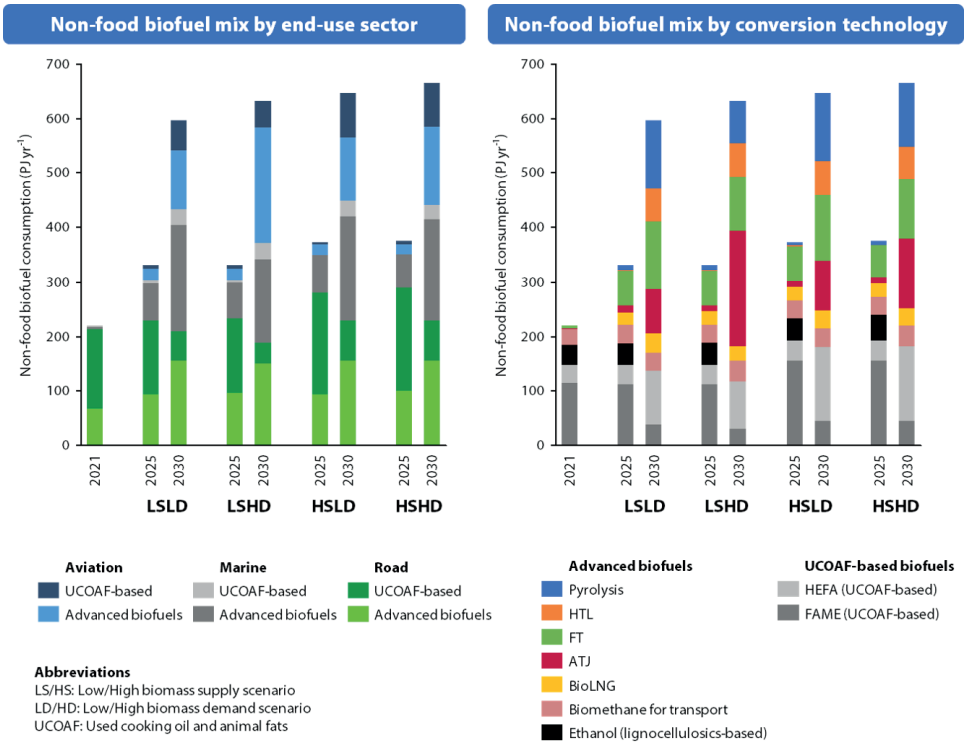


FIGURE 6-7: The mix of non-food biofuels by end-use sector (left) and conversion technology (right).

6.4.2 Biomass use

Figure 6-8 shows that total biomass use increases from 5.4 EJ in 2021 to 5.6 EJ in LD scenarios and 6.9-7.3 EJ in HD scenarios by 2030. HD scenarios show increased use of agricultural residues, primary forestry residues and imported wood pellets, sugarcane-based ethanol and lignocellulosics-based ethanol. In the LD scenarios the share of biomass use remains constant or declines slightly, while imports are particularly prominent in the first half of the decade.

RJF is mainly produced from UCOAF, agricultural residues (e.g., straw from cereals and corn stover), and forestry residues (i.e. sawmill by-products, primary forest residues, industrial wood residues, landscape care wood and black liquor). Intra- and extra-EU UCOAF potentials are fully exploited across all scenarios, which illustrates its key role in reaching biofuel targets cost-effectively, particularly in the short term. HD scenarios show a higher share of imported biomass (mainly wood pellets) and biofuels (mainly ethanol). Projected utilization rates of intra-EU biomass by 2030 (41-62%) leave some

room for further growth of advanced biofuels in the EU beyond 2030, especially since vast potentials of agricultural residues (0.8-1.8 EJ), forestry residues (0.7-2.6 EJ) and perennial crops (0.7-1.2 EJ) remain underutilized.

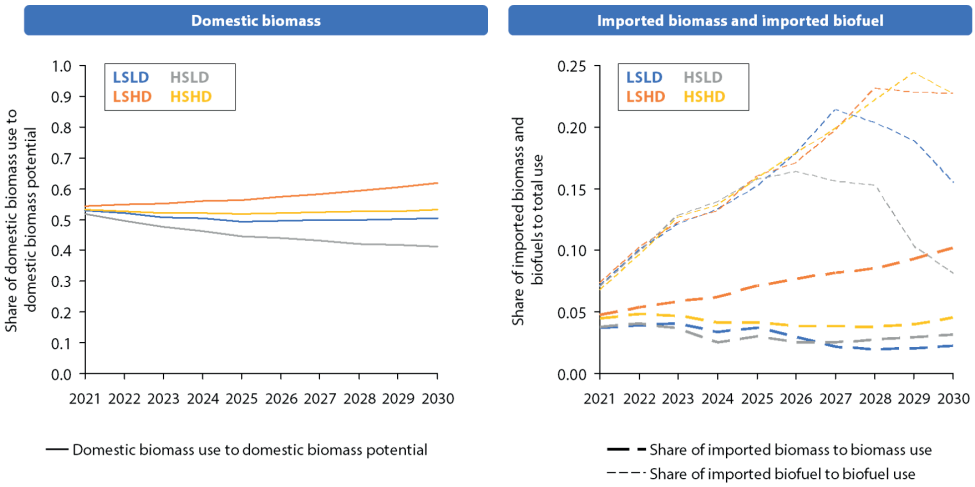


FIGURE 6-8: EU biomass use.

6.4.3 Cost

Figure 6-9 shows the marginal cost differential (left panel) and the total additional cost (right panel) for RJF. Both graphs were based on the differential between fossil jet fuel price and the marginal production cost of RJF, which is an average over RJF types weighted by production volume (advanced RJFs typically show a higher marginal cost differential than UCOAF-based RJF, as the former have a separate biofuel target). The total additional cost is the product of the marginal cost differential and production volume. The marginal cost differential can be interpreted as the maximum cost of RJF production at which it is economically preferred to supply RJF than alternative biofuel options serving the same target. This preference is governed by the additional production costs of RJF relative to other non-food biofuel options and the multiplier for RJF.

In all scenarios a cost differential between RJF and fossil jet fuel remains towards 2030, irrespective of conversion pathway. The cumulative additional costs in these scenarios vary between €7.7-11 billion over 2021-2030, which translates to an average cost differential of 11-16 € GJ^{-1} RJF (491-682 € t^{-1}). In all scenarios except LSHD, the cost differential decreases from roughly 40 € GJ^{-1} RJF (1740 € t^{-1}) in 2021 to 7-13 € GJ^{-1} RJF (280-540 € t^{-1}) by 2030. This drop is partly caused by fossil jet fuel prices increasing by

9 € GJ^{-1} over this period; the remainder is due to the availability of cheaper feedstocks and a reduction in production cost because of technological learning.

Learning effects are mainly driven by scale-dependent learning and reduce conversion costs for lignocellulosics-based technologies between 15% for cellulosic ethanol to 21-28% for HTL, FT, ATJ and pyrolysis over the period 2021-2030. For the LD scenarios, this reduction allows the RJF volume to double while additional costs stabilize during 2027-2030. Despite slightly larger cost reductions induced by market-driven learning (due to higher deployment) in the HD scenarios, total additional costs increase because of higher competition for biomass, high reliance on (more expensive) imports and high RJF production volumes, which implies that the model moves higher up the cost-supply curve. The same dynamics also drive up the marginal costs of other products; relative to the LSLD scenario, marginal costs of bio-based electricity and heat increase by roughly 15% and 60% (HSHD scenario) and 100% and 225% (LSHD scenario) during 2025-2030. The results for LSHD in 2030 were excluded from Figure 6-9, as they were an order of magnitude higher than the other scenarios, indicating the model requires very expensive solutions to fulfil the bioenergy demand.

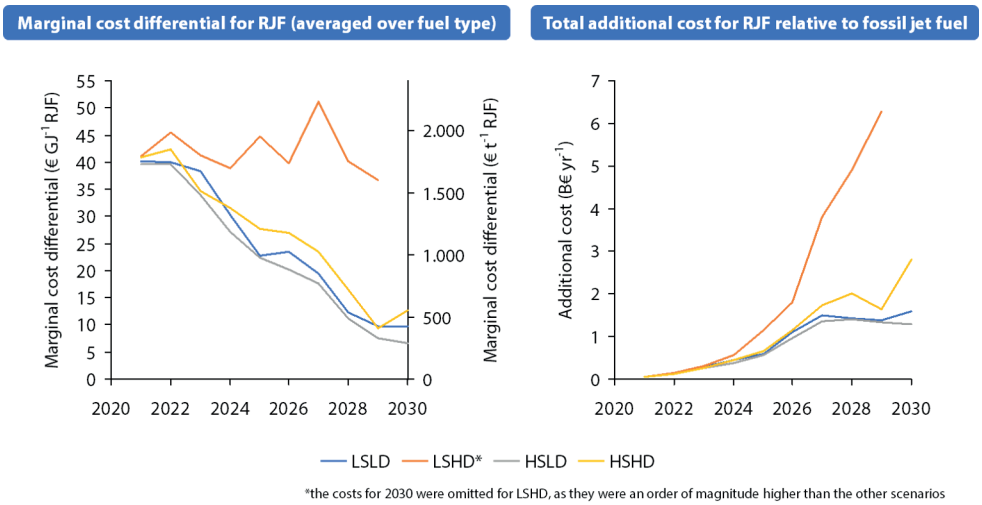


FIGURE 6-9: Additional cost of RJF introduction.

6.4.4 Greenhouse gas emissions

Figure 6-10 shows a 3-fold increase in reductions in combustion (left panel) and life-cycle (right panel) greenhouse gas emissions from non-food biofuels between 2021 and 2030. This increase is mainly attributed to the aviation and marine sectors, while emission reductions in road transport remain constant over time. The introduction of RJF

reduces combustion emissions in the aviation sector by 12-19 Mt CO_2-eq by 2030, which roughly equals the combustion emissions of domestic aviation (15 Mt CO_2-eq) [433]. The average life-cycle GHG emission reduction of RJF equals 77-79% over 2021-2030. Total combustion emission reductions from non-food biofuels in the marine sector (14-18 Mt CO_2-eq yr^{-1} in 2030) are comparable to the current emissions of domestic navigation (16 Mt CO_2-eq yr^{-1}) [433]. In comparison, renewable electricity use in road transport reduces combustion emissions by 7-11 Mt CO_2-eq in 2030 (cf. 5 Mt CO_2-eq in 2021).

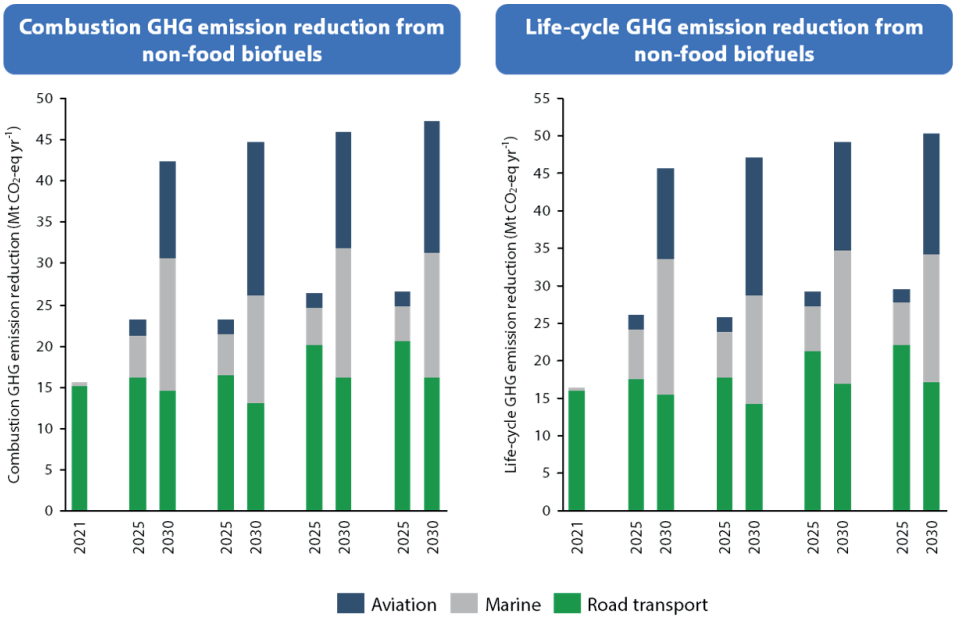


FIGURE 6-10: Combustion (left) and life-cycle (right) greenhouse gas emission reduction from non-food biofuels by end-use sector. Emission reductions from renewable electricity in road transport are not shown.

6.5 Sensitivity analysis and alternative policy scenarios

This section tests the impact of key assumptions on the model outcomes and explores alternative policy scenarios. The analyses were applied to the LSLD scenario.

6.5.1 Technology development

As technology development is uncertain and highly depends on future RD&D efforts, this sensitivity analysis evaluates the impact of the pace of technology development and associated cost reductions by varying the introduction year, doubling time, scaling factor and maximum deployment rate in a High technology development (HT) and Low technology development (LT) case (Table 6-3).

TABLE 6-3: An overview of the High technology development (HT) and Low technology development (LT) case.

	Introduction year			**Doubling time**			**Scaling factor**			**Maximum deployment rate**[i]		
	Base	LT	HT	Base	LT	HT	Base	LT	HT	Base	LT	HT
Fermentation (Lignocellulosics)	2015	2015	2015	5	7	3	0.8	0.8	0.7	150% (90%)	150% (90%)	200% (150%)
Fischer-Tropsch (FT)	2020	2023	2020	5	7	3	0.8	0.8	0.7			
Alcohol-to-Jet (ATJ)	2020	2023	2020	5	7	3	0.8	0.8	0.7			
Hydrothermal liquefaction (HTL)	2025	2027	2023	5	7	3	0.8	0.8	0.7			
Pyrolysis	2023	2025	2020	5	7	3	0.8	0.8	0.7			

i. The values in between brackets indicate the maximum growth rate after 3 years.

Figure 6-11 shows the resulting mix of non-food biofuels by end-use sector for the HT and LT case. The HT case provides more technology options, leading to lower cost of compliance (the cost differential for RJF almost dissolves towards 2030), reduced imports and a more diverse feedstock-technology portfolio. Learning effects reduce production costs by almost 50% for HTL, ATJ and pyrolysis (cf. 21-28% in the base case). Moreover, the earlier introduction of HTL and pyrolysis increases the role of these technologies at the expense of FT, which generally has higher production cost. These effects halve the cumulative additional costs of RJF production (€ 3.9 billion) over 2021-2030 compared to the base case.

The LT case could not be solved, as the advanced biofuel target could only be fulfilled by biogas and lignocellulosics-based ethanol until 2023, both of which require adaptation to infrastructure and fleet at high deployment rates. Hence, policies to support and expedite technology development are cardinal to the feasibility and affordability of the proposed advanced biofuel targets.

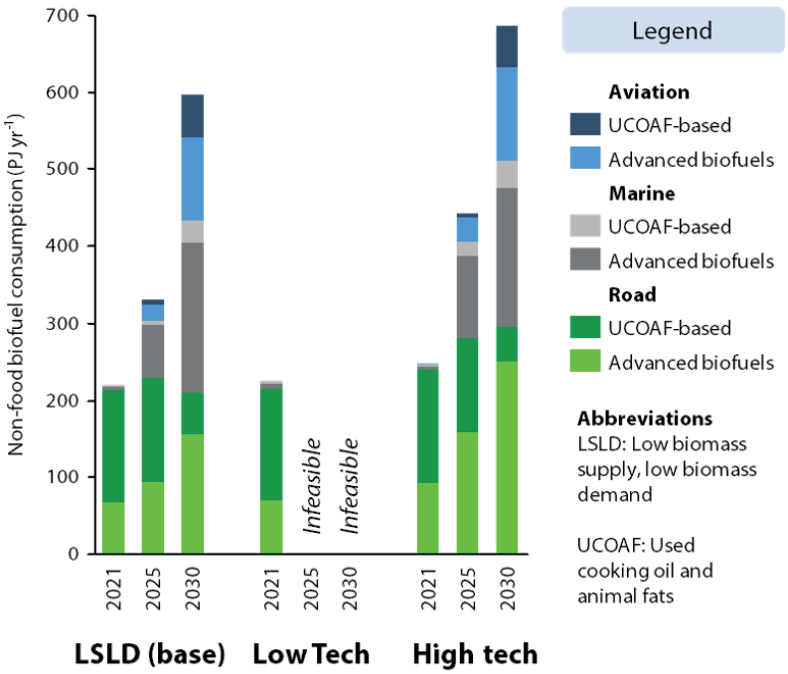


FIGURE 6-11: The mix of non-food biofuels by end-use sector for the low and high technology development case.

6.5.2 The multiplier for RJF

The RED-II proposal uses a multiplier to incentivize RJF production. However, the effectiveness of the multiplier depends on its size and the relative cost differential of RJF with respect to other biofuels. The following cases explore the impact of key policy levers (case 1 and 2) and volatility in fossil fuel prices (case 3 and 4) (Figure 6-12:):

1. **Size of the multiplier**. Case 1A and 1B evaluate the impact of different multipliers for RJF (1.0 and 2.0). The multiplier for marine biofuels is kept at 1.2.
2. **Excise duties or CO_2 price on transport fuels**. Some Member States partly or fully exempt road biofuels from excise duties, which decreases the cost differential for road biofuels and thus affects the relative attractiveness of RJF.[s] In case 2A such exemption were applied to road biofuels equal to the minimum EU excise duty rates on petrol (10.4 € GJ^{-1}), diesel (9.2 € GJ^{-1}) and natural gas (2.6 € GJ^{-1}) used in transport.[434] In case 2B the CO_2 price on fossil jet fuel was removed.
3. **Change in jet to diesel/gasoline price spread.** Changes in the spread between

s No exemptions can be given to the aviation biofuels, as generally no excise duty is levied on fossil jet fuel. Although EU legislation allows an excise duty to be levied on domestic flights or intra-EU flights when there is a bilateral agreement between Member States, few Member States do this.

fossil diesel/gasoline and jet fuel affects the relative cost differential. Case 3 investigates the effect of higher diesel/gasoline prices, by taking 2-year ratios instead of 10-year ratios for fossil fuels relative to crude oil. This particularly increases the ratios for diesel (1.31 cf. 1.18 in base) and gasoline (1.37 cf. 1.24 in base), while the ratio for jet fuel (1.29 cf. 1.30 in base) remains roughly constant.

4. **Elevated fossil fuel prices.** Case 4 evaluates the impact of a higher crude oil price scenario, which increases the oil price by 10-30% during 2021-2030 (S6.6).

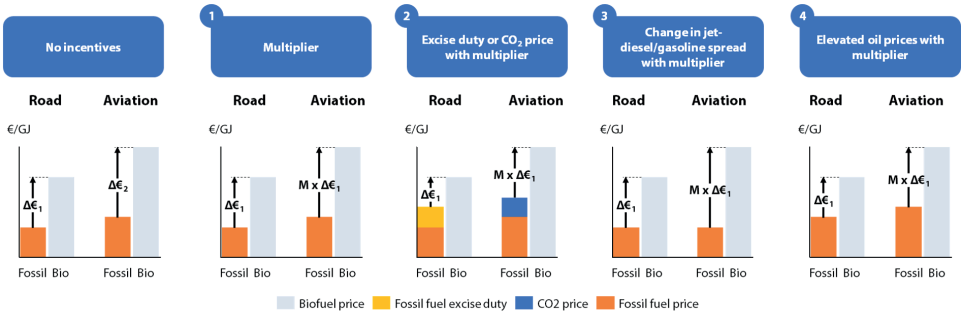


FIGURE 6-12: General dynamics of the multiplier for aviation biofuels. M indicates the multiplier for aviation biofuels. The relative size of the bars in the chart is illustrative only. Although only road and aviation are shown here, the pricing of marine (bio)fuels also affect system dynamics.

Figure 6-12 shows that the attractiveness of RJF is predominantly affected by the RJF multiplier and tax incentives for road transport biofuels. A multiplier of 2 (case 1B) leads to 273 PJ yr^{-1} RJF (6.3 Mt yr^{-1}) by 2030, but also results in a sharp decline in non-food biofuel consumption (514 PJ yr^{-1}) and lower combustion emissions reductions (36 Mt yr^{-1} CO_2-eq cf. 49 Mt yr^{-1} CO_2-eq in base). A multiplier of 1 (case 1A) leads to 62 PJ yr^{-1} RJF (1.4 Mt yr^{-1}) by 2030, largely because the conversion to HEFA-RJF is no longer attractive. RJF is only produced as a co-product of advanced biofuel production, as the price of fossil jet fuel is higher than diesel and gasoline. In case 1A non-food biofuel use in road and marine transport rise by 25% and 19% in 2030 relative to the base case. A tax exemption for road transport biofuels (case 2A) yields 96 PJ yr^{-1} RJF (2.2 Mt yr^{-1}), but in this case RJF is produced as a co-product of advanced biofuel production because of the 1.2 multiplier on RJF. Tax exemptions in road transport reduce non-food biofuel consumption in the aviation and marine sectors by 42% and 6%, while increasing the use of non-food biofuels in road transport by 32%. Although both cases still contain some RJF consumption, simultaneous removal of the multiplier and application of tax incentives for road transport biofuels will likely lead to negligible volumes of RJF.

The other cases were found to have insignificant impact when applied individually. It

is shown that the current CO_2 prices potentially applied through EU ETS and CORSIA do not alter the amount of RJF produced. Similarly, the assumed volatility in fossil fuel prices is not sufficient to change the mix of non-food biofuels, suggesting the system dynamics are inert up to a certain tipping point.

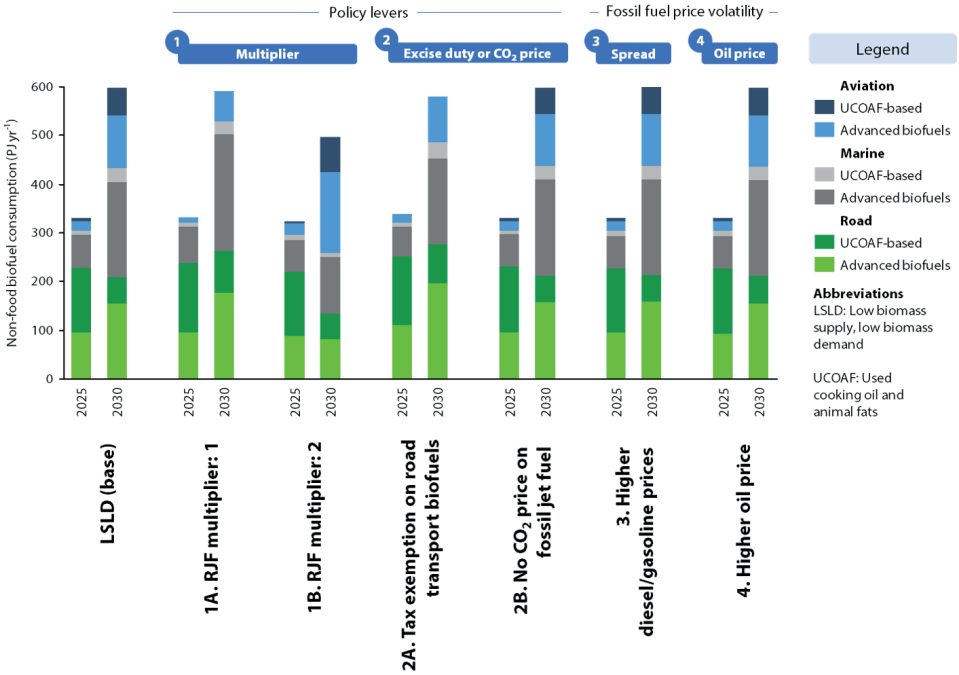


FIGURE 6-13: The mix of non-food biofuels by end-use sector for the sensitivity cases affecting the attractiveness of RJF.

6.5.3 A biofuel target across all transport sectors

In this analysis, the overall target for renewable transport fuels was extended to cover intra-EU aviation and marine, while the multiplier for aviation and marine biofuels was removed. The use of non-biobased fuels and renewable electricity in these sectors was assumed negligible. As this leads to 16% higher demand for non-food biofuels over the period 2021-2030, this analysis could only be run using the high technology development case (Table 6-3). Fuel demand for aviation was aligned with own projections (S6.1). Fuel demand for marine transport was obtained from industry projections.[435] The intra-EU share of total fuel use for aviation (39%) and marine (35%) was estimated from emission records.[436,437]

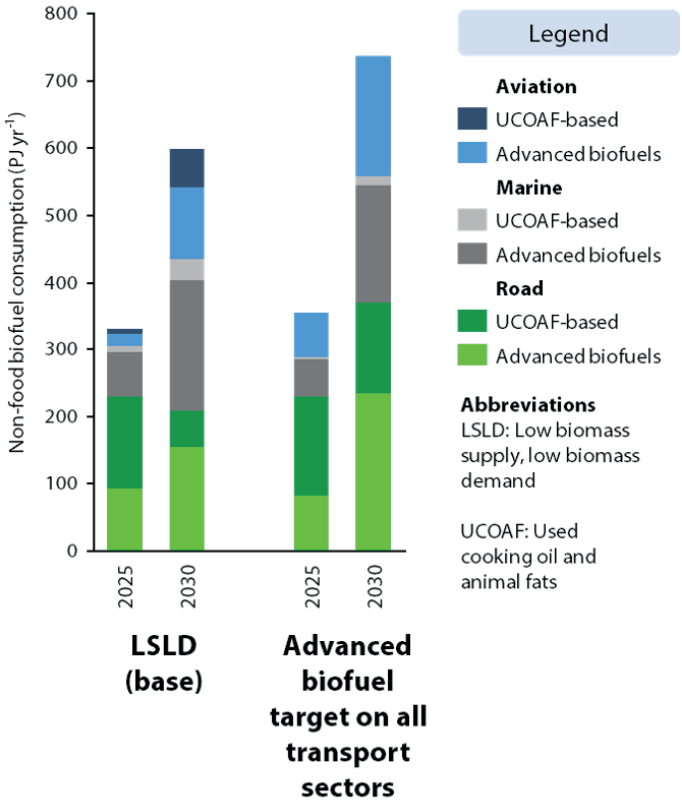


FIGURE 6-14: Mix of non-food biofuels by end-use sector for a target across all transport sectors.

Figure 6-14 shows a significant increase in non-food biofuels consumption in road transport compared to the base case (379 PJ yr^{-1} in 2030 cf. 209 PJ yr^{-1} in base), while RJF consumption increases slightly to 176 PJ yr^{-1} (4.1 Mt yr^{-1}) in 2030. The higher price for fossil jet fuel compared to diesel and gasoline is sufficient to instigate RJF production, but insufficient to cover the additional cost for HEFA-RJF relative to HEFA-diesel. RJF is mainly produced as a co-product in cases where it does not increase production costs (i.e. FT, ATJ, HTL and pyrolysis). ATJ is a particularly important technology in this analysis, as the E10 blend wall is already reached in 2021. The relative shares of UCOAF-based and advanced biofuels do not change significantly compared to the base case. However, this case shows increased imports, system costs and marginal costs due to increased pressure on the system. This case also involves a more ambitious growth of advanced biofuel production capacity than the base case.

The introduction of RJF could also be incentivized by a separate biofuel target for aviation and marine. However, this sensitivity analysis shows that a transport-wide target leads to a higher non-food biofuel share in intra-EU aviation (15%) and marine (21%) than in road transport (3.1%). A separate target for aviation or marine of the size of the renewable transport fuels target (6.8% by 2030) will thus likely lead to higher cost of compliance.

6.6 Discussion

6.6.1 Implications for RJF adoption in aviation

Depending on biomass supply and demand, the base case results show 165-261 PJ yr^{-1} (3.8-6.1 Mt yr^{-1}) RJF production by 2030, representing roughly 6-9% of total EU jet fuel consumption. The RJF supply scenarios highly depend on the development of advanced biofuel technologies and the presence of adequate (policy) incentives. The introduction of RJF reduces aviation-related combustion emission by 12-19 Mt yr^{-1} CO_2-eq by 2030, offsetting 53-84% of projected emission growth of the sector in the EU by 2030. However, vast growth of RJF beyond 2030 is required if the emission gap continues to grow.

The introduction of RJF is largely driven by the 1.2 multiplier for RJF, (advanced) biofuel targets, and the high price of fossil jet fuel relative to other fossil fuels. Additional incentives for RJF will increase RJF volumes and increasingly shield RJF development from market volatility, but a higher multiplier may also dilute the biofuel targets and lead to lower overall GHG emission reductions. Increasing the use of RJF depends on biomass mobilization (especially UCOAF) and development of (advanced) biofuel technologies, including technical certification for use in commercial aviation.

The cost differential of RJF over fossil jet fuel drops significantly from 40 € GJ^{-1} in 2021 to 7-13 € GJ^{-1} in 2030, due to increasing oil prices and decreasing production costs. The CO_2 abatement cost of RJF are high (91-176 € t^{-1} CO_2 in 2030) compared to projected CO_2 prices and other bioenergy options.[334] EU ETS and CORSIA will thus likely provide a marginal incentive for RJF. The RED-II proposal allocates the cost of biofuel use to suppliers of road transport fuel, as road transport is the only obligated transport segment (jet fuel suppliers are not obliged to supply biofuels). The cost burden of RJF on the road transport sector is of the order of 0.24-0.31 €-cents per liter, averaged over 2021-2030. If the cost would be allocated to the aviation sector instead, the average costs would amount to 1.0-1.4 € per departing passenger on intra-EU flights.

6.6.2 *Implications for the EU biofuel portfolio*

This study shows that the RED-II proposal increases consumption of non-food biofuels, particularly in the aviation and marine sectors, which correspond to 28-41% and 29-34% of total non-food biofuel consumption in the EU in 2030. This shift is caused by the imposed multiplier for aviation and marine biofuels and the high price for fossil jet fuel and marine gasoil relative to road transport fuels. Increased consumption of non-food biofuels in the aviation and marine sectors, which have few options to reduce their GHG intensity, can lead to greater emission reductions in transport, provided renewable electricity use in road transport increases.

The use of advanced biofuels grows rapidly because of the imposed sub-target. The conversion cost of advanced biofuels reduces by 15%-28% over the period 2021-2030 through technological learning, while the availability of cheaper feedstocks and higher oil prices further instigate cost reductions. Successful commercialization of advanced biofuel technologies is vital to the feasibility of biofuel targets, as 52-58% of biofuel volumes (393-450 PJ yr^{-1}) by 2030 are produced by technologies which are currently not yet mature (i.e. ATJ, FT, HTL and pyrolysis) or widely commercialized (e.g. lignocellulosics-based ethanol). The deployment of these technologies requires persistently high deployment rates (30-42% y^{-1}) during 2021-2030, which implies a rapid acceleration compared to the average growth rate in biofuel production in the EU (10% y^{-1}) and the United States (13% y^{-1}) during 2006-2016.[72] Categorized biofuel targets alone will not necessarily stimulate commercialization of new technologies, as was observed in the United States.[438] A solid investment climate and incentives to mobilize domestic biomass and commercialize advanced biofuel technologies are therefore encouraged.

6

6.6.3 *Discussion on key assumptions and model characteristics*

Several assumptions deserve additional attention as they are important drivers of model results:

- **The pace of technology development**. The introduction year, technological learning potential and the deployment rate of biofuel technologies largely drive model results (rather than cost minimization), but highly depend on RD&D efforts. Low technology development impedes target compliance, while faster technology development reduces imports and system costs and leads to a more diverse feedstock-technology portfolio.
- **Techno-economic and life-cycle emissions data.** The performance data of advanced biofuel technologies are largely based on process modeling studies. The variance in cost and GHG emission estimates can be significant due to lack of empirical validation, especially for immature technologies such as pyrolysis and

HTL.[214,232] These assumptions particularly affect system cost and life-cycle GHG emission reduction, but marginally affect the technology portfolio, which is mainly driven by biofuel targets and the pace of technology development.

- **Additional cost of RJF production.** It was assumed that RJF production using FT, pyrolysis or HTL does not incur additional costs compared to diesel-only production. Although additional costs affect the relative attractiveness of RJF production, the production of HEFA RJF illustrates that additional cost can be absorbed to a certain extent, under the assumption of a 1.2 multiplier and relatively high fossil jet fuel price compared to other fossil fuels.
- **Policy context.** Amendments to the RED-II proposal at EU or national level may impact the results, particularly when affecting non-food biofuel targets, sustainability criteria, and incentives for non-food biofuel use in the aviation and marine sectors and renewable electricity use in road transport (some of which were tested in the sensitivity analysis).
- **Biomass demand and supply**. Biomass demand and supply were modeled exogenously. For some biomass demand segments, exogenous modeling of biomass demand is justified because demand is defined by policy targets (i.e. advanced biofuels). Biomass demand from other segments (e.g. bio-based electricity and heat) depends on the competitiveness of bioenergy relative to other renewable energy technologies which was not explicitly modeled here. Furthermore, the development of extra-EU biomass markets may limit imports to the EU and/or instigate exports from the EU and thus affect the cost and feasibility of target compliance.

6.7 Recommendations for further research

This study shows that RJF consumption could grow significantly in the coming decade, depending on policy incentives, technology development and biomass supply. It is therefore encouraged to include RJF in other (bio)energy models to explore the potential of RJF on a national, regional and global level. It is further recommended to include a more detailed representation of RJF in sectoral models of the aviation industry to study the impact of RJF introduction and regulatory measures (e.g. a per-passenger surcharge) in terms of fuel cost, market growth and climate impact.

The RESolve-Biomass model may be improved by a broader and more detailed technology scope. For example, the use of lower-quality biofuels (e.g. partially upgraded pyrolysis/HTL biocrude) for marine applications may contribute to higher biofuel use in the marine sector and faster development of these technologies.

The temporal scope of this study covers 2021-2030. It is encouraged to further explore

the role of bioenergy in the EU beyond 2030, based on future policy options, trends in domestic biomass supply and demand, and the development of bioenergy markets outside the EU. Moreover, as deep GHG emission reductions are required to reach climate mitigation targets, it becomes increasingly important to explore the optimal allocation of biomass among end-use sectors, while considering the interaction between bioenergy and other renewable energy sources.

S6 Supplementary Information

S6.1 Aviation-related emission projections in the EU

Aviation-related emissions in the EU were projected based on industry growth rates, efficiency gains and operational improvements (Table 6-4, Table 6-5 and Table 6-6).[70,397] Greenhouse gas emissions in this paper comprise CO_2, CH_4 and N_2O emissions. The emissions include all flights departing from EU airports. Emissions were obtained from Eurostat.[433] The industry target caps emissions from 2020 and halves emissions by 2050 relative to 2005. In Figure 6-15 it was assumed that emission reductions to achieve the 2050 target are initiated in 2035. The emission trajectory in the RCP 2.6 scenario was adapted from Cames et al.[393], who quantified that emissions need to be reduced by 67% in 2050 relative to 2020 to keep the contribution of aviation-related emissions to global emissions constant after 2020. The RCP 2.6 scenario follows an emission scenario likely leading to a temperature rise ranging from 0.9 to 2.3 °C (mean 1.6), relative to pre-industrial times.[4]

Besides the Baseline scenario discussed in the main text, Figure 6-15 also shows a High growth and Low growth scenario. Only in case of low industry growth and optimistic efficiency gains and operational improvements, the industry target may be achieved without additional measures in the coming decade. In the Baseline and High growth scenario, there is an increasing gap between projected and targeted CO_2 emissions from 2020 onwards. The figures also show that an equal share emission trajectory requires deeper emission reductions than the industry target.

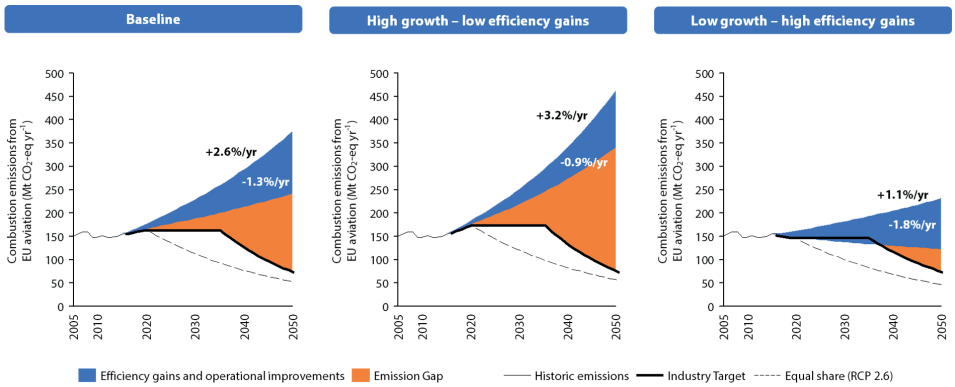


FIGURE 6-15: Combustion emissions from EU aviation with improvements in fuel efficiency and operations versus an industry target and RCP 2.6 scenario (shown from 2005-2050).

TABLE 6-4: Fuel burn growth rates for the Baseline, high growth and low growth scenario.[70]

Industry growth rate (% yr^{-1})	Baseline	High growth	Low growth
2017–2020	2.7%	0.9%	3.5%
2021–2025	2.8%	1.1%	3.3%
2026–2030	2.5%	1.2%	3.1%
2030–2050[i]	2.5%	1.2%	3.1%
Average	2.6%	1.1%	3.2%

i. Extrapolated from 2026-2030.

TABLE 6-5: Operational improvements for all scenarios.[397]

	Operational improvements (% yr^{-1})
2010–2020	0.33%
2020-2030	0.37%
2030–2040	0.24%
2040-2050[i]	0.24%

i. Extrapolated from 2030-2040.

TABLE 6-6: Efficiency gains for the Baseline, low growth and high growth scenario.[397]

	Baseline	Low efficiency gains	High efficiency gains
Efficiency gains (% yr^{-1})	0.96%	0.57%	1.5%

S6.2 Establishing demand for biofuels

RED-II proposal

The RED-II proposal contains six renewable fuel categories according to the feedstock used:

- Category 1: Advanced biofuels: biofuels produced from feedstocks in Annex IX – part A (e.g. algae, agricultural and forestry residues).
- Category 2: Biofuels produced from feedstocks in Annex IX – part B (i.e. used fats and oils and molasses).
- Category 3: Renewable liquid and gaseous fuels: liquid or gaseous fuels other than biofuels whose energy content comes from renewable energy sources other than biomass.
- Category 4: Waste-based fossil fuels: e.g. carbon capture and utilization.
- Category 5: Renewable electricity.
- Category 6: Food and feed-based biofuels.

The RED-II proposal contains an overall target for category 1-5 fuels (1.5% in 2021 increasing to 6.8% by 2030) and a sub-target for category 1 fuels (0.5% in 2021 increasing to 3.6% by 2030), see Figure 6-16. Furthermore, it caps the contribution of food and feed-based biofuels to 7% in 2021,

gradually decreasing to 3.8%. The contribution of category 2 fuels is capped at 1.7% (constant over time).

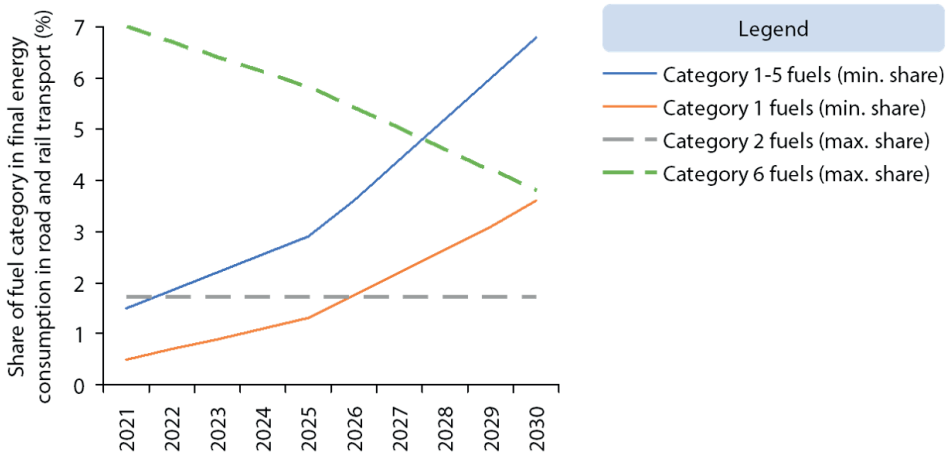


FIGURE 6-16: RED-II targeted share of different renewable fuel category in final energy consumption in road and rail transport for 2021-2030.[68]

Demand projections for category 1-5 fuels in this paper

Figure 6-17 shows how the RED-II targets are translated into demand projections of the different biofuel categories for the low and high demand scenario. The advanced sub-target for category 1 fuels could directly be transposed into a demand profile. The share to be filled by category 1 and 2 biofuels ("cat 1-2 fuels" in Figure 6-17) was calculated by subtracting the projected share of category 3-5 fuels from the renewable fuels (category 1-5) target. If the consumption of category 1 and category 1-2 fuels in a member state in 2020 exceeded the minimum share in 2021 as specified in the RED-II proposal, the share was kept constant until the RED-II share exceeded the consumption.

The uncertainty regarding the role of fuels of non-biological origin (category 3-4 fuels) and renewable electricity (category 5 fuels) was captured in the high and low biomass demand scenarios. The low and high biomass demand scenario assume a 0.5% and 0% share of renewable fuels of non-biological origin by 2030, respectively. Furthermore, the share of renewable electricity in the road transport sector in the high biomass demand scenario was calculated from the product of projected electricity use in road transport (0.87% in the EU by 2030) and domestic renewable electricity production in the PRIMES 2016 reference scenario.[415] The RED-II proposal prescribes that member states may choose to take the national share of renewable electricity or the average EU share of renewable electricity. We have assumed that member states choose whichever share is higher. In the low demand scenario, the penetration of electricity in road transport was assumed to be twice as high (1.74%), anticipating on a faster electrification of the car fleet across the EU.

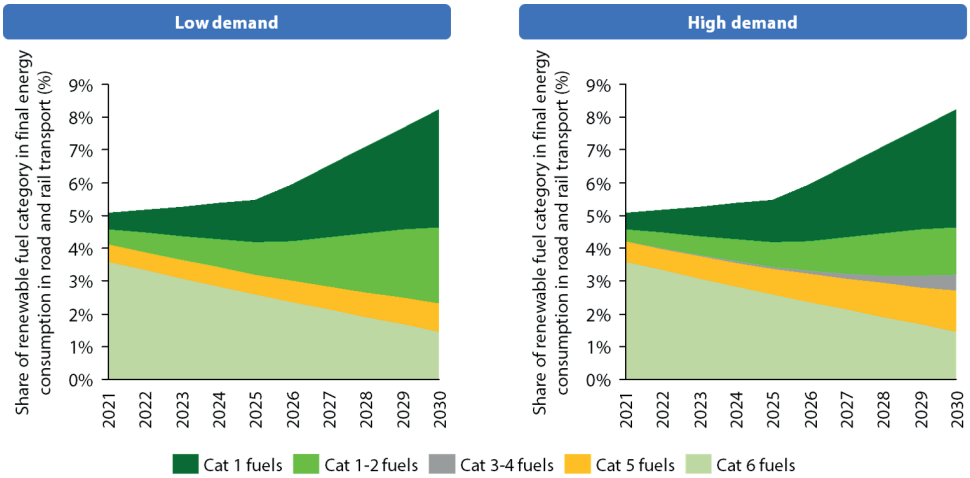


FIGURE 6-17: Translation of the targets for renewable transport fuels in the RED-II proposal. The figure shows the EU average; targets per member state may differ due to a different share of renewable electricity in the energ mix. Category 1-2 fuels may be filled by both category 1 and 2 fuels.

Demand projections for category 6 (food- and feed-based) biofuels in this paper

The demand profile for food and feed-based biofuels (hereafter indicated as 'food-based biofuels') poses a challenge, as the RED-II proposal introduces a declining cap for this fuel type instead of a target. We assume that the average EU share of food-based biofuels declines from 3.6% in 2021 to 1.4% by 2030 (Figure 6-17). This biofuel demand is fulfilled by food-based biofuels, unless advanced biofuels (category 1) are more competitive. The paragraphs below explain the underlying assumptions for this demand profile.

The amount of food and feed-based biofuels (hereafter indicated at 'food-based biofuels') in the EU in 2015 was 3.3%.[416] However, there is a tendency in the EU to move away from food-based biofuels. Firstly, the contribution of food-based biofuels is capped at 7% as from the 2015 "iLUC Directive" (Directive (EU) 2015/1513).[64] The RED-II proposes a gradual reduction of the cap to 3.8% by 2030. Secondly, with stricter GHG emission reduction thresholds and iLUC factors for food-based biofuels (which are not yet included in the calculation of the GHG emission reduction), it becomes more challenging for food-based biofuels to meet the sustainability criteria for biofuels. Based on the typical GHG emission reductions listed in Annex V and VI of the RED-II proposal (without iLUC factors), the GHG emission reduction thresholds listed in the iLUC Directive and RED-II proposal restrict the construction of new edible oil-based and starch-based plants and the import of food-based biofuels from 2016 onwards (except sugarcane ethanol). Thirdly, food-based biofuels only contribute to the overall EU renewable energy target in the RED-II proposal (i.e. they do not contribute to a sub-target or overall transport target). As a result, food-based biofuels will need to compete with other forms of renewable energy.

Given the poor market outlook for food-based biofuels in the EU, we assumed the consumption of food-based biofuels to increase only marginally to 3.6% in 2021 (EU average). The model was not able to further increase this share, as we prohibited the construction of new edible oil-based and starch-based plants and the import of food-based biofuels from 2016 onwards, based on the imposed GHG emission reduction thresholds. Under this assumption, food-based biofuels can only be produced by existing capacity, new sugar beet-based ethanol capacity or the import of sugarcane ethanol.

As mentioned above, from 2021 onwards, food-based biofuels are only incentivized by the overall renewable energy target and need to compete with other forms of renewable energy. As RESolve-Biomass includes only bioenergy options, we could not model this competition explicitly. We therefore assumed that existing capacity retires after 20 years and lifetime extension of existing edible oil-based and starch-based plants is not competitive with other forms of renewable energy. On the other hand, we assumed that new sugar beet-based ethanol plants and imported sugarcane-based imports are sufficiently incentivized by the RED-II. Given the few options the model had left to produce food-based biofuels, only a gradual reduction from 3.6% in 2021 to 1.4% by 2030 gave a feasible model solution.

In sum, the constructed demand profile of food-based biofuels was based on the maximum share of food-based biofuels yielding a feasible model solution. The model solution was particularly restricted by:

- Assuming the typical GHG emission reductions listed in Annex V and VI is a proxy for system performance, which restricts construction of edible oil-based and starch-based plants;
- Assuming capacity retires after 20 years and lifetime extension is not competitive with other forms of renewable energy.

The first assumption neglects the fact that GHG emission savings depend on the method used and may deviate from actual emission reductions achieved by (future) technologies in different contexts. For example, some studies show starch-based ethanol and oil crop-based biodiesel are able to reach 70% GHG emission reduction.[24,63,291,439] However, various scholars have shown iLUC emissions associated with food-based biofuels (especially for oil-crop based biodiesel) impede achievement of the 70% GHG emission reduction threshold.[45,304,306] The second assumption highly depends on cost developments in renewable energy technologies.

Alleviating aforementioned restrictions would result in higher volumes of food-based biofuels, provided food-based biofuels are able to compete with other renewable energy sources. Moreover, the production of more food-based diesel substitutes may reduce the amount of food-based ethanol (provided it is cheaper than ethanol, and consequently reduce the need for (more expensive) drop-in alternatives (e.g. ATJ), which are currently introduced to breach the E10 blend wall.

S6.3 Biomass supply

S6.3.1 Biomass categorization

The biomass categorization used in the figures and tables of this paper is listed in the table below. The categorization is largely based on the categorization of Biomass Policies.[408] Tall oil was not included in the model. Instead, existing tall oil capacity in Sweden and Finland (10 PJ) was deducted from the overall advanced biofuel targets.[438]

TABLE 6-7: Biomass categorization.

Feedstock category		Feedstocks included
Import edible oils		Palm oil
Import food-based biofuel		Food-based biodiesel, bioethanol
Import lignocellulosic biofuel		Lignocellulosic ethanol
Import lignocellulosic biomass		Wood pellets
Import used fats and oils		Used fats and oils
Lignocellulosics	Energy crops	Miscanthus, perennials, reed canary grass, switchgrass
	Woody biomass	Landscape care wood, Other industrial wood residues, Paper cardboard, Post consumer wood, Primary forestry residues, Prunings and pits from olives, Prunings from fruit trees, Saw dust, Sawmill by-products,
	Other residues	Leaf and beet top from sugar beet, Stover from grain maize, Straw from cereals, Straw from rice, Stubbles from OSR and Rapeseed, Verge grass
Lignocellulosic biomass (fuelwood)		Additional harvestable stemwood, Current fuelwood production for bioenergy
Miscellaneous		Black liquor, Collected VFG, Organic waste from Industry
Oils and fats (Edible oils)		Rapeseed, Soy, Sunflower seed
Oils and fats (Used fats and oils)		Used fats and oils
Sugar and starch crops		Cereals, Forage Maize, Maize, Sugar beet
Waste (Manure and sludges)		Common sludges, Dry Manure, Wet manure
Waste (MSW and landfill)		Landfill and MSW

S6.3.2 Cost-supply curves

The cost for domestic biomass were obtained from Elbersen et al.[408], who established feedstock cost per type of biomass. Feedstock cost was based on market prices for biomass types which are already traded (e.g. straw, types of wood chips, fire wood) and road-side costs for feedstock for which the market is not yet developed (e.g. dedicated perennial crops for lignocellulosic and woody biomass). The future prices were presented in real price levels without applying an inflation correction. It was furthermore assumed that the costs decline by 10% between 2020 and 2030 because of technological learning and efficiency improvements.

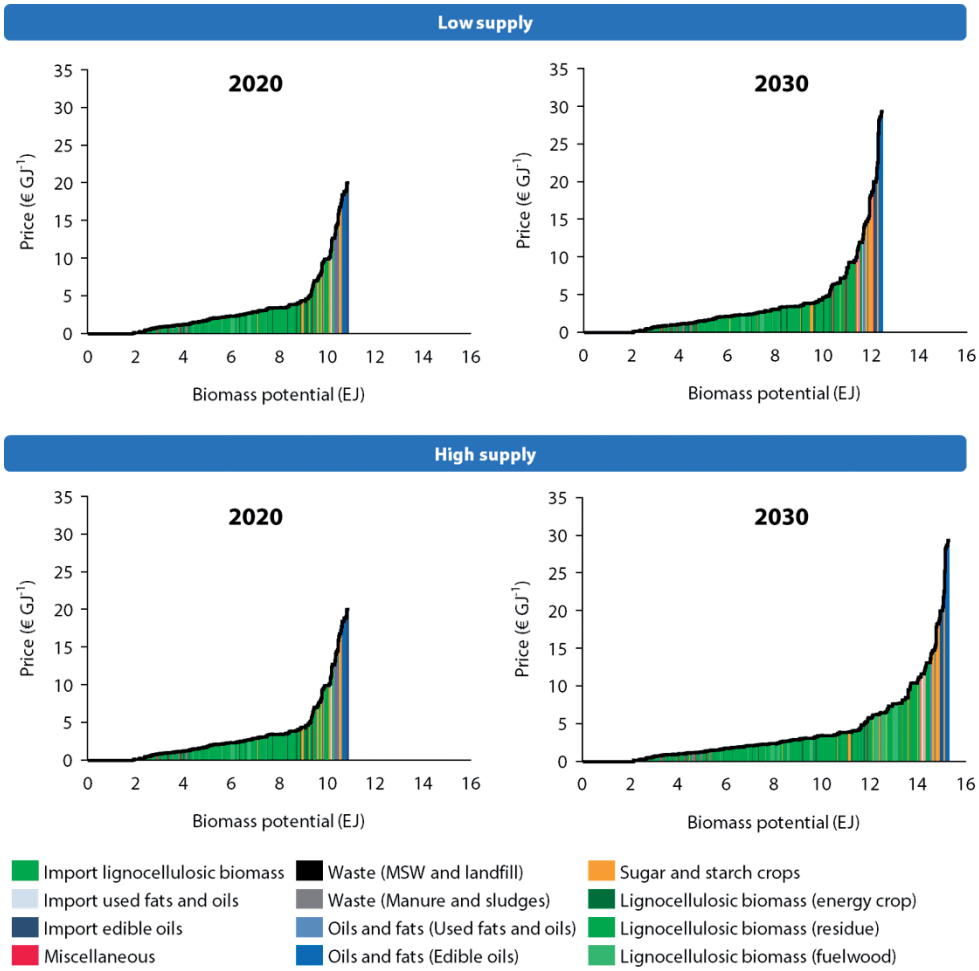


FIGURE 6-18: Cost-supply curves for domestic and imported feedstocks.[408–410]

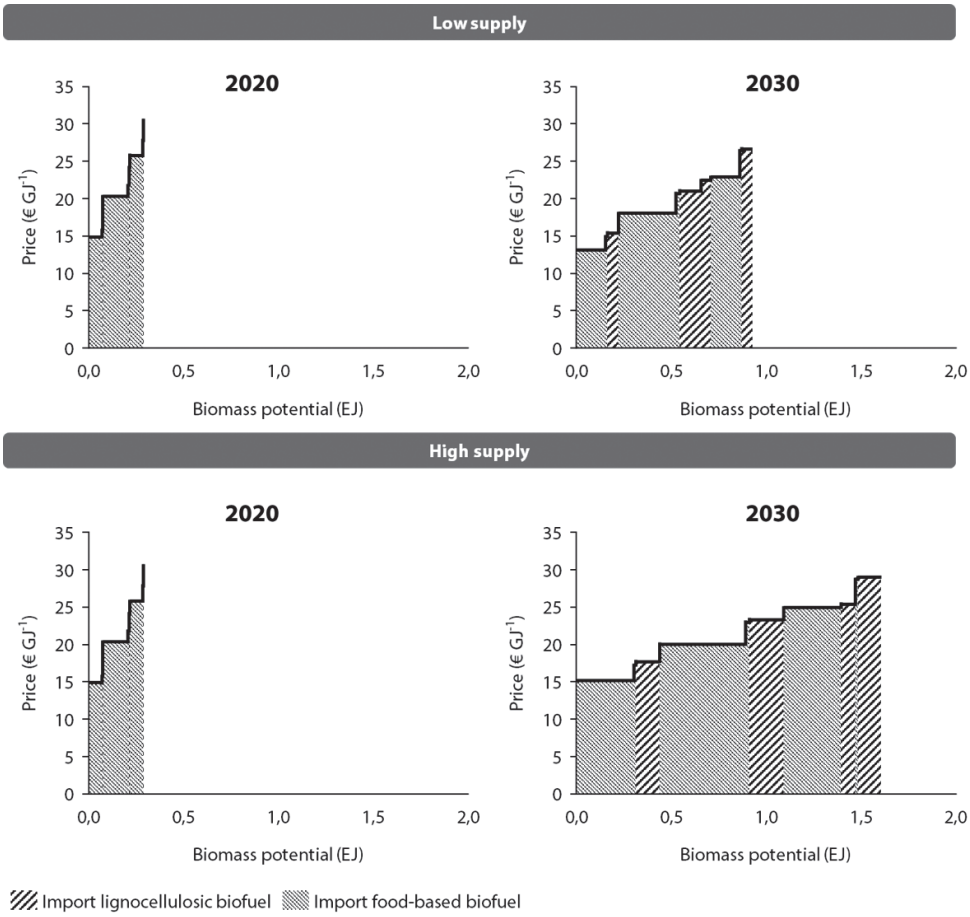


FIGURE 6-19: Cost-supply curves for imported biofuels.[410]

S6.3.3 Import products and regions

Imports were assumed to enter the EU market at the large harbors of Belgium, The Netherlands and Germany.

TABLE 6-8: Selected imported products from typical import regions

Product	Import region	Ref.
Used cooking oil	US, China, Indonesia (Argentina was excluded due to low potentials)	413
Food-based biodiesel	Argentina, Indonesia	410
Food-based ethanol	Brazil, Mozambique	410
Lignocellulosic ethanol	Brazil, Ukraine	410
Wood pellets	Russia (Northwest), US (Southeast), Canada (East), Brazil, Mozambique	410
Palm oil	Global (particularly southeast Asia)	411,412

S6.4 Technologies

S6.4.1 Non-biofuel technology scope

In RESolve-Biomass, bio-based heat and power can be generated from solid and liquid biomass (also pyrolysis oil) or biogas by co-firing with coal, dedicated boilers or combined heat and power systems. A distinction is made between household scale installations and small-, medium- and large-scale industrial applications. Lactic acid is co-produced with ethanol. Ethylene is produced from ethanol. Methanol, BTX, SNG and hydrogen are produced using gasification of biomass.

S6.4.2 Yield distribution

The table below presents the yields for the biofuel technologies, based on the sources listed in Table 6-1 of the main text.

TABLE 6-9: Yield distribution of selected technologies.

Technology	Feedstock	Main products[i]	Yield	RJF	D	G	HFO	EtOH	H & E	Other[ii]
			$GJ_{products}$ GJ_{feed}^{-1}							
Fatty Acid Methyl Ester (FAME)	Oils and fats	FAME, Gl	1.07		96-97%					3-4%
Fermentation	Sugar	EtOH	0.88					100%		
	Starch	EtOH	0.55					100%		
	Lignocellulosics	EtOH, H, E	0.39					64%	36%	
Hydrotreated Esters and Fatty Acids (HEFA)	Oils and fats	D, P, N	1.09		91%					9%
		D, HEFA-RJF, P, N	1.11	54%	26%					20%
Digestion and biogas upgrading	Manure and sludges, landfill gas, and organic waste	B	0.57-0.60							100%
Biogas liquefaction	Biogas from manure, sludges and landfill	LNG	0.92							100%
Fischer-Tropsch (FT)	Lignocellulosics	D, E, N	0.45		67%				12%	20%
		D, E, N, FT-RJF	0.45	17%	51%				12%	20%
		DME, H, E	0.55						9%	91%
Alcohol-to-Jet (ATJ)	Lignocellulosic ethanol	G, ATJ-RJF	0.89	75%	9%	16%				
Hydrothermal liquefaction (HTL)	Woody biomass	D, G, HFO	0.56		38%	48%	14%			
		D, G, HFO, HTL-RJF	0.56	30%	8%	48%	14%			
Pyrolysis	Woody biomass	D, G, HFO	0.50		29%	58%	14%			
		D, G, HFO, Pyrolysis-RJF	0.50	7%	22%	58%	14%			

i. B=Biogas, D=Renewable diesel, DME=Renewable Dimethyl Ether, E=Renewable electricity, EtOH=bioethanol, FAME=FAME biodiesel, G=Renewable gasoline, Gl=Glycerine, H=Heat, HFO=Renewable heavy fuel oil, LNG= Renewable Liquefied natural gas, N=Renewable Naphtha, P=Renewable propane, and RJF=Renewable jet fuel.

ii. Other includes biogas, bioLNG, DME, naphtha, LPG, and glycerin.

S6.4.3 Greenhouse gas emission performance

TABLE 6-10: Greenhouse gas emission performance of selected technologies.

Product	Feedstock	Fossil fuel comparator	GHG emission saving with respect to fossil fuel comparator		Proxy system	Ref.
			Without iLUC	With iLUC (mean value)		
		g CO_2-eq MJ^{-1}	g CO_2-eq MJ^{-1}	g CO_2-eq MJ^{-1}		
ATJ diesel	Lignocellulosics	94	73%	73%	Corn stover ATJ	232,440
ATJ gasoline	Lignocellulosics	94	73%	73%		
ATJ jet fuel	Lignocellulosics	94	73%	73%		
FT DME	Lignocellulosics	94	93%	93%	Average of waste and farmed wood	290
FT diesel	Lignocellulosics	94	93%	93%		
FT jet fuel	Lignocellulosics	94	93%	93%		
FT HFO	Lignocellulosics	94	93%	93%		
LNG[i]	Forage maize, organic waste from Industry, verge grass	76	60%	60%	Biowaste, close digestate, no off-gas combustion	290
LNG[i]	Manure	76	77%	77%	Manure-Maize 30-70% close digestate, no off-gas combustion.	441
LNG[i]	VFG	76	60%	60%	Biowaste, close digestate, no off-gas combustion	290
LNG[i]	Sludges	76	163%	163%	Manure, open digestate	290
LNG[i]	Landfill gas	76	79%	79%	Municipal waste	290
Biogas	Forage maize Organic waste from Industry Verge grass	56	50%	50%	Biowaste, close digestate, no off-gas combustion	290
Biogas	Manure	56	72%	72%	Manure-Maize 30-70% close digestate, no off-gas combustion.	441
Biogas	VFG	56	50%	50%	Biowaste, close digestate, no off-gas combustion	290
Biogas	Sludges	56	179%	179%	Manure, open digestate	290

Biogas	Landfill gas	56	74%	74%	Municipal waste	290
HEFA diesel	Used fats/oils	94	77%	77%	Average of used cooking oil and tallow	290
HEFA jet fuel	Used fats/oils	94	77%	77%		
HTL diesel	Lignocellulosics	94	81%	81%	In-situ hydrogen generation	232
HTL gasoline	Lignocellulosics	94	81%	81%		
HTL jet fuel	Lignocellulosics	94	81%	81%		
Pyrolysis diesel	Lignocellulosics	94	77%	77%	In-situ hydrogen generation	232
Pyrolysis gasoline	Lignocellulosics	94	77%	77%		
Pyrolysis HFO	Lignocellulosics	94	77%	77%		
Pyrolysis jet fuel	Lignocellulosics	94	77%	77%		
Lignocellulosics-based Ethanol	Agricultural residues	94	90%	90%	Wheat straw	290
Lignocellulosics-based Ethanol	Wood-based	94	78%	78%	Average of waste and farmed wood	290

i. The biogas emission factors, corrected for the yield loss (8%), were used to calculate the emission factors for LNG.

S6.5 Transport segments and blend walls

TABLE 6-11: Baseline constraints on biofuel usage in road, marine and aviation.

Product	Maximum blending percentage by volume	Applicable to transport segment
Road (busses, cars & trucks)		
Renewable diesel	100% (all modes)	Diesel cars only, busses and trucks
FAME biodiesel[i]	7% (all modes)	Diesel cars only, busses and trucks
Renewable gasoline	100% (all modes)	Gasoline cars only
Bioethanol[i]	10% (cars)	Gasoline cars only
Biogas	30% (cars)[ii]	CSNG cars
Renewable DME	100% (trucks, cars, busses)	Diesel cars only, busses and trucks
Marine		
Renewable Diesel	100%	All ships
FAME biodiesel	7%	All ships
Renewable heavy fuel oil	100%	HFO ships
Renewable LNG	100%	LNG ships
Aviation[iii]		
HEFA-RJF	50%	All aviation
FT-RJF	50%	All aviation
HTL-RJF	30%	All aviation
Pyrolysis-RJF	30%	All aviation
ATJ-RJF	50%	All aviation

i. In the baseline the use of biodiesel and ethanol at higher blending levels was excluded (B30, B100 and E85), based on the limited market introduction of these high-blend fuels[442] and flex-fuel vehicle sales[443] in the EU.

ii. Except Sweden, where 100% is allowed.

iii. The blend level RJF is specific to the type of RJF and incorporated in the ASTM specification of the respective RJF type. No specification exists yet for HTL-RJF, Pyrolysis-RJF and ethanol-based ATJ-RJF. The maximum blend levels were therefore estimated based on expected blend levels.

S6.6 Price projections of fossil products

Figure 6-20 shows the price projections of fossil fuels, chemicals and CO_2. The projections of crude oil, natural gas, coal and CO_2 were obtained from the PRIMES reference 2016 scenario.[415] The range in fossil fuel prices in Schoots & Hammingh[444] was applied to the Primes reference 2016 prices. The projections of jet fuel, diesel, naphtha, gasoline, propane and heavy fuel oil (HFO) were established relative to the oil price based on the average ratio (on energy basis and without taxes and duties) in 2007-2017 (Table 6-9).[445–450] In some cases, time series of US prices were used as European time series were not publicly available. The price of LNG was calculated by adding the same liquefaction cost for bio-LNG to the price of natural gas. The marine gas oil

(MGO) price was coupled to the HFO price by a factor 1.6.[451] The price of chemicals was coupled to the oil price or natural gas price (in case of hydrogen) as was done in S2Biom.[407] The electricity price was projected using the electricity market model COMPETES.[407,432]

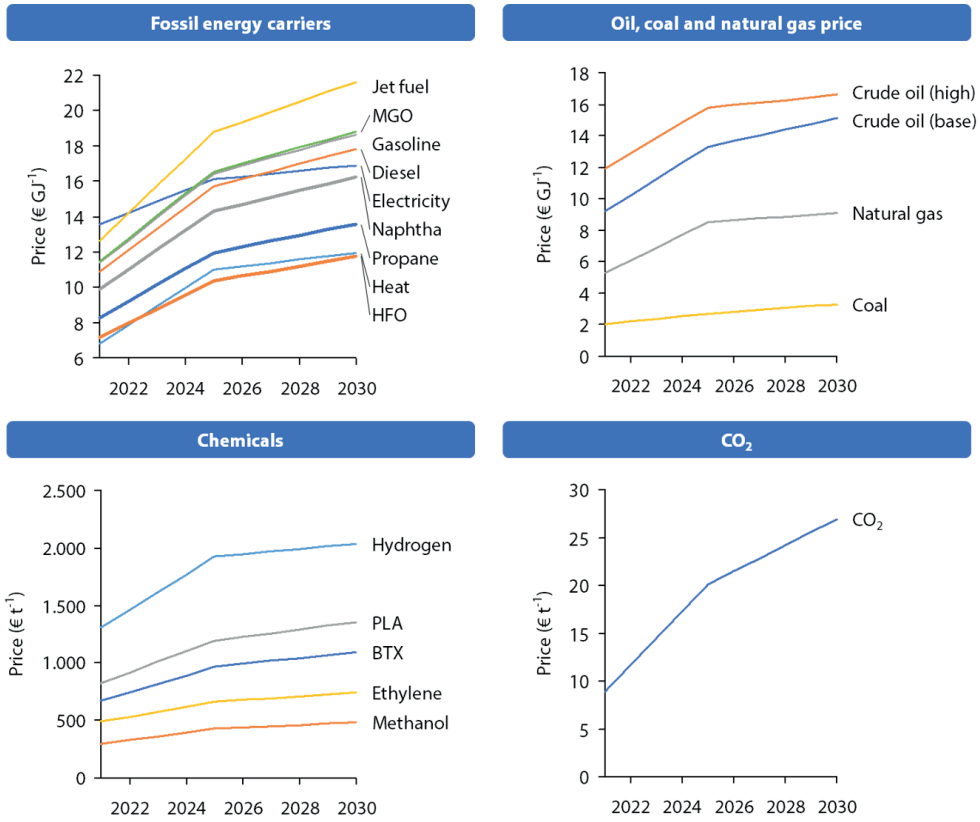


FIGURE 6-20: Price projections of reference fossil resource-based products and CO_2.

TABLE 6-12: Assumed price ratios of fossil products relative to crude oil (on energy basis, € GJ^{-1} product per € GJ^{-1} oil).

	Jet fuel	Gasoline	Diesel	Naphtha	HFO	Propane
10-year ratio	1.08	0.78	0.90	1.30	1.24	1.18
2-year ratio	1.10	0.78	0.81	1.29	1.37	1.31

7

Synthesis of the main findings

7.1 On the production costs of renewable jet fuel

The production costs of RJF were assessed based on the following research question:

> *What are the production costs of renewable jet fuels compared to fossil jet fuel in the short (2020) and medium term (2030)?*

The findings of the previous chapters with relation to this research question will be discussed in the following sections.

RJFs likely remain more expensive than fossil jet fuel in the short and medium term

Chapter 2 quantifies the minimum fuel selling price (MFSP) of different feedstock-technology combinations (Figure 7-1). The MFSP reflects the price at which RJF needs to be sold to achieve a zero net present value. As the technology maturity level varies between the assessed technologies (and hence also the timing of the construction of the nth plant), the analysis used the Pioneer Plant method to estimate the production costs for a first-of-a-kind ('pioneer') plant. This method, developed by RAND corporation, employs two equations to describe the cost growth and the plant performance of a pioneer plant relative to an nth plant as a function of nine process features (e.g. the number of commercially unproven process areas).

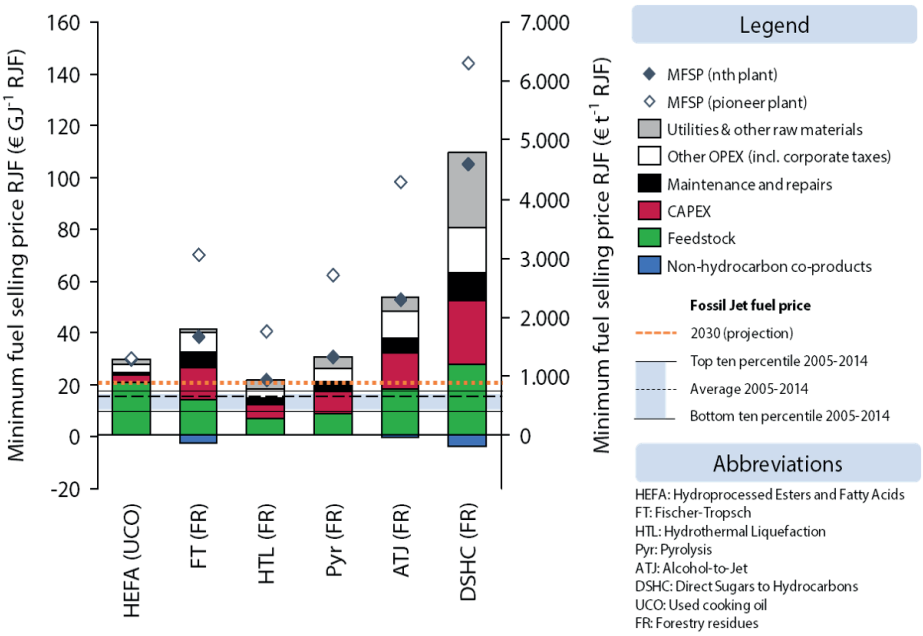


FIGURE 7-1: The minimum fuel selling price of various RJF conversion pathways for n^{th} and pioneer plants (Chapter 2). The fossil jet fuel price projection for 2030 was aligned with Chapter 6.

Figure 7-1 shows that none of the pathways assessed (pioneer and n^{th} plant) can produce RJF below historic or future (2030) fossil jet fuel prices. The MFSP of the current benchmark for RJF, the HEFA technology based on used cooking oil (UCO), was quantified at 30.3 and 29.3 € GJ^{-1} for a pioneer and n^{th} plant, respectively. The production costs of HEFA are highly dependent on feedstock prices, as feedstock costs represent 70% of the overall MFSP. Although HTL and pyrolysis are relatively immature technologies, they provide promising alternatives for HEFA; both technologies yield higher MFSPs for a pioneer plant (40.9 € GJ^{-1} and 63.3 € GJ^{-1}), but show lower or similar MFSP for n^{th} plants (21.8 € GJ^{-1} and 30.9 € GJ^{-1}). The low MFSP for HTL and pyrolysis is caused by relatively high conversion efficiencies and modest capital investment. The FT pathway yields a moderate MFSP due to high capital investments. Biochemical pathways (i.e. ATJ and DSHC) show relatively high MFSPs, because of lower conversion efficiencies and high capital investment associated with lignocellulosic sugar extraction and fermentation. The uncertainty in feedstock prices, capital investment and conversion efficiencies lead to considerable ranges, especially for immature technologies for which assumptions could not yet be validated with commercial plant data (e.g. HTL, pyrolysis, FT, ATJ, DSHC). Nonetheless, the sensitivity analysis and literature survey conducted in Chapter 2 confirm that n^{th} plant MFSPs of HEFA, HTL and pyrolysis are found on the lower end of the cost spectrum.

Supply chain optimization can reduce production costs of RJFs

Besides the selection of the feedstock and conversion pathway, the production costs of RJF are also affected by supply chain design and production location. Chapter 2 estimates cost reductions associated with two co-production strategies: co-location and retro-fitting. Co-location involves installing a separate entity adjacent to an existing facility. Retro-fitting installs a 'bolt-on' unit to the existing facility such that by-products can be used for alternative purposes. In Chapter 2, a generalized inventory of co-production benefits was developed, including reductions in labor costs (work force may be shared), feedstock costs (feedstock may already be available on-site), local taxes and capital expenditure (as land and facilities may be shared). The analysis shows that a retro-fitting strategy with pulp mills based on black liquor gasification reduces the MFSP of FT RJF by 20% for n^{th} plants and 15% for pioneer plants. Co-location strategies with pulp mills, beet sugar mills and wheat ethanol facilities across the EU were shown to reduce the MFSP of RJF by 4-8% for n^{th} plants and 5-8% for pioneer plants. The analysis also shows wide RJF MFSP ranges exist within the EU; RJF production Eastern Europe and Portugal reduces RJF MFSPs by 28%, while production in Scandinavia increases RJF MFSPs by 39% (compared to the EU average). The observed differences were largely caused by variation in feedstock prices and labor costs.

Chapter 3 employs a cost optimization model to analyze the impact of and interrelation between four cost reduction strategies for biofuel production: economies of scale, intermodal transport networks, co-location with existing industries, and distributed supply chain configurations (i.e. supply chains with an intermediate pre-treatment step to reduce biomass transport cost). The investigated system produces middle-distillate biofuels (including RJF) from forestry biomass using HTL, in the context of the existing Swedish forest industry. Simultaneous implementation of all cost reduction strategies yielded minimum biofuel production costs of 18.1 € GJ^{-1} for HTL RJF, which is lower than the projected fossil jet fuel price for 2030 (Figure 7-1). Minimum production costs were achieved around production scales of 15 PJ yr^{-1} fuel output (17.9 PJ yr^{-1} feedstock input). The cost increase sharply for lower production scales (by 39% for 1 PJ yr^{-1} fuel output), but rise modestly for higher production scales as biomass transport distances increase (<0.2% for 50 PJ yr^{-1} fuel output). Disabling co-location benefits with pulp mills, sawmills, district heating systems and refineries increased production costs by up to 10%. Restricting train and sea transport increased production costs by up to 6%. Distributed supply chain configurations were introduced once biomass supply became increasingly dispersed, but did not provide a significant cost benefit (<1%). Co-location benefits were found to favor large-scale centralized production, while intermodal transport networks positively affect the benefits of economies of scale.

Decreasing production costs and an increasing oil price could bring price parity with fossil jet fuel within reach by 2030

Chapter 6 uses a European bioenergy model, RESolve-Biomass, to quantify the role of RJF under the proposed EU Renewable Energy Directive II (RED-II) in 2021-2030. RESolve-Biomass optimizes the feedstock-technology portfolio (based on total system cost) to fulfill a certain demand for bio-based products. The model incorporates technology maturity, technological learning and competing demand for biomass from other bio-based power, heat, chemicals and transport fuels (road, marine and aviation). The uncertainty regarding the biomass supply potential and competing demand for biomass was captured in a high/low biomass supply scenario (HS/LS), combined with a high/low biomass demand scenario (HD/LD) (see also section 7.3). The set-up of the model allows the user to track the marginal production costs of RJFs in the various scenarios over time (Figure 7-2).

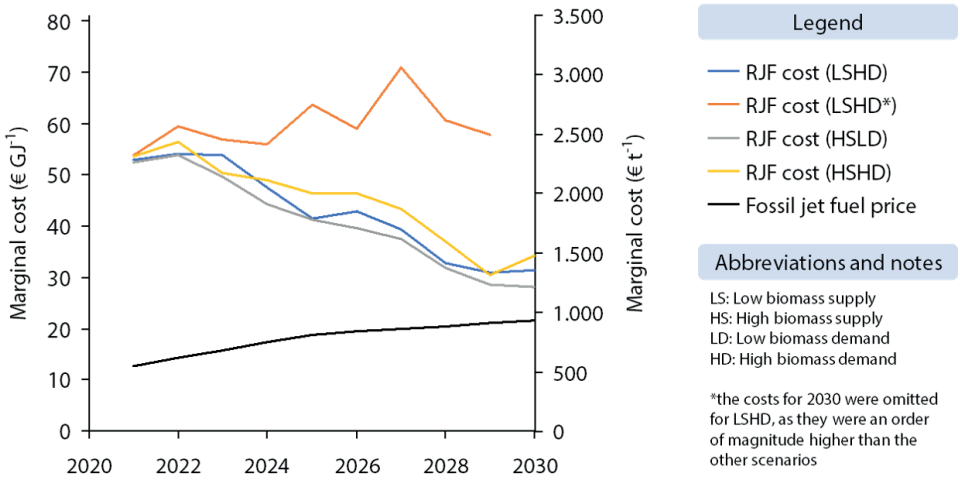


FIGURE 7-2: The development of the marginal costs of RJF and the fossil jet fuel price over time in RESolve-Biomass (Chapter 6).

Figure 7-2 confirms the results of Chapter 2; RJF production costs remain higher than fossil jet fuel, although production costs can reduce over time. In all scenarios except *LSHD*, the cost differential between RJF and fossil jet fuel decreases from roughly 40 € GJ^{-1} in 2021 to 7-13 € GJ^{-1} by 2030. This drop relies on three factors: increasing oil prices, the introduction of new technologies and technological learning, and the availability of sufficient biomass. In these projections, fossil jet fuel prices increase by 9 € GJ^{-1} during 2021-2030, under the assumption that oil demand in developing countries grows, while production stabilizes outside the Organisation of Petroleum Exporting Countries.[415] Production costs fall due to the availability of novel technologies, cheaper feedstocks and technological learning. The drop in production costs is a direct result of the assumed regulatory context (the RED-II proposal), which contains dedicated stimuli for RJF (enabling learning) and biofuel technologies based on lignocellosic biomass (broadening the feedstock base and enabling learning). Learning effects are mainly driven by scale-dependent learning and reduce conversion costs for HTL, FT, ATJ and pyrolysis by 21-28% over the period 2021-2030. Increased biomass supply in the *HS* scenarios broadens the feedstock base, reduces competition effects and helps to contain system costs. The *HD* scenarios show slightly larger cost reductions induced by market-driven learning (due to higher capacity deployment), but also demonstrate higher feedstock costs due to increased competition for biomass. The fierce competition for biomass in the *LSHD* scenario neutralizes all cost reductions from technological learning.

7.2 On the climate impact of renewable jet fuel

The climate impact of RJF was assessed based on the following research question:

> *What is the climate impact from CO_2, CH_4 and N_2O emissions of renewable jet fuel production systems compared to fossil jet fuel and how can it be improved?*

The findings of the previous chapters with relation to this research question will be discussed in the following sections.

RJF comes in different shades of green

Chapter 4 quantifies the well-to-wake life-cycle greenhouse gas (GHG) emissions of RJF conversion pathways in a US context. The analysis did not include land use change (LUC) emissions. The life-cycle GHG emissions were compared to the average emission intensity for fossil jet fuel in the US (87.5 gCO_2-eq MJ^{-1}) and the -50% and -60% GHG emission reduction threshold used in the US Renewable Fuel Standard (RFS2) for advanced biofuels (including biofuels produced from all feedstocks except corn starch) and lignocellulosic biomass-based biofuels.[65] The proposed thresholds in the EU Renewable Energy Directive (RED-II) proposal, inserted for comparison, require a GHG reduction of -60% and -70% for installations commencing production from 2015 and 2021 onwards, relative to a fossil fuel comparator of 94 g CO_2-eq MJ^{-1}.[68]

Figure 7-3 shows that the life-cycle GHG emissions of the investigated pathways range between 6 g CO_2-eq MJ^{-1} for FT based on forestry residues and 72 g CO_2-eq MJ^{-1} for sugarcane-based DSHC producing a RJF which can be blended at higher levels than the conventional DSHC RJF (using additional hydrogen). The current benchmark for RJF, the UCO-based HEFA RJF, yields a GHG emission reduction of 69% compared fossil jet fuel (US average). The majority of pathways comply with the most stringent emission reduction thresholds of the US RFS2 and the proposed EU RED-II. Pathways based on food crops generally show higher GHG emissions than pathways based on residues and lignocellulosic crops, because of high emissions related to fertilizer use. Furthermore, hydrogen (produced from natural gas) is often a major contributor to the life-cycle GHG emissions of RJFs, especially for pyrolysis and HTL (using ex-situ hydrogen generation), HEFA, and DSHC. FT shows low GHG emissions as the process does not require external hydrogen and produces excess electricity. DSHC shows the highest GHG footprint due to a relatively low conversion efficiency and high hydrogen consumption.

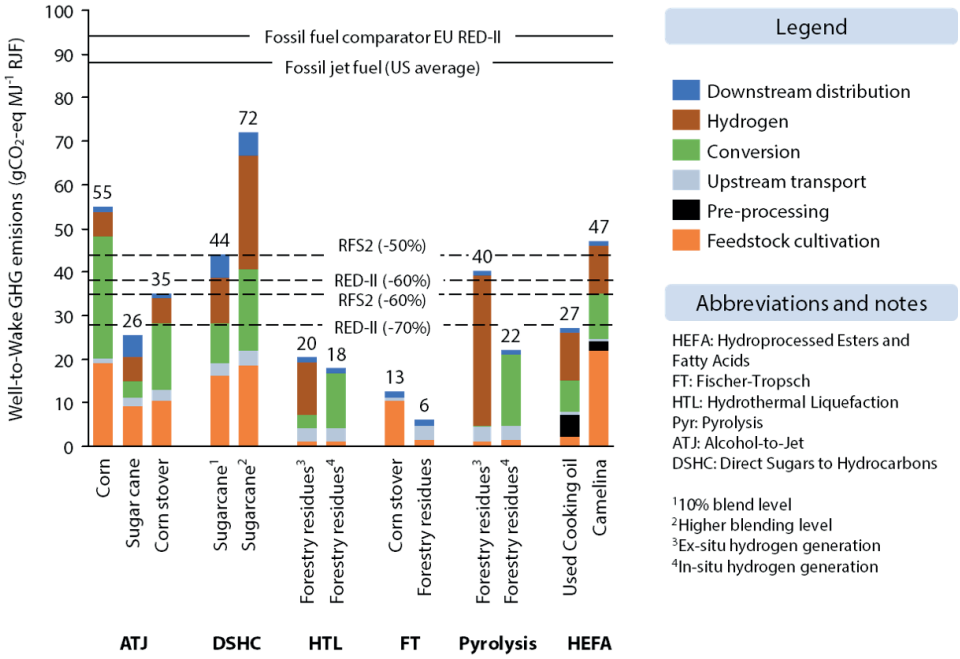


FIGURE 7-3: Life-cycle greenhouse gas performance of various RJF conversion pathways using energy allocation (Chapter 4).

The production context can make or break the climate change mitigation value of RJF

The impact of LUC emissions, carbon debt and foregone sequestration[t] on the overall climate impact of RJF can be significant, and may in some cases exceed the impact of life-cycle emissions. These effects are generally time- and context-dependent. The Relative Climate Impact (RCI) performance indicator was introduced in Chapter 5 to capture the full range of emissions associated with RJF production. The RCI quantifies the net climate impact of a production system over time relative to a fossil baseline, i.e. an RCI of -0.5 indicates a 50% climate impact reduction relative to a fossil baseline. The RCI formulation offers the flexibility to analyze and compare system performance for different analytical time horizons (TH_A) and climate impact categories (e.g. cumulative GHG emissions, radiative forcing and temperature change). A collateral benefit of the RCI formulation is that it is relatively robust to uncertainties associated with modeling radiative forcing and temperature change.[37,56] The RCI was used to show how the production context can alter the climate impact of a feedstock-technology combination.

t Foregone sequestration entails the future sequestration that would have occurred in the intended biomass production area if no bioenergy was produced.

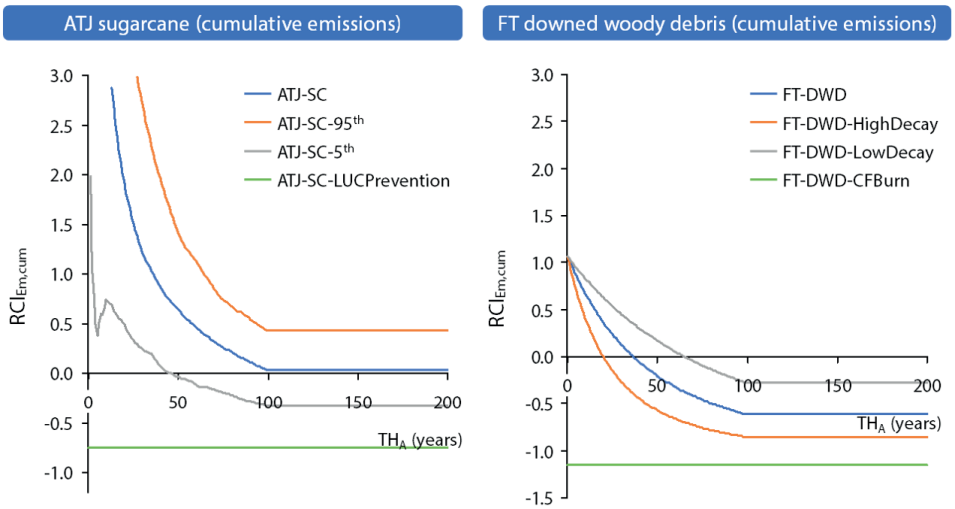


FIGURE 7-4: The relative climate impact of the ATJ sugarcane and FT downed woody debris pathway, for varying system contexts (Chapter 5).

Figure 7-4 shows the RCI for cumulative emissions ($RCI_{Em,cum}$) for two stylized conversion pathways producing RJF: the ATJ-sugarcane (ATJ-SC) and FT-downed woody debris (FT-DWD) systems. The feedstock-technology combinations used in these systems are equal to the ATJ (sugarcane) and FT (forestry residues) discussed in the previous section (Figure 7-3), but the scope of emission fluxes and the production context is different. The ATJ-SC, ATJ-SC-95th and ATJ-SC-5th systems assume sugarcane production on Brazilian cerrado soils with mean, high and low carbon stocks, respectively. As the conversion of these soils instigates varying quantities of LUC emissions, a profound difference exists between sugarcane production on low-carbon or high-carbon cerrado. The cumulative emissions of the ATJ-SC-5th are 4% and 33% lower than the fossil baseline after 50 and 100 years, while the cumulative emissions of the ATJ-SC-95th system are 142% and 43% higher after 50 and 100 years. In the ATJ-SC-LUCPrevention system, sugarcane cultivation for bioenergy purposes is accompanied by measures to increase agricultural yields, such that sugarcane is produced on existing agricultural land and LUC emissions are prevented. RJF produced in this context reduces cumulative emissions by 75% from the onset of production.

The FT-DWD system represents a production context in which downed woody debris (DWD) is extracted from the forest to produce biofuels. In the counterfactual scenario (i.e. a scenario in which no bioenergy is produced) the DWD was left to decay. The production and combustion of biofuels immediately releases the carbon stored in the DWD, which causes a carbon debt relative to the counterfactual scenario in which carbon

is slowly released during the decay of the DWD. The FT-DWD, FT-DWD-HighDecay, FT-DWD-LowDecay systems use DWD from tree species with moderate, high and low decay rates. These systems create a different amount of carbon debt, as shown by the spread in $RCI_{Em,cum}$, which varies between -0.57 and 0.17 at TH_A=50 years and -0.85 and -0.28 at TH_A=100 years. The FT-DWD-CFBurn system describes a production context in which the DWD would be burnt in the forest if it were not converted to biofuels (e.g. to prevent forest fires), which does not lead to a carbon debt because the carbon is also released immediately. This production context shows a 116% reduction in cumulative emissions.

These examples intend to illustrate that the climate impact of RJF does not depend solely on its life-cycle emissions, but also on the (feedstock) production context as some contexts can avoid or cause LUC emissions, carbon debt or foregone sequestration. A site-specific inventory of all emission fluxes related to a production context is encouraged to aid the selection of conversion pathways and production contexts which consistently show a climate benefit, such as the ATJ-SC-LUCPrevention and FT-DWD-CFBurn systems. The following section also discusses means to actively shape the right production context for RJF production.

The climate impact of RJF can be reduced by improving conversion pathways and shaping the right production context

Chapter 4 shows that the use of hydrogen produced from biomass or by electrolysis using renewable electricity can reduce the life-cycle GHG emissions. This particularly applies to hydrogen-intensive pathways such as pyrolysis (ex-situ hydrogen generation) (-71%), HTL (ex-situ hydrogen generation) (-48%), DSHC (-20%/-30%) and UCO-based HEFA (-34%). The application of carbon capture and storage (CCS) can achieve even higher life-cycle emissions reductions for some technologies; in Chapter 5 it is calculated that CCS reduces life-cycle emissions of FT and ATJ RJF by 108 and 27 gCO_2 MJ^{-1}, which means that RJF production with CCS can yield net negative GHG emissions. Improving feedstock yields and conversion efficiencies can mitigate the contribution of LUC emissions, carbon debt and foregone sequestration. Moreover, the net GHG emission reduction achieved by RJF will grow with increasing emission intensity of fossil jet fuel, driven by the trend towards the utilization of more heavy and sour (high sulfur) crude oil types.[42,328]

The risk of LUC emissions, carbon debt or foregone sequestration can be (partially) mitigated by shaping the right production context. Direct LUC emissions can be avoided by using feedstocks which do not require land (e.g. residues or CO_2) or can be reduced by producing bioenergy feedstocks on low carbon stock soils. For example, the UCO-

based HEFA system investigated in Chapter 5 produces RJF, which reduces all climate impact categories by 77%. The risk of indirect LUC emissions and carbon debt can be mitigated by supplementing bioenergy production with efforts to optimize land/forest management, improve agricultural yields, increase supply chain efficiencies, and integrate bioenergy, food and feed production.[304,380–384] The Shared Socio-economic Pathways 1 (SSP 1) scenario represents such a storyline, in which increased land use for biomass production increases is supplemented with a reduction in land use for food production caused by agricultural yield improvements, changing food consumption patterns and low population growth.[385] Furthermore, production contexts in which the counterfactual scenario yields immediate or additional climate impacts can yield low RCI values (e.g. the FT-DWD-CFBurn system).

Value judgments in environmental (and techno-economic) analysis are inevitable and may affect the results

An inter-study comparison of the environmental and techno-economic performance of conversion pathways is a delicate exercise, due to diverging methods, input data, and temporal and geographical scope. To facilitate a fair comparison between RJF pathways, Chapter 2 and 4 assess the techno-economic and environmental performance using a harmonized method and quantify the impact of input data variability in sensitivity analyses. However, value judgments regarding the selected allocation method and performance indicator remain inevitable and can affect the observed performance of RJF production systems and their relative merit order.

As most technologies produce RJF as part of a product slate, some form of allocation is required to distribute the environmental and economic burden among RJF and its co-products. The burden can be allocated according to their energy, mass and economic value. Alternatively, system expansion (the displacement method) awards a credit to co-products based on the yield of the co-product and its GHG emission intensity or market price. There is no scientific consensus on the most appropriate allocation method for bioenergy LCAs, as each procedure has benefits and drawbacks. Chapter 4 shows that the allocation procedure affects the absolute and relative GHG emission reduction of production systems, particularly those producing large quantities of co-products. For example, the WtWa GHG emissions of FT and corn stover-based ATJ pathways shown in Figure 7-3 fall by 9 and 13 g CO_2-eq MJ^{-1} when allocating the co-produced electricity using the displacement method. This implies the former pathway yields negative well-to-wake GHG emissions and the latter meets a more stringent emission reduction threshold.

The appropriateness of an allocation method varies with the assessment context. For example, in an international regulatory context (e.g. quantifying the emission reductions from RJF in CORSIA), Chapter 4 recommends using energy and economic allocation (for non-energy co-products), as it leverages the universal character of energy allocation while adequately valuing non-energy co-products. For the economic analysis in Chapter 2, economic allocation was selected for fuel co-products (e.g. diesel), as it is more robust than system expansion to variability in the share of RJF in the overall product slate.[49] System expansion would have imposed an excessive burden on the price of RJF, as it generally uses market prices for co-products which tend to be (much) lower than the price calculated using other allocation procedures.

Furthermore, RJF production systems demonstrate different emission profiles in terms of emissions timing and species. Chapter 5 shows that the choice of impact category and analytical time horizon, which are essentially value judgments, can significantly affect the absolute and relative performance of RJF production systems, because it alters the importance of one-time versus sustained emission fluxes and short- versus long-lived climate forcers. Systems associated with LUC emissions show a high emission flux initially (e.g. ATJ-SC), while systems associated with foregone sequestration or carbon debt generally exhibit a more constant emission profile over time (e.g. FT-DWD) (Figure 7-4). Similarly, crop-based systems often have a larger contribution of short-lived GHG species (CH_4 and N_2O) than systems based on residues due to higher fertilizer use. The evaluation of systems using short analytical time horizons would hence benefit systems associated with carbon debt relative to systems associated with LUC emissions. Similarly, Chapter 5 shows that instantaneous and rapidly responding impact categories (i.e. instantaneous radiative forcing) apply less weighting to large initial emission fluxes associated with LUC, compared to cumulative and slowly responding impact categories (e.g. cumulative temperature change). The climate impact of (bioenergy) systems should thus ideally be compared using different impact categories and time horizons, which are chosen based on the research or policy objectives, especially when the comparison involves systems with time-dependent emission profiles.

7.3 On the future supply of renewable jet fuel

The future supply of RJF within the EU was assessed based on the following research question:

> *What is the contribution of renewable jet fuel to reducing aviation-related greenhouse gas emissions in the European Union towards 2030 and how is its contribution affected by policy incentives, technological progress, biomass supply and competing biomass demand?*

The findings discussed in this section largely draw upon Chapter 6, which uses a cost optimization model (RESolve-Biomass) to project RJF consumption in the EU, based on the anticipated regulatory context in the EU, the availability of biomass and conversion technologies, and competition for biomass from other bio-based sectors. The study evaluated four base scenarios combining a high/low biomass supply scenario (HS/LS) and high/low biomass demand scenario (HD/LD). The high biomass supply scenario assumes more support to mobilize intra-EU biomass and potentials of imported biomass, particularly of UCO. The high biomass demand scenario assumes increased use of biomass in the heat, electricity, and chemicals sector. It also assumes lower use of renewable electricity in road transport, which implies a larger share of the renewable fuel target needs to be covered by biofuels. Food-based RJFs were excluded from the model scope, corresponding with the sustainability commitment of the airline members of SAFUG. Import of RJF to the EU was also excluded from the model scope.

RJF consumption could increase to 165-261 PJ (3.8-6.1Mt) in the EU by 2030

The biomass supply-demand scenarios project that RJF consumption in the EU increases from 1 PJ in 2021 to 165-261 PJ (3.8-6.1 Mt) by 2030 (Figure 7-5). This represents 6-9% of total jet fuel consumption at EU airports and 24-33% of total biofuel consumption in the EU by 2030. These results highly depend on the presence of biofuel targets and a multiplier mechanism for RJF as embedded in the RED-II proposal[68] and a the commercialization of technologies able to unlock cheaper and more abundant supplies of lignocellulosic biomass, such as ATJ, FT, HTL and pyrolysis. These technologies were assumed to be commercially available by 2020, 2020, 2023 and 2025, respectively, based on their Fuel Readiness Level (Figure 1-4).

By 2030, 109-213 PJ yr^{-1} (2.5-4.9 Mt yr^{-1}) RJF is produced from lignocellulosic biomass using technologies which are currently not yet commercialized. RJF based on lignocellulosic biomass is initially produced using FT and ATJ technologies driven by sub-targets for advanced biofuels, while pyrolysis and HTL are added to the technology portfolio upon commercialization. The introduction of new technologies is essential to increase RJF volumes, because the potential of HEFA is constrained by the supply of sustainable oils and fats. Furthermore, the growth of HEFA RJF volumes occurs mainly at the expense of the supply of HEFA diesel to road transport.

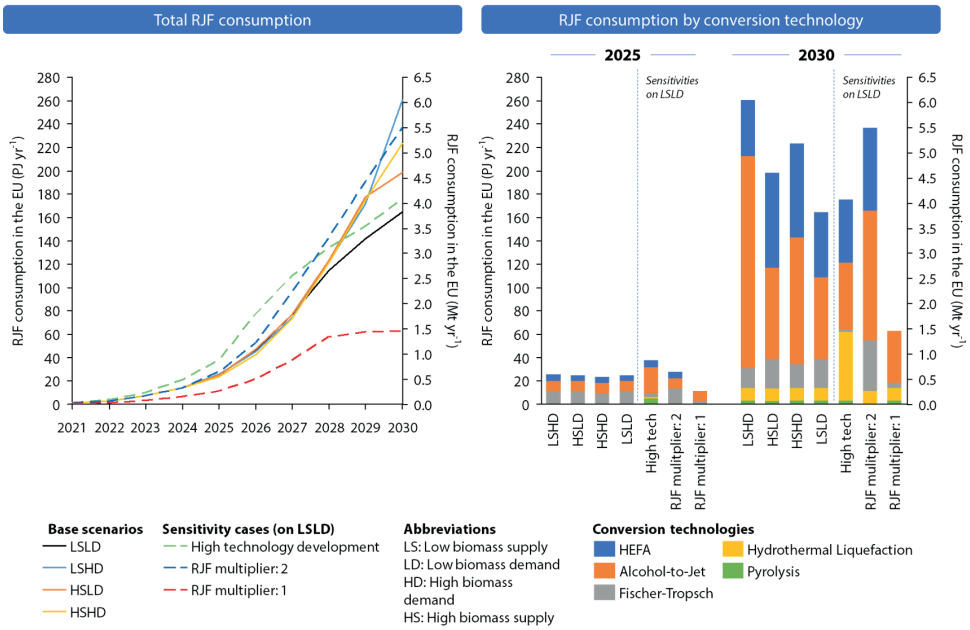


FIGURE 7-5: Projected RJF consumption in the EU for 2021-2030, total volumes and disaggregated by conversion technology (Chapter 6).

The supply of and demand for biomass affects overall RJF volumes and system costs (see next section). RJF volumes are positively affected by high supply of UCO and animal fats (*HSLD* and *HSLD*) and high demand for advanced biofuels, of which RJF is often a co-product (*LSHD* and *HSHD*). Total biomass use increases from 5.4 EJ in 2021 to 5.6 EJ in *LD* scenarios and 6.9-7.3 EJ in *HD* scenarios by 2030. RJF is mainly produced from UCO and animal fats, agricultural residues (e.g., straw from cereals and corn stover), and forestry residues (i.e. black liquor, sawmill by-products, primary forest residues, industrial wood residues and landscape care wood).

When the multiplier is removed (*RJF multiplier: 1*), projected RJF consumption for 2030 drops to 62 PJ yr^{-1}. Furthermore, the production of HEFA RJF is no longer attractive as the production of HEFA RJF incurs additional cost relative to producing only HEFA diesel, due to lower middle-distillate yield and more stringent upgrading requirements. Projected RJF consumption for 2030 increases to 237 PJ yr^{-1} when the multiplier is increased (*RJF multiplier: 2*), since a higher multiplier provides an additional incentive for RJF and increasingly shields RJF development from market volatilities.

Expedited technology commercialization and increased technological learning (*High technology development*) is shown to accelerate the pace of RJF uptake and reduce RJF costs significantly (the cost differential almost dissolves towards 2030). It also leads to a more diverse feedstock-technology portfolio, which reduces the pressure on biomass resources with limited availability and/or high costs (e.g. UCO and biomass imports) and relatively expensive conversion technologies (e.g. ATJ). Conversely, a scenario with lower technology development rates than the base scenarios could not be solved by the model, underlining the fact that technology development is a strong prerequisite for meeting the proposed RED-II biofuel targets.

RJF could reduce annual combustion emissions in aviation by 12-19 Mt CO_2-eq yr^{-1} in the EU by 2030, offsetting 53-84% of projected emission growth

The introduction of RJF reduces annual aviation-related combustion emissions in the EU by 12-19 Mt CO_2-eq yr^{-1}.[u] This would offset 53-84% of projected emission growth of the sector by 2030. The remaining emission reductions (3.6-10 Mt CO_2-eq yr^{-1}) should be covered by purchasing offsets through the CORSIA mechanism if the sector is to reach its emission target of carbon-neutral growth after 2020. Emission reductions increase with the consumption of RJF, which depends on the size of policy incentives, the pace of technology development, biomass supply and biomass demand (see previous section).

The introduction of RJF leads to a life-cycle GHG emission reduction of 12-18 Mt CO_2-eq yr^{-1} by 2030. The average life-cycle GHG emission reduction of the RJF portfolio equals 77-79% compared to fossil jet fuel, which is largely driven by the high share of RJF based on lignocellulosic biomass and the exclusion of food-based biofuels. This assessment does not quantify the impacts of LUC, carbon debt and foregone sequestration. Emissions associated with land conversion (foregone sequestration and direct LUC emissions) are, however, likely low because RJF is mainly produced from residual biomass, such as UCO, forestry residues and agricultural residues. The carbon debt associated with primary forestry residues has not been quantified, but can delay the climate change mitigation effect depending on the tree species and counterfactual scenario (Chapter 5). The biomass supply scenarios used in this analysis rely on biomass potentials which include maximum extraction rates for agricultural and forestry residues to mitigate the risk of soil organic carbon loss. Furthermore, biomass used for conventional known competitive uses was deducted from the supply potentials to avoid indirect LUC emissions which may occur when residues are diverted from an

u CO_2 emissions from the combustion of RJF was assumed to be zero, in line with the IPCC Guidelines for National Greenhouse Gas Inventories emissions from biofuels.[423] Life-cycle emission reductions per fuel type (without iLUC factors) were derived from typical GHG emission savings reported in Annex V and VI of the RED-II proposal[68], supplemented with data from Edwards et al.[290] and De Jong et al.[232]

original use for bioenergy purposes. The exception includes the UCO import potential from Indonesia, China and the US in the *HS* scenarios, which are based on the current collectable potential (165 PJ) instead of the low indirect LUC potential used in the *LS* scenarios (44 PJ).[77] Consequently, approximately 60 PJ of RJF in the *HS* scenarios (total RJF use: 198-223 PJ) contains a risk of indirect LUC emissions, as using the additional UCO can lead to substitution effects. A large share (97 PJ) of the difference between of the collectable and low indirect LUC potential arises from UCO that is allegedly used for human consumption in China; diversion of this feedstock stream to bioenergy would likely instigate a growing demand of vegetable oils (potentially causing LUC emissions), but would also reduce the health threat associated with UCO consumption.[77]

A declining cost differential allows RJF consumption to grow while total cost stabilize

Most scenarios show a decline in the marginal cost differential between RJF and fossil jet fuel (Figure 7-6), due to increasing fossil jet fuel prices, the availability of novel technologies, cheaper feedstocks, and technological learning (see section 7.1). In the *LD* scenarios, this reduction allows the RJF volume to double while annual additional costs stabilize during 2027-2030. Despite slightly larger conversion cost reductions induced by market-driven learning (due to higher deployment) in the *HD* scenarios, total additional costs increase because of higher competition for biomass, high reliance on (more expensive) imports and high RJF production volumes, which implies that the

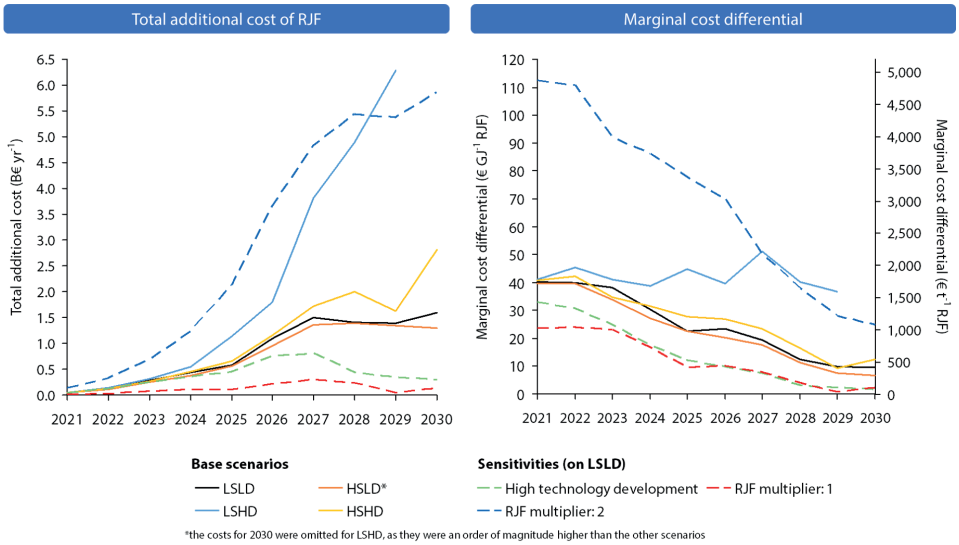


FIGURE 7-6: Total additional cost of RJF use and the marginal cost difference between RJF and fossil jet fuel (Chapter 6). All scenarios use the same fossil jet fuel price development.

model needs to move higher up the RJF cost-supply curve.

The cumulative additional costs for the base scenarios (except LSHD) vary between €7.7-11 billion over 2021-2030, which translates to an average cost differential of 11-16 € GJ^{-1} RJF (491-682 € t^{-1}). The average CO_2 abatement cost of RJF are high (160-222 € t^{-1} CO_2) compared to projected CO_2 prices and other bioenergy options.[334] The results for LSHD by 2030 were excluded from Figure 7-6, as they were an order of magnitude higher than the other scenarios, indicating the model requires very expensive (and unrealistic) solutions to fulfil the bioenergy demand due to the high strain on biomass supply.

RJF consumption and annual additional cost can be effectively decoupled by accelerating technology development. Whereas the RJF volumes of the *LSLD* scenario and *High technology development* case are comparable over time, the latter case shows declining annual cost from 2027 onwards. This decline is largely driven by dramatic cost reductions because of technological learning, reduced biomass/biofuel imports and a more diverse feedstock-technology portfolio. The lowest costs per unit RJF are achieved by the case with the lowest RJF volumes (*Multiplier: 1*), because only the cheapest options in the RJF cost-supply curve enter the model solution. The highest costs are achieved by the *Multiplier: 2* case, as a higher multiplier allows more expensive RJF types into the model solution.

It costs a few Euros per departing passenger to achieve carbon-neutral growth with RJF and carbon offsets

Figure 7-7 shows the cost of two mitigation strategies to achieve carbon-neutral growth between 2021-2030. The first is solely based on carbon offsets; the second combines RJF and carbon offsets. The figure is based on RJF consumption and costs as projected in the LSLD scenario. The baseline projection assumes CO_2 prices increase from 9 € t^{-1} in 2021 to 27 € t^{-1} by 2030, while the high price projections assumes CO_2 prices grow from 41 € t^{-1} in 2021 to 80 € t^{-1} by 2030.[337,415]

The cumulative cost of the mitigation strategy with RJF are 3.4-4.5 higher than without RJF (1.5-1.9 using high CO_2 price projections). However, the difference between both strategies reduces over time as the cost differential of RJF decreases and the carbon price increases. Moreover, the costs of the mitigation strategy including RJF stabilize over time, while the costs of a mitigation strategy solely based on carbon offsets grow as the price of carbon offsets increases. The RED-II proposal essentially allocates the cost burden of RJF to the road transport sector (aviation is not an obligated party), which is of the order of 0.24-0.37 €-cents per liter (averaged over 2021-2030). If the

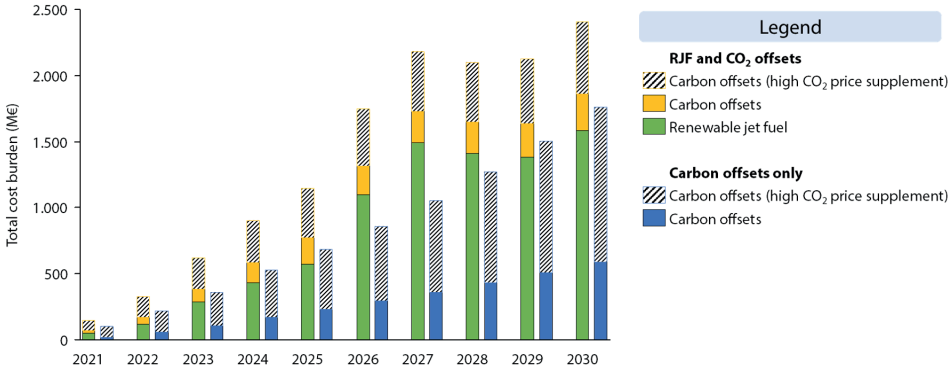


FIGURE 7-7: Emission mitigation costs of the EU aviation sector to achieve carbon-neutral growth (based on LSLD scenario). The baseline CO_2 price grows from 9 € t^{-1} in 2021 to 27 € t^{-1} by 2030.[415] The high CO_2 supplement assumes a CO_2 price, which increases from 41 € t^{-1} in 2021 to 80 € t^{-1} by 2030 (1 $=1 €).[337]

7

cost burden of RJF was allocated to aviation instead, the average cost per departing passenger equals €0.85-1.1, €1.0-1.4 or €3.9-5.1 per passenger departing on all, intra-EU or domestic flight, respectively.[v]

In a mandated biofuel market, the development of RJF goes at the expense of biofuel use in other transport sectors

As the biofuel market in the EU largely exists by the grace of the biofuel targets established by the RED-I and RED-II, the targets determine the total amount of biofuels supplied to the market. This implies that the increase of RJF consumption goes at the expense of biofuels supplied to other sectors. Whereas the road transport sector currently accounts for the vast majority of biofuel consumption, the multiplier mechanism for aviation and marine biofuels increases the share of biofuel supplied to these sectors to approximately 60% of total EU biofuel supply by 2030. This also implies that GHG emission reductions from biofuels also shift from the road transport sector to the aviation and marine sector.

Moreover, the multiplier incentive slightly reduces the total GHG emission reduction in the transport sector from biofuel as less biofuel is needed to achieve the same target; a multiplier of 1, 1.2 and 2 for RJF lead to lower overall GHG emission reductions of 51, 49, and 36 Mt CO_2-eq yr^{-1} by 2030, compared to 46 Mt CO_2-eq yr^{-1} in 2021. These figures exclude GHG emission reductions from renewable electricity use in road transport, which increase from 5 Mt CO_2-eq yr^{-1} in 2021 to 7-11 Mt CO_2-eq yr^{-1}. Chapter 6 also

v Data on annual departures in the EU were obtained from Eurostat[458] and were extrapolated to 2030 using industrial growth rates used in Chapter 6.

explored elevated biofuel targets as a solution to this issue. However, an increase in biofuel consumption combined with ambitious targets for advanced biofuels puts the cost and feasibility of target compliance at risk; for instance, an increment of 29% in biofuel consumption leads to a reduction of 64 Mt CO2-eq yr^{-1}, but also significantly increases extra-EU imports of biomass and biofuels, system costs, and marginal costs due to higher pressure on the system. Moreover, it requires persistently high growth rates of biofuel production capacity based on lignocellulosic biomass (46% yr^{-1} on average over 2021-2030), as this case could only be solved by the model using the assumptions from the *High technology development* case.

8

Conclusions and recommendations

8.1 Executive summary

In 2010, the global aviation industry emitted 743 Mt CO_2-eq yr^{-1}, which represented approximately 1.5% of total anthropogenic greenhouse gas (GHG) emissions. While aviation-related GHG emissions are projected to increase 3.6- to 6.2-fold between 2010 and 2050 due to rapid sectoral growth, global GHG emissions should reduce by 40-70% during the same period to realize the ambition to limit global average temperature increase to well below 2 °C, as agreed upon in the Paris Agreement. Renewable jet fuel (RJF) produced from biomass is regarded as one of the main options to reduce GHG emissions in the aviation industry in the coming decades. However, current consumption of RJF is negligible, which is mainly caused by high production costs and low oil prices.

This thesis addresses the production costs, climate impact and future supply of RJF. Chapters 2-5 quantify the production cost and climate impact for a wide range of RJF production systems, including Hydroprocessed Esters and Fatty Acids (HEFA), Fischer-Tropsch (FT), pyrolysis, hydrothermal liquefaction (HTL), Alcohol-to-Jet (ATJ) and Direct Sugars to Hydrocarbons (DSHC). The findings of these chapters were integrated into a bioenergy systems model in Chapter 6 to assess the future supply of RJF and the associated GHG emission reductions in the aviation industry in the EU towards 2030.

The **production costs** of RJF conversion pathways likely remain higher than fossil jet fuel in the short (2020) and medium term (2030), although decreasing production costs and increasing oil prices could bring price parity with fossil jet fuel within reach by 2030. The production costs of the current benchmark for RJF, the HEFA technology based on used cooking oil, was quantified at 30.3 € GJ^{-1} (1303 € t^{-1}), which is 2.8 times higher than the average jet fuel price in 2017.[452] The cost differential between fossil jet fuel and RJFs was projected to decrease to 7-13 € GJ^{-1} by 2030, due to increasing oil prices, the commercialization of novel conversion technologies (particularly pyrolysis and HTL), access to cheaper feedstocks, and technological learning through the deployment of additional biofuel production capacity. Optimized supply chain design and co-production strategies with existing industries (e.g. pulp and paper mills, refineries) were shown to potentially reduce production costs of RJF by up to 20%.

The **climate impact** of RJF from CO_2, CH_4 and N_2O emissions varies between conversion pathways and production contexts, but can be significantly lower than fossil jet fuel. Life-cycle GHG emission reductions for the investigated RJF pathways varied between 18% for DSHC and 94% for FT pathways. The majority of investigated conversion pathways reduce life-cycle GHG emissions by more than 70%. Pathways based on food crops generally show higher life-cycle GHG emissions than pathways based on residues and lignocellulosic crops, because of N_2O emissions related to fertilizer use.

Hydrogen use is often a major contributor to life-cycle GHG emissions, especially for pyrolysis, HTL, DSHC and HEFA. Land use change emissions, carbon debt and foregone sequestration can exceed life-cycle emissions and may delay, limit or even eliminate the climate change mitigation value of RJF. The risk of these emission fluxes can be mitigated by carefully shaping the right production context. For example, the risk of indirect land use change emissions and carbon debt can be mitigated by supplementing bioenergy production with efforts to optimize land/forest management, improve agricultural yields, increase supply chain efficiencies, and integrate bioenergy, food and feed production. Improved conversion efficiencies, higher feedstock yields and the application of carbon capture and storage help to further reduce the climate impact of RJFs. Moreover, the climate impact reduction of RJF increases when the trend towards the utilization of more heavy and sour (high sulfur) crude oil types pursues.

The **future supply** of RJF and the associated GHG emission reductions depend on policy incentives, the pace of technology development, and biomass supply and demand. Based on the anticipated regulatory context in the EU between 2021-2030, RJF supply could increase to 165-261 PJ yr^{-1} (3.8-6.1 Mt yr^{-1}) in the EU by 2030, covering 6-9% of total jet fuel consumption at EU airports. Model results show that RJF is initially produced using the HEFA technology, while FT, ATJ, pyrolysis and HTL are added to the technology portfolio upon commercialization. The introduction of RJF reduces aviation-related combustion emissions by 12-19 Mt CO_2-eq yr^{-1} in the EU by 2030, offsetting 53-84% of projected emission growth by 2030 (Figure 8-1). The produced RJF shows average life-cycle emission reductions of 78-80% compared to fossil jet fuel. Emissions from land use change, foregone sequestration and carbon debt are not included in this estimate, but the risks are at least partially mitigated because RJF is mainly produced from residual biomass, including used cooking oil and animal fats, agricultural residues and forestry residues. The associated cumulative costs over 2021-2030 were estimated at €7.7-11 billion, which translates to approximately 11-16 € GJ^{-1} RJF (491-682 € t^{-1}), 160-222 € t^{-1} CO_2 abated, or 1.0-1.4 € per departing passenger on intra-EU flights. These scenario projections mainly depend on policy incentives (based on the 2016 Renewable Energy Directive II (RED-II) proposal) and the availability of new conversion technologies. Efforts to expedite technology development, particularly of technologies able to convert lignocellulosic biomass, reduce production costs and increase RJF supply by unlocking cheaper and more abundant biomass feedstocks. High biomass supply, particularly of used cooking oil, helps to contain production costs. Higher demand for biofuels boosts RJF consumption, but also increases production costs due to fiercer competition for biomass and higher reliance on imports of biomass and biofuels.

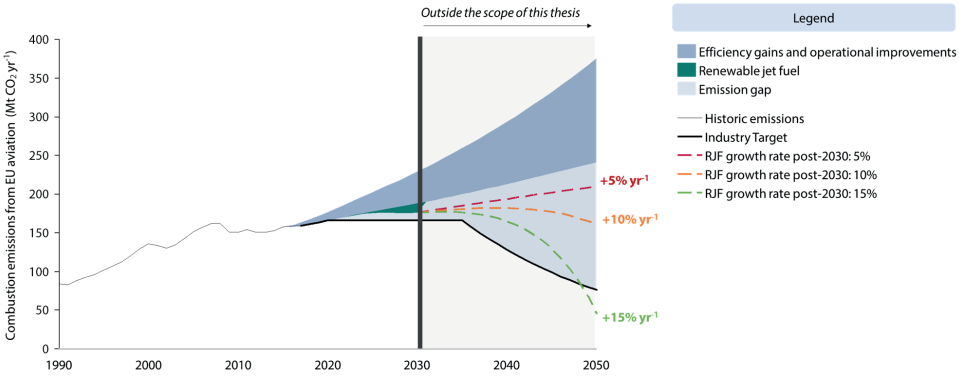


FIGURE 8-1: Projection of combustion emissions from EU aviation with the contribution of RJF, based on the LSLD scenario (Chapter 6), with an extrapolation of emission reductions from RJF post-2030.

8.2 Green Horizons? – That depends on a set of pre-conditions

This thesis finds that the introduction of RJF can reduce the climate impact of the aviation industry in the coming decade, provided a set of crucial pre-conditions are met:

1 *Pre-condition 1: Focus on RJFs which show robust climate impact reductions*

Robust climate impact reductions lay at the core of the rationale for RJF and are essential for the public acceptance of RJF. While the sustainability criteria in current policy frameworks are largely based on a static characterization of the life-cycle emissions of feedstock-technology combinations, the importance of time-dependent emission fluxes requires evaluators to move towards a time-dependent characterization of the full bioenergy production context. This time-dependent characterization should include carbon debt, foregone sequestrations, (in)direct land use change emissions, and time-dependent parameters such as yield improvements or carbon intensities of fossil products. The Relative Climate Impact (RCI) performance indicator introduced in Chapter 5 provides an approach to incorporate time-dependent emissions and define climate impact reduction thresholds based on a temporal dimension and the climate impact of choice (e.g. GHG emissions, radiative forcing, temperature change).

There is no silver bullet for sustainable production of RJF in terms of feedstock-technology combination, as the production context can make or break the climate impact of RJF. Life-cycle emissions of RJF can be reduced by using renewable hydrogen or applying carbon capture and storage. The risk of LUC emissions, carbon debt or foregone sequestration can be (partially) mitigated by using residual biomass

and shaping the right production context. Systems with high feedstock yields and conversion efficiencies can mitigate the contribution of LUC emissions, carbon debt and foregone sequestration. Furthermore, an integrated vision on bioenergy, food and feed production can help to optimize land use and avoid LUC emissions from crop-based biomass. Chapter 5 identifies several examples of RJF production contexts showing consistent climate impact reductions, for instance HEFA based on used cooking oil (provided substitution effects are avoided), FT based on forestry residues (provided forestry residues would otherwise be burnt in the forest), and ATJ based on sugarcane (provided sugarcane production is accompanied by measures to prevent indirect LUC emissions, e.g. by increasing agricultural yields).

2 Pre-condition 2: Support the development of new conversion technologies

The aforementioned RJF volumes (3.8-6.1 Mt RJF yr^{-1}) and associated emission reductions (12-19 Mt CO_2-eq yr^{-1}) by 2030 require average annual growth rates of RJF production capacity ranging between 73-82% yr^{-1} during 2021-2030. These growth rates are much higher than the average growth rate in biofuel production in the EU (10% yr^{-1}) and the United States (13% yr^{-1}) during 2006-2016.[72] Furthermore, Figure 8-1 shows that sustained growth rates between 10% and 15% are required after 2030 to reduce aviation-related GHG emissions with 50% by 2050. The HEFA technology is currently the only commercially available option for RJF production, but its supply potential is constrained by the supply of sustainable oils and fats and competition from other sectors. Model calculations project that 59-82% of total RJF consumption is supplied by technologies which are not commercialized today (e.g. HTL, pyrolysis, FT, ATJ). The technology readiness of FT and ATJ suggests that these technologies could supply RJF at commercial scale in the short term, while pyrolysis and HTL show promising economic and environmental performance in the medium term. The DSHC technology shows less promising production costs and life-cycle GHG emissions, particularly due to a low conversion efficiency.

The commercialization of these technologies unlocks more abundant and cheaper (lignocellulosic) biomass feedstocks, which is essential to increase RJF volumes and contain the costs. Furthermore, the development of a diverse feedstock-technology portfolio reduces pressure on particular feedstock types, which is important to avoid elevated feedstock prices and adverse sustainability impacts such as indirect land use change emissions from substitution effects. Early support is important, especially given the growing urgency of emission reductions and the time and resources it takes to commercialize technologies and obtain ASTM certification. A significant reduction in RJF production costs is possible by 2030 and beyond, provided technology developers are facilitated to gain experience and production systems reach larger scales. At the

same time, a long-term strategic vision is required to realize sustained and sustainable growth of RJF volumes beyond 2030.

3 *Pre-condition 3: Create a structural financing mechanism to cover the cost differential between RJF and fossil jet fuel*

The production costs of RJF are projected to decrease towards 2030, but remain higher than fossil jet fuel. A stable financing mechanism for RJF will increase the demand for RJF and justify investments to increase the supply of RJF. The cumulative funds required to cover the price gap were estimated at €7.7-11 billion over 2021-2030 to achieve 3.8-6.1 Mt RJF yr^{-1} in the EU by 2030. In these scenarios, the cost premium of RJF relative to fossil jet fuel decreases from +310% in 2021 to +30-60% in 2030. In this light, the voluntary uptake of RJF by individual airlines seems unrealistic, given the competitive character of the industry and the fact that fuel costs account for approximately 30% of airline operating expenditures.[18] Moreover, the projected cost reductions only occur when early support is provided to develop new technologies and deploy production capacity. Industry-wide (regulatory) mechanisms will hence be necessary to cover the cost differential between RJF and fossil jet fuel.

Mechanisms which set a price on CO_2 emissions, such as the EU ETS or CORSIA, will likely not provide a substantial incentive for RJF in the short term, as the CO_2 abatement costs of RJF (160-222 € t^{-1} CO_2, averaged over 2021-2030) are much higher than current CO_2 prices (85% of the global carbon offsets is currently priced at less than 8 € t^{-1} CO_2[336]). Existing biofuel incentive policies, such as the US RFS2 and EU RED-I, provide a voluntary opt-in for RJF. However, a level playing field with other types of biofuels has led to limited consumption of RJF thus far, because the current production costs of RJF tend to be higher than road biofuels. The multiplier mechanism for RJF included in the RED-II proposal increases RJF consumption, since it provides an additional incentive for RJF and increasingly shields RJF development from market volatilities. However, a multiplier dilutes the biofuel target, unless it is accompanied with increased (yet realistic) biofuel targets. Moreover, a voluntary opt-in for RJF in biofuel incentive policies seems to have limited long-term durability, as it the cost burden is essentially shifted to obligated sectors, such as the road transport sector. More durable funding mechanism should therefore be developed to safeguard long-term support for RJF.

8.3 Recommendations for policy makers

Early adoption of renewable jet fuel (RJF) is required to structurally reduce the climate impact of the aviation industry towards 2050, particularly when projected industry growth rates are maintained. As airlines lack the financial resources or appetite to cover these costs themselves, stable policy incentives which adequately cover the price gap

will likely be the major driver for the emergence of RJF production. The political choice to incentivize RJF is associated with relatively high CO_2 abatement cost (160-222 € t^{-1} CO_2) compared to other bioenergy options and can affect biofuel use in other sectors, particularly in the road transport sector. Nonetheless, RJF is one of the main options to decarbonize aviation on the short- to medium term, whereas other sectors may alternative mitigation options (e.g. renewable electricity).

Policy incentives for RJF require an integrated vision on markets for aviation, road and marine biofuels, since RJF and other biofuels are inextricably linked and often part of the same product slate. At the same time, the incentive mechanisms should recognize the specific context of RJF, because RJFs are associated with more stringent quality criteria, lower technology readiness levels and higher production costs. As stated in the previous section, EU ETS and CORSIA will likely not provide substantial incentives for RJF in the short term due to high CO_2 abatement costs of RJF. The voluntary opt-in for RJF in the RED-II and RFS2, combined with additional incentives for RJF (such as a multiplier), stimulates RJF production in the short term and drives reductions in RJF costs. However, such system seems to have a limited durability on the longer term as it shifts the cost burden to obligated sectors, such as road transport.

It is therefore recommended to transform policy incentives for RJF over time towards a system in which the cost burden is carried by the aviation industry. Carbon-neutral growth in the aviation industry can be effectively achieved by combining RJF and carbon offsets. Chapter 7 shows total cumulative costs of such combined mitigation strategy equal €9.3-12 billion for the EU aviation industry during 2021-2030, of which €7.7-11 billion is required to cover the RJF cost differential with fossil jet fuel. The costs of a mitigation strategy solely based on carbon offsets are 3.6-4.5 times lower, but increase over time as the price of carbon offsets increase. On the contrary, a mitigation strategy including early adoption of RJF can decrease RJF production costs over time and stabilize the mitigation cost towards 2030. The cost of RJF translates into an average cost of €1.0-1.4 or €3.9-5.1 per departing passenger on intra-EU or domestic flights (averaged over 2021-2030). This surcharge would lead to 3.8-6.1 Mt RJF yr^{-1} by 2030, which approximately equals the current jet fuel demand of domestic aviation in EU member states. The modest size of the surcharge provides scope for governments and (state-owned) airports to develop incentive mechanisms for RJF, such as RJF blending targets, differentiated landing fees, or dedicated airport charges, while a consistent geographical coverage should avoid excessive impact on the relative competitiveness of airlines and airports. As this surcharge would only cover the cost differential between RJF and fossil jet fuel, additional support (e.g. government grants or loan guarantees) remains necessary to support technology development in the short term, especially

because cost reduction of RJF relies on technological change and technological learning across the entire supply chain.

It is further recommended to tailor policy incentives to production systems and production contexts which yield consistent climate reductions. The common method in policy frameworks to establish the climate impact of bioenergy pathways is based on a static characterization of the life-cycle emissions of feedstock-technology combinations, using linear amortization for LUC emissions occurring at the onset of biofuel production. However, this method has been criticized for the inability to appropriately address emissions timing and the focus on a single impact category (i.e. GHG emissions), which may lead to inaccurate or incomplete quantification of the climate impact of bioenergy production.[56–61] It is therefore recommended that policy frameworks move towards a method which acknowledges the time-dependent nature of LUC emissions, foregone sequestration and carbon debt, and quantifies the actual climate response to temporal emission profiles. The Relative Climate Impact (RCI) performance indicator introduced in Chapter 5 provides an approach to incorporate time-dependent emission fluxes and allow evaluators to define climate impact reduction thresholds based on a temporal dimension and the climate impact category of choice (e.g. GHG emissions, radiative forcing, temperature change).

8.4 Recommendations for the aviation industry

Limiting global warming to 2 °C requires 40-70% reduction of GHG emission by 2050 (relative to 2010) and zero or net-negative GHG emissions at the end of the century. This implies that strong mitigation efforts are needed across all sectors. The aspiration to reduce the emissions from the aviation industry by 50% in 2050 (relative to 2005) aligns well with achieving the 2 °C target. However, the projected industry growth poses a significant challenge, as the gap between global aviation-related GHG emissions and the industry target increases from 0.13-0.46 Gt CO_2-eq yr^{-1} by 2030 to 2.2-2.5 Gt CO_2-eq yr^{-1} by 2050 (including projected efficiency and operational improvements).

Sustainably produced renewable jet fuel (RJF) can be produced in significant quantities and reduce aviation-related GHG emissions. However, the potential of RJF is finite, given the physical limits imposed by the supply of sustainable biomass and competing demand and the temporal limits imposed by the pace of biomass mobilization and technology development. The RJF volumes projected in Chapter 6 (3.8-6.1 Mt RJF yr^{-1} by 2030) offset a large part of the emission growth in the EU, but demand high feedstock mobilization rates and unprecedented growth of biofuel production capacity. The reliance on RJF to structurally reduce its GHG emissions commands a pro-active attitude of the aviation industry towards the development of the biofuel sector, especially since

RJF can stabilize the cost of compliance with the industry's emission targets on the longer term (as opposed to carbon offsets). This implies that aviation stakeholders (particularly airlines) partner with stakeholders along the bioenergy supply chain and show (joint) financial commitment from the onset to increase RJF uptake on the short term. Moreover, the social license for using RJF relies on robust sustainability criteria for RJF and adequate communication to the wider public. The aviation industry is therefore encouraged to advocate for credible sustainability criteria (e.g. in the context of CORSIA) and actively participate in the public sustainability debate, for example by expanding the SAFUG member base and propagating the SAFUG pledge to the wider public.

Aviation's decarbonization challenge increases beyond 2030 as the emission gap widens. Closing the global emission gap in 2050 (2.2-2.5 Gt CO_2-eq yr^{-1}) with RJF requires approximately 700-800 Mt RJF yr^{-1} (30-34 EJ yr^{-1}), which represents 2.5-2.8 times the current global fossil jet fuel demand or 8.8-10 times the current global production of biofuels.[11,14,72] This requires consistently high growth rates of RJF production capacity (Figure 8-1) and likely lead to high pressure on biomass resources. It is therefore recommended to start formulating a more diversified long-term strategy to meet the industry's emission targets. This strategy could for instance include efforts to expedite the development of CO_2-based RJFs and hybrid/electric propulsion systems.

8.5 Recommendations for further research

The findings of this thesis provide scope for further research on the following topics:

- **Include RJFs in (bio)energy and aviation system models.** The results of this thesis show that the supply of RJF could grow significantly in the coming decade. It is therefore encouraged to include RJF in other (bio)energy models to explore the potential of RJF on a national, regional and global level. It is further recommended to include a more detailed representation of RJF in sectoral models of the aviation industry to study the impact of RJF introduction and regulatory measures (e.g. a per-passenger surcharge) in terms of fuel cost, market growth and climate impact.
- **Extend the temporal scope to 2050 and beyond.** The challenge of mitigating aviation-related GHG emissions becomes even more pressing beyond 2030. The potential and climate impact of biofuels (and their allocation among sectors) beyond 2030 highly depends on future trends in population growth, agricultural efficiencies, biofuel policy and technological improvements.[322,385] It is therefore recommended to include RJFs in integrated assessment models to obtain a broader view on the role of RJFs in climate change mitigation scenarios. Furthermore, this

timeframe provides scope for including alternative feedstocks (e.g. CO_2 and algae), options which combine bioenergy and carbon capture and storage (BECCS), and more advanced biorefining configurations which allow for the co-production of biofuels and chemicals. In addition, the advent of electric propulsion systems in aviation may also start to play a role on this timescale.

- **Use the Relative Climate Impact indicator to compare and select bioenergy production contexts.** The Relative Climate Impact (RCI) performance indicator introduced in Chapter 5 is well-suited to incorporate time-dependent emission profiles associated with LUC emissions, carbon debt and foregone sequestration. It further provides the flexibility to quantify the climate impact of production systems for different impact categories. It is therefore encouraged to apply the RCI formulation to more (detailed) case studies to identify bioenergy production contexts which consistently show a climate benefit. It is recommended that these case studies focus on feedstocks which have a low risk of LUC emissions or carbon debt (e.g. used cooking oil, municipal solid waste or residual biomass from annual crops) or production contexts in which bioenergy production is accompanied by optimized land/forest management or other LUC mitigation measures (e.g. increasing agricultural efficiencies).[304,380–382]
- **Improve the understanding of the non-GHG climate impacts of RJF production and use**. As the impact of aviation-related short-lived emission species (particularly aerosols, water vapor, and NO_x) is estimated to be 2-5 times larger than the impact of CO_2 combustion emissions alone, it is recommended to further ongoing research on the impact of RJF on the quantity and type of emission species associated with the combustion of RJF.[38,41,453] Furthermore, the scope of climate forcers can be expanded to include surface albedo, surface roughness and evapotranspiration (associated with feedstock production) to evaluate their relative importance to the overall climate impact of RJF.
- **Quantify the wider sustainability impact of RJF use.** The production of RJF may also affect other environmental and socio-economic sustainability indicators, such air quality, employment, land use, and water use. The quantification of these parameters is important to avoid adverse sustainability impacts and assess whether the environmental, socio-economic and health benefits of RJF justify the (public) investments required to increase the use of RJF.
- **Assess the role of biofuels in the maritime sector.** The emission mitigation challenge for the maritime industry is similar to the aviation industry; it currently represents 1.6% of global anthropogenic emissions, of which 79% is emitted in

internationally, but emissions from international shipping are projected to increase by 50%-250% between now and 2050 due to industry growth.[393,435] Chapter 6 shows the consumption of marine biofuels could also increase significantly in the coming decade. It is therefore recommended to perform a more detailed analysis of the future supply of marine biofuels in the context of the wider bio-based economy.

9

Conclusies en aanbevelingen

9.1 Samenvatting

In 2010 was de uitstoot van de mondiale luchtvaartsector 743 Mt CO_2-eq jr^{-1}. Dit staat ongeveer gelijk aan 1.5% van de door mensen veroorzaakte mondiale uitstoot van broeikasgassen. De verwachting is dat de uitstoot van de luchtvaarsector groeit met een factor 3,6 tot 6,2 tussen 2010 en 2050 door de snelle groei van de sector. Om de opwarming van de aarde te beperken tot 2 °C, zoals afgesproken in de klimaatdoelen van Parijs, zal tegelijkertijd de uitstoot van broeikasgassen 40% tot 70% verminderd moeten worden. De introductie van hernieuwbare vliegtuigbrandstoffen (HVB), geproduceerd van biomassa, is een belangrijke maatregel om luchtvaart-gerelateerde uitstoot van broeikasgassen in de komende decennia te verminderen. HVB wordt op dit moment slechts weinig gebruikt, vooral door de hoge productiekosten en lage olieprijs.

Dit proefschrift kijkt naar de productiekosten, klimaatimpact en toekomstige productie van HVB. In Hoofdstuk 2-5 zijn de productiekosten en klimaatimpact van verscheidene HVB-productiesystemen berekend, zoals *Hydroprocessed Esters and Fatty Acids* (HEFA), *Fischer-Tropsch* (FT), pyrolyse, *hydrothermal liquefaction* (HTL), *Alcohol-to-Jet* (ATJ) en *Direct Sugars to Hydrocarbons* (DSHC). De uitkomsten van deze hoofdstukken zijn geïntegreerd in een bio-energiemodel in Hoofdstuk 6 om de toekomstige productie van HVB en de bijbehorende emissiereducties in de Europese luchtvaartsector tot 2030 te kwantificeren.

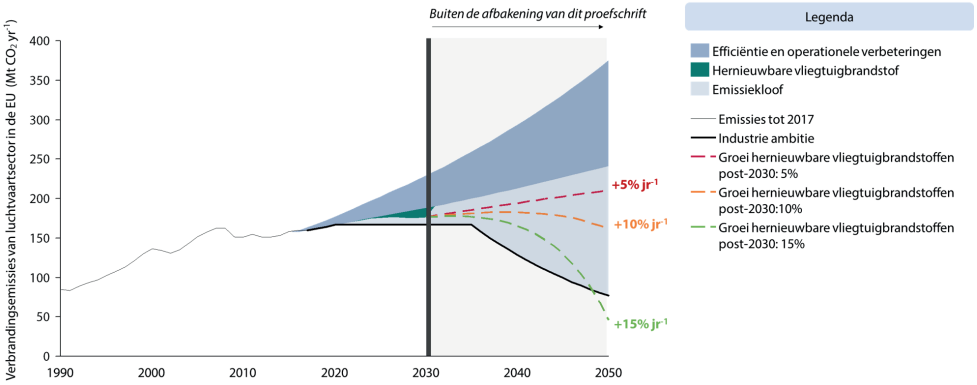
De **productiekosten** van HVB zullen waarschijnlijk hoger blijven dan fossiele vliegtuigbrandstof op de korte (2020) en middellange termijn (2030), hoewel afnemende productiekosten en hogere olieprijzen het kostenverschil aanzienlijk verminderen. De huidige productiekosten voor HVB, gebaseerd op HVB geproduceerd van afgewerkt frituurvet met de HEFA technologie, bedragen 30,3 € GJ^{-1} (1303 € t^{-1}) en zijn ongeveer 2,8 keer hoger dan de gemiddelde prijs van vliegtuigbrandstoffen in 2017.[452] De resultaten laten zien dat het kostenverschil tussen hernieuwbare en fossiele vliegtuigbrandstoffen terugloopt tot 7-13 € GJ^{-1} in 2030 door hogere olieprijzen, de ontwikkeling van nieuwe conversietechnologieën (met name pyrolyse en HTL), toegang tot goedkopere biomassa en leereffecten door de groei van productiecapaciteit voor biobrandstoffen. De productiekosten van HVB kunnen tot 20% verlaagd worden door productieketens te optimaliseren en coproductie-strategieën te formuleren met bestaande industrieën zoals de pulp- en papierindustrie of olieraffinaderijen.

De **klimaatimpact** van HVB door CO_2, CH_4 en N_2O emissies verschilt tussen productieketens en tussen productiecontexten, maar kan significant lager zijn dan fossiele vliegtuigbrandstoffen. De onderzochte productieketens behalen een broeikasgasreductie over de gehele levenscyclus variërend van 18% voor DSHC tot 94%

voor FT (vergeleken met fossiele vliegtuigbrandstoffen). De meeste productieketens behalen een broeikasgasreductie van ten minste 70%. Ketens gebaseerd op voedselgewassen behalen over het algemeen lagere broeikasgasreducties dan ketens gebaseerd op residuen of lignocellulose gewassen, doordat de bemesting van voedselgewassen gepaard gaat met relatief veel N_2O emissies. Waterstofgebruik is vaak een significant deel van de broeikasgasemissies van HVB, met name voor pyrolyse, HTL, DSHC en HEFA. Emissies door landgebruiksveranderingen, koolstofschuld of gederfde koolstofopslag zijn in sommige gevallen hoger dan de levenscyclus-emissies en kunnen de klimaatwinst van HVB vertragen, verlagen, of zelfs elimineren. Het risico op deze emissies kan worden gemitigeerd door de juiste productiecontext te scheppen. Het risico op een koolstofschuld of emissies door indirecte landgebruiksverandering kan bijvoorbeeld worden verlaagd door biomassa productie te combineren met inspanningen om het land- en bosmanagement te optimaliseren, de opbrengsten van gewassen te verhogen, de keteneffici̇ëntie te verbeteren of voedsel-, voer- en bio-energie-productie beter te integreren. De klimaatimpact van HVB kan nog verder worden verlaagd door de conversie-efficiëntie en gewasopbrengst te verhogen of CO_2-afvang en opslag toe te passen. De klimaatwinst van HVB kan verder toenemen wanneer zwaardere en zuurdere ruwe oliesoorten gebruikt gaan worden om fossiele vliegtuigbrandstoffen te produceren.

De **toekomstige productie** van HVB en de bijbehorende emissiereducties hangen af van stimuleringsmaatregelen, de snelheid van technologieontwikkeling, het aanbod van biomassa en de vraag naar biomassa. De toekomstige productie van HVB kan groeien naar 165-261 PJ jr^{-1} (3,8-6,1 Mt jr^{-1}) in de EU in 2030, gebaseerd op het verwachte Europese bio-energiebeleid tussen 2021 en 2030. Deze productie komt overeen met 6-9% van het brandstofgebruik op vliegvelden in de EU. Initieel wordt HVB geproduceerd door de HEFA-technologie; FT, ATJ, pyrolyse en HTL worden aan het portfolio toegevoegd zodra deze technologieën op grote schaal toegepast kunnen worden. De introductie van HVB vermindert luchtvaart-gerelateerde emissies met 12-19 Mt CO_2-eq jr^{-1} in de EU in 2030. Dit neutraliseert 53-84% van de verwachte emissiegroei in 2030 (Figuur 9-1). De gemiddelde broeikasgasreductie van HVB bedraagt 78-80% ten opzichte van fossiele vliegtuigbrandstoffen. Emissies door landgebruiksveranderingen, koolstofschuld of gederfde koolstofopslag zijn niet meegenomen in deze berekeningen. Het risico op deze emissies is echter klein omdat HVB met name wordt geproduceerd van residuen, zoals afgewerkt frituur- en dierlijk vet en landbouw- en bosbouwresiduen. De cumulatieve kosten van HVB bedragen €7,7-11 miljard gedurende 2021-2030. Dit staat ongeveer gelijk aan 11-16 € GJ^{-1} HVB (491-682 € t^{-1}), 160-222 € per vermeden ton CO_2, of 1,0-1,4 € per vertrekkende passagier op een vlucht binnen de EU. Deze projecties hangen met name af van stimuleringsmaatregelen (gebaseerd

op het Renewable Energy Directive II (RED-II) voorstel van de Europese Commissie) en de beschikbaarheid van nieuwe conversietechnologieën. Inspanningen om de ontwikkeling van conversietechnologieën te versnellen (met name technologieën die lignocellulose biomassa kunnen omzetten) kunnen de kosten verlagen en de productie van HVB verhogen door toegang te verschaffen tot goedkopere en ruimer beschikbare vormen van biomassa. Een hoge beschikbaarheid van biomassa, met name afgewerkt frituurvet, kan de kosten ook verlagen. Een hogere vraag naar biobrandstoffen zorgt voor hogere productie van HVB, maar leidt ook tot hogere productiekosten door de concurrentie met andere sectoren en een grotere afhankelijkheid van import van biomassa en biobrandstoffen.



FIGUUR 9-1: Projectie van de verbrandingsemissies van de luchtvaartsector in de EU met de bijdrage van HVB, gebaseerd op het LSLD-scenario (Hoofdstuk 6), met een extrapolatie van emissiereducties door HVB na 2030.

9.2 Groene vergezichten? – Dat hangt af van een aantal randvoorwaarden

Dit proefschrift laat zien dat de introductie van HVB de klimaatimpact van de luchtvaartsector kan verlagen in het komende decennium, mits aan een aantal randvoorwaarden wordt voldaan.

1 Randvoorwaarde 1: Focus op HVB-types die een robuuste klimaatwinst opleveren

Een robuuste klimaatwinst is de kern van de motivatie voor HVB en is essentieel voor het maatschappelijk draagvlak voor HVB. De duurzaamheidscriteria in het huidige bio-energiebeleid zijn gebaseerd op een statische beschrijving van de levenscyclus-emissies van biomassa-technologie combinaties. Gezien de impact van tijdsafhankelijke emissies op de klimaatimpact van bio-energie, wordt beleidsmakers aangeraden om een methode te gebruiken die tijdsafhankelijke emissies adequaat meeneemt.

Een dergelijke methode zou emissies gerelateerd aan landgebruiksverandering, koolstofschuld of gederfde koolstofopslag kunnen meenemen, evenals andere tijdsafhankelijke parameters, zoals verbeteringen in gewasopbrengsten en de koolstofintensiteit van fossiele producten. De *Relative Climate Impact* (RCI) indicator, geïntroduceerd in Hoofdstuk 5, neemt tijdsafhankelijke emissies mee en biedt de mogelijkheid om een minimale klimaatimpact-reductie te definiëren op basis van een gekozen tijdshorizon en klimaatimpact-categorie (bijvoorbeeld broeikasgasemissies, aardopwarmingsvermogen of temperatuursverandering).

De productiecontext is van grote invloed op de klimaatwinst van een productiesysteem. Levenscyclus-emissies van HVB kunnen worden verlaagd door gebruik te maken van duurzaam geproduceerde waterstof of CO_2-afvang en -opslag. Het risico op emissies door landgebruiksveranderingen, koolstofschuld of gederfde koolstofopslag kan (deels) worden gemitigeerd door residuen te gebruiken en de juiste productiecontext te scheppen. Productiesystemen met hoge gewasopbrengsten en conversie-efficiënties kunnen de bijdrage van landgebruiksveranderingen, koolstofschuld of gederfde koolstofopslag verminderen. Daarnaast kan een geïntegreerde visie op de productie van bio-energie, voedsel en voer bijdragen om landgebruik te optimaliseren en emissies door landgebruiksveranderingen te vermijden. Hoofdstuk 5 geeft enkele voorbeelden van productiecontexten waarin robuuste klimaatwinst geboekt wordt, bijvoorbeeld wanneer gebruik wordt gemaakt van afgewerkt frituurvet in combinatie met de HEFA technologie (mits vervangingseffecten worden vermeden), bosbouwresiduen in combinatie met de FT technologie (mits deze residuen anders zouden worden verbrand in het bos) of suikerriet in combinatie met de ATJ technologie (mits suikerriet productie gepaard gaat met maatregelen om indirecte landgebruiksverandering tegen te gaan, zoals het verhogen van de gewasopbrengst).

2 Randvoorwaarde 2: Steun de ontwikkeling van nieuwe conversietechnologieën

De productiecapaciteit van HVB moet met 73-82% jr^{-1} groeien gedurende 2021-2030 om de eerdergenoemde HVB productie (3,8-6,1 Mt HVB jr^{-1}) en emissiereductie (12-19 Mt CO_2-eq jr^{-1}) te realiseren. De groeisnelheden zijn relatief hoog vergeleken met de gemiddelde groeisnelheid van de productiecapaciteit van biobrandstoffen in de EU (10% jr^{-1}) en de Verenigde Staten (13% jr^{-1}) gedurende 2006-2016.[72] Figuur 9-1 laat zien dat na 2030 de groeisnelheid consequent rond 10-15% moet liggen om luchtvaart-gerelateerde emissies in 2050 te verlagen met 50%. De HEFA-technologie is op dit moment de enige technologie die op grote schaal HVB kan produceren. Het opschalingspotentieel van deze technologie wordt echter beperkt door de beschikbaarheid van duurzame oliën en vetten en de concurrerende vraag vanuit andere sectoren. Modelprojecties laten zien dat 59-82% van de totale hoeveelheid HVB

in 2030 geproduceerd wordt door technologieën die op dit moment nog niet op grote schaal gebruikt worden (bijvoorbeeld HTL, pyrolyse, FT, ATJ). Gezien de technologische status van FT en ATJ, kunnen deze technologieën op de korte termijn gebruikt worden om de HVB-productie verhogen. Pyrolyse en HTL laten veelbelovende productiekosten en klimaatwinst zien op de middellange termijn. De productiekosten en klimaatwinst van de DSHC-technologie is minder veelbelovend, met name door een lage conversie-efficiëntie.

De ontwikkeling van deze nieuwe technologieën ontsluit meer en goedkopere vormen van (lignocellulose) biomassa. Dit is essentieel om de HVB-productie te verhogen en de kosten werkbaar te houden. Daarnaast reduceert een divers biomassa-technologie portfolio de druk op bepaalde biomassa stromen. Dit is belangrijk om hoge biomassaprijzen en nadelige milieueffecten te vermijden, zoals emissies door indirecte landgebruiksveranderingen. Vroegtijdige steun is belangrijk, met name door de groeiende urgentie van emissiereducties en de tijd die het kost om technologieën te ontwikkelen en ASTM-certificering te verkrijgen. De kosten van HVB kunnen significant verlaagd worden richting 2030 en daarna, mits technologieontwikkelaars gefaciliteerd worden om ervaring op te doen en hun technologie op te schalen. Tegelijkertijd is er een langetermijnstrategie nodig om constante en duurzame groei van HVB-productie na 2030 te bewerkstellingen.

3 *Randvoorwaarde 3: Creëer een structureel financieringsmechanisme om het kostenverschil tussen HVB en fossiele vliegtuigbrandstoffen op te vangen*

De projecties laten zien dat de productiekosten van HVB kunnen dalen richting 2030, maar hoger blijven dan de kosten van fossiele vliegtuigbrandstoffen. Een stabiel financieringsmechanisme voor HVB is daarom nodig om de vraag naar HVB te vergroten en investeringen uit te lokken. De cumulatieve kosten om het prijsverschil te dichten worden geschat op €7,7-11 miljard gedurende 2021-2030 om een productieniveau te bereiken van 3,8-6,1 Mt RJF jr^{-1} in de EU in 2030. In deze scenario's gaat de meerprijs van HVB ten opzichte van fossiele vliegtuigbrandstoffen omlaag van +310% in 2021 naar +30-60% in 2030. Vrijwillig gebruik van HVB door luchtvaartmaatschappijen lijkt hiermee onrealistisch, gegeven het competitieve karakter van de sector en het feit dat brandstofkosten ongeveer 30% van de totale operationele kosten bedragen.[18] Daarnaast kunnen deze kostenreducties alleen worden bewerkstelligd als er vroegtijdige steun is voor de ontwikkeling van conversietechnologieën en de bouw van nieuwe productiecapaciteit. Industrie-brede mechanismen (bijvoorbeeld met behulp van regelgeving) zijn daarom nodig om het kostenverschil tussen HVB en fossiele vliegtuigbrandstoffen te dekken.

Mechanismen die een prijs op CO_2 zetten, zoals EU ETS en CORSIA, zullen waarschijnlijk weinig stimulans bieden voor HVB productie op de korte termijn, gezien de hoge mitigatiekosten van HVB (160-222 € t^{-1} CO_2, gemiddelde over 2021-2030) en de huidige prijs voor CO_2 (85% van de CO_2 compensatie credits kosten minder dan 8 € t^{-1} CO_2[336]). Huidige stimuleringsmaatregelen voor biobrandstoffen, zoals de US RFS2 en EU RED-I, bieden een vrijwillige *opt-in* voor HVB. Echter, een dergelijk gelijk speelveld met andere biobrandstoffen heeft nog niet geleid tot verhoogde productie van HVB, omdat de huidige productiekosten van HVB hoger zijn dan de productiekosten van andere biobrandstoffen. De *multiplier*, van toepassing op HVB in het RED-II voorstel, geeft een extra stimulans aan HVB en verhoogt de productie van HVB. De *multiplier* zorgt echter ook voor een verwatering van de doelstelling voor biobrandstoffen. Daarnaast lijkt een vrijwillige *opt-in* voor HVB in bio-energiebeleid een gelimiteerde houdbaarheid te hebben, omdat het de kosten verschuift naar gemandateerde sectoren, zoals de wegtransportsector. Het is daarom belangrijk om te zoeken naar duurzamere stimuleringsmaatregelen om de steun voor HVB ook te kunnen waarborgen op de lange termijn.

9.3 Aanbevelingen voor beleidsmakers

Een vroegtijdige introductie van hernieuwbare vliegtuigbrandstoffen (HVB) is belangrijk om de klimaatimpact van de luchtvaartsector structureel te verlagen richting 2050, met name gezien de groeiprojecties van de sector. Aangezien luchtvaarmaatschappijen niet de financiële ruimte kunnen of willen creëren om het kostenverschil tussen HVB en fossiele vliegtuigbrandstoffen op te vangen, zal de introductie van HVB voor een groot deel afhangen van adequate en stabiele stimuleringsmaatregelen. De politieke keuze om het gebruik van HVB te stimuleren gaat gepaard met relatief hoge mitigatiekosten (160-222 € t^{-1} CO_2) vergeleken met andere vormen van bio-energie en zal effect hebben op het gebruik van biobrandstoffen in andere sectoren, met name de wegtransportsector. Desalniettemin hebben andere sectoren meerdere alternatieven om emissies te reduceren (bijvoorbeeld door elektrificatie), terwijl HVB de belangrijkste optie is om de klimaatimpact van de luchtvaartsector op de korte en middellange termijn terug te dringen.

Stimuleringsmaatregelen voor HVB vereisen een geïntegreerde visie op brandstofgebruik in de luchtvaartsector, wegtransport en scheepvaart, aangezien HVB-productie vaak gepaard gaat met de productie van andere biobrandstoffen. Tegelijkertijd moeten stimuleringsmechanismen ook rekening houden met de specifieke context van HVB, die getypeerd wordt door hoge kwaliteitseisen, hoge productiekosten en de premature staat van de meeste conversietechnologieën. EU

ETS en CORSIA zullen waarschijnlijk niet genoeg stimulans geven aan de productie van HVB op de korte termijn, gezien de hoge mitigatiekosten van HVB. De vrijwillige *opt-in* voor HVB in de RED-II en RFS2, in combinatie met additionele stimuleringsmaatregelen voor HVB (zoals een *multiplier*), verhoogt de HVB-productie op de korte termijn en leidt tot kostenreducties. Dergelijke maatregelen lijken echter beperkt houdbaar, omdat de meerkosten van HVB gedragen worden door andere gemandateerde sectoren, zoals de wegtransportsector.

Het wordt daarom aanbevolen om stimuleringsmaatregelen voor HVB op den duur om te vormen naar een mechanisme waarin de kosten worden gedragen door de luchtvaartsector zelf. Klimaatneutrale groei van de sector kan effectief worden bereikt door HVB te combineren met CO_2 compensatie. Hoofdstuk 7 laat zien dat de cumulatieve kosten van zo'n gecombineerde mitigatiestrategie voor de luchtvaartsector in de EU €9,3-12 miljard bedragen gedurende 2021-2030, waarvan €7,7-11 miljard wordt gebruikt om het kostenverschil tussen HVB en fossiele vliegtuigbrandstoffen te dekken (de rest wordt gebruikt voor CO_2 compensatie). Hoewel de cumulatieve kosten van een mitigatiestrategie enkel gebaseerd op CO_2 compensatie 3,6-4,5 keer lager zijn over dezelfde tijdsspanne, zit er een opgaande trend in de kosten van zo'n mitigatiestrategie door de stijgende prijs van CO_2. De gecombineerde mitigatiestrategie laat daarentegen zien dat vroegtijdige steun aan HVB zorgt voor kostenreducties en een stabilisering van de totale kosten richting 2030. De kosten van HVB bedragen €3,9-5,1 of €1,0-1,4 per vertrekkende passagier op een binnenlandse vlucht of een vlucht binnen de EU (gemiddelde over 2021-2030). Een dergelijke toeslag zou de productie van 3,8-6,1 Mt HVB jr^{-1} in 2030 dekken. Dit volume staat ongeveer gelijk aan het huidige gebruik van vliegtuigbrandstoffen voor binnenlandse vluchten in alle EU-lidstaten. De bescheiden hoogte van de toeslag biedt ruimte aan overheden en (genationaliseerde) luchthavens om stimuleringsmaatregelen voor HVB te ontwikkelen, zoals een doelstelling voor HVB-gebruik, gedifferentieerde landingskosten of specifieke heffingen. Een consistente geografische dekking van deze maatregelen moet ervoor zorgen dat de onderlinge concurrentie tussen luchtvaartmaatschappijen en luchthavens zo min mogelijk wordt beïnvloed. De eerdergenoemde toeslag dekt alleen het kostenverschil tussen HVB en fossiele vliegtuigbrandstof; additionele stimuleringsmaatregelen voor de ontwikkeling van nieuwe conversietechnologieën blijven nodig, vooral omdat de kostenreducties voor HVB afhangen van nieuwe conversietechnologieën en technologische leereffecten in de hele productieketen.

Daarnaast is het belangrijk om stimuleringsmaatregelen te koppelen aan productiesystemen en productiecontexten die een robuuste klimaatwinst opleveren. De huidige methode om de klimaatimpact van bio-energiesystemen te berekenen

is gebaseerd op een statische beschrijving van de levenscyclus-emissies van een biomassa-technologie combinatie, waarin tijdsafhankelijke emissies (zoals die van landgebruiksveranderingen) vaak worden uitgespreid over een subjectief gekozen tijdsperiode. Verscheidene studies laten zien dat deze methode kan leiden tot een incompleet en inaccuraat beeld van de klimaatimpact van bio-energiesystemen, doordat er geen rekening wordt gehouden met de timing van emissies en systemen alleen beoordeeld worden op basis van broeikasgasemissies (en bijvoorbeeld niet op de resulterende klimaateffecten, zoals temperatuurstijging).[56–61] Het zou daarom beter zijn als stimuleringsmaatregelen een methode gebruiken die tijdsafhankelijke emissies gerelateerd aan landgebruiksverandering, koolstofschuld of gederfde koolstofopslag op de juiste manier meeneemt en de werkelijke klimaatimpact van een bio-energiesysteem berekent. De *Relative Climate Impact* (RCI) indicator, geïntroduceerd in Hoofdstuk 5, neemt tijdsafhankelijke emissies mee en biedt regelgevende instanties de mogelijkheid om een minimale klimaatimpact-reductie te definiëren op basis van een gekozen tijdshorizon en klimaatimpact-categorie (bijvoorbeeld broeikasgasemissies, aardopwarmingsvermogen of temperatuursverandering).

9.4 Aanbevelingen voor de luchtvaartsector

De 2 °C doelstelling, afgesproken in het Parijs akkoord, vraagt een reductie van broeikasgassen van 40-70% in 2050 (ten opzichte van 2010) en nul of negatieve emissies aan het einde van de eeuw. Dit impliceert dat alle sectoren hun steentje bij moeten dragen. De ambitie van de luchtvaartsector om broeikasgasemissies met 50% terug te dringen in 2050 (ten opzichte van 2005) komt redelijk overeen met de 2 °C doelstelling. Echter, de geprojecteerde groei van de sector vormt een aanzienlijke uitdaging, aangezien de kloof tussen de mondiale uitstoot en de ambitie van de sector groeit van 0,13-0,46 Gt CO_2-eq jr^{-1} in 2030 naar 2,2-2,5 Gt CO_2-eq jr^{-1} in 2050 (efficiëntie- en operationele verbeteringen zijn hierin meegenomen).

Duurzaam geproduceerde hernieuwbare vliegtuigbrandstoffen (HVB) kunnen geproduceerd worden in significante hoeveelheden en kunnen luchtvaart-gerelateerde emissies verminderen. Echter, de hoeveelheid HVB is eindig, gezien de fysieke limieten op de beschikbaarheid van duurzame biomassa en de vraag naar biomassa van andere sectoren. Tevens is de opschalingssnelheid van HVB gelimiteerd door de snelheid waarmee conversietechnologieën ontwikkeld kunnen worden en biomassa gemobiliseerd kan worden. De resultaten in Hoofdstuk 6 laten significante volumes HVB zien (3,8-6,1 Mt jr^{-1} in 2030), genoeg om een groot deel van de emissiegroei tot 2030 te neutraliseren. Deze projecties hangen echter af van een snelle mobilisatie van biomassa en een ongeëvenaarde groei van productiecapaciteit voor biobrandstoffen.

Een proactieve houding van de sector ten opzichte van de ontwikkeling van HVB is essentieel, gezien de afhankelijkheid van de sector van HVB om haar broeikasgasemissies terug te dringen. Vroegtijdige steun aan de ontwikkeling van HVB kan tevens de mitigatiekosten van de sector op de middellange termijn stabiliseren, in tegenstelling tot CO_2-compensatie. Deze steun houdt bijvoorbeeld in dat de sector (met name luchtvaartmaatschappijen) al in een vroeg stadium partnerships en (gezamenlijke) financiële verplichtingen aangaat met actoren in de productieketen om de productie van HVB te verhogen. Het maatschappelijk draagvlak voor HVB is gebaseerd op robuuste duurzaamheidscriteria voor HVB. Dit vraagt om adequate communicatie naar het publiek. De luchtvaartsector wordt daarom opgeroepen om zich in te zetten voor geloofwaardige duurzaamheidscriteria (bijvoorbeeld in de context van CORSIA) en zich actief te mengen in het publieke debat over duurzaamheid, bijvoorbeeld door de uitbreiding van SAFUG en het publiekelijk uitdragen van de SAFUG-boodschap.

Na 2030 wordt de uitdaging om de emissies van de luchtvaartsector te reduceren alleen maar groter, gezien de groei van de sector. Het invullen van de mondiale emissiekloof in 2050 (2,2-2,5 Gt CO_2-eq jr^{-1}) vraagt om ongeveer 700-800 Mt HVB jr^{-1} (30-34 EJ jr^{-1}). Dit staat ongeveer gelijk aan 2,5-2,8 keer de huidige consumptie van vliegtuigbrandstoffen of 8,8-10 keer de huidige mondiale productiecapaciteit voor biobrandstoffen.[11,14,72] Dit vereist een constant hoge groei van HVB productiecapaciteit (Figuur 9-1) en zal waarschijnlijk de druk op het aanbod van biomassa verhogen. Het wordt daarom aanbevolen om nu al te beginnen met het formuleren van een gediversifieerde strategie om de klimaatambities van de industrie op de lange termijn te verwezenlijken. Een dergelijke strategie kan bijvoorbeeld sturen op het versnellen van de ontwikkeling van hybride/elektrische vliegtuigen en technologieën om HVB te produceren uit CO_2.

9.5 Aanbevelingen voor toekomstig onderzoek

De bevindingen van dit proefschrift leiden tot de volgende aanbevelingen voor toekomstig onderzoek:

- **Voeg HVB toe aan bio-energie- en luchtvaartmodellen.** De resultaten van dit proefschrift laten zien dat de productie van HVB significant kan toenemen in het komende decennium. Het wordt daarom aangeraden om HVB toe te voegen aan bio-energiemodellen om de toekomstige productie van HVB te onderzoeken op nationaal, regionaal en mondiaal niveau. Een gedetailleerdere beschrijving van HVB in modellen van de luchtvaartsector kan daarnaast gebruikt worden om de effecten te bestuderen van de introductie van HVB en gerelateerde stimuleringsmaatregelen (bijvoorbeeld een passagierstoeslag) op de brandstofkosten, marktgroei en klimaatimpact van de sector.

- **Verleng de tijdshorizon tot 2050 en verder.** De uitdaging om luchtvaart-gerelateerde emissies te reduceren wordt groter na 2030. De beschikbaarheid en klimaatwinst van biobrandstoffen (en de onderverdeling tussen sectoren) na 2030 hangt sterk af van toekomstige bevolkingsgroei, landbouwopbrengsten, bio-energiebeleid en technologische ontwikkelen. Het wordt daarom aanbevolen om de productie van HVB op te nemen in geïntegreerde analysemodellen om de rol van HVB in mitigatiescenario's in een bredere context te kunnen plaatsen. De tijdsspanne na 2030 geeft de ruimte voor een prominentere rol van andere grondstoffen (zoals CO_2 en algen), de combinatie van bio-energie en CO_2 afvang en opslag (*BECCS*) en geavanceerde bioraffinageconcepten waarin biobrandstoffen en biochemicaliën tegelijkertijd worden geproduceerd.
- **Gebruik de *Relative Climate Impact* indicator om bio-energiesystemen en productiecontexten te vergelijken en selecteren.** De *Relative Climate Impact* (RCI) indicator, geïntroduceerd in Hoofdstuk 5, neemt tijdsafhankelijke emissies mee gerelateerd aan landgebruiksverandering, koolstofschuld of gederfde koolstofopslag. Daarnaast is het mogelijk om de klimaatimpact te kwantificeren en te vergelijken op basis van verschillende impactcategorieën, zoals broeikasgasemissies of temperatuurstijging. Het wordt daarom aangeraden om de RCI-indicator toe te passen op gedetailleerde casestudies om bio-energiesystemen met een robuuste klimaatwinst te selecteren. Het is aan te raden om deze casestudies te baseren op vormen van biomassa met een laag risico op landgebruiksveranderingen of koolstofschuld (bijvoorbeeld afgewerkt frituurvet, gemeentelijk afval of residuen van jaarlijkse gewassen) en contexten waarin de productie van bio-energie gepaard gaat met maatregelen om het risico op landgebruiksveranderingen in te dammen.[304,380–382]
- **Verbeter het begrip van de andere klimaateffecten van HVB.** Gezien de klimaatimpact van kortlevende emissiesoorten (zoals aërosolen, waterdamp en NO_x) gerelateerd aan de huidige luchtvaart 2-5 keer zo groot wordt geschat als de klimaatimpact van CO_2, is het van belang dat het huidige onderzoek over de klimaatwinst van HVB wordt uitgebreid naar deze emissiesoorten.[38,41,453] Daarnaast kan de productie van HVB ook een effect hebben op de oppervlakte-albedo, oppervlakteruwheid en evapotranspiratie. Verder onderzoek moet uitwijzen hoe groot de effecten hiervan zijn ten opzichte van de totale klimaatwinst van HVB.
- **Kwantificeer ook andere duurzaamheidsindicatoren voor het gebruik van HVB.** HVB-productie kan een effect hebben op andere duurzaamheidsindicatoren, zoals luchtkwaliteit, werkgelegenheid, landgebruik en watergebruik. Het is belangrijk om deze parameters te kwantificeren om negatieve effecten te

vermijden en uit te zoeken of de maatschappelijke voordelen opwegen tegen de maatschappelijke investeringen.

- **Onderzoek de rol van biobrandstoffen in de scheepvaart.** De uitdaging voor de scheepvaart om emissies te reduceren is van dezelfde ordegrootte als voor de luchtvaartsector. Het huidige aandeel van de scheepvaart in de totale mondiale uitstoot van broeikasgassen bedraagt 1.6%, waarvan 79% wordt uitgestoten in internationale wateren. Tegelijkertijd groeien de emissies van de internationale schaapvaart met 50%-250% tussen nu en 2050 door groei van de industrie.[393,435] Uit Hoofdstuk 6 blijkt dat het gebruik van biobrandstoffen in de scheepvaart significant kan groeien in het komende decennium. Het wordt daarom aangeraden om gedetailleerder onderzoek te doen naar de toekomstige productie van biobrandstoffen voor de scheepvaart in de context van een ontwikkelende bio-economie.

Acknowledgements

ACKNOWLEDGEMENTS

De dag heeft mooie plannen – The day has grand plans. Life is a chain of largely coincidental events, which seemingly create wondrous experiences and inspiring interactions out of thin air.

This journey begins in a plane (true story). I was flying back from Thailand – a holiday destination which is ironically often used by the media to illustrate how much emissions are associated with flying. At the time, I was looking for an internship in the field of renewable energy in order to obtain my master's degree. When reading the in-flight magazine, Inez drew my attention to an article about biofuels used in aircraft. To my surprise, the pioneer in this area was a Dutch company called SkyNRG. Half a year later, I would complete my internship at SkyNRG and hear about an opening for a junior researcher on the topic of renewable jet fuel. On that day, I biked past a building with the above phrase painted on it.

In the years to follow, I had many inspiring encounters with people I would like to thank here. I would like to start by expressing my gratitude to Ric, Martin en André for your unceasing willingness to think along. Ric, your pragmatic approach has many a time saved me from losing track or pace. You have been of great support throughout all phases of my PhD – my apologies for walking unannounced into your office umpteen times. Martin, thank you for creating an atmosphere with plenty of room to explore new topics and initiate new projects. Your accessibility is arguably one of the main reasons for the pleasant atmosphere in the group. André, even though you were based in Groningen, I think your vision is omnipresent in this thesis. I admire your ability to combine a bird's-eyed view with a spot-on eye for detail. Thank you for being part of this project.

I also want to thank the Energy & Resources team, who have been of great support during these four years. Although not immediately apparent from the outside of the Unnik building, the warm atmosphere inside the building creates a great working place. I would like to thank all colleagues for the chill-out sessions in the coffee corner, discussions during lunch, soccer matches (including muscle soreness) and bike rides (except that one time on the dyke). Special thanks to those who, like me, populated the office at the end of the hallway every now and then; Jorge, Vassilis, Udeke, Ingeborg and Ioannis. Vassilis, I am happy I got the opportunity to work with you and exchange ideas on the last paper. Marnix and Mijndert, thanks for joining the ride and being my PhD partners in crime.

I should also thank the SkyNRG team, which I was happy to be part of over the past four and a half years. I enjoyed the team spirit and drive to explore new areas and build an industry from scratch. My experience at SkyNRG has allowed me to improve my

research, make it more relevant and valorize its results. Maarten, thank you for giving me the opportunity to combine the two functions. I always felt space to maintain my scientific integrity amid our discussions on policy, industry trends and technologies. Captain Falcon, I am leaving the ship, but there is no doubt it is heading somewhere great. SkyNRG is a great place thanks to the unique group of people; Maarten, Misha, Ox, Suus, Theye, Eline, Merel, Renco, Fransie, Charlotte, Appie, Rik, Myrna, Bart, Kasper, Hein, and of course Leroy. Go make this market.

The chapters in this thesis are mostly the result of joint efforts. During my PhD I had the pleasure to cooperate with many inspiring people. I would like to thank Raphael, Becky and Evangelos, with whom we explored the area of renewable jet fuels in its early days. I am grateful for the help of Elisabeth and Karin. Thank you for your enthusiasm and generous contributions to Chapter 3. I am looking forward to returning to the northernmost university in the future to further explore the area (I might even take the train again). Laura and Michael, thank you for supporting and guiding the research featured in Chapter 4. Your hospitability and expertise has been an important contributor to the quality and impact of this work. I also would like to thank Joost and Marc for sharing their time and brains. Joost, thank you for hosting me at ECN and helping me to unravel the RESolve-Biomass model. Marc, I very much appreciated the insightful conversations we had, always accompanied by the usual touch of humor.

I would also like to thank Mark, Robert, Steven and Florian who facilitated my stay at MIT, which was one of the highlights of my PhD. Mark and Robert, I really enjoyed our intensive collaboration. Thank you for joining my exploratory journey, raising challenging questions and providing valuable feedback. Carla, *dankie* for teaching me intro to Climate Science and your help to obtain the results discussed in Chapter 5. A big thanks to the LAE group who has been very welcoming during my stay in Boston.

The journey goes on. I am very grateful for those traveling along. Inez, a party spontaneously unfolds everywhere you go. I love those parties. Thank you for all support and happiness your presence brings along. I am very excited to embark on the adventures that lie ahead. Eit and Ded, thank you for creating a home I love to go back to. Rinne, I am not sure how we both ended up pursuing a PhD, yet here we are. Thanks for your optimism and energy. I would like to thank all my (extended) family and friends. For those who have been wondering what I have been doing exactly, I can highly recommend reading this book. It's only three hundred something pages. The comic at the beginning of this thesis is a great place to start. Special thanks to Selma, who helped to communicate my research to the wider public, including the design of the comic. Uutje, you've been a wonderful host over the last nine years, I am very happy to stay around for a little longer.

De Klaastoren, Utrecht (de Jong, 1953)[454]

About the Author

ABOUT THE AUTHOR

Sierk de Jong was born on 18 September 1991 in Wageningen, The Netherlands. He studied Liberal Arts and Sciences at University College Utrecht with a major in mathematics and physics. After obtaining his BSc in 2012, he enrolled in the master Energy Science at Utrecht University for its interdisciplinary approach to societally relevant issues such as climate change, sustainable growth and energy security. As part of his master's degree, he did an internship with the business development team of SkyNRG, an Amsterdam-based supplier of and market developer for renewable jet fuel.

Sierk joined the Copernicus Institute of Sustainable Development as a Junior Researcher on renewable jet fuels in 2014, while continuing his work at SkyNRG as a business developer. For SkyNRG he engaged in supply chain development activities, particularly in the Nordic countries. At the Copernicus Institute, he worked on the Renewable Jet Fuel Supply Chain Development and Flight Operations (RENJET) project. The results of this project constitute this thesis. He enjoyed the academic freedom to collaborate with research institutes working on related topics, such as Massachusetts Institute of Technology (MIT), Energy research Centre of the Netherlands (ECN), Lulea University of Technology (LTU) and the Joint Research Centre (JRC). He was a visiting PhD student at the Laboratory for Aviation and the Environment at MIT in early 2017, where he worked on a method to quantify the climate impact of bioenergy production systems (Chapter 5).

PUBLICATIONS

de Jong S, Hoefnagels R, Faaij A, Slade R, Mawhood R and Junginger M, The feasibility of short-term production strategies for renewable jet fuels – a comprehensive techno-economic comparison. Biofuels, Bioprod Biorefining 9:778–800 (2015).

Mawhood R, Gazis E, de Jong S, Hoefnagels R and Slade R, Production pathways for renewable jet fuel: a review of commercialization status and future prospects. Biofuels, Bioprod Biorefining 10 (2016).

Alves CM, Valk M, de Jong S, Bonomi A, van der Wielen LAM and Mussatto SI, Techno-economic assessment of biorefinery technologies for aviation biofuels supply chains in Brazil. Biofuels, Bioprod Biorefining 11 (2017).

de Jong S, Antonissen K, Hoefnagels R, Lonza L, Wang M, Faaij A et al., Life-cycle analysis of greenhouse gas emissions from renewable jet fuel production. Biotechnol Biofuels 10:1–18 (2017).

de Jong S, Hoefnagels R, Wetterlund E, Pettersson K, Faaij A and Junginger M, Cost optimization of biofuel production - the impact of economies of scale, integration, intermodal transport and distributed supply chain configurations. Appl Energy 195: 1055–1070 (2017).

de Jong S, Hoefnagels R, van Stralen J, Londo M, Slade R, Faaij A et al., Renewable Jet Fuel in the European Union Scenarios and Preconditions for Renewable Jet Fuel Deployment towards 2030. https://www.uu.nl/sites/default/files/renewable_jet_fuel_in_the_european_union_-_scenarios_and_preconditions_for_renewable_jet_fuel_deployment_towards_2030.pdf (2017).

Kluts I, Brinkman M, de Jong S and Junginger M, Biomass Resources: Agriculture. Advances in Biochemical Engineering/Biotechnology Berlin, Heidelberg: Springer Berlin / Heidelberg p. 1–14 (2017).

Tsiropoulos I, Hoefnagels R, de Jong S, Broek M van den, Patel M and Faaij A, Emerging bioeconomy sectors in energy systems modeling – integrated systems analysis of electricity, heat, road transport, aviation, and chemicals: a case study for the Netherlands. Biofuels, Bioprod Biorefining (2018).

Bosch J, de Jong S, Hoefnagels R and Slade R, Aviation biofuels: strategically important, technically achievable, tough to deliver. https://www.imperial.ac.uk/media/imperial-college/grantham-institute/public/publications/briefing-papers/BP-23-Aviation-Biofuels.pdf (2017).

References

REFERENCES

1. IPCC, *Climate Change 2014 Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. https://www.ipcc.ch/pdf/assessment-report/ar5/syr/SYR_AR5_FINAL_full_wcover.pdf (2014).

2. Myhre G, Shindell D, Bréon F-M, Collins W, Fuglestvedt J, Huang J *et al.*, *Anthropogenic and Natural Radiative Forcing*. *In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change.* (2013).

3. UNFCCC, *Paris Agreement*. http://unfccc.int/resource/docs/2015/cop21/eng/l09r01.pdf.

4. van Vuuren DP, Edmonds J, Kainuma M, Riahi K, Thomson A, Hibbard K *et al.*, The representative concentration pathways: An overview. *Clim Change* **109**:5–31 (2011).

5. Fuss S, Canadell JG, Peters GP, Tavoni M, Andrew RM, Ciais P *et al.*, Betting on negative emissions. *Nat Clim Chang* **4**:850–853 (2014).

6. Blanco G., Gerlagh R, Suh S, Barrett J, Coninck HC de, Morejon CFD *et al.*, *Drivers, Trends and Mitigation. In: Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. (2014).

7. Olivier JGJ, Schure KM and Peters JAHW, *Trends in Global CO2 and Total Greenhouse Gas Emissions*. (2017).

8. Sims R, Schaeffer R, Creutzig F, Cruz-Núñez X, D'Agosto M, Dimitriu D *et al.*, *Transport. In: Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. (2014).

9. Lee DS, Fahey DW, Forster PM, Newton PJ, Wit RCN, Lim LL *et al.*, Aviation and global climate change in the 21st century. *Atmos Environ* **43**:3520–3537 (2009).

10. Berntsen T and Fuglestvedt J, Global temperature responses to current emissions from the transport sectors. *PNAS* **105**:19154–19159 (2008).

11. Group on International Aviation and Climate Change (GIACC), *Global Aviation CO2 Emissions Projections to 2050*. https://www.icao.int/environmental-protection/GIACC/Giacc-4/Giacc4_ip01_en.pdf (2009).

12. International Civil Aviation Organisation, *2016 Environmental Report*. https://www.icao.int/environmental-protection/Documents/ICAO Environmental Report 2016.pdf (2016).

13. Energy Information Administration, *International Energy Outlook 2017.* https://www.eia.gov/outlooks/ieo/ (2017).

14. International Energy Agency, *Key World Energy Statistics 2017*. https://www.iea.org/publications/freepublications/publication/KeyWorld2017.pdf (2017).

15. van Vuuren D, Elzen M den, Lucas P, Eickhout B, Strengers B, Ruijven B van *et al.*, Stabilizing greenhouse gas concentrations at low levels: an assessment of reduction strategies and costs. *Clim Change* **81**:119–159 (2007).

16. Hileman JI, Ortiz DS, Bartis JT, Wong HM, Donohoo PE, Weiss MA *et al.*, *Near-Term Feasibility of Alternative Jet Fuels*. https://www.rand.org/content/dam/rand/pubs/technical_reports/2009/RAND_TR554.pdf (2009).

17. IATA, *IATA 2015 Report on Alternative Fuels*. https://www.iata.org/publications/Documents/2015-report-alternative-fuels.pdf (2014).

18. Gegg P, Budd L and Ison S, Stakeholder Views of the Factors Affecting the Commercialization of Aviation Biofuels in Europe. *Int J Sustain Transp* **9**:542–550 (2015).

19. The Institution of Engineering and Technology, *All Electric Aircraft. Key insights and resources emerging from an IET Aerospace Technical and Professional Network seminar in January 2016*. http://www.theiet.org/communities/techbites/-files/all-electric-aircraft.cfm?type=pdf (2016).

20. International Civil Aviation Organisation, *Resolution A39-3: Consolidated statement of continuing ICAO policies and practices related to environmental protection - Global Market-based Measure (MBM) scheme (39th general assembly)*. http://www.icao.int/environmental-protection/Documents/Resolution_A39_3.pdf (2016).

21. European Commission, *2 million tons per year : A performing biofuels supply chain for EU aviation August 2013 Update*. https://ec.europa.eu/energy/sites/ener/files/20130911_a_performing_biofuels_supply_chain.pdf (2013).

22. International Civil Aviation Organisation, *Draft Assembly Resolution text on a Global Market-based Measure (GMBM) Scheme*. http://www.icao.int/Meetings/GLADs-2016/Documents/Draft Assembly Resolution text on GMBM for 2016 GLADs.pdf (2016).

23. International Energy Agency, *Tracking Clean Energy Progress 2017*. https://www.iea.org/publications/freepublications/publication/TrackingCleanEnergyProgress2017.pdf (2017).

24. Chum H, Faaij A, Moreira J, Berndes G, Dhamija P, Dong H *et al.*, *Bioenergy. In: IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation*. https://www.ipcc.ch/report/srren/ (2011).

25. Bauen A, Howes J, Bertuccioli L and Chudziak C, *Review of the potential for biofuels in aviation*. https://www.theccc.org.uk/archive/aws2/Aviation Report 09/E4tech %282009%29, Review of the potential for biofuels in aviation.pdf (2009).

26. SAFUG, *Our Commitment to Sustainable Options*. http://www.safug.org/safug-pledge/(2017) [December 9 2015].

27. Sherbacrow B, *Paramount, CA GreenJet Refinery*. https://www.smgov.net/uploadedFiles/Departments/Airport/Sustainability/20150126_AltAir_Presentation.pdf(2015) [October 30 2016].

28. Mawhood R, Gazis E, de Jong S, Hoefnagels R and Slade R, Production pathways for renewable jet fuel: a review of commercialization status and future prospects. *Biofuel, Bioprod Bioref* **10** (2016).

29. Hamelinck BC, Cuijpers M, Spoettle M and Bos A Van Den, *Biofuels for Aviation*. https://www.ecofys.com/files/files/ecofys-2013-biofuels-for-aviation.pdf (2012).

30. Pearlson M, Wollersheim C and Hileman J, A techno-economic review of hydroprocessed renewable esters and fatty acids for jet fuel production. *Biofuels Bioprod, Bioref* **7**:89–96 (2013).

31. de Jong S, Hoefnagels R, van Stralen J, Londo M, Slade R, Faaij A *et al.*, *Renewable Jet Fuel in the European Union Scenarios and Preconditions for Renewable Jet Fuel Deployment towards 2030*. https://www.uu.nl/sites/default/files/renewable_jet_fuel_in_the_european_union_-_scenarios_and_preconditions_for_renewable_jet_fuel_deployment_towards_2030.pdf (2017).

32. Matas Güell B, Bugge M, Kempegowda R, George A and Paap S, *Benchmark of conversion and production technologies for synthetic biofuels for aviation*. SINTEF Energy Research, Trondheim (2012).

33. Seber G, Malina R, Pearlson MN, Olcay H, Hileman JI and Barrett SRH, Environmental and economic assessment of producing hydroprocessed jet and diesel fuel from waste oils and tallow. *Biomass and Bioenergy* **67**:108–118 (2014).

34. Staples MD, Malina R, Olcay H, Pearlson MN, Hileman JI, Boies A *et al.*, Lifecycle greenhouse gas footprint and minimum selling price of renewable diesel and jet fuel from fermentation and advanced fermentation production technologies. *Energy Environ Sci* **7**:1545–1554 (2014).

35. Klein-Marcuschamer D, Turner C, Allen M, Grey P, Dietzgen R, Gresshoff P *et al.*, Technoeconomic analysis of renewable aviation fuel from microalgae, Pongamia pinnata, and sugarcane. *Biofuels Bioprod, Bioref* **7**:416–428 (2013).

36. Atsonios K, Kougioumtzis M-A, D. Panopoulos K and Kakaras E, Alternative thermochemical routes for aviation biofuels via alcohols synthesis: Process modeling, techno-economic assessment and comparison. *Appl Energy* **138**:346–366 (2015).

37. Cherubini F, Fuglestvedt J, Gasser T, Reisinger A, Cavalett O, Huijbregts MAJ *et al.*, Bridging the gap between impact assessment methods and climate science. *Environ Sci Policy* **64**:129–140 (2016).

38. Stratton RW, Wolfe PJ and Hileman JI, Impact of Aviation Non-CO 2 Combustion Effects on the Environmental Feasibility of Alternative Jet Fuels. *Environ Sci Technol* **45**:10736–10743 (2011).

39. Elgowainy A, Han J, Wang M, Carter N, Stratton R and Hileman J, *Life-Cycle Analysis of Alternative Aviation Fuels in GREET*. https://greet.es.anl.gov/publication-aviation-lca (2012).

40. Caiazzo F, Malina R, Staples MD, Wolfe PJ, Yim SHL and Barrett SRH, Quantifying the climate impacts of albedo changes due to biofuel production: a comparison with biogeochemical effects. *Environ Res Lett* **9** (2014).

41. Moore RH, Thornhill KL, Weinzierl B, Sauer D, D'Ascoli E, Kim J *et al.*, Biofuel blending reduces particle emissions from aircraft engines at cruise conditions. *Nature* **543**:411–415 (2017).

42. Stratton RW, Wong HM and Hileman JI, *Life Cycle Greenhouse Gas Emissions from Alternative Jet Fuels*. http://web.mit.edu/aeroastro/partner/reports/proj28/partner-proj28-2010-001.pdf (2010).

43. Han J, Elgowainy A, Cai H and Wang MQ, Life-cycle analysis of bio-based aviation fuels. *Bioresour Technol* **150**:447–456 (2013).

44. Cherubini F, Bird ND, Cowie A, Jungmeier G, Schlamadinger B and Woess-Gallasch S, Energy- and greenhouse gas-based LCA of biofuel and bioenergy systems: Key issues, ranges and recommendations. *Resour Conserv Recycl* **53**:434–447 (2009).

45. Searchinger T, Heimlich R, Houghton R, Dong F, Elobeid A, Fabiosa J *et al.*, Use of U.S. Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land-Use Change. *Science* **319**:1238–1240 (2008).

46. Fargione J, Hill J, Tilman D, Polasky S and Hawthorne P, Land Clearing and the Biofuel Carbon Debt. *Science* **319**:1235–1238 (2008).

47. Schlamadinger B, Spitzer J, Kohlmaier GH and Lüdeke M, Carbon balance of bioenergy from logging residues. *Biomass and Bioenergy* **8**:221–234 (1995).

48. Holtsmark B, Harvesting in boreal forests and the biofuel carbon debt. *Clim Change* **112**:415–428 (2012).

49. Stratton RW, Wong HM and Hileman JI, Quantifying variability in life cycle greenhouse gas inventories of alternative middle distillate transportation fuels. *Environ Sci Technol* **45**:4637–4644 (2011).

50. Bailis RE and Baka JE, Greenhouse gas emissions and land use change from Jatropha curcas-based jet fuel in Brazil. *Environ Sci Technol* **44**:8684–8691 (2010).

51. Carter N, Stratton R, Bredehoeft M and Hileman J, Energy and Environmental Viability of Select Alternative Jet Fuel Pathways. 47th AIAA/ASME/SAE/ASEE Joint Propulsion Conference & Exhibit (2011).

52. Shonnard DR, Williams L and Kalnes TN, Camelina-Derived Jet Fuel and Diesel: Sustainable Advanced Biofuels. *Environ Prog Sustain Energy* **29**:383–392 (2010).

53. Cox K, Renouf M, Dargan A, Turner C and Klein-Marcuschamer D, Environmental life cycle assessment (LCA) of aviation biofuel from microalgae, Pongamia pinnata, and sugarcane molasses. *Biofuels, Bioprod Biorefining* **8**:579–593 (2014).

54. Chum H and Warner E, *Tools for greenhouse gas (GHG) assessment for biofuels: a comparison*. http://ieabioenergy2015.org/fileadmin/veranstaltungen/2015/IEA_Bioenergy_Conference/S08-4_Chum.pdf2015 IEA Bioenergy Conference, Berlin, October 27-29, 2015. (2015).

55. Wang M, Huo H and Arora S, Methods of dealing with co-products of biofuels in life-cycle analysis and consequent results within the U.S. context. *Energy Policy* **39**:5726–5736 (2011).

56. Levasseur A, Cavalett O, Fuglestvedt JS, Gasser T, Johansson DJA, Jørgensen S V. *et al*., Enhancing life cycle impact assessment from climate science: Review of recent findings and recommendations for application to LCA. *Ecol Indic* **71**:163–174 (2016).

57. Levasseur A, Lesage P, Margni M, Deschěnes L and Samson R, Considering time in LCA: Dynamic LCA and its application to global warming impact assessments. *Environ Sci Technol* **44**:3169–3174 (2010).

58. Daystar J, Venditti R and Kelley SS, Dynamic greenhouse gas accounting for cellulosic biofuels: implications of time based methodology decisions. *Int J Life Cycle Assess* **22**:812–826 (2017).

59. O'Hare M, Plevin RJ, Martin JI, Jones AD, Kendall A and Hopson E, Proper accounting for time increases crop-based biofuels' greenhouse gas deficit versus petroleum. *Environ Res Lett* **4** (2009).

60. Kendall A, Chang B and Sharpe B, Accounting for time-dependent effects in biofuel life cycle greenhouse gas emissions calculations. *Environ Sci Technol* **43**:7142–7147 (2009).

61. Cherubini F, Bright RM and Strømman AH, Global climate impacts of forest bioenergy: what, when and how to measure? *Environ Res Lett* **8** (2013).

62. Schwietzke S, Griffin WM and Matthews HS, Relevance of emissions timing in biofuel greenhouse gases and climate impacts. *Environ Sci Technol* **45**:8197–8203 (2011).

63. Creutzig F, Ravindranath NH, Berndes G, Bolwig S, Bright RM, Cherubini F *et al*., Bioenergy and climate change mitigation : an assessment. *GCB Bioenergy* **7**:916–944 (2015).

64. European Parliament and the Council, *Directive (EU) 2015/1513: amending Directive 98/70/EC relating to the quality of petrol and diesel fuels and amending Directive 2009/28/EC on the promotion of the use of energy from renewable sources*. http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32015L1513&from=EN (2015).

65. Environmental Protection Agency, *Regulation of fuels and fuel additives: Changes to renewable fuel standard program; Final Rule*. https://www.gpo.gov/fdsys/pkg/FR-2010-03-26/pdf/2010-3851.pdf (2010).

66. US Environmental Protection Agency, *Public Data for the Renewable Fuel Standard*. https://www.epa.gov/fuels-registration-reporting-and-compliance-help/public-data-renewable-fuel-standard(2018) [March 9 2018].

67. European Parliament and the Council, *Directive 2009/28/EC: On the promotion of the use of energy from renewable sources*. http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32009L0028&from=EN (2009).

68. European Commission, *Proposal for a directive of the European Parliament and of the council on the promotion of the use of energy from renewable sources (recast)*. http://eur-lex.europa.eu/resource.html?uri=cellar:151772eb-b7e9-11e6-9e3c-01aa75ed71a1.0001.02/DOC_1&format=PDF(2016).

69. El Takriti S, Pavlenko N and Searle S, *Mitigating International Aviation Emissions Risks and Opportunities for Alternative Jet Fuels*. https://www.theicct.org/sites/default/files/publications/Aviation-Alt-Jet-Fuels_ICCT_White-Paper_22032017_vF.pdf (2017).

70. Kousoulidou M and Lonza L, Biofuels in aviation: Fuel demand and CO2 emissions evolution in Europe toward 2030. *Transp Res Part D Transp Environ* **46**:166–181 (2016).

71. E4tech, *Sustainable Aviation Fuels - Potential for the UK aviation industry*. http://www.e4tech.com/wp-content/uploads/2015/06/SustainableAviationFuelsReport.pdf (2014).

72. BP, *BP Statistical Review of World Energy 2017*. http://www.bp.com/content/dam/bp/en/corporate/pdf/energy-economics/statistical-review-2017/bp-statistical-review-of-world-energy-2017-renewable-energy.pdf (2017).

73. Moavenzadeh J, Torres-Montoya M and Gange T, *Repowering Transport: Project White Paper*. http://www20.iadb.org/intal/catalogo/PE/2012/10371.pdf (2011).

74. Air Transport Action Group, *Beginner's Guide to Aviation Biofuels*. http://www.atag.org/component/downloads/downloads/60.html (2011).

75. Air Transport Action Group, *A sustainable flightpath towards reducing emissions - Position paper presented at UNFCCC Climate Talks, Doha*. (2012).

76. Mandolesi de Araújo CD, de Andrade CC, de Souza e Silva E and Dupas FA, Biodiesel production from used cooking oil: A review. *Renew Sustain Energy Rev* **27**:445–452 (2013).

77. Spöttle M, Alberici S, Toop G, Peters D, Gamba L, Ping S *et al.*, *Low ILUC potential of wastes and residues for biofuels Low ILUC potential of wastes and residues for biofuels*. https://www.ecofys.com/files/files/ecofys-2013-low-iluc-potential-of-wastes-and-residues.pdf (2013).

78. Bond JQ, Upadhye AA, Olcay H, Jae J, Xing R, Alonso M *et al.*, Environmental Science Production of renewable jet fuel range alkanes and commodity chemicals from integrated catalytic processing of biomass. *Energy Environ Sci* **7**:1500–1523 (2014).

79. Agusdinata DB, Zhao F, Ileleji K and DeLaurentis D, Life cycle assessment of potential biojet fuel production in the United States. *Environ Sci Technol* **45**:9133–9143 (2011).

80. Ekbom T, Hjerpe C, Hagström M and Hermann F, *Pilot study of Bio-jet A-1 fuel production for Stockholm-Arlanda Airport*. https://energiforskmedia.blob.core.windows.net/media/17972/foerstudie-foer-biobaserat-flygbraensle-foer-stockholm-arlanda-flygplats-vaermeforskrapport-1125.pdf (2009).

81. Pham V, Holtzapple M and El-Halwagi M, Techno-economic analysis of biomass to fuel conversion via the MixAlco process. *J Ind Microbiol Biotechnol* **37**:1157–1168 (2010).

82. Natelson RH, Wang W-C, Roberts WL and Zering KD, Technoeconomic analysis of jet fuel production from hydrolysis, decarboxylation, and reforming of camelina oil. *Biomass and Bioenergy* **75**:23–34 (2015).

83. Fulton L, Morrison G, Parker N, Witcover J and Sperling D, *Three Routes Forward for Biofuels : Incremental, Transitional, and Leapfrog*. (2014).

84. Merrow W, Phillips K and Myers C, *Understanding Cost Growth and Performance Shortfalls in Pioneer Process Plants*. https://www.rand.org/content/dam/rand/pubs/reports/2006/R2569.pdf (1981).

85. Gonzalez R, Treasure T, Phillips R, Jameel H and Saloni D, Economics of cellulosic ethanol production: green liquor pretreatment for softwood and hardwood, greenfield and repurpose scenarios. *BioResources* **6**:2551–2567 (2013).

86. Cardona C and Sánchez O, Fuel ethanol production: process design trends and integration opportunities. *Bioresour Technol* **98**:2415–2457 (2007).

87. International Energy Agency, *Technology Roadmap - Biofuels for Transport*. https://www.iea.org/publications/freepublications/publication/Biofuels_Roadmap_WEB.pdf (2011).

88. POET, *Project Liberty*. http://poet-dsm.com/liberty [October 10 2014].

89. Iogen, *Costa Pinto Project*. http://www.iogen.ca/raizen-project/ [January 21 2015].

90. IATA, *IATA 2013 Report on Alternative Fuels*. (2013).

91. Gibbons WR and Hughes SR, Integrated biorefineries with engineered microbes and high-value co-products for profitable biofuels production. In: Tomes D, Prakash L, Songstad D, editors. Biofuels: Global impact on renewable energy, production agriculture and technological advancements Springer Science + Business Media LLC p. 265–283(2009).

92. Čuček L, Martín M, Grossmann IE and Kravanja Z, Energy, water and process technologies integration for the simultaneous production of ethanol and food from the entire corn plant. *Comput Chem Eng* **35**:1547–1557 (2011).

93. Hytonen E and Stuart PR, Integrating Bioethanol Production into an Integrated Kraft Pulp and Paper Mill: Techno-Economic Assessment. *Pulp Pap Canada* **110**:25–32 (2009).

94. Naqvi M, Yan J and Dahlquist E, Black liquor gasification integrated in pulp and paper mills: A critical review. *Bioresour Technol* **101**:8001–8015 (2010).

95. Ragauskas AJ, Nagy M, Kim DH, Eckert C, Hallett JP and Liotta CL, From wood to fuels: Integrating biofuels and pulp production. *Ind Biotechnol* **2**:55–65 (2006).

96. Moshkelani M, Marinova M, Perrier M and Paris J, The forest biorefinery and its implementation in the pulp and paper industry: Energy overview. *Appl Therm Eng* **50**:1427–1436 (2013).

97. Krajnc D and Glavič P, Assessment of different strategies for the co-production of bioethanol and beet sugar. *Chem Eng Res Des* **87**:1217–1231 (2009).

98. Nourredini H, Bandlamudi SRP and Guthrie EA, A Novel Method for the Production of Biodiesel from the Whole Stillage-Extracted Corn Oil. *J Am Oil Chem Soc* **86**:83–91 (2009).

99. Balan V, Rogers C a., Chundawat SPS, Costa Sousa L, Slininger PJ, Gupta R *et al.*, Conversion of Extracted Oil Cake Fibers into Bioethanol Including DDGS, Canola, Sunflower, Sesame, Soy, and Peanut for Integrated Biodiesel Processing. *J Am Oil Chem Soc* **86**:157–165 (2008).

100. Jin Y, Jameel H, Chang H and Phillips R, Green Liquor Pretreatment of Mixed Hardwood for Ethanol Production in a Repurposed Kraft Pulp Mill. *J Wood Chem Technol* **30**:86–104 (2010).

101. Phillips RB, Jameel H and Chang HM, Integration of pulp and paper technology with bioethanol production. *Biotechnol Biofuels* **6**:13 (2013).

102. Ereev SY and Patel MK, Standardized cost estimation for new technologies (SCENT) - methodology and tool. *J Bus Chem* **9** (2012).

103. Queens University, *Economic Indicators*. http://www.chemeng.queensu.ca/courses/CHEE332/files/CEPCI_2014.pdf [June 5 2014].

104. Instituto Superior Técnico, *Economic Indicators*. http://web.ist.utl.pt/~ist11061/de/IndPrecos/Ec_indic_Jan08.PDF [June 5 2014].

105. Towler G and Sinnott R, *Chemical Engineering Design: Principles, Practice and Economics of Plant and Process Design*. Butterworth-Heinemann, Oxford, UK (2012).

106. Peters M, Timmerhaus K and West R, *Plant Design and Economic for Chemical Engineers*. McGraw-Hill, Columbus, US (2003).

107. Zhu Y, Tjokro Rahardjo S, Valkenburg C, Snowden-Swan L, Jones S and Machinal M, *Techno-economic Analysis for the Thermochemical Conversion of Biomass to Liquid Fuels*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-19009.pdf (2011).

108. Swanson RM, Satrio JA, Brown RC, Platon A and Hsu DD, *Techno-Economic Analysis of Biofuels Production Based on Gasification*. https://www.nrel.gov/docs/fy11osti/46587.pdf (2010).

109. Haarlemmer G, Boissonnet G, Imbach J, Setier P-A and Peduzzi E, Second generation BtL type biofuels – a production cost analysis. *Energy Environ Sci* **5**:8445–8456 (2012).

110. Tunå P and Hulteberg C, Woody biomass-based transportation fuels – A comparative techno-economic study. *Fuel* **117**:1020–1026 (2014).

111. Sarkar S, Kumar A and Sultana A, Biofuels and biochemicals production from forest biomass in Western Canada. *Energy* **36**:6251–6262 (2011).

112. Anex RP, Aden A, Kazi FK, Fortman J, Swanson RM, Wright MM *et al*., Techno-economic comparison of biomass-to-transportation fuels via pyrolysis, gasification, and biochemical pathways. *Fuel* **89**:S29–S35 (2010).

113. Meerman JC, Ramírez A, Turkenburg WC and Faaij a. PC, Performance of simulated flexible integrated gasification polygeneration facilities, Part B: Economic evaluation. *Renew Sustain Energy Rev* **16**:6083–6102 (2012).

114. Consonni S, Katofsky RE and Larson ED, A gasification-based biorefinery for the pulp and paper industry. *Chem Eng Res Des* **87**:1293–1317 (2009).

115. Ekbom T, Berglin N and Lögdberg S, *Black Liquor Gasification with Motor Fuel Production – BLGMF II*. Nykomb Synergetics AB, Stockholm, SE (2005).

116. Zhu Y, Biddy MJ, Jones SB, Elliott DC and Schmidt AJ, Techno-economic analysis of liquid fuel production from woody biomass via hydrothermal liquefaction (HTL) and upgrading. *Appl Energy* **129**:384–394 (2014).

117. Jones S, Valkenburg C, Holladay J, Stevens D, Kinchin C, Walton C *et al*., *Production of Gasoline and Diesel from Biomass via Fast Pyrolysis , Hydrotreating and Hydrocracking : A Design Case*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-18284.pdf.

118. Wright MM, Daugaard DE, Satrio JA and Brown RC, Techno-economic analysis of biomass fast pyrolysis to transportation fuels. *Fuel* **89**:S2–S10 (2010).

119. Brown TR, Thilakaratne R, Brown RC and Hu G, Techno-economic analysis of biomass to transportation fuels and electricity via fast pyrolysis and hydroprocessing. *Fuel* **106**:463–469 (2013).

120. Jones S, Meyer P, Snowden-Swan L, Tan E, Dutta A, Jacobson J *et al*., *Process Design and Economics for the Conversion of Lignocellulosic Biomass to Hydrocarbon Fuels Fast Pyrolysis and Hydrotreating*. https://www.nrel.gov/docs/fy14osti/60223.pdf (2013).

121. Crawford J, Techno-economic analysis of hydrocarbon biofuels from poplar biomass (Master Thesis). https://digital.lib.washington.edu/researchworks/bitstream/handle/1773/25142/Crawford_washington_0250O_12629.pdf?sequence=1(2013).

122. Kazi FK, Fortman J and Anex R, *Techno-Economic Analysis of Biochemical Scenarios for Production of Cellulosic Ethanol, NREL/TP-6A2-46588*. https://www.nrel.gov/docs/fy10osti/46588.pdf (2010).

123. Humbird D, Davis R, Tao L, Kinchin C, Hsu D, Aden A *et al*., *Process Design and Economics for Biochemical Conversion of Lignocellulosic Biomass to Ethanol*. https://www.nrel.gov/docs/fy11osti/47764.pdf (2011).

124. Hamelinck CN, Hooijdonk G Van and Faaij AP, Ethanol from lignocellulosic biomass : techno-economic performance in short-, middle- and long-term. *Biomass and Bioenergy* **28**:384–410 (2005).

125. Gnansounou E and Dauriat A, Techno-economic analysis of lignocellulosic ethanol: A review. *Bioresour Technol* **101**:4980–4991 (2010).

126. Air Resources Board, *NExBTL ® Renewable Diesel Singapore Plant*. http://www.arb.ca.gov/fuels/lcfs/2a2b/apps/neste-aus-rpt-031513.pdf p. 7(2012) [February 2 2015].

127. Valero, *Quarterly Report ended september 30, 2011*. http://www.valero.com/investorrelations/financialreports_filings_statements/documents/vec_3q11_10q.pdf(2011) [May 5 2015].

128. Port of Rotterdam, *Facts & figures: Rotterdam energy port and petrochemical cluster*. https://www.portofrotterdam.com/sites/default/files/Facts-Figures-Rotterdam-Energy-Port-and-Petrochemical-Cluster-Eng.pdf(2010).

129. Couper JR, *Process Engineering Economics*. Marcel Dekker, Inc., New York, US (2003).

130. KPMG, *Corporate tax rates table*. http://www.kpmg.com/global/en/services/tax/tax-tools-and-resources/pages/corporate-tax-rates-table.aspx [May 27 2014].

131. Johansson D, Berntsson T and Franck P-Å, Integration of FT fuel production with a complex oil refinery. *Int J Environ Sustain Dev* **13**:50–73 (2014).

132. Zheng Y, Lee C, Yu C, Cheng Y-S, Zhang R, Jenkins BM *et al.*, Dilute acid pretreatment and fermentation of sugar beet pulp to ethanol. *Appl Energy* **105**:1–7 (2013).

133. Blake F, *Weekly Refining Indicators Report (Week ending 13 February 2015)*. Scotia Howard Weil, New Orleans, US (2015).

134. Edwards MC and Doran-Peterson J, Pectin-rich biomass as feedstock for fuel ethanol production. *Appl Microbiol Biotechnol* **95**:565–575 (2012).

135. Huang H, Ramaswamy S, Al-dajani W, Tschirner U and Cairncross RA, Effect of biomass species and plant size on cellulosic ethanol : A comparative process and economic analysis. *Biomass and Bioenergy* **33**:234–246 (2009).

136. Confederation of European Paper Industries, *Key Statistics - European Pulp and Paper Industry*. http://www.cepi.org/publication/key-statistics-2012(2012).

137. Wessel H, New Graph Correlates Operating Labor for Chemical Process. *Chem Eng* **57**:209–210 (1952).

138. Eurostat, *Labour cost levels (lc_lci_lev)*. http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=lc_lci_lev&lang=en [May 10 2016].

139. Eurostat, *Labour cost index, nominal value - annual data (NACE Rev. 2) (lc_lci_r2_a)*. http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=lc_lci_r2_a&lang=en [July 9 2014].

140. Eurostat, *Gas prices for industrial consumers, from 2007 onwards - bi-annual data (nrg_pc_203)*. http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_pc_203&lang=en [May 23 2016].

141. Eurostat, *Electricity prices for industrial consumers, from 2007 onwards - bi-annual data (nrg_pc_205)*. http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_pc_205&lang=en [June 25 2016].

142. Kühner S, *Feedstock costs. Biomass based energy intermediates boosting biofuel production (BioBoost). Deliverable D1.1*. http://www.bioboost.eu/uploads/files/bioboost_d1.1-syncom_feedstock_cost-vers_1.0-final.pdf (2013).

143. Rotter S and Rohrhofer C, *Biomass Logistics. Biomass based energy intermediates boosting biofuel production (BioBoost). Deliverable 1.4*. http://www.bioboost.eu/uploads/files/bioboost_d1.4_fho_biomasslogistics_vers2.0-final.pdf (2013).

144. Platts, *Weekly biodiesel market report (December 31, 2013)*. http://www.platts.com/IM.Platts.Content/ProductsServices/Products/Biofuels-WeeklyGlobalBiodieselReport.pdf [June 25 2014].

145. Eurostat, *Purchase prices of the means of agricultural production (absolute prices) - annual price (from 2000 onwards) (apri_ap_ina)*. http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=apri_ap_ina&lang=en(2012) [July 9 2014].

146. Indexmundi, *Palm oil Monthly Price - Euro per Metric Ton*. http://www.indexmundi.com/commodities/?commodity=palm-oil&months=60&currency=eur [May 20 2014].

147. Platts, *European Marketscan*. https://www.platts.com/IM.Platts.Content/ProductsServices/Products/euromktscan.pdf(2014) [June 7 2015].

148. Poten & Partners, *LPG in World Markets. A Monthly Report on International Trends in LPG. February 2015*. http://www.poten.com/wp-content/uploads/2015/03/LPG-in-World-Markets-February-2015.pdf [June 6 2015].

149. Wright MM, Satrio JA, Brown RC, Daugaard DE and Hsu DD, *Techno-Economic Analysis of Biomass Fast Pyrolysis to Transportation Fuels*. https://www.nrel.gov/docs/fy11osti/46586.pdf (2010).

150. Katzer J, Ansolabehere S, Beer J, Deutch J, Ellerman D, Friedmann J *et al.*, *The Future of Coal*. https://energy.mit.edu/wp-content/uploads/2007/03/MITEI-The-Future-of-Coal.pdf (2007).

151. Lux Research, *Lux Alternative Fuels Tracker*. http://www2.luxresearchinc.com/products/market-data/alternative-fuels-tracker.html [May 3 2014].

152. Sugartech, *Sugar Factories of Europe*. http://www.sugartech.com/factories/list.php?regid=4 [May 7 2014].

153. Confederation of European Paper Industries, European Pulp Mill Database. Personal communication with CEPI. (2014).

154. Confederation Generale des Plantes de Betteraves, *La Betterave en 2014 - Assemblée Générale du 10 Décembre 2013*. www.cgb-france.fr/download.php?file=IMG/pdf/Rapport_Annu82eb.pdf (2013).

155. Jacobsen NB, Industrial Symbiosis in Kalundborg , Denmark. *J Ind Ecol* **10**:239–255 (2006).

156. Shi H, Chertow M and Song Y, Developing country experience with eco-industrial parks: a case study of the Tianjin Economic-Technological Development Area in China. *J Clean Prod* **18**:191–199 (2010).

157. Chertow MR, "Uncovering" Industrial Symbiosis. *J Ind Ecol* **11**:11–30 (2008).

158. Karlsson M and Wolf A, Using an optimization model to evaluate the economic benefits of industrial symbiosis in the forest industry. *J Clean Prod* **16**:1536–1544 (2008).

159. Sokka L, Pakarinen S and Melanen M, Industrial symbiosis contributing to more sustainable energy use – an example from the forest industry in Kymenlaakso, Finland. *J Clean Prod* **19**:285–293 (2011).

160. Van Berkel R, Fujita T, Hashimoto S and Fujii M, Quantitative assessment of urban and industrial symbiosis in Kawasaki, Japan. *Environ Sci Technol* **43**:1271–1281 (2009).

161. Ou L, Brown TR, Thilakaratne R, Hu G and Brown RC, Techno-economic analysis of co-located corn grain and corn stover ethanol plants. *Biofuels Bioprod, Bioref* **8**:412–422 (2014).

162. Gary J, Handwerk G and Kaiser M, *Petroleum Refining Technology and Economics*. CRC Press, Boca Raton, US (2007).

163. de Wit M and Faaij A, European biomass resource potential and costs. *Biomass and Bioenergy* **34**:188–202 (2010).

164. Digest B, *Amyris: Can their renewable jet fuel ever be affordable?* http://www.biofuelsdigest.com/bdigest/2013/06/27/amyris-can-their-renewable-jet-fuel-ever-be-affordable/(2013) [December 9 2014].

165. The Motley Fool, *Patience is Key After Amyris Earnings*. http://www.fool.com/investing/general/2013/11/01/patience-is-key-after-amyris-earnings.aspx [August 1 2014].

166. Platts, *Europe: ethanol price assessments (14 March 2014)*. http://www.platts.com/news-feature/2014/agriculture/ethanol-market-update/ethanol-europe [May 14 2014].

167. Kelloway A and Daoutidis P, Process Synthesis of Biore fi neries: Optimization of Biomass Conversion to Fuels and Chemicals. *Ind Eng Chem Res* **53**:5261–5273 (2014).

168. Smeets EMW, Lewandowski IM and Faaij APC, The economical and environmental performance of miscanthus and switchgrass production and supply chains in a European setting. *Renew Sustain Energy Rev* **13**:1230–1245 (2009).

169. Walsh ME, *U. S. Cellulosic Biomass Feedstock Supplies and Distribution*. http://ageconsearch.umn.edu/bitstream/7625/2/U.S. Biomass Supplies.pdf(2008) [December 8 2014].

170. Ericsson K, Nilsson LJ and Rosenqvist H, Energy crop production costs in the EU. *Biomass and Bioenergy* **33**:1577–1586 (2009).

171. Perlack RD and Stokes BJ (leads), *Biomass as Feedstock for a Bioenergy and Bioproducts Industry: An Update to the Billion-Ton Annual Supply*. https://www1.eere.energy.gov/bioenergy/pdfs/billion_ton_update.pdf (2011).

172. Rosillo-calle F, Teelucksingh S, Thrän D and Eiffert M, *The Potential and Role of Biofuels in commercial Air Transport - Biojetfuel*. http://www.bioenergytrade.org/downloads/T40-Biojetfuel-Report-Sept2012.pdf (2012).

173. Eni, *Eni Green Refinery (youtube movie)*. https://www.youtube.com/watch?v=0Mo5q_N2RqY(2014) [August 8 2014].

174. International Energy Agency, *From 1st to 2nd Generation Biofuel Technologies: An overview of current industry and RD&D activities*. Paris, France (2008).

175. Tecnon OrbiChem, *Caustic Soda*. http://www.orbichem.com/userfiles/CNF Samples/cas_13_11.pdf(2013).

176. Alibaba, *Industrial salt price (sodium chloride)*. http://www.alibaba.com/showroom/industrial-salt-price.html(2014).

177. Amyris, *Quarterly Report on Form 10-Q For the Quarterly Period Ended June 30, 2013*. http://investors.amyris.com/secfiling.cfm?filingID=1365916-13-96 (2013).

178. Daystar J, Gonzalez R, Jameel H, Kelley S, Park S, Phillips RB *et al*. http://innovation.research.wvu.edu/r/download/158951

179. Indexmundi, *Lime Prices*. http://www.indexmundi.com/en/commodities/minerals/lime/lime_t5.html(2011).

180. INSEE, *International prices of imported raw materials - Heavy fuel oil (Rotterdam)*. http://www.insee.fr/en/bases-de-donnees/bsweb/serie.asp?idbank=001642883(2013).

181. Eurostat, *HICP (2005 = 100) - monthly data (index) (prc_hicp_midx)*. http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=prc_hicp_midx&lang=en(2014) [March 19 2016].

182. Bureau of Labour Statistics, *Consumer Price Index - All Urban Consumers*. http://data.bls.gov/cgi-bin/surveymost?cu(2014) [July 9 2014].

183. Eurostat, *Price indices of agricultural products, output (2005 = 100) - annual data (apri_pi05_outa)*. http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=apri_pi05_outa&lang=en [July 5 2014].

184. Elbersen B, Startisky I, Hengeveld G, Schelhaas M-J and Naeff H, *Atlas of EU biomass potentials (Biomass Policies project)*. https://ec.europa.eu/energy/intelligent/projects/sites/iee-projects/files/projects/documents/biomass_futures_atlas_of_technical_and_economic_biomass_potential_en.pdfBiomass Futures. (2012).

185. Monforti F, Bódis K, Scarlat N and Dallemand J-F, The possible contribution of agricultural crop residues to renewable energy targets in Europe: A spatially explicit study. *Renew Sustain Energy Rev* **19**:666–677 (2013).

186. CEFS, CEFS Sugar Statistics. http://www.comitesucre.org/userfiles/CEFS Sugar Statistics Inquiry 2011 -FINAL Published(1).pdf (2013).

187. Jones S, Zhu Y, Anderson D, Hallen R, Elliot D, Schmidt A *et al.*, *Process Design and Economics for the Conversion of Algal Biomass to Hydrocarbons : Whole Algae Hydrothermal Liquefaction and Upgrading*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23227.pdf (2014).

188. Brown D, Rowe A and Wild P, Techno-economic comparisons of hydrogen and synthetic fuel production using forest residue feedstock. *Int J Hydrogen Energy* **1**:1–12 (2014).

189. Pearlson MN, A Techno-Economic and Environmental Assessment of Hydroprocessed Renewable Distillate Fuels (Master thesis). https://dspace.mit.edu/handle/1721.1/65508(2011).

190. Matti Lievonen (President & CEO Neste Oil), *Q2 Breakfast Meeting*. http://www.nesteoil.com/binary.asp?path=1;41;538;2385;12688;12892&field=FileAttachment(2009) [January 20 2015].

191. Meyer G, Thermal Properties of Microcrystalline and Fischer-Tropsch Waxes Fractionated in Short-Path Distillation. *SÖFW J* **138**:54–66 (2012).

192. Maarten A, Kootstra J, Beeftink HH, Scott EL and Sanders JPM, Comparison of dilute mineral and organic acid pretreatment for enzymatic hydrolysis of wheat straw. *Biochem Eng J* **46**:126–131 (2009).

193. Kalloinen A, Maija H, Riekkola T, Repo T, Markku L, van Weymarn N *et al.*, A novel alkaline oxidation pre-treatment for spruce, birch and sugar cane bagasse. *Bioresour Technol* **140**:414–420 (2013).

194. Argonne National Laboratory, *Lower and Higher Heating Values of Gas, Liquid and Solid Fuels*. http://cta.ornl.gov/bedb/appendix_a/Lower_and_Higher_Heating_Values_of_Gas_Liquid_and_Solid_Fuels.pdfThe Greenhouse Gases, Regulated Emissions, and Energy Use In Transportation Model. (2010).

195. Rose SK, Kriegler E, Bibas R, Calvin K, Popp A, van Vuuren DP *et al.*, Bioenergy in energy transformation and climate management. *Clim Change* **123**:477–493 (2014).

196. Yue D, You F and Snyder SW, Biomass-to-bioenergy and biofuel supply chain optimization: Overview, key issues and challenges. *Comput Chem Eng* **66**:36–56 (2014).

197. Batidzirai B, van der Hilst F, Meerman H, Junginger M and Faaij a. PC, Optimization potential of biomass supply chains with torrefaction technology. *Biofuels, Bioprod Biorefining* **8**:253–282 (2014).

198. Hoefnagels R, Junginger M and Faaij A, The economic potential of wood pellet production from alternative, low-value wood sources in the southeast of the U.S. *Biomass and Bioenergy* **71**:443–454 (2014).

199. Hoefnagels R, Searcy E, Cafferty K, Cornelissen T, Junginger M, Jacobson J *et al.*, Lignocellulosic feedstock supply systems with intermodal and overseas transportation. *Biofuels, Bioprod Biorefining* **8**:794–818 (2014).

200. Kudakasseril Kurian J, Raveendran Nair G, Hussain A and Vijaya Raghavan GS, Feedstocks, logistics and pre-treatment processes for sustainable lignocellulosic biorefineries: A comprehensive review. *Renew Sustain Energy Rev* **25**:205–219 (2013).

201. Uslu A, Faaij APC and Bergman PCA, Pre-treatment technologies, and their effect on international bioenergy supply chain logistics. Techno-economic evaluation of torrefaction, fast pyrolysis and pelletisation. *Energy* **33**:1206–1223 (2008).

202. Brinsmead T, Herr A and O'Connell D, Quantifying spatial dependencies, trade-offs and uncertainty in bioenergy costs: An Australian case study (1) – least cost production scale. *Biofuels, Bioprod Biorefining* **9**:21–34 (2014).

203. Wright M, Brown R and Boateng A, Distributed processing of biomass to bio-oil for subsequent production of Fischer-Tropsch liquids. *Biofuel, Bioprod Bioref* **2**:229–238 (2008).

204. Kim S and Dale BE, Comparing alternative cellulosic biomass biorefining systems: Centralized versus distributed processing systems. *Biomass and Bioenergy* **74**:135–147 (2015).

205. Dornburg V and Dornburg V, Efficiency and economy of wood-fired biomass energy systems in relation to scale regarding heat and power generation using combustion and gasification technologies. *Biomass and Bioenergy* **21**:91–108 (2001).

206. van der Hilst F and Faaij A, Spatiotemporal cost-supply curves for bioenergy production in Mozambique. *Biofuels, Bioprod Biorefining* **6**:405–430 (2012).

207. Searcy E, Flynn P, Ghafoori E and Kumar A, The relative cost of biomass energy transport. *Appl Biochem Biotechnol* **137**–**140**:639–652 (2007).

208. Flodén J, Opportunities and challenges for rail transport of solid wood biofuel. *Eur J Transp Infrastruct Res* **16**:512–553 (2016).

209. Karttunen K, Lättilä L, Korpinen O and Ranta T, Cost-efficiency of intermodal container supply chain for forest chips. *Silva Fenn* **47**:1–24 (2013).

210. Roni MS, Eksioglu SD, Searcy E and Jacobson JJ, Estimating the variable cost for high-volume and long-haul transportation of densified biomass and biofuel. *Transp Res Part D Transp Environ* **29**:40–55 (2014).

211. Mahmudi H and Flynn PC, Rail vs truck transport of biomass. *Appl Biochem Biotechnol* **129**–**132**:88–103 (2006).

212. Ekşioğlu S, Li S, Zhang S, Sokhansanj S and Petrolia D, Analyzing Impact of Intermodal Facilities on Design and Management of Biofuel Supply Chain. *J Transp Res Board* **129**:144–151 (2011).

213. Pettersson K, Wetterlund E, Athanassiadis D, Lundmark R, Ehn C, Lundgren J *et al.*, Integration of next-generation biofuel production in the Swedish forest industry – A geographically explicit approach. *Appl Energy* **154**:317–332 (2015).

214. de Jong S, Hoefnagels R, Faaij A, Slade R, Mawhood R and Junginger M, The feasibility of short-term production strategies for renewable jet fuels – a comprehensive techno-economic comparison. *Biofuels, Bioprod Biorefining* **9**:778–800 (2015).

215. Lin T, Rogríguez LF, Shastri YN, Hansen AC and Ting K, GIS-enabled biomass-ethanol supply chain optimization: model development and Miscanthus application. *Biofuels, Bioprod Biorefining* **7**:314–333 (2013).

216. Roni MS, Eksioglu SD, Cafferty KG and Jacobson JJ, A multi-objective, hub-and-spoke model to design and manage biofuel supply chains. *Ann Oper Res* **249**:351–380 (2017).

217. Kaylen M, Van Dyne DL, Choi YS and Blase M, Economic feasibility of producing ethanol from lignocellulosic feedstocks. *Bioresour Technol* **72**:19–32 (2000).

218. Parker N, Tittmann P, Hart Q, Nelson R, Skog K, Schmidt A *et al.*, Development of a biorefinery optimized biofuel supply curve for the Western United States. *Biomass and Bioenergy* **34**:1597–1607 (2010).

219. You F and Wang B, Life cycle optimization of biomass-to-liquid supply chains with distributed-centralized processing networks. *Ind Eng Chem Res* **50**:10102–10127 (2011).

220. Kim J, Realff MJ, Lee JH, Whittaker C and Furtner L, Design of biomass processing network for biofuel production using an MILP model. *Biomass and Bioenergy* **35**:853–871 (2011).

221. Natarajan K, Leduc S, Pelkonen P, Tomppo E and Dotzauer E, Optimal Locations for Methanol and CHP Production in Eastern Finland. *BioEnergy Res* **5**:412–423 (2012).

222. Natarajan K, Leduc S, Pelkonen P, Tomppo E and Dotzauer E, Optimal locations for second generation Fischer Tropsch biodiesel production in Finland. *Renew Energy* **62**:319–330 (2014).

223. Jonker JGG, Junginger HM, Verstegen JA, Lin T, Rodríguez LF, Ting KC *et al.*, Supply chain optimization of sugarcane first generation and eucalyptus second generation ethanol production in Brazil. *Appl Energy* **173**:494–510 (2016).

224. Rathmann R, Szklo A and Schaeffer R, Land use competition for production of food and liquid biofuels: An analysis of the arguments in the current debate. *Renew Energy* **35**:14–22 (2010).

225. Fischer G, Prieler S, van Velthuizen H, Berndes G, Faaij A, Londo M *et al.*, Biofuel production potentials in Europe: Sustainable use of cultivated land and pastures, Part II: Land use scenarios. *Biomass and Bioenergy* **34**:173–187 (2010).

226. Harvey M and Pilgrim S, The new competition for land: Food, energy, and climate change. *Food Policy* **36**:S40–S51 (2011).

227. Wetterlund E, Leduc S, Dotzauer E and Kindermann G, Optimal use of forest residues in Europe under different policies—second generation biofuels versus combined heat and power. *Biomass Convers Biorefinery* **3**:3–16 (2013).

228. Börjesson P, Hansson J and Berndes G, Future demand for forest-based biomass for energy purposes in Sweden. *For Ecol Manage* **383**:17–26 (2016).

229. Government Offices of Sweden, *Fossil-free transport and travel: The Government's work to reduce the impact of transport on the climate*. http://www.government.se/government-policy/environment/fossil-free-transport-and-travel-the-governments-work-to-reduce-the-impact-of-transport-on-the-climate/(2016).

230. International Energy Agency, *Energy policies of IEA countries: Sweden 2013 review*. https://www.iea.org/publications/freepublications/publication/Sweden2013_free.pdf (2014).

231. Tews IJ, Zhu Y, Drennan CV, Elliott DC, Snowden-Swan LJ, Onarheim K *et al.*, *Biomass direct liquefaction options: technoeconomic and life cycle assessment*. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-23579.pdf (2014).

232. de Jong S, Antonissen K, Hoefnagels R, Lonza L, Wang M, Faaij A *et al.*, Life-cycle analysis of greenhouse gas emissions from renewable jet fuel production. *Biotechnol Biofuels* **10**:1–18 (2017).

233. Arbogast S, Bellman D, Paynter JD and Wykowski J, Advanced bio-fuels from pyrolysis oil: The impact of economies of scale and use of existing logistic and processing capabilities. *Fuel Process Technol* **104**:121–127 (2012).

234. Elliott DC, Biller P, Ross AB, Schmidt AJ and Jones SB, Hydrothermal liquefaction of biomass: Developments from batch to continuous process. *Bioresour Technol* **178**:147–156 (2015).

235. Verkerk PJ, Anttila P, Eggers J, Lindner M and Asikainen A, The realisable potential supply of woody biomass from forests in the European Union. *For Ecol Manage* **261**:2007–2015 (2011).

236. Hektor B, Bruce L and Andersson K, *IEA task 40 Country report Sweden*. https://www.svebio.se/sites/default/files/Sweden country report 2014_v2_0.pdf (2014).

237. International Energy Agency, *Oil & Gas Security Emergency Response of IEA Countries - Sweden*. https://www.iea.org/publications/freepublications/publication/Sweden2012_OSS.pdf (2012).

238. Port directory, *Port directory*. https://www.port-directory.com/search/search&port_country=sweden&port_facilities=petroleum/ [September 23 2016].

239. Lundmark R, Athanassiadis D and Wetterlund E, Supply assessment of forest biomass – A bottom-up approach for Sweden. *Biomass and Bioenergy* **75**:213–226 (2015).

240. Swedish Forest Agency, *Skogliga konsekvensanalyser 2015 – SKA 15, Rapport 10 2015 (in Swedish)*. Jönköping, Sweden (2015).

241. Börjesson P, *Potential för ökad tillförsel och avsättning av inhemsk biomassa i en växande svensk bioekonomi, Rapport nr. 97 (in Swedish)*. http://portal.research.lu.se/ws/files/7279231/B_rjesson_P._2016._Rapport_nr_97_Milj_och_energisystem_Lunds_Universitet.pdf (2016).

242. Danielsson B-O, *Uppskattning av sågverkens produktion av trädbränslen inom mål 1-området i Dalarna-Gävleborg (in Swedish)*. Bioenergi i WX Mål 1. Ett strukturfondsprojekt inom Mål 1, Södra skogslänsregionen. Projektbilaga 2. GDE-Net (2003).

243. Delin L, Berglin N, Lundström A, Samuelsson Å, Backlund B and Sivard Å, *Bleached market kraft pulp mill, Reference and type mill, FRAM 09*. STFI-Packforsk, Stockholm, Sweden (2005).

244. Delin L, Berglin N, Samuelsson Å, Lundström A, Backlund B, Sivard Å *et al.*, *Kraftliner mill, FRAM 11*. STFI-Packforsk, Stockholm, Sweden (2005).

245. Swedish Forest Industries Federation, *Skogsindustriernas miljödatabas (in Swedish)*. http://miljodatabas.skogsindustrierna.org/simdb/Web/main/main.aspx?l1=home(2012) [February 2 2016].

246. Swedish Forest Industries Federation, Database of member companies. Swedish Forest Industries Federation (August 2012; updated November 2015) (2015).

247. Wiberg R and Forslund M, *Energiförbrukning i massa- och pappersindustrin 2011*. Skogsindustrierna, ÅF (2012).

248. Swedish Forest Agency, *Skogsstatistisk årsbok 2014 (Swedish Statistical Yearbook of Forestry 2014)*. Jönköping, Sweden (2014).

249. Swedish Energy Agency, *Wood fuel- and peat prices (Trädbränsle- och torvpriser)*. Eskilstuna, Swedish Energy Agency and Örebro, Statistics Sweden (2015).

250. Swedish Forest Agency, *Prices on roundwood in 2015*. (2016).

251. Skogforsk, *Skogsbränslets metoder, sortiment och kostnader 2011 (in Swedish)*. (2012).

252. Swedish Energy Agency, *Utbudet av biobränslen på kort och lång sikt (in Swedish)*. Swedish Energy Agency, Eskilstuna (2009).

253. Swedish District Heating Association, *Statistics over fuels and deliveries in Swedish district heating systems 2008-2015*. http://www.svenskfjarrvarme.se/Statistik--Pris/Fjarrvarme/Energitillforsel/(2016) [August 8 2016].

254. Isaksson J, Pettersson K, Mahmoudkhani M, Åsblad A and Berntsson T, Integration of biomass gasification with a Scandinavian mechanical pulp and paper mill – Consequences for mass and energy balances and global CO2 emissions. *Energy* **44**:420–428 (2012).

255. LNG in Baltic Sea Ports, *LNG in Baltic Sea Ports LNG Handbook*. http://www.lnginbalticseaports.com/assets/files/do_pobrania/LNGinBalticSeaPorts_LNGHandbook.pdf (2014).

256. Andersson V and Vadenbo A, *Hydrogen Pinch Analysis of Preemraff Göteborg and Preemraff Lysekil (Master's thesis)*. http://publications.lib.chalmers.se/records/fulltext/123626.pdf (2010).

257. Kons K, Bergström D, Eriksson U, Athanassiadis D and Nordfjell T, Characteristics of Swedish forest biomass terminals for energy. *Int J For Eng* **25**:238–246 (2014).

258. Athanassiadis D, Personal communication. (2013).

259. Ramsden T, Ruth M, Diakov V, Laffen M and Timbario T, *Hydrogen Pathways: Cost, Well-to-Wheels Energy Use, and Emissions for the Current Technology Status of Seven Hydrogen Production, Delivery, and Distribution Scenarios*. https://www.nrel.gov/docs/fy14osti/60528.pdf (2013).

260. Energy Information Administration, *U.S. Operating Crude Oil Distillation capacity*. https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mocggus2&f=a(2016) [October 4 2016].

261. Energy Information Administration, *U.S. Purchased Steam Consumed at Refineries*. https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=8_NA_8FS0_NUS_B&f=A(2016) [October 4 2016].

262. Braimakis K, Atsonios K, Panopoulos KD, Karellas S and Kakaras E, Economic evaluation of decentralized pyrolysis for the production of bio-oil as an energy carrier for improved logistics towards a large centralized gasification plant. *Renew Sustain Energy Rev* **35**:57–72 (2014).

263. Trafikverket, *Nationella Vägdatabasen NVDB (National Road Database)*. (2015).

264. JRC, TRANS-TOOLS ("TOOLS for TRansport Forecasting ANd Scenario testing"). Joint Research Centre (JRC) – Institute for Prospective Technological Studies (IPTS) (2009).

265. RRG Spatial Planning and Geoinformation, *Short Sea Shipping Routes in Europe*. (2008).

266. Athanassiadis D, Melin Y, Lundström A and Nordfjell T, *Marginalkostnader för skörd av grot och stubbar från föryngringsavverkningar i Sverige*. Umeå, Sweden (2009).

267. Janssen R, Turhollow AF, Rutz D and Mergner R, Production facilities for second- generation biofuels in the USA and the EU – current status. *Biofuels Bioprod, Bioref* **7**:647–665 (2013).

268. Searcy E and Flynn P, The impact of biomass availability and processing cost on optimum size and processing technology selection. *Appl Biochem Biotechnol* **154**:271–286 (2009).

269. Daugaard T, Mutti L, Wright M, Brown R and Componation P, Learning rates and their impacts on the optimal capacities and production costs of biorefineries. *Biofuels, Bioprod Biorefining* **9**:82–94 (2015).

270. Wright MM and Brown RC, Establishing the optimal sizes of different kinds of biorefineries. *Biofuels, Bioprod Biorefining* **1**:191–200 (2007).

271. Nguyen MH and Prince RGH, A simple rule for bioenergy conversion plant size optimisation: Bioethanol from sugar cane and sweet sorghum. *Biomass and Bioenergy* **10**:361–365 (1996).

272. Leboreiro J and Hilaly AK, Biomass transportation model and optimum plant size for the production of ethanol. *Bioresour Technol* **102**:2712–2723 (2011).

273. Svenska Petroleum & Biodrivmedelinstitutet, *Average Value of Annual Fuel Prices*. http://www.spbi.se(2016) [October 31 2016].

274. Skogsindustrierna, Swedish forest industry statistics. (2016).

275. Swedish Forest Agency, *Global framtida efterfrågan på och möjligt utbud av vireksråvara (in Swedish)*. Jönköping, Sweden (2015). Report No.: Report No 4.

276. Confederation of European Paper Industries, *Key Statistics 2015*. http://www.cepi.org/system/files/public/documents/publications/statistics/2016/FINALKeyStatistics2015web.pdf (2016).

277. Wetterlund E, Optimal Localisation of Next Generation Biofuel Production in Sweden – Part II. (2013).

278. de Jong J, Akselsson C, Egnell G, Löfgren S and Olsson BA, Realizing the energy potential of forest biomass in Sweden - How much is environmentally sustainable? *For Ecol Manage* **383**:3–16 (2016).

279. Liu G, Yan B and Chen G, Technical review on jet fuel production. *Renew Sustain Energy Rev* **25**:59–70 (2013).

280. Cobuloglu HI and Büyüktahtakin IE, Food vs. biofuel: An optimization approach to the spatio-temporal analysis of land-use competition and environmental impacts. *Appl Energy* **140**:418–434 (2015).

281. Jack MW, Scaling laws and technology development strategies for biorefineries and bioenergy plants. *Bioresour Technol* **100**:6324–6330 (2009).

282. GAMS, *GAMS Documentation 24.8 - Optcr*. https://www.gams.com/latest/docs/userguides/mccarl/optcr.htm(2017) [February 24 2017].

283. Flodén J, *The Heuristics Intermodal Transport Model Calculation System*. http://hdl.handle.net/2077/25879(2011).

284. Nederlandse Emissie Autoriteit, Factor costs of freight transport: an analysis of the development in time (in Dutch: Factorkosten van het goederenvervoer: Een analyse van de ontwikkeling in de tijd.). Commissioned by Adviesdienst Verkeer en Vervoer, Rijswijk, the Netherlands (2004).

285. Eurostat, *HICP (2015 = 100) - annual data (average index and rate of change)*. (2015).

286. OFX, *Historical Exchange Rates*. https://www.ofx.com/en-us/forex-news/historical-exchange-rates/ (2016) [February 2 2016].

287. International Civil Aviation Organisation, *Present and future trends in aircraft noise and emissions (Assembly 38th Session No. Working paper)*. http://www.icao.int/Meetings/a38/Documents/WP/wp026_en.pdf (2013) [September 2 2016].

288. Buxton N, COP 21 Charades: Spin, Lies and Real Hope in Paris. *Globalizations* **7731**:1–4 (2016).

289. Klein-Marcuschamer D, Turner C, Allen M, Gray P, Dietzgen RG, Gresshoff PM *et al.*, Technoeconomic analysis of renewable aviation fuel from microalgae, Pongamia pinnata , and sugarcane. *Biofuels, Bioprod Biorefining* **7**:416–428 (2013).

290. Edwards R, Larive J-F, Rickeard D and Weindorf W, *Well-to-Wheels analysis of future automotive fuels and powertrains in the European context WELL-TO-TANK (WTT) Report. Version 4.a*. http://iet.jrc.ec.europa.eu/about-jec/sites/iet.jrc.ec.europa.eu.about-jec/files/documents/report_2014/wtt_report_v4a.pdf (2014).

291. Hoefnagels R, Smeets E and Faaij A, Greenhouse gas footprints of different biofuel production systems. *Renew Sustain Energy Rev* **14**:1661–1694 (2010).

292. Wang M, Han J, Dunn JB, Cai H and Elgowainy A, Well-to-wheels energy use and greenhouse gas emissions of ethanol from corn, sugarcane and cellulosic biomass for US use. *Environ Res Lett* **7**:45905 (2012).

293. Hennecke AM, Faist M, Reinhardt J, Junquera V, Neeft J and Fehrenbach H, Biofuel greenhouse gas calculations under the European Renewable Energy Directive - A comparison of the BioGrace tool vs. the tool of the Roundtable on Sustainable Biofuels. *Appl Energy* **102**:55–62 (2013).

294. Kendall A and Yuan J, Comparing life cycle assessments of different biofuel options. *Curr Opin Chem Biol* **17**:439–443 (2013).

295. Argonne National Laboratory, *Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) GREET.net Computer Model*. https://greet.es.anl.gov/index.php?content=greetdotnet(2015) [February 2 2016].

296. Argonne National Laboratory, *Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) GREET_1_2015 Excel model*. https://greet.es.anl.gov/greet_1_series(2015) [February 2 2016].

297. United Nations Framework Convention on Climate Change (UNFCCC), *Report of the Conference of the Parties on its nineteenth session, held in Warsaw from 11 to 23 November 2013 Addendum*. http://unfccc.int/resource/docs/2013/cop19/eng/10a03.pdf#page=52%3C/a%3E%3C/i%3E%3Cbr%3E%3Cbr%3E%3Ca href= (2014).

298. Corporan E, Edwards T, Shafer L, Dewitt MJ, Klingshirn C, Zabarnick S *et al.*, Chemical,Thermal Stability, Seal Swell, and Emissions Studies of Alternative Jet Fuels. *Energy & Fuels* **25**:955–966 (2011).

299. Bhagwan R, Habisreuther P, Zarzalis N and Turrini F, An experimental comparison of the emissions characteristics of standard jet A-1 and synthetic fuels. *Flow, Turbul Combust* **92**:865–884 (2014).

300. Beyersdorf A and Anderson B, An overview of the NASA Alternative Aviation Fuel Experiment (AAFEX). TAC-2 Proceedings (2009).

301. Dunn JB, Mueller S, Kwon H-Y and Wang MQ, Land-use change and greenhouse gas emissions from corn and cellulosic ethanol. *Biotechnol Biofuels* **6**:51–64 (2013).

302. Davis SC, House JI, Diaz-Chavez R a., Molnar a., Valin H and DeLucia EH, How can land-use modelling tools inform bioenergy policies? *Interface Focus* **1**:212–223 (2011).

303. Wicke B, Smeets E, Dornburg V, Vashev B, Gaiser T, Turkenburg W *et al.*, The global technical and economic potential of bioenergy from salt-affected soils. *Energy Environ Sci* **4**:2669–2681 (2011).

304. Wicke B, Verweij P, van Meijl H, van Vuuren DP and Faaij AP, Indirect land use change: review of existing models and strategies for mitigation. *Biofuels* **3**:87–100 (2012).

305. Plevin RJ, Jones AD, Torn MS, Group R, Division ES and Berkeley L, The greenhouse gas emissions from indirect land use change are uncertain, but potentially much greater than previously estimated. *Environ Sci Technol* **44**:8015–8021 (2010).

306. Valin H, Peters D, Berg M van den, Frank S, Havlik P, Forsell N *et al.*, *The land use change impact of biofuels consumed in the EU - Quantification of area and greenhouse gas impacts (GLOBIOM report)*. https://ec.europa.eu/energy/sites/ener/files/documents/Final Report_GLOBIOM_publication.pdf (2015).

307. Edwards R, Mulligan D and Marelli L, *Indirect Land Use Change from increased biofuels demand*. (2010).

308. Gerssen-Gondelach SJ, Wicke B and Faaij APC, GHG emissions and other environmental impacts of indirect land use change mitigation. *GCB Bioenergy* **9**:725–742 (2016).

309. Ardente F and Cellura M, Economic Allocation in Life Cycle Assessment: The State of the Art and Discussion of Examples. *J Ind Ecol* **16**:387–398 (2012).

310. International Standards Organisation (ISO), *ISO 14040:2006. Environmental management. Life cycle assessment. Principles and framework*. http://www.iso.org/iso/catalogue_detail?csnumber=37456 (2006).

311. Huo H, Wang M, Bloyd C and Putsche V, Life-cycle assessment of energy use and greenhouse gas emissions of soybean-derived biodiesel and renewable fuels. *Environ Sci Technol* **43**:750–756 (2009).

312. Allen DT, Allport C, Atkins K, Cooper JS, Dilmore RM, Draucker LC *et al.*, *Framework and guidance for estimating greenhouse gas footprints for aviation fuels*. http://web.mit.edu/aeroastro/partner/reports/proj28/greenhs-gas-ftprnts.pdf (2009).

313. National Energy Technology Laboratory, *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*. https://www.netl.doe.gov/File Library/Research/Energy Analysis/Life Cycle Analysis/NETL-LCA-Petroleum-based-Fuels-Nov-2008.pdf (2008).

314. European Comission, *Study on actual GHG data for diesel, petrol, kerosene and natural gas*. https://ec.europa.eu/energy/sites/ener/files/documents/Study on Actual GHG Data Oil Gas Final Report.pdf (2015).

315. BioGrace, *BioGrace - Excel based biofuel GHG calculations. Version 4d*. http://www.biograce.net/home(2015) [July 9 2016].

316. Akhtar J and Amin NAS, A review on process conditions for optimum bio-oil yield in hydrothermal liquefaction of biomass. *Renew Sustain Energy Rev* **15**:1615–1624 (2011).

317. Feedipedia, *Soybean meal*. http://www.feedipedia.org/node/674(2016) [September 6 2016].

318. Cherian G, Camelina sativa in poultry diets: opportunities and challenges. Biofuel co-products as livestock feed opportunities and challenges p. 303–310(2012).

319. Wang M and Huo H, *Fuel-Cycle Assessment of Selected Bioethanol Production Pathways in the United States*. https://greet.es.anl.gov/files/2lli584z (2006).

320. Han J, Dunn JB, Cai H, Elgowainy A and Wang MQ, *Updated Sugarcane Parameters in GREET1 _ 2012, Second Revision*. https://greet.es.anl.gov/files/greet-updated-sugarcane (2012).

321. Worldbank, *Commodity Markets Pink Sheet*. http://www.worldbank.org/en/research/commodity-markets [August 30 2016].

322. Daioglou V, Doelman JC, Stehfest E, Müller C, Wicke B, Faaij A *et al.*, Greenhouse gas emission-curves for advanced biofuel supply chains. *Nat Clim Chang* **7**:920–924 (2017).

323. Reap J, Roman F, Duncan S and Bras B, A survey of unresolved problems in life cycle assessment. Part 2: Impact assessment and interpretation. *Int J Life Cycle Assess* **13**:374–388 (2008).

324. Li X and Mupondwa E, Life cycle assessment of camelina oil derived biodiesel and jet fuel in the Canadian Prairies. *Sci Total Environ* **481**:17–26 (2014).

325. Wang W, Tao L, Markham J, Zhang Y, Tan E, Batan L *et al.*, *Review of Biojet Fuel Conversion Technologies*. http://www.nrel.gov/docs/fy16osti/66291.pdf (2016).

326. Capaz RS and Seabra JEA, Chapter 12 – Life Cycle Assessment of Biojet Fuels. In: Chuck C, editor. Biofuels for Aviation Academic Press p. 279–294(2016).

327. Kaufman AS, Meier PJ, Sinistore JC and Reinemann DJ, Applying life-cycle assessment to low carbon fuel standards-how allocation choices influence carbon intensity for renewable transportation fuels. *Energy Policy* **38**:5229–5241 (2010).

328. Abella JP, Model to Investigate Energy and Greenhouse Gas Implications of Refining Petroleum. *Environ Sci Technol* **46**:13037–13047 (2012).

329. Luckow P, Wise MA, Dooley JJ and Kim SH, Large-scale utilization of biomass energy and carbon dioxide capture and storage in the transport and electricity sectors under stringent CO2 concentration limit scenarios. *Int J Greenh Gas Control* **4**:865–877 (2010).

330. van Vliet OPR, Faaij APC and Turkenburg WC, Fischer-Tropsch diesel production in a well-to-wheel perspective: A carbon, energy flow and cost analysis. *Energy Convers Manag* **50**:855–876 (2009).

331. Möllersten K, Yan J and Moreira JR, Potential market niches for biomass energy with CO2 capture and storage - Opportunities for energy supply with negative CO2 emissions. *Biomass and Bioenergy* **25**:273–285 (2003).

332. van Vuuren DP, Deetman S, van Vliet J, van den Berg M, van Ruijven BJ and Koelbl B, The role of negative CO2 emissions for reaching 2 C-insights from integrated assessment modelling. *Clim Change* **118**:15–27 (2013).

333. Clarke L, Edmonds J, Krey V, Richels R, Rose S and Tavoni M, International climate policy architectures: Overview of the EMF 22 International Scenarios. *Energy Econ* **31**:S64–S81 (2009).

334. Gerssen-Gondelach S, Saygin D, Wicke B, Patel MK and Faaij APC, Competing uses of biomass: Assessment and comparison of the performance of bio-based heat, power, fuels and materials. *Renew Sustain Energy Rev* **40**:964–998 (2014).

335. Schäfer AW, Evans AD, Reynolds TG and Dray L, Costs of mitigating CO2 emissions from passenger aircraft. *Nat Clim Chang* **6**:412–417 (2015).

336. World Bank, *State and Trends of Carbon Pricing*. http://www.worldbank.org/content/dam/Worldbank/document/Climate/State-and-Trend-Report-2015.pdf (2015).

337. Luckow P, Stanton EA, Fields S, Ong W, Biewald B, Jackson S *et al.*, *Spring 2016 National Carbon Dioxide Price Forecast*. http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008.pdf (2016).

338. Schjolset S, *The MSR : Impact on market balance and prices*. https://ec.europa.eu/clima/sites/clima/files/docs/0094/thomson_reuters_point_carbon_en.pdfThomson Reuters. (2014).

339. International Civil Aviation Organisation, *Offsets for International Aviation Emissions*. https://www.icao.int/Meetings/a38/Documents/Offsets for International Aviation Emissions.v10.14 August.pdf (2012).

340. Holtsmark B, Harvesting in boreal forests and the biofuel carbon debt. *Clim Change* **112**:415–428 (2012).

341. Cai H, Wang J, Feng Y, Wang M, Qin Z and Dunn JB, Consideration of land use change-induced surface albedo effects in life-cycle analysis of biofuels. *Energy Environ Sci* **9**:2855–2867 (2016).

342. Cai H and Wang MQ, Consideration of black carbon and primary organic carbon emissions in life-cycle analysis of Greenhouse gas emissions of vehicle systems and fuels. *Environ Sci Technol* **48**:12445–12453 (2014).

343. Staples MD, Olcay H, Malina R, Trivedi P, Pearlson MN, Strzepek K *et al.*, Water consumption footprint and land requirements of large-scale alternative diesel and jet fuel production. *Environ Sci Technol* **47**:12557–12565 (2013).

344. Lampert DJ, Cai H and Elgowainy A, Wells to wheels: water consumption for transportation fuels in the United States. *Energy Environ Sci* **9**:787–802 (2016).

345. Han J, Elgowainy A, Palou-Rivera I, Dunn JB and Wang MQ, *Well-to-Wheels Analysis of Fast Pyrolysis Pathways with GREET*. http://www.ipd.anl.gov/anlpubs/2011/12/71546.pdf (2011).

346. Talens Peiró L, Lombardi L, Villalba Méndez G and Gabarrell i Durany X, Life cycle assessment (LCA) and exergetic life cycle assessment (ELCA) of the production of biodiesel from used cooking oil (UCO). *Energy* **35**:889–893 (2010).

347. López DE, Mullins JC and Bruce DA, Energy life cycle assessment for the production of biodiesel from rendered lipids in the United States. *Ind Eng Chem Res* **49**:2419–2432 (2010).

348. Dunn JB, Elgowainy A, Vyas A, Lu P, Han J, Wang M *et al.*, *Update to Transportation Parameters in GREET*. https://greet.es.anl.gov/files/tansportation-distribution-13+&cd=1&hl=en&ct=clnk&gl=us (2013).

349. World Wildlife Fund, *The Energy Report - 100% renewable energy by 2050*. https://c402277.ssl.cf1.rackcdn.com/publications/384/files/original/The_Energy_Report.pdf?1345748859 (2011).

350. Cherubini F, Bright RM and Strømman AH, Site-specific global warming potentials of biogenic CO2 for bioenergy: contributions from carbon fluxes and albedo dynamics. *Environ Res Lett* **7**:45902 (2012).

351. Cherubini F, Peters GP, Berntsen T, Strømman AH and Hertwich E, CO2 emissions from biomass combustion for bioenergy: Atmospheric decay and contribution to global warming. *GCB Bioenergy* **3**:413–426 (2011).

352. Porsö C, Hammar T, Nilsson D and Hansson PA, Time-Dependent Climate Impact and Energy Efficiency of Internationally Traded Non-torrefied and Torrefied Wood Pellets from Logging Residues. *Bioenergy Res* **11**:1–13 (2017).

353. Zetterberg L and Chen D, The time aspect of bioenergy - climate impacts of solid biofuels due to carbon dynamics. *GCB Bioenergy* **7**:785–796 (2015).

354. Lamers P and Junginger M, The "debt" is in the detail: A synthesis of recent temporal forest carbon analyses on woody biomass for energy. *Biofuels, Bioprod Biorefining* **7**:373–385 (2013).

355. Hellweg S, Hofstetter TB and Hungerbuhler K, Discounting and the environment - Should current impacts be weighted differently than impacts harming future generations? *Int J Life Cycle Assess* **8**:8–18 (2003).

356. Zanchi G, Pena N and Bird N, Is woody bioenergy carbon neutral? A comparative assessment of emissions from consumption of woody bioenergy and fossil fuel. *GCB Bioenergy* **4**:761–772 (2012).

357. Pingoud K, Ekholm T, Soimakallio S and Helin T, Carbon balance indicator for forest bioenergy scenarios. *GCB Bioenergy* **8**:171–182 (2016).

358. Edwards MR and Trancik JE, Climate impacts of energy technologies depend on emissions timing. *Nat Clim Chang* **4**:347–352 (2014).

359. Edwards MR, McNerney J and Trancik JE, Testing emissions equivalency metrics against climate policy goals. *Environ Sci Policy* **66**:191–198 (2016).

360. Peters GP, Aamaas B, T. Lund M, Solli C and Fuglestvedt JS, Alternative "global warming" metrics in life cycle assessment: A case study with existing transportation data. *Environ Sci Technol* **45**:8633–8641 (2011).

361. Kendall A, Time-adjusted global warming potentials for LCA and carbon footprints. *Int J Life Cycle Assess* **17**:1042–1049 (2012).

362. Withers MR, Malina R and Barrett SRH, Carbon, climate, and economic breakeven times for biofuel from woody biomass from managed forests. *Ecol Econ* **112**:45–52 (2015).

363. Ericsson N, Porsö C, Åhlgren S, Nordberg Å, Sundberg C and Hansson PA, Time-dependent climate impact of a bioenergy system - methodology development and application to Swedish conditions. *GCB Bioenergy* **5**:580–590 (2013).

364. US Environmental Protection Agency, Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis. https://www.epa.gov/sites/production/files/2015-08/documents/420r07004.pdf (2010).

365. Russell MB, Woodall CW, Fraver S, D'Amato AW, Domke GM and Skog KE, Residence Times and Decay Rates of Downed Woody Debris Biomass/Carbon in Eastern US Forests. *Ecosystems* **17**:765–777 (2014).

366. Joos F, Roth R, Fuglestvedt JS, Peters GP, Enting IG, Von Bloh W *et al.*, Carbon dioxide and climate impulse response functions for the computation of greenhouse gas metrics: A multi-model analysis. *Atmos Chem Phys* **13**:2793–2825 (2013).

367. Meinshausen M, Raper SCB and Wigley TML, Emulating coupled atmosphere-ocean and carbon cycle models with a simpler model, MAGICC6 - Part 1: Model description and calibration. *Atmos Chem Phys* **11**:1417–1456 (2011).

368. Tanaka, K., Kriegler, E., Bruckner, T., Hooss, G., Knorr, W., Raddatz T, *Aggregated Carbon cycle, atmospheric chemistry and climate model (ACC2): description of forward and inverse mode.* http://pubman.mpdl.mpg.de/pubman/faces/viewItemOverviewPage.jsp?itemId=escidoc:994422:1(2007).

369. Mahashabde A, Wolfe P, Ashok A, Dorbian C, He Q, Fan A *et al.*, Assessing the environmental impacts of aircraft noise and emissions. *Prog Aerosp Sci* **47**:15–52 (2011).

370. Wolfe PJ, Aviation Environmental Policy and Issues of Timescale. http://hdl.handle.net/1721.1/101493Massachusetts Institute of Technology (2015).

371. Myhre G, Shindell D, Bréon F-M, W. Collins J, Fuglestvedt J, Huang D *et al.*, *Anthropogenic and Natural Radiative Forcing Supplementary Material. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. https://www.ipcc.ch/pdf/assessment-report/ar5/wg1/supplementary/WG1AR5_Ch08SM_FINAL.pdf (2014).

372. Withers MR, Malina R, Gilmore CK, Gibbs JM, Trigg C, Wolfe PJ *et al.*, Economic and environmental assessment of liquefied natural gas as a supplemental aircraft fuel. *Prog Aerosp Sci* Elsevier **66**:17–36 (2014).

373. Barrett SRH, Yim SHL, Gilmore CK, Murray LT, Kuhn SR, Tai APK *et al.*, Public health, climate, and economic impacts of desulfurizing jet fuel. *Environ Sci Technol* **46**:4275–4282 (2012).

374. Trivedi P, Malina R and Barrett SRH, Environmental and economic tradeoffs of using corn stover for liquid fuels and power production. *Energy Environ Sci* **8**:1428–1437 (2015).

375. Wolfe PJ, Aviation environmental policy effects on national- and regional- scale air quality, noise, and climate impacts (Master thesis). https://dspace.mit.edu/handle/1721.1/71505 (2012).

376. Reisinger A, Meinshausen M and Manning M, Future changes in global warming potentials under representative concentration pathways. *Environ Res Lett* **6** (2011).

377. Kreutz TG, Larson ED, Liu G and Williams R, Fischer-Tropsch Fuels from Coal and Biomass. 25th Annual International Pittsburgh Coal Conference p. 1–81(2008).

378. Brinkman M, Wicke B, Gerssen-Gondelach S, van der Laan C and Faaij A, *Methodology for assessing and quantifying ILUC prevention options*. http://www.uu.nl/sites/default/files/20150106-iluc_methodology_report.pdf (2015).

379. Simmons CT and Matthews HD, Assessing the implications of human land-use change for the transient climate response to cumulative carbon emissions. *Environ Res Lett* **11** (2016).

380. Jonker JGG, Junginger M and Faaij A, Carbon payback period and carbon offset parity point of wood pellet production in the South-eastern United States. *GCB Bioenergy* **6**:371–389 (2014).

381. Brinkman MLJ, Wicke B and Faaij APC, Low-ILUC-risk ethanol from Hungarian maize. *Biomass and Bioenergy* **99**:57–68 (2017).

382. Gerssen-Gondelach SJ, Wicke B, Borzęcka-Walker M, Pudełko R and Faaij APC, Bioethanol potential from miscanthus with low ILUC risk in the province of Lublin, Poland. *GCB Bioenergy* **8**:909–924 (2016).

383. van de Staai J, Peters D, Dehue B, Meyer S, Schueler V and Toop G, *Low Indirect Impact Biofuel (LIIB) Methodology*. http://www.ecofys.com/files/files/12-09-03-liib-methodology-version-0-july-2012.pdf (2012).

384. Peters D, Spöttle M, Hähl T, Kühner A-K, Cuijpers M, Stomph TJ *et al.*, *Methodologies for the identification and certification of Low ILUC risk biofuels*. https://ec.europa.eu/energy/sites/ener/files/documents/ecofys_methodologies_for_low_iluc_risk_biofuels_for_publication.pdf (2016).

385. Doelman JC, Stehfest E, Tabeau A, van Meijl H, Lassaletta L, Gernaat DEHJ *et al.*, Exploring SSP land-use dynamics using the IMAGE model: Regional and gridded scenarios of land-use change and land-based climate change mitigation. *Glob Environ Chang* **48**:119–135 (2018).

386. Verchot L, Krug T, Lasco RD, Ogle S, Raison J, Li Y *et al.*, Grassland In: 2006 IPCC Guidelines for National Greenhouse Gas Inventories. http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/4_Volume4/V4_06_Ch6_Grassland.pdf (2006).

387. Riahi K, van Vuuren DP, Kriegler E, Edmonds J, O'Neill BC, Fujimori S *et al.*, The Shared Socioeconomic Pathways and their energy, land use, and greenhouse gas emissions implications: An overview. *Glob Environ Chang* **42**:153–168 (2017).

388. Edmonds J, Hibbard K, Hijioka Y, Ishiwatari S, Kainuma M, Kato E *et al.*, *RCP Database (version 2.0.5)*. https://www.iiasa.ac.at/web-apps/tnt/RcpDb/dsd?Action=htmlpage&page=welcome (2017).

389. Meinshausen M, Smith SJ, Calvin K, Daniel JS, Kainuma MLT, Lamarque J *et al.*, The RCP greenhouse gas concentrations and their extensions from 1765 to 2300. *Clim Change* **109**:213–241 (2011).

390. Etminan M, Myhre G, Highwood EJ and Shine KP, Radiative forcing of carbon dioxide, methane, and nitrous oxide: A significant revision of the methane radiative forcing. *Geophys Res Lett* **43**:12,614-12,623 (2016).

391. Roe G and Baker M, Why Is Climate Sensitivity So Unpredictable? *Science* **318**:629–632 (2007).

392. Verstegen JA, van der Hilst F, Woltjer G, Karssenberg D, de Jong SM and Faaij APC, What can and can't we say about indirect land-use change in Brazil using an integrated economic - land-use change model? *GCB Bioenergy* **8**:561–578 (2016).

393. Cames M, Graichen J, Siemons A and Cook V, *Emission reduction targets for international aviation and shipping*. http://www.europarl.europa.eu/RegData/etudes/STUD/2015/569964/IPOL_STU(2015)569964_EN.pdf (2015).

394. IRENA, *Biofuels for aviation: Technology brief*. https://www.irena.org/DocumentDownloads/Publications/IRENA_Biofuels_for_Aviation_2017.pdf (2017).

395. Wise M, Muratori M and Kyle P, Biojet fuels and emissions mitigation in aviation: An integrated assessment modeling analysis. *Transp Res Part D Transp Environ* **52**:244–253 (2017).

396. Tsiropoulos I, Hoefnagels R, van den Broek M, Patel MK and Faaij APC, The role of bioenergy and biochemicals in CO2 mitigation through the energy system – a scenario analysis for the Netherlands. *GCB Bioenergy* **9**:1489–1509 (2017).

397. International Civil Aviation Organisation, *ICAO Environmental Report 2013*. http://www.icao.int/environmental-protection/Pages/EnvReport13.aspx2013 Environmental Report. (2013).

398. Eurostat, *Complete energy balances - annual data (nrg_110a)*. http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_110a&lang=en(2016) [July 27 2017].

399. Noh HM, Benito A and Alonso G, Study of the current incentive rules and mechanisms to promote biofuel use in the EU and their possible application to the civil aviation sector. *Transp Res Part D Transp Environ* **46**:298–316 (2016).

400. International Civil Aviation Organisation, *Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA)*. https://www.icao.int/environmental-protection/Pages/market-based-measures.aspx(2017) [August 14 2017].

401. European Commission, *Proposal for a Regulation of the European Parliament and of the Council amending Directive 2003/87/EC to continue curent limitations of scope for aviation activities and to prepare to implement a global market-based measure from 2021*. http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52017PC0054&from=EN (2017).

402. European Parliament and the Council, *Directive 2008/101/EC of the European Parliament and of the Council of 19 November 2008 amending Directive 2003/87/EC so as to include aviation activities in the scheme for greenhouse gas emission allowance trading within the community*. http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32008L0101&from=EN (2009).

403. European Commission, *Guidance Document - Biomass issues in the EU ETS*. https://ec.europa.eu/clima/sites/clima/files/ets/monitoring/docs/gd3_biomass_issues_en.pdf (2012).

404. Londo M, van Stralen J, Mozaffarian H, Uslu A and Kraan C, *Modelling Demand for Bio-Based Sectors In: Modeling and Optimization of Biomass Supply Chains*. Panoutsou C, editor. Elsevier, London (2017).

405. AEBIOM, *AEBIOM Statistical Report - European Bioenergy Outlook Full Report 2016*. http://www.aebiom.org/statistical-report-2016/ (2016).

406. Mai-Moulin T, Visser L, Fingerman K, Elbersen W, Elbersen B, Nabuurs G-J *et al.*, Sustainable sourcing overseas biomass for EU ambitions: Assessing net sustainable export potential from various sourcing countries. *submitted* (2017).

407. van Stralen J, Kraan C, Uslu A, Londo M and Mozaffarian H, *Integrated assessment of biomass supply chains and conversion routes under different scenarios. D7.3 S2Biom project*. http://www.s2biom.eu/images/Publications/D7.3_S2Biom_Integrated_Assessment_Final.pdf (2016).

408. Elbersen B, Staritsky I, Hengeveld G, Jeurissen L and Lesschen J-P, *Outlook of spatial biomass value chains in EU28. D2.3 Biomass Policies project*. http://www.biomasspolicies.eu/wp-content/uploads/2014/12/Outlook-of-spatial-biomass-value-chains-in-EU28.pdf (2016).

409. Elbersen B, Uslu A and Stralen J van, *Scenarios for Biomass Policies. Deliverable 2.1 of the Biomass Policies project*. http://www.biomasspolicies.eu/?page_id=414 (2015).

410. Fritsche UR and Iriarte L, *Biomass Policies Task 2.4: Sustainable Imports*. http://www.biomasspolicies.eu/wp-content/uploads/2014/12/Cost-supply-curves-for-sustainable-biomass-and-bioenergy-imports-to-the-EU-27.pdf (2016).

411. United States Department of Agriculture, *Oilseeds: World Markets and Trade*. http://usda.mannlib.cornell.edu/usda/current/oilseed-trade/oilseed-trade-08-10-2017.pdf (2017).

412. European Parliament, *MEPs call for clampdown on imports of unsustainable palm oil and use in biofuel*. http://www.europarl.europa.eu/news/en/press-room/20170329IPR69057/meps-call-for-clampdown-on-imports-of-unsustainable-palm-oil-and-use-in-biofuel(2017) [August 23 2017].

413. Spöttle M, Alberici S, Toop G, Peters D, Gamba L, Ping S *et al.*, *Low ILUC potential of wastes and residues for biofuels*. https://www.ecofys.com/files/files/ecofys-2013-low-iluc-potential-of-wastes-and-residues.pdf (2013).

414. Mozaffarian H, Londo M, Pantaleo M and Carolien Kraan, *Market analysis for lignocellulosic biomass as feedstock for bioenergy , biobased chemicals & materials in Europe: A quantitative estimate of biomass demand in 2020 and 2030. Deliverable 7.2 S2Biom project*. http://www.s2biom.eu/images/Publications/S2Biom_D7_2.final.pdf (2015).

415. Capros P, De Vita A, Tasios N, Siskos P, Kannavou M, Petropoulos A *et al.*, *EU Reference Scenario 2016: Energy, transport and GHG emissions trends to 2050*. https://ec.europa.eu/energy/en/data-analysis/energy-modelling (2016).

416. Eurostat, *Eurostat SHARES*. http://ec.europa.eu/eurostat/web/energy/data/shares(2016) [October 16 2017].

417. Han J, Tao L and Wang M, Well-to-wake analysis of ethanol-to-jet and sugar-to-jet pathways. *Biotechnol Biofuels* **10**:1–15 (2017).

418. Deurwaarder EP, Lensink SM and Londo HM, *BioTrans biofuels data*. http://web.archive.org/web/20090621084015/http://www.refuel.eu/fileadmin/refuel/user/docs/REFUEL_D10b__Data_report_Biotrans-def.pdf (2007).

419. Lensink S and van Zuilen CL, *Eindadvies basisbedragen SDE+ 2015*. https://www.ecn.nl/publicaties/PdfFetch.aspx?nr=ECN-E--14-035 (2016).

420. Lensink S, Wassenaar A, Luxembourg SL, Faasen CJ and Mozaffarian M, *Eindadvies basisbedragen 2011 voor elektriciteit en groen gas in het kader van de SDE-regeling*. https://www.ecn.nl/publications//PdfFetch.aspx?nr=ECN-E--10-082 (2010).

421. Songhurst B, *LNG Plant Cost Escalation*. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/02/NG-83.pdf (2014).

422. International Gas Union, *2016 World LNG Report*. www.igu.org/download/file/fid/2123 (2016).

423. Maurice LQ, Hockstad L, Hohne N, Hupe J, Lee DS and Rypdal K, *Mobile Combustion In: 2006 IPCC Guidelines for National Greenhouse Gas Inventories*. http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_3_Ch3_Mobile_Combustion.pdf (2006).

424. Eurostat, *Supply, transformation and consumption of renewable energies - annual data*. http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_107a&lang=en(2017) [October 19 2016].

425. EurObserv'ER, *Biofuels Barometer*. https://www.eurobserv-er.org/biofuels-barometer-2016/ (2016).

426. Eurostat, *Primary production - all products - annual data (nrg_109a)*. http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=nrg_109a&lang=en(2017) [August 23 2017].

427. United States Department of Agriculture, *EU-28 Biofuel Mandates in the EU by Member State*. http://gain.fas.usda.gov/Recent GAIN Publications/Biofuel Mandates in the EU by Member State_Berlin_EU-28_7-13-2015.pdf (2016).

428. Koks Z, Gazis E and Slade R, *Technological development of Fast Pyrolysis and Hydrothermal Liquefaction (master thesis)*. https://dspace.library.uu.nl/bitstream/handle/1874/344195/Final thesis Zita Koks.pdf?sequence=2 (2016).

429. de Wit M, Junginger M, Lensink S, Londo M and Faaij A, Competition between biofuels: Modeling technological learning and cost reductions over time. *Biomass and Bioenergy* **34**:203–217 (2010).

430. de Jong S, Hoefnagels R, Wetterlund E, Pettersson K, Faaij A and Junginger M, Cost optimization of biofuel production - the impact of economies of scale, integration, intermodal transport and distributed supply chain configurations. *Appl Energy* **195**:1055–1070 (2017).

431. Junginger M, de Visser E, Hjort-Gregersen K, Koornneef J, Raven R, Faaij A *et al.*, Technological learning in bioenergy systems. *Energy Policy* **34**:4024–4041 (2006).

432. van Hout M, Koutstaal P, Ozdemir O and Seebregts A, *Quantifying flexibility markets*. http://www.tennet.eu/nl/fileadmin/downloads/About_Tennet/Publications/Technical_Publications/TenneT_ECN_Quantifying_flexibility_markets.pdfEcn-E--14-039. (2014).

433. Eurostat, *Greenhouse gas emissions by source sector (source: EEA) (env_air_gge)*. http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=env_air_gge&lang=en(2017) [July 19 2017].

434. The council of the European Union, *Directive 2003/96/EC restructuring the Community framework for the taxation of energy products and electricity*. http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32003L0096&from=EN (2003).

435. International Maritime Organisation, *Third IMO Greenhouse Gas Study 2014*. http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Documents/Third Greenhouse Gas Study/GHG3 Executive Summary and Report.pdf (2015).

436. European Commission, *Proposal for a Regulation of the European Parliament and of the Council on the monitoring, reporting and verification of carbon dioxide emissions from maritime transport and amending Regulation (EU) n° 525/2013*. https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:52013PC0480&from=EN (2013).

437. EEA, *EU Emissions Trading System (ETS) data viewer*. https://www.eea.europa.eu/data-and-maps/dashboards/emissions-trading-viewer-1(2016) [October 30 2017].

438. Bitnere K and Searle S, *Effective policy design for promoting investment in advanced alternative fuels*. https://www.theicct.org/sites/default/files/publications/Advanced-alternative-fuels_ICCT-white-paper_21092017_vF.pdf (2017).

439. Bundesanstalt für Landwirtschaft und Ernährung, *Evaluations- und Erfahrungsbericht für das Jahr 2016*. https://www.ble.de/SharedDocs/Downloads/DE/Klima-Energie/Nachhaltige-Biomasseherstellung/Evaluationsbericht_2016.pdf;jsessionid=74789A27B5E65268D237FAA05BE4F8FD.2_cid335?__blob=publicationFile&v=3 (2017).

440. Argonne National Laboratory, *Greenhouse Gases, Regulated Emissions and Energy Use in Transportation (GREET) GREET.net Computer Model*. https://greet.es.anl.gov/index.php?content=greetdotnet(2016) [September 3 2017].

441. European Comission, *Annexes to the proposal for a directive of the European Parliament and the Council on the promotion of the use of energy from renewable sources (recast)*. http://eur-lex.europa.eu/resource.html?uri=cellar:151772eb-b7e9-11e6-9e3c-01aa75ed71a1.0001.02/DOC_2&format=PDF (2016).

442. Hamje H, Hass H, Lonza L, Maas H, Reid A, Rose K *et al.*, *EU renewable energy targets in 2020: Analysis of scenarios for transport fuels*. https://www.concawe.eu/wp-content/uploads/.../jec_biofuels_2013_report_final.pdf pp. 70 (2014).

443. ICCT, *European Vehicle Market Statistics - Pocketbook 2016/2017*. www.theicct.org/sites/default/files/publications/ICCT_Pocketbook_2016.pdf (2016).

444. Schoots K and Hammingh P, *Nationale Energieverkenning 2015. ECN---15-033 (in Dutch)*. http://www.ecn.nl/docs/library/report/2015/o15033.pdf (2015).

445. Indexmundi, *Propane Daily Price*. http://www.indexmundi.com/commodities/?commodity=propane&months=120%0A(2017) [July 20 2017].

446. Business Insider, *Naphtha (European) in USD - Historical prices*. http://markets.businessinsider.com/commodities/historical-prices/naphtha/17.6.2004_17.7.2017(2017) [July 24 2017].

447. INSEE, *International prices of imported raw materials - Brent crude oil (London) - Prices in US dollars per barrel*. https://www.insee.fr/en/statistiques/serie/000455743(2017) [July 24 2017].

448. INSEE, *International prices of imported raw materials - Heavy fuel oil (Rotterdam) - Prices in US dollars per tonne - FOB - 1% of sulfur*. https://www.insee.fr/en/statistiques/serie/001642883?idbank=001642883(2017) [July 17 2017].

449. Business Insider, *Oil (Brent) in USD - Historical Prices*. http://markets.businessinsider.com/commodities/historical-prices/oil-price/17.6.2017_1.1.2006?type=Brent(2017) [July 17 2017].

450. Hoefnagels R, Junginger M, Resch G, Matzenberger J, Panzer C and Pelkmans L, *Development of a tool to model European biomass trade. Report for IEA Bioenergy Task 40*. https://dspace.library.uu.nl/handle/1874/235231 (2013).

451. The Danish Maritime Authority, *North European LNG Infrastructure Project - A feasibility study for an LNG filling station infrastructure and test of recommendations*. http://www.dma.dk/themes/LNGinfrastructureproject/Documents/Final Report/LNG_Full_report_Mgg_2012_04_02_1.pdf (2012).

452. EIA, *Spot prices*. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_m.htm(2018) [March 6 2018].

453. Caiazzo F, Agarwal A, Speth RL and Barrett SRH, Impact of biofuels on contrail warming. *Environ Res Lett* **12** (2017).

454. de Jong D, Angular Distribution and Yield of the $Be^9(d,p)Be^{10}$ and $Be^9(d,t)Be^8$ Reactions. Utrecht University (1953).

455. Sustainable Aviation Fuel Users Group, *Global Policy Statement Indirect Land Use Change (ILUC)*. http://www.safug.org/assets/docs/iluc-global-proposition.pdf(2013) [June 29 2016].

456. Commercial Aviation Alternative Fuels Initiative, *Fuel Readiness Level (FRL)*. http://www.caafi.org/information/pdf/frl_caafi_jan_2010_v16.pdf(2010) [July 28 2016].

457. Intergovernmental Panel on Climate Change, N2O Emissions From Managed Soils, and CO2 Emissions From Lime and Urea application *In:2006 IPCC Guidelines for National Greenhouse Gas Inventories*. http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/4_Volume4/V4_11_Ch11_N2O&CO2.pdf (2006).

458. Eurostat, *Air passenger transport by reporting country [avia_paoc]*. http://appsso.eurostat.ec.europa.eu/nui/show.do?dataset=avia_paoc&lang=en(2017) [October 10 2016].