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MOST EFFICIENT USE OF BIOMASS – FOR BIOFUELS OR ELECTROFUELS?

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RENEWABLE TRANSPORTATION FUELS AND SYSTEMS 2018-2021

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f3 The Swedish Knowledge Centre for Renewable Transportation Fuels

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PREFACE

This project has been carried out within the collaborative research program *Renewable transportation fuels and systems* (Förnybara drivmedel och system), Project no. 50460-1. The project has been financed by the Swedish Energy Agency and f3 – Swedish Knowledge Centre for Renewable Transportation Fuels.

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

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SUMMARY

The transport sector in Sweden and in the EU is subject to several policy instruments aimed at driving the climate transition. In the case of fuels, there are e.g. fuel taxes and reduction obligations for petrol and diesel, and there are also proposals for parts of maritime and road transport to be included in the EU emissions trading scheme. At present, the only viable option is biofuels, but there is the option of using fossil-free fuels of non-biological origin (electrofuels) to meet the reduction obligation. However, the current focus is on creating long-term favourable conditions for biofuels and the Swedish government has recently announced that it intends to submit an application to the European Commission for continued state aid approval to exempt highly blended liquid biofuels from taxation for 10 years. Restrictions on biofuels from feedstocks with a high risk of indirect land-use change (currently this applies to palm oil, but soy oil, for example, may be added) could create further incentives for domestic production of biofuels in Sweden and the EU.

However, a strong focus on expanding domestic biofuel production capacity could lead to lock-in effects that slow down the development of alternative fuels and/or stranded assets in case demand for biofuels declines in the future due to competition from other alternatives. Conversion in other sectors may also be more costly if strong incentives for biofuels drive up biomass prices.

This report summarises the results of a study analysing how biofuel blending requirements in petrol and diesel could affect developments in the energy and transport systems, and how the blending requirement could affect the costs of reducing CO2 emissions in the EU as a whole. The aim is to investigate whether a requirement for biofuel use in the transport sector is compatible with ambitions to support cost-effective climate change mitigation in the medium (~20 years) and long (~40 years) term.

In 2040, the CO_2 reduction requirement for the EU energy system is assumed to -80% (compared to 1990 emissions) and in 2060 the requirement is -105%, i.e. 5% negative emissions annually. Investment costs for technologies such as wind, solar, batteries and electrolysers are expected to fall in the future, making electricity and hydrogen production cheaper. In addition to falling investment costs, it is assumed that there will be an increasing degree of electrification of the transport and industrial sectors, and that part of the fuel demand will be met by hydrogen. We quantify the cost of limiting CO_2 emissions from the EU energy system (via emission caps), with and without a requirement to blend biofuels into liquid fuels. This is done using a sector-integrated model (PyPSA-Eur-Sec) that includes all parts of the energy and transport systems and minimises the total cost of investment- and running costs. In addition to the comparison of costs, we analyse the impact of the blending requirement on system transformation, e.g. the importance of different technology solutions in different industries, heating and power generation.

Our results show that biofuel mandates the equivalent of 14%-17% of the current use of liquid fuels significantly increase the cost of the climate transition.

In the medium term (2040, 20% blending requirements):

- The cost of reaching the CO_2 target increases by between 10 and 66 billion € (2-14% of the cost of the whole energy system) compared to the case without mandatory blending.

- The cost increase is due to the use of biofuels instead of petrol and diesel in the transport sector even though cheaper ways to reduce CO_2 emissions by 80% are available. Available biomass can be used more efficiently in other sectors.

In the long term (2060, 50% blending requirement):

- The cost of reaching the CO_2 target increases by between 18 and 40 billion € (4-8% of the cost of the whole energy system) compared to the case without mandatory blending.
- The cost increase is mainly since biofuels are more expensive than electrofuels and fossil fuels that are compensated with negative emissions. In addition, it is more cost-effective to use biomass in stationary applications, which enables more CO_2 emissions to be captured and stored.

In both the medium and long term, the magnitude of the cost increase depends on the assumption of the amount of domestic biomass available. The cost increases may be compared to the cost of all liquid fuel (excluding taxes) in the transport sector in the EU in 2018, which was 282 billion €. The increases due to the blending requirement are therefore significant.

The report can inform policy makers on the size and shape of fuel mandates in the short and long term. The benefits of biofuel mandates should be weighed against the risk of increased costs in the long term if biomass is locked into the transport sector. It may also be important to further stimulate other non-fossil fuel options for liquid fuels and hydrogen production to free up biomass for material and negative emission uses through BECCS.

SAMMANFATTNING

Transportsektorn i Sverige och inom EU är föremål för en rad styrmedel som syftar till att driva på klimatomställningen. När det gäller drivmedel så finns t ex bränsleskatter och reduktionsplikt för bensin och diesel, och det finns också förslag på att delar av sjö- och vägtransport skall ingå i EU:s utsläppshandel. I dagsläget så används bara biodrivmedel men aktörer kan få möjlighet att också använda fossilfria drivmedel av icke-biologiskt ursprung (elektrobränslen) för att uppfylla reduktionsplikten. För närvarande ligger dock fokus på att skapa långsiktigt gynnsamma villkor för biodrivmedel och Sveriges regering har nyligen annonserat att den avser lämna in en ansökan till EU-kommissionen om fortsatt statsstödsgodkännande för att skattebefria höginblandade flytande biodrivmedel i 10 år. Begränsningar för biodrivmedel från råvaror med hög risk för indirekt ändrad markanvändning (för närvarande palmolja men exempelvis soja kan tillkomma) kan skapa ytterligare incitament för inhemsk produktion av biodrivmedel i Sverige och EU.

Ett starkt fokus på utbyggd inhemsk produktionskapacitet för biodrivmedel kan dock leda till inlåsningseffekter som bromsar utvecklingen för alternativa drivmedel och/eller strandade tillgångar i det fall efterfrågan på biodrivmedel i framtiden minskar p.g.a. konkurrens från andra alternativ. Omställningen inom andra sektorer kan också bli dyrare om starka incitament för biodrivmedel driver upp biomassapriserna.

Denna rapport sammanfattar resultaten i en studie som analyserar hur krav på inblandning av biodrivmedel i bensin och diesel kan påverka utvecklingen inom energi- och transportsystemen, samt hur inblandningskravet kan påverka kostnader för att minska CO_2-utsläppen i EU som helhet. Syftet är att undersöka om krav på biodrivmedelsanvändning i transportsektorn är förenligt med ambitioner att stödja kostnadseffektiv klimatomställning på medellång (~20 år) respektive lång (~40 år) sikt.

År 2040 antas ett krav på CO_2-reduktion för EU:s energisystem -80% (jämfört med utsläppen för 1990) och år 2060 är kravet satt till -105%, det vill säga 5% negativa utsläpp årligen. Investeringskostnader för tekniker som vind, sol, batterier och elektrolysörer antas sjunka i framtiden, vilket gör el och vätgasproduktion billigare. Utöver sjunkande investeringskostnader antas en ökande grad av elektrifiering av transport- och industrisektorerna, samt att en del av bränslebehovet tillgodoses av vätgas. Vi kvantifierar kostnaden för att begränsa CO_2-utsläppen från EU:s energisystem (via utsläppstak), med och utan krav på inblandning av biodrivmedel i flytande bränslen. Detta görs med en sektorkopplad modell (PyPSA-Eur-Sec) som innefattar alla delar av energi och transport-systemen och som minimerar den totala kostnaden av investeringar och löpande kostnader. Utöver jämförelsen av kostnader så analyserar vi hur inblandningskravet påverkar systemomställningen, t ex betydelsen av olika tekniklösningar inom olika industri, uppvärmning och elproduktion.

Våra resultat leder till slutsatsen att inblandningskrav motsvarande 14% - 17% av nuvarande användning av flytande bränslen driver upp kostnaden för klimatomställningen betydligt.

På **medellång sikt** (2040, 20% inblandningskrav):

- **Kostnaden för att nå CO_2-målet ökar med mellan 10 och 66 miljarder €** (2-14% av kostnaden för *hela* energisystemet) jämfört med fallet utan inblandningskrav.

- **Kostnadsökningen beror på att biodrivmedel används i stället för bensin och diesel** i transportsektorn trots att det finns billigare sätt att minska CO_2-utsläppen med 80% sett till hela energisystemet. Den biomassa som finns tillgänglig kan användas mer effektivt i andra sektorer.

På **lång sikt** (2060, 50% inblandningskrav):

- **Kostnaden för att nå CO2-målet ökar med mellan 18 och 40 miljarder € (**4-8% av kostnaden för *hela* energisystemet) jämfört med fallet utan inblandningskrav.
- Kostnadsökningen **beror främst på att biodrivmedel är dyrare** än elektrobränslen och fossila bränslen som kompenseras med negativa utsläpp. Dessutom är det mer kostnadseffektivt att använda biomassa i stationära anläggningar, vilket möjliggör att en större andel av CO_2-utsläppen kan fångas in och lagras.

Både på **medellång och lång sikt** beror storleken av kostnadsökningen på antagandet om mängden tillgänglig inhemsk biomassa. Kostnadsökningarna kan jämföras med kostnaden för allt flytande bränsle (oräknat skatter) inom transportsektorn i EU 2018, som var 282 miljarder €. Ökningarna till följd av inblandningskravet är alltså betydande.

Rapporten kan ge underlag till beslutsfattare angående storlek och utformning av drivmedelsmandat på kort och lång sikt. Fördelarna med biodrivmedelsmandat bör vägas mot risken för ökade kostnader på lång sikt vid en inlåsning av biomassa i transportsektorn. Det kan också vara viktigt att ytterligare stimulera andra icke-fossila alternativ för flytande drivmedel och vätgasproduktion för att frigöra biomassa till användningsområden som material och för negativa utsläpp genom BECCS.

CONTENTS

1 INTRODUCTION

The transport sector accounted for 30% of total greenhouse gas (GHG) emissions in EU-27 in 2019, with an increasing trend [1]. Recent developments of electric vehicles and proposed targets for phasing out internal combustion engine vehicles (ICEVs) [2] indicate a considerable electrification of land-based transport within the next few decades. However, the phase-out of ICEVs takes time and thus a liquid hydrocarbon fuel demand persists for some time even at high electrification rates [3, 4]. In maritime transport and aviation, a demand for liquid hydrocarbon fuels is likely to remain also long-term [5–7]. Alternative fuel solutions are thus required to achieve ambitious emissions targets.

Biofuels and electrofuels are the two available renewable liquid hydrocarbon fuel options [8], and another option is the continued use of unabated fossil fuels combined with carbon dioxide removal (CDR) elsewhere in the system [9–11].

Currently, conventional biofuels produced from food crops are the dominating option [12], but they are connected to land use change issues and other sustainability risks [13, 14], and are being phased out in the EU [15]. Biomass residues which are suitable for existing conventional biofuel processes (such as used cooking oil) are scarce [16]. Instead, advanced biofuels based on lignocellulosic biomass residues show a relatively large albeit uncertain potential [17], but no commercially operational production exists today.

Electrofuels are produced with hydrogen and carbon as feedstocks. Hydrogen can be sourced from electrolysers, which can use electricity when it is cheap in a system dominated by variable renewable energy (VRE). However, the potential depends on a substantial expansion of VRE (or other carbon emissions free) capacity, and thus can be seen as a large-scale option only in the longer term [18, 19].

An emissions cap-and-trade or tax is often seen as the first-best policy option for achieving targets, since it in theory leads to the least-cost attainment of emissions targets [20]. However, fuel mandates may be important tools for a country or for the EU in a second-best setting if the ideal policy first-best mix is hard to implement or if there are market barriers hindering abatement solutions [20–22]. Also, mandates may (i) support the development of promising technologies [20], (ii) reduce mitigation efforts in domestic industries that are pressured by international competition, and (iii) count towards other goals, such as improved energy security.

In the EU, transport fuels are subject to fuel taxes and blending mandates for achieving emissions targets, and there is a proposal to include the transport and additional industry sectors in the EU-ETS [23]. The proposal for the new Renewable Energy Directive (RED III) [24] includes renewable fuel mandates for the aviation (20% in 2035, out of which 5% electrofuels) [25] and road transport sectors (2.3% advanced biofuels for light transport in 2035), while the maritime sector is to reduce the energy intensity by 20% in 2035 compared to 2020 [26]. However, several countries have set targets that significantly surpass those of the EU as a whole. For instance, Sweden’s 2030 target for renewable fuels are 66% (diesel) and 23% (gasoline) [27] and Finland’s is 30% [28]. In the US, the Renewable Fuel Standard currently mandates a blending of around 10% biofuels into gasoline [29].

Biofuels present the main short-term option to fulfill fuel mandates [30], by blending them into the fuels used for aviation, road and maritime transport. The fuel mandates thus incentivise investments in biofuel production (supply chain and biorefineries) on a scale to satisfy a sizeble part of the demand for renewable fuels.

Although scaling up of new options such as CDR or renewable fuels based on VRE may prove to be challenging [31, 32], the future may also see a large cost reduction for electrofuels and CDR. In addition, sustainability constraints and competition for biomass may increase biomass prices and thus affect the competitiveness of biofuels. Investments in biofuels for achieving high fuel mandates in the near term therefore involve potential risks of stranded assets or lock-in effects.

A holistic assessment of biomass usage competitions in the energy system requires the inclusion of all energy sectors, which is covered in Integrated Assessment Models (IAMs) [33] but has been lacking in Energy System Optimization Models (ESOMs). An explicit representation of VRE [34–36] and variable production such as electrolysers (and thus electrofuels), demands a high spatio-temporal resolution, which is lacking in IAMs but is covered in ESOMs. However, ESOMs have recently been enhanced to encompass all energy sectors (sector-coupled) and a high spatio-temporal resolution for both supply and flexible demand [37–39], which enables a holistic analysis of biomass usage and of abatement alternatives for the transport sectors. None of the papers based on these sector-coupled models have specifically targeted biomass use or biofuels, and - to our knowledge - neither have biofuel mandates been investigated in energy system modeling studies. In order to do this, we expand the sector-coupled open source European ESOM PyPSA-Eur-Sec [37] with details on biomass and bioenergy options.

In this work, we investigate the competition for fuel supply under CO_2 emission reduction targets, and the effects of biofuel mandates on energy system costs. We do this by quantifying the increase in total energy system costs that biofuel mandates would lead to in the medium (~2040) and long term (~2060) perspectives.

2 MATERIALS AND METHODS

We use the PyPSA-Eur-Sec model [37] and trace the total system cost while successively forcing more of the biomass resource into fuel production. We thus investigate the additional cost of moving away from the optimal use of biomass [40] to scenarios which are constrained in terms of dedicated use of biomass for liquid fuel production. These latter scenarios may be viewed as proxies for policies which promote biofuels, i.e. biofuel mandates. We investigate this question for the medium (~2040) and long term (~2060). The two time-horizons are different in terms of CO_2 cap as well as other parameters, such as degree of electrification and technology maturity and costs, as outlined below. We assess the effect of carbon sequestration availability and investigate two different scenarios for domestic biomass potential: one conservative and one more optimistic. In addition, we allow import of biomass to Europe, but at a relatively high cost.

2.1 MODEL: PYPSA-EUR-SEC

The model used in this study is PyPSA-Eur-Sec [37], which is a sector-coupled full European energy system model including the power sector, transport, space and water heating, industry and industrial feed- stocks. The model co-optimizes capacity expansion of energy generation and conversion, as well as their production.

In this work, we expand the model by a rich biomass resource and bioenergy technology portfolio as outlined below. The further developed version of the model used in this work is available for free use under an open-source license [41].

We use a 37-node spatial resolution and an uninterrupted 1-hourly temporal resolution for a full year in overnight scenarios. The transmission grid is adapted to be a HVDC lossy transport model, and transmission is constrained to increase by max. 50% in terms of total line volume compared to today.

Energy demands stem from [17]. Technology data is elaborated in the appendix.

The model runs were performed on the Chalmers Centre for Computational Science and Engineering (C3SE) computing cluster, using 64 threads and 768 GB RAM (or 96 GB RAM for the lower resolution sensitivity runs).

2.2 BIOMASS AND BIOENERGY

A variety of biomass technologies and details on biomass classes are introduced in the model. Different biomass residue types are clustered into the categories solid and digestible biomass (Table 1). Solid biomass can be used for a variety of applications in heat, power and fuel production, and can be combined with carbon capture (Figure 1).

In the main scenarios, the domestic biomass availability is varied as stated in Table 1. Depending on the biomass scenario, solid and digestible biomass can together provide either 5 or 23% of the resulting total primary energy demand of around 16 PWh. A weighted average of country-level biomass costs used from the "high" biomass scenario for 2050 [17] is held constant across scenarios in this study.

Only biomass residues and wastes are included in the analysis, i.e. bioenergy crops are excluded. We note that studies find significant potential for bioenergy crops in EU but decided to focus on other biomass sources because the current political and policy context hints towards a limited role for dedicated cultivation in EU due to concerns about competition with food and risks for environmental impacts from cropland expansion. Thereby, the only option considered for producing liquid biofuels is based on solid biomass (i.e. biomass to liquid, BtL), and biofuel imports are excluded. All included biomass is assumed to bind as much carbon as it contains from the atmosphere, and no additional emissions are allocated to the biomass. Thus, if the biomass is combusted without CCS it is assumed to be carbon neutral.

Table 1: Domestic biomass scenarios (TWh). The digestible biomass is given in the biogas potential. Values from JRC [29]. A weighted average of country-level biomass costs used from the "high" biomass scenario for 2050 is held constant across scenarios

	Medium	High	Cost
	TWh	TWh	€/MWh
Forest residues	267	1654	12
Industry wood residues	76	381	6
Landscape care	42	214	8
Solid biomass	385	2249	
Manure and slurry	173	522	20
Municipal biowaste	122	222	0.14
Sewage sludge	8	15	17
Straw	186	601	10
Digestible biomass	489	1359	

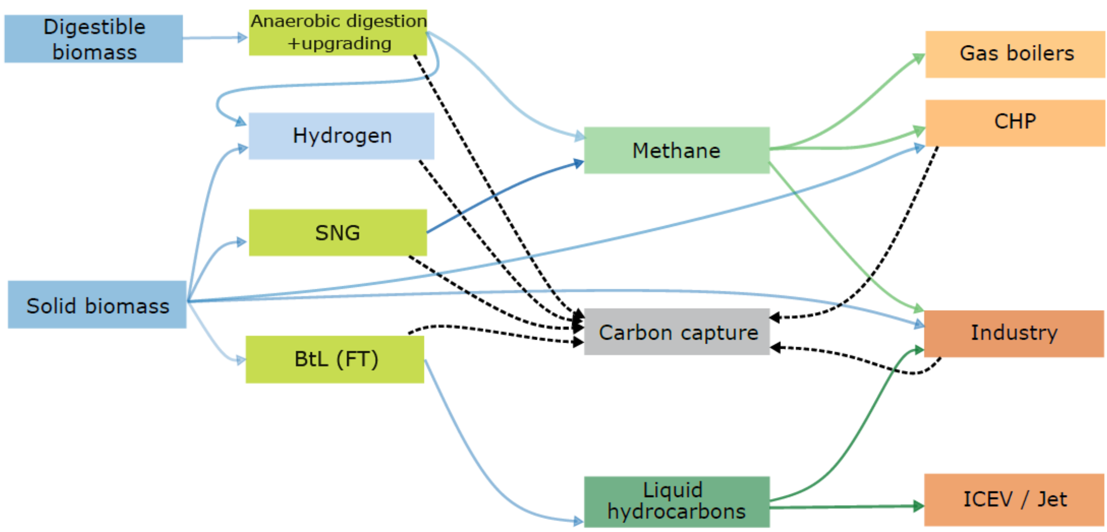

Figure 1: Simplified depiction of the biomass usage options in the model. Energy flows are shown, except for the dashed lines going to carbon capture (which is optional for each of the shown processes), which show mass flows of carbon. The captured carbon can be utilized for hydrocarbon production or sequestered. Hydrogen can also be produced through electrolysis and steam methane reforming (SMR), and can be used for numerous applications, including FCEVs, electrofuel production, as industry feedstock and for heating (not shown.)

2.2.1 Biomass imports

Biomass supply and demand in Integrated Assessment Models (IAMs) depend on many different factors, which makes it difficult to construct a global biomass supply curve based on their results. Still, global trade of biomass needs to somehow be represented in a regional ESOM to be more realistic. We use the model comparison in [42] which focuses on biomass use in carbon mitigation scenarios and select five models which represent the competition between biomass supply and food, pasture, and nature, and provide global biomass prices (two models also include competition for land for afforestation). For 2050, the global supply varies between 130-250 EJ in the different model results, and the price spans between 10-21 USD/GJ. Using the average of these models we assume that 175 EJ of biomass can be supplied globally and annually at a price of 15 USD/GJ. We use regional data on biomass use per capita and population estimates from [43] to find that 20 EJ biomass may be imported to Europe at the price of 15 €/GJ. For each additional EJ to be imported the price is assumed to increase by 0.25 €/GJ, based on the slope of the low-cost scenarios.

2021 wood chip prices were at around 8 €/GJ (30 €/MWh), i.e. the above prices assume a substantial price increase compared to today, which reflects an increased demand for biomass in scenarios complying with stringent GHG emission targets. We test the effect of this assumption on results in a sensitivity analysis. Only solid biomass can be imported, and the import prices are held the same for all scenarios.

2.3 SECTOR-SPECIFIC ASSUMPTIONS

For aviation, an increase in traveled passenger kilometers of 50% by 2040 and 100% by 2060 in Europe are assumed, compared to 2019 levels. An efficiency improvement of 3% and 20% in 2040 and 2060, respectively, is assumed [44, extrapolated for 2060]. Based on this, we assume a fuel demand increase compared to 2019 of 50% and 70% in 2040 and 2060, respectively. Electric or hydrogen-fueled aviation is not considered, as a conservative assumption based on expected long lead times delaying any significant market penetration.

Although shipping demand is projected to increase by 50% to 2050, efficiency measures may counteract this to result in 0-30% end energy demand increase, depending on the scenario [45]. We assume that efficiency measures are stronger towards 2060, resulting in a 20% increase compared to the base level, for both 2040 and 2060. [45] assumes an about 25% share of hydrogen-based fuels (ammonia and hydrogen) for 2040, and about 55% in 2050 in an ambitious scenario, with the rest being liquid or gaseous hydrocarbons (except very minor electrification). We thereby assume 25% and 70% hydrogen in 2040 and 2060, respectively, with the rest being liquid hydrocarbons. Electrification of shipping is not considered.

Total fuel demand in EU road transport consists of 64% passenger road transport and 36% freight road transport [46]. Passenger and freight road transport services (i.e. passenger-km and ton-km) are projected to increase by 15% and 24% in 2040 as well as 20% and 33% in 2050 compared to 2018 [47]. We assume increases of 25% and 40% for 2060. This results in: EV 34% 2040 and 68% 2060, FCEV 5% 2040, 32% 2060 (the freight share increases to 44% and is assumed to have 40% EVs and 60% FCEVs).

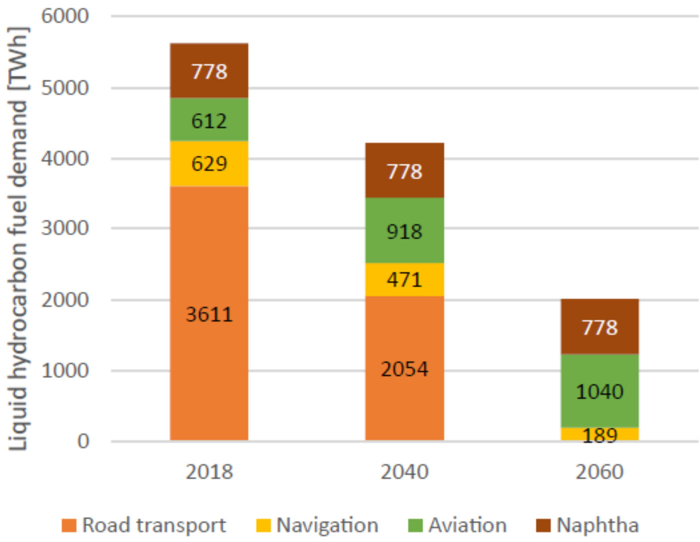

Figure 2: Assumed liquid hydrocarbon fuel demand in the years 2018 [47], 2040 and 2060.

Total initial transport fuel demand (2018) amounts to 4851 TWh and includes road transport (incl. non-electric trains), domestic and international aviation and navigation (Figure 2). The liquid fuel demand for industry feedstock (naphtha) is added on top of this and amounts to 778 TWh (held constant across years). The resulting total liquid fuel demand for transport amounts to 3444 TWh in 2040 (4223 TWh incl. naphtha, corresponding to ~30% of total primary energy demand) and 1233 TWh in 2060 (2011 TWh incl. naphtha, or ~15% of total primary energy demand). The inclusion of naphtha is justified as it is a part of the product mix from the Fischer-Tropsch process.

Table 2: Costs and demands of different transport fuels in 2018.

	Cost	Energy density	Demand 2018	Total cost
	€/l	MJ/l	TWh	Billion €
Gasoline	0.56	33	1083	61
Diesel	0.61	36	2528	168
Fuel oil	0.44	39	629	26
Jet fuel	0.44	35	612	28
				∑ 282

The Eurozone weighted average consumer price of Euro-super 95 (gasoline) in 2019 was 0.56 €/l excluding taxes and levies, 0.61 €/l for diesel and 0.44 €/l for low-Sulphur fuel oil [48]. The average price of jet fuel was 0.44 €/l [49], and the share of diesel in road transport was around 70% in 2018 [50]. The total cost of transport fuels in 2018 is estimated at 282 billion €, based on the data summarized in Table 2. This is later used for comparison of the results.

Steel production is assumed to be increasingly performed with hydrogen as a reduction agent (Direct Reduced Iron, DRI). The space heating demand is assumed to decrease by 16% in 2040 and 29% in 2060, through efficiency improvements in buildings.

Industrial heat is divided into three segments: low, medium and high temperature. In the low and medium temperature segments, biomass is an option, whereas methane is an option in all three. Direct electrification is an option in the low temperature segment and heat pumps are excluded in the base case. Thus, solid biomass competes for producing industrial process steam with electric boilers and methane boilers, and for producing medium temperature process heat with methane.

2.4 SCENARIOS

The scenarios are varied in four dimensions: target year, biomass availability and carbon sequestration potential, which have been identified as having a large influence on outcomes [51], as well as liquid biofuel quota.

Two target years are analysed, namely 2040 and 2060. Importantly, these target years are connected to different CO_2 emission targets, with an 80% reduction in 2040 compared to 1990 and a 105% reduction in 2060 (i.e. a net-negative target to represent the long-term need to remove carbon dioxide from the atmosphere; Sweden already has a net-negative target for after 2045.) Other than that, technology costs and efficiencies differ between the years, as presented in the appendix. For both years, it is assumed that conventional and renewable capacities existing in 2020 still exist in 2040 and 2060 unless they have reached the end of their lifetime. Also, it is assumed that national solar PV as well as on- and offshore wind capacities cannot be reduced below their 2020 values in 2040 and 2060. The two years are not interlinked, i.e. capacities built in scenarios for 2040 are not considered in scenarios for 2060.

Table 3: Biomass and carbon sequestration (CS) potentials assumed in the scenarios, for 2040 and 2060, resulting in eight base scenarios. In 2040, no carbon sequestration is assumed in the low CS scenarios, while in 2060 400 $MtCO_2$ is assumed because it is close to the minimum necessary to be able to achieve a net-negative target. For each of the base scenarios, different biofuel mandates of 20%, 50%, 100% and no mandate (i.e. free optimisation) are assessed.

	Biomass	CS
	TWh	$MtCO_2/a$
High bio, low CS	3608	0 | 400
High bio, high CS	3608	1500
Low bio, low CS	874	0 | 400
Low bio, high CS	874	1500

The biomass availability is varied as presented in Section 2.2. The carbon sequestration potential is assumed at either 0 or 1500 $MtCO_2$/year for 2040, and 400 or 1500 $MtCO_2$/year for 2060, as summarised in Table 3. The lower end represents the least amount necessary to reach the set target, while the upper end is high enough to never be reached in the scenarios, i.e. it does not set an active constraint.

Production of liquid biofuels π_{fu} is forced as a function of the share $\alpha \in [0, 1]$ of the total set demand $d_{fu,s}$ for each sector s: (i) liquid fuels in the transport *trp* (including land-based transport, marine and aviation) and (ii) industry *ind*.

$$\pi_{fu} \geq \alpha \sum d_{fu,s} \quad \forall s \in \{ind, trp\} \tag{1}$$

2.5 SENSITIVITY ANALYSIS

The sensitivity analysis is performed through runs of all the combinations of optimistic and pessimistic parameter value combinations outlined in Table 4. All parameter values for a group are set to either pessimistic or optimistic, i.e. for example all Fischer-Tropsch-related parameters including for Biomass to Liquid and Electrofuels. This results in 2^6=64 combinations. These are run for each of the four main scenarios for 2060, with the model temporal resolution lowered to 37 hours (instead of an hourly resolution) due to computational restrictions (a lower temporal resolution tends to slightly overestimate the biofuel share among liquid fuels).

Table 4: Assumed sensitivity ranges of key parameters directly relevant to liquid fuel supply in 2060. Ranges from DEA for 2050 [52], except for BtL, carbon sequestration, oil, gas and biomass imports, which are varied ±25%, except for the BtL efficiency (range based on literature) and carbon sequestration cost (assumed to have a higher cost variability). BtL includes the gasification unit as well as the FT-process.

				Optimistic	**Base**	**Pessimistic**
Fischer-Tropsch	Biomass to Liquid	Investment cost	€/kW	1500	2000	2500
		Efficiency		0.5	0.45	0.35
	Electrofuels	Investment cost	€/kW	675	900	1125
		Efficiency		0.9	0.75	0.6
Electrolyser		Investment cost	€/kW	150	250	400
		Efficiency		0.8	0.75	0.7
Carbon capture	CHP	Cost	€/ktCO_2/h	1600	2000	2800
	Industry	Cost	€/ktCO_2/h	1400	1800	2400
	DAC	Cost	€/ktCO_2/h	3000	4000	7000
Carbon storage		Cost	€/tCO_2	10	20	50
Fossils	Oil	Price	€/MWh	37.5	50	62.5
	Gas	Price	€/MWh	15	20	25
Biomass		Import price (base)	€/MWh	36	54	72

3 RESULTS AND DISCUSSION

In this section we present the resulting fuel supply and solid biomass usage in the main scenarios without fuel mandates, and then we assess the effect of enforcing biofuel mandates on the system and show why high mandates increase energy system costs substantially.

3.1 FUEL AND ELECTRICITY SUPPLY IN THE BASE SCENARIOS WITHOUT BIOFUEL MANDATES

In all 2040 base scenarios (i.e. without a biofuel mandate), liquid fuel demand is dominated by fossil fuels (Figure 7). The reason is that there are more cost-effective abatement options to achieve an overall -80% CO_2 emission reduction in the energy system. For example, the resulting electricity supply is almost fully supplied by non-fossil energy sources (mainly renewables, for which the resulting capacities are shown in Table 5). Also, electrification of transport, heat and industry contributes to decreasing emissions, and carbon capture is to some extent used in industry. With no carbon sequestration available, some 5% biofuels emerge in the optimal case if there is ample domestic biomass available, and 8% electrofuels emerge if there is little domestic biomass.

In the 2060 base scenarios, the liquid fuel supply differs substantially between being dominated by electrofuels if carbon sequestration is scarce and by fossil fuels if there is ample carbon sequestration available (Figure 4). With little carbon sequestration, the total electricity supply doubles compared to in the 2040 scenarios, while with ample carbon sequestration it increases by 30%. This additional electricity is covered mainly by solar PV and offshore wind power and is mainly used for usages which today rely on non-electric primary sources, i.e. supplying industry, heat and transport either directly with electricity or via producing hydrogen or methane which is used in those sectors.

It is interesting to note that the difference in total cost between the scenarios with little and ample carbon sequestration is small, despite the large difference in fuel mix (Figure 8). A continued reliance on fossil fuels which are compensated by CCS or other Carbon Dioxide Removal (CDR) measures involves risks and is subject to controversy [53–56].

Solid biomass is most cost-effectively used for CHP and industrial heat to varying degrees depending on the scenario, and with ample domestic biomass in 2060 also for producing some BioSNG. Biofuels make up a minor part of the biomass usage in all the optimal cases (Figures 4 and 7).

Now, optimal results may be rather sensitive to small perturbations in the system [40, 57] and therefore such results need to be handled with care. The question is to which extent a diversion from the optimal biomass usage and fuel supply affects system costs.

Table 5: Resulting VRE capacities in the base scenarios for 2040 and 2060, compared to values for Europe in 2020 [45]. The upper end of the resulting capacities is in scenarios with low carbon sequestration and low biomass.

[GW$_p$]	2020	2040	2060
Solar PV	161	925 - 1201	1598 - 3027
Onshore wind	183	697 - 899	806 - 1132
Offshore wind	25	154 - 252	273 - 782

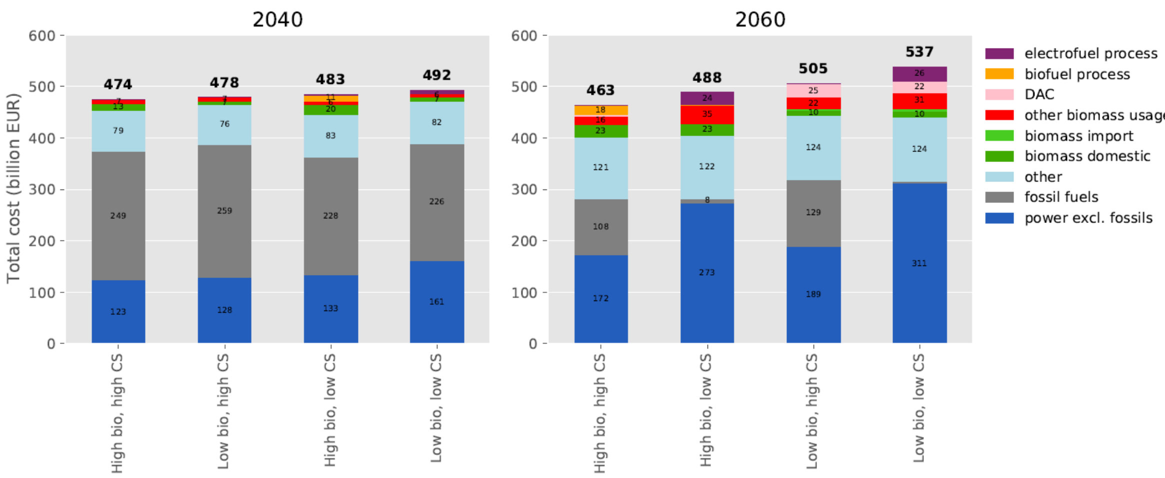

Figure 3: Total system cost [billion €] in the 2040 and 2060 scenarios at different biomass and carbon storage availability, without biofuel mandates.

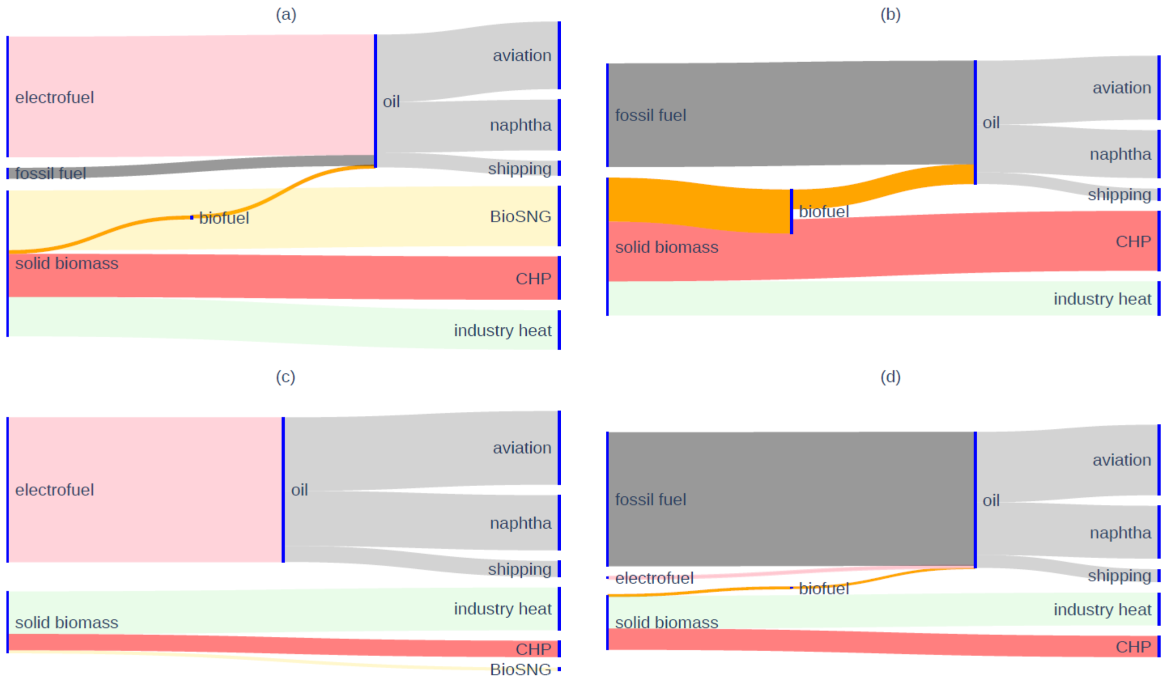

Figure 4: Sankey diagram of fuel supply and solid biomass usage in the base scenarios for 2060: (a) high biomass (bio), low carbon sequestration (CS), (b) high bio, high CS, (c) low bio, low CS, (d) low bio, high CS. Naphtha is used as a feedstock in industry.

3.2 HOW IS THE TOTAL SYSTEM COST AFFECTED WHEN BIOFUEL MANDATES ARE INTRODUCED?

Here, we assess the effect of enforcing a biofuel mandate on the system cost for the 2040 (Figure 9) and 2060 scenarios (Figure 8).

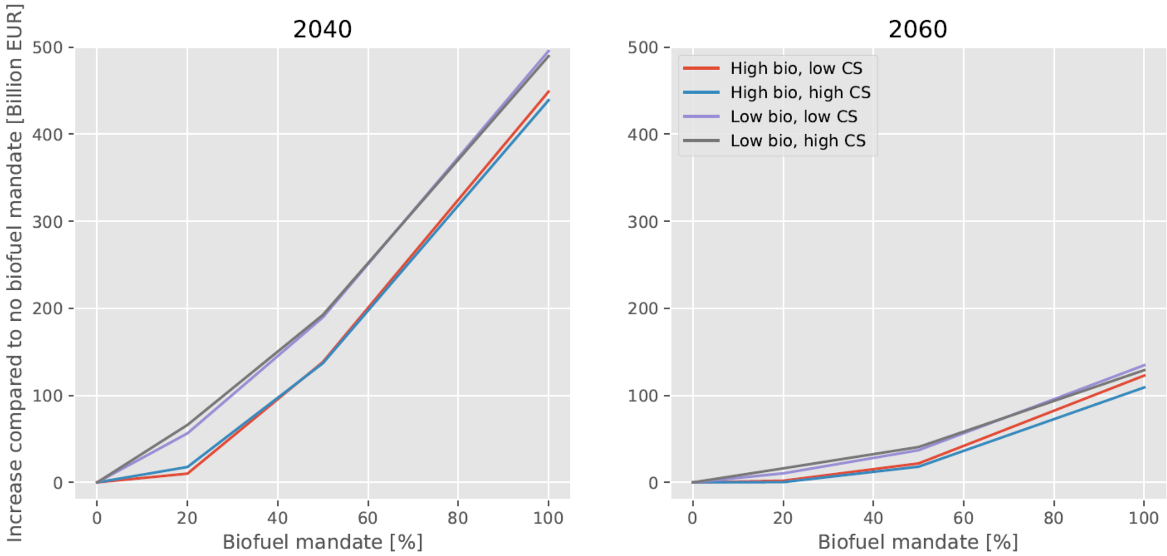

Figure 5: Total energy system cost increase compared to without a biofuel mandate.

3.2.1 Are biofuels a cost-effective transitional solution?

Biofuels are sometimes put forward as a transitional solution to reduce the emissions of the transport sector until electrification achieves high shares [4, 58]. Even though substantial electrification was assumed, the fuel demand in 2040 is still 71% of that in 2020 and corresponds to ~30% of the primary energy demand.

A biofuel mandate of 20% (corresponding to 14% of the fuel use in 2018), results in a cost increase of between 10 and 66 billion € (Figure 5). As a point of reference, the total cost for transport fuels in the EU in 2018 was estimated at 282 billion €, so the cost increase is substantial. Mandates of 50% lead to cost increases of between 100 and 150 billion €, and mandates of 100% to a very large cost increase of up to ca. 500 billion €.

While the amount of CO_2 storage capacity has only minor influence on the cost increase due to the mandates, the amount of available domestic biomass does. There is a steady difference of around 60 billion € between high and low availability of domestic biomass.

Due to an increased electrification, the liquid fuel demand decreases by half between 2040 and 2060, as outlined in Section 2.3. Thus, the same biofuel mandate (in %) requires twice the volume of biofuels in 2040 compared to 2060, which therefore results in a substantially higher cost. Pursuing a biofuel mandate which exceeds the future fuel demand in a shrinking market presents a risk of stranded assets for investors or the risk of a lock-in effect which increases the system cost.

3.2.2 Are biofuels a cost-effective long-term solution?

In the 2060 scenarios, the fuel demand has decreased to 40% of that in 2020 and amounts to ~15% of the primary energy demand. Thus, enforcing a biofuel mandate has a smaller effect on the total system cost. Additionally, the more ambitious emissions target requires measures to be taken also for the liquid fuel supply, and thus the least-cost abatement option is more expensive (either electrofuels or fossil fuels combined with CCS), and therefore the opportunity cost to biofuels is lower.

Figure 5 shows the cost increase due to biofuel mandates between no mandate and a 100% mandate. A biofuel mandate of 20% (corresponding to 7% of the 2020 fuel demand) leads to a cost increase of up to 10 billion €, while a 50% mandate (corresponding to 17% of the 2020 fuel demand) increases costs by 18-40 billion €. A 100% biofuel mandate increases cost by more than 100 billion €. Again, as a point of reference as to the size of the cost increase, the cost of transport fuels in the EU in 2018 was 282 billion €. With little domestic biomass, costly biomass imports are needed already at low mandates. The difference between low and high biomass supply is steady, albeit less so compared to the 2040 scenarios, and amounts to around 20 billion €.

3.2.3 What drives the cost increase when biofuel mandates are introduced?

When biofuels are pushed into the system, several things happen. Fuel costs increase due to biofuels being more expensive compared to both electrofuels and fossil fuels compensated with CCS. The BtL process has a rather low conversion efficiency and a high investment cost, even though rather optimistic base values were chosen. Also, as there is a cost-supply curve for biomass, the more biomass is demanded, the higher the cost is, especially when expensive imports are needed.

Also, as the available biomass is used for fuel production it cannot be used for industrial heat and CHP, which instead are covered by other, more expensive non-biomass options (direct electrification and methane). Thus, there is an opportunity cost of using solid biomass for liquid fuel production rather than for industrial heat and CHP (and at ample domestic biomass also for BioSNG), as other options there are more costly.

Furthermore, the potential for BECCUS is reduced, as a higher share of the biomass carbon can be captured in stationary combustion processes (assumed at 95%) compared to when producing fuels, where only the carbon not ending up in the fuel can be captured (~66% at a conversion efficiency η=45%). This has two effects: there is less biogenic carbon available for producing other hydrocarbons, and other, comparatively more expensive measures are needed to reduce emissions. Thus, rather expensive DAC is needed to produce renewable carbon and to enable more negative emissions, and more of e.g. biogas and power-to-methane are needed to decrease emissions in the system, at a higher cost.

3.2.4 Why are electrofuels are preferred in transport rather than biofuels when carbon storage capacity is low?

The carbon used for producing the electrofuels stems primarily from bioenergy with carbon capture (depending on the amount of low-cost biomass available), i.e. the carbon atoms are used twice in the system before being emitted to the atmosphere. This becomes important in the cases with little available carbon sequestration: fossil fuels cannot be compensated by CCS and DAC is more expensive, so renewable carbon atoms need to be utilized efficiently.

Also, solar and wind power are substantially more scalable resources than is biomass, and these serve as the main resources for producing electrofuels. When biofuel mandates are introduced, the VRE capacities stay similar to without mandates, and instead curtailment increases substantially. Electrolysers are flexible in their electricity demand and can utilise it when it is cheaper. Thus, they can also help to solve integration issues at high variable renewable shares [59–61], and thus more variable renewables can be utilised cost- effectively.

3.3 SENSITIVITY ANALYSIS

The sensitivity of results to the 64 different parameter combinations of pessimistic and optimistic technology assumptions as outlined in Section 2.5 is assessed. Figure 6 shows the sensitivity of system cost to different key parameters directly affecting transport fuels. The difference in total cost increase (i.e. the difference of the difference of system costs between a 50% and no mandate), between pessimistic and optimistic values of a specific parameter set is calculated for each combination of the other parameters. This gives a distribution for each parameter set, which is shown as a span with a distribution density. The further away this span is from zero, the more sensitive is the total cost to a given parameter.

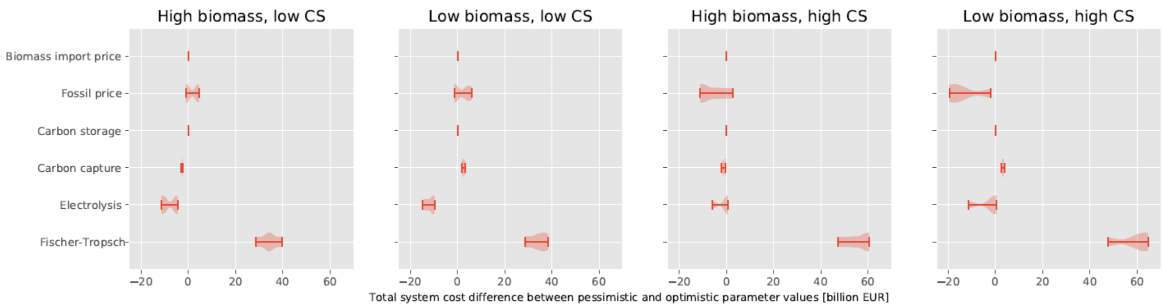

Figure 6: Violin plot of the parameter sensitivity of the system cost increase difference between pessimistic and optimistic parameter values for each extreme parameter value combination, of a 50% biofuel mandate in 2060 compared to without a mandate. This is shown in cases of low and high domestic biomass and low and high carbon storage potentials. The shaded areas show the distribution density of the outcome for a specific parameter when all other parameters are varied.

The total cost increase of a 50% biofuel mandate compared to having no mandate is insensitive to the carbon storage cost and the biomass import price, even though the lower import price value is set close to the current wood chip price. The cost of carbon capture shows a minor effect.

Instead, the largest effect can be observed for the investment cost and efficiency of Fischer-Tropsch (FT), which affects both BtL and electrofuels. If the cost is low and the conversion efficiency is high, the total cost increase of a biofuel mandate is substantially lower, and vice versa. Both the cost and the conversion efficiency affect this individually.

The cost and efficiency of electrolysis shows some effect on the total cost increase of a biofuel mandate. In this case, the span is below zero because a pessimistic value for electrolysis increases the cost for electrofuels and thereby decreases the cost difference to biofuels. Thus electrolysis is more expensive, the cost increase of a biofuel mandate is smaller, and vice versa. However, the difference is much smaller than for the FT parameters. This effect is larger with little carbon sequestration and when domestic biomass is scarce.

The oil price has an effect especially if there is ample carbon sequestration, since very limited fossil usage is allowed when carbon sequestration capacity is scarce. If the oil price is low (optimistic), the total cost increase of a biofuel mandate is larger and vice versa.

4 DISCUSSION

Biomass residues are a very limited resource, and domestic biomass residues can only cover a part of the liquid fuel demand, even if it were all used for biofuels and despite assuming an ambitious electrification of transport.

Within these bounds however, some factors are discussed below, which may affect the competitiveness of using the limited biomass for producing biofuels or are relevant to biofuel mandates.

Biofuel production and resource base

In the sensitivity analysis, the most sensitive parameter was found to be the cost and efficiency of Fischer- Tropsch processes. In the base case, these parameters were set to figures in the optimistic part of the range based on literature [62–64]. If a further 25% cost reduction is assumed, the competitiveness of biofuels increases, but a 50% fuel mandate still always resulted in a cost-increase (1-8%, compared to 4-8% in the base case) compared to without a mandate in 2060.

An increased potential of biomass could potentially make room for producing cost-competitive biofuels, if the biomass resource is low-cost. The main biomass sources that have not been included here are oil-rich food wastes and crops, due to issues outlined below.

The potential of oil-based rest-products is rather low [30]. The EU potential for used cooking oil (UCO) has been estimated at 60 PJ [16], which would correspond to 0.3% of the present EU transport fuel demand [17]. UCO imports displace what they would otherwise be used for, a gap which may be filled with fossils, and there are concerns of fraud [16].

Besides sustainability concerns [13, 14], food crops used for conventional biofuels have low yields and are thus also more sensitive to price increases due to land scarcity [65]. The reliance on food crops for bioenergy is being phased out in the EU [15].

In this study, biomass costs are used for the domestic biomass. However, especially for goods such as solid biomass that are tradable on the global market, prices may be substantially higher than the costs. This means that the actual fuel cost here is underestimated and using market prices for biomass would decrease the competitiveness of biofuels further and increase the cost of biofuel mandates.

Limitations for electrofuel production

Electrofuels rely on a low-carbon source of electricity for hydrogen electrolysis, and a renewable source of carbon, which are both limited today and may be so also in the foreseeable future [18, 19].

Achieving the high electricity generation capacities in Europe required for negative emission scenarios is a challenge. If cheap low-carbon electricity (e.g., mainly wind and solar PV) turns out to diffuse slowly, it is difficult to achieve ambitious emission targets. If domestic capacities are limited, electrofuels may instead be imported from regions with high solar and/or wind potentials and less land constraints, possibly produced at a lower cost than domestically [66].

Cost-competitiveness of biomass usage in industry and CHP

The cost-competitiveness of biomass usage for process heat in industry would be affected by a cheaper than expected electrification of industrial process heat. Industry heat pumps for steam generation could be a competitive option [67, 68], but it is uncertain to which extent [69]. In medium and high temperature applications, electrification is possible, but the uncertainty increases with the required temperature and options are currently in experimental or pilot stages of technological readiness [69]. Many processes such as steel are already electrified to a high extent in this study, but we were conservative with electric options for process heat. A sensitivity run where heat pumps for process steam were included resulted in biomass still being preferred for process steam. This, however, depends on the assumed coefficient of performance (COP), which depends on temperature differences to the heat sink; this is process specific and outside of the scope here to assess in more detail.

Biomass or other flexibility options are needed for CHP especially during cold dark doldrums, when both heating and electricity is needed but solar PV and wind generate little, and heat-pumps are less efficient [c.f. 70]. Biomass for CHP appears in the 2040 scenarios without carbon capture, and in a sensitivity analysis where BECCS was turned off for all technologies, CHP still appeared in 2060, to a similar extent as with BECCS turned on. Thus, this flexibility option provides an important system service and is not only due to the higher potential for BECCS compared to when producing biofuels. Other flexibility options for generation, such as batteries as well as heat and hydrogen storage are included in this study. A back-up system relying on renewables and not fossils is necessary at more ambitious emission targets, and biomass turns out to be a potentially cost-effective candidate for this.

Policy and co-benefits?

Even though renewable fuel shares turned out low at an 80% emission reduction, as other measures to achieve the targets were less costly, the cost increase of moderate biofuel mandates was found to be relatively small. Since the development of renewable fuels requires several parts in the supply chain to function, it may take time to set up the necessary infrastructure and logistics.

This goes for biofuels, which require the mobilisation of currently unused biomass residues as well as the investment in costly biofuel production facilities. It goes just as well for electrofuels, which require large amounts of clean electricity and a carbon source, as well as costly production facilities. Uncertainties along the value chain and regarding sustainability issues and future prices make investments risky. This hinders the development of renewable fuels, and thus directed policy may be warranted as a complement, even if a first-best cap-and-trade or tax policy is implemented for the whole energy system [20, 22, 71]. Such policies could include sector-specific targets, technology subsidies and fuel blending mandates.

A general view is that technologies should be supported to address two market failures: the external costs of GHG emissions as well as of learning effects, which lead to an underestimation of future benefits or they are not appropriated by the investor [20, 22]. Does this apply to biofuels?

Although the conversion technology may need time to develop, the biofuel price depends on both the investment and the resource (in contrast to e.g. VRE). Biomass scarcity and the competitiveness of other biomass usage options may lead to biomass price increases which surpass investment cost reductions achieved through learning effects. Thus, it can be questioned whether supporting advanced biofuels paves the way for a promising technology in terms of cost reduction potentials (see [72] for a similar argument).

However, there may be co-benefits and spillover effects between BtL and electrofuels, since they are both based on the FT-process. Thus, also the electrofuel process may improve in terms of cost and efficiency if BtL improves. It is also possible to combine biofuel and electrofuel production (for instance as electrobiofuels where biofuels are produced with a hydrogen addition, thereby using the biomass carbon more efficiently [18, 73]), or to reuse biofuel facilities for electrofuel production. It may also stimulate a transition to producing renewable chemicals in biorefineries. Therefore, supporting biofuels to some extent may still be a sensible investment in terms of research and development, as well as for setting up value chains and stimulating the mobilisation of currently unused biomass residues.

Nevertheless, care needs to be taken to ensure that production is indeed able to switch over time as outlined above, to avoid infrastructural lock-in effects. Institutional lock-ins related to actors with vested interests [74] may also present a challenge in this regard, if biomass streams are first stimulated and then directed away from renewable fuel production [75].

5 CONCLUSIONS

This work focuses on the competition for liquid fuel supply under CO_2 emission reduction targets, and the effects of biofuel mandates on the cost of the future European energy system. To the authors' knowledge, it is the first time this question has been investigated using a sector coupled energy system with high detail on biomass options including BECCS, and with a high temporal resolution.

Covering the liquid hydrocarbon fuel demand by renewable or carbon neutral options is one of the costliest mitigation options in the energy system and therefore is a cost-effective solution only at very ambitious emission targets. Transport electrification is expected to reduce liquid fuel demand and enforcing a high biofuel mandate early on requires substantial amounts of expensive biomass, and domestic potentials can only cover a small share. This shrinking fuel market may present a risk of stranded assets for investors if high biofuel mandates are pursued early on.

Results indicate that in the medium-term (~2040), a biofuel mandate of 20% results in a 2-4% total cost increase at a high availability of low-cost (domestic) biomass, while if domestic biomass is scarce the total cost increase amounts to 11-14%. A 50% mandate resulted in a cost increase of 137-193 billion €, or 29-40% of the total energy system cost.

In the long-term (~2060), liquid fuel demand is expected to be substantially lower due to electrification, and at a negative emissions target (-105%) liquid fuels need to be either renewable or compensated by CDR. However, biomass use for industry and CHP allows for more carbon capture than when producing biofuels, and CHP emerged as an important flexibility option. Electrofuels based on captured biogenic carbon emerged as the main fuel at a scarce carbon sequestration availability, while fossil fuels compensated by primarily BECCS emerged at an ample carbon sequestration availability. Notably, the difference in total cost was small between the two, but VRE capacities differed substantially. A biofuel mandate of 20% (corresponding to 7% of the 2020 fuel demand) affected total costs less than 0.4% at a high availability of low-cost (domestic) biomass and 2-3% if domestic biomass was scarce. A 50% biofuel mandate increased the cost by 18-40 billion €, or 4-8% of the total system cost. This corresponds to 6-14% of the cost of transport fuels in the EU in 2020 (excluding taxes and levies).

We conclude that even low biofuel mandates risk increasing total energy system costs substantially, and that this cost increase is higher if biofuel mandates are employed in the short- to medium term. Biofuel mandates were found to increase system costs across a range of parameter variations and scenarios. The cost drivers are (i) high biomass costs due to scarcity, (ii) opportunity costs for competing usages of biomass for industry heat and combined heat and power, and (iii) the cost-competitiveness and scalability of other abatement options (electrofuels and fossil fuels combined with CDR). Blending mandates should be inclusive to all alternative fuel options to enable a cost-effective decarbonisation of transport and biomass uses that provide highest mitigation value.

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APPENDIX

NOMENCLATURE

Table 6: Nomenclature

Abbreviation	
BECCUS	BioEnergy with Carbon Capture and Utilisation or Storage
BioSNG	Biogenic Substitute Natural Gas
BtL	Biomass-to-Liquid
C3SE	Chalmers Centre for Computational Science and Engineering
CC	Carbon Capture
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilisation
CDR	Carbon dioxide removal
CHP	Combined Heat and Power
COP	Coefficient of Performance
CS	Carbon Sequestration
DAC	Direct Air Capture
DRI	Direct Reduced Iron
ESOM	Energy System Optimisation Model
EU	European Union
EV	Electric Vehicle
FCEV	Fuel Cell Electric Vehicle
FT	Fischer-Tropsch
GHG	Greenhouse gas
HVDC	High Voltage Direct Current
IAM	Integrated Assessment Model
ICEV	Internal Combustion Engine Vehicle
NET	Negative Emissions Technology
PV	Photovoltaics
PyPSA	Python for Power Systems Analysis
RED	Renewable Energy Directive
SMR	Steam Methane Reforming
UCO	Used Cooking Oil
VRE	Variable Renewable Energy

RESULT GRAPHS

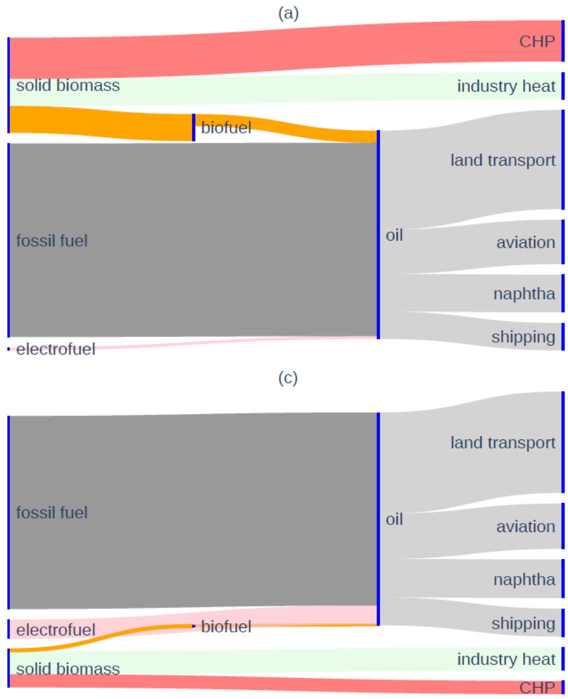

Figure 7: Sankey diagram of fuel supply and solid biomass usage in the base scenarios for 2040: (a) high biomass (bio), low carbon sequestration (CS), (b) high bio, high CS, (c) low bio, low CS, (d) low bio, high CS. Naphtha is used as a feedstock in industry

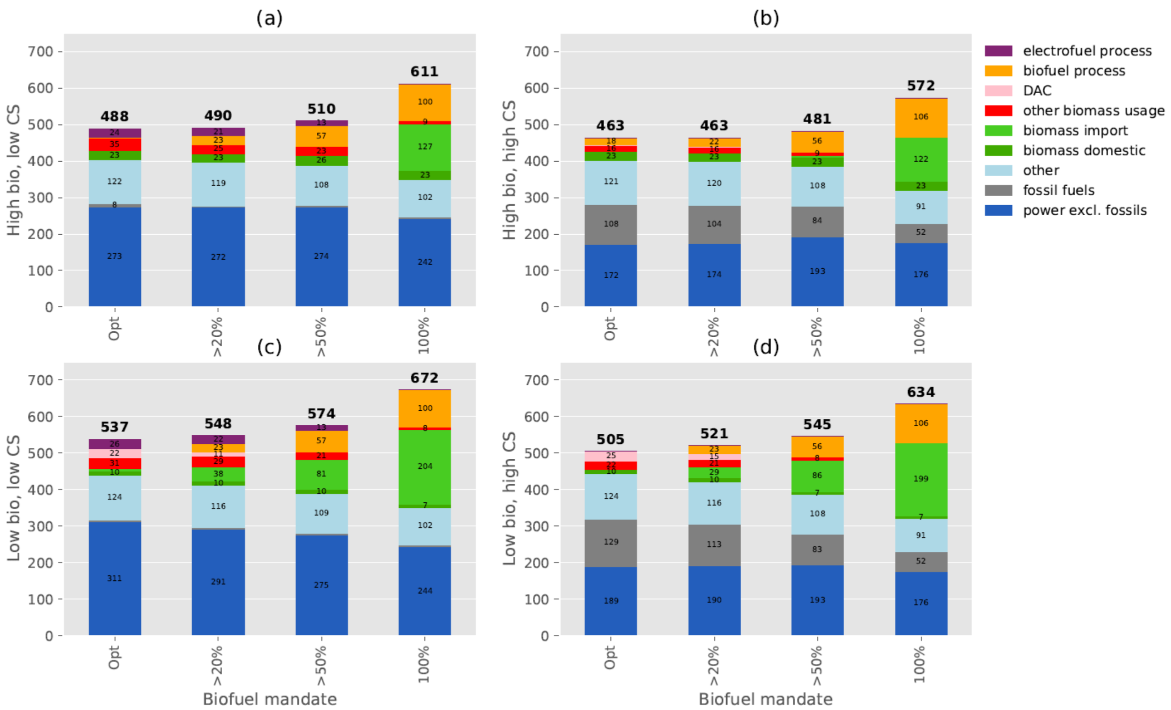

Figure 8: Total system cost [billion €/year] in the 2060 scenarios when pushing biofuels into the liquid fuel mix, at different biomass and carbon sequestration availability.

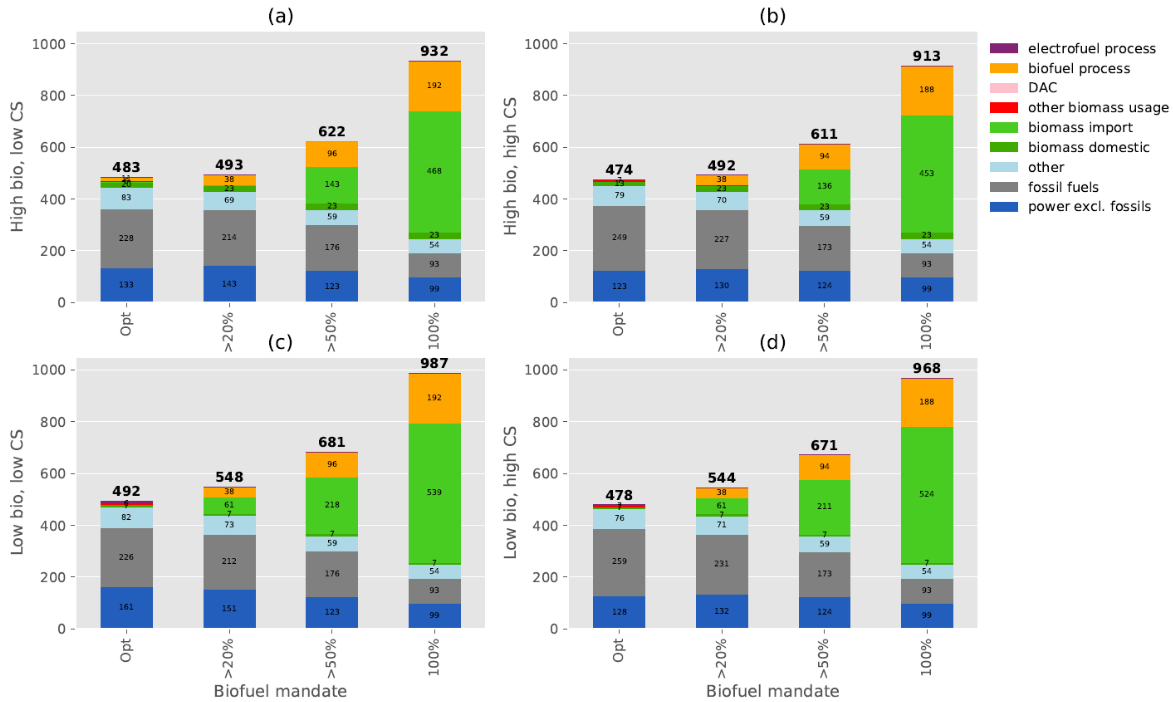

Figure 9: Total system cost [billion €/year] in the 2040 scenarios when pushing biofuels into the liquid fuel mix, at different biomass and carbon sequestration availability.

CARBON BALANCES OF BIOFUELS

Solid biomass carbon dioxide uptake from atmosphere, with $\%C_{sb}$=50%, e_{sb}=18 GJ/t, m_{CO_2}/m_C=44/12 (Eq. 2):

$$\varepsilon_{at}^{sb} = -\%C_{sb} \cdot \frac{3.6}{e_{sb}} \cdot \frac{m_{CO_2}}{m_C} \tag{2}$$

Liquid fuel carbon dioxide emission [tCO_2/MWh] at full combustion for diesel and methane based on -CH_2- simplification for diesel and e_{CH_2} =44 GJ/t_{LHV}, e_{CH_4} =50 GJ/t_{LHV} (Eq. 3):

$$\varepsilon_{fu} = \frac{3.6}{e_{CH_x}} \cdot \frac{m_{CO_2}}{m_{CH_x}} \tag{3}$$

The carbon share ending up in the fuel $C_{fu} : C_{in}$ can be estimated by Eq 4.

$$C_{fu} : C_{in} = \eta \cdot \frac{\varepsilon_{fu}}{\varepsilon_{sb}} \tag{4}$$

The rest is assumed to end up as CO_2, of which a part εs is separated, captured and stored with an efficiency η_ε, with the remainder ε_v being vented as CO_2 to the atmosphere in the exhaust gas.

The biogas produced from digestible biomass is assumed to contain 60 vol-% CH_4 (e=50 GJ/t, ρ =0.657 kg/m^3_n) and 40 vol-% CO_2 (ρ =1.98 kg/m^3_n), which calculates to 0.0868 tCO_2/MWh_{CH4}. The feedstock input potentials and costs for biogas are given for MWh_{CH4}, and thus MWh_{in} = MWh_{out} for the carbon balance calculations. Thereby, the C-content in the slush can be omitted, thus avoiding system boundary issues with the agricultural sector.

The carbon balance equals zero (Eq. 5):

$$\Delta\varepsilon = \varepsilon_{at} + \varepsilon_s + \varepsilon_v + \varepsilon_{fu} \cdot \eta = 0 \tag{5}$$

For the Fischer-Tropsch and methanation processes based on H_2 and CO_2 inputs, the CO_2 is assumed to be cycled within the process, and thus the input-output-ratio of carbon is unity, bar CO_2 leakage.

Table 7: Carbon balances of biomass to bioenergy options

	Biomass	e	η	ε_{at}	$C_{fu} : C_{in}$	ε_s	ε_v	e_{fu}	ε_{fu}
		GJ/t		tCO_2/MWh_{in}	%	tCO_2/MWh_{in}	tCO_2/MWh_{in}	GJ/t	tCO_2/MWh_{ot}
BioSNG	solid	18	0.7	-0.3667	37.8	0.2235	0.0046	50	0.198
BtL	solid	18	0.4	-0.3667	28	0.2585	0.0053	44	0.2571
Biogas	digestible	-	1	-(0.198+0.0868)	69.5	0.085064	0.001736	50	0.198

TECHNOLOGY ASSUMPTIONS

Table 8: Overnight investment cost assumptions per technology and year. All costs are given in real 2015 money.

Technology	Unit	2020	2040	2060	source
Onshore Wind	€/kW	1118	977	963	[76]
Offshore Wind	€/kW	1748	1447	1415	[76]
Solar PV (utility-scale)	€/kW	529	329	301	[76]
Solar PV (rooftop)	€/kW	1127	661	539	[77]
OCGT	€/kW	453	423	411	[76]
CCGT	€/kW	880	815	800	[76]
Coal power plant	€/kW$_{el}$	3845	3845	3845	[78]
Lignite	€/kW$_{el}$	3845	3845	3845	[78]
Nuclear	€/kW$_{el}$	6000	6000	6000	[79]
Reservoir hydro	€/kW$_{el}$	2208	2208	2208	[80]
Run of river	€/kW$_{el}$	3312	3312	3312	[80]
PHS	€/kW$_{el}$	2208	2208	2208	[80]
Gas CHP	€/kW	590	540	520	[76]
Biomass CHP	€/kW$_{el}$	3381	3061	2912	[76]
HVDC overhead	€/MWkm	400	400	400	[81]
HVDC inverter pair	€/MW	150000	150000	150000	[81]
Battery storage	€/kWh	232	94	75	[76]
Battery inverter	€/kW	270	100	60	[76]
Home battery storage	€/kWh	323	136	108	[76, 82]
Home battery inverter	€/kW	377	144	87	[76, 82]
Electrolysis	€/kW$_{el}$	650	300	250	[76]
Fuel cell	€/kW$_{el}$	1300	950	800	[76]
H_2 storage underground	€/kWh	3	1.5	1.2	[76]
H_2 storage tank	USD/kWh	11	11	11	[76, 83]
direct air capture	€/(tCO_2/h)	7000000	5000000	4000000	[76]
Methanation	€/kW$_{CH4}$	278	226	226	[84]
Central gas boiler	€/kW$_{th}$	60	50	50	[76]
Domestic gas boiler	€/kW$_{th}$	312	282	268	[76]
Central resistive heater	€/kW$_{th}$	70	60	60	[76]
Domestic resistive heater	€/kWh$_{th}$	100	100	100	[85]
Central water tank storage	€/kWh	0.6	0.5	0.5	[76]
Domestic water tank storage	€/kWh	18	18	18	[76, 86]
Domestic air-sourced heat pump	€/kW$_{th}$	940	805	760	[76]
Central air-sourced heat pump	€/kW$_{th}$	951	856	856	[76]
Domestic ground-sourced heat pump	€/kW$_{th}$	1500	1300	1200	[76]
CO_2 capture in CHP	€/(tCO_2/h)	3300000	2400000	2000000	[76]

Fischer-Tropsch	€/kW$_{FT}$/a	2100	1100	900	[76]
Steam Methane Reforming	€/kW$_{CH4}$	540	540	540	[87]
Steam Methane Reforming with CC	€/kW$_{CH4}$	1032	1032	1032	[87]
BioSNG	€/kW$_{th}$	2500	1550	1500	[87]
BtL	€/kW$_{th}$	2000	2000	2000	[76]
biogas plus hydrogen	€/kW$_{CH4}$	907	604	453	[76]
industrial heat pump medium temperature	€/kW	871	730	700	[76]
industrial heat pump high temperature	€/kW	1045	876	840	[76]
electric boiler steam	€/kW	80	70	70	[76]
gas boiler steam	€/kW	54	45	45	[76]
solid biomass boiler steam	€/kW	618	563	536	[76]
methanolisation	€/kW$_{MeOH}$	4513	2256	1504	[76]

Table 9: Efficiency, lifetime and FOM cost per technology (values shown correspond to 2020). Fixed Operation and Maintenance (FOM) costs are given as a percentage of the overnight cost per year. Hydroelectric facilities are not expanded in this model and are considered to be fully amortized. Coefficient of performance (COP) of heat pumps is modelled as a function of temperature.

Technology	FOM	Lifetime	Efficiency	Source
	[%/a]	[a]		
Onshore Wind	1.3	27		[76]
Offshore Wind	2.3	27		[76]
Solar PV (utility-scale)	1.7	35		[76]
Solar PV (rooftop)	1.2	30		[77]
OCGT	1.8	25	0.4	[76]
CCGT	3.3	25	0.56	[76]
Coal power plant	1.6	40	0.33	[78]
Lignite	1.6	40	0.33	[78]
Nuclear	1.4	60	0.33	[78]
Reservoir hydro	1	80	0.9	[80]
Run of river	2	80	0.9	[80]
PHS	1	80	0.75	[80]
Gas CHP	3.3	25		[76]
Biomass CHP	3.6	25		[76]
HVDC overhead	2	40		[81]
HVDC inverter pair	2	40		[81]
Battery storage		20		[76]
Battery inverter	0.2	10	0.95	[76]
Home battery storage		20		[76, 82]
Home battery inverter	0.2	10	0.95	[76, 82]
Electrolysis	2	25	0.66	[76]
Fuel cell	5	10	0.5	[76]

H_2 storage underground	0	100		[76]
H_2 storage tank		20		[76, 83]
direct air capture	5	20		[76]
Methanation	4	30	0.8	[84]
Central gas boiler	3.2	25	1.03	[76]
Domestic gas boiler	6.6	20	0.97	[76]
Central resistive heater	1.5	20	0.99	[76]
Domestic resistive heater	2	20	0.9	[85]
Central water tank storage	0.5	20		[76]
Domestic water tank storage	1	20		[76, 86]
Water tank charger/discharger			0.84	
Domestic air-sourced heat pump	3	18		[76]
Central air-sourced heat pump	0.2	25	3.4	[76]
Domestic ground-sourced heat pump	1.9	20		[76]
CO_2 capture in CHP	3	25		[76]
Fischer-Tropsch	3	25	0.65	[76]
Steam Methane Reforming	5.4	25	0.74	[87]
Steam Methane Reforming with CC	5.4	25	0.67	[87]
BioSNG	1.6	25	0.6	[87]
BtL	2.4	25	0.45	[76]
biogas plus hydrogen	4	25		[76]
industrial heat pump medium temperature	0.1	20	2.55	[76]
industrial heat pump high temperature	0.1	20	2.95	[76]
electric boiler steam	1.3	25	0.99	[76]
gas boiler steam	3.7	25	0.92	[76]
solid biomass boiler steam	5.5	25	0.89	[76]
methanolisation	1.2	20		[76]

Table 10: Costs and emissions coefficient of fuels.

Fuel	Cost	Source	Emissions	Source
	[€/MWh_{th}]		[tCO_2/MWh_{th}]	
coal	8.2	[88]	0.336	[89]
lignite	2.9	[80]	0.407	[89]
gas	20.1	[88]	0.198	
oil	50	[90]	0.257	
nuclear	2.6	[78]	0	
solid biomass			0	
digestible biomass			0	

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