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The role of biomass gasification in low-carbon energy and transport systems

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ABSTRACT

The design of future energy systems requires the efficient use of all available renewable resources. Biomass can complement variable renewable energy sources by ensuring energy system flexibility and providing a reliable feedstock to produce renewable fuels. We identify biomass gasification suitable to utilise the limited biomass resources efficiently. In this study, we inquire about its role in a 100% renewable energy system for Denmark and a net-zero energy system for Europe in the year 2050 using hourly energy system analysis. The results indicate bio-electrofuels, produced from biomass gasification and electricity, to enhance the utilisation of wind and electrolysis and reduce the energy system costs and fuels costs compared to CO_2-electrofuels from carbon capture and utilisation. Despite the extensive biomass use, overall biomass consumption would be higher without biomass gasification. The production of electromethanol shows low biomass consumption and costs, while Fischer-Tropsch electrofuels may be an alternative for aviation. Syngas from biomass gasification can supplement biogas in stationary applications as power plants, district heat or industry, but future energy systems must meet a balance between producing transport fuels and syngas for stationary units. CO_2-electrofuels are found complementary to bio-electrofuels depending on biomass availability and remaining non-fossil CO2 emitters.

1. Introduction

Reducing and eliminating GHG (greenhouse gas) emissions requires technical and societal transformations. Two of the largest CO_2 emitters in Europe are energy production and transport [1]. Replacing power generation capacity with variable renewable electricity sources (VRES) can drastically reduce the emissions in this sector. However, a certain level of flexible power plant production will remain necessary to produce electricity when VRES cannot deliver the demand [2,3]. In the transport sector, direct and battery electrification can cover large parts of the demand, but that still leaves heavy-duty and long-distance transport like trucks, coaches, deep-sea shipping and aviation in need of a high-density fuel. Biomass can represent a solution for both energy sectors, contributing to supplying the electricity demands and producing high-density fuels. However, biomass is a limited renewable resource and can only complement VRES for power production and electrification in transport. Mortensen et al. [4] clarify the necessity for deep electrification and hydrogen integration to mitigate excessive land use threat and remain within biomass constraints. However, Hannula & Reiner [5] consider that biomass can enable a gradual transition to sustainable transport compared to electrification. The authors call for a portfolio of technologies to appraise the potential of biomass-based fuels, although acknowledging the competition for this resource with the power and heating sectors.

Except for the direct use of biomass in combustion units to produce electricity, heat, or for industrial purposes, biomass requires processing into gaseous and liquid fuels. For the production of gaseous fuels, anaerobic digestion can convert wet biomass feedstocks as manure, organic or industrial waste into high-density

Abbreviations: CCS, carbon capture and storage; CCU, carbon capture and utilisation; CHP, combined heat and power; DME, dimethyl ether; FT, Fischer-Tropsch; GHG, greenhouse gas; GTL, gas-to-liquids; LMG, liquefied methane gas; POX, partial oxidation; SMR, steam methane reforming; VRES, variable renewable energy sources.

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fuels. Solid biomass as woodchips, forestry products or straw can be thermochemically processed in gasifiers, to produce syngas. Biomass gasification accepts a wide variety of inputs, including agricultural waste [6], biogas digestate [7] or even waste tires [8,9], but depending on the gasifier design and process, there are different requirements for the moisture content and size of the feedstock. Another thermochemical route is pyrolysis, a process that decomposes solid biomass at high temperatures in the absence of oxygen. Fast pyrolysis co-produces biochar, gas and a high oxygen content bio-oil with a low-calorific value that requires upgrading before converting to transport fuels [10,11]. Another thermochemical route, the hydrothermal liquefaction, is more permissive with the feedstock, with no moisture-level requirements since biomass breaks down in a water environment. This alternative route produces a low oxygen bio-oil that can be put through regular refining procedures to produce transport fuels, but the technology is still in its early development [12]. Biochemical routes can also process solid biomass through fermentation to ethanol, but this suffers from low yields and requires intensive feedstock pre-treatment [13]. Unlike the routes mentioned above, gasification is a flexible biomass conversion method on the output side. Syngas can be used directly in cogeneration units or converted efficiently to simple liquids or gases, like methanol or methane. It can also be upgraded with hydrogen from electrolysis to produce electrofuels, here named bio-electrofuels, which increases the production yields, an essential aspect in the context of biomass availability in future energy systems.

Previous research found biomass gasification a critical technology to break the biomass bottleneck and move from biofuels to bio-electrofuels [14,15]. At the same time, Mathiesen et al. [16] called for continued development and research in biomass gasification even before pursuing the end-fuels, since many of the components are shared, referring to producing methanol/DME (dimethyl ether) and methane. Ridjan et al. [17] found the production costs of bio-electrofuels starting from biomass gasification to have the lowest costs among the synthetic fuels, due to the simplicity of the process and high conversion rate. Lester et al. [18] also found that bio-electrofuels as methanol or drop-in liquids have better potential to eliminate fossil fuels from the transport sector due to low production costs and low biomass consumption compared to CO_2-electrofuels and biofuels.

Fewer studies focus on the potential of syngas from biomass gasification for other applications than the transport sector. Connolly et al. [19] mentions biogas and syngas as potential replacements for the remaining natural gas in the energy system to achieve a 100% renewable energy system for Ireland but clarifies that other solutions may exist, such as grid-scale battery storage. The same authors [20] suggest methane from biomass hydrogenation and CO_2 hydrogenation to replace natural gas in the context of 100% renewable energy system for Europe but acknowledge this would be an expensive solution. On the same note, Mathiesen et al. [16,21] also consider syngas from biomass gasification for balancing a 100% renewable energy system for Denmark, by also calculating that the existing Danish gas storages are sufficient for the energy systems in a context of security of supply.

The choice of fuel production pathways can have a considerable influence on the type and amount of biomass used in the energy system. Mortensen et al. [22] study the energy system integration aspects of biomass, investigating the potential of straw residues for ethanol or biogas production, finding that straw has more system benefits if used with biogas. The study limits the research at two biomass conversion technologies and does not compare the energy system effects of using straw for biomass gasification. However, Venturini et al. [23] found that straw is more valuable if gasified and subsequently converted to Fischer-Tropsch (FT) fuels than used for biogas purposes. On a plant level analysis, Butera et al. [24] demonstrate the high efficiency of producing methanol from straw, with better results than some state-of-the-art plants on wood gasification. Methanol is often proposed as a future fuel for road transport or shipping [14,25–27] or as an intermediate for the production of jet-fuels [28,29], but other jet-fuel pathways have received more attention, namely biofuels [30,31] or gas-to-liquid (GTL) pathways starting from biogas [32]. The production of jet-fuels and maritime shipping fuels may be the few transport sectors that will require large amounts of renewable liquid fuels in the scenario of extensive road transport electrification.

Despite the growing body of literature dealing with the variety of fuels in different transport sectors [31,33–41] and with full decarbonisation pathways [20,21,42–46], few of these studies include biomass gasification in their assessments [21,36,44–46]. Furthermore, to the knowledge of the authors, no studies inquire in detail the potential system effects of biomass gasification. We hypothesise that biomass gasification may have a more significant role in the design of future energy systems for both transport and stationary units. To verify our hypothesis, we use energy system analysis to identify the system effects of large-scale biomass gasification implementation. We consider both hydrogenated and non-hydrogenated pathways, and we include them in the assessment together with biogas and CO_2-electrofuels.

2. Methodology

A high temporal resolution and data granularity tool are required to capture the dynamics in highly renewable or net-zero energy systems. EnergyPLAN was the tool of choice to carry out this analysis due to its capacity to balance the entire energy system on an hourly basis while also enabling cross-sector integration, rather than simulating the transport sector separately. The tool allows for detailed electrofuel inputs and flexible hydrogen production and storage for using VRES based on hour-by-hour time series [47].

For this analysis, we use two alternative reference energy systems for Denmark and Europe for the year 2050. In the case of Denmark, we set up our reference starting from the IDA Energy Vision 2050 [21], a 100% renewable energy system that was further updated to reflect tool developments and knowledge improvements. The model is operated as a closed system, without transmission imports and exports, to maximise the interactions between energy sectors. We calibrated it with an excess electricity production of 10% of the domestic electricity demands and a gas grid balance of 0, meaning that gas demand matches gas production, an essential aspect of quantifying gaseous fuels. Transport, personal vehicles and rail are almost full electrified, while light-duty vehicles and busses have a lower electrification level. Methanol produced in equal shares through biomass hydrogenation and CO_2 hydrogenation supplies the remaining demands of heavy-duty, long-distance driving and shipping. Aviation uses jet fuel produced through methanol-to-jet fuel synthesis.

For the European model, we used the European Commission's low-carbon energy models for 2050 [48], converted to EnergyPLAN models as described in Ref. [49]. We use one of their most ambitious decarbonisation scenarios, the 1.5 TECH, further adapted for this analysis. Compared to the original conversion to EnergyPLAN in Ref. [49], we calibrated the model on similar boundaries as the model for Denmark. We set the excess electricity production to 10% of the household and service demands by decreasing all the VRES proportionally. The model operates as a closed system with the remaining power production (that is not hydro, nuclear or VRES) balanced by power plants using natural gas. All the remaining emissions are offset by carbon capture and storage (CCS). The personal transport, light-duty vehicles and rail are electrified in a proportion of 80–90%, while busses and heavy-duty vehicles use a mix of battery electrification, fuel cells, liquids and gaseous fuels. Shipping and aviation are assumed to use a mix of biofuels, electrofuels and some fossil fuels [48].

The reference scenarios differ in design and approach. The Danish model builds on the concept of Smart Energy Systems which entails that an energy system is 100% renewable, uses a sustainable level of bioenergy, makes use of the synergies between energy grids (electricity, thermal and gas) and energy storages and is affordable. Such a system has a high degree of flexibility, by using large-scale district heating systems with large heat pumps and combined heat and power (CHP) and flexible electrolysis combined with hydrogen storage for the efficient use of available VRES. The European model is an evolution of the traditional fossil-fuel energy system that still relies on these fuels but offsets the emissions through carbon capture and storage (CCS). Despite using large amounts of VRES, the 1.5 TECH model is less integrated and less energy-efficient, and unable to use the excess heat from industry and fuel production due to the low district heating levels. It also uses less flexible electrolysis capacities and less hydrogen storage. Compared to the Danish model, the European model is less detailed on the transport sector, providing an approximation of the mix of fuels without including any vehicle and transport infrastructure costs. Because of the differences between the two models, these prove suitable test-beds to understand if the choices of technologies and fuel production pathways influence the energy systems the same way. Table 1 shows an overview of the main parameters for the two models.

2.1. Alternative scenarios

In the alternative scenarios for Denmark and Europe, we built extreme scenarios where we replace the renewable fuel production pathways in the reference scenarios with production pathways that use solely biomass gasification and hydrogenation (bio-electrofuels) or solely CO_2 hydrogenation (CO_2-electrofuels). With this approach, we focus on liquid and gaseous hydrocarbons without altering the electricity demands for electric vehicles, nor the hydrogen demands for fuel cells in transport. The intention is to reflect systemic changes in the fuel production pathways rather than shifting all energy carriers in the transport sector for each model.

Table 1
Main parameters of the reference systems.

	Unit	Denmark	Europe
Primary energy supply			
On-shore wind	TWh/year	16.20	1800
Off-shore wind	TWh/year	53.88	1810
PV	TWh/year	6.35	1210
Wave	TWh/year	1.35	0
Biomass	TWh/year	64.52	2470
Conversion capacities			
On-shore wind	MWe	5000	640,000
Off-shore wind	MWe	11,610	380,000
PV	MWe	5000	840,000
Wave	MWe	300	0
Large CHP	MWe	3500	25,000
Small CHP	MWe	1500	
Power plants	MWe	1000	241,000
Electrolysis	MWe	8790	413,000
Energy demands			
Domestic electricity	TWh/year	32.92	1690
District heating	TWh/year	28.19	200
Individual heating	TWh/year	14.51	1180
Industry	TWh/year	11.82	2391
Transport demands			
Electrification	TWh/year	9.43	604
Liquid fuels (except aviation)	TWh/year	18.68	430
Gaseous fuels (incl. H2)	TWh/year	0	636
Liquid fuels aviation	TWh/year	8.01	670

The end-fuels considered are methanol, Fischer-Tropsch liquids and methane, where each fuel replaces another transport fuel in the reference scenarios either through the bio-electrofuel pathway or through the CO_2-electrofuel pathway, as follows and as illustrated in Fig. 1:

- Methanol for heavy-duty road and maritime transport, while aviation utilises jet fuel produced through the methanol-to-kerosene synthesis (HydroMeOH scenarios).
- Fischer-Tropsch liquids to produce diesel for heavy-duty road transport and shipping combined with jet fuel for aviation (HydroFT scenarios).
- Liquefied methane (LMG) as fuel for heavy-duty road transport and shipping, while aviation uses jet fuel produced through the gas-to-liquids process. Section 3 further describes each of these pathways (HydroGTL scenarios).

The illustration in Fig. 1 also entails that all pathways refer to hydrogenated fuels since these allow for higher yields and energy system flexibility than non-hydrogenated pathways. Previous research [14,34,50] has demonstrated that hydrogenation is required to supply all the transport demands using renewable fuels while also achieving energy system flexibility and dealing with biomass availability and land use. Hannula et al. [15] demonstrated that the output of a methanol and methane plant could be increased by 2–3 times depending on the type of gasification used, for the same biomass input. For the FT synthesis, Hillestad et al. [51] found a similar increase in the fuel output, of 2.4 times compared to a plant without hydrogen enhancement.

As in the reference scenarios, the alternative scenarios keep the same energy system boundaries, meaning that excess electricity production remains 10% of the domestic/service demands balanced by adjusting upwards or downwards the off-shore wind capacity. We assume that on-shore wind and photovoltaic capacities remain fixed partly due to land constraints and as a method for simplifying the visualisation of the changes brought to the alternative scenarios. Hence the variations in electricity demands are illustrated through variations in off-shore wind capacity. The gas balance in the model for Denmark is kept at 0 (all gas demands in stationary units are supplied internally) throughout all scenarios by using syngas from biomass gasification, in a closed energy system (with no external electricity transmission). In the model for Europe, natural gas with CCS realises the balancing by keeping the net CO_2 emissions at 0.

3. Technology descriptions and costs

Biomass gasification is one of the leading biomass conversion technologies. Gasification is the intermediate step between pyrolysis and combustion that extracts the energy from biomass to a syngas (also known as producer gas) in an endothermic process. Depending on the end-use of the resulting gas, the oxidising agents can be air, oxygen or steam, which directly influences the contents of the syngas, which may be a mixture of nitrogen, hydrogen, carbon monoxide, carbon dioxide, methane, water and impurities as chlorine, sulphur, tar and dust. This mixture can be used directly in stationary electricity and district heat production units or industrial combustion units with minimal cleaning, which is also the assumption in our analysis. The type of gasifier considered for this purpose is a fixed bed design, but other designs exist, such as the

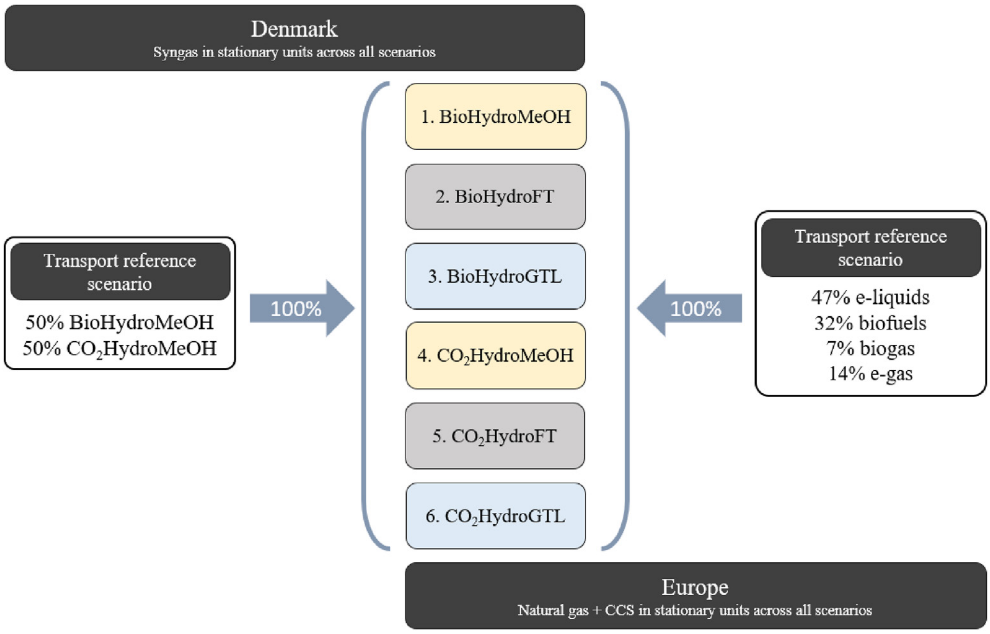

Fig. 1. The six 'extreme' scenarios in the transport sector produced as bio-electrofuels or CO_2-electrofuels.

circulating fluid bed and entrained flow gasifiers, more suitable for producing value-added liquid and gaseous fuels. The analysis considers such types of gasifiers to produce bio-electrofuels, combined with oxygen as an oxidising agent and extensive gas cleaning [12]. We assume overall biomass-to-syngas efficiency at 83% for this study [12].

The quality of the generated syngas depends mainly on the gasifier type, where fluid bed gasifiers require extra cleaning compared to entrained flow gasifiers to reduce or convert the content of hydrocarbons and tar compounds. The advantage with fluid bed gasifiers is the feedstock flexibility, where several publications have looked into the influence of different biomass blends for the production of quality syngas [52–54] as well as the output biochar quality, meaning that agricultural residues such as straw can be gasified and the nutrients returned to the agricultural soil [55,56]. Pre-treatment of biomass and post-treatment of syngas can be costly and energy-intensive steps [57], but downstream processes may enable synergies, e.g. heat for drying may be supplied by excess heat from the gas conversion process to either electricity or fuel. In our analysis, we consider a mix of biomass feedstock for gasification, including straw, woody products as well as energy crops and biogas digestate.

CO_2-electrofuels bypass the gasifier to use the CO_2 captured by point-source or direct-air capture units. Several concepts exist, but few tested on a large-scale. Among them, post-combustion and oxyfuel combustion technologies are the most mature. Post-combustion technology is meant to be adaptable and fit at the tailpipe of combustion plants, allowing for retrofitting existing heat and power plants or industrial combustion processes [58]. On the downside, such applications may result in heat and power penalties, reducing the efficiencies. Oxyfuel combustion uses oxygen instead of air for combustion, resulting in nitrogen-free flue-gas consisting of water vapour and CO_2. It fits well with capturing CO_2 from cement plants, but it is not very suitable for retrofitting older units and also needs a source of oxygen [58]. For this analysis, we consider the post-combustion technology in the CO_2-electrofuel scenarios.

For the electrolysers, we use an energy efficiency (LHV basis) of 79% for the Danish model and 69% for the European model [12], while also assuming 5% compression losses for hydrogen storage. Hydrogen storage combined with few operation hours for electrolysers enables the flexible operation of the fuel plants since the gasification and fuel syntheses are assumed to operate continuously. Such an approach allows for a more accurate comparison between the production pathways, especially as FT has a low tolerance to load variations [12], but the methanol and methane syntheses may be operated flexibly [59]. Other flexibility measures may also be possible that do not include hydrogen storage, where instead the plant output is flexible, producing fuels or electricity, depending on the price of electricity and market demands [60,61], but these are not analysed here.

The methanol pathway entails the presence of a methanol synthesis reactor. The conversion losses limit the efficiency of the methanol synthesis reactions due to the exothermic nature of the methanol synthesis, and a small percentage of syngas will be purged from the synthesis loop. Therefore, in the pathway using biomass gasification and hydrogenation, we assumed a conversion energy efficiency of 80% [62], while for the pathway using CO_2 hydrogenation it may reach up to 88% based on the chemical reaction. Due to the more significant syngas loss when using CO_2 for synthesis compared to synthesis based on CO, we consider a value of 84%.

The available literature on producing aviation fuel through the methanol-to-jet fuel synthesis is scarce, where Schmidt et al. [28] analysed jet fuel production from methanol, comparing it with the FT pathway. The conversion to jet fuel includes several steps as the DME and olefin syntheses, oligomerisation and hydrotreating. All steps are already used in existing large refineries, but lack the technical demonstration of the complete pathway, even though analyses on the quality of the distillate fractions fulfil the specifications for 100% drop-in jet fuel [28]. Our analysis assumes a reaction efficiency from methanol to jet fuel of 74%, based on the results in Ref. [63].

The FT synthesis has been used for several decades already, often connected with fossil fuels, but there is less experience with biomass as feedstock. The synthesis requires a stoichiometric H_2/CO ratio slightly higher than two, which can be achieved with the water-gas-shift reaction or with the addition of hydrogen. The FT reactions are not particularly selective, but all plants would be calibrated to produce as much of the heaviest hydrocarbons as possible, which may also incur a trade-off between production rate and product selectivity. Future efficiencies may range between 70 and 75% from syngas to FT liquids [12,34], which is also close to the theoretical limit of the process, where the remaining output ends up as excess heat. Not all of the output is jet fuel or diesel, as a part of the fuel will end up as methane, ethanol, gasoline or naphtha. De Klerk [64] refers to an FT jet fuel yield of 60% of the total FT liquids, which is the value Mortensen et al. [32] used in their analysis. Our analysis assumes that the side products of such a refinery account for 30% of the FT products, expecting that the remaining 10% is not usable for the transport sector. We deduct the 30% side products from jet fuel production from the rest of the road transport demand to make the pathways comparable.

The third pathway in this analysis is methanation which is also an exothermic reaction where the output is methane and water. We use a conversion efficiency of 82% for biomass hydrogenation [65] and 83% for CO_2 hydrogenation, based on the chemical reaction. The resulting methane gas can be used directly in the gas grid and then compressed or liquefied. In this analysis, we assume the methane is liquefied for heavy-duty road transport and shipping, while for aviation, we assume the GTL process converts the methane to jet fuels. Most of the technology descriptions for the FT technology explained in the previous paragraph still apply, except the presence of partial oxidation (POX)/steam reforming (SMR) for converting methane to syngas. Depending on the scale of the GTL plant, Mortensen et al. [32] suggest an overall efficiency of 50–65% by the year 2030, including FT synthesis, depending on the choice of methane reforming. Methane reforming is an established technology, and we estimate it at 85–90% of methane input. Combined with the FT synthesis, the overall liquid output is estimated to 62%, the value used in this analysis. The product selectivity is assumed to be the same as in the previous pathway, meaning 60% jet fuel and 30% other transport fuels, the latter deducted from the road transport demands.

Table 2 presents the investment costs for the main technologies considered in this analysis:

4. Results

This study quantifies the energy system effects of utilising biomass gasification for both fuel production and power generation. Key results are on wind end electrolysis capacities, biomass and primary energy supply, including total energy system costs and fuel costs.

4.1. Wind and electrolysis capacities

Using any of the CO_2-electrofuels to supply the transport demands requires 50–60% more off-shore wind capacity than the biohydrogenation pathways in the Danish models and up to 60–75% for the European models, as illustrated in Fig. 2. Another observation relates to the type of fuels produced in the pathways, where among bio-electrofuels the off-shore wind capacities remain similar, so producing methanol, FT liquids or methane has roughly the same effect. The differences appear when producing CO_2-electrofuels, which require significantly more electricity to achieve the same effect. There are approximately 2000 MW, and respectively 100 GW difference in favour of CO_2HydroMeOH pathway compared to the most wind intensive pathway, the CO_2HydroCH4 for Denmark and Europe. The CO_2HydroFT finds itself in between the two.

In regards to the electrolysis capacities, these follow the same trend as off-shore wind, wherein the case of Denmark the electrolysis capacities are 95–145% larger for CO_2-electrofuels than for bio-electrofuels. The differences are lower for the European scenario, but these still amount between 40 and 68% more capacity for CO_2-electrofuels. The modelling approach can explain this difference, where we use a flexible electrolysis capacity with 100% buffer capacity and large hydrogen storage of 7 days for the Danish model, compared to the European model where we only assume a smaller buffer on only 30% and only two days of hydrogen storage. Even so, the differences between the two types of electrofuel production are significant. As in the case of off-shore wind capacities, the electrolysis capacities for bio-electrofuels are similar, but differences occur between the end-fuels, with CO_2HydroCH4 requiring the largest electrolysis capacities, about 3000 MW more than the CO_2HydroMeOH pathway. As in the case of off-shore wind, the CO_2HydroFT finds itself between the other two pathways.

Table 2
Main investment costs used in the analysis.

	Unit	Investment (M€/unit)	Lifetime (years)	O&M (% of investment)	References
Electricity production					
On-shore wind	MWe	0.70	30	1.62	[66]
Off-shore wind	MWe	1.78	30	1.82	[66]
PV	MWe	0.49	40	1.59	[66]
Wave	MWe	1.60	30	4.90	[21]
Large CHP	MWe	0.80	25	3.25	[66]
Small CHP	MWe	1.10	25	2.36	[66]
Power plants	MWe	0.76	25	3.25	[66]
Fuel conversion					
Electrolysers	MWe	0.40–0.50	20	4.00	[12]
Hydrogen storage	GWh	17.00	30	1.00	[67]
Biogas plant	TWh/year	159.03	20	14.00	[12]
Biogas purification plant	MWfuel	0.25	15	2.50	[12]
Gasifier (power gen.)	MWfuel	1.33	20	3.00	[12]
Gasifier (fuel prod.)	MWfuel	1.57	20	3.00	[12]
Methanol synthesis	MWfuel	0.30	25	4.00	[34]
Methanol-to-kerosene	MWfuel	0.50	20	4.00	[68]
FT synthesis and upgrade	MWfuel	1.03	25	8.00	[12]
Methanation	MWfuel	0.20	25	4.00	[34]
Partial oxidation/Steam reforming	MWfuel	0.14	25	4.00	[69]
Post-combustion carbon capture	tCO2/year	300[a]	25	4.00	[58]

[a] Assuming a general cost for point source capture representative for a variety of sources.

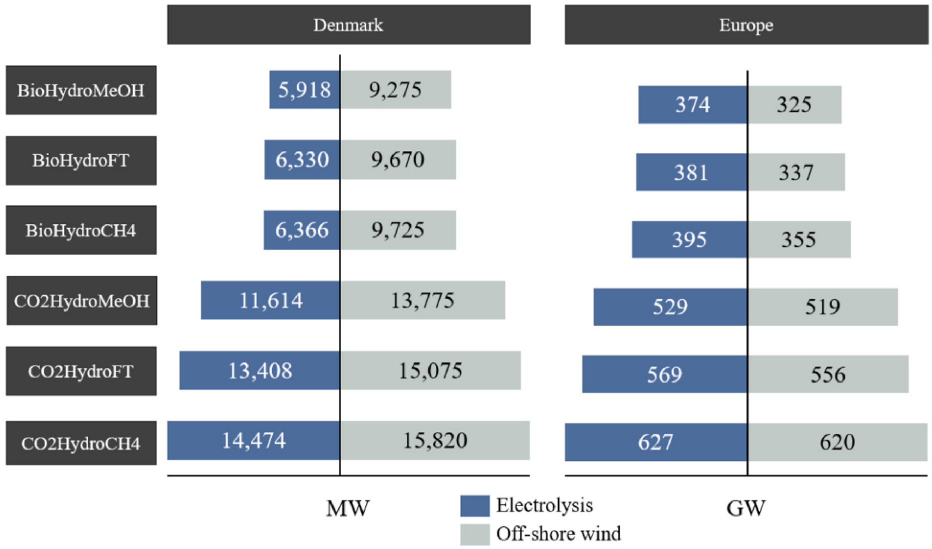

Fig. 2. Installed capacities for wind and electrolysis in the Danish and European models.

4.2. Biomass consumption

A boundary condition for the choice of technologies and production pathways is the amount of available biomass. In our analysis, we consider six extreme scenarios for Denmark and Europe, where we maximise the use of biomass gasification (Chapter 5 handles biomass availability). As such, in the case of Denmark, the total biomass consumption for producing bio-electrofuels is significantly higher than for CO_2-electrofuels by 30–45%, depending on the fuel production pathway. The BioHydroMeOH pathway has the lowest biomass consumption, with 18% higher biomass consumption for the FT pathway and 35% more biomass for the methane pathway. In regards to the biomass gasification for power generation, the results in Fig. 3 show approximately the same amount of gasified biomass for power generation across all three bio-electrofuels, indicating that the choice of fuel syntheses does not influence the operation of the power plants. However, it does influence the capacity of off-shore wind and electrolysis, as shown in Fig. 2.

In the case of the European model, the results are reasonably similar, the total biomass consumption for producing bio-electrofuels is 64–70% higher than in the case of CO_2-electrofuels, depending on the choice of pathway. As in the Danish model, the BioHydroMeOH pathway has the lowest biomass consumption among the bio-electrofuels, while the differences in natural gas consumption for the CO_2-electrofuel pathways are less evident, but these are still in the order of 100–200 TWh higher for FT and methane pathways.

In the future, there may be an interest to increase the ash output, a co-product of gasification that can be beneficial for soil fertility and carbon sequestration. We perform a sensitivity analysis that includes reducing the gasifier efficiencies from 83% to 70%, a low efficiency if the aim is to maximise the gas output. The analysis shows that the biomass consumption increases by 9–10 TWh in the BioHydroX scenarios, and by 6 TWh for the CO_2HydroX scenarios. In the European scenarios, where we only use gasification for fuel production, the increase in biomass consumption is 230 TWh. It may also be that not all gasifiers should produce biochar, in which case the gasifier efficiencies may be increased, with the current estimations suggesting 90% efficiency [12], reducing the amount of biomass they use.

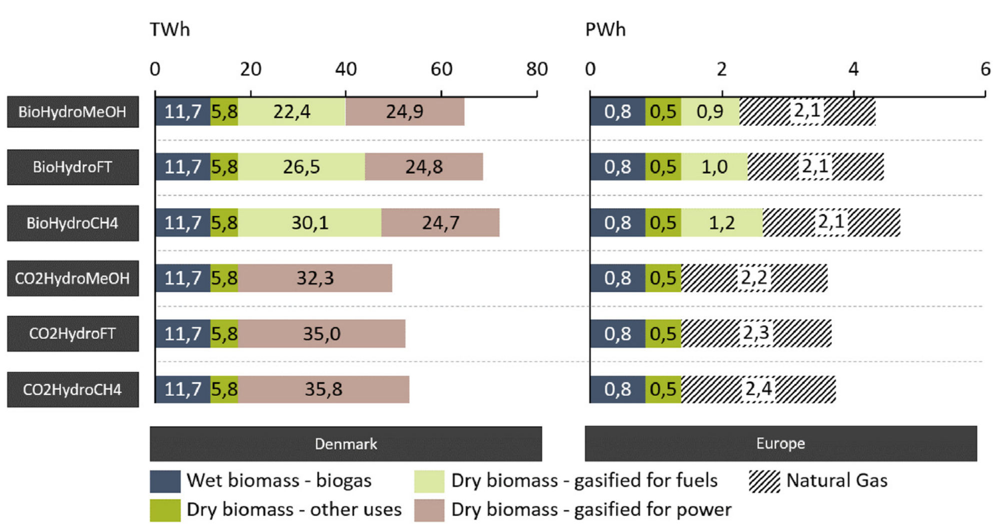

Fig. 3. Biomass and natural gas consumption in the Danish and European models.

4.3. Energy system costs

The choice of technologies and fuel production pathways influences the total cost of the energy system. A significantly larger capacity of wind and electrolysis is required to produce CO_2-electrofuels, although the production of these fuels does not use biomass directly, but can use biomass indirectly for power generation as in the case of the Danish models. An overview of the primary energy supply and energy system costs in Fig. 4 shows the increased overall fuel consumption for the CO_2 hydrogenation scenarios that account for approximately 30% more wind production to supply the same transport demands. The overall energy system costs reflect at 1–1.2 B€ higher for CO_2-electrofuels pathways due to the additional wind, electrolysis and hydrogen storage in the energy systems.

In the European models, we represent the transport sector without vehicle costs, which helps illustrate how the energy system costs differ without considering this aspect. The results in Fig. 4 illustrate that bio- and CO_2-electrofuels keep very similar cost differences between the pathways as in the Danish scenarios, illustrating that it is hardly the vehicle costs and their associated propulsion systems that influence the energy system costs. The differences between the two types of electrofuels are similar for the same end-fuels, varying between 60 and 90 B€ more for CO_2-electrofuels. Like in the Danish models, the main cost difference is represented by the increased capacities of wind, electrolysis and hydrogen storage, as illustrated in Fig. 2, which accounts between 25 and 30% more electricity used in these scenarios than the bio-electrofuels.

The reduction in gasifier efficiency is also considered from an energy system cost perspective and compared to increasing the biomass feedstock price. The results show that reducing the gasifier efficiencies from 83% to 70% has a limited effect on the total energy system costs, but the biomass price increase to 10 €/GJ in the Danish model (from 6 €/GJ) has 3–4 times larger cost impact than using less efficient gasifiers. In the model for Europe, we apply a similar approach, by increasing the cost of biomass from 8 €/GJ to 12 €/GJ, which entails energy system cost increases between 21 and 26 B€/year, which is four times larger than using the low-efficiency gasifiers.

4.4. Fuel costs

The fuel cost analysis is another measure for quantifying the differences between the pathways and end-fuels, as illustrated in Fig. 5. The price difference between bio-electrofuels and CO_2-electrofuels of 20–25% favours the former, due to the lower electricity consumption and reduced electrolysis and hydrogen storage capacity. For road transport and shipping, the lowest cost fuels are methanol and LMG, while FT diesel is significantly more expensive due to the higher resource consumption and expensive fuel synthesis. In the case of aviation fuels, jet fuel from methanol and FT jet show very similar costs, but at a considerable difference to the GTL jet fuel, primarily due to the numerous fuel conversions, which results in increased feedstock consumption.

The prime determinator for the significant cost difference between bio-electrofuels and CO_2-electrofuels is the presence of biomass, which contains both the carbon and hydrogen in its composition, thus requiring less electrolytic hydrogen. Considering a different price for electricity or lower cost for electrolysis would not be revealing parameters for potential cost variations, as this would apply to both types of electrofuels. The sensitivity analysis takes methanol as an example. It reveals that doubling the price of biomass from 6 €/GJ to 12 €/GJ, reducing the gasifier efficiency to 70% (the minimum efficiency for today) or doubling its investment cost does not make this type of methanol more expensive than the cost of methanol obtained from carbon capture. Therefore, biomass price may be a more volatile parameter that can have a more extensive influence on the final price of the fuel, but the gasifier efficiency and investment cost have a more limited effect.

Regarding the aviation fuels, the GTL pathway has received attention recently due to its potential to combine with biogas methanation [32], in the context where biogas has an increased role in the future energy system. Such a pathway would enable converting existing GTL plants using natural gas to produce future jet fuels. Our energy system and fuel cost analysis results revealed that the GTL pathway is the most expensive way of producing jet fuels, as shown in Fig. 5. A reduction in the cost of electrolysis or electricity would not bring it in line with the other jet fuels because of its significantly higher hydrogen consumption than FT and methanol-to-jet pathways (~50% more hydrogen). Improving the

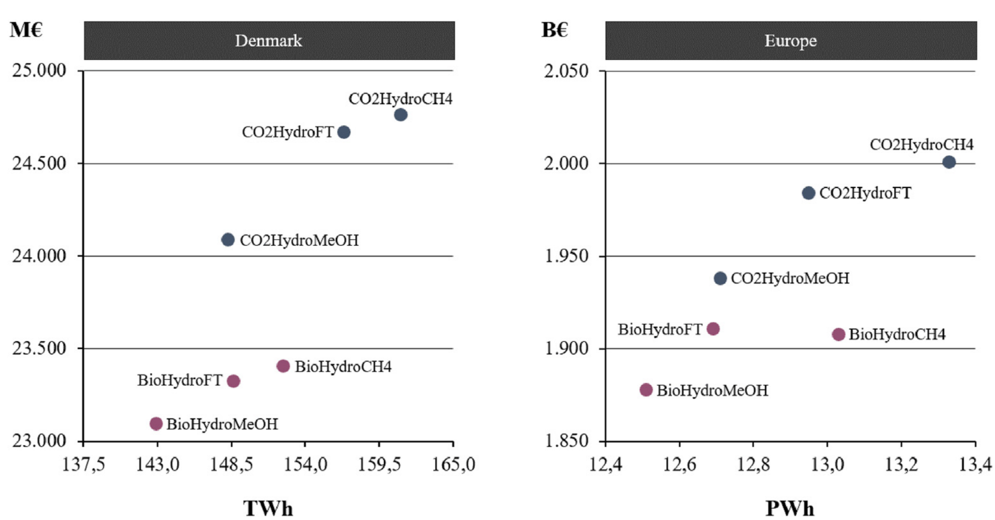

Fig. 4. Primary energy supply and total energy system costs in the scenarios for Denmark.

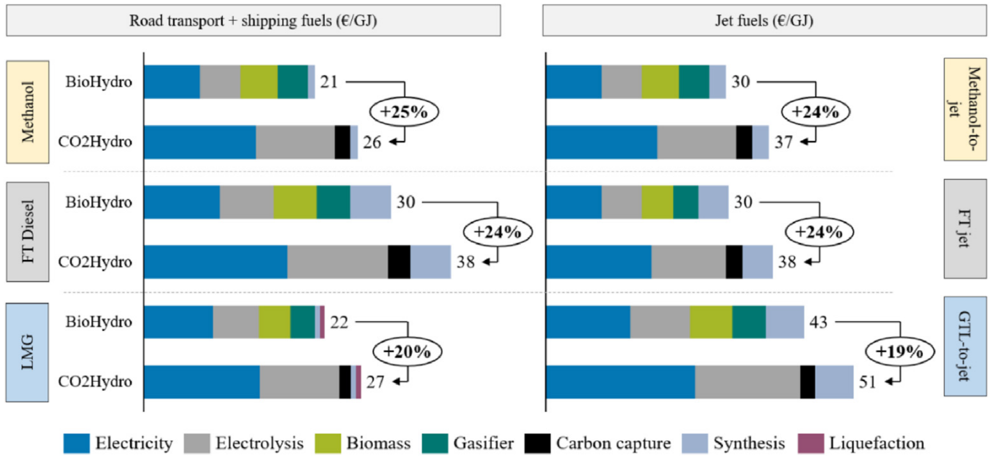

Fig. 5. Fuel prices for the six pathways split between road transport + shipping on the left and aviation on the right. Electricity price is based on off-shore wind investments, while the electrolysis has an efficiency of 69% and includes a 30% overcapacity with 48 h of hydrogen storage.

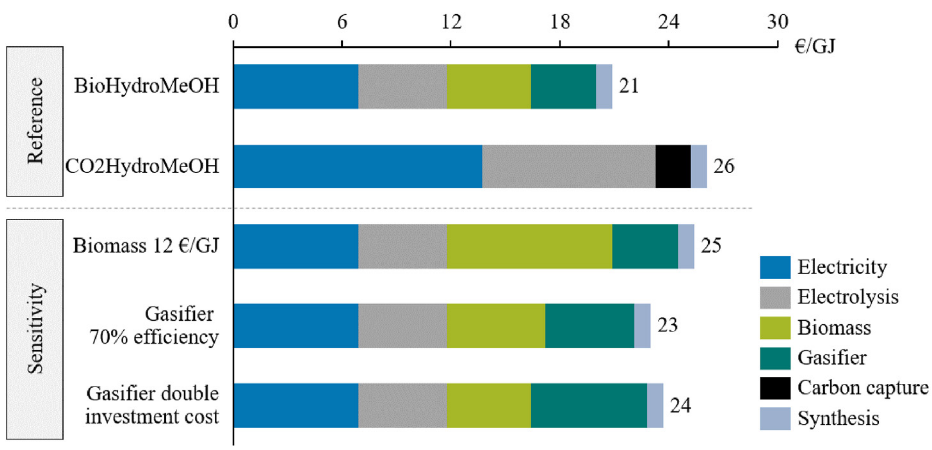

Fig. 6. Sensitivity analysis of biomass and biomass conversion to methanol.

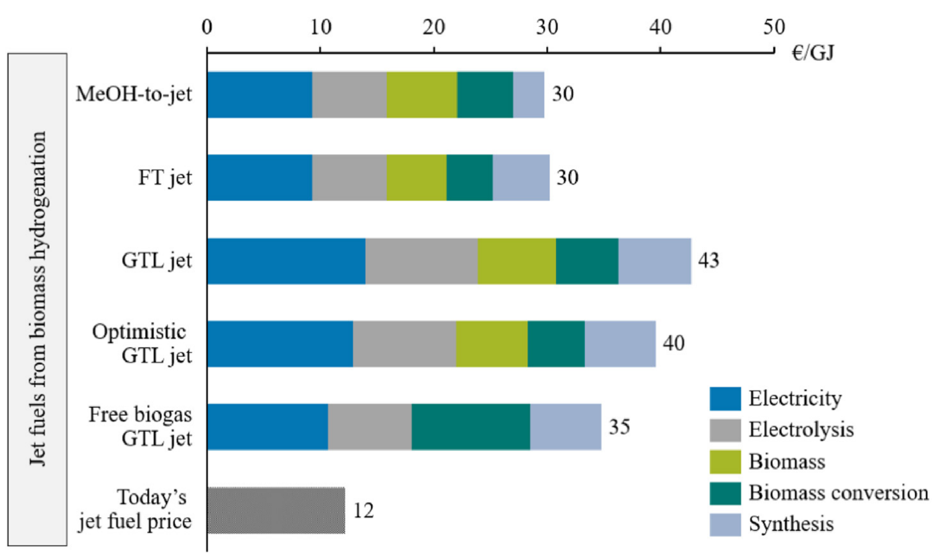

Fig. 7. Cost sensitivity for jet fuels produced through the biomass hydrogenation pathways.

conversion efficiencies of POX/SME and FT synthesis to theoretical maximums (i.e. 90% and 75%) would also not make this pathway sufficiently more cost-effective, as shown in Fig. 7. The same figure demonstrates that even with free biogas feedstock, producing jet fuels is not economical. In our previous study [70], biogas shows better system effects when used in other energy sectors instead of transport, where dry biomass and liquid fuels have the lowest costs. Even so, a large gap still exists compared to the price of today's jet fuels by a magnitude of more than two (See. Fig. 6).

There is also the aspect of the fuel prices for power generation. Our analysis for the Danish model found that approximately 24–36 TWh of biomass is converted to syngas for power generation, depending on the scenario (Fig. 3), but this is not the only option. There is also the possibility of using natural gas offset by carbon capture, as in the European model, biogas, biomethane, electromethane or even ammonia power plants. Electrolytic fuels are a more expensive solution [70], and low-cost renewable fuels may be necessary for the task of power generation, which would make them comparable to other cost-efficient types of power generation, like wind or solar. Fig. 8 illustrates the levelized cost of electricity for these options, highlighting that syngas options are a more expensive solution than biogas and biomethane, which are closer to the production of electricity from natural gas.

Raw syngas or biogas as fuels for power generation would require dedicated grids for transporting the gas to the power generation units which would entail a higher cost for these options if the fuel production cannot occur in proximity of the plants. In the case of syngas, it also means less biomass consumption due to eliminating the upgrade (methanation) to grid quality, a process bound to energy losses. Therefore, the upgraded syngas would be comparable in quality with other renewable gases as biomethane from biogas, which means they can combine in a single gas grid. However, this would also entail a higher cost for producing electricity than off-shore wind and raw biogas, as illustrated in Fig. 8.

5. Discussion

The effects of utilising biomass gasification appear beneficial to the energy system costs, but the available biomass resources limit its use in parts of the energy system where there is the most need for it. Fig. 9 illustrates two projection of biomass resources for Denmark and Europe.

The results indicate that the BioHydroX scenarios for Denmark use 65–72 TWh biomass, which is more than the total available biomass in the country. In these extreme scenarios, biomass may be sufficient if gasified and hydrogenated for supplying the transport demands, but insufficient if also used for electricity production. For the European energy system, considering the energy and transport demands suggested by the European Commission in the 1.5 TECH scenario [48], biomass gasification may fit within the available biomass resources. However, such a system will still be dependent on large amounts of natural gas. The two models are not directly comparable in this sense, as Denmark is one of the five regions in Europe with the highest biomass potential [74], with around 30–35 GJ/capita [23]. In comparison, global non-food biomass potential ranges between 13 and 28 GJ/capita in 2050 [75] and Europe with 15–16.5 GJ/capita [73,74]. Similarly, the EU potential varies widely, ranging from 6.6 to 21.8 EJ/year in 2050, excluding imports [73]. Solving the challenge of biomass availability will require other solutions, particularly an increased level of electrification for all transport sectors. It should cover transport modes previously considered difficult to electrify, as heavy-duty transport [76,77] or some types of ships or planes. Grid-scale energy storage may be another possibility, but current research has identified such solutions expensive, that will still require a significant level of power plants in the energy system [16,48,78].

The CO_2HydroX scenarios for Denmark represent another alternative for dealing with the biomass limitation. These illustrate the case where sufficient biomass exists for gasification and power production purposes independent of the fuel production pathways. The scenarios assume that carbon sources exist and can be captured from industrial sources, power plants and CHPs. However, even if all units would use carbon capture, there will likely be insufficient renewable carbon to supply the fuel production processes that require 7–10 Mt/year in the case of Denmark. Moreover, one must consider that power plants operate flexibly for few hours over the year, creating a fundamental conflict, as carbon capture technologies have high investment costs and long lifetimes requiring a high number of operating hours to be economically feasible [79,80]. In the CO_2HydroX scenarios, cogeneration and power plants operate at no more than 1500–2500 full load hours/year in the Smart Energy System model for Denmark and 3000–4000 full load hours/year in the carbon-neutral model for Europe, which may be insufficient to deploy carbon capture, unless forcing the operation of power plants. This solution will result in VRES curtailment and increased fuel consumption, like in the model for Europe. An alternative is the use of carbon from industrial resources, cement production or biogas purification, but this may also be insufficient, particularly if industries switch to zero-emission fuels [81] or electricity. Other solutions may require direct air capture or ammonia production for some parts of the transport sector and power generation, but the cost of such an alternative would remain high, due to the large electricity consumption. Furthermore, the high toxicity of ammonia may be an issue when compared with the other fuel options considered in this study.

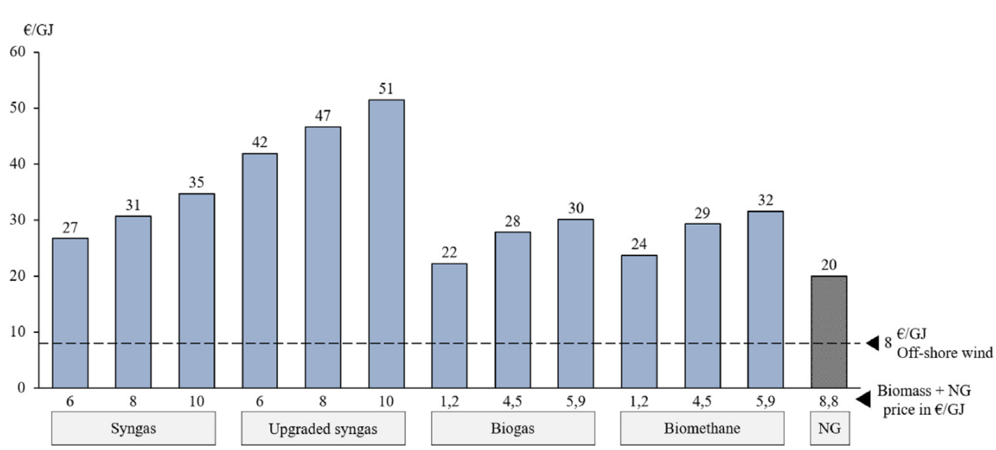

Fig. 8. Levelized cost of electricity for a CCGT in extraction mode with 4000 h of operation hours with different fuels options and prices, compared to the off-shore wind electricity price, all at 2050 cost and efficiency levels [66].

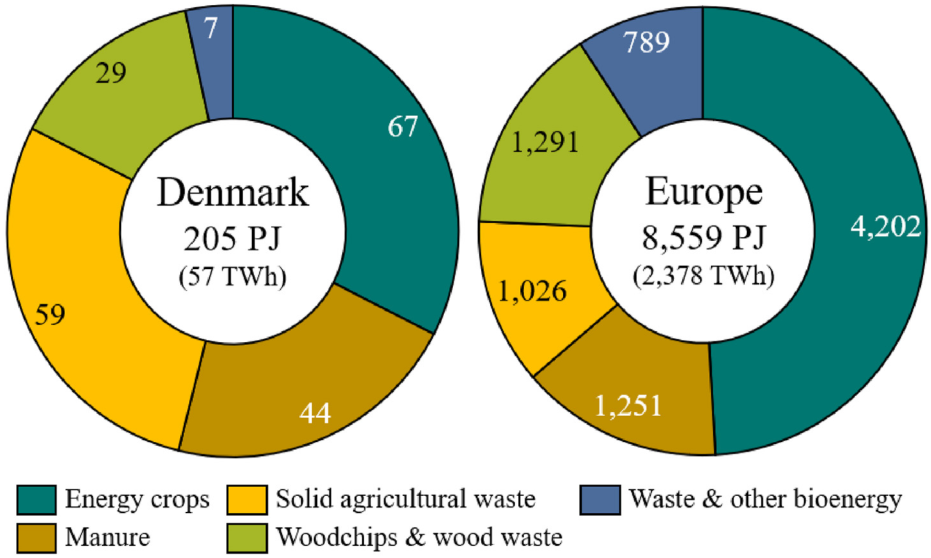

Fig. 9. Estimated domestic biomass potentials in 2050, excluding algae and waste. Adapted from Refs. [71–73].

Therefore, a prioritisation of the available resources must be considered for both biomass-based and CO_2-based fuels, as both solutions present challenges. Connolly et al. [14] find biomass gasification to be a transition technology that may jump-start the production of electrofuels, at least until the price of electricity will be lower than the price of biomass. We find that biomass gasification may be more than a transition technology in the long-term, but one that should stay. Within the prospect of biomass sustainability, but often neglected in energy system analyses, is the issue of soil management. Along with the production of syngas, biochar (ash) results as a co-product, but to this date, it is not considered a valuable output. Efforts have been put so far on maximising the carbon conversion to syngas, but gasifiers can be adjusted to leave more carbon in the biochar. This is important as biochar contains stable carbon, more stable than the carbon in biomass, and it can be a method for restoring carbon balance in the soil while also acting as a method for carbon sequestration [55]. Our energy system analysis results find that using less efficient gasifiers that produce biochar is a small price to pay, and may ultimately ensure a more optimised influx of biomass as an effect of improved soil management.

Despite the differences between the two pathways, a mix between sustainable biomass consumption and CCU will likely be necessary for the future. Biomass gasification alone may not have the potential to supply both transport demands and gas production for stationary units as in power production. The option of using predominantly CO_2-electrofuels is significantly more expensive, requiring non-fossil CO_2 sources that may not be available, as well as a larger land area to accommodate the increased electricity demands [22,33].

Considering critical aspects of energy efficiency, biomass limitations and costs, we find that biomass gasification combined with methanol production as primary fuel should be prioritised for the transport sectors where electrification is difficult. CO_2-electrofuels may be an add-on technology that may make use of the remaining large carbon emitters to produce high value-added fuels, as for aviation. A balance between producing fuels for transport and syngas for mainly power production should be achieved, as the low-cost renewable fuel options for electricity generation are more limited than for the transport sector.

6. Conclusion

In this study, we analysed the potential role of biomass gasification in the context of two different energy system designs for Denmark and Europe in the year 2050. The results demonstrated that utilising biomass gasification for the production of bio-electrofuels in the transport sector can reduce the energy system costs and improve the overall energy efficiency compared to energy systems dominated by CO_2-electrofuels. Despite the high biomass consumption in the bio-electrofuel scenarios, the overall biomass consumption would be higher in energy systems without biomass gasification due to their lower efficiency. Among the electrofuels investigated, methanol shows the lowest resource consumption and costs, but FT fuels may be an alternative for aviation.

Therefore, we find syngas from biomass gasification to have significant potential in supplementing biogas in stationary applications for power production and heat or industrial demands. A careful balance should be achieved between supplying syngas for power production and syngas for fuel synthesis, in which case CO_2-electrofuels can complement bio-electrofuels in the transport sector.

CRediT authorship contribution statement

Andrei David Korberg: Formal analysis, Software, Investigation, Resources, Data curation, Visualization, Writing – original draft, Writing – review & editing, Project administration. **Brian Vad Mathiesen:** Conceptualization, Methodology, Validation, Supervision, Funding acquisition. **Lasse Røngaard Clausen:** Resources, Data curation, Validation. **Iva Ridjan Skov:** Conceptualization, Resources, Funding acquisition.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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