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Assessing the feasibility of CO_2 removal strategies in achieving climate-neutral power systems: Insights from biomass, CO_2 capture, and direct air capture in Europe

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ABSTRACT

To achieve the European Union's goal of climate neutrality by 2050, negative emissions may be required to compensate for emissions exceeding allocated carbon budgets. Therefore, carbon removal technologies such as bioenergy with carbon capture (BECCS) and direct air capture (DAC) may need to play a pivotal role in the power system. To design carbon removal strategies, more insights are needed into the impact of sustainable biomass availability and the feasibility of carbon capture and storage (CCS), including the expensive and energy-intensive DAC on achieving net-zero and net-negative targets. Therefore, in this study the European power system in 2050 is modelled at an hourly resolution in the cost-minimization PLEXOS modelling platform. Three climate-neutral scenarios with targets of 0, -1, and -3.9 Mt CO_2/year (which agree with varying levels of climate justice) are assessed for different biomass levels, and CCS availability. Findings under baseline assumptions reveal that in a climate-neutral power system with biomass and CCS options, it is cost-effective to complement variable renewable energy with a mix of combined cycle natural gas turbines (CCNGT) for flexibility and BECCS as base load to compensate for the CO_2 emissions from natural gas and additional carbon removal in the net-negative scenarios. The role of these technologies becomes more prominent, with -3.9 $GtCO_2$/year target. Limited biomass availability necessitates additional 0.4–4 $GtCO_2$/year DAC, 10–50 GW CCNGT with CCS, and 10–50 GW nuclear. Excluding biomass doubles system costs and increases reliance on nuclear energy up to 300 TWh/year. The absence of CCS increases costs by 78%, emphasizing significant investments in bioenergy, nuclear power, hydrogen storage, and biogas. Sensitivity analysis and limitations of the study are fully discussed.

1. Introduction

To achieve the Paris Agreement of keeping the average global surface temperature increase below 2 °C and preferably 1.5 °C, cumulative emissions have to stay below 400 $GtCO_2$[1] from 2020 [1]. Since this carbon budget is a challenging target, considering current global CO_2 emissions of 38 $GtCO_2$ in 2021, carbon removal has a pivotal role in IPCC mitigation pathways,[2] with 52 to 1771 $GtCO_2$ scale globally [2].

Especially, the technologies bioenergy with carbon capture and storage (BECCS) and direct air capture (DAC) are estimated to realise a large share of these negative emissions, ranging from 2 to 7, and from 0.2 to 0.5 $GtCO_2$/year in 2050, in the world, and Europe, respectively. These two technologies both have a sizable impact on the power system, as BECCS generates electricity of 850–900 kWh/tCO_2, and DAC requires electricity of 350–600 kWh/tCO_2 and additional heat of 5.4–7.1 GJ/tCO_2 [3].

Considering ambitious EU climate-neutrality targets by 2050 [4], carbon removal technologies need to be integrated into the power system. However, many technoeconomic studies on EU power system decarbonisation neglect the options for BECCS or DAC, creating a research gap, such as [5–14]. The few studies including BECCS estimate that its contribution leads to 410- 1400 $MtCO_2$ of negative emissions,

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1 With a 67% likelihood of limiting temperature increase to 1.5 °C from 2020.
2 Intergovernmental Panel on Climate Change mitigation scenarios at https://www.ipcc.ch/.

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and requires 4–13 EJ of biomass in 2050, as demonstrated in studies by [15–19].These studies do not consider the uncertainties of biomass availability, leading to possible overestimation for power generation ranging from 2 to 20 EJ for Europe [20–24] depending on the choice of sustainability criteria [23,24]. For example, sustainability criteria related to indirect emissions, biodiversity preservation, water management, soil quality, competition for land on top of economic and technical feasibility of producing biomass, can reduce biomass potentials by 40 to 90% [22,25–27]. These comprehensive sustainability criteria are lacking in studies accounting for biomass in decarbonised power or energy systems (see Fig. 1). Some studies allocate the total biomass availability to the power sector without accounting for competing biomass demands in other sectors such as heat, transport and industry. When competing demands are considered in European long-term strategy studies [19, 28–30], only 30–50% of total bioenergy is used in the power sector in 2050. Yet, these studies may still have overestimated bioenergy resources as no strict sustainability criteria were taken into account. Mandley et al. [31] applied both comprehensive sustainability criteria and competition between regions and sectors based on a 2 °C target using global integrated assessment model IMAGE 3.2. They arrive at 3–4 EJ per year for the European power system, which is less than half the availability assumed in most studies, including those of Zuijlen et al. [19], and Zappa et al. [32].

With regard to DAC, technoeconomic analyses are limited, and studies rarely explore its interactions with the power sector [33]. With regards to integration to the power system, only one study [19] was found for the EU, finding an important role in net-negative emission scenarios. However, the study by Zuijlen et al. is limited to Western Europe and disregards uncertainties of biomass availability, or the possible interdependence between BECCS and DAC [34]. The advantages of DAC such as lower land and biodiversity impact, necessitate further investigation into the correlation between biomass availability and DAC [35].

Additionally, the role of BECCS and DAC can vary significantly under different emission targets. For a carbon neutral EU, power system emission targets are not straightforward, as it might have to compensate for past emissions, future cumulative emissions, or other sectors and regions. According to Pozo et al. [36], the cumulative CO_2 removal quota of the EU can range between 33 and 325 $GtCO_2$ up to 2100, based on historical emissions, global responsibility and capability. Pozo et al. notes that only about 30 $GtCO_2$ of this quota can be met by reforestation, the rest must be met by BECCS and DAC. If negative emissions only take place from 2050, this could mean up to −6.5 $GtCO_2$/year average emission target 2050 – 2100. Capros et al. [37] shows that scenarios with high reliance on negative emission technologies, the power sector is the only sector that has to go net-negative from 2050 with about −100 $MtCO_2$/year emission target.

In summary, current research highlights the insufficient insights into how the design and operation of the EU power system in 2050 depend on (1) sustainable biomass availability (2) net-negative emission requirements (3) the interaction between BECCS and DAC considering overall system costs, system adequacy, and energy security. This paper addresses these three knowledge gaps to understand the roles of biomass and carbon dioxide capture and Storage (CCS) technologies, and in particular BECCS and DAC, for achieving climate neutrality in the EU power system that potentially contributes to negative emissions. For this purpose, a case study for Europe 2050 in which capacity expansion and hourly operation are optimized under varying CO_2 emission targets is performed, The study applies a novel method in which a sustainable biomass availability framework, negative emission options including DAC is integrated with the advanced power system modelling platform, PLEXOS. The impacts are evaluated in terms of their effects on power system capacity configuration, annual generation, system costs, CO_2 emissions, CO_2 storage requirements, levelized costs of electricity, as well as fossil fuel and transmission dependence.

2. Methodology

To study the combined role of BECCS and DAC in the European power system, a model framework has been developed, with steps presented in Fig. 2. As a technoeconomic optimization study, this research excludes the current strategies and policies of EU+ countries. The focus is on informing policymakers rather than attempting to predict the future. The main components of the framework include power system cost-optimisation using PLEXOS,[3] with detailed technoeconomic descriptions of power generation, storage and transmission technologies in 2050, as well as demand for the EU^{+},[4] in 2050. The optimum power configurations in the model will be determined in a range of scenarios including varying emission caps and biomass/CCS availability. The output of the optimisation model will be analysed with performance indicators, including cost benefits, emission reduction, system reliability and robustness.

2.1. Power system model

PLEXOS[5] was chosen for power system optimization due to its advanced power plant representation (including planned outages, min/max downtime, heat rate curves etc.) by mixed integer linear and quadratic programming, hourly capacity expansion and operation unit commitment and economic despatch capabilities [38]. This power system optimisation modelling framework operates in 4 phases: long term (LT Plan) focuses on long-term planning, projected assessment of system adequacy (PASA), mid-term (MT Schedule) for medium to long-term decisions in power systems and short term (ST Schedule) for unit commitment and economic despatch operation analysis.

LT Plan optimizes the expansion of generation and transmission infrastructure, with discounting and end-year effects and integrates with PASA, MT Schedule, and ST Schedule phases. LT Plan operates in chronological or Load Duration Curve (LDC) modes and handles deterministic (applied in this model) or stochastic scenarios. Its objective is to minimize the net present value (NPV) of build costs, fixed operation and maintenance (FOM) costs and variable operating and maintenance (VOM) cost. PASA assesses system adequacy, creating maintenance events for MT Schedule and ST Schedule and calculates reliability statistics, primarily focusing on capacity reserve margin. PASA can run at different transmission detail levels, balancing capacity reserves using quadratic programming, and operates in annual steps. Next, MT Schedule handles medium-term objectives (hydro storages, fuel supply, emissions), constraints, pre-computed unit commitments, and new entry opportunities. Finally, ST Schedule uses mixed-integer programming to optimize unit commitment and economic despatch (UCED) and identifies power system adequacy, flexibility and limitations based on full chronology. It emulates market-clearing engines, accounting for generator offers, load forecasts, and transmission constraints. ST Schedule handles Monte Carlo simulation, financial optimization, and stochastic optimization, integrating market and fundamental data efficiently [39].

The geographical scope of the study includes the EU-27, UK, Switzerland, and Norway. To minimise computational time, countries with highly interconnected transmission networks are considered copperplate regions, as shown in Fig. 3. From here on, these regions are collectively referred to as EU^{+}. These 10 regions are connected via currently existing cross-border transmission lines, upgraded with transmission capacity expansion projections by ENSTO-E TYNDP [40].

In this model, the power system configuration is optimised with a

[3] More information about PLEXOS modelling tool: https://www.energyexemplar.com/plexos.

[4] EU^{+} in this study the geographical scope 'EU^{+}' includes EU-27, Switzerland, Norway and the UK.

[5] More information about PLEXOS modeling tool: https://www.energyexemplar.com/plexos.

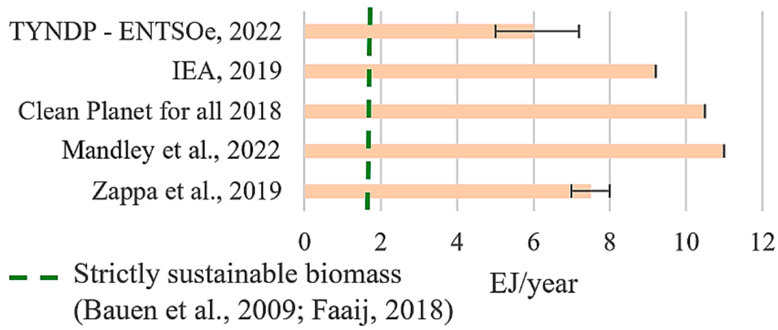

Fig. 1. Biomass use in selected studies in carbon neutral scenarios compared to strictly sustainable biomass potential by Bauen et al., 2009; Faaij, 2018. Apart from Mandley et al., where all energy sectors considered, biomass use refers to the power system alone. Black bar range shows the range of biomass use if more than one scenario is present in study.

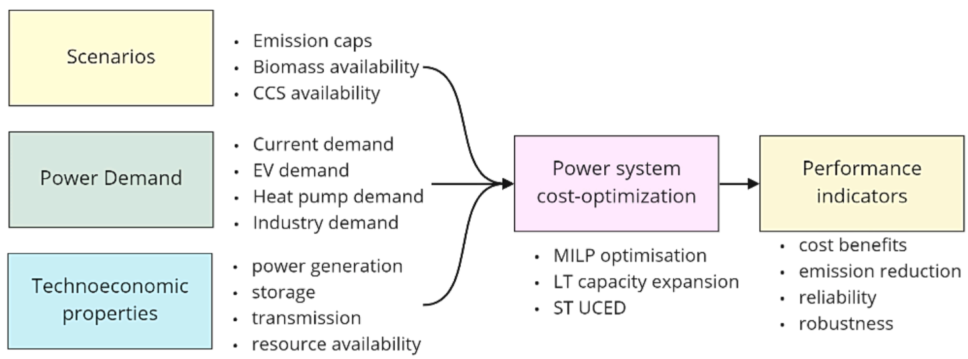

Fig. 2. Simplified methodology overview of this study with main power system optimisation inputs on the left and model output analysis on the right. These main components are further explained in Section 2.1 – 2.5. Abbreviations: CCS: carbon capture and storage, EV: electric vehicle, MILP: mixed integer linear programming, LT long term model run, ST: short term, UCED: unit commitment and economic despatch, sensitivity analysis is also included in the research, but excluded from the graph. All technoeconomic and demand input data is for 2050, EU^{+}.

Fig. 3. EU+ European regions considered in this study EU+ includes EU-27, Switzerland, Norway and the UK.

greenfield approach for 2050, with capacity expansion freely optimised for all technologies (except hydro and geothermal being pre-determined). LT capacity planning is executed with historical weather years selected from 1979 to 2020, with average to low hourly solar and wind capacity factors to avoid overestimation of iRES reliability. Constraints of the system include CO_2 emission restrictions, transmission capacity availability, technical potential of biomass, solar, hydro and wind energy. The model setup is displayed on Fig. 4.

2.2. Power demand

For hourly 2050 demand curves over a year, carbon intensive sectors are replaced with electricity directly, such as heat, transport and industrial processes, where possible. The 2050 hourly demand portfolio is constructed on historical load demand, recorded by the European Network of Transmission System Operators for Electricity [40]. Furthermore, projected future demand is added on top of historical demand. Following the methods of [32], the study considers hourly variable 500 TWh/year for heat pumps (HPs), and 800 TWh/year for electric vehicles (EVs) as assumed in the European Commission Roadmap for 2050 [42]. Additionally, about 500 TWh constant load is allocated to industry electrification and additional demand increase of 10%. The assumed value of loss of load is 100,000 €/MWh [19].

2.3. Biomass potentials

Determining biomass potential has 3 main components in this study:

1. Identifying upper bounds of sustainably produced biomass for energy sectors
2. Apply additional constraints on indirect emissions allowed, based on RED-II
3. Allocation of biomass available for the power sector

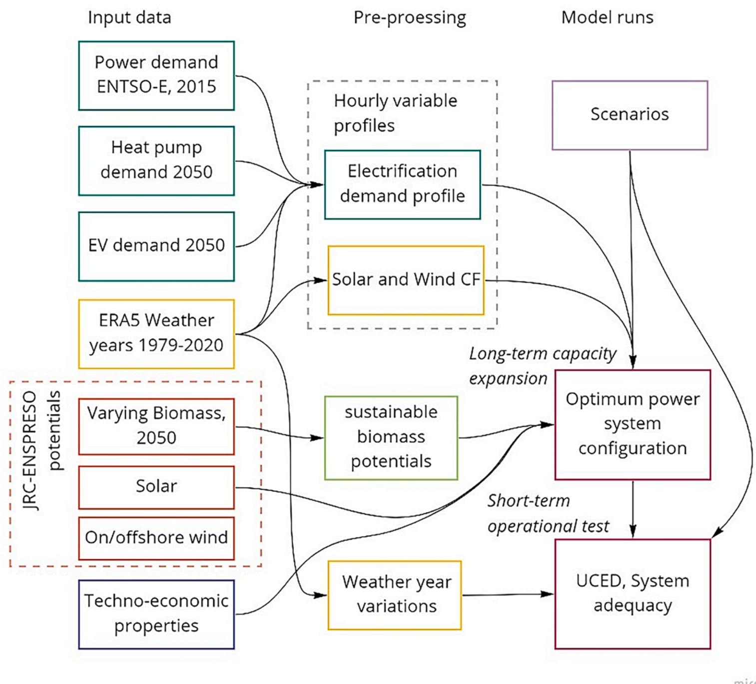

Fig. 4. Power system optimisation model design in PLEXOS Historical data (i.e., power demand curves and weather data) are adapted to 2050 with the methodology described in Sections 2.2 and 2.4.3.Abbreviations: EV: electric vehicle, ERA5: hourly weather data [41], JRC-ENSPRESO [26]: Biomass, solar and wind potentials from European Commission Joint Research Centre database, CF: capacity factor, UCED: unit commitment and economic despatch.

For the first component, a low, medium and high sustainability biomass potentials are determined in the EU$^+$, using EU-JRC-ENSPRESO [26] biomass availability data for 2050. At this first stage, sustainability criteria account for competition for land, exclusion or limitation of irrigation, and exclusion of high nature-value area and biodiversity-rich land, amongst others. These criteria are applied across three restriction levels, with high biomass availability having the least restriction and low availability having the most restriction. Detailed explanations of the three (low medium and high biomass availability) sustainability measures are provided in Appendix C.

Secondly, for indirect emission constraints, the revised Renewable Energy Directive (RED-II) [43] biomass sustainability framework has been applied, since the ENSPRESO database does not apply these criteria. This EU energy directive (RED-II) requires 80% life cycle greenhouse gas emission saving for biomass, compared to the fossil fuel comparator[6] from 2026 onwards. Therefore, biomass types failing to meet these criteria are excluded [43]. Since life cycle emissions of imported biomass from overseas can be highly uncertain, the option for extra EU$^+$ imports has been excluded. Although, Visser et al. [44] estimates 15 Mt wood pellet (about 0.25 EJ) import potential under the 80% emission saving criteria, this value is disregarded in this study, since biodiversity and soil quality losses in the origin countries are not considered in that study. Lastly, after identifying three restriction levels of biomass potentials (in compliance with RED-II), competition with other sectors (power, industry, transport) is accounted for. For this, the Clean Planet for all - European long-term strategy [35] has set three '1.5′ scenarios with net-zero ambition in 2050. The '1.5 Tech' scenario with technological advances and enhancement of natural sinks is considered consistent with the high biomass availability, while '1.5 life' is consistent with the medium biomass scenario, and '1.5 life-LB (low biomass) is consistent with the low biomass. This study aligns the shares of biomass in various energy sectors of the three 2050 net-zero scenarios with their associated biomass availabilities. This results in 55% - 67% biomass allocated to the power sector in 2050. Appendix D contains detailed biomass allocation across sectors.

Biomass types, with their associated RED-II emission saving and biomass participation in different sectors can be seen on table 1.

2.4. *Input data*

In this chapter the main input variables are described, including load demand, transmission capacity, technoeconomic specifications of generator and storage technologies, fuels and emission targets.

2.4.1. *Transmission*

Scenarios have been designed with fixed high-voltage cross-border transmission lines from ENTSOE-E 2027 cross-border expansion strategy [46], with countries aggregated in each modelled region (See transmission capacities in Appendix A).

2.4.2. *Generator parameters*

In this study, investment costs, fixed operation and maintenance (FOM) costs, variable operation (VOM) costs, and fuel costs are the main optimisation drivers. A uniform discount rate of 8% is used. All costs are expressed in €$_{2019}$, as the year 2019 marked the last period economically unaffected by the COVID-19 pandemic and the Ukrainian crisis. The more recent Eurozone indexes exhibit significant volatility that potentially affects data quality.

Major sources of techno-economic assumptions are the European Commission Outlook of the EU energy system up to 2050 [30] and JRC Cost development of low carbon energy technologies - Scenario-based cost trajectories to 2050 [47]. All costs efficiencies and lifetimes are based on projected values for the year 2050 by the listed sources. The considered generation technologies and their main specifications are summarised on table 2.

DAC technology costs are highly uncertain due to limited large-scale demonstrations. Estimates vary widely, ranging from 170 €/tCO_2 to 680

[6] Fossil fuel comparator: For biomass fuels used for the production of electricity, the fossil fuel comparator ECF(el) is 183 gCO_2eq/MJ electricity or 212 g CO_2eq/MJ electricity [44].

Table 1
Biomass categorisation, type, emission saving and sector sharing considered by this study.

Category	Sub-category	Biomass type	RED-II GHG emission saving[i]		Sharing energy sectors[h]
			Local	Export[j]	
Energy crops[a]	Dedicated perennials- woody/ lignocellulosic biomass[a]	Willow	80%	49%	all
		Poplar			
		Miscanthus, switchgrass, RCG			
Biomass from agriculture[b]	Secondary residues	Landscape care	74%	71%	all but transport
	Solid agricultural residues	Pruning and straw/stubble	85%	61%	all but transport
Biomass from forestry	Stemwood production[c]	Stem wood	91%	83%	all but transport
		Woodchips and pellets	91%	83%	all but transport
	Primary forestry Residues Biomass[d]	Logging residues	85%	55%	all but transport
	Secondary forestry residues[e]	Woodchips	85%	49%	all but transport
		Pellets	85%	49%	all but transport
		Sawdust	91%	83%	all but transport
Biomass from waste	Primary residues[f]	Biodegradable waste	91%	83%	all
	Tertiary residues[g]	Biodegradable waste			
		Sewage sludge, paper and cardboard waste, dredging spoils			

[a] Biomass from agricultural production activities of perennial crop, including short rotation forests (SRF): willow, poplar and other grassy crops,.
[b] Residues from agricultural cultivation, harvesting and maintenance activities(Potentials outside agricultural permanent cropland cultivation). Other solid agricultural residues (pruning, orchards residues, olive pitting), straw and stubbles,.
[c] Sustainable extracted forests biomass Includes tree plantations and Additionally harvestable stemwood,.
[d] Aggregated fuelwood and chips from primary residues. Forest biomass residues additionally harvestable from forest (top, branches, stumps and early pre-commercial thinning),.
[e] Cultivation and harvesting / logging activities in forests, like branches and roots and other wooded biomass,.
[f] Public greens (road side verges) Municipal,.
[g] Municipal Solid Waste (renewables), other waste (abandoned grass cuttings, vegetable waste, shells/husks),.
[h] Energy sectors sharing the different biomasses are: power sector, heat, transport, industry, more details about shares of different end use sectors in the Appendix.
[i] Indirect emissions of biomass includes extraction/cultivation, processing, transport and distribution (only local) annualised emissions from carbon stock changes caused by land-use change [35,45].
[j] Export-import between the EU$^+$ regions, where cross-border transport also accounted (2500–10,000 km).

€/tCO_2 [51]. This study adopts an average cost of 425 €/tCO_2. Furthermore DAC is a standalone system, with maximum capture rate of 2 tonne CO_2 per MWh electricity consumed.

For hydroelectric capacity, future capacity expansion possibilities are limited; therefore, current and planned capacity and geographical distribution are kept constant. Geothermal capacity is set at 37 GW allocated to countries in proportion to their economic geothermal potential [32]. Further technical assumptions of power generators are in Appendix A.

2.4.3. Intermittent renewable energy availability

The power output of intermittent renewable energy systems (iRES) highly depends on weather conditions [52]. Solar irradiation and outside temperature for photovoltaic systems and wind speed for wind turbines. Hourly solar photovoltaic capacity factor (CF), onshore and offshore wind CF at 100 m height has been applied from European Reanalysis, ERA5 database [41]. The 30 km spatial grid resolution of the database has been aggregated for the 10 regions by weighted mean. Weights are allocated based on solar/wind potentials of grid cells and countries described by JRC-ENSPRESO [26]. The detailed method of capacity factor calculations are in Appendix B.

From the ERA5 weather data, advantageous ‘good’, average and disadvantageous ‘bad’ weather years are classified to test sensitivity and adequacy. Hourly data from 1979–2020, creates 41 weather years for the 10 regions, translated to hourly capacity factors of photovoltaic solar, onshore wind, and offshore wind (Fig. 5).

Average annual capacity factors for the base weather year is presented in Table 3.

Besides the intermittent availability, wind and solar have different spatial and geophysical requirements, than conventional firm technologies, given the more location sensitive and greater spatial requirements. In this study solar and wind energy potential per region is based on EU JRC-ENSPRESO database (see Fig. 6), assuming a total of 4240 GW solar, 2000 GW onshore wind and 400 GW offshore wind potential in the EU$^+$region [26].

2.4.4. Biomass potentials and costs

Biomass potential, or the maximum biomass to be utilised by the EU$^+$ power system is a crucial right hand side constraint in the power system model. The values used in this study are shown in Fig. 7.

For biogas, a technical potential approximately 2 EJ/yr is available for the EU as a whole [32,53]. Price of biomass depends on the biomass type (Table 4). Biomass prices are assumed to be the same for low, medium and high biomass potentials. However, the impact of increased biomass prices and limitless biomass availability is explored during sensitivity runs.

Distance travelled have been calculated by average distance of regions from other regions. As a result, centrally located EU regions have a shorter distance from regions, than regions on outer edges For overseas import, an average of 10,000 km is assumed. Details of biomass transport assumptions in the Appendix E.

2.4.5. Fuel parameters

Baseline fuel assumptions are summarized on table 5. There are no availability constraints regrading natural gas, coal and uranium. Prices are considered uniform over the regions.

2.4.6. Emission target

Three different net CO_2 emission targets or constraints have been considered for this study for EU$^+$ in 2050 (for detailed description, see Appendix F.):

- Net-zero (net 0 GtCO_2/year), which is in accordance with the European Green Deal, where only net zero is required by the power

Table 2
Techno-economic specifications of considered power generation technologies and costs for 2050,.

	Technology	Build costs (€$_{2019}$/kW)	FOM[b] (€$_{2019}$/kW/year)	VOM[b] (€/MWh)	Efficiency[c] (-)	Lifetime (year)	Build time (year)
Firm technologies	OCNGT	660	7.0	13.0	44%	30	1
	CCGT	747	20.9	1.9	62%	30	3
	CCGT-CCS[d]	2122	37.1	3.0	55%	30	4
	PCSC	2335	34.3	3.7	48%	40	4
	PCSC—CCS[d]	4814	65.5	3.7	38%	40	5
	Coal IGCC	2903	45.3	5.0	47%	35	5
	Coal IGCC—CCS[d]	5075	6.3	0.4	41%	35	6
	OCBGT	505	25.2	2.8	44%	30	1
	Nuclear	6310	113.6	8.4	38%	60	7
Renewable technologies	Onshore Wind	1040	13.0	0.2	–	25	1
	Offshore Wind	1780	30.3	0.4	–	30	1
	Solar PV - Utility	400	8.9	0.0	–	25	1
	Solar PV – Rooftop	560	9.7	0.0	–	25	1
	BE[e]	3013	23.7	3.0	38%	25	3
	BECCS[d,e]	4535	66.4	6.3	30%	25	4
	Geothermal	4770	99.5	0.1	–	30	3
	Hydropower (PHS)	2751	27.6	0.3	–	60	3
	Hydropower (STO)	2751	27.6	0.3	–	60	3
	Hydropower (ROR)	2162	8.8	0.0	–	60	3
Complementary technologies	DAC[d,f]	42,500	–	142.5	–	20	1
	Hydrogen[i,g]	1750	10.8	0.0	70%[g]	15	1
	Battery[h,i]	1200	4.2	2.7	85%	12	1

Cost related figures are in €$_{2019}$, converted with EU-27 domestic industrial producer prices [48].
Abbreviations: OCNGT: open cycle natural gas turbine, OCBGT: open cycle biogas turbine, CCGT: Combined cycle gas turbine, PCSC: Pulverised coal super critical, IGCC: Integrated gasification combined cycle, PV: Photovoltaics, PHS: Pumped hydro storage, STO: dam storage, ROR: Run-of-river, CCS: Carbon capture and storage; DAC: Direct air capture of CO_2; BE: bioenergy, BECCS: Bioenergy with carbon capture and storage.
Build costs, FOM (fixed operational costs), VOM (variable operational costs) and lifetime are from PRIMES technoeconomic assumptions for 2050 [30], construction times are based on [19].
a Build costs include 8% interest during construction, assuming costs are evenly distributed during construction time.
[b] JRC ETRI [49], FOM as percentage of TCR in report.
[c] Efficiencies defined at low heating value (LHV).
[d] For all carbon capture technologies, 90% capture rate is assumed. Also, costs for CO_2 transport and storage are assumed to be 13.5 €/tCO_2 [19].
[e] Fluidised bed boiler power generation is assumed for Bioenergy (BE) and BECCS.
[f] For DAC, KW and MWh refers to the electric input required. Based on [19], investments costs of 425 €/tCO_2 and operation costs of 240 €/tCO_2 is assumed (including heat expenditures), with 100% capacity factor, capture rate is 2000 kgCO_2/MWh. DAC heat demand is excluded.
[g] Hydrogen storage includes electrolyser for P2G, hydrogen CCGT for G2P, and H_2 storage potential of 215 TWh and 3 kg/s maximum discharge. All assumptions based on LHV from [19,50].
[h] For batteries, 12 hour storage capacity is assumed for daily balancing.
[i] kW based on output.

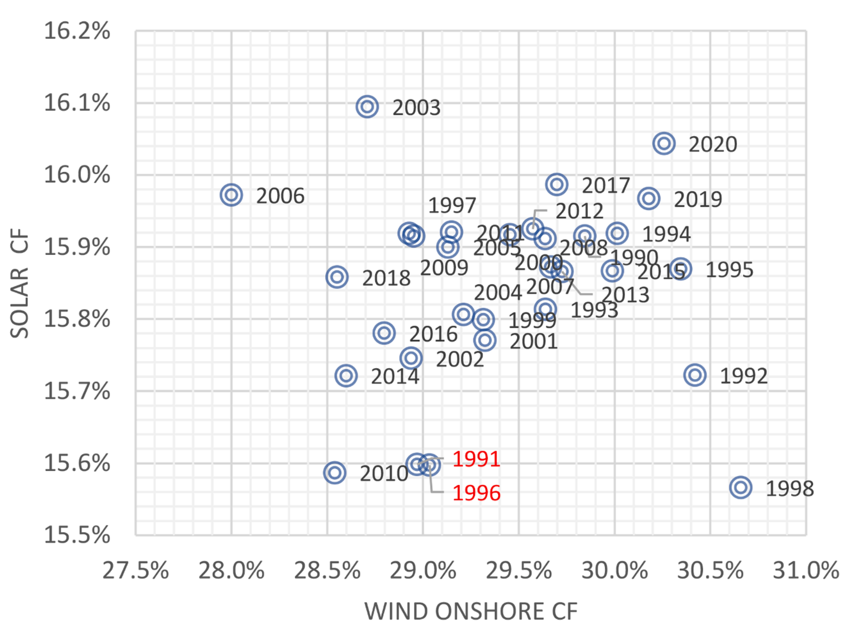

Fig. 5. weather year selection process, aggregated EU[+] annual average solar and wind capacity factors 1979–2020 from ERA5, average years are with blue, bad weather years with red, and good weather year with green., For the base scenarios 2014, for sensitivity 2010 and 2018 have been chosen.

Table 3
Annual average capacity factors in 2014 base year [%] Solar PV shows average between roof top and utility PV systems.

	Benelux	British Isles	Balkans	Baltic	Central Europe	France	Germania	Iberia	Italia	Scandinavia
Solar PV	12.6	11.6	15.0	11.8	13.1	14.8	13.2	18.3	17.3	11.1
Onshore wind	29.6	36.4	9.8	31.3	16.0	23.5	40.4	13.2	15.0	29.6
Offshore wind	49.0	56.2	9.5	57.4	49.6	45.6	56.1	34.0	28.1	49.0

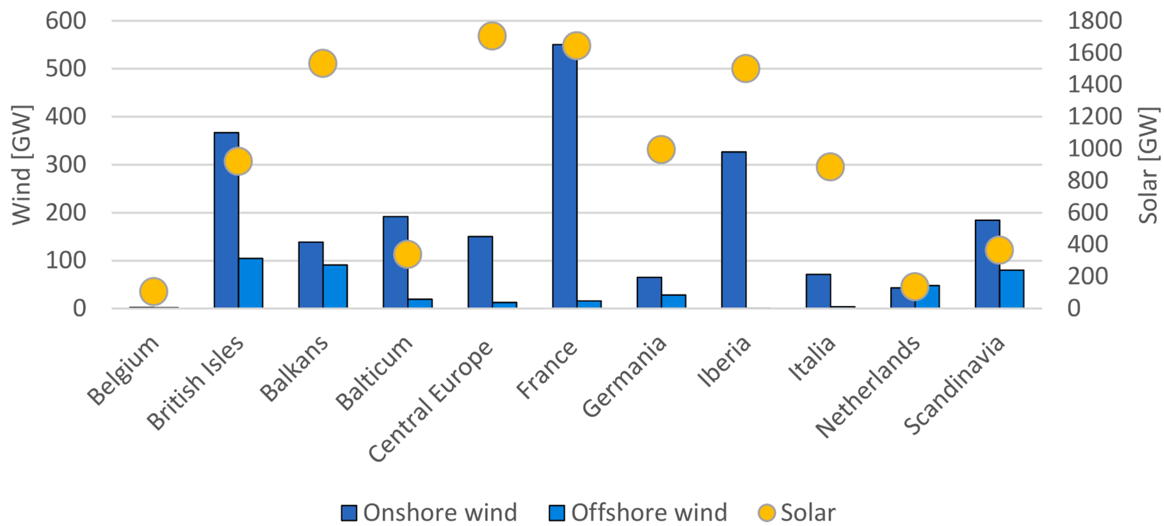

Fig. 6. Technical wind and solar potential in this study in GW, based on JRC-ENSPRESO assuming 170 W/m^2 average and 3% of the available non-artificial areas can be used for solar photovoltaics, and the medium average capacity factor scenario for onshore and offshore wind [26].

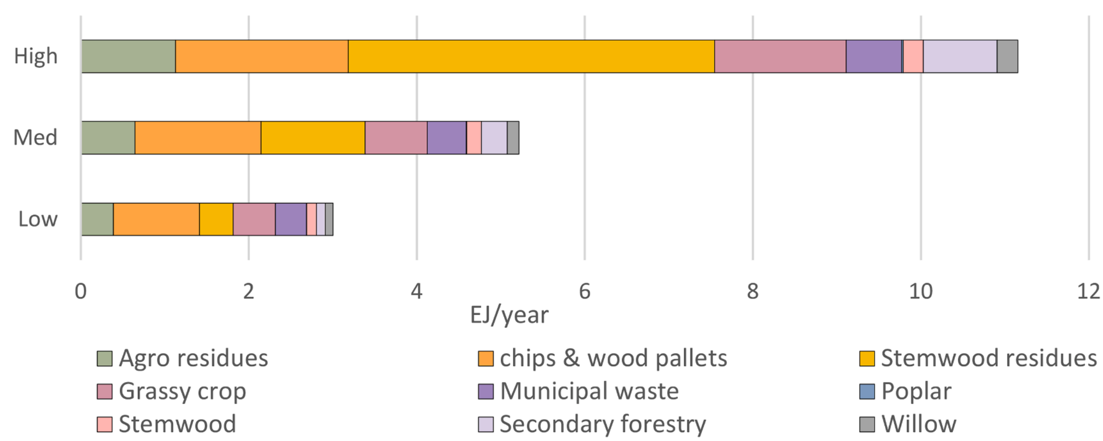

Fig. 7. Biomass potential in PJ/year per scenario based on the allocation methodology for the EU$^+$ power system in 2050 described in Section 2.3 Biomass potentials. These potentials serve as input data for PLEXOS modelling as upper limit per biomass type.

sector, and no compensation for other sectors or for carbon budget overshoot is required.

- Carbon budget focus (net −0.85 $GtCO_2$/year): CO_2 emissions exceeding the EU carbon budget from 2020 to 2050 must be compensated by the power system. Cumulative emissions until 2050 exceed EU budget by 42.5 $GtCO_2$. To compensate for these surplus emissions, −0.85 $GtCO_2$ net-negative annual emissions are required from 2050–2100 by the power system.
- Carbon removal responsibility (net −3.9 $GtCO_2$/year): where the EU has responsibility of carbon removal determined by Pozo et al., (2020), taking into account liability for climate change damage from historical emissions (on production basis, from 1850–2017). Following this principle, the EU$^+$ has responsibility of removing 195 $GtCO_2$.[7]

Each of these emission targets are enforced in the PLEXOS model as upper limits of net CO_2 emissions. These upper limits result in shadow prices of CO_2 emissions and no exogenous CO_2 price or tax was applied.

2.5. Scenario formulation

Table 6 represents the scenario space with variations in emission

[7] Removal responsibility met be afforestation is already excluded from this value.

Table 4
Biomass price assumptions including harvesting, processing and transport.

$€_{2019}$/GJ	Benelux	British Isles	Balkans	Baltic	Central Europe	France	Germania	Iberia	Italia	Scandinavia	Benelux
Agricultural waste	3.9	3.4	3.2	2.5	3.8	2.5	4.6	3.9	3.7	4.7	4.0
Miscanthus, switchgrass, RCG	6.4	6.6	4.0	3.3	4.0	5.3	5.7	8.0	6.0	8.2	5.4
Willow	11.8	11.5	5.2	9.4	8.9	9.8	11.1	14.3	0.0	5.6	10.5
Poplar	–	–	6.8	3.3	–	12.4	–	–	13.9	9.8	–
Fuelwood residues	4.8	5.5	1.9	2.6	3.3	4.3	4.8	3.4	5.0	4.6	4.9
Municipal waste	0.04	0.03	0.05	0.01	0.03	0.06	0.06	0.04	0.00	0.10	0.01
Fuelwood	3.9	3.5	2.2	3.4	3.4	3.7	3.9	4.4	4.1	3.8	4.0
Chips and pellets	8.1	7.3	2.5	3.4	5.0	7.6	7.6	9.2	8.5	7.7	8.1
Secondary Forestry residues	1.9	2.5	1.4	1.6	2.3	2.5	2.8	2.4	2.3	2.4	2.3
Sawdust	2.1	1.9	1.2	1.5	1.8	1.9	2.0	2.1	2.1	2.2	1.8

data is from EU-JRC ENSPRESO [45] prices include production harvesting and processing of biomass, taken from the CAPRI model, where expected future prices are calculated for 2050 given market changes and supply-demand relations. Costs include domestic transport of 100–200 km and converted to €2019 with EU-27 domestic industrial producer prices [48] The EU-JRC-ENSPRESO costs include domestic short-distance transport. For interregional and overseas trade, long-distance biomass transport costs have been included, considering loading costs shown on.

Table 5
Fuel cost and emission assumptions.

	Price (€/GJ)[a]	Emission factors[c] ($kgCO_2$/GJ)
Natural Gas	6.5	56
Coal	1.2	101
Uranium	0.54	0
Biogas	17.9[b]	0

[a] Fuel prices are from IEA World Energy Outlook predicted for 2050 (IEA, 2021b), unless stated otherwise.
[b] Biogas substrates are assumed to cost 6.4 €/GJ. Additionally, the production of biogas from these substrates through a digester costs 10.4 €/ GJ [19].
[c] Emission factors are taken from [54].

Table 6
Scenario summary.

Scenario Name		Biomass potential[c] [EJ/yr]	Net – CO2 Emission target[d] [GtCO2/year]	Technologies in the model
net 0 GtCO2/ year	No Bio	0	0	All
	Low Bio	3.1	0	All
	Med Bio	5.2	0	All
	High Bio	10.8	0	All
	No CCS[a]	5.2	0	All except CCS technologies[e]
net −0.85 GtCO2/ year	No Bio	0	−0.85	All
	Low Bio	3.1	−0.85	All
	Med Bio	5.2	−0.85	All
	High Bio	10.8	−0.85	All
	No CCS[a,b]	5.2	−0.85	All except CCS technologies[e]
net −3.9 GtCO2/ year	No Bio	0	−3.9	All
	Low Bio	3.1	−3.9	All
	Med Bio	5.2	−3.9	All
	High Bio	10.8	−3.9	All
	No CCS[a,b]	5.2	−3.9	All except CCS technologies[e]

all scenarios share fixed cross-border transmission, hydro and geothermal capacity, everything else is freely optimised. .
[a] exclusion of CCS simulates the possible future of not reaching technological maturity for large scale application by 2050 and/or low social/political acceptance.
[b] No CCS in the two negative emissions scenarios have proved infeasible.
[c] Biomass potentials based on sustainable biomass potential allocation methodology described in Section 2.3 and Fig. 7.
[d] Upper limits of CO_2 emissions for EU^+ 2050 are determined by methodology described in Section 2.4.6 and Appendix F.
[e] BECCS, DAC, Gas/Coal-CCS.

caps, biomass potential, and availability of carbon removal technologies. Some combinations are not compatible such as net-negative emission cap with the ‘No CCS’ technology constraint, they have proved to be infeasible.

Sensitivity runs include a high gas price of 20 €/GJ from February 2022 [55] Sönnichsen, has been applied to investigate the impact of potential future price increase. The high biomass prices are representing possible increased gap between supply and demand. For this, each base biomass price per type (see Table 4) is doubled. The potential impacts of lower or higher build costs of DAC and BECCS are also assessed with +/-50% change of build costs compared to base costs presented in Table 2. The ‘No biomass limits’ scenario investigates biomass utilisation by the power system without restrictions (unlimited potential, default price). Power system optimisation is also executed with different weather years of similar average capacity factors to see the impact of weather year choice on the system.

3. Results

In this section, the findings on how emission targets and biomass availability affect the roles of biomass and CCS, and in particular BECCS and DAC, in the EU+ power system are presented on the basis of the key indicators. This section starts with the impact on installed capacity and annual generation, total system costs, CO_2 emissions, CO_2 storage requirements, levelized costs, as well as reliance on fossil fuels and transmission dependence

Fig. 8 shows the significant impact of varying sustainable biomass availability combined with varying CO_2 emission targets on power system capacities and total system costs. Increasing sustainable biomass potential for net-zero and net-negative EU^+ power systems in 2050 decreases total costs in each emission scenario by 29%−51%, since it allows the system to reduce on DAC and nuclear capacity requirements.

Installed capacity increases significantly, compared to 2019 and correlates strongly with emission target and biomass potential as well. The decrease in total electricity generating capacity installed is 10%−20% from ‘No Bio’ to ‘High Bio’. Bioenergy without CCS (BE) has not been chosen, except for the ‘No CCS’ scenario. The combination of BECCS and natural gas is always preferred over BE. The reason for that is the lower costs and the 3 times faster ramping up capabilities of CCNGT, than BE for flexibility. Excluding biomass and CCS simultaneously has shown unfeasibility in this modelling context.

Natural gas with CCS, DAC, nuclear and battery capacities are decreasing with increased biomass potential. Most nuclear capacity is installed in Germany, Italy and the Benelux. The majority of BECCS

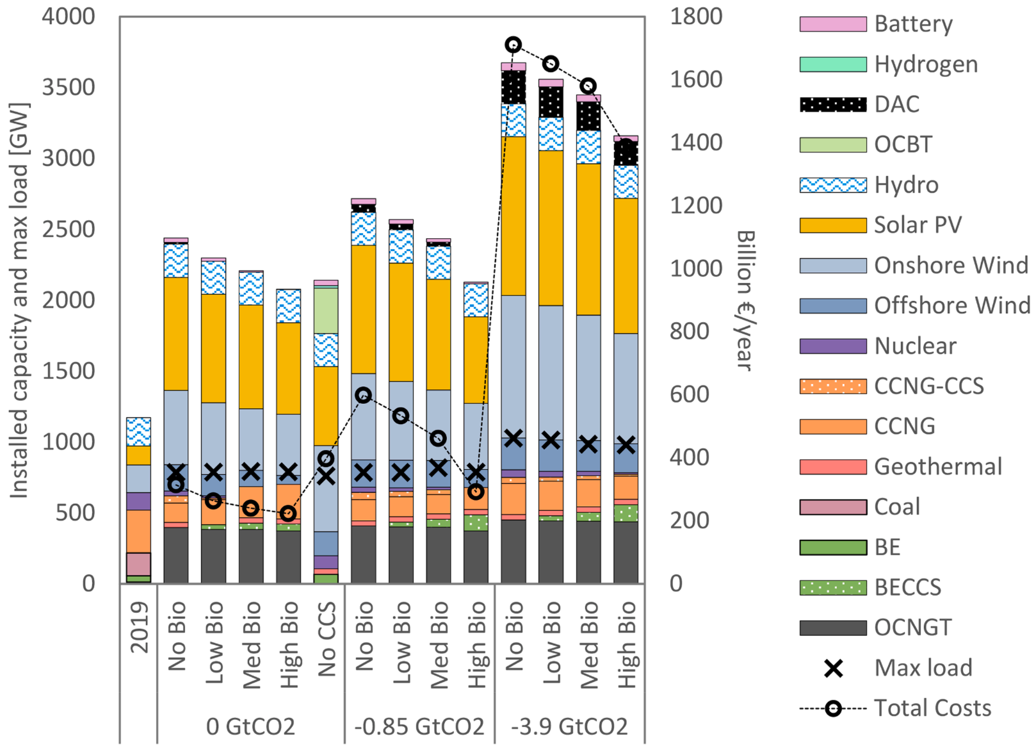

Fig. 8. Installed capacity in the EU in 2050, with max load and total system costs For 'No CCS, the medium biomass potential combination is shown. Hydro includes pumped hydro, run of river and dam. Solar PV combines utility and rooftop. Total costs are cost of generation over 2050, including all fixed and variable costs, annuity factor is considered for build costs with 8% interest. All scenarios have the constraint of installing at least 8% reserve capacity compared to peak demand. Geothermal and hydro are always built. Cost of transmission network is excluded, since mostly identical in each scenario 'No DAC' scenario is not present, it is identical to 'High Bio'. −3.9 $GtCO_2$ – No DAC combination is not feasible.

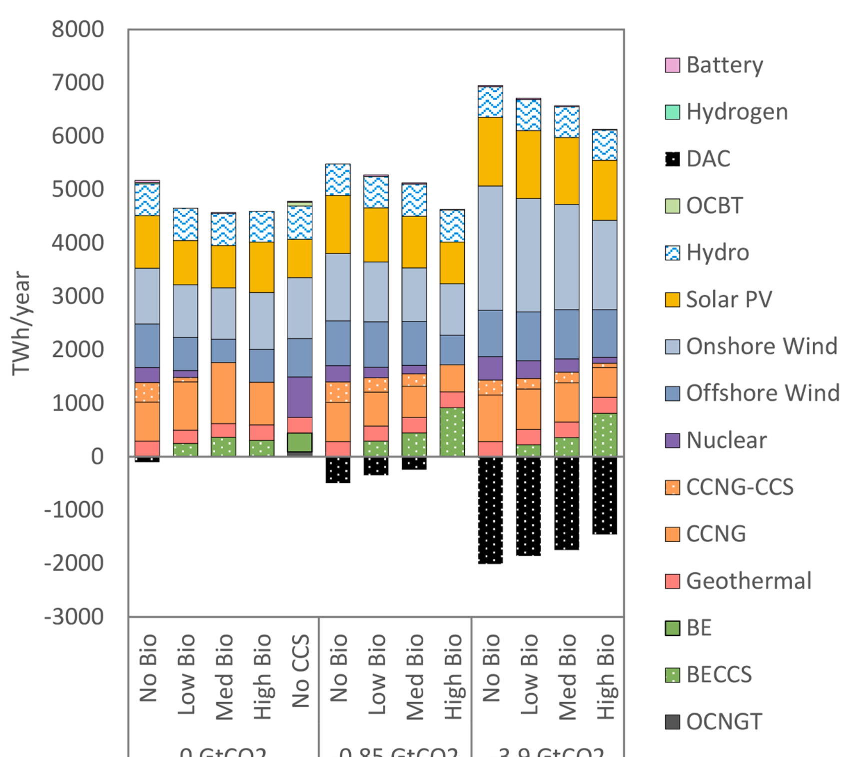

Fig. 9. Generation in the EU^{+} in 2050 in an average weather year, DAC is in the negative region due to being electricity consumer 'No DAC' scenario is not present, it is identical to 'High Bio'. −3.9 $GtCO_2$ – No DAC combination is not feasible. For 'No CCS, the medium biomass potential combination is shown.

capacity is installed in Central Europe (20%−25% depending on the scenario) and about 30%−40% in Germany, Scandinavia and France combined. The high level of open cycle natural gas turbine (OCNGT) installed capacity is most probably due to the 8% reserve capacity margin constraint. Hydrogen storage has only been installed in the 'No CCS' scenario. Also, the exclusion of CCS technologies resulted in 70 GW nuclear capacity, since negative emission technologies and flexibility provided by natural gas could not be built in this case. Total system costs vary between €200 and €1700 billion. The large increase is due to DAC capital and operational costs, ranging from €160 to €1300 billion/year. In case of the 'No CCS' scenario, cost increase is due to increased nuclear and hydrogen electricity storage.

Fig. 9 presents the short-term, hourly resolution UCED results and shows that during a representative weather year, biomass availability highly influences the net-negative emission scenarios and moderately the zero emission scenarios. Solar and onshore wind generation is almost unaffected by varying biomass potential and emission targets. Offshore wind generation on the other hand is increasing with increased DAC electricity demand. OCNGT generation is insignificant in most scenarios during this representative weather year. CCS is enabling natural gas use. About 10%−20% of the generation is natural gas based in all scenarios, except the 'No CCS' scenario. The exclusion of carbon capture and therefore natural gas, results in significant increase in nuclear use, with about 16% of electricity produced by nuclear. Average nuclear capacity factor is 94%. CCNG-CCS operates at capacity factor of 70%−90%, which is significantly higher than CCNG without CCS, ranging between 10%−40%, This indicates that installing CCS on CCNG is economically viable primarily under high-capacity factor conditions, to enable the maximization of CO_2 capture capabilities BECCS is operating on high capacity factors of 70%−95%. Battery and hydrogen storage are mostly operating <20%. For flexibility the first choice of the model is CCNG, which has the fastest rump up time and lower costs, than battery. Battery is used for daily balancing, with high capacity factors >50% during summer and lower during winter.

Although the use of natural gas with CCS is consistently decreasing with increasing biomass, natural gas without CCS is responding differently in net-zero scenarios. In this case, biomass as negative emission technology has an enabling role for natural gas use. About 1.1 tCO_2/MWh is removed by BECCS, while CCNGT emits 0.3 tCO_2/MWh, and CCNGT-CCS emits 0.004 tCO_2/MWh, given the 90% capture rate assumed. This results in compensable positive emissions even when CCS is applied to natural gas.

Each MWh BECCS enables 3.6 MWh of CCNGT or 27 MWh of CCNGT-CCS and still results in net-zero emissions. Levelized costs are around 130 €/MWh, 42 €/MWh and 75 €/MWh respectively. Simple cost optimisation of these 3 technologies to generate net-zero power prefers a combination of CCNGT and BECCS, without applying any CCNGT-CCS. Also, the ramp up time of CCNGT is 20% faster, than of CCNGT-CCS, making it more flexible to combine with intermittent RES. Most likely this is the reason, why the system is using CCNGT also in the 'No Bio' scenarios, when only CCNGT-CCS should be used from a cost minimisation perspective. With increased BECCS and CCNGT, offshore wind generation somewhat decreased. The reason for that can be the fact that solar and onshore wind have significantly lower costs and with highly flexible CCNGT, they become more attractive than offshore wind.

Table 7 summarises important power system performance indicators. Almost all indicators show the least favourable results for the −3.9 $GtCO_2$/year scenario, especially regarding cost of negative CO_2 emissions. CO_2 storage requirements increase significantly in the net-negative emission scenarios from about 0.4 $GtCO_2$/year to 4 $GtCO_2$/year, but are almost equal between biomass potential scenarios. Levelized cost of electricity (LCOE) increases by 38% when biomass is not available for the power system. With the −0.85 $GtCO_2$/year emission scenario, cost of negative emission is 4 times higher if biomass is removed compared to the high biomass scenario. This is the most significant difference as a result of changing biomass availability. In the −3.9 $GtCO_2$/year scenario, negative emission costs only increase by 23% when biomass is not available, since the large costs are mostly the result of large-scale DAC implementation. DAC costs are estimated around 300–370 €/tCO_2 excluding electricity costs. In the −3.9 $GtCO_2$ ambition scenarios the cost of carbon removal increases to 1300 −1700 €/tCO_2, since the power system needs to produce an additional 1500–1700 TWh/year for DAC consumption. Unserved energy is not presented on table 7, since all the scenarios scored equally for this indicator.

Cross-border transmission capacity factor does not change significantly with changing emission cap or biomass potential. Only in the −0.85 $GtCO_2$/year scenario it increases slightly with increasing biomass potential, since biomass cannot be transported in most cases inter-regionally, due to the RED-II criteria of emission saving would exceed

Table 7
Performance indicators of high, medium, low and no biomass potential scenarios combined with the varying net emission targets of 0, −0.85 and −3.9 $GtCO_2$/year.

	Total Cost (Bln €)			LCOE (€/MWh)	Negative emission costs (€/tCO_2)		CO_2 Storage requirement ($GtCO_2$/yr)			Cross-boarder transmission (CF %)		
	0	-0.85	-3.9	all	-0.85	-3.9	0	-0.85	-3.9	0	-0.85	-3.9
High Bio	223	292	1,387	49	82	1,369	0.31	1.09	4.15	82%	87%	85%
Med Bio	240	461	1,579	52	260	1,575	0.39	1.07	4.13	80%	86%	85%
Low Bio	263	533	1,649	57	317	1,630	0.45	1.02	4.06	81%	86%	83%
No Bio	314	599	1,710	68	335	1,642	0.35	1.13	4.21	82%	82%	82%

Colour code: green to red scale from best to worst performing scenario respectively, scaled for each indicator separately. Cost related indicators: total costs, levelized cost of electricity (LCOE) and cost of negative emissions. Emission indicators are storage requirements. Adequacy indicator is transmission requirements over 3 different weather years. LCOE does not vary between emission target scenarios, since extra costs of −0.85 and −3.9 $GtCO_2$/year systems are allocated to 'net-negative costs'.

the limit.

Fuel utilisation of biomass, nuclear, biogas and natural gas have been determined by the UCED simulations (Fig. 10). Utilisation of natural gas and nuclear decreases with increasing biomass potential in the net-negative scenarios. In the 'No CCS' scenario, only about half of the biomass potential is utilised and biogas is only applied in this scenario. Fuel use in the 'No Bio' scenarios seem to be unaffected by decreasing net CO_2 emission target. Even though the models did not contain any renewable energy participation constraints, renewable generation excluding biomass is ranging between 69% and 78% depending on the scenario, with the highest renewable participation at '−3.9 $GtCO_2$/year low bio' scenario.

Fig. 11 with breakdown of different types of biomass used shows that in the net-negative scenarios, 100% of the sustainable biomass potential in the EU^+ is utilised. In the net-zero emission scenarios the cheapest biomass types such as municipal waste or agricultural residues are utilized for 100%, but only 44% to 91% (2.7 to 4.7 EJ/year) of the overall biomass potential is required.

Additional regional breakdown of selected results can be seen in Appendix G.

4. Sensitivity analysis

Five additional scenarios have been designed to reveal how sensitive the results are to certain changes. Fig. 12 presents the changes compared with the representative, −0.85 $GtCO_2$/year, medium biomass potential scenario.

In terms of installed capacity, the most significant changes can be seen with increasing gas prices, lower discount rates, and no limits on biomass potential. With high gas prices, 155 GW of natural gas capacity is replaced by coal with CCS, nuclear, hydrogen and biogas turbines. With 3% discount rate, CAPEX intensive nuclear and DAC capacity increases, while significant decrease in solar and natural gas capacity is observed. With no limits in biomass potential, only 56 additional GW of BECCS capacity is built, and the need for DAC, nuclear and batteries completely disappears. Increased biomass prices do not impact the system significantly. Changes in BECCS CAPEX or build costs have little to no impact in capacity portfolios, while varying DAC CAPEX impacts capacity expansion decisions significantly. 50% build cost increase in DAC reduces its total installed capacity by 5 GW or 20%. As a result, less natural gas can be used without CCS, causing the retirement of 100 GW combined cycle natural gas turbine (CCNGT) and the installation of additional 40 GW CCNGT with CCS, 14 GW of nuclear and 75 GW of onshore wind. Onshore wind is most likely chosen in place of 132 GW solar PV, since the reduced CCNGT decreases flexibility. Decreasing DAC build costs by 50% results in the retirement of all BECCS and CCNGT with CCS, choosing an additional 50 GW DAC instead. With this additional DAC, the CCNGT capacity more than doubles, with onshore wind preferred over solar PV and offshore wind capacity.

Fig. 13 shows change in total cost, CO_2 storage requirements, and the use of biomass, nuclear and fossil fuels. The most significant change is nuclear generation in the 3% discount rate scenario, that increases by over 600% and in high gas prices by 400%. Lifting biomass potential constraints results in a 60% drop in total costs, while biomass use only increases by 20%, since DAC and nuclear are no longer required. Also, the system was able to utilise only the cheapest biomass sources (municipal waste, secondary forestry residues and sawdust). 32% decrease in total costs can be observed if the assumed discount rate is 3%.

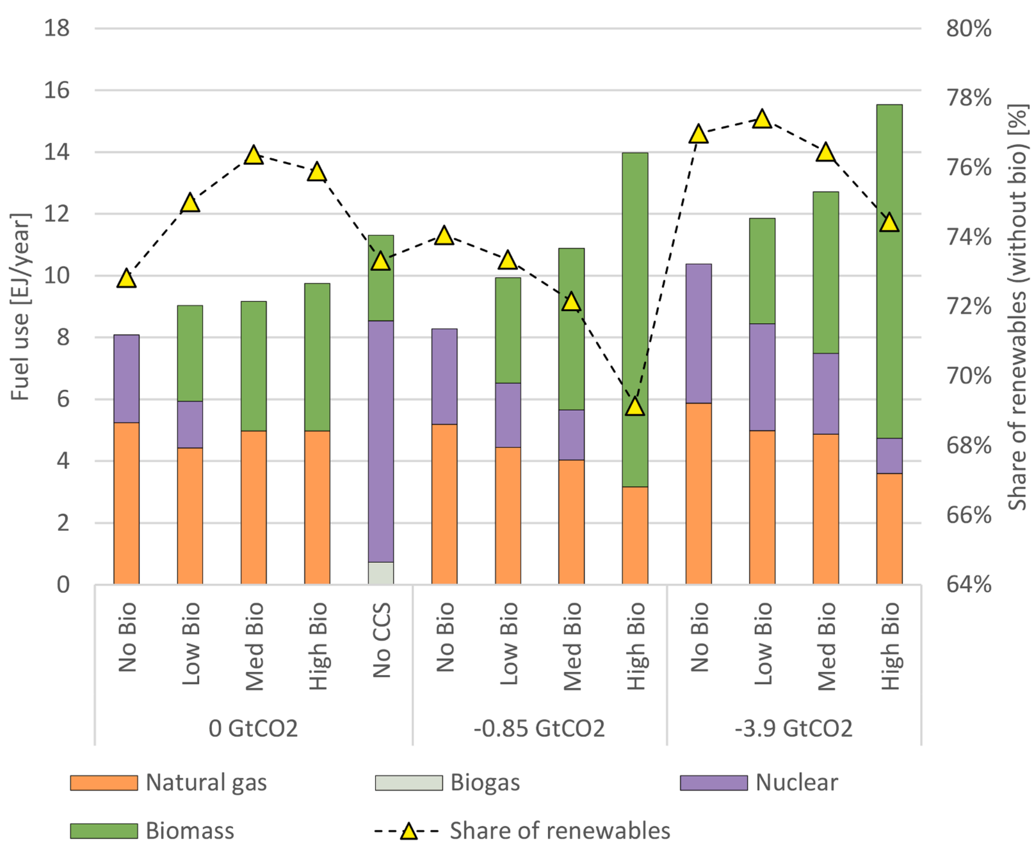

Fig. 10. Utilisation of different energy carriers in generation for 2050, EU^+region in different scenarios on the left axis and share of renewable generation (solar, wind, hydro and geothermal, excluding biomass) on the right For 'No CCS, the medium biomass potential combination is shown.

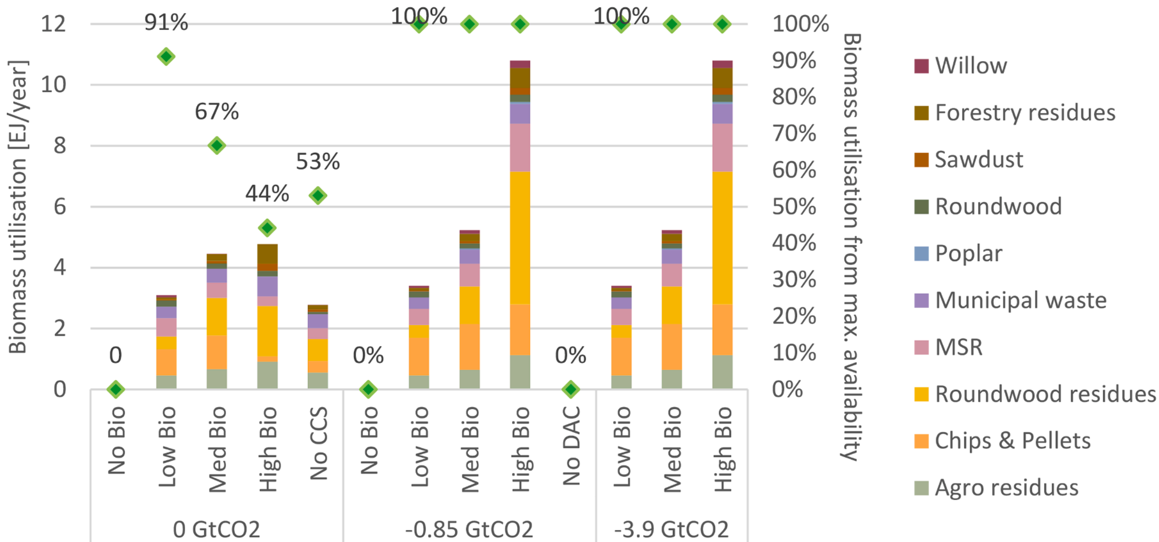

Fig. 11. Participation of different types of biomass in the EU+ power system in 2050 and the utilisation of total biomass potential per scenario in percentage, MSR: Miscanthus, Switchgrass, Reed Canary grass. For 'No CCS, the medium biomass potential combination is shown.

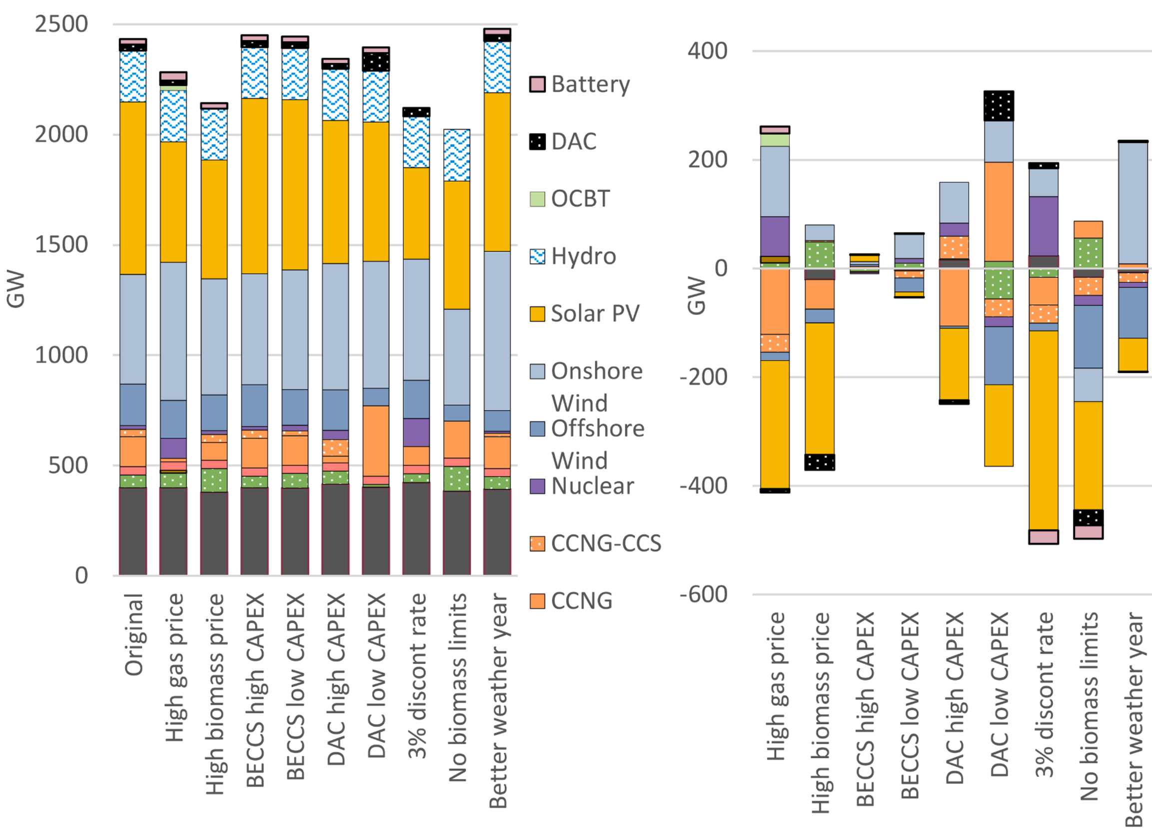

Fig. 12. EU+ power system capacities for 2050 in 9 sensitivity analysis scenarios, installed capacities in GW shown on the left, and changes in GW installed capacity compared to the 'Original' scenario on the right. Original stends for the representative $-0.85GtCO_2$, medium biomass scenario, high gas price is the scenario with €20/GJ, high biomass price is all the biomass prices doubles, 'high' and 'low' BECCS and DAC CAPEX is +/−50% of the original build costs in both cases (operational expenditures remain unchanged), no biomass limits lifts all limits on biomass use, interregional trade of biomass is also possible. 3% discount rate is the reduction of overarching discount rate in the model from 8% to 3% (including interest during construction). For 'other weather year' a similar weather year in annual averages to 2014, but different hourly variation has been chosen: 2016, to see the impact of the choice of the weather year.

5. Discussion

5.1. Limitations

The findings of this study have to be interpreted in the light of the following limitations.

Due to the greenfield approach, retrofitting of old power plants and the transition from the current power system were excluded. However, it is expected that most residual capacity will be decommissioned by 2050 apart from nuclear power plants, of which approximately 50–70 GW of

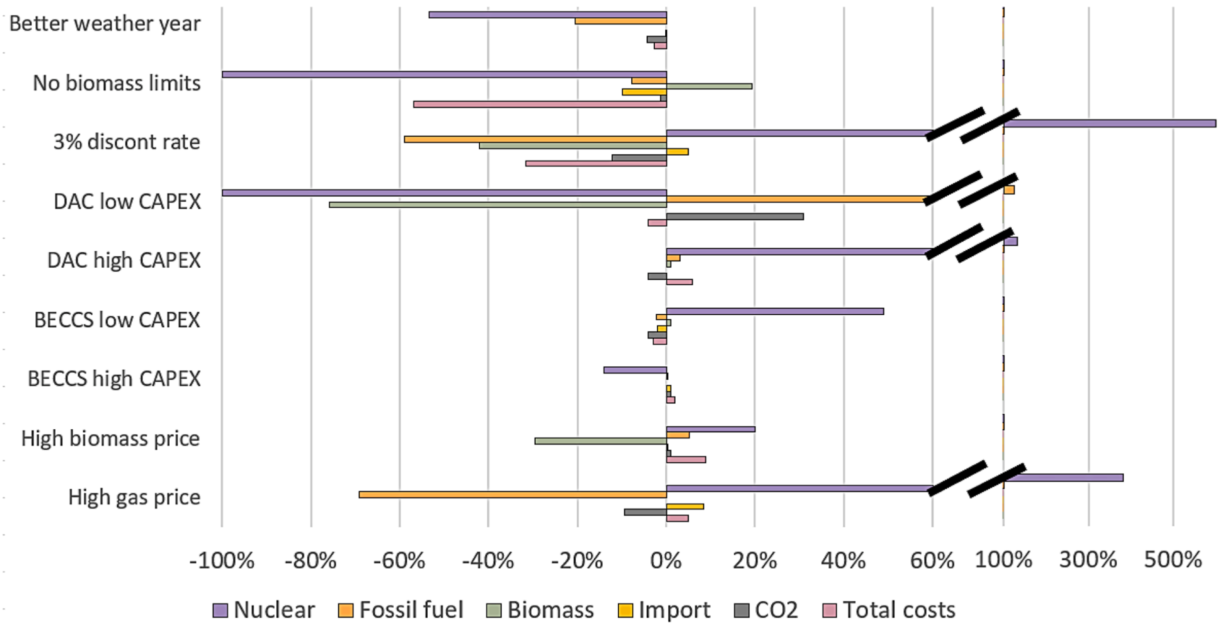

Fig. 13. change on a selection of important properties in the 5 sensitivity scenarios 'Nuclear', 'Fossil fuel' and 'Biomass' shows the change in total annual fuel utilisation, where 'Fossil fuel' includes natural gas and coal generation combined, 'CO_2' stands for changes in CO_2 storage requirements, Import shows the change in total annual cross-boarder transmission dependence.

capacity technically could still be operating [56,57], and hydropower plants; however, hydro capacities of this study account for existing capacities. Nevertheless, dynamic, long-term, capacity expansion models could show additional insights into the challenges achieving these configurations from 2020–2050. Also some generation technologies have been excluded from the technological palette, such as concentrated solar power (CSP) or tidal power plants, but their deployment between 2020–2050 is likely to be marginal [58–60]. Transmission system of the power model was fixed and reduced to cross-border transmission lines. Inclusion of higher transmission line resolution within countries could change storage and base load requirements and consequently the preferable share of variable renewables amongst others [61,62]. Since the scope of this study was limited to the power sector, some important interactions with the heat sector were not considered, e.g. combined heat and power generation and heat storage, or the required 5.4–7.1 EJ/$GtCO_2$ heat for DAC although costs related to DAC heat input are considered in the model. For electricity storage, bi-directional EV batteries have not been considered as this study focussed on utility scale technologies instead of demand side technologies.

Uncertainties in future cost, technology availability and efficiency improvements can significantly impact the power system design [63, 64]. Although some of these uncertainties are explored in sensitivity analysis, with regard to DAC, BECCS, and nuclear and gas prices, other technoeconomic assumptions can still affect future power system portfolios. Although sensitivity to gas price has been explored, the impact of possible intra-year variability of gas prices were not assessed in this study [65]. Our findings reveal that 72% of natural gas utilization occurs during winter, coinciding with maximum capacity factor operation for potential alternatives like biomass and nuclear energy. As alternatives are fully exploited during the winter months, it is improbable that natural gas usage will significantly decrease despite higher winter costs. Despite these sensitivities, uncertainties surrounding technology costs and efficiency improvements in 2050 persist [65–68]. These uncertainties arise from unpredictable technological advancements, market dynamics, regulatory changes, and external factors like resource availability and geopolitical developments. Further research is needed to explore the impact of these factors.

In this study, one electricity demand pattern for 2050 has been considered. However, other demand curves assumed for 2050 are not expected to impact the role of biomass and CCS significantly, since BECCS predominantly acted as baseload, as opposed to flexibility option. In terms of weather years, historical capacity factors have been considered, as opposed to future projected patterns [69]. This is to achieve hourly temporal resolution, as opposed to three hourly. However, weather patterns are highly likely to change until 2050 due to climate change [70]. Additionally, constant bioenergy efficiency is assumed, regardless of the source of biomass; however, it does not affect the outcomes largely, where 100% biomass is utilised.

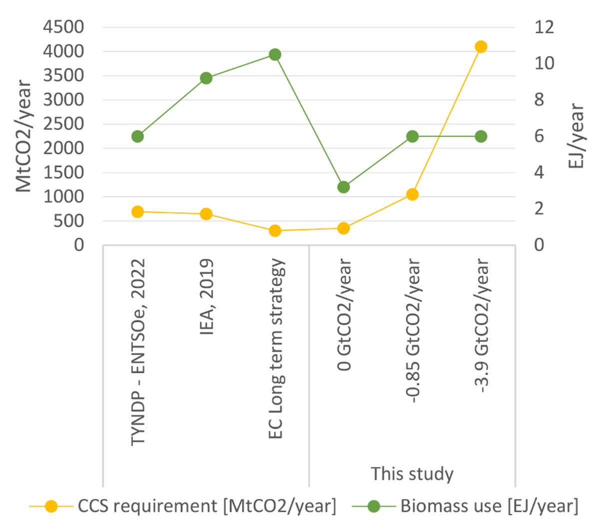

Fig. 14. Annual carbon capture and storage (CCS) requirement (including all power system related CCS, e.g. Gas+CCS, BECCS, DAC) in $MtCO_2$ per year in 2050 and annual biomass utilisation in EJ per year 2050 in a selection of relevant studies: Ten Year Network Development Plan 2022 [71], International Energy Agency: Net Zero by 2050 [72], And European Commission Long term strategy [35]. For this study, the 'Med Bio' results are displayed.

5.2. Comparison to literature

This study resulted in 0.3–1.1 $GtCO_2$/year of CO_2 stored in the net 0 and net −0.85 $GtCO_2$ scenarios which is in line with relevant studies (see Fig. 14). However, the 4.0 $GtCO_2$ captured in the net −3.9 $GtCO_2$ scenarios is much higher than in most studies, but in line with Pozo et al., [36].

Total and levelized costs are mostly in line with most power system optimisation studies [18,19,32,73–75]. Zappa et al., [32] find total system costs to be 400–570 billion € /year for 2050 for a 0 target scenario,[8] while this study resulted in 230–699 billion €/year for the 0 and −0.85 target scenarios. In a 2050 net-zero emission target scenario by Tatarewicz et al. [18], about 100 GW nuclear capacity is present with high biomass availability, contrarily to this study. The reason for this difference is most probably the long term dynamic planning of that study. When comparing cost related results of this study, it is important to highlight the 2019 currency used when expressed cost related results. The choice of 2019 Euros should be considered when comparing our results to recent studies as Eurozone industrial price indexes have risen by as much as 60% between 2019 and 2022, and 47% between 2019 and the first half of 2023 [48], these cost fluctuations should be considered when comparing to recent studies. van Zuijlen et al., [19] created a net-negative sensitivity scenario including DAC and BECCS. In their results, CCNGT is only used with CCS, compared to this study, where CCNGT is applied with and without CCS. The reason behind the difference could be the fact that CCNGT-CCS costs are 30% lower. In terms of DAC costs, the IEA [56] estimates about 220 €/tCO_2, which is consistent with the −0.85 $GtCO_2$ scenario negative emission costs. However, the −3.9 $GtCO_2$ scenarios resulted in significantly higher costs, questioning the feasibility of those scenarios.

As his paper aims to provide policymakers and stakeholders insights into the role of biomass and CCS in the 2050 power system, without any bias from current policy trends, the model outcomes are not automatically aligned to specific policies of EU^+ countries . The results show that Scandinavian countries preferably use significant amounts of biomass, DAC and other CCS technologies resulting in large CO_2 storage requirements. This is in line with the current decarbonisation strategies of Norway and Sweden which envision a key role for biomass and carbon capture [76]. These countries are also committed to provide negative-emissions by 2050 [77,78]. However, the model has consistently chosen Germany for large scale nuclear implementation, while Germany is taking a strong stand against nuclear [79]. On the contrary, in the pro-nuclear France, no nuclear was installed due to high potential of renewables including biomass. Also in Italia, nuclear was installed in numerous scenarios, while Italy itself is not using or planning to use nuclear in the future; however 'Italia' region also includes Switzerland where up to 40% of the electricity production is from nuclear [80].

6. Conclusion

This study finds that, the most prominent role of biomass and CCS in climate-neutral European power system is in the form of BECCS, while DAC is only applied when biomass alone is unable to fulfil negative emission targets. Besides the 100% utilisation of biomass via BECCS in the −0.85 and −3.9 $GtCO_2$/year scenarios, BECCS is also applied in the net-zero emission scenario, removing 0.4 $GtCO_2$/year and utilising 41%−91% of domestic biomass potentials (from high to low). Although net-zero and net-negative targets are theoretically feasible without biomass, overall EU^+ power system costs increase by 40%−100% and large-scale DAC and nuclear are required in this case. The net-zero scenario can be also achieved without CCS, although total power system costs increase by 78%, and large scale nuclear, plus hydrogen and biogas are installed. In case where DAC is not available, −0.85 and −3.9 $GtCO_2$ net emissions can only be achieved with high biomass potential together with CCS.

CCS is always installed with biomass, except when the biomass potential is restricted to low or none it is also installed with fossil fuels. Vice versa, bioenergy is only installed with CCS except when CCS is not available. The combination of natural gas without CCS as flexibility option, and BECCS as negative emission baseload is the optimum solution to complement variable renewable energy. The share of generation by solar, wind, and hydro hardly varies dependending on the availability of CCS and biomass and remains around 69% and 78%.

Biomass potential, CCS availability and emission targets all had significant impact on costs. The costs of negative CO_2 emissions in the −3.9 $GtCO_2$ scenario is 1300–1600 €/tCO_2, which is 5 times higher than carbon taxes predicted for Europe in 2050. In the −0.85 $GtCO_2$ scenario, high biomass potential can decrease CO_2 removal costs to 82 €/tCO_2 from 335 €/tCO_2 in a limited biomass scenario, making it highly competitive. Furthermore, the elimination of biomass in the power system would double the costs compared to a high biomass scenario.

Sensitivity analyses showed that the identified future role of biomass is robust, limitless biomass availability only increases biomass use by 20%. Also, the mixes of power system capacities are highly sensitive to DAC costs and discount rate. A 50% decrease in DAC build costs eliminates the use of BECCS, preferring only DAC as carbon removal option. Doubling biomass or varying BECCS prices did not significantly impact the system, revealing that the role of biomass does not depend on the biomass prices.

In summary, the elimination of biomass use in the power system could double total costs compared to a high domestic biomass potential scenario as the European power system either requires high biomass availability or DAC to reach climate neutrality. Without investment in either CCS or bioenergy, climate neutrality in the power system is unattainable, and the most optimum is to combine both in BECCS.

Future research is recommended to analyse these scenarios with multisectoral modelling of biomass as well as expand on biomass import options, higher spatial resolution, high electricity demand for green hydrogen, deployment from now onwards including retrofit options and inclusion of indirect emissions.

CRediT authorship contribution statement

Rebeka Béres: Writing – review & editing, Writing – original draft, Visualization, Validation, Methodology, Investigation, Data curation, Conceptualization. **Martin Junginger:** Validation, Supervision, Conceptualization. **Machteld van den Broek:** Validation, Supervision, Conceptualization.

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.

Data availability

Data will be made available on request.

Supplementary materials

Supplementary material associated with this article can be found, in the online version, at doi:10.1016/j.adapen.2024.100166.

[8] Only comparing 'base demand' scenarios for 2050, with similar electricity demand.

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