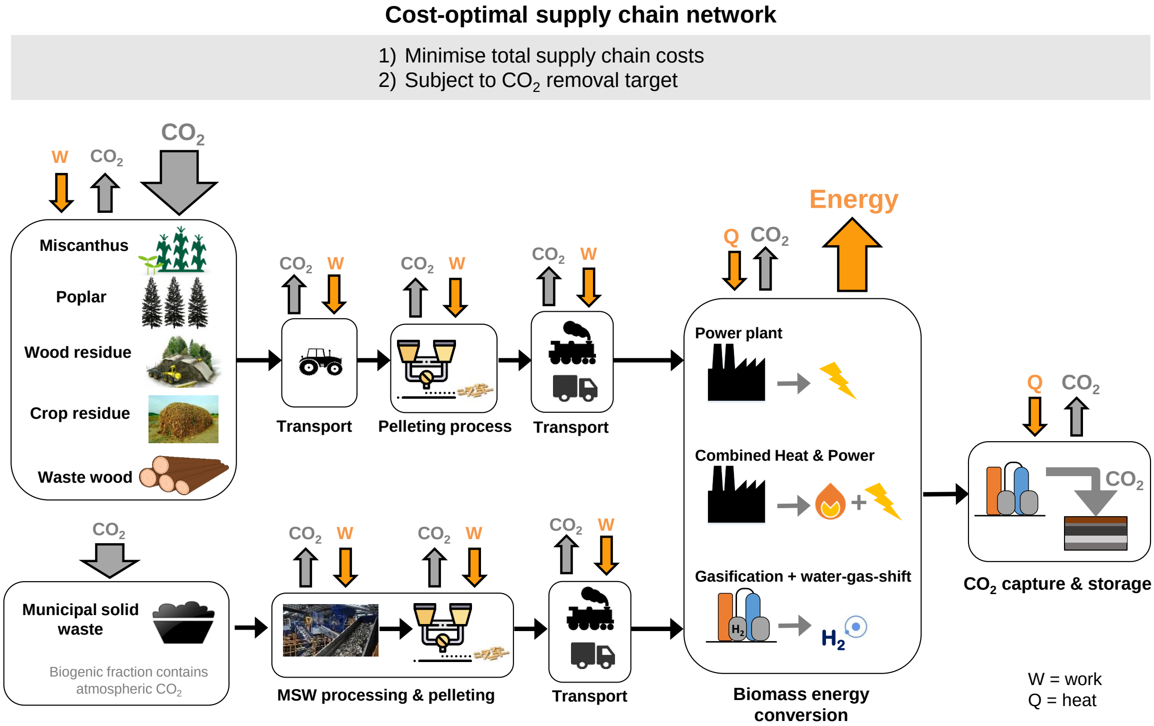
Graphical Abstract

Delivering carbon negative electricity, heat and hydrogen with BECCS – comparing the options

Mai Bui, Di Zhang, Mathilde Fajardy, Niall Mac Dowell



Highlights

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- Indigenous sources of biomass in the UK could generate up to 56 MtCO2 of negative emissions per year.
- All three pathways (electricity, heat, hydrogen) provides a substantial energy supply for the UK.
- It is more cost-effective to deploy technologies in combination, BE-CHP-CCS with BECCS and BHCCS.
- The cost-optimal combination of technologies is a function of the H_2, electricity and heat price.
- Capital cost savings (e.g. retrofit existing plants) and high capture rates enhance deployment.

Delivering carbon negative electricity, heat and hydrogen with BECCS – comparing the options

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Abstract

Biomass can be converted into a range of different end-products; and when combined with carbon capture and storage (CCS), these processes can provide negative CO_2 emissions. Biomass conversion technologies differ in terms of costs, system efficiency and system value, e.g. services provided, market demand and product price. The aim of this study is to comparatively assess a combination of BECCS pathways to identify the applications which offer the most valuable outcome, i.e. maximum CO_2 removal at minimum cost, ensuring that resources of sustainable biomass are utilised efficiently. Three bioenergy conversion pathways are evaluated in this study: (i) pulverised biomass-fired power plants which generate electricity (BECCS), (ii) biomass-fuelled combined heat and power plants (BE-CHP-CCS) which provide both heat and electricity, and (iii) biomass-derived hydrogen production with CCS (BHCCS). The design and optimisation of the BECCS supply chain network is evaluated using the Modelling and Optimisation of Negative Emissions Technology framework for the UK (MONET-UK), which integrates biogeophysical constraints and a wide range of biomass feedstocks. The results show that indigenous sources of biomass in the UK can remove up to 56 Mt_{CO_2}/yr from the atmosphere without the need to import biomass. Regardless of the pathway, Bio-CCS deployment could materially contribute towards meeting a national CO_2 removal target and provide a substantial contribution to a national-scale energy system. Finally, it was more cost-effective to deploy all three technologies (BECCS, BE-CHP-CCS and BHCCS) in combination rather than individually.

Keywords: carbon capture and storage, bioenergy with CCS, BECCS, biomass-derived hydrogen, carbon dioxide removal, negative emissions, gasification, WGS

1. Introduction

1.1. Achieving net negative emissions

Carbon capture and storage (CCS) and negative emission technologies (also known as carbon dioxide removal) will have an essential role in limiting global warming to 1.5°C target

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[1, 2, 3]. Potential negative emission technologies (NET) include afforestation and reforestation, direct air capture of CO_2 with storage (DACCS), enhanced weathering, biochar, ocean fertilisation, and bioenergy with carbon capture and storage (BECCS) [4, 5, 6, 7, 8, 9]. Across many of the scenarios presented by the integrated assessment modelling (IAM) community, negative CO_2 emissions are predominantly achieved with BECCS combined with afforestation [10, 11, 12, 13, 14, 15], or BECCS with DACCS [16, 17, 18, 19], but other CDR measures have yet to be included in IAM. Although these scenarios suggest that BECCS has an important role in the transition to a low carbon energy system, there are many technical, economic and social challenges that need to be addressed [20, 21, 22, 23, 24, 25, 26]. The main cause for concern is broadly around the questions about sustainability of large scale BECCS deployment [27, 28, 29, 30, 31].

The use of primary biomass for BECCS raises sustainability concerns, owing to the potential competition with other land uses, particularly food production, and significant need for fertilisation and irrigation [24, 32]. To address concerns around sustainability, secondary sources of biomass, e.g. municipal solid wastes, agricultural residues, have been proposed as a viable and economical bioenergy resource [33, 34, 35, 36]. Furthermore, supplementing primary biomass demand with secondary sources could enable the supply of biomass from solely indigenous sources, which could provide economic advantages in a growing global bioeconomy. The establishment of international trading of sustainable biomass could be vital to delivering affordable CDR services globally [37, 38, 39].

In the UK, the demand for fuel wood in 2014 was 4.9 Mt, of which only 354 kt was sourced from indigenous supply [40, 41]. The Drax power plant in the UK is the world's largest consumer of biomass for power generation, importing approximately 80% of its biomass supply from North America [42, 43, 44]. At the end of June 2019, the UK announced a new target that will require all greenhouse gas emissions to reduce to net zero by 2050 [45]. The UK's Committee on Climate Change (CCC) suggests that the UK would need to remove around 47 Mt_{CO_2}/yr of atmospheric CO_2 by 2050 to reach net-zero [46]. The CCC estimates that the UK could remove and sequester 20–65 Mt_{CO_2}/yr using BECCS, depending on the amount of sustainable biomass available [47].

Biomass can be converted into different end-products; either combusted to produce heat and electricity, or processed into bio-hydrogen or liquid biofuels (figure 1) [47]. Combining these conversions pathways with CCS provides net negative CO_2 emissions. However, the actual amount of CO_2 removal will vary with each pathway type. Combustion pathways (to generate heat and power) typically captures between 90 and 99% of the CO_2 from the flue gas [48, 49, 50, 51]. In contrast, the production of biofuels (i.e. a hydrocarbon) and their use will release CO_2 back to the atmosphere once combusted. Alternatively, biomass-derived hydrogen production with CCS (BHCCS) generates a non-carbon fuel, i.e. no CO_2 emitted upon combustion.

BECCS pathways (e.g. power generation [52, 53], or biofuel production [36, 54]) tend to be evaluated as individual technologies in terms of CO_2 removal potential and cost. Comparative assessments of multiple different BECCS pathways/technologies [55, 56] are important in identifying which BECCS application/s would likely provide the most valuable outcome, i.e. maximum CO_2 removal at minimum cost. Given that BECCS could provide

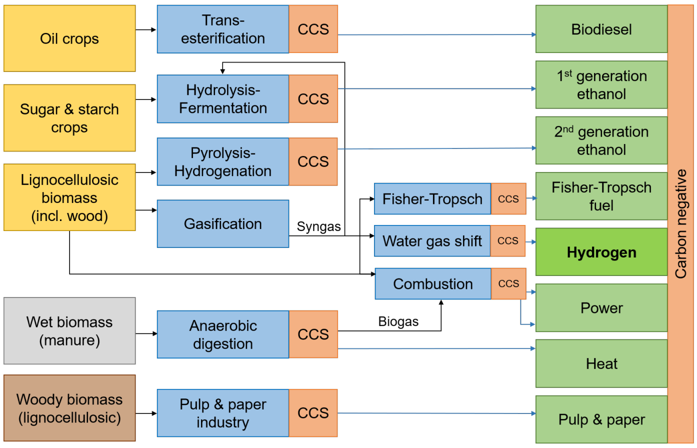

Figure 1: Different biomass feedstocks can be used with various BECCS pathways to generate distinct energy services, i.e. biofuel, electricity or heat, and thus have different "value" to an energy system. Some pathways will deliver more negative CO_2 emissions compared to others as some end-products release CO_2 back into the atmosphere.

multiple end-products, we need to investigate which combinations of BECCS pathways could provide maximum benefit. Sustainable biomass is a limited resource, therefore, it should be prioritised for the most valuable end-products that economically maximise CO_2 removal from the atmosphere.

1.2. Biomass feedstocks and BECCS pathways

Biomass feedstocks used for bioenergy in general can differ in composition, origin and shape. In terms of composition, the main biomass types used for bioenergy are lignocellulosic woody biomass, such as pine, eucalyptus, willow, lignocellulosic crops, such as perennial grasses or agricultural residues, oil crops, sugar and starch crops, and waste biomass such as wet manure or municipal solid waste (MSW). These different types of biogenic feedstock can originate from conventional agriculture (i.e. the main product or residues from a crop), energy dedicated agriculture (e.g. with perennial grasses and short rotation coppice), residues from forest management or municipal wastes. After collection, different processing pathways are available to facilitate transport, storage and/or conversion. Biomass can be transported and stored in the form of chips, pellets, briquettes, bales or bulky biomass. In addition to these supply options, further processing steps such as torrefaction can increase biomass mass and energy densities of biomass, which enhances fuel integrity in storage and transport, and improves the conversion performance [57, 58]. A summary of these feedstock options are outlined in figure 2.

By influencing density, moisture content and size, the shape of the biomass feedstock will mainly affect biomass transport and storage costs. Furthermore, the composition of the biomass feedstock however, has a direct impact on the conversion pathway and bioenergy end-product. Whilst oil and sugar crops can be transformed in biodiesel or first generation ethanol, lignocellulosic biomass can be more easily converted to heat and power through direct combustion, or syngas through gasification. Further conversion of syngas via water-

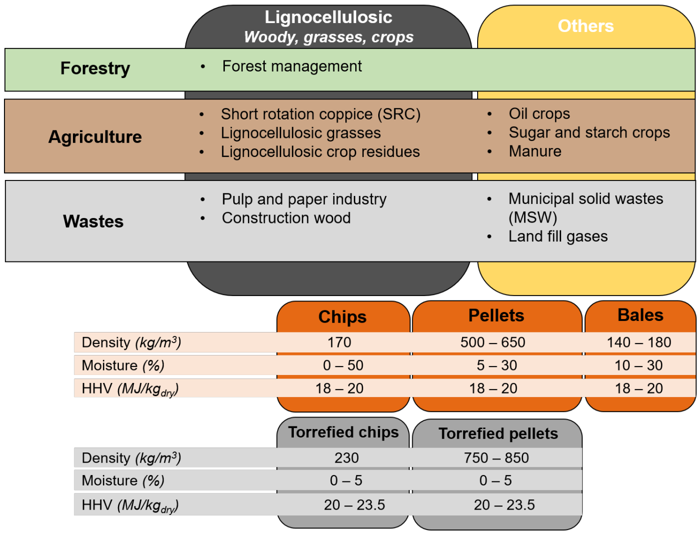

Figure 2: Different biomass feedstocks for bioenergy. Bio-feedstock may differ by composition – lignin, cellulosic, lignocellulosic, oil crop, origin – forestry, agriculture, wastes – and shape.

gas-shift reaction, fermentation, or Fischer-Tropsch process can then lead to hydrogen or first and second generation ethanol [59, 60]. Figure 1 maps the different BECCS pathways in relation with the adequate feedstock.

Each combination of biomass type, sector of origin and shape results in a different supply chain consisting of production, processing and transport, and thus, leads to different energy use, carbon footprint, water footprint, land footprint and cost. Rather than studying a "generic biomass", it is thus important to consider each case study specifically, as it will have a direct impact on BECCS sustainability. Among conventional crops, oil crops (e.g. palm, corn) or sugar and starch crops (e.g. sugarbeet) have been preferably used for biofuel production. To avoid competition with food production, lignocellulosic biomass from perennial grass crops (e.g. switchgrass) or agricultural residues (e.g. wheat straw, corn stover) have more recently been investigated for biofuel production [61, 62]. Lignocellulosic biomass is also what is preferably used for bioelectricity production. Wood chips and wood pellets are the primary source of cellulosic biomass for biomass-fired power plants [63, 64], but this is starting to be supplemented by perennial grasses and residues as well [65, 66, 67].

The different biomass feedstocks have distinctive characteristics. The main agriculture crops used for bioenergy – oil, sugar and starch crops – require yearly land preparation and harvest. These in-field operations typically involve seeding, tilling, packing of the land, herbicide spraying, fertiliser application (NPK), irrigation, harvesting and/or cutting and collection of the biomass. For agriculture residues, as by-products of a main crop, the difficulties lie in allocating life cycle CO_2 emissions, water and energy use between the main crop and residue production [71, 72]. Moreover, in certain cases, removing the residue from the field prevents the natural decomposition of the waste, reducing nutrient supply to the field. Therefore, in addition to collection of residue, supplementary nutrient input must be accounted for in the life cycle assessment of residue production and supply [71, 73].

Table 1: Deployment potential of the different biomass conversion technologies based on efficiency, feedstock availability and technology readiness levels (TRL). Apart from combustion, most of these pathways can generate hydrogen from biomass feedstock, source of data: [68] and [69]. Adapted from Bui et al. [70]

Conversion pathway	**Energy Efficiency**	**Suitable feedstocks**	**TRL Level**
Thermochemical Routes			
Combustion (e.g. power plants, CHP)	10–30	Biomass – dried to lower moisture and maintain efficiency. Waste biomass with limited levels of contamination to prevent pollutant emissions.	**TRL 9**
Biomass Pyrolysis	~50%	Lignocellulosic biomass (e.g. wood)	**TRL 4–5** Hydrogen production applications. **TRL 8** Bio-oil production for heating applications.
Biomass Gasification	~50%	Lignocellulosic biomass (e.g. wood)	**TRL 5** Good potential for innovation with CCS technology incorporated.
Biological Routes			
Bio-photolysis	Up to 22%	Water is the feedstock. Algae/bacteria converts water into hydrogen and oxygen.	**TRL 1–2**
Photo-fermentation	15%	Biomass containing organic acids, sugar & starch crops. However, there are sustainability concerns over the use of food crops.	**TRL 3–4**
Dark Fermentation	10%	Agricultural waste rich in carbohydrate. Lower H_2 potential from wet wastes. Using waste biomass avoids competition for food crops.	**TRL 4** Pretreatment of lignocellulosic materials could improve efficiencies.
Biological hybrid systems	Expected to be higher than other biological processes	Depends on which biological process are combined to create the hybrid system.	**TRL 3–4**

Compared to conventional crops, energy dedicated crops typically have higher yield and are perennial (i.e. do not need to be replanted). Therefore, although energy crops also require annual water and nutrient input, the land only needs to be prepared once over the crop lifetime. For example, miscanthus has a productive life of 15–20 years with a harvest yield of approximately 15 to 40 t_{DM}/ha/yr [66, 74, 75, 76]. In comparison, wheat is a one year rotation crop and has annual yields between 3–9 t_{DM}/ha [77]. Of all the feedstock types (figure 2), woody wastes from the pulp and paper industry, or wastes such as municipal solid waste (MSW) and landfill gases, overall require a less complex supply chain. However, the diversity in their quality, the potential toxic emissions upon their conversion and their low conversion performance are potential downsides which also must be considered [78].

Currently, large scale and high capacity hydrogen production is predominantly fossil fuel-based, by using either steam reforming of natural gas or gasification of coal. However, hydrogen generation processes from fossil fuels are very energy and CO_2 intensive [79], and biomass could represent a more sustainable alternative to produce renewable hydrogen [80]. Biomass-derived hydrogen remains very limited, as biomass is preferably used for biofuel or bioelectricity production [81]. Hydrogen yield from biomass is 16–18% based on dry biomass weight. Waste and biomass rich in sugars and complex carbohydrates (starch) are suitable feedstock for hydrogen production via fermentative biological processes [82]. For the lignocellulosic biomass, a pre-treatment step is required to remove lignin and to hydrolyse complex carbohydrates into their monomers, to facilitate fermentation and subsequent hydrogen production [79]. Lignocellulosic biomass is also suitable for thermochemical conversion either by gasification or pyrolysis of biomass (table 1) [83, 84]. Both processes employ steam reforming and water-gas-shift reactions to maximise the production of hydrogen [84]. Thermochemical biomass hydrogen production processes have an overall efficiency of around 50–55% (thermal to hydrogen) [85].

1.3. Study objectives

Typically, "BECCS" is thought of as a biomass-to-power technology (e.g. pulverised fuel power plants, combined heat and power plants), where biomass undergoes combustion with post-combustion CO_2 capture. However, other archetypes of "BECCS" are beginning to emerge such as biomass-derived H_2 production with CCS (BHCCS). Hydrogen is a versatile carbon-free fuel, which could help decarbonise fuel-dependent sectors such as heat, industry or transportation [86, 87]. Using biomass for hydrogen production with CCS will be net carbon negative, i.e. removes CO_2 from the atmosphere [88, 89]. These alternative technologies may also have an important role in providing CDR services.

The sustainability of biomass is a major concern when considering large-scale BECCS deployment. Therefore, it is important that this limited resource of sustainable biomass is prioritised for conversion pathways that provide maximum system benefit, i.e. minimum cost with maximum CO_2 removal and energy efficiency. This study sets out to comparatively assess the CDR potential and cost of three different bioenergy with CCS technologies:

1. **BECCS:** pulverised biomass-fired power plants with CCS, which generate electricity.
2. **BE-CHP-CCS:** biomass-fuelled combined heat and power (CHP) plants with CCS, which generate heat and electricity.

3. **BHCCS:** biomass-derived hydrogen production with CCS, which generates hydrogen using biomass gasification and water-gas-shift technology.

We assess these three BECCS technologies in terms of their capability of meeting national-scale negative CO_2 emission targets, integrating biogeophysical constraints and a wide range of biomass feedstocks, with the economically optimal design. We present a bottom-up spatial-temporal assessment of a BECCS supply chain network design for the UK using the Modelling and Optimisation of Negative Emissions Technology (MONET-UK) framework [90]. This study sets out to quantify and qualify the materiality of indigenous biomass in meeting these targets. Focusing only on indigenous sources, the biomass considered in this analysis include miscanthus, poplar, municipal solid waste (MSW), waste wood (Grade A and B), forest residue and crop residue. It should be noted that imported biomass has been excluded in this analysis.

The paper is structured as follows: Section 1 provides an overview of conversion pathways for different biomass feedstocks. Section 2 implements the MONET framework, using the UK as a case study to gain insights into the value of different BECCS technologies. Sections 3 to 5 evaluates cost-optimal deployment scenarios of BECCS, BE-CHP-CCS and BHCCS, firstly, deployment on an individual basis, and then in combination. Finally, some conclusions are drawn in Section 6.

2. Modelling and Optimisation of Negative Emissions Technology framework for the UK (MONET-UK)

The Modelling and Optimisation of Negative Emissions Technology framework for the UK (MONET-UK) is a spatially and temporally-explicit, multi-period optimisation model. MONET-UK is formulated as a mixed integer linear programming (MILP) model. This model is distinctly different to MONET-Global [23, 25, 26], which models the global BECCS supply chain co-deployed with other negative emissions technologies such as direct air capture and afforestation.[1]

Figure 3 illustrates the supply chain modelled by MONET-UK. Raw biomass from farms or waste collection sites is transported to the pellet production plants to be converted into pellets. These pellets are then transported to the conversion plants that use biomass to generate electricity/heat/hydrogen, where any CO_2 produced is captured (e.g. using post-combustion capture technology), and permanently stored in geological formations. The model can also allow pellets to be imported from abroad when the biomass demand cannot be met by indigenous biomass. However, the scenarios evaluated in this study only consider indigenous biomass sourced within the UK, with imported biomass being disabled. Figure 4 illustrates the modelling structure in this work – the model "inputs" is data and information specific to the UK (left boxes) and the results are the "outputs" (boxes on the right). The

[1]MONET-Global is another model in this framework which calculates the energy, water, carbon and land intensities of the biomass supply chain at a global level. It considers the importation of biomass to the UK from five different regions of the world: Brazil, Europe, China, India, and the USA. Further details are provided in previous publications [23, 25, 26].

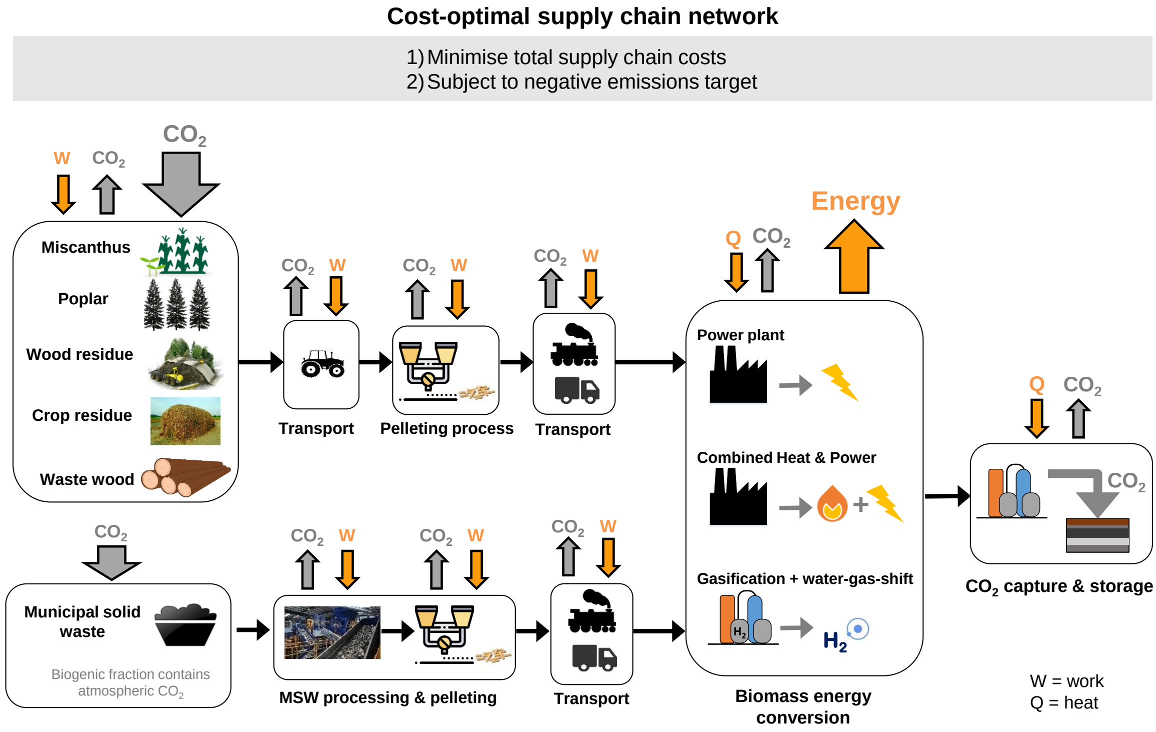

Figure 3: The Modelling and Optimisation of Negative Emissions Technology (MONET) framework. The left boxes show the input data and those on the right boxes show the model outputs. All costs and CO_2 emissions encompass the entire supply chain starting from the raw material to the final generation of product, i.e. hydrogen, electricity and/or heat.

outputs are obtained by minimising the total cost of the whole system subject to the CO_2 removal target [90, 70].

We employ the MONET framework to assess the potential contribution of three types of BECCS technologies in decarbonising the UK, hereafter referred to as MONET-UK. For this study, "BECCS" refers to ultra-supercritical pulverised biomass-fired power plant technology (generates electricity only). The biomass-fired combined heat and power (CHP) technology, denoted BE-CHP-CCS, generates both heat and electricity. The BHCCS technology considered is the biomass gasification technology [91, 92, 93, 94, 84]. The BHCCS process produces biomass-derived H_2 (i.e. bio-hydrogen), which could be converted into a transport fuel, or combusted to generate heat or power.

The methodology is as follows; firstly, we quantify the land availability for biomass cultivation, explicitly accounting for biogeophysical constraints. The evaluation considers the deployment of a single type of technology (BHCCS, BECCS or BE-CHP-CCS) for negative emissions. For each technology, we quantify and compare the (i) total CO_2 removal per year, (ii) cost of CDR, and (iii) energy generated. Given a CO_2 removal target of 47 Mt_{CO_2}/yr by 2050 [46], we then evaluate the deployment of all three technologies, considering how the cost-optimal combination of technologies would change over different hydrogen, electricity

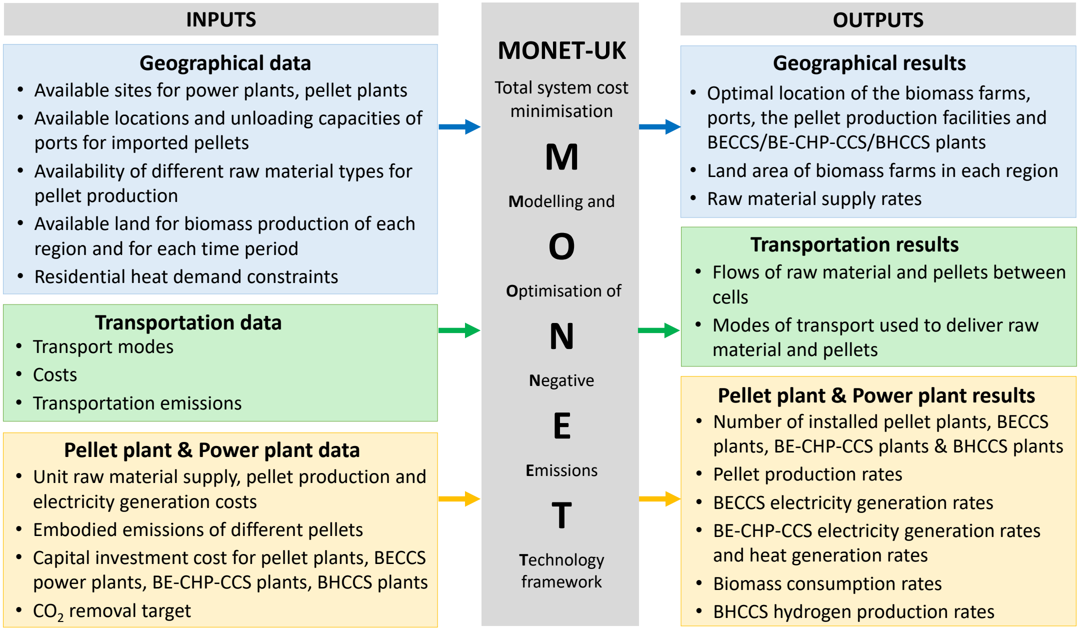

Figure 4: Modelling and Optimisation of Negative Emissions Technology framework for the UK (MONET-UK) optimises the design of a biomass supply chain network, minimising the total cost of the whole system subject to the CO_2 removal target. The model accounts for costs and CO_2 emissions along the entire supply chain starting from the raw material, intermediate processing (e.g. collection, harvest, pelleting) and the final product generation, i.e. hydrogen, electricity and/or heat.

and heat prices. To understand the drivers of technology selection, we also analyse how the combination of technologies changes under different scenarios (e.g. new build vs retrofit BECCS, different CO_2 capture rates).

An overview of the MONET framework and study methodology is presented below. The **Supplementary Material** provides the mathematical formulation and techno-economic input data for MONET-UK. Interested readers are directed to previous publications for further model details and analysis [90, 70].

2.1. UK biomass availability

For this study, Great Britain is discretised into 140 regions, 50 km by 50 km each. Six types of raw biomass material are considered: miscanthus, poplar, municipal solid waste (MSW), waste wood (Grade A and B) [40, 41], forest residue and crop residue. The UK generally has favourable conditions for bioenergy crops such as miscanthus and poplar (i.e. virgin biomass); given the presence of sufficient rain and sunshine over a year and limited periods of frost. The database for dry matter (DM) yields of miscanthus and poplar is from literature [95, 96, 97]. These yields are based on soil and meteorological data across Great Britain, and also accounts for the current and future changes in climate. The DM yields of virgin biomass are shown in figure 5 (a) and (b).

Great Britain has in total 3.17 Mha of woodland [98], which is estimated to generate over 1.3 Mton of forest residues (includes logging residues and remaining stumps) annually by 2036 [99]. Figure 5 (c) illustrates the forest residue DM yields across the UK, where Scotland generates up to 49% of the total forest residue in the UK. Agricultural crop residue availability varies with cultivated area, types of crops, yields resulting from different climate conditions, soil conditions and farming practices [100]. The DM yields of UK crop residues is shown in figure 5 (d), which is the sum of available residues [101] in the UK from farming barley, rapeseed and wheat (assuming a sustainable collection/removal rate of 35%).

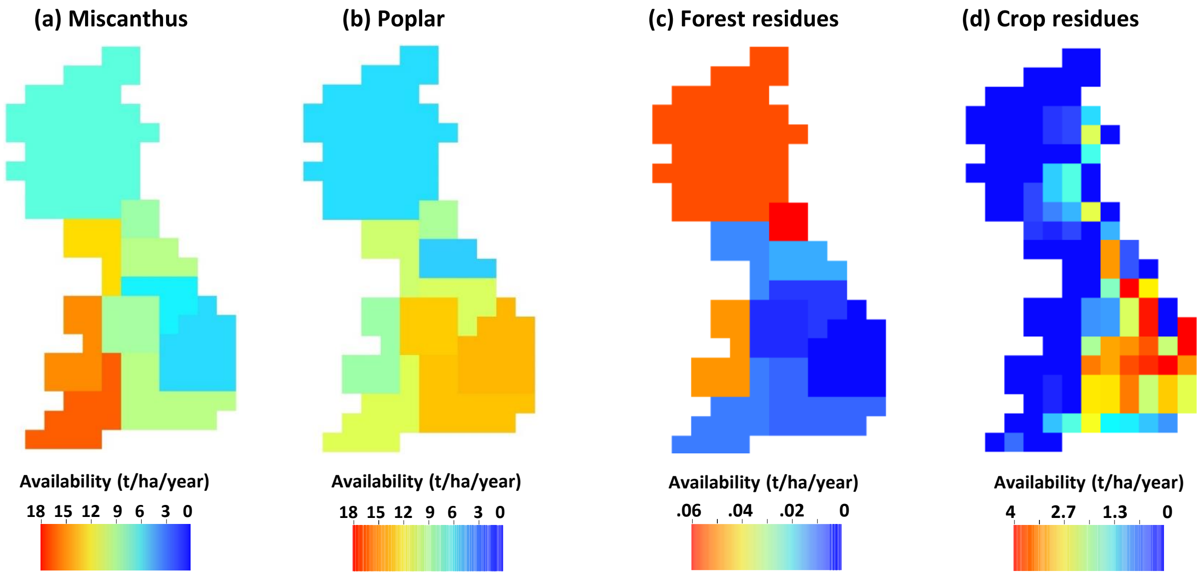

Figure 5: Biomass availability across Great Britain in terms of dry matter (DM) yield for (a) miscanthus, (b) poplar, (c) forest residues, and (d) crop residues. The DM yields of miscanthus and poplar are based on soil and meteorological data in 10 zones across Great Britain [96], whereas the forest residue and crop residue yield data is from the NNFCC [99] and MAPSAPAM [101], respectively. Adapted from Zhang et al. [90].

Waste biomass (i.e. waste wood and MSW) availability is assumed to be a function of UK population density [102] and population projections [103]. The UK generates a total of 3.3 Mt of waste wood (i.e. wood from construction, demolition, wood manufacturing processes, also pellets and wooden packing) [104]. The municipal waste generated in the UK is approximately 500 kg per person per year [105]. A processing facility separates this raw MSW into: a biogenic fraction (e.g. food, paper), recyclables (ferrous and non-ferrous metals, plastics and glass), water and residual waste for landfill. The biogenic component is further processed into a solid refuse-derived fuel (SRF) pellet product [106]. Figure 6 shows the distribution of waste wood and MSW availability according to population density across Great Britain, where populated cities such as London and Leeds have higher waste biomass availability of up to 18.2 t/ha.

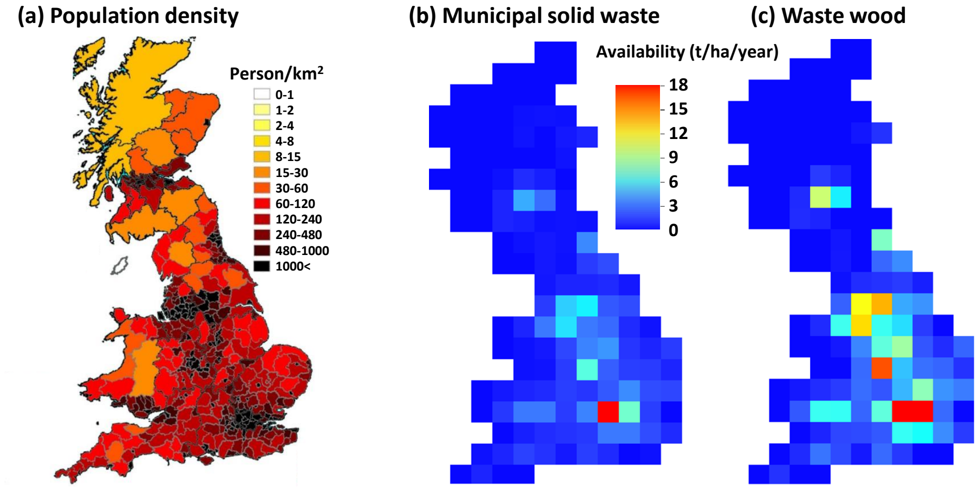

Figure 6: The distribution maps of the UK showing (a) UK population density and biomass dry matter yield of (b) waste wood, and (c) MSW. The availability of (b) MSW and (c) waste wood are a function of (a) population density. Populated cities tend to have higher waste availability of up to 18.2 t/ha/year. Adapted from Zhang et al. [90].

2.2. Land availability

Land constraints limit the site location and construction of the bioenergy conversion plants (i.e. BECCS, BHCCS) and pelleting plants. Based on data of land cover type [107], the land area is classified into three categories. The red colour in figure 7 (a) corresponds to land that is not suitable for the construction of process plants, e.g. bodies of water, swamps, suburban areas, national parks and conservation areas. The amber colour represents land that can possibly be used for construction, but may be limited due to logistical reasons, these include heather grassland and mountain habitats. Land deemed suitable for siting of power plants and pelleting facilities is shown in green.

Figure 7 (b) shows the land suitable for biomass planting in a green colour, where the total land available for biomass cultivation is 8.4 Mha. The product of this biomass land availability with the DM yield data (in figures 5 and 6) and corresponding energy density determines the total annual bioenergy potential for the UK, shown in figure 7 (c), where the maximum bioenergy potential is 57 MWh/ha/year. The permanent grassland used for livestock grazing in the UK is approximately 6.1 Mha, which historically, has remained relatively constant [109]. The land area for livestock grazing is deducted, therefore, the maximum land available to grow biomass crops is 2.3 Mha. A separate study performed by the UK Energy Technologies Institute (ETI), estimated a maximum of 1.22 Mha of biomass land availability by 2050 [110]. The impact of both assumptions was studied in a previous publication [90].

2.3. Biomass pellet prices and availabilities

The different costs incurred along the biomass supply chain are incorporated into the average price calculation of each biomass pellet type, which include:

- Cost of harvesting the raw material [111],

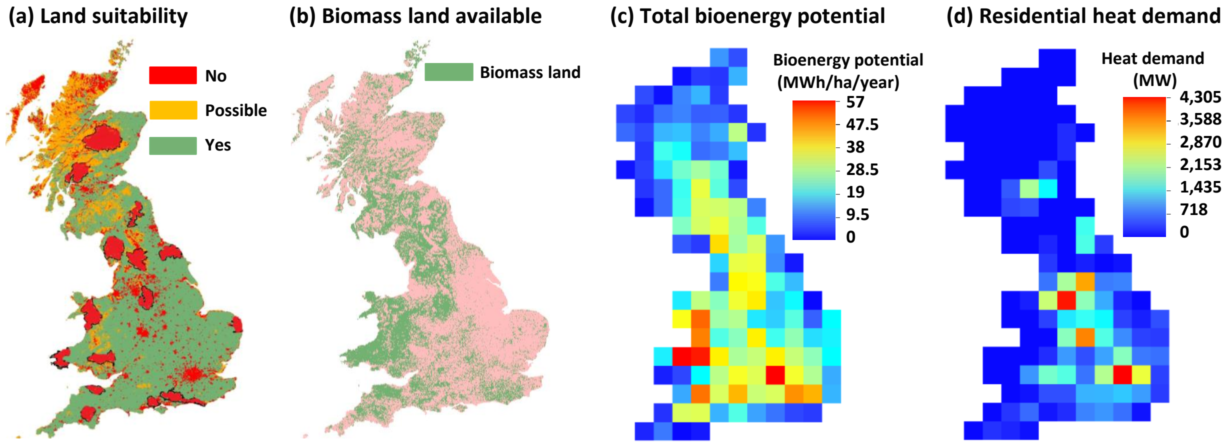

Figure 7: (a) Land available for the construction of power plants and pellet plants shown in green, whereas red is unsuitable (e.g. lakes, cities, national parks) and amber is "possible". (b) Land available for the cultivation of virgin biomass (green). The product of (b) biomass land availability, biomass yield (figures 5 and 6) and corresponding energy density results in (c) total bioenergy potential map. The residential heat demand map (d) is created using the 2015 total natural gas household consumption [108] spatially disaggregated based on UK population. Adapted from Zhang et al. [90].

- Pellet plant processing cost and personnel cost [112],
- Pellet plant annualised capital expenses (CAPEX) [63],
- Conversion rate of raw material into pellets, accounts for material loss and moisture removal (figure 9 bottom Sankey diagrams),
- Transportation costs – calculated average specific for the UK.

The price calculation of miscanthus pellets on arrival at the power plant is shown in figure 8. The raw material miscanthus costs £49/t and the cost of processing and conversion (figure 9) and transport resulting in final pellet cost at £119/t. The biomass energy density is multiplied by the biomass availability to calculate energy availability for each biomass type. The calculated pellet price and energy availability of forest residue, waste wood [113], MSW [106], crop residue [114], virgin biomass [111] and imported pellets (from US and EU) [115] are summarised in figure 10. The energy availability of "indigenous virgin biomass" has an error bar to indicate the range between the two crops considered, poplar (lower) and miscanthus (higher). Imported pine pellets from abroad is assumed to have unconstrained energy availability, however, imported biomass is not utilised in this analysis.

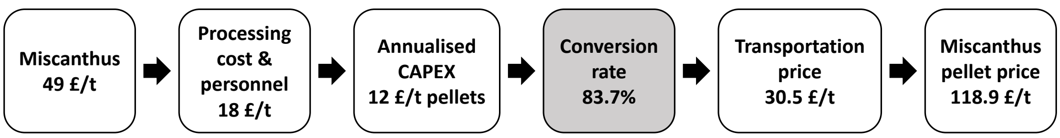

Figure 8: The pellet price calculation for miscanthus accounts for the costs incurred along the supply chain, from harvest, transport to pelleting plant, and transport to power plant. This calculation also considers the pellet conversion rate [106, 116] shown in Figure 9.

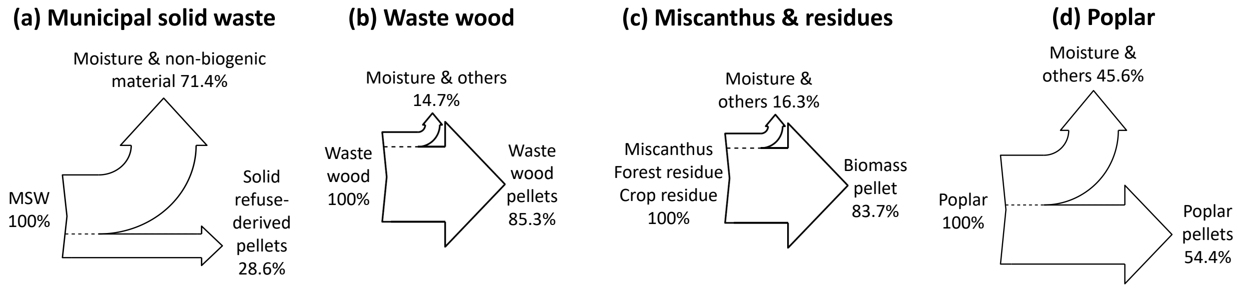

Figure 9: Pellet conversion rates [106, 116] for (a) MSW, (b) waste wood, (c) miscanthus, forest residue and crop residue, and (d) poplar. The moisture and non-biogenic components are removed and there is some material loss.

2.4. Technical and economic assumptions for BECCS facilities

2.4.1. Biomass-fired power plant with CCS (BECCS)

The BECCS technology is a high efficiency 500 MW ultra-supercritical power plant with post-combustion CO_2 capture using advanced solvent and heat recovery, designed for 90% CO_2 capture rate [117]. The CAPEX of a greenfield BECCS system (i.e. new build) was derived based on the capital cost of a coal-fired power plant with CCS (from the Integrated Environmental Control Model [118]) and additional capital investment associated with the conversion of coal-fired units into dedicated biomass units, as reported by Drax [119]. The BECCS retrofit scenario only considers the capital cost of converting coal-fired units into biomass-fired [119]. The BECCS electricity generation efficiency varies between 30–36%$_{\mathrm{HHV}}$, depending on the biomass pellet type and composition (determined with IECM [118]). Due to its high moisture content (figure 9) and lower heating value, the combustion of MSW in the BECCS power plants results in the lowest system/electrical efficiency of 30%. In contrast, the combustion of higher grade fuels (e.g. virgin biomass) in BECCS plants provide higher efficiency [120].

2.4.2. Biomass-fired combined heat and power plant with CCS (BE-CHP-CCS)

The BE-CHP-CCS system considered here uses circulating fluidised bed (CFB) technology, which have a high degree of fuel flexibility and is capable of achieving high boiler efficiencies with low-grade fuels (e.g. low heating value, high moisture content), without the need for fuel pre-processing [34, 35, 121]. Therefore, the BE-CHP-CCS system is assumed to have an electrical generation efficiency of 36%$_{\mathrm{HHV}}$ and heat generation efficiency of 29% with all biomass pellet types [55, 122, 123], including waste wood and MSW, which have lower heating value. The techno-economic assumptions are based on a 100 MW_e BE-CHP-CCS system, designed for 90% CO_2 capture [122]. Waste incineration is permitted according to UK waste management regulations [124, 125]. Thus, waste biomass fuel pellets are acceptable for use in CHP systems for "Energy-from-Waste" and delivers higher total efficiency compared to the power plant equivalent [126]. In the UK, "Energy-from-Waste" plants predominantly focus on electricity generation rather than mixed generation of electricity and heat, unlike other EU countries with high heat demand (e.g. hot water or steam) [127].

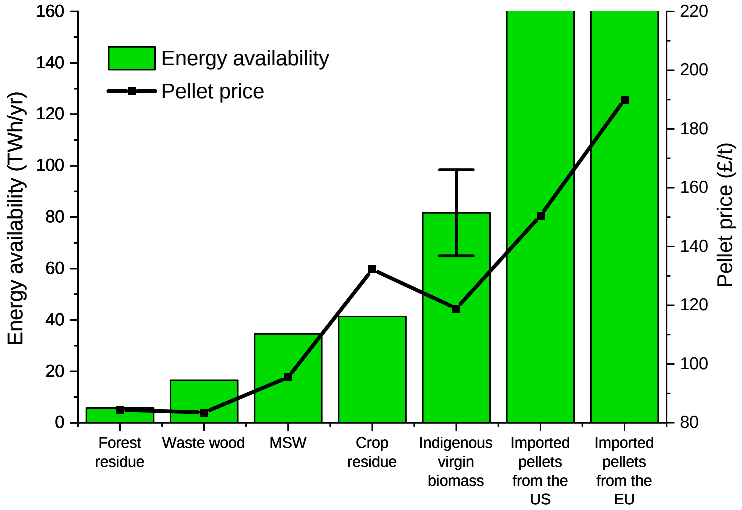

Figure 10: Biomass pellet price (black line) and energy availability (green bars). Pellet prices have been calculated using the method outlined in Zhang et al. [90]. The energy availability is the product of the biomass availability and corresponding energy density of the biomass type. The error bar for indigenous virgin biomass shows the energy availability range, where miscanthus is higher and poplar is lower. The availability of imported pellets from the US and EU is assumed to be unlimited (relative to indigenous sources). Adapted from Zhang et al. [90].

2.4.3. Biomass-derived hydrogen production with CCS (BHCCS)

The techno-economic assumptions for the BHCCS system is based on biomass gasification technology with water-gas-shift (WGS), which is deemed to be the most mature BHCCS technology with the highest TRL (table 1). The CO_2 capture process is based on chemical absorption technology using MDEA (capture from shifted syngas) or MEA solvent (capture from flue gas) [128, 129]. Depending on the process topology (e.g. capture at different locations), the CO_2 capture rate can vary between 56% (lower CAPEX of 4218 £/kW) [129] and 90% (higher CAPEX of 4902 £/kW) [130]. Although similar, biomass gasification is more complicated and less efficient than coal gasification due to heterogeneity of the biomass composition. Biomass is especially reactive and hydrophilic in nature, which imposes handling and safety equipment costs [121]. Hydrogen production from natural gas steam methane reforming (SMR) with CCS is a commercial operation, and is capable of producing hydrogen at >99.9% purity [128]. In comparison, a BHCCS system has greater complexity with more unit operations, e.g. gasification, WGS, CO_2 absorption, contaminant removal, and/or purification [130]. The hydrogen purity standards and technical specifications may vary across different applications (e.g., combustion, fuel cells).[2] Consequently, the CAPEX and OPEX costs of BHCCS is significantly higher than both coal gasification and natural gas SMR with CCS [130].

[2]ISO standards are available for various hydrogen technologies [131]. Hydrogen fuel cell vehicles are particularly sensitive to fuel purity, and the hydrogen product will need to meet technical specifications of ISO 14687 [132].

Biomass gasification is capable of processing all of the biomass feedstock types (virgin wood, straw, forest residues, agricultural residues, MSW and waste wood) in the form of chips or pellets, demonstrated in various projects from pilot up to commercial scale [68, 69, 133, 134]. In comparison with coal, biomass has half the energy density, lower hydrogen content (∼6%) and higher oxygen content (∼40%), which lower hydrogen production efficiency. Biomass gasification occurs at high temperature and pressure with controlled level of air oxygen. The oxygen within biomass and heterogeneous composition presents operational challenges. Due to the high moisture content of biomass, drying is required before gasification, reducing the BHCCS system efficiency further to around 40% [128, 130]. The H2A techno-economic case studies by NREL show that hydrogen production using biomass gasification without CCS has an estimated energy efficiency of 44% (current) to 46% (future 2040 start-up) [135].[3] Therefore, any future improvements to BHCCS efficiency will likely be marginal. Thus, the system efficiency of a greenfield BHCCS plant in this study is assumed to be 40% [128].

Table 2: Techno-economic assumptions used for the three biomass conversion technologies, BHCCS, BECCS and BE-CHP-CCS, in Scenario 1 base case where all systems are greenfield.

	BHCCS	**BECCS**	**BE-CHP-CCS**
Build type	Greenfield	Greenfield	Greenfield
Technology	Biomass gasification with water-gas-shift to produce H_2	500 MW ultra-supercritical BECCS plant using advanced solvent and heat recovery [117]	100 MW_e circulating fluidised bed CHP plant
System efficiency	40% [128] (kWh in/kWh H_2 out)	∼30–36%$_{HHV}$ (depending feedstock) [118]	Electrical: 36%$_{HHV}$ [55, 122] Heat: 29% [55, 122]
Fuel	Pellets	Pellets	Pellets
CO_2 capture rate	90%	90%	90%
CAPEX (£/kW)	4902 [130]	2721 [118, 119]	2437 [55, 122]

3. Modelling scenarios

The MONET-UK model is used to evaluate the plant performance results, obtained by minimising the total cost of the whole system subject to the CO_2 removal target. The

[3]Considers an indirectly-heated biomass gasifier, conventional catalytic steam reforming, water gas shift, and pressure swing adsorption purification. The fluidising gas is steam and no oxygen (i.e. from air or pure) is fed to the gasifier. Poplar is the assumed biomass feedstock.

Table 3: Techno-economic assumptions used for the three biomass conversion technologies, BHCCS, BECCS and BE-CHP-CCS, in Scenario 2. Here, the BHCCS and BE-CHP-CCS plants are greenfield, whereas the BECCS plant is retrofitted on existing power plants, reducing the CAPEX significantly.

	BHCCS	**BECCS**	**BE-CHP-CCS**
Build type	Greenfield	**Retrofit**	Greenfield
Technology	Biomass gasification with water-gas-shift to produce H_2	500 MW ultra-supercritical BECCS plant using advanced solvent and heat recovery [117]	100 MW_e circulating fluidised bed CHP plant
System efficiency	40% [128] (kWh in/kWh H_2 out)	~30–36%$_{HHV}$ (depending feedstock) [118]	Electrical: 36%$_{HHV}$ [55, 122] Heat: 29% [55, 122]
Fuel	Pellets	Pellets	Pellets
CO_2 capture rate	90%	90%	90%
CAPEX (£/kW)	4902 [130]	**1581** [119]	2437 [55, 122]

Table 4: Techno-economic assumptions used for the three biomass conversion technologies, BHCCS, BECCS and BE-CHP-CCS, in Scenario 3, which are all greenfield, i.e. newly built plants. BHCCS operates at a lower CO_2 capture rate, thereby lowering the CAPEX costs compared the base case.

	BHCCS	**BECCS**	**BE-CHP-CCS**
Build type	Greenfield	Greenfield	Greenfield
Technology	Biomass gasification with water-gas-shift to produce H_2	500 MW ultra-supercritical BECCS plant using advanced solvent and heat recovery [117]	100 MW_e circulating fluidised bed CHP plant
System efficiency	40% [128] (kWh in/kWh H_2 out)	~30–36%$_{HHV}$ (depending feedstock) [118]	Electrical: 36%$_{HHV}$ [55, 122] Heat: 29% [55, 122]
Fuel	Pellets	Pellets	Pellets
CO_2 capture rate	**56%**	90%	90%
CAPEX (£/kW)	**4218** [129]	2721 [118, 119]	2437 [55, 122]

specified net negative CO_2 emissions target is 47 Mt_{CO_2}/year by 2050, which is in line with the recent targets set by the UK's Committee on Climate Change [46]. The techno-economic assumptions used in this work are shown in tables 2 to 4. Although the power plants have a lifetime of 30 years, the economic life time of the investment is assumed to be 20 years.[4]

In this study, we only consider fuel pellets produced from indigenous sources of biomass in the UK, which include MSW, waste wood, forest residue, crop residue and virgin biomass (quantified in sections 2.1 to 2.3). Imported biomass pellets are not being considered in this particular study. Heat production from BE-CHP-CCS is constrained by: (i) the UK residential heat demand shown in figure 7 (d) [108], and (ii) the inability to transport heat between cells. Supply chain emissions of virgin biomass pellets from marginal land in the UK were calculated using the MONET-Global framework [23, 25, 26] and used to specify the embodied carbon emissions of the biomass. This study is divided into two modelling analyses:

- Part 1 – Optimal BECCS pathway on an individual technology basis
- Part 2 – Cost-optimal combination of BHCCS, BECCS and BE-CHP-CCS deployment

In the Part 1 analysis, no constraints on feedstock type in any of the technologies are applied, determining the maximal potential of each technology. However, Part 2 considers feedstock constraints which prevent the use of waste-derived biomass pellets produced from waste wood and MSW in BECCS power plants. Due to power plant regulatory constraints in the UK, BECCS power plants are limited to using biomass pellets produced from indigenous virgin biomass, forest and crop residues. The UK waste management regulations [124, 125] permit the combustion of waste-derived biomass pellets in CHP plants. Biomass gasification technology is also capable of processing a wide variety of biomass feedstocks. Therefore, BE-CHP-CCS and BHCCS plants could utilise any of the six biomass pellets considered (i.e. made from miscanthus, poplar, forest/crop residues, waste wood or MSW).

The following sections present the results of this two part study.

4. Optimal BECCS pathway evaluated on an individual technology basis

We evaluate whether the national CO_2 removal targets are achievable with existing resources of indigenous biomass feedstock (quantified in section 2.3) using the MONET-UK framework. To compare the performance of BHCCS, BECCS and BE-CHP-CCS, we evaluate different technical and economic metrics, including the average CDR cost, generated energy (i.e. in the form of hydrogen, electricity, heat) and the required negative emissions credit (NEC) to incentivise investment. This section analyses the three technologies on an individual basis, i.e. deployment of only one type of BECCS technology. The techno-economic assumptions are based on greenfield installations of BHCCS, BECCS and BE-CHP-CCS (data presented in table 2). The objective is to identify the cost optimal and most resource efficient BECCS pathway (either hydrogen, electricity or CHP generation) for meeting a given UK CO_2 removal target.

[4] This study used a "snapshot" optimisation approach to determine the final result at the end of the time period. This approach was employed to improve computational efficiency, however, omits the consideration of CAPEX reduction through a learning rate. Interested readers are directed to a previous study [90], which has analysed the effect of CAPEX learning rate on the economic viability of an evolving BECCS system over time.

The achievable CO_2 removal (Mt_{CO_2}/year) increases with the additional utilisation of a given indigenous biomass type (from left to right in figures 11–13). The left-most biomass types are the lowest-grade waste fuels (e.g. MSW) and moving towards the right utilises higher grade fuels (e.g. forest residues and virgin biomass). Figure 10 shows that using all available indigenous biomass in the UK can deliver up to 56 Mt of CO_2 removal per year, resulting in an average CO_2 removal cost of £151/t_{CO_2} using BHCCS technology, £146/t_{CO_2} using BECCS, or £131/t_{CO_2} using BE-CHP-CCS. This CO_2 removal cost is a function of various techno-economic factors, including the biomass moisture content, biomass fuel price, technology capital cost, and system efficiency. At the CCC target of 47 Mt_{CO_2}/year [46], the average cost of CO_2 removal reduces to £149/t_{CO_2} with BHCCS, £139/t_{CO_2} using BECCS, or £122/t_{CO_2} using BE-CHP-CCS.

The BE-CHP-CCS technology has the lowest average CO_2 removal cost of the three technologies due to its low CAPEX and moderate efficiency ($36\%_{HHV}$). Although BHCCS has the highest efficiency of the three technologies (table 2), it also has the highest CAPEX. Therefore, CO_2 removal cost using BHCCS technology is generally high. As the efficiency of BECCS is low when MSW is utilised, the CO_2 removal cost is highest at the CO_2 removal rate of 12 Mt_{CO_2}/year. As biomass of higher quality is used, BECCS efficiency improves and CO_2 removal cost reduces to become less than BHCCS.

The energy generated can be considered in terms of the relevant energy vector (figure 12), e.g. thermal energy, chemical energy, or converted into the electricity generation equivalent

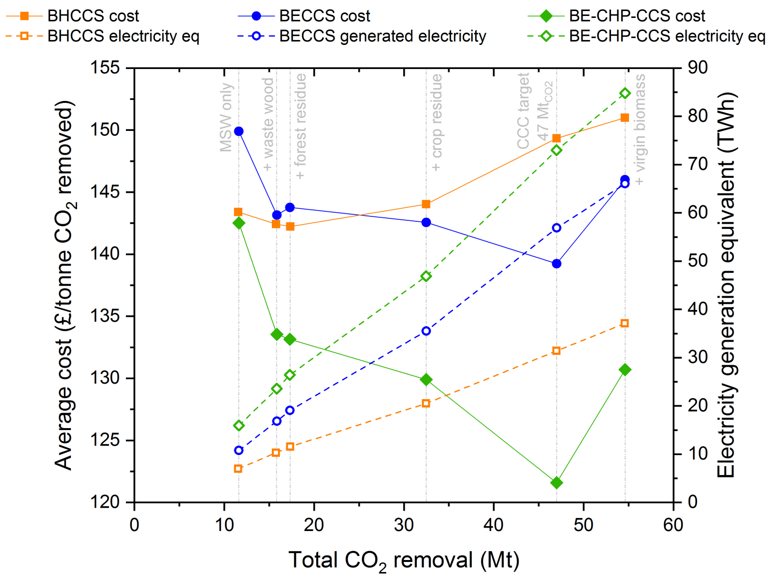

Figure 11: Comparison BHCCS, BECCS and BE-CHP-CCS, three different biomass conversion technologies that provide CO_2 removal (Mt_{CO_2} per year) in terms of electricity generation equivalent (TWh) and the corresponding average CDR cost (£/t_{CO_2} removed). The total CO_2 removal increases with the addition of an indigenous sources of biomass feedstock, with the left-most being the lowest-grade waste fuels (e.g. MSW), moving towards the right utilises higher grade fuels (e.g. residues and virgin biomass).

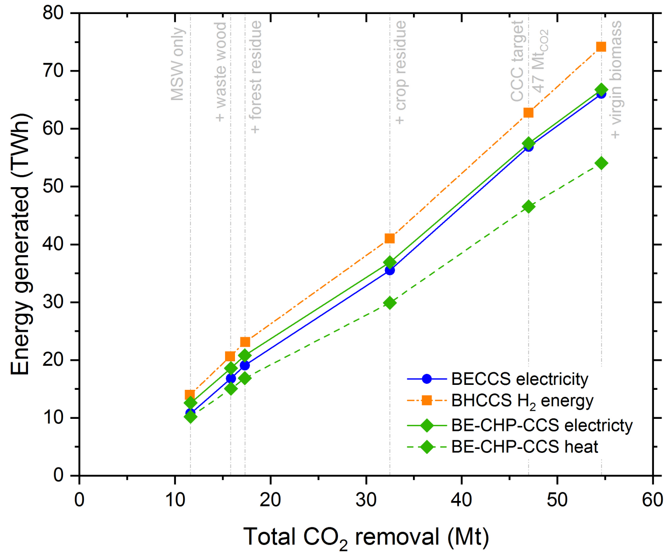

Figure 12: Comparison BHCCS, BECCS and BE-CHP-CCS in terms of product/energy generated (TWh), in the form of electricity, hydrogen (chemical energy) and heat (thermal energy). The total CO_2 removal (Mt_{CO_2} per year) increases with the addition of an indigenous sources of biomass feedstock, with the left-most being the lowest-grade waste fuels (e.g. MSW), moving towards the right utilises higher grade fuels (e.g. virgin biomass).

(figure 11). If all of the available indigenous biomass in the UK was utilised (i.e. 56 Mt_{CO_2}/year removal), BHCCS technology would produce up to 74 TWh of hydrogen. This is equivalent to 11% of the transport energy demand in the UK for 2030 [136], or 37 TWh electricity equivalent – if this hydrogen was used to generate electricity. The deployment of BECCS plants instead would generate up to 66 TWh of electricity, which could meet 13% of the UK's predicted 2030 electricity demand. Alternatively, employing BE-CHP-CCS could generate 67 TWh of electricity and 54 TWh of heat (total of 85 TWh electricity equivalent). These results demonstrate that all technology pathways could provide a meaningful supply of clean energy, and have the potential to make a substantial contribution to the UK's energy system.

Policies and legislation have been largely successful at encouraging the deployment of low carbon energy technologies and disincentivising the use of fossil fuels. Since the Climate Change Act was passed in 2008, GHG emissions in the UK have continued to reduce, reaching 44% below 1990 levels in 2018. The Climate Change Act mandates the reduction of GHG emissions by 100% compared to 1990 levels (up from a previous commitment of 80%). The transition to a net-zero emissions economy will need deeper decarbonisation, necessitating large-scale deployment of CO_2 removal technologies. However, the economics of CDR technologies such as BECCS are unfavourable in the absence of incentives, e.g. contracts-for-difference, credits that can be auctioned to CO_2 emitters [137, 138, 139].

The concept of a "negative emissions credit" (NEC) [53] has been proposed as a payment

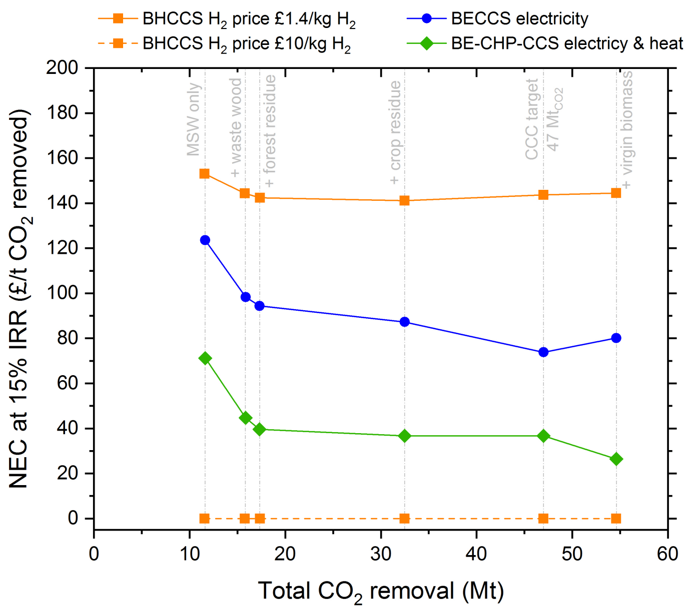

Figure 13: Comparison BHCCS, BECCS and BE-CHP-CCS in terms of the necessary negative emissions credit (NEC) to achieve an internal rate of return (IRR) of 15%. The total CO_2 removal (Mt_{CO_2} per year) increases with the addition of an indigenous sources of biomass feedstock, with the left-most being the lowest-grade waste fuels (e.g. MSW), moving towards the right utilises higher grade fuels (e.g. residues and virgin biomass).

to CDR providers (i.e. the operator of a facility that generates negative CO_2 emissions)[5] for the net removal of 1 tonne of CO_2 from the atmosphere [137, 138, 139, 140]. The calculated NEC required to achieve an internal rate of return (IRR) of 15% for the three technology options is illustrated in figure 13. The revenue from the sale of generated energy is included in this NEC calculation and considers the following assumptions for energy sales:

- Electricity selling price of £85/MWh_{el} based on combined-cycle gas turbine (CCGT) levelised costs [141, 142];
- Heat selling price of £36.4/MWh_{th} based on natural gas residential heating costs [141, 143, 86];
- Hydrogen [6] selling prices of: (i) £10/kg H_2 (£254/MWh_{H_2}) which is the current hydrogen selling price [144, 145]; and (ii) £1.40/kg H_2 (£36/MWh_{H_2}) which is based on projections of future H_2 price for bus transportation [86].

Figure 13 shows that BECCS would require a NEC of £86/t_{CO_2} to achieve an IRR of 15%, whereas the NEC needed for BE-CHP-CCS is significantly lower at £32/t_{CO_2}. In the case when hydrogen is sold at the current market price of £10/kg of H_2 [144, 145], no NEC

[5]The supplier of biomass pellets will not directly receive NECs, instead, revenues arise from selling biomass. Alternatively, BECCS operators may choose to establish an independent biomass supply chain to secure supply and price stability.

[6]The production cost of biomass-derived hydrogen is £3.7/kg of H_2, whereas steam methane reforming (SMR) has significantly lower production costs of £1.5–1.6/kg of H_2 [128].

is needed to make BHCCS economically viable. At the projected future price of hydrogen (£1.40/kg H_2) [86], the NEC required to achieve 15% IRR with BHCCS is £145/t_{CO_2}, making this the least viable scenario. The comparison of NEC for BHCCS with the two hydrogen price scenarios highlights the importance of product price on the economic viability of BECCS technologies. The effect of product price will be explored in further detail in the next section.

5. Cost-optimal combination of technologies at different product prices

Whilst all three technologies BHCCS, BECCS and BE-CHP-CCS provide negative emissions, they generate three different products, i.e. H_2, electricity and heat. The role and value of each of these products in the energy system differs, and could service one or multiple sectors (e.g. power, industry, heating, transport). Therefore, the price of each product would vary, resulting in different levels of return on investment. From a systems perspective, the deployment of multiple BECCS technologies could potentially be more cost effective and resource efficient (compared to just individual technologies, i.e. section 4). This cost-optimal combination is a function of product selling prices, e.g. sale price of H_2, heat, electricity.

In this section, the MONET framework is used to determine the cost-optimal combination of BHCCS, BECCS and BE-CHP-CCS required to meet the CDR target of 47 Mt_{CO_2}/year over different product prices. To understand potential techno-economic drivers of technology deployment, we evaluate the cost-optimal combination of technologies and negative emissions price (achieving IRR of 15%) under different scenarios:

- **Scenario 1 (base case):** Deployment of all technologies (BHCCS, BECCS and BE-CHP-CCS) will be greenfield plants, i.e. new build systems (data in table 2).
- **Scenario 2 (retrofit BECCS):** The BECCS plants are retrofit installations on existing power plants, significantly reducing the capital cost. The BHCCS and BE-CHP-CCS plants are greenfield installations (uses data in table 3).
- **Scenario 3 (BHCCS with 56% CO_2 capture):** All technologies will be deployed as greenfield plants. The BHCCS plant operates at a lower CO_2 capture rate of 56%, lowering its CAPEX cost compared the base case scenario (table 4).

The lower and upper bound selling prices for each product is based on literature data where:

- Hydrogen selling price varies between £30 to 140/MWh_{H_2},
- Electricity price varies between £40 to 160/MWh_{el},
- Heat selling price varies from £0 to 80/MWh_{th}.

The price of hydrogen used for bus transport is projected to be £36/MWh_{H_2} (£1.40/kg H_2) by 2030 [86], thus the lower bound hydrogen price of £30/MWh_{H_2} was used [146]. The current selling price of hydrogen of £10/kg of H_2 (£254/MWh_{H_2}) [144, 145] is economically viable without a NEC (figure 13). Here in this section, the selling price of £140 /MWh_{H_2} is considered and is shown to be sufficiently high enough to demonstrate the price threshold at which BHCCS is viable. These hydrogen selling prices are within the range of production cost estimates by the Committee on Climate Change, which report a minimum cost of

£27/MWh_{H_2} (gas reforming with CCS) and maximum at £127/MWh_{H_2} (biomass gasification with CCS) [146].

The lower bound electricity price of £40/MWh_{el} is the projected cost of electricity from onshore and offshore wind turbines (estimated to be £40–60/MWh_{el}) [146]. The upper bound for electricity price of £160/MWh_{el} was chosen based on the international median domestic electricity price of £151.2/MWh_{el} in 2018 [147].

Heat price is often determined by the heat source, which can result in a broad range of costs and prices [143]. The mean heat price of non-bulk heat network schemes (higher price compared to bulk schemes) is of £75.2/MWh_{th}, thus, the upper limit for heat price was £80/MWh_{th}. The lower bound heat price of £0/MWh_{th} represents situations of heat "dumping", where surplus thermal energy is discarded [148].

5.1. Scenario 1: Base case

Figure 14 is a series of ternary diagrams illustrating the cost-optimal combination of technologies selected to deliver the CDR target of 47 Mt_{CO_2}/year under the base case scenario. As shown by figure 14 (a), BECCS is not economically viable within the electricity price range considered and zero BECCS is deployed. In comparison to BECCS, the BE-CHP-CCS plant has comparable system/electrical efficiency and lower CAPEX (table 2). Both technologies generate electricity, however, BE-CHP-CCS also provides heat. The combination of these factors makes BE-CHP-CCS more attractive than BECCS, thus, BE-CHP-CCS is deployed at higher levels as shown by Figure 14 (b).

Although BHCCS has significantly higher CAPEX, the system efficiency of BHCCS is also greater than the other two technologies. Therefore, at some combinations of product prices, BHCCS can become economically viable. Under the base case assumptions, figure 14 (c) shows that the BHCCS technology is preferred when the hydrogen price is $\geq$ £80/MWh_{H_2} and electricity price is $\leq$ £110/MWh_{el} across the heat price range of £0 to 80/MWh_{th}. There are areas within these price boundaries that use a combination of both BHCCS with BE-CHP-CCS. Across the remaining product prices, the cost-optimal technology is BE-CHP-CCS, dark blue area in figure 14 (b).

5.2. Scenario 2: Retrofit BECCS

The base case scenario demonstrated that BECCS is not economical compared to BE-CHP-CCS under greenfield economic assumptions. The viability of BECCS may improve in a retrofit scenario. As shown in table 3, a retrofit installation of BECCS in existing power plants has significantly lower CAPEX compared to new installations of BHCCS and BE-CHP-CCS. In contrast to the base case scenario, this retrofit scenario utilises BECCS when the heat price is lowest at £0–10/MWh_{th}. The utilisation share of BECCS is 100% when electricity price is £40–50/MWh_{el} and hydrogen selling price $<$£80/MWh_{H_2} (red dots in figure A.17, Appendix A). Both BECCS and BE-CHP-CCS are deployed together when electricity price is $\geq$ £60/MWh_{el}, illustrated in figure 15 (a) and (b).

The share of BHCCS utilisation in figure 15 (c) the retrofit scenario has a similar trend to figure 14 (c) of the base case scenario. BHCCS is deployed at high hydrogen price of $\geq$ £80/MWh_{H_2} and low electricity prices $<$£110/MWh_{el}. As electricity price and heat

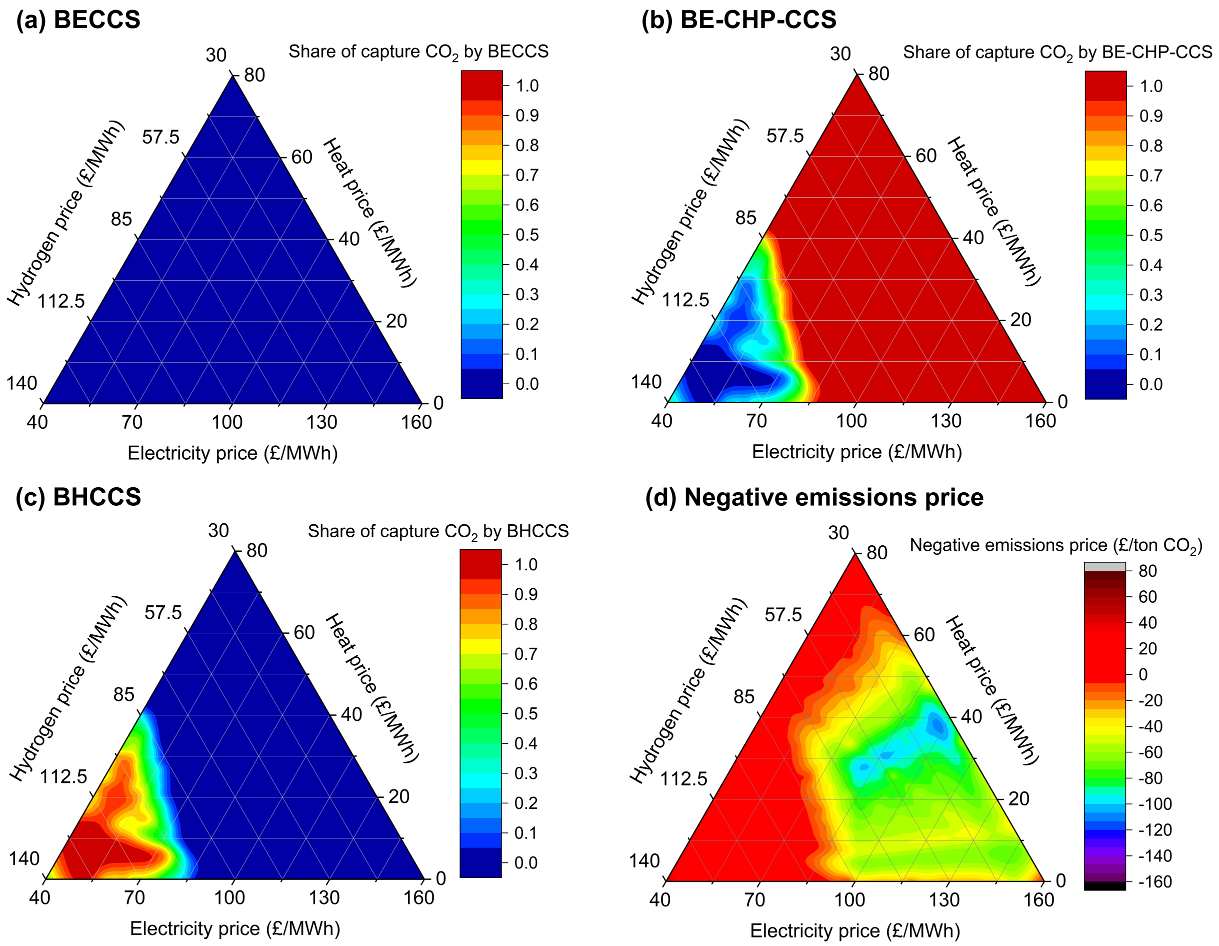

Figure 14: The cost optimal combination of different technologies under Scenario 1 (base case), where all installations are new installations (i.e. greenfield) – uses data in table 2. To remove the target total of 47 Mt CO_2/year, the cost optimal share of BECCS (a), BE-CHP-CCS (b) and BHCCS (c) varies across different prices of hydrogen (£/MWh_{H_2}), electricity (£/MWh_{el}) and heat (£/MWh_{th}). The corresponding negative emissions price (d) required to achieve an internal rate of return of 15% is calculated across the different prices of hydrogen, electricity and heat.

price increase, the share of BHCCS decreases and BE-CHP-CCS is deployed instead. For the range of product prices considered, BE-CHP-CCS is utilised across most of the price range, whereas deployment of BHCCS is limited. Although its CAPEX is higher than BECCS in this scenario, BE-CHP-CCS has greater system efficiency and produces slightly more electricity (figure 12). The key economic advantage of BE-CHP-CCS is the ability to generate and sell two products (heat and electricity). Despite its lower CAPEX, retrofit BECCS plants only become economically competitive when heat prices are $\leq$ £10/MWh_{th}.

This scenario highlights the trade-off between technology capital cost and the value of the products generated. Whilst capital cost savings can be helpful, the main factors that drive economic performance is the sale price of the products and amount of product generated (i.e. single/multiple products and conversion efficiency of feedstock to product).

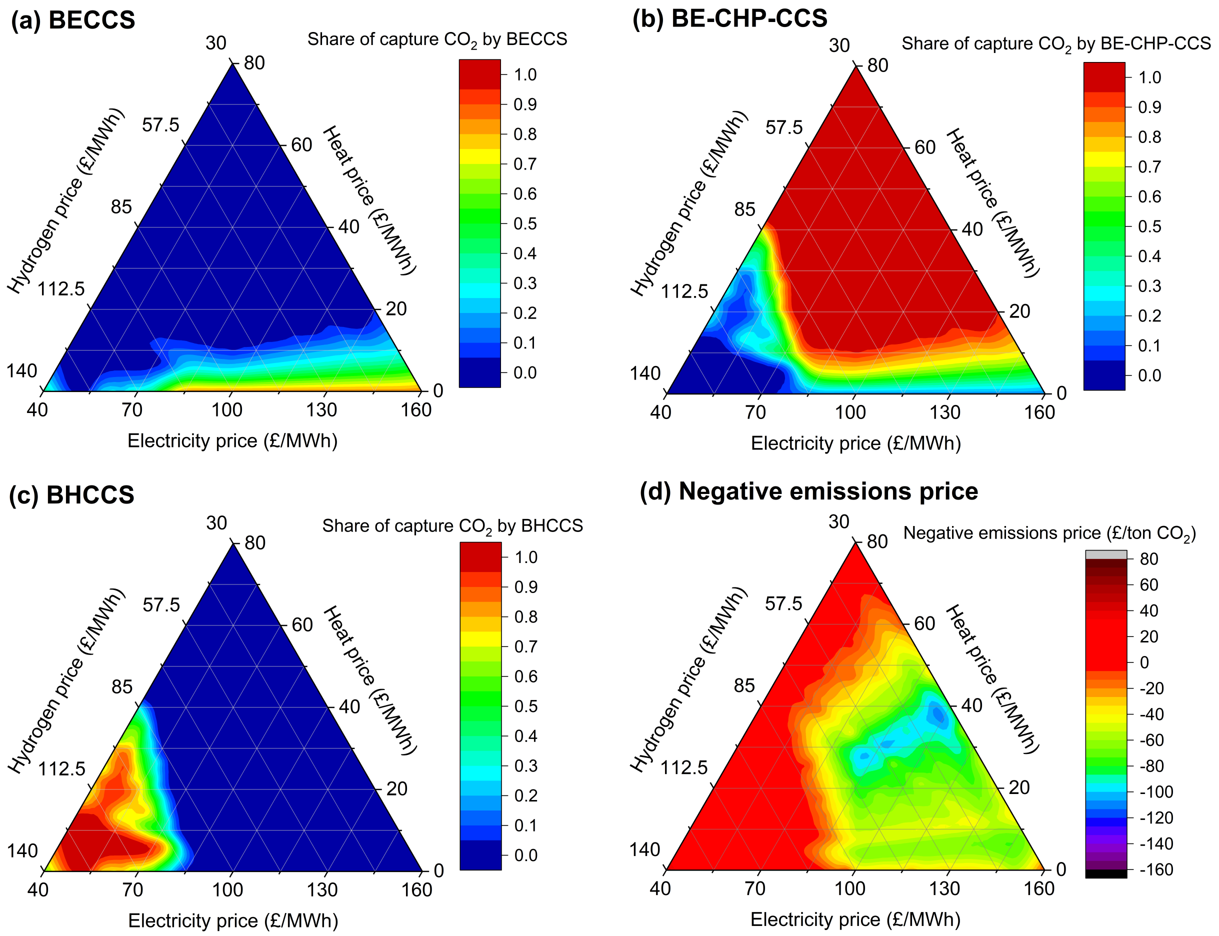

Figure 15: The cost optimal combination of different technologies under Scenario 2 (retrofit BECCS) – uses data in table 3 – where the installation of BECCS in existing power plants reduces CAPEX, and greenfield installations of BHCCS and BE-CHP-CCS are considered. To remove the target total of 47 Mt CO_2/year, the cost optimal share of BECCS (a), BE-CHP-CCS (b) and BHCCS (c) varies across different prices of hydrogen (£/MWh_{H_2}), electricity (£/MWh_{el}) and heat (£/MWh_{th}). The corresponding negative emissions price (d) required to achieve an internal rate of return of 15% is calculated across the different prices of hydrogen, electricity and heat.

5.3. Scenario 3: BHCCS with 56% CO_2 capture

As shown in the previous two scenarios, the cost-optimal combination of technologies is a function of the CAPEX for the different technologies. More importantly, the cost-optimal technology combination is predominantly driven by the sale prices of the different products. For instance, BHCCS can be economically competitive if there is a high hydrogen selling price and relatively low prices for electricity and heat. To minimise residual CO_2 emissions, hydrogen production using steam methane reforming (SMR) with CCS would operate with a high CO_2 capture rate of 90%. However, to maximise production of hydrogen and operate economically, SMR with CCS typically operates with lower CO_2 capture rate of 56% [128, 129]. Table 4 shows a reduction in CAPEX when the BHCCS uses a lower 56% CO_2

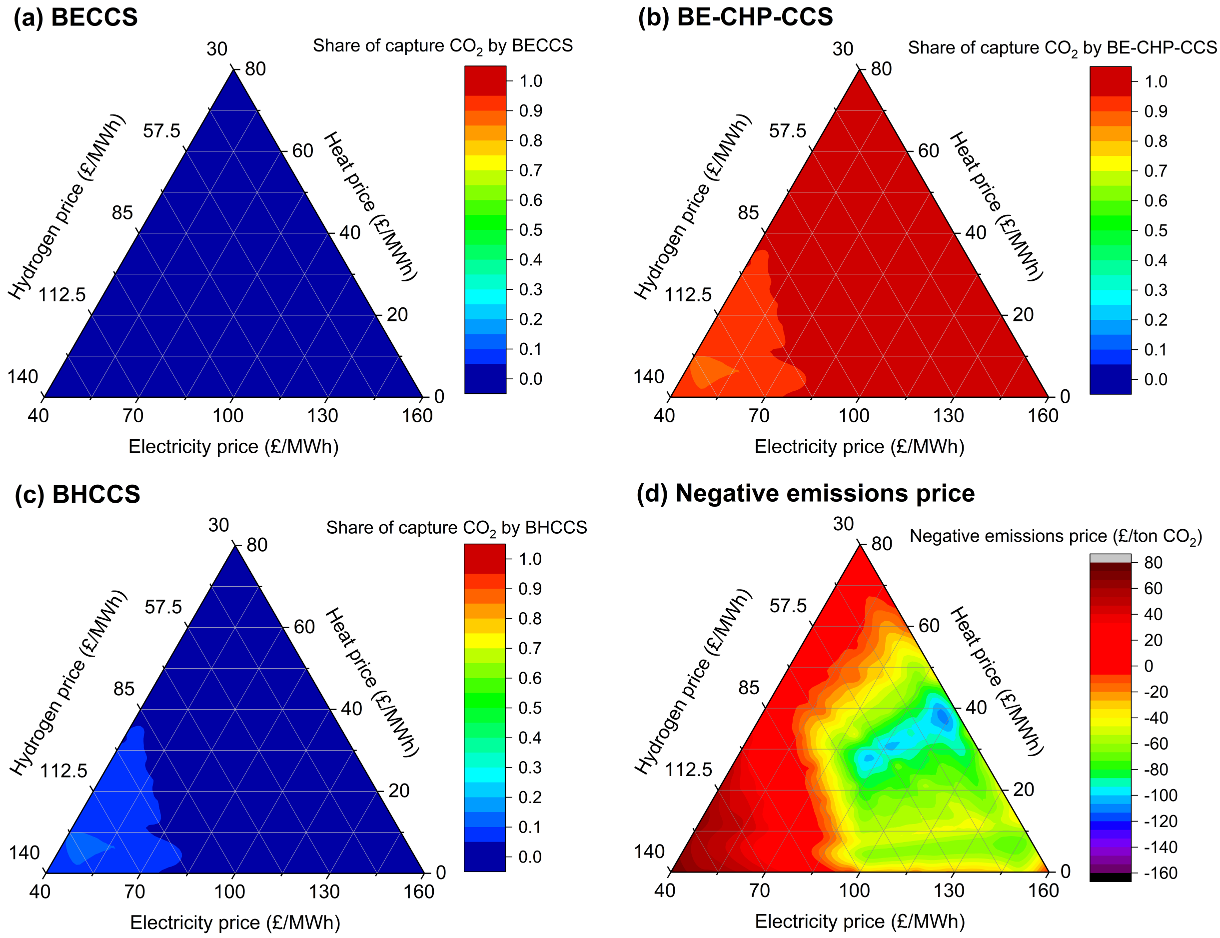

Figure 16: The cost optimal combination of different technologies under Scenario 3 (BHCCS with 56% CO_2 capture) – uses data in table 4 – where all technologies are deployed as greenfield installations, however, the use of lower CO_2 capture reduces the CAPEX of BHCCS. To remove the target total of 47 Mt CO_2/year, the cost optimal share of BECCS (a), BE-CHP-CCS (b) and BHCCS (c) varies across different prices of hydrogen (£/MWh_{H_2}), electricity (£/MWh_{el}) and heat (£/MWh_{th}). The corresponding negative emissions price (d) required to achieve an internal rate of return of 15% is calculated across the different prices of hydrogen, electricity and heat.

capture rate. However, this saving in CAPEX does not promote technology deployment. As illustrated by figure 16 (c), the deployment of BHCCS significantly reduces when it operates with 56% CO_2 capture rate. Instead, BE-CHP-CCS becomes the most cost-effective and efficient technology to deploy. Even at the highest hydrogen prices of £120–140/MWh_{H_2}, only 15–20% of CDR is provided from BHCCS with the remainder being supplied with BE-CHP-CCS.

These results demonstrate that the viability of BECCS technologies is highly dependent on the CO_2 capture rate, which significantly outweighs any benefits from capital cost saving. From the perspective of a "negative emissions provider", the aim is to maximise CO_2 removal at minimal cost, hence, it would be more favourable to use higher CO_2 capture rates of at least 90%. It is now evident that "towards zero emissions CCS" could be realised in power plant applications, with studies[7] demonstrating the techno-economic feasibility of CO_2 capture rates above 90% (up to 99%) [48, 49]. Currently, SMR-based H_2 production with CCS can provide CO_2 capture rates of between 53% and 90% [149, 128, 150]. However, auto-thermal reforming (ATR) [8] processes could achieve higher capture rates of 90–95% [150]. The ability to use >90% capture rates could enhance economic performance and promote the deployment of BECCS technologies.

5.4. Economic viability of BECCS technologies – negative emissions price

The negative emissions price necessary to achieve an internal rate of return (IRR) of 15% is calculated for each scenario across these different product prices, shown in (d) of figures 14 to 16. The negative emissions price can be used as an indicator of economic viability/performance for CDR technologies. This is calculated across different combinations of product prices for hydrogen, electricity and heat. If the negative emissions price is more than zero (red area), the CDR provider needs to receive a negative emissions credit in order to achieve an IRR of 15%. Conversely, scenarios with negative emissions price less than zero (orange, green, blue and purple regions) are potentially profitable, even in the absence of incentives. Therefore, evaluating the negative emissions prices can help quantify the product price limits for hydrogen, electricity and heat at which different scenarios become profitable.

As shown in figures 14 to 16, BE-CHP-CCS is the dominant technology deployed to meet the CDR target across the range of product prices considered. The profiles of cost-optimal technology deployment for the three scenarios are similar, with some differences at regions of low electricity price and heat price $\leq$ £10/MWh_{th}. Consequently, the negative emissions price distribution for the three scenarios follow similar trends. The calculated negative emissions price at a particular point is a function of: (i) the sale price of products, and (ii) the combination of technologies deployed.

The negative emissions price for the three scenarios reveals the following key differences when compared to Scenario 1 (base case):

- Scenario 2 (retrofit BECCS) – the deployment of retrofit BECCS plants instead of BE-CHP-CCS improves profitability (more green/yellow where heat price $\leq$ £10/MWh_{th}).
- Scenario 3 (BHCCS with 56% capture) – in the absence of BHCCS technology deployment, the region of high hydrogen price and low electricity price is less profitable and requires higher NEC to achieve 15% IRR (region is brown/dark red).

There is a small region that corresponds to hydrogen price <£130/MWh_{H_2}, electricity price <£100/MWh_{el} and heat price <£60/MWh_{th}, which would require a negative emissions credit (<£80/t_{CO_2}) to achieve an IRR of 15%.

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[7] Study of amine-based absorption process using 30 wt% monoethanolamine (MEA) solution for post-combustion CO_2 capture (PCC) from power plants. The techno-economic performance of >90% capture was evaluated for an ultra-supercritical pulverised coal power plant with PCC and a natural gas combined cycle with PCC.

[8] ATR requires three times more electricity than an SMR due to the need of an ASU for oxygen [151, 150]. Therefore, ATR has a much lower energy efficiency compared to SMR.

These results indicate that the deployment of any of the three technologies (BHCCS, BECCS or BE-CHP-CCS) can be profitable at most of the product prices considered in this study.

6. Conclusions

6.1. Can BHCCS and BECCS deliver net negative CO_2 emissions?

Combining sustainable sources of bioenergy with CCS provides a means to remove CO_2 from the atmosphere. However, the degree of achievable negative CO_2 emissions will vary depending on the BECCS pathway employed.

Bioenergy combustion pathways are relatively mature, with power plants and CHP plants currently being used to generate electricity and/or heat worldwide. There is growing interest in biomass-derived H_2 production with CCS (BHCCS), which generates hydrogen and removes CO_2 from the atmosphere. Hydrogen could help decarbonise fuel-dependent sectors such as heat, industry or transportation. The CO_2 capture and storage component is mature and has reached commercial scale. Therefore, the availability of feasible CCS technologies is not a barrier for large-scale BHCCS deployment.

There are different pathways to produce hydrogen from biomass with a range of benefits and disadvantages in terms of economic and environmental performance. Biological processes are considered to be more environmentally benign with lower energy intensity. However, biological processes tend to have low yield and production rates. Biological routes are still in the earlier phases of development and have only been demonstrated at pilot scale. In contrast, thermochemical processes provide higher stoichiometric yield of H_2 and larger production rates.

Of the different technologies for biomass-derived hydrogen production, biomass gasification seems to be considered the most mature technology and is commercially available at mid-scale. Subsequently, this study uses techno-economic assumptions based on hydrogen production using biomass gasification technology.

We present a bottom-up assessment of a spatial-temporal BECCS design for the UK using the Modelling and Optimisation of Negative Emissions Technology (MONET-UK) framework. The indigenous biomass feedstocks considered in the model include municipal solid waste (MSW), waste wood, forest residue, crop residue and virgin biomass (poplar and miscanthus). In total, indigenous biomass from the UK could contribute up to 56 Mt_{CO_2}/yr of CO_2 removal without the need to import biomass. Regardless of the pathway, BECCS deployment in the UK could materially contribute towards the net CO_2 removal target of 47 Mt_{CO_2}/year by 2050 as specified by the UK's Committee on Climate Change.

6.2. What is the role of biomass-based negative emissions technology?

In this work, we investigate the potential negative emissions contribution from three different archetypes of bioenergy with CCS:

1. BECCS: pulverised biomass-fired power plants which generates electricity.
2. BE-CHP-CCS: biomass-fuelled combined heat and power (CHP) plants which generates heat and electricity.

3. BHCCS: biomass-derived hydrogen production with CCS.

Using the available biomass in the UK, the aim was to determine whether BHCCS could possibly deliver net negative CO_2 emissions, making comparisons against the other BECCS technologies.

The evaluation first considers the deployment of a single type of technology and its potential to meet specific national-scale negative emissions targets. Any of the three technologies, BECCS, BHCCS or BE-CHP-CCS, are capable of delivering a sufficient level of CO_2 removal required to meet the UK's negative emissions target. A cost comparison revealed that BE-CHP-CCS technology had the lowest average CO_2 removal cost of the three technologies due to its low CAPEX and moderate efficiency ($36\%_{HHV}$). Although BHCCS had the highest efficiency ($40\%_{HHV}$), it also had the highest CAPEX. Therefore, BHCCS technology generally has higher CO_2 removal cost.

All technology pathways could provide a meaningful supply of clean energy, and have the potential to make a substantial contribution to the UK's energy system. If all of the available indigenous biomass in the UK was utilised to achieve 56 Mt_{CO_2}/year of CO_2 removal:

- BHCCS could produce up to 74 TWh of hydrogen, which is equivalent to 11% of the transport energy demand in the UK for 2030 [136].
- BECCS plants would generate up to 66 TWh of electricity, which could meet 13% of the UK's predicted 2030 electricity demand.
- BE-CHP-CCS could generate 67 TWh of electricity and 54 TWh of heat (total of 85 TWh electricity equivalent).

In general, BECCS technologies have unfavourable economics in the absence of incentives, which also depend on the sale price of the products generated. Therefore, the concept of a "negative emissions credit" (NEC) has been proposed as a payment to CDR providers for the net removal of 1 tonne of CO_2 from the atmosphere [137, 138, 139].

The evaluation of the technologies on an individual basis under base case economic assumptions were not profitable without negative emission credits. BECCS required a NEC of £86/t_{CO_2} to achieve an IRR of 15%, whereas the NEC needed for BE-CHP-CCS was significantly lower at £32/t_{CO_2}. In the case when the hydrogen sale price was £10/kg of H_2 (current market value) [144, 145], no NEC is needed to make BHCCS economically viable. However, at the projected future price of hydrogen of £1.40/kg H_2 [86], BHCCS required a NEC of £145/t_{CO_2} to achieve 15% IRR, making this the least viable scenario.

The second phase of the study highlighted the importance of considering a system where all three technologies are deployed together. The cost-optimal combination of technologies is a function of the sale price of hydrogen, electricity and heat. The retrofit BECCS scenario demonstrated that capital cost savings can be helpful in promoting the deployment of the technology. Although BECCS had significantly lower CAPEX, BE-CHP-CCS was the main technology deployed across the product price range considered due to its ability to generate revenue from the sale of two products (electricity and heat). Therefore, the main factors shown to enhance technology deployment are: (i) the sale price of the products, and (ii) amount/number of product/s generated (e.g. single/multiple products, low/high conversion efficiency). In the scenario of BHCCS with 56% CO_2 capture, the viability of BECCS technologies is highly dependent on the CO_2 capture rate and significantly outweighs any benefits from capital cost savings. Compared to BHCCS with 56% capture rate, BE-CHP-CCS was more favourable due to its higher CO_2 capture rate of 90%. Thus, BECCS technologies should focus on being a "negative emissions provider" and prioritise maximising CO_2 removal at minimal cost. By enabling flexibility to deploy multiple technologies, it was possible to achieve profitable scenarios across most of the product prices considered in this study. The regions requiring a NEC (up to £80/t_{CO_2}) to achieve an IRR of 15% corresponds to areas where hydrogen price is <£130/MWh_{H_2}, electricity price is <£100/MWh_{el} and heat price is <£60/MWh_{th} (red/brown regions of (d) in figures 14 to 16).

Biomass-derived hydrogen may well have an important role in meeting CO_2 removal targets. However, as these results demonstrate, it is more cost-effective to deploy BHCCS alongside other CDR technologies, e.g. BE-CHP-CCS. One key research priority is to develop understanding on how to integrate these BECCS technologies into a national-scale energy system. This should also account for how BECCS technology deployment may evolve as the demand for electricity, heat or hydrogen changes in the future, e.g. evolution of additional infrastructure such as a hydrogen transport network. As more countries legislate ambitious emission reduction targets (e.g. net-zero targets in UK, France, Norway), the development of cost-optimal and socially equitable pathways to achieve cross-sector decarbonisation will become increasingly important. Therefore, multi-system optimisation models combined with economic development models could potentially contribute towards such efforts [152]. This would help evaluate the value and role of different BECCS technologies in decarbonising various sectors (e.g. electricity, heat, transport, and industry). Further research is also needed to improve biomass-derived hydrogen production processes with CCS in terms of energy efficiency, reducing costs and operating with higher CO_2 capture rates above 90%. Lastly, future work needs to evaluate the CO_2 stream and hydrogen product exiting the BHCCS process to ensure these streams satisfy the technical specification requirements of the transport and storage network, also ensuring these meet any product purity standards (e.g. ISO standards for hydrogen fuel).

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Appendix A. Cost-optimal combination of BECCS technologies Scenario 2

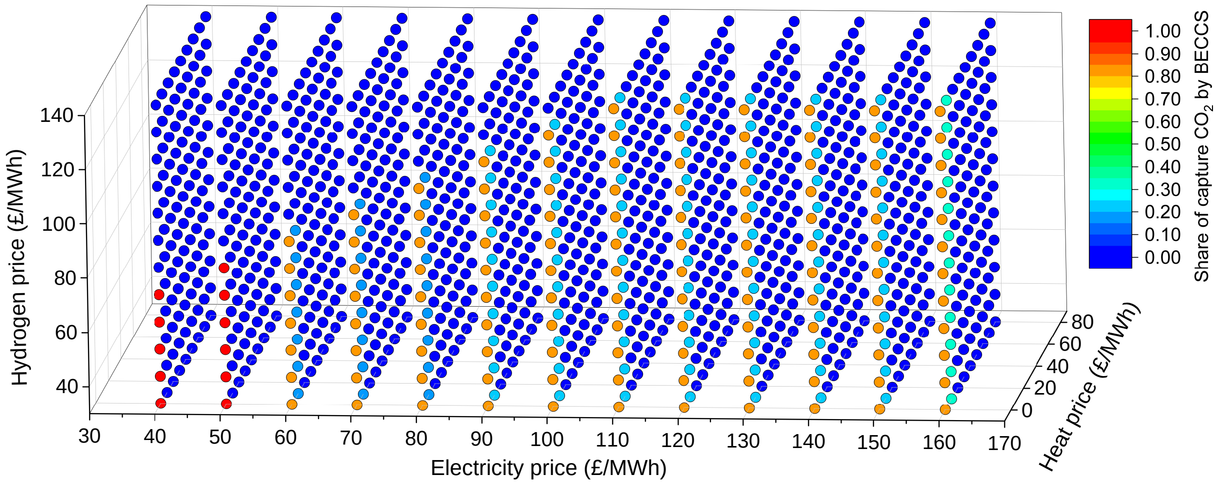

Figure A.17: The cost optimal deployment of BECCS under Scenario 2 (retrofit BECCS) – uses data in table 3 – where the installation of BECCS in existing power plants reduces CAPEX, and greenfield installations of BHCCS and BE-CHP-CCS are considered. In order to remove a total of 47 Mt/year of CO_2, the cost optimal share of BECCS varies across different prices of hydrogen (£/MWh$_{H_2}$), electricity (£/MWh$_{el}$) and heat (£/MWh$_{th}$).

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