Committee on Climate Change
March 2012

Bioenergy review

Technical paper 3
Appropriate use of scarce bioenergy

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Acknowledgements

The Committee would like to thank:

The team that prepared the analysis for the paper: David Joffe, Nina Meddings, Alex Kazaglis, Eric Ling, Ute Collier and Adrian Gault.

A number of individuals who provided significant support: Ewa Kmietowicz, Alexis Raichoudhury and Michael Humphries.

A wide range of stakeholders who sent us evidence, attended our stakeholder meetings, or met with us bilaterally.

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Ute Collier, CCC
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Introduction and key findings

The Committee’s bioenergy review provides an assessment of the potential roles for bioenergy given lifecycle emissions and other sustainability concerns, and also considers alternative uses for bioenergy feedstocks. The main report is available on our website: http://www.theccc.org.uk/reports/bioenergy-review.

More detailed analysis on appropriate use of bioenergy is covered in this technical paper. Three further technical papers are available on the website covering:

Technical Paper 1. Is bioenergy low-carbon?
Technical Paper 2. Global and UK bioenergy supply scenarios
Technical Paper 4. Biomass in power generation

In this paper, we set out the background to, methodology for and results from our analysis of appropriate uses of bioenergy. We begin with an overview of the various technologies that can be used to cultivate and process biomass feedstocks into useful fuels. We then consider alternative, non-energy uses of biomass feedstocks. We describe our methodology for examining the trade-offs between these various energy and non-energy applications, and finally present and discuss the results of this analysis.

This paper should be read alongside supporting reports:

• from Pöyry, who we commissioned to provide a detailed assessment of the range of biomass substitution options in industry, and
• from Redpoint, who we jointly commissioned with DECC to develop a modelling tool for analysis of the appropriate uses of bioenergy feedstocks.

The key findings from our analysis are as follows:

• **Appropriate use of limited sustainable bioenergy supply in the long term:** Given limits to the global supply of sustainable bioenergy, it is important that this is used in an optimal fashion. In general, this implies use in applications where there are currently no feasible low-carbon alternatives to hydrocarbon input. However, our analysis has illustrated that the appropriate use depends crucially on whether or not carbon capture and storage (CCS) is an available technology (Figure 1).
  – If CCS is available, it is appropriate to use bioenergy in applications with CCS, making it possible to achieve negative emissions. These applications could include power and/or heat generation, the production of hydrogen, and the production of biofuels for use in aviation and shipping.
If CCS is not available, bioenergy use should be skewed towards heat generation in energy-intensive industry, and to biofuels in aviation and shipping, with no appropriate role in power generation or surface transport.

In either case, the use of woody biomass in construction (rather than as an energy source) should be a high priority, given that this generates negative emissions through a very efficient form of carbon capture.

**Appropriate use of bioenergy supply in the near to medium term.** Our analysis suggests a path to 2050 characterised by the transitional use of bioenergy resources in non-CCS power generation and surface transport, ongoing use in industry and construction but limited use in heating buildings (apart from some smaller-scale, local uses). There is a strong role for aviation and shipping biofuels in the medium term, with the extent to which this continues dependent on availability of CCS.

- **To 2020:** bioenergy resources are used across the range of available applications including construction, heat and power generation and surface transport, with some early deployment in aviation.
- **To 2030:** there is continued use of biomass in construction, industrial heat, anaerobic digestion (AD) and combined heat and power (CHP), and biofuels in surface transport, with increasing use in aviation and shipping.
- **To 2040:** there is continued use in construction, industrial heat and CHP. Use in surface transport starts to decline as this sector electifies, while there is increased use in aviation/shipping and applications with CCS where available.
To 2050: use in construction and industrial heat continues, with almost all remaining bioenergy used in CCS applications where available. Without CCS, there is ongoing use of aviation/shipping biofuels and increased use in industrial heat.

- **Implications of bioenergy availability for overall low-carbon strategy.** Our analysis has revealed that supplies of sustainable bioenergy may only just be sufficient to make meeting the 2050 target achievable, and only then if CCS is available.

  - The analysis therefore highlights the need to demonstrate CCS technology as a matter of urgency, given its potentially crucial role in providing a negative emissions option when used with bioenergy.

  - More generally, it suggests the need to develop a range of bioenergy options, and to pursue bioenergy paths that offer flexibility regarding their future role (e.g. biomethane injection into the gas grid, gasification pathways for ligno-cellulosic feedstocks).

  - Going beyond bioenergy, our analysis suggests a clear role now for investment in nuclear and wind power generation, energy efficiency improvement, electric forms of heat in buildings, and battery and hydrogen electric vehicles (i.e. these are very unlikely ever to be displaced by bioenergy).

We set out the evidence underpinning these findings in four sections:

1. Bioenergy chains
2. Non-energy uses of biomass
3. Appropriate use of bioenergy resources: methodology
4. Appropriate use of bioenergy resources: results
1. Bioenergy chains

There are a large number of individual technologies that can be used in the area of bioenergy. The fact that these can also be combined in a variety of ways therefore means that there are numerous possible bioenergy chains. This is illustrated by Figure 2 below, although as this shows technologies in groups rather than individually this understates the number of possible chains.

The range of technologies involved in bioenergy chains can be broadly categorised as follows: cultivation; pre-processing; intermediate processing; liquid fuel production; end-use applications (including generation of heat and power). Cultivation of established and emerging bioenergy feedstocks is covered in Technical Paper 2, while use in the power sector is covered in Technical Paper 4, together with the report from Mott MacDonald on biomass conversion of coal plant. Detailed descriptions and technology status for the key remaining categories are presented in Annex A of this paper.

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**Figure 2: Bioenergy feedstock conversion chains**

<table>
<thead>
<tr>
<th>Feedstock</th>
<th>Conversion routes</th>
<th>Heat and/or Power</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil crops</td>
<td>(Biomass upgrading$^1$) + combustion</td>
<td>Biodiesel</td>
</tr>
<tr>
<td>Sugar and starch crops</td>
<td>Transesterification or hydrogenation</td>
<td>Bioethanol</td>
</tr>
<tr>
<td>Lignocellulosic Biomass</td>
<td>(Hydrolysis) + fermentation</td>
<td>Syndiesel/ renewable diesel</td>
</tr>
<tr>
<td>Biodegradable MSW</td>
<td>Gasification (+ secondary process)</td>
<td>Methanol, DME</td>
</tr>
<tr>
<td>Photosynthetic micro-organisms</td>
<td>Pyrolysis (+ secondary process)</td>
<td>Other fuels and fuel additives</td>
</tr>
<tr>
<td>e.g. microalgae and bacteria.</td>
<td>Anaerobic digestion (+ biogas upgrading)</td>
<td>Biomethane</td>
</tr>
<tr>
<td></td>
<td>Other biological/ chemical routes</td>
<td>Hydrogen</td>
</tr>
<tr>
<td></td>
<td>Bio-photochemical routes</td>
<td></td>
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Notes: (i) Parts of each feedstock, e.g. crop residues, could also be used in other routes. (ii) Each route also gives co-products. (iii) Biomass upgrading includes any one of the densification processes (pelletisation, pyrolysis, torrefaction, etc.).

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$^1$ Available from http://www.theccc.org.uk/reports/bioenergy-review/supporting-research

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Biomass feedstocks generally have a relatively low energy density compared with fossil fuels and therefore face considerable challenges in transportation and storage. They also often have greater variation in physical characteristics (e.g. moisture content, chemical composition) potentially leading to problems with reliable use for some energy applications. A range of technologies can be used to address these issues, to increase energy density, homogeneity and/or transportability and produce solid, gaseous or liquid biofuels:

- **Solid biomass:**
  - Chipping is a relatively low-energy process and improves transportability. It does not achieve as great an improvement in density as pelletisation, which involves greater compaction and more water removal, but requires greater energy input. Neither chipping nor pelletising involves significant thermal treatment of the feedstock.
  - **Pyrolysis** and **torrefaction** involve thermal treatment of biomass, in the absence of oxygen, so that rather than combustion occurring the biomass decomposes into one or more of the following products: liquid bio-oil, a mixture of hydrocarbon gases (known as synthesis gas, or ‘syngas’) and a dense solid char. Torrefaction mainly produces a solid product, which has significantly greater energy density than the raw feedstock and also has greater grindability and resistance to water exposure (‘hydrophobia’). Although pyrolysis oil is a ‘difficult’ product (e.g. due to high acidity and poor stability) it can be combusted directly for heat and/or power, or upgraded for use in more advanced applications such as transport.

- **Gaseous biofuels:**
  - **Gasification** is a similar process to pyrolysis, although it occurs in the presence of a greater amount of oxygen, and produces a greater proportion of syngas rather than bio-oil. The resultant syngas – generally predominantly consisting of CO₂, carbon monoxide (CO) and hydrogen (H₂), as well as small amount of other compounds of hydrogen and carbon – can either be combusted directly or used as the basis for producing a variety of fuels, such as liquid biofuels (via the Fischer Tropsch process), high-purity H₂ or biomethane (also known as synthetic natural gas, or bio-SNG) via a methanation process.
  - Another way to produce bio-methane is via **anaerobic digestion** – this is generally used with wet feedstocks, such as food wastes and farm slurries. This produces biogas, which is typically around 60% methane, with the remainder primarily consisting of CO₂, together with other trace gases plus grit. Biogas can be combusted directly, or upgraded to biomethane for use in compressed natural gas (CNG) vehicles or for injection into the natural gas pipeline network.
• Liquid biofuels: There are a variety of processes for producing liquid biofuels, including fermentation, hydrotreatment and use of the products of gasification/pyrolysis in further processes.

  – **Fermentation** – either using established processes with sugar and starch crops, or more advanced technologies with more woody feedstocks – produces ethanol, which is typically used to displace petrol in transport. Hydrotreatment can be used to produce biodiesel (known as hydrotreated vegetable oil, HVO) and/or bio-kerosene (hydrotreated renewable jet, HRJ).

  – The **Fischer-Tropsch** process can be used to produce bio-substitutes for a range of hydrocarbon fuels, including petrol, diesel and kerosene. It converts the relative simple bio-compounds in synthesis gas (e.g. from gasification or pyrolysis) into a crude hydrocarbon, which can then be broken down into the desired products using methods similar to those used in refining oil products.

Given that many of these conversion processes involve the emission of CO₂ to atmosphere, there is the possibility to capture and store this CO₂, potentially resulting in negative emissions. Carbon capture and storage (CCS) could potentially be applied across a range of conversion processes, such as electricity generation, hydrogen production, large-scale CHP, bio-SNG production and biofuel production.

A variety of other technologies, or variants of those described above, can also be used within bioenergy chains. A more detailed description of some of these technologies can be found in Annex A, while more exhaustive reviews are available elsewhere (e.g. ERP, 2011).

A wide range of bioenergy technologies have been included in Redpoint’s modelling of bioenergy uses for the Committee and DECC, described in subsequent sections. Where technologies have been omitted, this was generally due to a lack of data. Furthermore, where conclusions have been drawn in this report they tend not to focus on the importance of specific technologies, but on more general characteristics involving emissions characteristics (e.g. efficiency, applicability of CCS), alternatives to bioenergy and fossil fuels in a given application and near-term deployability.
2. Non-energy uses of biomass

Biomass can be used for its physical properties as well as for its energy content. In this capacity, biomass can reduce emissions by being incorporated into the physical product being produced (e.g. producing glass bottles from bioplastic to displace glass bottles). The benefits of biomass product substitution are three-fold:

- **Displacement of carbon-intensive products**: by substituting carbon-intensive products (such as cement in construction or oil in plastics) with low-carbon biomass-based alternatives, the emissions that would otherwise be produced are avoided.

- **Materials efficiency**: in some cases the bio-based products have significantly lower materials demand than their carbon-intensive counterparts. For example, bio-based plastic bottles are only 10% of the mass of an equivalent glass container.

- **Storage of biogenically-sequestered CO₂ (negative emissions potential)**. For some product substitution options, carbon that is sequestered during the cultivation of the biomass is locked up in products for a substantial period of time. For example, if wood is used in construction the carbon is stored in the buildings for decades (or even centuries), which may be preferential to burning the wood and releasing this carbon as CO₂ back into the atmosphere.

The Committee commissioned consultants Pöyry to provide a detailed assessment of the range of biomass product substitution options and their technical abatement potential. Details of the range of options considered and the methodology for analysis is contained within the consultancy report.

In this section we describe the key aspects of the Committee’s approach to product substitution, focusing on:

- Option selection
- Approach to analysis of wood in construction

**Option selection**

A high level screening of a wide range of product substitution options was undertaken by Pöyry and, on the basis of feasibility and likelihood of producing significant carbon savings, a shortlist was created. This shortlist included:

- Packaging: liquid packaging board and bio plastic bottles to substitute for glass.
- Iron and steel: bio-coke substitution for fossil coke in the blast furnace.
- Chemicals sector: bio-based ammonium and bio-based adipic acid production.
• Construction sector: using structural wood products to replace steel, cement and bricks in construction.

A more detailed assessment of abatement potential was then carried out, which suggested that only bio-coke and wood in construction have abatement potentials greater than 1MtCO₂ (Table 1).

However, bio-coke is unlikely to be a preferential use of biomass compared with power or heat. This is because bio-coke has a high biomass requirement in order to create a product that can provide the mechanical strength properties required in the blast furnace (around two units of biomass are required to produce each unit of bio-coke). Further, there are several critical uncertainties surrounding the potential for substitution of fossil coke with bio-coke with estimates of substitution potential varying from 20% to 100% across different sources.

Given these considerations, only wood in construction options were taken forward to the appropriate use modelling. However, there may be niche opportunities for the bio-coke option to be applied in particular contexts.

<table>
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<th>Table 1: Abatement potential from product substitution options</th>
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<td>Steel production</td>
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<td>Chemicals</td>
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**Approach to the analysis of wood in construction**

In the construction sector there is the potential to use wood products to replace concrete, steel and bricks, for example in building structures and cladding. Although there are a wide range of wood construction products in the market, we used a selection of representative products in this analysis: to substitute for concrete and steel, glulaminated beam represented a suitable structural product, and to substitute for bricks in non-structural uses (i.e. cladding), planed sawnwood was chosen.
Supply issues

The supply scenarios developed as part of this Review (Technical Paper 2) focused on resources that might be available for energy applications, in the context of competing demands. For example, it is unlikely that high quality timber would be used for energy applications, given demands from other sectors. The supply scenarios therefore do not reflect the full resource that could be used for wood in construction, only that part of the resource likely to be competed for by energy applications. The types of wood that are appropriate for construction are large and small diameter roundwoods and softwoods. In our supply scenarios, this resource is contained within the category of forestry and forestry residues and woody biomass.

It is likely that more resource could be made available for wood in construction than is identified in this analysis. A further comprehensive assessment of resource availability for wood in construction is therefore required that considers potential both in existing forests (e.g. through better management) and new forests (which would need to include an analysis of the best application of spare land).

Carbon storage

A full assessment of the potential for wood in construction to store carbon emissions, including end-of-life considerations and whether the co-products can be utilised is required to reduce uncertainty about these options. There does, however, appear to be significant potential:

- Wood is around 50% carbon, and so the use of wood in long-lived construction offers the opportunity for this carbon to be considered stored. These benefits are potentially significant and would make this use of bioenergy preferable to other uses.

- The extent to which carbon can be considered “stored” depends upon what happens to the wood at the end of its life – for example the wood could be sent to landfill, burned for power or heat, or recovered and reused. In this assessment we have not analysed these options in detail; however we show results for the wood in construction options if these emissions were able to be stored.

- One complexity is that around 50% of the resource required to produce a construction material forms an off-cuts co-product which could be burned for energy, or stored. Given uncertainties, we assume that only the biomass that actually forms part of the construction material can be stored (i.e. around 50% of the resource used is stored), with the remainder added to the sawmill co-products resource category, for use in the energy system.

To calculate the storage potential, an assumption of the energy content of wood is 19 MJ/kg, which results in an abatement factor of around 0.21 kgCO₂ per kg of construction material.

Other considerations of using wood in construction include the thermal, structural and lifetime properties which may be different from conventional construction products. A high-level assessment of these differences was conducted by Pöyry and is outlined in the consultants’ report.
3. Appropriate use of bioenergy resources: methodology

Aims of the analysis
We have undertaken detailed modelling of long-term bioenergy pathways and their role in meeting carbon budgets and renewable energy targets. The goal of this work has been to help inform the development of a strategic approach to using bioenergy, which:

- ultimately reflects long-term best uses
- keeps options open e.g. to respond to technology breakthroughs
- helps reduce emissions cost-effectively in the near term provided lock-in is limited.

Given the significant uncertainties in this area (e.g. availability of sustainable resource, future technology availability and costs, fossil fuel prices), the analysis has attempted to divide potential uses of bioenergy into four broad categories:

- Desirable (under most scenarios)
- Desirable if available (but availability uncertain)
- Desirable depending on circumstances (e.g. if other technologies prove not to be available)
- Undesirable (under most scenarios).

Modelling approach
Bioenergy resources can have value to the energy system in two main ways:

- reduced costs of abatement/meeting the renewables target (e.g. conversion of coal-fired plants to biomass vs. offshore wind)
- increased overall abatement where bioenergy is the only alternative to fossil fuels (e.g. aviation biofuels)

Over time, as bioenergy value increases (i.e. the carbon price increases as emission constraints tighten), we would expect increasing emphasis on high levels of additional abatement.

To examine the trade-offs, we used a least-cost optimisation model developed by Redpoint and Ecofys. Figure 3 provides an overview of the modelling approach. Although rich in detail, it should be emphasised that the model is a tool for generating insights and testing different scenarios, not for providing detailed projections for the future. The model:

- identifies least-cost means to achieve emissions targets and the 2020 renewables target for a given set of energy service demands, maximum available bioenergy supply and bio and non-bio technology characteristics. The assumed energy service demands factor in a wide range of energy efficiency improvements in buildings, industry and transport.
• builds and operates a stock of technologies (bio and/or non-bio) to meet these energy service demands, within constraints around technology availability, build rates etc. It uses assumptions on technology characteristics (costs, efficiencies, etc.) developed for our previous advice (e.g. on the fourth carbon budget), complemented with estimates for bioenergy technologies from E4tech.

• considers alternative uses for bioenergy across sectors (e.g. for heat generation in industry, or – via various processes – as liquid biofuels for use in surface transport or aviation), which compete with other non-bio technologies to supply energy.

• focuses on CO₂ emissions, which are reduced from current levels of around 540 MtCO₂ to 105 MtCO₂ in 2050 (further details on the emissions trajectory used are given below). It includes emissions associated with the production and transportation of bioenergy, whether or not these would occur in the UK or in other countries. It takes as an input the bioenergy supply scenarios developed as part of the review (see Technical Paper 2).

Further details are provided in Redpoint’s accompanying report, available on the Committee website².

The following sections set out in more detail the approaches and assumptions in specific areas of the modelling.

² http://www.theccc.org.uk/reports/bioenergy-review/supporting-research. Note that subsequent to writing this paper, some minor additional changes were made to the model and dataset. Hence detailed modelling results in Redpoint’s report may differ slightly from those presented here.
Data

We drew on a range of existing sources for costs and performance data, for both bio- and non-bio resources and technologies. Data on bioenergy resources and technologies were reviewed in a short project we commissioned from E4tech. Data sources are summarised in Annex B.

Emissions constraint

The constraint for emissions in 2050 was derived from a starting point of an 80% reduction vs. 1990 levels of all Kyoto greenhouse gas (GHG) emissions, including the UK share of international aviation and shipping (IA&S). This gives an overall limit of 160 MtCO₂e. Subtractions were then made from this overall allowance, based on assumed levels of emissions in 2050 for sectors outside the model, in order to calculate the 2050 emissions constraint for the sectors within the model:

- For non-CO₂ emissions a reduction of 70% vs. 1990 levels was assumed, leaving 55 MtCO₂e remaining emissions of these gases in 2050
- For industry, an allowance totalling between 42-69 MtCO₂ was made for process emissions (i.e. CO₂ emissions resulting from chemical reactions rather than fuel combustion to provide energy), and various other sources of industry emissions not characterised in the model
  - Baseline emissions from industry categories outside the model — predominantly refineries, ‘other energy supply’, process emissions — were assumed to stay constant from 2030 at 69 MtCO₂. This is the level, in the absence of any further identified options to abate these emissions, in the Committee’s fourth carbon budget Medium Abatement scenario.
  - In those runs in which CCS was assumed to be available, abatement via CCS is assumed to reduce this by 27 MtCO₂/year by 2050. This is in line with the potential identified for the Committee in Element Energy (2010)

These adjustments resulted in allowed 2050 emissions within the scope of the model of 63 MtCO₂e in a world with CCS, and 36 MtCO₂e in a world without CCS. For the trajectory of allowed emissions between 2011 and 2050, a linear rate of reduction was assumed (Figure 4).

Feedstocks

Scenarios for feedstock availability were developed in-house (see Technical Paper 2). Further assumptions were made regarding production costs and physical properties of feedstocks.

Most domestic feedstocks were assumed to be in their ‘raw’ form, with various options for pre-processing/conversion characterised explicitly in the model. However oil crop resources (both domestic and imported) were assumed to be pre-processed (i.e. in oil form), with costs and lifecycle emissions calculated accordingly. Similarly, agricultural residue imports were assumed to be pre-processed where necessary (e.g. into straw pellets), as it is unlikely that bulky, low-energy density feedstocks would be transported internationally in ‘raw’ form.
Although production costs were used as inputs to the model, competition for limited resources is likely to drive the value of feedstocks to the energy system above their production cost – the least-cost optimisation effectively simulates a market where this value to the system represents the price.

**Lifecycle emissions**

While bioenergy is treated as zero emissions under current emissions reporting and UK carbon budget accounting, clearly, it is important to account for lifecycle emissions when assessing appropriate uses of bioenergy to meet the long-term global climate objective (see Technical Paper 1).

Lifecycle emissions are included in the model for all bioenergy feedstocks and fuels. Assumptions were commissioned from Ecofys and derived from a number of sources: Renewable Energy Directive (RED) values, BioGrace, DECC carbon calculator, supplemented with proprietary data.

In line with current RED accounting, lifecycle emissions included in the model cover emissions associated with cultivation, transport and processing (whether this occurs in the UK or overseas) but exclude land use change emissions. However, we assume implicitly that the latter are minimal given the design of our resource availability scenarios which focus on use of abandoned agricultural land.

Processing emissions arise both from combustion of fuels to provide energy inputs and from the embedded emissions in chemicals used as part of processing. The former are endogenised within the model (given required energy inputs – taken from the sources above – resulting emissions will vary depending on the extent to which the given energy vector is decarbonised); the latter are fixed parameters.

![Figure 4: Assumed trajectories for CO₂ emissions within the modelling, with and without CCS](source: CCC)
**Imports**

A number of potential pathways exist for the globally traded solid resources (woody biomass and dry agricultural residues) covered by our supply scenarios: for example, they could be imported in basic form and combusted for heat/power, imported and converted to liquid biofuels in the UK, or converted to liquid biofuels overseas and then imported.

Rather than make *a priori* assumptions about these pathways (e.g. to assume that a certain proportion of the resource is imported as chips/pellets/biofuels), which could restrict model outcomes, we allow the model to choose the balance between them. This is done via ‘dummy’ import technologies which represent overseas pre-processing/conversion. These technologies have the same characteristics as the UK equivalents, but also include international transport costs in their operating costs.

A similar approach is taken for imported oil resources, given that they can potentially be used in a variety of applications either directly or having first undergone a conversion process. However for conventional ethanol (i.e. ethanol produced from food and fodder crops) imports are assumed to be in the form of the refined fuel (given that this is the only realistic pathway for these crops), with associated processing and transport costs included within the product cost.

Maximum build quantity (group) constraints are applied to the dummy import technologies for advanced bioethanol and for advanced biodiesel, based on global production in IEA (2011) *Technology Roadmap – Biofuels for transport*, pro-rated to the UK according to its current share of bioethanol and biodiesel consumption.

**Energy service demands**

Energy service demands are generally based on the Committee’s analysis for the fourth carbon budget, extrapolated to 2050 based on the Spread Effort pathway from the March 2011 version of DECC’s 2050 calculator. They include demand reductions from a range of energy efficiency measures (e.g. insulation) as well as behavioural measures (e.g. turning down thermostats).

- **Electricity.** Total electricity demand is endogenous in the model and depends on the uptake of electric heating and electric vehicles. However, a given level of ‘core’ demand is assumed (e.g. electricity required for lights and appliances), which is unaffected by choices within the model except in terms of the technologies used to supply the demand. This demand is split according to four categories: peak, mid-merit (seasonal), mid-merit (diurnal) and baseload. Further details on the representation of electricity demand and supply are given below.

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3 However, as transport costs are similar for oils and biofuels these are included in the costs of the feedstock rather than the operating costs of the dummy import technologies.
• **Heat.** Total heat demand is disaggregated according to the detailed heat segments used in the Committee’s analysis for the fourth carbon budget. These include disaggregation by sector (residential, non-residential, industrial space, industrial process), counterfactual fuel (gas/electricity/non-net bound), building or process type (detached/flat/other for residential; small public/large public/small private/large private for non-residential; small/large for industrial space; low temperature/high temperature for industrial process), building location (urban/suburban/rural), building age (solid wall/pre-1990/post-1990/new build). Different heat technologies have different characteristics (suitability, load factor, typical size, cost and efficiency) depending on demand segment.

• **Surface transport.** Service demands are characterised in terms of vehicle-kilometres for different vehicle types (cars, vans, buses, rigid HGVs, large rigid HGVs, small articulated HGVs and large articulated HGVs).

• **Aviation and shipping.** For aviation, service demand is characterised in terms of plane-kilometres\(^4\), based on the Committee’s Aviation Review (Likely Scenario). For shipping, service demand is characterised in terms of TWh of fuel demand based on the Committee’s Shipping Review (Central Scenario)\(^5\).

**Wood in construction**

The characterisation of alternative (i.e. non-energy) uses of bioenergy feedstocks in the model was based on analysis for the Committee by Pöyry (see section 2 above). Three options for using woody biomass in construction (displacing steel, concrete or bricks) were identified for inclusion in the model. Emissions savings for the three options were calculated as a combination of the carbon stored in the wood (and therefore not emitted) and the carbon intensity of the products displaced. The emissions savings from displacing conventional construction materials was assumed to be today’s UK carbon intensity of production, unless CCS is assumed to be available. In a world with CCS, the carbon intensity of these materials was assumed to fall by 2050 to a level consistent with the application of CCS to their production.

**Power sector representation**

As for any energy system model (e.g. MARKAL, ESME), the representation of the electricity sector in the modelling is less detailed than is needed to examine the future of the sector in detail. However, the characterisation of electricity generation and consumption is sufficient to represent the different possible roles of bioenergy within the sector:

- **Baseload,** generating practically all the time

- **Seasonal mid-merit,** generating around half the time, to meet electricity demand for heating during the coldest months of the year

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\(^4\) Converted from seat-kms using an assumption of 100 seats per plane

\(^5\) End-use technology choices do not need to be modelled explicitly as they are independent of fuel type within the model. Liquid hydrocarbons – fossil or biofuels – are the only available fuel types and maximum blend limits are applied such that fleet modifications are not required.
- **Diurnal mid-merit**, generating around half the time, during the day but not at night
- **Peak**, generating around 10% of the time, at times of peak demand and/or low intermittent renewable generation

The technologies that can generate or demand electricity are characterised according to these splits. On the generation side, we specify in which modes a technology can operate (e.g. nuclear plants are assumed to operate at baseload or seasonal mid-merit but cannot vary output on a within-day basis, more flexible plants can fulfil all four roles). For despatchable technologies, this is relatively straightforward as the above modes correspond well to the possible ways in which they can be operated.

For intermittent renewables, this representation is less good, with the assumption made that they operate as inflexible baseload plant; while this is clearly not an accurate representation, it does at least represent the inflexibility of their generation profile. In the long term, when we expect to have smart grids and increasing proportions of moveable demand, this treatment is likely to be less problematic. Furthermore, the requirement for a certain quantity of peaking generation – and, in most runs, thermal plant operating on a seasonal mid-merit basis – means that capacity is also available to provide occasional back-up to renewables with variable output. Nevertheless, it is important to sense check the modelling results in this area, to check consistency with more detailed modelling exercises.

There are two further considerations to take into account regarding the demand profiles of technologies that create additional demands for electricity:

- **Electrification of heat**, via heat pumps and/or resistive electric heating, would create a significant increase in the seasonality of electricity demand. As outlined in the Committee’s fourth carbon budget report, this may lead to a situation in which low-carbon plant operates largely on a seasonal basis, for around 6 months of the year, to meet this demand. As this plant would generate fairly consistently during the winter months, this role would be available to relatively inflexible plant (e.g. potentially including CCS and nuclear plants).

- **Flexible electricity demands** (e.g. those from electric vehicles or hydrogen production via electrolysis) do not conform to any of the generation shapes outlined above. Rather they can be used to fill in the gaps in the load profile at off-peak times on a within-day basis, enabling demand for ‘diurnal mid-merit’ generation (i.e. generating during the day but not at night) to be converted to demand for baseload generation (Figure 5). This opportunity is clearly unavailable for conversion of seasonal mid-merit demand to baseload, as it is not plausible for electricity demand for EV charging to move to times of lower demand (i.e. the summer).
Electricity demand for space heating is therefore defined as having the ‘seasonal mid-merit’ shape. Any load that is flexible on a diurnal basis is defined as having negative demand for ‘diurnal mid-merit’ generation with correspondingly higher demand for baseload generation. The addition of 1 kWh of flexible diurnal demand is represented as an increase of 2.15 kWh of baseload demand and a reduction of 1.15 kWh in diurnal mid-merit demand.

Existing ‘core’ (i.e. non-heat, non-transport) demands for electricity were split into baseload, diurnal mid-merit and peaking, based on load duration curves provided to the Committee as part of previous detailed hourly modelling of the electricity system by Pöyry, and projected forward out to 2050. Demand for seasonal mid-merit generation is dependent on the prevalence of electric space heating technologies, and is therefore endogenous within the model.

The link between electricity generation and demand in the model is via a ‘electricity grid’ dummy technology, which serves two purposes: to account for losses in transmission and distribution (assumed to be 8%) and to account for grid costs. The calculation of grid costs is based on those used for the Committee’s fourth carbon budget analysis, with the electricity distribution costs varying by load shape; these distribution costs have been derived from original analysis and modelling by Strbac et al (2010).

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6 These changes to the demands were calculated from the assumed average load factors for baseload (generating at an average of 96% of capacity when plant is available) and diurnal mid-merit (generating at an average of 51% for every 45 units of additional demand, 51 units of diurnal mid-merit generation can be eliminated, to be replaced with 96 units of baseload generation. The ratios of these numbers to the 45 units of demand give the figures of 1.15 and 2.15 respectively.
The inclusion of ‘retrofit’ functionality in the model enables an existing technology to be converted into a different technology, with associated costs of conversion, de-rating of capacity, change in efficiency and lifetime extension. This is used to represent the potential to convert existing coal-fired power plants fully to biomass, based on the outputs of work by Mott MacDonald7.

For the purposes of this modelling, the existing coal fleet was split into plants opting out of the Large Combustion Plant Directive (LCPD) and those opted in to both the LCPD and the Industrial Emissions Directive (IED); in practice, some plants will opt in to the LCPD but opt out of the IED.

**CCS**

The costs of CCS power generation with fossil fuels have been taken from Mott MacDonald (2010). For the application of CCS to biofuel plants, costs and efficiencies are derived from their non-CCS equivalents with adjustments based on Element Energy (2010) data for CCS application to refineries. These include additional capital and fixed operating costs, and adjustments to efficiencies to reflect the energy penalty associated with CCS. The data for application of CCS to industrial CHP have been taken directly from the same study. All of these data include the costs of CO₂ capture, transportation and geological storage.

CO₂ capture rates are assumed to be 90% for power generation (as per the Mott MacDonald assumptions) and hydrogen production (as per H2A assumption, see below) and CHP with CCS (as per Element Energy assumptions), and 80% for biofuels production with CCS (as per Element Energy’s assumption for applying CCS to refineries, reflecting the potentially more diverse number of sources of CO₂ for these processes and hence a greater challenge for maximal capture.

A group build rate constraint is applied to all technologies with CCS, across power generation, hydrogen production, industrial abatement and biofuel production, based on an assumed maximum combined cumulative installed capacity of 3 GW by 2020, 7 GW by 2025 and 15 GW by 2030. These are consistent with an intermediate scenario between the 10 GW and 20 GW scenarios for 2030 explored in Pöyry (2009), which identified the higher level of deployment as being plausible only if everything went completely as planned with CCS demonstration and roll-out.

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7 Available from http://www.theccc.org.uk/reports/bioenergy-review/supporting-research
Hydrogen

The cost and efficiency data for hydrogen production technologies were based on those in H2A (2008). Six hydrogen production technologies were included, at two different scales:

- Large-scale production, via coal gasification with CCS, steam methane reforming (both with and without CCS) and biomass gasification (with and without CCS). Production at large scale then requires, for use in transport, distribution of hydrogen to the fuelling stations. A pipeline distribution infrastructure has been assumed, with costs taken from Joffe (2010), based on data from Yang and Ogden (2007).

- Distributed production, via electrolysis of water and steam methane reforming without CCS. No further hydrogen distribution infrastructure was assumed to be required, as a distributed approach enables hydrogen production to occur at, or very close to, fuelling facilities.

A group build rate constraint is applied to deployment of all hydrogen production technologies, at the same level as that for all CCS deployment. For those hydrogen production routes that involve use of CCS hydrogen, both the hydrogen and CCS group constraints apply.

District heating and CHP

District heating (DH) is represented in the model in two ways:

- Dedicated biomass district heating ‘technologies’ with costs, load factors and efficiencies specific to each detailed heat segment. Costs include both the heat source and network costs.

- Utilisation of surplus heat from CHP technologies. The heat source and network are represented separately. The heat from the heat source can be used to satisfy demand directly (i.e. on-site CHP rather than district heating), or can be utilised via a dummy heat network ‘technology’ which provides the link to end-users. This dummy technology has associated costs and an efficiency which reflects losses in transporting the heat.

Maximum build quantity group constraints are applied to both the dedicated and dummy technologies. These represent the estimated total heat load suitable for district heating over time based on NERA & AEA (2010) Decarbonising Heat: Low-Carbon Heat Scenarios for the 2020s.

CHP technologies within the model are constrained to operate at baseload or mid-merit load, i.e. not peak load: firstly because this is a more realistic mode of operation and secondly to ensure broad consistency with likely district heating loads.

A limitation of the model with regard to district heating is that the DH technologies can supply heat to individual heat demand segments, with no constraints on the share of residential vs. other heat demands. In practise, viability of district heating networks depends on a mixed heat load to ensure a smoother demand profile. This is an area for future development of the model.

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8 Note: direct supply of heat from CHP technologies is limited to industrial heat segments. In practise, some commercial users may also employ these technologies.
**Biomethane to grid**

An option for decarbonising uses of natural gas is the injection into the gas grid of biomethane (produced either via AD plus biogas upgrading or via gasification plus methanation). Options for biomethane injection via AD were characterised in terms of cost of biomethane and potential for cost-effective injection into the grid (i.e. taking into account proximity to the gas grid and the scale of gas production), based on SKM Enviros (2011) for DECC. Those for the gasification route (known as bio-SNG) were based on analysis NERA & AEA (2010).

No overall constraint on biomethane injection into the grid were imposed, as the volumes available were well below levels at which such constraints would bind. Allocation of the biomethane to end-uses was decided by the model, but in most cases this is likely to be arbitrary, as the costs and benefits of using one unit of biomethane to displace one unit of fossil natural gas do not vary by end-use.

**Infrastructure coverage and constraints**

The model contains costs for many, but not all, elements of the energy infrastructure implied by its results. Wherever possible, attempts have been made to ensure a ‘level playing field’ between competing technologies so that any exclusion of infrastructure costs does not bias the model’s choices. These omissions are where the infrastructure already exists and can therefore be treated as a sunk cost:

- Gas transmission and distribution – the costs for existing capacity are treated as sunk, which is likely to be largely a valid assumption for at least the next 25 years, according to Redpoint (2010). The model does not generally choose to expand use of the natural gas grid over the period to 2050, due to opportunities for energy efficiency and the imperative to decarbonise, so the omission of costs for expansion of capacity does not affect its choices.

- Liquid fuel infrastructure – the costs of the existing infrastructure for liquid fuel distribution and dispensing are treated as sunk. A significant expansion of this infrastructure is not anticipated, given targets for improvements in the fuel efficiency of new vehicles and opportunities to switch to lower-carbon vehicles, requiring electrical charging or hydrogen fuelling infrastructure.

For the introduction of new technologies that have significant infrastructure implications (e.g. heat pumps, district heating, hydrogen vehicles) a full set of infrastructure costs have been included. This includes electricity grid infrastructure, district heating networks and both pipelines and fuelling stations for hydrogen vehicles. For compressed natural gas (CNG) vehicles, these are assumed to use natural gas or biomethane delivered via the existing pipeline network, with additional costs included for fuelling facilities.

Constraints on the rate at which infrastructure can be developed are implicitly included in constraints on technology deployment.
Biofuel conversion technologies

A description of the conversion technologies included in the model are provided in Annex A, and data sources for costs and efficiency are outlined in Annex B.

The model has the facility to represent co-products within the least-cost optimisation. Co-products can provide value both in economic terms (if they have a market value) and in terms of abatement potential by substituting for more carbon-intensive materials/products. The most significant co-product, and the one currently represented in the model, is dried distillers grains with solubles (DDGS) from the production of bioethanol from sugar and starch crops. This can be sold as animal feed and displace growth of fodder crops with its associated emissions, and is therefore assigned a negative emissions credit in the model.

Other co-products include naphtha from the production of FT biodiesel. However rather than assigning them separate values, we have assumed that they are used to provide energy back into the conversion process, thereby increasing the overall efficiency of conversion of feedstock to fuel.

Blend rates for biofuels

Blend rates for biofuels were advised by E4tech as part of their data review (Table 2).

<table>
<thead>
<tr>
<th>Table 2: Blend rate limits assumed</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel</td>
</tr>
<tr>
<td>----------------------</td>
</tr>
<tr>
<td>Bioethanol</td>
</tr>
<tr>
<td>Biodiesel FAME</td>
</tr>
<tr>
<td>Biodiesel HVO</td>
</tr>
<tr>
<td>Biodiesel FT</td>
</tr>
<tr>
<td>Biojetfuel FT</td>
</tr>
<tr>
<td>Biojetfuel HRJ</td>
</tr>
<tr>
<td>Biodiesel UPO</td>
</tr>
<tr>
<td>Biojetfuel UPO</td>
</tr>
<tr>
<td>Biobutanol</td>
</tr>
</tbody>
</table>

Source: E4Tech (2011) for CCC

10 Note that this is uncertain, as some think that UPO will only ever be used as a minor blending component rather than a full drop in fuel (e.g. AEA Modes 2 assumes no use of UPO in aviation)
A limitation of the model with respect to blend rates for biofuels is that these can be specified only as a set of fixed rates which the model can choose between (and which has been limited due to the additional complexity and modelling runtime associated with additional options), rather than a range within which the model can optimise precisely.

**Discount rates**

The following capital annualisation factors were applied (Table 3), alongside the standard social time preference discount rate of 3.5%.

<table>
<thead>
<tr>
<th>Technology type</th>
<th>Annualisation factor</th>
</tr>
</thead>
<tbody>
<tr>
<td>Intermediate conversion</td>
<td>10%</td>
</tr>
<tr>
<td>Power</td>
<td>10%</td>
</tr>
<tr>
<td>Heat</td>
<td></td>
</tr>
<tr>
<td>Residential</td>
<td>7%</td>
</tr>
<tr>
<td>Commercial and Industrial</td>
<td>10%</td>
</tr>
<tr>
<td>Surface transport</td>
<td></td>
</tr>
<tr>
<td>Cars</td>
<td>7%</td>
</tr>
<tr>
<td>Vans and HGVs</td>
<td>10%</td>
</tr>
<tr>
<td>Aviation and shipping</td>
<td>10%</td>
</tr>
</tbody>
</table>

*Source: CCC*

**Build constraints**

A variety of build constraints can be applied in the model including both minimum and maximum build quantities, and absolute or proportional build rates (i.e. based on cumulative capacity installed in previous time periods). These can be applied to individual technologies and/or to groups of technologies (retaining freedom for the model to choose the mix of technologies within the overall group constraint).

- **Power and CHP.** Maximum build constraints (quantity and rate) are taken from Arup (2011) and Pöyry (2011) for renewables. Nuclear build-rate assumptions are consistent with those in the Committee’s Renewable Energy Review (2011). We also apply minimum build quantities for non-bio renewable technologies, again consistent with the Renewable Energy Review, in order to drive cost reductions that would allow later cost-effective deployment.

- **Transport.** Build constraints are applied consistent with previous detailed modelling for the Committee’s fourth carbon budget report, in order to represent a more realistic uptake trajectory as against sudden adoption of low-carbon vehicles in later periods. This can be done via either maximum growth constraints which limit sales according to current stock or minimum build quantity constraints in earlier periods\(^\text{11}\).

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\(^{11}\) The functionality for applying growth rate constraints significantly increases the runtime of the model; minimum build quantity constraints can be applied as a proxy. Note that the constraints applied were relatively low (6% of the stock in 2020 rising to 9% in 2050) and not binding in any of the scenarios we have tested.
• **Heat.** Maximum build constraints (quantity and rate) are applied based on previous analysis for the Committee’s fourth carbon budget report and Renewables Review. Maximum build quantities reflect the suitability of different technologies for different heat demand segments and ‘S-curve’ market growth (slow initially, then gathering pace before saturating at stock turnover), with low-carbon heat markets reaching maturity by 2030.

• **Biofuel conversion technologies.** Availability/build constraints for conversion technologies were based on CCC assumptions, informed by current technology development and build rates for other types of plant in the model (Table 4). They were reviewed by E4tech as part of their data review.

• **Anaerobic Digestion.** Build constraints were adapted from SKM Enviros (2011), which provides scenarios for uptake of different AD technologies; these were summed to provide group build rates, with the model able to optimise across technologies within groups. A further adjustment was made to separate out the effect of feedstock constraints in the SKM Enviros scenarios.

• **Other.** Build constraints for other technologies are covered in the relevant sections above (CCS, hydrogen, district heating, bio-SNG).

<table>
<thead>
<tr>
<th>Table 4: Build rate constraints assumed</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Technologies</strong></td>
</tr>
<tr>
<td>Conventional ethanol, Biodiesel FAME</td>
</tr>
<tr>
<td>Biodiesel HVO, Biojetfuel HRJ</td>
</tr>
<tr>
<td>Biobutanol, Cellulosic ethanol, Cellulosic biobutanol¹, Biodiesel FT, Biojetfuel FT, BioDME, Biodiesel PPO, Torrefaction²</td>
</tr>
<tr>
<td>Pyrolysis oil, Upgraded pyrolysis oil (UPO)²</td>
</tr>
<tr>
<td><strong>Maximum build rates</strong></td>
</tr>
<tr>
<td>1 x S3, 1 x S2, 3 x S1 plants per 5-year period from 2011; double this from 2040</td>
</tr>
<tr>
<td>1 x S3, 1 x S2, 3 x S1 plants per 5-year period from 2015; double this from 2030</td>
</tr>
<tr>
<td>1 x S3, 1 x S2, 3 x S1 plants per 5-year period from 2020; double this from 2040</td>
</tr>
<tr>
<td>1 x S3, 1 x S2, 3 x S1 plants per 5-year period from 2025; double this from 2045</td>
</tr>
</tbody>
</table>

Note: S1-3 refer to plant sizes characterised within the model, based on the sources in Annex B. Note these are not equivalent for all plant types – see Annex B for capacity values. ‘S1 only’ and ‘S3 only’. ‘S1 only’.

**Calibration**

Where necessary (i.e. where the model would otherwise choose to build greater quantities), maximum group build quantity constraints are applied to a range of technology groups to 2020, consistent with DECC’s Renewables Roadmap. These include:

• air source heat pumps, ground source heat pumps and biomass boilers in the residential, non-residential and industrial sectors

• AD biomethane to grid, AD CHP, AD heat only and AD electricity only

• Advanced biofuels conversion technologies

Constraints have been imposed on minimum build of certain renewable technologies in the period to 2020, to reflect underlying technology policy implied by the Renewables Roadmap to reduce costs via ‘learning by doing’ and to create options for later deployment. The minimum constraints have been set at the lower end of the range for each technology in the Roadmap. The model is then free to deploy further quantities above this minimum level on a cost-effective basis, up to the maximum build constraints specified.

**Mothballing and early scrappage**

Within the least-cost optimisation, the model can choose to add technologies but not to use them for their full lifetime (e.g. delaying use or prematurely/temporarily ceasing use). However, constraints have been applied in some areas to prevent unrealistic patterns of behaviour driven by ‘penny switching’ (i.e. large changes in the model’s choices resulting from small changes in assumptions) within the model. Specifically, biofuels plants are constrained to have a minimum load factor of 50% once built, while vehicles are constrained to have a minimum load factor of close to 100% (implying that ‘build’ rates are very largely determined by stock turnover).

**Scenarios**

We have examined a number of scenarios to explore the potential role of bioenergy in meeting carbon budgets and long-term emissions targets, and to test the robustness of conclusions to different states of the world. The key characteristics which define each scenario are:

- Available bioenergy resources
- Fossil fuel prices
- Technology availability/ costs / characteristics

In all scenarios we have assumed that:

(i) both emissions targets and renewable energy targets must be met; and

(ii) emissions associated with production of bioenergy are accounted for whether these occur in the UK or overseas.
The resource availability scenarios used were developed internally for the bioenergy review and are described in more detail in Technical Paper 2. These are summarised below (Table 5). The fossil fuel prices scenarios used were taken from DECC’s latest fossil fuel prices projections.\(^\text{13}\)

<table>
<thead>
<tr>
<th>Abbreviated name</th>
<th>Full Name</th>
<th>Total primary bioenergy in 2050 (TWh/yr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CLU</td>
<td>Constrained Land Use</td>
<td>108</td>
</tr>
<tr>
<td>ELU</td>
<td>Extended Land Use</td>
<td>213</td>
</tr>
<tr>
<td>FLC*</td>
<td>Further Land Conversion</td>
<td>504</td>
</tr>
</tbody>
</table>

Source: CCC  
Note: For the ‘FLC’ scenario we assume the Agricultural Land Conversion sub-scenario in which land use change emissions are minimal.

Table 6 summarises the scenarios we have examined.

The ‘base case’ scenario assumes the Extended Land Use scenario for resource availability, central fossil fuel prices, availability of CCS (and hydrogen) and central assumptions for technology costs. Other scenarios vary one or more of these parameters.

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Bio-resources</th>
<th>Fossil fuel prices</th>
<th>CCS</th>
<th>Other technology availability/ costs</th>
<th>Targets and lifecycle emissions</th>
<th>Rationale</th>
</tr>
</thead>
<tbody>
<tr>
<td>ELU, CCS, high oil price</td>
<td>ELU</td>
<td>central</td>
<td>Y</td>
<td>base</td>
<td>base</td>
<td>Base case. Key questions are: can emissions targets be met? What are the main uses of bioenergy?</td>
</tr>
<tr>
<td>ELU, CCS, no H2</td>
<td>ELU</td>
<td>central</td>
<td>Y</td>
<td>no hydrogen</td>
<td>base</td>
<td>What happens if hydrogen technologies do not prove viable? Do we see biofuels in surface transport? Which technologies are used to provide peak electricity demand? Is CCS applied to other technologies?</td>
</tr>
<tr>
<td>ELU, CCS, high H2 costs</td>
<td>ELU</td>
<td>central</td>
<td>Y</td>
<td>high hydrogen costs(^\text{14})</td>
<td>base</td>
<td>As no hydrogen but less extreme</td>
</tr>
<tr>
<td>ELU, CCS, high EV costs</td>
<td>ELU</td>
<td>central</td>
<td>Y</td>
<td>high electric vehicle costs(^\text{15})</td>
<td>base</td>
<td>What is the impact of high EV costs? Does this push more bio-resources into surface transport?</td>
</tr>
</tbody>
</table>

\(^\text{13}\) [http://www.decc.gov.uk/assets/decc/statistics/analysis_group/81-iag-toolkit-tables-1-29.xls]
## Table continued: Summary of modelling sensitivity runs

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Bio-resources</th>
<th>Fossil fuel prices</th>
<th>CCS</th>
<th>Other technology availability/costs</th>
<th>Targets and lifecycle emissions</th>
<th>Rationale</th>
</tr>
</thead>
<tbody>
<tr>
<td>ELU, no CCS</td>
<td>ELU</td>
<td>central</td>
<td>N</td>
<td>base</td>
<td>base</td>
<td>What happens if CCS does not prove viable? How are patterns of use affected? Is biomass still used for power generation? Do we see greater use in heat and/or transport?</td>
</tr>
<tr>
<td>ELU, no CCS, high oil price</td>
<td>ELU</td>
<td>high oil</td>
<td>N</td>
<td>base</td>
<td>base</td>
<td>How are patterns of bioenergy use affected if CCS does not prove viable and oil prices are high? Do we see use of biofuels in surface transport?</td>
</tr>
<tr>
<td>ELU, no CCS, high biofuel costs</td>
<td>ELU</td>
<td>central</td>
<td>N</td>
<td>high biofuel production costs&lt;sup&gt;16&lt;/sup&gt;</td>
<td>base</td>
<td>What happens if costs for second generation biofuels prove to be higher than currently assumed? Are resources for which they compete used in heat and/or power generation (with or without CCS) instead?</td>
</tr>
<tr>
<td>CLU, CCS</td>
<td>CLU</td>
<td>central</td>
<td>Y</td>
<td>base</td>
<td>base</td>
<td>What is the impact of a lower available supply of bioenergy? Can emissions targets still be met?</td>
</tr>
<tr>
<td>FLC, CCS</td>
<td>FLC</td>
<td>central</td>
<td>Y</td>
<td>base</td>
<td>base</td>
<td>What is the impact of a greater available supply of bioenergy? Does this change the quantity of bioenergy used? Is the pattern of use affected?</td>
</tr>
<tr>
<td>FLC, no CCS</td>
<td>FLC</td>
<td>central</td>
<td>N</td>
<td>base</td>
<td>base</td>
<td>What happens if there is a greater available supply of bioenergy and CCS does not prove viable? Does this change the quantity of bioenergy used? Is biomass still used for power generation? Do we see greater use in heat and/or transport?</td>
</tr>
</tbody>
</table>

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<sup>14</sup> 50% increase in the long-term capital costs of fuel cell vehicles and hydrogen turbines

<sup>15</sup> 50% increase in long-term vehicle capital cost for fuel cell and pure battery electric vehicles, with a 25% increase for PHEVs

<sup>16</sup> 3. 50% increase in the long-term capital costs of advanced biofuel production facilities
4. Appropriate use of bioenergy resources: results

Use of bioenergy in the long term

Examining the results of these scenarios, we draw a number of key conclusions:

- In the long term (i.e. to 2050), emissions targets will be very difficult to meet without some – albeit limited – bioenergy penetration, together with the use of CCS technology.

- In the base case (and other scenarios with ELU resource levels and availability of CCS), the emissions target is met via a combination of bio and non-bio technologies, and use of CCS with bioenergy to provide negative emissions (which offset residual fossil emissions in those sectors in which emissions are more difficult to reduce). This reflects the fact that there are a small number of specific economic activities where alternatives to hydrocarbons may either be infeasible (e.g. in aviation) or have not yet been identified (e.g. in iron and steel).

- However if either one of these conditions is relaxed, there is a shortfall between net emissions and the emissions target:
  - with a lower level of available resource (i.e. as in the CLU scenario), even with CCS and maximum abatement available from non-bio technologies such as heat pumps and EVs, there is a shortfall of 6 MtCO$_2$ in 2050. Given that emissions targets cannot be met with the lower (CLU) resource availability even with CCS, we did not run further sensitivities using this level of resource (Figure 6)
  - with the same (ELU) level of available resource but without CCS, there is a shortfall of 36 MtCO$_2$ (Figure 7)

- If the level of available bioenergy resource is higher (i.e. in the FLC scenario), our analysis suggests that it is possible to meet the emissions target even if CCS is not available. However this would imply land use change exceeding reasonable currently estimated sustainability limits, requiring trade-offs versus other desirable environmental and social objectives (see Technical Paper 2).

- Therefore if CCS does not prove a viable technology, and/or trends in food or energy crop productivity suggest that the land use required to achieve the level of bioenergy resource in our ELU scenario is unsustainable, achieving the 2050 target will require one or more of:
  - bioenergy technology breakthroughs (e.g. algae)
  - breakthroughs in other areas (e.g. production of iron and steel without hydrocarbons, or to allow product substitution)
  - further reductions in non-CO$_2$ emissions, or
  - changes in consumer behaviour (e.g. in relation to diet or travel behaviour).
Figure 6: CO₂ emissions in 2050 under a range of scenarios for bioenergy supply, assuming availability of CCS

Source: CCC modelling, using model developed by Redpoint Energy and Ecofys.
Notes: Allowed emissions of 105 MtCO₂ based on 2050 target of 160 MtCO₂e, adjusted for 55 MtCO₂e non-CO₂ emissions which are outside the scope of the model. Availability of CCS is assumed. Other industry emissions include industrial process CO₂ emissions and CO₂ emissions from other energy supply industries which are also outside the scope of the model; these are assumed to be 42 MtCO₂ incorporating 27 MtCO₂ of abatement potential from CCS on process emissions. Bioenergy lifecycle emissions include overseas lifecycle emissions for imported bioenergy, as well as those occurring in the UK. Negative emissions credits result from carbon storage in CCS or wood in construction. Where the model is unable to meet the 2050 target, it reduces emissions to the lowest level possible. In these results, Further Land Conversion (FLC) denotes specifically our Agricultural Land Conversion scenario, in which there are negligible land use change emissions.

Figure 7: CO₂ emissions in 2050 in scenarios with and without CCS

Source: CCC modelling, using model developed by Redpoint Energy and Ecofys.
Notes: Extended Land Use scenario. Allowed emissions of 105 MtCO₂ based on 2050 target of 160 MtCO₂e, adjusted for 55 MtCO₂e non-CO₂ emissions which are outside the scope of the model. Other industry emissions include industrial process CO₂ emissions and CO₂ emissions from other energy supply industries which are also outside the scope of the model; these are assumed to be 69 MtCO₂ in the scenario without CCS and 42 MtCO₂ in the scenario with CCS based on previous analysis for our fourth carbon budget report which identified 27 MtCO₂ of abatement potential from CCS on process emissions. Bioenergy lifecycle emissions include overseas lifecycle emissions for imported bioenergy, as well as those occurring in the UK. Negative emissions credits result from carbon storage in CCS or wood in construction. Where the model is unable to meet the 2050 target, it reduces emissions to the lowest level possible.
For a given level of bioenergy resource, availability of CCS also has a crucial influence on the long-term pattern of bioenergy use. Figure 8 shows the amount of bioenergy used across different sectors in 2050, under the range of ELU resource scenarios, with and without CCS:

- In scenarios with CCS, the majority of bioenergy use in 2050 is in applications with CCS. In most scenarios, these results suggest a strong role for hydrogen production from bioenergy with CCS, used for both transport and power generation. However, the key point to note here is the extent to which CCS is favoured, rather than the precise applications to which it is applied. In practice this would depend on the relative feasibility, costs and performance of different applications. If hydrogen is assumed to be unavailable, resources are instead diverted to production of biodiesel, with capture of CO₂ emissions from this process. The resulting fuel is used both for heat in industry and in transport.

- In scenarios without CCS, there is an increased and very strong role for bioenergy in industrial heat applications. We also start to see liquid biofuel use in aviation and shipping, and some use in HGVs. This reflects the limited alternatives available in industry and aviation and shipping which mean that, without negative emissions from use of biomass with CCS to offset residual fossil fuel use, use of bioenergy to reduce emission in these sectors is of high value. The high efficiency of using biomass for industrial heat compared to converting it to liquid biofuels means that this application is favoured.

- In all scenarios, whether or not CCS is available, there is a role for wood in construction for those feedstocks which are suitable.

- There is a limited long-term role for liquid biofuels in surface transport, reflecting that there is a range of alternatives for decarbonising this sector, and that even if liquid biofuels were produced with CCS these would better be used in aviation and shipping.

- Similarly, in all scenarios, there is no long-term role for power generation from solid biomass without CCS as this provides no significant additional benefit to the system: unlike biomass power generation with CCS, it does not provide negative emissions (creating headroom for hard-to-reduce sectors), and by 2050 is an expensive option compared to other low-carbon alternatives for decarbonising power (reflecting the fact that premium markets for bioenergy emerge and consequently its price increases significantly).

These results broadly hold when the level of resource is increased:

- Where available, CCS applications remain a key use of bioenergy resources, and uses in wood in construction and industrial heat continue to feature. However, we now also see a strong role for aviation and shipping biofuels (produced without CCS) and some liquid biofuels in surface transport, while use in power generation with CCS is reduced.
• With higher resource levels, it is possible to meet the emissions constraint by using biofuels to reduce emissions in aviation and shipping – to the extent that some of the more expensive measures in other sectors can be avoided (e.g. some electric (battery and fuel cell) vehicles and some heat pumps in the residential sector and, in turn, biomass power generation with CCS, hydrogen turbine and some non-bio renewables generation) – leaving slightly higher emissions in those sectors.

• Essentially, the higher biomass resource creates additional options for reducing emissions, and thus the relative importance of maximising the abatement per tonne of biomass reduces, with cost considerations more of a factor. With a lower resource, there is a greater imperative to use it to maximise abatement, primarily in applications with CCS even where these are expensive (e.g. power).

**Bioenergy in context**

While key to meeting emissions targets, bioenergy plays a relatively small role in the context of the wider energy system in this analysis, highlighting the need where possible to pursue alternative options for reducing emissions including energy efficiency, electrification of heat and transport, and renewable and other low-carbon power generation.

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**Figure 8: Bioresource use in 2050 under a range of scenarios**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Bioresource use in 2050 – primary energy basis (TWh/year)</th>
</tr>
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<tbody>
<tr>
<td>CLU, with CCS</td>
<td></td>
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<tr>
<td>ELU, with CCS</td>
<td></td>
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<tr>
<td>ELU, with CCS, high oil price</td>
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<tr>
<td>ELU, with CCS, no hydrogen</td>
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<tr>
<td>ELU, with CCS, high hydrogen costs</td>
<td></td>
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<tr>
<td>ELU, with CCS, high EV and FCV costs</td>
<td></td>
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<tr>
<td>ELU, no CCS</td>
<td></td>
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<tr>
<td>ELU, no CCS, high oil price</td>
<td></td>
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<tr>
<td>ELU, no CCS, high biofuel costs</td>
<td></td>
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<tr>
<td>FLC, with CCS</td>
<td></td>
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<tr>
<td>FLC, no CCS</td>
<td></td>
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</tbody>
</table>

**Source:** CCC modelling, using model developed by Redpoint Energy and Ecofys.

**Notes:** In these results, Further Land Conversion (FLC) denotes specifically our Agricultural Land Conversion scenario, in which there are negligible land use change emissions. EV denotes battery and plug-in hybrid electric vehicles. FCV denotes fuel cell and fuel cell plug-in hybrid vehicles. The model can choose whether or not to use the full available bioenergy resource; in the FLC scenarios there are small amounts of unused resource. In these results, power and hydrogen production with CCS are selected. In practice however, a range of CCS applications may be appropriate, with the balance dependent on relative technology performance and economics. This could result in a higher penetration of aviation and shipping biofuels if these are produced with CCS.

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17 Solar, geothermal
Figures 9 to 12 show the mix of electricity, heat and transport fuel inputs in 2050 across a range of scenarios based on the ELU level of resource. They demonstrate that in all cases, with this level of resource, alternatives to bioenergy are generally deployed where possible to reduce emissions, and put into context the scale of contribution from bioenergy:

- In power, bioenergy sources account for 2.5% of total generation at most (Figure 9).
  - Where CCS is not available, there is no role for biomass power generation. Biomass power generation also disappears (together with a range of other more expensive technologies) with higher levels of resource, as a result of a lower level of electrification within the energy system (total generation is around 700 TWh/year compared to around 800 TWh/year in most scenarios with CLU and ELU levels of resource); generation from other more expensive non-bio renewables is also reduced.
  - In most scenarios with CCS, these CCS technologies account for around 15% of generation while non-bio renewables and nuclear account for around 40% each.\(^{18}\)
    Unabated fossil generation has a minor role, meeting peak demand. In scenarios without CCS, total generation increases to around 900 TWh/year as, without negative emissions from biomass CCS, greater emissions reductions through electrification are required in the energy system. This increase comes from non-bio renewables, as nuclear is already at its assumed maximum installed capacity. The amount of generation from nuclear is actually lower in this scenario as, rather than operating at baseload, it has to operate in load-following mode some of the time, a role occupied by gas CCS in those runs in which this option is available.

- In heat, the share of total heat demand from bioenergy sources ranges from 2% to 25% (Figure 10).
  - This is mainly industrial process heat; in terms of a share of that demand the range is 3% to 93%. The figure depends heavily on CCS availability.
    - In scenarios without CCS, the share is at the high end of the range (reflecting the lack of alternatives to decarbonising this sector which means that without negative emissions from biomass CCS, reducing emissions in this and other hard-to-treat sectors becomes a high value use of bioenergy resources, and reflecting the efficiency of using biomass in these applications).
    - The share in most scenarios where CCS is available is between 5-10%, with the rest of process heat supply remaining as fossil. This is a result of the model’s preference for hydrogen production (and power generation) from biomass with CCS. In practice however, other CCS applications, including industrial heat, could provide similar benefits in terms of abatement/economics.
  - Outside of industrial process heat, heat supply in buildings is dominated by heat pumps, with resulting emissions close to zero

\(^{18}\) With higher resource, non-bio renewables account for slightly less (33%), with slightly more unabated fossil than other scenarios. With central resource but no hydrogen, non-bio renewables account for slightly more (50%), making up for hydrogen turbine generation.
Figure 9: Electricity generation in 2050 across a range of scenarios

Source: CCC modelling, using model developed by Redpoint Energy and Ecofys.
Notes: In these results, Further Land Conversion (FLC) denotes specifically our Agricultural Land Conversion scenario, in which there are negligible land use change emissions. EV denotes battery and plug-in hybrid electric vehicles. FCV denotes fuel cell and fuel cell plug-in hybrid vehicles.

Figure 10: Heat supply in 2050 across a range of scenarios

Source: CCC modelling, using model developed by Redpoint Energy and Ecofys.
Notes: In these results, Further Land Conversion (FLC) denotes specifically our Agricultural Land Conversion scenario, in which there are negligible land use change emissions. EV denotes battery and plug-in hybrid electric vehicles. FCV denotes fuel cell and fuel cell plug-in hybrid vehicles.
In surface transport, liquid biofuels account for between 0% and 11% of energy demand (Figure 11).

- In most scenarios with ELU levels of resource or less and with CCS available, there is no role for liquid biofuels. They appear only in scenarios without CCS or with higher levels of resource, or where hydrogen is not available, and are generally used in heavy duty vehicles where alternatives are more limited/expensive. Instead, surface transport is largely decarbonised with electric cars and vans, and hydrogen vans, buses and HGVs. Some residual fossil emissions remain in ELU scenarios with CCS (where negative emission from biomass with CCS can offset them) but are negligible in scenarios without CCS.

- With higher resource levels, there are more residual fossil emissions, and fewer electric (battery and fuel cell) vehicles. The additional bioenergy resources can be used to reduce emissions in other sectors to the extent that some of the more expensive measures in surface transport can be scaled back.

In aviation and shipping, use of liquid biofuels depends on the availability of CCS and on the level of available resource (Figure 12).

- Where CCS is available, in scenarios with ELU levels of resource or less, aviation/shipping remain fossil-based, with emissions offset by use of bioenergy resources in CCS applications in other sectors to create negative emissions (although CCS could be potentially applied to biofuels production leading to greater penetration of aviation/shipping biofuels).

- The most unusual scenario is where CCS is available and we have higher levels of resource: here the greater supply of feedstock mean aviation biofuels become cost-effective and reach penetration of almost 80%. There are enough resources to reduce emissions in this sector sufficiently, so that some of the more expensive measures in other sectors can be scaled back.

- In scenarios without CCS, penetration of aviation biofuels is around 15% under the ELU resource scenario, and 95% (the maximum penetration possible within the blend limit applied) under the FLC resource scenario. This reflects the lack of alternatives to decarbonising this sector which means that without negative emissions from biomass CCS, reducing emissions in this and other hard-to-treat sectors becomes a high value use of bioenergy resources.

To the extent that a residual amount of liquid fuels remain in surface transport in 2050, the relative benefits of using any available biofuels in different transport sectors are very similar. In some of the runs, therefore, the model does choose to use some of its limited liquid biofuel resource in surface transport even in 2050, leaving greater quantities of fossil fuels in aviation and shipping.

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19 There are fewer FCV vehicles overall, even though the amount of bioenergy resources going to this application is higher. In the high resource scenario with CCS, all hydrogen is produced via biomass gasification with CCS, whereas in the central resource scenario with CCS, although the total amount of hydrogen produced is higher, only half comes from bioenergy sources with the remainder from steam methane reforming with CCS.
Figure 11: Surface transport energy inputs in 2050 across a range of scenarios

![Surface transport energy inputs in 2050 across a range of scenarios](image1)

Source: CCC modelling, using model developed by Redpoint Energy and Ecofys.
Notes: In these results, Further Land Conversion (FLC) denotes specifically our Agricultural Land Conversion scenario, in which there are negligible land use change emissions. EV denotes battery and plug-in hybrid electric vehicles. FCV denotes fuel cell and fuel cell plug-in hybrid vehicles.

Figure 12: Aviation and shipping energy inputs in 2050 across a range of scenarios

![Aviation and shipping energy inputs in 2050 across a range of scenarios](image2)

Source: CCC modelling, using model developed by Redpoint Energy and Ecofys.
Notes: In these results, Further Land Conversion (FLC) denotes specifically our Agricultural Land Conversion scenario, in which there are negligible land use change emissions. EV denotes battery and plug-in hybrid electric vehicles. FCV denotes fuel cell and fuel cell plug-in hybrid vehicles. The results for the FLC, with CCS scenario differ from those in the main Bioenergy Review report as a higher blend limit was allowed here.
Even so, there are two reasons why it is sensible to plan on using available biofuels in aviation and/or shipping rather than surface transport in 2050:

- Given uncertainties over the precise extent of abatement opportunities across sectors, and the possibility of slippage elsewhere in attempts to reduce emissions, it is sensible to plan to decarbonise surface transport fully using battery electric and hydrogen vehicles to the extent possible.

- Our expectations for vehicle costs suggest that electric and/or hydrogen vehicles would comprise all new vehicle sales in surface transport in 2050, having become cost-effective well before this point. Therefore, even if any residual use of liquid fuels in surface transport were to remain in 2050, continued turnover of the vehicle stock would lead to their elimination soon after 2050 (e.g. by 2055). Investment in biofuel production plants to operate in 2050 and beyond would therefore need to plan for their full output to be suitable for the aviation and shipping sectors.

- In the FLC scenario, the greater availability of bioenergy provides the model with the freedom to use bioenergy in ways that deliver less abatement but a greater cost saving, such as much greater biofuel production without CCS. However, this is not a sensible planning assumption, as we do not expect the UK to be able to access this quantity of sustainable bioenergy at affordable cost, given anticipated limits on the global sustainable resource and competing demands from other countries.

**Implications for the energy system**

Our analysis highlights the need to demonstrate CCS technology as a matter of urgency, given its potentially crucial role in providing a negative emissions option when used with bioenergy, and also in abating emissions from carbon-intensive industries.

More generally, it suggests the need to develop a range of bioenergy options, and to pursue bioenergy paths that offer flexibility regarding their future role (e.g. biomethane injection into the gas grid, gasification pathways for ligno-cellulosic feedstocks).

Going beyond bioenergy, our analysis suggests a clear role now for investment in nuclear and wind power generation, energy efficiency improvement, electric forms of heat in buildings, and battery and hydrogen electric vehicles (i.e. these are very unlikely ever to be displaced by bioenergy).

**Key conclusions: medium term**

Our analysis suggests a path to 2050 characterised by the transitional use of bioenergy resources in non-CCS power generation and surface transport, and ongoing use in industry and construction (Figure 13). There is a strong role for aviation and shipping biofuels in the medium term, with the extent to which this continues dependent on availability of CCS:
• To 2020: bioenergy resources are used across the range of available applications including construction, heat and power generation and surface transport, with some early deployment in aviation.

• To 2030: there is continued use of biomass in construction, industrial heat, AD and CHP, and biofuels in surface transport, with increasing use in aviation and shipping.

• To 2040: there is continued use in construction, industrial heat and CHP. Use in surface transport starts to decline as this sector electrifies, while there is increased use in aviation/shipping and applications with CCS where available.

• To 2050: use in construction and industrial heat continues, with almost all remaining bioenergy used in CCS applications where available. Without CCS, there is ongoing use of aviation/shipping biofuels and increased use in industrial heat.

This holds across the range of scenarios we have examined (Figure 14):

• The pattern of bioenergy use to 2040 is similar across all of the runs in the CLU and ELU resource scenarios, with differences between runs largely reflecting acknowledged uncertainties:
  – The scenarios place varying proportions of liquid biofuels into surface transport, rather than aviation or shipping. For example, under the ELU scenarios in 2030 the core run places around 45% of liquid biofuels into surface transport in 2030, compared with only 13% in the ‘no hydrogen’ run.
**Figure 14: Bioresource use over time in different scenarios**

2020

CLU, with CCS
ELU, with CCS
ELU, with CCS, high oil price
ELU, with CCS, no hydrogen
ELU, with CCS, high hydrogen costs
ELU, with CCS, high EV and FCV costs
ELU, no CCS
ELU, no CCS, high oil price
ELU, no CCS, high biofuel costs
FLC, with CCS
FLC, no CCS

2030

CLU, with CCS
ELU, with CCS
ELU, with CCS, high oil price
ELU, with CCS, no hydrogen
ELU, with CCS, high hydrogen costs
ELU, with CCS, high EV and FCV costs
ELU, no CCS
ELU, no CCS, high oil price
ELU, no CCS, high biofuel costs
FLC, with CCS
FLC, no CCS

2040

CLU, with CCS
ELU, with CCS
ELU, with CCS, high oil price
ELU, with CCS, no hydrogen
ELU, with CCS, high hydrogen costs
ELU, with CCS, high EV and FCV costs
ELU, no CCS
ELU, no CCS, high oil price
ELU, no CCS, high biofuel costs
FLC, with CCS
FLC, no CCS

2050

CLU, with CCS
ELU, with CCS
ELU, with CCS, high oil price
ELU, with CCS, no hydrogen
ELU, with CCS, high hydrogen costs
ELU, with CCS, high EV and FCV costs
ELU, no CCS
ELU, no CCS, high oil price
ELU, no CCS, high biofuel costs
FLC, with CCS
FLC, no CCS

Source: CCC modelling, using model developed by Redpoint Energy and Ecofys.
The emphasis on different uses is affected by the pattern of fossil fuel prices. For example, in 2040 the ELU scenarios without CCS contain show greater allocation of bioenergy to liquid fuel production (and less to heat) in a high oil price world than in a world of central fossil fuel prices.

The strong but transitional role for biofuels in surface transport reflects several factors:

- Biofuels would be a cost-effective way of reducing emissions in surface transport in the medium term, during the period in which roll-out of electric and hydrogen vehicles is ongoing, but a significant amount of liquid fuels remain in surface transport.

- In the medium-term, when carbon constraints are slightly less binding, using bioenergy to lower abatement costs by avoiding use of petrol and diesel (rather than maximising the quantity of abatement delivered) is reasonable.

- On the approach to 2050, the strongly increasing value of bioenergy mirrors a similar rise in the carbon price (Figure 15). The emphasis is therefore more strongly on maximising abatement from bioenergy (i.e. its use with CCS or where the only alternative is fossil fuels).

- By 2050 it is both possible and desirable to have rolled out electric and hydrogen vehicles to a very large extent, thus radically reducing the role of liquid fuels in surface transport.

The following charts (Figures 16-19) provide more detail on the model’s choices over the period to 2050, at 10-year intervals from 2020.
Figure 16: Electricity generation over time in different scenarios

Source: CCC modelling, using model developed by Redpoint Energy and Ecofys.
Figure 17: Heat output over time in different scenarios

Source: CCC modelling, using model developed by Redpoint Energy and Ecofys.
Figure 18: Surface transport fuel consumption over time in different scenarios

Source: CCC modelling, using model developed by Redpoint Energy and Ecofys.
Figure 19 Aviation and shipping fuel consumption over time in different scenarios

Source: CCC modelling, using model developed by Redpoint Energy and Ecofys.
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Annex A – Bioenergy technologies

Cultivation technologies

Microalgal oil production

Microalgae include a wide variety of photosynthetic microorganisms capable of fixing CO₂ to produce biomass more efficiently and rapidly than terrestrial plants. Many algal strains exhibit high lipid content (up to 50% of biomass), much of this as triglycerides, the main component of plant oils used in the production of biodiesel via hydro treatment or transesterification.

Due to these characteristics, microalgae have very high potential energy yields relative to other feedstocks, consume little water, and can be cultivated on non-arable land or in brackish, saline, or waste water. Production of microalgal biofuels is therefore considered to be attractive because microalgae can be cultivated without causing indirect land use change (ILUC).

The potential for algae has been understood for many years and research has been widely undertaken since the 1970s, for example under the US DOE Aquatic Species Program (1978-1996). Cultivation of microalgae has been undertaken for the production of nutritional supplements, with around 9,000 tonnes of algal biomass currently produced commercially each year. Production is concentrated in a small number of firms in the United States and Australia.

Microalgae are cultivated in open ponds or closed photobioreactors before they are harvested and their oils extracted:

- An open pond system consists of a shallow circuit exposed to the atmosphere, in which the pond contents are cycled around and mixed with a paddlewheel.
- Photobioreactors are closed systems of transparent chambers that do not allow direct gas exchange with the atmosphere. The algal cultures in the ponds or photobioreactors are fertilized with CO₂ and provided with sufficient nitrogen, phosphorous, sulphur, and other trace nutrients.

Co-products include animal feed and nutritional supplements. In addition, microalgae cultivation can also be used for wastewater treatment due to ability to accumulate heavy metals and metabolize toxic compounds, while generating oxygen.

Biofuel production processes using microalgal oil include transesterification to produce FAME biodiesel and hydrotreatment to produce hydrotreated vegetable oil (HVO) biodiesel or hydrotreated renewable jet (HRJ) aviation biokerosene.

Production of biofuels from microalgal oil is well understood, with the major challenges relating to cultivation and harvesting of microalgae and extraction of the algal oil at sufficiently low cost. The innovations necessary to reduce costs of cultivation, harvesting and oil extraction require significant research and development, and are only expected over the longer term.
While microalgae are cultivated commercially for higher value products, there are currently no meaningful amounts of microalgal biofuels produced commercially in the world. Neither of the main potential cultivation methods (open ponds or closed photobioreactors) are currently mature technologies, and it is not clear which technologies have the greater potential to be economically viable:

- **Open ponds** are currently the dominant cultivation methods for microalgae, due to their lower cost than photobioreactors. However, there is less control over operating conditions, and algal growth can be inhibited by contaminants such as grazers, pathogens and competing algal species.

- **Photobioreactors** in principle allow better process control, higher biomass concentrations due to higher surface-to-volume ratios to facilitate light permeation), and reduced contamination while reducing evaporation and CO$_2$ losses. Photobioreactors are currently significantly more expensive to build than open ponds; while there may be scope for substantial cost reductions, it is not clear that photobioreactors could reach cost-competitiveness with open ponds.

- A third option is to combine closed and open systems by initially growing algae in closed reactors under controlled conditions to promote cell division and prevent contamination, before transferring the algae to an open pond and subjecting to nutrient deprivation to stimulate cell concentration and oil production for a short time before contamination occurs.

In cultivation processes investigated to date, cultivation of algae with high lipid content requires nutrient (especially nitrogen, phosphorous, or silicon) deprivation, which lowers yields; processes that offer both high lipid content and high yields have yet to be developed.

Further research, development and demonstration are required to develop:

- fast-growing algal strains with high lipid content, e.g. through genetic engineering
- understanding of conditions for culture that allow rapid production of algal biomass with high lipid content and minimal growth of competing strains
- understanding of optimal construction materials, cultivation scale, design of heating and cooling systems and CO$_2$ administration methods for both open and closed systems.

There are currently no documented low cost algal harvesting options for biofuels applications. Harvesting options under consideration include:

- Capturing algal biomass following natural settling or floating (due to buoyancy e.g. from high oil content);
- Facilitating settling using flocculation process (co-precipitation of algal cells with calcium carbonate, and other chemicals)
- Facilitating floating using a dissolved air floatation process (co-precipitation of algal cells with calcium carbonate, and other chemicals).
Processes currently used to recover oil from conventional oil crops are not appropriate for algal biomass. There are currently no documented low cost oil extraction options for biofuels applications. Solvent and mechanical extraction options are under consideration. Key barriers to cost-effective extraction are the high water content of algal biomass, and variability in lipid content occurring with changes in algal populations and climatic variations.

A number of studies (e.g. Clarens et al. (2010); Lardon et al. (2009)) estimate lifecycle emissions of microalgae cultivation to be high, mainly due to energy inputs and high mineral fertilizer use. These studies highlight the necessary advances in reducing fossil fuel inputs associated with nutrient use, harvesting and extraction.

More significantly, it is likely that much of the carbon content of algal biofuels will not be atmospheric CO$_2$. This is because atmospheric CO$_2$ cannot diffuse into intensive microalgal mass cultures at a sufficient rate to enable high growth. This means that to enable sufficient yields, the majority of the CO$_2$ required by the algae must be supplied from non-atmospheric sources. This CO$_2$ would therefore be produced during the combustion of fossil fuels or biomass during power generation or industrial processes and captured for transfer to the algae cultivation process.

**Intermediate processing technologies**

**Gasification**

Gasification is the partial combustion of a feedstock in a reactor at high temperature (e.g. 850°C) in the presence of a limited quantity of oxygen to produce syngas. The gases generated are cleaned by removing the tars, then filtered and the clean gas collected. Suitable feedstocks are dried, ground ligno-cellulosic (woody) biomass feedstocks from agriculture, forests or municipal solid waste.

Syngas is a mix of mainly carbon monoxide (CO) and hydrogen (H$_2$) with some CO$_2$, methane (CH$_4$) and higher carbon compounds. Syngas can be combusted directly in gas engines or turbines to provide heat and electrical power. Syngas can also be converted to a range of hydrocarbons such as transport biofuels through the Fischer-Tropsch process, used to produce hydrogen or converted to bio-synthetic natural gas (bio-SNG or biogas, composed mainly of CH$_4$ and CO$_2$) through a methanation process.

Gasification technology has been in place for several decades, and a number of demonstration and commercial biomass gasification plants are currently operational.

**Anaerobic digestion**

Anaerobic digestion (AD) is the processing of wet organic wastes such as animal manure, sewage effluent or food crop processing wastes to produce biogas, composed mainly of CH$_4$ and CO$_2$. Biogas is a clean burning fuel with similar qualities to natural gas and relatively low CO, NOx and particulate emissions.
Biogas can be combusted on-site, or cleaned and upgraded to produce biomethane either to be injected into the natural gas grid, or compressed / liquefied and used as a vehicle fuel. AD is a mature technology; it is currently used to produce bio-SNG at the small domestic scale (e.g. in India and China), or the larger community scale (e.g. Denmark and Germany).

The use of biogas as a vehicle fuel currently requires costly processes to remove hydrogen sulphide (to avoid engine corrosion) and CO₂ (to increase energy density); new clean-up technologies currently under development may reduce costs (water scrubber absorption, pressure swing adsorption, membrane separation, or chemical adsorption).

**Pyrolysis**

Pyrolysis is the decomposition of fossil or biomass feedstocks at high temperatures and with minimal oxygen. Suitable feedstocks are relatively dry carbonaceous material (10% moisture content) such as lignocellulosic feedstocks (e.g. waste wood). Pyrolysis produces a combination of solid char, liquid oil, and gaseous products, with the relative proportions of these components depending on the process conditions used. To produce a liquid pyrolysis oil, a process known as fast (or flash) pyrolysis is used. Fast pyrolysis is a medium temperature process with short processing times: chopped feedstock is heated at around 500°C in the near absence of oxygen for around one second to produce pyrolysis gases; these gases are then rapidly cooled to below 100°C and condensed to produce pyrolysis oil.

Pyrolysis oil has similar properties to crude oil. Pyrolysis oil can be combusted for heat and/or power, used as feedstock for gasification or upgraded to produce substitutes for diesel or aviation kerosene through hydro-deoxygenation (using high pressure hydrogen and a catalyst). The solid char produced by this process can be sequestered or used for its energy content.

As pyrolysis oil is a liquid with greater energy density than unprocessed, or chipped or pelletised feedstocks, it is easier and cheaper to transport, allowing conversion to final fuels to take place at a greater distance from the site of production of biomass. Pyrolysis oil also exhibits superior ash control and easier feeding into high pressure gasifiers than chipped or pelletised feedstocks. However, pyrolysis oil is a strong acid, requiring costly storage and handling equipment constructed of corrosive resistant materials. In addition its low flashpoint raises safety issues.

While fast pyrolysis technologies are commercially available, there are no plants producing pyrolysis oil from biomass in the UK. However, some high temperature pyrolysis plants are used for the processing of wastes, and produce gases which are combusted to generate electricity and heat. Internationally, several pyrolysis pilot plants have been constructed in Germany, the US, Australia and Brazil; however, costs remain prohibitive for development of commercial scale plants.
Liquid fuel production technologies

Pure plant oil processing

Pure plant oil (PPO) is obtained by crushing oil producing seeds. PPO is relatively cheap to produce as it requires no conversion processes.

PPO can in principle be used as a diesel substitute. However, PPO has inferior performance characteristics: it is more viscous and has poorer cold temperature performance than commercial diesel, requiring modifications to the vehicle engine; and diesel is required to start up and shut down the engine, requiring separate onboard storage for diesel and PPO. Furthermore, PPO integrates poorly with existing fuel supply infrastructure, and is therefore best suited to fleet vehicles using depot fuelling.

Fermentation – conventional ethanol

Fermentation is the use of microorganisms (e.g. yeasts or bacteria) to convert sugars to alcohol. Conventional bioethanol is produced from the fermentation of sugar and starch crops. Production of bioethanol has been encouraged since 1975 in Brazil, and more recently in the United States. In 2007, production of corn ethanol in the United States reached 24.4 billion litres; production of sugar cane ethanol in Brazil reached 18.0 billion litres.

To produce bioethanol, the feedstock is first pre-treated: corn, wheat or barley grains are pre-treated by milling, liquefaction and fractionation; sugarcane or sugar beet crops are pre-treated by cooking and mechanical pressing. Sucrose is extracted directly from pre-treated sugar crops, while pre-treated starch crops are converted to glucose via hydrolysis. The sucrose and glucose are then fermented by yeast cells and the ethanol is recovered by distillation.

Bioethanol can be used in conventional petrol vehicles at blends of up to 10%, or in flex-fuel vehicles at blends of up to 85% ethanol (E85). Ethanol has a higher octane rating than petrol, offering improved engine performance and potentially fuel efficiency in specially designed engines for E85 blends. However, there are disadvantages to use of bioethanol as a transport biofuel. Ethanol is hydrophilic, absorbing water which can result in the separation of ethanol and petrol in vehicle fuel tanks, and corrosive, causing damage to fuel pipelines. Therefore ethanol needs to be blended close to the point of sale, which increases costs. Furthermore, ethanol has poor energy density than petrol and ethanol vehicles therefore require more frequent refuelling.

Bioethanol produced from starch crops also produces dried distillers’ grains and soluble (DDGS), which can be used for animal feed, reducing demand (and land required) for other animal feed crops.

Conventional bioethanol production is a mature technology with significant production capacity in the UK. Some scope for improvement exists in optimising energy use (e.g. combustion of process residues) and exploiting commercial prospects for co-products.
**Fermentation – cellulosic ethanol**

While conventional ethanol production involves conversion of the sucrose or starch content of biomass feedstocks such as sugar or starch crops, cellulosic ethanol production involves conversion of the cellulose and hemicellulose content of a wider range of lignocellulosic (woody) feedstocks. In these feedstocks the cellulose content is protected by lignin and hemicellulose, requiring more complex treatment.

Feedstocks are based upon agricultural and forest biomass (either residues or dedicated crops) but could also include the potential recovery of biomass from urban municipal solid waste (MSW) streams. Cellulosic ethanol production comprises pre-treatment, fractionation, enzymatic hydrolysis, fermentation, and ethanol recovery:

- **Pre-treatment.** Feedstock pre-treated to open cellular structure and expose cellulose and hemicellulose to enzymes for subsequent hydrolysis. Pre-treatment methods include: biological e.g. use of wood-degrading fungi, physical (mechanical breakdown by milling), chemical e.g. acid and alkali based pulping processes or combination pre-treatments e.g. steam explosion (current state-of-the-art). Optimal pre-treatment method varies with feedstock.

- **Fractionation.** Separation of the base components of cellulose, hemicellulose and lignin to facilitate processing

- **Enzymatic hydrolysis.** Use of biological agents (enzymes or micro-organisms) to break down cellulose into to hexoses (C6 sugars) e.g. glucose and hemicellulose into pentoses (C5 sugars) e.g. xylose. Enzymes that break down cellulose and hemicelluloses are known as cellulases and hemicellulases, respectively.

- **Fermentation.** Hexose sugars can be fermented using standard yeast as in conventional bioethanol production. However standard yeast is not suitable for fermenting pentose sugars, which requires novel micro-organisms.

- **Ethanol recovery: distillation of fermented product to obtain ethanol.**

Unlike with conventional ethanol production, cellulosic ethanol production does not result in significant quantities of co-products that substitute for animal feed (e.g. DDGS). A lignin residue with high energy content is produced, which can be combusted for heat and power or to produce biomaterial co-products. An alternative process is gasification of the lignocellulosic feedstock and fermentation of the syngas. Depending on the fermentation process, it is possible to produce bioethanol with no side products.

Ethanol production from ligno-cellulosic feedstocks has been under development for the last two to three decades and technical feasibility is proven; however until recent development of improved micro-organisms and enzymes costs have been prohibitively high for commercialisation. Different phases of the conversion process are at different levels of maturity:
• Pre-treatment is currently between demonstration and commercial stages, with dilute acid, concentrated acid and steam explosion processes are closest to commercialisation and steam explosion considered as the state-of-the-art. R&D is required to optimise pre-treatment for different feedstocks and subsequent processing, and to lower costs.

• Fractionation is currently at the R&D stage. If successful, fractionation technologies could address inhibition of enzymatic hydrolysis by lignin content of pre-treated substrate, which slows enzyme activity and increases production costs.

• Enzyme production for hydrolysis is now at commercial stage. R&D is ongoing on cellulase genes produced by cellulose-digesting insect species. Firms currently undertaking R&D include Codexis in partnership with Royal Dutch Shell, and Iogen. The USDOE-funded National Renewable Energy Laboratory research programme to reduce the cost of enzymatic hydrolysis was set up in 1999 in association with Genencor and Novozymes.

• Enzymatic hydrolysis is at early demonstration stage. A major challenge relates to inhibitors that slow enzyme activity and increase production costs. As well as lignin, the synthesised glucose itself is an inhibitor. Inhibition by glucose could be addressed by combining hydrolysis with fermentation of the carbohydrate intermediates (simultaneous saccharification and fermentation). Enzyme recycling, where enzymes are attached to a non-reactive substance prior to hydrolysis and subsequently recovered and re-used rather than lost as they bind to ligno-cellulose components during typical hydrolysis processes, could also reduce costs. Despite reductions in enzyme costs (e.g. the cost of cellulase production preparations has decreased by up to 95% in recent years), costs remain high and are a barrier to full-scale process commercialization.

• Fermentation is at commercial stage for hexose sugars, but at the research/pilot stage for pentose sugars (though moving towards commercialisation). R&D is ongoing on development of organisms capable of converting both C6 and C5 sugars together with high yields, and on processes for simultaneous saccharification and fermentation such as bacterial systems that are capable of cellulose hydrolysis and glucose fermentation together, and enzymes for fermentation that operate at the higher temperatures (55 degrees C) required for hydrolysis.

Further cost reductions could be achieved through better process integration, and optimisation of the trade-offs between cost and efficiency offered by the different technologies at each stage in the production process. The technology to produce bioethanol through gasification of lignocellulosic feedstock and fermentation of syngas is proven at pilot scale, and demonstration scale is expected in the near future.
**Fermentation – conventional and cellulosic biobutanol**

Butanol (C₆H₁₃OH), like ethanol, is produced through fermentation of sugars.

Biobutanol is a substitute for petrol or bioethanol; it has a higher energy density than ethanol, a less corrosive nature and lower water solubility so unlike bioethanol can be used in conventional petrol vehicles at high blends, and can be transported in oil pipelines. Biobutanol can be produced from both sugar and starch feedstocks (conventional biobutanol), and lignocellulosic feedstocks (cellulosic biobutanol).

To produce biobutanol, the feedstock is first pre-treated using auto-hydrolysis to release the cellulose and hemi-cellulose; these are then converted to sugars via enzymatic hydrolysis. The sugars are then fermented to produce a solution containing butanol, acetone and ethanol. Butanol is toxic to the fermentation organisms that produce it; the fermentation process therefore produces a solution with a very low concentration (around 2%) of butanol. Butanol is isolated from this solution by distillation; due to the low concentration and the presence of acetone and ethanol, the distillation process is complex and costly.

Due to the low concentration of butanol and the presence of acetone and ethanol in the solution produced by the fermentation process, the distillation process is complex and costly.

Biobutanol production is relatively mature; the SunOpta BioProcess Group developed a cellulosic biobutanol plant in France in 1985. However, significant cost reductions are required to achieve commercial potential. Current R&D is focused on developing fermentation processes with improved microbial and enzymatic technology, to produce butanol with fewer co-products and deliver better conversion efficiency.

**Hydrotreatment**

Hydrotreatment is the conversion of triglycerides contained in oils and fats to biofuels by reacting the triglycerides with hydrogen using a catalyst (catalytic hydrogenation). Triglycerides can be converted to Hydrotreated Vegetable Oil (HVO) biodiesel, a diesel substitute, or Hydrotreated Renewable Jet (HRJ) biokerosene, an aviation kerosene substitute. HVO biodiesel can be used in conventional diesel vehicles at any blend. A number of airlines have conducted test flights using HRJ biokerosene.

Hydrotreatment is similar to a number of well-established refinery techniques. The first commercial scale HVO plant was commissioned by Finnish company Neste Oil in 2007 using the company’s NExBTL process; Neste have since opened two additional, larger commercial scale HVO plants in Rotterdam and Singapore.

**Transesterification**

Transesterification is the reaction of vegetable oil with methanol in the presence of a catalyst to separate the glycerol molecule from the chemical composition of the vegetable oil, producing Fatty Acid Methyl Ester (FAME) biodiesel with glycerol as a co-product. FAME biodiesel is produced from vegetable oil derived from oil crops such as oilseed rape, or from waste oil.
FAME biodiesel is primarily a transport biofuel. At low blends, FAME improves engine performance by increasing the oxygen content of the fuel. However, FAME has poorer cold temperature performance than commercial diesel (particularly FAME produced from more saturated vegetable oils), restricting use at very high blends, while biofuels produced from more unsaturated oils age relatively rapidly.

Transesterification is a relatively mature technology, and FAME is currently the most common form of biodiesel. FAME process technology is available from a number of providers, and the capital costs are relatively low.

**Fischer-Tropsch synthesis**

Fischer-Tropsch (FT) synthesis is the catalytic conversion of syngas produced from feedstocks via gasification to a hydrocarbon fuel. FT synthesis can produce substitutes for a range of hydrocarbon fuels including petrol, diesel and aviation kerosene.

Fischer-Tropsch synthesis is a mature technology. It was developed in Germany in 1923 and used there during World War II to produce liquid fuels from coal. In the 1980s South African oil company SASOL built FT plants to convert coal into diesel and gasoline, due to UN trade sanctions and lack of domestic petroleum resource.

To produce FT-biodiesel and FT-biokerosene, first the biomass feedstocks are gasified and the syngas cleaned. The syngas is conditioned to obtain the desired ratio of hydrogen to carbon monoxide (typically a molar ratio of around 2:1) via a water-gas shift reaction. The syngas is then passed over catalysts such as transition metal catalysts based on iron and cobalt at high temperature (around 200-350°C) and pressure (around 20-40 bar) to produce the hydrocarbon fuel. The composition of the fuel can be adjusted by varying temperature and pressure. The process produces a crude hydrocarbon product, which is hydrocracked (broken down with the addition of hydrogen) to produce the desired hydrocarbon fuel and a number of by-products.

By-products of FT synthesis include a range of substances (e.g. olefins, paraffins, oxygenated products such as alcohols, aldehydes, acids and ketones), whose proportions can be varied by adjusting temperature, pressure, feed gas composition (ratio of H2/CO), catalyst type and catalyst composition.

A number of barriers to application of the FT process to biomass feedstocks remain. Syngas typically contains tars and other contaminants that inhibit the FT catalytic reaction; with biomass-based syngases, the contaminants and overall composition of the gas mix vary with feedstock, making the syngas more difficult to process. Potential solutions include processing biomass into sufficiently small particles to obtain tar free syngas, improved gasification processes (e.g. a two-stage gasification process to produce cleaner syngas) or development of improved catalysts capable of resisting inhibitors. Current processes to clean syngas sufficiently incur significant cost.

The FT process is a relatively mature technology, and is currently used in South Africa, Qatar, and Malaysia to produce liquid fuels through conversion of coal and natural gas, though gasification processes are not currently optimised for FT synthesis. Application of the FT
process to biomass feedstocks is proven at the pilot and demonstration scales but has not reached the commercial stage.

It is expected that, in addition to technological breakthroughs, there is scope for cost reduction from economies of scale and learning experience with deployment of large scale commercial plants.

**Pyrolysis oil upgrading**

Pyrolysis oil can be upgraded to a range of fuels (e.g. petrol, diesel, aviation kerosene) in existing crude oil refineries or in purpose-built pyrolysis oil upgrading facilities. Upgrading processes include reacting the pyrolysis oil with hydrogen to saturate hydrocarbon structures, and thermal treatment to improve temperature performance.

According to NNFCC and Low CVP (2010), development of cost-effective pyrolysis oil upgrading technologies will need to overcome a number of challenges:

- High oxygen content
- High acid number (this makes re-use of existing hydrocrackers possibly problematic)
- High water content
- High metals content (particularly potassium and calcium)
- Immiscibility of pyrolysis oils with petroleum oils

Pyrolysis oil upgrading is currently at the R&D stage. Refining company UOP is developing upgrading technology, which is expected to be commercially available from around 2012/13.

**Carbon capture and storage (CCS) in biofuel production**

In all conversion processes, there is a significant difference between the carbon content of the feedstock and that of the final fuel produced. This difference can arise from two factors: a difference in the carbon-intensity (gCO₂/kWh) of the inputs and outputs, and the energy losses in the conversion process. For example, production of a liquid biofuel via the Fischer-Tropsch (FT) process without CCS has a conversion efficiency of around 67%, while the carbon-intensity of the energy carrier falls from around 350g/kWh in the sold biomass input, to around 250g/kWh in the biofuel. Combining these factors suggests that only around 50% of the carbon in the biomass feedstock ends up in the biofuel, with the remainder emitted to atmosphere or contained in ash or char.

The residual carbon from the conversion process (the fraction of the carbon present in the feedstock that does not end up in the fuel) could in principle be captured and stored. If CCS is available, biomass conversion with CCS presents the possibility of transforming use of bioenergy from a carbon-neutral energy source to one that is carbon-negative. In addition, many conversion processes require fossil fuel combustion to generate heat and power.
Application of CCS technologies to these processes could reduce the fossil CO₂ emissions during conversion.

The residual carbon from the conversion process takes two forms: residue from the conversion process (e.g., lignin in cellulosic ethanol), or carbon content of substances produced during the conversion process (e.g., CO₂ stream produced during fermentation of bioethanol, CO₂ component of gasification syngas).

The conversion residue can be stored or combusted to provide energy for the conversion process, releasing the bio CO₂. However, if CCS were applied during the combustion process, the bio CO₂ could be captured from the flue gases via absorption (use of chemical or physical solvents to scrub the gases and collect the CO₂); in this case, CCS could also be applied to any fossil fuel combustion involved. Similarly, CCS could be applied to capture the carbon content of substances produced during the conversion process.

We model conversion processes with CCS using assumptions on costs and energy requirements based on a range of potential capture sources with different characteristics within a large refinery complex, as set out in Element Energy (2010). Under these assumptions, maximum share of site emissions considered technically and economically feasible for capture is estimated at around 80%. Due to the heterogeneity of processes underlying these assumptions, we consider the assumed costs and energy requirements to be sufficient to account for the application of CCS to the combustion of conversion residues, combustion of fossil fuel inputs, and capture of the carbon content of substances produced during the conversion process.

For our appropriate use modelling, we model CCS variants of the following technologies:

- Conventional and cellulosic ethanol production (large scale)
- Conventional and cellulosic biobutanol production (large scale)
- FAME biodiesel production (large scale)
- HVO biodiesel and HRJ biojetfuel production (large scale)
- FT biodiesel production and FT biojetfuel production (large scale)
- Pyrolysis oil production (large scale)
- BioDME production (large scale)
- Hydrogen production via Biomass gasification, Coal gasification and Steam Methane Reforming
Annex B – Data used in the modelling

Technologies

Data sources used to characterise technologies in the modelling are summarised in the table below (see references section for full source references).

<table>
<thead>
<tr>
<th>Technology type</th>
<th>Technology</th>
<th>Data source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-processing</td>
<td>Chipping, Pelletising</td>
<td>Derived from E4tech (2010)</td>
</tr>
<tr>
<td>Liquid fuel</td>
<td>Biodiesel FAME plant(^1,2)</td>
<td>Pöyry (2010), capital costs adjusted following E4tech data review</td>
</tr>
<tr>
<td></td>
<td>Biodiesel HVO plant, biojetfuel HRU plant(^1,2)</td>
<td>Pöyry (2010), biojetfuel plant replica of biodiesel plant</td>
</tr>
<tr>
<td></td>
<td>Biodiesel FT plant, biojetfuel FT plant(^1,2)</td>
<td>NNFCC (2011) scaled for different feedstocks based on Pöyry (2010), biojetfuel plant replica of biodiesel plant</td>
</tr>
<tr>
<td></td>
<td>Biodiesel PPO (pure plant oil) plant</td>
<td>SAC (2005)</td>
</tr>
<tr>
<td></td>
<td>Pyrolysis oil plant(^1)</td>
<td>Pöyry (2010), capital costs adjusted following E4tech data review based on Bridgwater (2011)</td>
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<tr>
<td></td>
<td>Pyrolysis upgrading plant</td>
<td>E4Tech estimate (based on various sources, available on request)</td>
</tr>
<tr>
<td></td>
<td>Ethanol plant(^1)</td>
<td>Pöyry (2010), capital costs adjusted following E4tech data review</td>
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<tr>
<td></td>
<td>Biobutanol plant</td>
<td>Pöyry (2010)</td>
</tr>
<tr>
<td></td>
<td>Cellulosic ethanol plant(^1,2)</td>
<td>NNFCC (2011)</td>
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<td></td>
<td>Cellulosic biobutanol plant(^1)</td>
<td>E4tech estimate (based on various sources, available on request)</td>
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<td></td>
<td>BioDME plant(^1)</td>
<td>Pöyry (2010)</td>
</tr>
<tr>
<td>Gaseous fuel</td>
<td>AD BTG</td>
<td>SKM Enviros (2010)</td>
</tr>
<tr>
<td></td>
<td>Bio-SNG(^1)</td>
<td>NERA &amp; AEA (2010)</td>
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<tr>
<td></td>
<td>Hydrogen production</td>
<td>Production data adapted from US DOE H2A tool, distribution data from Joffe (2010)</td>
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### Table B1: Key sources of technology data

<table>
<thead>
<tr>
<th>Technology type</th>
<th>Technology</th>
<th>Data source</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Power</strong></td>
<td>Gas turbine (CCGT, CCGT with CCS, OCGT)</td>
<td>Mott Macdonald (2010), Redpoint IDM for build rate constraints (EMR baseline scenario)</td>
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<tr>
<td></td>
<td>ACT electricity</td>
<td>Arup (2011)</td>
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<tr>
<td></td>
<td>AD electricity</td>
<td>SKM Enviros (2010)</td>
</tr>
<tr>
<td></td>
<td>Biodiesel engine</td>
<td>NNFCC (2010); DECC (2011) RO banding study for build rate constraints</td>
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<tr>
<td></td>
<td>Bioliquid electricity</td>
<td>Arup (2011)</td>
</tr>
<tr>
<td></td>
<td>Biomass IGCC, Biomass IGCC with CCS (cofiring and dedicated)</td>
<td>E4Tech estimate (based on various sources, available on request)</td>
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<tr>
<td></td>
<td>Dedicated biomass plant</td>
<td>Mott Macdonald (2010), DECC (2011) RO banding study for build rate constraints</td>
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<td></td>
<td>Converted (from coal) biomass plant</td>
<td>Mott Macdonald (2011)</td>
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<td></td>
<td>Existing coal plant</td>
<td>Mott Macdonald (2011)</td>
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<td>New coal plant with CCS, New enhanced co-firing coal plant with CCS</td>
<td>Mott Macdonald (2010), Arup (2011) for incremental co-firing costs, DECC (2011) RO Banding study for build rate constraints</td>
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<td>Energy from waste</td>
<td>Arup (2011)</td>
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<tr>
<td></td>
<td>Landfill gas plant</td>
<td>Arup (2011)</td>
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<td></td>
<td>Sewage gas plant</td>
<td>Arup (2011)</td>
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<tr>
<td><strong>Non-bio renewables</strong> and nuclear</td>
<td>Arup (2011)</td>
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<tr>
<td>Technology type</td>
<td>Technology</td>
<td>Data source</td>
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<tr>
<td>-----------------</td>
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</tr>
<tr>
<td>CHP</td>
<td>AD CHP</td>
<td>SKM Enviros (2010)</td>
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<td></td>
<td>Bioliquid CHP</td>
<td>NNFCC (2010)</td>
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<tr>
<td></td>
<td>Biomass CHP</td>
<td>AEA (2010) Interaction between different incentives to support renewable energy and their effect on CHP: RO and RHI; DECC (2011) RO banding study for group build rate constraints</td>
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<td></td>
<td>Gas turbine CHP</td>
<td>Mott Macdonald (2010)</td>
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<td></td>
<td>Advanced Conversion Technology CHP</td>
<td>Arup (2011)</td>
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<td></td>
<td>Bio-syngas CHP</td>
<td>Ecofys (2010) Feasibility of small-scale gasification from biomass to green gas (Dutch language), Mott MacDonald (2010)</td>
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<td></td>
<td>Energy from waste CHP</td>
<td>Arup (2011)</td>
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<td></td>
<td>Flexible fuel CHP</td>
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<td>Heat</td>
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<tr>
<td></td>
<td>Heat pumps</td>
<td>NERA &amp; AEA (2010)</td>
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<td></td>
<td>Bioliquid boiler</td>
<td>DECC renewable heat supply curve (adjusted to CCC heat segments)</td>
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<td></td>
<td>Biomass boiler</td>
<td>NERA &amp; AEA (2010)</td>
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<tr>
<td></td>
<td>Conventional coal/oil boiler</td>
<td>NERA &amp; AEA (2010)</td>
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<td></td>
<td>Conventional electric heating</td>
<td>NERA &amp; AEA (2010)</td>
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<td></td>
<td>Methane boiler</td>
<td>NERA &amp; AEA (2010)</td>
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<tr>
<td>District heating</td>
<td>Dedicated biomass DH</td>
<td>DECC renewable heat supply curve (adjusted to CCC heat segments)</td>
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<td>Surplus heat utilisation</td>
<td>derived from DECC renewable heat supply curve (biomass DH)</td>
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Table B1: Key sources of technology data

<table>
<thead>
<tr>
<th>Technology type</th>
<th>Technology</th>
<th>Data source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transport</td>
<td>BEV car, van</td>
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<tr>
<td></td>
<td>CNG bus, HGV</td>
<td>CCC (2010)</td>
</tr>
<tr>
<td></td>
<td>FCV car, van, bus, HGV</td>
<td>CCC (2010)</td>
</tr>
<tr>
<td></td>
<td>FCV-PHEV car, van</td>
<td>CCC (2010)</td>
</tr>
<tr>
<td></td>
<td>ICE car, van, bus, HGV</td>
<td>CCC (2010)</td>
</tr>
<tr>
<td></td>
<td>PHEV car, van</td>
<td>CCC (2010)</td>
</tr>
<tr>
<td></td>
<td>Plane, Ship</td>
<td>dummy to represent fuel switching</td>
</tr>
</tbody>
</table>

Notes
* BioH2 gasification, Coal Gasification with CCS, Steam Methane Reforming (SMR), Distributed SMR (2 tpd), Electrolyser (2 tpd)
** Onshore wind, offshore wind, solar, hydro, geothermal, tidal range, tidal stream, wave
† ASHP ATA, ASHP ATW, ASHP ATW storage, GSHP, GSHP storage
1 With and without CCS. For plant with CCS, CCS element based on Element Energy (2009) Potential for the application of CCS to UK industry and natural gas power generation. 2 UK and overseas. Imports other than 1G ethanol are represented via dummy technologies (with the same characteristics as the UK equivalents) which convert the raw feedstock to the final imported product, and include international transport costs within their operating costs. Costs of transporting feedstocks/fuels within the UK, based on E4tech (2010) Biomass prices for heat and power, were included in the operating costs of UK conversion and end-use technologies, thereby allowing them to vary by end-use application. Estimates to 2050 were used where available e.g. in Pöyry (2010) but not all data sources covered this time period. Where estimates were provided for earlier years only, costs and efficiencies were held constant from the last year available. Thus likely learning rates/cost reductions over time may not be fully reflected for all technologies.

Conversion plant capacities

Table B2: Assumed conversion plant capacities

<table>
<thead>
<tr>
<th>Plant</th>
<th>Size 1 (MW)</th>
<th>Size 2 (MW)</th>
<th>Size 3 (MW)</th>
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</thead>
<tbody>
<tr>
<td>Conventional ethanol</td>
<td>64</td>
<td>128</td>
<td>255</td>
</tr>
<tr>
<td>Cellulosic ethanol</td>
<td>64</td>
<td>128</td>
<td>255</td>
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<tr>
<td>Biodiesel FAME (also used as proxy for PPO)</td>
<td>40</td>
<td>100</td>
<td>200</td>
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<tr>
<td>Biodiesel HVO</td>
<td>103</td>
<td>206</td>
<td>308</td>
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<tr>
<td>Biojetfuel HRJ</td>
<td>103</td>
<td>206</td>
<td>308</td>
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<tr>
<td>Biodiesel FT</td>
<td>103</td>
<td>414</td>
<td>1080</td>
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<tr>
<td>Biojetfuel FT</td>
<td>103</td>
<td>414</td>
<td>1080</td>
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<tr>
<td>Pyrolysis oil</td>
<td>120</td>
<td>480</td>
<td>1253</td>
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<tr>
<td>Biodiesel UPO</td>
<td>333</td>
<td>–</td>
<td>–</td>
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<tr>
<td>Biojetfuel UPO</td>
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<tr>
<td>Butanol</td>
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<td>334</td>
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<tr>
<td>Cellulosic butanol</td>
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<td>Torrefaction</td>
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<td>Biodiesel (PPO)</td>
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<tr>
<td>BioDME</td>
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Source: See Table B.1