Programme Area: Bioenergy

Project: Biomass to Power with CCS

Title: Development and Deployment Opportunities Assessment and Technology and Demonstration Benefits Assessment

Abstract:

This report, the final deliverable from the project, contains both the Development and Deployment Opportunity Assessment and the Technology and Demonstration Benefits Assessment. The report covers all eight technologies selected for detailed investigation.

Context:

The Biomass to Power with CCS Phase 1 project consisted of four work packages: WP1: Landscape review of current developments; WP2: High Level Engineering Study (down-selecting from 24 to 8 Biomass to Power with CCS technologies); WP3: Parameterised Sub-System Models development; and WP4: Technology benchmarking and recommendation report. Reports generally follow this coding. We would suggest that you do not read any of the earlier deliverables in isolation as some assumptions in the reports were shown to be invalid. We would recommend that you read the project executive summaries as they provide a good summary of the overall conclusions. This work demonstrated the potential value of Biomass to Power with CCS technologies as a family, but it was clear at the time of the project, that the individual technologies were insufficiently mature to be able to 'pick a winner', due to the uncertainties around cost and performance associated with lower Technology Readiness Levels (TRLs).

Biomass to Power with CCS Project

TESBiC: Techno-Economic Study of Biomass to power with CCS

PM 07 – D4.1 and D4.2

D4.1: Development and Deployment Opportunities Assessment

D4.2: Technology and Demonstration Benefits Assessment

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V0.3

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Distribution

This report has been prepared by the TESBiC consortium under contract to the ETI.

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0 EXECUTIVE SUMMARY

The **T**echno-**E**conomic **S**tudy of **Bi**omass to Power with **C**CS (TESBiC) project is concerned with the performance of a techno-economic assessment of the current and potential future approaches to the combination of technologies which involve the generation of electricity from biomass materials, and those which involve carbon capture and storage (CCS). In Work Package 1 of the project, a total of 28 technologies were assessed - and one of the outcomes of WP1 was the selection of a shortlist of eight technology combinations by the project team, following consultation with ETI, for further study in the subsequent Work Packages:

1. Co-firing biomass in a pulverised coal power plant, with post-combustion CO_2 capture by amine scrubbing [cofire amine]
2. Dedicated biomass combustion, with post-combustion CO_2 capture by amine scrubbing [bio amine]
3. Co-firing biomass in a pulverised coal power plant, with CO_2 capture by oxy-fuel firing technology, using cryogenic O_2 separation [cofire oxy]
4. Biomass combustion in a dedicated power plant, with CO_2 capture by oxy-fuel firing technology, using cryogenic O_2 separation [bio oxy]
5. Dedicated biomass combustion, with CO_2 capture by post-combustion carbonate looping using a coal-fired calciner [cofire carb loop]
6. Dedicated biomass chemical-looping-combustion using solid oxygen carriers [bio chem loop]
7. Co-firing biomass in a coal powered Integrated gasification combined cycle (IGCC) plant, with pre-combustion CO_2 capture by physical absorption [cofire IGCC]
8. Dedicated biomass IGCC, with pre-combustion CO_2 capture by physical absorption [bio IGCC]

The two previous work packages within the TESBiC project, i.e. the high level engineering case studies (WP2) and sub-model parameterisation (WP3), yielded the 2010 base case values and the correlations between the costs, performance and environmental characteristics for all eight biomass CCS technology combinations. These base case values are summarised below in Table 0.

Table 0: Comparison of 2010 base case parameters for the 8 TESBiC technologies

	(1) Cofire amine	(2) Bio amine	(3) Cofire oxy	(4) Bio oxy	(5) Cofire carb loop	(6) Bio chem loop	(7) Cofire IGCC	(8) Bio IGCC
TRL	6 to 7	4 to 5	6	5	5	4 to 5	6	4 to 5
Scale (MW_e)	399	49	389	49	247	268	461	40
Co-firing	22%	100%	20%	100%	58%	100%	20%	100%
CO_2 capture	90%	90%	95%	95%	90%	100%	90%	90%
LHV efficiency	35%	23%	34%	23%	35%	38%	35%	33%
Capex (£/kW_e)	2,080	5,270	2,370	5,680	3,400	2,470	2,390	5,420

NB: throughout this study, capex is shorthand for “specific investment costs”, i.e. capital cost is shorthand for total investment cost

In this work package (WP4), cost reductions and efficiency improvements are projected for the years 2020, 2030, 2040 and 2050, for each of the eight technology combinations.

The electrical efficiencies of the eight biomass power plants with CO_2 capture in the year 2010, expressed on a LHV basis, were taken directly from the engineering case studies in WP2. The estimates of the improvements in the unabated power plant efficiencies over the period 2010 to 2050 were based on our internal assessment of the future potential of each power generation technology, taking data from the WP1 review report and cross-checking with confidential ETI ESME data for coal CCS plants in 2010 and 2050. Overall, the projected efficiencies for the unabated plants in TESBiC are generally a good match to those provided in the ETI ESME database. The efficiency penalty of adding capture was then applied to the different technologies, in order to derive efficiencies with capture – these capture penalties are also assumed to improve over time.

The net CO_2 emissions of the eight biomass CCS plants over the period 2010-2050 were derived using the same approach as in WP1, i.e. using the co-firing ratios, the % CO_2 capture rates and the standard coal and biomass feedstock emissions factors (given in the Annex), to determine the contributions of upstream, capture and uncaptured biomass (and coal) CO_2 emissions. There are various metrics available to quantify these "negative emissions" – the net CO_2 emissions per unit electricity generated (gCO_2e/kWh_e) is commonly used. However, for biomass CCS plants with a fixed power output, this increases towards zero as plant electrical efficiencies improve – whereas if the amount of feedstock is fixed, the power output will increase as the net CO_2 emissions remain fixed. A more useful metric to show the influence of co-firing % and CO_2 capture rates is given in Figure 0.1.

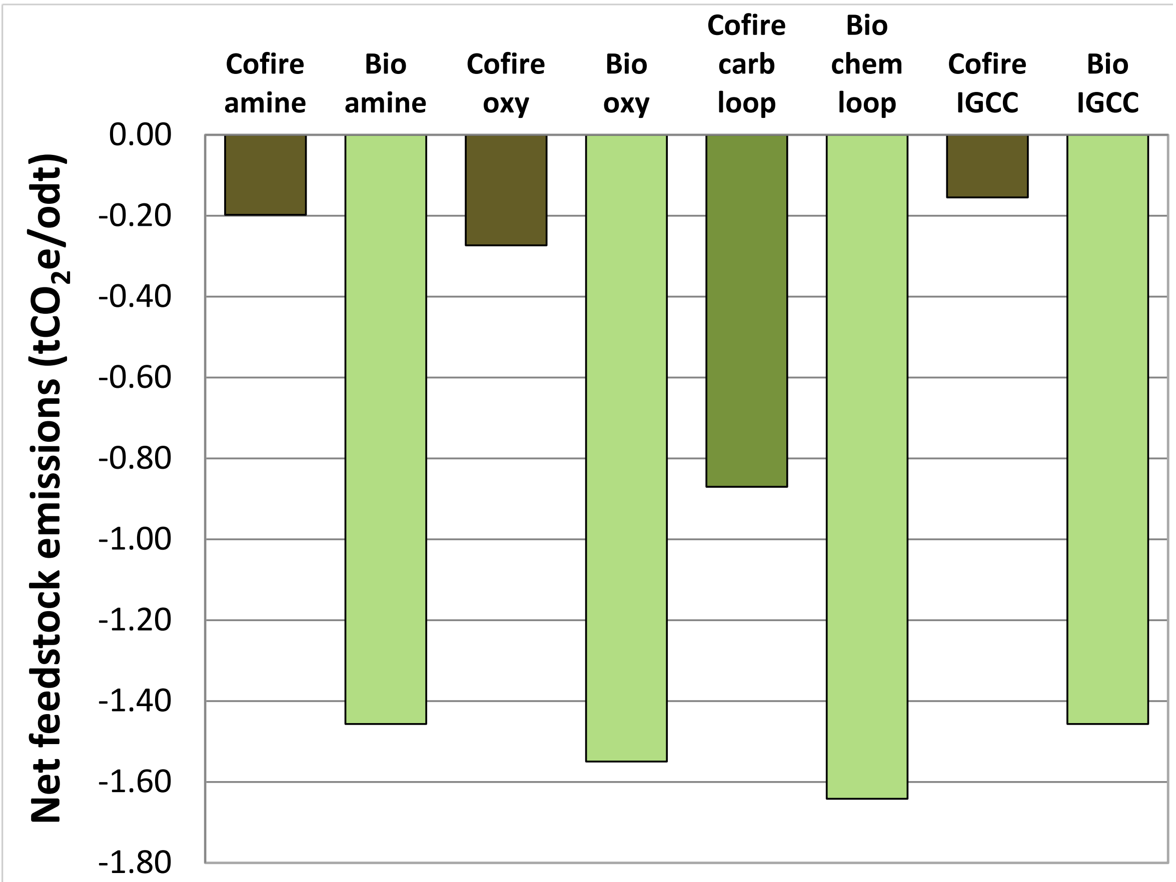

Figure 0.1: Negative CO_2 emissions per oven dried tonne of feedstock input

The largest amount of CO_2 is captured from the atmosphere per tonne of feedstock when using only biomass (as in bio amine/oxy/IGCC/chem loop), and a high CO_2 capture rate. However, these significant negative CO_2 emissions often come at a high cost, either in capital costs or feedstock. Cofire carb loop only uses coal in the calciner, with a notable impact on the CO_2 emissions result. The cofire amine/oxy/IGCC options contain high enough biomass co-firing rates (20% or 22%) so that the net CO_2 emissions are small, but negative.

The current capital costs of the eight biomass power plants with CO_2 capture were taken directly from the engineering case studies in WP2. These are all based on 2010 values, for a commercial plant. The capital costs for the eight technology combinations are projected to decrease by 25-30% by 2050, based on assumptions from ESME. The fixed and non-fuel variable operating costs in the year 2010 were also taken directly from the engineering case studies in WP2, and scaled down with the capital costs over time.

The impact of plant scale is evident from the much higher unit capex of the small-scale dedicated bio amine/oxy/IGCC options in the Base Case. Bio chem loop has a similar capex to the larger-scale cofire amine/oxy/IGCC options, with cofire carb loop slightly more expensive. One of the key results from the decadal modelling, i.e. the improvements in the capital costs and efficiencies over time (up to 2050), shows a clear grouping of the technologies by scale. Dedicated biomass plants at small scale are more expensive and less efficient than biomass co-firing with coal at large scale, whilst looping technologies appear relatively efficient for their intermediate scale, as shown in Figure 0.2.

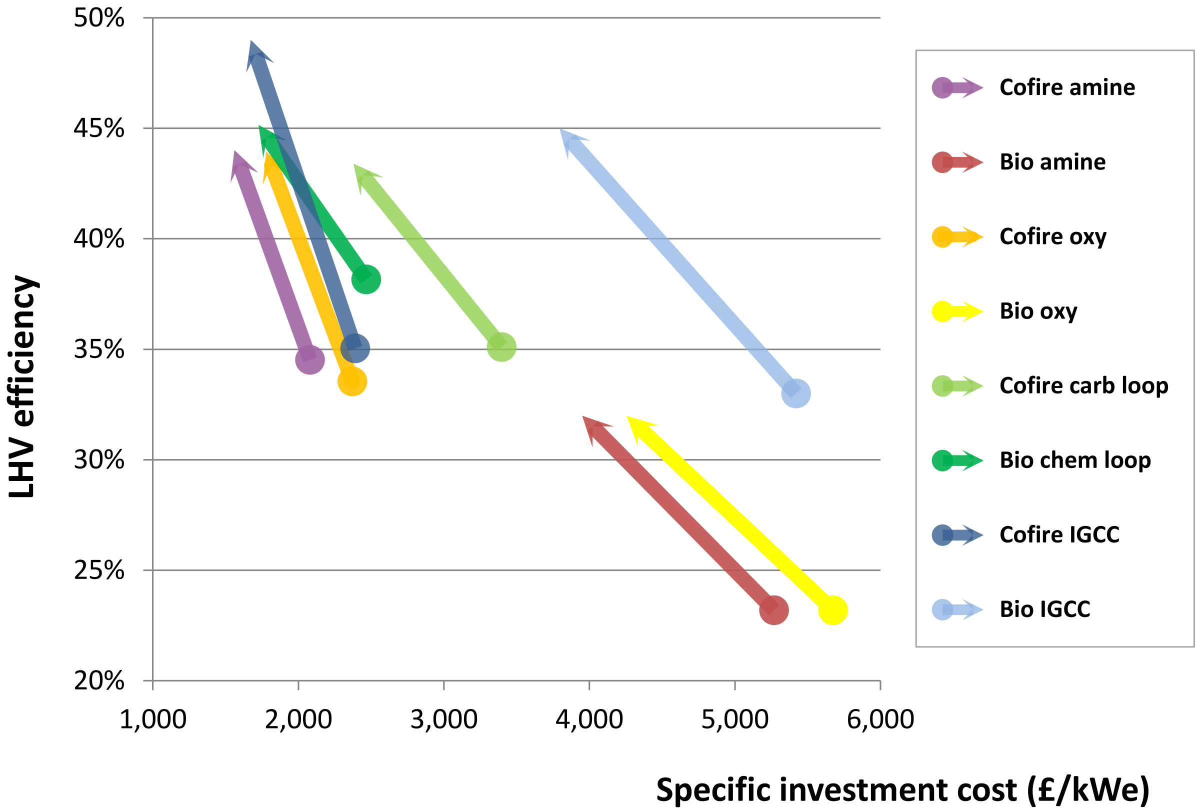

Figure 0.2: LHV electrical efficiency and capex development over time

All of the current and projected efficiencies, emissions, capital and operating costs etc. were used to calculate the cost of CO_2 captured, the cost of CO_2 avoided and the levelised cost of electricity

(LCOE). The LCOE is calculated using a discounted cost of capital, adding the annual fixed and variable operating costs, and finally adding the feedstock costs divided by the plant electricity generation efficiency (Figure 0.3). The data again indicates that the cofire amine/oxy/IGCC options are again the cheapest option (due to cheap coal prices), with dedicated bio amine/oxy/IGCC options the most expensive power generation options when using pellets. However, these small-scale plants could access cheaper biomass chips, which would have a significant impact on their LCOE, bringing it much closer to the LCOE of the looping options (using pellets). Many of these LCOE conclusions translate directly into the same messages for the cost of CO_2 captured and cost of CO_2 avoided (due to the formulas used – see the Annex for full details).

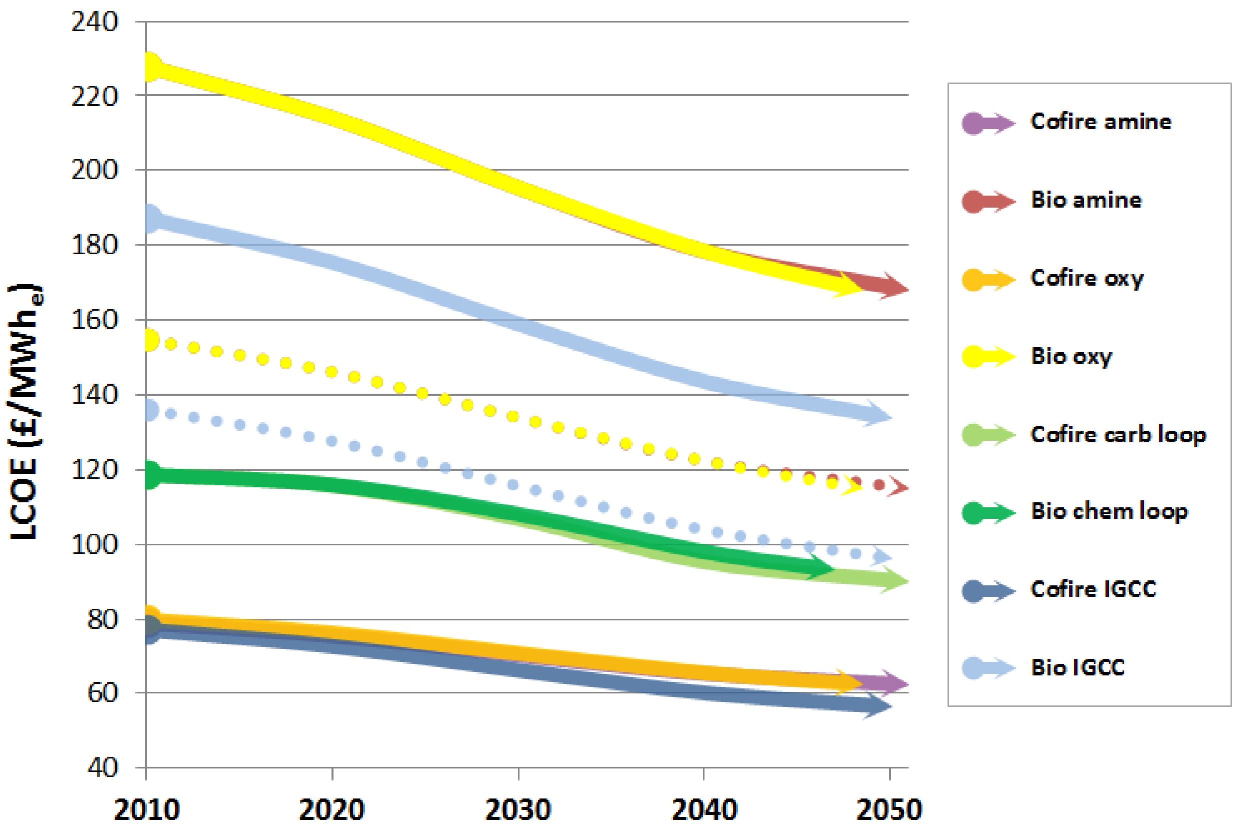

Figure 0.3: LCOE over time. Solid lines = pellets, dotted lines = chips

Key performance parameters for the eight TESBiC technologies have been projected and compared, analysed versus fossil CCS technology data, and benchmarked at common plant scales (for example, at a small scale of 50 MWe and at an intermediate scale of 250 MWe). In summary, the corresponding Sections 1, 4 and 5 of this report have shown that:

- The large-scale biomass co-firing technologies using solvent scrubbing, oxy-fuel and IGCC with physical absorption (cofire amine/oxy/IGCC, respectively) have low capital costs and similar overall generation efficiencies (with future upside potential for cofire IGCC). These similarities, and low coal costs, are reflected in the low LCOE and low costs per tonne of CO_2 captured and avoided for all these technologies.

- The dedicated biomass technologies (bio amine/oxy/IGCC) typically have higher specific investment costs, even when benchmarked at the same scale. The combustion technologies (bio amine & oxy) also have relatively low generation efficiencies. These facts are reflected in the higher LCOE values and costs per tonne of CO_2 captured and avoided for these technologies. However, the major advantages of the dedicated biomass technologies are that they do not involve fossil fuel utilisation and that they offer very significant negative CO_2 emissions per kWh generated at small-scale.
- Bio chem loop shows potential for relatively high generation efficiencies and low capital costs across a range of scales, and could offer attractive negative CO_2 emissions. Cofire carb loop appears to have higher capital costs, but similar LCOE (coal used in the mix) – and both looping technologies have co-product revenues that help offset their modest operating costs. However, compared to the other six options, there are much larger technical risks attached to the development of these looping technologies. The LCOE values and the costs per tonne of CO_2 captured and avoided lie between the ranges seen for the co-firing and dedicated biomass plant options.
- In general terms, the plant scale (MW_e) is the principal driver of capex (£/MW_e), rather than the choice of technology, with larger plants having lower capital costs. The co-firing %, i.e. the weighted feedstock cost, is one of the key drivers of LCOE, with dedicated biomass options using pellets always having significantly higher LCOE than co-firing with coal.
- The cost of CO_2 captured lies in the range £80-190/tCO_2, and is highest for the small-scale dedicated biomass technologies if using pellets (although closer to £110/tCO_2 using chips). The cost of CO_2 avoided versus an unabated coal power plant lies in the range £30-90/tCO_2, and again is lowest for the large-scale plants, or those using the cheapest feedstock (coal or biomass chips).
- Significant increases in the electricity generation efficiencies and reductions in the capital costs of all of the technologies have been projected for the period 2010 to 2050. By their nature, these projections have large uncertainties attached, although we note the level of optimism assumed was consistent with that in other data sources used (e.g. ESME, BVCM).

The future projections of the TRL values for the eight technology combinations have also been prepared. In most cases, the current TRL values and the projections to 2020 are reasonably well understood. Thereafter, it was considered in most cases that an increase of one TRL unit per decade would represent the situation where all the technologies were advancing in an incremental fashion, with none of the technologies being particularly favoured. The results of this analysis indicate that the current most advanced biomass CCS technologies would achieve full commercialisation in the 2030's, or perhaps a little early, with the less advanced technologies such as chemical and carbonate looping achieving commercialisation in the 2040's.

Biomass CCS technologies currently represent one of the very few practical and economic means of removing large quantities of CO_2 from the atmosphere, and the only approach that involves the generation of electricity at the same time. This would appear to make this approach to power generation very attractive given that many industrialised countries have stringent targets for the reduction of CO_2 emissions. It is clear, however that the available biomass CCS technologies are relatively expensive in terms of both capital and operating costs, and that financial incentives will be required. Presently, there are also no specific financial incentives anywhere in the world for the generation of electricity particularly with negative CO_2 emissions. It is clear that in most cases, the most significant barriers to the deployment of biomass CCS technologies will be economic and regulatory in nature, rather than technical. These factors have been discussed in some detail in Section 6 of this report and have been taken into account when assessing the future projections of the TRL values from 2010 to 2050 for the biomass CCS technologies.

In Section 7 of the report, each of the eight biomass CCS technologies has been re-examined and their likely future development has been described. An outline development roadmap for each of the technologies has been prepared. In the case of the more developed capture technologies, the route to further development after demonstration of the capture technology on coal-fired plant would involve demonstration of the technology at commercial scale on a dedicated biomass plant or a coal plant co-firing biomass. The roadmaps for many of the biomass CCS technologies are clearly very closely tied to the development of coal CCS technology. For the less well developed capture technologies (chemical and carbonate looping), fairly conventional development roadmaps, involving component testing, small and large pilot scale testing, and larger scale demonstration have been defined.

The final Section 8 of the report is concerned with the identification of specific biomass CCS technologies that would be best suited as potential candidates for further development and deployment in the UK, in order to build the existing UK expertise and technology base. In this context, an investment budget of the order of £30 million for biomass CCS development and demonstration projects was set, based on the discussions with the ETI.

Dedicated biomass chemical looping combustion and to a lesser extent cofired carbonate looping came out as two of the more attractive biomass CCS technology combinations for possible development and demonstration in the UK. This was due to their attractive prospects in terms of offering relatively high efficiency and low capex at a range of scales, the significant level of existing UK expertise (at least at the academic level), and most importantly, the potential for first mover advantage to make a significant impact in the IP space, given the size of the budget available to ETI. However, there are several technical hurdles to be overcome in the development and scale-up of the two looping technologies, and large uncertainties attached to the cost estimates considered in this study.

The TESBiC consortium recommends the following UK technology demonstration for consideration:

A flexible pilot plant with dual inter-connected circulating fluidized bed (CFB) reactors, suitable for investigating, testing and demonstrating primarily chemical looping combustion, but that can also be used to test and demonstrate post-combustion carbonate looping capture, as well as oxy-fuel combustion of biomass

This plant would have the greatest benefit if it were to offer:

- Dual CFB operation in chemical looping combustion mode, using biomass, coal or natural gas feedstocks. There is potential value in investigating dual hydrogen generation through steam oxidation of the metal

- Dual CFB operation with carbonate looping capturing CO_2 from an external flue gas stream, plus the option to use biomass instead of coal in the calciner. There is potential value in investigating biomass combusted *in situ* in the carbonator, instead of using an external flue gas stream
- Single CFB oxy-fuel combustion of biomass, achieved by shutting down the interconnection and changing out the looping solid for sand
- Effective heat transfer and temperature control via steam generation, without necessarily the requirement to generate electricity further downstream (since steam turbines are proven technology). This would save on upfront capital costs, and the heat and other co-products could still be sold - but the plant would not generate power revenues or subsidies (e.g. ROCs for advanced thermal conversion technologies)

An investment of about £30 million to build an approximately 10-14 MW_{th} flexible looping plant is estimated. This is likely to include fuel costs, maintenance and staffing during construction and for a limited initial experimental program, but not ongoing operating costs or any revenues. Given its low innovation value, a downstream steam turbine (~5MW_e) is not necessarily required if heat transfer and steam generation can be proven – if power generation equipment capital costs have to be included within the £30 million, then the proposed scale-up in the looping technologies would have to be smaller. Such a plant would ideally be located beside an existing power plant in order to utilise fuel handling infrastructure and possibly a slip-stream flue gas supply.

The UK currently has a relatively strong position in chemical and carbonate looping technologies, though mainly at a laboratory scale or through access to pilot plants built elsewhere in the world. General CFB expertise in the UK has been somewhat lacking in the past, but with the presence of Alstom and Foster Wheeler in the UK, several large-scale CFB biomass combustion power plants in the planning pipeline, and the acquisition of Lentjes AE&E by Doosan Power Systems, there is strong potential for the UK's CFB expertise to improve rapidly in the near future.

A pilot plant as proposed above would retain UK competitiveness in the rapidly-growing arena of looping technologies, and achieve a first mover advantage from taking both looping technologies up in scale by an order of magnitude (~1MW up to ~10MW). The choice to build a multi-purpose flexible pilot plant is likely to be significantly less expensive than building two (or even three) separate plants, and would make best use of the funds available to the ETI in this area.

1 DECADAL MODELLING: EIGHT BIOMASS CCS TECHNOLOGY COMBINATIONS

The two previous work packages within the TESBiC project, i.e. the high level engineering case studies (WP2) and sub-model parameterisation (WP3), yielded the 2010 base case values and the correlations between the costs, performance and environmental characteristics for all eight biomass CCS technology combinations. In this work package (WP4), cost reductions and efficiency improvements are projected for the years 2020, 2030, 2040 and 2050, for each of the eight technology combinations.

The overall 'decadal modelling' methodology, is set out below. This process was conducted during an internal workshop at the beginning of WP4, before the values and assumptions were reviewed, debated and modified where necessary by the TESBiC consortium partners, to reach a consensus on the most likely future projections. All the current and projected efficiencies, emissions, capital and operating costs were then gathered together into one single spread-sheet, and used to calculate metrics such as cost of CO_2 captured, cost of CO_2 avoided, levelised cost of electricity (LCOE), as explained in the following sub-sections. This spread-sheet was also used to input new technology data into the ETI BVCM study, and in extending the WP3 models to 2050.

1.1 Projecting LHV electrical efficiencies

The LHV electrical efficiencies of the eight biomass power plants with CO_2 capture in the year 2010 were taken directly from the engineering case studies in WP2. Unabated efficiencies in 2010 were derived for pulverised coal combustion, biomass combustion, coal & biomass IGCC power plants, with data at a range of scales taken from the unabated plant cases in WP2. Where there was not an unabated case given, data from the WP1 review report was used, as well as confidential data from ETI ESME and the bioenergy "Technology Innovation Needs Assessment" (TINA) owned by the Low Carbon Innovation Coordination Group (LCICG). It was assumed that the efficiencies for large co-firing plants would be sufficiently similar to coal-only plants to be within the error margins, and hence not worth considering separately. The efficiencies of small-scale and large-scale power plants are sufficiently different to merit separate consideration, as only using a single efficiency value would not be representative of the higher efficiencies of larger-scale plants compared with the lower-efficiencies generally seen with smaller plants. Biomass is more reactive than coal in a gasification environment, and the little available data on biomass IGCC plants suggest that they will have similar efficiencies to coal IGCC plants when at the same scale – hence we are not considering separate unabated baseline efficiencies for coal and biomass IGCC.

Improvements in unabated power plant efficiencies to 2050 were based on the future potential of each power generation technology (taking data from the WP1 review report, TINA bioenergy and internal consortium assessments), as well as cross-checking with confidential ETI ESME data for coal CCS plants in 2010 and 2050. Our TESBiC projected efficiencies for unabated plants are generally a good match with ESME. One exception is for large-scale pulverised coal combustion, where our WP4 projected efficiencies for 2050 (51% LHV) are more optimistic than ESME (which appears to perhaps be unduly pessimistic), but not as optimistic as assuming every operating plant is a new breed of ultra-super critical (USC) pulverised coal plant at 56% LHV electrical efficiency. Therefore, the efficiency value chosen for the large-scale unabated coal combustion baseline within WP4 is closer to being an estimated fleet average, rather than best-in-class. These unabated baseline efficiency assumptions are given below in Table 1.

Table 1: Unabated baseline plant efficiencies

LHV efficiency	2010	2020	2030	2040	2050
Pulverised coal combustion @49MW$_e$	38.6%	40.0%	42.1%	44.2%	45.6%
Pulverised coal combustion @399MW$_e$	44.0%	45.4%	47.5%	49.6%	51.0%
Biomass combustion @49MW$_e$	33.0%	34.2%	36.0%	37.8%	39.0%
Biomass combustion @250MW$_e$	38.0%	39.4%	41.5%	43.6%	45.0%
IGCC @40MW$_e$	41.0%	43.0%	46.0%	49.0%	51.0%
IGCC @460MW$_e$	43.0%	45.4%	49.0%	52.6%	55.0%

The efficiency penalty for adding CO_2 capture to a power plant in 2010 was also derived from the case studies in WP2, as the difference between 2010 unabated and abated plant efficiencies. These efficiency penalties are expected to fall over time as the capture technologies improve – the extent of these improvements were based on the future potentials identified in the WP1 review report, and sense-checked against the generic improvements given in TINA CCS. For example, the efficiency penalty for amine scrubbing was estimated to fall from ~10%-points currently to 7%-points by 2050. These efficiency penalties are shown in Table 2.

Table 2: Capture efficiency penalties

%-points (LHV)	2010	2020	2030	2040	2050
Cofire amine	9.5%	9.0%	8.3%	7.5%	7.0%
Bio amine	9.8%	9.2%	8.4%	7.6%	7.0%
Cofire oxy	10.4%	9.7%	8.7%	7.7%	7.0%
Bio oxy	9.8%	9.2%	8.4%	7.6%	7.0%
Cofire carb loop	4.8%	4.7%	4.3%	3.8%	3.5%
Bio chem loop	0%	0%	0%	0%	0%
Cofire IGCC	8.0%	7.6%	7.0%	6.4%	6.0%
Bio IGCC	8.0%	7.6%	7.0%	6.4%	6.0%

Starting at the "with capture" biomass CCS plant LHV electrical efficiency values seen in 2010 (as shown in Table 0), we therefore have projected plant efficiencies with capture to 2050, by using the improvements in unabated plant efficiencies, plus improvements in the capture technology penalty. Efficiency improvements in the unabated baseline power technologies (of 7-12%-points) are expected to be significantly larger than the improvements in capture efficiency penalties (up to 3.4%-points). Error bounds of +/- 3%-points were also assumed for all eight technology combinations, with 5%-points on the downside for the looping technologies. These error bounds are not assumed to change over time.

The looping technologies are slightly special cases. Bio chem loop does not have an "unabated" baseline per say, as the plant with capture operates without a capture efficiency penalty (and would not be able to operate without the metal oxide capture loop). Overall efficiencies with capture are assumed to improve in line with efficiency improvements in dedicated biomass combustion, since the use of pressurised combustors and gas turbines or H_2 production for use in a fuel cell (i.e. higher capex configurations more akin to BIGCC) were not considered.

Cofire carb loop uses a dedicated biomass combustion power plant, with a coal-fired calciner. Therefore, the overall plant efficiency is estimated as a co-firing weighted average of coal and dedicated biomass plant efficiencies. In the current base case, this works out at 0.58 * unabated biomass efficiency + 0.42 * unabated coal combustion efficiencies, less the capture efficiency penalty of 4.8%-points. It was assumed that future increases in large-scale unabated biomass and coal combustion will also increase the overall weighted plant efficiency, as well as the improvement in capture penalty (down to 3.5%-points by 2050).

In terms of the intermediate years, we fitted shaped curves, based on each technology's likely deployment profile to 2050. More developed technologies (likely to be scaled up in the 2020's and heavily deployed in the 2030's) will see greater improvements in their efficiency in the early periods than later on. In comparison, less developed technologies are likely to have to wait longer before their first "Nth-of-a-kind" plant is built; hence their efficiency improvements are more back-loaded in their profiles. This topic, of when different technologies are expected to reach "Nth-of-a-kind" plant scale, is discussed in greater detail in Section 1.7.

The results of this exercise are shown below in Figure 1. The impact of plant scale is clearly seen, with the low efficiencies with capture of the small-scale dedicated bio amine & oxy technologies, with cofire & bio IGCC technologies able to achieve much higher efficiencies. However, of particular note are the medium-scale looping technologies, which on account of their low efficiency penalties, potentially have similar efficiencies to the larger-scale co-firing amine/oxy/IGCC technologies. Overall, efficiencies are projected to increase by 7%-points to 14%-points by 2050, with the largest potential increases seen in IGCC.

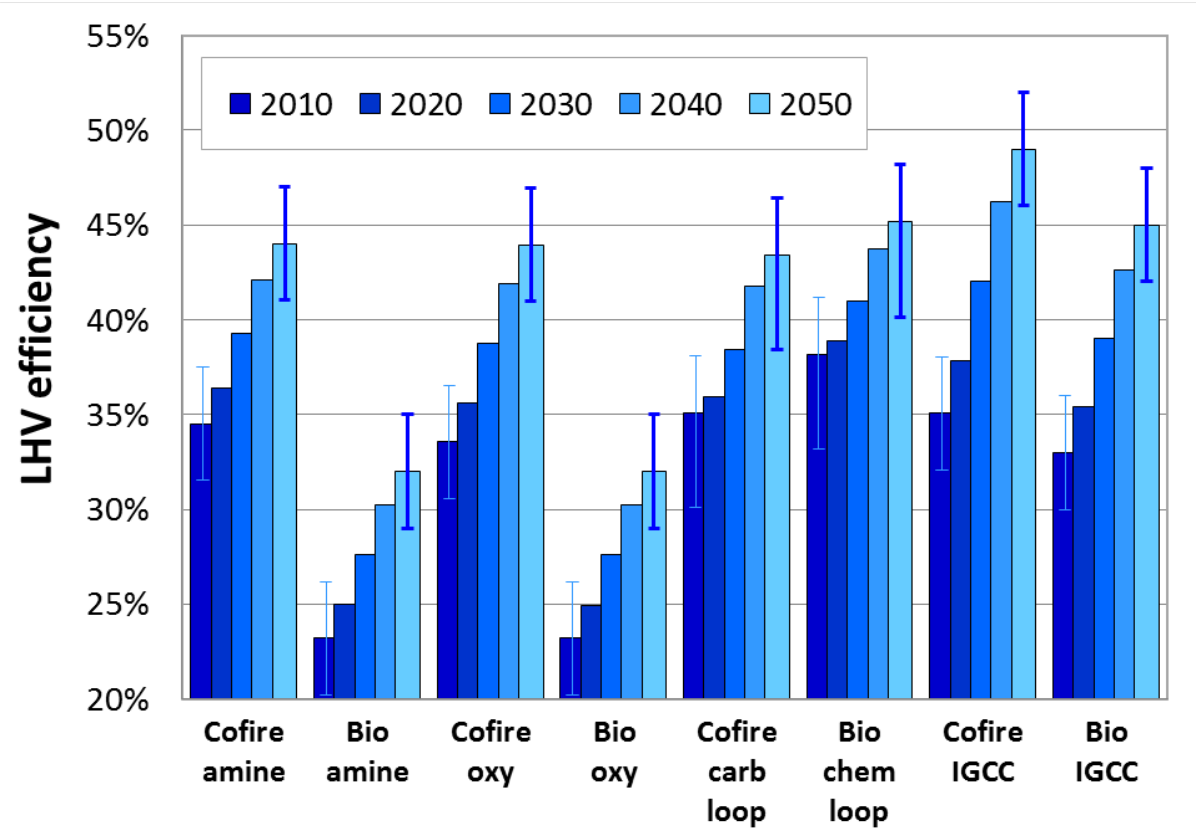

Figure 1: LHV electrical efficiencies, over time

1.2 Projecting CO_2 emissions

Each of the eight TESBiC biomass CCS technology combinations will have a variety of different CO_2 emissions sources and sinks that have to be considered when calculating the net CO_2 emissions of the power generated by the plant. There are firstly upstream (life-cycle) emissions in the cultivation, harvesting, processing and transport of biomass to the plant, as well as upstream emissions for any coal mining, processing and transport. The biomass and coal feedstocks are then converted into CO_2 and useful energy in the plant. Some of the CO_2 goes uncaptured (up to around 10% in some cases), and is released into the atmosphere – for biogenic CO_2 this is net neutral (returning plant carbon back into the atmosphere), whereas for any coal-derived CO_2 this equates to a release of fossil CO_2 into the atmosphere. The majority of the CO_2 is however captured; for any coal-derived CO_2, this is net neutral (returning fossil carbon back underground), whereas for biogenic CO_2 this equates to a net sequestration of atmospheric CO_2 (i.e. negative emissions).

The Annex explains the formulas, capture rates and emissions factors used to calculate all six contributing terms discussed here, and their impact on the overall net CO_2 emissions of a biomass plant. There are then several metrics available for displaying these net CO_2 emissions, as discussed below, and as set out in the Annex.

A metric already in common usage by the power industry to measure the emissions performance of power plants is the net CO_2 emissions per unit electricity generated (**gCO_2e/kWh_e**). For unabated fossil power plants, this metric is large and positive, and any increases in plant electrical efficiency intuitively lead to a decrease in the metric (i.e. towards zero).

As shown in Figure 2, when applied to the TESBiC technologies, this metric is strongly dependent on the extent of biomass co-firing. For dedicated biomass CCS options, the gCO_2e/kWh_e metric is large and negative, due to the large amount of biogenic CO_2 being sequestered out of the atmosphere. For the co-firing options, the metric is much closer to zero, as the CO_2 sequestered from the 20-22% of biomass input into the plant is enough to counteract the uncaptured coal emissions and upstream biomass and coal emissions, and keep the net CO_2 emissions negative (but small in absolute terms). The cross-over point between positive and negative emissions is at ~11-13% biomass co-firing (although this is dependent on CO_2 capture rates, assumed biomass/coal emission factors and upstream emissions).

If it is assumed that the nameplate capacity of designed plants (MW_e) remains constant over time, then the annual electricity output (TWh_e/yr) will also remain constant. As the plant LHV electrical efficiency with capture improves over time, less feedstock will be required to generate the same amount of power. This means less carbon is being input into the plant, and hence less CO_2 is captured or emitted. The resulting gCO_2e/kWh_e values therefore **increase**, i.e. move towards zero over time. This also explains why the least electrically efficient options (bio amine & oxy) have the most negative values for gCO_2e/kWh_e. Bio chem loop and bio IGCC are both dedicated biomass power plants, but their higher efficiency means less CO_2 is captured per kWh_e generated. Cofire carb loop is similarly high efficiency, but only 58% biomass co-firing, with a notable impact on the CO_2 emissions result.

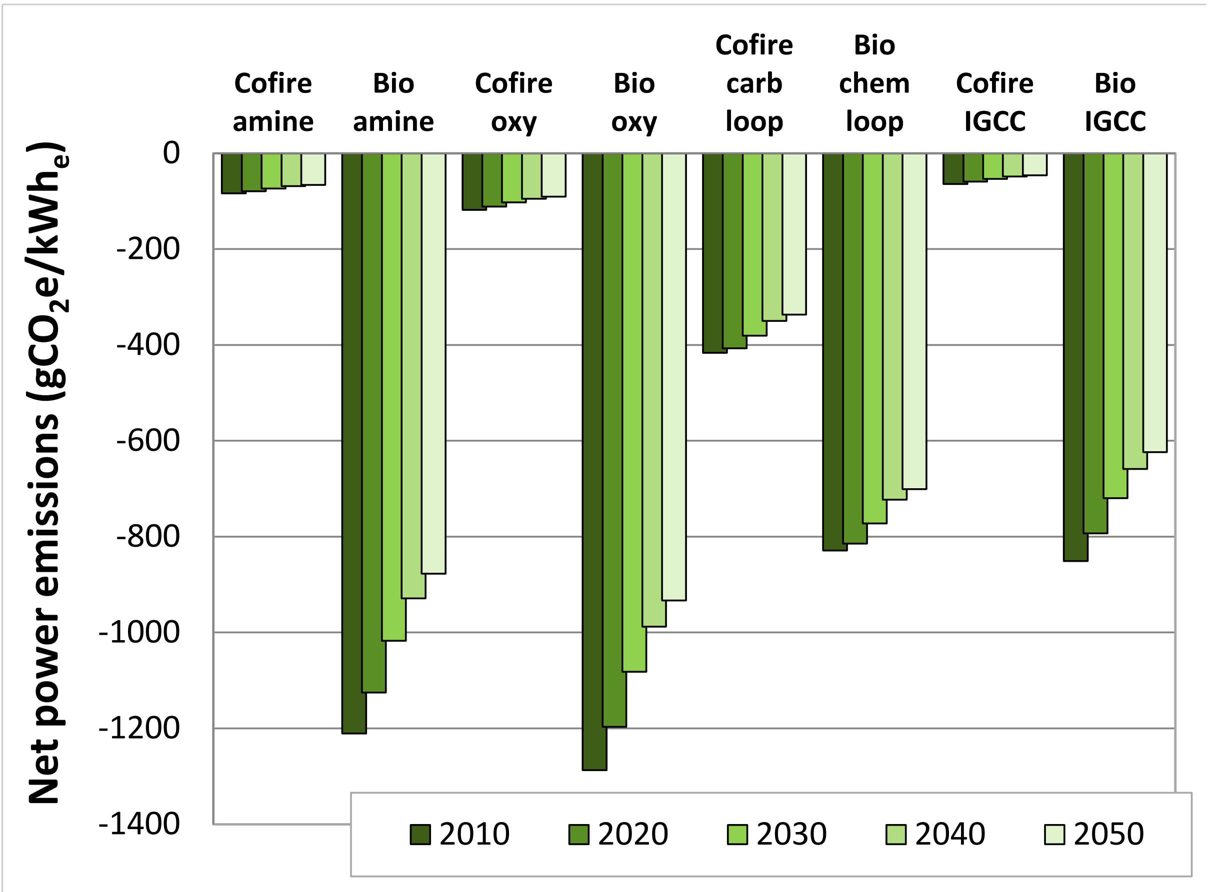

Figure 2: Net CO_2 emissions per unit electricity generated, over time

Whilst the results using this metric might be slightly counter-intuitive when applied to biomass CCS, the assumption has to be (in the absence of high carbon prices/taxes) that any such plant will be built primarily as a means of delivering power rather than reducing CO_2 and that the overall economics of the plant will be the principal determinant of plant design. Also, as will be shown later, these significant negative CO_2 emissions also come at a high cost.

However, if instead it is assumed that the amount of feedstock input into a designed plant (TWh_{th}/yr) remains constant over time, then the amount of CO_2 captured, and the net CO_2 emissions, will also remain constant. As the plant LHV electrical efficiency improves over time, more power will be generated using the same amount of feedstock. A metric that can be used to show this effect is the electricity generated per unit CO_2 captured (**MWh_e/tCO_2**), as shown in Figure 3. As expected, this chart has a very similar shape to the LHV electrical efficiencies shown in Figure 1.

An alternative metric, the net CO_2 emissions per unit of feedstock (**tCO_2e/odt**), does not depend on the plant LHV electrical efficiency at all – and is only influenced by the feedstock emissions assumptions, the biomass co-firing % and the plant CO_2 capture rate. This metric is illustrated in Figure 4, and does not change over time. Bio chem loop has the highest savings due its 100% CO_2 capture rate and use of only biomass. The cofire amine/oxy/IGCC options have much lower savings due to high proportions of coal consumed (the colours being indicative of higher coal %s).

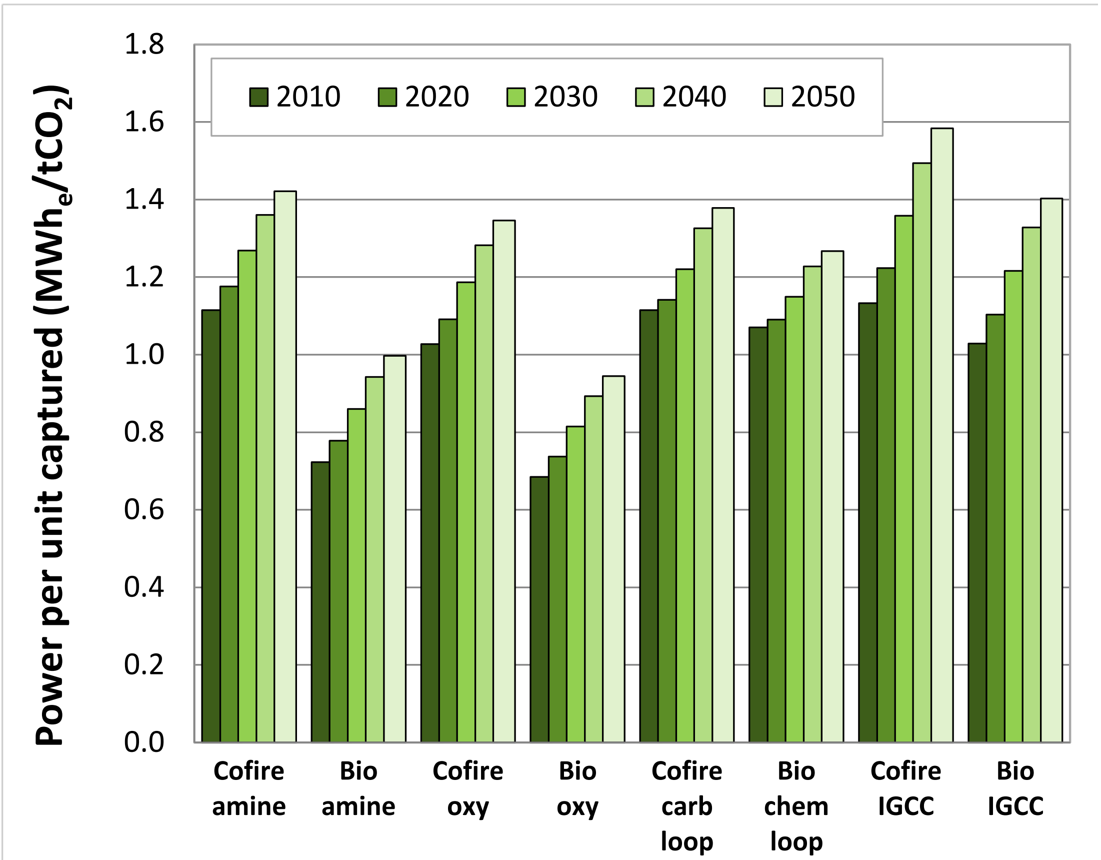

Figure 3: Electricity generated per tonne of CO_2 captured, over time

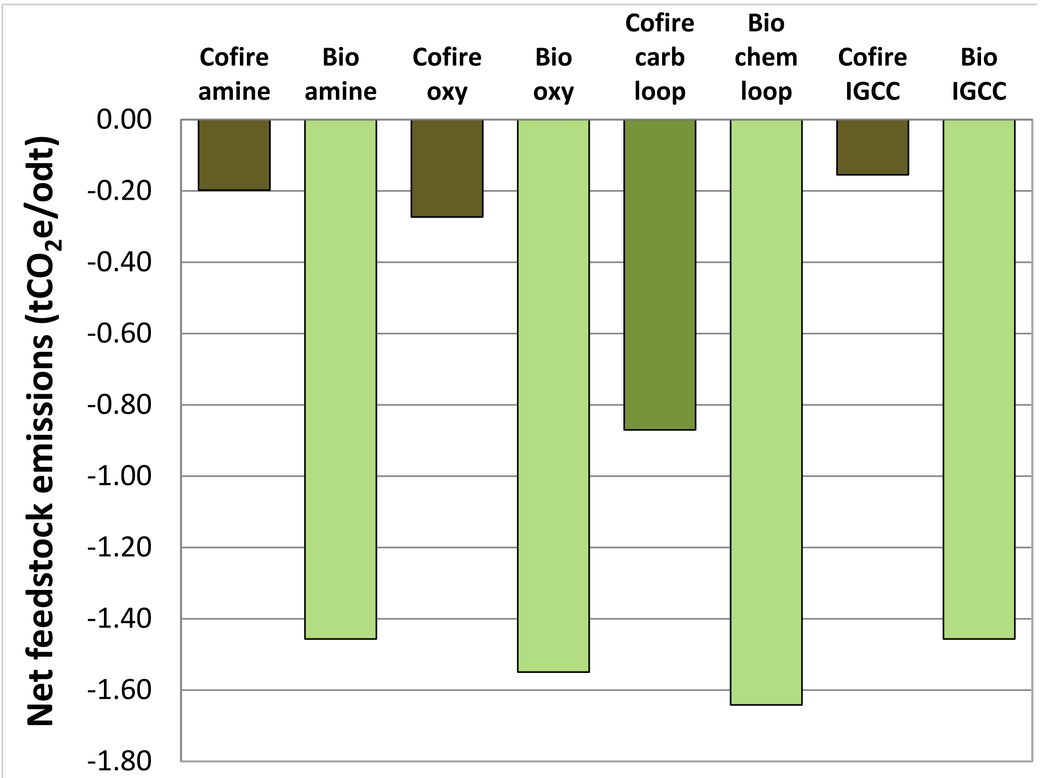

Figure 4: Net CO_2 emissions per oven dried tonne of feedstock input

The two alternative metrics shown in Figure 3 and Figure 4 are perhaps more intuitive to understand in the context of biomass CCS, as they show the beneficial impact of generating more power from the same amount of feedstock, as well as choosing biomass instead of coal to maximise the CO_2 savings per unit of feedstock. However, these metrics are less commonly used in the power industry today, since power output is still the primary concern (rather than net negative CO_2 savings, or optimal use of limited biomass resources).

1.3 Projecting capital costs

The capital costs of the eight biomass power plants with CO_2 capture were taken directly from the engineering case studies in WP2. These are all based around 2010 values, for a commercial "Nth-of-a-kind" plant. Evaluating "first-of-a-kind" plant costs was out of scope for this TESBiC study, but we note that they are expected to be significantly higher than the costs given in the analysis below.

The ETI ESME input data gives estimates for the 2010 and 2050 capital costs of pulverised coal with CCS (unspecified whether amine or oxy-fuel) and IGCC coal with CCS, as well as unabated cases. Over the period 2010 to 2050, ESME assumes a 15% drop in capex for unabated combustion power plants (25% for unabated IGCC), and a 25% drop for combustion plants with CCS (30% for IGCC with CCS).

Given the similarity between coal and co-firing options, we therefore applied the ESME % cost reduction factors to the 2010 capital costs of the eight biomass CCS options, in order to derive 2050 values – i.e. we ensured consistency with the level of optimism assumed in ESME. Importantly, ESME also assumes the same % reduction in capex occurs for unabated biomass combustion plants as for coal combustion plants – this reduction to 2050 was also sense-checked against the unabated capex projections in the bioenergy TINA. We therefore applied the same % cost reduction factors for bio amine/oxy/IGCC as for their respective cofire amine/oxy/IGCC technologies. ESME clearly doesn't have equivalent technologies for bio chem or cofire carb loop options, but given their modest TRL/potential for further innovation, we assumed a 30% cost reduction factor by 2050.

We did examine the CCS TINA carried out by the LCICG. However, we were not able to compare these estimates with our data, as no absolute costs were given in the TINA, and relative reductions were either broken down into the wrong sub-components, or were aggregated to a whole power, CO_2 capture, transport & storage level (out of scope).

To derive capital costs in the intermediate years, we again fitted shaped curves, based on each technology's likely deployment profile to 2050. More developed technologies likely to be heavily deployed in 2020 and 2030 will see greater cost reduction in the early periods than later on – whilst less developed technologies are likely to have to wait longer before their first "Nth-of-a-kind" plant is built, hence their cost reductions are more back-loaded in their curve. It is also worth noting that all these cost reductions, including intermediate years, are a close match to the generic TRL-derived cost reduction curves already used throughout the ETI BVCM technology database.

Error bounds vary according to the level of technology development, and certainty regarding engineering or study estimates. Using the values estimated in the engineering case studies (WP2), and from calculations carried out in WP1, we are assuming capital cost uncertainties of:

- +/- 25% for the co-firing amine/oxy/IGCC technologies. This is consistent with IEA (2011)

- +/- 35% for the equivalent bio amine and bio oxy technologies
- +/- 50% for the cofire carb loop and bio chem. loop technologies

The results are shown below in Figure 5. The impact of plant scale is clearly seen with the higher capital costs of the small-scale dedicated biomass options. Bio chem loop, although only at medium scale, has a similar capex to the larger-scale cofire amine/oxy/IGCC technologies. Capital costs are projected to fall by 25-30% by 2050.

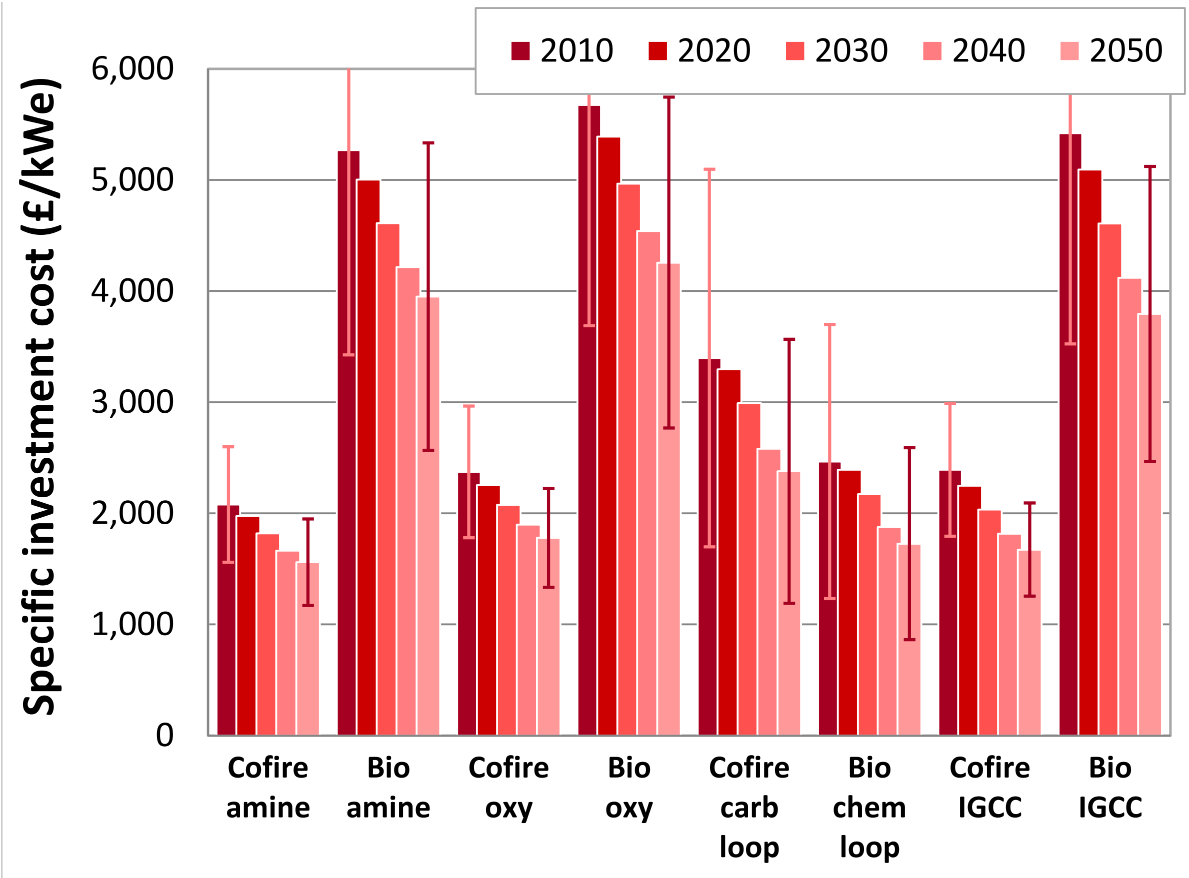

Figure 5: Specific investment cost projected to fall over time

1.4 Projecting operating costs

The fixed and non-fuel variable operating costs of the eight biomass power plants with CO_2 capture in the year 2010 were taken directly from the engineering case studies in WP2. These are again for "Nth-of-a-kind" plants. The calculation formulas are again given in the Annex.

In all cases, the fixed opex is set as 5% of Total Installed Costs as applied in WP2. Assuming the same 5% is maintained going forwards, fixed opex therefore falls to 2050 in line with the capital costs of each technology. This is more optimistic than the ESME estimates, which assume the fixed opex for coal CCS remains constant to 2050.

For simplicity, the non-fuel variable operating costs are also assumed to fall to 2050 in line with the capital costs of each technology. For example, in amine scrubbing, this opex reduction can be attributed to improvements in solvent formulation and thermal integration. We note that this is also at odds with ESME, which assumes that the variable opex for coal CCS remains constant to 2050. It should be noted that the variable operating costs were very low for looping technologies, due to the inclusion of co-product credits for the sale of spent sorbent (CaO for cement manufacture), or spent metal carrier. Finally, the makeup costs associated with cooling water consumption were not accounted for in any of the eight technology combinations.

1.5 Levelised cost of electricity (LCOE)

LCOE is calculated using a discounted cost of capital, adding fixed and variable operating costs, and finally adding feedstock costs divided by the plant efficiency – a full formula is given in the Annex. In all the Base Case calculations, we assume a biomass pellet price of £27/MWh, and a coal price of £7/MWh, along with a plant technical/economic lifetime of 30 years, a capacity factor of 85%, and 10% discount rate. The LCOE results are shown below in Figure 6, for the Base Case plant scales.

Due to their high energy and bulk density, and lower handling and storage costs, pellets are more attractive for long distance transport than chips. In general, this will mean that chips will only be sourced and consumed locally, and hence only able to supply smaller power plants – larger plants will require too much biomass from too great a radius for chips to be likely to be economically viable. Many of the <50MW$_e$ biomass (non-waste) combustion power plants in the UK are using locally sourced forestry chips. Larger biomass power plants >200MW$_e$ (either in operation, or planned) are much more likely to be sited on the coast of the UK, with access to much larger resources of imported pellets. We therefore examine the cost impact of using low-cost chips in small-scale plants only, and assume that medium- and large-scale plants are likely to only use more expensive pellets.

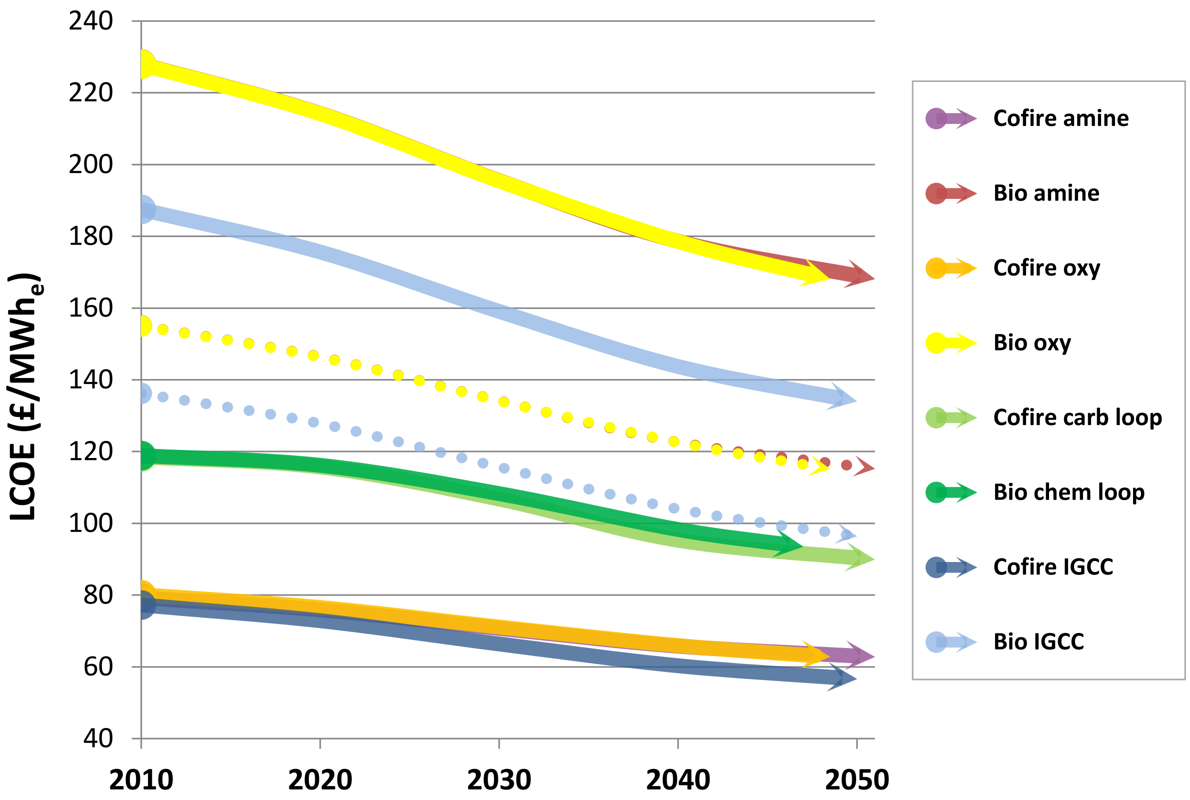

Figure 6: LCOE over time, Base Case scales. Solid lines = pellets, dotted lines = chips

The large-scale options (cofire amine/oxy/IGCC) show very similar low LCOE values, mainly due to their low capex, and low coal prices. Bio chem loop and cofire carb loop show similar intermediate LCOE values, which reflect the medium-scale of the power plants involved. Of the two, bio chem loop has the lower capital costs and slightly higher efficiency, but higher feedstock costs (only biomass pellets used); whereas cofire carb loop has higher capital costs and slightly lower efficiency, offset by lower average feedstock costs (mix of coal and biomass pellets).

Bio amine & oxy show very similar and high LCOE values, due to their high capex and lower efficiencies. The LCOE for bio IGCC is slightly lower due to its higher electrical efficiency mitigating the effect of the high pellet costs. However, these small-scale plants are able to switch from using biomass pellets (solid lines in the Base Case) to using significantly lower-cost biomass chips (dotted lines). This fall in biomass costs from £27/MWh to £10/MWh leads to a decrease in LCOE by ~30%, as shown in Figure 6. This highlights the sensitivity of LCOE to feedstock costs – the LCOE of bio IGCC using chips is now similar to that of the looping options using pellets.

We note that a higher discount rate (e.g. 15%) could have been used throughout the analysis – this would lead to an increase in LCOE of ~10-20%. Using a lower (social) discount rate of 3.5% would lead to a decrease in LCOE of ~15-25%. This highlights the sensitivity of LCOE to capital costs, and the terms under which project financing is agreed.

1.6 Cost of CO_2 captured

The cost of CO_2 captured is calculated by multiplying the LCOE (£/MWh_e) by the annual electricity output (MWh_e/yr), then dividing by the annual CO_2 emissions captured (tCO_2/yr) – the formula used is given in the Annex. However, this varies very little over time, since improved capital costs and plant efficiencies mean that both the LCOE and the amount of CO_2 captured per year decrease in step (if it is assumed that plant power output remains constant. Alternatively, if the plant feedstock input remains constant, then the amount of CO_2 captured will be fixed, but the LCOE will fall as the annual electricity output rises – again, giving little change in the cost of CO_2 captured.)

Figure 7 is therefore only shown using 2010 costs and capture rates, with the dark bars assuming all the biomass used is in the form of pellets. This chart shows again that the dedicated bio amine/oxy/IGCC options are the most expensive, with cofire amine/oxy/IGCC options being the cheapest, and the looping technologies as an intermediate option when comparing cost of CO_2 captured. However, if the small-scale options (bio amine/oxy/IGCC) were to use chips instead, their cost of CO_2 captured would fall by ~30%, and become competitive with the looping options. The impact of using this cheaper biomass feedstock is shown by the lighter bars in Figure 7.

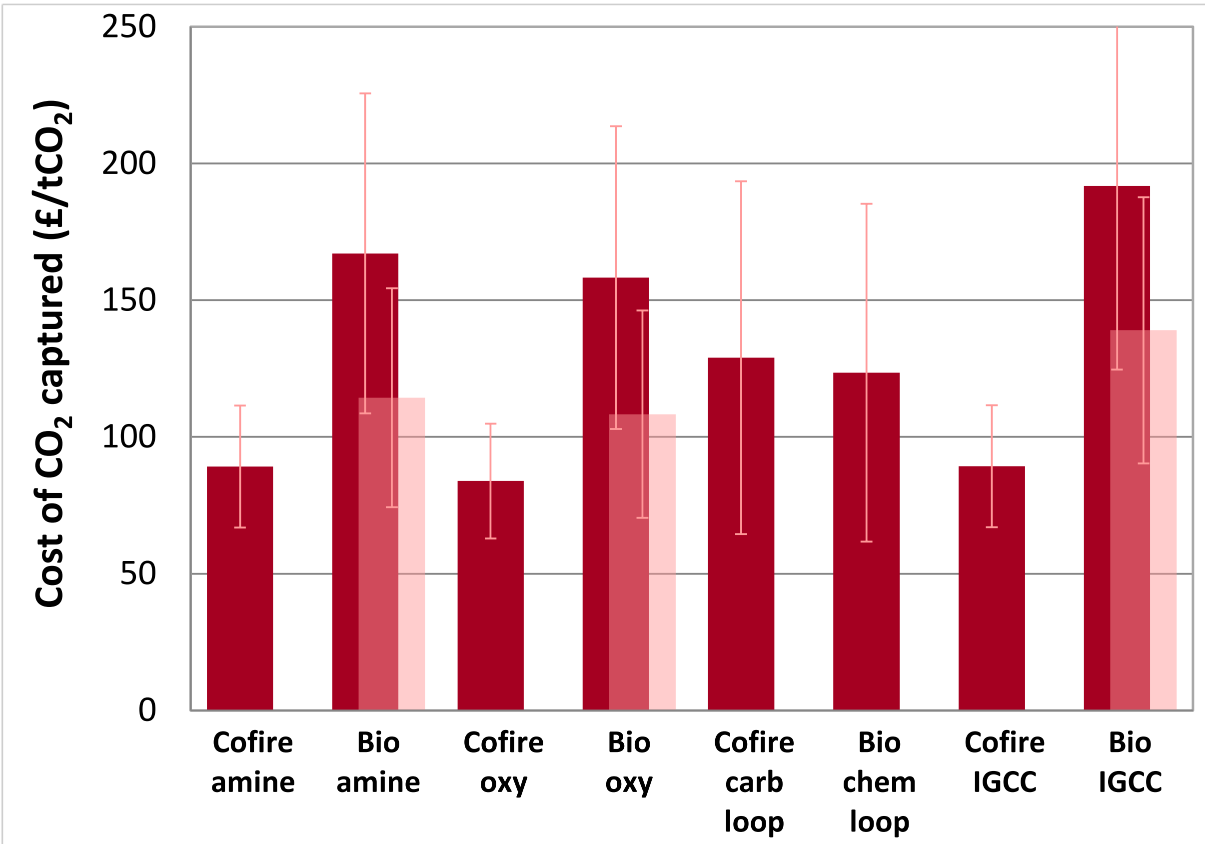

Figure 7: Cost of CO_2 captured in 2010, Base Case scales. Dark bars = pellets, light bars = chips

1.7 Projecting how TRLs may change over time

Several technologies were not considered advanced enough to be able to contribute to significant UK deployment in 2050, and were scoped out during WP1[1]. To already have mass deployment by 2050 (TRL 9), a technology has to be commercially available by 2040 at the latest (TRL 8). Industry lead times from early demonstration (TRL 6) to commercial availability are likely to be about 15 years, and so if the technology cannot reach a pilot stage (TRL 5) by 2020, then it was judged unlikely to significantly figure in the UK energy system in 2050. This is a relatively conservative view of development across a portfolio of technologies, based on past experience within the power industry, and not an accelerated innovation effort directed at single technologies.

From the WP1 final report, we already have data for the current TRLs and estimated TRLs in 2020. It should however be noted that both looping technologies have progressed almost half a TRL in the last year since the WP1 report was written, as a consequence of successful start of operations of two pilot plants at MW scale (the EU CaOling project[2], and ÉCLAIR project at TUDarmstadt[3]).

After 2020, based on the fairly conservative power industry development timeframes set out in WP1, it has been assumed that most technologies would be able to achieve +1 TRL every 10 years, assuming that all technologies are developed in an incremental fashion (with no 'picking winners'). These assumptions were validated during the May 2012 bioenergy SAG meeting at ETI.

[1] This TRL development is taken straight from the early part of Deliverable 1.3 (scope section 1.5), where we explained why we were scoping out technologies that couldn't make it to TRL 5 by 2020
[2] CaOling project (2012) Available at: http://www.caoling.eu/index.php
[3] EST-TU Darmstadt (2010) ""Fluidized Bed Based Looping Processes for Carbon Capture", Available at: http://www.est.tu-darmstadt.de/images/stories/ccs_workshop/101103_TUD-EST_Epple.pdf and http://www.vattenfall.com/en/ccs/clc-darmstadt.htm

Some of the dedicated biomass CCS systems are currently more than one TRL point behind their co-firing CCS equivalent options, i.e. bio amine and bio IGCC. This gap is primarily due to a lack of dedicated biomass CCS projects under development (i.e. no overall systems built at the pilot scale), rather than immature components. Since there is a large proportion of shared equipment and experience between coal and biomass systems, with little difference in flue gas clean-up requirements, co-firing CCS developments at higher TRLs will have cross-over benefits that should allow these similar dedicated systems to mature faster in the short-term (e.g. +1.5 TRL by 2020).

The TRL values for each technology combination are projected to increase over time and come up against the hard ceiling of TRL 8/9 when they achieve mass deployment. With regard to TRL error bounds, 2020 is probably the most uncertain date - we know current TRLs fairly accurately, although there is a spread based on different project developers and research group activities.

Our estimates for TRL development are given below in Figure 8. This shows the steady expected TRL progression of all technology combinations to reach mass deployment by 2050, with the potential for bio amine and bio IGCC technologies to develop slightly faster in the near-term.

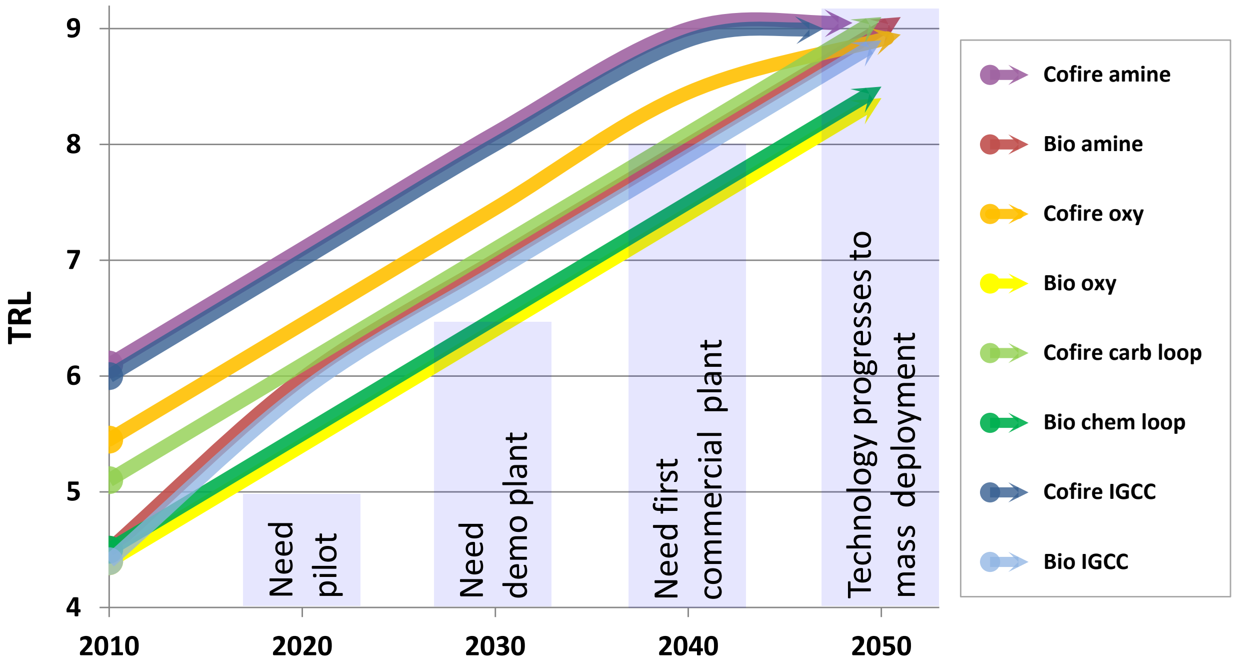

Figure 8: Likely TRL development & milestones to be met to enable mass deployment by 2050

We note that since all the biomass CCS technology combination have a system TRL well below TRL 8 (first commercial plants); none are currently available for construction at the 2010 commercial costs for a "Nth-of-a-kind" plant given in the sections above. Due their lower TRL (and smaller scale), current plant capital costs will be significantly higher. We note that the scope of the TESBiC project was only to focus on the impact of a full-scale roll-out of different biomass CCS technologies by 2050, and not to focus on first-of-a-kind (FOAK) costs.

It is therefore valuable to explain when each technology combination is expected to reach the "Nth-of-a-kind" costs, i.e. TRL 8. As shown in Figure 8 above, at expected incremental development rates, these first commercial plants are expected to be built in the following years, as shown in Table 3:

Table 3: Estimated year when TRL 8 reached

Technology	Year
Cofire amine	2030
Cofire IGCC	2030
Cofire oxy	2035
Bio amine	2040
Cofire carb loop	2040
Bio IGCC	2040
Bio oxy	2045
Bio chem loop	2045

As can be seen, the cofire amine/oxy/IGCC options are expected to reach commercial plant scale in the 2030's, followed by the dedicated bio amine/oxy/IGCC and looping options in the 2040's. From this commercialisation year forwards, the "Nth-of-a-kind" plant costs then begin to apply – i.e. the technology costs will have finally reached a "learning-by-doing" cost reduction curve as the deployment ramps up. Before this commercialisation year, plant capital costs could be up to 30-80% above the "Nth-of-a-kind" plant costs, based on their current TRLs of between 4.5 and 6.

1.8 Discussion

Figure 9 summarises some of the key results from the decadal modelling – that of improvements in capital costs and efficiencies over time, the grouping of technologies by scale (dedicated biomass vs. co-firing), along with the relatively attractive opportunity for power generation with significant negative CO_2 emissions presented by bio chem loop and cofire carb loop technologies.

Overall, the decadal modelling and comparison of all eight TESBiC technologies has indicated that that with regards to capex and efficiencies, there is little to choose from between the large-scale cofire amine/oxy/IGCC options, as they all currently lie within the same error bounds, with IGCC potentially higher efficiency in the future. The medium-scale looping technologies are again similar – bio chem loop is slightly ahead on capex and efficiency, but slightly behind cofire carb loop on TRL development. The small-scale dedicated bio amine & oxy options also share similarities, however, bio IGCC is more efficient, and hence has a lower LCOE.

Plant scale (MW_e) is the principal driver of capex, not the choice of technology. Co-firing percentage, i.e. average feedstock cost, is the key driver of LCOE, with dedicated biomass options being significantly more expensive than co-firing with coal, due to the high price of biomass pellets. Capital costs do also contribute significantly to LCOE, whereas operating costs are less important. The cost of CO_2 captured lies between £80 and 190/tCO_2, and is highest for small-scale bio options.

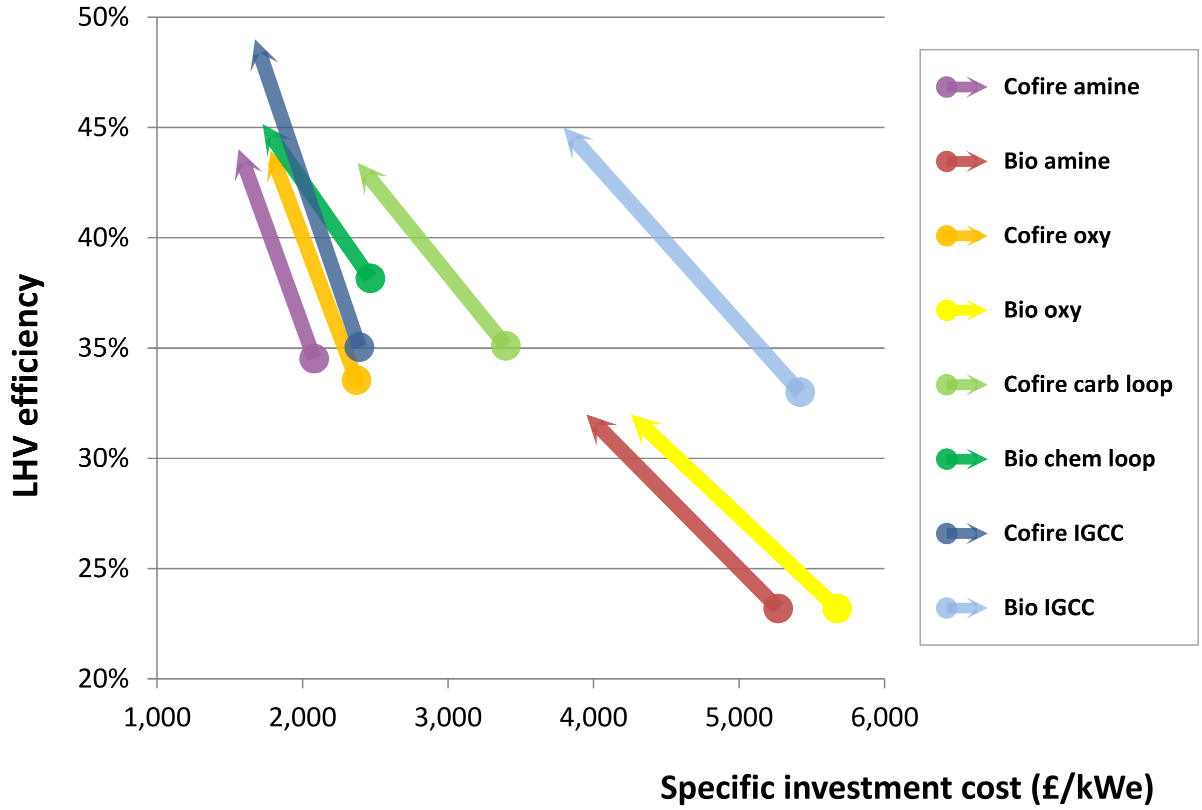

Figure 9: Projected LHV electrical efficiency & capex development over time, Base Case scales

2 EXTENSION OF THE WP3 MODELS

On completion of the decadal modelling for each technology combination within TESBiC, the detailed models in WP3, i.e. techno-economic outputs (e.g. capex, opex, efficiency, emissions) as a function of the main operational inputs (e.g. plant nameplate and operating capacities, carbon capture extent and biomass co-firing percentage) were then extended up to 2050.

The piecewise linear models developed for the eight technology combinations in WP3 were run while retaining the same model coefficient matrix as described in the WP3 deliverable report, and by adopting the projected values described above for setting the technology's base case in each decade. In this way, the techno-economic outputs were obtained for each decade, i.e. separate models were developed for each technology in 2010, 2020, 2030, 2040 and 2050 – delivered as different tabs/worksheets within the same workbook in MS Excel (for example Figure 10 shows the multiple decadal worksheets for cofire oxy).

Technology: co-firing coal+biomass+oxycombustion

	Model coefficients				A coefficient matrix			
	y(i) = y(xb(j))+ A (i, j).x((j)-xb(j))				Inputs			
				units	MWe	Mwe		%
Outputs	**Base values yb**	**Units**		**Outputs**	nameplate capacity	operating capacity	Co-firing extent	carbon capture extent
Capital Cost	1737.496859	k£/MWe		Capital Cost	-1.6564	0	1.602	11.53
Non-fuel Operating Cost	5.175	£/MWhe		Non-fuel Operating Cost	-0.0027	0	0	0.0364
Generation efficiency	44	%		Generation efficiency	0.0006	0.01676	-0.077	-0.1064
CO2 emissions	-96.98181818	kg CO2/MWhe		CO2 emissions	-0.001	0.28813	-10.3261	-7.8599
SOx emissions	0.391	kgSOx/Mwhe		Sox emissions	0	0	0	-0.002
NOx emissions	0.391	kgNOx/Mwhe		Nox emissions	0	0	0	-0.0006

		Inputs				
Case 1		**Actual values (x)**	**Base values (xb)**	**Outputs (y)**	**Values**	
	Nameplate capacity	398	398	Capital Cost	1737.496859	k£/MWe
	Capacity factor	100	100	Non-fuel Operating cost	5.175	£/MWhe
	Co-firing extent	20	20	Generation Efficiency	44	%
	CO_2 capture extent	95	95	CO_2 emissons	-96.9818182	kg CO2/MWhe
				SOx emissions	0.391	kgSOx/Mwhe
				NOx emissions	0.391	kgNOx/Mwhe

		Inputs	
		Actual	Base values

Model 2010 | Model 2020 | Model 2030 | Model 2040 | **Model 2050**

Figure 10: Sample screenshot of the extended WP3 model for cofire oxy

3 INTERFACE WITH BVCM

On completion of the decadal modelling for each technology combination within TESBiC, the BVCM technology database was augmented to include all eight biomass CCS technology combinations. The following key TESBiC parameters were manually input into the database for the years 2010, 2020, 2030, 2040 and 2050:

- Plant net electrical output (MW_e), and allowable range
- Biomass co-firing (%)
- CO_2 capture rate (%)
- Availability (%) and turndown (%)
- Specific investment cost (£/MW_e) – Low/Medium/High cases
- Fixed operating cost (£/MW_e/yr) – Low/Medium/High cases
- Variable non-fuel operating cost (£/MW_e/yr) – Low/Medium/High cases
- Plant net LHV electrical efficiency (%) – Low/Medium/High cases

The expanded technology database was uploaded into the BVCM architecture in early May 2012, and the full BVCM model was run to generate new sets of results and sensitivity scenarios. The deliverables from BVCM Phase 1, originally produced before the decadal TESBiC data was available, have also now been fully updated using the new modelling results, with key messages communicated to the ETI's Bioenergy Strategic Advisory Group on 15-16th May 2012.

The results suggest that significant opportunity exists for negative emissions (in the range of 50 to 100 million tonnes of CO_2 sequestered per year) via carbon capture and storage technologies in the power sector. Bio chem loop appears to be particularly preferred for deployment by the BVCM model, appearing in many scenarios, due to its low capex and high efficiency at intermediate scale (268 MW_e), along with large negative CO_2 emissions per kWh electricity generated. Cofire amine & oxy are also present in several scenarios, particularly in the earlier years. However, we note that under more modest CO_2 sequestration targets, biomass heating, bioSNG and bio-hydrogen routes tend to dominate the overall bioenergy sector, with biomass to power with CCS playing a more modest role.

4 VIABILITY OF BIOMASS CCS WITH FOSSIL CCS

As well as carrying out decadal modelling of the eight biomass with CCS technologies, we also modelled coal and gas CCS technologies to 2050, using the following data sources:

- IEA (2011) "Cost and performance of carbon dioxide capture from power generation". This is a meta-analysis of numerous engineering studies, mainly based in OECD countries, including index inflation to current costs. The capex and efficiency of amine scrubbing, oxy-fuel and IGCC coal CCS technologies are examined, as is natural gas with amine scrubbing CCS. This dataset gave us our 2010 baseline, including all non-fuel operating costs being fixed at 4% of capital costs.

- Confidential input data to the ETI's ESME model. This gives estimates for the 2010 and 2050 costs and performance of pulverised coal with CCS (unspecified whether amine or oxy-fuel), IGCC coal with CCS, and Natural gas with CCS. As above, we used these relative % capex reductions from ESME to derive coal and gas CCS capex in 2050, with a curve fitted to derive the values in the intermediate years, starting from the IEA values in 2010. As a reminder, the ESME capex reductions to 2050 assume a 25% drop for coal and gas combustion plants with CCS (or a 30% drop for IGCC with CCS). For the coal CCS efficiency projections, the same values as for the co-firing CCS cases were used, with gas CCS using the efficiency values directly from ESME (reaching 62% LHV electrical efficiency by 2050).

4.1 Costs and efficiency of fossil CCS

The costs and efficiencies of coal and natural gas CCS from the IEA (2011) and ETI ESME references are plotted below in Figure 11. These are all N^{th}-of-a-kind plants at large scale (500+ MW_e), i.e. costs and efficiencies are directly comparable with each other. Figure 11 shows that the IEA and ESME data is a good match for natural gas CCS. It is also a reasonable match for the unspecified pulverised coal CCS plant compared to its coal oxy-fuel and amine scrubbing comparators, although the ESME data is more pessimistic with regards to efficiency improvements. However, the ESME data for coal IGCC is a poor match to the IEA coal IGCC data – ESME assumes a much higher capex than for other fossil CCS options, and a more pessimistic improvement in IGCC efficiency to 2050.

This is at odds with one of the central messages of the IEA (2011) study, as communicated in TESBiC WP1, which states that although unabated coal IGCC plants are likely to be more expensive than unabated coal combustion plants, the costs of adding pre-combustion capture are significantly less than those of adding post-combustion capture, and hence the resulting capital costs of coal combustion with CCS and coal IGCC with CCS plants are expected to be similar. The IEA (2011) data below in Figure 11 shows this result.

We therefore chose to use the IEA (2011) data as the fossil CCS comparator in the TESBiC study[4]. The IEA data also only assumes a ±25-30% error bound, whereas the ESME data assumes a -40%/+60% error bound. The key results for each of the 8 TESBiC technology combinations are given alongside the IEA fossil CCS baseline data in Table 4.

[4] We note that natural gas CCS is rather an outlier, and without a direct biomass comparison in the TESBiC project. Although natural gas CCS has very low capital costs and high efficiencies, natural gas costs considerably more than coal, and is less carbon intensive (hence much less CO_2 is captured per kWh_e generated). As a result, gas CCS has a fairly competitive LCOE, but actually has the highest £/tCO_2 captured of the fossil CCS technologies – almost triple the coal CCS technologies.

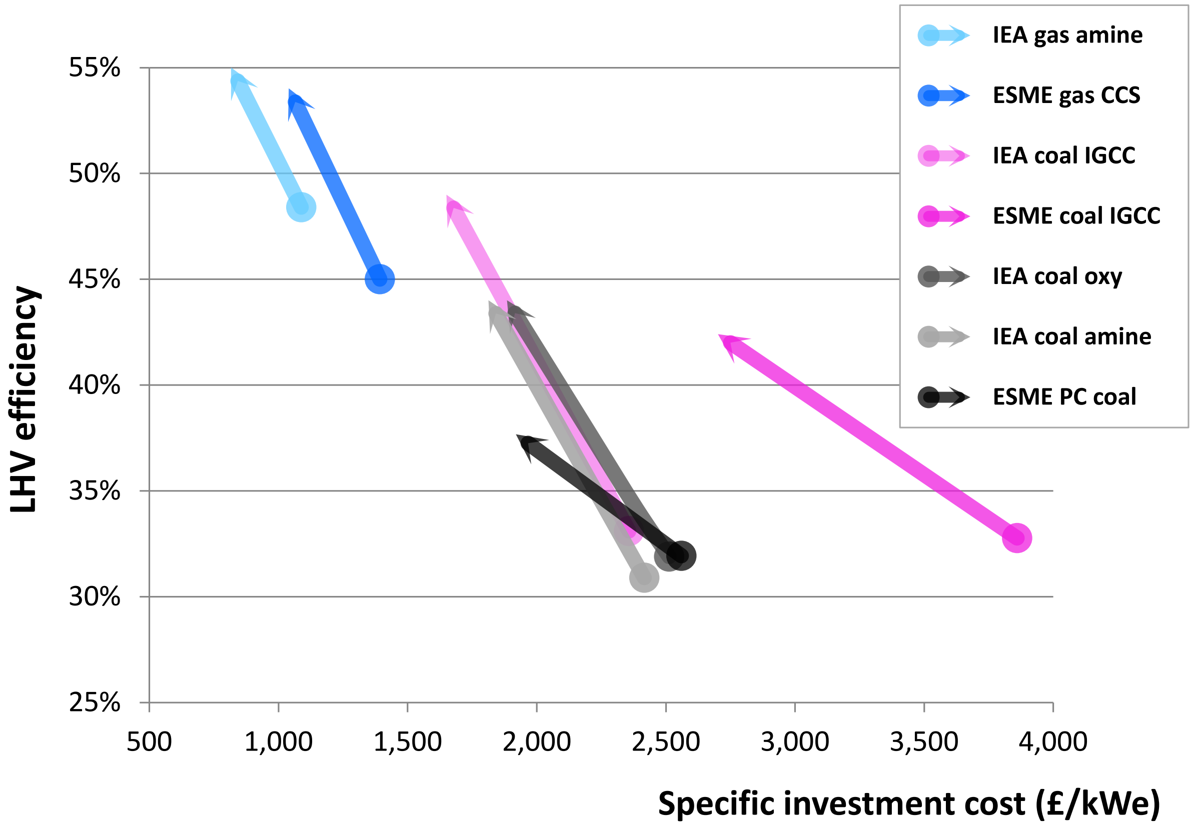

Figure 11: Development of fossil CCS plant efficiency and capex to 2050

Comparing Figure 11 with Figure 9, there is remarkably little difference in capital costs or efficiencies between the three IEA baseline coal CCS technologies, and their three respective co-firing cases modelled in the TESBiC project (cofire amine/oxy/IGCC). This strong overlap is to be expected, given the wide error bounds and variance in additional project costs considered, and since biomass co-firing proportions are only ~20%. Additional biomass handling equipment is therefore likely to be modest, and the impact of the biomass on plant efficiency will be fairly limited (especially if dry pellets are used). As a further check, the costs and efficiencies of the IEA baseline unabated coal and TESBiC unabated co-firing plants were compared, and showed an even closer match, which is sensible, given the much higher TRLs involved and narrower uncertainty bounds.

The inclusion of biomass co-firing has more of an impact on the levelised cost of electricity (LCOE), mainly due to the significantly higher costs of biomass feedstocks compared to coal – therefore the LCOE of TESBiC cofire amine/oxy/IGCC options are slightly above their IEA fossil CCS baselines. However, the key difference between the IEA coal CCS baseline and TESBiC co-firing technologies is that whilst the pure coal CCS plants still emit 80 to 170 gCO_2e/kWh_e generated, the co-firing technologies have net CO_2 emissions of -45 to -120gCO_2e/kWh_e generated. The addition of biomass has therefore taken a fossil CCS plant from being slightly CO_2 positive, to slightly CO_2 negative – an important consideration given the UK electricity grid needs to be almost completely carbon neutral by 2030 (Committee on Climate Change, 2010[5]). The exact values depend heavily on the CO_2 capture

[5] Committee on Climate Change (2010) "Chapter 6: Power sector decarbonisation to 2030" The Fourth Carbon Budget: Reducing emissions through the 2020s, available at: http://downloads.theccc.org.uk.s3.amazonaws.com/4th%20Budget/4th-Budget_Chapter6.pdf

%, amount of co-firing carried out, and whether any upstream biomass emissions (i.e. CO_2 emissions in cultivation, harvesting, processing and transport to the power plant) are covered in the calculation. Note that biomass is considered carbon neutral under the existing EU ETS and that the CCC recommendations do not include these life cycle emissions in their calculations of carbon neutrality. However, this TESBiC study does assume a generic upstream biomass emissions factor in the calculation of the net CO_2 balance for each technology – see the Annex for details.

The three dedicated biomass cases using the same capture technologies (bio amine/oxy/IGCC) have much higher capital costs, and lower efficiency than the IEA fossil CCS baseline or cofire amine/oxy/IGCC options. However, as explained before, these plants are at a much smaller scale (Base Cases of ~50 MW_e compared to ~400 MW_e). LCOEs are therefore also significantly higher, although with potential to use cheaper biomass chips instead of pellets. These technologies have net CO_2 emissions of -620 to -1,420gCO_2e/kWh_e generated.

Bio chem loop has similar capex and efficiency compared to the IEA fossil CCS baseline, with cofire carb loop at a slightly higher capex. This is primarily since these two technology options (in the Base Case) are based on medium-scale dedicated biomass power plants (~250 MW_e), with the benefits of the more novel capture technologies offsetting any disadvantages of the slightly smaller power plant (compared to a large coal plant). However, LCOEs are elevated (~70% higher than fossil CCS) due to higher biomass pellet costs compared to coal. Cofire carb loop has intermediate net CO_2 emissions of -340 to -420gCO_2e/kWh_e generated, due to the use of coal in the calciner. Bio chem loop uses only biomass, and hence has net emissions of -700 to -830gCO_2e/kWh_e generated.

4.2 Cost of CO_2 avoided

IEA (2011) also gives reliable cost, efficiency and emissions data for unabated coal combustion power plants. In 2010, this average unabated plant has a LCOE of £69/MWh_e and emissions of +840 gCO_2e/kWh, falling to a LCOE of £53/MWh_e and emissions of +680 gCO_2e/kWh in 2050. We note coal plant capex and efficiency improvements are somewhat offset by projected increases in coal prices. These unabated coal plant figures were used to derive the cost of CO_2 avoided for each of the 8 TESBiC technologies, as shown in Figure 12.

The cost of CO_2 avoided is calculated based on differences in LCOE and net CO_2 emissions compared to an unabated coal power plant (from the relevant decade) - the exact formula is given in the Annex. The cost of CO_2 avoided only falls gradually over time, since although improved efficiencies mean lower LCOE, they also result in increased gCO_2e/kWh, i.e. “less negative” emissions. For clarity, the values shown are therefore only for an average over 2010-2050.

Figure 12 shows the usual three groupings of the Base Case technologies, with cofire IGCC the cheapest method of saving CO_2 versus an unabated coal power plant of the day. As shown by the lighter bars below, switching the small-scale dedicated biomass technologies from using pellets to chips dramatically reduces their cost of avoided CO_2 to be much more in line with the looping options, and closer to the large-scale co-firing options.

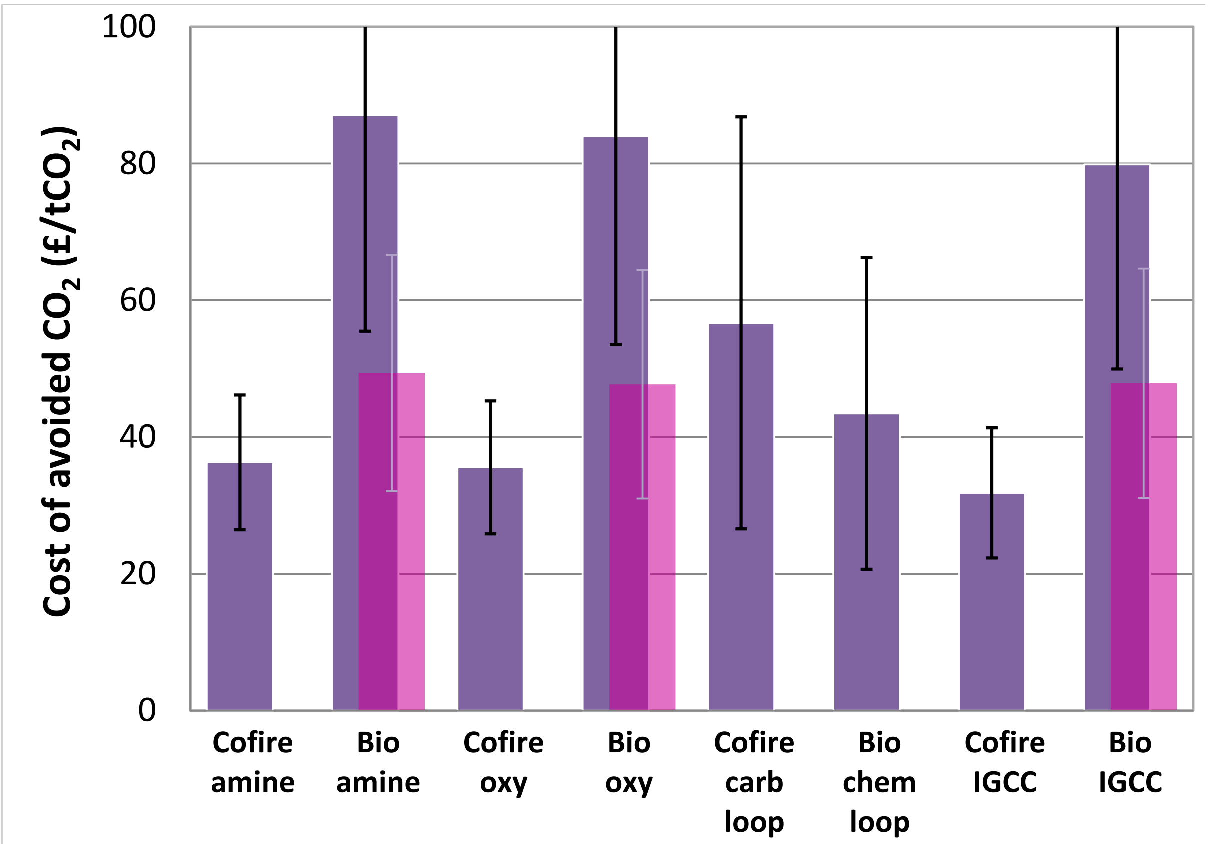

Figure 12: Cost of avoided CO_2, Base Case scales. Dark bars = pellets, light bars = chips

4.3 Discussion

In summary, comparing the 8 TESBiC technologies against fossil CCS technologies indicates that cofire amine/oxy/IGCC and bio chem loop options have capital costs and efficiencies that are within the error bounds of coal CCS capital costs and efficiencies. Cofire carb loop is slightly more expensive than fossil CCS, with bio amine/oxy/IGCC at a greater disadvantage in terms of capital costs and efficiencies, due to their much smaller Base Case scales. Furthermore, biomass pellets usually cost significantly more than coal, thereby impacting LCOE calculations, which also explains why coal CCS technologies have a lower LCOE than co-firing CCS options. Chips are considerably cheaper than pellets, and could be viable for use in small-scale power plants where local supplies are available.

Coal and gas CCS technologies still emit a non-negligible amount of CO_2, which may not be economically or politically acceptable in a completely decarbonised power grid. Introducing more than 10% biomass co-firing will generally remove these remaining CO_2 emissions, and give a net negative emissions power plant. As noted above, we have assumed a fixed upstream biomass emissions factor for use in the CO_2 calculations of all eight TESBiC technologies (i.e. biomass is not considered completely carbon neutral).

Table 4: Summary matrix comparing key results in 2010 and 2050 for the 8 TESBiC technologies at Base Case scales, and fossil CCS technologies from IEA (2011)

	Cofire amine	Bio amine	Cofire oxy	Bio oxy	Cofire carb loop	Bio chem loop	Cofire IGCC	Bio IGCC	IEA coal amine	IEA coal oxy-fuel	IEA coal IGCC	IEA gas amine
Current TRL	6 to 7	4 to 5	6	5	5	4 to 5	6	4 to 5	6 to 7	6	6	5 to 6
Scale (MW_e)	399	49	389	49	247	268	461	40	545	543	546	461
Co-firing %	22%	100%	20%	100%	58%	100%	20%	100%	0%	0%	0%	0%
CO_2 capture	90%	90%	95%	95%	90%	100%	90%	90%	87%	92%	88%	87%
2010												
LHV efficiency	35%	23%	34%	23%	35%	38%	35%	34%	33%	32%	33%	48%
Capex (£/kW_e)	2,080	5,268	2,371	5,675	3,397	2,467	2,391	5,420	2,417	2,513	2,358	1,089
LCOE (£/MWh_e)	79	228 (155)	80	228 (155)	119	119	82	189 (136)	69	70	66	76
Emissions (gCO_2e/kWh)	-84	-1,210 (-1,340)	-118	-1,287 (-1,417)	-416	-829	-64	-851 (-942)	+169	+110	+148	+95
£/tCO_2 captured	88	165 (112)	82	156 (106)	132	127	87	193 (140)	72	71	73	209
£/tCO_2 avoided*	39	90 (51)	39	87 (50)	60	46	38	86 (52)	38	37	34	45
2050												
LHV efficiency	44%	32%	44%	32%	43%	45%	49%	45%	44%	44%	49%	55%
Capex (£/kW_e)	1,560	3,951	1,779	4,256	2,378	1,727	1,674	3,794	1,813	1,885	1,768	817
LCOE (£/MWh_e)	63	168 (115)	63	168 (115)	90	93	57	134 (96)	53	55	48	73
Emissions (gCO_2e/kWh)	-66	-877 (-917)	-90	-933 (-1,027)	-337	-701	-46	-624 (-691)	+119	+80	+100	+83
£/tCO_2 captured	89	168 (115)	85	159 (109)	124	118	90	188 (135)	79	77	79	230
£/tCO_2 avoided*	33	83 (47)	32	80 (45)	51	40	25	73 (42)	27	27	17	59

* Measured against an unabated pulverised coal combustion power plant from IEA (2011)

** Numbers in brackets are for chips – all other numbers are for pellets

5 BENCHMARKING AT A SINGLE SCALE

All of the decadal modelling analysis given in Sections 1 - 4 above was conducted at the Base Case plant scales given in Table 0 – i.e. co-firing options at large scale (~400MW_e), looping options at intermediate scale (~250MW_e), and dedicated biomass options at small scale (~50MW_e).

However, given the very significant influence of plant nameplate capacity (MW_e) on the specific investment costs, it is highly informative to also compare all eight biomass CCS technologies when built at the same common plant scale. This benchmarking process is carried out at 50MW_e, as well as at 250MW_e, to show the impact of building each technology at small-scale, as well as at intermediate scales. An even larger scale (e.g. 500MW_e) was not chosen, since dedicated biomass combustion power plants are typically limited to the <300MW_e range, i.e. some of the technologies will be reaching their physical limits, and cannot realistically be compared at very large scales.

For each technology, using the known Base Case total investment costs given at a certain nameplate capacity, we have derived new total investment costs at the new benchmark scales by applying a generic engineering scaling exponent to the ratio of plant scales. The specific investment cost is then derived at the new benchmark scale (i.e. the scaling factor applies to total costs, not to the specific costs). For the fixed operating costs, the same assumption remains that they are 5%/yr of total installed costs at the new scale, with the variable non-fuel operating costs assumed to scale linearly in proportion to nameplate capacity. All the re-scaling formulas used in this benchmarking exercise are set out in the Annex.

Capex vs. LHV efficiency

Starting with benchmarking at 50MW_e, all the co-firing and looping technologies show a significant increase in specific investment cost (compared to their Base Case values shown in Figure 9), and slight decreases in LHV electrical efficiency. Below in Figure 13, we re-plot Figure 9 for a single 50MW_e scale. The familiar groupings are still visible: bio amine and bio oxy are the least efficient options, whereas cofire and bio IGCC have the potential to reach the highest efficiencies in the future[6]. Interestingly, the capex for cofire carb loop has increased significantly at this small benchmark scale, although efficiency remains competitive. Alongside the co-firing options, bio chem loop potentially remains one of the lowest capex options, and with high efficiency.

Now benchmarking at 250MW_e, the co-firing options show an increase in specific investment cost, looping options remain unchanged, and the dedicated biomass options show a significant decrease in capex (compared to Base Case values). Below in Figure 14, we re-plot Figure 9 for a single 250MW_e scale. The technologies are now much more tightly bunched together, almost lying completely within each other's uncertainty bounds (not shown). This again confirms the primary importance of scale, rather than technology choice, in determining capital costs. However, there are still notable differences in efficiency, with bio chem loop still currently the most efficient option.

[6] Note that different chemical looping configurations involving pressurised chambers and gas turbines, or H_2 generation for a fuel cell could have significantly higher electrical efficiencies, but have not been considered in this study

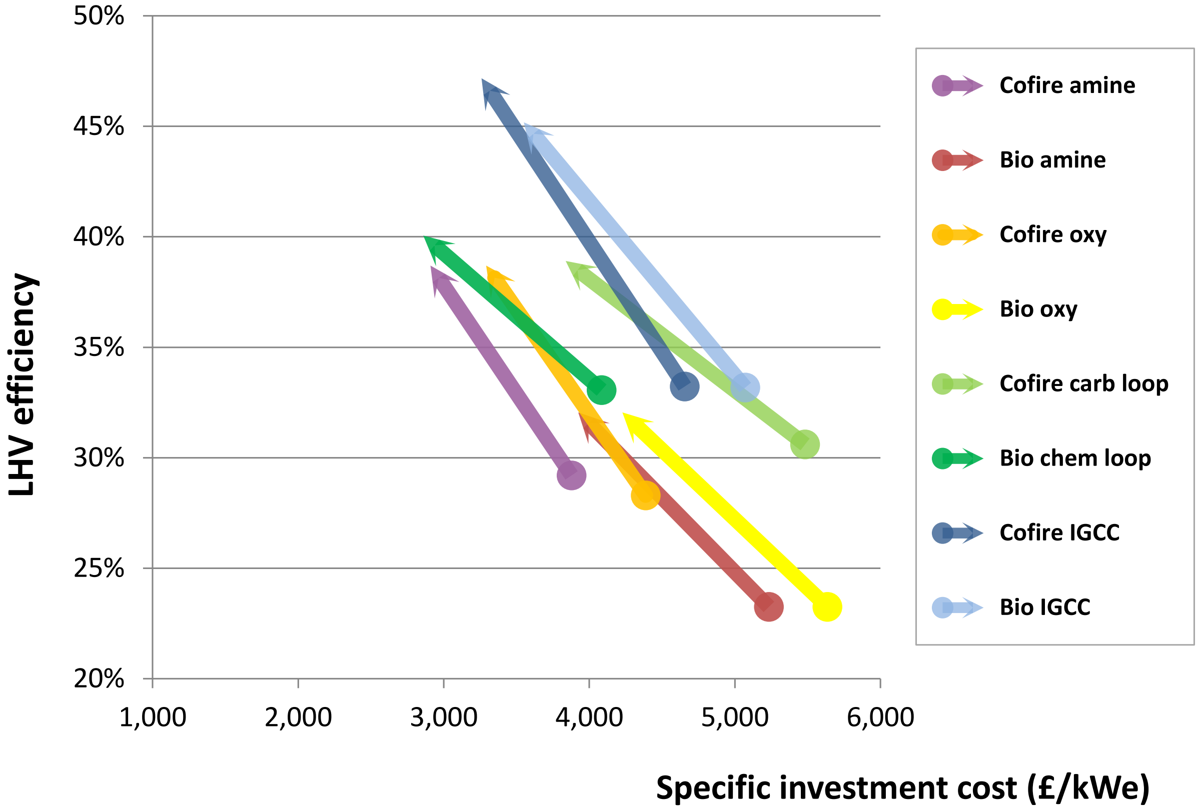

Figure 13: Projected LHV electrical efficiency & capex development over time at 50MW$_e$

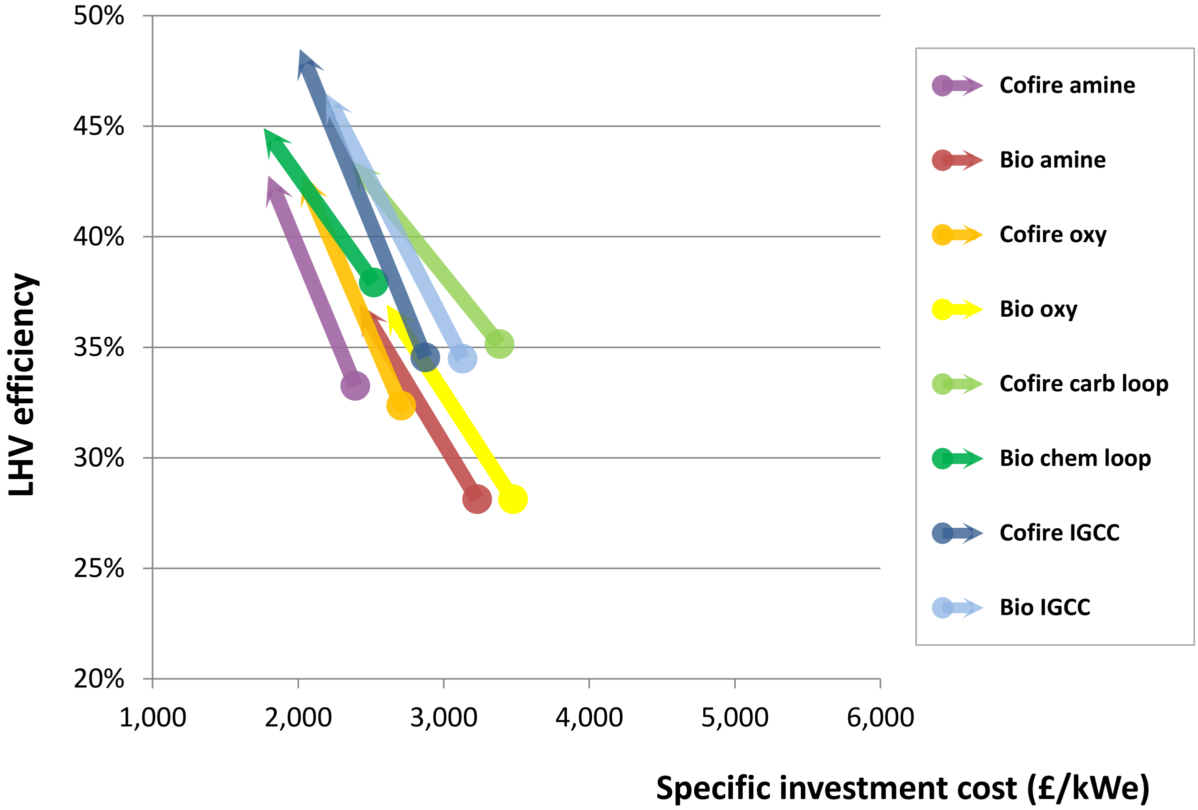

Figure 14: Projected LHV electrical efficiency & capex development over time at 250MW$_e$

LCOE

In Figure 15, we re-plot Figure 6 for a 50MW$_e$ benchmark scale. Since this is a small-scale plant, either biomass pellets or chips could realistically be used. The lower section of this chart (solid lines) shows the LCOE results when the biomass used is only pellets (as in the Base Case), with the upper section (dotted lines) showing the lower LCOE results when the biomass used is only chips. The lower chart shows three distinct groupings again, with low efficiency bio amine & oxy having the highest LCOE, the higher efficiency bio IGCC, bio chem loop and cofire carb loop options in the middle, and cofire amine/oxy/IGCC with the lowest LCOE. The switch to using chips instead of pellets dramatically lowers the LCOE, with many options now having very similar LCOE (~£80-100/MWh$_e$) in 2050, since the price of chips (£10/MWh) is much closer to the price of coal (£7/MWh).

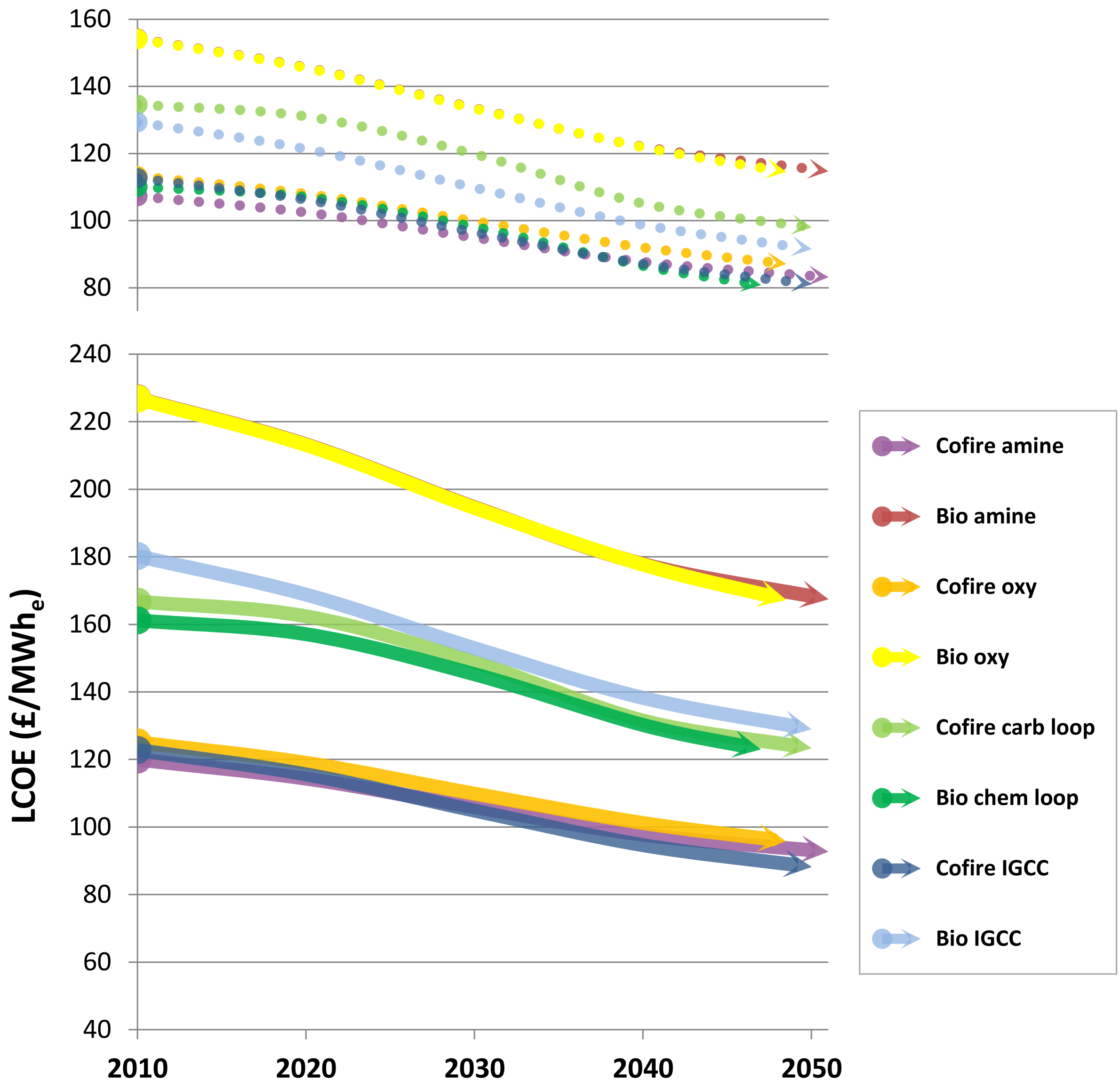

Figure 15: LCOE over time at 50MW$_e$, solid lines (below) = pellets, dotted lines (above) = chips

Below in Figure 16, we re-plot Figure 6 for a $250MW_e$ benchmark scale. This is done using only pellets as the biomass feedstock, since locally available chips are unlikely to be able to meet the annual feedstock demands (~1million odt/yr) of a $250MW_e$ dedicated biomass plant. The same three groupings as in Figure 15 are apparent again.

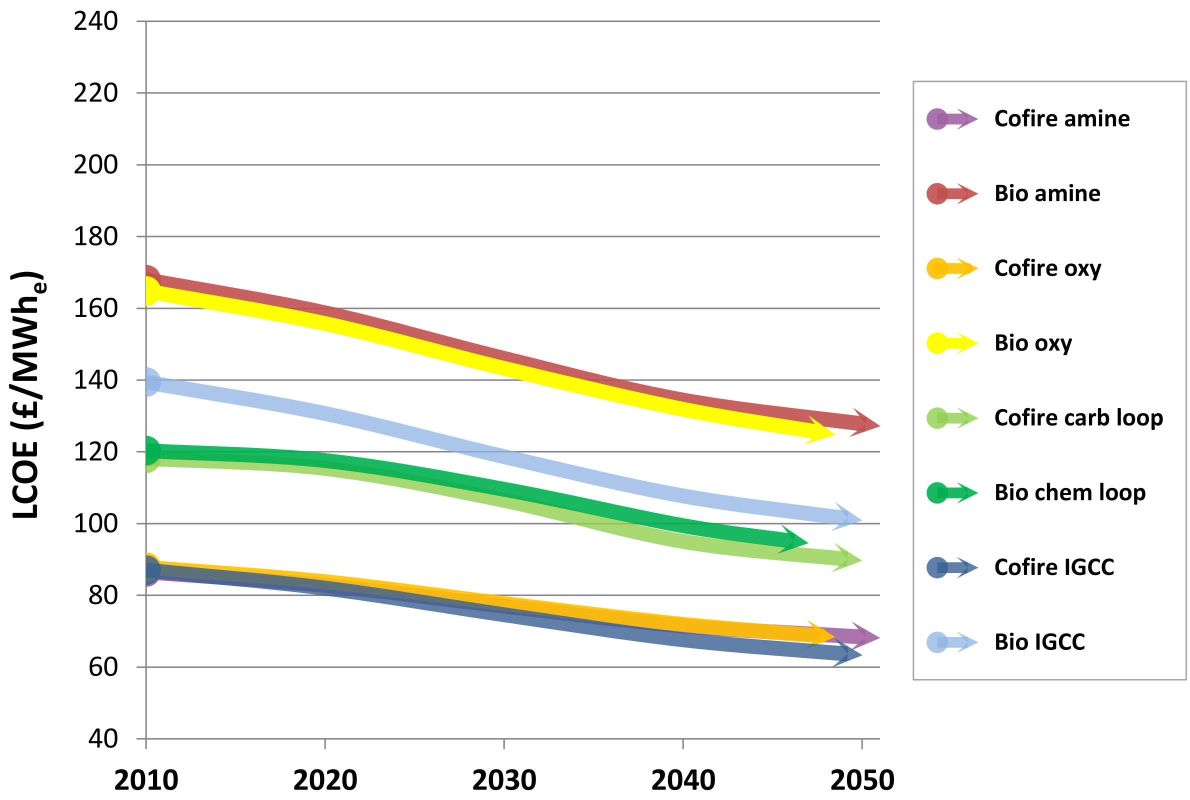

Figure 16: LCOE over time at $250MW_e$, all biomass used as pellets

Metrics for CO_2 emissions

The three CO_2 metrics discussed in Section 1.2 change very little with different plant scales. There are some shifts due to slight changes in electrical efficiencies from the Base Cases, but the main influences of biomass co-firing %s, CO_2 capture rates and coal/biomass emissions factors remain unchanged, and hence there is little value in benchmarking at 50 and 250 MW_e for these metrics. Similarly, results with chips and pellets only vary slightly due to a difference in the upstream biomass emissions, with the net CO_2 emissions using chips slightly more negative than when using pellets.

Cost of CO_2 captured

Given the dependency between LCOE and the cost of CO_2 captured, Figure 17 and Figure 18 (compared to Figure 7) show several similarities to the benchmarking LCOE changes. The co-firing options again are the cheapest cost of CO_2 captured (due to coal vs. pellet prices), with the switch between biomass pellets and chips noticeably reducing the cost of CO_2 captured for the other options. Interestingly, the $50MW_e$ case with chips shows very similar cost of CO_2 captured across the board (range of ~£100-130/tCO_2), since the slight differences in LCOE shown in Figure 15 are balanced by the different amounts of CO_2 captured (with lower efficiency plants capturing more CO_2 whilst they generate the benchmark $50MW_e$).

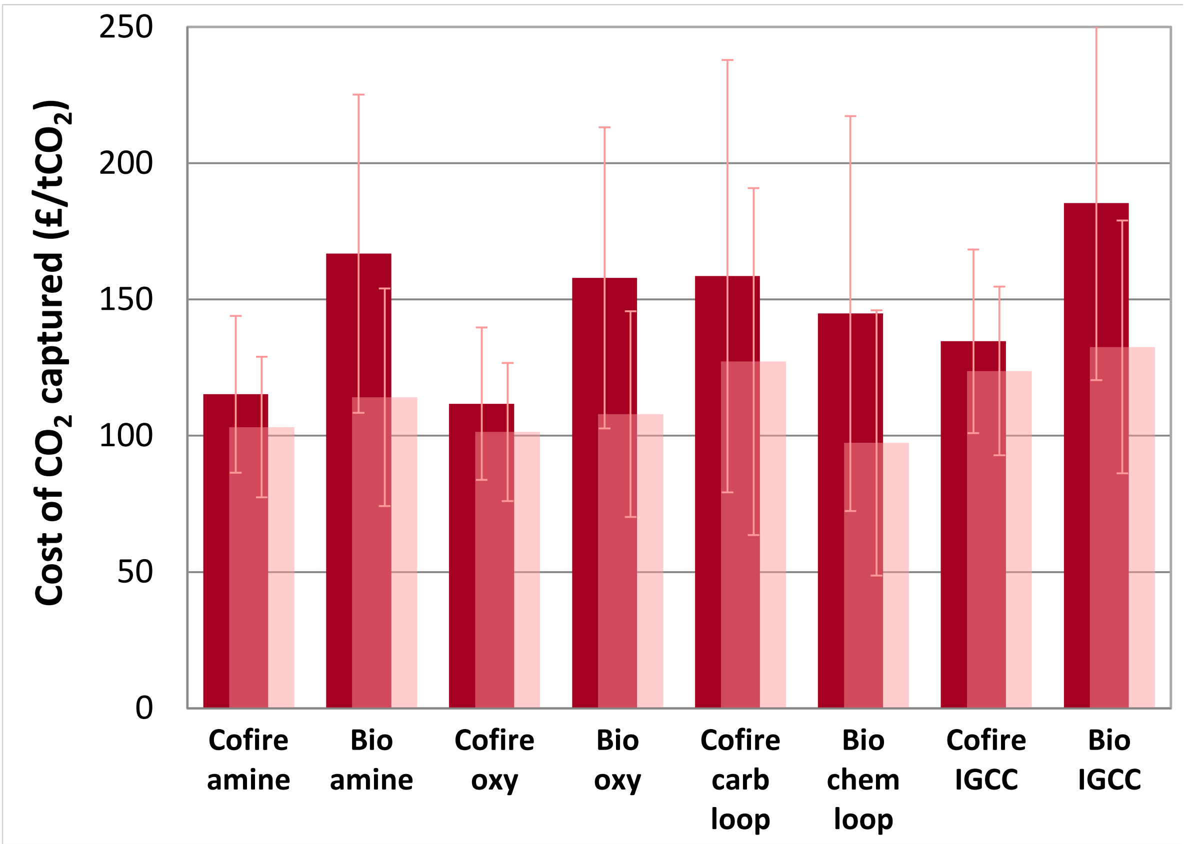

Figure 17: Cost of CO_2 captured in 2010, at 50MW$_e$ scale. Dark bars = pellets, light bars = chips

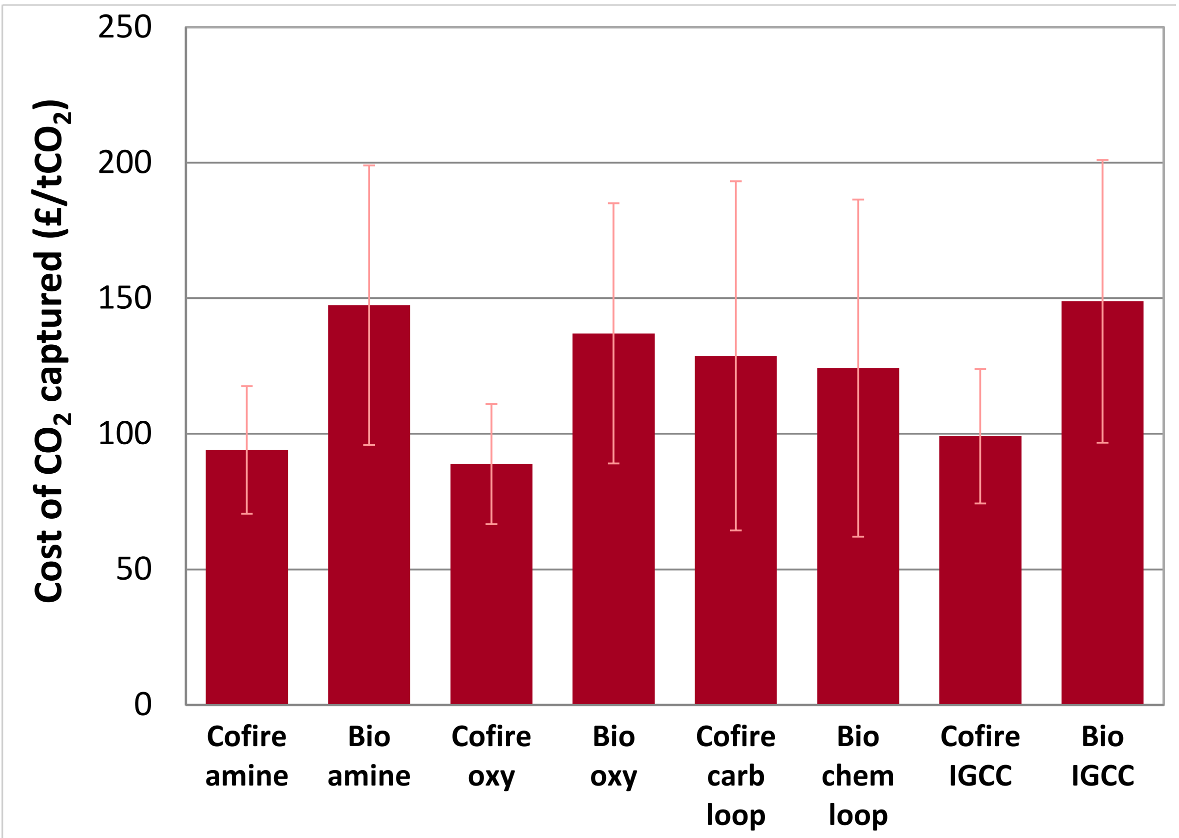

Figure 18: Cost of CO_2 captured in 2010, at 250MW$_e$ scale. All biomass as pellets

The differences in cost of CO_2 captured at $250MW_e$ are primarily to do with the average feedstock costs (coal vs. pellets), because again, capital costs are bunched, and the additional CO_2 captured by the less efficient plants when generating their $250MW_e$ is not enough to offset the higher LCOE.

Cost of CO_2 avoided

The comparator technology remains an unabated coal power plant (from the relevant decade) for this benchmarking exercise. As discussed above in Section 4.2, the cost of CO_2 avoided only falls slightly over time; hence we only present average 2010-2050 values here. The Base Case values in Figure 12 were dominated by the choice of scales. Figure 19 below shows a tighter grouping when using a common scale of $50MW_e$, with costs of avoided CO_2 between £60-90/tCO_2 when using pellets, or £30-65/tCO_2 when using chips. Now that scale does not play a part in the cost of CO_2 avoided result, feedstock costs dominate – those technologies that maximise the use of low-cost chips (i.e. the dedicated biomass technologies) are able to achieve the lowest costs of CO_2 avoided. Bio chem loop appears to potentially be the most attractive technology in both cases (by quite some distance), although the uncertainty bars are large for this earlier stage technology.

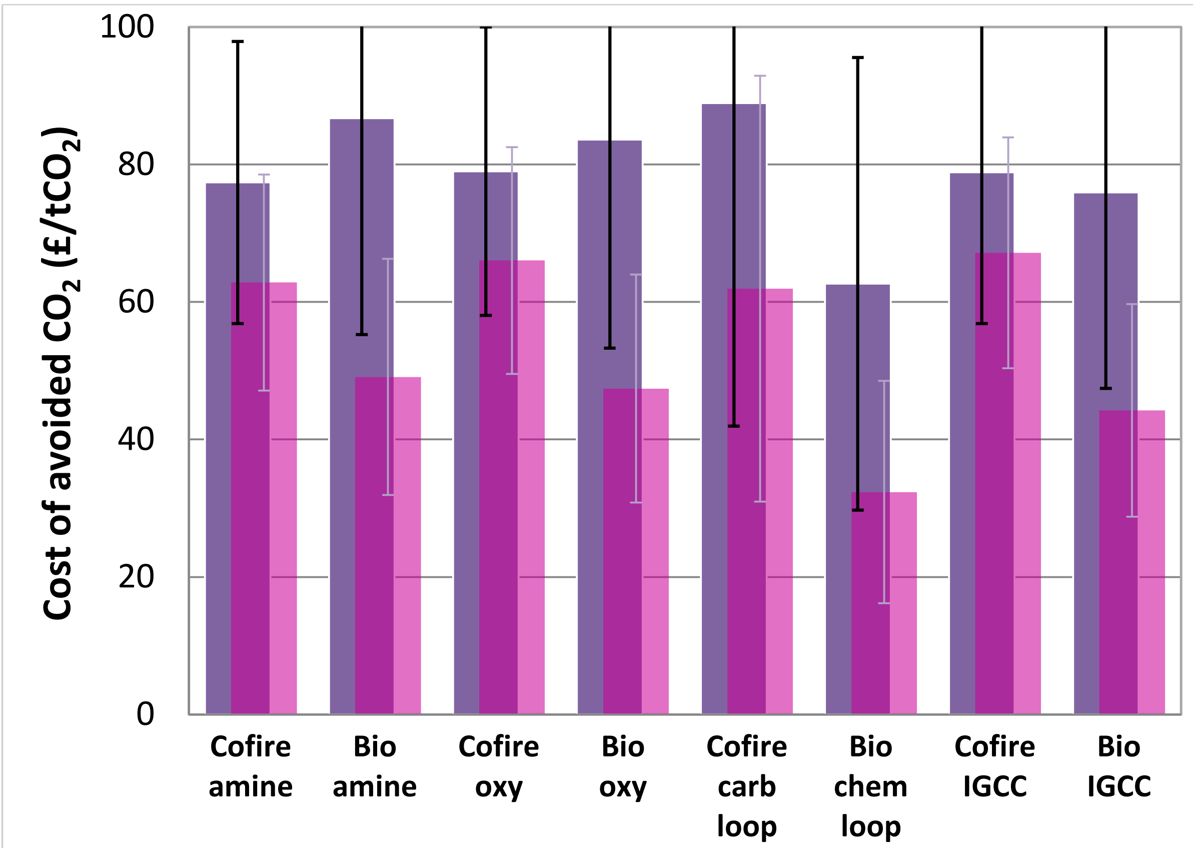

Figure 19: Cost of CO_2 avoided, at $50MW_e$ scale. Dark bars = pellets, light bars = chips

Figure 20 shows the results of benchmarking at $250MW_e$. Although the spread of capital costs are much tighter at this single scale, the difference between pellet and coal prices can be clearly seen, with the co-firing options offering the lowest cost of CO_2 avoided – although bio chem loop could also be attractive.

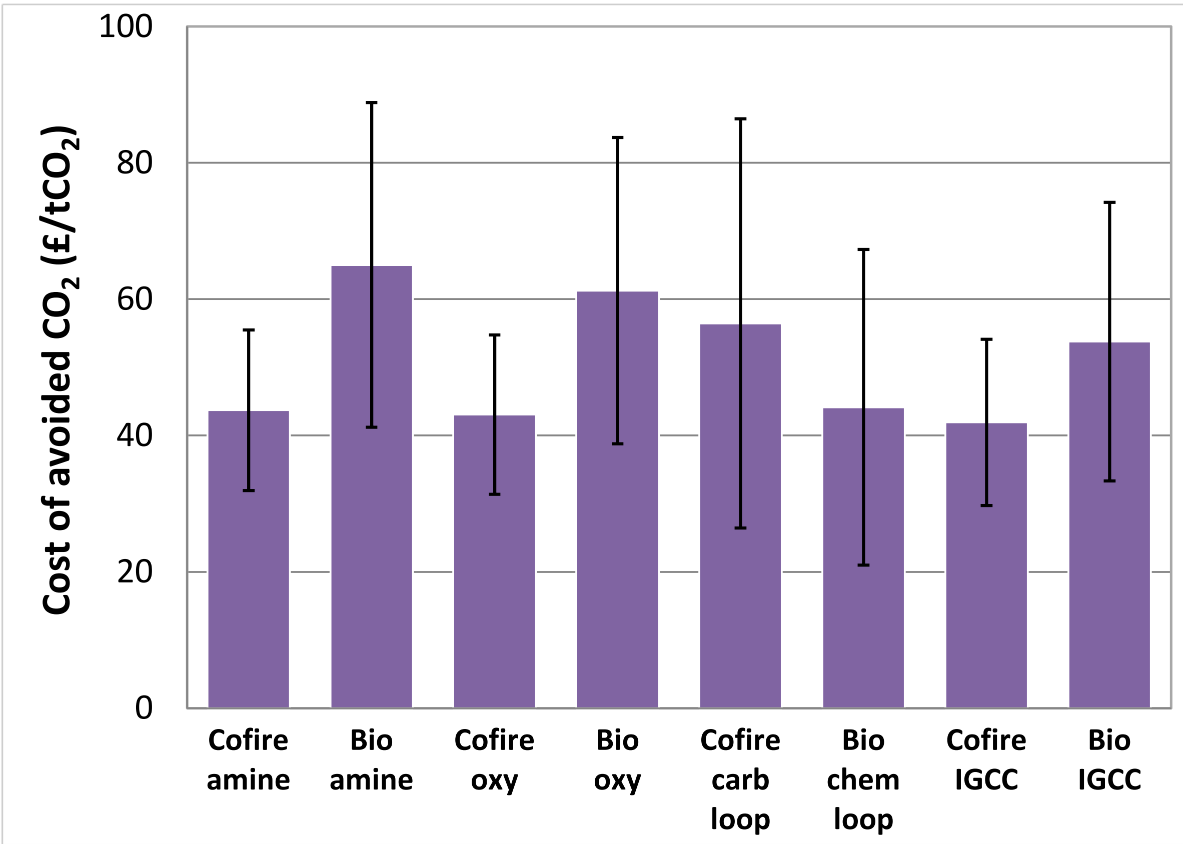

Figure 20: Cost of CO_2 avoided, at 250MW_e scale. All biomass as pellets

Table 5: Summary matrix comparing key results in 2010 and 2050 for the 8 TESBiC technologies at 50MW$_e$ with pellets

	Cofire amine	Bio amine	Cofire oxy	Bio oxy	Cofire carb loop	Bio chem loop	Cofire IGCC	Bio IGCC
Scale (MW$_e$)	50	50	50	50	50	50	50	50
Co-firing %	22%	100%	20%	100%	58%	100%	20%	100%
CO_2 capture	90%	90%	95%	95%	90%	100%	90%	90%
2010								
LHV efficiency	29%	23%	28%	23%	31%	33%	33%	33%
Capex (£/kW$_e$)	3,878	5,233	4,387	5,635	5,482	4,084	4,656	5,071
LCOE (£/MWh$_e$)	120	227	125	227	167	161	123	180
Emissions (gCO_2e/kWh)	-99	-1,207	-140	-1,284	-477	-957	-68	-846
£/tCO_2 captured	113	165	108	156	162	150	132	186
£/tCO_2 avoided*	82	90	84	87	94	66	88	81
2050								
LHV efficiency	39%	32%	39%	32%	39%	40%	47%	45%
Capex (£/kW$_e$)	2,908	3,925	3,291	4,226	3,838	2,859	3,259	3,550
LCOE (£/MWh$_e$)	93	167	96	167	123	123	88	129
Emissions (gCO_2e/kWh)	-75	-876	-103	-931	-376	-790	-48	-621
£/tCO_2 captured	116	167	114	158	152	138	135	182
£/tCO_2 avoided*	72	83	73	82	84	60	73	73

* Measured against an unabated pulverised coal combustion power plant from IEA (2011)

Table 6: Summary matrix comparing key results in 2010 and 2050 for the 8 TESBiC technologies at 50MW$_e$ with chips

	Cofire amine	Bio amine	Cofire oxy	Bio oxy	Cofire carb loop	Bio chem loop	Cofire IGCC	Bio IGCC
Scale (MW$_e$)	50	50	50	50	50	50	50	50
Co-firing %	22%	100%	20%	100%	58%	100%	20%	100%
CO_2 capture	90%	90%	95%	95%	90%	100%	90%	90%
2010								
LHV efficiency	29%	23%	28%	23%	31%	33%	33%	33%
Capex (£/kW$_e$)	3,878	5,233	4,387	5,635	5,482	4,084	4,656	5,071
LCOE (£/MWh$_e$)	107	154	113	154	135	110	113	129
Emissions (gCO_2e/kWh)	-122	-1,336	-161	-1,413	-535	-1,048	-86	-937
£/tCO_2 captured	101	112	98	106	131	102	121	134
£/tCO_2 avoided*	67	51	70	49	67	36	75	49
2050								
LHV efficiency	39%	32%	39%	32%	39%	40%	47%	45%
Capex (£/kW$_e$)	2,908	3,925	3,291	4,226	3,838	2,859	3,259	3,550
LCOE (£/MWh$_e$)	83	115	87	115	98	81	81	92
Emissions (gCO_2e/kWh)	-92	-969	-118	-1,025	-421	-865	-60	-688
£/tCO_2 captured	104	115	103	108	121	91	124	129
£/tCO_2 avoided*	58	46	61	45	54	28	58	39

* Measured against an unabated pulverised coal combustion power plant from IEA (2011)

Table 7: Summary matrix comparing key results in 2010 and 2050 for the 8 TESBiC technologies at 250MW$_e$ (with pellets)

	Cofire amine	Bio amine	Cofire oxy	Bio oxy	Cofire carb loop	Bio chem loop	Cofire IGCC	Bio IGCC
Scale (MW$_e$)	250	250	250	250	250	250	250	250
Co-firing %	22%	100%	20%	100%	58%	100%	20%	100%
CO_2 capture	90%	90%	95%	95%	90%	100%	90%	90%
2010								
LHV efficiency	33%	28%	32%	28%	35%	38%	35%	35%
Capex (£/kW$_e$)	2,393	3,229	2,707	3,477	3,383	2,520	2,873	3,129
LCOE (£/MWh$_e$)	87	168	88	165	118	120	87	139
Emissions (gCO_2e/kWh)	-87	-988	-123	-1,061	-416	-834	-65	-814
£/tCO_2 captured	93	147	87	137	132	128	97	150
£/tCO_2 avoided*	47	68	47	64	60	46	49	58
2050								
LHV efficiency	43%	37%	42%	37%	43%	45%	49%	47%
Capex (£/kW$_e$)	1,794	2,422	2,030	2,608	2,368	1,764	2,011	2,190
LCOE (£/MWh$_e$)	68	127	68	125	90	95	63	101
Emissions (gCO_2e/kWh)	-68	-760	-93	-809	-336	-704	-46	-604
£/tCO_2 captured	94	146	90	136	124	119	99	146
£/tCO_2 avoided*	40	62	39	58	50	41	34	49

* Measured against an unabated pulverised coal combustion power plant from IEA (2011)

6 POLITICAL, LEGISLATIVE, INCENTIVES AND OTHER FACTORS

Importance of biomass CCS in the energy mix recognised

This project has at its core the assessment of the potential contribution of biomass CCS in meeting an 80% reduction in UK's CO_2 emissions by 2050. In this section of the report, a number of key legislative and political factors which are shaping the short term development of biomass CCS technologies are examined, and an attempt is made to describe the government policy and other instruments needed to encourage and support these technologies into the longer term future.

There has recently been increasing interest from Government and its advisors in the potential for biomass CCS. For example, the Committee for Climate Change indicated that

"CCS should be demonstrated as a matter of urgency, particularly because the negative emissions ensuing when this is used with biomass may be required to meet long-term emissions target".

The Government's recent Bioenergy Strategy (April 2012) agreed indicating that

"The combination of bioenergy production with CCS could be a key mitigating option for the future through production of 'negative emissions', significantly increasing the cost effective options towards 2050"

"These negative emissions could then be used to offset fossil fuel emissions from other harder to decarbonise sectors. This makes BE-CCS an exceptionally valuable technological option"

"Without CCS there is only a minor role for the long term use of biomass in power generation (to 2050) due to availability of low carbon alternatives in this sector"

The United Nations Industrial Development Organisation (UNIDO) in its Global Technology Roadmap for CCS in Industry (February 2011[7]) considers that the application of CCS to biomass processes is an extremely important area for future research emphasizing:

"More detailed scientific studies are needed on costs, long-term contribution on GHG reduction and early opportunities [for biomass CCS]. Furthermore, a dedicated BECCS pilot and demonstration programme should be facilitated by policymakers."

The statements provide a clear endorsement of the potential of these technologies, and the key next step is to identify the regulatory and other instruments required to promote the necessary developments in this area. In addition, it is also important for the Governments to ensure that the overall public sentiment is conducive both to long term, large scale biomass use (e.g. through continued work on sustainability and the impacts of biomass use such as initiated through the Biomass Strategy) as well as to the long term storage of large volumes of CO_2 underground.

Incentives for negative CO_2 are a pre-requisite for deployment at scale

It is clear that the use of biomass for power production with carbon capture and storage is currently one of the very few technically available options for generating negative CO_2 emissions both rapidly and in significant quantities. However, no commercial organisation will deploy biomass CCS technologies until the economics become attractive, and industrial R&D in this area will be restricted because of the lack of a clear exploitation route.

[7] Carbo,M, (Feb 2011) Global Technology Roadmap for CCS in Industry. Biomass-based industrial CO_2 sources: biofuels production with CCS

Given that the LCOE from biomass CCS technologies are higher than their fossil fuel CCS or unabated biomass power generation counterparts (especially for smaller-scale dedicated biomass units), biomass CCS technologies will not be deployed without financial compensation for their negative CO_2 emissions. This needs to become a major, and reliable, revenue stream for plant developers, in order for biomass CCS to become competitive with other power generation technologies. These incentive mechanisms do not currently exist in a form that would see biomass CCS deployed.

The IPCC (2006)[8] Guidelines for GHG inventory reporting states that emissions from stationary biomass combustion sources with CCS may be used for lowering national GHG emissions:

- Combustion Chapter 2 – *"If the plant is supplied with biofuels, the corresponding CO_2 emissions will be zero, so the subtraction of the amount of gas [captured and] transferred to long-term storage may give negative emissions. This is correct since if the biomass carbon is permanently stored it is being removed from the atmosphere"*
- CCS Chapter 5 – *"Negative emissions may arise......if CO_2 generated by biomass combustion is captured. This is a correct procedure and negative emissions should be reported as such."*

Despite this potential to account for negative GHG emissions at a national level, policy frameworks that actually impact technologies or specific projects, such as the EU Emissions Trading System (EU ETS), do not allow for reporting negative emissions in this way (Ascui, 2010[9]). The EU ETS only considers liabilities from positive CO_2 emissions – this would only work to incentivise low (say 10%) biomass co-firing ratios for coal CCS, in order to avoid paying for any uncaptured coal emissions (by moving from >100gCO_2e/kWh down to zero emissions). The EU ETS as it currently stands does not incentivise negative emissions from biomass power generation. Further difficulties are presented by the inability to give free allocations of EUAs (emission permits) to power generation technologies, the very low price of EUAs, and by the fact that 100% biomass power generation technologies are not covered by the EU ETS.

At a global level, the United Nations Framework Convention on Climate Change (UNFCC[10]) has not yet developed policies that support biomass CCS:

- The Clean Development Mechanism (CDM) for projects in developing countries grants Certified Emission Reductions Units (CERs) for below-baseline emissions reductions. However, CCS technologies are not currently recognised for CDM
- The Joint-Implementation (JI) is a bilateral project-based mechanism between developed countries, granting Emission Reduction Units (ERUs) for below-baseline emissions reductions. This would require co-operation between the Governments to convert Kyoto Protocol "Assigned Amount Units" (AAUs) into ERUs. Domestic (unilateral) projects, although far simpler to implement, are not currently enabled

Along with an increased awareness of biomass CCS by Governments, there needs to be clarification or changes in the above accounting frameworks to provide clear signal of the value of negative CO_2 emissions, and remove developer and investor uncertainty. Alternatively, new incentive options could be developed, such as a subsidy per unit of captured emissions, or a carbon tax where revenues

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[8] IPCC (2006) "Guidelines for National Greenhouse Gas Inventories: Volume 2 Energy", available at: http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol2.html
[9] Ascui, F. (2010) "BECCS in the carbon markets: challenges and opportunities", 1st international Bio-CCS workshop, Orleans
[10] http://unfccc.int/kyoto_protocol/mechanisms/emissions_trading/items/2731.php

are recycled to subsidize biomass emissions captured with CCS. Ricci (2012)[11] has compared the efficiency of several policy instruments regarding the adoption of CCS and biomass CCS.

The EU's ETS does not incentivise negative carbon power generation technologies, and currently neither does the UNFCCC. The development of suitable market stimuli for biomass CCS is fundamental to its future deployment, and this will require appropriate changes to the relevant legal and policy frameworks, at both national and international levels. However, any significant investment in biomass CCS will remain highly dependent on the regulatory risk associated with the CO_2 revenue stream, hence policy makers need to provide as much long-term certainty as possible.

Strong dependence on coal CCS developments

The technical development work on biomass CCS, both in stand-alone configurations, but perhaps more importantly, in co-fired configurations with coal needs to continue and proceed to component testing, pilot scale and demonstration scale, as appropriate. The current CCS development programmes in Europe are focused principally on the use of coal, with some programmes looking at gas utilisation. In some cases, increasing the share of biomass in the fuel mix would seem to be a logical development. It is therefore essential that support is given to the development of coal and gas-based CCS plant since delays in Government support and/or project development in this area will inevitably lead to similar delays in establishing biomass CCS projects.

Given the small technical differences, and the higher TRL of co-firing options versus dedicated biomass CCS options, there is a high level of dependency between coal CCS development timelines and those of biomass CCS. This dependency on utilising existing coal/gas CCS infrastructure (proposed 'clusters') and the biomass feedstock location/availability will also be important while considering biomass CCS plant locations.

The UK Electricity Market Reform (EMR) will be introducing an emissions performance standard[12], which will effectively prevent the building of new unabated coal plants, i.e. new coal-fired plants will have to use CCS. The current energy sector development envisages coal CCS demonstrator plants within the next few years, deploying post-combustion, pre-combustion and oxy-fuel systems, with funding from the EU NER300 and UK CCS Competitions. Biomass is not specifically targeted but, it is desirable that these demonstration plants should be capable of biomass co-firing. Adding biomass co-firing ability after a coal CCS plant is built is more difficult and expensive than the plant being originally designed with biomass storage space and handling equipment included.

Coal CCS development programmes need to successfully demonstrate capture technologies at scale as a priority, given the technical cross-overs to biomass CCS. However, any new coal-fired CCS plant to be built in the UK should also be designed with a biomass co-firing capacity. The regulatory arrangements to encourage renewable energy production need to be designed to reflect the gradual build-up of biomass throughput within CCS plant designed originally for coal.

[11] Ricci, O. (2012) "Providing adequate economic incentives for bioenergies with CO_2 capture and geological storage", available at: http://www.sciencedirect.com/science/article/pii/S0301421512000948

[12] DECC (2012) "Planning our electric future: a White Paper for secure, affordable and low-carbon electricity", available at: http://www.decc.gov.uk/en/content/cms/legislation/white_papers/emr_wp_2011/emr_wp_2011.aspx

Dedicated biomass projects potentially represent a missed opportunity

The UK Government is not advocating the construction of new dedicated biomass plant without CCS. This is principally a reflection of the availability of a significant tranche of older pulverised coal plant which can be substantially or completely converted to biomass. Dedicated biomass plant most likely to be built up to 2020 will be relatively small (<300 MW_e) and will not be designed to be capture-ready. There is a serious risk that this opportunity to test and demonstrate biomass CCS will be lost.

Some commentators, e.g. some NGOs and the Scottish Government are advocating that all biomass should currently be used in small community-scale heat or CHP projects rather than in large scale power generation. The rationales for this decision are complex, possibly geography-specific especially due to the high costs (at least within 2020 timescales) associated with small scale biomass CCS operations. On the other hand, for large scale dedicated biomass units, Government will need to encourage them to be built in excess of the 300 MW_e threshold to be capture-ready, and hence enable them to form an additional component of any CCS demonstration programme. Alternatively, the 300MW_e threshold for capture-ready plant could be lowered in the future if some of the capture technologies prove viable at smaller scales (e.g. carbonate or chemical looping).

Biomass supply chain development and wastes

The development of biomass CCS implies the extensive use of biomass in large scale power generation plant. Since the UK has little indigenous biomass resource in comparison to the volumes needed for a biomass CCS programme, it is evident that much of this biomass will be imported (many of the unabated coal conversion or dedicated biomass plants planned will be using imports). Whilst the potential availability of large volumes of global biomass is helpful in terms of diversity of supply, it does mean that any biomass CCS project will probably need to be designed to operate with a variety of different biomass feedstocks to enable security of supply.

Although the indigenous biomass is limited, waste resources are highly concentrated in some areas of the UK, and offer a potential resource opportunity. Therefore, consideration may need to be given to the use of wastes and their potential for integration into biomass CCS. Legislation is systematically driving the reduction, recycling and energy recovery of waste, rather than facilitating landfill. Despite its low cost, the variable nature of waste resources, combined with its relatively low volumes when compared to imported biomass, makes it less attractive than e.g. wood-based systems.

Sustainability constraints will impact some feedstocks

It also has to be recognised that biomass sustainability standards are increasingly being required for biomass use in the energy market and that these standards will gradually become more constraining. Generators will have to ensure that biomass meets certain sustainability criteria in order to attract financial support from April 2013. The TESBiC study has assumed throughout that the upstream emissions of biomass are to be counted in the calculation of the net CO_2 balance of each biomass CCS combination (see the Annex for pellet and chip values). Representative values have been selected, based on average biomass power life cycle emissions and the results of initial modelling by the ETI's Biomass Value Chain Model (BVCM) project. These upstream emissions could even make the difference, i.e. the balance between negative and positive net emissions for a co-firing CCS plant. We note that upstream emissions factors for coal and natural gas have also been used in TESBiC calculations - values are given in the Annex.

7 ROADMAP FOR THE EIGHT TECHNOLOGIES AND BENEFITS CASE

7.1 Biomass co-firing in a pulverised coal power plant, with post-combustion amine scrubbing

Current status

The co-firing of biomass in coal-fired power stations is either fully commercial or is in the large scale demonstration phase, depending on the co-firing ratio being considered and the specific co-firing technology being considered. An overall TRL value of 8-9 currently, and TRL 9 by 2020 would appear to be appropriate. The main technology developers and equipment suppliers for biomass co-firing and the conversion of coal boilers to 100% biomass firing are the major power plant boiler makers, e.g. Doosan Power Systems, Alstom, Hitachi etc. and the suppliers of the biomass processing and handling storage equipment and systems.

Post-combustion CO_2 capture using solvent scrubbing is at small-scale demonstration scale (TRL 6) moving to larger scale demonstration (TRL 7), for coal firing, but has not yet been applied commercially to biomass co-firing in large pulverised coal boilers. However, this is not a significant step technically. The flue gas clean-up process upstream of the solvent scrubbing system will cope with any differences in the flue gas chemistry due to the biomass co-firing. The major commercial companies involved in the development and demonstration of solvent scrubbing systems for power plant applications include MHI, HTC, Kerr McGee, Aker, Fluor, Alstom, Doosan Babcock, and Cansolv.

Overall, the combination of solvent scrubbing applied to pulverised coal boilers with biomass co-firing is currently considered to be at TRL 6, i.e. at small scale demonstration level. It is considered that the TRL value should increase to 7, i.e. full scale demonstration plant stage by 2020. This technology combination is likely to be most attractive commercially for large utility plants where the economies of scale associated with both the capture and transportation of the CO_2 can best apply, for example in existing CCS clusters. For that reason, the involvement of the large power utility companies, and their suppliers, will be essential to the successful development and deployment of this technology combination.

A number of demonstration and pilot plants have been built to study amine-based and other solvents for the capture of CO_2 from coal and natural gas flue gases. For example, the pilot plant at the University of Texas in Austin, USA, an MEA campaign was conducted as a baseline to compare CO_2 absorption and stripping performance using an experimental potassium carbonate/piperazine solvent. At Seoul thermal power plant, in Korea, a pilot plant treating 2 tonnes per day of CO_2 has been operated using MEA as the absorbent in a real flue gas side stream from Boiler Unit 5, a natural gas-fired boiler. The CASTOR pilot plant, at Esbjerg power station in Denmark is a 1 tonne per hour unit using 30% aqueous MEA solution. The plant was operated at 93% CO_2 removal efficiency, producing approximately 850 kg/hour of CO_2. The ENEL slipstream pilot plant at Brindisi Sud power station, at 2.25 tonne CO_2 per hour, which will use 20 wt% MEA solution, is currently being built. The Australian Low Emissions Technology Demonstration Fund (LETDF) is currently building two post-combustion capture projects. One is a natural gas combined cycle plant powered by coal bed methane; the other is a 25 tonnes per day capture plant on International Power's 1600 MW Hazelwood brown coal PF plant in Victoria's Latrobe Valley. At the CO_2 extraction plant at the Boundary Dam lignite fired power plant in Southern Saskatchewan, Canada, the pilot plant was used to evaluate the performance and reliability of proprietary CO_2 solvent extraction technologies, and to obtain engineering data that can be used for the design of commercial scale CO_2 absorption units

In particular, in the UK, there has also been significant activity on the installation and operation of amine scrubbing prototype and pilot plant on coal-fired power station sites over the past five years, viz:

- RWE npower has installed a 10,000 $Nm^3\ h^{-1}$ Cansolv amine scrubbing pilot plant at Aberthaw power station in south Wales,
- Scottish and Southern Electricity, Doosan Power Systems and Vattenfall have installed a 100 tonnes per day of CO_2 amine scrubbing pilot plant at Ferrybridge power station in Yorkshire, and
- Scottish Power installed and operated a 1000 m^3 per hour carbon capture pilot plant at Longannet power station in Scotland.

These activities provide a very strong technical base in this technology in the UK.

Further development requirements

There is expected to be significant technical and commercial development by the key power companies and suppliers, on both biomass co-firing with coal in large power plant boilers and solvent scrubbing technologies, over the next decade or so.

The development of the biomass co-firing technology will be aimed at:

- increasing the percentage of biomass co-fired with coal and other fossil fuels, and of the conversion of coal boilers to 100% biomass firing, and
- increasing the degree of fuel flexibility of the systems to include biomass fuels with higher ash contents, more difficult ash chemistries and higher sulphur and chlorine contents.

For post-combustion CO_2 capture technologies, much of the current and future technical developments are associated with the planned demonstration activities, and are aimed at finding technical and economic improvements at industrial scale in the following subject areas:

- The optimisation of the amine formulations and of the CO_2 scrubbing and solvent stripping cycles,
- The reduction of the energy requirement for the stripping of the loaded solvent, and of the system power requirement,
- The minimisation of the costs associated with amine degradation, and
- The control of the corrosion of the internal surfaces of the CO_2 scrubbing and stripping units and the associated equipment.

The future deployment of both the biomass co-firing and solvent scrubbing technologies, up to and beyond full commercialisation in the 2020s, will depend largely on the international political response to climate change over the next few years, and in particular the decisions taken at a political level about the future role of coal in the fuel mix for power generation. This subject is discussed in Section 44 above.

It should be noted in this context that the level of flue gas cleaning required upstream of the entry to the solvent scrubbing system is such that the application of this technology to biomass co-firing is only a very small step forward technically from its application to coal firing.

UK benefits

Currently, the UK, along with a number of Northern European countries including Denmark, the Netherlands and Belgium, has a significant technical lead in biomass firing and co-firing in large power plant boilers, and this situation may continue for a further 5 years or so. Thereafter, the emphasis will swing for a few years towards the potential export markets for retrofit and new-build projects in Europe, North and South America and the Far East. There are a small number of UK companies which may be in a position to benefit from these developments.

There are also a small number of active developers of solvent scrubbing technologies for CO_2 capture from boiler flue gases in the UK. These companies are currently concerned over the next few years with the commercialisation of these technologies for application as retrofits to large coal-fired boiler plants. In some cases, these plants will be actively engaged in the co-firing of biomass materials, initially at low co-firing ratios.

The major UK power utility companies have been very active in the development of both biomass firing and co-firing with coal, and in solvent scrubbing technologies. They, of course, are the principal end-users of these technologies and will be interested in being informed purchasers of the technologies and in ensuring that the technical developments will meet their needs.

As stated above, the question as to whether or not significant numbers of new-build coal power plants, with or without carbon capture, are built in the UK will be resolved at the political level, and the outcome of this process must be subject to a significant degree of uncertainty. Whilst the proposed Electricity Market Reforms (EMR) looks likely to prevent the construction of new unabated coal plants, there may be a potential programme emerging under the auspices of the CCS Competition.

Technology roadmap

In this context, the future development of biomass co-firing with carbon capture by solvent scrubbing is very closely associated with the future development of power generation from coal, and the extent to which biomass co-firing and solvent scrubbing have roles in these developments. The barriers to development are commercial and political rather than technical. There is no distinct or independent technology roadmap for biomass CCS in this case.

7.2 Biomass combustion in a dedicated power plant, with CO_2 capture by solvent scrubbing

Current status

The combustion of a wide range of biomass materials in dedicated power stations based on grate firing and on bubbling fluidised bed and circulating fluidised bed combustion systems is a commercial technology. There are a large number of industrial and utility plants operating worldwide, based mainly on grate firing and fluidised bed combustion technologies, and a number of experienced equipment suppliers. It is clear that an overall TRL value of 8 to 9 would be appropriate for this technology.

There are a large number of equipment suppliers of stoker and fluidised bed fired boiler plants for biomass materials, covering the industrial and utility boiler market across the world. In Europe, the major OEMs for industrials scale biomass boilers include are Aalborg Energie, AE&E Group, Aker Kvaerner, B&W Volund, Doosan Power Systems, Foster Wheeler Global Power, Keppel Seghers, Metso Power, Martin Engineering, and Vyncke Energietech.

As stated above, post-combustion CO_2 capture using solvent scrubbing is at small-scale demonstration scale (TRL 6) moving to larger scale demonstration (TRL 7), for coal firing. However, despite the relative maturity of the components involved, there is no experience with the application of amine scrubbing to dedicated biomass plants at any scale (even pilot scale).

Therefore, the combination of solvent scrubbing applied to dedicated biomass boilers is considered to be between TRL 4 and 5, i.e. pre-pilot plant scale. The major commercial companies involved in the development and demonstration of solvent scrubbing systems for power plant applications include MHI, HTC, Kerr McGee, Aker, Fluor, Alstom, Doosan Babcock, and Cansolv.

However, the technical differences between CO_2 solvent scrubbing from coal and biomass flue gases are considered to be relatively small, since the flue gases are cleaned to very high standards upstream of the solvent scrubber. It is therefore expected that the technical and commercial developments in amine scrubbing technologies for coal CCS will have major cross-over benefits for dedicated biomass technologies, i.e. the combined system TRL could improve rapidly to reach TRL 6 (small-scale demonstration) by 2020.

Thereafter, the only significant barrier to the application of this technology to a dedicated biomass plant will be commercial, i.e. will be due to the lack of a financial incentive scheme for power plant systems generating negative CO_2 emissions, rather than technical.

Further development requirements

There are no major development issues associated with dedicated biomass beyond the background developments carried out by all of the large boilermakers, and those that would normally be addressed at the contract stage.

A number of these are associated with the fuel quality issues. For instance, with some biomass materials, there may be concerns about high chlorine and alkali metal contents, which can lead to:

- increased risks of excessive ash deposition on boiler surfaces,
- increased metal wastage rates of high temperature boiler components due to fireside corrosion, and
- negative impacts on SCR catalyst performance.

There are ongoing developments associated with these subject areas, aimed at increasing the fuel flexibility of combustion systems and boilers for biomass firing. As stated above, the developments associated with the application of solvent scrubbing technologies are generally incremental in nature, and are associated with the application of the technology at demonstration and commercial scales. There are no significant additional development requirements specifically associated with their application to dedicated biomass combustion plants, beyond those described in Section 48 above.

UK benefits

There are a small number of UK suppliers of both biomass combustion equipment and boilers for biomass at the relevant scales of operation, and UK developers of solvent scrubbing technologies for CO_2 capture. As with all of the relevant CO_2 reduction technologies, the large power utility companies in UK have also been active in these developments, because of their desire to help direct the development efforts in directions appropriate to their future needs, and their interest in becoming an informed purchaser of the relevant technologies

Technology roadmap

The route to further development of this technology combination after demonstration of the solvent scrubbing technology on coal-fired plant would involve demonstration of the technology at commercial scale on a dedicated biomass boiler. This is clearly dependent on there being a specific financial incentive for the generation of electricity with negative CO_2 emissions. The barriers to development are therefore commercial and political rather than technical. There is no distinct or independent technology roadmap for biomass CCS in this case.

7.3 Biomass co-firing in a coal boilers with CO_2 capture by oxy-fuel firing

Current status

As discussed in Section 48 above, the co-firing of biomass in coal-fired power stations is commercial or is in the large scale demonstration phase, depending on the specific co-firing technology being considered. An overall TRL value of 8-9 currently, and TRL 9 by 2020 would appear to be appropriate for this component of this technology combination. The combustion of fossil fuels under oxyfuel conditions with CO_2 capture is not yet fully commercial. A number of integrated pilot plants have been or are currently being built, and detailed plans to build commercial power plants and to convert existing thermal power plants to oxy-combustion are being developed at the present time. The current TRL of oxy-fuel technology is therefore around 5 to 6. There is a high level of international activity on this subject area, and it is judged that oxy-fuel firing technology is likely to reach TRL 7 to 8 for power plant applications by 2020.

However, the combination of biomass co-firing in a pulverised coal boiler with oxy-fuel firing is only just at TRL 5, with biomass co-firing tests thought to have recently been carried out at the Schwarze Pumpe oxy-fuel pilot plant. It is considered that the TRL value should increase to between 6 and 7, i.e. small to large-scale demonstration stage by 2020.

Vattenfall has constructed, and operated since 2009, a 30 MW_{th} oxy-coal pilot plant at their **Schwarze Pumpe** power station south of Cottbus. This includes an ASU, sub-critical steam generator, air quality control system equipment, flue gas coolers, and indirect-cooled (ammonia refrigeration) CO_2 purification system designed to purify CO_2 from 100% of the flue gas flow. This pilot unit has operated for several thousands of hours with significant operation in oxy-combustion mode to supply the design information needed for a larger demonstration unit. Endesa in Spain has been awarded funding for a 323 MW_e (gross) circulating fluidized bed oxy-coal project, at **Compostilla,** Spain. The project is scheduled for start-up in 2016. The technology development and FEED studies has been conducted over the period 2009-2012, and construction of the plant is to occur between 2012 and 2016.

Endesa has also been cooperating with CIUDEN, a Spanish government-funded research organization, in the construction and operation of a nominal 30 MW_{th} oxy-coal circulating fluidized bed pilot plant in **El Bierzo, Spain**. This pilot plant uses liquid oxygen delivered to the site. It will conduct CO_2 purification unit operations on only a slip stream of the flue gas. CIUDEN has also installed a 20 MW_{th} oxy-pulverized coal boiler at this site. Oxy-coal operations of the pulverized coal pilot plant are expected to commence in late 2010 with the fluidized bed operations following by about 12 months.

In August 2010, the U.S. Department of Energy announced that $1 billion in Recovery Act funding would go towards the construction of the FutureGen 2.0 project in **Meredosia, Illinois** to repower

Amergen's 200 MW Unit 4 with oxy-combustion technology. The project will use a Babcock and Wilcox boiler and Air Liquide will provide the ASU and CPU. The unit will capture 90% of the CO_2 produced and plans to geologically sequester up to 1.2 million tonnes per year (1.3 million tons per year) of CO_2. The project plans to have FEED and the NEPA process complete by 2012 and begin operation in 2016.

CS Energy has re-commissioned a 25 MW_e pulverized coal power plant in **Biloela, Australia** for the purpose of conducting oxy-coal operations. The new facility will be a 30 MW_e oxy-combustion plant, and the first integrated oxy-combustion system in operation in the world. The project will capture the CO_2 and then truck it about 200 km (125 miles) away where it will be geologically sequestered in the Denison Trough. It is planned to sequester 60 tonnes (66 tons) per day over a three year period. It was announced on October 13, 2010 that construction had hit the halfway mark, and most of the equipment has been received on site. Commissioning was planned to begin in early 2011. The project has several partners including CS Energy, the Australian Coal Association, Xstrata Coal, Cooperating Research Centre for Coal in Sustainable Development (CCSD), IHI, Mitsui, Schlumberger, J-Power, J-Coal and the Cooperative Research Centre for Greenhouse Gas Technologies (CO_2/CRC), the Australian government and the Queensland government.

In January 2010, Total began operation on Europe's first "end-to-end" carbon capture, transportation and storage at its demonstration facility in **Lacq, France**. The technology uses oxy-combustion of natural gas instead of coal, and produces a flue gas that is 90% CO_2. This gas is piped 27 km (17 miles) where it is injected 4500 meters underground into a depleted natural gas reservoir. The project plans to sequester 120,000 tonnes (132,000 tons) of CO_2 over a two year period and then monitor the site for an additional three years.

Doosan Babcock has demonstrated a 40MW_{th} OxyCoal burner in collaboration with the UK Government and other sponsors in Renfrew, Scotland. The burner is a full-sized utility burner suitable for installation as a retrofit or in a new unit. Work began on the unit in the summer of 2009, and the testwork was completed in 2010.

Babcock and Wilcox tested a 30MW_{th} oxy-combustion unit at their Clean Environment Development Facility (CEDF) in Alliance, Ohio in the 2007-2008 timeframe. Bituminous, sub-bituminous and lignite coals were all tested, and the switching between air firing and oxygen enriched flue gas was demonstrated. The environmental performance of the unit was very promising with the SO_x removal approximately the same, and the NO_x emissions were 40-70% lower than air-blown combustion, depending on the fuel. The mixing of the oxygen into the flue gas ductwork was also demonstrated.

ENEL has proposed building a 48 MW_{th} Pilot Plant at the **Brindisi Coal fired Power Plant** in Italy. This will be a scale-up of the 5 MWth ENEL/ITEA pressurized oxy-coal facility in Gioia del Colle, Italy that has been in operation since 2005. The pilot plant plans to begin operation in 2012.

Further development requirements

As discussed above, it is anticipated that the technical direction of the further development of the biomass co-firing and firing technology over the next few years will be in two principal subject areas, viz:

- The increasing of the percentage biomass co-firing that can be achieved without significant additional negative impacts on the power plant performance and integrity, and

- The increasing of the degree of fuel flexibility, i.e. to include the capability to co-fire biomass fuels with higher ash contents, and with more difficult ashes with lower fusion temperatures and higher chlorine contents, etc.

This work will, in the main, involve the establishment of long term demonstration projects involving biomass firing and co-firing at selected coal power plants, with extensive programmes of plant operation and monitoring and with the appropriate supporting R&D activities on ash deposition behaviour, fireside corrosion, environmental control, etc.

Oxyfuel firing technology has now been demonstrated at large pilot scale, and the major emphasis of future development is increasingly on full scale boiler demonstration projects, with an element of supporting R&D activity. There is currently significant R&D effort, for instance, on the risks of boiler tube corrosion issues because of the potential for increasing concentrations of CO_2, H_2O, sulphur oxides and HCl in the flue gases in contact with the high temperature boiler surfaces within the flue gas recirculation loop. This is one of the key technical risk areas and this work will continue with corrosion monitoring of the demonstration and commercial plants.

There is also significant development effort on the use of membrane separation techniques for oxygen separation, and on the integration of these systems with the boiler island. It is claimed by a number of the companies involved in these developments that the use of membrane separation technology as an alternative to conventional cryogenic separation, for oxygen production can provide significant savings in capital and operating costs, and significant reductions in the energy requirements. It is anticipated that the membrane separation technology may have the first applications at the scales of operation relevant to the power industry over the next five years.

UK benefits

As described above, there are a number of UK power utility and equipment supply companies involved in the development of both the biomass co-firing and the oxyfuel firing technologies. They will, most likely, be involved in the large scale demonstration and first commercial scale plants, provided that the commercial environment is suitable. There are UK projects currently in the UK CCS Competition which may be able to benefit from this technology.

Technology roadmap

The route to full commercialisation of this technology combination is fairly straightforward technically, and is dependent largely on the creation of the appropriate regulatory and commercial environment As such, there is no real requirement for a technology roadmap in the conventional sense.

7.4 Biomass combustion in a dedicated power plant, with CO_2 capture by oxy-fuel firing

Current status

As stated above, the combustion of a wide range of biomass materials in grate fired and fluidised bed boilers with conventional steam turbines is a fully commercial technology with many plants in operation worldwide, firing a wide range of biomass materials. An overall TRL value of 8 to 9 currently would appear to be appropriate for this.

There are a large number of equipment suppliers of stoker and fluidised bed fired boiler plants for biomass materials, covering the industrial and utility boiler market across the world. In Europe, the major OEMs for industrials scale biomass boilers include are Aalborg Energie, AE&E Group, Aker

Kvaerner, B&W Volund, Doosan Power Systems, Foster Wheeler Global Power, Keppel Seghers, Metso Power, Martin Engineering, and Vyncke Energietech. The oxy-fuel combustion of fossil fuels with CO_2 capture is not yet commercial. A number of integrated pilot plants have been or are currently being built, mainly with coal firing only (TRL 5 to 6). Detailed proposals for both new-build power plants and the conversion of existing pulverised coal power plants to oxy-fuel combustion are being developed at the present time. However, despite the relative maturity of the components involved, there is no experience with the application of oxy-fuel capture to dedicated biomass plants at any scale (even pilot scale). Therefore, the combination of oxy-fuel combustion applied to dedicated biomass boilers is considered to be between TRL 4 and 5, i.e. pre-pilot plant scale.

Given the high level of international activity that is planned over the next few years in coal oxy-fuel combustion, it is expected that these technical and commercial developments will have major cross-over benefits for dedicated biomass technologies, i.e. the combined system TRL could improve rapidly to reach TRL 6 (small-scale demonstration) by 2020.

Future development requirements

The key next stage in the development of this technology combination is the demonstration at industrial scale of the application of oxyfuel firing to a dedicated biomass power plant. In the absence of a regulatory and commercial environment that specifically favours the generation of power with negative CO_2 emissions, the first industrial demonstrations of oxyfuel firing for solid fuels will be with coal. The translation of the oxyfuel technology to dedicated biomass combustion is a relatively short step from the technical point of view.

There is significant development effort on the use of membrane separation techniques for oxygen separation. There is also significant R&D effort on boiler tube corrosion issues because of the potential increase of the concentrations of CO_2, H_2O, sulphur oxides and HCl in the flue gases in contact with the high temperature boiler surfaces within the flue gas recirculation loop.

UK benefits

As discussed above, a number of UK power utility companies and equipment suppliers are actively involved in the supply of biomass boilers and the development of oxyfuel firing systems. It is most likely that a number of these companies will be involved in the potential demonstration projects involving the oxyfuel firing of coal, and perhaps subsequently in the oxyfuel firing of biomass in a dedicated boiler.

Technology roadmap

The large scale demonstration of oxyfuel firing and the first commercial plant, involving a solid fuel, will almost certainly involve coal firing. The subsequent application of oxyfuel technology to a dedicated biomass combustion plant is relatively short step technically. As stated above, the principal barriers to the wider deployment of this technology combination are regulatory and commercial rather than technical.

7.5 Biomass combustion with CO_2 capture by post-combustion carbonate looping

Current status

The exothermic nature of the reversible reaction involving calcination of calcium carbonate is attractive from a view point of supplementary production of electricity (in addition to that from the unabated power plant) and thereby relatively lower efficiency penalty with CO_2 capture as compared to that for amine scrubbing. Furthermore, a smaller air separation unit (ASU) (compared to that for oxyfuel combustion) and cheap sorbent (crushed limestone) are advantageous. Technical issues such as sorbent deactivation, compatibility of biomass feedstocks within calciners and optimisation of reactor design merit further research in this technology.

Currently, no industrial research/pilot facility exists in the UK to develop and test CO_2 capture by post combustion carbonate looping. The majority of the UK industry's efforts in post-combustion capture are focussed on deploying first generation amine scrubbing. World-leading expertise and track-record in CFB technology, a prominent component within the carbonate looping process, appears to be based mostly in North America and continental Europe. On the academic side, however, strong R&D expertise exists in carbonate looping at Imperial, Cranfield and Cambridge. Imperial College is also participating in the EU CaOling project, coordinated by Endesa (a major European utility company), which recently (19th April 2012) released some data from its 1.7 MWth 'Le Pereda' pilot plant. The pilot plant is fitted to a slip stream from an existing 50 MW_e CFB boiler, owned by Hunosa (the largest coal miner in Spain). Foster Wheeler, an EU OEM and a partner within the CaOling project recently also introduced calcium looping technology on the development and scale up map shown in Figure 21.

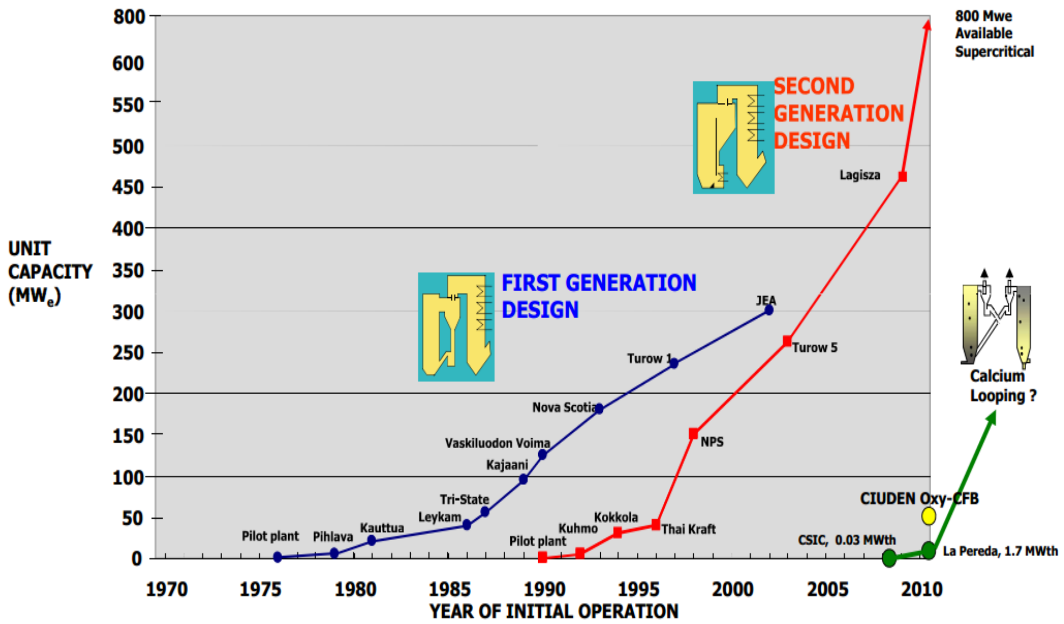

Figure 21: Scale-up of CFB applications (Source: www.caoling.eu)

This development along with the 1MW_{th} prototype pilots by TU Darmstadt and Alstom has meant that the current TRL for carbonate looping has improved from 4 to 5. However, the application of carbonate looping with biomass co-firing (either as biomass in the calciner, or biomass-derived flue gases) still has not yet been demonstrated at pilot scale, hence the TESBiC technology combination of biomass co-firing with post-combustion carbonate looping remains between TRL 4 and 5.

Future development requirements

Further development of carbonate looping post combustion technology is most likely expected through scale-up to small demonstration scales (30 to 50 MW_e). However, such scale-up cannot be expected as an immediate next development stage as it will be a significant step-up from the status quo, i.e. laboratory experiments (in kW_{th}) and research plant tests (<2 MW_{th}); thus data and experience from interim scale-ups of the order of 10 to 30 MW_{th} will be essential before progress is made at small demonstration scales. For instance, in the CaOling project, lessons will be learnt from the laboratory experiments and the Le Perada plant data (1.7 MW_{th}) and development in the next stage will be aimed at process design and scale-up towards a 20-30 MW_{th} plant.

In order to progress the TRL of biomass co-firing with carbonate looping, it will also be crucial to direct the development efforts to understand and fill the existing gaps particularly in the following seven areas as identified in the TESBiC project:

- Careful consideration needs to be given to the design of practical transfer systems for the movement of the hot solids between the reactors, though it should be noted that initial tests in the EU CaOling project, at 1.7 MW_{th} scale (and released only in April 2012) have indicated that the small pilot-scale rig performs as anticipated, with CO_2 capture rates of 90 % achieved only two months after cold testing
- The physical strength and the abrasion resistance of the sorbent
- Impact of purge and replenishment streams of sorbent on its overall average reactivity
- Uncertainty around the usage of biomass in the calciner dictates the maximum extent of co-firing in the overall technology combination and needs further research and development.
- The level of NO_x emissions (although lower than that from conventional biomass fired power plant boiler) also needs further investigations.
- Combustion of biomass in the carbonator of the dual fluidised bed system, with *in situ* capture of the CO_2 produced is another configuration has the potential to significantly reduce costs as it would avoid the requirement of a separate boiler.
- The integration with cement manufacture, allowing partial decarbonisation of cement plants (by 50 %) through their utilisation of spent CaO in place of $CaCO_3$ as a feedstock, is another significant potential advantage and opportunity to reduce overall UK CO_2 emissions.

UK benefits

The intellectual property (IP) space related to post combustion carbonate looping is sparser than the other technology combinations (except chemical looping) considered in the TESBiC project. However, with the TRL progressing by 1 point since 2011, the early mover advantage is gradually (at least as of now) diminishing. The academic expertise within the UK, the lessons learnt through active participation in collaborative projects on pilot scale demonstration worldwide, and the existing industrial expertise (for example CFB know-how at Doosan through Doosan Lentjes) need to be collectively exploited to set-up a pilot and more importantly scale-up demonstration project, where carbonate looping can be investigated.

By helping to reduce CO_2 emissions associated with cement manufacture (and without the requirement for CO_2 capture technology to be physically installed in the cement plant), the technology has significant secondary benefits. For example, in June 2011, Alstom and Heidelberg cement announced a decision to investigate carbonate looping at a Norcem cement plant in Norway.

Technology roadmap

The carbonate looping based technology combination is emerging as one of the potential cost-effective ways of biomass CCS, although overall, significant investment (hundreds of £millions) globally is required to advance this technology combination to TRL 6 by 2025 and 8 to 9 by 2050. At the same time, a number of relatively modest investments totalling up to say £50-70 million by 2020, can be targeted towards filling the identified R&D gaps and thereby gaining a share of the IP space (and hence a competitive edge) whilst possible/available.

7.6 Dedicated biomass chemical looping combustion

Current status

CO_2 capture is an inherent part of the chemical looping combustion process and hence the technology does not suffer from an efficiency penalty (though the base efficiency is limited to that of a steam cycle for non pressurized operation; i.e. for natural gas combustion, a gas-turbine combined cycle power plant combined with post-combustion CO_2 capture is more efficient than a chemical looping system. However, this limitation does not apply when solid fuels are used). The technology is still at an early development stage with most of the research effort focused on optimizing reactor design and identifying a suitable oxygen carrier within the constraints of cost, performance, and environmental parameters.

The current TRL of chemical looping combustion is estimated to between 4 and 5 on the basis of the recent progress on pilot scale (and projected demonstration plants), and may be expected to reach a TRL of 5 to 6 by 2020. One advantage in the development of pilot-scale chemical looping combustion is its technological similarities to high-temperature solid sorbent capture e.g. calcium carbonate-looping. The 1 MW_{th} pilot plant currently under operation by TU Darmstadt may be switched quickly between operating as either a chemical- or a carbonate - looping plant. Similar to carbonate looping, no industrial research/pilot facility currently exists in the UK to develop CO_2 capture by chemical looping combustion. As mentioned earlier, the majority of the UK industry's efforts are focussed on deploying first generation amine scrubbing, and chemical looping is considered as second generation. Academic research in chemical looping is mainly carried out at Cambridge, Leeds and Imperial College, but the operational experience with bubbling or circulating fluidised bed technology is mostly within Europe (Chalmers, CSIC, TU Darmstadt). Industrial partnership in developing chemical looping has been limited but is gradually increasing; Alstom has planned a $3MW_{th}$ plant.

Future development requirements

Further development of chemical looping combustion needs to happen through scale-up to small demonstration scales (~15-20 MW_e). Again as highlighted in Section 7.5 above, such scale-up cannot be expected to be the next immediate development stage as it will be a significant step-up from the status quo, i.e. laboratory experiments and small research plant tests (<2 MW_{th}). Thus data and know-how gained from interim scale-ups of the order of 10 to 20 MW_{th} will be essential before progress is made at small demonstration scales. Additionally, as can be observed from the amine based post combustion CO_2 capture development (Section 48 and Section 7.2), there is clear evidence that rapid TRL progression of capture technology is achieved only with essential techno-economic know-how and experience is gained from a large number of laboratory, pilot scale and small scale demonstration plants.

For bio chem loop specific issues that still need to be systematically investigated at realistic practical scales are the following:

- A variety of oxygen carriers need to be tested for chemical looping combustion in terms of:
  - Stability under multiple oxidation/reduction cycles
  - Mechanical resilience and resistance to agglomeration
  - Ensuring that it is environmentally benign and cost effective
- Checking solid circulation and operational stability at scales in the range of 20 to 30 MW_e is another area that merits research.
- Also the flexibility of a CLC plant to either optimize power generation or produce hydrogen is a considerable asset but needs further experimental R&D. Potential alternative plant designs are of interest, e.g. a) chemical looping combustion - combined cycle, whereby the air and fuel reactors are pressurised and the exhaust gas streams are expanded through a turbine, or b) including a separate gasification etc.
- The level of NO_x emissions is a key unknown when using only biomass feedstocks within a CFB-based chemical looping combustion configuration.

UK benefits

The intellectual property (IP) space for dedicated biomass chemical looping combustion is sparser than the other seven technology combinations considered within the TESBiC project. Early mover opportunity for development and pilot scale-up and the consequent commercial exploitation still exists. However, with the planned pilot demos and laboratory scale experiments (outside the UK), this advantage will diminish quickly.

Again, as in the case of carbonate looping, the strong existing academic expertise within the UK can be combined with the UK's emergent CFB expertise to set-up a pilot and more importantly scale-up demonstration project. Although the UK's expertise in CFB technology has been historically modest, one positive development has been the recent (November 2011) acquisition of AE&E Lentjes GmbH by Doosan Power Systems, bringing a CFB technology into a UK engineering firm portfolio.

Technology roadmap

Again, quite similar to post combustion carbonate looping, chemical looping shows potential to offer a cost-effective way of biomass CCS with the additional potential flexibility of hydrogen production. However, overall, significant investment is required to advance this technology combination to TRL 6 by 2020-2025 and 8 to 9 by 2050. At the same time, a number of relatively modest investments summing up to say, £50-70 million by 2020, can be targeted towards filling the identified R&D gaps and thereby gaining a share of the IP space (and hence a competitive edge) whilst possible/available.

7.7 Biomass co-firing in a coal IGCC power plant with CO_2 capture by physical absorption

Current status

At the present time, no coal or biomass IGCC plants have been built in the UK, although a number are in operation in the USA, Netherland, Spain and Italy, with power outputs ranging from 50 to 500 MW_e. Further coal IGCC projects are planned or are under construction, and these have power outputs ranging from 250 to 600 MW_e. These projects include GreenGen in China and Edwarsport in the USA.

In large coal-fired boilers, significant, and increasing, levels of biomass are currently being co-fired on a fully commercial basis, and this could be replicated in coal IGCC plants. Pre-combustion CO_2 capture using solvent scrubbing in coal gasification chemical plant is at big-scale demonstration (TRL 9 in North Dakota chemical plant from which CO_2 is captured and transported for EOR in Canadian Weyburn reservoir), but has not yet been applied commercially to IGCC power plants nor for biomass co-gasification in large IGCC. Only small pre-combustion CO_2 capture pilot plant, at 4 tonnes/hour, has been tested in the Puertollano IGCC power plant, where small amounts of biomass, less than 8% thermal, was co-gasified with a feedstock mixture of local coal and refinery petcoke. So the current TRL of co-gasification with CCS could be set to 6. The two technologies, power IGCC with co-gasification and pre-combustion CO_2 capture from syngas have been separately demonstrated at big scale but few were integrated at such scale in coal IGCC power plant. Many projects are planned to capture CO_2 in coal IGCC before 2020 (Edwarsport in USA, GreenGen in China). We could suppose that the TRL of coal IGCC power plant will likely be 9 in 2020. For co-firing, unless employed in these projects, the TRL of co-gasification power plant will be 6 in 2020.

Future development requirements

As stated above, there is expected to be significant technical and commercial development by the key power companies and suppliers, on both biomass co-gasification with coal in large IGCC power plant and solvent scrubbing technologies, over the next decade or so.

The development of the biomass co-firing technology will be aimed at:

- increasing the percentage of biomass co-fired with coal and other fossil fuels, and of the conversion of coal boilers to 100% biomass firing, and
- increasing the degree of fuel flexibility of the systems to include biomass fuels with higher ash contents, more difficult ash chemistries and higher sulphur and chlorine contents.

For pre-combustion CO_2 capture technologies, much of the current and future technical developments are associated with the planned demonstration activities, and are aimed at finding technical and economic improvements at industrial scale in the following subject areas:

- Increasing the pressure of the system, by improving mechanical compression of the feedstock,, which would decrease the energy penalty for solvent regeneration by flashing the rich solvent prior to the steam stripping stage,
- Decreasing the energy penalty for cryogenic air separation,
- The development of membrane air separation (ITM),
- Increasing the flexibility of the system to permit more rapid start-up, and
- Increasing the capacity factor, especially for fully integrated IGCC.

As stated above, the future deployment of both the biomass co-gasification and pre-combustion solvent scrubbing technologies, up to and beyond full commercialisation in the 2020s, will depend largely on the political response to global warming worldwide over the next few years. The decisions taken at a political level about the future role of coal in the fuel mix for power generation will be of particular importance. The deployment of biomass CCS technologies will be dependent on the introduction of a specific financial incentive for the generation of negative CO_2 emission levels from power plants.

UK benefits

The major British power utility companies have been very active in the development of both biomass firing and co-firing with coal, and in solvent scrubbing technologies. They, of course, are the principal end-users of these technologies and will be interested in being informed purchasers of the technologies and in ensuring that the technical developments will meet their needs.

Currently, BP with its involvement in the In Salah CO_2 storage project (Algeria) has demonstrated some experience in pre-combustion solvent scrubbing technologies for carbon dioxide capture and fixed bed slagging gasifier technology originally developed by British Gas Lurgi is licensed in the UK, though there is not much evidence of a strong UK supply chain for gasification. Unlike continental Europe, UK Plc lacks having large-scale gasifier developers in this country, and with no IGCC plants yet, most of the technology can be anticipated to be imported, thereby yielding very limited UK benefits, as compared to that for cofire amine/oxy and bio amine/oxy technology combinations.

As stated above, the question as to whether or not significant numbers of new-build coal IGCC power plants, with or without carbon capture, are built in the UK will be resolved at the political level, and the outcome of this process must be subject to a significant degree of uncertainty.

Technology roadmap

The future development of biomass CCS by biomass co-gasification with pre-combustion carbon capture by solvent scrubbing is very closely associated with the future development of power generation from coal, and the extent to which biomass co-firing and solvent scrubbing have roles in these developments. The 2Co Energy's 650MW$_e$ coal IGCC (Don Valley Power Project) is aimed to capture CO_2 with pre-combustion for EOR in North Sea and that this project has recently topped the list of CCS demonstration projects selected for financial support within the EU NER300 scheme, is a booster for this technology in UK. It will be the biggest coal gasification plant with pre-combustion carbon capture, and is planned to start in 2016. Generally, the principal barriers to development are commercial and political rather than technical.

As stated for biomass co-firing within PC (Section 48), biomass co-gasification with coal is likely to be most attractive commercially for large utility plants where the economies of scale associated with both the capture and transportation of the carbon dioxide can best apply. Large quantities of biomass could be used in large scale coal IGCC with very modest levels of additional investment compared to those necessary for dedicated biomass power plants. For that reason, the involvement of the large power utility companies, and their suppliers, will be essential to the successful development and deployment of this technology combination.

7.8 Dedicated biomass IGCC power plant, with CO_2 capture by physical absorption

Current status

The general consensus within the industry is that there are no insurmountable technical barriers to the development of dedicated biomass gasification technology. Biomass gasification in fixed bed and fluidised bed reactors is a relatively well understood technology. There may be a requirement to place limits on the moisture content of the biomass feedstock for some applications, say by using the waste heat for the drying of the feedstock prior to gasification; and for the adjustment of the biomass ash fusion behaviour by using fireside additives to avoid troublesome ash deposition on reactor and heat exchanger surfaces. As with all solid fuel gasification systems, there will be a requirement for the development of the appropriate syngas cooling and cleaning processes for specific fuels and particular applications.

The separation of CO_2 from coal syngas is an established technology in the chemical industry, but there has been no demonstration of CO_2 capture from biomass gasification. A TRL of 4 would appear to be appropriate if we consider only small scale laboratory. Having said that, however, it is considered that the difference between CO_2 solvent scrubbing from coal and biomass syngases is relatively small, since the syngases are cleaned to very high standards upstream of the solvent scrubber. Overall, therefore no major technical obstacles are expected to limit the development of this option, which would allow considering a TRL of 5 to 6 by 2020 and 9 by 2050.

As stated above, the most important barriers to the application of this technology to a dedicated biomass plant will be commercial, i.e. the relatively high capital costs and the lack of a specific incentive scheme for power plant systems generating negative CO_2 emissions.

Future development requirements

As for cofiring IGCC, for bio IGCC with pre-combustion CO_2 capture technologies, much of the current and future technical developments are associated with the planned pilot scale and demonstration activities, and are aimed at finding technical and economic improvements at industrial scale in the following subject areas:

- increasing the pressure of the system by improving mechanical compression of the feedstock to decrease the energy penalty for solvent regeneration,
- decreasing the energy penalty for cryogenic air separation, e.g. by the development of membrane air separation (ITM),
- increasing the flexibility for faster start-up, and
- increasing the capacity factor especially for full integrated IGCC.

As stated above, the developments associated with the application of the solvent scrubbing technologies are generally incremental in nature, and are associated with the application of the technology at demonstration and commercial scales. There are no significant additional development requirements specifically associated with their application to dedicated biomass IGCC plants, beyond those described for the case of dedicated biomass combustion (Section 50) above.

UK benefits

Currently, BP with its involvement in the In Salah CO_2 storage project (Algeria) has demonstrated some experience in pre-combustion solvent scrubbing technologies for carbon dioxide capture and fixed bed slagging gasifier technology originally developed by British Gas Lurgi is licensed in the UK, though there is not much evidence of a strong UK supply chain for gasification. Unlike continental Europe, UK Plc lacks having large-scale gasifier developers in this country, and with no IGCC plants yet, most of the technology can be anticipated to be imported, thereby yielding very limited UK benefits, as compared to that for cofire amine/oxy and bio amine/oxy technologies. However, UK benefits can be derived by the country's process engineering companies focusing on system integration involving biomass feedstock processing, IGCC and CO_2 capture.

Technology roadmap

As stated above, the future deployment of both the biomass gasification and pre-combustion solvent scrubbing technologies, up to and beyond full commercialisation in the 2020s, will depend largely on the political response to global warming worldwide over the next few years, and in particular the decisions taken at a political level about the future role of coal in the fuel mix for power generation. There are no major development issues associated with dedicated biomass beyond the background developments carried out by all of the large OEM companies, and those that would normally be addressed at the contract stage. The further deployment of biomass CCS technologies will be dependent on the introduction of a specific financial incentive for the generation of negative CO_2 emission levels from power plants.

It is possible in this scenario that the biomass co-firing ratio in coal IGCC plants may increase as a means of developing the use of biomass at higher scales of operation, which could be expected to be mature by 2050. It may however be that 100% biomass IGCC would remain at small scale (<50 MW_e).

8 SELECTION OF TECHNOLOGIES FOR DEVELOPMENT AND DEMONSTRATION

The techno-economic analysis performed in the TESBiC project covered:

- selecting eight out of twenty eight biomass CCS technology combinations for further study, based on a review of the technology landscape,
- performing high level process engineering case studies on each of the selected technology combinations, including the identification of the key knowledge gaps and of the future development requirements,
- formulating and parameterising the economic and process sub-models spanning 2010 up to 2050 timescales
- considering non-technical macro factors, such as, political, legislative and development incentives

The knowledge distilled from the aforementioned analysis, combined with the potential opportunity for ETI's additionality and its funding budget have been used to recommend specific biomass CCS technologies as potential candidates for further development and deployment in the UK. Based on prior discussions with the ETI, their investment budget for biomass CCS development and demonstration projects was understood to be of the order of £30 million.

The large scale co-fired options (amine/oxy/IGCC) look promising in the UK context, since there is a great deal of work already underway on coal (and gas) with considerable interest in the DECC CCS innovation programme or the NER 300 competition. The ETI could possibly allocate some of its demonstration funding to influence the inclusion of ~10% of biomass co-firing in the competition demonstrators. This extent of co-firing would neutralise the final positive CO_2 emissions (e.g. from +169 gCO_2e/kWh down to zero emissions), and yet not require negative CO_2 incentives. However, it is unlikely that the ETI could influence individual projects, to modify their fuel specification to include biomass, and it may already be too late for the ETI to take advantage of this potential option. Funding the inclusion of biomass storage and handling equipment is also a low innovation activity (well beyond TRL 6). Bearing in mind the size of ETI's demonstration budget, the current IP space, the levels of investments required (and in some cases investments already made elsewhere) to build whole plants, and the low likelihood of first-mover advantage; it is probably unlikely that the ETI can be additional in biomass cofiring amine/oxy/IGCC technologies.

Dedicated bio amine and bio oxy do not appear to be as attractive options, due to their high capital costs and low efficiencies relative to other technology combinations. The bio IGCC option, although slightly more attractive in terms of efficiencies, has not been recommended here given UK's limited expertise in IGCC or large-scale biomass gasification - although this picture is anticipated to improve with the experience gained once the ETI-funded co-fired IGCC demonstration (Costain) plant is operational, and with the top ranking achieved by the Don valley Power Project in the recently announced NER300 CCS demonstration projects shortlist. Again, given the similarities to cofire amine/oxy/IGCC technologies, and the size of the investment required, it is probably unlikely that the ETI can be additional in this space. It should be noted that although the TRLs for the overall dedicated biomass technology combinations (bio amine, bio oxy and bio IGCC) are low, the individual component TRLs are high enough that from a technical perspective, building these plants is possible – the main hurdle preventing their deployment lies in the economics, and lack of negative

CO_2 incentives. Provided the cofire amine/oxy/IGCC technologies are successfully demonstrated, it would be expected that their dedicated biomass options would be deployed in the following years, given the right negative CO_2 incentives.

Bio chem loop, and to a lesser extent cofire carb loop, are potentially two of the more attractive biomass CCS technology combinations for potential development and demonstration in the UK. They could offer high efficiency and low capital costs, building on existing UK expertise at the academic level. Most importantly, there is potential for technology acceleration and valuable IP generation by scaling-up both technologies, even with ETI budget constraints (unlike amine, oxy or IGCC technologies, £billions do not have to be spent to accelerate development). For both looping technologies, there could be opportunities to address known technical risks, existing knowledge gaps and uncertainties by:

- scaling up from the current ~1.7 MW_{th} (0.8 MW_e) scale
- achieving long-term reliable operation with high CO_2 capture rates
- testing various types of coal and biomass feedstocks
- testing potential of the use of biomass in a realistic oxygen carrier reducing reactor
- analysis of NO_x emissions
- characterisation of solids looping
- carrying out project-specific detailed engineering cost studies

For bio chem loop, achieving high reaction rates and maintaining activity levels over time are key concerns, particularly when solid fuels are used (for non-pressurized operation, GTCC with post-combustion capture is preferred over chemical looping on efficiency grounds for the utilisation of natural gas). For cofire carb loop, demonstrating the viability of integrating limestone and spent sorbent flows with cement industry processes, and demonstrating the combustion of biomass at scale in both the carbonator and calciner reactors will be highly valuable. These are not part of the current CaOling project. It should be noted that both looping technologies have low TRLs, several technical hurdles to overcome, and large uncertainties associated with their costs and efficiencies, i.e. are still in research and development to pilot stages. However, the potential rewards and benefits for a relatively modest investment from ETI potentially make these technologies attractive for UK development and demonstration.

The following recommendation for UK technology demonstration is made:

A flexible pilot plant with dual inter-connected circulating fluidized bed (CFB) reactors, suitable for investigating, testing and demonstrating primarily chemical looping combustion (but also has the capability to be reconfigured to test post-combustion carbonate looping capture as well as oxyfuel combustion).

This plant would have the greatest benefit if it were to offer:

- Dual CFB operation in chemical looping combustion mode, using biomass, coal or natural gas feedstocks. There is also potential value in investigating dual hydrogen generation through steam oxidation of the metal.

- Dual CFB operation with carbonate looping capturing CO_2 from an external flue gas stream, plus the option to use biomass instead of coal in the calciner. There is also potential value in investigating biomass combusted *in situ* in the carbonator, instead of using an external flue gas stream.
- Single CFB oxy-fuel combustion of biomass, achieved by shutting down the interconnection and changing out the looping solid for sand.
- Effective heat transfer and temperature control via steam generation, without necessarily the requirement to generate electricity further downstream (since steam turbines are proven technology). This would save on upfront capital costs, and the heat and other co-products could still be sold - but the plant would not generate power revenues or subsidies (e.g. ROCs for advanced thermal conversion technologies)

An investment of about £30 million to build an approximately 10-14MW_{th} (equivalent to about 5 MW_e) flexible looping plant is estimated. This would be likely to include fuel costs, maintenance and staffing during construction and for a limited initial experimental program, but not ongoing operating costs or any revenues.

The costs above are rough estimates at this stage, since although there is data available for chemical looping and carbonate looping from WP2, these WP2 costs are for a N^{th}-of-a-kind plants at optimised efficiencies and ~300MW_e scale, whereas the plant recommended above is a first-of-a-kind pilot plant at very small-scale, that also has to be flexible enough to operate in different configurations (hence is unlikely to be fully optimised). To resolve this, the first step would be to create a more detailed design specification for the proposed plant and its associated facilities, and then a FEED study to evaluate capital and running costs. There are some similarities between the pilot plant proposed and the existing pilot plants at TU Darmstadt, and the EU CaOling project, which may allow approximate cost estimates.

The UK currently has a strong position in these areas, though mainly either at a laboratory scale or through access to plants built elsewhere in the world. General CFB expertise in the UK has been somewhat lacking in the past, but with the presence of Alstom and Foster Wheeler in the UK, several large-scale CFB biomass combustion power plants in the planning pipeline, and the acquisition of Lentjes AE&E by Doosan Power Systems, there is strong potential for the UK's CFB expertise to improve rapidly in the near future.

The design, construction and operation of the proposed pilot plant above would provide valuable intellectual property and help to retain UK competitiveness in this rapidly-growing technical arena of work. The choice to build a multi-purpose flexible pilot plant would be likely to be less expensive than building two (or even three) separate plants, and would make best use of the funds available to the ETI in this area.

9 CONCLUSIONS

In the current work package, WP4, projections of the costs and efficiencies of the eight selected biomass CCS technology combinations to 2020, 2030, 2040 and 2050 have been made using a range of sources, including data from TESBiC WP1, WP2, WP3, ETI's ESME, ETI's BVCM project, IEA (2011) and TINA (for bioenergy and CCS) analyses. The costs and efficiencies of fossil CCS technologies were also projected to 2050, and compared against the projected values for the selected biomass CCS technology combinations.

On completion of this decadal modelling for each technology combination within TESBiC, the detailed parameterised models developed in WP3, i.e. the key techno-economic outputs (e.g. capex, opex, efficiency, emissions) as a function of the main operational inputs (e.g. nameplate and operating capacities, carbon capture extent and co-firing percentage) were then projected up to 2050. The key data were also fed into the technology database of the BVCM study.

In summary, the results of the comparison and benchmarking of the key performance parameters of the eight TESBiC biomass CCS technologies has indicated:

- The large-scale biomass co-firing technologies using solvent scrubbing, oxy-fuel and IGCC with physical absorption (cofire amine/oxy/IGCC, respectively) have low capital costs and similar overall generation efficiencies (with future upside potential for cofire IGCC). These factors. Along with the relatively low fuel and operating costs associated with cofiring, are reflected in the low LCOE values and low costs per tonne of CO_2 captured and avoided, for all these technologies.
- The dedicated biomass technologies (bio amine/oxy/IGCC) typically have higher specific investment costs, even when benchmarked at the same scale. The combustion technologies (bio amine & oxy) also have relatively low generation efficiencies. These facts are reflected in the higher LCOE values and costs per tonne of CO_2 captured and avoided for these technologies. However, the major advantage of the dedicated biomass technologies is that they offer very significant negative CO_2 emissions at small-scale, and the possibility of using lower grade and possibly lower cost or locally-sourced biomass materials.
- Bio chem loop shows potential for relatively high generation efficiencies and low capital costs across a range of scales, and could offer attractive negative CO_2 emissions. Cofire carb loop appears to have higher capital costs, but similar LCOE (coal used in the mix) – and both looping technologies have co-product revenues that help offset their modest operating costs. However, compared to the other six options, there are much larger technical risks attached to the development of these looping technologies. The LCOE values and the costs per tonne of CO_2 captured and avoided lie between the ranges seen for the co-firing and dedicated biomass plant options.
- In general terms, the plant scale (MW_e) is the principal driver of capex (£/MW_e), rather than the choice of technology, with larger plants having lower capital costs as expected.
- The co-firing %, i.e. the weighted feedstock cost, is one of the key drivers of LCOE, with dedicated biomass options using relatively expensive wood pellets always having significantly higher LCOE than co-firing with coal.

- The estimated costs of CO_2 captured lie in the range £80-190/tCO_2, and are highest for the small-scale dedicated biomass technologies if using pellets (although closer to £110/tCO_2 using chips).
- The costs of CO_2 avoided compared to those for an unabated coal power plant lie in the range £30-90/tCO_2, and again are lowest for the large-scale plants, and/or those using the cheapest feedstock (i.e. coal or biomass chips).
- Significant increases in the electricity generation efficiencies and reductions in the capital costs of all of the technologies have been projected for the period 2010 to 2050. By their nature, these are associated with large uncertainties attached, although we note the level of optimism assumed was consistent with the main data sources used (e.g. ESME, BVCM).

The future projections of the TRL values for the eight technology combinations have also been prepared. In most cases, the current TRL values and the projections to 2020 are reasonably well understood. Thereafter, it was considered in most cases that an increase of one TRL unit per decade would represent the situation where all the technologies were advancing in an incremental fashion, with none of the technologies being particularly favoured. The results of this analysis indicate that the currently most advanced biomass CCS technologies would achieve full commercialisation in the 2030's, or perhaps a little earlier, with the less advanced technologies achieving commercialisation in the 2040's.

Biomass CCS technologies currently represent one of the very few means of practically and economically removing large quantities of CO_2 from the atmosphere, and the only approach that involves the generation of electricity at the same time. This would appear to make this approach to power generation very attractive given many industrialised countries have stringent targets for the reduction of CO_2 emissions. It is clear, however that the available biomass CCS technologies are relatively expensive in terms of both capital and operating costs, and that specific subsidies will be required. It is also the case that at the present time, there are no specific financial incentives anywhere in the world for the generation of electricity with negative CO_2 emissions. In most cases, the most significant barriers to the deployment of biomass CCS technologies will be economic and regulatory in nature, rather than technical. These factors were taken into account when assessing the future projections of the TRL values from 2010 to 2050 for the biomass CCS technologies.

Each of the eight biomass CCS technologies has been re-examined and their likely future development has also been described. An outline development roadmap for each of the technologies has been prepared. In the case of the more developed capture technologies, the route to further development after demonstration of the capture technology on coal-fired plant would involve demonstration of the technology at commercial scale on a dedicated biomass plant or a coal plant co-firing biomass. The roadmaps for many of the biomass CCS technologies are clearly very closely tied to the development of coal CCS technology. For the less well developed capture technologies (chemical and carbonate looping), fairly conventional development roadmaps, involving component testing, small and large pilot scale testing, and larger scale demonstration have been defined.

Finally, the TESBiC consortium carried out a preliminary assessment of the suitability of the biomass CCS technologies as candidates for further development and deployment in the UK, with ETI support. Dedicated biomass chemical looping combustion, and to a lesser extent biomass co-firing with post-combustion carbonate looping, came out as potentially being two of the more attractive biomass CCS technology combinations for further development and demonstration in the UK. This was a result of their prospective for achieving relatively high efficiency and low capex, the significant level of existing UK expertise (at least at the academic level), and most importantly, the potential for first mover advantage to make a significant impact in the IP space, despite the limited funding budget available. However, there are several technical hurdles to be overcome in the development and scale-up of these technologies, and large uncertainties attached to the cost estimates in this study.

The TESBiC consortium's recommendation is to consider a UK pilot demonstrator based on a flexible looping technology for construction, with financial support from ETI. This flexible plant would have dual inter-connected circulating fluidized bed (CFB) reactors, and the associated flue gas and fuel feeding, solids recirculation, heat transfer and flue gas cleaning systems for investigating and testing both chemical looping combustion as well as post-combustion carbonate looping capture, potentially along with alternative configurations such as dedicated biomass oxy-fuel combustion.

An investment of about £30 million to build an approximately 10-14MW_{th} flexible looping plant is estimated. This is likely to include fuel costs, maintenance and staffing during construction and for a limited initial experimental program, but not ongoing operating costs or any revenues. Given its low innovation value, a downstream steam turbine (~5MW_e) is not necessarily required if heat transfer and steam generation can be proven – if power generation equipment capital costs have to be included within the £30 million, then the proposed scale-up in the looping technologies would have to be smaller. Such a plant would ideally be located beside an existing power plant in order to utilise fuel handling infrastructure and possibly a slip-stream flue gas supply.

10 ANNEX

This short Annex contains details of the calculation formulas used in deriving some of the key metrics presented in this WP4 report, as well as the feedstock energy densities, emissions factors and prices assumed throughout the study.

Glossary of development status terms

TRL = Technology Readiness Level

TRL 1 = Basic research

TRL 2 = Theoretical research

TRL 3 = Applied research

TRL 4 = Bench-scale test rig

TRL 5 = Pilot plant

TRL 6 = Small-scale demonstration plant

TRL 7 = Full-scale demonstration plant

TRL 8 = First commercial plants (N^{th}-of-a-kind)

TRL 9 = Mass deployment of fully commercial plants

General plant size formulas

LHV = Lower Heating Value. All energy units throughout the TESBiC study are measured in LHV, and not Higher Heating Values

"Scale" = "Nameplate capacity" = Plant net LHV electrical power output (MW_e)
= Gross LHV electrical power output (MW_e) – plant parasitic loads (MW_e) – CO_2 capture equipment parasitic loads (MW_e) – CO_2 compression parasitic load (MW_e)

Annual electricity output (TWh_e/yr) = Plant net LHV electrical power output (MW_e) x 8766 (hrs/yr) x Annual availability factor (85%)

Total feedstock LHV thermal energy input (MW_{th}) = Biomass feedstock LHV thermal energy input (MW_{th}) + Coal feedstock LHV thermal energy input (MW_{th})

Plant net LHV electrical efficiency (%) = Plant net LHV electrical output (MW_e) / Total feedstock LHV thermal energy input (MW_{th})

Cofiring % = Biomass feedstock LHV thermal energy input (MW_{th}) / [Total feedstock LHV thermal energy input (MW_{th})]

odt = oven dried tonne = tonne of feedstock as received x (1 – moisture content)

Total feedstock consumption (odt/yr) = Annual biomass consumption (TWh_{th}/yr) / Biomass feedstock LHV energy density (MWh/tonne) x (1 – biomass moisture content) + Annual coal consumption (TWh_{th}/yr) / Coal feedstock LHV energy density (MWh/tonne) x (1 – coal moisture content)

Cost formulas used

"Capex" = "Capital costs" = **Specific Investment Cost (£/kW$_e$)** = Total investment cost (£m) / Scale (MW$_e$) x 1000

Total investment cost (£m) = Total installed cost (£m) x 1.30

Levelised cost of capital (£m/yr) = Annual loan repayment of the Total Investment Cost at 10% discount rate, over plant lifetime of 30 years. Excel function "*PMT(10%, 30, Total Investment Cost)*"

"Opex" = "Operating costs" = Fixed operating costs (£m/yr) + Variable non-fuel operating costs (£m/yr)

Fixed operating costs (£m/yr) = Total installed cost (£m) x 5%/yr. This covers operation & maintenance, labour, admin/general overheads and insurance costs

Variable non-fuel operating costs (£m/yr) = Annual cost of solvents, catalysts, chemicals, waste and ash disposal, and other cost items that vary with plant output, net of any co-product revenues. Biomass (and any coal) costs are considered separately, and water costs are excluded for consistency across the technologies.

Fuel costs (£m/yr) = Annual biomass consumption (TWh$_{th}$/yr) x Biomass price (£/MWh$_{th}$) + Annual coal consumption (TWh$_{th}$/yr) x Coal price (£/MWh$_{th}$)

"LCOE" = **Levelised cost of electricity (£/MWh$_e$)** = [Levelised cost of capital (£m/yr) + Fixed operating costs (£m/yr) + Variable non-fuel operating costs (£m/yr) + Fuel costs (£m/yr)] / Annual electricity output (TWh$_e$/yr)

Fuel costs (£m/yr) / Plant net electrical output (TWh$_e$/yr) = [Biomass price (£/MWh$_{th}$) x [Cofiring %] + Coal price (£/MWh$_{th}$) x [1 - Cofiring %]] / Plant net LHV electrical efficiency (%)

CO_2 formulas used

CO_2 capture rate % = CO_2 emissions captured (MtCO_2/yr) / [CO_2 emissions captured (MtCO_2/yr) + CO_2 emissions uncaptured (MtCO_2/yr)]

Plant net CO_2 emissions (MtCO_2e/yr) = Uncaptured coal emissions (MtCO_2e/yr) – Captured biomass emissions (MtCO_2e/yr) + Upstream coal emissions (MtCO_2e/yr) + Upstream biomass emissions (MtCO_2e/yr)

Uncaptured coal emissions (MtCO_2e/yr) = Coal combustion emissions factor (tCO_2/MWh$_{th}$) x [1 - CO_2 capture rate] x Annual coal consumption (TWh$_{th}$/yr)

Captured biomass emissions (MtCO_2e/yr) = Biomass combustion emissions factor (tCO_2/MWh$_{th}$) x [CO_2 capture rate] x Annual biomass consumption (TWh$_{th}$/yr)

Upstream coal emissions (MtCO_2e/yr) = Coal upstream emissions factor (tCO_2/MWh$_{th}$) x Annual coal consumption (TWh$_{th}$/yr)

Upstream biomass emissions (MtCO_2e/yr) = Biomass upstream emissions factor (tCO_2/MWh$_{th}$) x Annual biomass consumption (TWh$_{th}$/yr)

Captured coal emissions (MtCO_2e/yr) = Coal combustion emissions factor (tCO_2/MWh$_{th}$) x [CO_2 capture rate] x Annual coal consumption (TWh$_{th}$/yr). Although this can be a significant amount of

CO_2, this is not counted in the plant net emissions calculation, as this is fossil carbon being dug up, but then sequestered back underground

Uncaptured biomass emissions ($MtCO_2e/yr$) = Biomass combustion emissions factor (tCO_2/MWh_{th}) x [1 - CO_2 capture rate] x Annual biomass consumption (TWh_{th}/yr). Although this can be a significant amount of CO_2, this is not counted in the plant net emissions calculation, as this is biogenic carbon being absorbed by growing plants, but then released back into the atmosphere

Net CO_2 emitted per unit electricity generated (gCO_2e/kWh_e) = Plant net CO_2 emissions ($MtCO_2e/yr$) / Plant net electrical output (TWh_e/yr) x 1000

Electricity generated per unit CO_2 captured (MWh_e/tCO_2) = Plant net electrical output (TWh_e/yr) / [Captured biomass emissions ($MtCO_2e/yr$) + Captured coal emissions ($MtCO_2e/yr$)]

Net CO_2 emitted per unit feedstock input (tCO_2e/odt) = Plant net CO_2 emissions ($MtCO_2e/yr$) / Total feedstock consumption (odt/yr) x 1,000,000

Cost of CO_2 captured (£/tCO_2) = LCOE (£/MWh_e) x Annual electricity output (MWh_e/yr) / CO_2 emissions captured (tCO_2/yr)

Cost of CO_2 avoided (£/tCO_2) = [$LCOE_{\text{TESBiC biomass CCS}}$ (£/MWh_e) – $LCOE_{\text{IEA unabated coal}}$ (£/MWh_e)] / [Net CO_2 emitted per unit electricity $\text{generated}_{\text{IEA unabated coal}}$ (gCO_2e/kWh_e) – Net CO_2 emitted per unit electricity $\text{generated}_{\text{TESBiC biomass CCS}}$ (gCO_2e/kWh_e)] x 1000. This assumes that the comparator technology in each decade is an unabated coal power plant, from IEA (2011)[13]

Benchmarking formulas used for plant re-scaling

Total investment cost_{old} (£m) = Specific investment cost_{old} (£/kW_e) x Scale_{old} (MW_e) / 1000

Total investment cost_{new} (£m) = Total investment cost_{old} (£m) x [Scale_{new} (MW_e) / Scale_{old} (MW_e)] ^0.7

Specific investment cost_{new} (£/kWe) = Total investment cost_{new} (£m) / Scale_{new} (MW_e) x 1000

Total investment cost_{new} (£m) = Total installed cost_{new} (£m) x 1.30

Fixed operating costs_{new} (£m/yr) = Total installed cost_{new} (£m) x 5%/yr

Variable non-fuel operating costs_{new} (£m/yr) = Variable non-fuel operating costs_{old} (£m/yr) x [Scale_{new} (MW_e) / Scale_{old} (MW_e)]

Feedstock emission factors

Feedstock combustion and upstream emissions factors are taken from ETI ESME, Herold (2003)[14], Weisser (2007)[15] and EERE (2000)[16]. Different upstream emissions factors for pellets and chips were considered, due to their different process steps and energy required. From the BVCM model, an approximate average for UK chips would be ~50 $kgCO_2e/odt$, with imported pellets at ~200 $kgCO_2e/odt$. These equate to the values seen in the table below.

[13] IEA (2011) "Cost and Performance of Carbon Dioxide Capture from Power Generation", Working Paper, Fickenrath, M.

[14] Herold, A. (2003) "Comparison of CO2 emission factors for fuels used in Greenhouse Gas Inventories and consequences for monitoring and reporting under the EC emissions trading scheme", The European Topic Centre on Air and Climate Change (ETC/ACC), ETC/ACC Technical Paper 2003/10, available at: http://acm.eionet.europa.eu/docs/ETCACC_TechnPaper_2003_10_CO2_EF_fuels.pdf

[15] Weisser (2007) "A guide to life-cycle greenhouse gas (GHG) emissions from electric supply technologies", Energy 21, 1543-1559

[16] EERE (2000) "APPENDIX Environmental Assessment 2. Upstream emission factors from coal and natural gas production", available at: http://www1.eere.energy.gov/buildings/appliance_standards/residential/pdfs/ea_app2.pdf

(tCO_2e/MWh)	Combustion emissions	Upstream emissions
Bituminous coal	0.34	0.008
Natural gas	0.20	0.020
Biomass pellets	0.36	0.040
Biomass chips	0.36	0.010

Feedstock energy densities

LHV energy densities per tonne of as received feedstock are taken from WP2, and cross-checked with meta-analysis data from the Biomass Energy Centre (2012)[17] and Stafell (2011)[18].

	Energy density (MWh/tonne)	Average moisture content
Bituminous coal	23.5	13%
Natural gas	46.4	0%
Biomass pellets	17	9%
Biomass chips	12.5	30%

Feedstock prices

The following table shows the resource prices assumed throughout the TESBiC study. Coal and natural gas prices in 2010 and 2050 are from the ETI ESME model, with biomass pellets and chip prices taken directly from WP2. These biomass prices are based on current prices paid in the UK, of ~£50/odt for UK forestry chips delivered to a plant, and ~£135/odt for imported wood pellets. Both biomass pellets and chips have prices significantly above those of coal.

Resource price (£/MWh)	2010	2020	2030	2040	2050
Bituminous coal @13% moisture	6.6	6.9	7.2	7.5	7.8
Natural gas	26.5	27.7	29.0	30.3	31.6
Biomass pellets @9% moisture	27.0	27.0	27.0	27.0	27.0
Biomass chips @30% moisture	10.1	10.1	10.1	10.1	10.1

ESME assume a UK biomass price of £10/MWh, which does not change over time, hence we also assume that our TESBiC biomass prices will not change to 2050. As a final sense-check, we note that IEA (2011) gives a European coal price of £8.2/MWh, a natural gas price of £22.3/MWh, and traded biomass price (presumed pellets) of £25.8/MWh. These are reasonably close matches to the more UK-specific values given above.

[17] Bioenergy Energy Centre (2012) "Typical calorific values of fuels", available at: http://www.biomassenergycentre.org.uk/portal/page?_pageid=75,20041&_dad=portal&_schema=PORTAL

[18] Stafell, I (2011) "The Energy and Fuel Data Sheet", University of Birmingham, available at: http://wogone.com/science/the_energy_and_fuel_data_sheet.pdf