Bio-energy with carbon capture and storage (BECCS): Opportunities for performance improvement

Mai Bui[a,b], Mathilde Fajardy[a,b], Niall Mac Dowell[a,b,*]

[a] *Centre for Process Systems Engineering, Imperial College London, South Kensington, London SW7 2AZ UK*
[b] *Centre for Environmental Policy, Imperial College London, South Kensington, London SW7 1NA UK*

Abstract

This study evaluates the performance of a 500 MW pulverised fuel BECCS system. A performance matrix is developed to assess the opportunities for BECCS performance improvement in terms of: energy efficiency, carbon intensity, and pollutant emissions. The effect of fuel properties was analysed for variable (i) coal type (high/medium sulphur content), (ii) biomass type (wheat straw and wood chips), (iii) moisture content, and (iv) biomass co-firing proportion %. It was observed that the co-firing of biomass increased the quantity and quality of waste heat available for recovery from the exhaust gas. The opportunities to improve energy efficiency in the BECCS system include enhancing heat recovery and using high performance solvents for CO_2 capture, such as biphasic materials. Implementing these approaches increased the power generation efficiency from $31\%_{\mathrm{HHV}}$ (conventional MEA system) to $38\%_{\mathrm{HHV}}$ (using "new solvent" with heat recovery). Furthermore, power generation efficiency was found to influence the carbon intensity on an annual basis and annual capacity (load factor) of the BECCS system. Significant reductions to SO_X emissions were achieved by increasing biomass co-firing % or using low sulphur coal.

Keywords: Biomass, bio-energy, BECCS, carbon capture and storage (CCS), efficiency, co-firing, co-combustion, greenhouse gas removal (GGR)

---

*Corresponding author, Email: niall@imperial.ac.uk

Preprint submitted to Fuel *April 20, 2017*

1. Introduction

1.1. *Bio-energy with carbon capture and storage (BECCS)*

Carbon capture and sequestration (CCS) and "negative emissions" technologies will play an essential role in achieving deep reductions in atmospheric CO_2 concentration [1]. There is growing interest in bio-energy with carbon capture and storage (BECCS) as a promising negative emissions technology, and as a means to meet global warming targets of below 2°C target [1] and 1.5°C set by COP21 [2]. This highlights the importance of having BECCS as a CO_2 mitigation option.

The BECCS technology was first introduced for hydrogen production [3], before the concept was adapted for "negative emissions" electricity generation [4]. Over the lifetime of biomass growth, there is a net transfer of atmospheric CO_2 into the biomass. The CO_2 arising from the combustion of this biomass is captured and stored in geological formations, enabling the permanent removal of CO_2 from the atmosphere [5, 6], and potentially achieving an overall negative carbon balance [5, 6, 7, 8, 9, 10, 11, 12]. Biomass is generally considered a CO_2 neutral substitute for fossil fuels, where co-combustion has also been shown to reduce the emissions of pollutants SO_X, NO_X and particulates [13, 14, 15]. Another important advantage of bio-energy with CCS is that it provides reliable firm low carbon electricity, unlike intermittent renewable energy sources (IRES) such wind or photovoltaic [16, 17]. The economic loss caused by power outages is two orders of magnitude greater than the cost of electricity [17]. Therefore, this emphasises the value of having firm capacity technologies to balance the use of IRES in an electricity system. Bio-energy with CCS is recognised as a practical and immediate approach to mitigating the use of coal and decarbonising the electricity sector.

1.2. *Approaches to improve efficiency*

1.2.1. *Enhancement of fuel properties*

The fuel composition and properties of biomass differ significantly from coal [18]. Biomass typically has lower HHV (higher heating value) and higher moisture content in comparison with coal. Furthermore, co-firing biomass tends to increase fouling and slagging in the boiler furnace [19, 20, 21, 22]. Consequently, biomass co-firing tends to reduce the energy efficiency of the power plant [22, 23, 24]. The CO_2 capture process imposes an additional energy penalty due to heat requirements for solvent regeneration [25, 26]. Enhancements to energy efficiency are required to minimise the marginal cost of electricity generation, enabling operation of the power plant at higher load factor [27, 28]. Therefore, BECC performance improvements would improve commercial viability of the technology and encourage large scale deployment.

Coal blending to meet power plant requirements is conventional practice [29, 30, 31]. Until recently, the main motivation for coal blending has been to reduce cost and to utilise more readily available coal resources, *i.e.*, indigenous coal. However, as the fuel markets change, the availability of indigenous coals is declining, increasing the use of imported coals [31]. Fuel quality has an impact on almost every aspect of power plant operation and performance. Boilers are typically designed based on a fuel specification, where there is normally an allowable range for important fuel properties [29] (*e.g.*, HHV, moisture content, ash content and composition, grindability). Table 1 shows typical fuel property requirements for a pulverised coal-fired power plant. Within these property limits, the power plant is expected to produce full load [30]. However, deviation from this design fuel specification can be detrimental to plant performance as efficiency would reduce outside the recommended property limits. The use of alternative fuels in power plants requires detailed evaluation of the resulting impacts on performance and cost [30]. The following lists the impact of fuel properties on certain plant performance [29, 30, 31]:

- **Fuel handling and storage:** heating value, moisture content, volatile matter content, ash content and composition, grindability;
- **Pulverising/milling:** heating value, moisture content, volatile matter content, ash content and composition;
- **Combustion performance in the boiler furnace:** moisture, ash,

volatile matter, heating value, particle size distribution;

- **Ash management/handling and influence on heat transfer:** heating value, moisture, ash content and composition;

- **Pollutant emissions:** sulphur content, nitrogen content.

Depending on how performance is impacted, modifications to equipment and operations may be required. In the case of biomass co-firing, various power plant configurations and modifications have been developed to improve biomass co-firing performance [32, 33, 34, 35, 36]. To minimise the risk to normal boiler operation during biomass co-firing, necessary plant modifications may include separate fuel feeding systems, the addition of biomass-dedicated burners and ash handling systems. For appropriate design of the combustion facility, it is essential that the fuel characteristics (*e.g.*, moisture, ash, heating value, ignition temperature) of the biomass are well understood [37].

Fuel blending to meet power plant specifications and requirements enables the use of alternative fuels, whilst maintaining energy output and preventing damage to the boiler. Additionally, fuel blending can be used as a means of complying with emission regulations, notably sulphur or mercury emissions [31]. For instance, SO_X emissions during the combustion of high sulphur bituminous coals have been shown to reduce significantly by co-firing with fuels of low sulphur content, *e.g.*, biomass [14, 38, 39, 40], or low sulphur coal [41]. Although certain biomass fuel properties reduce plant efficiency (*e.g.*, high moisture) [22, 24], some fuel properties can be used to improve the overall combustion performance. In comparison to pure coal, biomass typically has higher oxygen content and greater volatile matter [23, 35], which improves the reactivity and ignition characteristics of the fuel blend [31, 42], and reduces unburnt carbon [43].

Another approach to enhance performance is the development of biomass pretreatment techniques which improve biomass fuel properties, thus reducing the negative impacts of fuel properties that cause slagging/fouling and reduced combustion performance. It is desirable to alter the physical properties of biomass to match those of coal, minimising the need to modify fuel handling

Table 1: Typical coal quality requirements for a pulverised coal-fired power plant [30]. ar = as received, mf = moisture free, daf = dry and ash free. The 'Typical limits' are ranges commonly reported from both literature and survey of power plant operators, where those in the brackets indicate the outer limits that are acceptable under certain circumstances.

Parameter	Desired values	Typical limits
Heating value (MJ/kg ar)	High	Min 24–25 (23)
Moisture content (% ar)	4–8	Max 12
Volatile matter (% mf)	20–35 15–20	Min 20 (side-fired furnaces) Max 20 (down-fired furnaces)
Ash content (% mf)	Low	Max 15–20 (max 30)
Sulphur content (% daf)	Low	Dependent on local pollution regulations and flue gas desulphurisation capacity
Nitrogen content (% daf)	Low	(0.8–1.1), dependent on local pollution regulations and NO_X control measures
Chlorine content (% daf)	Low	Max 0.1–0.3 (max 0.5)
Hardgrove Grindability Index	High	Min 50–55 (min 39)

and combustion equipment [42]. Biomass pretreatment can involve mechanical, thermal, chemical or biological processes.

The "densification" process increases the bulk density of biomass to improve the efficiency of downstream steps, including storage, handling, supply/feed [44]. Biomass densification can be achieved through pelletising mills [45], briquette presses [46], screw extruders or agglomeration (*i.e.*, binding powder particles) [47]. The options for pretreatment include:

- **Leaching or washing:** removes undesirable chemical components that cause ash deposition issues (*i.e.*, the silicates, chlorides and sulphates of potassium and calcium), or corrosion (*i.e.*, acidic compounds formed from chlorine and sulphur) [42].

- **Dry torrefaction:** generates biomass fuel with similar properties to coal, *e.g.*, reduces moisture content, increases heating value, reduces propensity to reabsorb H_2O, improves grindability/milling characteristics, particles are more spherical, also size is smaller and more uniform [42, 44, 48]. During torrefaction, raw biomass is heated up to temperatures between 200 and 300°C[49]. The energy requirement is a function of the inlet biomass moisture content at the inlet, torrefaction temperature and reaction time. For an inlet biomass moisture content of 15%, the energy requirement has been found to be around 90 kWh per ton of biomass [50]. However, this value typically increases significantly with higher moisture content as the drying heat requirement constitutes a large fraction of the total heat duty for torrefaction.

- **Hydrothermal carbonisation or wet torrefaction:** end-product is similar to dry torrefaction but wet torrefaction produces a solid with greater energy density [51].

- **Steam explosion:** pressurisation with saturated steam causes physical and chemical changes, the end-product has high density and low moisture reabsorption [44]. During the process, heat is required to heat the biomass and generate the steam at the selected temperature. The heat duty varies with the temperature of the process and biomass type. For instance, the heat duty for steam explosion of switchgrass is 150 kWh per ton of biomass at 140°C, whereas wheat straw requires 210 kWh per ton of biomass at 180°C [52].

Each densification and pretreatment process vary in terms of energy consumption, impacts on chemical and physical properties, as well as end-product quality [47]. From an energy efficiency perspective, there will be a compromise between the energy consumption of the pretreatment process and level of fuel enhancement. To determine the value of biomass pretreatment, the impact of enhancing specific fuel properties on the overall power plant performance needs to be assessed carefully.

Blending or co-firing biomass together with coal can provide a fuel that meets power plant requirements. The biomass reduces the emissions of pollutants SO_X and NO_X, whereas coal increases the heating value to improve combustion performance. Further improvements to fuel properties can be achieved through biomass pre-treatment (*e.g.*, drying, densification). Detailed evaluation of the effect of blended fuel properties and fuel enhancement is necessary to understand biomass co-firing combustion behaviour, as well as the subsequent effect on power plant performance.

Due to limitations on fuel specification (as seen in Table 1), thus, the biomass-coal co-firing ratio is restricted in existing coal pulverized boilers. In a recent report on biomass co-firing, the IEA Bioenergy recommended a maximum biomass co-firing ratio of 10% of the energy input, beyond which, negative impacts on combustion performance and ash management may occur. However, the co-firing ration can increase up to 40% if the biomass has been milled to the right particle size [53]. Using the specifications of a relatively low moisture biomass, this would translate in a maximum co-firing of around 60% in terms of mass basis. This value can be considered as the maximum co-firing ratio on a mass basis, beyond which, adjustments (*e.g.* move the flame detection system) or design modifications (*e.g.* bring the ignition plane back to its initial position, ash deposition protection measures) must be performed on the boiler technology [53].

1.2.2. Process design for efficiency improvements

The CO_2 capture process requires low grade thermal energy for solvent regeneration, typically sourced as saturated steam at ∼3 bar [25, 54]. The steam is predominantly supplied through steam extraction from the stream cycle of the power plant, which imposes an efficiency penalty on the system [55, 56]. Several options for steam extraction and steam cycle design have been developed to minimise the efficiency penalty incurred due to CO_2 capture, these include:

- Steam extraction at the cross-over pipe between the intermediate pressure (IP) and low pressure (LP) turbines [57, 58, 59, 60, 61];
- Extraction of steam from within the LP steam turbine at a suitable point [62];
- Optimised designs for steam cycle retrofits [54, 63].

An alternative approach is to modify the process configuration of the CO_2 capture process to reduce the energy penalty and improve efficiency. Some studies focus on cost-effective stripper configurations to improve energy efficiency, *e.g*, Karimi *et al.* (2011) [64], Van Wagener & Rochelle (2011) [65]. Various configurations for CO_2 removal from natural gas-based power plant have also been evaluated [66, 67, 68]. Amrollahi *et al.* (2012) combined lean vapour compression with absorber inter-cooling to decrease energy consumption from 3.74 to 2.71 MJ/kg CO_2 [68], whereas Øi *et al.* (2014) reduced heat consumption from 3.26 MJ/kg CO_2 (baseline) to 2.90 MJ/kg CO_2 by only using the vapour recompression configuration [66]. In contrast, Zhang *et al.* (2016) focussed on evaluating configurations that minimised capital expense. There are several extensive reviews on configuration modifications for CO_2 capture in coal-fired power plants [69, 70, 71, 72]. Of these process modifications, the split-flow configurations shows promise, providing a 8.3% reduction to reboiler duty (full load), thus, reducing the efficiency penalty substantially [73].

Process modifications can be implemented to use waste heat recovery and further improve the overall energy efficiency [74]. There are three potential approaches to recover waste energy:

1. Heat recovery or heat integration within the power plant to improve efficiency;
2. Waste heat recovery from the CO_2 capture process to use in the power plant and improve efficiency;
3. Heat recovery from the power plant to use in the CO_2 capture process, reducing the energy penalty.

Examples of the first approach include flue gas heat recovery, which can be utilised for fuel drying [75], or applied in a low pressure economiser to heat the steam cycle condensate [76, 77, 78, 79]. Pfaff *et al.* (2010) [74] investigated approaches to recover energy from the CO_2 capture process to enhance power plant efficiency. Heat recovered from the stripper overhead condenser and the CO_2 compressor intercoolers in the capture process were used to pre-heat the power plant steam cycle condensate and combustion air [74]. Alternatively, flue gas heat recovery can supply energy for solvent regeneration in the CO_2 capture process [80, 81, 82, 83, 84]. For this approach, the amount of heat that is recoverable from flue gas depends on: (i) the point along the pollution control pathway (*e.g.*, exit of boiler, electrostatic precipitator, flue gas desulphurisation); and (ii) fuel type and quality [55]. In a coal-fired power plant, the measured flue gas temperature at the economiser outlet is $\sim$345°C [85], whereas the solvent regeneration temperature is typically 120°C [86, 87, 88]. All of these studies investigated the implementation of efficiency enhancements for applications in fossil fuel power plants. The moisture content of biomass can change significantly, affecting the flue gas heat transfer rate [89] and flue gas volume flow rate [30], which in turn influences power plant thermal efficiency [82]. Therefore, an extensive performance assessment of biomass-specific power systems is necessary.

1.3. Study objectives

To improve the energy efficiency of BECCS in this study, heat recovery from boiler exhaust flue gas is used to supply heat for the CO_2 capture process. This paper evaluates the performance of a 500 MW dedicated BECCS system under different operating conditions (*e.g.*, variable fuel properties, different capture solvents, and effect of heat recovery). The effects on combustion performance from different: (i) coal types (high and medium sulphur content), (ii) biomass types (wheat straw and clean wood chips with variable moisture content), and (iii) biomass co-firing proportions percentage was demonstrated. Blending coal with biomass provides the benefit of reducing pollutant emissions. Also, by varying fuel moisture content, the impact of drying biomass on plant performance was investigated. Additionally, the effect of solvent technology (*e.g.*, different heat duty) and biomass co-firing proportion on the system energy efficiency and carbon intensity was evaluated. These results lead to the development of a performance matrix which summarises the effect of key process parameters.

The remainder of the paper is structured as follows: (i) First the methodology and modelling procedure is presented. (ii) The performance of a 500 MW BECCS plant is evaluated, assessing the influence of fuel quality and biomass co-firing proportion on the adiabatic flame temperature, SO_X and NO_X emissions, heat recovery, plant efficiency and carbon intensity. (iii) A performance matrix is developed to assess the opportunities for BECCS performance improvement in terms of minimising pollutant emissions, enhancing power efficiency, reducing carbon intensity. Lastly, (iv) the paper concludes with a discussion of future directions for this research field.

2. Methodology

The modelling procedure used to assess performance of the 500 MW pulverised fuel BECCS system has been summarised below. Detailed equations and descriptions of the models is available in Bui *et al.* (2017)[83].

2.1. Power plant and CO_2 capture model

The fuel types selected for this analysis included (i) high sulphur coal, (ii) low sulphur coal, (iii) clean virgin wood chip, and (iv) wheat straw. The moisture content of biomass fuels varied between 5% to 50%. The properties and composition of these fuels is provided in Table 2.

Three CO_2 capture solvents were considered:

1. High heat duty scenario: MEA with a regeneration energy requirement of 3600 MJ/t_{CO_2} [90], and temperature of 120°C;
2. Medium heat duty scenario: industrial solvent Cansolv, which requires 2300 MJ/t_{CO_2} and 120°C in the reboiler [86, 87];
3. Low heat duty scenario: uses "new solvent" that operates at 2000 MJ/t_{CO_2} and 80°C [83].

The "new solvent" heat duty is based on performance data for biphasic solvent systems, which can achieve overall heat duty reduction of 30% compared to conventional MEA systems [93]. The heat duty of 2900 MJ/t_{CO_2} has been reported to be the attainable limits for MEA systems [88]. Therefore, a 30% reduction to an energy requirement of 2000 MJ/t_{CO_2} is in accordance with the state-of-the-art systems in literature [94, 95].

The ultra-supercritical 500 MW coal-fired power plant with 90% post-combustion CO_2 capture was modelled in the Integrated Environment Controlled Model (IECM) software [90]. The fuel and solvent data was implemented in the IECM model to calculated the fuel firing flow rate and the net power output, which was subsequently used to determine the power plant efficiency ($\%_{HHV}$) and carbon intensity (kg CO_2 emitted per MWh generated).

2.2. Thermochemical combustion model

The thermochemistry of the co-combustion of coal with biomass was modelled in the software FactSage 7.0 [96, 97]. Table 3 summarises the coal and biomass fuel blending scenarios modelled in FactSage, where the biomass co-firing proportion was increased from 0% to 50% at increments of 5%. The fuel

Table 2: Fuel properties and composition for the coal and biomass types used for this analysis.

	High sulphur coal	Medium sulphur coal	Clean wood chips	Wheat straw
Reference	[90]	[91]	[91]	[14, 92]
HHV (MJ·kg^{-1} dry)	27.14	27.06	19.16	19.22
Fuel composition	wt %	wt %	dry wt %	dry wt %
C	63.75	64.6	50	48.7
H	4.5	4.38	5.4	5.7
O	6.88	7.02	42.2	39.1
Cl	0.29	0.023	0.02	0.32
S	2.51	0.86	0.05	0.01
N	1.25	1.41	0.3	0.6
Moisture	11.12	9.5	–	–
Ash	9.7	12.2	2.0	5.5
Ash composition	% ash	% ash	% ash	% ash
SiO_2	46.8	50	43.1	56.2
Al_2O_3	18.0	30.0	8.9	1.2
Fe_2O_3	20.0	9.8	3.9	1.2
CaO	7.0	4.0	28.0	6.5
MgO	1.0	0.5	4.2	3.0
Na_2O	0.6	0.1	2.0	1.3
K_2O	1.9	0.1	5.5	23.7
TiO_2	1.0	2.0	0.4	0.06
P_2O_5	0.2	1.8	2.2	4.4
SO_3	3.5	1.7	1.8	1.1
MnO	0	0	0	1.34

firing flow rates from IECM in tonnes per hour was used as the mass basis for the calculations in FactSage. To ensure complete combustion, the excess air coefficient (λ) of 1.3 was used, which maintain an O_2 concentration of ~5 – 6% in the flue gas (in accordance with industrial practice).

Table 3: Coal and biomass co-combustion scenarios modelled in FactSage.

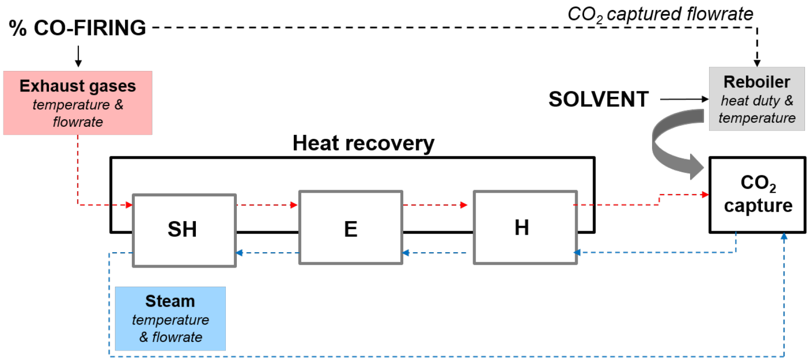
Scenario	Coal type	Biomass type
A	Medium sulphur coal	Wheat straw 5% moisture
B	Medium sulphur coal	Wheat straw 16% moisture
C	Medium sulphur coal	Wood chip 5% moisture
D	Medium sulphur coal	Wood chip 50% moisture
E	High sulphur coal	Wheat straw 5% moisture
F	High sulphur coal	Wheat straw 16% moisture
G	High sulphur coal	Wood chip 5% moisture
H	High sulphur coal	Wood chip 50% moisture

The combustion of each fuel blend was simulated from 200°C to the adiabatic flame temperature (the AFT was calculated in FactSage). The subsequent flue gas mixture was cooled from the AFT to 370°C (predicted flue gas temperature at the boiler exit in IECM). The objective was to calculate the following properties for each biomass co-firing scenario: (i) AFT, (ii) SO_X and NO_X emissions, and (iii) exhaust gas properties at 370°C. These calculated exhaust gas properties, *i.e.*, AFT, gas flow rate and specific heat capacity, were subsequently implemented in the heat recovery model.

2.3. Heat recovery model

A heat recovery model was developed in MATLAB; it was based on a heat exchanger system consisting of a heater, an evaporator and a super-heater [98]. Using the input data from the FactSage analysis, the heat exchanger model (shown in Figure 1) was used to calculate the "recoverable heat", which is the percentage of solvent heat duty recoverable from the boiler exhaust gases.

Figure 1: Schematic of the heat recovery model consisting of the super-heater (SH), evaporator (E) and heater (H).



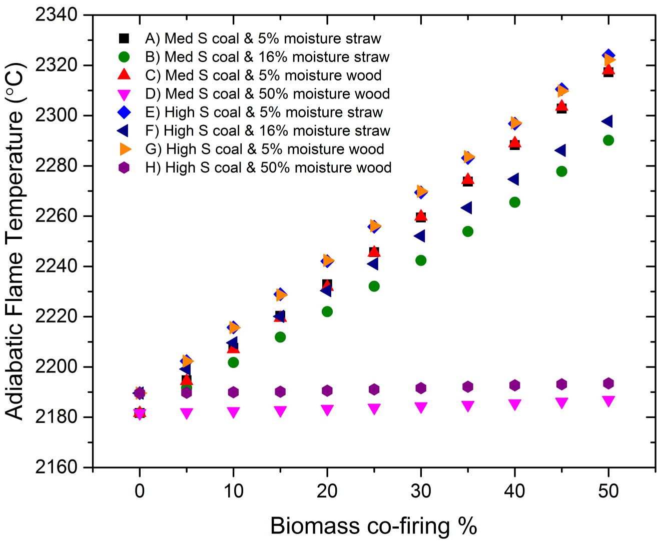
3. Performance evaluation of a 500 MW BECCS system

3.1. Adiabatic flame temperature (AFT)

Figure 2 illustrates that AFT generally increased with higher biomass co-firing proportions. For all fuel blends, the overall higher heating value (HHV) of the blended fuel reduced as biomass co-firing % increased, thus, the fuel firing rate increased in order to meet the specified power plant capacity (500 MW). The biomass moisture content had a significant influence on the degree at which AFT increased. The coal co-fired with biomass of low 5% moisture achieved the highest AFT increase. Compared to firing medium sulphur coal alone, 50% co-firing with 5% moisture wood/straw increased the AFT by 136°C (Scenario A and C). The straw with moderate moisture content of 16% also provided a substantial increase of 108°C in AFT at 50% biomass co-firing. In contrast, there was a marginal 4 – 5°C increase in AFT when co-firing coal with biomass of 50% moisture. The medium sulphur coal had higher ash content compared to high sulphur coal (shown in Table 2), consequently, co-firing the same biomass with medium sulphur coal generated lower AFT compared to high sulphur coal.

The fuel moisture and ash content had a strong impact on the combustion performance (*i.e.*, AFT), which is concordant with previous research [99]. The selection of fuels that reduce the moisture and ash content of the overall blend

Figure 2: Adiabatic flame temperature (AFT) for different co-firing scenarios with coal and biomass.



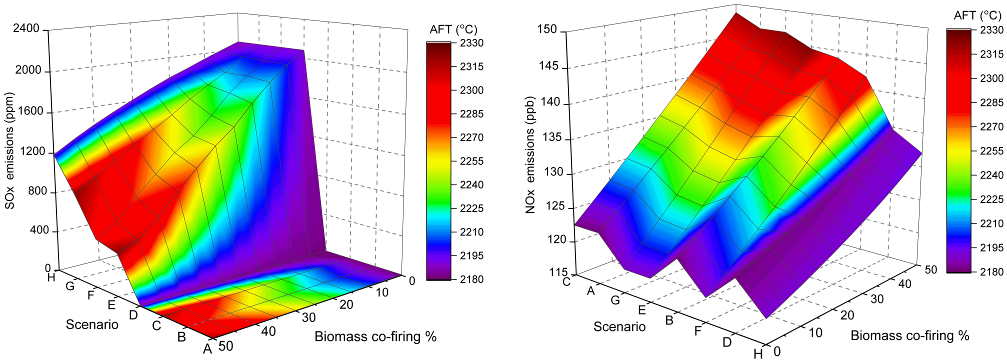
can provide higher AFT and potentially achieve greater flue gas temperatures.

3.2. Pollutant emissions

The SO_X and NO_X emissions have been represented as concentration of the exhaust flue gas at 370°C (from the FactSage analysis) in terms of parts per million (ppm) and parts per billion (ppb), respectively. Typically, the reduction in SO_X emissions during biomass co-firing are due to: (i) reduction in fuel sulphur content, (ii) presence of chemical compounds in ash that can absorb SO_2 (*e.g.*, alkali oxides) [14].

Figure 3 (left) shows that SO_X emissions reduced as the biomass co-firing proportion increased. Furthermore, the SO_X emissions from high sulphur coal co-firing were significantly greater than the medium sulphur coal scenarios. The scenarios involving high sulphur coal, Figure 4 (left), demonstrate SO_X emissions decreased linearly with higher biomass co-firing %, which can be attributed to the biomass (both the wood chip and wheat straw) having significantly lower

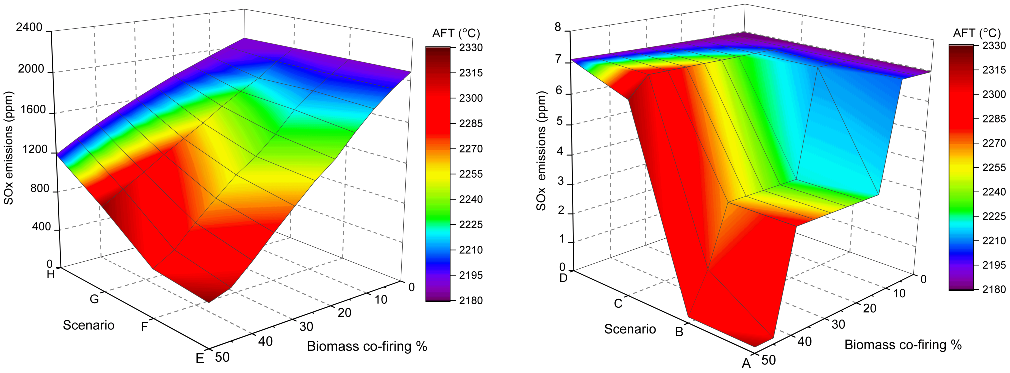
Figure 3: Emissions of SO_X (left) and NO_X (right) during the co-combustion of coal with biomass at different co-firing percentages. Refer to Table 3 for fuel blends in each Scenario.



sulphur content compared to coal. In contrast, biomass co-firing with medium sulphur coal resulted in a non-linear decrease of SO_X emissions, shown by Figure 4 (right). As discussed by Bui *et al.* (2017) [83, 84], this non-linear (step-change) behaviour may be the result of equilibrium reaction shifts that occur at low fuel sulphur content. The FactSage analysis revealed that the alkali metal oxides in the ash also contributed to the reduction in SO_X emissions, specifically CaO, MgO [14, 100], Na_2O and K_2O [101, 102].

Some experimental studies suggest increased biomass co-firing % reduced NO_X emissions [103, 104]. However, other studies have indicated high proportions of biomass co-firing can lead to NO_X emissions increasing [40, 105] or remaining unchanged [106] compared combustion of coal alone. The variation in the effect of biomass co-firing on NO_X emissions across different studies is due to the combustion conditions having a significant effect on the level of NO_X emissions during biomass co-firing [14, 15, 40, 107]. In particular, temperature and the presence of N_2 can significantly influence NO_X emission levels [108]. At combustion temperatures >1300°C, thermal and prompt NO_X reaction pathways can occur leading to NO_X formation from the N_2 in air [105, 109, 110]. Figure 3 (right) shows AFT was above 1300°C, resulting in higher NO_X emissions due to increased formation from N_2 in air. In practice, combustion condi-

Figure 4: The SO_X emissions when biomass is co-fired with coal of high sulphur content (left) and medium sulphur content (right). Refer to Table 3 for fuel blends in each Scenario

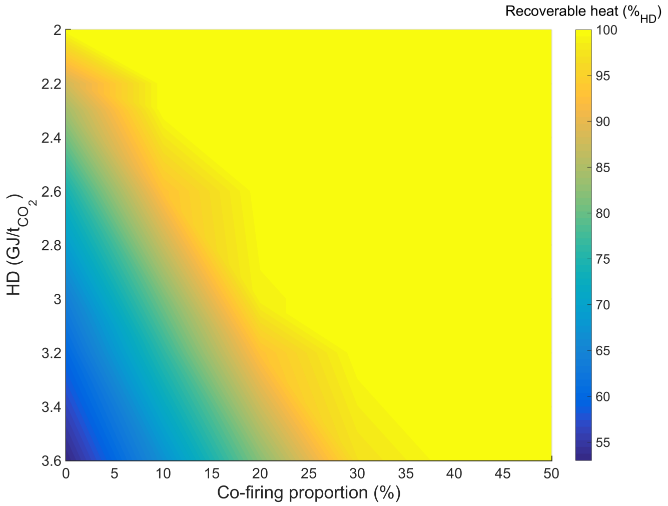


tions are optimised and controlled to ensure NO_X emissions are minimal (*e.g.*, temperature maintained below 1300°C, air staging, fuel staging) [105]. Future modelling work will need to consider such combustion control mechanisms to ensure the prediction of NO_X emissions are an accurate representation of an actual power plant combustion system.

3.3. Heat recovery

The heat recovery evaluation was conducted for co-combustion scenario of high sulphur coal with 16% moisture wheat straw (Scenario F). Figure 5 illustrates the influence of solvent heat duty and biomass co-firing proportion on the recoverable heat (percentage of heat duty compensated by flue gas heat recovery). Of the three solvent scenarios at 0% biomass co-firing (*i.e.*, firing coal alone), heat recovery can only fulfil 100% of the regeneration energy requirements for the "new solvent" scenario (*i.e.*, heat duty of 2000 MJ/t_{CO_2}). To meet the specified power plant capacity, the fuel firing rate had to increase as the biomass co-firing % increased, as a consequence of biomass having a lower HHV compared to coal. As a result, the flow rate of the exhaust gas leaving the boiler increased with higher biomass co-firing proportions, thereby increasing the amount of recoverable heat. Once biomass co-firing proportion reaches

Figure 5: The fraction of solvent heat requirement that can be supplied from flue gas heat recovery as a function of the solvent heat duty (HD) and biomass co-firing percentage.

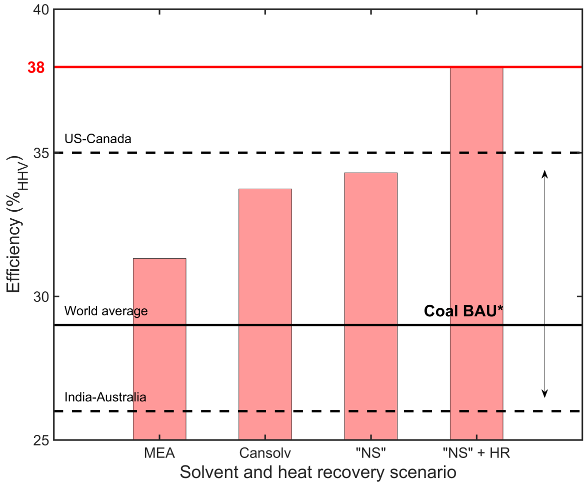


40%, heat recovery is capable of supplying all of the energy requirements in all three solvent scenarios. Therefore, flue gas heat recovery could enable operation of a BECCS plant without an efficiency penalty from CO_2 capture. However, this would be at the expense of some capital investment.

3.4. Plant efficiency

The plant efficiency for different scenarios at 50% biomass co-firing is illustrated by Figure 6. The MEA system (baseline) had an efficiency of $31\%_{\mathrm{HHV}}$. A significant increase in BECCS plant efficiency was achieved by using a more advanced CO_2 capture solvents and flue gas heat recovery. The scenario using "new solvent" and heat recovery achieved $38\%_{\mathrm{HHV}}$ efficiency, which is 8% higher than the world average of 30% (LHV, or slightly $<29\%_{\mathrm{HHV}}$) for coal-fired power plants [111]. Thus, these efficiency enhancements address the energy penalty issues caused by co-firing biomass and solvent regeneration.

Figure 6: Efficiency ($\%_{\mathrm{HHV}}$) of a 500 MW BECCS plant using different capture solvents and HR at 50% biomass co-firing, compared with average power plant efficiencies worldwide. NS = new solvent, HR = heat recovery, BAU = business as usual.



3.5. Carbon intensity

As the biomass co-firing proportion is increased, the BECCS plant becomes more carbon negative (Figure 7). Additionally, the carbon negativity of the system increased as the plant efficiency decreased. As shown in Table 4 at 50% biomass co-firing, the low efficiency MEA system captured -296 kg CO_2/MWh, whereas the 'new solvent' system with heat recovery captured -244 kg CO_2/MWh. Although counter-intuitive, the rationale is that a system with higher efficiency would burn less fuel per MWh of electricity generated, thus, less CO_2 is captured from the atmosphere. This highlights the importance of identifying an appropriate performance matrix for the evaluation of BECCS.

It is important to note that this conclusion holds as long as the CO_2 emissions associated with biomass supply chain – or biomass carbon footprint (BCF) – do not offset the amount of CO_2 removed by the power plant. There is a maximum carbon footprint value, which is a function of the biomass carbon content, co-firing proportion and capture rate, beyond which, the facility is no

Figure 7: System carbon intensity as a function of the biomass co-firing proportion %.

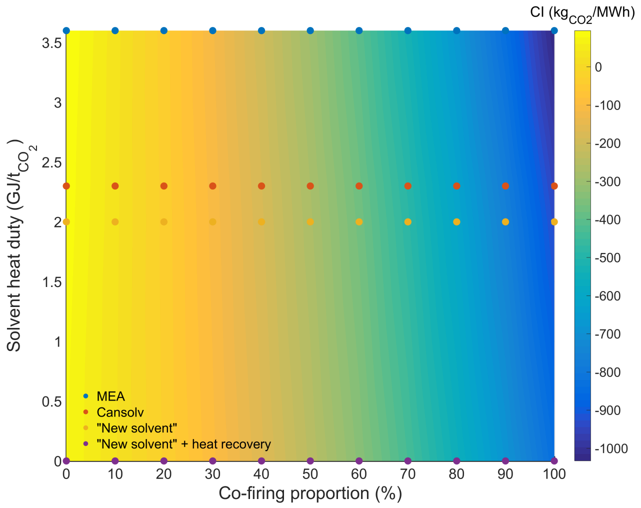


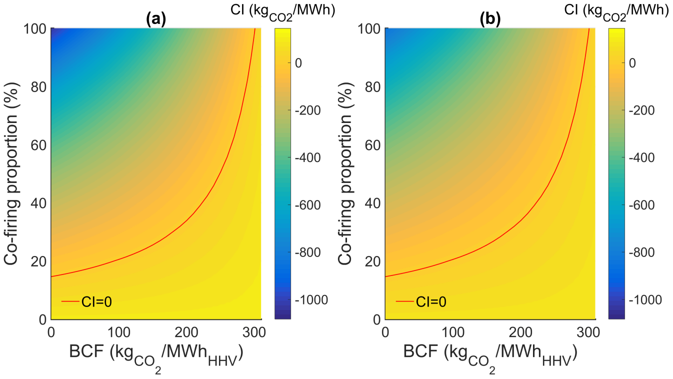
Table 4: Effect of solvent type on the carbon intensity and efficiency of a 500 MW BECCS plant co-firing 50% biomass with 90% CO_2 capture.

System	Efficiency ($\%_{\mathrm{HHV}}$)	Carbon intensity (kg CO_2/MWh)
MEA	31.3	-296
Cansolv	33.7	-275
New solvent	34.3	-271
New solvent + heat recovery	38.0	-244

longer carbon negative. In this configuration, facilities that are more efficient at converting biomass into power will emit less CO_2 than their less efficient counterparts. The effect of biomass carbon footprint in $\mathrm{kg}_{\mathrm{CO}_2}/\mathrm{MWh}_{\mathrm{HHV}}$ and co-firing proportion on the power plant carbon intensity is illustrated for wheat straw at 90% capture rate in figure 8a (low efficiency MEA process) and 8b (high efficiency new solvent process).

As can be observed in both figures, less efficient plants are slightly more carbon negative for values below the BCF upper limit, and more carbon positive

Figure 8: System carbon intensity (CI) as a function of the biomass co-firing proportion % and biomass carbon footprint (BCF), for a MEA solvent (left) and a "new solvent" (right).



for values above the BCF upper limit compared to the more efficient plants. The BCF upper limit increases with co-firing, from 93 kg_{CO_2}/MWh_{HHV} at 20% co-firing, to 301 kg_{CO_2}/MWh_{HHV} at 100% co-firing. To put this in context, bioelectricity facilities are required to report emissions 60% lower than the EU mean electricity carbon intensity, according to the UK Bioenergy strategy [112]. This translates into a limit of 285 kg_{CO_2}/MWh_e for embedded GHG emission in the biomass supply chain, or a limit of 128 kg_{CO_2}/MWh_{HHV} when assuming a maximal biomass conversion efficiency of $45\%_{HHV}$. These limits are over the BCF upper bound at 20% co-firing, which underlines the importance of considering the biomass carbon footprint during identification of BECCS performance indicators.

4. BECCS performance matrix

The results are summarised into a BECCS performance matrix in Table 5, which illustrates the effect of key properties on the plant performance. The measures for performance in a BECCS system include: (i) pollutant reduction, (ii) energy efficiency, (iii) CO_2 negativity, or (iv) a combination of these.

Table 5: Performance matrix for a BECCS system, demonstrating the relationship between process properties and performance indicators. ∗ For a power plant of a given capacity, the use of a fuel with lower HHV will require higher fuel firing rates, which will increase the flow rate of flue gas, leading to higher heat recovery.

Performance parameter	Ash content	Sulphur content	Moisture content	HHV	Biomass co-firing %	Solvent heat duty
NO_X ↓	dependent on combustion conditions, *e.g.*, temperature <1300 °C					
SO_X ↓	↑	↓	↓	–	↑	–
AFT ↑	↓	–	↓	–	↑	–
Heat recovery ↑	↓	–	↓	↓ ∗	↑	↓
Efficiency ↑	↓	–	↓	↑	↓	↓
CO_2 negativity ↑	↑	–	↑	↑	↑	↑
Exhaust gas flow rate ↑	–	–	↑	↓	↑	–

4.1. Reduction of pollutant emissions

The reduction of pollutant emissions from a power plant will be necessary for two possible reasons: (i) satisfy stringent emission regulations [43], or (ii) meet requirements of downstream processes for air pollution control [113, 114, 115]. Blending coal with biomass can be used as a means to reduce pollutant emissions of SO_X and NO_X [32], as the results from this study have demonstrated. Significant reductions to SO_X emissions can be achieved by increasing the biomass co-firing proportion (decrease in overall sulphur content). Fuel selection is another important factor; selecting coals that have low sulphur content can significantly reduce SO_X emissions. The SO_X levels ranged from 420 – 1180 ppm when high sulphur coal was co-fired with biomass, whereas the use of medium sulphur coal reduced SO_X emissions to <10 ppm (satisfying tolerance requirements of amines). Further reductions to SO_X can be achieved by utilising biomass with ash that contains alkali metal oxides (*e.g.*, CaO, MgO, Na_2O and K_2O). However, biomass ash containing silicates, chlorides and sulphates of potassium and calcium are undesirable as they increase slagging and fouling formation [42].

Although co-firing with fuels of low nitrogen content will contribute to reductions in NO_X emissions [103, 104], NO_X formation is mainly influenced by combustion conditions. To minimise NO_X emissions for each specific fuel blend, the combustion conditions require optimisation or reconfiguration of the burners. Some approaches used to reduce NO_X formation include fuel/air staging [110], or replacing N_2 gas with CO_2 (reduces NO_X formation from the N_2 in air) [41].

4.2. Improvement to power efficiency

To improve the efficiency of the BECCS systems and reduce the marginal cost of electricity generation, it is important to consider the following:

- Fuel selection for ideal combustion properties;
- High performance solvents (low heat duty and regeneration temperature);
- Heat recovery (increases with higher AFT and flue gas flow rate).

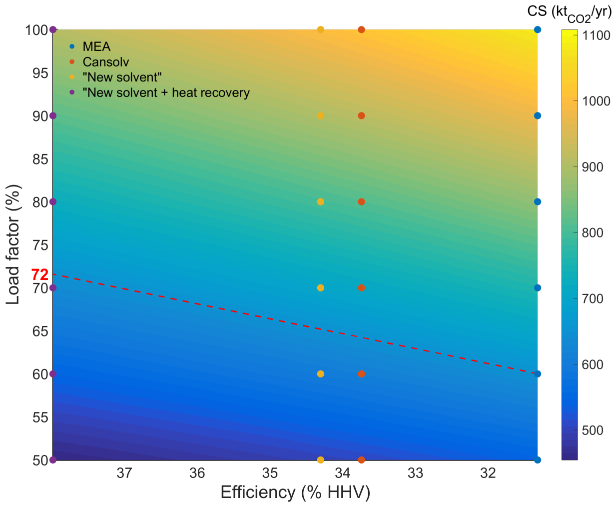
The fuel properties that would improve efficiency include higher HHV, lower moisture and ash content. For instance, selecting coals with lower ash content, whereas low moisture biomass with low tendency for ash deposition is ideal. To minimise the energy penalty from CO_2 capture, utilise a high performance solvent with low heat duty and low regeneration temperature.

Although the heat in the exhaust gas at the boiler exit is considered “waste” from the perspective of electricity generation, this is useful energy, in terms of quality and quantity, for solvent regeneration in the CO_2 capture process. The implementation of a heat recovery system would require capital investment. However, the advantage would be that heat recovery could allow BECCS to operate without the efficiency penalty associated with CO_2 capture. Thus, enhancing heat recovery conditions can indirectly improve plant efficiency. However, some factors that improve heat recovery tend to reduce efficiency. For instance, co-firing fuels with low HHV (*e.g.*, biomass) reduces plant efficiency, however, requires higher fuel firing rate and increases the flue gas flow rate, which in turn increases recoverable heat.

4.3. Enhancement of CO_2 negativity

The systems with lower efficiency will be more carbon negative (per MWh basis) as they consume more biomass fuel, which captures and permanently stores more CO_2 from the atmosphere. Consequently, enhancing the CO_2 negativity per MWh for a BECCS system would require implementing measures that reduce efficiency. This may involve co-firing biomass with low fuel quality (*e.g.*, high moisture and ash) or using the least efficient CO_2 capture system (*e.g.*, solvents with high heat duty such as MEA). The use lower quality fuels can reduce fuel costs. Also, the least efficient subcritical plants generally will have lower capital costs compared to the high efficiency supercritical or ultrasupercritical power plants [116], further cost reductions are possible by retrofitting the current fleet of power plants for BECCS, most of which use subcritical technology [117, 118]. However, it is essential to consider the impact of plant efficiency on the annual dispatch load of the system.

Figure 9: Annual negative carbon emissions (kt_{CO_2}/yr), *i.e.*, avoided CO_2 emissions, as a function of the system efficiency ($\%_{HHV}$) and load factor (%) of a BECCS system.



The load factor (annual capacity) of a power plant is a function of the plant efficiency. Systems that have higher efficiency will have lower marginal costs for electricity generation, which enables them to be economically competitive with other power generation technology. Therefore, enabling these plants to operate at higher load factors (higher annual dispatch factor) [27, 28]. Figure 9 illustrates the influence of plant efficiency and annual capacity (load factor %) on the annual avoided CO_2 emissions. The low efficiency MEA system captures 0.66 Mt_{CO_2} annually at 60% capacity. However, the high efficiency system using new solvent and heat recovery capture the same amount of CO_2 annually but will operate at a capacity factor of 72%. Thus, increasing the CO_2 negativity (*e.g.*, decreasing plant efficiency) of a BECCS plant on a MWh basis will not necessary increase the annual CO_2 mitigation potential.

5. Conclusion

BECCS has the potential provide negative emissions, whilst providing reliable firm power generation capacity. However, marginal costs are higher compared to other power generation technologies due to the energy penalty incurred from the CO_2 capture process and use of biomass fuel. This study evaluates opportunities to improve the performance of BECCS through: (i) pollutant reduction, (ii) efficiency enhancement, and (iii) CO_2 negativity.

Biomass co-firing with coal has been reported to provide significant reductions in SO_X and NO_X emissions. The thermochemical analysis demonstrates that increasing biomass co-firing proportion reduced SO_X emissions due to the decrease in fuel sulphur content. Fuel selection is also an important factor in reducing SO_X formation. For instance, co-firing low sulphur coal reduced SO_X by up to two orders of magnitude. Although some alkali metals are associated with ash deposition problems, these ash component have a role in SO_X reduction. The NO_X emissions were mainly dependent on combustion conditions, therefore, conditions may need to be calibrated to minimise NO_X formation.

Factors that enhance efficiency in a BECCS system include the use of high performance solvents (low heat duty) and using heat recovery to supply energy for solvent regeneration. The efficiency can be improved indirectly by increasing the recoverable heat from the flue gas, *e.g.*, greater AFT or higher flue gas flow rate. By using a high performance solvent with heat recovery, the BECCS system could achieve an efficiency of $38\%_{\mathrm{HHV}}$, higher than the current fleet of coal-fired power plant with efficiencies ranging from 26 – 35%.

On the other hand, to achieve greater carbon negativity (on a per MWh basis), a low efficiency system is more desirable due to increased consumption of biomass fuel, which results in more CO_2 being captured and permanently stored. Increasing the CO_2 negativity per MWh would involve using biomass with high moisture and ash content or utilising the least efficient capture solvent, *e.g.*, MEA. However, increasing CO_2 negativity on a MWh basis (*e.g.*, low efficiency) will not equate to higher CO_2 mitigation. It is important to consider the impact of efficiency on the dispatch rate of the system in the electricity market. Typically, reducing the efficiency of a power plant will decrease its annual capacity factor, lowering its dispatch rate in comparison to the high efficiency systems.

The major barrier for commercial deployment of BECCS is the lack of economic and political drivers, rather than technical (assuming fossil-fuel CCS is now a proven technology) [26]. The potential role of BECCS in the electricity grid is unique as it will provide reliable firm capacity, whilst also providing a means to decarbonise the electricity sector [16, 17]. To enhance the economic viability and encourage deployment of BECCS plant with higher CO_2 negativity, financial incentives for electricity generation with negative CO_2 emissions would be necessary. To improve the commercial potential of BECCS, there is a need to develop sustainable biomass supply chains and establish suitable CO_2 sequestration sites [26].

6. Acknowledgements

The authors would like to acknowledge funding from the EPSRC under grants EP/M001369/1 (MESMERISE-CCS), EP/M015351/1 (Opening New Fuels for UK Generation) and EP/N024567/1 (CCSInSupply). Mathilde Fajardy thanks Imperial College London for funding a PhD scholarship.

References

[1] IPCC, Climate Change 2014: Mitigation of Climate Change. Working Group III Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change., Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 2014.

[2] COP21, The 2015 United Nations Climate Change Conference, 30 November to 12 December 2015, http://www.cop21.gouv.fr/en/.

[3] R. H. Williams, Fuel Decarbonization for Fuel Cell Applications and Sequestration of the Separated CO_2 CEES Report 295, Tech. rep., Center for Energy and Environmental Studies, Princeton University (1996).

[4] H. J. Herzog, E. M. Drake, Carbon dioxide recovery and disposal from large energy systems, Annual Review of Energy and the Environment 21 (1996) 145–166.

[5] F. Kraxner, S. Nilsson, M. Obersteiner, Negative emissions from BioEnergy use, carbon capture and sequestration (BECS)–the case of biomass production by sustainable forest management from semi-natural temperate forests, Biomass and Bioenergy 24 (4–5) (2003) 285–296.

[6] S. Fuss, J. G. Canadell, G. P. Peters, M. Tavoni, R. M. Andrew, P. Ciais, R. B. Jackson, C. D. Jones, F. Kraxner, N. Nakicenovic, C. Le Quere, M. R. Raupach, A. Sharifi, P. Smith, Y. Yamagata, Betting on negative emissions, Nature Climate Change 4 (10) (2014) 850–853.

[7] K. Möllersten, J. Yan, J. R. Moreira, Potential market niches for biomass energy with CO_2 capture and storage – Opportunities for energy supply with negative CO_2 emissions, Biomass and Bioenergy 25 (3) (2003) 273–285.

[8] K. Möllersten, L. Gao, J. Yan, M. Obersteiner, Efficient energy systems with CO_2 capture and storage from renewable biomass in pulp and paper mills, Renewable Energy 29 (9) (2004) 1583–1598.

[9] J. S. Rhodes, D. W. Keith, Engineering economic analysis of biomass IGCC with carbon capture and storage, Biomass and Bioenergy 29 (6) (2005) 440–450.

[10] C. Azar, K. Lindgren, M. Obersteiner, K. Riahi, D. P. van Vuuren, K. M. G. J. den Elzen, K. Möllersten, E. D. Larson, The feasibility of low CO_2 concentration targets and the role of bio-energy with carbon capture and storage (BECCS), Climatic Change 100 (1) (2010) 195–202.

[11] M. Fajardy, N. Mac Dowell, Can BECCS deliver sustainable and resource efficient negative emissions?, Energy and Environmental Science (2017) in press.

[12] N. Mac Dowell, M. Fajardy, Inefficient power generation as an optimal route to negative emissions via BECCS?, Environmental Research Letters (2017) in press.

[13] D. Loeffler, N. Anderson, Emissions tradeoffs associated with cofiring forest biomass with coal: A case study in Colorado, USA, Applied Energy 113 (2014) 67–77.

[14] H. Spliethoff, K. R. G. Hein, Effect of co-combustion of biomass on emissions in pulverized fuel furnaces, Fuel Processing Technology 54 (1–3) (1998) 189–205.

[15] H. Spliethoff, W. Scheurer, K. R. G. Hein, Effect of co-combustion of sewage sludge and biomass on emissions and heavy metals behaviour, Process Safety and Environmental Protection 78 (1) (2000) 33–39.

[16] A. Boston, H. K. Thomas, Managing flexibility whilst decarbonising the GB electricity system, Tech. rep., http://erpuk.org/project/managing-flexibility-of-the-electricity-sytem/ (2015).

[17] C. F. Heuberger, I. Staffell, N. Shah, N. Mac Dowell, Quantifying the value of CCS for the future electricity system, Energy & Environmental Science 9 (8) (2016) 2497–2510.

[18] S. V. Vassilev, C. G. Vassileva, V. S. Vassilev, Advantages and disadvantages of composition and properties of biomass in comparison with coal: An overview, Fuel 158 (2015) 330–350.

[19] M. Pronobis, Evaluation of the influence of biomass co-combustion on boiler furnace slagging by means of fusibility correlations, Biomass and Bioenergy 28 (4) (2005) 375–383.

[20] T. Heinzel, V. Siegle, H. Spliethoff, K. R. G. Hein, Investigation of slagging in pulverized fuel co-combustion of biomass and coal at a pilot-scale test facility, Fuel Processing Technology 54 (1998) 109–125.

[21] S. B. Hansen, P. A. Jensen, F. J. Frandsen, H. Wu, M. S. Bashir, J. WadenbÃď ck, B. Sander, P. Glarborg, Deposit probe measurements in large biomass-fired grate boilers and pulverized-fuel boilers, Energy & Fuels 28 (6) (2014) 3539–3555.

[22] M. Pronobis, The influence of biomass co-combustion on boiler fouling and efficiency, Fuel 85 (4) (2006) 474–480.

[23] L. L. Sloss, Emission from cofiring coal, biomass and sewage sludge, CCC/175, IEA Clean Coal Centre, London, United Kingdom, 2010.

[24] S. Fogarasi, C.-C. Cormos, Assessment of coal and sawdust co-firing power generation under oxy-combustion conditions with carbon capture and storage, Journal of Cleaner Production 142, Part 4 (2017) 3527–3535.

[25] K. Goto, K. Yogo, T. Higashii, A review of efficiency penalty in a coal-fired power plant with post-combustion CO_2 capture, Applied Energy 111 (2013) 710–720.

[26] A. Bhave, R. H. S. Taylor, P. Fennell, W. R. Livingston, N. Shah, N. Mac Dowell, J. Dennis, M. Kraft, M. Pourkashanian, M. Insa, J. Jones, N. Burdett, A. Bauen, C. Beal, A. Smallbone, J. Akroyd, Screening and techno-economic assessment of biomass-based power generation with CCS technologies to meet 2050 CO_2 targets, Applied Energy 190 (2017) 481–489.

[27] N. Mac Dowell, N. Shah, The multi-period optimisation of an amine-based CO_2 capture process integrated with a super-critical coal-fired power station for flexible operation, Computers & Chemical Engineering 74 (2015) 169–183.

[28] N. Mac Dowell, I. Staffell, The role of flexible CCS in the UK's future energy system, International Journal of Greenhouse Gas Control 48, Part 2 (Flexible operation of carbon capture plants) (2016) 327–344.

[29] A. M. Carpenter, Coal blending for power stations, IEACR/81, IEA Coal Research, London, United Kingdom, 1995.

[30] A. M. Carpenter, Switching to cheaper coals for power generation, CCC/01, IEA Coal Research, London, United Kingdom, 1998.

[31] L. L. Sloss, Blending of coals to meet power station requirements, CCC/238, IEA Clean Coal Centre, London, United Kingdom, 2014.

[32] J. Dai, S. Sokhansanj, J. R. Grace, X. Bi, C. J. Lim, S. Melin, Overview and some issues related to co-firing biomass and coal, The Canadian Journal of Chemical Engineering 86 (3) (2008) 367–386.

[33] R. Fernando, Fuels for biomass cofiring, CCC/102, IEA Clean Coal Centre, London, United Kingdom, 2005.

[34] R. Fernando, Cofiring of coal with waste fuels, CCC/126, IEA Clean Coal Centre, London, United Kingdom, 2007.

[35] R. Fernando, Cofiring high ratios of biomass with coal, CCC/194, IEA Clean Coal Centre, London, United Kingdom, 2012.

[36] S. van Loo, J. Koppejan, The Handbook of Biomass Combustion and Co-ïňĄring, Earthscan, London, United Kingdom, 2008.

[37] A. A. Bhuiyan, A. S. Blicblau, A. K. M. S. Islam, J. Naser, A review on thermo-chemical characteristics of coal/biomass co-firing in industrial furnace, Journal of the Energy Institute.

[38] A. Demirbaş, Potential applications of renewable energy sources, biomass combustion problems in boiler power systems and combustion related environmental issues, Progress in Energy and Combustion Science 31 (2) (2005) 171–192.

[39] W. L. Van De Kamp, D. J. Morgan, The co-firing of pulverised bituminous coals with straw, waste paper and municipal sewage sludge, Combustion Science and Technology 121 (1–6) (1996) 317–332.

[40] L. Cheng, X. P. Ye, B. C. English, D. Boylan, T. Johnson, B. Zemo, Co-firing switchgrass in a 60-megawatt pulverized coal-fired boiler: Effects on combustion behavior and pollutant emissions, Energy Sources, Part A: Recovery, Utilization, and Environmental Effects 38 (3) (2016) 322–329.

[41] E. Rokni, A. Panahi, X. Ren, Y. A. Levendis, Curtailing the generation of sulfur dioxide and nitrogen oxide emissions by blending and oxy-combustion of coals, Fuel 181 (2016) 772–784.

[42] B. N. Madanayake, S. Gan, C. Eastwick, H. K. Ng, Biomass as an energy source in coal co-firing and its feasibility enhancement via pre-treatment techniques, Fuel Processing Technology 159 (2017) 287–305.

[43] I. Barnes, Understanding pulverized coal, biomass and waste combustion, CCC/205, IEA Clean Coal Centre, London, United Kingdom, 2012.

[44] J. S. Tumuluru, J. R. Hess, R. D. Boardman, C. T. Wright, T. L. Westover, Formulation, pretreatment, and densification options to improve biomass specifications for co-Firing high percentages with coal, Industrial Biotechnology 8 (3) (2012) 113–132.

[45] T. Filbakk, G. Skjevrak, O. Høibø, J. Dibdiakova, R. Jirjis, The influence of storage and drying methods for Scots pine raw material on mechanical pellet properties and production parameters, Fuel Processing Technology 92 (5) (2011) 871–878.

[46] P. Purohit, A. K. Tripathi, T. C. Kandpal, Energetics of coal substitution by briquettes of agricultural residues, Energy 31 (8–9) (2006) 1321–1331.

[47] J. S. Tumuluru, C. T. Wright, J. R. Hess, K. L. Kenney, A review of biomass densification systems to develop uniform feedstock commodities for bioenergy application, Biofuels, Bioproducts and Biorefining 5 (6) (2011) 683–707.

[48] F. R. Kargbo, J. Xing, Y. Zhang, Pretreatment for energy use of rice straw: A review, African Journal of Agricultural Research 4 (11) (2009) 1560–1565.

[49] P. C. A. Bergman, A. R. Boersma, R. W. R. Zwart, J. H. A. Kiel, Torrefaction for biomass co-firing in existing coal-fired power stations, Tech. Rep. July, Energy research Centre of the Netherlands ECN (2005). `doi:ECN-C--05-013`.
URL `http://www.ecn.nl/publications/PdfFetch.aspx?nr=ECN-C--05-013`

[50] A. Uslu, A. P. C. Faaij, P. C. A. Bergman, Pre-treatment technologies, and their effect on international bioenergy supply chain logistics. Techno-economic evaluation of torrefaction, fast pyrolysis and pelletisation, Energy 33 (8) (2008) 1206–1223. `doi:10.1016/j.energy.2008.03.007`.

[51] W. Yan, T. C. Acharjee, C. J. Coronella, V. R. Vásquez, Thermal pretreatment of lignocellulosic biomass, Environmental Progress & Sustainable Energy 28 (3) (2009) 435–440.

[52] H. Shahrukh, A. O. Oyedun, A. Kumar, B. Ghiasi, L. Kumar, S. Sokhansanj, Comparative net energy ratio analysis of pellet produced from steam pretreated biomass from agricultural residues and energy crops, Biomass and Bioenergy 90 (2016) 50–59. `doi:10.1016/j.biombioe.2016.03.022`.
URL `http://dx.doi.org/10.1016/j.biombioe.2016.03.022`

[53] W. R. Livingston, J. Middelkamp, W. Willeboer, S. Tosney, B. Sander, S. Madrali, M. Hansen, The status of large scale biomass firing: The milling and combustion of biomass materials in large pulverised coal boilers, Tech. rep., IEA Bionergy (2016).
URL `http://www.ieabcc.nl/publications/IEA{_}Bioenergy{_}T32{_}cofiring{_}2016.pdf`

[54] L. M. Romeo, S. Espatolero, I. Bolea, Designing a supercritical steam cycle to integrate the energy requirements of CO_2 amine scrubbing, International Journal of Greenhouse Gas Control 2 (4) (2008) 563–570.

[55] M. Lucquiaud, J. Gibbins, On the integration of CO_2 capture with coal-fired power plants: A methodology to assess and optimise solvent-based post-combustion capture systems, Chemical Engineering Research and Design 89 (9) (2011) 1553–1571.

[56] E. Sanchez Fernandez, M. Sanchez del Rio, H. Chalmers, P. Khakharia, E. L. V. Goetheer, J. Gibbins, M. Lucquiaud, Operational flexibility options in power plants with integrated post-combustion capture, International Journal of Greenhouse Gas Control 48, Part 2 (Flexible operation of carbon capture plants) (2016) 275–289.

[57] N. Y. Nsakala, J. Marion, C. Bozzuto, G. Liljedahl, M. Palkes, D. Vogel, M. Guha, H. Johnson, S. Plasynski, Engineering feasibility of CO_2 capture on an existing US coal-fired power plant, in: First National Conference on Carbon Sequestration, U.S. Department of Energy (DOE), National Energy Technology Laboratory, 2001.

[58] M. Lucquiaud, J. Gibbins, Effective retrofitting of post-combustion CO_2 capture to coal-fired power plants and insensitivity of CO_2 abatement costs to base plant efficiency, International Journal of Greenhouse Gas Control 5 (3) (2011) 427–438.

[59] N. Ceccarelli, M. van Leeuwen, T. Wolf, P. van Leeuwen, R. van der Vaart, W. Maas, A. Ramos, Flexibility of low-CO_2 gas power plants: Integration of the CO_2 capture unit with CCGT operation, in: 12th International Conference on Greenhouse Gas Control Technologies (GHGT-12), Vol. 63, Energy Procedia, pp. 1703–1726.

[60] M. Thern, K. Jordal, M. Genrup, Temporary CO_2 capture shut down: Implications on low pressure steam turbine design and efficiency, in: 7th

Trondheim Conference on CO_2 capture, Transport and Storage, Vol. 51, Energy Procedia, 2014, pp. 14–23.

[61] M. Lucquiaud, E. S. Fernandez, H. Chalmers, N. Mac Dowell, J. Gibbins, Enhanced operating flexibility and optimised off-design operation of coal plants with post-combustion capture, in: 12th International Conference on Greenhouse Gas Control Technologies (GHGT-12), Vol. 63, Energy Procedia, 2014, pp. 7494–7507.

[62] T. Sanpasertparnich, R. Idem, I. Bolea, D. deMontigny, P. Tontiwachwuthikul, Integration of post-combustion capture and storage into a pulverized coal-fired power plant, International Journal of Greenhouse Gas Control 4 (3) (2010) 499–510.

[63] M. Lucquiaud, J. Gibbins, Steam cycle options for the retrofit of coal and gas power plants with postcombustion capture, in: 10th International Conference on Greenhouse Gas Control Technologies (GHGT-10), Vol. 4, Energy Procedia, 2011, pp. 1812–1819.

[64] M. Karimi, M. Hillestad, H. F. Svendsen, Capital costs and energy considerations of different alternative stripper configurations for post combustion CO_2 capture, Chemical Engineering Research and Design 89 (8) (2011) 1229–1236.

[65] D. H. Van Wagener, G. T. Rochelle, Stripper configurations for CO_2 capture by aqueous monoethanolamine and piperazine, Energy Procedia 4 (2011) 1323–1330.

[66] L. E. Øi, T. Bråthen, C. Berg, S. K. Brekne, M. Flatin, R. Johnsen, I. G. Moen, E. Thomassen, Optimization of configurations for amine based CO_2 absorption using Aspen HYSYS, in: 7th Trondheim Conference on CO_2 capture, Transport and Storage (2013), Vol. 51, Energy Procedia, 2014, pp. 224–233.

[67] Y. Zhang, B. Freeman, P. Hao, G. T. Rochelle, Absorber modeling for ngcc carbon capture with aqueous piperazine, Faraday Discussions 192 (0) (2016) 459–477.

[68] Z. Amrollahi, P. A. M. Ystad, I. S. Ertesvåg, O. Bolland, Optimized process configurations of post-combustion CO_2 capture for natural-gas-fired power plant–Power plant efficiency analysis, International Journal of Greenhouse Gas Control 8 (2012) 1–11.

[69] Y. Le Moullec, M. Kanniche, Screening of flowsheet modifications for an efficient monoethanolamine (MEA) based post-combustion CO_2 capture, International Journal of Greenhouse Gas Control 5 (4) (2011) 727–740.

[70] H. Ahn, M. Luberti, Z. Liu, S. Brandani, Process configuration studies of the amine capture process for coal-fired power plants, International Journal of Greenhouse Gas Control 16 (2013) 29–40.

[71] A. Cousins, L. T. Wardhaugh, P. H. M. Feron, Preliminary analysis of process flow sheet modifications for energy efficient CO_2 capture from flue gases using chemical absorption, Chemical Engineering Research and Design 89 (8) (2011) 1237–1251.

[72] A. Cousins, L. T. Wardhaugh, P. H. M. Feron, A survey of process flow sheet modifications for energy efficient CO_2 capture from flue gases using chemical absorption, International Journal of Greenhouse Gas Control 5 (4) (2011) 605–619.

[73] N. Mac Dowell, N. Shah, Dynamic modelling and analysis of a coal-fired power plant integrated with a novel split-flow configuration post-combustion CO_2 capture process, International Journal of Greenhouse Gas Control 27 (2014) 103–119.

[74] I. Pfaff, J. Oexmann, A. Kather, Optimised integration of post-combustion CO_2 capture process in greenfield power plants, Energy 35 (10) (2010) 4030–4041.

[75] IEAGHG, CO_2 capture in low rank coal power plants, Technical Study 2006/1, IEA Greenhouse Gas R&D Programme (IEA GHG), Cheltenham, United Kingdom, 2006.

[76] D. Wang, A. Bao, W. Kunc, W. Liss, Coal power plant flue gas waste heat and water recovery, Applied Energy 91 (1) (2012) 341–348.

[77] X. Wang, Z. Hu, S. Deng, Y. Xiong, H. Tan, Effect of biomass/coal co-firing and air staging on NO_X emission and combustion efficiency in a drop tube furnace, in: J. Yan, D. J. Lee, S. K. Chou, U. Desideri, H. Li (Eds.), International Conference on Applied Energy (ICAE2014), Vol. 61, Energy Procedia, 2014, pp. 2331–2334.

[78] G. Xu, S. Huang, Y. Yang, Y. Wu, K. Zhang, C. Xu, Techno-economic analysis and optimization of the heat recovery of utility boiler flue gas, Applied Energy 112 (2013) 907–917.

[79] G. Xu, C. Xu, Y. Yang, Y. Fang, Y. Li, X. Song, A novel flue gas waste heat recovery system for coal-fired ultra-supercritical power plants, Applied Thermal Engineering 67 (1–2) (2014) 240–249.

[80] T. Harkin, A. Hoadley, B. Hooper, Process integration analysis of a brown coal-fired power station with CO_2 capture and storage and lignite drying, Energy Procedia 1 (1) (2009) 3817–3825.

[81] T. Harkin, A. Hoadley, B. Hooper, Reducing the energy penalty of CO_2 capture and compression using pinch analysis, Journal of Cleaner Production 18 (9) (2010) 857–866.

[82] N. Mac Dowell, M. Fajardy, On the potential for BECCS efficiency improvement through heat recovery from both post-combustion and oxy-combustion facilities, Faraday Discussions 192 (0) (2016) 241–250.

[83] M. Bui, M. Fajardy, N. Mac Dowell, Bio-Energy with CCS (BECCS) performance evaluation: Efficiency enhancement and emissions reduction, Applied Energy 195 (2017) 289–302.

[84] M. Bui, M. Fajardy, N. Mac Dowell, Thermodynamic evaluation of carbon negative power generation: Bio-energy CCS (BECCS), Energy Procedia.

[85] S. Basu, A. K. Debnath, Chapter IV General Instruments: Temperature Measurement - Various Measuring Points and Range Selection, Academic Press (imprint of Elsevier Ltd.), London, UK, 2015, pp. Pages 241–244.

[86] M. Campbell, Technology innovation & advancements for Shell Cansolv CO_2 capture solvents, in: 12th International Conference on Greenhouse Gas Control Technologies (GHGT-12), Vol. 63, Energy Procedia, pp. 801–807.

[87] A. Singh, K. Stéphenne, Shell Cansolv CO_2 capture technology: Achievement from First Commercial Plant, in: 12th International Conference on Greenhouse Gas Control Technologies (GHGT-12), Vol. 63, Energy Procedia, pp. 1678–1685.

[88] G. Rochelle, E. Chen, S. Freeman, D. Van Wagener, Q. Xu, A. Voice, Aqueous piperazine as the new standard for CO_2 capture technology, Chemical Engineering Journal 171 (3) (2011) 725–733.

[89] L. Westerlund, R. Hermansson, J. Fagerström, Flue gas purification and heat recovery: A biomass fired boiler supplied with an open absorption system, Applied Energy 96 (2012) 444–450.

[90] M. B. Berkenpas, J. J. Fry, K. Kietzke, E. S. Rubin, Integrated Environmental Control Model Getting Started, Tech. Rep. April, Center for Energy and Environmental Studies, Carnegie Mellon University (2001).

[91] IEAGHG, CO_2 Capture at Coal Based Power and Hydrogen Plants, Report, International Energy Agency Greenhouse Gas R&D Programme (IEAGHG) (2014).

[92] S. V. Vassilev, D. Baxter, L. K. Andersen, C. G. Vassileva, An overview of the chemical composition of biomass, Fuel 89 (5) (2010) 913–933.

[93] Q. Ye, X. Wang, Y. Lu, Screening and evaluation of novel biphasic solvents for energy-efficient post-combustion CO_2 capture, International Journal of Greenhouse Gas Control 39 (2015) 205–214.

[94] L. Raynal, P. Alix, P.-A. Bouillon, A. Gomez, M. l. F. de Nailly, M. Jacquin, J. Kittel, A. di Lella, P. Mougin, J. Trapy, The DMX^{TM} process: An original solution for lowering the cost of post-combustion carbon capture, Energy Procedia 4 (2011) 779–786.

[95] P. Markewitz, W. Kuckshinrichs, W. Leitner, J. Linssen, P. Zapp, R. Bongartz, A. Schreiber, T. E. Muller, Worldwide innovations in the development of carbon capture technologies and the utilization of CO_2, Energy & Environmental Science 5 (6) (2012) 7281–7305.

[96] C. W. Bale, P. Chartrand, S. A. Degterov, G. Eriksson, K. Hack, R. Ben Mahfoud, J. Melançon, A. D. Pelton, S. Petersen, FactSage thermochemical software and databases, Calphad 26 (2) (2002) 189–228.

[97] C. W. Bale, E. Bélisle, P. Chartrand, S. A. Decterov, G. Eriksson, K. Hack, I. H. Jung, Y. B. Kang, J. Melançon, A. D. Pelton, C. Robelin, S. Petersen, FactSage thermochemical software and databases – recent developments, Calphad 33 (2) (2009) 295–311.

[98] W. L. Luyben, Heat exchanger simulations involving phase changes, Computers and Chemical Engineering 67 (2014) 133–136.

[99] M. Sami, K. Annamalai, M. Wooldridge, Co-firing of coal and biomass fuel blends, Progress in Energy and Combustion Science 27 (2) (2001) 171–214.

[100] P. Marier, H. P. Dibbs, The catalytic conversion of SO_2 to SO_3 by fly ash and the capture of SO_2 and SO_3 by CaO and MgO, Thermochimica Acta 8 (1) (1974) 155–165.

[101] V. R. Gray, Retention of sulphur by laboratory-prepared ash from low-rank coal, Fuel 65 (11) (1986) 1618–1619.

[102] J. V. Ibarra, J. M. Palacios, A. M. de Andrés, Analysis of coal and char ashes and their ability for sulphur retention, Fuel 68 (7) (1989) 861–867.

[103] M. M. Roy, K. W. Corscadden, An experimental study of combustion and emissions of biomass briquettes in a domestic wood stove, Applied Energy 99 (2012) 206–212.

[104] M. M. Roy, A. Dutta, K. Corscadden, An experimental study of combustion and emissions of biomass pellets in a prototype pellet furnace, Applied Energy 108 (2013) 298–307.

[105] T. Nussbaumer, Combustion and co-combustion of biomass: Fundamentals, technologies, and primary measures for emission reduction, Energy & Fuels 17 (6) (2003) 1510–1521.

[106] A. Gani, K. Morishita, K. Nishikawa, I. Naruse, Characteristics of co-combustion of low-rank coal with biomass, Energy & Fuels 19 (4) (2005) 1652–1659.

[107] H. Rüdiger, A. Kicherer, U. Greul, H. Spliethoff, K. R. G. Hein, Investigations in combined combustion of biomass and coal in power plant technology, Energy & Fuels 10 (3) (1996) 789–796.

[108] Y. Hu, S. Naito, N. Kobayashi, M. Hasatani, CO_2, NO_X and SO_2 emissions from the combustion of coal with high oxygen concentration gases, Fuel 79 (15) (2000) 1925–1932.

[109] EPA, Technical bulletin: Nitrogen oxides (NO_X), why and how they are controlled, Tech. rep., North Carolina, US (1999).

[110] I. Obernberger, T. Brunner, G. Bärnthaler, Chemical properties of solid biofuels–significance and impact, Biomass and Bioenergy 30 (11) (2006) 973–982.

[111] IEA, OECD, Power Generation from Coal: Measuring and Reporting Efficiency Performance and CO_2 Emissions, Tech. rep. (2010).

[112] DECC, UK Bioenergy Strategy, Tech. Rep. April, DECC (2012).
URL `https://www.gov.uk/government/uploads/system/uploads/attachment{_}data/file/48337/5142-bioenergy-strategy-.pdf`

[113] D. Adams, Flue gas treatment for CO_2 capture, CCC/169, IEA Clean Coal Centre, London, United Kingdom, 2010.

[114] M. Azzi, S. Day, D. French, B. Halliburton, A. Element, O. Farrell, P. Feron, Impact of flue gas impurities on amine-based PCC plants – Final Report, Australian National Low Emissions Coal Research and Development (ANLEC R&D), CSIRO, Australia, 2013.

[115] L. Linde, Implementation of beccs in a polygeneration system—a techno-economic feasibility study in the district heating network of stockholm, Thesis (2016).

[116] J. Turner, Lean and clean: why modern coal-fired power plants are better by design, Power Technology, http://www.power-technology.com/features/featurelean-and-clean-why-modern-coal-fired-power-plants-are-better-by-design-4892873/, 2016.

[117] D. Probasco, B. Ruhlman, Coal-fired generation cost and performance trends, Power Magazine, http://www.powermag.com/coal-fired-generation-cost-and-performance-trends/, 2011.

[118] X. Tan, Supercritical and ultrasupercritical coal-fired power generation, Journal of the Washington Institute of China Studies 6 (1) (2012) 53–72.