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# A Techno-economic assessment of the reduction of carbon dioxide emissions through the use of biomass co-combustion ☆

D.R. McIlveen-Wright [a,*], Y. Huang [a], S. Rezvani [a], J.D. Mondol [a], D. Redpath [a], M. Anderson [a], N.J. Hewitt [a], B.C. Williams [b]

[a] School of the Built Environment, University of Ulster, Jordanstown, Newtownabbey BT37 0QB, UK
[b] Biomass CHP Ltd., Blackwater Museum, N. Ireland, UK

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ABSTRACT

Using sustainably-grown biomass as the sole fuel, or co-fired with coal, is an effective way of reducing the net $CO_2$ emissions from a combustion power plant. There may be a reduction in efficiency from the use of biomass, mainly as a result of its relatively high moisture content, and the system economics may also be adversely affected.

The economic cost of reducing $CO_2$ emissions through the replacement of coal with biomass can be identified by analysing the system when fuelled solely by biomass, solely by coal and when a coal-biomass mixture is used.

The technical feasibility of burning biomass or certain wastes with pulverised coal in utility boilers has been well established. Cofiring had also been found to have little effect on efficiency or flame stability, and pilot plant studies had shown that cofiring could reduce $NO_x$ and $SO_x$ emissions.

Several technologies could be applied to the co-combustion of biomass or waste and coal. The assessment studies here examine the potential for co-combustion of (a) a 600 MWe pulverised fuel (PF) power plant, (i) cofiring coal with straw and sewage sludge and (ii) using straw derived fuel gas as return fuel; (b) a 350 MWe pressurised fluidised bed combustion (PFBC) system cofiring coal with sewage sludge; (c) 250 and 125 MWe circulating fluidised bed combustion (CFBC) plants cofiring coal with straw and sewage sludge; (d) 25 MWe CFBC systems cofiring low and high sulphur content coal with straw, wood and woody matter pressed from olive stones (WPOS); and (e) 12 MWe CFBC cofiring low and high sulphur content coal with straw.

The technical, environmental and economic analysis of such technologies, using the ECLIPSE suite of process simulation software, is the subject of this study. System efficiencies for generating electricity are evaluated and compared for the different technologies and system scales. The capital costs of systems are estimated for coal-firing and also any additional costs introduced when biomass is used. The Break-even electricity selling price is calculated for each technology, taking into account the system scale and fuel used.

Since net $CO_2$ emissions are reduced when biomass is used, the effect of the use of biomass on the electricity selling price can be found and the premium required for emissions reduction assessed. Consideration is also given to the level of subvention required, either as a Carbon dioxide Credit or as a Renewable Credit, to make the systems using biomass competitive with those fuelled only with coal.

It would appear that a Renewable Credit (RC) is a more transparent and cost-effective mechanism to support the use of biomass in such power plants than a Carbon dioxide Credit (CC).



## 1. Introduction

The most effective means of reducing net $CO_2$ emissions from coal-based power plants and among the most efficient and inexpensive uses of biomass are two complementary features of cofiring biomass with coal [1].

The demand for electricity is growing steadily throughout the developed world and dramatically in the less developed countries and fossil fuels will continue to play a major role in power generation. Renewable energy sources, such as biomass or wastes, offer an attractive method of reducing greenhouse gas emissions, if they replace part or all of the fossil fuels in a power plant, and would probably be the best (cheapest and lowest risk) method for electricity generators to implement renewable energy [2], [3]. For some time the co-combustion of coal and biomass has received widespread interest as a means of conserving coal reserves and

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* Corresponding author. Tel.: +44 028 90366808.
*E-mail address:* dr.mcilveen-wright@ulster.ac.uk (D.R. McIlveen-Wright).

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reducing net $CO_2$ emissions, as reported by Hein and Bemtgen [4] and Sami et al. [5], in addition to the drive to use renewable resources, several other environmental advantages have been reported e.g. cofiring high-sulphur bituminous coal with 20% straw gave a net reduction in NO and $SO_2$ emissions [6]. In the EU27 Member states it has been calculated that cofiring could make up 20–35% of the estimated gap between current electricity generation from renewables and the 2010 target [7].

It is clear that there are good technical and environmental reasons for cofiring biomass with coal, but widespread implementation will depend on favourable economic factors. There have already been some attempts at examining the economics of cofiring. For example, a techno-economic analysis of the retro-fitting of coal boilers for cofiring with biomass, based on pilot plant results, has been carried out and the additional specific costs per unit of electricity generated and Mton of $CO_2$ emissions reduction calculated [8].

In the present paper computer simulations of a range of power plant systems were carried out and the key features are reported and compared. Details of these technologies and their technical and environmental analyses have been reported elsewhere [9], and the economic factors of the systems are examined here. In general the systems using coal solely as their fuel generate electricity more cheaply than those using biomass, or cofiring with biomass. However there are potential incentives for promoting the use of renewable energy and/or reducing carbon dioxide emissions.

Several different mechanisms for supporting renewables have been proposed, tried and often changed over time. Because of the uncertainty in energy policy concerning whether a national feed-in tariff or a tradable green certificate scheme is the more effective support mechanism for renewable energy [10], [11], [12], [13], no particular type of support is used in this paper, rather a generic support mechanism for renewables is employed. Similarly, no specific model for avoided carbon dioxide emissions has been chosen.

What has been done is to assess how much of a Renewable Credit or Carbon Credit would be necessary, regardless of the mechanism, to make each of the analysed systems competitive with large scale PF coal-fired power plants, in terms of their BESP (Break-even electricity selling price), as well as some of the smaller power generation plants.

## 2. Method and scope of assessment

The process simulation package, ECLIPSE [14], was used to perform techno-economic assessment studies of each technology using, initially, coal as the fuel. ECLIPSE has been successfully used to analyse a wide range of power generation systems using biomass, such as wood combustion plants [15] and fuel cells integrated with biomass gasification [16].

## 3. Technologies assessed

A variety of power generation technologies, a range of sizes of power plant and a number of blends of coals/biomasses/wastes as feedstocks were considered. The power generation technologies studied were pulverised fuel firing (PF), pressurised fluidised bed combustion (PFBC) and atmospheric pressure circulating fluidised bed combustion (CFBC). The power plant sizes ranged from 600 MWe for the PF plants, to 12 MWe for the smallest of the CFBC plants. A low and a high sulphur bituminous coal was used blended with straw, wood, the woody matter from pressed olive stones (WPOS) and sewage sludge. A technical and environmental assessment of the systems examined here has already been published elsewhere [17].

The analysis of these feedstocks is given in Table 1. *Federal* coal was taken as the standard coal in these studies. It has a relatively high sulphur content, so limestone was considered to be necessary as an absorbent for capturing 95% of the sulphur. For some of the studies a low-sulphur coal (*Bellambi*) was also assessed.

Fuel moisture contents are shown in Fig. 1.

In the 1990s coal prices remained relatively steady, but, as with other fuels, they have varied considerably since around 2004. (See Fig. 2).

**Table 1**
Analysis of Feedstocks Used.

| Feedstock | Federal coal | Bellambi coal | Wheat straw | Wood | WPOS | Sewage sludge |
|---|---|---|---|---|---|---|
| Water (% ar) | 6.30 | 6.00 | 14.2 | 33.3 | 13.5 | 4.0 |
| Ash (% db) | 6.62 | 13.83 | 4.55 | 0.9 | 10.0 | 21.88 |
| HHV (MJ/kg daf) | 35.64 | 36.18 | 19.90 | 18.73 | 20.89 | 22.94 |
| LHV (MJ/kg daf) | 34.25 | 35.00 | 18.20 | 17.37 | 19.77 | 21.13 |
| *Ultimate analysis (% daf)* | | | | | | |
| Carbon | 84.0 | 87.6 | 48.84 | 51.0 | 52.06 | 53.92 |
| Hydrogen | 5.70 | 4.70 | 7.08 | 6.0 | 6.04 | 7.85 |
| Nitrogen | 1.50 | 1.90 | 1.28 | 0.1 | 3.59 | 5.06 |
| Sulphur | 2.60 | 0.80 | 0.16 | <0.1 | 0.64 | 0.89 |
| Chlorine | 0.14 | 0.01 | 0.28 | 0 | 0 | 0.38 |
| Oxygen | 6.06 | 4.99 | 42.36 | 42.9 | 37.67 | 31.90 |

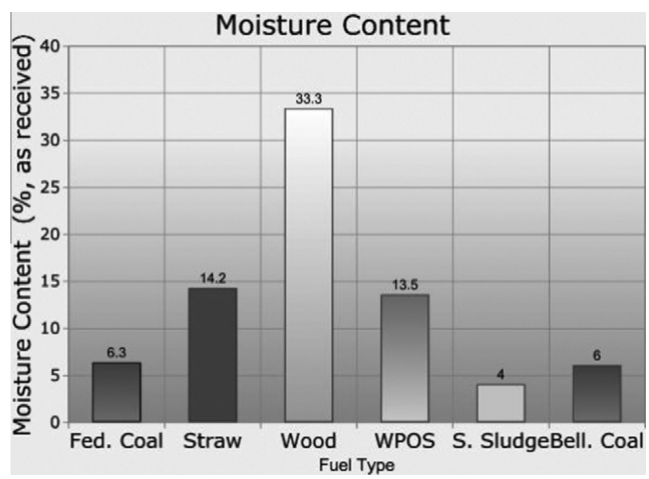


**Fig. 1.** Moisture content of fuels.

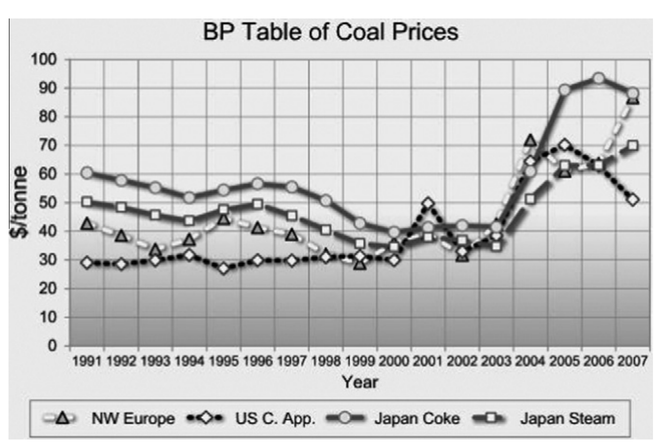


**Fig. 2.** Coal Prices (BP, 2008 [18]).

Hence it is difficult to put a definite figure on coal prices that could be reliable over a long time period and used for power plant planning.

In order to have a reasonable estimate of fuel costs, the value of \$1.80/MMBtu (equivalent to \$1.701/GJ) for the coals, from a US DOE sponsored report [19] (DOE/NETL, 2007), published in 2007 was used. A gate fee of \$20/tonne was used for the dried sewage sludge and a notional \$5.00/GJ for the other biomass fuels.

The cost, in \$ (2008) per tonne, derived for each fuel, is shown in Fig. 3.

A total of 29 processes, as outlined in Table 3, were studied in this work.

### 3.1. PF combustion systems

All the studies using a PF combustion system were based upon the Amer 9 power station at Geertruidenberg in the Netherlands [20]. This is a 600 MW supercritical PF coal-fired power station with flue gas desulphurisation (FGD) [21], [22].

Four processes were based around this technology, as described in Table 3. The first process (Process Number One – PN1) was the standard process as described elsewhere [23], using the standard coal. The second process (PN2) involved replacing one level of coal burners with straw burners so that 20% of the total thermal input to the boiler could be changed from coal to chopped processed straw. No other changes were required to the process apart from balancing flows to the steam cycle and the FGD system. The third process (PN3) involved replacing one level of coal burners with sewage sludge burners so that 20% of the total thermal input to the boiler could be changed from coal to dried sewage sludge cake. Again no other changes were required to the process apart from balancing flows to the steam cycle and the FGD system.

The fourth process (PN4) was based on the use of fuel gas from a straw gasifier as a reburn fuel. Reburn technologies achieves a $NO_x$ emission reduction of about 50% by staging the combustion within the furnace [24], [25].

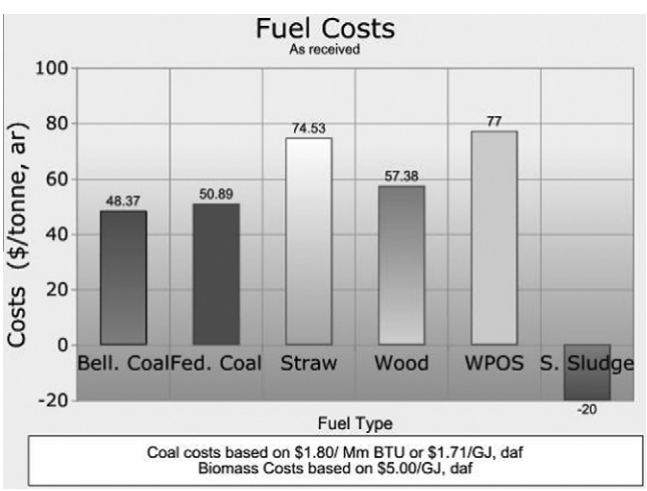


**Fig. 3.** Cost of fuel.

**Table 2**
Superheated Steam Conditions for the CFBC Systems.

| Plant Size (MWe) | Pressure (bar) | Temperature (°C) | Reheat |
|---|---|---|---|
| 12 | 80 | 480 | None |
| 25 | 92 | 495 | None |
| 125 | 160 | 538 | Reheat to 538 °C |
| 250 | 160 | 538 | Reheat to 538 °C |

**Table 3**
Technical and environmental indicators for all systems assessed.

| Process number | Technology, fuel | Efficiency (%) | Total $CO_2$ (g/kWh)* | Net $CO_2$ (g/kWh)** |
|---|---|---|---|---|
| PN1 | 600 MWe PF, 100% Federal coal | 44.0 | 759 | 759 |
| PN2 | 600 MWe PF, 20% straw | 43.8 | 773 | 610 |
| PN3 | 600 MWe PF, 20% sewage sludge | 43.8 | 765 | 765 |
| PN4 | 600 MWe PF, 20% Straw (reburn) | 43.2 | 818 | 625 |
| PN5 | 350 MWe PFBC, 100% federal coal | 41.2 | 783 | 783 |
| PN6 | 350 MWe PFBC, 20% sewage sludge | 41.1 | 792 | 634 |
| PN7 | 250 MWe CFBC, 100% federal coal | 39.0 | 841 | 841 |
| PN8 | 250 MWe CFBC, 20% straw | 38.7 | 858 | 678 |
| PN9 | 250 MWe CFBC, 20% sewage sludge | 39.0 | 866 | 866 |
| PN10 | 125 MWe CFBC, 100% federal coal | 39.0 | 841 | 841 |
| PN11 | 125 MWe CFBC, 20% straw | 38.7 | 859 | 678 |
| PN12 | 25 MWe CFBC, federal coal only | 30.2 | 1107 | 1107 |
| PN13 | 25 MWe CFBC, federal coal + 50% straw | 29.5 | 1163 | 558 |
| PN14 | 25 MWe CFBC, federal coal + 50% wood | 28.2 | 1266 | 552 |
| PN15 | 25 MWe CFBC, federal coal + 50% WPOS | 29.2 | 1172 | 580 |
| PN16 | 25 MWe CFBC, Bellambi coal only | 30.2 | 1095 | 1095 |
| PN17 | 25 MWe CFBC, Bellambi coal + 50% straw | 29.6 | 1157 | 550 |
| PN18 | 25 MWe CFBC, Bellambi coal + 50% wood | 28.2 | 1259 | 543 |
| PN19 | 25 MWe CFBC, Bellambi coal + 50% WPOS | 29.2 | 1166 | 566 |
| PN20 | 25 MWe CFBC, wood only | 26.5 | 1433 | 0 |
| PN21 | 25 MWe CFBC, straw only | 29.1 | 1213 | 0 |
| PN22 | 12 MWe CFBC, Federal Coal Only | 29.5 | 1132 | 1132 |
| PN23 | 12 MWe CFBC, federal coal + 50% straw | 28.9 | 1192 | 600 |
| PN24 | 12 MWe CFBC, Bellambi Coal Only | 29.5 | 1120 | 1120 |
| PN25 | 12 MWe CFBC, Bellambi coal + 50% straw | 28.8 | 1182 | 590 |
| NP1 | 25 MWe CFBC, 100% WPOS | 28.5 | 1228 | 0 |
| NP2 | 12 MWe CFBC, 100% wood | 26.3 | 1443 | 0 |
| NP3 | 12 MWe CFBC, federal coal + 50% wood | 27.5 | 1296 | 575 |
| NP4 | 12 MWe CFBC, 100% straw | 28.4 | 1242 | 0 |

* Total $CO_2$ refers to the gross emissions of $CO_2$ from this power plant.
** Net $CO_2$ refers to the emissions of $CO_2$ from the fossil fuel used in this power plant, since biomass is assumed to be $CO_2$ neutral. Gross $CO_2$ and net $CO_2$ will be the same where only fossil fuel is used.

### 3.2. PFBC Combustion Systems

The first of the two PFBC systems uses only the standard coal (PN5) whereas the second system (PN6) is co-combusted with a mixture of 80% standard coal and 20% dried sewage sludge. Both are based on the 350 MW Karita New Power Station Number One system [26], [27].

### 3.3. CFBC combustion systems

Twenty-three assessment studies were based on the CFBC systems, as tabulated in Table 3. The 125 and 250 MW CFBCs were based on the Gardanne power plant [28], [29] and the 25 and 12 MW CFBCs based on Midkraft's 78 MWth CFBC power plant at Grenaa in Denmark.

The superheated steam inlet conditions at the high-pressure steam turbine for the different processes are given in Table 2. The system technologies are described more fully elsewhere [30].

## 4. Technical results

A full appraisal of the technical, and environmental features of these systems has been described elsewhere [31], but only certain key indicators of performance are needed to assess the effects of using biomass or wastes on $CO_2$ emissions reduction.

The indicator of technical performance is taken to be the LHV Net Electrical Efficiency (Efficiency, %). The $CO_2$ emission level is taken as a measure of the environmental performance (total $CO_2$). Where biomass is used as the fuel, the $CO_2$ released by the biomass may be offset from the total $CO_2$ emissions (net $CO_2$), assuming that it has been sustainably grown [32].

## 5. Economic results

### 5.1. Method of assessment

A full economic analysis was carried out for all systems using the ECLIPSE process simulation package.

The TCI (Total Capital Investment) is the total capital investment of building the power station, starting from a "green field" site, including the normal infrastructure that would be contained within the boundary fence, i.e. roads, offices, control rooms, services, utilities, etc. Added to this is an allowance for the working capital, capital fees and contingency. There is no allowance for additional capital cost for "first-of-its kind" costs and no costs due to the additional risks incurred with financing the construction of a novel, prototype or demonstration plant. A Northern European location is assumed for the plant, with similar construction costs to the UK.

The calculation of the SCI (Specific Capital Investment) requires a value for the electricity production, or electricity sent out. The electricity sent out is the gross power generated by the power station, less the power required by all the auxiliaries on-site and less the losses from the on-site transformers. It assumes that the power station operates at design load for the defined plant occupancy; no allowance is made for part load operation. The calculation of the electricity sent out is performed using a consistent set of environmental conditions, such as ambient air and cooling water conditions.

The BESP is the price that the generator must charge for the electricity that is sent out to the grid in order that, over the lifetime of the station, its net present worth is zero. In other words, the present day value of the net income is equal to present day value of the capital investment. The present day value of the net income is the sum of the net annual income over the lifetime of the plant, discounted back to the present day value, using a given discounted cash flow rate. The present day is taken as the first day that the commissioned power station starts operation. The net annual income includes the income from selling the electricity produced and any other valuable by-products as well as the cost of fuel, raw materials, services (water, effluent, and solids disposal), operating and maintenance labour and supplies, and insurance. The net annual income is of course affected by the occupancy of the power station. The present day value of the capital investment is the TCI (Total Capital Investment) appreciated over the construction and commissioning times of the plant using the given discounted cash flow rate. No allowance is made for inflation, payment of taxes or profit, except as is allowed for setting a value for the discounted cash flow rate.

The typical values for the capital and operating cost indices and factors large and small power stations are given below (See Table 4).

These analyses are too detailed to show here, but certain indicators have been selected. The economic indicators for a system are taken to be: (a) the Total Capital Investment (TCI) in $M (2008); (b) Specific Capital Investment (SCI or SI) i.e. Capital Investment (in 2008 $) per Installed Net kWe; and (c) the Break-even Electricity Selling Price (BESP) in $/MWh.

Whilst every effort is made to validate the capital cost estimation data, using published information and actual quotations from equipment vendors, the absolute accuracy of this type of capital cost estimation procedure has been estimated at about ±25–30%. However, although the absolute accuracy of a single cost estimate may be only ±25–30%, what has been done in these studies is to compare families of similar technologies, composed of similar types of equipment. Therefore, the comparative capital cost estimates, which are based on the accurate calculation of a difference in a basic design by the mass and energy balance program, should be valid.

### 5.2. Calculated values for specific investment

The specific capital investment (SCI or SI) for the supercritical PF system with FGD, fired by coal only (system PN1), was found to be $1453/kWe and the Break-even Electricity Selling Price to be $53.5/MWh. This corresponds well with a report (DOE/NETL, 2007) for the US DOE, which found the SI for such plants to be $1562/kWe and the BESP to be $66/MWh on average [33] and validates the ECLIPSE economic analysis to some extent.

### 5.3. Calculated BESP values

The calculated Break-even Electricity Selling Prices for the large and small scale systems are shown in Figs. 6 and 7 respectively.

## 6. Support mechanisms

In many countries financial mechanisms have been advocated or introduced to support the use of renewables or to reduce $CO_2$ emissions in recent years.

These mechanisms will not be detailed in this paper as they tend to be changed frequently. However, the level of support

**Table 4**
Typical Economic indices for large and small systems.

| Economic indices and factors | Power station > 100 MWe | Power station < 100 MWe |
|---|---|---|
| Construction time (years) | 4 | 2 |
| Commissioning time (years) | 0 | 0 |
| DCFR (%) | 7.5 | 7.5 |
| Capital fees (%TCI) | 2 | 2 |
| Working capital (%TCI) | 2 | 2 |
| Contingency (%TCI) | 10 | 10 |
| Plant occupancy (%) (1st Year, 2nd, Rest) | 40/60/85 | 60/85/85 |
| Plant life (years) | 25 | 25 |
| Operating cost (%TCI) | 1.1 | 1.1 |
| Maintenance cost (%TCI) | 2.3 | 2.3 |
| Insurance cost (%TCI) | 2.0 | 2.0 |

needed to make the biomass or co-fired systems competitive with coal-fired systems is calculated and assessed. Two types of support are discussed; a Renewables support, which is based on overcoming the increased cost of electricity for biomass and co-fired systems (in comparison with coal-fired systems) in \$/MWh and a Support for $CO_2$ Emissions Avoided/Reduction in \$/tonne of $CO_2$. For simplicity these will be known as a Renewable Credit (RC) and a Carbon Credit (CC) respectively in this paper.

Support mechanisms also exist for the reduction of $SO_x$ and $NO_x$ emissions, which could be available for biomass cofiring or combustion, but these are not considered in this paper, although they could well have an impact on the power plant economics.

### 6.1. Carbon credit

#### 6.1.1. The effect on economics of biomass co-combustion systems of $CO_2$ emissions reduction

As can be seen from the Tables 3 and 5 (and Figs. 4–7), co-combustion of biomass with coal has a negative impact on the efficiency, specific capital investment (SI) and electricity generation cost (BESP) of all of the systems. However, there was a concomitant reduction in net $CO_2$ emissions resulting from the biomass cofiring. It is generally accepted that some form of support should be given to support the benefits arising from biomass cofiring.

One way of comparing the economic performance of the different biomass co-combustion systems is to offset the increase in Break-even Electricity Selling Price, due to using biomass instead of coal, with the reduction in $CO_2$ emissions achieved by this displacement. This is the simple form of Carbon Credit (CC) that is used here. These figures are presented in Table 6 and Fig. 8. Fig. 8 shows the subventions (CC and BESP increase) needed to make each system competitive with the 25 MWe CFBC plant fuelled solely by coal (PN12).

Note: Renewable Credit is not the same as BESP increase, since the increase in BESP would be applied to all units of electricity

**Table 5**
Economic indicators for all systems.

| Process number | Technology, fuel | TCI* | SCI** | BESP*** |
|---|---|---|---|---|
| PN1 | 600 MWe PF, 100% Federal Coal | 874 | 1453 | 53.5 |
| PN2 | 600 MWe PF, 20% Straw | 908 | 1512 | 63.5 |
| PN3 | 600 MWe PF, 20% Sewage Sludge | 888 | 1480 | 0.0 |
| PN4 | 600 MWe PF, 20% Straw (reburn) | 1034 | 1726 | 67.4 |
| PN5 | 350 MWe PFBC, 100% Federal Coal | 602 | 1670 | 62.6 |
| PN6 | 350 MWe PFBC, 20% Sewage Sludge | 625 | 1784 | 0.0 |
| PN7 | 250 MWe CFBC, 100% Federal Coal | 460 | 1840 | 68.9 |
| PN8 | 250 MWe CFBC, 20% Straw | 480 | 1921 | 76.7 |
| PN9 | 250 MWe CFBC, 20% Sewage Sludge | 475 | 1897 | 0.0 |
| PN10 | 125 MWe CFBC, 100% Federal Coal | 283 | 2267 | 110.9 |
| PN11 | 125 MWe CFBC, 20% Straw | 299 | 2390 | 114.2 |
| PN12 | 25 MWe CFBC, Federal Coal Only | 70 | 2784 | 95.9 |
| PN13 | 25 MWe CFBC, Federal Coal + 50% Straw | 78 | 3124 | 107.7 |
| PN14 | 25 MWe CFBC, Federal Coal + 50% Wood | 73 | 2920 | 130.0 |
| PN15 | 25 MWe CFBC, Federal Coal + 50% WPOS | 71 | 2852 | 115.6 |
| PN16 | 25 MWe CFBC, Bellambi Coal Only | 68 | 2716 | 90.8 |
| PN17 | 25 MWe CFBC, Bellambi Coal + 50% Straw | 78 | 3124 | 119.6 |
| PN18 | 25 MWe CFBC, Bellambi Coal + 50% Wood | 73 | 2920 | 128.7 |
| PN19 | 25 MWe CFBC, Bellambi Coal + 50% WPOS | 71 | 2852 | 114.2 |
| PN20 | 25 MWe CFBC, Wood Only | 76 | 3056 | 164.5 |
| PN21 | 25 MWe CFBC, Straw Only | 83 | 3328 | 142.9 |
| PN22 | 12 MWe CFBC, Federal Coal Only | 41 | 3230 | 108.8 |
| PN23 | 12 MWe CFBC, Federal Coal + 50% Straw | 48 | 3770 | 140.1 |
| PN24 | 12 MWe CFBC, Bellambi Coal Only | 41 | 3230 | 105.7 |
| PN25 | 12 MWe CFBC, Bellambi Coal + 50% Straw | 48 | 3770 | 138.6 |
| NP1 | 25 MWe CFBC, 100% WPOS | 71 | 2852 | 133.6 |
| NP2 | 12 MWe CFBC, 100% Wood | 44 | 3460 | 148.9 |
| NP3 | 12 MWe CFBC, Federal Coal + 50% Wood | 45 | 3548 | 132.5 |
| NP4 | 12 MWe CFBC, 100% Straw | 42 | 3341 | 147.2 |

* TCI means Total Capital Investment.
** SCI means Specific Capital Investment.
*** BESP means Break-even Electricity Selling Price.

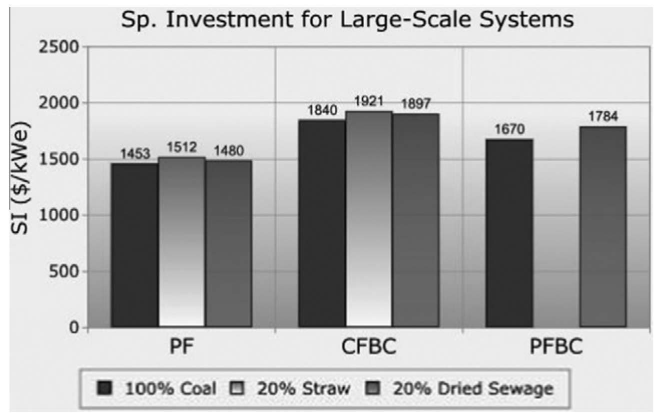


**Fig. 4.** Specific Investment of large scale systems.

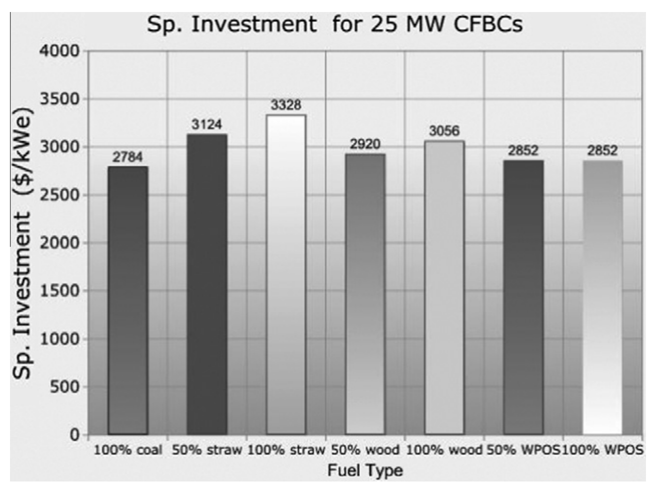


**Fig. 5.** Specific Investment for 25 MW CFBCs.

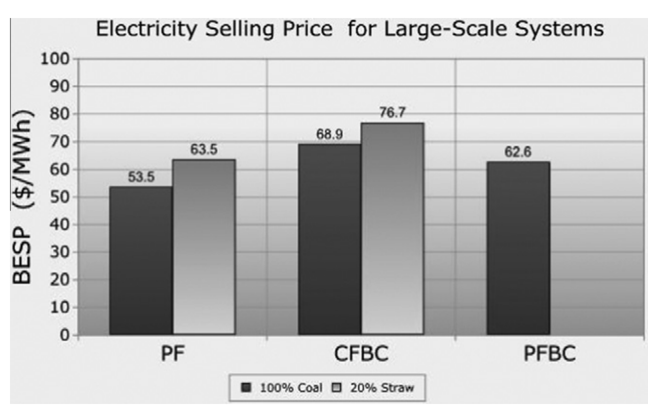


**Fig. 6.** Break-even electricity Selling Price for the large systems.

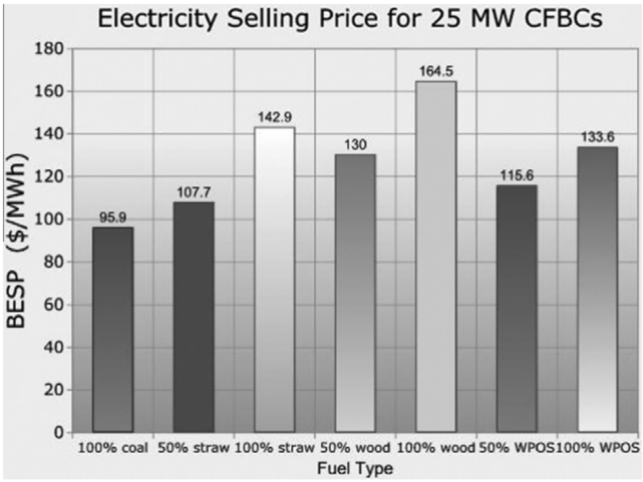


**Fig. 7.** Break-even electricity Selling Price for the 25 MWe CFBC systems.

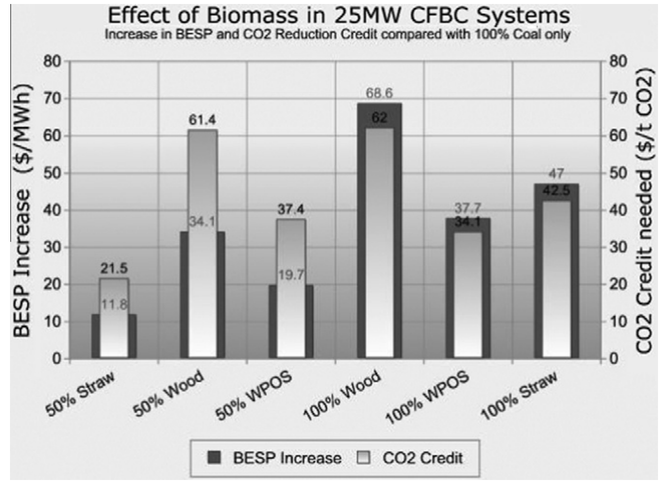


**Fig. 8.** The BESP increase due to cofiring or firing with biomass and the CO2 credit required to nullify this increase in BESP in the 25 MWe CFBCs.

generated by a co-combustion system, whereas it is assumed here that the RC would only be paid for the units generated from biomass.

For small-scale combustion of wood (PN20) to compete with large-scale production of electricity for sale on the open market (e.g., compared with PN1, the 600 MW supercritical PF plant) a carbon credit of 146.2 $/tonne of $CO_2$ emission avoided is required.

When comparing the other 25 MWe CFBC systems with the "coal only" (PN12) version, the carbon credit required for 50% wood co-combustion (PN14) is very similar to direct combustion (PN20), it increases slightly from 61.4 to 62.0 $/tonne $CO_2$ avoided. Therefore to encourage small industrial scale CFBC combustion of wood, or co-combustion of coal with wood, a credit of about 62 $/tonne $CO_2$ avoided would be required. WPOS requires lower credit of about 37 $/tonne of $CO_2$ emission avoided to encourage its use.

In Fig. 10 co-combustion of straw with coal in large PF and CFBC power plants is compared with large scale PF (PN1). Co-combustion of straw with coal in either a PF boiler system (PN2) or a large scale CFBC system (PN8) require a credit of 67.1 and 47.9 $, respectively is required for each tonne of $CO_2$ avoided.

### 6.2. Renewable credit

The Renewable Credit would be used to compensate for the increase in the cost of electricity generation (per kWh or MWh) for using biomass. Since it is assumed that the Renewable Credit would only be paid on units of electricity generated from Renewables i.e. biomass, then the value of the RC per MWh is given by:

$$RC = \text{BESP Increase}/\text{Percentage of cofired biomass}$$

Here it is also used to assess the effect of moving from 600 MW PF power plants to smaller (250 MW) and much smaller (25 and 12 MW) CFBCs.

**Table 6**
Carbon Credit and Renewable Credit for using biomass in the 25 MW CFBCs (as compared with 25 MWe CFBC).

| Co-combustion system | PN13 | PN14 | PN15 | PN20 | PN21 | NP1 |
|---|---|---|---|---|---|---|
| % Biomass | 50 | 50 | 50 | 100 | 100 | 100 |
| Biomass type | Straw | Wood | WPOS | Wood | Straw | WPOS |
| System compared with | PN12 | PN12 | PN12 | PN12 | PN12 | PN12 |
| Increase in BESP ($/MWh) | 11.8 | 34.1 | 19.7 | 68.6 | 47.0 | 37.7 |
| RC ($/MWh) | 23.6 | 68.2 | 39.4 | 68.6 | 47.0 | 37.7 |
| Reduction in $CO_2$ missions (g/kWh) | 549 | 555 | 535 | 1107 | 1107 | 1107 |
| CC, Cost $/t $CO_2$ | 21.5 | 61.4 | 37.4 | 62.0 | 42.5 | 34.1 |

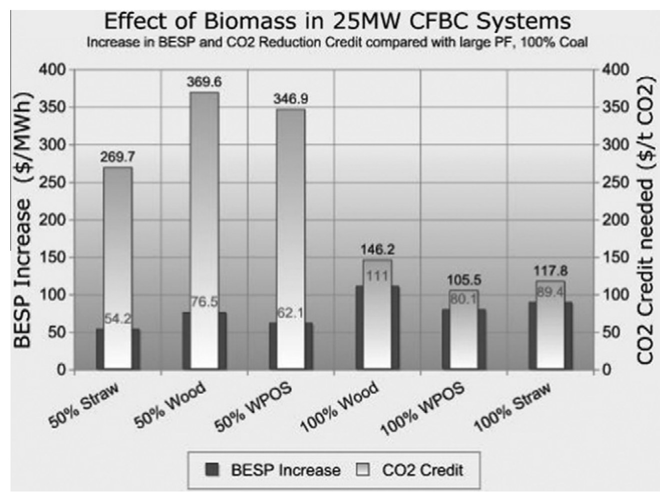


**Fig. 9.** A comparison of the increase in BESP and reduction in net $CO_2$ emissions for 25 MW CFBCs compared to the large scale PF system using 100% (Federal) coal.

### 6.3. RCs and large systems

Fig 10 shows that an increase in BESP of 10.0 $/MWh would compensate for using 20% straw in a PF power plant and 7.8 $/MWh in a 250 MW CFBC, corresponding to an RC value of 50 and 39 $/MWh, respectively. However, if we compare with the PF power plant (PN1), from Table 5 it can be seen that there is an increase in BESP of (76.7–53.5) 23.2 $/MWh, which corresponds to an RC of 116 $/MWh in order to compensate for using 20% straw in a 250 MW CFBC (PN8) instead of coal-firing a 600 MW PF power plant. This difference is principally due to the drop in efficiency between the 600 MW PF and the 250 MW CFBC (see Table 3) from 44% to 38.7%, rather than due to the use of biomass.

### 6.4. RCs and 25 MW CFBCs

From Fig 8 and Table 6, it can be seen that around 70 $/MWh would compensate for 50% cofiring of wood, or 100% wood firing; and around 40 $/MWh would suffice for WPOS firing or cofiring, when compared with the 25 MW 100% coal fuelled CFBC.

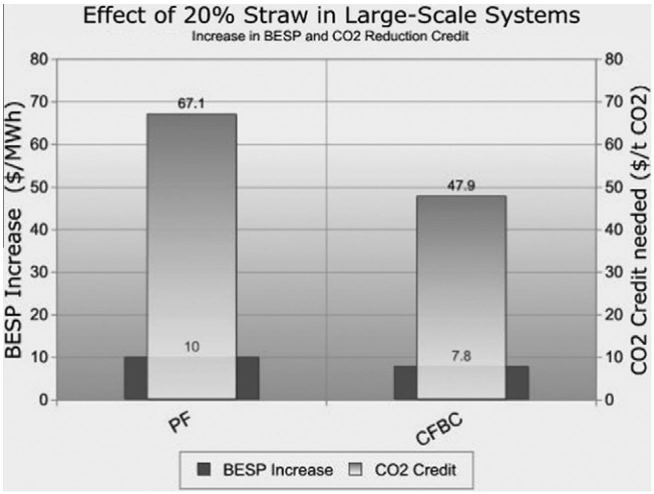


**Fig. 10.** $CO_2$ Credit required to offset increase in BESP for large systems.

If these 25 MW CFBCs are compared with PN1 – the 600 MW PF power plant (using coal only), then an RC of between 110 and 150 \$/MWh would be needed for the 50% cofired 25 MW CFBCs and between 80 and 110 \$/MWh for the 100% biomass-fuelled CFBCs (see Table 7 and Fig. 9).

### 6.5. RCs and 12 MW CFBCs

If we consider the smaller 12 MW CFBCs and compare them to PN1, then an RC of 160 – 185 \$/MWh would be needed to make the 50% cofired 12 MW CFBCs competitive and around 95 \$/MWh for the 100% biomass systems (see Table 8 and Fig. 11).

### 6.6. RC compared with CC

If the overall income for RCs and for CCs is calculated for a year, assuming an 85% plant occupancy, it can be seen from Table 9 that the RC is consistently less than the CC. This implies that it would cost the taxpayer less to make cofiring competitive through the RC support mechanism than with the CC. However, the CC itself is based on certain assumptions, and evaluating it is not straightforward.

Table 9 shoes how much the CC and RC payments would need to be in order to compete economically with PN1, the 600 MW supercritical PF power plant.

It is clear from the table that, for all the different power plants and co-combustion scenarios, the CC costs per annum are greater that RC costs. RCs have also other advantages over CCs since they would be more easily calculated, monitored, traded and less vulnerable to world market fluctuations.

**Table 7**
A comparison of the increase in BESP, RC and CC for 25 MW CFBCs compared to the large scale PF system using 100% (Federal) coal.

| Co-combustion system | PN12 | PN13 | PN14 | PN15 | PN20 | PN21 | NP1 |
|---|---|---|---|---|---|---|---|
| % Biomass | 0 | 50 | 50 | 50 | 100 | 100 | 100 |
| Biomass Type | 0 | Straw | Wood | WPOS | Wood | Straw | WPOS |
| System compared with | PN1 | PN1 | PN1 | PN1 | PN1 | PN1 | PN1 |
| Increase in BESP (\$/MWh) | 42.4 | 54.2 | 76.5 | 62.1 | 111 | 89.4 | 80.1 |
| RC (\$/MWh) | | 108.4 | 153 | 124.2 | 111 | 89.4 | 80.1 |
| Reduction in $CO_2$ emissions (g/kWh) | | 201 | 207 | 179 | 759 | 759 | 759 |
| CC, Cost \$/t $CO_2$ | | 269.7 | 369.6 | 346.9 | 146.2 | 117.8 | 105.5 |

**Table 8**
A comparison of the increase in BESP and reduction in net $CO_2$ emissions for 12 MW CFBCs compared to the large scale PF system using 100% (Federal) coal.

| Co-combustion system | PN22 | PN23 | PN24 | PN25 | NP2 | NP3 | NP4 |
|---|---|---|---|---|---|---|---|
| % Biomass | 0 | 50 | 0 | 50 | 100 | 50 | 100 |
| Biomass type | 0 | Straw | 0 | Straw | Wood | Wood | Straw |
| System compared with | PN1 | PN1 | PN1 | PN1 | PN1 | PN1 | PN1 |
| Increase in BESP (\$/MWh) | 55.3 | 86.6 | 52.2 | 85.1 | 95.4 | 79 | 93.7 |
| RC (\$/MWh) | | 173.2 | | 170.2 | 95.4 | 158 | 93.7 |
| Reduction in $CO_2$ Emissions (g/kWh) | | 159 | | 169 | | 184 | |
| Cost \$/t $CO_2$ | | 531.4 | | 491.1 | | 417.9 | |

*Note*: PN24 and PN25 used Bellambi coal, the others used Federal coal.

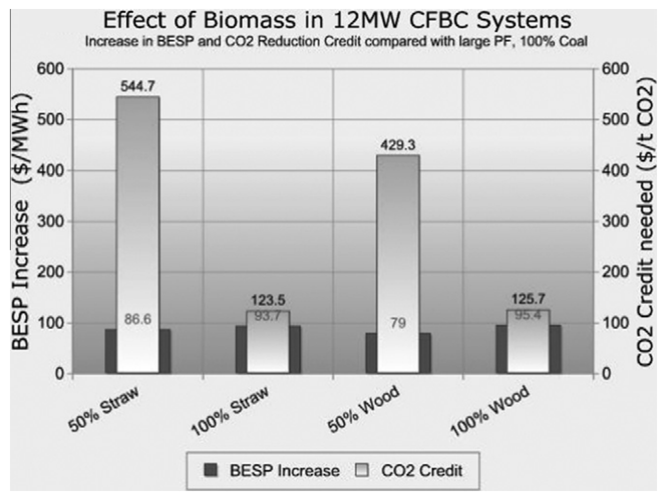


**Fig. 11.** A comparison of the increase in BESP and reduction in net CO2 emissions for 12 MWe CFBCs compared to the large scale PF system using 100% (*Federal*) coal.

The RC is probably a more transparent support mechanism for biomass combustion and cofiring than the CC, since it does not rely on assuming the carbon neutrality of the biomass, which is really only an attribute of an energy crop, or involve a life cycle analysis (LCA) of the power plant with the fuel production within the system boundaries [34]. Wheat straw, and WPOS are not energy crops, but agricultural wastes. However, if they were left to rot in the fields, their greenhouse potential as methane emissions would be greater than if they were combusted [35]. For simplicity, the net $CO_2$ emissions for wheat straw, WPOS and dried sewage sludge have been calculated in the same way as for energy crops, but the validity of such a method may not always be applicable.

## 7. Conclusions

Clearly there are many difficulties in comparing biomass combustion at small scale with biomass/coal cofiring in large and small power plants or with systems fuelled only by coal. Problems would occur in any case if the technical and economic properties of different technologies at widely different scales are compared, even if they are using the same fuel [36].

Generic Renewable Credit (RC) and Carbon Credit (CC) systems have been explored here and estimates of their respective values for competitivity with supercritical PF systems made. The RC method would appear to be preferable.

**Table 9**
The possible RC or CC payments needed to make cofiring economically equivalent to coal combustion only (PN1).

| Process number | BESP increase* | $CO_2$ cost | Electricity generated at 85% occupancy | Renewable units | Total RC required | RC per renewable unit only** | Net CO2 | CC required | CC-RC |
|---|---|---|---|---|---|---|---|---|---|
| | $/MWh | $/tonne | MWh/a | MWh/a | $ m/a | $/MWh | ktonnes/a | $ m/a | $ m/a |
| PN1 | | | 44,67,600 | 0 | | | | | |
| PN2 | 10 | 67.1 | 44,67,600 | 893,520 | 44.7 | 50 | 2725 | 182.9 | 138.2 |
| PN8 | 23.2 | 286.4 | 18,47,092 | 369,418 | 42.9 | 116 | 1252 | 358.7 | 315.8 |
| PN11 | 60.7 | 749.4 | 932,053 | 186,411 | 56.6 | 303.5 | 632 | 473.6 | 417.0 |
| PN13 | 54.2 | 269.7 | 175,420 | 87,710 | 9.5 | 108.4 | 98 | 26.4 | 16.9 |
| PN14 | 76.5 | 369.6 | 167,505 | 83,753 | 12.8 | 153 | 92 | 34.2 | 21.4 |
| PN15 | 62.1 | 346.9 | 173,447 | 86,724 | 10.8 | 124.2 | 101 | 34.9 | 24.1 |
| PN17 | 66.1 | 316.3 | 176,038 | 88,019 | 11.6 | 132.2 | 97 | 30.6 | 19.0 |
| PN18 | 75.2 | 348.1 | 168,116 | 84,058 | 12.6 | 150.4 | 91 | 31.8 | 19.1 |
| PN19 | 60.7 | 314.5 | 174,028 | 87,014 | 10.6 | 121.4 | 98.5 | 31.0 | 20.4 |
| PN23 | 86.6 | 544.7 | 91,936 | 45,968 | 8.0 | 173.2 | 55 | 30.0 | 22.1 |
| PN25 | 85.1 | 503.6 | 92,613 | 46,307 | 7.9 | 170.2 | 55 | 27.5 | 19.6 |
| NP3 | 79 | 429.3 | 87,945 | 43,972 | 6.9 | 158 | 51 | 21.7 | 14.8 |

* Relative to process PN1 (large scale supercritical PF coal system).
** Where RC is given just for the percentage of electricity generated from biomass, not all electricity generated.

In the three large scale technologies reviewed here, there is little reduction in efficiency incurred through cofiring even 20% straw or dried sewage sludge with coal and the values of RC and CC required to promote cofiring over "coal only" are relatively small.

For the "small" 12 and 25 MWe CFBCs an efficiency penalty for using biomass, mainly due to the corresponding moisture content of the respective type of biomass, must be endured. When the CFBC is solely or 50% fuelled by biomass, separate diminution handling and feeding requirements may be necessary, leading to additional capital costs and higher electricity generation prices. Compared with the same scale of CFBC (25 MWe) using only coal, a CC from 20 to 65 \$/tonne $CO_2$ and an RC between 25 and 70 \$/MWh would be required. (The higher values corresponded to systems using wood, which had the highest moisture content of the biomass types investigated).

When the small CFBCs are compared with the large PF reference plant (PN1), relatively large values of CC and RC would be required, but some of this can be attributed to economies of scale and the comparatively lower efficiencies of any small-scale combustion power plant.

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