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CONTRIBUTION OF THE ENERGY RESEARCH CENTRE UNIVERSITY OF ULSTER

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1 Abstract

The Energy Research Centre of the University of Ulster was responsible for performing the techno-economic assessment studies within the Industrial Biomass Co-combustion Project. These studies have been successfully performed using the ECLIPSE process simulator based on information supplied by our partners within the project. Techno-economic assessment studies on a wide range of power generation systems and feedstocks have been performed. The power generation systems studied included pulverised fuel (PF) combustion, pressurised fluidised bed combustion (PFBC) and atmospheric pressure fluidised bed combustion (FBC), with sizes ranging from 12MWe to 600MWe. The feedstocks included two different coals, straw, wood chips, woody material from pressed olive stones (WPOS) and sewage sludge.

Straw has a negative effect on the overall performance due to its high moisture content, the high capital cost of straw processing equipment and the high purchase price of the straw feedstock. With large scale PF co-combustion of coal and 20% straw the overall efficiency was reduced by 0.2%, the capital costs increased by 20 MECU and the electricity selling price (BESP) increased by 5.9 ECU/MWh. However the use of straw reduced the net CO_2 emissions by about 20%. To make PF co-combustion competitive with similar coal only systems a credit of 39.5 ECU/tonne CO_2 avoided is required. When using gasified straw as a reburn fuel in a PF boiler the overall efficiency was reduced by 0.8%, the capital costs increased substantially by 94 MECU and the BESP increased by 8.2 ECU/MWh. However this reduced the NO_x emissions by 50% and the net CO_2 emissions by about 20%. It is difficult to justify the increased costs involved in this system in comparison with coal-over-coal reburn technology and co-combustion with straw unless there are substantial operational benefits. With large scale CFBC co-combustion of coal and straw the overall efficiency was reduced by 0.3%, the capital costs increased by 12 MECU and the BESP increased by 6.1 ECU/MWh. The use of straw reduced the net CO_2 emissions by about 20%. To make CFBC co-combustion competitive with similar coal only systems a credit of 37.4 ECU/tonne CO_2 avoided is required.

The addition of 20% sewage sludge to a PF boiler reduced the efficiency by 0.2% and increased the capital cost by 8 MECU. To make PF co-combustion of sewage sludge competitive with similar coal only systems a price of 13.6ECU/tonne could be paid for the dried sewage sludge compared to 32 ECU/tonne for the coal. The addition of 20% sewage sludge to a PFBC system reduced the efficiency by 0.1% and

increased the capital cost by 13 MECU. To make PFBC co-combustion of sewage sludge competitive with similar coal only systems a price of 6.5 ECU/tonne could be paid for the sewage sludge. However, the PFBC is a slurry fed system therefore wet sewage filter cake could also be used without any economic penalty. The addition of 20% sewage sludge to the large scale CFBC reduced the efficiency by 0.2% and increased the capital cost by 9 MECU. To make CFBC co-combustion of sewage sludge competitive with similar coal only systems a price of 11.8 ECU/tonne could be paid for the sewage sludge. There is a penalty of 20 ECU/dry tonne if wet sewage filter cake is used in this system instead of dried sewage sludge. However, PF, PFBC and CFBC are all potentially attractive routes for co-combusting coal and sewage sludge, especially as under normal circumstances a gate fee would be available to take the sewage sludge.

The co-combustion of coal with 50% straw in a 25MWe CFBC system reduced the overall efficiency by 0.7%, increased the capital costs by 5 MECU and increased the BESP by 23 ECU/MWh. The use of straw reduced the net CO_2 emissions by about 50%. To make small scale CFBC co-combustion competitive with similar coal only systems a credit of 42.6 ECU/tonne CO_2 avoided is required. A similar 12MWe CFBC system requires a credit of 45 ECU/tonne CO_2 avoided. The performance of the 12MWe BFBC systems showed a 10 - 12% improvement in capital cost over the equivalent CFBC system, although the overall system performance was adversely effected by the slightly lower combustion efficiency and the lower sulphur capture efficiency. The use of a low sulphur coal had a small beneficial effect on the performance of the FBC systems studied. In particular the BFBC systems benefited due to the lower sulphur capture efficiency compared to the CFBC. The economic advantage depends on the relative price differential between the low and high sulphur coal.

Wood has quite a high negative impact on efficiency, due to its higher moisture content, but less of an impact on the capital cost due to its easier reception, preparation and feeding compared with straw. The co-combustion of coal with 50% wood in the 25MWe CFBC systems reduced the overall efficiency by 2.0%, increased the capital costs by 2 MECU and increased the BESP by 11.7 ECU/MWh. The use of wood reduced the net CO_2 emissions by about 46%. To make CFBC co-combustion of wood competitive with similar coal only systems a credit of 22.7 ECU/tonne CO_2 avoided is required. The co-combustion of coal with WPOS in the 25MWe CFBC system reduced the overall efficiency by 1.0%, increased the capital costs by 1 MECU and increased the BESP by 4.3 ECU/MWh. The use of WPOS reduced the net CO_2 emissions by about 50%. To make CFBC co-combustion of WPOS competitive with similar coal only systems a credit of 8 ECU/tonne CO_2 avoided is required.

Of the three biomass feedstocks studied straw is the least attractive biomass for reducing CO_2 emissions, because of its high moisture content, its high capital cost for reception, storage and feeding and its high purchase price of 60ECU/tonne in Denmark. WPOS is the most attractive biomass because of its good feedstock properties and its low price of 23ECU/tonne in Greece. Wood is not as attractive as WPOS due to its high moisture content and its slightly higher purchase price. A credit of about 40ECU/tonne CO_2 avoided would encourage large scale PF and CFBC co-combustion of straw with coal and also small industrial scale FBC combustion of straw or co-combustion of coal with straw. To encourage small industrial scale FBC combustion of wood or co-combustion of coal with wood a credit of about 22ECU/tonne CO_2 avoided would be required. WPOS requires only a small credit of 8 ECU/tonne of CO_2 emission avoided to encourage its use. These figures are heavily dependent on the price paid for the biomass.

2 INTRODUCTION

There is a great deal of concern about global warming and the potential catastrophic effect that this could have on the environment. The most important greenhouse gas that contributes to global warming is carbon dioxide (CO_2) and the main source of CO_2 emissions is from the combustion of fossil fuels. Power generation is a major user of fossil fuels and the demand for electricity is growing steadily throughout the developed world and dramatically in the less developed countries. The replacement of all or part of these fossil fuels by renewable energy sources, such as biomass and waste, is an attractive means of reducing greenhouse gas emissions. Biomass and waste are also attractive because they are indigenous fuels, providing local employment and a boost to the rural economy. Conventional ways of disposing of waste, such as landfilling and dumping to sea are also becoming more difficult, more expensive and are no longer an acceptable solution.

The APAS Clean Coal Technology Programme showed that it was technically feasible to co-combust certain wastes or biomass with coal in utility boilers. Co-firing was also found to have little effect on combustion efficiency or flame stability. In addition, pilot plant tests showed that co-firing could reduce NO_x and SO_x emissions. However, there was concern that the impurities in some biomasses and wastes, particularly the alkali metals and halogens, could cause operational problems with regard to slagging, fouling or corrosion. There was also concern about the disposal of the ash, which in normal coal combustion can be used in construction applications, and about the emission of heavy metals and toxic organic compounds. This project addresses all of these areas. The role of the Energy Research Centre of the University of Ulster is to provide an overall techno-economic assessment of this work.

3 OBJECTIVES

The work of the Energy Research Centre, University of Ulster mainly concerns the techno-economic assessment of the different biomass/waste co-processing systems, which are being developed by the other partners involved in this project. Comparisons are made of the performance of these technologies with the equivalent technologies that are fuelled by coal or biomass alone, at appropriate scales of operation.

4 METHODOLOGY

The in-house personal computer based process simulation package, ECLIPSE, was used to perform techno-economic assessment studies of each technology using, initially, coal as the fuel. The data obtained from the partners was then used to adapt these studies for biomass and waste co-firing applications. ECLIPSE was developed for the European Commission over the period since 1986 by the Energy Research Centre of the University of Ulster (1,2). A techno-economic assessment study is performed in logical stages, and the first stages involve the preparation of a process flow diagram for the system to be analysed, the addition of the technical design data and the completion of a converged mass and energy balance. When the mass and energy balance has been completed the next stages involve the environmental impact analysis, capital and operating cost estimation and then the economic analysis. These analyses provide all the data required to complete the assessment study.

ECLIPSE contains all of the program modules needed to complete rapid and reliable step-by-step technical, environmental and economic evaluations of chemical and allied processes, including mass and energy balances, capital costing and economic analyses. ECLIPSE uses generic chemical engineering equations and formulae and includes a high accuracy steam-water thermodynamics package for steam cycle analysis. It has its own chemical industry capital costing program covering over 100 equipment types. The chemical compound properties database and the plant cost database can both be modified to allow new or conceptual processes to be evaluated.

The main criteria that have been used for comparing the economic performance of power generation systems are the total capital investment (TCI), the specific capital investment (SCI) and the break-even electricity selling price (BESP). The following standard assumptions have been used to make these evaluations.

The TCI 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 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, 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 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.

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 (%) (1^{st}, 2^{nd}, 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

The most significant component of the direct costs of power generation is the capital cost. The method used to calculate the capital cost is as follows. The ECLIPSE process simulator is used to develop a process flow diagram for the power station under evaluation. This process flow diagram includes all the equipment contained within the boundary fence, which is required to be included in the cost estimate. A mass and energy balance is then performed on this process flow diagram. The information produced by the mass and energy balance provides the basic design data for each item of equipment, i.e. flows, temperatures, pressures, heat transfers, etc. It also provides the basic data for calculating the operating costs, such as fuel and raw materials used, electricity produced, by-products formed and waste streams to be disposed of. The basic equipment design data produced by the mass and energy balance calculation is then further processed in order to provide the information required to calculate the capital cost. The estimation of the capital cost is based on historical data which relates the basic capital cost of the item of equipment to a specific size parameter. Thus for a tank this would be its volume, for a heat exchanger its surface area and for a pump its flow rate, etc. Other correction factors are then taken into account, such as materials of construction and operating conditions. On top of the corrected basic capital cost an allowance is then made for installation costs, such as civil works, pipework and valves, electrics and instrumentation, and other services.

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 we are doing in these studies is comparing 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 ASSESSMENT STUDIES

The assessment studies considered a variety of power generation technologies, a range of sizes of power plant and a number of blends of coals/biomasses/wastes as feedstocks. The power generation technologies studied were pulverised fuel firing (PF), pressurised fluidised bed combustion (PFBC) and atmospheric pressure fluidised bed combustion (FBC). The power plant sizes ranged from 600MWe for the PF plants, to 12MWe for the smallest of the FBC 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. The analysis of these materials 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. The limestone flow was adjusted so that the systems using either high or low sulphur coals would have the same SO_x emissions.

There are several problems associated with the use of straw as a fuel (3). It has a high moisture content, low energy density and high volatile content when compared to coal. Its moisture content, bulk and inhomogeneous form cause handling and feeding problems. Around 70% of the combustible portion of straw is emitted as volatiles, which means that the distribution and mixing of combustion air as well as the design of the burner(s) and the combustion chamber must be carefully planned. In addition, corrosion can be caused in the combustion chamber due to the many compounds of chlorine in straw. Straw ash has relatively low softening and melting temperatures, because of the high alkali metal content, and so slagging problems can occur at relatively low surface temperatures.

The experiences at the 80 MWth CFBC plant at Grenaa were that, during operation with a coal/straw mixture, the main problems occurred in the superheaters located in the overhead convective pass of the boiler. High-temperature corrosion was found and attributed to the high chlorine and alkaline content of the straw, enhanced by the use of high-sulphur coal (4). The final superheater steam temperature was 505°C during the 1½ years of operation before failure. Also, the potassium content of the CFBC material was found to be the prime indicator of fouling propensity. A shift from high-sulphur to low-sulphur coal led to a sharp decrease in potassium content and to the fouling rate. The lessons for co-firing coal and straw (or other materials with a high content of aggressive elements) from the Grenaa plant were:

The sulphur /potassium ratio of the fuel should be kept low, and proper consideration should be given to the inherent fouling and corrosion mechanisms during the design and deployment of the heat transfer surfaces.

In the smaller systems it would be difficult to design or position heat transfer surfaces to resist high temperature corrosion at reasonable cost. For this reason it is expected that the system would be of a relatively simple design, but the superheated steam temperatures would be maintained below 500°C.

The other biomass or waste feedstocks that were considered for these simulations were wood, WPOS and sewage sludge. While each of these materials has its own concerns, particularly on the handling and storage sides, none of them cause such major problems as straw, with regard to slagging, fouling or corrosion.

5.1 Studies Based on PF Combustion System

All the studies using a PF combustion system were based upon the Amer 9 power station at Geertruidenberg in the Netherlands (5). This is a 600MW supercritical PF coal fired power station with flue gas desulphurisation (FGD)(6)(7). Coal for the power station is imported from various countries and transhipped by barges from the seaports. Normal coal storage facilities are provided from where the coal is pulverised in mills and then pneumatically transferred using preheated primary air to a two pass once through boiler, with a spirally wound single furnace and tangentially fired low NO_x burners. Most of the unburned coal and ash is removed at the base of the furnace, with the rest carried forward with the hot gases and removed in cold-side electrostatic precipitators. Before reaching these electrostatic precipitators the hot gases are cooled first by transferring heat to steam in the superheater tubes and the reheater tubes, then by transferring heat to condensate in the economiser section and finally by transferring heat to combustion air in the air preheater section.

The steam cycle is a supercritical single reheat system. The steam that leaves the superheater is sent to the turbine stop valve. It is then expanded in the high pressure turbine. The steam turbines have facilities for steam extraction and allow for steam to be tapped off to the regenerative feedwater heaters. Drains from the three high pressure feedwater heaters are fed to the deaerator. The steam from the high pressure turbine is then reheated before passing through one double flow intermediate pressure and three double flow low pressure turbines. At the crossover from the intermediate to the low pressure turbines steam is extracted for the deaerator. The steam from the low pressure turbine is condensed and the condensate is pumped through the four low pressure feedwater heaters to the deaerator. Drains from the four low pressure feedwater heaters are pumped in with the condensate feed. From the deaerator tank the boiler feed pump forces the condensate through the three high pressure surface-type feedwater heaters and the economiser before entering the boiler and completing the steam cycle.

The cooled gases are exhausted via the induced draught fan to a wet limestone FGD system where most of the SO_x is removed. This process is based on the Deutsche Babcock design (6). The flue gas from the electrostatic precipitators is first cooled against the clean gas and then fed to the base of the spray tower. Limestone solution is circulated through the sprays in the tower and the SO_2 in the flue gas reacts to form calcium sulphite. In the base of the spray tower the calcium sulphite is oxidised to gypsum which then settles out. The gypsum solution is pumped through a hydrocyclone and then fed onto a filter table where most of the water and impurities are removed. The gypsum is then ready for sale for use in plasterboard manufacture and the wastewater is treated to separate the impurities. The clean gas is then reheated before being vented up the stack to the atmosphere.

Five processes were based around this technology. The first process (PN1) was the standard process as described above, 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. In the standard Amer 9 power station the coal is burned in six levels of burners all with the same stoichiometry of about 1.2. With reburn technology, the bottom 5 sets of burners burn the main coal fuel but with a reduced stoichiometry of 1.12. The top set of burners burn the reburn fuel at a stoichiometry of 0.9. Above this top set of burners overfire air is then added to complete the combustion stoichiometry to 1.2 overall. This technology has been demonstrated using natural gas as the reburn fuel at Longannet in Scotland and is about to be demonstrated using pulverised coal as the reburn fuel at Vado Ligure in Italy.

Process PN4 will use biogas as the reburn fuel from a straw gasifier. In this process dried straw is fed to a fluidised bed gasifier operating at 800°C. The straw is completely gasified at this temperature and a raw syngas with a calorific value of approximately 5 MJ/kg is produced. This raw syngas is cooled to 200°C and then filtered to remove ash particles. At this temperature most of the alkali metals condense on the ash particles and are also filtered out. The filtered syngas is then fed to the PF boiler system to be used as the reburn fuel. The heat removed from the raw syngas is used for raising steam, which is then mixed with the steam from the PF boiler system and fed to the steam turbine. This obviously involves more significant changes to the balancing of flows with the PF boiler steam system in particular.

The fifth process is based on pretreatment of straw using pyrolysis followed by char washing to remove chlorides and alkali metal salts (PN5). The char is used to replace some of the coal feed to the PF boiler and the pyrolysis gas is then used as reburn fuel in the PF boiler. Use of reburn technologies achieves a NO_x emission reduction of about 50% by staging the combustion within the furnace. In the pyrolysis system a flow of 5.56 kg/s straw is conveyed to straw mills and mixed with air before pyrolysis, wherein a proportion of the feedstock is combusted to maintain the exit temperature at 550 °C. Char is then separated from the pyrolysis gas in a cyclone. A percentage of the gas is also removed at this stage and is burned to provide heat to raise the incoming air temperature to 400 °C. The pyrolysis gas that is sent to the PF boiler as reburn fuel has a flow of 42.5 kg/s with a LHV of 7.2 MJ/kg. The char that has been removed from the gas stream is washed in water to remove alkali metal salts and then dried to 50%.

The char produced in the pyrolysis section has a mass flow of 8.2 kg/s and a LHV of 32.7 MJ/kg. This is milled and mixed with the federal coal flow of 36.78kg/s. The coal plus char provides 80% of the thermal input for the system. The remaining 20% thermal input is provided by the pyrolysis gas which acts as a reburn fuel.

5.2 Studies Based on PFBC Combustion System

Two different power generation systems have been studied under the general heading of PFBC. They are both based on a conceptual 350MWe sub-critical PFBC system. The first of the two PFBC systems uses only the standard coal (PN6) whereas the second system (PN7) is co-combusted with a mixture of 80% standard coal and 20% dried sewage sludge. The following description is generally applicable to both of these systems.

Normal coal storage facilities are provided from where the coal is crushed in grinders and then mixed with water. This fuel paste is pumped into the combustor. Limestone is fed through lock hoppers into the combustor. Dry limestone sorbent is used due to the relatively high sulphur content of the coal. The boiler is a bubbling pressurised fluidised bed combustor. Incoming air is compressed in a two stage compressor which is powered by a gas turbine driven by the exhaust gases. The outlet from the low pressure compressor passes through an intercooler, in order to limit the outlet temperature from the high pressure compressor to 300°C. The air from the compressor passes along a concentric pipe, where some heat is transferred from counterflowing flue gas, before it enters the pressure vessel. The pressure vessel contains the combustor and a set of cyclones. The air is forced through cyclone coolers to reach the base of the combustor and mix with the bed material. Some air is tapped off and cooled in an air cooler by low pressure condensate. This air is injected into the combustor to distribute the fuel paste evenly across the bed. The relatively low fluidising velocity gives a dense bubbling bed which limits the amount of material carried over into the flue gas. The low operating temperature (860°C) helps to reduce NO_x formation. Sulphur retention is achieved by adding limestone and therefore no additional FGD is required.

The bubbling bed in the combustor gives very good heat transfer and tubes within the bed remove heat for superheating, reheating, evaporation and final economising. Approximately 50% of the ash is removed from the bed of the combustor and heat is extracted from this for low pressure boiler feedwater heating. The rest of the solids are carried forward with the hot gases. Sets of high efficiency cyclones separate all of the particles down to 10micron from the flue gas. This cyclone ash is cooled first in the pressure vessel by incoming air and then in external heat exchanger where it gives up heat for low pressure boiler feedwater heating. From the gas turbine exit the flue gas passes to a three stage waste heat boiler, where the flue gas gives up heat to the boiler feedwater via two high pressure economisers and one low pressure economiser. The remaining particulates are removed in cold-side electrostatic precipitators. The cooled gases are exhausted via the stack to the atmosphere.

The steam which leaves the superheater is sent to the turbine stop valve. It is then expanded in the high pressure turbine. The steam turbines have facilities for steam extraction and allow for transfer of steam to the regenerative feedwater heaters. For the PFBC there is no requirement for a third high pressure heater since adequate feedwater heating is provided by the waste heat boiler. Drains from the two high pressure feedwater heaters are fed to the deaerator. The steam from the high pressure turbine is reheated before passing through an intermediate pressure and a double flow low pressure turbine. At the crossover from the intermediate to the low pressure turbines steam is extracted for the deaerator. Drains from the low pressure feedwater heaters are fed to the condenser.

The steam from the low pressure turbine is condensed and the condensate is pumped through two low pressure surface-type heaters and parallel economisers to the deaerator. Here the incoming water is heated by direct contact with the bleed steam. The economisers used for low pressure feedwater heating are the final stage of the waste heat boiler, the air compressor intercooler, the cyclone ash cooler and the fuel paste distribution air cooler. The boiler feed pump forces the condensate through two high pressure surface-type feedwater heaters and a parallel economiser, which is the intermediate stage of the waste heat boiler. The feedwater is then heated by the final stage of the waste heat boiler and the economiser before entering the boiler and completing the steam cycle.

5.3 Studies Based on FBC Combustion System

An example of the process is described below for the case of wood as the fuel. Most of this process description is the same for all the fuels used, except in the fuel handling and preparation. In addition, for sulphur-containing fuels, such as coal, limestone would be added for in-bed sulphur removal.

Wood from a nearby forest is harvested, chipped and transported to the power station. On reception it is transferred from the lorries into a ground hopper with multiple screw conveyor, via magnetic separation, size separation and reduction stages (screening) and on to storage on a belt conveyor. It is stored in piles of chips in the open, in sufficient quantities for 14 days throughput. It is assumed that negligible wood mass loss, due to bacterial action, would occur in this time period. It is also assumed that changes in moisture content due to rain or drying out would cancel each other, i.e. the moisture content and wood mass are taken to be the same at the time of use as at the time of delivery.

Wood, with a moisture content of approximately 50% (on a dry basis) is taken from storage, screened, and then transferred pneumatically to buffer storage ready for use in the fluidised bed combustor. No wood drying stage is included. Air, preheated by the flue gases, enters the fluidised bed combustor. Approximately 30% excess air in the two small-scale systems (and 20% excess air in the two larger CFBCs) is used to ensure complete combustion. The amount of heat transferred from the combustion of the wood to the steam cycle depends on the moisture content of the wood feedstock, as energy must be used to drive off the moisture in the drying and heating stage of combustion and raise it to the outlet temperature of the combustor. Radiant energy from the flames during combustion is transferred to boiler tubes lining the combustor walls and is used to vaporise water coming from the steam drum. Heat is also transferred from the hot gases to the steam to superheat it, and to the condensate in the economiser section to preheat the condensate.

The ash is removed from the bottom of the combustor; the gases go on to the combustion air preheater while the superheated steam is then fed to the steam turbine. The conditions used in the simulation for the steam turbines are those of commercially available turbines for the anticipated power output. The type and size of boiler used generally determine the steam conditions, but the characteristics of the biomass fuel must also be taken into account. In only the two largest systems, producing 250 MWe and 125 MWe, was steam reheating included, together with multiple stage feed water preheating. In the other power stations a single low pressure feed water heater was used. For all of these systems the final turbine discharged to a condenser, operating at 0.06 Bar Abs. The superheated steam inlet conditions at the high-pressure steam turbine for the different processes are given in Table 2.

The following assessment studies were based on the CFBC systems.

PN8	250MWe CFBC	Federal Coal Only
PN9	250MWe CFBC	Federal Coal + 20% Straw
PN10	250MWe CFBC	Federal Coal + 20% Sewage Sludge
PN11	125MWe CFBC	Federal Coal Only
PN12	125MWe CFBC	Federal Coal + 20% Straw
PN13	25MWe CFBC	Federal Coal Only

PN14	25MWe CFBC	Federal Coal + 50% Straw
PN15	25MWe CFBC	Federal Coal + 50% Wood
PN16	25MWe CFBC	Federal Coal + 50% WPOS
PN17	25MWe CFBC	Bellambi Coal Only
PN18	25MWe CFBC	Bellambi Coal + 50% Straw
PN19	25MWe CFBC	Bellambi Coal + 50% Wood
PN20	25MWe CFBC	Bellambi Coal + 50% WPOS
PN21	25MWe CFBC	Wood Only
PN22	25MWe CFBC	Straw Only
PN23	12MWe CFBC	Federal Coal Only
PN24	12MWe CFBC	Federal Coal + 50% Straw
PN25	12MWe CFBC	Bellambi Coal Only
PN26	12MWe CFBC	Bellambi Coal + 50% Straw

Similar studies were made for 12MWe BFBC systems, although the detailed results are not presented, only the overall results and conclusions

6 RESULTS

The technical, environmental and economic results of all of the systems modelled are presented in Tables 3 to 15 and shown in Figures 1 to 7. The discussion of these results will be considered under the following topics

6.1 Large Scale Co-combustion of Coal and Straw

In this section eight different processes are considered, PN1 - a coal fired PF boiler, PN2 - co-combustion of coal and straw in a PF boiler, PN4 - gasified straw as a reburn fuel in a PF boiler, PN5 - pyrolysed straw as a reburn fuel in a PF boiler, PN8 - a 250MWe coal fired CFBC, PN9 - co-combustion of coal and straw in a 250MWe CFBC, PN11 - a 125MWe coal fired CFBC and PN12 - co-combustion of coal and straw in a 125MWe CFBC.

With the PF boiler systems, the thermal input of coal to PN1 is 1367MW and the power produced on the steam turbines is 649MWe. The total auxiliary power consumption is 47MWe, mainly in the combustion air fans and condensate pumps, leaving a net electrical generation of 601.5MWe, which leads to an efficiency of 44.0%.

The gaseous CO_2 emissions are equivalent to 760g/kWh of net electricity generated. When 20% straw is co-combusted with the coal in PN2, with the same thermal input, the power generated from the steam turbines is reduced slightly by about 1MWe due to the higher moisture content of the straw. The auxiliary power consumption goes up slightly by less than 0.5MWe, mainly due to the increased load on the combustion air fans. The total effect is to reduce the net electrical generation to 600.3MWe and reduce the efficiency to 43.8%. The total gaseous CO_2 emissions increase slightly to 773g/kWh, however when the contribution from the straw is excluded the net CO_2 emissions reduce significantly to 610g/kWh.

When 20% of the thermal input of the power plant is provided as a reburn fuel obtained from the gasification of straw, PN4, an increased thermal input of about 20MW is required to achieve about the same power generation from the steam turbines. The auxiliary power consumption goes up significantly by over 3.5MWe, mainly due to the increased load on the fans required for the reburning fuel and the overfire air. The total effect is to reduce the net electrical generation to 599.1MWe and reduce the efficiency to 43.2%. The total gaseous CO_2 emissions increase to 818g/kWh, however when the contribution from the straw is excluded the net CO_2 emissions again are reduced significantly to 600g/kWh. The main advantage of reburning is the reduced NO_x emissions and the results show that the NO_x emissions are also reduced to about half the normal level.

Adding 20% reburn fuel from the pyrolysis of straw, PN5, has a much more negative effect on the overall performance of the PF power station than from the gasification of straw. An increased thermal input of about 110MW is required to achieve about the same power generation from the steam turbines. The auxiliary power consumption also goes up by about 5.6MWe, mainly due to the increased load on the fans required for the reburning fuel and the overfire air and the power required by the pyrolysis unit and the char wash/preparation unit. The total effect is to reduce the net electrical generation to 596.9MWe and reduce the efficiency to 40.4%. The total gaseous CO_2 emissions increase to 844g/kWh, however when the contribution from the straw is excluded the net CO_2 emissions again are reduced to 535g/kWh. The main advantage of reburning is the reduced NO_x emissions and the results show that the NO_x emissions are also reduced to about half the normal level.

The economic analysis of the PF boiler systems shows that the total capital cost of PN1 is 515 MECU, giving a specific investment of 856 ECU/kWe and a break-even electricity selling price (BESP) of 31.5 ECU/MWh. The addition of 20% straw in PN2 increases the solids reception, storage and handling costs by 20 MECU, giving a specific investment of 891 ECU/kWe and a BESP of 37.4 ECU/MWh. The addition of 20% straw as a reburn fuel has an even more dramatic effect on the capital cost, due to the additional cost of the straw gasifier, syngas cooler and syngas filter. In PN4 therefore the capital cost increases by 94 MECU, giving a specific investment of 1017 ECU/kWe and a BESP of 39.7 ECU/MWh. No capital cost estimation was made for the straw pyrolysis and char wash systems in PN5 due to the significance uncertainties in the design of these systems. However, the large effect on the overall electricity generation efficiency potentially makes PN5 an unattractive option. These BESP figures are based on a coal cost of 32 ECU/tonne and a straw cost of 60 ECU/tonne, which is representative of the costs in Denmark.

With the large scale CFBC combustion systems, the thermal input of coal to PN8 is 641MW and the power produced on the steam turbines is 270MWe. The total auxiliary power consumption is nearly 20MWe, mainly in the combustion air fans and condensate pumps, leaving a net electrical generation of 250MWe, which leads to an efficiency of 39.0% and gaseous CO_2 emissions of 841g/kWh. When 20% straw is co-combusted with the coal in PN9, for the same thermal input the power generated from the steam turbines is reduced by over 2MWe, again due to the high moisture content of the straw, with a similar auxiliary power consumption. The total effect is to reduce the net electrical generation to 248.1MWe and reduce the efficiency to 38.7%. The total gaseous CO_2 emissions increase to 858g/kWh, however when the contribution from the straw is excluded the net CO_2 emissions reduce significantly to 676g/kWh. The overall technical results of the 125MWe CFBC systems, PN11 and PN12 are very similar to the larger 250MWe CFBC systems. This is because the combustion efficiency, steam cycle efficiency and fixed losses are very similar for both systems. However, the economics of the two systems are substantially different due to the economies of scale of the larger system.

The economic analysis of the larger CFBC combustion system shows that the total capital cost of PN8 is 271 MECU, giving a specific investment of 1080 ECU/kWe and a BESP of 40.1 ECU/MWh. The addition of 20% straw in PN9 increases the solids reception, storage and handling costs by 12 MECU, giving a specific investment of 1140 ECU/kWe and a BESP of 46.2 ECU/MWh. With the 125MWe CFBC combustion system the total capital cost of PN11 is 167 MECU, giving a substantially increased specific investment of 1330 ECU/kWe and a BESP of 46.4 ECU/MWh. The addition of 20% straw in PN12 increases the solids reception, storage and handling costs by 9 MECU, giving a specific investment of 1400 ECU/kWe and a BESP of 53.3 ECU/MWh.

The addition of straw in systems PN2, PN4, PN5, PN9 and PN12 all have a significant adverse impact on the economics of large scale coal fired power stations. However, they are reducing the net CO_2 emissions by nearly 20% and for the cases of PN4 and PN 5 are also reducing the NO_x emissions by nearly 50%. Clearly a price is being paid for reducing CO_2 and NO_x emissions. The important issue is how competitive this price is with the alternative means of reducing CO_2 emissions, such as the combustion of straw on its own at a smaller scale. This issue will be considered in section 6.6.

6.2 Large Scale Co-Combustion of Coal and Dried Sewage Sludge

In this section six different processes are considered, PN1 - a coal fired PF boiler, PN3 - co-combustion of coal and sewage sludge in a PF boiler, PN6 - a 350MWe coal fired PFBC, PN7 - co-combustion of coal and sewage sludge in a 350MWe PFBC, PN8 - a 250MWe coal fired CFBC and PN10 - co-combustion of coal and sewage sludge in a 250MWe CFBC.

The effect of the addition of 20% sewage sludge, PN3, on the performance of a coal fired PF boiler is very similar to the addition of 20% straw, but for different reasons. With the same thermal input as PN1, the power generated from the steam turbines is reduced slightly by about 1MWe, this time due to the high ash content of the sewage sludge. The auxiliary power consumption goes up by about 0.9MWe, due to the increased load on the combustion air fans and on the ash/fly ash removal system. The total effect is to reduce the net electrical generation to 600.0MWe and reduce the efficiency to 43.8%. The total gaseous CO_2 emissions increase slightly to 765g/kWh. The economic analysis of the PF boiler systems shows that the addition of 20% sewage sludge increases the solids reception, storage and handling costs by 8 MECU, giving a specific investment of 872 ECU/kWe.

With the PFBC systems, the thermal input of coal to PN6 is 875MW and the power produced from the gas turbine is 77.4MWe and from the steam turbines is 295.4MWe. The total auxiliary power consumption is 12MWe, mainly in the condensate pumps, leaving a net electrical generation of 360.6MWe and an efficiency of 41.2%. The gaseous CO_2 emissions are equivalent to 783g/kWh of net electricity generated. The addition of 20% sewage sludge, PN7, has quite a significant effect on the overall performance of the coal fired PFBC system. With the same thermal input as PN6, the power generated from the gas turbine goes up to 82.6MWe, due to the higher volatile matter content of the sewage sludge and the power generated by the steam turbines is reduced by about 7MWe to 288.2MWe. The auxiliary power consumption is unchanged which means that the total effect is to reduce the net electrical generation by 2MWe and reduce the efficiency slightly to 41.1%. The total gaseous CO_2 emissions increase slightly to 792g/kWh. The economic analysis of the PFBC systems shows that the total capital cost of PN6 is 355 MECU, giving a specific investment of 984 ECU/kWe and a BESP of 36.9 ECU/MWh. The addition of 20% sewage sludge increases the solids reception, storage and handling costs by 9 MECU and the PFBC and gas turbine costs by 6MECU, giving a total cost of 368 MECU and a specific investment of 1026 ECU/kWe.

The addition of 20% sewage sludge to the large scale CFBC, PN10, has only a very small effect on its overall performance. The high ash content of the sewage sludge has less of an effect on fluidised bed systems than the PF boiler due to the lower operating temperatures, which means that the ash is not melted during the combustion process. In the economic analysis, the addition of 20% sewage sludge increases the solids reception, storage and handling costs by 9 MECU giving a total cost of 280 MECU and a specific investment of 1118 ECU/kWe.

For this study sewage sludge is considered to be a waste, not a renewable energy source, and therefore what is important is the cost of disposing of this waste not the reduction in CO_2 emissions. To calculate the cost of disposing of the sewage sludge it was assumed that the BESP for the three processes using sewage sludge, PN3, PN7 and PN10 is the same as the BESP for the equivalent coal only systems. An economic analysis was then performed to determine the price that could be paid for the sewage sludge to give this BESP. For the PF boiler system with 20% sewage sludge, PN3, to give a BESP of 31.5ECU/MWh a price of 13.6ECU/tonne could be paid for the sewage sludge. For the PFBC system with 20% sewage sludge, PN7, to give a BESP of 36.9ECU/MWh a price of 6.5ECU/tonne could be paid for the sewage sludge. For the CFBC system with 20% sewage sludge, PN10, to give a BESP of 40.1ECU/MWh a price of 11.8ECU/tonne could be paid for the sewage sludge. Therefore, the most economic route for co-combustion of coal and sewage sludge is using a PF boiler, followed by CFBC and then PFBC. However all three cases are potentially attractive routes, especially as under normal circumstances a gate fee would be available to take the sewage sludge.

These figures assume that the sewage sludge is in dried pellet form and therefore the filtered sewage sludge must be dried and transported to the power station for use. It has been calculated that the drying cost would be approximately 20ECU/tonne dry matter. Therefore, for the power station to take filtered sewage sludge a gate fee of 6.4ECU/tonne is required for the PF boiler and 8.2ECU/tonne for the CFBC system to break-even with coal only operation. The situation with the PFBC system is different in that the feed system for the PFBC is a slurry. Therefore the PFBC could take filtered sewage sludge at no extra processing cost and could afford to pay the same 6.5ECU/tonne dry basis for the filtered sewage sludge as the dried sewage sludge. These figures are gate fees or gate values and therefore transport costs have not been included as they are site specific.

6.3 Small Scale Co-Combustion of Coal and Straw

In this section eight different processes are considered, PN13 - a high sulphur coal fired 25MWe CFBC, PN14 - co-combustion of a high sulphur coal and straw in a 25MWe CFBC, PN23 - a 12MWe high sulphur coal fired CFBC, PN24 - co-combustion of a high sulphur coal and straw in a 12MWe CFBC, PN17 - a low sulphur coal fired 25MWe CFBC, PN18 - co-combustion of a low sulphur coal and straw in a 25MWe CFBC, PN25 - a 12MWe low sulphur coal fired CFBC and PN26 - co-combustion of a low sulphur coal and straw in a 12MWe CFBC

With the 25MWe CFBC systems, the thermal input of coal to PN13 is 79.5MW and the power produced on the steam turbines is 26.2MWe. The total auxiliary power consumption is 2.2MWe, mainly in the combustion air fans and condensate pumps, leaving a net electrical generation of 24MWe, which leads to an efficiency of 30.2%. This efficiency is much lower than the larger CFBC systems due mainly to the less efficient steam cycle and the higher fixed losses. The gaseous CO_2 emissions are equivalent to 1107g/kWh reflecting this lower efficiency. When 50% straw is co-combusted with the coal in PN14, with the same thermal input, the power generated from the steam turbines is reduced by 0.5MWe due to the higher moisture content of the straw. The auxiliary power consumption is unchanged at 2.2MWe giving a net electrical generation of 23.6MWe and a reduced efficiency of 29.5%. The total gaseous CO_2 emissions increase slightly to 1163g/kWh, however when the contribution from the straw is excluded the net CO_2 emissions reduce significantly to 567g/kWh. The economic analysis of the 25MWe CFBC systems shows that the total capital cost of PN13 is 41 MECU, giving a specific investment of 1700 ECU/kWe and a BESP of 56.1 ECU/MWh. These poorer economic figures compared with the large scale CFBC systems reflect the diseconomies of small scale operation as well as the lower efficiencies. The addition of 50% straw in PN14 increases the solids reception, storage and handling costs by 5 MECU, giving a specific investment of 1980 ECU/kWe and a BESP of 79.1 ECU/MWh.

System PN23, the 12MWe CFBC system has a coal thermal input of 43MW and the power produced on the steam turbines is 13.8MWe. The total auxiliary power consumption is 1.2MWe, again mainly in the combustion air fans and condensate pumps, leaving a net electrical generation of 12.6MWe, which leads to an efficiency of 29.5%. This efficiency slightly lower than the 25MWe CFBC system due mainly to the less efficient steam cycle. The gaseous CO_2 emissions are equivalent to 1132g/kWh reflecting this slightly lower efficiency. When 50% straw is co-combusted with the coal in PN24, with the same thermal input, the power generated from the steam turbines is reduced by 0.3MWe due to the higher moisture content of the straw. The auxiliary power consumption is unchanged at 1.2MWe giving a net electrical generation of 12.4MWe and a reduced efficiency of 28.9%. The total gaseous CO_2 emissions increase slightly to 1192g/kWh, however when the contribution from the straw is excluded the net CO_2 emissions reduce significantly to 578g/kWh. The economic analysis of the 12MWe CFBC systems shows that the total capital cost of PN23 is 24 MECU, giving a specific investment of 1910 ECU/kWe and a BESP of 61.5 ECU/MWh. Again, compared with the 25MWe systems these poorer economic figures mainly reflect the diseconomies of small scale operation. The addition of 50% straw in PN24 increases the solids reception, storage and handling costs by 4 MECU, giving a specific investment of 2260 ECU/kWe and a BESP of 86.4 ECU/MWh.

The addition of straw in systems PN14 and PN24 all have a significant adverse impact on the economics of small scale CFBC power stations. However, they are reducing the net CO_2 emissions by nearly 50% and a price is being paid for reducing these emissions. Again, the important issue is how competitive this price is with the alternative means of reducing CO_2 emissions, such as the combustion of straw on its own. This issue will be considered in section 6.6.

With regard to the systems which use low sulphur Bellambi coal (PN17, PN18, PN25 and PN26) as opposed to the ones that use high sulphur Federal coal (PN13, PN14, PN23 and PN24), in all cases there is a slight improvement in efficiency with the lower sulphur coal. This improvement is mainly brought about by the lower addition rate of limestone that is required to the CFBC system in order to control the SO_2 emissions. This improved efficiency and lower limestone addition rate is also reflected in the slightly improved economic analysis for the low sulphur coal systems. The BESP shows a 2% - 4% reduction with the low sulphur coal systems, which in part is justified as it reflects the higher efficiency and lower capital costs involved. However, the BESP is also based on the same price in ECU/GJ for both coals, whereas in reality the lower sulphur coal would demand a higher price than the high sulphur coal. Therefore, the relative merits of co-combusting straw with either high or low sulphur coals depend on the fuel price.

6.4 Small Scale Co-Combustion of Coal and Wood

In this section four different processes are considered, PN13 - a high sulphur coal fired 25MWe CFBC, PN15 - co-combustion of a high sulphur coal and wood in a 25MWe CFBC, PN17 - a low sulphur coal fired 25MWe CFBC and PN19 - co-combustion of a low sulphur coal and wood in a 25MWe CFBC.

The effect of the addition of 50% wood, PN15, on the performance of a 25MWe CFBC system is quite different from the addition of 50% straw, PN14, for a number of reasons. With the same thermal input as PN14, the power generated from the steam turbines is reduced by about 1 MWe due to the much higher moisture content of the wood than the straw. The auxiliary power consumption is slightly higher which has the effect of reducing the net electrical generation to 22.5MWe and the efficiency to 28.2%. The total gaseous CO_2 emissions increase to 1266g/kWh, however when the contribution from the wood is excluded the net CO_2 emissions reduce significantly to 592g/kWh. The economic analysis of the 25MWe CFBC system shows that the capital cost of the solids reception, storage and handling units is much cheaper for the 50% wood system than the 50% straw system. This gives a lower specific investment of 1920 ECU/kWe and a much lower BESP of 67.8 ECU/MWh. The main reason for the much lower BESP in the 50% wood system than the 50% straw system is the much lower cost for the wood compared with the straw. The wood is assumed to be coppiced willow with a cost of 26 ECU/tonne. This is only applicable to small CFBC systems where transport distances are negligible.

Again the use of low sulphur coal in process PN17 and PN19 improves the efficiency slightly, reduces the emissions slightly and improves the economics slightly compared with the use of high sulphur coal. The same considerations apply as was discussed in the section on co-combusting coal and straw.

6.5 Small Scale Co-Combustion of Coal and WPOS

In this section four different processes are considered, PN13 - a high sulphur coal fired 25MWe CFBC, PN16 - co-combustion of a high sulphur coal and WPOS in a 25MWe CFBC, PN17 - a low sulphur coal fired 25MWe CFBC, PN20 - co-combustion of a low sulphur coal and WPOS in a 25MWe CFBC.

WPOS is a renewable energy source, the same as wood and straw, with a slightly lower moisture content than straw but a higher ash content. Therefore the effect of the addition of 50% WPOS, PN16, on the performance of a 25MWe CFBC system is very similar to the addition of 50% straw, PN14, as the higher ash content does not have a large effect. With the same thermal input as PN14, the power generated from the steam turbines is reduced slightly by less than 0.2 MWe due to the higher ash content of the WPOS. The auxiliary power consumption is slightly higher which has the effect of reducing the net electrical generation to 23.3 MWe and the efficiency to 29.2%. The total gaseous CO_2 emissions increase to 1172g/kWh, however when the contribution from the WPOS is excluded the net CO_2 emissions reduce significantly to 572g/kWh. The economic analysis of the 25MWe CFBC system shows that the capital cost of the solids reception, storage and handling units is also much cheaper for the 50% WPOS system than the 50% straw system. This gives a lower specific investment of 1810 ECU/kWe and a much lower BESP of 60.4 ECU/MWh. Again, the main reason for the much lower BESP in the 50% WPOS system than the 50% straw system is the much lower cost for the WPOS compared with the straw. The WPOS price is based on information supplied for the situation in Greece and is assumed to be 23 ECU/tonne and there are no transport costs included in this figure.

The use of low sulphur coal in process PN17 and PN20 improves the efficiency slightly, reduces the emissions slightly and improves the economics slightly compared with the use of high sulphur coal. The same considerations apply as was discussed in the section on co-combusting low sulphur coal and straw.

6.6 Economics of Biomass Co-Combustion Systems

As has been mentioned in previous sections, all of the systems that involved co-combustion of biomass with coal have a negative impact on the efficiency, capital cost and electricity generation cost (BESP). However, they all give a reduction in net CO_2 emissions and they should be given a credit for this. One way of comparing the economic performance of the different biomass co-combustion systems is to look at the cost of reducing the emissions by 1 tonne of CO_2. These figures are presented in Table 16 and Figure 7. Of the three biomass feedstocks studied straw is the least attractive biomass for reducing CO_2 emissions, because of its high moisture content, its high capital cost for reception, storage and feeding and its high purchase price of 60ECU/tonne in Denmark. WPOS is the most attractive biomass basically because of its good feedstock properties and its low price in Greece. Wood is not as attractive as WPOS due to its high moisture content and its slightly higher purchase price.

For small scale combustion of straw (PN22) to compete with large scale production of electricity for sale on the open market (PN1) a credit of 88.9 ECU is required for each tonne of CO_2 emission avoided. Co-combustion of straw with coal in either a PF boiler system (PN2) or a large scale CFBC system (PN9) is a much more attractive means of reducing CO_2 emissions as a lower credit of 39.5 and 37.4 ECU respectively is required for each tonne of CO_2 avoided. When looking at small scale CFBC systems (PN13), which are not competing with large scale electricity production on the open market, then co-combustion (PN14) is not as attractive as direct combustion (PN22) and the credit required increases from 38.8 to 42.6 ECU/tonne CO_2 avoided. This is due to the additional capital cost incurred in receiving, storing and feeding two different feedstocks for this small size of power plant. However, these figures show that a credit of about 40ECU/tonne CO_2 avoided would encourage large scale co-combustion of straw with coal and also small industrial scale CFBC combustion of straw or co-combustion of coal with straw. Not shown in the table is the figure for 12MWe CFBC plant, but the figure here for co-combustion of coal with straw is 45 ECU/tonne CO_2 avoided.

For small scale combustion of wood (PN21) to compete with large scale production of electricity for sale on the open market (PN1) a credit of 63 ECU/tonne of CO_2 emission avoided is required. When looking at small scale CFBC systems (PN13) the credit required for co-combustion (PN15) is very similar to direct combustion (PN21), it increases slightly from 21.0 to 22.7 ECU/tonne CO_2 avoided. This is due to the lower capital cost penalty incurred for receiving, storing and feeding the wood chips compared with straw. Therefore to encourage small industrial scale CFBC combustion of wood or co-combustion of coal with wood a credit of about 22ECU/tonne CO_2 avoided would be required. WPOS requires only a small credit of 8 ECU/tonne of CO_2 emission avoided to encourage its use.

7 Comparison of Work Foreseen and Work Done

A full technical, environmental and economic assessment of most of the processes foreseen in the original work programme has been completed. Due to difficulties in establishing economic data for the straw pyrolysis/char washing and straw leaching processes these pretreatment processes were not examined in detail. However, additional work on pressurised BFBC of coal and sewage sludge and atmospheric pressure FB gasification of straw with fuel gas cleaning as a pretreatment process, followed by clean fuel gas reburning in a PF boiler, were performed to replace these.

8 CONCLUSIONS

The ECLIPSE process simulator was used successfully to perform technical, environmental and economic assessment studies on a range of power generation systems based on combustion and co-combustion of a wide range of feedstocks. The power generation systems considered included a PF boiler, PFBC and FBC, the sizes ranged from 600MWe to 12MWe and the feedstocks included two different coals, straw, wood chips, WPOS and sewage sludge. The following conclusions were drawn:

- With large scale PF co-combustion of coal and 20% straw the overall efficiency was reduced by 0.2%, the capital costs increased by 20 MECU and the BESP increased by 5.9 ECU/MWh.. However the use of biomass straw reduced the net CO_2 emissions by about 20%. To make co-combustion competitive with similar coal only systems a credit of 39.5 ECU/tonne CO_2 avoided is required.

- When using gasified straw as a reburn fuel in a PF boiler the overall efficiency was reduced by 0.8%, the capital costs increased substantially by 94 MECU and the BESP increased by 8.2 ECU/MWh.. However this reduced the NO_x emissions by 50% and the net CO_2 emissions by about 20%. It is difficult to justify the increased costs involved in this system in comparison with coal-over-coal reburn technology or coal-over-coal reburn technology with co-combustion of the straw.

- The use of straw pyrolysis and char wash as a pretreatment system in large scale co-processing of straw and coal in a PF boiler has a large effect on the overall electricity generation efficiency. There are also significance uncertainties in the design of these systems, which makes capital cost estimation difficult. Therefore, at this point in time this is not an attractive option.

- With large scale CFBC co-combustion of coal and 20% straw the overall efficiency was reduced by 0.3%, the capital costs increased by 12 MECU and the BESP increased by 6.1 ECU/MWh. The use of biomass straw reduced the net CO_2 emissions by about 20%. To make co-combustion competitive with similar coal only systems a credit of 37.4 ECU/tonne CO_2 avoided is required.

- The addition of 20% sewage sludge to a PF boiler reduced the efficiency by 0.2% and increased the capital cost by 8 MECU. To make co-combustion of sewage sludge competitive with similar coal only systems a price of 13.6ECU/tonne could be paid for the dried sewage sludge compared to 32 ECU/tonne for the coal.

- The addition of 20% sewage sludge to a PFBC system reduced the efficiency by 0.1% and increased the capital cost by 13 MECU. To make co-combustion of sewage sludge competitive with similar coal only systems a price of 6.5 ECU/tonne could be paid for the sewage sludge. The PFBC is a slurry fed system therefore wet sewage filter cake could also be used without any economic penalty.

- The addition of 20% sewage sludge to the large scale CFBC reduced the efficiency by 0.2% and increased the capital cost by 9 MECU. To make co-combustion of sewage sludge competitive with similar coal only systems a price of 11.8 ECU/tonne could be paid for the sewage sludge. There is a penalty of 20 ECU/dry tonne if wet sewage filter cake is used instead of dried sewage pellets.

- PF, PFBC and CFBC are all potentially attractive routes for co-combusting sewage sludge, especially as under normal circumstances a gate fee would be available to take the sewage sludge.

- The co-combustion of coal with 50% straw in the 25MWe CFBC systems reduced the overall efficiency by 0.7%, increased the capital costs by 5 MECU and increased the BESP by 23 ECU/MWh. The use of biomass straw reduced the net CO_2 emissions by about 50%. To make co-combustion competitive with similar coal only systems a credit of 42.6 ECU/tonne CO_2 avoided is required.

- The co-combustion of coal with 50% straw in the 12MWe CFBC systems reduced the overall efficiency by 0.6%, increased the capital costs by 4 MECU and increased the BESP by 24.9 ECU/MWh. The use of biomass straw reduced the net CO_2 emissions by about 50%. To make co-combustion competitive with similar coal only systems a credit of 45 ECU/tonne CO_2 avoided is required.

- The performance of the 12MWe BFBC systems showed a 10 - 12% improvement in capital cost over the equivalent CFBC system, although the overall system performance was adversely effected by the slightly lower combustion efficiency and the lower sulphur capture efficiency.

- The use of a low sulphur coal had a small beneficial effect on the performance of all of the systems studied. In particular the BFBC systems benefited due to the lower sulphur capture efficiency compared to the CFBC. The economic advantage depends on the relative price differential between the low and high sulphur coal.

- The co-combustion of coal with 50% wood in the 25MWe CFBC systems reduced the overall efficiency by 2.0%, increased the capital costs by 2 MECU and increased the BESP by 11.7 ECU/MWh. The use of biomass wood reduced the net CO_2 emissions by about 46%. To make co-combustion competitive with similar coal only systems a credit of 22.7 ECU/tonne CO_2 avoided is required.

- The co-combustion of coal with 50% WPOS in the 25MWe CFBC systems reduced the overall efficiency by 1.0%, increased the capital costs by 1 MECU and increased the BESP by 4.3 ECU/MWh. The use of biomass WPOS reduced the net CO_2 emissions by about 50%. To make co-combustion competitive with similar coal only systems a credit of 8 ECU/tonne CO_2 avoided is required.

- Of the three biomass feedstocks studied straw is the least attractive biomass for reducing CO_2 emissions, because of its high moisture content, its high capital cost for reception, storage and feeding and its high purchase price of 60ECU/tonne in Denmark. WPOS is the most attractive biomass basically because of its good feedstock properties and its low price in Greece. Wood is not as attractive as WPOS due to its high moisture content and its slightly higher purchase price.

- A credit of about 40ECU/tonne CO_2 avoided would encourage large scale PF and CFBC co-combustion of straw with coal and also small industrial scale CFBC combustion of straw or co-combustion of coal with straw. To encourage small industrial scale CFBC combustion of wood or co-combustion of coal with wood a credit of about 22ECU/tonne CO_2 avoided would be required. WPOS requires only a small credit of 8 ECU/tonne of CO_2 emission avoided to encourage its use. These figures are heavily dependent on the price paid for the biomass.

9 Appendices

9.1 REFERENCES

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9.2 Abbreviations/Symbols

BESP	Break-even Electricity Selling Price
BFBC	Bubbling Fluidised Bed Combustor
CFBC	Circulating Fluidised Bed Combustor
daf	dry ash free
db	dry basis
DCFR	Discounted Cash Flow Rate
ECLIPSE	Acronym for Process Simulator
FGD	Flue Gas Desulphurisation
HHV	Higher Heating Value
LHV	Lower Heating Value
MECU	Million ECU
NAI	Net Annual Income
NPW	Net Present Worth
PBP	Pay-Back Period
PF	Pulverised Fuel
PFBC	Pressurised Fluidised Bed Combustion
PVCI	Present day Value of Capital Investment
PVNI	Present day Value of Net Income
SCI	Specific Capital Investment
TCI	Total Capital Investment
WPOS	Woody material from Pressed Olive Stones

	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

Table 1 Analysis of Feedstocks Used

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

Table 2 Superheated Steam Conditions for the FBC Systems

System Number	PN1	PN2	PN3	PN4	PN5
Co-Firing Fuel (20%)	-	straw	Sewage	-	-
Reburn Fuel (20%)	-	-	-	Gasified straw	Pyrolysed Straw
Thermal Input HHV (MW)	1425	1143 / 300	1155 / 289	1116/346	997/569
LHV	1367	1097 / 274	1108 / 260	1071/317	957/520
Steam Turbine Output (MWe)	648.7	647.88	647.91	650.01	649.63
Auxiliary Consumption (MW)	47.2	47.61	47.92	50.91	52.75
Fans	10.96	11.48	11.57	14.66	14.78
Pumps	25.77	25.74	25.74	25.88	25.81
Coal-Crusher	2.84	2.84	2.87	2.32	2.06
FGD System	3.58	3.19	3.17	3.17	3.38
Cooling Water	3.92	3.97	3.97	4.16	3.94
Reburn Fuel Utility	-	-	-	0.63	2.68
Other	0.13	0.39	0.63	0.09	0.10
Net Power Production (MWe)	601.5	600.3	600.0	599.1	596.9
Electrical Efficiency %HHV	42.2	41.8	41.6	41.0	38.1
% LHV	44.0	43.8	43.8	43.2	40.4
Gaseous Emissions (g/kWh)					
Total CO_2	759	773	765	818	844
Net CO_2 excl biomass	759	610	765	600	535
SO_x	0.93	0.77	0.89	0.73	0.60
NO_x	0.96	1.1	1.07	0.50	0.38

Table 3 PF Boiler Systems – Technical and Environmental Results

Cost M ECU (1998)	PN1	PN2	PN3	PN4
Solids Recpt, Storage & Prep	41	61	48	71
Ash/Slag/Dust Handling	15	15	16	18
Fans and Heaters	37	37	37	37
Boiler System	152	152	152	152
Gasifier/Cooler/Filter	0	0	0	61
Steam System/Stack	56	56	56	56
Steam Turbine/Generator	107	107	107	107
Water Treatment/Cooling	28	28	28	28
FGD	79	79	79	79
Total Capital Cost	515	535	523	609
Sp. Investment (ECU/kWe)	856	891	872	1017
BESP (ECU/MWh)	31.5	37.4	See Text	39.7

Table 4 PF Boiler Systems – Economic Results

System Number	PN6	PN7
Co-Firing Fuel (20%)	-	Sewage
Thermal Input (MW) HHV	906	729/182
LHV	875	698/174
Gas Turbine Output (MWe)	77.4	82.6
Steam Turbine Output (MWe)	295.4	288.2
Auxiliary Consumption (MWe)	12.2	12.2
Solids Prep/Feeding	2.0	2.0
Pumps	6.7	6.7
Cooling Water	3.5	3.5
Net Power Production (MWe)	360.6	358.6
Efficiency % HHV	39.8	39.4
% LHV	41.2	41.1
Gaseous Emissions (g/kWh)		
Total CO_2	783	792
Net CO_2 excl biomass	783	634
SO_x	1.5	1.4
NO_x	1.0	1.2

Table 5 PFBC Combustor Systems – Technical and Environmental Results

Cost M ECU (1998)	PN6	PN7
Solids Recpt, Storage & Prep	32	41
Ash/Slag/Dust Handling	5	5
PFBC, Cyclones	134	138
Gas Turbine	41	43
HRSG, Stack	36	36
Steam System	20	20
Steam Turbine/Generator	71	69
Water Treatment/Cooling	16	16
Total Capital Cost	355	368
Sp. Investment (ECU/kWe)	984	1026
BESP (ECU/MWh)	36.9	See Text

Table 6 PFBC Combustor Systems – Economic Results

Process	PN8	PN9	PN10	PN11	PN12
Coal Type	Federal	Federal	Federal	Federal	Federal
Biomass Type	0	Straw	Sewage	0	Straw
Thermal Input (MW HHV)	667	674	671	334	340
Thermal Input (MW LHV)	641	641	642	321	324
Steam Turbine Output (MWe)	269.8	267.6	270.5	134.9	135.1
Auxiliary Power (MWe)					
Feed Preparation	0.6	0.4	0.5	0.3	0.3
Feed Conveying	0.7	0.7	0.7	0.3	0.4
Gas Cleaning	0.3	0.3	0.3	0.2	0.2
Compressors and Fans	8.9	8.9	9.1	4.5	4.5
Pumps and Cooling	9.3	9.3	9.5	4.7	4.7
Total Auxiliary Power (MWe)	19.8	19.5	20.1	9.9	9.9
Net Electrical Output (MWe)	250.0	248.1	250.4	125.0	125.2
Efficiency (%HHV)	37.5	36.8	37.3	37.5	36.8
Efficiency (%LHV)	39.0	38.7	39.0	39.0	38.7

Table 7 Large Scale CFBC Systems – Technical Results

Process	PN8	PN9	PN10	PN11	PN12
Coal Type	Federal	Federal	Federal	Federal	Federal
Biomass	None	straw	sewage	none	straw
CO_2 g/kWh	841	858	866	841	859
CO_2 excl biomass (g/kWh)	841	678	866	841	678
SO_2 g/kWh	1.4	1.4	1.4	1.4	1.4
NOx g/kWh	0.9	0.7	1.1	0.9	0.7

Table 8 Large Scale CFBC Systems – Environmental Results

Capital Cost (MECU 1998)	PN8	PN9	PN10	PN11	PN12
Coal Type	Federal	Federal	Federal	Federal	Federal
Biomass	none	Straw	sewage	none	Straw
Solids Recp, Storage & Feeding	24	36	33	14	22
CFBC	143	143	143	87	88
Steam Turbine	66	66	66	45	45
Steam System & Stack	23	23	23	12	12
Water Treatment/Cooling	15	15	15	9	9
Total MECU	271	283	280	167	176
ECU/kWe	1080	1140	1118	1330	1400
BESP ECU/MWh	40.1	46.2	See Text	46.4	53.3

Table 9 Large Scale CFBC Systems – Economic Results

Process	PN13	PN14	PN15	PN16	PN17	PN18	PN19	PN20	PN21	PN22
Coal Type	Federal	Federal	Federal	Federal	Bellambi	Bellambi	Bellambi	Bellambi	none	None
Biomass Type	none	straw	wood	WPOS	none	straw	wood	WPOS	wood	Straw
Thermal Input (MW HHV)	82.69	85.08	84.47	83.60	82.75	85.11	84.50	83.63	86.26	87.47
Thermal Input (MW LHV)	79.47	79.73	79.73	79.72	80.00	80.00	80.00	79.99	79.99	80.00
Steam Turbine (MWe)	26.26	25.71	24.73	25.54	26.35	25.76	24.78	25.59	23.37	25.35
Auxiliary Power (MWe)										
Feed Prep & Conveying	0.30	0.23	0.33	0.35	0.26	0.21	0.31	0.33	0.27	0.14
Compressors and Fans	1.04	1.06	1.07	1.04	1.03	1.05	1.06	1.03	1.10	1.09
Pumps and Cooling	0.89	0.86	0.83	0.85	0.88	0.86	0.83	0.85	0.78	0.85
Total Aux Power (MWe)	2.23	2.15	2.23	2.24	2.18	2.12	2.20	2.22	2.16	2.07
Net Output (MWe)	24.0	23.6	22.5	23.3	24.2	23.6	22.6	23.4	21.2	23.3
Efficiency (%HHV)	29.1	27.7	26.6	27.9	29.2	27.8	26.7	27.9	24.6	26.6
Efficiency (%LHV)	30.2	29.5	28.2	29.2	30.2	29.6	28.2	29.2	26.5	29.1

Table 10 25MWe CFBC Systems – Technical Results

Process	PN13	PN14	PN15	PN16	PN17	PN18	PN19	PN20	PN21	PN22
Coal Type	Fed	Fed	Fed	Fed	Bell	Bell	Bell	Bell	none	None
Biomass	None	straw	wood	WPOS	none	straw	wood	WPOS	wood	Straw
CO_2 g/kWh	1,107	1,163	1,266	1,172	1,095	1,157	1,259	1,166	1,433	1,213
CO g/kWh	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	1.4	0.4
Net CO_2 (g/kWh)	1107	567	592	572	1095	559	586	566	0	0
SO_2 mg/Nm3	201	198	199	205	61	60	59	61	0	61
SO_2 g/kWh	0.90	0.92	0.98	0.94	0.27	0.27	0.29	0.28	0.00	0.29
NOx mg/Nm3	255	190	190	195	350	260	255	265	145	285
NOx g/kWh	1.1	0.9	0.9	0.9	1.6	1.2	1.2	1.2	0.8	1.4

Table 11 25MWe CFBC Systems – Environmental Results

Capital Cost MECU (1998)	PN13	PN14	PN15	PN16	PN17	PN18	PN19	PN20	PN21	PN22
Coal Type	Fed	Fed	Fed	Fed	Bell	Bell	Bell	Bell	none	None
Biomass	none	Straw	Wood	WPOS	None	straw	wood	WPOS	wood	Straw
Solids Recp	5	10	7	6	5	10	7	7	8	12
CFBC	19	19	19	19	18	19	19	18	21	20
Steam Turbine	12	12	12	12	12	12	12	12	11	12
Steam System	3	3	3	3	3	3	3	3	3	3
Water Treat/Cool	2	2	2	2	2	2	2	2	2	2
Total MECU	41	46	43	42	40	46	43	42	45	49
ECU/kWe	1700	1980	1920	1810	1660	1960	1900	1790	2110	2110
BESP ECU/MWh	56.1	79.1	67.8	60.4	54.0	77.9	66.6	59.2	79.3	99.0

Table 12 25MWe CFBC Systems – Economic Results

Process	PN23	PN24	PN25	PN26
Coal Type	Federal	Federal	Bellambi	Bellambi
Biomass Type	none	straw	none	Straw
Thermal Input (MW HHV)	44.45	45.73	44.48	45.74
Thermal Input (MW LHV)	42.71	42.86	43.00	43.00
Steam Turbine Output (MWe)	13.81	13.50	13.86	13.57
Auxiliary Power (MWe)				
Feed Preparation	0.01	0.01	0.01	0.01
Feed Conveying	0.18	0.14	0.16	0.13
Gas Cleaning	0.00	0.00	0.00	0.00
Compressors and Fans	0.56	0.57	0.55	0.56
Pumps and Cooling	0.44	0.43	0.45	0.44
Total Auxiliary Power (MWe)	1.20	1.15	1.17	1.13
Net Electrical Output (MWe)	12.6	12.4	12.7	12.4
Efficiency (%HHV)	28.3	27.1	28.6	27.1
Efficiency (%LHV)	29.5	28.9	29.5	28.8

Table 13 12MWe CFBC Systems – Technical Results

Process	PN23	PN24	PN25	PN26
Coal Type	Federal	Federal	Bellambi	Bellambi
Biomass	None	straw	none	straw
CO_2 g/kWh	1132	1192	1120	1182
Net CO_2 g/kWh	1132	578	1120	574
SO2 mg/Nm3	206	209	63	62
SO2 g/kWh	0.9	1.0	0.3	0.3
NOx mg/Nm3	255	190	350	260
NOx g/kWh	1.2	0.9	1.6	1.2

Table 14 12MWe CFBC Systems – Environmental Results

Capital Cost MECU (1998)	PN23	PN24	PN25	PN26
Coal Type	Federal	Federal	Bellambi	Bellambi
Biomass	None	straw	None	Straw
Solids Recp & Storage	3	6	3	6
CFBC	11	12	11	12
Steam Turbine	7	7	7	7
Steam System & Stack	2	2	2	2
Water Treat/Cooling	1	1	1	1
Total MECU	24	28	24	28
ECU/kWe	1910	2260	1870	2230
BESP ECU/MWh	61.5	86.4	59.2	84.8

Table 15 12MWe CFBC Systems – Economic Results

Co-combustion System	PN2	PN9	PN14	PN15	PN16	PN21	PN22	PN21	PN22
System Compared with	PN1	PN8	PN13	PN13	PN13	PN13	PN13	PN1	PN1
Increase in BESP (ECU/MWh)	5.9	6.1	23	11.7	4.3	23.2	42.9	47.8	67.5
Reduction in CO_2 Emissions (g/kWh)	149	163	540	515	535	1107	1107	759	759
Cost ECU/t CO_2	39.5	37.4	42.6	22.7	8.0	21.0	38.8	63.0	88.9

Table 16 Cost of Reduction CO_2 Emissions

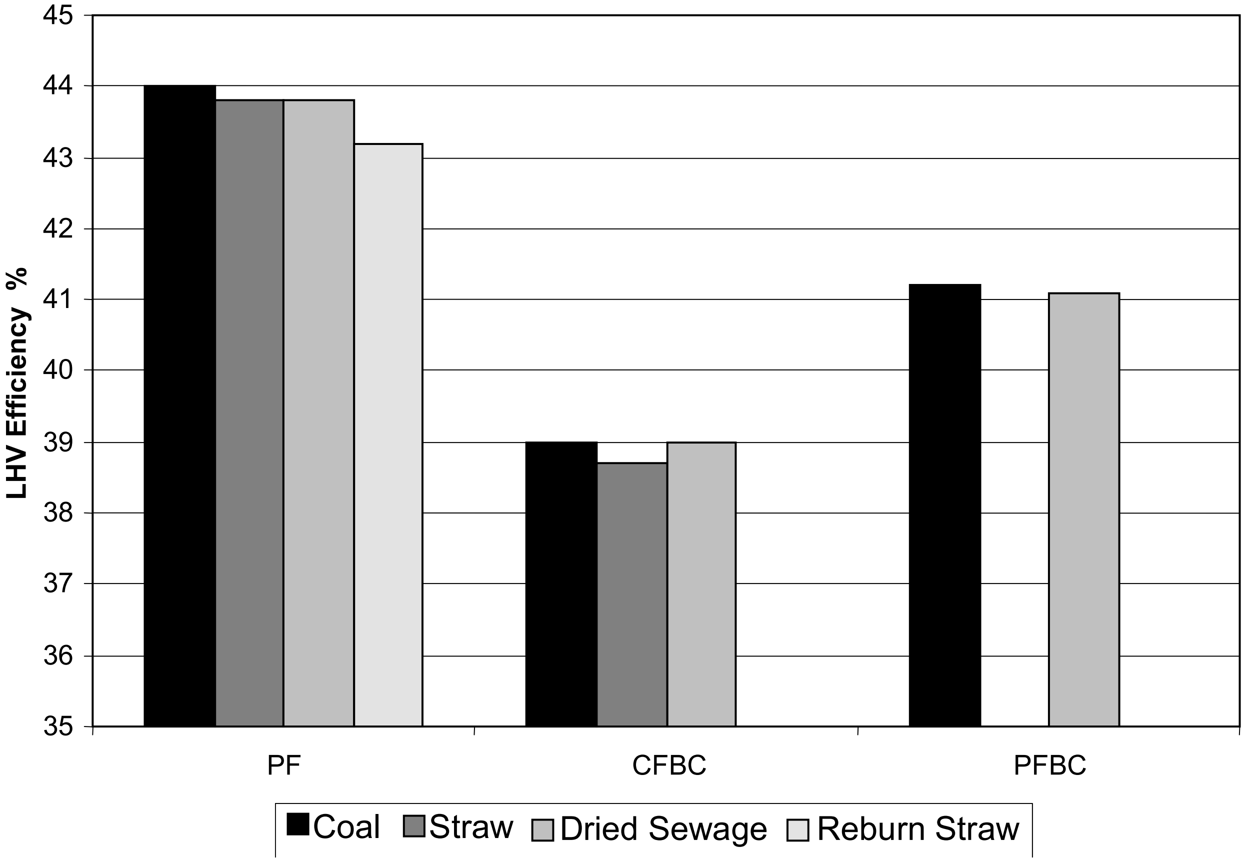

Figure 1. Efficiency of Large Scale Systems

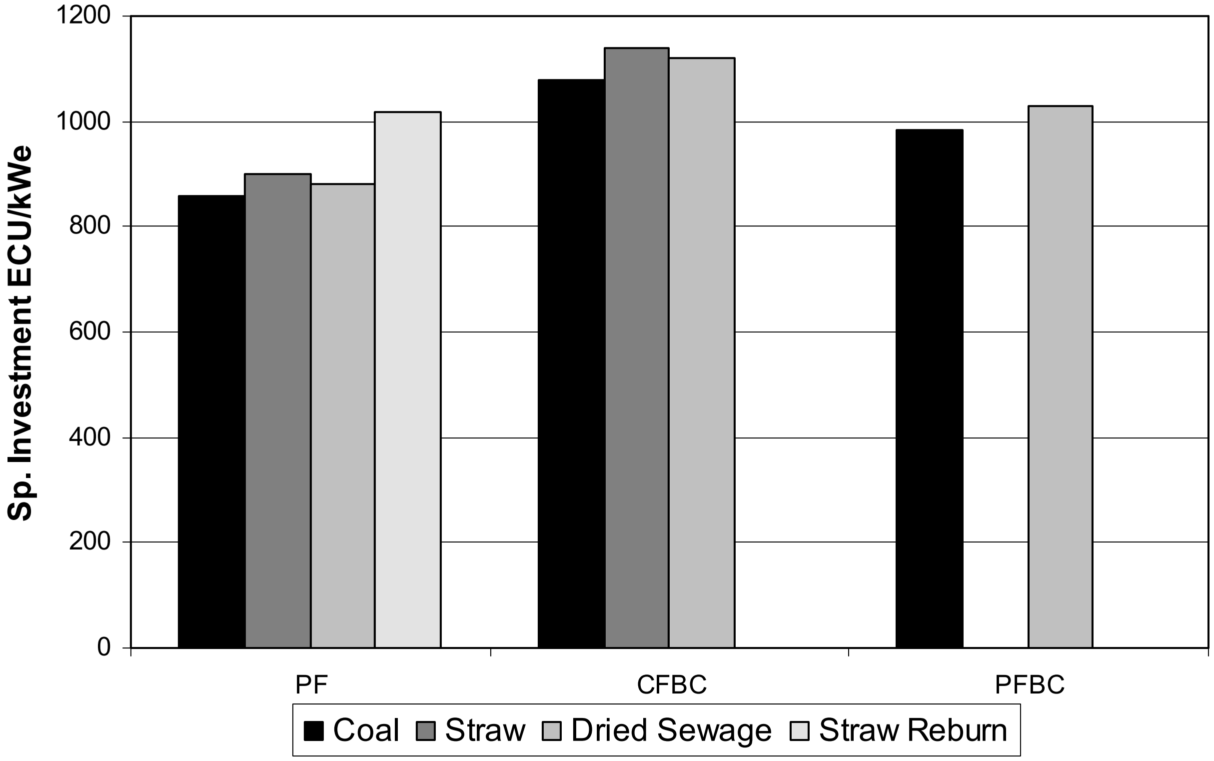

Figure 2 Specific Investment of Large Scale Systems

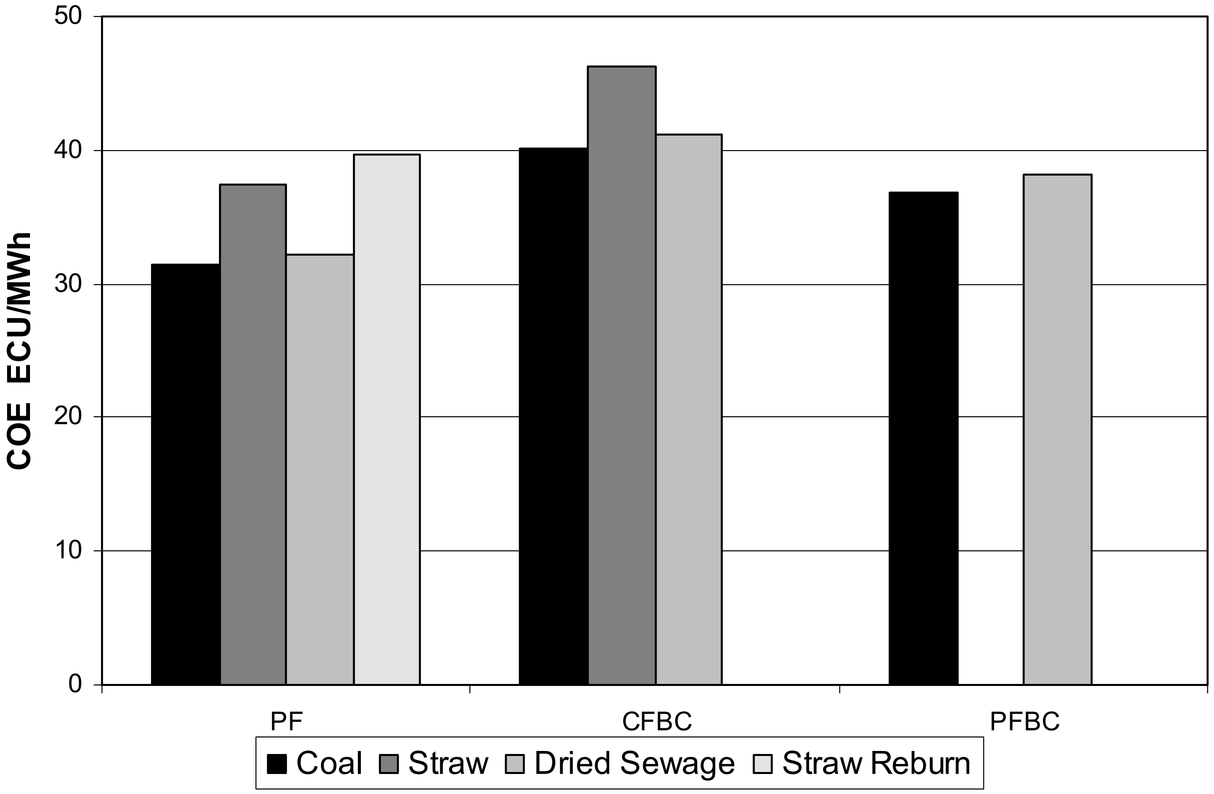

Figure 3 BESP of Large Scale Systems

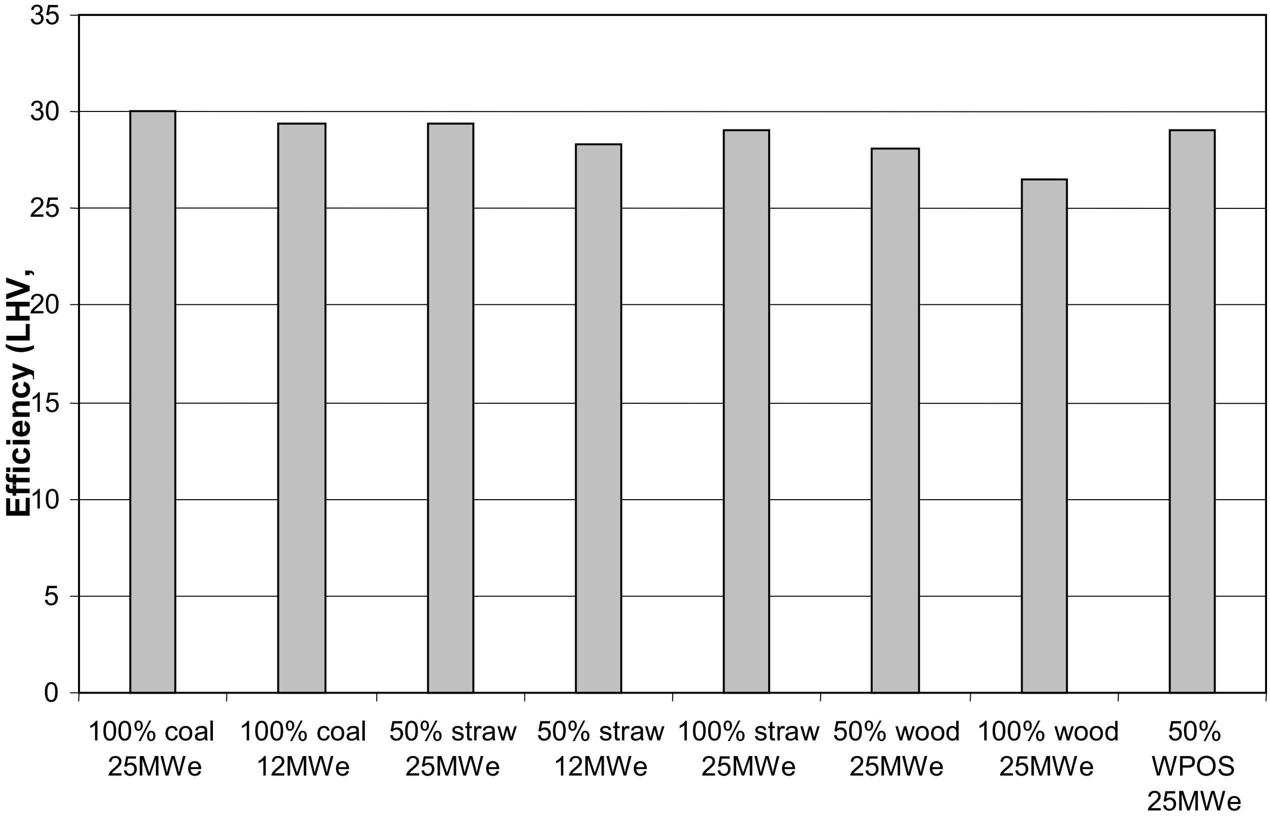

Figure 4. Efficiency of Small Scale Systems

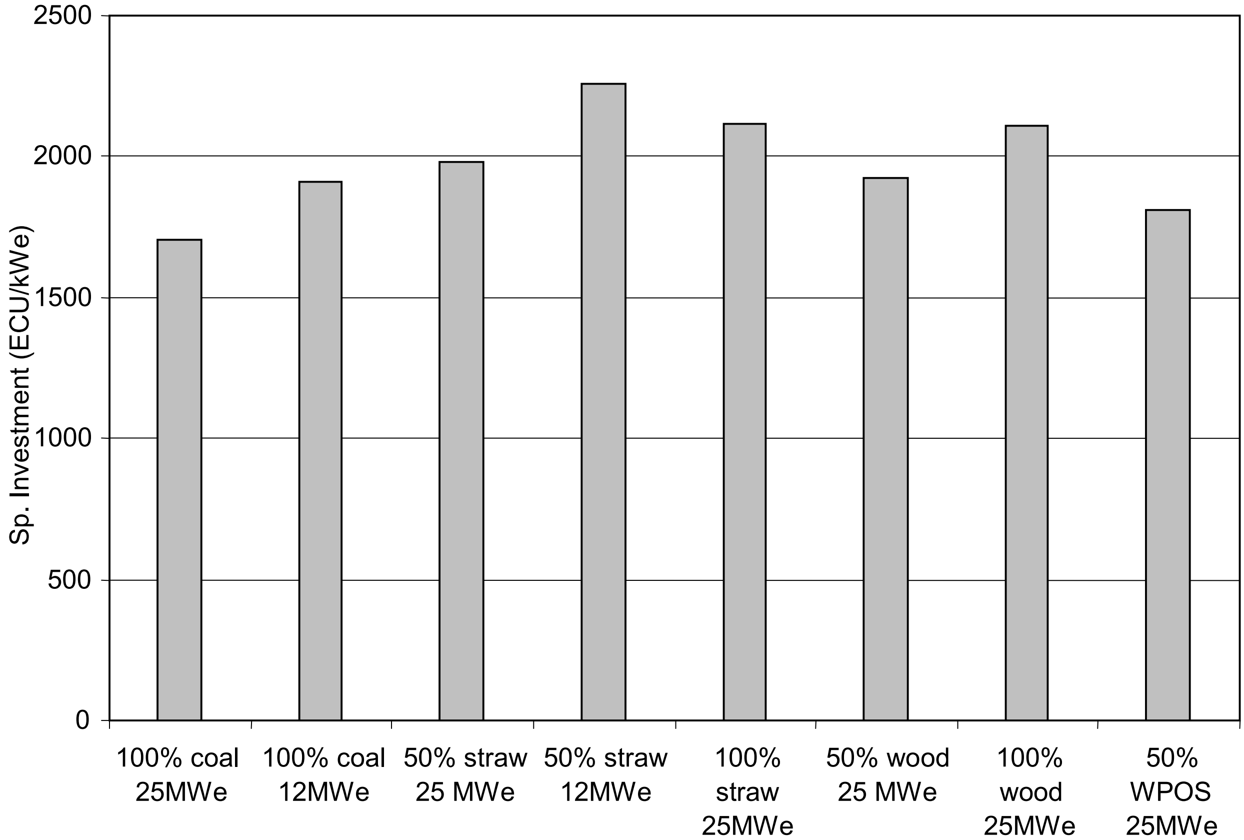

Figure 5. Specific Investment of Small Scale Systems

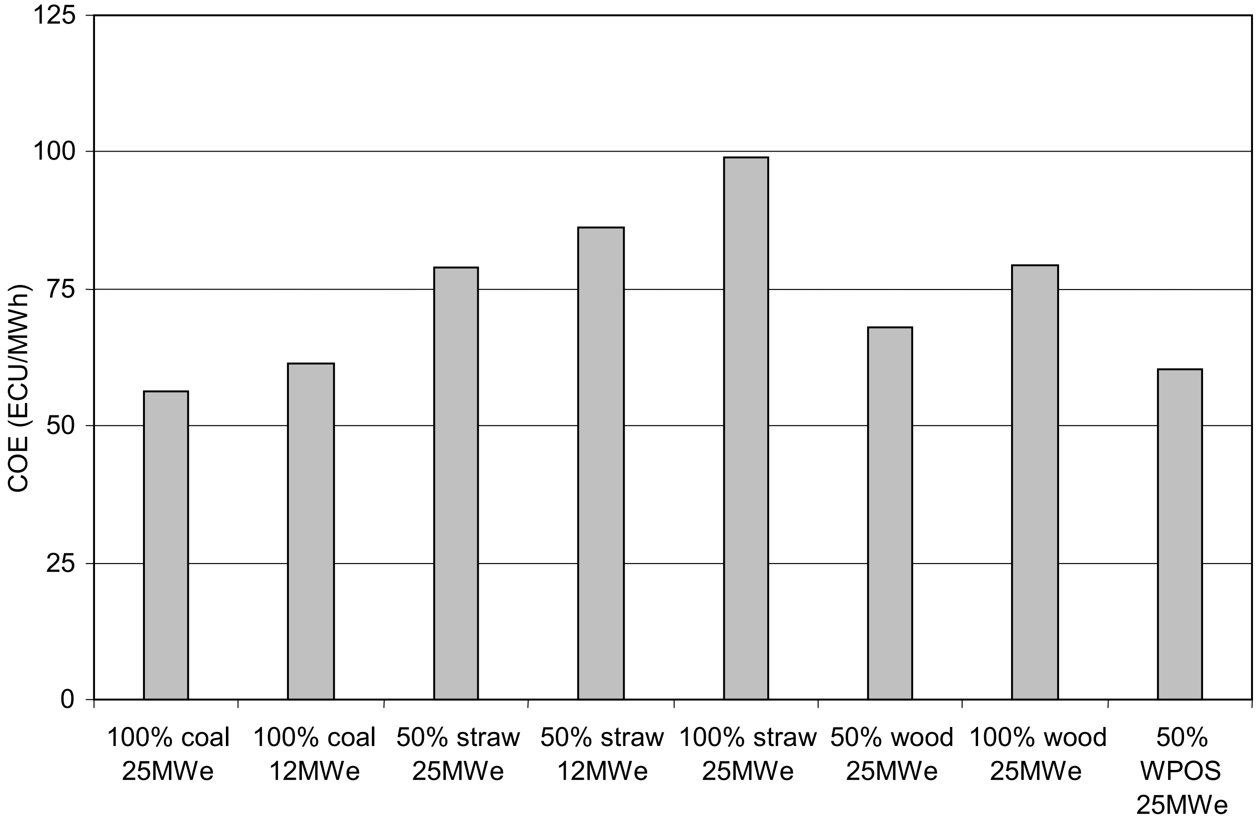

Figure 6. BESP of Small Scale Systems

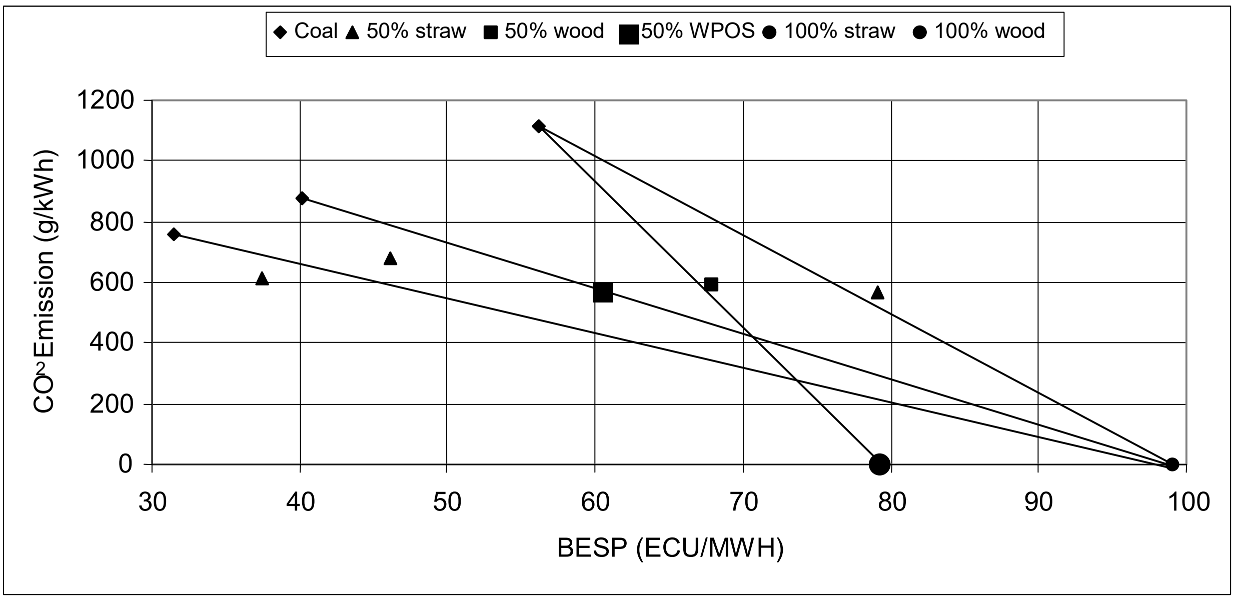

Figure 7 Economics of CO_2 Emission Reduction