Imperial College

OF SCIENCE, TECHNOLOGY AND MEDICINE

INTERNATIONAL ENERGY AGENCY (IEA) BIOENERGY TASK40 ON:

‘Sustainable International BioEnergy Trade:
Securing supply and demand’

Co-firing Report- United Kingdom

Report prepared by:
The Bioenergy Group (BEG)
Imperial College London
Centre for Energy Policy and Technology (ICEPT)

Miles Perry & Frank Rosillo-Calle

Report T40UK02R
November 2006

Executive Summary

The Role of Task 40

Task 40 was established by the International Energy Agency (IEA) in December 2003 with the aim of focusing on international biotrade and its wider implications[1]. International biotrade has expanded rapidly in recent years. Forestry and agricultural residues, wood chips, pellets and briquettes for use in co-firing and green power, and bioethanol and biodiesel for transport, are all now traded at significant scales in national, regional and global energy markets. The driving force behind the expansion in bioenergy is the potential it holds in providing an affordable and practical renewable source of energy for climate change mitigation, energy security, and rural development.

In order to initiate the development of the framework for the sustainable provision of biomass for energy globally, Task40 has outlined key short-term objectives as follows:

- Provide information, modelling tools, environmental impact analyses etc. for evaluating biomass markets at different levels.
- Evaluate the factors influencing the supply and demand of biomass for energy.
- Investigate biotrade and exchange national experiences.
- Identify strategies to overcome biotrade barriers.
- Assess sustainability criteria for biotrade and provide “best practice guidelines”.
- Increase public awareness of international biotrade

The Role of UK Task 40

UK became a full Member of IEA Task 40 on 1st January 2006. One of the deliverables agreed by the Task 40 membership was the preparation of Country Reports (see T40UK1R for UK report). In addition, UK Task 40 agreed to prepare a Co-firing Report to assess the potential of this rapidly growing market in the UK.

UK is increasingly dependent on energy imports as North Sea oil and gas reserves are running out. Bioenergy remains one of the key components for the provision of low carbon energy in the transport, electricity and heat sectors. The key national instruments for incentivising these bioenergy markets are either in place or under active development e.g. the Renewables Obligation (RO) and the proposed Renewable Transport Fuels and Heat Obligations. Biomass is likely to be the major potential source of low carbon energy in the UK; this role has been further reinforced by the Energy Review which proposes to increase the use of RE. However, given its limited indigenous potential, a significant share may need to be secured through sustainable and reliable imports. Areas of particular interest for biotrade in the UK include biodiesel and bioethanol for transport and woody biomass and crop residues for CHP and co-firing.

---

[1] For further details of Task 40 objectives, visit www.bioenergytarde.org

Introduction

The co-firing of biomass with coal in the UK represents a major market for imported biomass. Around 1.5 million tonnes of biomass was co-fired in the UK in 2005. Over one million tonnes of this biomass was imported.

This report provides a review of the history and current status of the co-firing sector in the UK, demonstrates the impact of the sector on the UK's bioenergy trade and compares the UK co-firing scene to experiences in other countries. It also examines the effect that changes in legislation can have on the level of co-firing in the UK, and therefore on the level of bioenergy trade. The report consists of two main parts. The first part provides an overview of the co-firing sector and technologies; the second part looks at historical background, legislation, and possible future directions.

Overview of Coal Technologies

Since co-firing is not a standalone technology, its future depends on the future of fossil fuel power plants – in particular coal. Subcritical pulverised fuel (PF) plants are currently the most common type of coal plant in the UK and around the world. The average thermal efficiency for this type of plant is 36%. Newer coal plants employing supercritical or gasification technology are likely to be able to achieve 40-45% efficiency, with considerable greenhouse gas emissions savings.

Emissions Control Techniques

Emissions savings can also be achieved through cleaning of the coal prior to combustion and use of re-burning and selective catalytic reduction technologies. The most promising avenue for emissions reduction comes from emerging carbon capture and storage (CCS) technology. CO_2 can be captured post-combustion from the flue gas at the power plant. This requires use of a chemical or physical solvent. The costs of post-combustion capture are highest in gas streams with a lower concentration of CO_2. Pre-combustion capture can be practised in gasification plants. Here a concentrated stream of carbon monoxide is produced from the gasification of the coal, making the process less costly than post-combustion capture.

Co-firing Methods

UK power plants use direct co-firing. This is where combustion of biomass and coal take place in the same boiler. The coal and biomass can either be co-milled or injected separately into the boiler. Typically, coal mills can handle 10-15% biomass. Higher proportions of biomass co-firing can be achieved through investment in direct injection systems, co-firing of biomass and coal in separate boilers with a common steam link or employing advanced technology such as biomass gasification.

Technical Barriers to Co-firing

Biomass has different properties from coal. It is bulkier and therefore requires storage space and it degrades and therefore must be used quickly. In addition, the moisture content of the biomass can corrode the boiler and create mould and dust hazards while the volatility of some biomass increases fire risk. Co-firers who rely on the sale of coal ash for concrete must also ensure that the presence of biomass ash in the coal ash does not prevent the ash from meeting the required technical specifications.

Electricity Generation in the UK

Coal was largest single source for UK electricity until 1999 when it was overtaken by gas, thanks to the use of combined cycle gas turbine technology. However, the use of gas has stalled in recent years while the recent Energy Review published by the UK Government confirmed that coal would have “a role to play” in the UK’s energy future. However, coal plants totalling 7.4 GW of generating capacity will close by 2016 rather than upgrade their emissions control equipment as required under the EU Large Combustion Plant Directive. Some generators have announced plans to build clean coal plants though none are yet under construction.

UK Co-firing Scene

Co-firing began in 2002 when it was made eligible for credits under the Renewables Obligation system. 2.5 TWh of electricity was generated from co-firing in 2005, a 148% increase on the previous year. It was initially intended that co-firing be given temporary support as a means of creating a market to support energy crop production in the UK. However, the requirement to use energy crops for co-firing has been successively relaxed and co-firers have preferred to use biomass residues as feedstock.

The initial growth in co-firing was rapid since little investment is required to co-mill low proportions of biomass, making co-firing a competitive technology relative to other renewables (wind, solar etc.). At the same time, the apparently temporary nature of co-firing support meant that co-firers did not invest heavily in specialist equipment. Also, little investment was made in the processing equipment or supplier contracts necessary to co-fire energy crops. This was partly due to ongoing uncertainty over the precise definition of an ‘energy crop’ under the legislation.

From April 2006, the cap on the support awarded for co-firing has been tightened, resulting in an inevitable decrease in the level of biomass co-fired. While the amount of co-firing eligible for Renewables Obligation Certificates (ROCs) remains capped, co-firers who have both electricity generation and supply businesses remain in a better position to continue co-firing since these companies do not have to rely on selling their co-fired ROCs to third parties. Since biomass is considered carbon neutral, the economic viability of co-firing is also helped by its contribution to carbon abatement under European Emissions Trading Scheme (EU-ETS). However, the carbon price is not yet sufficiently high to support the commercial co-firing of biomass without further support.

Co-firing and International Bioenergy Trade

At least 74% of co-fired biomass (over 1 million tonnes) comes from imports. The most common products are palm residue, palm oil, olive cake, tall oil and wood pellet. Given that the UK co-firing market is limited by the Renewables Obligation cap (rather than by cost or technology), a different policy regime could see biomass imports increase at least threefold without the need for investment in advanced co-firing technology.

Palm oil and tall oil are used as an ignition fuel in power plants, replacing heavy fuel oil. Palm kernel expeller is a residue from palm oil production. It is also used as animal feed. Since the production of palm oil is predicted to increase in years to come (as a result of demand for biodiesel), availability of palm kernel expeller should increase significantly.

Tall oil and wood pellet both come from residues from the forestry and paper industries mainly in Scandinavia, Russia and Canada. Production of wood pellet across the world is expanding rapidly although there is also strong growth in demand for pellets for commercial and domestic heating in European markets. Some use has been made of products such as shea and sunflower residue. Use of products such as these could expand considerably if secure, affordable supplies are found. At the moment, most imported feedstock arrives into the UK in a form suitable for co-milling or injection into the plant. In future, it may become profitable for operators to establish facilities where both domestic and imported feedstock can be processed for co-firing and other uses. This is a promising area for future study.

Co-firing and Energy Crops

As the co-firing legislation stands, co-firers wishing to continue after 2009 will be required to use an increasing proportion of energy crops in their biomass mix. The Government’s Energy Crop Scheme awards payments to farmers who grow miscanthus or short rotation coppice. Around 20,000 hectares of these crops will be planted by 2007/08. In the medium-term, large amounts of co-product from transport biofuel plantations are expected to become available for use as bioenergy. The Renewables Obligation allows these co-products to be defined as energy crops for the purposes of co-firing, although the regulator reserves the right to decide on crop eligibility on a case-by-case basis.

Future of Co-firing in the UK and the potential impacts on international biotrade

Despite the current rules’ emphasis on co-firing support being temporary and directed towards the cultivation of traditional energy crops, the recent Energy Review did acknowledge that co-firing should have a long-term role in the UK’s electricity generation. This is especially important if the current generation of pulverised fuel coal-fired power plants are to be replaced with new coal facilities.

A consultation document has been released outlining proposed changes to the co-firing rules. These changes include removing the link between the co-firing of energy crops and other forms of biomass from 2007. This change would be extremely positive as far as biotrade is concerned since the viability of co-firing biomass would depend exclusively on its own commercial merits rather than being linked to those of energy crops. In the longer term the consultation document propose the replacement of the Renewables Obligation’s current 1 ROC = 1 MWh framework. Instead different technologies would be allocated different ROC bands. In this way, the cap on co-fired ROCs would be replaced with a ROC value of less than 1 ROC per MWh.

Given that co-firing is one of the most economical forms of renewable electricity generation, a switch to banding could expand the market for imported biomass considerably. However, no information on the calibration of the bands is yet available. This will be crucial in determining the competitiveness of co-firing under the future ROC system.

Conclusions and Recommendations

As electricity generation from coal appears to have a long-term future in the UK, co-firing can continue to play a valuable role in contributing to renewable energy targets and reducing greenhouse gas emissions. Even if carbon capture and storage were to become viable in the UK, co-firing would still have a vital role since the CO_2 captured from combustion of biomass would in effect amount to a net withdrawal from the atmosphere.

It is recommended that the proposed changes to the co-firing regulations, a move to a banded ROC system and an end to the compulsory co-firing of energy crops, be adopted as government policy. However, the total environmental benefit of co-firing cannot be properly assessed unless the ROC system is also altered to require greater reporting of where imported biomass comes from and how far it has travelled. This way, more ROCs could be awarded to biomass with the lowest greenhouse gas balance.

Acknowledgements

The authors would like to thank all the people and organisations who have offered their time for informal communications during the writing of this report. They include Renewable Fuel Supply Ltd., TallOil UK Ltd. and Dr. Jeremy Woods from the Imperial Centre for Energy Policy and Technology.

In addition, we would also like to thank the following organisations who have provided financial support to UK Task 40:

Drax, DEFRA, DfT, DTI, Czarnikow Sugar, Home Grown Cereals Authority (HGCA) and Wessex Grain

Table of Contents

Introduction

This report provides a review of the history and current status of the co-firing sector in the UK and demonstrates the impact of the sector on bioenergy trade between the UK and other countries. Though the report is UK-focused, it also compares the UK scene to experiences of co-firing and advanced combustion technologies in the Netherlands and elsewhere.

The report is divided into two sections. The first section provides an overview of different technologies for co-firing and generating electricity from coal. It also gives an outline of carbon capture and storage techniques that may be incorporated into future coal-fired power stations.

The second section gives a brief history of co-firing in the UK, stressing the importance of imported biomass for the co-firing sector. It also examines the effect that changes in legislation can have on the level of co-firing in the UK, and therefore on the level of bioenergy trade. The section also examines the commercial viability of co-firing under different carbon price and policy support scenarios.

Part I – Co-firing Technologies and the Future of Coal

Introduction

This section of the report presents a brief overview of the main techniques for generating electricity from coal, the technologies available for emissions reduction and CO_2 capture and storage and the compatibility of each technology with biomass co-firing. The section then looks at the different technologies available for co-firing of biomass and the associated operational issues.

I.1. Overview of Coal Technologies

Since co-firing is not a stand-alone technology, its long-term future is tied to that of fossil fuel generation, and in particular to coal. The major technologies available for coal-fired power plants are described briefly below. Pulverised fuel plant is currently the technology in most common use in the UK and worldwide. Plants that use supercritical, gasification or fluidised bed combustion technologies (FBC), or a combination will be referred to in this report as clean coal technologies (CCTs).

I.1.1 Subcritical Pulverised Fuel (PF) Plant

This is the ‘conventional’ technology used by all coal-fired power stations in the UK. Coal delivered to the power plant is pulverised into a fine powder that is then transported to the furnace where combustion occurs in the presence of a controlled level of air. The heat produced drives steam through a series of tubes, creating electricity from steam-powered turbines. The average thermal efficiency for PF plants is around 36% in the OECD countries and around 30% in China (Wicks & Keay, 2005).

I.1.2 Supercriticial (SC) and Ultrasupercritical (USC) Coal Plant

SC and USC plants operate at higher pressures and temperatures than conventional PF facilities. SC plants are commercially available and capable of achieving thermal efficiencies of around 45%. USC plants offer the prospect of further improvement. It is estimated that a 1% point increase in a plant's thermal efficiency can lead to a CO_2 emissions reduction of around 2%. Therefore the potential exists to reduce emissions by 10 – 25% through replacement of old subcritical plant with SC technology (Wicks & Keay, 2005). If SC technology is introduced through the retrofit of existing PF plant, the costs and barriers to achieving these CO_2 savings could be considerably reduced. This is because plant construction costs and obstacles such as finding a suitable location and obtaining planning permission would be diminished (MitsuiBabcock, 2006). However, retrofitted SC plant is not likely to achieve the same efficiency as specifically designed SC facilities.

I.1.3 Fluidised Bed Combustion (FBC)

FBC can take place in either a bubbling bed (BFBC) or a circulating bed (CFBC) system. In each case, the motion of the bed aids combustion by cleaning the coal while in the combustion chamber. FBC results in lower NOx emissions compared standard PF combustion because it takes place at lower temperatures (800-900^{o}c) than the temperature at which most NOx form (IEA Clean Coal Centre, 2006). In BFBC, combustion of solid fuel takes place in a bed normally composed of sand with a depth of around one metre. In CFBC, the solid fuel particles are held in the flue gas inside the combustion chamber, though a dense bed is still required in the lower furnace. In CFBC, a cyclone is also used so that fuel particles that pass through the combustion chamber can be separated from the flue gas and recycled. An advantage of FBC technologies is that they allow SO_2 to be removed by adding limestone to the bed, removing the need to install flue gas desulphurisation equipment. FBC technologies are normally appropriate for coal feedstocks that have high ash content or variable properties. Thermal efficiency of FBC plants is normally 3-4 percentage points below that achieved by equivalent PF plants. Thermal efficiencies in excess of 40% can be achieved in pressurised fluidised bed combustion (PFBC). This is when the same process takes place under high pressure conditions. It is also possible that efficiency could be improved further by the application of combined cycle technology (IEA Clean Coal Centre, 2006a).

I.1.4 Gasification

Combustion of the solid coal takes place in a shortage of oxygen, producing syngas, a mixture of CO and H_2, which is then cleaned and combusted in the presence of air or oxygen. The highest thermal efficiencies can be obtained from integrated gasification combined cycle (IGCC) technology. IGCC plant maximises efficiency by using the syngas to drive a gas turbine as well as powering a steam turbine through the heat created by the reaction. Current IGCC plants are capable of achieving efficiency of over 40% (IEA Clean Coal Centre, 2006c), though it has been suggested that efficiency of up to 56% is achievable (Wicks & Keay, 2005).

I.2 Emissions Control Techniques

A variety of technologies are available to enhance the environmental performance of coal plant. These technologies are important since any improvement in the environmental performance of coal plants in general will increase the likelihood that electricity generation from coal will continue in the long-term. Some methods involve treatment of the flue gas after combustion and can therefore be applied to any of the above technologies, with or without co-firing. Other methods are more specific to particular types of plant.

I.2.1 Coal Preparation

The coal is washed prior to pulverisation to remove other mineral impurities. This can reduce the ash content of the coal by up to 50%, reducing SO_2 emissions and increasing thermal efficiency (thereby reducing CO_2 emissions per KWh of electricity).

I.2.2 Flue Gas Desulphurisation (FGD)

SOx is removed from the flue gas by spraying the gas with lime or a similar alkaline material. In a typical UK power plant, SOx emissions can be reduced from 2,000 mg/Nm^3 to 500 mg/Nm^3 through FGD installation (DTI, 2005). At present, the take-up of FGD in the UK is increasing as coal-fired plants face the introduction of new SO_2 emission limits from the Large Combustion Plant Directive[2].

I.2.3 Selective Catalytic Reduction (SCR)

NOx emissions are removed from the flue gas by the release of an appropriate reagent (over a catalyst) so that NOx breaks down into atmospheric N_2 and water. The process is able to remove 80-90% of NO_x emissions (IEA Clean Coal Centre, 2006d). Selective non-catalytic reduction is also available. In this case, the reagent is released at higher temperature but without a catalyst. This process is only 30 – 50% effective at reducing NO_x emissions.

I.2.4 Re-burning

Up to 70% of NO_x emissions can be removed by firing a secondary fuel into the upper section of the furnace. The secondary fuel is usually natural gas, though syngas, coal or oil can be used. The hydrocarbons in the secondary fuel react with the NO_x emitted from primary combustion in the lower furnace, reducing the NO_x to atmospheric N_2. There is then a final combustion stage where carbon monoxide and the remaining hydrocarbons from the secondary fuel are combusted in the presence of air. Re-burning usually requires a secondary fuel load equivalent to 10-30% of the plant's total heat input (IEA Clean Coal Centre, 2006b). One advantage of the process is that the same feedstock can be used as both primary and secondary fuel.

I.2.5 Carbon Capture and Storage

Potentially, CO_2 emissions from a given power plant can be reduced by 80-90% through the capture and subsequent storage of emitted CO_2 (DTI, 2006). Though, several technologies exist for the capture of $CO_{2,}$ widespread use of carbon capture and storage (CCS) systems will depend on the establishment of an economic framework that gives generators an incentive to invest in CCS technologies. If CCS

---

[2] The Large Combustion Plant Directive, 2001/80/EC, limits the level of SO_x, NO_x and particulate emissions permissible from large combustion plants. Eventually, plants that do not observe stated emissions limit values are required to close

becomes commonplace in fossil fuel power plants, the co-firing of biomass could greatly increase these plants' CO_2 mitigation. This is because the sequestration of CO_2 derived from 'carbon-neutral' renewable biomass would represent a net withdrawal of CO_2 from the atmosphere. Although many proven CCS technologies exist, further research is needed to minimise the efficiency loss and additional input energy requirements of CCS and perfect techniques for CO_2 storage. The following section describes some of the available CCS technologies, largely based on the overview given in IEA, 2004.

I.2.5.1 Post-Combustion Capture

Post-combustion capture involves the removal of CO_2 from the flue gas of a power plant. This can be through use of a chemical solvent such as amine or a physical solvent such as Selexol (IEA, 2004). The chemical solvent reacts with the CO_2 to form a compound from which the CO_2 can then be extracted. The solvent is heated to break down the compound, releasing high-quality CO_2 which can be captured. The energy inputs required for post-combustion capture are significant. This is because considerable heat energy is needed to separate the CO_2 from the solvent. The need for energy could be reduced by use of alternative solvents (such as sterically-hindered amines) which form a weaker bond with the CO_2.

A physical solvent forms a weak bond with the CO_2 under pressurised conditions. The CO_2 is then released when the pressure is reduced. In this process, energy is required for the pressurisation of the gas. The cost of this process per tonne of CO_2 is inversely proportional to the concentration of CO_2 in the gas such that the cost doubles when the concentration of CO_2 is halved.

Oxyfuel combustion provides a way to improve the purity of the post-combustion CO_2 stream, thus facilitating its separation. Whether this process is economically viable depends on the cost saving in CO_2 separation relative to the cost of producing the oxygen to be used as a combustion gas.

I.2.5.2 Pre-Combustion Capture

Pre-combustion capture is a viable option for gasification plants. The syngas produced by the incomplete combustion of the coal contains a mixture of carbon monoxide and hydrogen. By reacting the syngas with steam in a catalytic shift converter, the gas is converted into additional hydrogen and CO_2. Since the syngas contains a higher concentration of CO_2 than the flue gas, the pre-combustion capture process requires less capital and energy than post-combustion capture.

Physical separation of CO_2 by use of a membrane is a possible means of both pre and post-combustion CO_2 removal. Its most promising application is in the separation of CO_2 from methane at source in the extraction of natural gas. At present, however, membrane technology is not suitable for use in power plants since the membranes are relatively unsuccessful in recovering significant amounts of pure CO_2 (IEA, 2004).

I.2.5.3 Transport and Storage of CO_2

Pipeline is the preferred method of transport for the captured CO_2 since, if local conditions permit, it allows CO_2 to be transported in the gaseous state in which it is captured. Other transportation options, e.g. road, would require the liquification of the CO2 and would therefore increase the energy use and reduce the efficiency of the whole carbon capture process (DTI, 2003). However, once in a liquid or supercritical state, the transport of CO_2 by pipeline or ship is fairly economical. Since CO_2 is 10-100 times denser than natural gas or hydrogen “CO_2 transportation is more akin to oil transportation” (IEA, 2004 p. 79).

The CO_2 can be stored in deep oceans or in a geological feature containing permeable rock that can be sealed with rock impermeable to CO_2. Oil and gas fields that are depleted or near depletion are attractive locations for CO_2 storage since they are known to contain a seal which prevented the escape of the fuel prior to the initial exploitation of the field. The locations will normally have already been mapped as part of the fossil fuel extraction. In addition, the economic viability of capture and storage can be improved by using the CO_2 for enhanced oil recovery (EOR) from mature oil fields. The use of CO_2 for enhanced oil recovery is currently practised in the USA. For example, CO_2 produced from the Great Plains Synfuel Plant in North Dakota is used to recover oil from fields in Saskatchewan, Canada[3].

CO_2 can also be stored in saline aquifers. These are geological features which can either be open, in which case the CO_2 can move laterally along a flat rock formation, or closed, in which case the aquifer has a defined boundary capable of storing the CO_2. This storage option is practised on a commercial basis during gas extraction from the Sleipner field in the North Sea[4]. In this process, a mixture of CO_2 and natural gas is extracted from the field. The CO_2 is then separated and pumped into an adjacent aquifer while the pure natural gas is exported. Research into the technical feasibility of carbon storage is ongoing. Issues to be resolved include the possibility of leakage of the CO_2 back into the atmosphere and the legality of dumping CO_2 at sea. It is likely that former oil and gas fields will be able to store CO_2 in the long-term since they have stored fossil fuels in the past and the areas have already been extensively mapped. There are several trial CO_2 storage sites operating worldwide where the behaviour of the CO_2, once injected, is constantly monitored. See http://www.co2captureandstorage.info for a database of projects.

Although there is currently no commercial example of carbon capture and storage operating at an electricity plant, the technology required is merely a combination of the capture and storage techniques above. The possibility of geological CO_2 storage is currently being considered for several new IGCC plants in the UK (DTI, 2006b; E.ON UK, 2006)

I.2.5.4 Potential Costs of CCS

In IEA, 2004, it was estimated that the total cost of CCS at present would range from \$50-\$100 (€63 - €126) per tonne of CO_2 captured. Transportation costs are estimated at \$1-\$5 per tonne of CO_2 transported 100km by pipeline or \$15-\$25 per tonne of CO_2 transported 5,000km by ship. The least efficient carbon capture technique was found

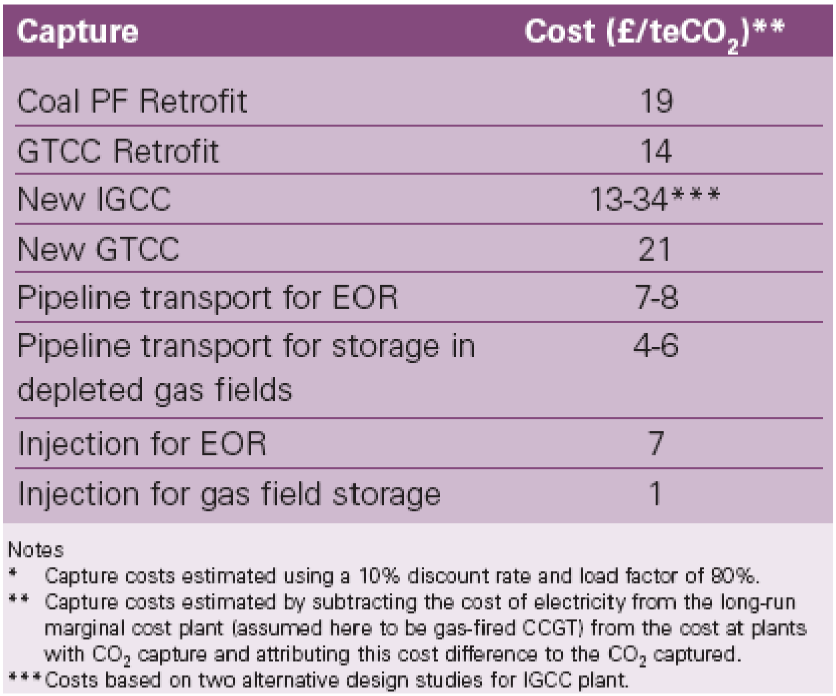
---

[3] http://www.dakotagas.com/Products/index.html

[4] http://www.statoil.com/statoilcom/SVG00990.NSF?OpenDatabase&artid=01A5A730136900A3412569B90069E947

to be the use of chemical solvent in a conventional PF power plant. This required a 39% increase in the input energy required by the plant and led to a 12% loss in efficiency. By contrast, the use of Selexol, a physical solvent, in an IGCC coal plant reduced the additional fuel requirement to 15% with a 6% efficiency loss. In general, CCS costs per tonne of CO_2 captured are lower for processes that produce a stream of concentrated CO_2. This means that CO_2 capture is cheaper per tonne for coal-fired power stations than gas-fired power stations. It also means that it is cheaper to apply CCS to IGCC coal plants than to conventional PF plants. This is interesting because, without CCS, IGCC plants would usually be more costly. In Table 1, below, the projected capture, transport and storage costs for a variety of options are compared. Note that, depending on plant design, carbon abatement from an IGCC can be more cost effective than from a retrofitted PF plant. This means that the establishment of an appropriate incentive framework to encourage CCS could make the difference between whether PF plants or IGCC become the most economical choice of coal generation in future.

Table 1: Comparison of Costs for Carbon Capture and Storage Options in the North Sea



Capture	Cost (£/teCO_2)**
Coal PF Retrofit	19
GTCC Retrofit	14
New IGCC	13-34***
New GTCC	21
Pipeline transport for EOR	7-8
Pipeline transport for storage in depleted gas fields	4-6
Injection for EOR	7
Injection for gas field storage	1

Notes

* Capture costs estimated using a 10% discount rate and load factor of 80%.

** Capture costs estimated by subtracting the cost of electricity from the long-run marginal cost plant (assumed here to be gas-fired CCGT) from the cost at plants with CO_2 capture and attributing this cost difference to the CO_2 captured.

*** Costs based on two alternative design studies for IGCC plant.

Source: DTI, 2003 NOTE: Perhaps would be a good idea to re-type this table

Costs for the eventual storage of the CO_2 are generally low, as Table 1 shows. However, costs can vary greatly since they are dependent on the location of the storage site. It is also possible that CCS costs can be partly offset by sale of recovered oil, gas or coal-bed methane.

I.3 Co-firing Methods

In general, the techniques available for co-firing can be classified as either direct or indirect. In indirect co-firing, the ash from the biomass is kept separate from the coal ash – i.e. separate combustion of the two feedstocks takes place. In direct co-firing the biomass and coal are fired together so that a mixed ash is left behind. Possible co-firing techniques include:

I.3.1 Direct Co-firing by Co-milling

This was initially the most popular method of co-firing in the UK (DTI, 2005) though several plants now operate direct injection systems. In co-milling, coal and biomass are pulverised together at a mill to achieve size reduction and drying of both feedstocks. The fuel is then fed into the furnace for operation of the coal-fired plant. This method has very low capital cost as little or no modification to existing coal plants is required and both feedstocks are blended simultaneously. The major disadvantage of co-milling is that the presence of the biomass degrades the grinding performance of the coal mills (DTI, 2005). Up to 10% sawdust can be co-fired with coal at E.ON’s Ironbridge plant (Goh, 2005) while literature suggests that the maximum weight of biomass that can be co-milled is around 15% (DTI, 2005; Spath & Mann, 2001).

I.3.2 Direct Co-firing by Direct Injection

Biomass is fed directly into the same boiler as the coal, but via a separate feeding system. This method is more costly than co-milling, since it requires greater modifications to existing coal plant. However, direct injection can be a relatively simple and cost-effective way to increase the proportion of biomass co-fired at a typical coal plant. A direct injection mechanism can take six months to become fully operational and repay the initial investment in six months (RWE npower, 2006b). Direct injection also has the advantage that the biomass does not affect the flow of the pulverised coal or the performance of the coal milling equipment. In addition, direct injection can employ separate burners for each fuel type. This allows the biomass and coal to be fired in the same boiler but ensures separate combustion of each fuel. The separate injection mechanism also provides additional control since biomass with poor milling qualities can be rejected without affecting the coal stock.

I.3.3 Indirect Co-firing

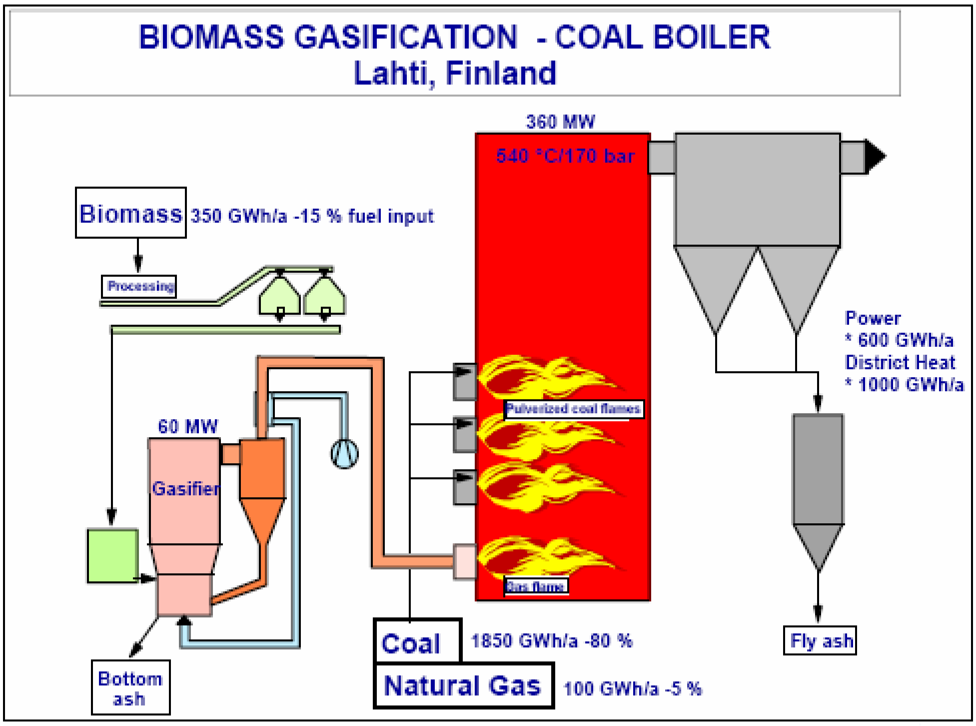
This occurs when the combustion of the biomass and coal occur separately. It has the advantage of allowing maximum flexibility since it is possible to combine almost any combination of feedstocks and combustion techniques according to the operator’s requirements. The most indirect co-firing plants may consist of separate fossil fuel and biomass boilers linked only by a common connection to a steam turbine. In several plants, the combustion of biomass and fossil fuels occurs in separate boilers that share common turbines and condensers (IEA Clean Coal Centre, 2002). The separation of feedstocks during combustion also ensures that the biomass ash does not contaminate the coal ash, which can be sold as a construction material.

I.3.4 Co-firing with oil or natural gas

Co-firing of palm oil has taken place on a trial basis at Littlebrook, an oil-fired power station in the UK. Aside from this trial, there has not been large-scale commercial co-firing of biomass in the UK other than with coal. Electrabel also trialled co-firing of bio-oil from pyrolysis at the gas-fired Harculo power station. This co-firing was halted in 2005 due to technical problems and a reduction in the subsidy given to green power generation (Electrabel, 2005). Nevertheless, there is considerable potential for natural gas to be fired with biomass in a number of the technologies above. When used as a reburn fuel, 5% - 25% natural gas can reduce NO_x emissions from boilers firing coal, biomass and/or MSW by 50-70% (Babu, 2001).

In addition, natural gas can be co-fired with biomass as part of a multi-fuel system such as that operating in Lahti, Finland. Here, as Figure 1 shows, gasified biomass, pulverised coal and natural gas can be fired simultaneously through the use of separate burners attached to a single multi-fuel boiler.

Figure 1: Co-firing of Biomass, Coal and Natural Gas in Lahti, Finland



Source: Kurkela, 2002

In terms of CCS, the cost per tonne of carbon abatement is greater for combined cycle natural gas plants than for coal plants due to the lower concentration of CO_2 emissions in the flue gas.

I.3.5 Co-firing with Clean Coal Technologies: some examples

Given the possibility of co-firing fossil fuels with biomass directly or indirectly, the possibility exists for any future fossil fuel plant to incorporate a biomass co-firing element. This section reviews documented examples of co-firing biomass using CCTs.

Pletka (2003) evaluates the feasibility of retrofitting a coal-fired plant in the US with a system where a gasifier is used to produce syngas from biomass. The syngas can then be fed directly into the main coal boiler and/or used as a reburn fuel for NO_x reduction. One advantage of this system is that there are no theoretical limits to the proportions in which biomass and coal can be used. Also, gasification of the biomass reduces the impurities being fired in the coal boiler and hence reduces corrosion. The option is also available to fit a cyclone to the gasifier so that the syngas is cleaned before entering the boiler. This increases the capital cost of the modification but minimises the amount of impurities entering the coal boiler and ensures that the biomass char does not affect the saleable coal ash. The model used in the study predicted a slight improvement in thermal efficiency of the plant, owing to the reduced throughput of coal. The economic viability of the retrofit was found to depend on local factors such as the relative abundance of coal and biomass, the level of emissions limits and incentives for renewable energy use or carbon reductions. In the chosen location (Nebraska) the cost of coal was relatively low. It was found that a premium 1.4-1.8 US cents/kWh on top of the price of electricity would be needed to guarantee the viability of the project. This is comparable to the 1.8 US cent/kWh tax credit offered to wind power in the US and is comparable with the premium that would be needed to incentivise other types of renewable electricity generation (wind, solar, standalone biomass, hydroelectric).

McIlveen-Wright et al. (2006) examine the viability of combusting coal together with 20% biomass (by thermal input) in both large-scale CFBC and gasification systems. The addition of 20% biomass was not found to have a significant effect on the efficiency of the plant in each case.

Examples of the indirect co-firing of biomass with fossil fuels can be found at Aabenraa and Avedøre in Denmark. At Aabenraa, there are three separate boilers where straw, wood chip and coal are combusted in parallel. Steam is heated to progressively higher temperatures by each feedstock before driving a steam turbine to produce electricity (California Biomass Collaborative, 2004). The Avedøre 2 plant was also intended to fire fossil fuels and biomass in parallel boilers. Originally the main USC boiler was intended to fire coal dust while straw was fired in a second boiler. However, a retrofit of the main boiler was subsequently carried out to allow the boiler to fire a variety of fuels such as wood pellet or natural gas (DBDH, 2005).

I.3.6 Co-firing in the Netherlands

In the Netherlands, co-firing of biomass with fossil fuels has been practised since the mid-1990s. It began with the co-firing of abundant domestic supplies of waste wood and sewage sludge before the sector diversified into other domestic and imported fuel sources (Raven, 2005; Juninger et al., 2006). The 2002 coal covenant has also been important in encouraging the continued development of co-firing in the Netherlands. This is an agreement between the Dutch Ministry for the Environment and the electricity producers which demands a 3.2 Mt reduction in CO_2 emissions between 2008 and 2012.

The Netherlands has a number of power stations that co-fire biomass using advanced technologies as well as coal-fired power plants that use direct injection and co-milling technologies similar to those used in the UK (see sections 6 & 7 of this report). The Amer 9 coal-fired power plant has been fitted with a gasifier, allowing the plant to co-fire waste wood. This is the result of a research project into ways of disposing of the Netherlands' abundant supply of waste wood – a resource that power plants were able to acquire for a negative fee due to high landfill charges. The gasifier is capable of producing 5% of the plant's energy requirement. It was originally intended that the syngas produced would be cleaned extensively of impurities prior to combustion in the main boiler. This would have the advantage of allowing greater flexibility in the fuels that could be gasified at the plant. However, due to the severity of damage caused to the syngas cooler, a simpler design was eventually used where the syngas is only partially cleaned prior to combustion (IEA Task 32, 2006).

An existing IGCC coal plant at Buggenum has also been converted to fire 70% coal and 30% biomass. Biomass co-fired includes wood, chicken litter and sewage sludge (Meijer et al., 2006).

I.4. Technical Barriers to Co-firing

Relative to coal, biomass has three main undesirable properties. It is bulkier than coal, more volatile and has higher moisture content. Biomass degrades more quickly than coal, meaning that it cannot be stored on-site for a long period of time (DTI, 2005). This also means that a co-milled mixture of biomass and coal must be prepared shortly before the fuel is to be fired or else the quality of the feedstock will be affected by the degradation of the biomass. The calorific value of the biomass is also important as this determines the rate at which biomass must be fed into the boiler in order to maintain the output level of the plant. Biomass that is lower in density also requires a greater volume to be milled in order to produce a given fuel input. It is also important that the moisture content of the biomass is as low as possible. A high moisture content adversely affects the fuel performance of the biomass, either requiring greater treatment before combustion in order to dry the fuel or through adversely affecting its combustion performance in the boiler. Corrosion of the boiler can also be worsened through the high chlorine and alkali content of biomass fuels (NREL, 1998). Corrosion can be lessened through selection of low chlorine biomass fuels and by reaction of the alkali chlorides with the sulphur contained in the fuel to form less corrosive alkali sulphates and hydrochloric acid.

Co-firing of biomass also entails health and safety risks in addition to those created by the firing of coal. These have to be managed carefully. Biomass typically contains 80% volatile matter on a dry-ash-free basis, compared to 45% for bituminous coals and 10% for anthracitic coals (DTI, 2005). This means that co-firing feedstock has the potential to be considerably more explosive. The Department for Trade and Industry (DTI) Best Practice literature suggests that the biomass-coal mixture should contain a maximum of 45% volatile matter overall so as to remain within the parameters ordinarily found in different coal supplies. It was also found that provided the mixture contains no more than 15% biomass by weight, the explosive characteristics of the mixture are dominated by the properties of the coal. Additional health hazards from biomass handling include the higher risk of respiratory problems due to the build-up of dust and mould where the biomass is stored.

Biomass fuels typically have a lower ash and sulphur content than coal. In the UK, significant penalties exist for the disposal of coal ash, incentivising the sale of ash to secondary markets (such as cement manufacture). The effect of co-firing biomass on the saleability of the coal ash is therefore crucial to the economics of co-firing. European Standard EN 450 “Fly ash for concrete” allows for the fly ash to be derived from alternative fuels, within specified limits. Several studies to date (Boylan et al., 1999, Meijer, 2006) have found that co-firing biomass in limited percentages does not have a significant effect on the quality of the fly ash. In Boylan et al., 1999, it was found that using fly ash derived from co-firing of coal with 30% did not affect the plastic or hardened properties of the concrete produced. It is necessary nevertheless for the buyers of the fly ash to be involved in the testing of fuels for co-firing to ensure that fly ash still meets their specifications. However, in the case of indirect co-firing it is possible to keep the coal ash separate from the biomass-derived ash, thus guaranteeing the integrity of both. It is possible that separate secondary markets also exist for the biomass-derived ash. For example, ash derived from the combustion of straw can be returned to the fields for use as fertiliser (EUBIONET, 2005).

Part II - Co-firing and Bioenergy Trade in the UK

Introduction

This section gives a brief history of co-firing in the UK, stressing the importance of imported biomass for the co-firing sector. It also examines the effect that changes in legislation can have on the level of co-firing in the UK, and therefore on the level of bioenergy trade. The section also examines the commercial viability of co-firing under different carbon price and policy support scenarios.

II.1 Use of Coal for Electricity Generation in the UK

Until 1999, coal was the largest fuel source for electricity generation in the UK. It accounted for 67% (43 Mtoe) of fuel for electricity generation in 1970. By 2005 this had fallen to 37% (33 Mtoe). Prior to 1990, less than 1 Mtoe of natural gas per year had been used for electricity generation. By 2005, this had risen to 29 Mtoe, or 33% of fuel input. The increase in the contribution of gas to final electricity output is even greater since the so-called *dash for gas* was driven by the rapid take-up of combined cycle gas turbine (CCGT) technology, where the same combustion of gas at the power plant drives both a gas turbine and a steam turbine, increasing the efficiency of the plant. By 2005, 148 TWh of electricity were provided by CCGT. This amounts to 39% of all generation and only 2.5 TWh less than all other conventional thermal technologies (i.e. single turbine oil, coal and gas plants) (DTI, 2006c).

UK gas production peaked in the year 2000, however, and is now in decline while wholesale gas prices have risen substantially since the year 2000. In 2005, both electricity from CCGT and total gas used in electricity generation declined from the 2004 levels. At the same time, 59 Mt of coal (84% of total coal demand) was used in electricity generation, compared to 51 Mt in 1999. The recent Energy Review (DTI, 2006) stressed that coal will continue to have a “role to play” (p. 17) in UK electricity generation.

II.1.2 Future of Coal Generation in the UK

From 2008, the requirements of the Large Combustion Plant Directive come into effect. As a result, operators of each affected UK coal plant – those approved before 1987 whose thermal fuel input is at least 50 MW – have to choose whether each facility will 'opt-in' or 'opt-out' of the directive. Opting-in means plants will have to observe new lower emissions limit values (ELVs) for SO_2, NOx and dust, which in practice will require all plants that have not already done so to install flue gas desulphurisation systems by 2008. If plants choose to opt out, they are obliged, after 2008, to cease operations permanently after a further 20,000 hours of operation and no later than 2016. As table 2 shows, 5 coal-fired plants are due to opt-out of the LCPD and are therefore due to close by 2016. These plants have a combined installed generating capacity of 7.4 GW.

The implications of the plant closures for UK co-firing are twofold. Firstly, operators of plants that have opted out of LCPD will not invest in any technologies to increase the level of biomass co-firing if the necessary investment will not be repaid within the 20,000 hour lifetime of the plant. Secondly, it leaves the possibility that the ‘generation gap’ (DTI, 2006, p95) left by the closure of coal (and nuclear) facilities will be filled by the commissioning of new fossil fuel plants incorporating advanced co-firing techniques.

Table 2: LCPD Status of UK Plants Accredited for Co-firing under the Renewables Obligation*

Plant / Operating Company	Installed Generating Capacity (kW)	LCPD Status (Opted in / out)
Kilroot AES Kilroot Power Ltd.	527,200	In
Aberthaw RWE npower	1,552,500	In
Lynmouth Alcan	420,000	Not known
Cottam EDF Energy	2,000,000	In
Didcot 'A' RWE npower	2,100,000	Out
Drax Drax Power	4,065,000	FGD already installed therefore LCPD compliant
Eggborough British Energy	2,000,000	FGD already installed therefore LCPD compliant
Ferrybridge C Scottish & Southern Energy	2,035,000	In
Fiddler's Ferry Scottish & Southern Energy	1,995,000	In
Ironbridge E.ON UK	970,000	Out
Kingsnorth E.ON UK	2,034,000	Out
Littlebrook RWE **	2,220,000	Out
Ratcliffe-on-Soar E.ON UK	2,034,000	In
Rugeley International Power	1,000,000	In
Tilbury RWE npower	1,085,000	Out
Uskmouth Carron Energy	393,000	In
West Burton EDF Energy	2,040,000	In
Cockenzie Scottish Power	1,200,000	Out
Longannet Scottish Power	2,400,000	In
Coal plant opted in	**22,041,700**	
Coal plant opted out	**7,389,000**	

Source: OFGEM, 2006; DEFRA, 2006.

Notes:

* - Opt in/out information correct as at February 2006.

** - Littlebrook is an oil-fired power station

Studies have been commissioned by the DTI to investigate the potential for installing CCT retrofits to existing coal plants under the auspices of the UK Cleaner Coal Technology Programme[5]. In June 2006, the electricity generator and supplier Scottish and Southern Energy announced plans to retrofit an existing PF station with a 500 MW super-critical boiler and turbine, creating the first clean coal plant in the UK (Scottish and Southern Energy, 2006). The development is intended to be ‘capture ready’, allowing the deployment of carbon capture and storage technologies in the future. E.ON UK is investigating construction of an IGCC plant (Modern Power Systems, 2006). Construction of IGCC plant is more costly than retrofitting supercritical components to existing plants. Its advantage is that pure CO_2 is produced, making CCS more cost effective. The final construction therefore depends on the establishment of an appropriate incentive framework for CCS in the UK. RWEnpower and E.ON UK are also considering replacing the opted out Tilbury and Kingsnorth plants respectively with plant incorporating supercritical and carbon capture technology.

II.2 UK Co-firing Scene

In 2005, the UK generated more electricity from co-firing than from wind power for the first time. 2.5 TWh of electricity was generated from co-firing, a 148% increase on the 2004 level. This made co-firing the 3rd largest generator of renewable electricity behind large-scale hydro and landfill gas (DTI, 2006c). Given that there was no biomass co-firing for electricity in the UK before 2002, the development of the sector has been rapid. However, 1.5 Mt of biomass was co-fired by UK power plants in 2005 compared to 52 Mt of coal. This means on average, UK power plants co-fired less than 3% biomass by mass, compared to an estimated technical potential of up 15% for co-milling and higher for advanced co-firing techniques.

---

[5] http://www.dti.gov.uk/energy

II.2.1 Regulatory Framework[6]

The development of co-firing on a commercial scale in the UK began with the establishment of the Renewables Obligation (RO) in 2002. This is a system of tradeable permits in which suppliers of electricity are obliged to produce Renewables Obligation Certificates (ROCs) to guarantee that a given percentage of the total electricity supply was generated from eligible renewable sources. The level of the RO began at 3% in 2002 and will rise to 15% by 2015. Co-firing was originally included as a ROC-eligible activity with the intention that it should be a transitional technology, used temporarily by the electricity supply industry in order to develop a market for UK-grown energy crops. For this reason, co-fired ROCs were initially limited to a maximum of 25% of each supplier's ROC claim. As the RO legislation stands at present (October 2006), co-firing will cease to ROC-eligible from 2016, suppliers will be obliged to claim progressively less of their ROCs from co-firing from April 2006 and a specified percentage of energy crops[7] must be used in the co-firing feedstock from 2009. The Renewables Obligation does not require energy crops to be grown in the UK. However, grant funding has been made available for the development of UK energy crops. See section II.4 below.

From April 2006, the co-firing limit on suppliers' ROC claims fell from 25% to 10%. This has had a significant effect on the co-firing industry, effectively halving the size of the market[8] and meaning that, at present, co-firing remains viable only for vertically integrated companies. These companies are both suppliers and generators of electricity. Since they are the buyers of their own ROCs, they do not need to worry about finding a buyer for them. Table 3 below gives a timetable for the introduction of co-firing restrictions and their effect on the market for both energy crops and other feedstocks. If the composition of the feedstocks remains similar to that seen in 2005, tha majority of the other feedstocks are likely to come from imported residue-based products. It is assumed, for illustrative purposes, that electricity supplied remains at

---

[6] NB - Co-firing regulations are currently under review and are likely to be amended in 2007. See section 11 for details.

[7] The Renewables Obligation defines Energy Crops as "a plant crop planted after 31st December 1989 and grown primarily for the purpose of being used as a fuel"

[8] The proportion of ROCs that can be claimed from co-firing fell by more than 50%, but this is partly counteracted by an overall increase in the level of the RO.

the 2004 level. Overall, the market for energy crops will have grown by 2016 while the market for other biomass will contract. However, there is considerable year-on-year variation as reductions in the co-firing limit and increases the mandatory energy crop mix are counteracted by growth in the overall size of the RO.

Table 3: forthcoming restrictions on UK co-firing

Total electricity supplied (2004) 344.23 TWh

Year	Renewables Obligation (% of electricity supplied)	Cofiring Limit (% of ROC claim)	Minimum Energy Crop Mix (% energy content)	Electricity from Energy Crops (GWh)	Electricity from Other Co-fired Biomass (GWh)
April 2009 – March 2010	9.7%	10.0%	25.0%	834.76	2504.27
April 2010 – March 2011	10.4%	10.0%	50.0%	1790.00	1790.00
April 2011 – March 2012	11.4%	5.0%	75.0%	1471.58	490.53
April 2012 – March 2013	12.4%	5.0%	75.0%	1600.67	533.56
April 2013 – March 2014	13.4%	5.0%	75.0%	1729.76	576.59
April 2014 – March 2015	14.4%	5.0%	75.0%	1858.84	619.61
April 2015 – March 2016	15.4%	5.0%	75.0%	1987.93	662.64

Source: DTI 2006c, OPSI, 2006

II.2.2 Co-firing 2002-2006: a period of rapid growth

From the beginning of the RO in 2002, the economics of co-firing in the UK have been characterised by the following factors.

UK coal generation is significant in size. The large-scale of coal generation in the UK means that significant amounts of electricity can be generated by co-firing small proportions of biomass. It is estimated that the PF plants in the UK can co-fire in excess of 10% biomass by weight using existing milling equipment and feeding a coal-biomass mixture into the main boiler on the existing conveyor. Co-firing greater proportions of biomass would require greater capital investment such as separate milling systems and direct injection mechanisms. Such investment is not necessary in the short-term since it is the ROC-claim limit (currently 10% of each supplier's ROC claim) rather than the plants' technical potential that limits the level of co-firing in the UK. In 2005, 5% of the electricity generated from coal would allow for approximately 4.5 TWh of electricity to be produced from co-firing[9]. The actual level co-fired, limited by ROC eligibility, was 2.5 TWh.

One ROC is awarded per MWh of renewable electricity. Regardless of the technology used or the origin of the feedstock, one MWh of renewable electricity is equivalent to one ROC. Therefore, it is logical for rational operators to generate the lowest-cost ROCs first by generating ROCs from the cheapest source of biomass. Given its stated advantages (high thermal efficiency and low capital cost) co-firing became competitive under this regime.

The regulatory framework did not offer certainty to decision-makers. From the start of the RO, operators knew that the ROC-eligibility of co-firing was a temporary arrangement. Under the original RO legislation, the ROC-eligibility of co-firing was due to end in 2011 with 75% of co-fired feedstocks coming from energy crops from 2006. In 2004, the regulations were relaxed to those shown in Table 2. They are due to change again in the near future (see Future of Co-firing section below). Since co-firing requires relatively little capital investment compared to other forms of renewable electricity, the RO regulations explicitly rule out grandfathering of co-firing support. Under grandfathering, co-firing investments would be protected from any subsequent regulatory changes that might damage its viability. A common form of grandfathering consists of a feed-in tariff. This would guarantee that electricity generated from co-firing would receive a specified premium price for an agreed period. Without grandfathering, operators wishing to invest in co-firing technology need to consider not only whether the technology is viable under current economic conditions but also whether a change in the regulatory regime is likely and what the effect of such a change would be. Additional uncertainty exists over the precise operational definitions of terms in the RO legislation (e.g. precisely what can be

---

[9] 136,257 GWh of electricity were generated from coal in 2005 (DTI 2006c). Assume biomass has net calorific value of 16,370 compared to 24,614 for South African coal (DTI 2005). 136.257 * 0.05 * 0.665 = 4.53 TWh

eligible as an energy crop) and whether the burning of a given feedstock will be permitted by the local Environment Agency.

In combination, the factors listed above encouraged the rapid development of co-firing on a large scale. At the same time, uncertainty over the future of the co-firing framework made it unattractive for operators to invest in specialised equipment or secure long-term supply chains. The feedstocks chosen by operators were those that could be milled in the same mill as the coal with minimal modification or added directly to the conveyor transporting the pulverised coal into the boiler. From this perspective, the most desirable fuels were processed by-products of olive and palm and wood pellets.

II.2.2.1 Decision-making under the Co-firing regime: an operator's dilemma[10]

As the above section shows, co-firing began with the introduction of the RO in 2002. At this time, electricity generators could co-fire until 2011 but had only four years (until 2006) in which to establish an energy crop infrastructure. Since the carbon price alone is insufficient to incentivise co-firing (see II.2.3 below), the Renewables Obligation was crucial to the establishment of co-firing in the UK. Also, since there is no grandfathering for co-firing support, operators needed to predict the future prices of both feedstocks and ROCs in order to assess the profitability of co-firing projects.

In this situation, each generator had to consider:

- how easily their plant could be modified for co-firing.
- which types of feedstock and technology were most suitable to their plant.
- whether it was worth developing an energy crop infrastructure (remembering that co-firing was due to end in 2011).
- whether the ROC price could fall. A sector-wide increase in the proportion of electricity generated from renewable sources will cause the ROC price to fall, damaging a project's viability. An expansion in co-firing will cause the price of co-fired ROCs to fall, regardless of whether there is a price in the fall of

---

[10] The comments in this section of the report are partly derived from personal communications with representatives from electricity generation companies in the UK

ROCs as a whole. This is because there is an absolute cap on the size of the co-fired ROC market.

- what confidence they had in the co-firing rules. Future ROC earnings could be altered by any change to the Renewables Obligation. For example, a policy to explicitly support wind power would release more ROCs onto the market, thus reducing the ROC price for co-firing.

Some operators in the UK electricity industry, notably EDF, Scottish Power, Scottish and Southern Energy, E.ON and RWE, are vertically integrated companies - operating both as generators and suppliers of electricity. Whereas electricity (and therefore ROCs) is created by *generators* of electricity, the RO obliges *suppliers* to present ROCs each year. Vertically integrated companies have the advantage of playing both roles. They can therefore generate co-fired ROCs for their own use as an electricity supplier. Thus they have a guaranteed market and are in a better position to invest in co-firing mechanisms. This distinction has been especially relevant since April 2006 when the limit on co-fired ROCs was tightened.

A notable exception to vertical integration is Drax Power, an independent generator whose main asset consists of a large coal-fired power station. Since the company does not supply electricity to end users it must ensure that any ROCs generated can be sold to other parties.

At the start of the RO, any generator thinking of co-firing needed a system that could produce ROCs quickly, with a short repayment time on the investment. Since the least capital-intensive method of co-firing biomass is co-milling, this was initially the most common method in the UK. Various types of biomass can be co-milled with coal in quantities of up to 10% mass. This has occurred at several power stations including Ironbridge (Goh, 2005), Longannet and Cockenzie.

Some UK plants have now installed more specialised co-firing equipment such as dedicated biomass burners or direct injection mechanisms. Advantages of such investments include the possibility of co-firing a greater variety of fuels and avoiding damage to the coal milling equipment from the biomass. In choosing whether or not to invest in such equipment, each company has to reach its own conclusion about how the co-firing legislation will evolve (bearing in mind that it has been altered several times). Generators with a diverse portfolio of renewable investments also need to compare the net marginal benefit from investing in co-firing relative to wind, hydro and other technologies, bearing in mind that over-supply of renewable electricity would cause the ROC price to fall.

Scottish and Southern Energy has installed a series of dedicated biomass burners at its Ferrybridge C Power Station, allowing biomass and coal to be burned in the same boiler but through different burners and conveyors. This will allow the station to increase its co-firing to 10% of energy input (Engineeringtalk, 2006). Drax Power, the largest independent generator in the UK, is developing a supply and processing infrastructure around the co-firing of locally-grown energy crops (Drax Power, 2005). This involves setting up long-term contracts with local suppliers with a view to meeting the RO’s energy crop requirements. It is worth noting that since Drax is essentially an independent coal-fired power station, it is reliant on co-firing for any ROCs it wishes to produce. Given the lack of grandfathering and the fact that co-firing regulations are currently subject to review, other operators are delaying making long-term decisions about the future of co-firing.

II.2.3 Effect of the Carbon Price on the Economics of Co-firing

Under the European Emissions Trading Scheme (EU-ETS), an overall cap is placed on CO_2 emissions. Individual industrial facilities are allocated a number of CO_2 emissions permits in accordance with each Member State’s National Allocation Plan. Facilities that exceed their permitted emissions must purchase surplus permits from other operators. In this way, every tonne of CO_2 emitted by a power station has a market price – reflecting either the cost incurred from the purchase of emissions permits or the income the plant could otherwise have earned from the sale of the permit. Under EU-ETS, most forms of biomass are considered carbon neutral and can therefore be burned without using up emissions permits. Therefore, a generator who co-fires biomass with coal effectively receives three sources of income

- the ROC value of the electricity
- the carbon price of the coal emissions foregone
- the price of the electricity itself

On 27/10/2006, the quoted carbon price was €11.85 per tonne of CO_2[11]. In order to incentivise co-firing, a carbon price of at least €20 is needed (See Appendix A). The carbon price exceeded €20 during much of 2005, reaching a peak of almost €30 in April 2006, before falling to a price of €10-15 (DTI, 2006). On this basis, it appears that co-firing in the UK is close to becoming an economically viable activity without the support of the Renewables Obligation. However, a permanent increase in the carbon price is needed for this to occur. This means that any future tightening in the emissions permits issued under EU-ETS will have a significant effect on the viability of co-firing in the UK.

II.2.4 Co-firing vs. Dedicated Biomass Plant Regulations

Under the RO system, the distinction between a co-firing plant and a dedicated biomass plant is important. This is because, while suppliers can only submit a limited proportion of their ROC claim from co-firing, unlimited amounts of standalone biomass are ROC-eligible. In order to receive normal ROCs (rather than co-firing ROCs), a plant must derive no more than 10% of its input energy from fossil sources and must use the fossil energy only for specified purposes (e.g. ignition, standby generation). If these rules are breached (for example if the station fires 50% fossil fuel in a given month), the station may be eligible to claim *co-fired* ROCs for the 50% of electricity derived from biomass. However, if a station fires more than 75% fossil input in *any* given month, it can no longer receive normal ROCs (OFGEM, 2006b).

The distinction between the two plant types is not immediately relevant for the UK co-firing sector since most co-firing occurs either at sewage stations or large coal plants with minimal biomass modification and hence no possibility of firing over 90% biomass. However, it does demonstrate that the co-firing of biomass in dedicated plants enjoys a greater level of policy incentives than combustion of the same biomass in a coal-fired plant. Whether this is an ideal situation is debatable since, on the one hand, coal-fired plants can incorporate biomass into their operations without much investment and therefore require less policy support than dedicated plants. On the other hand, if it is assumed that a given amount of coal and biomass are to be burned

---

[11] Source: http://www.pointcarbon.com

for energy in any case, it is optimal to fire them together and allow the biomass energy to gain from the greater thermal efficiency of coal plants.

As discussed in section I.3.5, it is possible to burn biomass and fossil fuels in separate boilers, sharing common equipment such as steam turbines. Though the UK RO legislation does not contain specific guidance as to what constitutes a single generating station, the guidance published by OFGEM states that any combination of equipment on a single site will normally be considered a single generating station. This means that it is very difficult for a generator to exploit mutual efficiency gains between biomass and fossil fuels without being issued co-fired ROCs (which have a lower value and smaller market than normal ROCs).

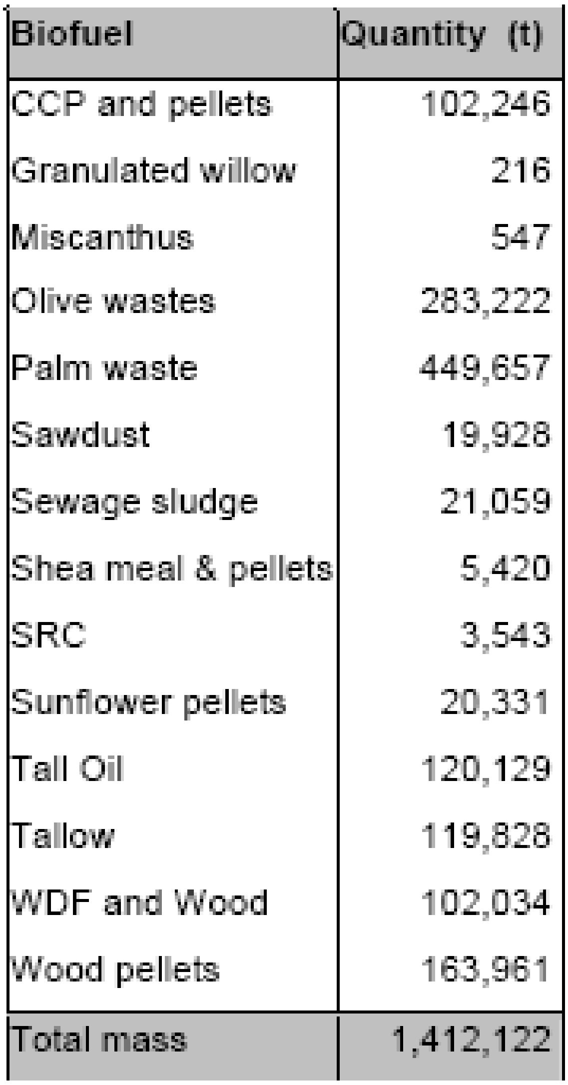
To understand the implications of this, consider the Avedøre plant in Denmark. This facility has a straw-fired boiler and a second boiler, originally designed for coal but also capable of firing wood pellet and a variety of other fuels. Under UK regulations, the facility would be regarded as a single station because the two boilers share common characteristics such as a common steam linkage, premises and ownership (OFGEM, 2006c). This means it would not be possible, for example, to classify the straw boiler as a biomass plant and separate its ROC claims from those generated by the main boiler. The plant would still be able to claim biomass ROCs in months where the total energy input is more than 90% biomass. It could also claim co-fired ROCs in months where the total energy input is less than 90% biomass. However, were the plant to fire more than 75% fossil fuel in a given month, the plant would no longer be able claim biomass ROCs and would become a full-time co-firing facility.

From the bioenergy trade, point of view, this framework is discouraging. At present, there are few dedicated biomass plants in the UK. These are all designed to make use of a specific local resource (e.g. poultry litter). It would be especially risky to commission a biomass plant that relies on imported bioenergy due to security of supply concerns and the volatility of biofuel markets (see section II.3 below). Such a plant might still be viable if, like Avedøre, it were designed to burn a variety of biomass and fossil fuels. However, the current RO system discourages this since a plant risks being classified as a permanent co-firing facility if it has to fire substantial fossil inputs in a given month.

II.3. Co-firing and international bioenergy trade

II.3.1 Significance of the UK market. Table 4 shows the levels of biomass co-fired in UK power plants in 2005. As the table shows, the most important co-firing feedstocks were palm products, olive waste, tall oil and wood pellet. With the possible exception of some of the wood pellet, all of these fuels will have been imported into the UK. This means that at least 74% by mass of the UK's co-firing feedstock, over 1 million tonnes of biomass, was derived from imports. Given that UK coal plants co-fired less than 3% biomass (by mass) in 2005, and that, if policy incentives are right, levels in excess of 10% are achievable without investments in advanced technology such as gasification, an expansion of co-firing in the UK could have a significant impact on the worldwide demand for various types of biomass residue.

Table 4: Feedstocks used for Co-firing in 2005



Biofuel	Quantity (t)
CCP and pellets	102,246
Granulated willow	216
Miscanthus	547
Olive wastes	283,222
Palm waste	449,657
Sawdust	19,928
Sewage sludge	21,059
Shea meal & pellets	5,420
SRC	3,543
Sunflower pellets	20,331
Tall Oil	120,129
Tallow	119,828
WDF and Wood	102,034
Wood pellets	163,961
Total mass	1,412,122

Source: Woods J. et al., 2006

This section examines each of the main biomass feedstocks from 2005 in closer detail.

II.3.2 Oil Palm

Oil palm products have a variety of potential uses in UK fossil-fired power stations. The products used in the greatest quantity are palm kernel and palm kernel expeller (PKE). Both are residues left over from the production of palm oil. PKE is already traded internationally as an animal feed due to its high protein content. There is therefore competition for its use as a fuel source although it is an agricultural by-product (Malaysian Palm Oil Board). PKE is attractive for co-firing since it can be co-milled, with little additional capital expenditure, and combusted directly with coal in the main boiler of a power station. It also has a high calorific value, comparable to that of sawdust with lower moisture content (DTI, 2005). Its value as an agricultural commodity may limit its availability as an economical feedstock if co-firing is to expand significantly.

Palm oil itself can be used in PF plants as an ignition fuel, replacing fossil-derived heavy fuel oil. In this way, the CO_2 emissions that would have been created by the fuel oil (approximately 3 tonnes of CO_2 per tonne of heavy fuel oil[12]) are avoided. Ignition fuels count as a ROC-eligible fuel source in the same way as solid biofuels that replace coal. Therefore, their economic viability is equally dependent on the ROC price[13]. The competitiveness of alternative ignition fuels in co-firing is also harmed (relative to their competitiveness in industrial uses) by the exemption of heavy fuel oil from excise duty when it is used in electricity generation.

International trade statistics (Eurostat, 2006) provide a rough guide to the quantity of palm kernel and PKE imported into the UK[14]. Under the 8-digit Combined Nomenclature (CN8) classification, feedstocks for co-firing fall under the codes for palm kernel – 12071000 and palm oil cake – 23066000. However, both products have alternative uses. In particular, palm oil cake is commonly used for animal feed. Nevertheless, as figure 1 shows the statistics do demonstrate the substantial influence of co-firing on the level of palm kernel imports into the UK.

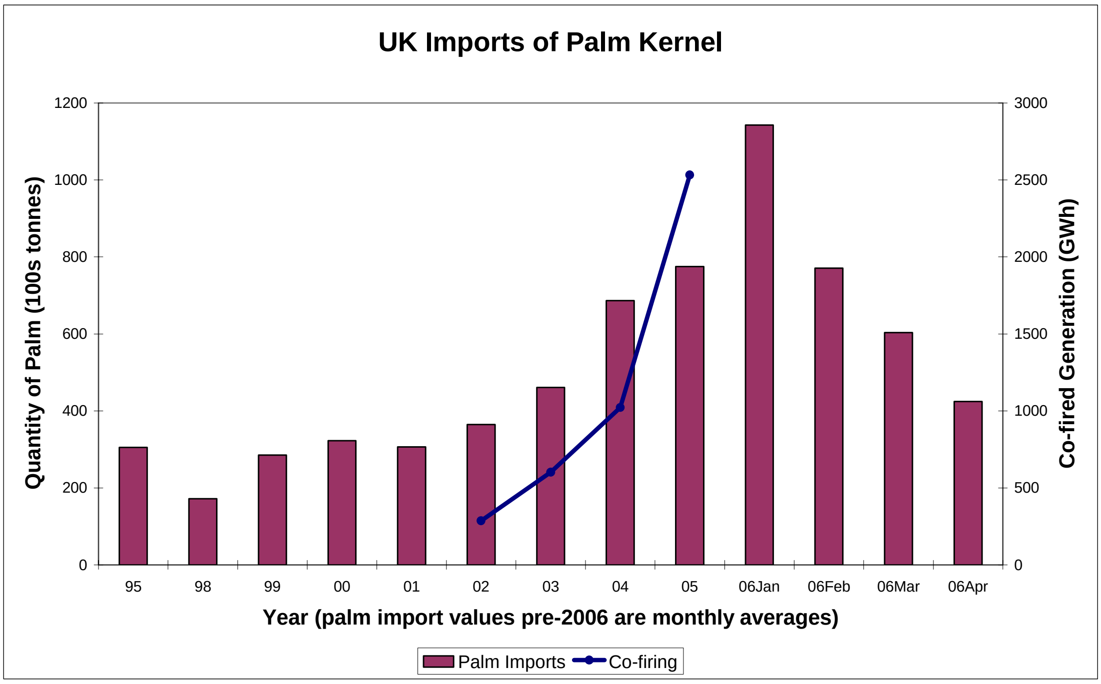
---

[12] Personal communication with Talloil UK Ltd.

[13] ibid.

[14] (see Appendix A for a discussion of the applicability of Eurostat trade statistics)

Figure 1: UK Imports of Palm Kernel and UK Generation from Co-firing



(Source DTI 2006c & Eurostat, 2006)

Between 1995 and 2001, the UK imported up to 390,000 t per year of the two codes mentioned above. In 2002, the first year in which there was co-firing of biomass at UK power stations, the level of imports rose by 12% to 437,000 t. In 2005, the quantity of imports reached 930,000 t. A substantial decline in the level of imports is expected in 2006 as a result of the reduced ROC limit. This cannot be necessarily be deduced from figure 1 since the substantial fall in imports from April to May 2006 could also be due to the seasonal nature of the demand for both biomass fuel and animal feed.

Of the major UK electricity generators, only RWEnpower is a member of the Roundtable on Sustainable Palm Oil, an association of NGOs and participants in the palm oil industry dedicated to establishing the principles and practice of sustainable palm oil cultivation. In 2005, the majority of palm kernel products (73%) imported into the UK came from Malaysia and 17% was imported from Indonesia (Eurostat, 2006). It is estimated that over 20 Mt of oil palm residues were produced by Malaysia and Indonesia in 2006 (Woods J. et al., 2006).

The annual average prices for palm oil and palm kernel oil from January – September 2006 were $455/Mt and $574/Mt respectively (World Bank, 2006). Worldwide use of palm oil is expected to increase dramatically in the next few years due to its suitability for biodiesel production. In Malaysia, the use of Envodiesel, a 5% blend of refined palm oil with fossil-derived diesel fuel, is being encouraged. This is estimated to use 500 kt of palm oil per year (Malaysian New Straits Times, 2006). Palm oil is also being refined in Europe for use as a biodiesel. This extra demand could limit availability of palm oil for co-firing. However, if the demand is met by a significant increase in palm cultivation, this would lead to a significant increase in the availability of PKE and consequently a sharp fall in the PKE price. Whether this will lead to increased use of PKE for co-firing will then depend on the regulatory framework and procurement policies in European markets.

II.3.3 Olive Cake

Olive cake is a by-product from the production of olive oil that takes place in several Mediterranean countries. It is attractive as a fuel for co-firing since, like PKE, it can easily be co-milled with coal without the need for significant capital expenditure. Olive cake or pomace can also be used as animal feed. However, unlike PKE, it is a low-value feed comparable to straw (FAO, 1984). It was previously regarded as a waste whose disposal was problematic for olive-producing countries (Bowell, 2006).

Compared to PKE, international trade statistics for olive cake provide a more useful guide. This is because the CN8 classification provides a separate code for olive cake that is likely to be used for energy. Also, the vast majority of world production and consumption of olive oil takes place in the Mediterranean – the European Community accounts for over 75% of global production (UNCTAD, 2005). This means that countries supplying import and/or export statistics to Eurostat at CN8 level account for a large proportion of the global trade.

Wet olive cake is classified under CN code 23069019. This cake contains over 3% olive oil and is the substance that remains at an olive mill after the virgin oil has been extracted through pressing of the olives. Non-virgin olive oil is produced by treating of wet olive cake with a chemical solvent. Wet olive cake is exported from Tunisia, the world's 4th largest olive oil producer, to major markets such as Spain and Italy, but not to the UK. 23069011 is olive cake containing 3% olive oil or less. This is dry olive cake, suitable for energy use. Large imports of dry olive cake into the UK began in 2003 when 11,000 t were imported. In 2005, over 172,000 t were imported, of which over which 130,000 t came from Spain – the world's largest producer of olive oil. In 2005, the UK was the largest importer of dry olive cake in Europe, accounting for 55% of imports (intra-EU and extra-EU combined). Since olive cake is a low-value by-product it is possible that larger quantities will become available if a large-scale market for olive cake as an energy source develops. It is estimated that 5 Mt of olive cake is produced worldwide each year, with over 3 Mt coming from Spain, Italy and Greece (Woods et al., 2004). This compares to 318,000 t of olive cake (wet and dry) traded imported by EU Member States in 2005.

II.3.4 Wood Pellet

Given the reduction in the ROC limit for co-firing from 2006, it is unlikely that significant quantities of wood pellet are currently used for co-firing in the UK. However, prior to the reduction in the ROC limit, wood pellet was the main feedstock for co-firing behind olive and palm products. Wood pellet is a dense wood fuel with low moisture content. It is typically made from sawdust compressed into pellets of 6-12mm diameter and held together using lignin from the wood (ETSU, 2001). Like olive and palm products, it has the advantage of being easy to manage as a feedstock and is suitable for co-milling or direct injection into the main boiler of a coal-fired power station. Though wood pellet is a manufactured product, and is therefore more expensive than other forms of clean wood, it has several characteristics that make it preferable as a fuel source. Pellets have a moisture content of below 8% compared to 40-50% for wood chip. In addition, the fact that pellets are a uniform product manufactured to stated specifications allows plant operators more certainty over the fuel's performance than would be the case with non-processed wood inputs. The pellets remain solid until milling (reducing dust hazard) but then break down into a uniform distribution of particles small enough to achieve complete combustion once milled. Wood pellet also has good flow characteristics since the pellets are small and dense with relatively low moisture content (ETSU, 2001).

In some cases, wood chip may be preferable to pellet. Since wood chip is a less processed product, it is typically available at lower cost per tonne than wood pellet (IPA Energy Consulting, 2005). It can therefore be more cost effective to use wood chip in facilities that intend to combust biomass on a large-scale. However, it is more difficult to co-mill wood chip since it has a greater particle size and higher moisture content compared to wood pellet.

At present, there is an emerging market for wood pellet in the UK. Prior to the 1999 EU-funded project *Introducing Wood Pellet Fuel to the UK* (ETSU, 2001), the product was not used in the UK. The heat market in the UK, both domestic and commercial, is dominated by natural gas thanks to abundant domestic supplies (until recently) and the coverage provided by the national gas grid. However, the availability of pellet and recent increases in the price of natural gas have led to growth in the use of wood pellet in the domestic market with scope for further expansion into commercial and industrial heat markets. Despite developments in the heat market, the demand for pellet in the UK was dominated by the co-firing sector.

Domestic production of wood pellet in the UK is small but increasing. The largest commercial plants, such as Balcas[15] and Welsh Biofuels[16] have a stated production capacity of 50,000 tonnes of pellet per year. Further increases in pellet production are constrained by lack of raw materials. Potentially, over 1 million tonnes of forest waste and arboricultural arisings are available in the UK annually (Biomass Task Force, 2005). However, competition with the furniture board industry is a considerable barrier to the industry’s expansion (Illsley et al. 2005). Some of the approximately 20,000 ha of dedicated energy crops due to be planted by 2009 may be pelletised. The information provided by trade statistics at CN8 level is of limited value when attempting to gauge the scale of wood pellet imports for co-firing in the UK (see Appendix B). Imports of 44013 – sawdust and wood waste (whether or not pelletised or made into logs, briquettes or some other compact form) stood at around 90 kt per year between 2000 and 2004 before rising to 20.5 kt per month from January 2005 until January 2006. This high level of import has not been sustained beyond January

---

[15] http://www.balcas.com
[16] http://www.welsh-biofuels.co.uk

2006, suggesting that the import of wood pellet for co-firing comprised a substantial portion of this trade flow.

The future of wood pellet as a competitive co-firing feedstock depends partly on its value for alternative uses. Further increases in the gas price will lead to increasing competition from heat markets for pellets, especially if improvements in marketing and supply infrastructure improve the attractiveness of pellets for smaller-scale customers (as opposed to large power stations). At the same time, production of wood pellet is expanding across Europe. In 2004/05, 1.8 million tonnes were produced in Europe (Wood Pellet Association of Canada, 2006). Wood pellets are usually produced in locations close to an abundant raw material supply. Since the raw material is usually sawdust (rather than new roundwood) most pellets are produced in countries with a large wood products sector. For example, Finland produces over 150,000 tonnes of pellet for export annually. Although the raw material is waste from Finnish sawmills, much of the wood originates in neighbouring Russia where the forest products industry is less well-developed but wood is abundant (Heinimö & Alakangas). Balcas Ltd. has recently announced its intention to construct a new wood pellet facility in the UK. The facility consists of a wood-fuelled CHP and pellet-making plant. Part of its intended feedstock is local pine planted over 25 years ago for which few alternative markets have been identified (Scotsman, 2006).

II.3.5 Co-products from Transport Biofuels

As a result of the EU Biofuels Directive 2003/30/EC, production and consumption of biofuels for transport is set to increase dramatically in each Member State. This includes the production of bioethanol from cereal grains and biodiesel from oil crops. Production of both of these fuels will release substantial levels of co-product, increasing the supply of many co-firing feedstocks. The Directive sets a target for alternative fuels to count for 5.75% of transport fuel sales (by energy content) by 2010. Though this target is unlikely to be met, EU Member States have introduced a range of fiscal incentives and obligations to promote the use of biofuels. These include measures to encourage the blending of up to 5% (volume) biodiesel and bioethanol with diesel and petrol respectively.

Bioethanol is currently produced around the world using a variety of feedstocks. In Brazil, it is made from sugar cane and sold on domestic markets as a transport fuel, as well as exported to markets such as Japan, the EU and the USA. The by-product from sugar cane production is bagasse, which has a 47% moisture content and low protein content (Smeets et al., 2005). Although it has the potential to be used as a local heat and power source, it is unlikely to be traded internationally.

In Europe, large quantities of wheat are used to produce bioethanol. The largest producer of ethanol from wheat is the Spanish firm Abengoa, producing over 200,000 tonnes of ethanol per year. For each tonne of wheat converted to ethanol, approximately 0.5 tonnes of straw and 0.4 tonnes of DDGS (Distillers Dried Grain with Solubles) are produced (Smeets et al., 2005). This means that combustible by-products with a net calorific value of over 12 GJ are produced per tonne of bioethanol derived from wheat (see Appendix C for details of feedstock and residue characteristics). It is estimated by eBIO, the European Bioethanol Fuels Association (eBIO, 2006), that 12 billion litres of ethanol will be necessary for the EU to meet the 2010 target for bioethanol penetration in the transport market[17]. If grain ethanol were used to meet target, this would produce 14 Mt of DDGS (distillers dried grains with solubles) and 16.5 Mt of straw, both of which could be used for co-firing. This scenario is unlikely since the EU is also a producer of ethanol from sugar beet and imports bioethanol from Brazil. Whereas straw is co-produced with wheat regardless of the crop’s end use, DDGS is a co-product of the distillation process that produces ethanol. Therefore, even with no net increase in European wheat cultivation, diverting some of the existing wheat crop towards bioethanol would release additional quantities of DDGS.

Biodiesel can be made from a variety of crops. These are predominantly vegetable oils from crops such as rapeseed, palm, soy and sunflower seed. Biodiesel is also produced from crops such as jatropha as well as animal fats and used cooking oil.
To meet the Biofuels Directive target, demand for biodiesel will need to reach over 13 billion litres in 2010[18]. This will require substantial increases in the production of a

---

[17] The target is for biofuels to account for 5.75% of the energy content of transport fuels by 2010

[18] EU 25 - Energy and transport outlook to 2030 (European Commission, 2003) gives 2010 gasoline and diesel oil demand as 142.1 Mtoe and 182.1 Mtoe respectively.

variety of oil crops, in turn releasing substantial quantities of by-products such as PKE, soy husks and sunflower pellets. According to FAO statistics (FAO, 2006) 32 Mt of palm oil were produced worldwide. This is projected to have risen to 45.9 Mt (FAO, 2006b) by 2016. The extra production will increase the availability of PKE from 3.2Mt to 4.6Mt. The production of empty fruit bunches will also increase from 29Mt to 41Mt under this projection. Since the FAO projection is not based on accelerating growth in EU demand for biodiesel (see p.24), this projection can be considered conservative.

Were the EU's estimated 13 billion litre demand for biodiesel to be met from rapeseed oil, this would require the production of 30 Mt of (dry) rapeseed, releasing 30 Mt of rape-meal and 50Mt of straw. In 2005, production of rapeseed in the EU-25 was approximately 15.5 Mt (FEDIOL, 2006). Rapeseed meal has a variety of uses including as a high protein animal feed and ingredient for bioplastics and cosmetics (Ienica, 2005) but may become economical as a combustion material if availability increases substantially as a result of increased biodiesel production from rapeseed.

In reality, biodiesel is likely to be produced from a combination of soy, sunflower, palm and rape oils in the short-term, releasing a variety of by-products with potential use in co-firing. As table 4 shows, UK power plants have already co-fired palm and sunflower residues and cereal co-products.

II.3.6 Other Products

Tall oil - This is a by-product created by the chemical pulping of wood in paper mills. It has been used in some UK plants as an alternative ignition fuel, replacing heavy fuel oil or palm oil. As in the case of palm oil, tall oil has the advantage of displacing the CO_2 emissions from heavy fuel oil but its economic viability depends on its ROC value. The tall oil used in the UK is imported from countries such as Russia, Sweden and Canada where chemical pulping is used in the paper industry[19].

[(182.1 * 0.0575)/ .78] * 1,000 = 13.423 billion litres

[19] Personal communication with Talloil UK Ltd. In the UK, the same process is performed mechanically and does not produce tall oil.

Tallow,- tallow is an animal by-product, has also been use as an ignition fuel and heavy fuel oil replacement. Since the end of 2005, operators wishing to burn tallow have had to comply with the European Waste Incineration Directive (WID) 2000/76/EC (Official Journal of the European Communities, 2000). In practice, the extra conditions and cost required to comply with WID have halted the use of tallow in power stations. This therefore expands the potential market for palm oil and tall oil to be used as ignition fuels in future, should the ROC environment permit.

Other Feedstocks - Imported products that have been co-fired by UK plants in small amounts include pellets and meal of shea, sunflower, palm shell. These feedstocks could play a larger role in UK co-firing in future if increased co-firing demand or competition from other markets increases the price of palm oil and olive cake. Like palm and olive cake, shea, sunflower and palm shell are the by-products from oil or butter manufacture. The residual meal has an established market as an animal feed which determines the initial price at which it would be available as a source of bioenergy.

Domestic Processing – As Table 4 shows, the majority of feedstock currently imported to the UK consists of palm and olive residue, wood pellet and plant oils capable of replacing fuel oil. These are products which require little further preparation prior to their co-firing with coal. Crops such as SRC, miscanthus and clean waste wood are suitable for direct injection into coal-fired boilers but require greater processing of the feedstock (DTI, 2005). In future, it may therefore be profitable for operators to establish facilities to process domestic and imported biomass for use in co-firing.

II.4. Co-firing and Energy Crops

The Renewables Obligation Order (OPSI, 2006) defines an energy crop as “a plant crop planted after 31st December 1989 and grown primarily for the purpose of being used as a fuel”. Energy crops can be grown in the UK or imported from elsewhere. Several schemes exist to support the production of energy crops at UK and EU level.

The ultimate criterion for a feedstock to qualify as an energy crop under the Renewables Obligation is that the co-firer must satisfy OFGEM of the crop's eligibility. OFGEM is the UK electricity regulator, responsible for the management of the Renewables Obligation. SRC and miscanthus are generally accepted as energy crops. Annual crops grown specifically for energy use, including the co-products of cereals or oil crops grown for transport fuels *do* qualify as energy crops on the basis that they are "grown primarily… for use as a fuel" (OFGEM 2006b, p9). It is therefore possible to co-fire co-products of cereals, grown for the manufacture of bioethanol, as energy crops. However, it is not possible to classify as energy crops co-products where over 50% of the total crop revenue derives from non-fuel use. Therefore, it would not be possible to co-fire *as energy crops* the co-products of wheat grown for use in the food or beverage industry. In all cases, OFGEM reserve the right to consider each potential energy crop on a case-by-case basis, requiring the co-firer to supply additional supporting evidence of a crop's eligibility where necessary. In this section, energy crops where the entire crop is grown with the intention to be used as energy (i.e. SRC or miscanthus rather than the co-products of transport biofuels) will be referred to as *traditional energy crops*.

At EU level, two support schemes support the cultivation of energy crops. The Single Payment Scheme of the Common Agricultural Policy allows farmers to claim the setaside payment for industrial crops grown on setaside land. Any crop grown on setaside land is eligible for the setaside payment, provided the majority of the sales revenue of the crop comes from end products that are not used for food or animal fodder. For crops that have a potential use as food or animal fodder, it is necessary for the grower to sign a contract with a processor or collector in order to receive the single payment (DEFRA, 2005). In addition, the Energy Crop Aid Scheme allows a maximum of 1.5 million hectares across the EU-15 to be used to grow energy crops for which farmers receive a payment of €45 per hectare[20]. Conditions for this aid are similar to those for crops grown on setaside land. All crops with potential energy uses are eligible, except sugar beet, provided farmers sign appropriate contracts with the processing industry (European Commission).

---

[20] The European has recently proposed extending the Energy Crop Aid Scheme to the 10 new Member States. It has also been proposed that the maximum eligible area be increased to 2 million hectares. See http://www.euractiv.com/en/energy/eu-extend-energy-crop-aid-scheme/article-158169

In addition to European support, the UK Energy Crops Scheme (ECS) provides establishment grants for the plantation of short rotation coppice (SRC) and miscanthus. It also provides support for SRC producer groups. Under ECS, establishment grants of around £1,000 (€1,478) per hectare are paid to farmers who plant these crops for local energy users. At the scheme's closure to new applicants in August 2006, about 3,370 ha of miscanthus and 1,160 ha of SRC[21] had been planted. This represented 67% of the scheme’s targeted plantation area for miscanthus and under 7% for SRC. A further 15,000 ha are due to be planted in 2007/08, thus meeting 90% of the scheme’s targeted plantation area. The targets themselves represent only a fraction of the planted area necessary to supply a large-scale co-firing market from domestic fuel sources[22]. The condition that plantations be located within a reasonable distance of the intended market (10-25 miles) limits the locations where crops can be grown under the scheme, although crops can be grown further away if it is demonstrated that there are no adverse environmental impacts.

Since the Renewables Obligation originally gave co-firing a temporary role and it rewards co-firing on a per MWh basis, it initially encouraged the maximum take-up of renewable electricity in the shortest time using the cheapest technologies available. Under this arrangement, it was far more advantageous for operators to co-fire biomass residues of the types listed in Table 4 than to manage and process a reliable supply chain of traditional energy crops.

Compared to traditional energy crops, co-firing of residue-derived material requires minimal commitment on the part of the plant operator and can be used as a marginal activity. This allows operators to decide on an ad hoc basis whether or not to co-fire biomass based on market conditions such as quality and availability of biomass, the ROC price and the level of demand for electricity. However, operators have to be confident that a sufficient throughput of biomass will be co-fired to make it viable to maintain biomass storage and handling facilities.

---

[21] DEFRA, personal communication

[22] 250,000 hectares of energy crops would be necessary to replace 5% by weight of the UK’s 2004 coal-for-electricity use with biomass. See Rosillo-Calle & Perry, 2006. p.25

The requirement that a greater share of energy crops be used from 2008 alters this situation. From 2009, facilities wishing to co-fire biomass will have to be confident in their ability to find feedstocks that are eligible as energy crops, even if they wish to co-fire mainly residue-derived biomass. Clear guidance on which crops would qualify under the DEFRA definition is lacking and this has led to considerable uncertainty in the electricity and fuel supply industries.

Co-firing from traditional energy crops requires a much greater level of commitment and a more proactive procurement process than that needed to co-fire residue-derived feedstock. The operator must make a credible commitment to the farmer that they will purchase the crop once it is ready for harvest, 2-3 years after planting. This is not only because of farmers' risk aversion. A plantation is only eligible for support under the Energy Crop Scheme provided the intended purchaser of the crop has signalled their intent to purchase at the time of planting. This condition is also implied in the definition of an energy crop – one that is grown primarily for the purpose of being used as a fuel. Though some operators are beginning to formalise their supply arrangements for energy crops[23], it is not yet known whether the co-firing of energy crops will be economically viable on the same large-scale as co-firing of residue-derived biomass.

A crucial aspect of the requirement to co-fire a specified percentage of energy crops is that it links an operator's ability to co-fire any biomass, with the co-firing of energy crops. Therefore, unless an operator is able to co-fire energy crops, it will not be able to co-fire at all. This is one of the many elements of the co-firing legislation currently under review (see section II.5.1).

II.5. Future of co-firing in the UK and the potential impacts on international biotrade

There have been several changes to the UK energy outlook since the original formulation of the regulations concerning co-firing and the RO. Firstly, although large-scale co-firing has been extremely successful in replacing large amounts of coal

---

[23] See http://www.draxpower.com/environment.php?page=biomass for example

combustion with biomass, this has not led to the emergence of large-scale energy crop cultivation or large-scale combustion of biomass in dedicated plants. In 2005, electricity generated from farm waste, poultry litter, meat and bone waste, straw and energy crops combined was 0.85 TWh compared to 2.53 TWh from co-firing. Secondly, recent increases in gas prices and the decline of UK production of natural gas have led to increasing concerns over the diversity of UK energy sources and increased interest in coal, including CCT and co-firing as a large part of the UK's future electricity generation.

As a result of these factors, there is now a "broad consensus" that co-firing "should play a long-term role in reducing the UK's carbon emissions" (DTI, 2006). Since co-firing is not an economically viable activity on its own, this statement implies there will be some change in the RO to allow co-firing to continue beyond 2016.

II.5.1 Proposed Changes to Co-firing Rules

On October 9, 2006, the government published a consultation document outlining proposed changes to the rules regarding the role of co-firing within the Renewables Obligation (DTI, 2006e). It proposed that the current 'non-discriminatory' RO be replaced with a system of banded ROCs. Under such a system, the current quantitative restrictions on the proportion of ROCs that could be claimed for co-firing and the proportion of energy crops required in the feedstock would be abolished. A type of ROC tariff would instead be introduced where types of renewable electricity generation that are the most desirable but least commercially viable, such as wave power or off-shore wind, would receive the most ROCs per MWh. It is likely that co-firing would receive the least ROCs per MWh and that more ROCs would be awarded per MWh of co-firing using energy crops as the input. Compared to the current arrangement, a banded ROCs system would have four key differences:

1. Operators would be free to choose between residue-derived feedstocks and energy crops on the basis of crop specifications and price competitiveness. The extent to which either is more widely used would also depend on the precise calibration of the ROC bands for energy crops and imported feedstocks for co-firing. However, energy crops would not have a guaranteed

share of the co-firing market, as would be the case with the current arrangement from 2009.

2. Operators would be free to continue to use co-firing as a marginal, ad hoc activity. Rather than having to source energy crops from specific sources, operators would be free to decide how much co-firing to perform as a ‘core’ activity supplied by specifically intended feedstock and how much to undertake only when market conditions are favourable.
3. There would be no quantitative limit to the amount of co-firing that is ROC-eligible. Therefore, the co-firing market and the market for imported feedstocks could expand considerably. The market would be limited only by the technical limits to co-firing in UK coal plant and the availability of large quantities of feedstock. Despite the lifting of quantitative restrictions, the feedstocks would still have to be competitively priced, perhaps more so than at present, in order to overcome the favourable ROC values given to other forms of electricity generation.
4. The calibration of the ROC bands for co-firing, relative to other forms of renewable electricity, will be crucial for the renewable energy sector as a whole. If too many ROCs are awarded per MWh of co-firing this will harm the development of the rest of the renewable electricity sector in the UK. If too few ROCs are awarded then co-firing will not be competitive at current carbon prices. It should be noted that a switch to banding will mean that there is no longer a one-for-one link between the number of ROCs produced and the level of renewable electricity generated in the Renewables Obligation overall.

Any re-banding of the Renewables Obligation will not come into force until 2009 at the earliest. In the meantime, the consultation document suggests that from 2007, following adjustments be made:

- That the requirement to co-fire a minimum percentage of energy crops be removed from the Renewables Obligation entirely, but with the cap on co-fired ROCs remaining in place.
- That normal ROCs be awarded for the co-firing of energy crops without limit.

These changes would immediately improve the long-term viability of co-firing since the ability to co-fire would no longer be contingent on operators’ ability to secure an energy crop infrastructure. At the same time, the co-firing of energy crops would be encouraged as these would no longer face the capped ROC market available to the rest of the co-fired material. Instead, ROCs created from the co-firing of energy crops would be ‘normal’ ROCs and have the same market value as ROCs from wind, solar and other renewables. However, it is unlikely that these changes will lead to a significant short-term increase in the level of energy crops co-fired. This is because SRC and miscanthus require a 2-3 year lead-in. In addition, the Energy Crops Scheme that provided the establishment grant for existing plantations is currently closed to new applicants.

The final significant change announced in the consultation document is an amendment to the definition of an ‘energy crop’. It has been suggested that the definition be amended to the following:

> “energy crops” means a plant crop planted after 31st December 1989 which is grown primarily for the purpose of being used as a fuel, or which is one of the following:
>
> a) miscanthus giganteus;
> b) salix (also known as short rotation coppice willow);
> c) populus (also known as short rotation coppice poplar).

(DTI, 2006e, p. 59)

There are two motivations behind this change – a liberalisation of the definition itself and a reduction in the bureaucracy required to certify a crop as an energy crop. Under the new definition, the fact of having planted one of the crop varieties stated above is taken as self-evident proof of the intention to use the crop primarily as a fuel. In addition, plantations of the varieties above will be saleable as energy crops, upon harvesting, regardless of whether they are sold within bilateral agreements struck at the time of planting. However, this change in the definition does nothing to resolve the ongoing uncertainty as to the energy crop eligibility of annual crops and co-products of cereals (especially those where the primary product is wheat, grain or oil for transport biofuels).

II.5.2 Generators' Co-firing Plans[24]

The changes announced in the Energy Review are still subject to a consultation process, beginning in September 2006. It is therefore too early to predict the effect on UK generators' co-firing plans. Grandfathering of co-fired ROCs is explicitly rejected in the Energy Review[25]. This means that investors in new co-firing projects would need to know when a banded ROC system will be introduced, what the level of banding will be and what guarantees/volatility exist concerning the level of banding. Without this information, a generator would not be able to determine the payback period or return on investment for a co-firing project. In addition, an investor would need to know the level of banding in order to determine the competitiveness of an investment in co-firing relative to other renewable energy projects.

As discussed in section II.2.1, the fall in the size of the co-fired ROC market since April 2006 has meant that co-firing has mainly been limited to integrated generator-suppliers in the UK. Although most independent generators have ceased to co-fire, since co-firing is relatively non-capital-intensive, these generators could resume co-firing if the outcome of the Energy Review is favourable (i.e. a lifting of the co-fired ROC ceiling, a small reduction in the ROCs awarded per MWh and minimal energy crop requirement).

An additional concern for operators with a diverse portfolio of renewable investments is that moves to prolong the long-term viability of co-firing could damage the competitiveness of alternative renewable investments.

Though the majority of co-firing in the UK has taken place on a co-milling, minimal investment basis, some generators have invested in other co-firing technologies. Ferrybridge C Power Station has installed a series of burners, allowing biomass and coal to be burned in the same boiler but through different burners and conveyors. This will allow the station to increase its co-firing to 10% of energy input (Engineeringtalk, 2006). Drax Power, the largest independent generator in the UK, is concentrating on

---

[24] This section is based on media reports and personal communications with UK electricity generators. Precise details of firms' future co-firing policies could not be obtained due to commercial sensitivity.

[25] If co-fired ROCs were 'grandfathered', existing co-firing project would continue to receive 1 ROC / MWh, even after rule changes awarding less than 1 ROC / MWh to new co-firing projects.

developing a supply and processing infrastructure to allow the co-firing of energy crops via direct injection (Drax Power, 2005). Both of these investments were initiated before the Energy Review (at a time when the ROC-eligibility of co-firing was to expire in 2016).

III. Conclusions and Recommendations

As long as heat and power generation from fossil fuel plants continues, co-firing can play a useful role in reducing plants' net greenhouse gas emissions**.** This is especially true if CCS from fossil fuel plants becomes viable as the storage of CO_2 combined with absorption by the growth of sustainable biomass can lead to a net CO_2 reduction from the atmosphere. One potential danger from co-firing is 'coal lock-in', where co-firing prolongs the life of coal plants that would otherwise close. There is no evidence of this phenomenon in the UK. Indeed, if future fossil fuel plants are capable of accepting various feedstocks, such as Avedøre, then incentives to co-fire could reduce the level of fossil fuel use to minimal, or standby, levels.

In the UK, the long-term future of coal power, and with it co-firing, appears secure. Given the difficulties in incentivising the co-firing of domestic energy crops or residues, demand for residue-derived bioenergy feedstocks totalling several million tonnes can be predicted. However, developments in the UK co-firing market can be greatly affected by seemingly minor changes in legislation. One reason for this is the preference towards policy instruments that let the market decide where to allocate renewable energy resources and let different renewable energy technologies compete against each other.

Imports of co-firing into the UK could increase substantially if, as has been suggested, support for co-firing is made permanent and is separated from support for energy crops. The eventual competitiveness of imported biomass will depend on the price of feedstocks, the carbon price and the calibration of bands under new ROC arrangements. In 2005, under 3% of biomass was co-fired in UK power plants. If market conditions are right, over 10% could be co-fired. At this level, in the absence of new policies to incentivise energy crops or co-firing of domestic residues, over 3 million tonnes of biomass would be imported annually.

3.1 Recommendations

- The proposed removal of the minimum energy crop requirement from the UK co-firing regulations is to be welcomed. If co-firing from imported residues is environmentally beneficial and economically competitive, its future should not depend on subsidy of the energy crop market.
- The proposed switch from a cap on co-firing for ROCs to a banded system is to be welcomed. If calibrated correctly, this could increase co-firing in the UK substantially, without reducing other forms of renewable electricity.
- The actual environmental benefit from co-firing cannot be assessed without further information concerning the greenhouse gas balance and sustainability of the feedstocks used. It is recommended that operators be required to supply more information on the origin of co-fired biomass.
- The ROC-value of co-firing should take into account its greenhouse balance by making some kind of deduction for energy use during production, transport and processing of the crop. This is not the same as incentivising energy crops over imported biomass since emissions would not count from plant residues where the original plant was not cultivated for energy (e.g. olive cake).
- Co-firing operators should have freedom to choose the biomass feedstock based on price and technical specifications.

Appendix A: Economics of Co-firing under EU-ETS

It is estimated that a carbon price in excess of €20 is needed for co-firing to economically viable without the support of the Renewables Obligation. This is based on the quoted prices of coal, biomass, carbon and ROCs and the calorific values of coal and biomass. €20 is the minimum carbon price estimate since it compares coal with low-cost sawdust without accounting for the capital cost of investing in co-firing equipment.

Title of the Table

	Coal	**Biomass**	**Data Source / Notes**
Fuel needed per MWh of electricity* (kg)	348.82	505.62	Commission of the European Communities, 2006
Cost of fuel (£)	13.46	25	DTI, 2006d. Scottish Executive, 2004
Carbon Price (€/tCO_2)	11.85	11.85	http://www.pointcarbon.com
Carbon Price (£/tCO_2)	7.93	7.93	
Carbon Emission (tCO_2/MWh)	0.85	0	Commission of the European Communities, 2006
Carbon Cost (£/tCO_2)	6.75	0	
ROC Price (£/MWh)	0	(39.84)	http://www.nfpa.co.uk **NB – this is the average price of ROCs at auction in October. It is unlikely that co-fired ROCs will sell for this price, if there are traded at all (put this in a note at the foot of the table).**
Total Cost with ROCs (£/MWh)	20.20	(14.84)	
Total Cost without ROCS (£/MWh)	20.20	25	
Carbon price needed for biomass co-firing to be competitive (£)		13.57	= (Biomass Cost – Coal Cost) ÷ Coal Carbon Emissions (tCO_s/MWh)
Carbon price needed for biomass co-firing to be competitive (€)		20.31	

* Assuming coal and biomass are both fired in a PF coal plant with 40% efficiency

Appendix B: Eurostat Trade Statistics

Eurostat trade statistics represent an amalgamation of trade statistics collected by the national statistical agencies of Member States. Their usefulness in tracking bioenergy imports and exports is limited by the methodological practices used in collection of the statistics. In particular, differences exist between different Member States' national statistics data collection methodology. This is most important in the case of reporting thresholds. These are the maximum value or volume of import or export activity a firm is permitted to undertake before it must submit its trade data to the national authority that collects trade statistics. The existence of a threshold means that not all international trade in a given commodity will be recorded. Each individual transaction within the EU will not necessarily be recorded as an import or export in both the destination and country of origin. Differences in Member States' data reporting thresholds mean that the import and export figures provided by Eurostat are not necessarily symmetrical. Country A may be obliged to report an export to Country B, but Country B may not have to report the corresponding import. Furthermore, Member States have different policies towards the estimation of trade flows that fall beneath the reporting threshold (Eurostat, 2006a).

In the UK, a firm must report intra-EU trade if it imports or exports goods with a value in excess of £225,000 in a calendar year. Once £225,000-worth of goods have been imported (exported), the firm is obliged to record its imports (or exports) from that point onwards. A firm is permitted to stop recording its intra-EU trade flows only once it has imported (exported) less than the threshold value for a whole calendar year (ending in December). The reporting threshold for extra-EU trade is set according to European Commission Regulation (EC) 1917/2000. This states that any customs declaration in excess of €1000 will be recorded.

Since the market for co-firing biomass with fossil fuels is characterised by large shipments being made to power stations, it is likely that most imports of biomass for co-firing into the UK are captured by the trade statistics. The application of an intra-EU threshold based on value traded per firm per year rather than individual shipment value increases the probability that most shipments for co-firing will be captured by the trade statistics.

Trade statistics do not differentiate products by end use. The extent to which a country's energy trade behaviour can be deduced by trade statistics therefore depends on the precision of the trade classification system and the extent to which alternative uses exist for a given product. These difficulties are summarised below for commonly-used imported feedstocks in the UK.

Olive cake **–** identification of the appropriate bioenergy source is not difficult since the CN8 classification system differentiates between olive cake that is suitable for oil recovery (and hence of a higher value and not imported into the UK in large quantities) and that which is suitable only for use as bioenergy and animal feed. The trade statistics do not differentiate between the latter two uses. However, imports of dry olive cake were below the UK reporting thresholds until 2003. Given the rapid increase in imports from 2003 on and the coincidental timing with the introduction of large-scale co-firing in the UK, it is reasonable to assume that the majority of the imported olive cake is for co-firing with fossil fuels.

Palm kernel products **–** identification of the appropriate bioenergy source is more problematic than in the case of olive cake. The majority of the inflow is likely to have been classified as 23066000, palm oil cake. This is imported into the UK in greater quantities than 1207100, palm kernel. However, imports of both commodities increased from 2002 onwards. Substantial quantities of both products, especially palm oil cake, were imported prior to 2002, demonstrating that palm kernel products have a value as an established tradable commodity apart from their energy use. The trade statistics must therefore be interpreted with caution since, though they appear to show a clear link between the introduction of large-scale co-firing and palm kernel imports, the effect of co-firing on the level of imports cannot be separated from developments in the animal feed market.

Wood pellet **–** identification of the appropriate traded commodity is problematic in the case of fuel wood imports, especially in pelletised form. Although wood pellet imports are classified under section 44 (fuel wood) of the CN8 system, there is no classification for pellets other than 44013 - sawdust and wood waste whether or not agglomerated into pellets, briquettes or similar forms.

Appendix C: Availability of Residues from Transport Biofuels

The information shown in the tables below is derived from various sources. It uses the mass balance equations of palm, rapeseed and wheat to demonstrate how much co-product is produced as a result of transport biofuel production. The mass cultivation scenarios shown are purely hypothetical. They are included to demonstrate the scale at which co-products may be produced.

Palm Oil

As Table C1 shows, over 76 PJ of PKE per year, will be available by 2015 according to the FAO Agricultural Outlook. This figure should should be viewed as a minimum estimate since it assumes that demand for biodiesel will enjoy linear growth in the EU-25. Also, the FAOSTAT data for palm oil production in 2005 is lower than the figure produced by USDA (www.fas.usda.gov). USDA estimates that almost 40 Mt of palm oil was produced in 2005, compared to the FAO estimate of 32 Mt.

Table C1: Potential Palm Residue Production

	Information	**Units**	**Notes & Sources**
	Present Production		
A	World palm oil production	32 Mt	http://faostat.fao.org (2005 production)
B	PKE produced per tonne of palm oil	0.1t	Woods et al., 2006
C	PKE Net Calorific Value	16.722 MJ/kg	DTI, 2005
D	Estimated PKE production (Mass)	3.2 Mt	A*B
E	Estimated PKE production (Energy)	53.51 PJ	C*D
F	Empty Fruit Bunches (EFB) produced per tonne of palm oil	0.9t	Woods et al., 2006

G	EFB Net Calorific Value	4.4 MJ/kg	IPA Energy Consulting, 2005
H	Estimated EFB Production (Mass)	28.8 Mt	A*F
I	Estimated EFB Production (Energy)	126.72 PJ	G*H
Projected Future Production			
J	Future Palm Oil Production	45.9 Mt	FAO, 2006b Projection for 2015
K	Future PKE Production (Mass)	4.59 Mt	
L	Future EFB Production (Mass)	41.31 Mt	
M	Future PKE Production (Energy)	76.75 PJ	
N	Future PKE Production (Energy)	181.76 PJ	

Rapeseed

As Table C2 shows, over 28 Mt of rape meal and 49 Mt of straw were produced worldwide in 2005. Were additional rapeseed to be grown to meet the EU’s 2010 biodiesel demand in full, an additional 47 Mt of straw and rape meal would be produced. This is an unlikely scenario, however, as a variety of crops can be used to produce biodiesel.

Table C2: Potential Rapeseed Residue Production

	Information	Units	Notes & Sources
Present Production			
A	World rapeseed production (dry)	47.6 Mt	http://faostat.fao.org (2005 production)
B	Rape meal produced per tonne of	0.59t	Elsayed et al., 2003

	rapeseed		
C	Rape meal Net Calorific Value	24.04 MJ/kg	Alterner, quoted in Armstrong et al., 2002
D	Estimated Rape meal production (Mass)	28.084 Mt	A*B
E	Estimated Rape meal production (Energy)	675 PJ	C*D
F	Straw produced per tonne of rapeseed	1.04 t	Elsayed et al., 2003
G	Straw Net Calorific Value	13.52 MJ/kg	Newman, 2003
H	Estimated Straw Production (Mass)	49.5 Mt	A*F
I	Estimated Straw Production (Energy)	669 PJ	G*H
Hypothetical Future Production (rapeseed used for biodiesel)			
J	2010 Biodiesel Demand in EU-25	13 billion litres	European Commission, 2003
K	Litres of Biodiesel per tonne of rapeseed (fresh)	422 litres	Smeets et al., 2006
L	Rapeseed (fresh) needed for biodiesel production	30.8 Mt	(1/G) * F
M	Rapeseed (dry) needed for biodiesel production	28.89 Mt	Elsayed et al., 2003
N	Rape meal co-produced with biodiesel (Mass)	17.08 Mt	
O	Rape meal co-produced with biodiesel (Energy)	410.62 PJ	
P	Straw co-produced with biodiesel (Mass)	30 Mt	
Q	Straw co-produced with biodiesel (Energy)	408 PJ	

Wheat

As table C3 shows, over 385 Mt of wheat straw were produced worldwide. Diverting wheat towards manufacture of bioethanol – whether this is in addition to or instead of food and fodder production – would release 0.5t of DDGS for every tonne of wheat cultivated. As the table shows, cultivation of the wheat needed to satisfy the estimated EU-25 bioethanol demand would release 14 Mt of DDGS and 18 Mt of straw onto the fodder and bioenergy markets.

Table C3: Potential Wheat Residue Production

	Information	**Units**	**Notes & Sources**
Present Production			
A	World wheat production (dry)	630 Mt	http://faostat.fao.org (2005 production)
B	DDGS produced per tonne of dry wheat (when destined for distillation)	0.5 t	Smeets et al., 2006 See Note i
C	DDGS Net Calorific Value	14.8 MJ/kg	DTI, 2005
D	Estimated DDGS production (Mass)	N/A – DDGS only produced when wheat is fermented and distilled	
E	Estimated Net Calorific Value DDGS co-produced per tonne of dry wheat	7.4 GJ	B*C
F	Straw produced per tonne of (dry) wheat	0.61188t	Smeets et al., 2006 See Note ii
G	Straw Net Calorific Value	13.48 MJ/kg	Newman, 2003
H	Estimated straw production (Mass)	385.5 Mt	A*F
I	Estimated straw production (Energy)	5,196 PJ	G*H

Hypothetical Future Production (wheat used for bioethanol)			
J	EU – 25 estimated demand for bioethanol	12 billion litres = 9.56 Mt	eBIO, 2006
K	Wheat (dry) required per tonne of bioethanol	3.03 t	Smeets et al., 2006
L	Wheat (dry) required to meet EU-25 bioethanol demand	28.97 Mt	J*K
M	DDGS co-produced with bioethanol (Mass)	14.49 Mt	
N	DDGS co-produced with bioethanol (Energy)	214.45 PJ	
O	Straw co-produced with bioethanol (Mass)	17.73 Mt	
P	Straw co-produced with bioethanol (Energy)	238.95 PJ	

Notes:

i) From mass balances given in Smeets et al., 2006.

3.499 tonnes of wheat (fresh) = 3.03 tonnes of wheat (dry) + moisture

Therefore, 1 tonne of wheat (dry) = 1.154785 tonnes (fresh)

1 tonne of wheat (fresh) = 362 litres of bioethanol

Therefore, 1 tonne of wheat (dry) = 362 * 1.154785 = 418.03 litres of bioethanol

1 kg DDGS = 5/6 litres of bioethanol

Therefore, 1 tonne of DDGS = [(5/6) * 10^3] / 418.03 = 2 tonnes of wheat (dry)

ii) 3.03 tonnes of wheat (dry) = 1.854 tonnes of straw

Therefore, 1 tonne of dry wheat = 0.61188 tonnes of straw

Appendix D: List of Abbreviations

BFBC - Bubbling Fluidised Bed Combustion

CCS - Carbon Capture and Storage

CCGT - Combined Cycle Gas Turbine

CCT - Clean Coal Technology

CFBC - Circulating Fluidised Bed Combustion

CN8 - 8-digit Combined Nomenclature

CO - Carbon Monoxide

CO_2 - Carbon Dioxide

DDGS - Distillers Dried Grains with Solubles

DEFRA - Department for Environment, Food and Rural Affairs

Ebio - European Bioethanol Fuels Association

ECS - Energy Crop Scheme

ELV - Emissions Limit Value

EOR - Enhanced Oil Recovery

EU-ETS - European Union Emissions Trading Scheme

FBC - Fluidised Bed Combustion

FGD - Flue Gas Desulphurisation

GW - Gigawatt

H_2 - Hydrogen

IGCC - Integrated Gasification Combined Cycle

KWh - Kilowatt-hour

LCPD - Large Combustion Plant Directive

LECs - Levy Exemption Certificates

MSW	-	Municipal Solid Waste
Mt	-	Mega-tonne
Mtoe	-	Mega-tonne of Oil Equivalent
MW	-	Megawatt
N_2	-	Nitrogen
NO_x	-	Nitrogen Oxides
PF	-	Pulverised Fuel
PFBC	-	Pressurised Fluidised Bed
PKE	-	Palm Kernel Expeller
RO	-	Renewables Obligation
ROC	-	Renewables Obligation Certificate
SC	-	Supercritical
SCR	-	Selective Catalytic Reduction
SRC	-	Short Rotation Coppice
SO_2	-	Sulphur Dioxide
SO_x	-	Sulphur Oxides
TWh	-	Terrawatt-hour
UK	-	United Kingdom
US	-	United States
USC	-	Ultrasupercritical
WID	-	Waste Incineration Directive

References

Armstrong et al., 2002. Energy and Greenhouse Balance of Biofuels for Europe – an update. Concawe, report no. 2/02.

Babu, S., 2001. Role of Natural Gas in Promoting Bioenergy as a Component of the Sustainable Energy Scenario. Presentation to Natural Gas/Renewable Energy Hybrids Workshop, Morgantown, West Virginia, 08/08/2001

Biomass Task Force, 2005. Report to Government, October 2005.
www.defra.gov.uk/farm/crops/industrial/energy/biomass-taskforce/pdf/btf-finalreport.pdf
Accessed 15/11/2006

Bowell, R., 2006. Full Steam Ahead… *European Power News*. 31 (4) p18

Boylan, D.M. Larrimore, C.L. Fouad, F., 1999. Properties of concrete containing wood/coal fly ash mixtures.
Sixteenth Annual International Pittsburgh Coal Conference, Pittsburgh, PA (US), 10/11/1999--10/15/1999

California Biomass Collaborative, 2004. Biomass Technology Assessment--SMUD ReGEN Program.
http://biomass.ucdavis.edu/pages/reports.html

Commission of the European Communities, 2006. Commission Decision Establishing Guidelines for the Monitoring and Reporting of Greenhouse Gas Emissions Pursuant to Directive 2003/87/EC of the European Parliament and of the Council.
Accessed through
http://www.defra.gov.uk/environment/climatechange/trading/eu/permits/pdf/comm-decision06.pdf 30/10/2006

DEFRA (Department for Environment, Food and Rural Affairs), 2005.
Set-aside Handbook and Guidance for England, 2006 edition. PB11304.
http://www.defra.gov.uk/farm/capreform/pubs/pdf/Setaside2006.pdf .
Accessed 28/11/06

DEFRA (Department for Environment, Food and Rural Affairs), 2006. United Kingdom National Emission Reduction Plan for implementation of the revised Large Combustion Plants Directive (2001/80/EC).
http://www.defra.gov.uk/environment/airquality/lcpd/index.htm . Accessed 12/08/06.

DBDH (Danish Board of District Heating), 2005. Avedøre Unit 2 – the world's largest biomass-fuelled CHP plant. *News from DBDH*. 3 2005.
www.dbdh.dk/pdf/ren-energy-pdf/avedore-unit-2.pdf

Drax Power, 2005. Short rotation coppice willow processing trial proceeds to second phase. Press Release: 05/09/05.
http://www.draxpower.com/press.php?page=archive

DTI (Department of Trade and Industry), 2003. Review of the Feasibility of Carbon Dioxide Capture and Storage in the UK. URN 03/1261.
http://www.dti.gov.uk/publications/index.html

DTI (Department of Trade and Industry), 2005. Best Practice Brochure: Co-firing of Biomass (Main Report). Report No. COAL R287 DTI/Pub URN 05/1160.
http://www.dti.gov.uk/publications/index.html

DTI (Department of Trade and Industry), 2006. The Energy Challenge. Energy Review. A report.
http://www.dti.gov.uk/energy/review/page31995.html

DTI (Department of Trade and Industry), 2006b. CO_2 Capture and Underground Storage in the UK. The Valleys Energy Project: A Case Study. URN 06/755.
http://www.dti.gov.uk/energy/review/page31995.html

DTI (Department of Trade and Industry), 2006c. Digest of United Kingdom Energy Statistics (DUKES 2006). URN 06/87
http://www.dti.gov.uk/energy/statistics/publications/index.html

DTI (Department of Trade and Industry), 2006d. Quarterly Energy Prices, September 2006.
http://www.dti.gov.uk/energy/statistics/publications/index.html

DTI (Department of Trade and Industry), 2006e. Reform of the Renewables Obligation and Statutory Consultation on the Renewables Obligation Order 2007.
http://www.dti.gov.uk/consultations/page34162.html

eBIO (European Bioethanol Fuels Association), 2006. Revision of the 2003/30/EC: Priorities for the Bioethanol Sector. Presentation by Dr. Lutz Guderjahn at European Parliament hearing on Strategy for Biomass and Biofuels, 01/06/06.
http://www.ebio.org/downloads/publications/060601_eBIO_presentation_B&B_hearing_EP_final.pdf . Accessed 02/12/06.

Electrabel, 2005. Environmental Report 2005
http://www.electrabel.com/corporate/aboutelectrabel/documents/mmv_environmentalreport_en.pdf#search=%22co-firing%20natural%20gas%20harculo%22

Elsayed et al., 2003. Carbon and Energy Balances for a Range of Biofuels Options. Project Number B/B6/00784/REP, URN 03/836.

Engineeringtalk, 2006. Fans boost efficiency of green power generator. *Engineeringtalk* 29/06/06.
http://www.engineeringtalk.com

ETSU, 2001. Introducing Wood Pellet Fuel to the UK. ETSU B/U1/00623/REP DTI/Pub URN 01/10104

EUBIONET, 2005. Biomass Co-firing: an Efficient way to Reduce Greenhouse Gas Emissions. http://eubionet.vtt.fi Accessed 09/10/06.

European Commission, 2003. EU-25 Energy and Transport Outlook to 2030, Part IV. http://ec.europa.eu/dgs/energy_transport/figures/trends_2030/5_chap4_en.pdf . Accessed, 05/12/06

European Commission. Infosheet – the Energy Crops Scheme. http://ec.europa.eu/agriculture/capreform/infosheets/energy_en.pdf . Accessed 28/11/06

Eurostat, 2006. Lookup of External Trade Statistics, http://ec.europa.eu/comm/eurostat/ . Accessed 20/08/06

Eurostat, 2006a. Statistics on the trading of goods – User guide. Office for Official Publications of the European Communities, Luxembourg.

E.ON UK plc. Swift and efficient planning process is key to Energy Review, says E.ON UK Chief Executive. Press release 11/07/06. http://www.eon-uk.com/pressRelease.aspx?id=963&month=0&year=0&p=1 . Accessed 22/08/06

FAO, 1984. Utilisation des sous-produits de l'olivier en alimentation animale dans le bassin Méditerranéen. FAO, Rome, 1984. http://www.fao.org/DOCREP/004/X6545F/X6545F00.htm#TOC

FAO, 2006. http://faostat.fao.org . Lookup of agricultural production statistics. Accessed 04/12/06

FAO, 2006b. OECD-FAO World Agricultural Outlook 2006-2015. OECD Publications, 2006.

FEDIOL, 2006. http://www.fediol.be/6/stats2005/EU_seed_prod_2005.pdf Lookup of EU-25 rapeseed production statistics, accessed 04/12/06.

Goh, 2005. Ironbridge Power Station host Supergen Bioenergy Meeting. *British Bioenergy News*. Issue 2.

IEA, 2004. Prospects for CO_2 Capture and Storage. http://www.iea.org/textbase/nppdf/free/2004/prospects.pdf

IEA Clean Coal Centre, 2002. Experience of Indirect Cofiring of Biomass and Coal (Profile Document). http://www.iea-coal.org.uk/publishor/system/component_view.asp?LogDocId=81046. Accessed 22/08/06

IEA Clean Coal Centre, 2006. http://www.iea-coal.org.uk/content/default.asp?PageId=71 . Accessed 22/08/06.

IEA Clean Coal Centre, 2006a.

http://www.iea-coal.org.uk/content/default.asp?PageId=73 . Accessed 22/08/06.

IEA Clean Coal Centre, 2006b.
http://www.iea-coal.org.uk/content/default.asp?PageId=85 . Accessed 22/08/06

IEA Clean Coal Centre, 2006c.
http://www.iea-coal.org.uk/content/default.asp?PageId=74 . Accessed 22/08/06.

IEA Clean Coal Centre, 2006d.
http://www.iea-coal.org.uk/content/default.asp?PageId=80 . Accessed 22/08/06.

IEA Task 32, 2006 http://www.ieabcc.nl/database/info/cofiring/91.html

Ienica, 2005. Oilseed Rape and Turnip Rape.
http://www.fediol.be/6/stats2005/EU_seed_prod_2005.pdf . Accessed 04/12/06

Illsley et al., 2005. Promoting environmental justice through industrial symbiosis: establishing a regional market for low-cost renewable energy amongst rural Scottish households by using Scottish forest industry waste to provide wood pellet fuel. Presentation to International Sustainable Development Conference Helsinki, 6-8 June 2005

IPA Energy Consulting, 2005. The Economics of Co-firing to Department of Trade and Industry. URN 06/1959
http://www.dti.gov.uk/files/file34449.pdf

Juninger et al., 2006. IEA Bioenergy Task 40 – Country Report for the Netherlands. ISBN 90-73958-96-2
http://www.bioenergytrade.org

Kurkela, 2002. Gasification-based Co-firing of Biomass and Recovered Fuels in Coal-fired Boilers. Presentation to Amsterdam Biomass Conference, June 2002.

Malaysian New Straits Times, 2006. Pushing the Case for Envodiesel, *Malaysian New Straits Times*, 09/09/2006.
http://www.mpoc.org.my/envo_120906_01.asp

Malaysian Palm Oil Board. Quality and Characteristics of Malaysian Palm Oil Cakes/Expellers. Paper available on request from Malaysian Palm Oil Board.
http://www.mpob.gov.my/

McIlveen-Wright et al., 2006. A comparison of circulating fluidised bed combustion and gasification power plant technologies for processing mixtures of coal, biomass and plastic waste. *Fuel Processing Technology* (Article in Press).

Meijer, 2006. Co-firing: Learning from Over a Decade of Dutch Experience in a Growing Field. *Modern Power Systems*, June 2006.
http://www.modernpowersystems.com

MitsuiBabcock, 2006. Clean Coal Technology and the Energy Review.

http://www.mitsuibabcock.com

Modern Power Systems, 2006. Clean Coal Ramps Up in the UK. *Modern Power Systems*, Vol 26, Issue 7, p.3
http://www.modernpowersystems.com

Newman, 2003. A Trial Burn of Rape Straw and Whole Crops Harvested for Energy Use to Assess Efficiency Implications. Report prepared for DTI by Energy Power Resources Ltd., URN 03/1569.

NREL (National Renewable Energy Laboratory), 1998. Fireside Issues Associated with Coal-Biomass Co-firing. NREL/TP-570-25767
http://www.p2pays.org/ref/19/18953.pdf Accessed 08/10/06.

OFGEM, 2006. Stations over 50kW accredited for the RO and for the RO & CCL.
http://www.ofgem.gov.uk Accessed 21/08/06.

OFGEM, 2006b. Renewables Obligation: Fuel Measurement and Sampling Guidance. Ref: 59/06
http://www.ofgem.gov.uk Accessed 17/09/06.

OFGEM 2006c. Renewables Obligation: Guidance for generators over 50kW. Ref: 61/06
http://www.ofgem.gov.uk Accessed 17/09/06.

Official Journal of the European Communities, 2000. Directive 2000/76/EC. 28/12/2000, L332/91.

OPSI (Office of Public Sector Information), 2006. The Renewables Obligation Order 2006. Statutory Instrument 2006 No. 1004

Pletka, 2003. Gasification could bring respectability to co-firing. *Modern Power Systems*. June, 2003.

Raven, 2005. Strategic Niche Management for Biomass. A comparative study on the experimental introduction of bioenergy technologies in the Netherlands and Denmark. PhD Thesis, Eindhoven Technical University

Rosillo-Calle F, Perry M, 2006. Country Report for the United Kingdom. Country, Report T40UK1R. Preport prepared for IEA Task 40,
http://www.bioenergytrade.org

RWEnpower, 2006. Personal communication with economic regulations section. 05/09/06.

RWEnpower, 2006b. Direct Injection – the Aberthaw Story. REA Biomass Workshop, September 2006.
http://www.r-e-a.net

RWEnpower, 2006c. Extract from company website. Last accessed 08/11/2006.

http://www.rwenpower.com/cr/Green_fuels.aspx

Scottish Executive, 2004. Enterprise and Culture Committee, Evidence Received for Renewable Energy in Scotland Inquiry, Submission from the Wood Panels Industry Federation.
http://www.scottish.parliament.uk/business/committees/enterprise/inquiries/rei/ec04-reis-woodpanelindust.htm Accessed 30/10/2006.

Scottish and Southern Energy, 2006. Excerpt from website, accessed 24/08/06
http://www.scottish-southern.co.uk/SSEInternet/index.aspx?id=2550&terms=clean+coal&searchtype=1&fragment=True

Scotsman, 2006. £24m Biomass Plant wins First Minister's Backing. 17/11/2006
http://news.scotsman.com/politics.cfm?id=1702692006 . Accessed 28/11/2006

Smeets et al., 2005. Supportive Study for the OECD on Alternative Developments in Biofuel Production across the World. Report NWS-E-2005-141. OECD, Directorate for Food, Agriculture and Fisheries.

Spath and Mann, 2001. A Life Cycle Assessment of Biomass Co-firing in a Coal-fired Power Plant. *Clean Production Processes 3 81-91*.

UNCTAD, 2005. New olive agreement comes up for adoption. Press Release: UNCTAD/PRESS/PR/2005/014. 22/04/05

Utility Week, 2005. The Cost of Carbon Capture. *Utility Week* vol. 23, issue 14.

Vom Berg & Feuerborn, 2005. Present Situation and Perspectives of CCP Management in Europe. www.flyash.info/2005/53vom.pdf Accessed 09/10/06

Wicks, R.; Keay, M., 2005. Can Coal Contribute to Sustainable Development? *Energy and Environment*, 16 (5) 767-779.

Wood Pellet Association of Canada. "Biomass" Responsible, Sustainable, Renewable Energy Option. Presentation by John Swaan, Executive Director, Wood Pellet Association of Canada; March 23, 2006.

Woods J., Tipper R,. et al./ DTI, 2006. Evaluating the Sustainability of Co-firing in the UK. URN 06/1960 http://www.dti.gov.uk/files/file34448.pdf