Correction List

p2, last but one line buy should be by.

p4, Table 1.2 "%" added to biomass excluding co-firing percentage.

p6, line 4 "of" inserted between "half" and "the".

p7, Figure 1.3 column label changed from "hydr" to "hydro" .

p19, "section 1.1.1.1" replaced with "section 4.3.1".

p27, "section 1.1.1" replaced with "section 4.3.".

p28, Table 1.4, units added to values of pour point (°C) and vapour pressure (kPa).

p32, line 7 "so as to" has been replaced by "to".

p37, second bullet point "which was assumed to have a life of 10 years as it was using existing plant" added after "co-firing".

p41, line 19 " coverall all" replaced with "covered all".

p45, line 3 " by Conversion and Resource" added to give full name of company.

p47, line 13 "Rankin" replaced with "Rankine".

p51, line 4 "model" added after "ASPEN PLUS".

p58, line 6 "Stirling" replaced with "Sterling".

p67, line 7 " Section **Error! Reference source not found.**" replaced with " Section 4.3".

p76, line 20 "levelly" replaced with Levy".

p84, line 14 "is Sweden" replaced with "in Sweden".

p104, line 5 " Varity" replaced with "Variety".

p114, line 8 " in inferred" replaced by " the inferred".

p114, line 14 " given to shows" replaced by " given to show".

p119, Table 4.10 miscanthus base 3% ash char LHV changed from 0.22 to 31.34 and char energy changed from 31.34 to 6.93.

p135, Table 4.14 "C°" replaced with "°C".

p154, line 7 " has power to heat ratios" replaced by "gives power to heat ratios".

p156, line 9 " and the, then" replaced with "then:".

p157, line 1 "Figure 4.20" replaced by "Figure 4.19".

p158, line 1 "oil bio-oil" replaced with "old bio-oil".

p167, line 10, "conveying" replaced by "conveyor".

p169, line 19 "£445" replaced by £445k".

p169, line 22 "£1,143" replaced by "£1,143k".

p199, line 13, reference number added for the "Hinton" report

p251, blank lines removed to allow caption for Figure 7.4 to be on same page as the figure.

p254, line 4 " at is maximum" replaced by " at it's maximum".

p254, line 10 " it is like that" replaced by " it is likely that".

p295, line 3 "Table 4.19" replaced by "Table 7.19".

p310, line 20 "(R^2)" replaced with " (R^2 of 0.96)".

p320, line 5 "generator grating" replaced with "generator rating".

A TECHNO-ECONOMIC ASSESSMENT OF THE USE OF FAST PYROLYSIS BIO-OIL FROM UK ENERGY CROPS IN THE PRODUCTION OF ELECTRICITY AND COMBINED HEAT AND POWER

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A Techno-economic assessment of the use of fast pyrolysis bio-oil from UK energy crops in the production of electricity and combined heat and power

John Geoffrey Rogers

Doctor of Philosophy

2009

Summary

This thesis investigates the cost of electricity generation using bio-oil produced by the fast pyrolysis of UK energy crops. The study covers cost from the farm to the generator's terminals. The use of short rotation coppice willow and miscanthus as feedstocks was investigated. All costs and performance data have been taken from published papers, reports or web sites. Generation technologies are compared at scales where they have proved economic burning other fuels, rather than at a given size. A pyrolysis yield model was developed for a bubbling fluidised bed fast pyrolysis reactor from published data to predict bio-oil yields and pyrolysis plant energy demands. Generation using diesel engines, gas turbines in open and combined cycle (CCGT) operation and steam cycle plants was considered. The use of bio-oil storage to allow the pyrolysis and generation plants to operate independently of each other was investigated. The option of using diesel generators and open cycle gas turbines for combined heat and power was examined. The possible cost reductions that could be expected through learning if the technology is widely implemented were considered.

It was found that none of the systems analysed would be viable without subsidy, but with the current Renewable Obligation scheme CCGT plants in the 200 to 350 MWe range, super-critical coal fired boilers co-fired with bio-oil, and groups of diesel engine based CHP schemes supplied by a central pyrolysis plant would be viable. It was found that the cost would reduce with implementation and the planting of more energy crops but some subsidy would still be needed to make the plants viable.

Keywords Miscanthus, willow, CCGT, diesel, combustion

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A Techno-economic assessment of the use of fast pyrolysis bio-oil from UK energy crops in the production of electricity and combined heat and power

1 Background

1.1 Electricity generation in the UK

1.1.1 The generation mix

The electricity supply industry in the UK has been restructured in a way that maximises competition. As such the market rather than any individual organisation is responsible for the number and type of power stations in operation. The market consists of a network of different kinds of contract that are tailored to the needs of the parties involved. All but the largest consumers have contracts with electrical retailers. The electrical retailers and some large consumers have contracts with the power station operators. Both the electrical retailers and power station operators have contracts with the distribution companies who own the transmission and distribution networks. Under the British Electricity Trading and Transmission Arrangements (BETTA) introduced in the Electricity Act 2004 [1] the National Grid Company is responsible for the minute by minute operation of the system and uses a balancing market to accommodate differences between actual power flows and the contracted ones. Some of the large power companies own electrical retailers and power stations. The working of this network of contracts is overseen by a government regulator the office of gas and electricity markets (Ofgem). The key point is that each company is responsible for its own long term strategic planning. This means that any national energy policy can only be implemented by introducing market mechanisms that make it economically advantageous to follow the adopted energy policy.

Electricity in the UK is generated by a mixture of coal fired steam cycle units, nuclear reactors, gas fired combined cycle gas turbines and some generation from renewable sources. Table 1.1 shows the total installed capacity taken from Digest of UK electricity supply [2] of each type of power station in service in 2007.

Table 1.1 Generation capacity of power stations operating in the UK in 2007

type of power station	MW_e
coal or dual fired	29,998
combined cycle gas turbine (CCGT)	26,973
nuclear	10,979
other fired steam plant	6,825
pump storage	2,744
renewables other than wind and hydro	1,565
natural flow hydro	1,420
OCGT + diesel	1,404
wind	1,042

This mix will change considerably over the next 10 years. From the station information on the British Energy web site [3] the nuclear capacity will be down to 4,758 MWe by 2017. By 2014 the 11,550 MWe of older coal and oil fired plants that have opted out of the EU Large Combustion Plant Directive for limiting SO_X, NO_X, and particulate emissions will have to close [4].

To compensate for this reduction in capacity the power generators have applied for consent to build a mixture of gas fired combined cycle gas turbine (CCGT), supercritical coal fired power station and generation from renewable energy sources. Although there is some proving trials with marine generation systems using wave power or tidal flow the bulk of the renewable generation is planned to come from wind turbines (on shore and off shore) and biomass plants. This study uses the definition of biomass provided by The Royal Commission on Environmental Pollution in its 2005 report [5].

It defines biomass fuel as being residues derived from forestry, specifically grown energy crops and dry agricultural residues like straw and chicken litter.

The government considers that new nuclear power stations should be built [6], but only if they are economically viable.

The installed capacity does not give the proportion of electricity that is generated from each source as there are differences in the average running hours and load of each type of power station. These differences arise from:

- Lack of load demand: under BETTA contracts are placed to cover the expected demand for each 30 minute period of the day. If there is not a contract for the load from a particular power station it does not run;
- Different maintenance requirements for the different technologies;
- Lack of the primary energy source. This mainly affects wind turbines, if the wind is not blowing they cannot generate;
- Ambient air temperature, the output from gas turbines reduces with increasing inlet air temperature;
- Plant condition, the efficiencies and outputs of power plants reduce with running hours due to ware on key components and build up of deposits on heat exchangers.

The amount of generation that a power station achieves is measured by the Capacity Factor for the power station (CF). The capacity factor is the ratio of the amount of electricity exported from the power station to the amount that could be exported if it ran for 24 hours a day 365 days a year at rated output. The capacity factors for different types of power station have been taken from Digest of UK Energy Statistics (DUKES) [7] and are shown in Table 1.2.

Table 1.2 Capacity factors for different types of power station

type of power station	CF
coal	62.5%
combined cycle gas turbine (CCGT)	63.2%
nuclear	59.6%
pump storage	16.1%
biomass excluding co-firing	56.6%
natural flow hydro	36.3%
wind	27.5%

Oil fired plant, open cycle gas turbines and diesel generators all had low capacity factors. The figure for nuclear power is low reflecting long maintenance periods in 2007; in 2003 it was up to 77.8%.

1.1.2 Electricity generation from renewable sources in the UK

The role of renewable energy in reducing greenhouse gases and improving the security of supply has been recognised by both the European Union and the United Kingdom government [8-11]. The government has set a target of 10% of electricity generation from renewables by 2010 with an aspiration target of 20% by 2020. This has lead to the imposition of an annually increasing target for the proportion of electricity to be generated by renewable sources being imposed on the electricity suppliers. This target is called the Renewable Obligation (RO). It is a mechanism that effectively charges those suppliers who do not meet the obligation and rewards those that do; its impact is discussed further in Section 1.1.4.1. The RO was introduced in 2002 and is set to 7.8% for 2007/2008 rising to 20% by 2015. The scheme is scheduled to end by 2027 when the Government anticipates that the generation costs from renewable sources will be competitive with that from other sources.

The proportion of electricity supplied by each type of generator has been calculated from figures reported in the Digest of UK Energy Statistics [7] and these are shown in Figure 1.1.

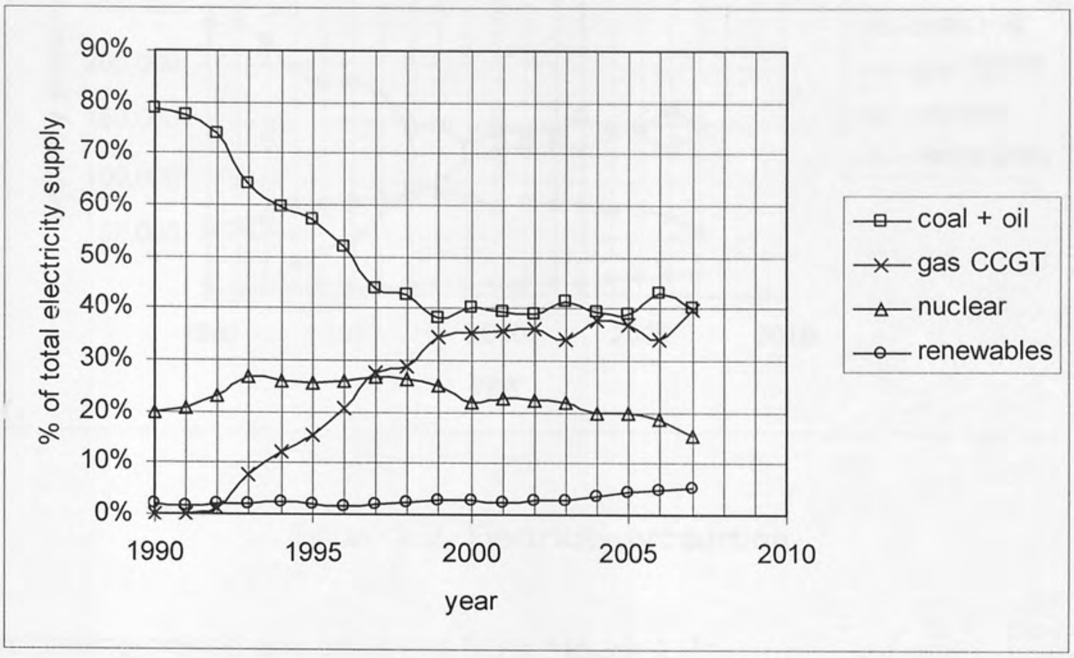

Figure 1.1 Share of the electricity generated by each type of generator

Figure 1.1 shows that some progress has been made towards the 2010 target since the RO mechanism was introduced in 2002. The key parameter from the perspective of CO_2 reduction is the level of generation from fossil fuel rather than the percentage of renewable generation; this is shown in Figure 1.2.

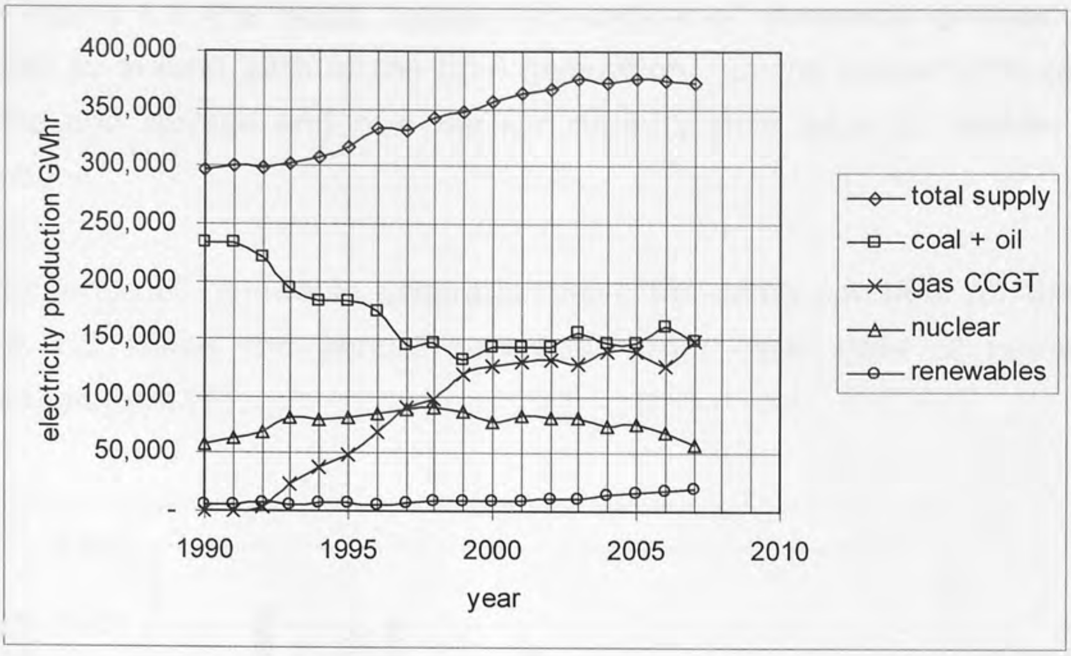

Figure 1.2 Electricity production

The following trends are apparent from Figure 1.2:

- Demand growth may have stopped but the 2007 demand is considerably above the 1990 level which is the base date for the Kyoto accord;
- Gas fired CCGTs appear to have displaced about half of the coal generation. On average a CCGT emits 42% of the CO_2 that the same capacity coal fired power station would do, so this has resulted in around a 30% drop in CO_2 emissions since 1990. However the mix appears to have stabilized;
- The generation from nuclear sources is falling as old plants are decommissioned and are not replaced by new nuclear stations;
- There has been some growth in the use of renewables since the RO was introduced.

Although the Government has recognised the desirability of building new nuclear plants none have been consented or ordered; consequently if an increase in CO_2 emissions is to be avoided the amount of renewable generation must expand to at least match the reduction in nuclear generation.

From Figure 1.1 this would require the amount of renewable generation to increase to around 22% of the total generation. In the longer term carbon capture and storage and new nuclear capacity may allow for further CO_2 reductions.

Not all forms of renewable generation have the same potential for growth. Figure 1.3 shows the annual generation from each class of renewable generation from [6].

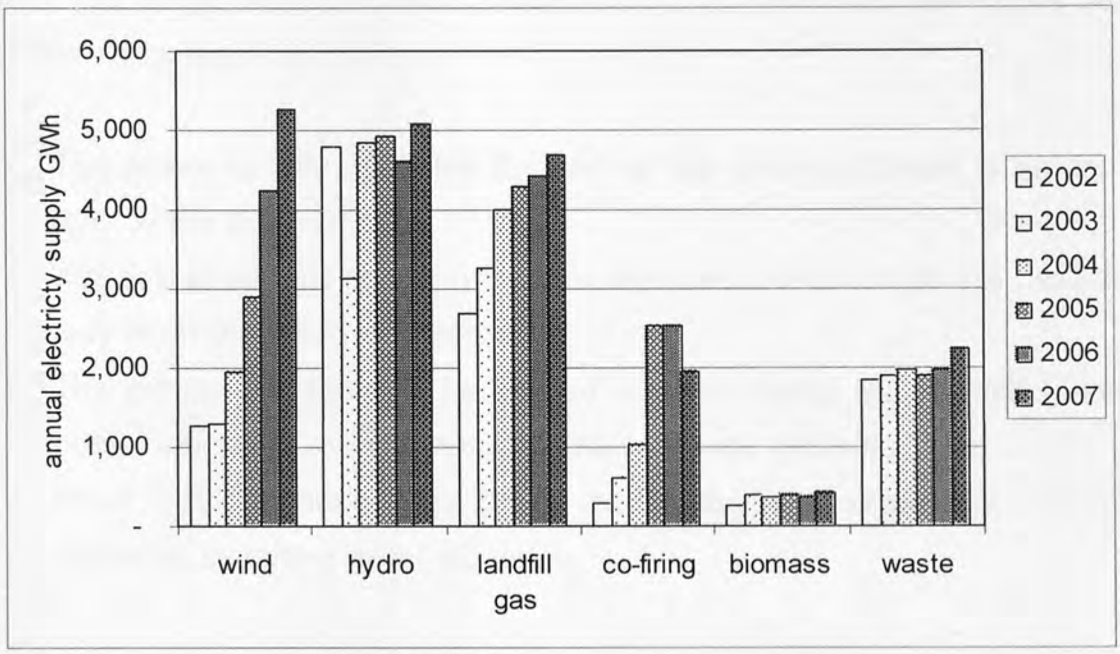

Figure 1.3 Electricity supplied from different types of renewable generators

Waste is defined here as municipal solid waste combustion, sewage digestion, animal waste digestion and animal waste combustion i.e. all processes where there would be a cost associated with the disposal of the waste if it was not used as a fuel. Strictly speaking landfill gas is also covered by this definition of waste combustion but it is shown separately due to its size. The growth potential for waste based systems is limited by the availability of the waste; as such they are not freely expandable.

Biomass only includes plants where biomass is the main fuel; co-firing is biomass that is burnt as a supplementary fuel to coal.

Wind power, landfill gas and co-firing have all increased since the RO measure was introduced. The situation with biomass is deceptive as the planning, construction and commissioning period for a new power station tends to be longer than that for a wind farm. Consequently it takes longer for the effect of any market stimulus to be reflected in the generation figures. New dedicated biomass plants are being commissioned at Lockerbie (44MWe) and Wilton (30 MWe) and others are planned for Barry and Sheffield and these could add up to 2,700 GWh to the biomass total if they all go ahead by 2010.

Britain has large untapped wind, wave and tidal resources but these suffer from the following drawbacks:

- The power is only available for part of the time and there is no control over when that will be;
- The resources are concentrated on the coast and on high ground a long way from the electricity demand;
- The generators have to be spread across a large area which leads to public objection to developments on aesthetic grounds;
- Wind turbines have little or no capability to increase generation in response to falling grid frequency.

Consequently electricity grid limits will restrict how much wind power the UK electricity system could use without major system works. It is not within the scope of this study to calculate this limit. However a rough estimation can be made by assuming that it would be uneconomic to have so many wind turbines that there would not be sufficient load on the system for them. From National Grid's demand figure for July and August 2007 [12] the minimum electricity demand was 21.8 GWe. Nuclear reactors cannot be shut down overnight so if the expected nuclear capacity for 2018 from Section 1.1.1 is subtracted from this load the potential maximum size of the wind power fleet would be around 17 GWe. The National Grid Company's seven year operating plan estimates that by 2014/2015 the wind power fleet will be 16 GWe [13]. The average capacity factor for wind turbines is around 27% [7] so the maximum annual wind power generation is likely to be around 40,000 GWh or 11% of the total 2007 electricity supply.

From the capacity figures in Figure 1.3 and allowing for the new and planned biomass plants the total non-wind renewables will produce around 17,000 GWh/year or 4.6% of the total 2007 electricity supply. From this quick check it looks like the maximum RO target of 20% is unlikely to be met by relying on the expansion of wind power and already planned projects. Any tidal or wave power stations that are built will suffer from the same problems as wind power; consequently they will need to share the minimum system demand with wind power and so will only displace wind generation. As such they will only increase the total amount of renewable generation if their capacity factors are higher than those for wind turbines. Of course the targets could be met by the existing renewable plant if there is a considerable drop in demand. Figure 1.2 shows the total electricity supply from 1990 to 2007 and although demand may have stabilized there is no sign of a reduction. Consequently generation from biomass will need to increase to provide the desired level of renewable generation.

1.1.3 The use of biomass in UK electricity generation

When biomass is burnt as a fuel it releases CO_2 in to the atmosphere; however it is considered a carbon neutral fuel as all the carbon released was originally absorber from the CO_2 in the atmosphere by the growing biomass. This means that provided the biomass is replanted there is no net gain in the CO_2 level in the atmosphere. In reality, the crop is not entirely carbon neutral as it has to be planted, fertilised, managed, harvested, chipped, and transported which normally involves the use of diesel powered equipment. Thornley [14] showed that when these emissions are taken account of, carbon emissions from electricity generation using biomass energy crops were 10-20% of those from fossil fuelled plants.

Biomass can be burnt in solid form either in dedicated power stations or mixed with coal in large coal fired power stations (co-firing). In each case the heat released from the biomass raises steam in a boiler which is expanded in a turbine to produce power. The dedicated plants are relatively small and tend to have low thermal efficiencies.

This is partly due to their size but they are also subject to temperature limits imposed by the corrosive nature of the biomass ash [15-16].

Existing coal plants are bigger and so justify the expense of a more complex steam cycle; consequently their thermal efficiency is higher than that for a dedicated biomass plant. But the amount of biomass that can be burnt in existing coal boilers tends to be limited by the ability of the coal mills to grind the biomass or the need to install dedicated biomass burners [17]. There is also a problem in getting sufficient biomass to fire a 2000MW_e power station operating at a high co-firing ratio. Consequently there are limits to the co-firing ratios that can be achieved on existing coal plant. This does help avoid the high temperature corrosion problems associated with burning biomass as the corrosive combustion products from the biomass are diluted with less corrosive ones from the coal. However as the majority of the fuel burnt is coal it has limited benefit in reducing the CO_2 output from the plant.

As both of the existing options for burning solid biomass have drawbacks it is worthwhile examining alternative technologies for exploiting biomass in high efficiency plants. One way to do this it is to convert the biomass into a secondary fuel that is suitable for use in internal combustion engines, gas turbines or high temperature steam boilers. This can be done by various techniques including:

- Crushing to produce oil for processing into biodiesel;
- Fermenting into alcohol;
- Digesting in an oxygen free environment (anaerobic digestion) to produce bio-gas;
- Heating in a low oxygen environment to produce gas;
- Heating in an oxygen free environment to produce a liquid bio-oil, pyrolysis gas and solid char.

The first two of these processes requires suitable feedstock and only use part of the available biomass but they produce a product that is suitable for transport fuel. As such the market price for their product is higher than the electricity generators are able to afford for their fuel.

Anaerobic digestion is best suited to slurries rather than dry biomass.

Both pyrolysis and gasification use thermal degradation to produce secondary fuels; however pyrolysis can produce a high proportion of the secondary fuel as a liquid. This has the advantage that a liquid is much easier to transport and store than a gas. As will be discussed in Chapter 2, there have been a number of techno-economic studies that have compared the costs of gasification and pyrolysis systems, but as they compare systems with equal functionality the impact of exploiting the transportability and storability of bio-oil has not been fully explored in a techno-economic study.

1.1.4 Support mechanisms for generation from renewable sources

With the exception of hydroelectric schemes generation from renewable sources did not enter the UK market until there were financial support mechanisms in place. The first support mechanism for generation from renewable resources was the Non Fossil Fuel Obligation (NFFO), this was introduced under the 1989 Electricity act. This obliged the Regional Electricity Companies to purchase a fixed percentage of the electricity they retailed from non fossil fuel generators. Non fossil fuel generators were invited to tender to supply this electricity under NFFO contracts which were awarded on a lowest cost basis. Unfortunately many holders of these contracts were unable to honour them. Although existing NFFO contracts are still running the mechanism was replaced by the RO scheme in 2002. As NFFO contracts only relate to existing plant they will not be considered in this study.

1.1.4.1 Renewables Obligation Certificates

The Renewables Obligation (RO) sets an obligation on each electrical retailer to source a minimum proportion of its electricity sales from renewable generation. Renewable generators are issued with a Renewables Obligation Certificate (ROC) for each MWh of electricity they produce.

The renewable generators sell the ROCs to the electrical retailers (in practice a number of companies have both retail and renewable generation subsidiaries so the sales may be notional). Should the retailers fail to acquire sufficient ROCs they are charged a "buy-out price" on their short fall. The money raised from collection of the buy-out payments is then redistributed to the holders of the ROCs. Consequently the market value of a ROC reflects the buy-out price plus the expected recycle payment.

The main difference between the RO and NFFO schemes is that developers waited until they secured a fixed long-term NFFO contract before building the plant that the contract related to. NFFO contracts were awarded to the projects with the lowest cost of generation. If the developer found that their estimated costs were unrealistic the projects did not get built. Under the RO developers build the plant then offer the ROCs for sale once the plant has earned them.

The ROC scheme is administered by the Office of Gas and Electricity Markets (OFGEM) which publishes an estimation of the worth of a ROC to a supplier in its annual reports [18]. Renewable generators can sell their ROCs through auction sites. One of these is run by the Non-Fossil Purchasing Agency who published its quarterly auction prices on the web [19]. The ROC values from both these sources are shown on Table 1.3

Table 1.3 Historic values of ROCs

ROC values £/MWh				
year	03-04	04-05	05-06	06-07
auction price	£44.95	£40.41	£46.93	£48.06
OFGEM valuation	£49.28	£42.54	£45.06	£53.43

The auction prices in Table 1.3 are the average of the auction price for the period minus the £0.50/ROC commission charged by the Non-Fossil Purchasing Agency for selling them; as such they represent the income to the generator. The OFGEM valuation is the total of the by-out price and the redistribution; as such it is calculated retrospectively.

The auctions are held quarterly so the bid price reflects what the buyers think the worth of the ROCs will be after the redistribution has been calculated.

The 2007 energy white paper [8] proposed that established renewable generation technologies like co-firing and landfill gas should receive less ROCs/MWh than emerging technologies. This was put into practice under The Renewables Obligation Order 2009 [9]. Under this order pyrolysis based generation plant receive 1 ROC for each 0.5 MWh of net electrical generation.

1.1.4.2 Carbon emission trading

Under the EU Emission Trading Scheme [20] large energy users have CO_2 emissions allowances which they must stay within. These allowances are allocated by sector and the total number of allowances will be reduced year on year in line with the desired reduction in greenhouse gases. If they operate inside this allowance they can sell the surplus allowance to other plants that may have problems staying inside their own limit. The scheme is being implemented in 3 phases, Phase 1 is now over and Phase 2 runs from 2008 - 2012. Under the UK implementation arrangements for Phase 2 [21] large electricity producers will receive allowance for a large part of their existing emissions but will have to buy their remaining requirement through an auction or from registered sites in other sectors. In the 2008 budget [22] it was announced that under Phase 3 which comes into force in 2013 large electricity generators will have to buy all their initial allowances by auction. As the Phase 2 market has not settled down it is not yet clear what the financial value of traded or auctioned allowance will be. But as it is bound to add costs to fossil fuel generation or restrict their annual output this scheme can only improve the competitiveness of renewable generation.

1.1.4.3 Climate change levy

The climate change levy is in effect a tax payable by industrial consumers of energy (the money raised is used to reduce the employers' national insurance payments so although it is a tax it is supposed to be cost neutral for "business" as a whole).

Businesses can receive up to 80% discount from the levy by adopting approved energy efficiency or carbon saving measures. The electricity generation industry is exempt from the levy but large electricity consumers can get relief from the levy by getting their electricity from renewable generation [23]. The levy was set at £4.30/MWh in 2007 [24].

1.1.5 Combined heat and power market in the UK

Combined heat and power (CHP) is the generation of usable heat and electricity from the same plant. Heat for industrial process can be extracted from the generation plant at high temperature (which reduces the electrical generation output and generation efficiency) or taken at low temperature from the heat rejected from the thermal cycle of the electrical generator and used for space heating. As this heat would normally be discharged to the environment it is often considered as "free heat". In principle this should be a low cost way of providing heat; however there are the following drawbacks with these systems:

- Power station steam cycles are optimised for electricity production and reject heat from their steam cycle at a few degrees above ambient air temperature (typically 30°C) which is too cold for most heating applications. Raising this temperature reduces the efficiency of the steam cycle.
- Modern power stations are built away from large heat loads and it is not practical to transmit heat long distances.
- The seasonal and daily heat demands are not in step with the electricity demand. In particular the difference between winter and summer space heating loads is much more than the difference in winter and summer electricity loads.

Consequently there is very little heat sold from large power stations. However there are some CHP stations that have been specifically designed to meet a local heat load and sell (or use on site) the electricity that is effectively produced as a "co-product" of the heat generation.

The electricity may well be the more valuable product but the key point is that the CHP power station is sized and operated to meet the heat load.

As CHP schemes can have higher overall energy efficiency (as they have a usable heat efficiency as well as an electricity generation efficiency) than electricity-only generation stations the use of CHP power stations is considered to be a way of reducing CO_2 emissions. Consequently the government has set a target of 10GWe installed CHP capacity by 2010 [25]. Figure 1.4 is taken from DUKES [26] and shows the progress made in achieving this.

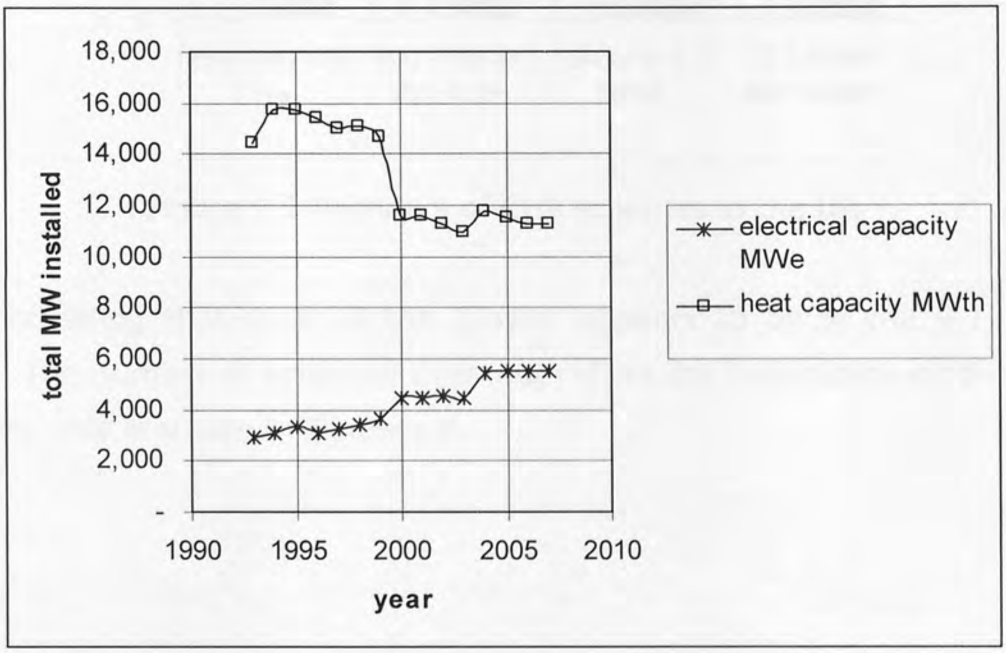

Figure 1.4 Energy output from CHP plants in the UK

Figure 1.4 indicates that it is unlikely that this target will be met. It is also noticeable that the ratio of electricity to heat generated is increasing. This is due to the adoption of more efficient generation plant. CHP plants come in a wide range of sizes from spark ignition gas engines rated at 10s of kW_e to combined cycle gas turbine plant with back pressure steam turbines rated at 100s MW_e. Figure 1,5 shows the distribution of the different sizes of schemes from [26].

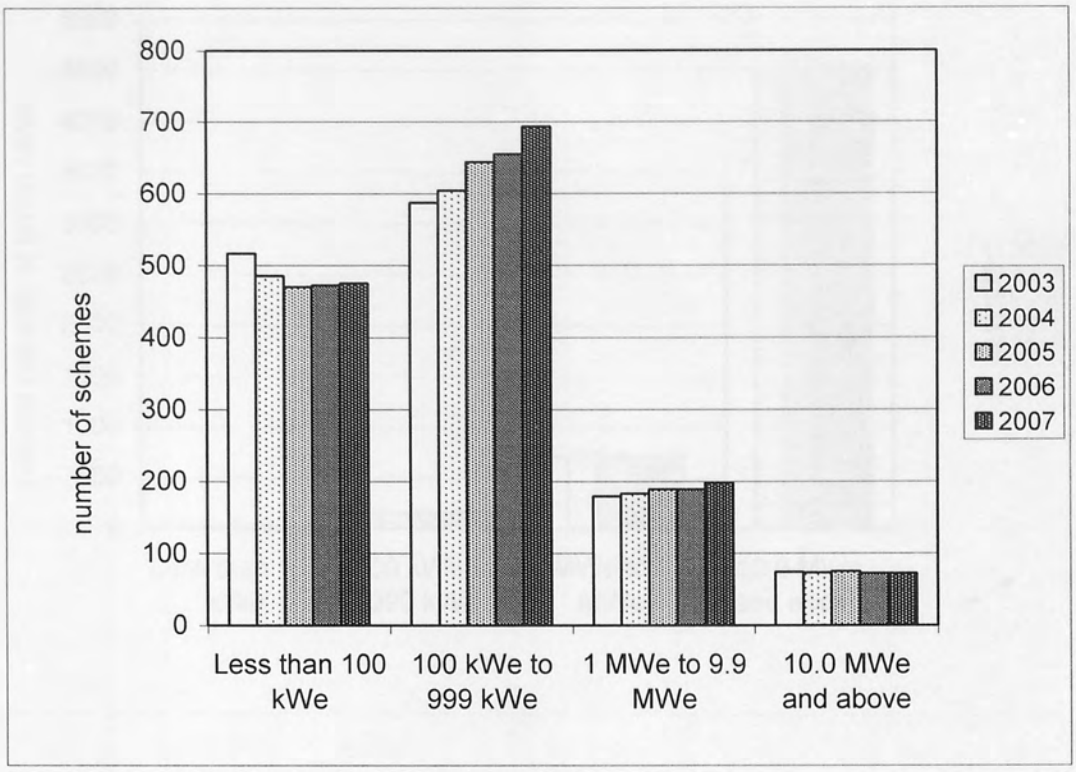

Figure 1.5 Numbers of CHP schemes in the UK

It is interesting that most of the growth appears to be in the 0.1–1 MW_e range. The number of schemes does not reflect the importance of the larger schemes; this is shown in Figure 1.6.

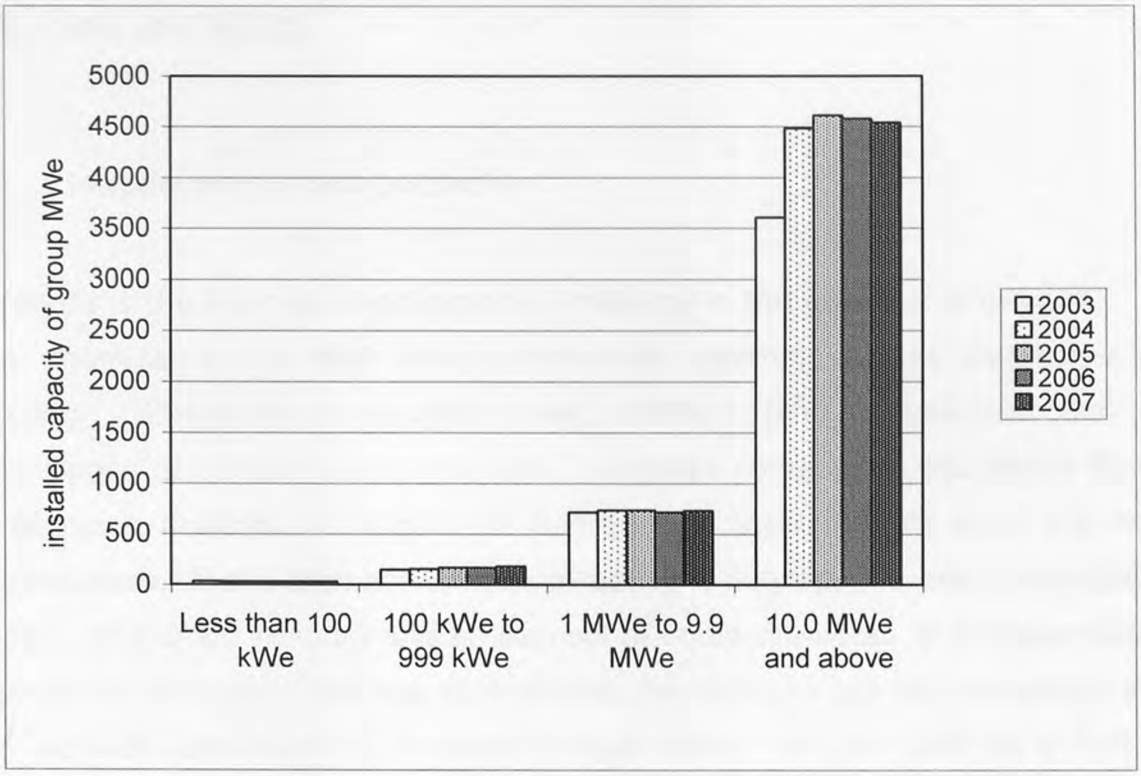

Figure 1.6 Total capacity of each size group of CHP plants installed in the UK

Figure 1.6 demonstrates the dominance of the sector by a few large industrial CHP systems. From Figure 1.5 it appears that there has been no growth in this sector in the last few years. It is possible that all the suitable large industrial sites have already considered CHP schemes and that there is limited scope for growth in this sector. But in a study into the potential for district heating based CHP schemes in the UK in 2003 Wiltshire [27] found that depending on finance options available there could be between 2,000 and 18,000 MWe of viable district heating based CHP schemes. The study did not include a breakdown by size but the potential for London was 2,400 MWe and at least 13 other cities had potential demands of 130–815 MWe. It may not be practical to install city-wide schemes but the report did identify 80 postcodes with loads of 2–16 MWe. Schemes covering this size of area would be simpler to implement. Consequently it can be concluded that there is potential for the CHP market in the UK to increase beyond the government's target.

1.2 Fast pyrolysis

1.2.1 Introduction to fast pyrolysis

Pyrolysis is the thermal degradation of material in the absence of oxygen. The chemical bonds that bind compounds together can be overcome by heating. Chemical compounds have different binding energies and so decompose at different temperatures. Complex compounds like those found in biomass undergo a number of degradation steps before they are fully decomposed. If the biomass is heated rapidly it degrades to non condensable gases, solid char, vapours and an aerosol of liquid droplets. If these products are rapidly removed from the heat source the vapours can be condensed and the aerosols coalesced to produce a liquid which can be used as a fuel or chemical feedstuff - this is fast (or flash) pyrolysis and the liquid product is referred to as bio-oil. If the vapours are left in a hot environment they undergo secondary cracking into gases and long chain polymers. These polymers are hard to handle and make the liquid unsuitable for use as a fuel.

It has been established [28] that the following conditions are required to get good quality bio-oil:

- Rapid heating of the biomass to 500°C;
- Short vapour residence time - from vapour formation to subsequent cooling and condensation should be less than 2 seconds;
- Feed moisture content of less than 10% of the mass of the wet feedstock (all moisture levels given in this thesis are calculated on a wet basis).

If these conditions are met it is possible to get a bio-oil yield of up to 75% of the Dry Ash Free (daf) mass of the feedstock, depending on the feedstock used [29].

Some non-condensable gases are produced along with the vapours. These are a mixture of carbon dioxide, carbon monoxide, hydrocarbon gases and hydrogen [30]. The yield and composition of these gases vary with the pyrolysis temperature, feedstock and residence time. These pyrolysis gases can be used as an auxiliary fuel source for the pyrolysis plant.

Not all the biomass is vaporised or liquefied in the pyrolysis process. Pyrolysis takes place at a temperature below the melting points of alkali metals and silica; these combine with any residual biomass and carbon to form small particles of solid char. The char is a high carbon fuel that may also be used to make activated charcoal or used as a soil conditioner.

Fast pyrolysis (referred to henceforth simply as "pyrolysis") should not be confused with slow pyrolysis which is the process used to produce charcoal or long duration high temperature pyrolysis used to convert waste. These processes will produce tar like liquids [31] which are less suitable for use as a fuel than bio-oil.

Pyrolysis yields are not always quoted in a consistent way in the literature. They can be expressed as:

- A fraction of the daf mass (i.e. the mass of the feedstock minus its moisture and ash content) of the feedstock;
- A fraction of the dry mass of the pyrolysis feedstock (i.e. the mass of the feedstock minus its moisture);
- A fraction of the mass of the feedstock (which will have been dried so that its moisture content is less than 10%).

The daf yield is the yield from the organic portion of the biomass. As such it is the most appropriate measure for comparing yields from different varieties of biomass and different pyrolysis conditions. Biomass that is suitable for use in pyrolysis plants (see section 4.3.1) contains up to 3% ash. This dilutes the biomass and so reduces the yields of bio-oil and gas but as the ash is non volatile it all ends up in the char so the char yield is increased.

Any free water in the feedstock also dilutes the biomass and so will reduce the yields of pyrolysis products including the organic liquid however the water in the feedstock will end up diluting the bio-oil which will increase the mass yield of the bio-oil.

Likewise capacities can be expressed as daf t/day, Oven Dried Tonne/day (odt/d) or t/day in the case of the actual mass feed to the reactor. These are all metric measurements where 1t is 1000kg; some American papers and reports quote masses in US tons (2000 lbs) which is abbreviated to ton in this thesis.

Unless stated otherwise the following conventions are used in this thesis:

- Yields are quoted on a daf basis;
- Capacities are in oven dried tonne per day (odt/d);
- Wet masses are in tonne (t);
- Dry mass are in oven dried tonne (odt).

however as the feed moisture level and ash content are not always quoted in the literature the other units are also occasionally used to preserve the integrity of the original data.

1.2.2 Types of pyrolysis plants

There has been a wide range of pyrolysis reactors investigated for both biomass and waste conversion. These have been comprehensively reviewed in [28,29] so only brief descriptions the processes that have been implemented at a commercial scale are given here.

1.2.2.1 Bubbling Fluidised Bed

A Bubbling Fluidised Bed (BFB) reactor is a heated vessel that has a bed of fine particles (typically sand) brought into motion by the flow of heated circulating (fluidising) oxygen free gas.

Biomass particles are introduced to the bed where they are supported by the fluidised bed. Pyrolysis takes place in the bed and the aerosol, vapour and gas products are removed by the circulating gas. As pyrolysis takes place the biomass particles reduces in size until they are light enough to be carried from the bed as a char by the gas flow. These char particles are separated from the gas stream by one or more cyclones and possibly a secondary filter. The de-charred gas is then quenched by mixing it with a circulating flow of cooled liquid which condenses the vapours and allows the aerosols to coalesce around the liquid drops. Any remaining aerosols and fine droplets can be removed from the gas stream by electrostatic precipitators before the gas is blown back through a re-heater into the reactor. The basic components of the system are shown diagrammatically in Figure 1.7.

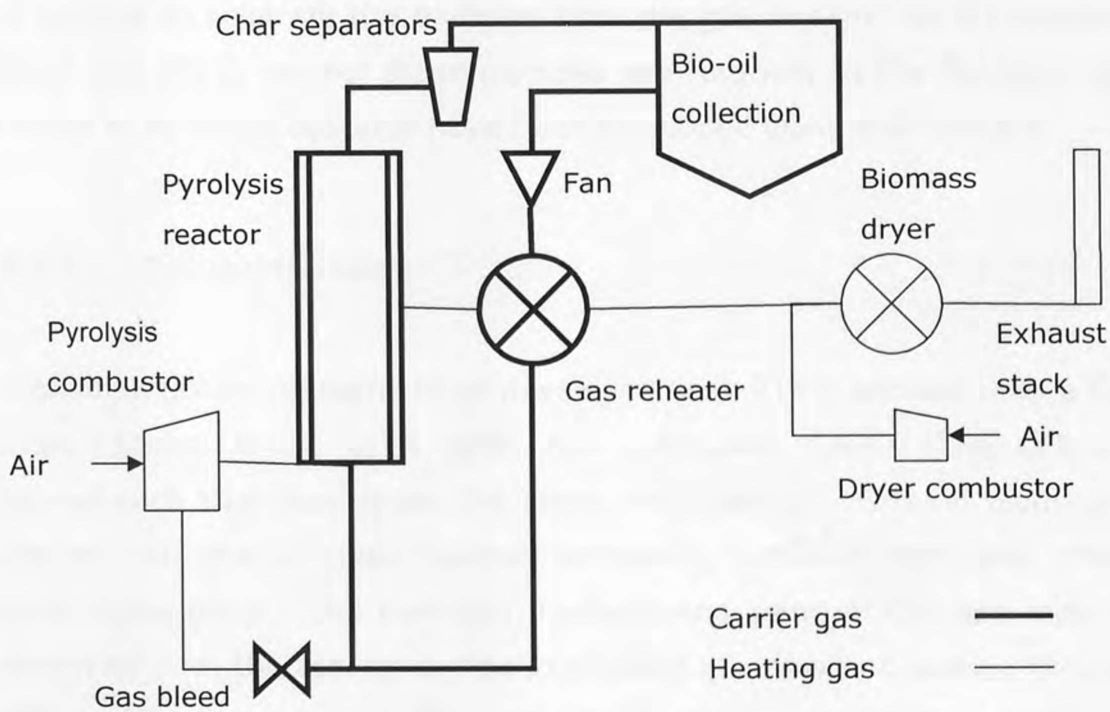

Figure 1.7 Main components of a bubbling fluidised bed pyrolysis plant

Figure 1.7 does not represent a real plant and has been simplified to only shows sufficient detail to understand the process flows. This process was developed at the University of Waterloo in Canada [32] and has been commercialized by Dynamotive who market it as the BioTherm® process [33-35].

Dynamotive have commissioned a 200 t/day plant where the bio-oil is used to fire a 2.5MW_e gas turbine in an industrial CHP application.

Dynamotive report the following mass yields from a wood derived feedstock on an as fed basis bio-oil 72%, char 15% and gases 13% [33].

1.2.2.2 Circulating fluidised bed

For a BFB based pyrolysis reactor to work correctly the gas flow has to be set so that it is high enough to carry the char particles away from the bed but not so high as to carry the bed material out of the reactor. A way to avoid this balancing act is to allow some of the bed to be carried off with the gas and use a cyclone to separate the particles from the gas stream. In a Circulating Fluidised Bed (CFB) reactor these particles are returned to the fluidised bed. Two types of pyrolysis systems have been developed using this concept.

1.2.2.2.1 Transported bed

The Canadian Ensyn company have developed their RTP™ process uses a CFB pyrolysis reactor linked to a CFB char combustor [36]. The CFB are configured such that they share the same bed material. Ground biomass is introduced into the pyrolysis reactor containing turbulent hot sand where pyrolysis takes place. The pyrolysis products and some of the bed material are removed from the reactor by the circulating gas flow and passed through a cyclone. The gas, vapours and aerosols are then sucked into a condenser where the bio-oil is condensed and removed. The sand and char are removed by the cyclone and enter the second CFB reactor where combustion air is added. The char and some of the circulating gas are combusted, thereby heating the sand. The heated sand is carried out of the combustion CFB by the circulating gas and is then separated from the exhaust gas flow in a cyclone. The heated sand then flows back to the first reactor to provide the heat source for the pyrolysis reactions. A simplified diagram of the basic plant is shown in Figure 1.8.

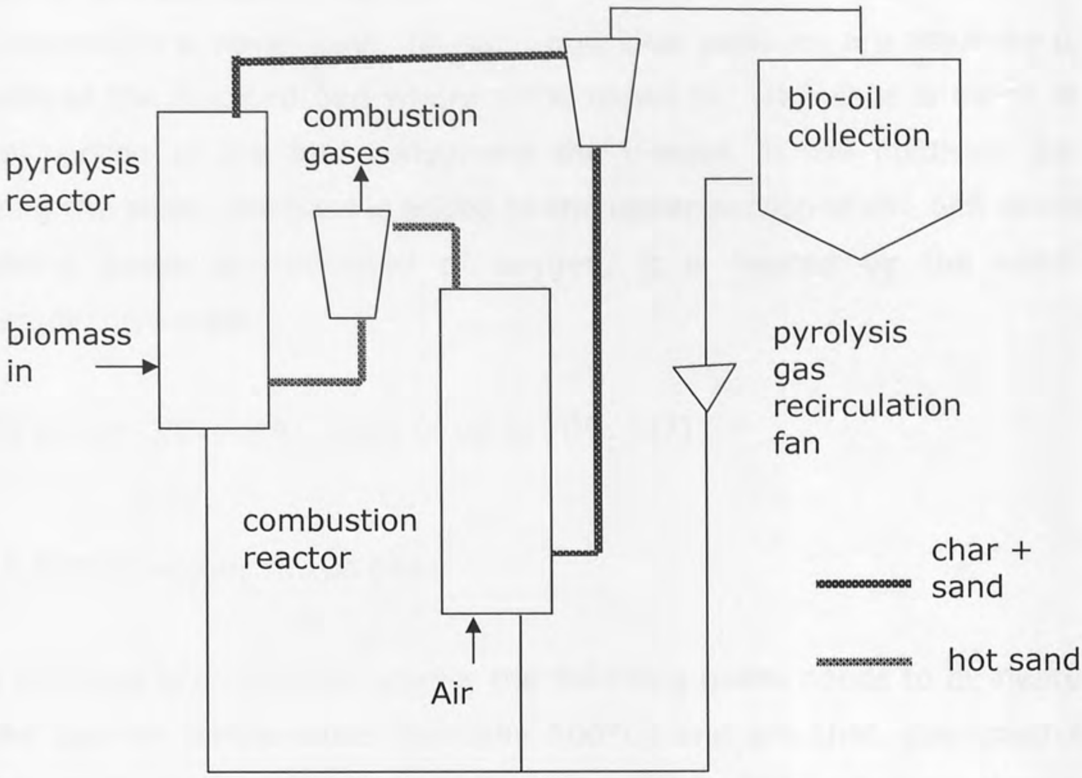

Figure 1.8 Main components of a transported bed pyrolysis unit

The largest Ensyn plant to date is rated at 100 t/day of dry residual wood. This process was the first to enter commercial use and has mainly used to produce chemical feedstocks; however the bio-oil produced has been used in industrial scale combustion trials.

Ensyn report the following yields on an ash free basis: bio-oil 71 - 80%, char 12 - 20% and gases 5 - 12% using a wood derived feedstock and bio-oil 60 - 67%, char 16 - 28% and gases 8 - 17% using a bark derived feedstock [36]

1.2.2.2.2 Integrated CFB reactor

The IEA Bioenergy Agreement liquefaction Group proposed that a char combustor be integrated in a CFB pyrolysis reactor. The Centre for

Renewable Energy Sources (CRES) in Greece has developed a pyrolysis unit based on this configuration [37].
It is heated in a novel way, the sand and char particles are returned to the bottom of the fluidised bed where air is blown in. The char is burnt in this lower portion of the bed consuming the oxygen in the fluidising air and heating the sand. Biomass is added to the upper portion of the bed where the fluidising gases are depleted of oxygen; it is heated by the sand and undergoes pyrolysis.

CRES report DAF bio-oil yields of up to 70% [37]

1.2.2.3 Mechanically mixed beds

In a fluidized bed pyrolysis reactor the fluidizing gases needs to be heated up to the reactor temperature (typically 500°C) and are then quenched along with the pyrolysis product to typically below 50°C. Although some designs try and recover the heat in the fluidizing gas it is generally lost to the process. One way to overcome this is to mechanically mix the biomass with a granular heating medium (sand or steel balls) rather than using a fluidized bed. This has been done by Forschungezentrum Karlsruhe (FZK) of Germany, who use a twin screw or LR-(Lurgi-Ruhrgas) mixer reactor as the basis for their pyrolysis system [38]. The bio-oil is collected in two phases and then mixed with the char to form slurry which will then be used in a gasifier to produce Syngas and eventually a high quality liquid fuel by Fischer-Tropsch synthesis. A 12 dry t/day reactor has been built and operated.

Dry feed product yields of 60-70% bio-oil, 20-30% char have been reported for this process using a wood feed [38].

1.2.2.4 Rotating Cone Reactor

The Biomass Technology Group (BTG) of the Netherlands has developed a pyrolysis process that does not utilise a fluidized bed, or employ a carrier gas. The ground biomass and heated sand are introduced to the top of a spinning cone within an air-tight vessel [39]. The action of the cone mixes the hot sand with the biomass and pyrolysis takes place.

The gases, vapours and aerosols are drawn from the vessel and the vapours condensed. The sand and char leave the bottom of the cone and are passed into a combustor where the char is burnt and the sand is heated ready for re-entry into the reactor. This plant is shown diagrammatically in Figure 1.9.

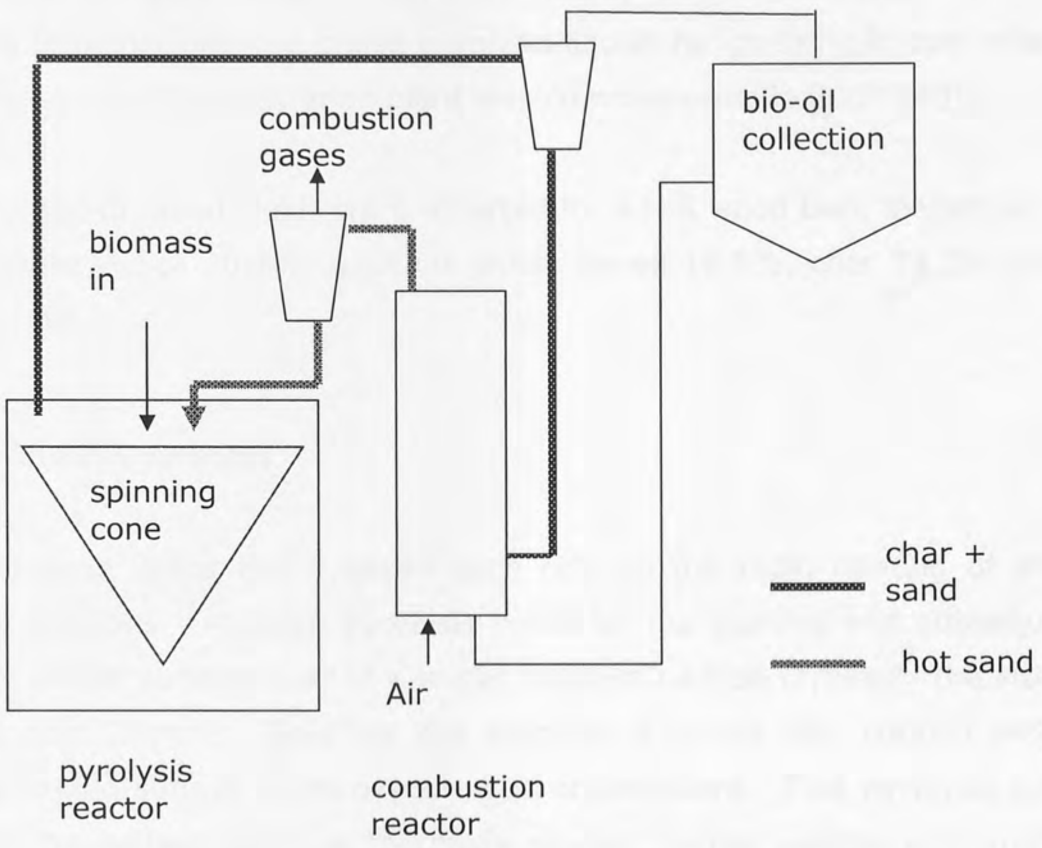

Figure 1.9 Diagram of a spinning cone pyrolysis unit

BGT has commissioned a 50 t/day plant. BTG give a bio-oil yield estimate of 70% for woody biomass and between 60 - 70% for straw like materials [39]. The basis for the yield calculation was not stated.

1.2.2.5 Vacuum pyrolysis

A pyrolysis system where biomass is heated in a reduced pressure environment was developed by the University of Laval Canada. It was commercialized as the Pyrocyling™ by Pyrovac International Inc who are no longer trading. The process involves feeding biomass under vacuum conditions along a heated plate where pyrolysis takes place. The pyrolysis vapours, aerosols and non condensable gases are sucked from the vessel and the liquid collected by two condenser units that collect the heavy and aqueous phase separately. The solid char exits the reactor through a cooled screw feeder and air lock. The system has mainly been considered for waste recycling into char and two phase pyrolysis liquids for co-firing in coal boilers. A 71 dry odt/day demonstration plant was commissioned in 2000 [40].

The following dry feed yields were reported for a soft wood bark feedstock: dense phase bio-oil 30.7%, aqueous phase bio-oil 19.6%, char 29.2% gases 20.5% [40].

1.2.2.6 Ablative pyrolysis

Pyrolysis units which use fluidised beds rely on the rapid heating of small biomass particles. Ablative pyrolysis relies on the heating and subsequent pyrolysis of the surface layer of a larger biomass particle (typically the size of a wood chip 25mm). Basically the biomass is forced into contact with a moving heated surface in an oxygen free environment. Fast pyrolysis takes place at the surface which is thermally eroded, as the particle is in motion relative to the heating surface. The pyrolysis products are removed from the particle exposing fresh biomass to the heated surface. Ablative pyrolysis plants do not employ carrier gas and so should have less heat loss than fluidised bed systems, they also do not need to have the biomass reduced to below 2mm. However the engineering challenge of producing a heated ablating plate with rotating blades or a pressure disc all within a gas tight environment is considerable. As a surface rather than a volume phenomenon the economies of scale are likely to be less favourable for an ablative unit compared with that for a fluidised bed. PYTEC Thermochemische Anlagen GmbH have produced a 6 odt/day plant and have plans for a 48 odt/day plant [41-42].

Yields of 60% bio-oil, 34% gas and 6% char have been reported for this process using woodchips. Unfortunately it was not stated if this was a DAF, dry feed or as fed yield [41]

The NREL vortex reactor [43] is a type of ablative pyrolysis plant where particles are blown tangentially into a heated cylindrical reactor. Centrifugal force pushes the particle against the wall of the reactor where ablative pyrolysis takes place. As the particle losses momentum it spirals down the reactor and leave through a hole in its base. Although it has been used at a laboratory scale Interchem Industries had problems operating it at an industrial scale.

There is good agreement in the bio-oil yield between the different processes. The composition of bio-oil and the yields for different feedstocks is discussed in more detail in Section 4.3.

1.2.3 Characteristics of bio-oil

There has been a lot of work done on developing standard analytical tests so that bio-oils can be classified and compared [44-49] this will enable standards for bio-oil to be agreed between bio-oil producers and bio-oil consumers. Some of the key characteristics that affect the use of bio-oil have been summarised in Table 11 of VTT report 450 [48] and are reproduced as Table 1.4.

Table 1.4 Characteristics of bio-oil

Property	Range (wet basis)
density (15°C) kg/dm^3	1.11 – 1.30
lower heating value MJ/kg	13 - 18
kinematics viscosity cSt	10 – 80 @ 50°C
thermal conductivity W/mK	0.35 – 0.43
specific heat capacity J/gK	2.6 – 3.8 @ 25-60°C
pour point °C	-9 to -36
coke residue wt%	14 - 23
flash point °C	40 - 110
ignition limit °C	110 – 120
ignition temperature °C	600 - 700
water wt%	20 - 30
char wt%	0.01 - 1
vapour pressure kPa	5.2 @ 33.5°C
surface tension mN/m	29.2
carbon wt% (dry)	32 – 49 (48 – 60)
hydrogen wt% (dry)	6.9 – 8.6 (5.9 – 7.2)
nitrogen wt% (dry)	0 – 0.4
oxygen wt% (dry)	44 – 60 (34 – 45)
sulphur ppm	60 – 500
chlorine ppm	3 – 75
ash wt% (dry)	0.01 – 0.02
pH	2.0 – 3.7
potassium + sodium ppm	5 - 500

1.2.4 Key differences between bio-oil and mineral oils

1.2.4.1 Heating value

It is common practice to use the Higher Heating Value (HHV) when quoting the calorific value of fuels (i.e. the energy released on combustion). This is the value measured when the fuel is completely oxidised and any resulting water vapour condensed and returned to the original temperature of the fuel (25°C is assumed). The water vapour can originate from liquid water in the fuel or from the combustion process. However in most applications the exhaust gases are expelled at temperatures above 100°C. This means that the latent heat of the water vapour in the exhaust gases is "lost" to the application. For this reason in many applications the Lower Heating Value (LHV) of the fuel is used. This is the HHV minus the heat lost if the water vapour is expelled at 150°C rather than returned to 25°C.

The bio-oil applications being considered in this thesis (diesel engines, gas turbines and combustion in boilers) all have exhaust gas temperatures above 100°C so it is appropriate to use the LHV for the calorific value of the fuel. From Table 1.4 the LHV for bio-oil is typically in the range 13 - 18 MJ/kg. This is much lower than mineral oils (41.5 MJ/kg for No.2 fuel oil and 40 MJ/kg for No.6 fuel oil [47]). Bio-oil has a specific density around 1.2 kg/l compared to 0.92 - 0.99 kg/l for mineral oils so the difference in energy densities (MJ/l) is less, however it still requires around 2.3 times the volume of bio-oil to provide the same energy input as a given volume of mineral oil.

1.2.4.2 Moisture Content

Bio-oil is a complex mixture of water insoluble pyrolyic lignin, and water soluble organic acids, non-polar hydrocarbons, anhydrosugars and other oxygenated compounds [48]. Water vapour is present in the pyrolysis vapours. It comes from the moisture in feedstock and the chemical reactions that the biomass has undergone during pyrolysis.

The water is absorbed by the soluble compounds in the bio-oil. If the water content of bio-oil exceeds a certain level, the bio-oil will separate into an aqueous holocellulose-derived phase and a dense lignin-derived phase [48]. This critical level depends on the feedstock used to make the bio-oil. It is around 32% - 35% for wood-derived bio-oil and 17% - 28.5% for straw-derived bio-oil. Separation should be avoided as the aqueous phase has a very low heating value and the dense phase is hard to handle and atomise.

The water is in solution, so it cannot be removed by centrifuges, nor can it be removed by heating without the loss of other volatile compounds within the bio-oil. Consequently it is not practical to dewater bio-oil.

Bio-oil cannot be directly blended with mineral oils. However it is possible to form an emulsion with bio-oil and mineral oil and this is discussed in Section 1.2.5.2.

1.2.4.3 pH

Bio-oil has a pH of around 2.3; mineral oil has a pH of around 5. The lower pH means that bio-oil handling systems need to be made of acid resistant materials (typically 300 series stainless steels or HDPF plastics [48,50]).

1.2.4.4 Viscosity

Bio-oil has a viscosity that is between the value for No 2 fuel oil and No 6 heavy fuel oil. The viscosity of softwood pyrolysis oil has been measured as 110 cSt at 20°C, 28 cSt at 40°C and 15 cSt at 50°C [48]. So heating the bio-oil will reduce its viscosity to a level where it can be readily pumped. An alternative approach is to add a solvent to make it free-flowing.

1.2.4.5 Stability

Bio-oil consists of a number of intermediate chemicals condensed during the process of thermal degradation. This bio-oil is not in thermodynamic equilibrium and so some chemicals reactions will continue during storage to improve the thermodynamic equilibrium of the bio-oil. It has been found that this results in changes in bio-oils viscosity, molecular weight and co-solubility with time. In addition to producing long chain molecules these reactions generate gas and water. The changes in moisture content and co-solubility can also cause the bio-oil to split into two or more phases as described in section 1.2.4.2. These aging reactions are accelerated by heating, the presence of oxygen or the presence of a catalyst. The alkali metals that are present in the char can act as a catalyst. To improve stability bio-oil should be stored at a cool temperature (around room temperature), in air tight tanks and have minimum char content. The addition of solvents has also been shown to improve the stability of bio-oil [51-52].

1.2.4.6 Char contamination

The residual char produced during pyrolysis consists of fine particles of carbon, ash, and alkali metals. Most of this char is removed by the pyrolysis plant; however some of the finer particles remain in the gas stream and are collected with the bio-oil in the quench. These particles are a problem as they can erode fuel systems, act as a catalyst to promote bio-oil aging and cause corrosive alkali metal deposits in the hot gas passes of conversion equipment.

1.2.5 Use of bio-oil

It is clear from the foregoing that existing designs for mineral oil fired plants will require modifications to the fuel handling, storage and atomisation systems when converting to bio-oil. Trials on the combustion properties have been carried out [53-54] their basic findings are that bio-oil is hard to ignite and flame stability is a problem in a cold combustor or furnace.

However if the ignition zone of the burner is warm and the fuel has been heated it will ignite and burn stably. The high moisture content means that the time period between fuel entering the combustion chamber and ignition is longer than that for mineral oil but as the moisture flashes into steam it aids atomisation so the time for complete combustion of the bio-oil can be less than for mineral oil. Preheating of combustion air also aids ignition. Bio-oil needs to be heated (or have a solvent added) to reduce its viscosity, to allow fuel injection and atomisation systems to function properly.

In short bio-oil needs similar treatment to heavy fuel oil to burn effectively.

1.2.5.1 Furnaces

There have been a number of trials burning bio-oil in conventional furnaces [55-58]. Successful commercial scale co-firing trials using dedicated burners have been carried out in coal and gas fired boilers [59-60]. These have established that with suitably designed burners bio-oil can be used as a furnace fuel.

1.2.5.2 Diesel engines

Bio-oil will not self-ignite in a diesel engine. The following techniques have been used to overcome this problem:

- Add ignition improver additives to the bio-oil[29];
- Use dual injection diesel engines with a pilot diesel fuel [61-63];
- Form an emulsion of bio-oil and diesel [64-65];
- Use an oxygen enriched air supply [66];
- Preheat the combustion air [67];

This study is concerned with unmodified bio-oil so the use of additives will not be explored (this is based on the assumption that an upgraded fuel would be targeted at the transport market where it could command a higher price than it could fetch in the power generation market).

Although engines have run on emulsions the majority of the energy input for these comes from the diesel fuel, and as such it is effectively co-firing of bio-oil with diesel. As diesel generation is not economic in the UK it is unlikely that emulsions will be used for power generation. The tests with an enriched oxygen air supply were successful; however the technology to provide the air supply is not economically viable at these scales. Consequently this study will concentrate on pilot fuel engines. These will be discussed further in Section 4.6.

1.2.5.3 Gas turbines

Trials of bio-oil firing in gas turbine (GT) combustion chambers were carried out [68-69] and it was found that with some modification to the fuel systems bio-oil could be fired in GT combustors. Dynamotive working with Orenda Aerospace Corporation have successfully carried out extended trials on a 2.5 MW_e OGT2500 GT [70]. This collaboration has led to the inclusion of an OGT2500 in Dynomotive's 2.5 MW_e West Lorne industrial CHP plant which is currently supplying power to the Ontario Power Authority [71]. This is the worlds first commercial scale pyrolysis combined heat and power plant. The exhaust gases from the GT are used to raise steam for the adjacent wood flooring plant.

Dynamotive reported that the following steps were needed to achieve satisfactory performance:

- The engine modifications were developed in co-operation with the GT manufacturer;
- Fuel additives were used to reduce corrosive deposits on the hot gas path components;
- Turbine washing equipment has been installed;
- Anti corrosion protective coatings have been applied to the hot gas path components.

The OGT2500 is a long established industrial GT which has been used in a wide range of applications. It has a silo combustor with a relatively long residence time which allows complete combustion of the bio-oil. The long residence time also increases the chance that any char particles in the bio-oil will burn. The GT is started up on diesel oil and gradually changed over to bio-oil once the combustion chamber is hot.

Many of these features are the same as those required to burn poor quality fuel oils or crude oil. GTs fired on crude and heavy fuel oils have been used for a number of years so it is likely that GTs can be made to reliably operate on bio-oil.

1.3 SUPERGEN biomass and bio-energy consortium

The government recognised that more research would be needed in order to meet future energy requirements in a sustainable way. In response to this in 2003 the Engineering and Physical Science Research Council (EPSRC) set up a series of 13 research programmes under the title of SUPERGEN [72]. Each of these programmes looks into a particular aspect of introducing sustainable generation or improving sustainability of existing generation or enabling technologies to allow sustainable generation to be utilised. The programmes are carried out by consortia of academic and industrial partners, and are funded in four-year phases. The Biomass and Bioenergy Consortium is concerned with development of energy from biomass, and this study was carried out as part of the consortium's Phase 1 programme. For Phase 1 the consortium comprised Aston University, University of Leeds, Cranfield University, Imperial College, the University of Ulster, the University of Manchester and the University of Sheffield, as well as Rothamsted Research Institute, the Institute of Grassland and Environmental Research and Forest Research. The industrial partners were initially Alstom, E.ON UK, and Rural Generation, with Bical, Biomass Engineering, and Coppice Resources joining the consortium during Phase 1.

The work was organised into six work packages:

- WP1 Process and techno-economic assessment;
- WP2 Fuel specification and matching to conversion;
- WP3 Thermal reactor modelling;
- WP4 Minimisation of engineering risk;
- WP5 Co-firing and co-processing;
- WP6 Networks (British Biomass and Bio-energy Forum).

The present study was funded under work package 1 of this programme, and focussing specifically on pyrolysis-based systems.

1.3.1 Process and techno-economic assessment work package

The aims of this work package were [74]:

- Technically analyse complete bio-energy process options;
- Integrate components from other work packages, to optimise routes, and highlight areas to maximise performance and economics;
- Assess economic performance;
- Assess life cycle performance;
- Examine socio-economic factors, including social acceptability, land-use, landscape, transport, processing, emissions;
- Carry out multi-criteria evaluation of technical, economic, environmental and social consequences of an agreed set of options (Case Studies), with stakeholder involvement.

Essentially this work package comprised techno-economic and socio-economic models of a number of case studies covering a range of generation technologies and plant outputs. The case studies were chosen to match established processes or processes that were close to being proven at a pilot plant scale. The technologies and plant outputs considered are shown in Table 1.5.

It was one of the objectives of the present study to carry out the four pyrolysis-based case studies included in the work package; however the study extends well beyond this narrow scope in its consideration of the full size range of possible pyrolysis systems.

Table 1.5 WP1 case studies

Biomass input (equiv)	250 KWe		2 MWe		5 MWe		25 MWe	
Mode	PO	CHP	PO	CHP	PO	CHP	PO	CHP
Gasifier (IC engine) - wood	X	X						
Gasifier (IC engine) - wood			X	X	X	X		
Gasifier (IC engine) - miscanthus					X	X		
Gasifier (atmos. CC) - wood							X	
Gasifier (press. CC) - wood							X	
Gasifier (press. CC) - miscanthus							X	
Combustion (CFB) - wood							X	
Combustion (grate) - wood				X	X	X	X	X
Combustion (grate) - miscanthus				X			X	
Combustion (grate) - straw							X	
Pyrolysis (IC engine) - wood					X	X		
Pyrolysis (gas turbine) - wood					X	X		
Co-combustion, 500 MWe (PF) - wood							X	

The feedstocks considered were miscanthus and short rotation coppiced willow woodchips. The case studies were chosen so that it should be possible to infer the likely relative costs of the technologies at different plant sizes.

The techno-economic assessment was carried out using the following assumptions:

- The real interest rate (i.e. the interest rate after the effect of general inflation has been removed) would be 5, 10, or 15 %;
- The project life would be 21 years This was to allow a complete number of 3 year coppicing cycles to be completed for the woodchip. An exception was made for co-firing which was assumed to have a life of 10 years as it was using existing plant.
- The plant gate price of biomass would be £40, £50, or £60 per odt.

Other case specific data will be referred to where appropriate.

It is not appropriate to give a full report of this work here but a summary paper has been published [73].

2 Review of previous techno-economic studies

A number of techno-economic studies have dealt with the generation of electricity using bio-oil produced by the fast pyrolysis of biomass or parts of the infrastructure needed for such a system. They form the background to the subject and define the limits of current investigations. They are also possible sources of data for future work. Some of the studies compare a number of alternative biomass to power routes, and in these cases only those aspects related to fast pyrolysis routes are covered by this review.

The papers and reports selected for this review have been chosen to ensure that the full range of activities involved in a pyrolysis bio-oil power generation system is covered. They have been selected on the bases that they are up to date, clear in their methodology, and have come from a range of sources. This inevitably means that they have come from a number of different countries; consequently there are differences in the units used, assumptions made about the availability of feedstocks, financing assumptions and potential market prices. They also quote prices at different base dates. As such their published costs cannot be directly compared. Given their diverse terms of reference there is little point in converting all of the findings to a common base to find an average cost of electricity production. However there are some attributes that once brought to a common base data and currency should be able to be compared. These are:

- Product yields;
- Capital costs;
- Labour requirement;
- Process electrical power requirement;
- Repair and maintenance costs.

This has been done where possible and the findings used in Chapters 4, 5, 6 and 7.

A number of the papers chosen are connected in so far as they show the evolution of ideas from a particular institution. As such they draw on the earlier work. This is not a criticism but it means that where values are repeated form earlier work they should not be considered to have been arrived at independently. The papers are identified by author and year of publication and the relationships between them are shown in Figure 2.1.

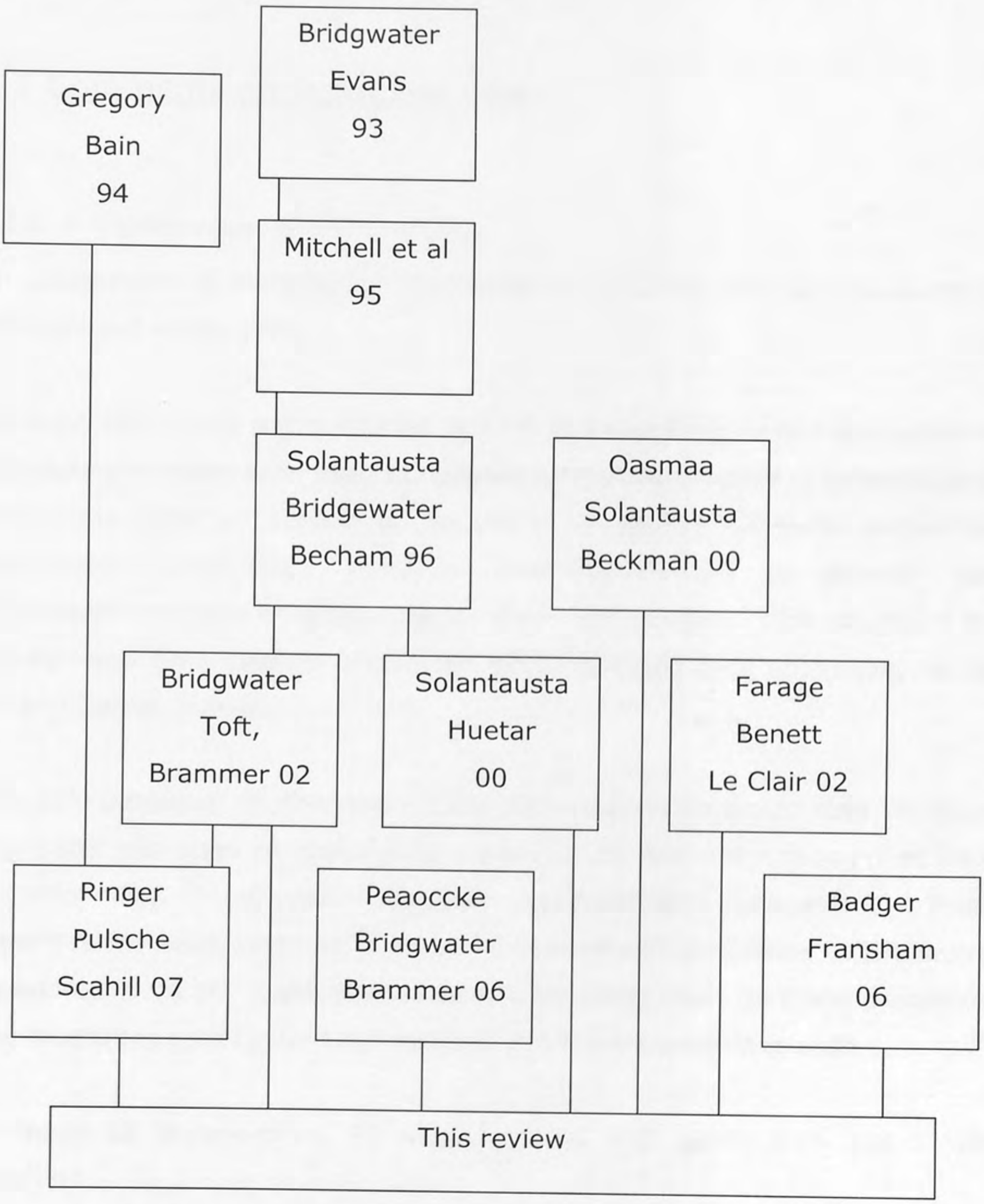

Figure 2.1 papers and reports included in this review

There are a number of key technical papers that relate to the theory and practical performance of pyrolysis plants and energy crop production that are not commented on in this review. This is on the basis that although they provide key data for any study of the topic, their purpose was not to address the economic viability of commercial plants. Where appropriate their findings are discussed in the relevant chapters.

2.1 Comments on individual papers

2.1.1 A V Bridgwater, G D Evans 1993,

An assessment of thermochemical conversion systems for the processing of biomass and refuse [76].

Although this report was published in 1993 it is still a key report as it contains cost data that have been used in updated forms in a number of other studies. The study used a survey of suppliers of various biomass conversion technology (gasification, pyrolysis and liquefaction) to provide cost estimations and performance data for their technologies. The results of the survey were then used to assess the applicability of each technology to the UK and Danish market.

The IEA Database of Thermochemical Conversion Processes held at Aston University was used to identify 22 organisations that were thought to have systems that could soon become commercially realisable. These organisations were approached to see if they would participate in the study; 18 agreed to do so. Desk studies were then undertaken on these processes, questionnaires sent to the organisations and the organisations visited.

Of these 18 organisations 15 were involved with gasification and 5 with pyrolysis.

The pyrolysis organisations surveyed were:

- Egemin BV, Antwerp Belgium;
- Ensyn, Ontario Canada;
- University of Hamburg, Germany;
- Université Laval Québec Canada;
- Wastewater Technology Centre, Toronto, Canada.

A further organisation, Interchem Industries of Kansas USA, was also identified as a possible originator of a pyrolysis system and was included in the survey but was not visited as the authors had visited them shortly before the study. The report concentrated on the conversion technologies; although it did identify suitable plant trains for power generation and feedstock preparation.

2.1.2 Mitchell C P, Bridgwater A V, Stevens D J, Toft A J, Watters M P, 1995 Technoeconomic assessment of biomass to energy [77]

This paper and the associated BEAM report [78] present the findings of two IEA Bioenergy Agreement Activities:

- Task IX – Technoeconomic assessment of wood fuel;
- Task X – Production utilisation interface.

BEAM stands for BioEnergy Assessment Model and is a spreadsheet based assessment tool that covered all the activities from crop production to electricity generation or ethanol production. This work was a collaboration between The Department of Forestry Aberdean University, the Energy Research Group at Aston University, Cascade Research Washington USA, ETSU Harwell Laboratory UK and NREL Golden Colorado USA. The BEAM model linked models of biomass production, conversion and electricity production (or ethanol production) using interfacing modules. This structure allowed for existing models from the various partners to be integrated into a single tool. As a consequence the model utilises the expertise of the specialist collaborators while maintaining a common set of base conditions.

The basic models incorporated into BEAM are shown in Table 2.1.

Table 2.1 Processes covered by BEAM

short rotation coppiced willow or poplar	Residues from conventional forestry	municipal solid waste		
feed pre-treatment				
Combustion in a circulating fluid bed combustor with steam cycle generation plant	Fast pyrolysis in bubbling fluidised bed reactor and generation by a duel fuel diesel engine	Atmospheric gasification with a dual fuel engine	Integrated Gasification Combined Cycle (IGCC) using a pressurised gasifier,	Ethanol production by acid hydrolysis, fermentation and distillation

The short rotation coppice model covers all the cost associated with the production of the crops, their storage (with associated losses) and transportation to the conversion site. The forest residue model covered the costs of collection and delivery of the residues and a payment for the grower. Municipal solid waste was only considered as an integrated mass burn incinerator with a steam cycle for electricity generation. In order to compare the systems the costs for a plant with an output of 20 MWe were calculated for each system.

2.1.3 Y Solantausta, A V Bridgwater & D Beckman, 1996

Electricity Production by advanced biomass power systems, [79]
This report presents the result of the Pyrolysis Collaborative Project organised by the International Energy Agency which was carried out in 1992-1994. The study investigated the following processes:

- Pressurised gasification with gas turbine / stream turbine combined cycle;
- Atmospheric gasification with gas turbine / stream turbine combined cycle;
- Pressurised gasification with a steam injected gas turbine;
- Atmospheric gasification with diesel generation;
- Fast pyrolysis with diesel generation;
- Fast pyrolysis with gas turbine / steam turbine combined cycle.

Conventional combustion was not studied in detail although it was used as a bench mark for the new technologies. Wood was used as the fuel for all the processes as it is widely available in many countries and can be used in all the conversion processes.

As the economies of scale are different for different technologies a range of generation plants from 5-60 MWe were considered.

The conversion processes were modelled using ASPEN PLUS process modelling software to obtain energy and material balances. Established plant models were used for the gas turbines and generic ones for the diesel engines.

Capital costs were taken from project survey data including Bridgewater and Evans [76]. The reported costs were adjusted to bring them to a common extent of supply so that they represented the Total Plant Cost (TPC) to the owner (i.e. all the cost of constructing, commissioning and financing the plant excluding consenting and land purchase costs). All estimates were reported in US dollars and are for plants located in central Europe.

2.1.4 A V Bridgwater, A J Toft, J G Brammer, 2002

Techno-economic comparison of power production by biomass fast pyrolysis with gasification and combustion [81]

This paper is a techno-economic study that compares combustion, gasification, and pyrolysis as means of generating electricity from wood chips. The plant output range covered is nominally 1-20 MW_e (although some of the presented data covered a wider range). All the pyrolysis plant based generation options used pilot fuelled diesel generators. The scope of the paper covers all activities from plant gate to grid connection point.

The paper assumes a central European location and is priced in € at 2000 base date.

As the paper assumed a fixed delivered feedstock price it did not address the issues of variable feedstock transport cost.

Decoupling of bio-oil production from electricity production was considered. An arrangement of multiple pyrolysis plants feeding a centralised diesel generation station was investigated but few savings were identified. However there was some cost benefit found when using several small generators supplied by a single central pyrolysis plant.

To enable the newer technologies to be compared with combustion a learning factor of 10% was applied to the capital costs for the novel sections of the gasification and pyrolysis plants. The learning factor is a measure of how much the cost is expected to fall with a doubling of installed units. The estimated prices for the 10th plant are used in the comparison exercise. No performance improvements were projected for the new technologies.

The cost of transporting bio-oil from a number of pyrolysis plants to a central point was modelled. It was assumed that the supply of biomass was uniformly distributed and that each conversion plant is the same distance from the central generation station. It was assumed that each conversion plant was fed from biomass in its own wedge shaped sector.

The performance data of the pyrolysis plant was taken from yields obtained in small scale test plants. It has been adjusted to take into account the fact that commercial feedstock would include bark.

2.1.5 Peacock GVC Bridgwater AV and Brammer JG,2006

Techno-economic assessment of power production from the Wellman and BTG fast pyrolysis processes [86].

This paper reports work carried out under EU Contract JOR-CT98-0197 by Conversion and Resource Evaluation Ltd (CARE) and Aston Universities BERG group. The study was commissioned to compare the likely cost of two potentially commercial systems; the BTG Ltd rotating cone pyrolysis plant and a bubbling fluidised bed plant designed by Wellman Ltd. The paper used the findings of the contract and expanded the scope to include electricity generation.

The capital cost for each system was calculated using component cost data and installation factors from [84]. The work was carried out with the co-operation of the system suppliers who confirmed the estimations were in the same order as their own. The paper includes generation cost associated with a diesel plant provided by Omrod diesels.

The study was based on 48 daf t/day plants with the results scaled over a 6 - 240 daf t/day range.

The generation plant was assumed to be located on the same sites as the pyrolysis plants and used all the bio-oil produced.

The study considered costs and made no allowances for profit, return on investment or taxes. As both plants were considered to be in the same state of development learning factors were not used in this study.

The main strength of this study is the way in which it covers the pyrolysis plant. Flow sheets and mass balances were drawn up for both processes and agreed with the equipment suppliers. The capital cost of the systems was then calculated using published component data costs and installation factors.

The paper reports that the TPC for the 48 daf t/day Wellman plant was within 5% of Wellman's own estimate for a similar plant.

In the case of the BTG rotating cone no suitable plant analogue could be found so it was estimated to be a multiple of the cost of the fluidised bed reactor. A sensitivity analysis was then carried out to see how changing the multiple would affect the final bio-oil price. A 100% change in the ratio resulted in just a 5% change in the bio-oil price so the lack of a suitable estimate for this component was not considered critical to the outcome of the study.

2.1.6 Oasmaa A, Solantausta Y, Beckman D, 2000

Comparisons of alternative routes for biomass fuel biomass pellets, pyrolysis oil and tall oil pitch [87]

This paper looks at the relative cost of using wood pellets and bio-oil from fast pyrolysis as ways of utilising forestry products in power generation and district heating schemes in Sweden. It takes much of its data from existing wood pelleting schemes which are often part of timber processing plants. The paper is unusual in that it assumes the conversion plants themselves are integrated into district heating/industrial CHP plants. This allows for much of the process heating energy to be recovered and used for low grade steam or hot water heating.

The study is based on plants with a feed capacity of 100,000 odt/year (this relates to 342 odt/day with a 80% capacity factor). Pellet plants exist at this size but it is possible that a 2 stream pyrolysis plant would be needed to reach this capacity.

The report uses Swedish Krona prices converted to US dollars at SEK 8/$ at a 1998 base date.

The base data has come from existing timber processing plants. Much of it is commercially sensitive and so is unaccredited.
The industrial sources have had the opportunity to comment on the draft paper. This paper assumes that there are many common processes between wood pellet manufacturing and pyrolysis of wood. It used costs from the wood pellet industry as the bases for its cost estimates for both processes. Many of the pyrolysis plant cost have been inferred from earlier work on similar process without much explanation of the underlying assumptions. However the real interest in this paper comes from its coverage of the feed preparation plant and the cost estimates for modifying combustion plant to burn bio-oil.

2.1.7 Solantausta OY, Huetair J,2000

Power production from wood comparison of the Rankine Cycle to concepts using gasification and fast pyrolysis [88]

This paper compares methods of generation of electricity from biomass for 2 MWe power plants in Finland. The small scale was selected to take advantage of the lower transport cost when using locally supplied forest residue wood chips. The bio-oil from the pyrolysis plant was used in diesel generators.

Plant costs were taken from industrial partners and previous published IEA work including ref [76].

The cost data were provided on a whole plant basis and are given in both Finish Markkas and US Dollars at 1998 base date. All costs estimates exclude operators profit and taxes.

CHP applications have been considered as a separate section of the paper.

The cost of electricity was calculated for the three technologies over a range of operating hours. These were repeated for high and low values of fuel cost, discount rate and projected technical performance improvements to see if this would affect the relative cost of competing technologies.

2.1.8 Farag IH, LaClair CE, Barrett C, 2002

Technical, Environmental and Economic Feasibility of Bio-oil in New Hampshire's North County [89].

New Hampshire's traditional timber processing industries (including power generation) are in decline and this study was commissioned to look at alternative uses for low grade timber waste. Part of the motivation for doing this was to find an economic way to manage the extensive forest of the area. This report was produced by the University of New Hampshire in partnership with local business organisations and government bodies.

The study reviewed the published literature and patents that describe the processes used by the two main companies (Dynamotive and Ensyn) who have commercial pyrolysis plants. It concluded that despite the relative commercial maturity of the Ensyn Rapid Thermal Processing (RPT) process the Dynamotive BioTherm process was more able to produce a marketable standard Bio-oil. A memorandum of understanding was signed with Dynamotive who subsequently provided much of the base data used in this study. This access to up to date commercial data is the real value of this study.

The report is written from the perspective of the northern counties of The State of New Hampshire where timber cost is little more than the cost of harvesting and transporting the wood and where energy costs are low. As such much of the priced data would not reflect the situation for an energy crop fired plant in the UK. However the performance data should be the same although the period when air drying of timber is effective will be longer in the UK due to the warmer winters.

2.1.9 Badger Philip C , Fransham Peter , 2006

Use of Mobile Fast Pyrolysis plants to densify biomass and reduce biomass handling cost - a preliminary assessment [92].

This is an American paper and is concerned with the economics of using forestry residuals and underbrush as a fuel. Renewable Oil International (who employ P Badger) aim to develop a mobile pyrolysis plant that can operate near the harvest site and so reduce the transport cost associated with biomass. The paper covers the difference in costs of the facilities needed for transport and fuel handling at the power station between bio-oil and woodchips fired power stations. As such it has costs for bio-oil and woodchip handling plant.

2.1.10 Gregoire Catherine E and Bain Richard L 1994

Technoeconomic analysis of the production of biocrude from wood [94]

This is a relatively early study that looks at the feasibility of a large commercial plant based on 4 x 225 dry ton/day wood capacity pyrolysis units. The plant produces bio-oil and uses the other pyrolysis products to fuel the process and produce some surplus electricity and steam for sale. It contains some unusual features that may be worth reconsidering.

Vortex reactors are used for the pyrolysis plant. As an ablative reactor the vortex reactor uses whole wood chips rather than ground wood particles.

The char and the excess non-condensable gases are burned to heat the pyrolysis plant with the resulting flue gases being used to raise steam for electricity generation and direct sales to a heat consumer.

Heat is taken from the bio-oil condenser system and used to dry the wood chip in a silo dryer. Unfortunately since this paper was written experience has shown that to get good quality bio-oil it is necessary to have a liquid quench rather than high temperature condensers. Although heat is removed from the quenching liquid it will not be at a suitable temperature to fully dry the wood chips.

2.1.11 Ringer M, Putsche V, Scahill J ,2006

Large scale pyrolysis oil production: a technology assessment and economic analysis [96].

This report reviews the published literature on different fast pyrolysis systems and carries out an economic assessment based on an ASPEN PLUS model of a 550 odt/d BFB pyrolysis plant. Like Farag et al [89] this report assumes that there is a ready supply of low cost wood chips from forestry management to use a feedstock. It also assumes that there should be a market for bio-oil as a replacement for #2 distillate fuel oil and # 6 residual heavy fuel oils fuel oils in modified installations so it does not cover the costs of power generation using bio-oil.

The report discusses state of development of the technology in the following areas:

- Requirements to obtain high bio-oil yields;
- Pyrolysis reactor design;
- Bio-oil stability;
- Product specification;
- Applications in existing or modified devices;
- Environmental safety and health issues.

Although a competent review it adds little to that conducted by Bridgwater and Peacocke [28] in 2000, and updated in 2004 [29]. It is also unfortunate that it does not discuss the work of Oasmaa, Kuoppala, Gust, and Solantausta [97-99] on the phase separation of pyrolysis liquids from forest residuals as it raises serious issues for the use of this feedstock.

The report does include a table of bio-oil production costs from 7 sources covering a range of plant sizes from 2.4 to 1000 t/d but it does not attempt to bring the costs up to a common base date or to put them on a consistent bases.

The study used a heavily updated version of an ASPEN PLUS ® model used by Gregory and reviewed in section 2.1.10. The basic model covers the following process:

- Feed handling and drying;
- Pyrolysis;
- Quench;
- Heat recovery;
- Product recovery and storage;
- Gas recycle;
- Steam and power production;
- Utilities.

The model is of a BFB pyrolysis unit taking 550 odt/d of woodchip. The wood chips are assumed to have a moisture content of 50% (wet basis) and they are dried to 7% before being ground. They are ground to < 2mm and heated to 500°C in the pyrolysis reactor. The product yields were taken from the Bridgwater, Toft and Brammer paper reviewed in Section 2.1.4. The chemical compositions of the products were assumed from [100]. Elemental balance calculations were performed to establish the composition of the char and the IGT coal model was used to find it's HHV. The ash was modelled as SiO_2.

One unusual feature of this model retained from the one used by Gregory is the use of heat recovery stages within the bio-oil collection system. There is an assumption that the vapours can be cooled to 200°C without liquid formation, work by Lederlin and Gauthier suggest that this is not the case [103] and some fractional condensation will occur, this is turn will collect some of the aerosol droplets that have been observed in pyrolysis vapours [104]. Heat is also taken from the second stage of condensers for use in the woodchip dryer. Any remaining aerosols are removed by a scrubber then an electrostatic precipitator and finally to a third condenser that is cooled by chilled water. The paper acknowledges that this complex arrangement may not be practical due to the requirement for rapid quenching and notes that it has not been tested in any pilot plants.

All of the char and excess (i.e. that which is not needed for bed fluidisation) pyrolysis gas is burnt to heat the fluidising gas and pyrolysis vessel with the exhaust being used to raise steam which is used in a small steam turbine (5MWe 620°C 34 bar). This is a very strange set of operating conditions for a steam turbine, 620°C steam temperatures can be achieved with austenitic steels but these are normally only economic for used in large supercritical boilers [105], the market for 5MWe steam turbines is mainly for small combined cycle gas turbine plants or for steam plant with waste or biomass fired boilers where the steam temperature is likely to be nearer 450°C [88]. These would have a lower cycle efficiency and hence lower electrical output for a given heat input.

The capital cost estimate was produced on a bottom up basis with the component costs and installation costs contained in the ASPEN ICARUS Questimate ® Vertion 11.1 tool. The pyrolysis reactor was assumed to cost the same a fluidised bed boiler.

The paper considers that bio-oil is most likely to be considered as a replacement for #6 heavy fuel oil which has a price of $4.75/GJ LHV and goes on to discus options for upgrading the oil to meet #2 distillate fuel oil standard which has a market price of $10.12/GJ LHV.

2.1.12 Chiaramonti D, Oastmaa A and Solantausta, 2007

Power Generation using fast pyrolysis liquids from biomass [106]

Although not a technoeconomic analysis this paper is worth mentioning as it contains an up to date literature review of research into bio-oil applications.

2.2 Data Comparisons

As mentioned at the start of this chapter the different assumptions used when calculating the likely cost of electricity or bio-oil means that the values quoted in the different studies should not be directly compared; however some of the underling data can be.

2.2.1 Product yields

The papers do not report product yields in the same way. Ringer, Putsche, and Scahill (Section 2.1.11) use the performance data from Bridgwater, Toft, and Brammer (Section 2.1.4) which is reported on a % of dry feed. The yields are:

- Water free oil 59.9%;
- Reaction water 10.8%;
- Char and ash 16.2%;
- Gas 13.1%.

This would give a wet bio-oil yield of 73% assuming a feedstock moisture level of 8%.

Farag, LaClai, and Barrett (Section 2.1.8) quote the yields on a wet basis assuming that the feedstock is dried to less than 10% moisture. They quote the following yields:

- Bio-oil 72%;
- Solid char 15%;
- Non condensable gases 13%.

These are consistent with the values used by Gregoire and Bain (Section 2.1.10) who user yields of:

- Bio-oil 73.7%;
- Char 14.1;

- Gases 12.2%.

The other papers only give bio-oil yields Oasmaa, Solantausta,and Beckman (Section 2.1.6) quote a bio-oil yield of 70% of the dry biomass feed.

Solantausta, and Huetair (Section 2.1.7) quote a bio-oil yields of 60 – 75% of the pyrolysis plant feed i.e. on a wet basis.

All these papers have a consistent bio-oil yield. Peacock, Bridgwater and Brammer (Chapter 2.1.5) use a higher yield of 79% bio-oil to pyrolysis feed but they are using a low ash (0.48%) sawdust as a feed where the other processes use woodchips. The impact of feedstocks is discussed in Section 4.3.

2.2.2 Pyrolysis Plant Capital Cost

The reviewed papers used a variety of costing techniques so it is interesting to see what degree of agreement there is between them. All costs were adjusted to pound sterling at the base dates of the papers using the average for the year of the monthly average spot exchange rate from the Bank of England's web site [107]. The costs were then indexed up to 2006 level using the US Chemical Engineering magazine Plant Cost Index.

The studies break down the capital costs into different extent of supplies but with the exception of Peacock, Bridgwater and Brammer (Section 2.1.5) they all give prices for pyrolysis plants with associated wood handling, storage and preparation plants. In the case of the Peacock, Bridgewater and Brammer paper the costs for wood handling, storage and preparation plant sized to supply the Welman plants have been estimated from charts in the earlier paper by Bridgwater, Toft, and Brammer (Section 2.1.4).

The sizing graph in Bridgwater, Toft, and Brammer shows the cost of a number of different designs of pyrolysis plant over the feed range 4.8 to 96 odt/d. These costs were obtained by survey of equipment suppliers.

As it consists of data from a number of process plant designs it should not be used as a sizing curve for a particular design of pyrolysis plant. Likewise extrapolation beyond the range of the data may have little validity. Consequently it has only been used to provide comparative estimates for the case studies in the other reports for plants with capacities of up to 120 odt/d.

The quotes provided by Dynamotive to Farag, LaClai, and Barrett (Section 2.1.8) have been increased by 15% to include interest during commissioning and commissioning activities (the rational behind this figure is given in Chapter 5). These are owners costs which would not be included in a suppliers turnkey quote (a contingency figure had already been added to cover other owners cost by the authors of the report). This increases their scope of supply to be the same as the Total Plant Cost (TPC) reported in the other studies.

The updated Total Plant Costs for the various plants have been plotted in Figure 2.2.

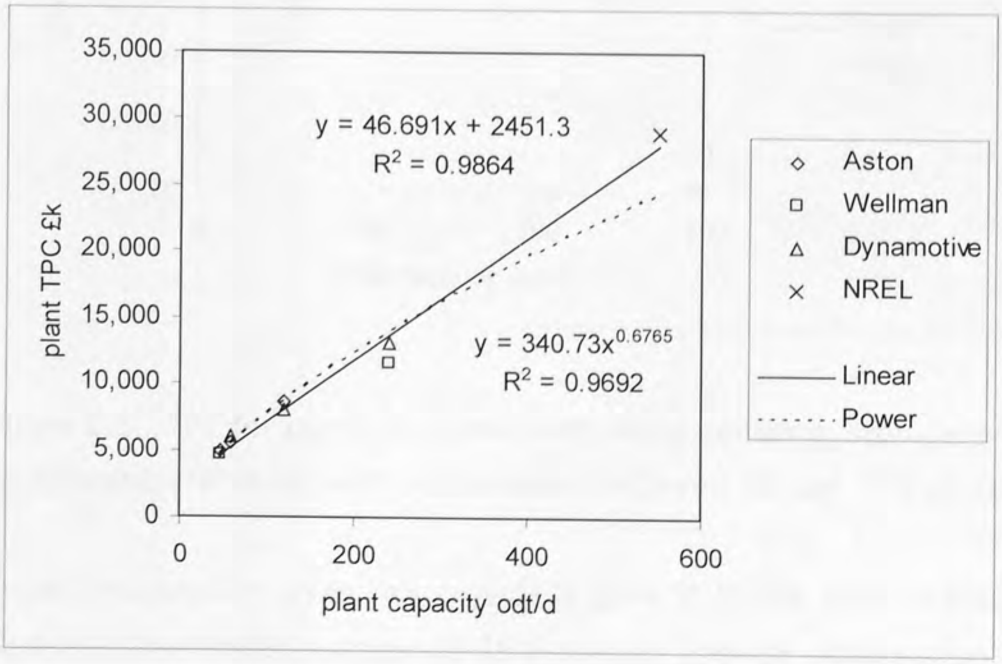

Figure 2.2, TPC for pyrolysis plants with wood handling, storage and preparation facilities.

Aston refers to estimations made using the formula in Bridgwater, Toft, and Brammer, Wellman are the estimates from Peacock, Bridgwater and Brammer, Dynamotive are the estimates from Farag, LaClair, and Barrett and NRE is the estimate from Ringer, Putsche, and Scahill.

Both linear and power law curves have been fitted to the data using Microsoft Excel least square fit algorithms. These are show on Figure 2.2. There appears to be a strong linear relationship between plant capital costs and size. This is partially due to the large jump in plant capacities between the NREL plant and the rest. In Figure 2.3 only the plants in the range of 48 - 240 odt/d are included to remove this effect.

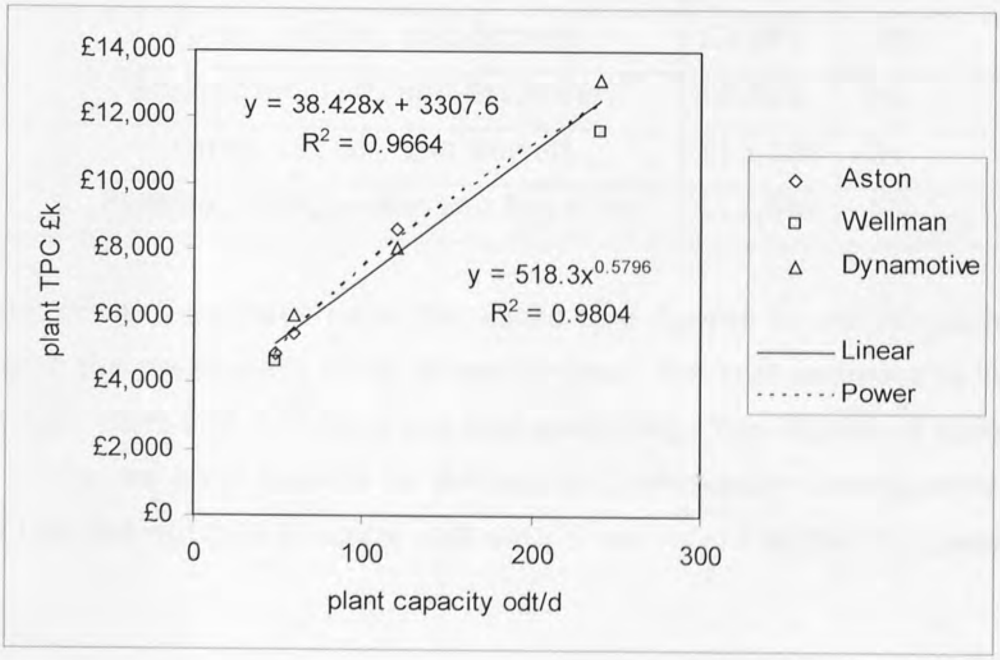

Figure 2.3, TPC for pyrolysis plants with wood handling, storage and preparation facilities with consumption between 48 and 240 odt/d

Both linear and power curves can provide a good fit to the data. This may in part be due to the limited number of data points. The key observation here is not so much the shape of the curve that can be fitted to the data but the fact that the estimates from the different sources are in reasonable agreement with each other.

Table 2.2 shows the difference between one cost estimate from the average of the estimates for the same size plants expressed as a percentage of the average value.

Table 2,2 Capital Cost of Pyrolysis Plants from different papers

Capacity	Study	TPC	difference from the average
odt/d		£k	
48	Peacock, Bridgwater and Brammer	£4,595	-3%
48	Bridgwater, Toft, and Brammer,	£4,869	3%
60	Farag, LaClair, and Barrett	£6,061	5%
60	Bridgwater, Toft, and Brammer,	£5,487	-5%
120	Farag, LaClair, and Barrett	£8,081	-3%
120	Bridgwater, Toft, and Brammer,	£8,619	3%
240	Farag, LaClair, and Barrett	£13,132	6%
240	Peacock, Bridgewater and Brammer	£11,586	-6%

The Total Plant Costs have been calculated to 5 figures to aid comparison, in practice at the preliminary stage of any project the cost estimate is likely to be between -35% and +20 % of the final cost [84]. The degree of agreement is well within the error bounds for project cost estimation consequently it can be said that the published capital cost data is consistent across the papers.

2.2.3 Diesel engine capital cost

Three papers gave costs for diesel generators. Peacock, Bridgwater and Brammer (Section 2.1.5) included a suppliers estimate of €2.9M for a converted 2.5MW medium speed diesel generator with fuel handling and storage facilities

Bridgwater, Toft, and Brammer (Section 2.1.4) included a sizing equation for diesel generators and use a 10% up rating to cover additional cost associated

with dual firing on bio-oil. This equation gives an estimate of €2.16M for a 2.5MW diesel generator.
Solantausta, and Huetair (Section 2.1.7) includes an estimate of $1,356 /kWe, This paper is to a 1998 base date the other two are at a 2000 base date.

These estimates have been converted to Sterling at their base dates and then indexed up to 2006 using the CE index to give the values shown in Table 2.3.

Table 2.3 Estimations of the TPC for a 2.5 MWe diesel generator

Paper	TPC £m	difference from average
Peacock, Bridgwater and Brammer	£2.25	3%
Bridgwater, Toft, and Brammer	£1.68	-23%
Solantausta, and Huetair	£2.64	21%

Given the lack of detail specification for the engines and auxiliary systems in the papers this is an acceptable agreement.

2.2.4 Feed Preparation plant

It is generally acknowledged that this plant will represent a considerable portion of the overall plant cost. However few details of the cost breakdown for the plant have been included in any of the papers. Solantausta, and Huetair (Section 2.1.7) gives a breakdown of costs but they specifies steam dryers which would probably not be used in the UK. Badger and Fransham (Section 2.1.9) do have a costs breakdown for a timber combustion plant but it does not include final size reduction or drying equipment. The situation is complicated by the fact that there are restrictions in the unit size for hammer mills and dryers so it is likely that a family of costing equations would be needed for this plant area. Another key parameter that is needed is the operating regime of the feed preparation plant. It is unlikely that road deliveries could be accepted on a 24 hour a day basis in the UK so the reception equipment needs to match the expected delivery profile. Hammer mills and rotary dryers are noisy plant items; these may well be subject limits on the times of day that they can operate in order to meet planning restrictions on site boundary noise levels. These factors could account for up to a four fold increase in the peak handling capacity of the plant; consequently the proposed running regime needs to be stated before a capital cost estimate can be made for the feed preparation plant.

2.2.5 Labour

This is a complex issue as it will depend on the degree of automation, operating regime of the feed preparation plant, the flexibility of the workforce and the hours worked. As the assumptions for most of these are not given in the papers comparison of the given values may have limited value.

The situation can be further confused if the plant is co-located with another process as is often the case with waste wood fired combustion plants. In these cases staff are often shared between processes so it is hard to identify the workload imposed by the individual processes. This may explain why Oasmaa, Solantausta , and Beckman (Section 2.1.6) assume a total staff of 10 for a 300 odt/d plant on an existing site where Farag, LaClair, and Barrett (Section 2.1.8) have 19 staff for a stand alone 240 odt/d plant.

The inclusion of fractional values for staffing level needs to be justified. It may be possible for one operator to cover more than one process area in which case as long as the total staffing for the plant is a whole number each process can have fractional staffing levels. An operator can be shared between areas if at least one of the tasks is interruptible and the work areas are physically close to each other. It may be possible that some support function can be performed by part time staff or covered by a service contract. In these instances fractional staffing is also realisable however this is only likely to represent a small portion of the overall labour cost. It should be noted that if fuel reception is only carried out during the day shift the staffing required for the other shifts may be reduced.

Table 2.4 Shift Manning levels

papers	60 odt/d	120 odt/d	240 odt/d	550 odt/d
Bridgwater, Toft, and Brammer	3	4	6	
Peacock, Bridgwater and Brammer	5	6	6	
Farag, LaClair, and Barrett	2	3	4	
Ringer, Putsche, and Scahill				6

Table 2.4 has been drawn up making the following assumptions:

- The manning level for the 1,6 and 20MWe plants in Bridgwater, Toft, and Brammer are assumed to correspond to 60,120,240 odt/d plants;
- A 5 shift cycle is assumed for the Dynamotive plant in Farag, LaClair, and Barrett;
- The Wellman estimate is taken as the full shift complement in Peacock, Bridgwater and Brammer;
- In all these cases a full feed preparation crew has been included in the shift.

To establish a realistic manning level a provisional operator task analysis would need to be undertaken. This will identify the number of operator task that need to be carried out in parallel which in turn gives the number of operators needed. It is important to cover all operational states in the analysis. Operations tend to depend on the number of plant items to be operated not their size so provisional Piping and Instrumentation Diagrams (P&IDs) are needed to perform this analysis.

There are health and safety implication in low manning levels particularly with material handling plants, plants with a high fire risk or plants with a toxic chemical risk. This can lead to a site rule that you should never have less than 2 people on site at any time. This does not preclude periods of unmanned operation.

Shift patterns also need to be considered. In organisations with ridged job definitions the traditional 5 shift cycle may be used. However with a more flexible workforce it could be possible to adopt a 4 shift system with day staff covering some of the operations.

It is also likely that a fuel reception operator may be needed to sample incoming wood deliveries and monitor deliveries for fraud.

2.2.6 Electrical power

Three of the papers given estimations of the electrical loads of the plants these are shown in Table 2.5 and plotted in Figure 2.4.

Table 2.5 Estimation of electrical power consumption

papers	plant size odt/d	electrical load KW_e	KWh_e/odt
Peacock, Bridgwater and Brammer	48	556	278
Farag, LaClair, and Barrett	60	550	220
	120	962	192
	240	1788	179
Ringer, Putsche, and Scahill	550	4312	188

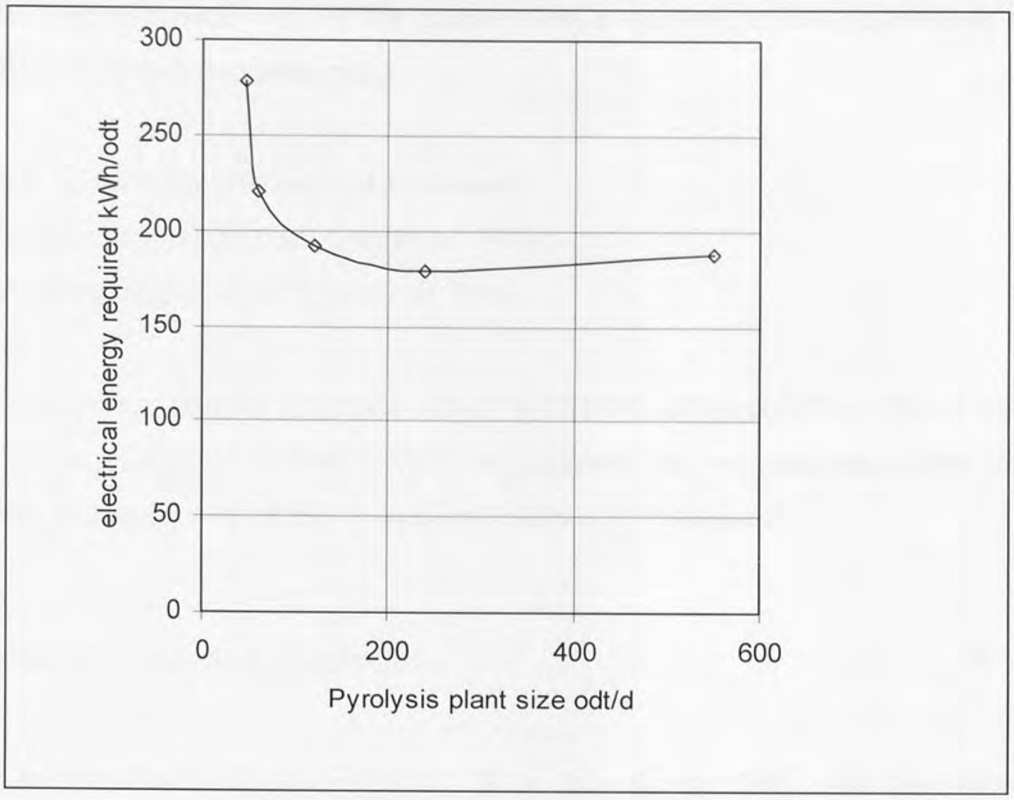

Figure 2.4 Electrical energy required by pyrolysis plants

From Figure 2.4 it would appear that there is an agreement that above a certain size the electrical load settles out around 190 kWh_e for each odt/d of capacity. This would correspond to and electrical consumption of 684 MJ/odt. assuming the biomass as a LHV of 18 GJ/odt the electrical consumption represents 3.8% of the energy input to the plant. A survey of European biomass CHP plants using BFB technology reported that there electrical requirement is between 2.5-5% of their fuel input [108], which is consistent with the estimate produced in this section.

Oasmaa, Solantausta and Beckman (section 2.1.6) quote a electrical consumption of 40 kWh / MWh of wood processed. 1 MWh is 3.6 GJ or 0.2 odt wood so this estimate would be 720 MJ/odt for a 100,000 odt/year plant. Given the use of generic data to convert the units this is in reasonable agreement with the value derived from Figure 2.4.

Comparing the electrical energy used with the energy in the biomass does not take into account the losses incurred in electricity generation.

If the following typical values for conversion parameters for a pyrolysis based generation system are assumed:

- 18 GJ/odt for the LHV of biomass;
- A bio-oil energy conversion of 70%;
- A generator net efficiency of 38%.

1 odt of biomass should produce about 4,788 MJ of electricity. If the plant's electrical consumption is 684 MJ/odt processed the internal electricity demand would be around 14% of the electrical output of the plant.

2.2.7 Maintenance and Overheads

These are estimated at between 2 - 10 % of TPC without giving an explanation of how the estimates were arrived at or a description of what is covered under the heading. It may well be that the maintenance and insurance cost of a plant using new technology is not known but it should be possible to give the bases for the estimate.

3 Object and Methodology

3.1 Scope of study

Most of the studies reviewed in Chapter 2 have similar scopes that can be summarised as:

- A single pyrolysis plant is used to supply one or more generators;
- Generator size between 0.5-50 MW_e;
- The feedstock is wood chip or more usually waste wood from forestry or timber processing;
- The bio-oil is consumed shortly after production;
- No consideration is given to sale of surplus char.

It is the intention of this study to go beyond these bounds in a comprehensive techno-economic study of the potential use of bio-oil in the UK electricity and combined heat and power markets.

3.1.1 Pyrolysis generation arrangements

For combustion and gasification processes electricity generation is closely coupled to the biomass conversion. As bio-oil is a liquid it can be stored and transported. This allows the following options for electricity generation via pyrolysis:

- Close-coupled - where the bio-oil is burnt as it is made;
- Local time decoupled - where the bio-oil is made and stored for later use in a generator on the same site as the pyrolysis plant;

- Remote time decoupled - where the bio-oil is made at a pyrolysis site then transported to one or more generation sites. This also includes the situation of multiple pyrolysis units supplying bio-oil to a remote generation station.

All these options are investigated in this study.

3.1.2 Installation size

It is a general observation that if the size of the plant item increases its specific cost (capital cost / throughput) decreases. There are physical limits on the size of any plant item. The limiting factor on the size of pyrolysis reactors is the requirement to transfer sufficient heat to the biomass for fast pyrolysis to take place. The limit will be dependent on the technology used. However there is no reason why a number of pyrolysis reactors should not be located on the same site. This should allow materials handling plant and staff to be fully utilised.

Previous studies have established the costs of generation for particular sizes (or range of sizes) of generator outputs. This is appropriate if the purpose of the study is to investigate the options for local generation embedded in rural electricity grids. However this is of little interest in the UK. Given that the UK grid can accommodate power stations of up to 4 GWe output a more relevant question is what is the cost of generation from a particular pyrolysis-generator combination when implemented at its optimum size?

Any study that compares plants of different biomass consumption needs to address the issues of biomass availability and transport costs. Accordingly this study includes investigations into transport costs and crop harvest to establish realistic size limitations for UK based pyrolysis plants that use UK grown energy crops. This should establish realistic limits to the sizes of both pyrolysis plant installation and networks of pyrolysis plants supplying a single power station.

It is anticipated that this will allow the generation cost for the use of bio-oil in combined cycle gas turbine plants (CCGT) and conventional boiler/steam-cycle plants to be investigated at scales where they have proved to be economic when fired with other fuels. This approach has led to a number of plant arrangements being considered for investigation. These are shown in Table 3.1.

Table 3.1 Plant configuration covered by this study

case	pyrolysis plant configuration	generation equipment	market
1	single reactor	diesel	power only
2	single reactor	diesel	CHP
3	single reactor	GT	power only
4	single reactor	GT	CHP
5	single reactor	off site diesel	CHP
6	multiple reactors on a site	CCGT	power only
7	multiple reactors on a site	sub critical steam cycle	power only
8	multiple reactors on a site	supercritical steam cycle	power only
9	network of multiple reactors sites	sub critical steam cycle	power only
10	network of multiple reactors sites	supercritical steam cycle	power only

In most cases the generation plants will be sized to consume the bio-oil produced by the pyrolysis plant configuration. This is a departure from previous studies which compare the cost of generation from different technologies at the same electrical output and reflects the fact that in the UK the limiting factor on the size of a biomass fuelled power stations is the availability of the biomass, not the availability of an electrical load.

It should be possible to compare the results from Cases 1 to 4 to those from some of the existing studies (adjusted to the same basic conditions). The other cases have not been considered in the literature.

3.1.3 Feedstocks

All previous studies have used wood waste from the forestry and timber processing industries (i.e. untreated timber waste) or short rotation coppiced willow as there feedstock. There is limited availability of forestry and timber processing waste in the UK [5,109] so this study will concentrate on the use energy crops. The suitability of an energy crop for use in a pyrolysis plant depends on its production costs, yield, and ash content (this affects the pyrolysis yield as discussed in Section 4.3). Two suitable energy crops that can be grown in the UK are coppiced willow and miscanthus. This study will look at both these energy crops.

Coppice willow is normally chipped when harvested or before transport and so needs similar handling plant to that used for forestry residuals. Miscanthus is normally bailed when harvested and so needs a completely different materials handling system. As the yield, transport costs and handling costs for both feedstocks are likely to be different and have different scaling factors, both feedstocks will be considered at each size of pyrolysis site. The cost of generation using both crops will be calculated for cases 1, and 6 this should establish the least cost feedstock for a particular size of pyrolysis installation. The least cost feedstock for that pyrolysis arrangement will then be used for the other application using the same arrangement. It is assumed that if a particular feedstock is preferred for the multiple pyrolysis cases it will be used for the network of multiple pyrolysis cases.

3.2 Methodology

3.2.1 Assessment Criteria

There are a number of criteria that can be used to compare generation systems. The criterion that combines both capital and operating cost is the break even selling price of electricity (BESP), i.e. that price which the plant must get for its electricity to just cover its construction and operating costs. This will be calculated for each of the cases in Table 3.1 for standard conditions. In keeping with most European studies the following costs will be excluded from the calculation:

- Profit made by the crop producers, haulage contractor or process plant operators as these are business-set targets;
- Corporation tax and capital allowances, as the impact of these depend on the profit made;
- Land purchase as this varies from site to site and would be hard to assess for projects using existing farm land or industrial sites;
- Eventual site decommissioning and demolition costs;
- Connection cost to the National Electricity grid as this is very site specific and will not vary with changes in generation technology;
- Heat distribution and utilisation cost for CHP plants as these impact on the viability of an entire CHP scheme not just on the means of generating the heat, they are also project specific;
- CO_2 emission allowances as these would tend to increase the costs of fossil fuel generation rather than reduce the cost from renewable generation;
- ROCs and climate change levy payments. The BESP will be calculated without subsidies as their impact will be the same in most cases. The effect of the mechanisms will be included in the discussion of each system.

The following costs will be included in the calculation:

- Total Plant Cost (i.e. the total capital cost to the owner);
- Repair and maintenance (including consumables). This will be considered as a fixed cost. In practice this would have both fixed and variable components but as the running hours will be considered fixed the variable elements can be considered as fixed.
- Staffing costs including National Insurance payments and overheads;
- Insurance and Business Rates;
- Biomass farm gate price;
- Biomass transport costs;
- Support fuel for diesel engines.

Once the basic BESP has been established the sensitivity of this to changes in cost and performance parameters will be assessed.

The BESP will be calculated on the basis of constant costs and performance for each year of operation of the plant. In most cases plants (particularly those using new designs) operate at reduced output during the first few years while the operators optimise the process. Likewise the operational costs have a tendency to fall with time as the operators become more experienced. All the technologies being compared in this study are in a similar early state of development so they will have similar time profiles for performance and operating costs. Consequently a flat time profile can be used in order to rank the technologies. A more detailed analysis taking into account these annual variations in costs will be carried out on the most promising options to try and get a more realistic estimate of the minimum electricity price that could be tolerated for these systems to be profitable; this is done in Chapter 8. The impact of Learning Effects (reduction in cost with number of plants produced and operating experience) will also be investigated to estimate the likely costs as the technology matures.

3.2.2 BESP calculation

One way of calculating the BESP is to estimate the total of the fixed and variable costs over the lifetime of the plant and divide it by the net generation from the plant. This simple approach has two main drawbacks; how are finance charges accounted for, how is inflation accounted for.

3.2.2.1 Financing costs

The capital cost (Total Plant Cost) of the project can be calculated but the owner will need to find this capital. It will either be financed by the company's shareholders (effectively reinvesting potential dividend payment) or will be raised from the financial markets in the form of loans and corporate bond issues. The financing costs will include the actual capital cost and the remuneration paid to the providers of the finance. This remuneration can be in the form of interest paid on loans, shareholder dividends, or interest on corporate bonds. It is likely that a project will be financed by a number of mechanisms which could change over the life of the project as the perceived risk of the project change. This makes the financing charges complicated to calculate and subject to the financing scenarios chosen. Although financing scenarios modelling is a part of the assessment process for real projects it has little impact on the choice between competing technologies.

An alternative approach to modelling the financial costs is to look at the income an investor could get from the capital cost invested in a fixed term annuity. This operates like a repayment mortgage in reverse in that a capital sum is invested and the investor receives a regular annual income for the duration of the term of the annuity (life of the plant). The income from a annuity is calculated by the following formula:

$$A = Cr(1+r)^n/((1+r)^n-1)$$

Where A is the annuity charge, C the capital costs, r the interest rate and n the project life.

A reasonable estimation of the long term interest rate is needed to be able to apply this formula. Utility scale power projects are likely to be built by the existing utility companies. These companies include interest payment and debt summaries in their annual reports. From a brief examination of some of the utilities accounts it appears that EON paid an average interest (total net interest is assumed to be paid on the total net debt) of between 5% and 6.5% in the period 2003 - 2006 [113]. Scottish Power paid 2.8% in 2005 [114] and RWE quote an after tax investment discount rate between 6.5% - 8.5% [115], and their corporate bond coupon values are between 5% and 6%. These are multinational companies with complex international multi currency financial structures so it is not surprising that there is a spread of values, but it would appear that interest rates actually paid by the utility companies are in the region of 5% to 9%.

3.2.2.2 Inflation

Future charges and payments will be subject to inflation. There are a number of measures of inflation. The following are shown in Figure 3.1:

- The UK Retail Price Index (RPI) this is a general measure of consumer price rises in the UK;
- RPI calculated without housing costs, which may be a more appropriate measure of industrial inflation [110];
- The US Chemical Engineering magazine Plant Cost Index; this is frequently used to index plant construction costs but it does not cover operation cost;
- Gross average weekly wage for workers in the energy and water industries [111];
- Consumer Price Index (CPI) the measurement the UK governments uses for inflation targets [110].

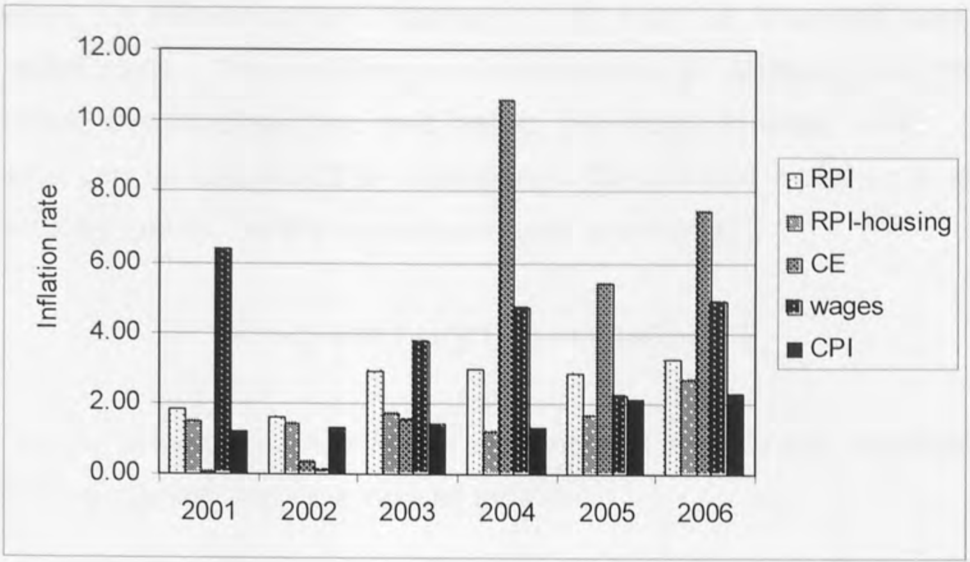

Figure 3.1 different measures of inflation

It is clear from Figure 3.1 that there is no such thing as "The Rate of Inflation". Instead appropriate indexes are needed for each costs and income stream. It is also clear that these rates do not follow simple trends so, like financing costs, inflation predictions are in effect scenario models.

3.2.2.3 Annualised costs

One way round the issues of having to carry out financing and inflation modelling is to consider the costs for a typical full year of commercial operation. The BESP is defined as the price where the annual income matches the annualised costs. It is assumed that the costs and income have been inflated by the same amount and so the effects of inflation cancel each other out giving the BESP at today's prices. The main issue with this approach is the handling of the financing of the capital cost. If an annuity payment is being used to represent the cost of capital and the annual payment calculated using a commercial interest rate the financial markets will have already taken inflation into account when setting the interest rate.

Consequently an allowance for inflation is built into the financing cost but not into the other costs. This problem can be overcome by stripping out the rate of inflation from the interest rate and using the "real" interest rate. The real interest rate can be calculated by considering the amount owed on a loan after the first interest period before any repayments are made.

$$P(1+r) = P(1+d)(1-i) \text{ - equation 3.1}$$

Where P is the principal sum, r is the real interest rate, d the nominal interest rate set by the market and i the rate of inflation.

equation 3.1 simplifies to

$$r = d - i - id$$

If both d and i are less than 10% their product can be considered negligible.

From Figure 3.1 both the CPI and RPI minus housing costs were around 2.5% in 2006. If this is used with the market interest rates paid by RWE and EON the appropriate real interest rates to use would be 2.5 - 6.5 %. It is worth noting that the market rates reflect the full range of businesses owned by these groups. Many of these businesses are mature and are considered a low financial risk. It is likely that a new venture like a pyrolysis based plant would be considered high risk so it would be appropriate to use a higher range of rates. Consequently real interest rates of 5% and 10% are used in this thesis.

The studies reviewed in Chapter 2 that used annualised costs (Bridgwater, Brammer, Toft and Solantausta, Huetair) used real interest rates of 10%.

3.3 Basic Assumptions

3.3.1 Plant life

In common with most of the existing studies a plant life of 20 years will be assumed. The RWE annual report quotes 15 to 20 years as the life of a thermal plant [115]. Most UK power stations are older than this but they have had considerable amounts spent on refurbishing them.

3.3.2 Base date

As it is the latest date for which cost indexes are available 2006 has be chosen as the base date for this study. The average value of fuel costs for 2005, 2006, and 2007 will be used to try and remove some of the market volatility of energy costs. Similarly the average for the year of the Bank of England monthly spot market exchange rates will be used [107].

This gives £1 = $1.8197 and £1 = € 1.4668

3.3.3 Labour costs

There appears to be limited consensus in the literature as to the appropriate staffing level and structure for pyrolysis plants. Consequently it does not appear to be appropriate to discriminate between different grades of staff when estimating the staffing costs. For each staff member the cost of employment will be calculated on the basis of:

- 52 weeks of the average wage for all employees in the energy and water industries [111];
- Employer's National Insurance contribution of 11% of earnings above £87/week [116];

- Employer's contribution to staff pension of 5% of earnings.
- Training allowance of £1,000/year;
- Payroll administration of 5% of earnings [117].

The employer's pension contribution and training allowance have been included on the assumption that the most of the staff will need to be quite skilled so they will need training and will probably have some additional benefits to their salaries. When all these considerations are taken into account the employment costs comes to £38k/year per employee.

Plant investment decisions often offsetting savings in labour costs against capital expenditure. To do this you need to know how much capital can be financed by the annual employment cost of an employee. The annuity charge formula used in section 3.2.2.3 can be rearranged as:

$$C_e = S((1+r)^n-1)/r(1+r)^n$$

Where C_e is the capital equivalent to one employee, S the annual staff cost per employee, r the real interest rate, and n the project life. Using a plant life of 20 years the capital equivalent per employee is £474k with a real interest rate of 5% and £324k with a rate of 10%.

3.3.4 Estimation of char price

None of the studies address the topic of char sales. The Dynamotive designed plants sell surplus char [58]. As a high carbon powder the char could be used as a chemical feedstock or co-fired in a pulverised fuel or fluidised bed boiler. As such it should be a marketable renewable low sulphur fuel which should fetch at least the same price per GJ as woodchip and possible more as it is effectively pre-ground and dried.

3.3.5 Estimation of heat price

A realistic estimate of the selling price of heat is needed to enable a BESP to be calculated for CHP plants. The Chartered Institution of Building Services Engineers publishes a developer's guide for community heating and CHP [118]. This guide states that to be attractive to heat customers the heat selling price should be 15% less than the total cost of generating the heat by another means. It has been assumed that in most cases this means that the heat from the CHP is worth 85% of the cost of heat generated in a gas boiler.

A CHP system includes one or more heat recovery systems (exhaust heat recovery boiler, coolant heat exchanger or lubrication oil cooler heat exchanger), and a heat distribution system. A heat-only system consists of a fired boiler and heat distribution system. The payment for the heat from a CHP source would have two components, one calculated from the fuel costs of the alternative boiler plant and the other from the capital and operating costs of the boiler plant. However the heat recovery systems will also have a similar capital and operating cost. It has been assumed that the component of the heat payment to cover capital and operating costs for the fired boiler will cover the equivalent costs for the heat recovery systems. Hence the net income from heat sales will be 85% of the value of the fuel savings.

The average price paid for gas in 2005 to 2007 was 1.625 p/kWh (including 0.07 p/kWh climate change levy) [119]. If a typical value of 80% is assumed for the efficiency of a non-condensing gas boiler and allowing for a 15% discount on the gas price a realistic maximum net heat price would be 1.76 p/kWh or £4.8 /GJ.

3.3.6 Estimation of electricity price

As a general principle the electricity used by the biomass preparation, pyrolysis and generation plant will either be taken directly from the generator output or be provided under contract by the generator at no charge.

However an indication of the market cost of electricity is needed to help assess the viability of a plant. For CHP and diesel generators it can be assumed that these will be embedded in the distribution system, often supplying large consumers directly. Larger plants will sell into the wholesale market which is made up of a number of long and short term contracts. RWE publish a graph of the average market prices in their annual accounts [115]. This has been reproduced here as Figure 3.2 along with the average industrial consumer price from DUKES Table 3.1.2 [119].

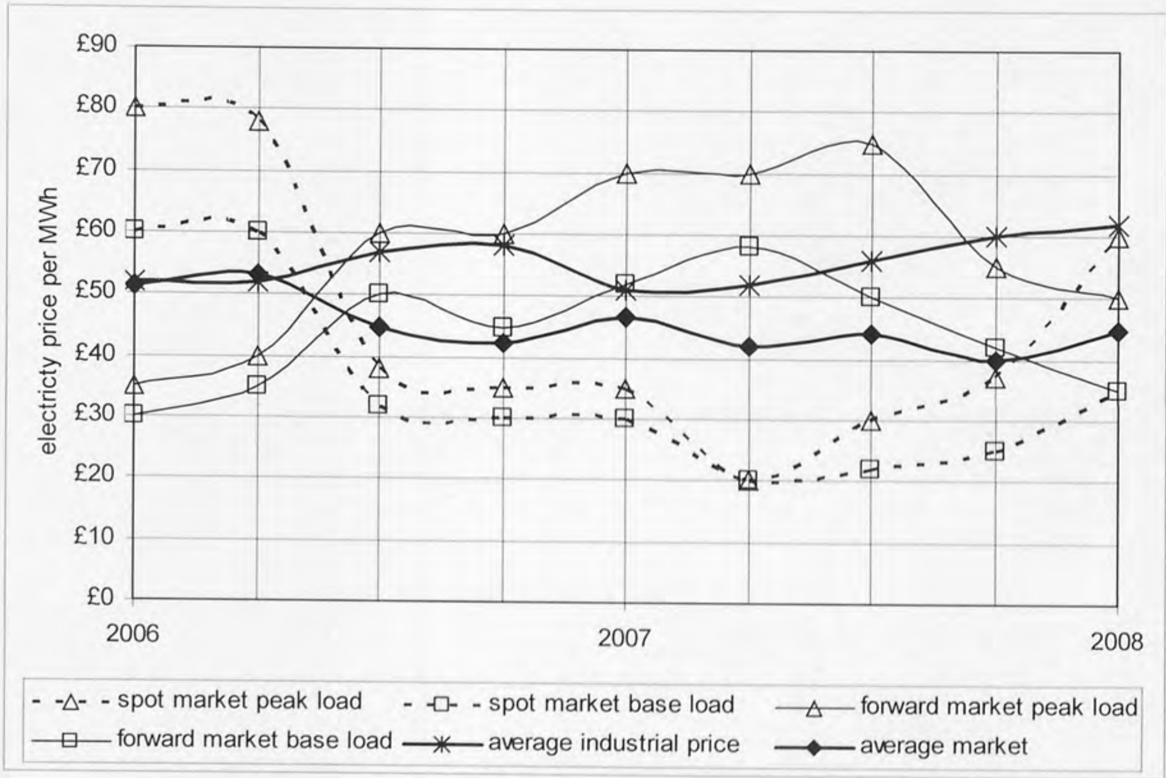

Figure 3.2 Electricity prices

The "average market" trend is the simple average of the forward and spot market prices for both the peak and base load trends. The amount of electricity sold in each category would be needed to calculate a true average price. It is clear from Figure 3.2 that the market is volatile and that there appears to be little short term correlation between industrial sale price and the wholesale cost of electricity.

OFGEM use an 18 month hedge model to estimate the wholesale price that an electricity supplier is likely to pay for electricity this ranged from £35/MWh in February 2005 rising to £55/MWh in October 2006 then falling to £45/MWh by February 2008 [120]. For comparison purposes in this study the average of the industrial prices for 2006 £55/MWh plus £3.2/MWh climate change levy [117] will be used for the value of consumer generated electricity and the average market price of £40/MWh for the wholesale purchase price of electricity.

4 Subsystem performance

None of the plant arrangements listed in Table 3.1 exist as real plants using energy crops as fuel. However the systems can be broken up into subsystems that have had detailed studies conducted on them or on analogous plants. To calculate the cost of production it is necessary to know the operating and capital costs of the plant and how it is going to perform in terms of its feedstock conversion efficiencies, energy requirements and labour requirements. This chapter discusses the modelling of the performance of the main subsystems in relation to their throughput, conversion efficiencies and energy requirements. Staffing costs are considered on a whole plant basis in Chapter 6.5.6. The basic subsystems are:

- Biomass handling - transport, reception, storage, reclaim, drying, size reduction and feed;
- Bio-oil production - pyrolysis, bio-oil collection, storage and forwarding, char storage and sales;
- Electricity generation - including heat collection for CHP sites.

As there are considerable differences in the plant required to handle and store miscanthus and woodchip the biomass handling subsystem for each energy crop will be covered by a different section.

Mobile pre-processing plants have been proposed in the USA [92,133]. This mobile plant involves trailer mounted equipment which would normally be considered as abnormal loads on UK roads. Although this would not prevent their use it would restrict the locations where they could be used. The time spent setting up and dismantling the equipment would mean that there would need to be a considerable store of biomass at a particular site before such an approach would be economic. As such this approach may be more appropriate for an intermediate store rather than a field store.

If the pre-processing train is split between locations it creates additional handling and storage requirements and prohibits the sharing of staff between the pre-processing plant and the pyrolysis plant. Consequently the use of mobile pre-processing plant has not been considered in this study and all processing plant will be assumed to be located at the pyrolysis plant.

4.1 Woodchip handling plant

A key part of any power station is the fuel handling system; the same is true for pyrolysis plants. The key requirements of the feedstock handling system are:

- The incoming trucks must be unloaded quickly;
- The pyrolysis reactor needs a steady supply of dry ground biomass;
- A stockpile is needed to supply feed during periods when the site cannot receive any deliveries;
- Buffer hoppers are required to accommodate mismatches in the running hours of different pieces of equipment;
- The processing plant needs protection from foreign bodies and oversized feedstock;
- The operations of the feedstock handling and preparation plants must not produce a noise or dust nuisance to close neighbours.

The issue of noise is significant as it will probably have an impact on operating hours and the need to have some operations carried out inside buildings. There is no general planning guidelines on noise levels from new industrial plants however Planning Policy Guidance 24 (PPG24) gives planning guidance for new housing near existing noise sources [122]. This quotes a World Health Organisation guideline that "general daytime outdoor noise levels of less than 55dB(A)L_{eq} are desirable to prevent any significant community annoyance" and "based on limited available data a level of less than 35 dB(A) is recommended to preserve the restorative process of sleep".

As people sleep indoors PPG24 suggests a figure of 48 dB(A) for an outside night time limit. Another relevant document is BS4142 1990 "Methods for rating industrial noise affecting mixed residential and industrial areas"; this suggests that an industrial plant is likely to receive complaints about noise if it is responsible for a rise in noise level of 10dB(A) above background but not if the noise level rise is less than 5dB(A) above background. It is likely that the noise measured at the nearest point of habitation to a new plant will have to satisfy both these sets of criteria to gain approval. The night time limit may restrict the use of diesel front end loaders operating in outside areas.

Another limit on operating hours could come from restrictions on the night time use of Heavy Goods Vehicles (HGV). Gloucestershire County Council are proposing a 9 hour night time curfew on HGV movements within the Cotswolds AONB [123] and similar measures could be adopted in other populated rural areas.

These restrictions mean that delivery and stock pile operations may be limited to daytime and evenings only.

If a plant only receives a few truck loads of woodchip a day the handling plant become relatively simple. A self unloading truck dumps its load in a loading bay; a front end loader is then used to transfer the wood into a stock pile or a buffer hopper. The buffer hopper is either in the form of a silo with a screw feeder or a rectangular hopper with a drag link feeder in its base. The front end loader is used to top up the hopper from the stock pile as required. If the delivery rate is such that it cannot be handled by a front end loaded more complex plant system should be considered. Toft carried out a detail analysis of the requirements for such a plant [81-82]. The basic processes are described in Table 4.1.

Table 4.1 Requirements for a woodchip handling plant

Stage	description	sizing criteria
reception	the trucks must be weighed on entry and exit and load sampled	should not cause a bottleneck for deliveries
unloading	self unloading or truck tipper	fast enough to avoid large number of trucks unloading at same time
screening for objects	non wood objects can damage the handling equipment	more of a protection issue than a capacity one
screening for size	oversized wood can cause blockages in chutes and conveyors	between 5% and 30% of flow [93]
stocking out	the plant will need to have a reserve stock pile to cover times when it does not receive deliveries	the stocking out rate should equal the reception rate
reclaiming	taking woodchips from the stock pile to the dryer hopper	the reclaim rate must be more than the pyrolysis plant consumption rate
dryer hopper	needed to provide a constant supply of woodchip to the dryer	will need to hold sufficient wood chip to cover times when reclaiming plant not operating
dryer	to reduce the moisture content to an acceptable level for fast pyrolysis	sized for 50% in 8% out (see section 4.3.1.3)
grinder hopper	act as a buffer between the dryer which operates 24h a day and the grinder which may have noise limitation on operating times	sized to hold the dryer output during the grinder non operating period
grinding	a hammer mill or tub grinder is used to reduce the woodchip to dust	typically require to reduce 25 mm chip to <2 mm
pyrolysis hopper	to provide feed to the pyrolysis plant when the grinder is not operating	sized to hold the pyrolysis plant's requirement during the grinder non operating period

A number of items in Table 4.1 are sized to take into account restrictions on plant operating hours that it is assumed will be placed on a plant as part of the planning process. Others are sized to deal with the volume of material delivered in a truck load. These constraints mean that the plant items in the feed handling and preparation plant do not scale directly with the capacity of the pyrolysis plant.

There are a number of wood burning power stations operating in the USA. The equipment costs of the systems used to handle chipped wood have been investigated by Badger [93] and Antares [121]. The operational strategies of these plants have been examined and an alternative one that is suitable to UK conditions has been proposed.

4.1.1 Operating philosophy

The US wood handling plant appears to be designed to be operated as a simple stream as outlined in Table 4.1 [93]. However this involves an element of double handling. If the pyrolysis plant is designed to be operated at all times (base load) it will consume a considerable fraction of the day's deliveries within the delivery day. This means that some deliveries can be routed directly to the buffer hopper that feeds the plant thus avoiding double handling. If a plant has a 12 hour delivery day and a dryer hopper capacity of 9 hours it could take up to 21 hours requirement of woodchips directly from the trucks to the buffer hopper (assuming well spaced deliveries). This would account for up to 62% of the deliveries. If the plant is configured so that it can bypass the stock pile it has three logically exclusive modes of operation:

- From unloading station direct to dryer hopper;
- From unloading station to stock pile;
- From stock pile to dryer hopper for the feed preparation plant (possibly via unloading station).

The fact that these are mutually exclusive operations can be exploited when considering staffing levels and equipment provision.

4.1.2 Storage Capacity

The US plants mainly use wood that is derived from forestry residuals left over from logging operations and wood waste from processing plants as fuel. Normally this will need to be transported from its source soon after it has been produced. Logging operations are carried out throughout the year but will be interrupted by periods of bad weather; consequently the US plants have several weeks' fuel storage on site. This leads to having large wood piles managed by front end loaders and bulldozers.

The situation with Short Rotation Coppice (SRC) willow is different. It is desirable to harvest this crop during the winter to minimise its alkali metal content, green matter contamination and moisture content. Consequently a strategy that required the woodchips to be transported as the crop was harvested would lead to a seasonal peak in the demand for trucks which would result in poor utilisation of the truck fleet. It has also been found in Sweden and the UK that the moisture content of stored woodchip reduces with time [85,157]. A truck carrying seasoned woodchips with a moisture content of 30% will transport 40% more dry mater than it would do carrying green woodchips with a moisture content of 50%. Consequently transport cost can be reduced if woodchips are stored near their harvest site. This means that the storage requirement at the pyrolysis plant will be limited to the longest period that supplies may be interrupted. There are likely to be planning restrictions on truck movements at weekends and Bank Holidays so in practice the on site store should hold between 3 and 5 days of fuel.

This storage capacity will be split between a stock pile where the woodchips are placed then retrieved for use later and a buffer stores which feeds the plant.

4.1.3 Plant size

4.1.3.1 Simple systems

Simple systems of loading bays, stock piles and plant hoppers filled by front end loaders are limited by the time it takes for a front end loader to stock out a truck delivery. The basic operation modes of such a system is shown in Figure 4.1. As will be shown in Section 6.2.1 the lowest cost method of woodchip delivery is in $120m^3$ trailers. Badger [93] quotes a 9 m^3 bucket size for a typical front end loader; this would take at least 14 operations to shift $120m^3$ of woodchip (in practice it will not be possible to fill the bucket on every trip to the stock pile). So if it takes 5 minutes to manoeuvre the truck in the unloading bay, 10 minutes to unload it and a further 15 minutes to move the woodchips to the stock pile (assuming that stock pile management can not go on at the same time as truck unloading) it looks like a simple loading bay operation could cope with up to 2 deliveries an hour. One on site weighbridge should be able to cope with this level of deliveries.

In practice it can not be assumed that trucks will arrive equally spaced throughout the day. Badger [93] and Toft [82] both quote a design guideline of allowing for 50% of a days delivery to take place in 30% of the available day. This can be restated as: the day's deliveries will be 60% of those that could have been made in the day if there was an endless supply of trucks. The length of the delivery day will depend on any delivery restrictions on the pyrolysis site and practical limitations on the loading hours at the field store which is supplying the woodchips. If loading can only be carried out during daylight the delivery day from any one store will be 8 hours. If all the deliveries for the day came from the same field store this would give an equivalent delivery day of 4.8 hours with the plant working at maximum rate.

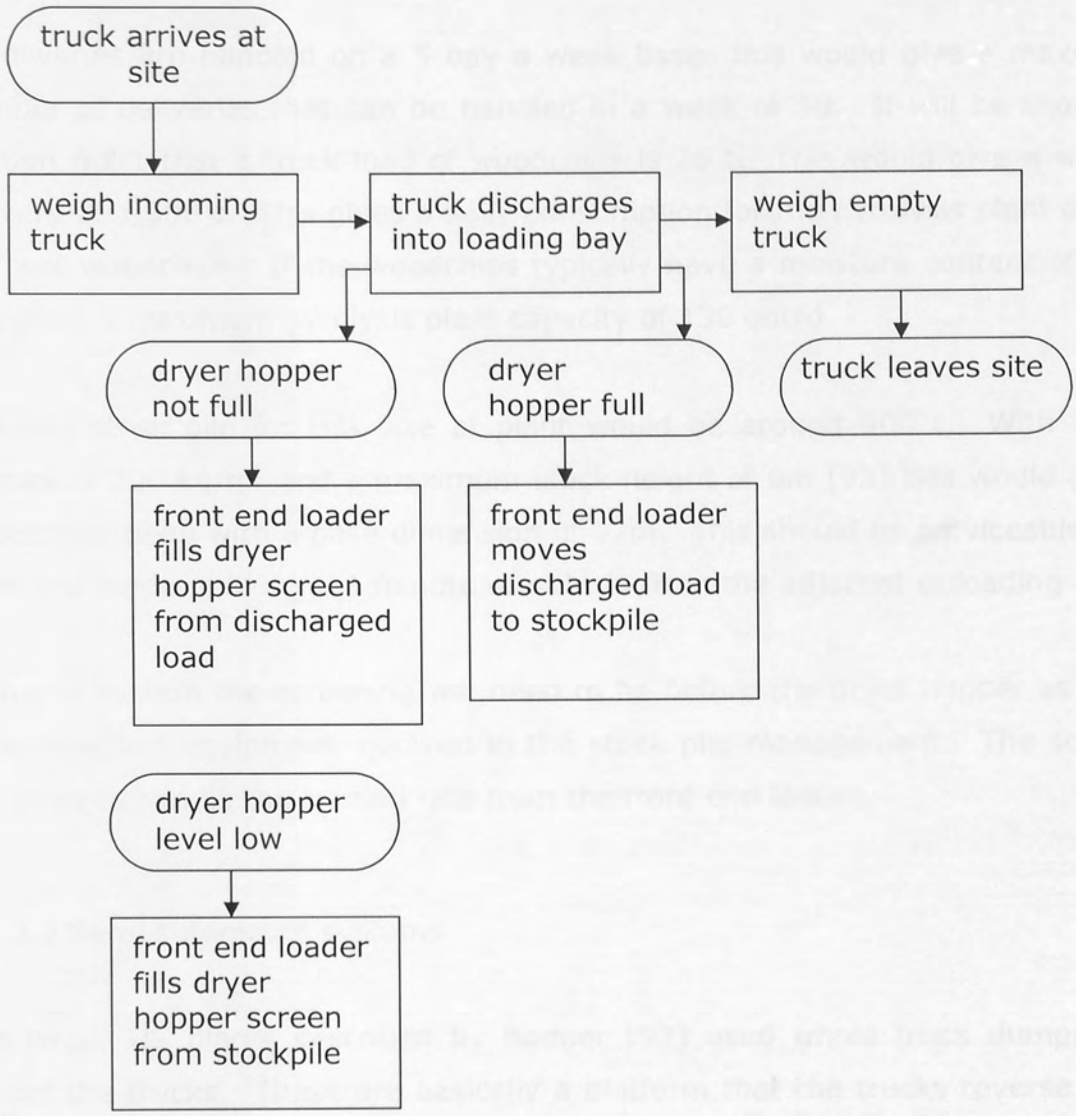

Figure 4.1 Operation of a simple woodchip handling plant

If deliveries are handled on a 5 day a week bases this would give a maximum number of deliveries that can be handled in a week of 50. It will be shown in Section 6.2.1 that a truck load of woodchips is 26 t. This would give a weekly delivery of 1,300 t. This gives a daily consumption for the pyrolysis plant of 186 t of wet woodchips. If the woodchips typically have a moisture content of 30% this gives a maximum pyrolysis plant capacity of 130 odt/d.

A 5 day stock pile for this size of plant would be around 900 t. With a wet density of 220 kg/m^3 and a maximum stack height of 6m [93] this would give a trapezoidal heap with a base dimension of 32m. This should be serviceable by a front end loader making a 1 minute round trip from the adjacent unloading area.

With this system the screening will need to be before the dryer hopper as there is no handling equipment involved in the stock pile management. The screens are sized to handle the loading rate from the front end loader.

4.1.3.2 Semi automated systems

The larger US plants described by Badger [93] used whole truck dumpers to unload the trucks. These are basically a platform that the trucks reverse on to which then tilts up at an angle of 75° allowing the load to fall out the rear tailgate of the trailer into a hopper. This system allowed standard trucks to be unloaded in a reasonable time, typically 5 minutes. The other advantage of this system is that standard truck trailers can be used; this is particularly relevant if wood waste is being purchased from a wide number of sources. It is less relevant if there is a dedicated fleet of trucks servicing the plant. Using costs from [93] it appears that it is possible to purchase 38 walking floor self unloading trailers for the costs of one truck tipper. Assuming that each truck does two round trips a day between the pyrolysis site and a field store it would be possible to deliver 2000 t a day of woodchips to a site with 38 trucks. A single truck tipper is unlikely to unload more than 1200 t of wood a day once allowances are made for truck manoeuvring time and spacing of deliveries. Consequently it would appear to be economic to invest in self unloading trailers rather than whole truck dumpers.

In cases where the delivery rate exceeds the capacity of a front end loader driver to manage, the self unloading trucks can unload into ground hoppers with drag link feeders. The basic arrangement is shown in Figure 4.2. The drag link feeders discharge on to a common conveyor which feeds a screening plant. The screening plant feeds a bidirectional conveyor. In one direction this conveyor feeds the dryer hopper in the other it feeds a radial stacker that produces a C shaped triangular profile storage pile. Using the dimensions given in [93] a radial stacker's pile could hold up to 550 t of wet woodchip (at 30% moisture). This is smaller than the stock pile for the simple loading bay so woodchips will need to be put out to stock from the stacker's pile by a front end loader. However as the front end loader can be working one end of the pile as the stacker is building the other end it should be possible to build the stock pile while the stacker is in operation. Reclaim is by front end loader into a hopper with a drag link feeder that discharges onto the bidirectional conveyor which is now running in the other direction to transports the woodchips to the dryer hopper.

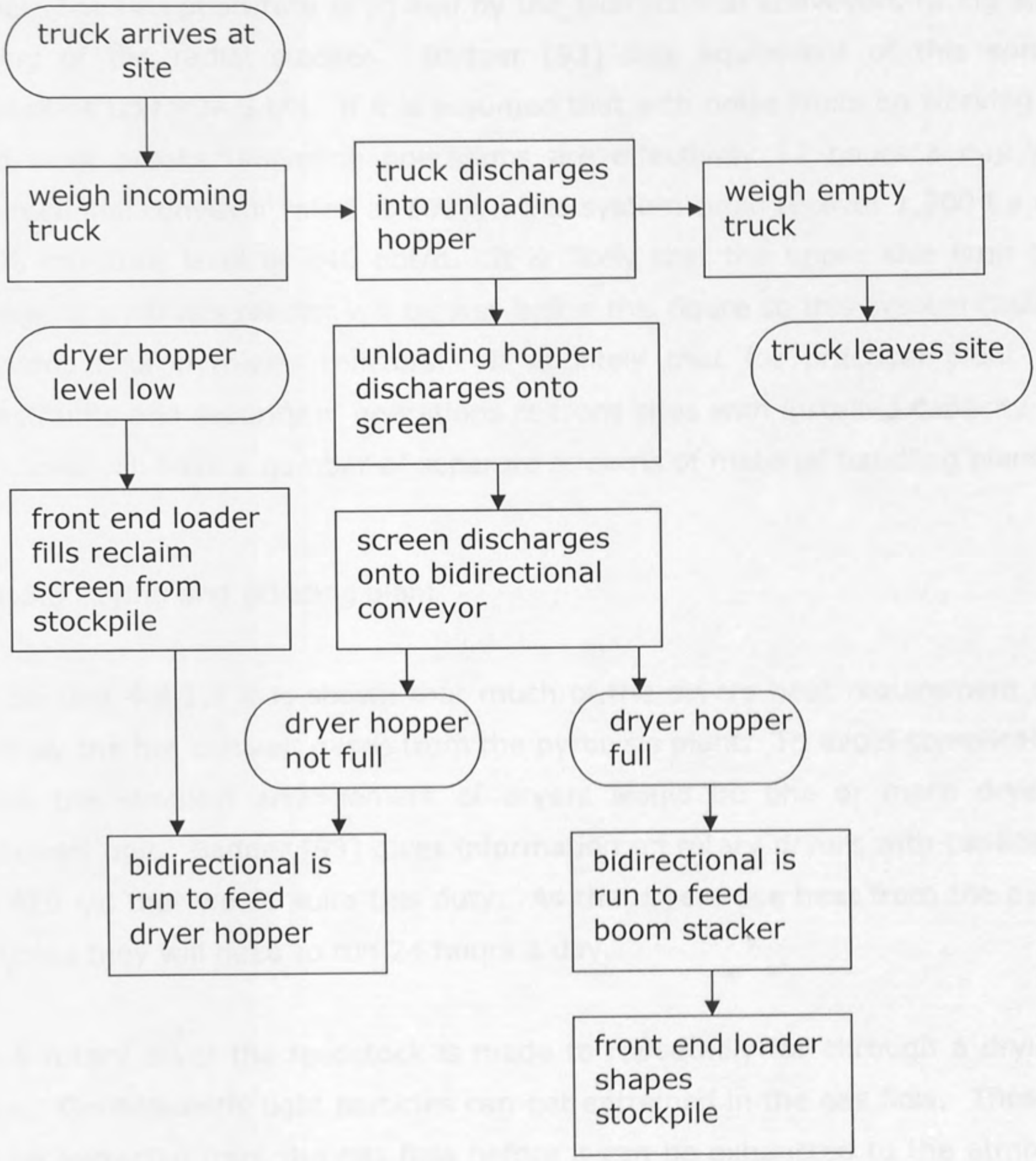

Figure 4.2 Operation of a semi automatic woodchip handling plant

This system can cope with a number of unloading hoppers operating at the same time. The reception rate is limited by the bidirectional conveyors rating and the rating of the radial stacker. Badger [93] lists equipment of this sort with capacities up to 98.5 t/h. If it is assumed that with noise limits on working times and work breaks unloading operations are effectively 12 hours a day with a bidirectional conveyor rated at 100 t/h this system could recover 1,200 t a day at 30% moisture level or 840 odt/d. It is likely that the upper size limit to any design of pyrolysis reactor will be well below this figure so this system could feed a number of pyrolysis reactors. It is likely that for practical plant layout constraints and security of operations reasons sites with installed capacity above this level will have a number of separate streams of material handling plant.

4.1.3.3 Drying and grinding plant

In Section 4.4.1.5 it is shown that much of the dryers heat requirement can be met by the hot exhaust gases from the pyrolysis plant. To avoid complicate duct work the simplest arrangement of dryers would be one or more dryers per pyrolysis unit. Badger [93] gives information on rotary dryers with capacities up to 410 t/d that would suite this duty. As the dryers use heat from the pyrolysis process they will need to run 24 hours a day.

In a rotary dryer the feedstock is made to repeatedly fall through a drying gas flow. Consequently light particles can get entrained in the gas flow. These need to be extracted from the gas flow before it can be exhausted to the atmosphere either by a cyclone or a bag filter. This effect would preclude the use of rotary dryers on ground feedstock; consequently the dryers are place before the grinders in the feed preparation chain.

Biomass is normally reduced to the size required by pyrolysis plants in hammer mills or tub grinders. These work by percussive action and so are inherently noisy. Consequently they may not be run at night. This means that the woodchips from the dryer discharge will need to be stored in a hopper or silo for the time when the hammer mills cannot be used. Likewise the pyrolysis reactor feed silo will need to have sufficient material in it to allow the pyrolysis reactor to keep running with the mill shut down. A 200 odt/d pyrolysis reactor converts 217 t of wood with a 8% moisture level. If the mill is run for 12 hours a day it would need to be rated at 18 t/h. CPM supply grinders for wood pelleting plant with though puts from 1 to 30 t/h [125] so there should no problems is getting suitably sized grinders.

4.1.4 Possible installations

It is possible to use the information in Section 4.1.3 to size suitable woodchip handling and pre-processing plants for a range of pyrolysis sites. This has been done in Table 4.2.

Table 4.2 Equipment sizes for woodchip handling and pre-processing plants for a range of pyrolysis sites

size	odt/d	50	100	150	200	400	600	800
number of reactors		1	1	1	1	2	3	4
wet woodchips	t/d	91	182	273	364	728	1091	1455
truck loads		5	10	15	20	40	59	79
rate	trucks/h	0.7	1.4	2.1	2.8	5.6	8.2	11
unloading hoppers		0	0	1	1	2	2	3
stock out rate	t/h	0	0	38	51	101	152	202
reclaim rate	t/h	60	60	60	120	120	120	120
reclaim time	h	1.5	3	4.6	3	6.1	9.1	12.1
dryer silo	t	35	69	103	137	137	137	137
dryer size	t/h	3.8	7.6	11.4	15.2	15.2	15.2	15.2
grinder silo	t	41	82	82	109	109	109	109
grinder size	t/h	9.1	18.1	13.6	18.1	18.1	18.1	18.1
pyrolysis silos	t	41	82	82	109	109	109	109

Table 4.2 has been drawn up on the following assumptions:

- The maximum size of pyrolysis reactor has been assumed to be 200 odt/d;
- The system is sized for woodchips with a 45% moisture level as this is likely to be the top end of the acceptable moisture range;
- Each truck is assumed to carry 26 t of wet woodchips;
- Sites with less than 2 deliveries an hour do not need a semi automated stocking out system;
- The sites with less than 200 odt/day demand are assumed to use a 4.5m^3 bucket front end loaders those with 200 odt or more are assumed to use ones with a 9m^3 bucket;
- The systems are configured so that there is one dryer and one grinder per pyrolysis unit;

- The buffer storage between processing stages is in the form of steel silos that are fed by inclined conveyors and emptied by auger conveyors mounted in the base of the silos;
- The dryer silo is sized to supply the dryer for 9 hours when the woodchip handling plant is shut down;
- The grinders are assumed to operate for 6 hours a day on the 50 and 100 odt/d sites and 12 hours a day on the other sites;
- The grinder silos are sized to store the output from the dryer for the time that the grinders are not operating;
- The pyrolysis silos are sized to supply the pyrolysis reactor for the time that the grinders are not operating.

It is recognised that these plants have been sized to fit a hypothetical set of operating constraints and other arrangement could be equally valid.

4.1.5 Electrical power requirement for woodchip pre-processing

Drying and grinding operations use considerable amounts of electrical power. Badger [93] reports that rotary dryers consume on average 20kWh of electricity for each odt of feed processed. He also gives loads for hammer mills but as these are used to reduce oversized wood to chip size they may not be representative of the power needed to reduce woodchips to sub 2 mm particles suitable for use in a pyrolysis reactor. A major supplier of wood pelleting plants estimates that it takes 15kWh/t to grind woodchips (with 10% moisture content) to sawdust [125]. As wood pellets are made from small particles this is likely to be a reasonable estimation of the requirements for a pyrolysis plant. The values of the electrical power required by the feeders and conveyors identified in Table 4.2 have been estimated from data in [93]; there appears to be a considerable reduction in the power required by conveyors as their size increase this was also noted in [86]. The estimated loads for the complete woodchip handling plants are listed in Table 4.3.

Table 4.3 Electrical energy requirements of woodchip handling and pre-processing plants

size	odt/d	50	100	150	200	400	600	800
conveyors	kWh/odt	8	4	4.5	3.4	1.8	1.3	1.1
milling	kWh/odt	15	15	15	15	15	15	15
drying	kWh/odt	20	20	20	20	20	20	20
total	kWh/odt	43	39	39.5	38.4	36.8	36.3	36.1

4.2 Miscanthus handling plant

Although the suitability of miscanthus as a feedstock for fast pyrolysis has been established in the laboratory there are no published techno-economic studies of fast pyrolysis using this feedstock. The use of miscanthus in various industrial applications has been examined, it has been used in industrial combustion trials carried out at Elean Power Station [126] and has been shown to be similar to straw in handling and combustion characteristics. Straw has been burnt in a bubbling fluidised bed combustor [127] so it can be concluded that miscanthus can be used in an industrial scale bubbling fluidised bed pyrolysis reactor. Researchers into the potential of using miscanthus in fibre boards have reported that chopping and hammering of miscanthus is straight forward [130] which also implies that it can be readily processed.

Miscanthus is less dence than wood and it has a lower moisture content provided it is harvested well outside its growing period (this is normally preferred for power generation purposes as the alkali metal content also reduces during the winter period) [129]. DEFRA recommend that miscanthus is harvested then stored in commpressed bales. As there is a relatively short harvesting period most of the harvested crop will need to be stored before it is used. This can be in a field store, at an intermediate store or at the pyrolysis plant.

The direct use of off site pelletised miscanthus will not be investigated as from a techno-economic point of view the plant will be similar to that required for low moisture content SRC woodchips.

4.2.1 System Description

It is assumed that the government guidelines for planting and growing miscanthus [129] has been followed and that the miscanthus is gathered in large "Hesston" bales that weigh around 0.5 t (assuming a moisture content around 20%). The miscanthus can be stored on site as bales before it is needed. The bales need to be split and the miscanthus shredded before it is dried. The shredded miscanthus is light so it is not suitable for use in a rotary dryer so it is proposed that band dryers are used instead. Miscanthus handling and pre-processing will suffer the same delivery and operating hour constraints as the woodchip plants discussed in Section 4.1.1.

The maximum delivery which can be made in a flat bed truck towing a draw bar trailer is 36 bales (around 18 t). As with woodchip the reception plant has to be sized to clear the incoming trucks in an acceptable time.

Feasibility studies on baled feedstock handling for biomass to ethanol and a 200,000 ton / year straw co-firing scheme in Chariton Valley Iowa has been carried out in the US [131-132].

The Chariton report includes the results of a trial where the trucks were unloaded in a loading bay using a forklift truck taking 3 bales at a time. The bales were restacked in a storage barn. This achieved an average unloading rate of 15 minutes for 24 bales. This would correspond to 22.5 minutes for a 36 bale load. Trucks would need time to get into and out off the unloading bay so it is unlikely that such a system could cope with more than 2.2 trucks an hour which gives a delivery rate of 40 t/h.

The unloading rate was achieved by unloading 3 bales at a time. Although this may be acceptable for unloading a truck it is unlikely that the conveyor transporting bales to the pre-processing plant will handle bales piled 3 high on it. Consequently there is not the option to directly feed the plant from the truck. If it is assumed that the time to take 1 bale from the store area to the plant conveyor is the same as that required to unload 3 bales from the truck loading 1 bale at a time onto a conveyor one loader driver could recover 32 bales an hour or 16 t/h. The operation modes of a forklift truck based system is shown in Figure 4.3.

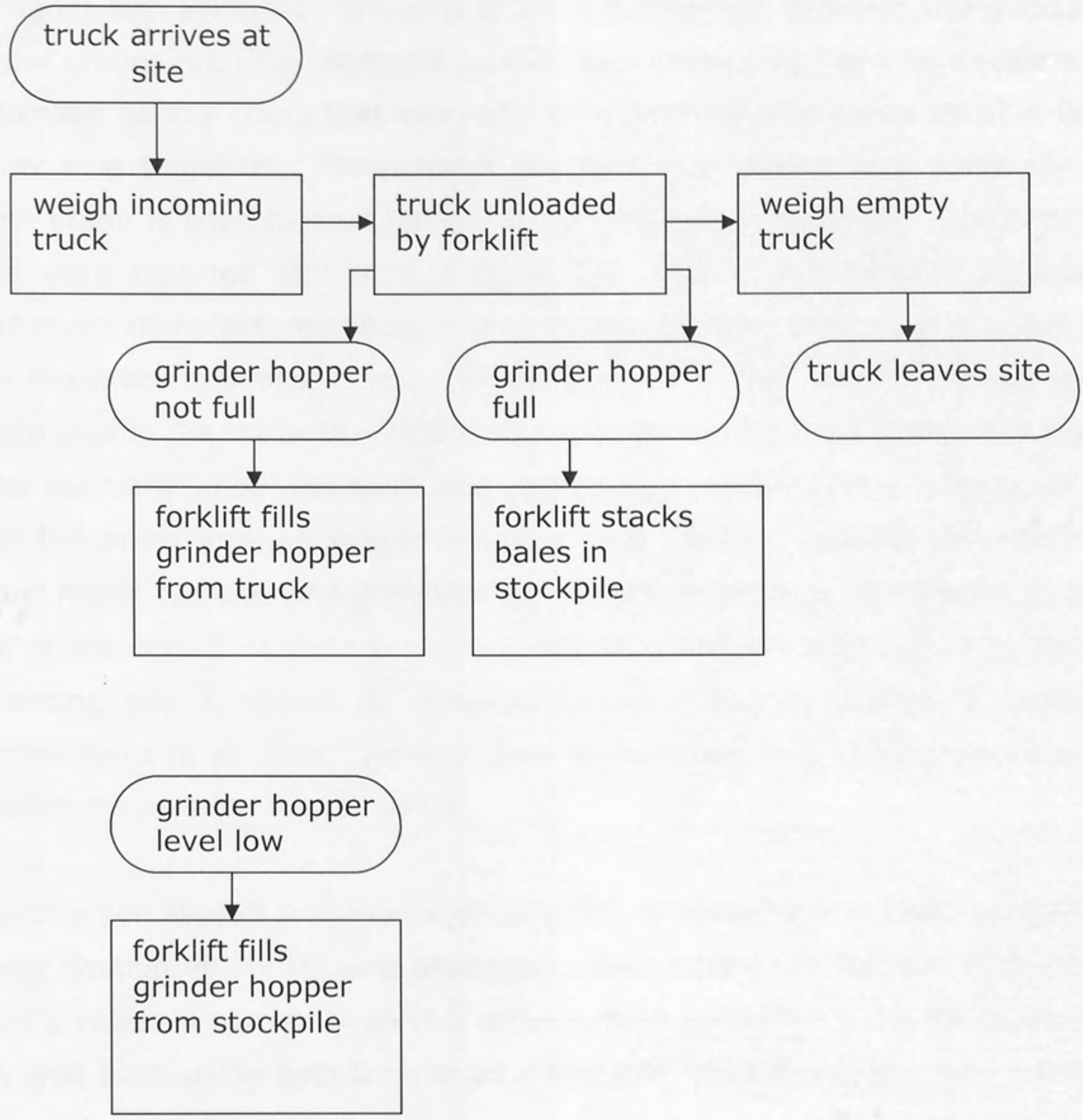

Figure 4.3 Operation of a simple baled miscanthus handling plant

If higher unloading or recovery rates are required systems using automatic gantry cranes are use. In these system each unloading bay is equipped with an automatic gantry crane that can take a layer of Hesston bales off of a flat bed trailer at a single lift. These bales are then routed to a local stock pile. The same crane is used to load the conveyor that feeds the plant. Systems of this type were reported as having a cycle time of 6 to 7.5 minutes although the equipment manufacture's thought that this could come down to 5 minutes [132]. The maximum practical number of Hesston bales that can be transported in a single load in the UK is 36. This is achieved by having a flat back truck towing a draw bar trailer, both the truck and trailers load platform carry 3 layers of bales, with the bales arrange lengthwise in 2 rows [201]. Consequently each cycle would move 12 bales and the truck would take 3 cycles or 18 minutes to unload. If it is assumed that the truck driver will un-sheet the load before entering the unloading bay it should be possible for each bay to unload 3 truck/trailer combinations in an hour. As each bale is nominally 0.5 t this gives each bay a maximum reception rate of 54 t/h.

The Chariton study's proposed system [132] is based on the installation at Elean Power Station in the UK and Studstrup Power Station in Demark both of which have 2 reception bays. With this arrangement deliveries could be handled on a day shift basis using both bays or on a two shift basis if only one bay is available.

The Chariton study assumes that trucks arrive at the plant and unhitch their trailers in a buffer park, the truck then picks up a freshly unloaded trailer. The trailers are then hitched to a separate plant based tractor which moves them into an unloading bay when it becomes available. This arrangement reduces the waiting time for the trucks, maximises the throughput of the un-loading bays, and ensures that only truck drivers that are familiar with the process use the automatic equipment. At Elean the straw is supplied by a single contractor who manages the logistics and uses a dedicated fleet of trucks [126,128].

The automatic crane is used to retrieve bales from the store and place them on a feeder conveyor which transports then to the boiler.

In the case of a pyrolysis plant the automatic cranes would recover the bales to feed the grinder feed conveyor. As the same equipment is used for stocking out and reclaim the reclaim rate equals the stocking out rate i.e. a maximum of 54 t/h. A diagram of the operation modes of system is shown in Figure 4.4.

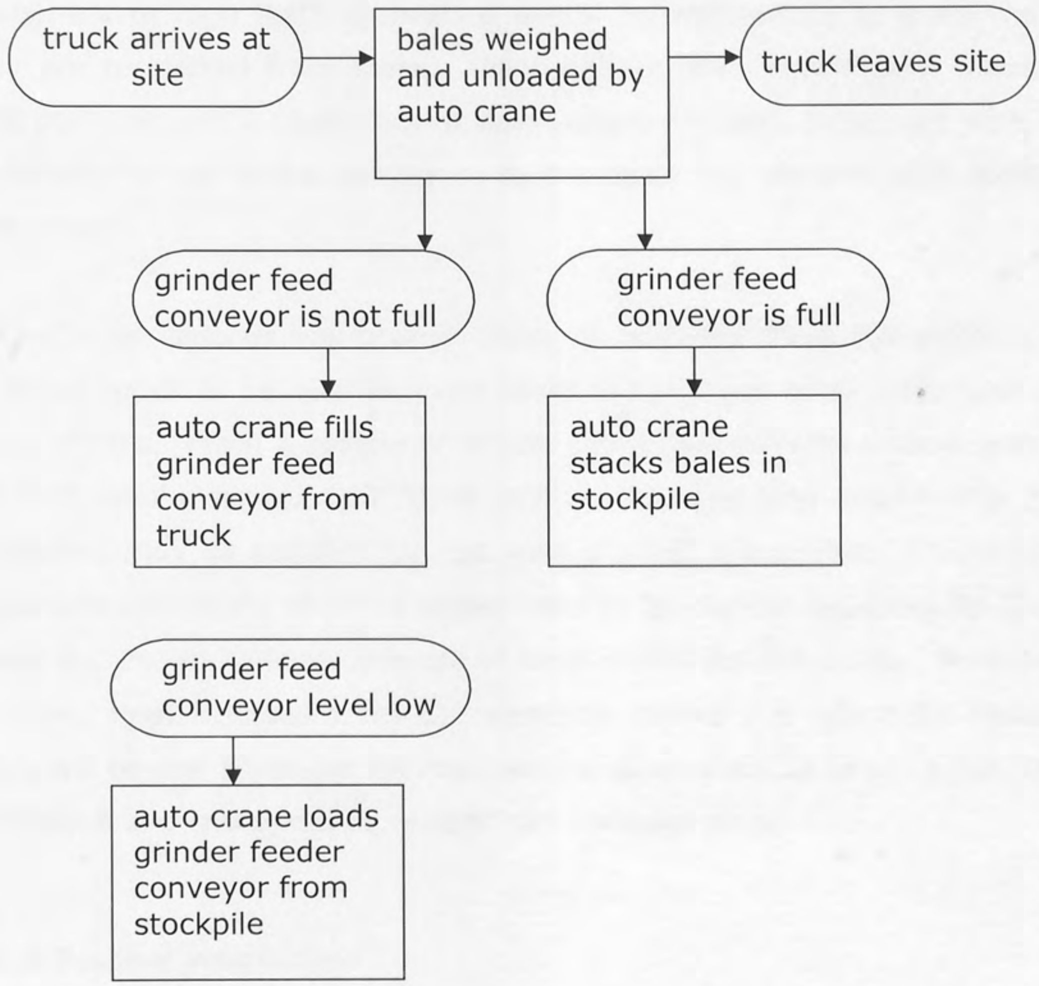

Figure 4.4 Operation of an automatic baled miscanthus handling plant

As mentioned earlier the bales need to be shredded before the miscanthus can be processed. The Hess study into producing ground straw as a feedstock [133] included reports of field trial carried out with Diamond Z 1352L tub grinders grinding bales of barley straw. A feed rate of 26 ton per hour was achieved with an average particle size of 1.7 mm which would be suitable for use in a fluidised bed pyrolysis reactor. Given that whole bale handling requires complex equipment or high staffing levels it would be appropriate to grind the bales as they are recovered from store. Once ground the miscanthus is likely to have light particles which could form a dust hazard on open conveyors so it would be preferable to use screw conveyors to transport the material and buffer silos to hold it in.

Once the miscanthus has been reduced to particles these will need to be dried. As straw tends to be relatively dry there is not much experience with operating straw dryers. From a review of dryers types that may be usable with gasifiers [161] it would appear that band dryers, fluidised bed dryers and pneumatic conveyors may be suitable for use with ground miscanthus. Fluidised bed and pneumatic conveying systems would need to be custom designed for the plant so it was decided to consider the use of band dryers for this study. As the dryer will be using heat rejected from the pyrolysis reactors it has been assumed that there will be one dryer per reactor. As the dryer runs 24 hours a day the hopper between it and the pyrolysis reactor can be quite small.

4.2.2 Possible installations

It is possible to use the information in Section 4.2.1 to size suitable miscanthus handling and pre-processing plants for a range of pyrolysis sites this has been done in Table 4.4.

Table 4.4 Equipment sizes for miscanthus handling and pre-processing plants for a range of pyrolysis sites

size	odt/d	50	100	150	200	400	600	800
number of reactors		1	1	1	1	2	3	4
moisture		0.25	0.25	0.25	0.25	0.25	0.25	0.25
daily consumption	t/d	67	134	200	267	534	800	1067
daily stock out		26.8	53.6	80	106.8	213.6	320	426.8
delivery	t/d	94	188	280	374	748	1120	1494
loads	trucks	6	11	16	21	42	63	83
delivery day	h	7.2	7.2	7.2	7.2	7.2	7.2	7.2
rate	trucks /h	0.8	1.5	2.2	2.9	5.8	8.8	11.5
manual bays		1	1	1				
auto bays					1	2	3	4
grind hours		6	6	12	12	12	12	12
grinder size	t/h	11.2	22.3	16.7	22.3	22.3	22.2	22.2
dryer silo storage time	h	18	18	12	12	12	12	12
dryer silo size	t	51	101	100	134	134	134	134
dryer size	t/h	2.8	5.6	8.3	11.1	11.1	11.1	11.1

Table 4.4 has been drawn up on the following assumptions:

- The maximum size of pyrolysis reactor has been assumed to be 200 odt/d;
- The system is sized for miscanthus with a 25% moisture level as bales with moisture levels much above this are liable to rot;
- Each truck is assumed to carry 18 t of baled miscanthus;
- Automatic unloading facilities are installed in sites with delivery rates above 2.2 trucks an hour;
- The automatic unloading cranes include weigh recording systems. Weighbridges are installed on the smaller plants without automatic cranes;

- The systems are configured so that there is one dryer per pyrolysis unit and one grinder per reception bay;
- The grinders are assumed to operate for 6 hours a day on the 100 and 150 odt a day sites and 12 hours a day on the other sites;
- The dryer silos are sized to supply the dryers for the time that the grinders are not operating.

It is recognised that these plants have been sized to fit a hypothetical set of operating constraints and other arrangement could be equally valid.

4.2.3 Electrical power requirement for miscanthus pre-processing

The mobile tub grinder used the study for a proposed bio-refinery in Idaho [133] use diesel engines. The trials on straw found that they required of 35.4 kWh of diesel fuel per ton of straw ground. This would correspond to 39 kWh/t. In a fixed installation the grinders would be power by electric motors, if the diesel engine is assumed to be 40% efficient and the electric motor 80% efficient the grinding energy would be 20 kWh_e/t. The tests were carried out on straw with a moisture content of 11% so this corresponds to a grinding energy of 22.5 kWh/odt.

In his review of dryers Brammer [161] quotes a band dryer with a throughput of 1.5 odt/hr of having a power consumption of 60 kW. The reference performance data for this dryer was for woodchip with an inlet moisture level of 50% and an exit level of 15%. This data was used to calculate the water removed by the dryer. This was then used to calculate the mass flow of miscanthus that required the same mass of water to be evapourated. It was found that a dryer which can dry an input of 1.51 t/hour of woodchip can dry 4.67 t/hour of miscanthus with a moisture content of 25% to 8%.

The situation is more complicated than this simple calculation suggest in that the biomass needs to be heated up before any drying takes place, different materials have different drying characteristics and a faster throughput will require more energy to drive the band. However in the absence of performance data for the dryer on miscanthus a figure of 13 kWh/odt will be assumed for the dryer power.

The Chariton study [132] states that for a twin bay system that the installed drive capacity for the manual system is 3,563 Hp and that for the auto system is 3,883 Hp i.e. each bridge crane has 160 Hp (120 kW) of drives on it. As the system can handle 54 ts per hour this would imply a crane energy of 2.2 kWh/t. However some 80% of the bales will need double handling in which case the power requirement becomes 4.4 kWh/t or 5.9 kWh/odt

Combining the grinding, drying and crane electrical energy estimate the total pre-processing electrical energy requirements for miscanthus is 41 kWh/odt.

4.3 Pyrolysis yields

Before carrying out a techno-economic evaluation of pyrolysis plants it is essential to have a realistic model that predicts the yields from the plant.
The purpose of this model is:

- To predict the energy available in the bio-oil produced from a range of biomasses that the plant could use;
- To predict the energy available in the pyrolysis gases and char that are by-products of the production of bio-oil;
- To estimate suitable limits for use in sensitivity analysis.

4.3.1 Mass yield calculation

4.3.1.1 Biomass composition

The chemical composition of the biomass may differ for a number of reasons including:

- Varity planted;
- Time in storage;
- Maturity of plantation;
- Soil contamination of the harvested crop;
- Fertilizer application;
- Residual green mater when harvested, ideally energy crops should be harvested in their dormant fully senescent state but there is a possibility that some leaves will end up in the harvested crop.

Consequently it is necessary to consider the range of feedstock that is likely to be available to any proposed plant.

It is possible to find fast pyrolysis yield data from laboratory test on a range of both woody biomass and grasses. Unfortunately there has not been any fast pyrolysis data on coppiced willow published. SRC willow produces wood chips from the whole of the tree i.e. the tops, side branches, twigs and bark. This means that producing a representative sample is not a trivial mater. In an examination of Swedish standing coppice willow [134] it was found that the bark proportion varied between 56% for twigs to 15% for 5 year old growth with an average of 19% across the complete stand. 3 years is often quoted as the cropping period for willow, wood of this age and under was found to have 34% of its dry matter as bark. The proportion of bark is significant as the ash content of the bark is in the region of 4.1 - 4.8 % where that for the hart wood is 0.9 - 1.0 %.

This would give an ash content in the range 1.6 - 2.9 % depending on the thickness of the wood when harvested and the amount of thin wood that is included with the woodchips. This spread is reflected in the analysis of various willow samples in Table 4.5.

The ash content of miscanthus depends on when it is harvested. This due to the effect of leaf drop and the leaching of alkali metals if the crop is left to winter in the field before harvesting.

Details of the elementary composition of a number of samples of willow and miscanthus have been taken from ENC Laboratories on line database [135] are shown in Table 4.5.

Table 4.5 elementary composition of energy crops

		Dry basis			Dry ash free				
feedstock	Ash	C	H	O	C	H	O	HHV MJ/kg	ref
miscanthus low k	1.10%	0.49	0.06	0.44	0.50	0.06	0.44	19.62	[136]
miscanthus giganteus	1.60%	0.48	0.06	0.44	0.49	0.06	0.44	19.88	[137]
miscanthus silbefeln	3.00%	0.47	0.06	0.44	0.49	0.06	0.45	19.31	[138]
average miscanthus	1.90%	0.48	0.06	0.44	0.49	0.06	0.44	19.60	
SD miscanthus	0.86%	0.009	0.003	0.002	0.004	0.003	0.005	0.29	
willow wood + bark	1.20%	0.50	0.06	0.43	0.50	0.06	0.43	19.75	[140]
willow chips >10mm	1.60%	0.49	0.06	0.43	0.50	0.06	0.44	19.60	[139]
willow tops	2.30%	0.49	0.06	0.41	0.51	0.06	0.42	19.79	[138]
willow small <2mm	2.80%	0.48	0.06	0.43	0.49	0.06	0.45	18.75	[138]
average willow	1.98%	0.49	0.06	0.43	0.50	0.06	0.43	19.47	
SD willow	0.87%	0.010	0.001	0.009	0.008	0.001	0.010	0.49	

It is clear from Table 4.5 that for both miscanthus and SRC willow wood chips the ash content will be in the range 1% - 3% and that the chemical composition of any variety of biomass is relatively constant.

4.3.1.2 Organic liquid yield

It has been shown in a number of studies that the pyrolysis organic mass yield reduces with increasing ash content of the original biomass. This is thought to be due to the alkali metals in the ash acting as a catalyst [145-147]. There is published yield data for a range of different feedstocks from laboratory scale fluidized bed fast pyrolysis rigs operating at temperatures between 450 - 550 °C carried out at NREL [147], Aston University [143], Waterloo University [144],and VTT [48] these have been plotted in Figure 4.1, 4.2, 4.4, 4.5 and 4.6. The mass yields from these studies were expressed as percentages of the dry ash free content of the biomass feed.

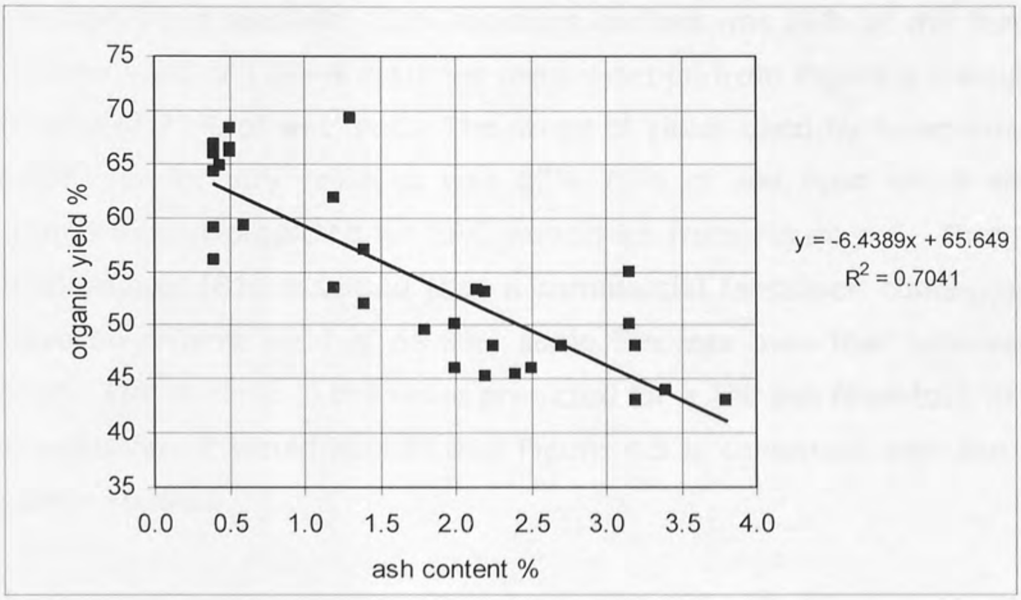

Figure 4.5 Variation of organic yield with feedstock ash content

Although Figure 4.5 uses data from different series of experiments using different species of biomass it does show a general trend that organic liquid yields reduces with feedstock ash content.

The coefficient of determination of the trend in Figure 4.5 is poor. However it is acceptable for use in this study as the requirement is for a tool that can predict how the yield changes as the feedstock ash content varies inside its specified range rather than a tool which can accurately predict the yield for a specified ash content. The coefficient of determination could be readily changed by excluding some of the data points or changing the range of ash contents considered. This was not done as it was not clear if there was a justification for excluding wayward points. From observation it appears that the true value of the organic yield could be ±5% from that indicated by the trend line. It is only possible to compare the predictions from Figure 4.5 with other studies when the ash content and feedstock moisture levels have been given. The yield used by Peacocke [86] for a 0.5% ash wood feed with 10% moisture content was 79% of wet feed. If a reaction water yield of 12% is assumed the prediction from Figure 4.5 would give a bio-oil yield of 77% of wet feed. The range of yields used by Solantausta and Huetair [88] for forestry residues was 60%-75% of wet feed which shows a similar range to that predicted for SRC woodchips from Figure 4.5. Bridgwater, Toft and Brammer [81] assumed that a commercial feedstock containing bark would have an organic yield of 59.9%, some 5% less than that achieved with white wood. This is close to the value predicted for a 1% ash feedstock in Figure 4.5. Consequently it would appear that Figure 4.5 is consistent with the values used in other studies.

4.3.1.3 Limitation on acceptable organic liquid yield

Bio-oil consists of the organic liquid, reaction water and residue moisture from the biomass. The organic yield is independent of the amount of feedstock residue moisture (provided that the feedstock has a low moisture level; if it is much above 15% it can inhibit the rate of heating of the biomass which will impact on organic yields). The reaction water yields were given in the NREL [147], Waterloo [144] and Aston [143] publications. This is shown in Figure 4.6.

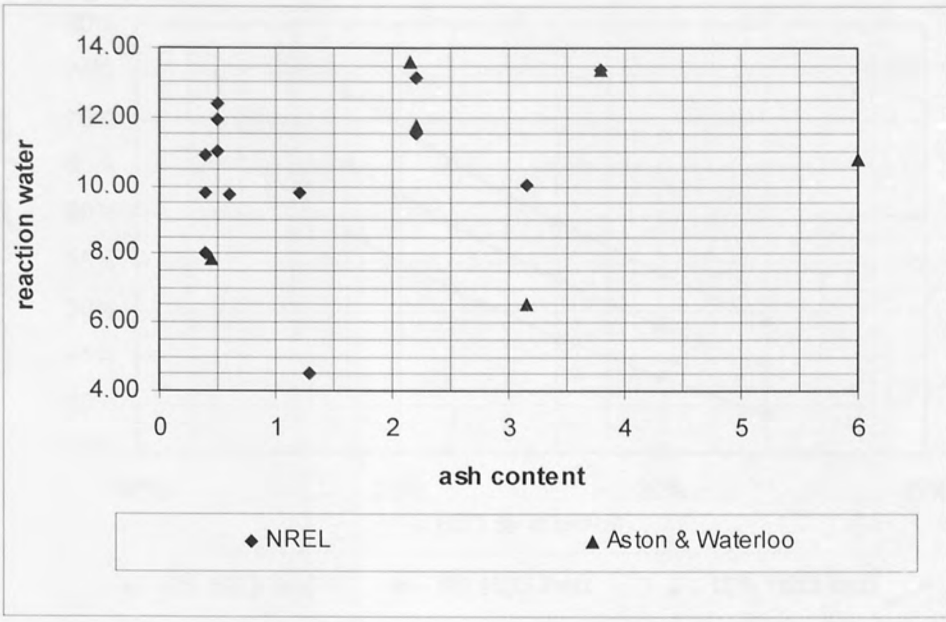

Figure 4.6 Variation of reaction water with feedstock ash content

From Figure 4.6 there appears to be no relationship between the reaction water and feedstock ash content. If a conservative estimate of 12% of the dry biomass is assumed for the reaction water yield it is possible to calculate the moisture level of the bio-oil for different organic yields at different feedstock moisture contents. This is done by assuming that the bio-oil consist of the organic liquid, all the residual moisture and the reaction water. This has been calculated for 3 feedstock moisture levels and the results plotted in Figure 4.7.

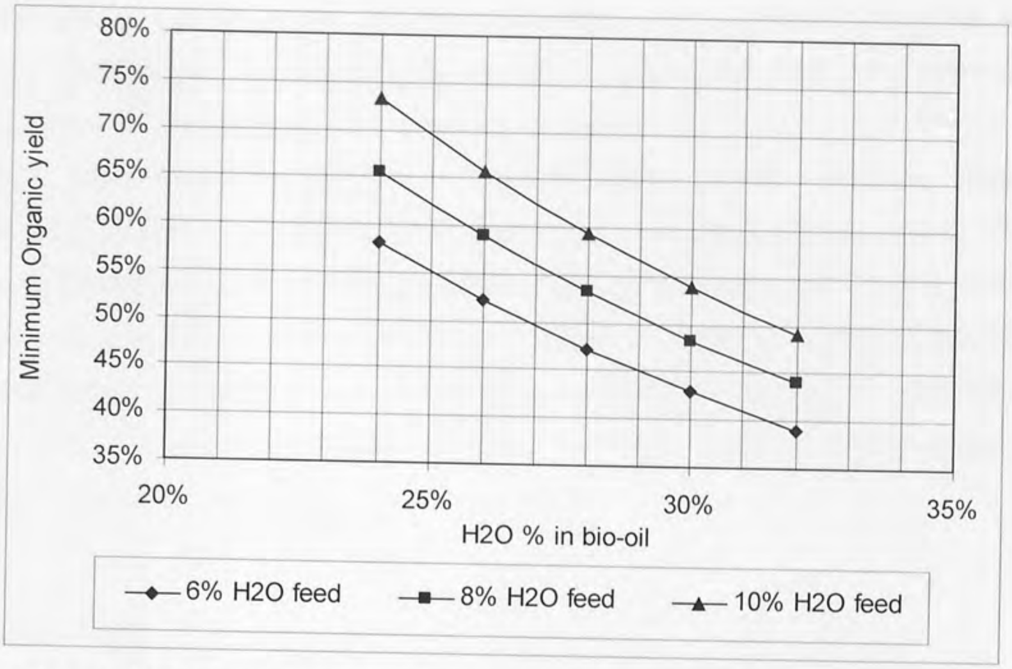

Figure 4.7 bio-oil moisture levels for different organic liquid yield

Figure 4.7 shows that a reduction in organic yield will result in an increase in moisture level of the bio-oil. This will reduce the calorific value of the bio-oil and may lead to phase separation of the bio-oil [151]. The economic impact of change in calorific value with ash content could be offset by making the biomass price vary with ash content, but an ash content that resulted in a yield where phase separation occurs should be avoided for operational reasons.
There is not yet an agreed specification for bio-oil, but a specification proposed by a working group in 1996 [149] suggested a maximum water content of 32%, however perspective engine, gas turbine and boiler suppliers recommended 25%-26% to VTT[48].

From Figure 4.5 it is possible to estimate the range of organic yields from potential energy crops to be 46% to 59%. Given this range of yields it appears from Figure 4.7 that the biomass will need to have a moisture content of less than 8% in order to satisfy the less onerous of these specifications. This is a very stringent specification for the feedstock dryer and it may restrict the use of higher ash content biomass.

In practice there will be some mixing of biomass from different sources in the plant store and the bio-oil from different days operations will be mixed in the bio-oil storage tanks (it has been shown in section (7.1.1.2), that there is an operational advantage in having a considerable bio-oil storage capacity) consequently it would be reasonable to assume an average organic mass yield of 53% of dry feed when predicting pyrolysis plant production. If an 8% moisture feed is used this will produce a bio-oil oil moisture content of around 28.5% As special fuel injection systems will need to be developed for bio-oil (see Sections 1.2.5.1- 1.2.5.3) it is reasonable to assume that they could be designed for 29% rather than the 26% requested.

4.3.1.4 Char Yield

Char yields have been reported by NREL, Aston and Waterloo [147,143,144] and these have been plotted in Figure 4.8

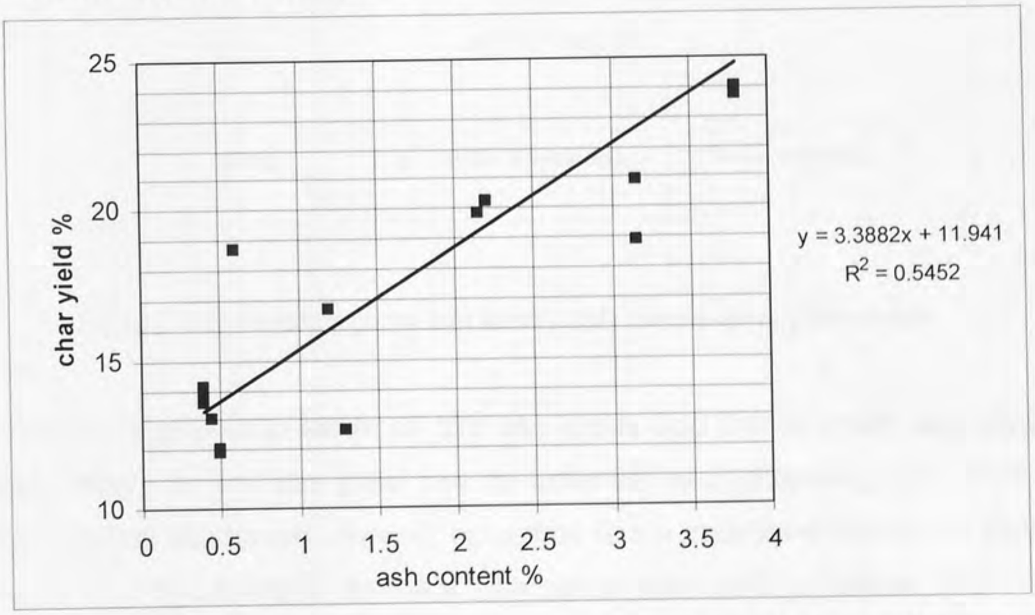

Figure 4.8 Relationship between ash levels and char yields.

Like the organics case Figure 4.8 shows a general trend rather than a strong correlation but it can be used for estimation of yields and likely ranges of yields. From observation it appears that the true value could be ±3% from that indicated by the trend line.

4.3.1.5 Gas Yield

The reported gas yields are shown in Figure 4.9

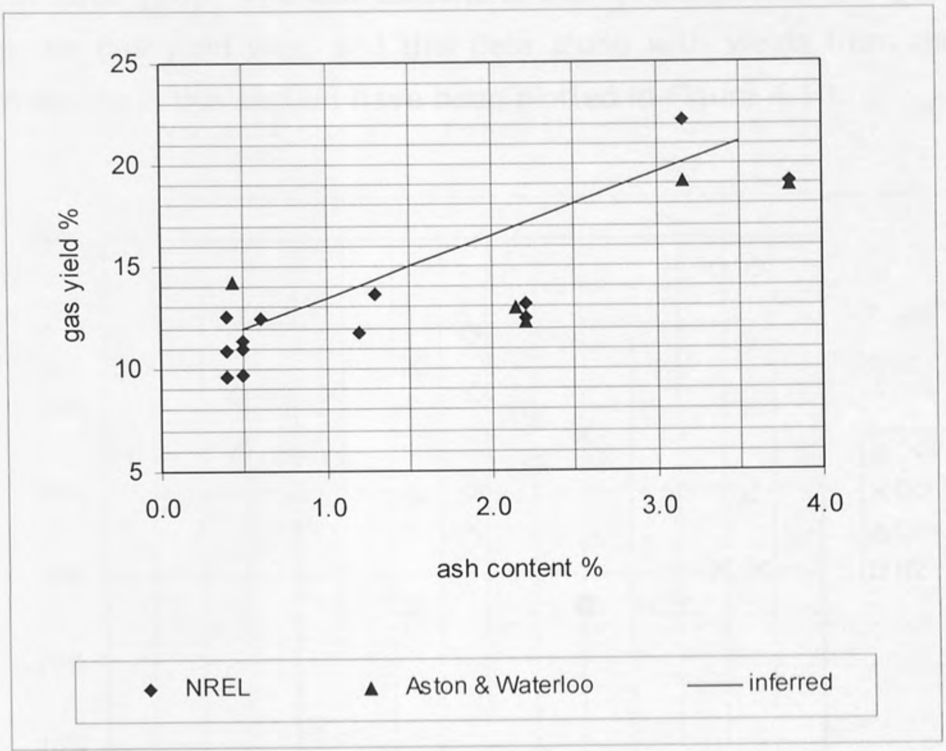

Figure 4.9 Relationship between ash levels and gas yields.

The nature of relationship between the gas yields and the biomass ash content is not clear. However the gas yield can be inferred by subtracting the other yields from the original feedstock. Having accepted linear relationships for organic and char yields and assuming a constant reaction water yield it follows that the gas yield must be linear. This inferred relationship is plotted in Figure 4.9 and it is within the spread of the reported data.

4.3.1.6 Gas Composition

Pyrolysis gas has been reported to be a mixture of carbon dioxide, carbon monoxide, and methane, with traces of hydrogen and hydrocarbon gases. Gas compositions from a number of sources were published by Bridgwater and Peacocke in 2000 [28]. The ash content of the feedstock was not given in this report but the gas yield was, and this data along with yields from the papers referred to earlier in this section have been plotted in Figure 4.10.

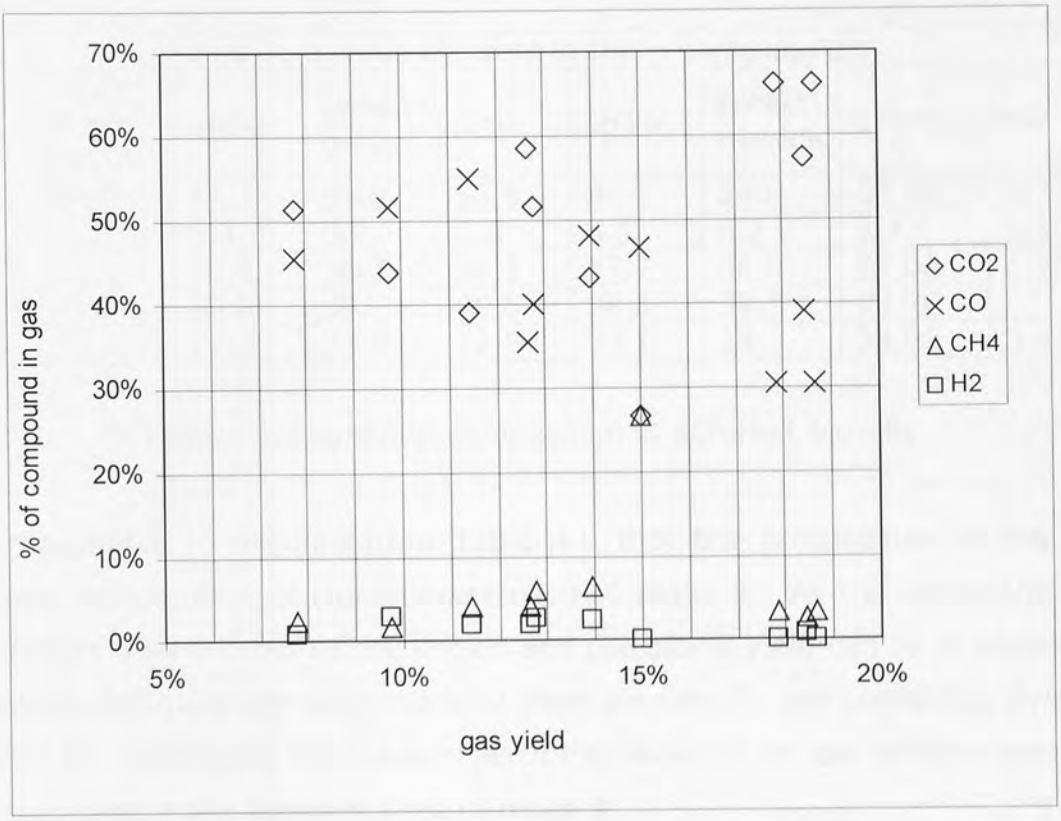

Figure 4.10, Components of pyrolysis gas for different gas yields.

From Figure 4.10 it appears that the concentration of CO_2 rises as the concentration of CO falls. There may a tendency for the concentration of CO to fall with increasing gas yield but the spread of data does not allow this to be estimated. Given the spread of data it was decided to look at the impact of sets of possible gas composition with the concentration of each gas varied within its reported range.

4.3.1.7 Elemental balance calculation

The total mass for each element of the all the pyrolysis products must equal the mass of the element in the biomass feedstock as shown in Table 4.5.

Bio-oils from a number of sources have been analyzed at VTT as part of their work on producing a standard for bio-oil [48] this is shown in Table 4.6.

mass % of each element in the organic liquid								
	mixed hard wood	poplar	switch grass	pine	straw	Forest residue	average	sd
C	56.9	57.3	55.8	55.8	55.3	56.6	56.28	0.77
H	6.2	6.3	6.9	5.8	6.6	6.2	6.33	0.38
O	37.1	36.3	36.3	38.2	37.7	36.9	37.08	0.76
closure	100.2	99.9	99	99.8	99.6	99.7	99.70	
HHV_{dry}	23.1	22.3	23.8	22.9	23.1	23	23.03	0.48

Table 4.6 Elemental composition of different bio-oils

It is reasonable to assume from Table 4.6 that the composition of bio-oil is relatively independent of the biomass used to make it. As the compositions of the biomass feed and bio-oil are known and the bio-oil yield can be predicted it is possible to estimate the total mass of each element in the remaining pyrolysis products by subtracting the mass of each elemental in the bio-oil from the mass of the element in the biomass used to make it.

The mass of the char can be predicted so the combined mass of the gas and reaction water can be estimated.

The chemical compositions of water, carbon dioxide, carbon monoxide and methane are known. So it is possible to calculate the elemental masses for a speculative combination of reaction water and pyrolysis gases.

Consequently it is possible to estimate the mass of each element in the char by subtracting the elemental masses in the other pyrolysis products from that in the original feedstock. This has been done in Table 4.7.

Table 4.7 Char composition for different reaction water yields, pyrolysis gas composition and mass yields

Cases	base	5% CH4	0% CH4	65% CO2	45% CO2	14% H2O	10% H2O
1% ash SRC willow feedstock							
C	76.38%	75.51%	77.26%	78.10%	71.75%	81.02%	71.75%
H	5.73%	5.18%	6.28%	5.73%	7.10%	4.36%	7.10%
O	13.48%	14.91%	12.06%	11.77%	16.75%	10.21%	16.75%
2% ash SRC willow feedstock							
C	76.13%	75.25%	77.01%	77.85%	75.10%	79.93%	72.34%
H	6.76%	6.21%	7.31%	6.76%	6.76%	5.64%	7.88%
O	13.50%	14.93%	12.07%	11.78%	14.53%	10.83%	16.18%
3% ash SRC willow feedstock							
C	75.96%	75.08%	76.84%	77.69%	74.93%	79.17%	72.75%
H	7.47%	6.92%	8.02%	7.47%	7.47%	6.52%	8.42%
O	13.51%	14.95%	12.08%	11.79%	14.55%	11.25%	15.78%

The base case is for mid range values of gas concentrations from Figure 4.10 of 52.5% CO_2, 45% CO and 2.5% CH_4; with a reaction water yield of 12% from Figure 4.2. The gas yields were taken from the inferred characteristic shown in Figure 4.5.

In the other cases only one of the values is varied from the base case. Each case is identified by the value that is at variance with the base case. In the 0% CH4 case the CO was increased 46.25% to and CO_2 to 53.75% to maintain the mass closure, likewise for the 5% CH_4 case the CO was reduced to 43.75% and the CO_2 to 51.25%.

The number of decimal places in Table 4.7 is given to show the ranges of char composition that may be produced. There is no evidence in the experimental data to refine these figures further than 1-2%.

4.3.2 Energy yield calculations

Table 4.6 gives measured values of the HHV for bio-oil on a dry basis (i.e. the HHV of the organic content of the bio-oil) as 23.03 MJ/kg. The energy yield is the mass yield for organics from the trend line of Figure 4.5 multiplied by the HHV of the bio-oil. Table 4.5 gives an average measured HHV for the dry biomass, the average value for all the biomass samples is 19.5 MJ/kg and this has been used to calculate the energy yield on a daf basis (i.e. the energy in the organics / energy in the DAF biomass feed used to produce it). The results are shown in Figure 4.11

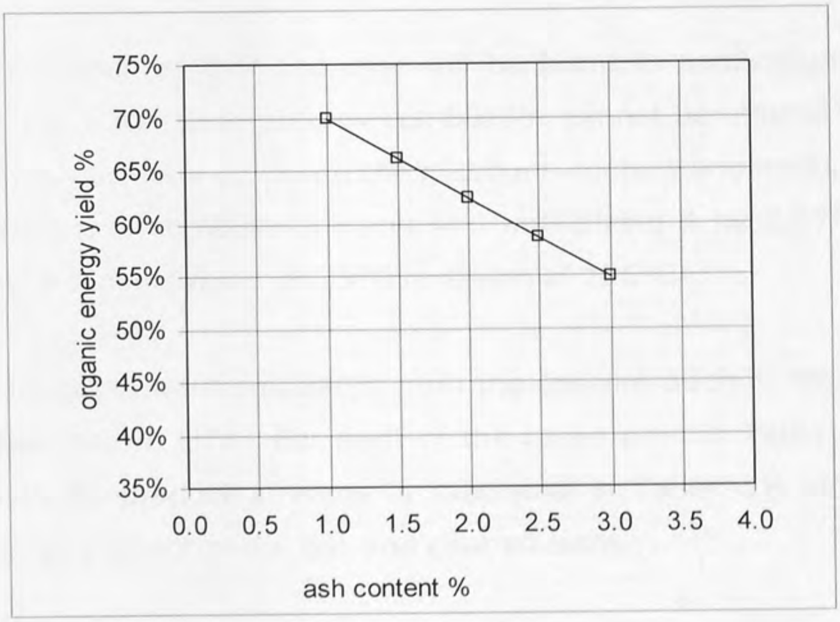

Figure 4.11 Organic liquid energy yield calculated on a dry HHV basis.

The heating values of the gas and char streams have to be calculated from their chemical constituency.

The elemental balance calculations show that the char may have a higher oxygen concentration than other high carbon fuels. Consequently it was decided to use an empirical formula derived by W Boie in 1953 to calculate the HHV for the chars.

This has been shown to produce good estimates (within 5%) when compared with measurements made on a wide range of biomass [148]. The Boie equation is:

$$HHV = 35.16\ C + 116.225\ H - 11.09\ O + 6.28\ N + 10.465\ S\ \text{MJ/kg}$$

where C,H,O,N and S are the mass fraction of the elements when measured by ultimate analysis. The formula was derived after considering 16 biomass fuels, 66 coal/coke/char fuels and 67 liquid fuels (oils and alcohols). The levels of nitrogen and sulphur in biomass and bio-oil are less than 1% so these terms were ignored.

As it has been assumed that the char will be burnt in applications where the latent heat in the water generated by combustion cannot be utilised the LHV was calculated. This was done by taking the hydrogen content and multiplying it by 9 to give the weight of combustion water and multiplying it by 2.675 MJ/kg (the heat required to convert water at 25°C to steam at 125°C).

The LHV of the gases were calculated from the concentration of the combustible gases and their known LHV. For each of the cases used in Table 4.7 the total energy of both by-product streams is tabulated in Table 4.8 along with the combined energy content of the gas and char streams.

Table 4.8 Energy in char and pyrolysis gas streams in MJ/kg feed

Cases	Base	5% CH4	0% CH4	65% CO2	45% CO2	14% H2O	10% H2O
1% ash							
char LHV	30.64	29.67	31.61	31.44	30.17	31.38	29.91
char energy	4.70	4.55	4.85	4.82	4.62	4.81	4.59
gas LHV	5.78	6.89	4.67	4.52	6.54	5.78	5.78
total gas energy	0.78	0.93	0.63	0.61	0.88	0.66	0.89
char+gas energy	5.48	5.48	5.48	5.43	5.51	5.47	5.48
2% ash							
char LHV	31.50	30.52	32.48	32.30	31.02	32.10	30.90
char energy	5.90	5.71	6.08	6.05	5.81	6.01	5.78
gas LHV	5.78	6.89	4.67	4.52	6.54	5.78	5.78
total gas energy	0.95	1.14	0.77	0.75	1.08	0.84	1.07
char+gas energy	6.85	6.85	6.85	6.79	6.89	6.85	6.85
3% ash							
char LHV	32.09	31.11	33.07	32.89	31.62	32.60	31.59
char energy	7.10	6.88	7.31	7.27	6.99	7.21	6.98
gas LHV	5.78	6.89	4.67	4.52	6.54	5.78	5.78
total gas energy	1.13	1.35	0.91	0.88	1.28	1.02	1.25
char+gas energy	8.23	8.23	8.23	8.16	8.27	8.22	8.23

The LHV of the gas is determined by the definition of the case so is independent of the feedstock ash content. The char composition is dependent on the elemental balance which depends on the stream yields which are a function of the ash content of the feedstock. As it is not possible to predict which case is the most likely to represent the performance of a real pyrolysis plant it is worth considering the average value of each of the energy streams across the range of cases. This has been done in Table 4.9.

Table 4.9 average values of pyrolysis char and gas streams

		average	standard deviation % of average value
1% ash			
char LHV	MJ/kg char	30.69	2.6%
total char energy	MJ/kg DAF feed	4.70	2.6%
gas LHV	MJ/kg gas	5.71	15.3%
total gas energy	MJ/kg DAF feed	0.77	17.6%
char + gas energy	MJ/kg DAF feed	5.47	0.4%
2% ash			
char LHV	MJ/kg char	31.55	2.4%
total char energy	MJ/kg DAF feed	5.91	2.4%
gas LHV	MJ/kg gas	5.71	15.3%
total gas energy	MJ/kg DAF feed	0.94	16.9%
char + gas energy	MJ/kg DAF feed	6.85	0.4%
3% ash			
char LHV	MJ/kg char	32.14	2.3%
total char energy	MJ/kg DAF feed	7.11	2.3%
gas LHV	MJ/kg gas	5.71	15.3%
total gas energy	MJ/kg DAF feed	1.12	16.5%
char + gas energy	MJ/kg DAF feed	8.22	0.4%

It is noticeable from Table 4.9 that although the energy content of the gas stream varies considerably with the change in its composition as indicated by its high standard deviation of 16.5% to 17.6% the total energy in the gas and char is remarkably independent from the composition of the gas stream or the reaction water yield with standard deviations of 0.4% of the average value for all cases at a given ash level. This is an important finding as it means that although the gas composition and reaction water yields cannot be accurately predicted from Figures 4.6 and 4.10 the total energy content of the gas and char can be predicted. This is significant if the gas and char are being used to provide heat for the pyrolysis process. All of the gas and some of the char will be needed by the process leaving the surplus char as a marketable by-product. Table 4.5 shows that LHV of the char is less variable than that for the gases and this variability may not mater if it is sold on a LHV basis. The energy available in the surplus char is discussed in Section 4.4.2 .

Table 4.5 shows that the composition of miscanthus is slightly different from that of willow, so the base case assumptions were applied to both feedstocks. These results are shown in Table 4.10.

Table 4.10 char and gas energy yields in MJ/kg daf feed for miscanthus and willow

Cases	Base SRC willow	Base miscanthus
1% ash		
char LHV	30.64	29.56
char energy	4.70	4.53
gas LHV	5.78	5.78
total gas energy	0.78	0.78
char + gas energy	5.48	5.31
2% ash		
char LHV	31.50	30.61
char energy	5.90	5.73
gas LHV	5.78	5.78
total gas energy	0.95	0.95
char + gas energy	6.85	6.69
3% ash		
char LHV	32.09	31.34
char energy	7.10	6.93
gas LHV	5.78	5.78
total gas energy	1.13	1.13
char + gas energy	8.23	8.06

The same yield estimates were used for both crops which results in the same gas compositions; consequently the only differences are in the char composition. From this simple comparison it would appear that the ash content has a far greater impact on the combined energy of the char and gases than the type of biomass does.

So far yields have been expressed as percentages of dry ash fee mass yields. This is consistent with much of the published data however it is not practical to fully dry the feedstock, and the feedstock will contain ash. The impact of feedstock moisture was discussed in chapter 4.3.1.3. It should also be noted that feedstock moisture dilutes the dry biomass and hence reduces the yield / kg of wet feed. The moisture in the feedstock will be condensed with the bio-oil and evaporated during combustion of the bio-oil in the same way as the reaction water is, this will reduce the LHV of the bio-oil.

Ash also dilutes the biomass and so reduces yields. Fast pyrolysis takes place at around 500°C which is below the melting point for both miscanthus and wood ash [15] consequently all the ash will remain in the char (in practice unless some form of filtering is applied to the bio-oil it will contain some char and hence some ash). This concentrated ash dilutes the char, reducing its heating value.

The yield data for the base case conditions from Table 4.7 have been calculated taking into account the dilution effect of the feedstock moisture and ash content for both miscanthus and SRC willow and are shown in Tables 4.11.

Table 4.11 LHV yield data for miscanthus and SRC willow taking into account moisture and ash content

Parameter	unit	SRC Willow	Miscanthus
biomass ash level		1.0%	1.0%
biomass feed moisture		8.0%	8.0%
biomass LHV	MJ/kg wet feed	16.44	16.32
bio-oil mass yield		72.9%	72.9%
bio-oil moisture		26.0%	26.0%
bio-oil LHV	MJ/kg	15.23	15.23
bio- oil energy	MJ/kg wet feed	11.10	11.10
bio-oil energy yield	bio-oil/biomass	67.5%	68.0%
gas + char energy	MJ/kg wet feed	4.92	4.24
gas + char yield	gas+char/biomass	29.8%	25.9%
total pyrolysis energy	MJ/kg wet feed	16.02	15.34
char LHV	MJ/kg char	28.29	23.73
char ash concentration		6.2%	6.2%
biomass ash level		2.0%	2.0%
biomass feed moisture		8.0%	8.0%
biomass LHV	MJ/kg wet feed	16.17	16.28
bio-oil mass yield		66.4%	66.4%
bio-oil moisture		28.3%	28.3%
bio-oil LHV	MJ/kg	14.66	14.66
bio- oil energy	MJ/kg wet feed	9.73	9.73
bio-oil energy yield	bio-oil/biomass	60.2%	59.7%
gas + char energy	MJ/kg wet feed	6.11	5.44
gas + char yield	gas+char/biomass	37.7%	33.3%
total pyrolysis energy	MJ/kg wet feed	15.84	15.17
char LHV	MJ/kg char	28.04	24.46
char ash concentration		9.8%	9.8%

Table 4.11 continues on next page

Table 4.11 continuation. LHV yield data for miscanthus and SRC willow taking into account moisture and ash content

biomass ash level		3.0%	3.0%
biomass feed moisture		8.0%	8.0%
biomass LHV	MJ/kg wet feed	16.01	16.13
bio-oil mass yield		60.1%	60.1%
bio-oil moisture		31.2%	31.2%
bio-oil LHV	MJ/kg	13.98	13.98
bio- oil energy	MJ/kg wet feed	8.40	8.40
bio-oil energy yield	bio-oil/biomass	52.4%	52%
gas + char energy	MJ/kg wet feed	7.27	6.61
gas + char yield	gas+char/biomass	45.4%	40.9%
total pyrolysis energy	MJ/kg wet feed	15.67	15.01
char LHV	MJ/kg char	27.86	24.90
char ash concentration		12.3%	12.3%

Table 4.11 contains the answers to the questions raised in Section 4.3. For both SRC willow and miscanthus the bio-oil energy yield is likely to be between 11.1 MJ/kg feed and 8.4 MJ/kg feed with the yield falling linearly as the biomass ash content increases from 1% to 3%. If the biomass ash content is above 3 % the moisture level of the bio-oil will be unacceptably high for use as a fuel.

This fall in bio-oil yield is largely compensated for by an increase in the combined energy yields from the pyrolysis gas and char streams from 4.9 MJ/kg feed to 7.27 MJ/kg feed for SRC willow and 4.24 MJ/kg feed to 6.61 MJ/kg for miscanthus.

Although the bio-oil yields are similar for both SRC willow and miscanthus for a given ash content the char and gas energy yields are consistently higher for SRC willow than miscanthus.

4.3.3 Comparison with commercial plant performance

It is worthwhile comparing these estimates with the reported yields of Dynamotive's pilot fast pyrolysis plant [35]. To do this the SRC willow model spreadsheet was rerun with a feedstock moisture level of 3% to give comparable conditions.

Table 4.12 Comparison between pilot plant production and model predictions

Parameter	Dynamotive	Model
Feed moisture	3%*	3%
Feedstock ash %	1.5%*	1.5%
Bio-oil mass yield	70%	68%
Bio-oil moisture	22.5%.*	21.3%
Bio-oil LHV	16.6 MJ/kg	16.9 MJ/kg

* the value used is the mid point of the range of values quoted in the referenced report.

Table 4.12 shows that the predictions of the model based on reported experimental data is consistent with reported data from an industrial pilot plant.

Dynamotive's web site [153] also gives an independent laboratory analysis of a char sample from one of its plants which had a HHV of 28.26 MJ/kg and an ash content of 11.07%. Assuming the Dynamotive char was made from a wood feedstock it should be possible to compare this result with the model predictions for SRC willow. The 2 % ash SRC is predicted to produces char with a HHV of 29.51 MJ/kg and an ash content of 9.83% which compare well with the Dynamotive data.

Of course consistency between the model's prediction and reported data from a pilot plant at a single operating point does not validate the model but if there was a serious discrepancy it would cast doubt over the utility of the model.

4.4 Thermal Model of the pyrolysis process

Pyrolysis is an endothermic process, i.e. it needs an external heat source to maintain the process. This can be provided by burning some or all of the pyrolysis gas and char depending on the process design. As shown in Table 4.6 the amount of energy stored in the pyrolysis gas and char varies with feedstock ash content. It is likely that there is more energy in the pyrolysis gas and char than is needed by the process so there should be a surplus of char or heat that could be exported from the process [101]. If the pyrolysis plant is using a feedstock that is the by-product of another process it is possible that a suitable heat load would be available to use the surplus heat. This is less likely if the plant is a power station using energy crops (unless it utilises a steam cycle); in this case the surplus energy should be extracted as char and sold. An estimation of the thermal loads of the plant is needed in order to find out how much surplus char is likely to be produced. The types of pyrolysis plants were discussed in Section 1.1.1. A plant that is readily scalable and that enables the pyrolysis char to be extracted is needed for a power station application. A bubbling fluidized bed (BFB) reactor satisfies both these requirements. Figure 1.7 is a diagram showing the gas routes for a generic BFB plant. Figure 1.7 is purely a diagrammatic representation of the process not an actual plant. The biomass, bio-oil and char paths have been omitted for clarity. There are two basic gas paths through the plant; one for the pyrolysis gases and carrier gas and the other for the heating gas.

The carrier gas is used to fluidise the bed of the pyrolysis reactor and transport the pyrolysis products out of the reactor. It gets cooled in the quench along with the pyrolysis liquid and vapours and so needs reheating before it is blown back into the pyrolysis reactor. The pyrolysis gas adds to the total amount of gas in the circuit. This will cause the pressure in the circuit to rise.
To prevent this happening (and to extract some energy) the excess gas is bled off and burnt in the pyrolysis combustor.

The hot gas from the pyrolysis combustor heats the pyrolysis vessel via a heating jacket, and then passes through a gas/gas heat exchanger where it reheats the circulating gases. Any heat left in the gas is then used in the biomass dryer. The biomass dryer has a separate combustor to provide additional heat if there is insufficient heat in the flow from the reheater to dry the biomass.

The major heat loads are:

- The pyrolysis reactor;
- The gas reheater;
- The biomass dryer.

In order to come up with an estimate for the plant thermal load it is necessary to consider each of the heat loads separately to see how they can best supplied.

4.4.1 Pyrolysis reactor heat demand

Provided the fluidising carrier gas is preheated to the vessel temperature there are 3 heat loads associated with the pyrolysis reactor. These are:

- The enthalpy of pyrolysis;
- Evaporation of any residual moisture in the biomass;
- Radiation conduction and convection losses.

4.4.1.1 Enthalpy of pyrolysis

The enthalpy of pyrolysis h_p has been defined as "the energy required to raise biomass from room temperature to the reaction temperature and convert the solid biomass into the reaction products of gas, liquids and char" by Daugaard and Brown who have measured it for a number of feedstocks in a laboratory bubbling fluidised bed fast pyrolysis unit operating at 500°C [154] and the results shown in Table 4.13

Table 4.13 Enthalpy of pyrolysis for different materials

Material	h_p kJ/kg of dry biomass	uncertainty kJ/kg
oak	1460	± 208
oat hulls	780	± 200
pine	1640	± 330
corn stove	1350	± 280

This is one set of experimental results that are not backed up with any theoretical estimation but it is worth noting that the test rig used was calibrated by evaporating methanol and raising it to 500°C. A good agreement was obtained between the measured value of the heat required to do this and the theoretical value calculated from the known characteristics of methanol.
It is clear that the enthalpy of pyrolysis is dependent on the feedstock used. The oat hulls have a much lower value than the more solid materials. Given that willow chips are wooden and miscanthus stems require more strength than oat husk it was decided to use 1500 kJ/kg dry biomass, the average of the values of h_p for oak, pine and corn stove as an estimation for h_p of energy crops.

Work published on "the high heat of fast pyrolysis for large particles" [155] has a graph which indicates that fast pyrolysis is complete at 400°C and at this temperature the energy for pyrolysis h_p should be 1500 kJ/kg.

This agreement is not as close as it appears as the product mix will be different at 400°C from that at 500°C and there will be an additional heat requirement to raise the products (or biomass) up to 500°C.

As the conditions in reference [154] are similar to those for commercial pyrolysis plants a value of 1,500 kJ/DAF kg for h_p will be assumed for this study. The feedstock for a pyrolysis plant will contain some water when this is allowed for 1,380 kJ/kg is required for pyrolysis of the biomass for a feed with 8% moisture content (a separate allowance is used to evaporate the free moisture).

4.4.1.2 Energy required to evaporate any residual moisture

Any dry biomass that is in contact with moist air will absorb some moisture from the air. Consequently even if the biomass is fully dried it is likely that there will be some residual free moisture in the biomass. This free moisture will evaporate and be superheated in the pyrolysis reactor then condensed with the bio-oil in the quench. The heat lost in residual fee moisture has been calculated as 3350 kJ/kg of free moisture assuming:

- 2.06 kJ/kg for the specific heat of water vapour (from Figure 4.12);
- 4.18 kJ/kg for the specific heat of liquid water;
- a biomass storage temperature of 30°C;
- 2,257 kJ/kg for the latent heat of vaporisation of water.

This gives a total energy requirement of 3.43 MJ/kg of moisture in the biomass. For a 8% moisture feed this comes to 274 kJ/kg of feed.

4.4.1.3 Radiation conduction and convection losses

For conventional pulverised fuel (pf) power station boilers the radiation and conduction losses are typically 0.25% [156].

In order to heat the bed to 500°C the surface of the pyrolysis reactor will need to be at a temperature above 500°C. If this is maintained by an outer heating vessel its outer surface will also be above 500°C. This is similar to the wall tube temperature on modern steam generating boilers. These losses are all proportional to the surface area of the boiler, however the throughput of both pf furnaces and fluidized beds are proportional to their volume. Consequently the sizes of the loss will scale with throughput to the power of 2/3. This would imply the following relationship for a plant of throughput Q_a with losses of L_a and a plant of throughput Q_b and losses L_b

$$L_b = L_a.(Q_a/Q_b)^{2/3}$$

A modern 500MW$_e$ pf boiler would have a fuel input of around 3500 t/d where a pyrolysis plant process between 50 odt/d to 200 odt/d.
From the equation above this should correspond to losses in the region of 4% - 1.7%. Of course there are many differences between a coal pf boiler and a pyrolysis reactor so this can not be taken as anything but a very rough estimate of the losses; but as they are quite small when compared to the other thermal loads this should not unduly affect the accuracy of the overall calculation. A mid range value of 3% of total heat input to the pyrolysis reactor has been assumed for the radiation, convection and conduction losses from the plant.

The heat loads estimated in Section 4.4.1, and 4.4.1.2 total to 1,654 kJ/kg feed which would make the radiation conduction and convection losses come to 50kJ/kg feed.

4.4.1.4 Gas reheater load

The circulating gases will have been cooled to 50°C in the quench and will need reheating to 500°C to avoid cooling the reactor bed. The specific heats of gases have been calculated from data in Perry's Chemical Engineers Handbook [160] as shown in Figure 4.12.

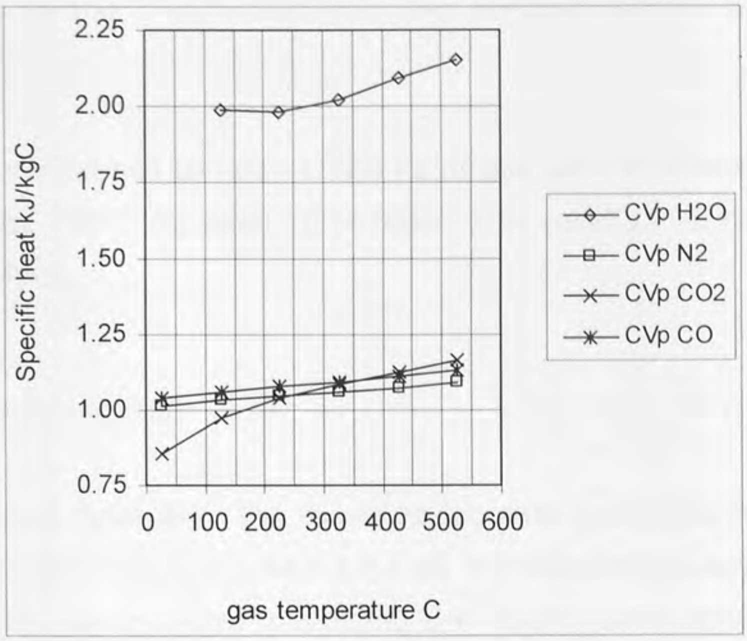

Figure 4.12 Variation of the specific heat of gasses with temperature

On start up the circulating gas will be mainly nitrogen (or a mixture of gases other than oxygen) but as gases are bled from the system the gas composition will approach that of the pyrolysis product gas. Pyrolysis gas is mainly a mixture of carbon dioxide and carbon monoxide. The average value over the temperature range 50°C - 600°C for specific heat for the 3 gasses are 1.07 kJ/kgC for nitrogen, 1.03 kJ/kgC for carbon dioxide and 1.09 kJ/kgC . Given that the gas composition will change over the duration of a run from nitrogen to a roughly equal mix of carbon dioxide and carbon monoxide it was decided to use the average values for the 3 gasses over the temperature range 27°C to 527°C for the specific heat of the circulating gas this came to 1.076 kJ/kg°C.

The mass gas flow is required to calculate the heat load of the reheater. This is a function of the bed design. The process flow diagrams in the Welman designed reactor described in [86] had a gas mass flow / biomass flow ratio of 1.268 where the Aspen model described in NREL paper [96] uses a fraction of 2.75. Fluidised beds remain stable over a range of gas flows [102] so both of these flows could be acceptable. However more fan power is needed to generate a higher gas flow so the lower value from the Wellman design was used in this study.

The gas reheater heat has to raise 1.268 kg of gas with an average specific heat of 1.076 kJ/kg by 450°C for each kg of feed. This results in a heat requirement of 614 kJ/kg of feed.

4.4.1.5 Biomass drying load

The requirement to have very low moisture biomass feedstock for fast pyrolysis was discussed in Sections 1.2.1, and 4.3.1.3. Consequently a pyrolysis plant will require a biomass dryer unless it is using pre dried waste wood from a timber processing plant. The amount of heat required will depend on the initial moisture level of the biomass. This will vary with the type of energy crop.

Freshly harvested coppice willow has a moisture content of around 50% but it has been shown in a number of studies that if it is stored as woodchips in ventilated piles this will reduce down to 30% during storage [85,90,157]. It may be necessary to design a plant to accept freshly felled timber for a plant that uses forestry residues as a feedstock if there is no opportunity to store feedstock. However the recommended practice for willow coppicing is to carry it out during the winter when the trees are dormant. This means that most of the harvest will need to be stored consequently it would be appropriate to consider the after storage moisture level as the normal level.

The situation with miscanthus is slightly different. If the crop is harvested in the growing season it can have a moisture level of 55%, but if it is left standing it will go into a dormant state with a lower moisture level and some of the nutrients (including alkali metals) returning to the soil or washed out by rain. If it is harvested in this cessant state it has a moisture level between 15% and 25%.

In Section 4.3.1.3 it was concluded that the biomass may need to be dried to 8% moisture to produce acceptable bio-oil from the likely range of energy crops available. Figure 4.13 shows the energy required to dry biomass to produce 1kg of pyrolysis feedstock with moisture levels of 6%, 8% and 10%.

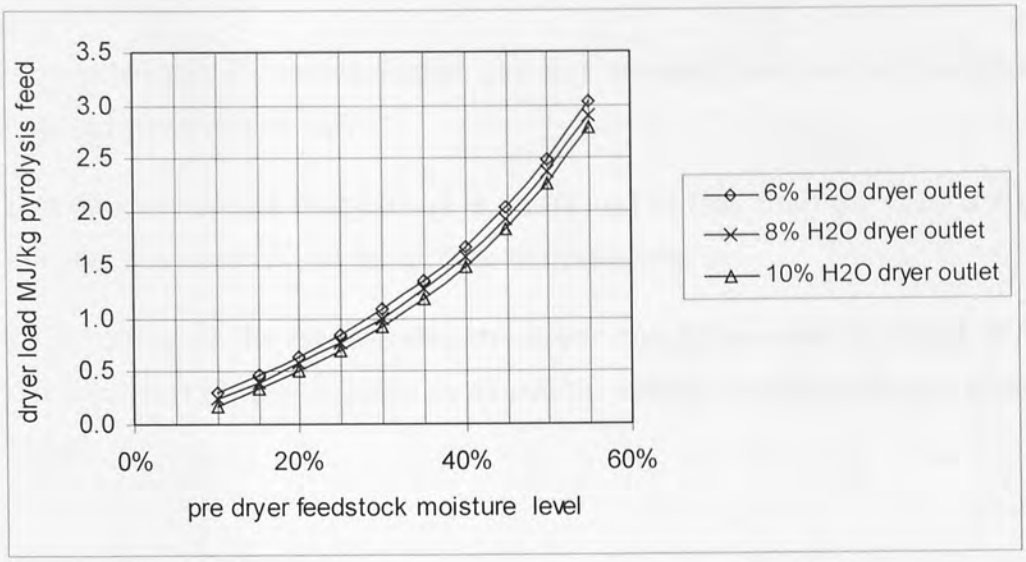

Figure 4.13 biomass dryer heat requirement.

Biomass can be dried by passing air that is not saturated with moisture through it. It has been assumed that the drying air will have to exit the dryer at a temperature above 100°C to guarantee that it is not saturated. Consequently the dry biomass and absorbed moisture needs to be heated (from an ambient of 15°C) to 100°C. An average specific heat of 2.3 kJ/kg has been assumed for the biomass [160].

4.4.1.6 Supplying the thermal loads

Heat can only be transferred from a hot medium to a cold one so it is necessary to consider the temperatures of the various heat loads. To get maximum utilisation of the heat the loads are connected in series such that the Lower temperature processes are heated from the exhaust heating gas of higher temperature ones.

The maximum efficiency can be obtained by selecting a gas flow such that all the loads can be met by this cascading gas flow (i.e. there are no auxiliary combustors needed to provide additional heat). The heat load of each stage is dependent on the temperature drop across it and the gas flow. The following minimum temperatures are fixed by the process design:

- Pyrolysis reactor heating jacket gas exit temperature can not be below the bed temperature of 500°C;
- It is recommended that bio-oil is quenched to less than 50°C so the gas leaving the quench will be at this temperature;
- To be effective the gas leaving the dryer should be near to 100°C it should not be much hotter to avoid evaporating volatile chemical in the biomass [161].

All the heat is transmitted by the exhaust gas from the combustor. As heat transfer is proportional to the temperature drop of the heating media and the mass flow of the heating media a high combustor temperature results in a lower exhaust gas flow being required to transfer the heat. As there is some heat lost from the process in the exhaust gas flow from the dryer it is desirable to reduce the gas flow to a minimum. The design temperature of the exhaust gas from the combustor will depend on:

- The ash melting point of the fuel, (assuming that a non slagging furnace is used);
- The excess air above the stochiometric requirement needed to produce full combustion and reduce CO production;
- The material of construction of the combustor;
- Need to limit thermal NO_x production.

The fuel for the combustor is likely to be a mixture of the pyrolysis gas and char, biomass or natural gas. Natural gas is ash free but the other fuels contain ash. The melting point of wood and miscanthus ash have been reported to be in [15] as around 1300°C with ash softening temperatures between 1000°C and 1250°C. As the ash in the biomass feed is concentrated in the char it may be assumed that the char's ash has a similar melting point to the biomass ash. Biomass combustors used for district heating plants are reported as having combustion temperatures in the region of 800°C to 1200°C [162] which is consistent with the notion of keeping the combustion temperature just below the ash melting point.

Once a suitable combustion temperature has been selected the temperature differential across the pyrolysis reactor is fixed so the gas flow required to provide the heat required by the pyrolysis reactor can be calculated. Given the gas flow, temperature at the pyrolysis reactor's exhaust and the heat loads it is possible to calculate the temperature at the gas re-heater's exhaust and the energy available for the dryer. This has been done for different combustor temperatures in Table 4.14 and for a combustor temperature of 800°C in Figure 4.14.

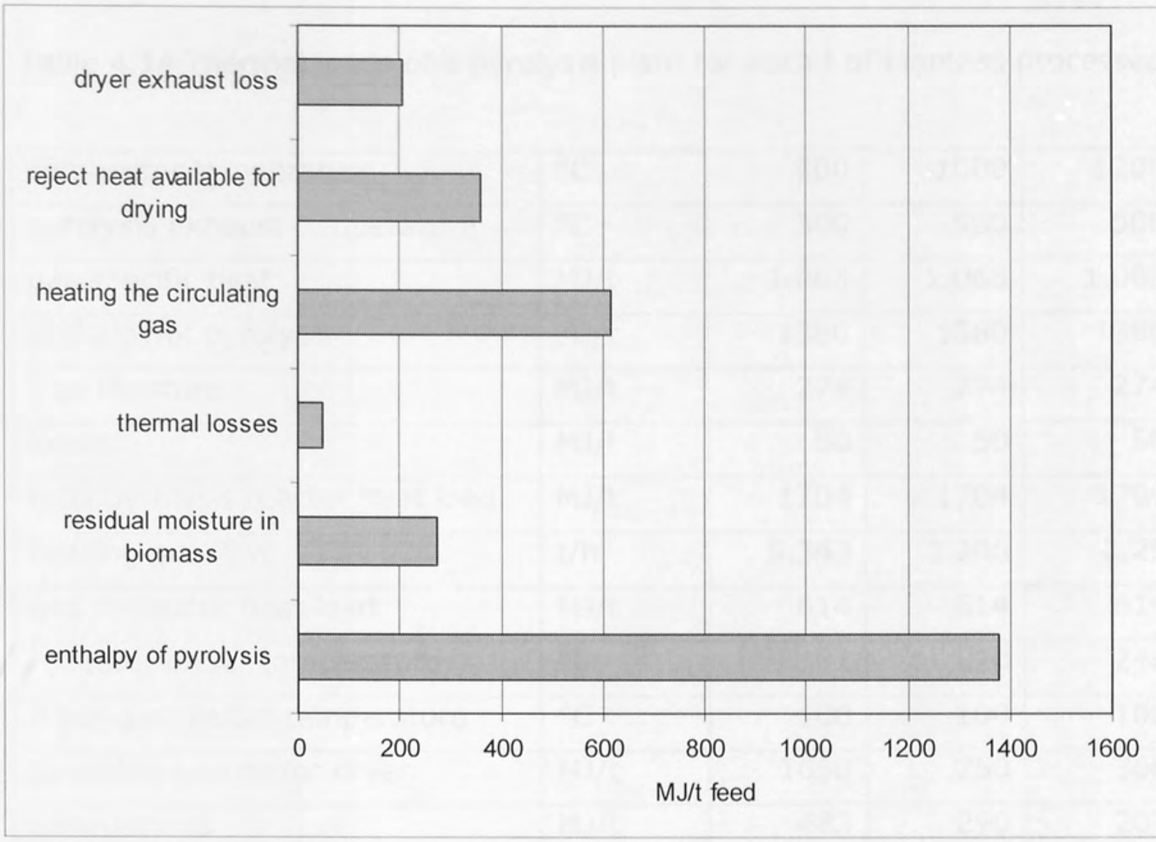

Figure 4.14 heating loads supplied by the main combustor of a BFB pyrolysis unit operating at 800°C.

Figure 4.14 shows that the major heat load is the enthalpy of pyrolysis. The heat lost through the circulating gas is 14% of the total energy requirement this is a loss that would not be present on pyrolysis reactors that do not use fluidised beds.

Table 4.14 Thermal loads of a pyrolysis plant for each t of biomass processed

combustor temperature	°C	800	1000	1200
pyrolysis exhaust temperature	°C	500	500	500
gas specific heat	MJ/t	1.063	1.063	1.063
enthalpy of pyrolysis	MJ/t	1380	1380	1380
free Moisture	MJ/t	274	274	274
losses	MJ/t	50	50	50
total pyrolysis reactor heat load	MJ/t	1704	1704	1704
heating gas flow	t/h	5.343	3.206	2.29
gas re-heater heat load	MJ/t	614	614	614
reheater outlet temperature	°C	392	320	248
dryer gas outlet temperature	°C	100	100	100
available energy for dryer	MJ/t	1658	750	360
exhaust loss	MJ/t	483	290	207
total process heat	MJ/t	4459	3358	2885

The heat loads in Table 4.14 have been calculated assuming:

- The biomass has a 8% moisture level;
- The specific heat of the heating gas (i.e. the exhaust gases from the combustor) is the average value of a 78% Nitrogen 22% Carbon Dioxide mix over the temperature range 300K - 800K using data from [160];
- The exhaust losses have been calculated on the basis of an 15°C ambient air temperature.

The energy required by the dryer is shown in Figure 4.13. If more energy is in the drying gas stream than is required to dry the biomass the dryer gas exit temperature will rise which may result in an undesirable emission from the dryer exhaust of a "blue haze" of chemicals that are lost from the pyrolysis products [161].

To avoid this combustor exit temperatures which result in a dryer heat supply that is more than that required to dry the biomass at the minimum expected moisture level should be avoided. For miscanthus the minimum expected moisture content is 15%. From Figure 4.9 it would appear that 400 MJ/t would be needed to dry the feedstock to 8%. For SRC willow the minimum moisture content is 30% and from Figure 4.13 the dryer energy needed would be 1000 MJ/t. It is apparent from Table 4.14 that a combustor exit temperature of 1200 °C would be suitable for both feedstocks.

The complete thermal load of the plant is the combination of the pyrolysis plants loads and any additional heat needed by the biomass dryer. The heat requirements for the dryer have been taken from Figure 4.13 assuming a pyrolysis feed moisture level of 8% and have been used with the contents of Table 4.14 to calculate the total heat requirement of the pyrolysis plant and biomass dryer assuming a combustor temperature of 1200°C. This is shown in Figure 4.15.

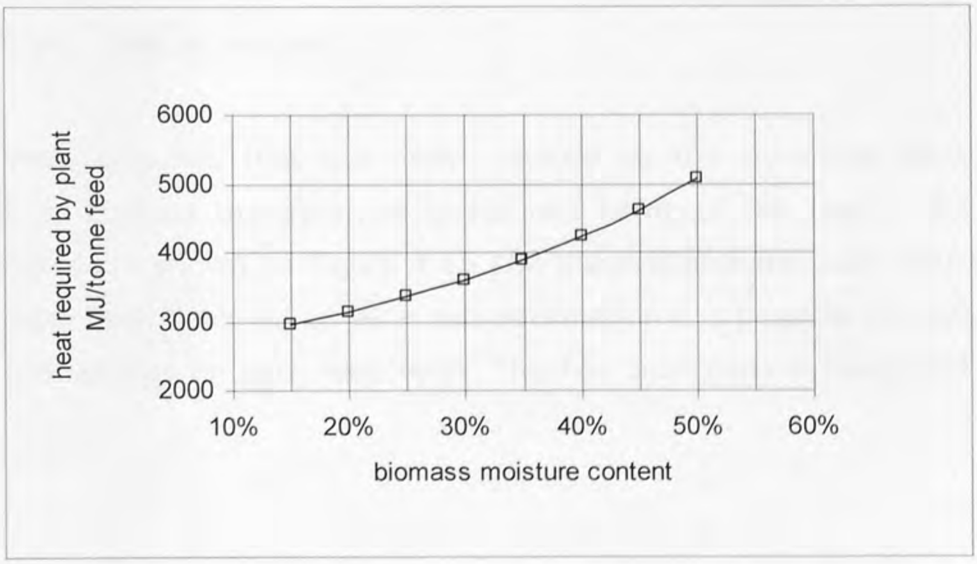

Figure 4.15 Combined heat load of the pyrolysis plant and biomass dryer.

It is worthwhile comparing these predictions with the reported performance of the Dynamotive plant described in [33] which is reported to need 2.5 MJ of heat to produce 1 kg of bio-oil at a mass yield of 70%, this corresponds to an energy requirement of 1.75 MJ/kg of pyrolysis plant feed.

This is lower that the values shown in Figure 4.15. However the Dynamotive plant has some important differences to the one modelled here the main ones are:

- Natural gas is used as the heating fuel and so a higher combustion temperature could be used;
- The Dynamotive plant uses dry sawdust as a feedstock so does not have a biomass dryer consequently all the usable heat in the pyrolysis reactor exhaust can be used to reheat the fluidising gas;
- The sawdust has a moisture content of 3% compare to the dried energy crops moisture content of 8% so the energy lost by evaporating free moisture will be lower.

Given these process differences it is not surprising that there is not good agreement between the model and the process plant.

4.4.2 Surplus char production

It has been assumed that the heat required by the pyrolysis plant will be provided by burning the pyrolysis gases and some of the char. The energy requirements are shown on Figure 4.15 and the available gas plus char energies are available from Table 4.11. With this information it is possible to calculate the surplus char energy for each feedstock. This has been done in Figure 4.16.

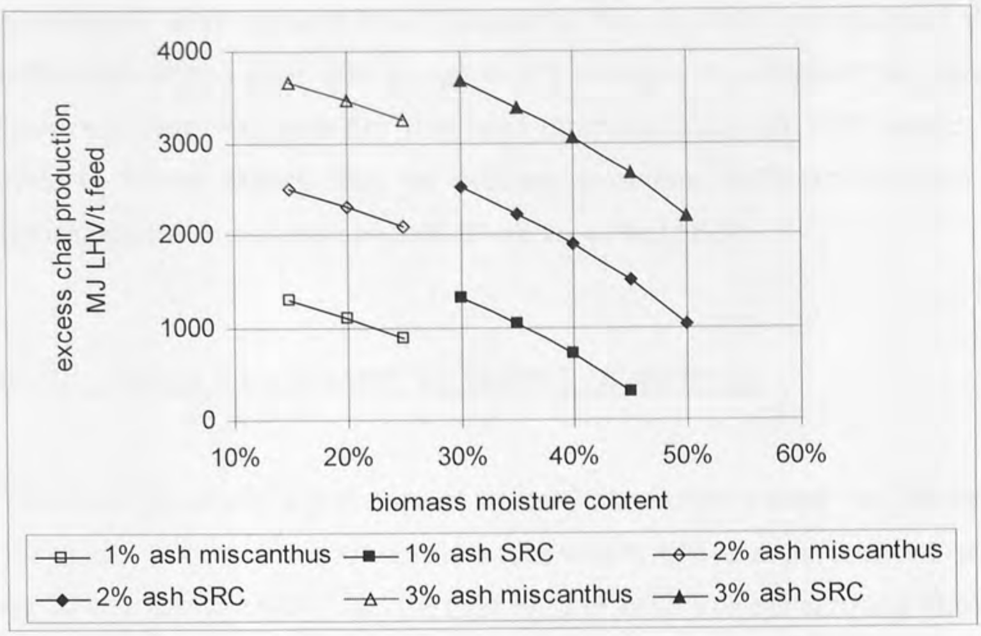

Figure 4.16 char surpluses

It has been assumed that in practice miscanthus will have a moisture content in the 15% to 25% range and SRC will have a moisture content between 30% and 50%.

As miscanthus has a lower moisture content than willow one might expect it to have more surplus char, Figure 4.16 shows that this is not the case. The carbon content of willow from Table 4.5 is 1% higher than that for miscanthus. As it has been assumed that the bio-oil produced from both feedstocks has the same carbon content and that the mass yields are the same for both feedstocks the additional carbon in the willow will end up in the char, raising its heating value. From Table 4.6 it would appear that the carbon content of bio-oil from grasses is lower than that in the bio-oil made from wood. If this proves to be the case for miscanthus and willow the energy contents of the char could be similar and the excess char yield for the miscanthus will be higher than that shown in Figure 4.16. It is worth noting that with a 1% ash SRC feedstock the available char and gas energy is 4.92 MJ/kg which should provide the heat requirements providing the biomass moisture level is less than 48%.

This is consistent with reports from industrial plants, BTG states that the heat from combustion of the char and gases in it's process is sufficient to supply both the process requirements and dry the feed biomass from 40-50% water to 10% [39]. Similarly Ensyn states that its process provides sufficient excess heat to dry feedstock with a moisture content of up to 45% [163].

4.5 Bio-oil yields expressed in terms of energy

As with mass yields there is a choice of basis that energy yields can be calculated on. To be useful in a techno-economic assessment the energy content should be expressed in the same terms as the fuel is sold on. Fundamentally there are 3 possible bases for reporting energy content:

- HHV_{dry} i.e. the heating value of the fuel once any free moisture has been evaporated;
- HHV_{wet} i.e. the HHV of the as received fuel including any free moisture;
- LHV i.e. the energy that is available for use in a heat cycle that exhausts gases at 125°C.

It is worth considering the impact of using each system for payment for biomass. Consider the cost of the wet biomass needed to provide 1kg of pyrolysis feed at 8% moisture at a cost of 0.3p/MJ under the 3 pricing basis. This has been plotted in Figure 4.17.

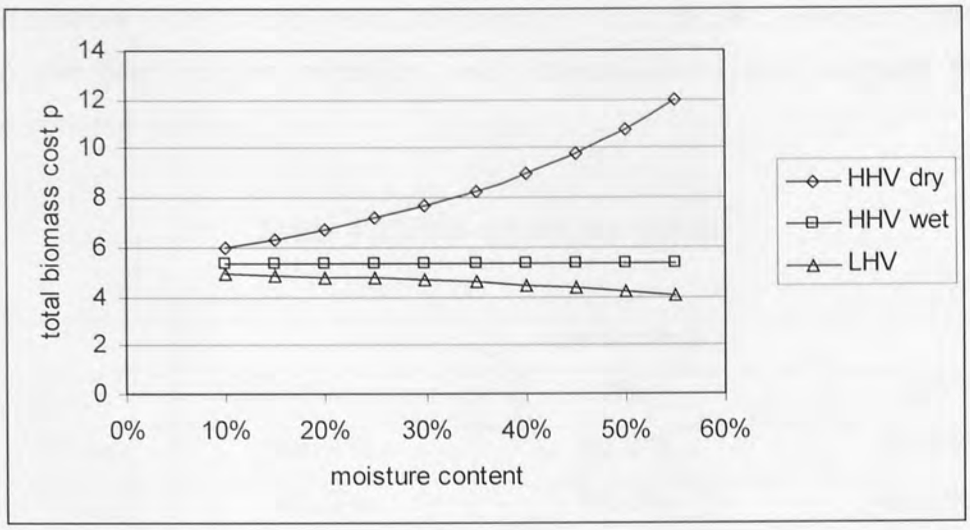

Figure 4.17 total biomass cost to provide 1kg of pyrolysis feed

Clearly paying on a HHV_{dry} basis would leave the biomass costs very dependent on the biomass moisture content and so is not to be recommended. Using the HHV_{wet} basis the biomass costs is independent of moisture content. There is a drop of biomass cost with moisture level if the biomass is priced on a LHV basis. It is possible that this could compensate for extra char needed to dry the wetter biomass but as there are also additional transport costs associated with higher moisture content it would be more appropriate to pay on an as-received HHV basis (HHV_{wet}) with some form of premium paid for drier biomass. The HHV_{wet} will be directly proportional to the dry matter content of the biomass as such it will relate to the price per odt which has traditionally been used for some agricultural products.

If the energy input is to be measured on a HHV_{wet} basis the energy of the bio-oil should be measured on the same basis to give a true energy yield. However as bio-oil is likely to be sold on a LHV basis the yield in terms of the unit of sales would be calculated as:

Yield = LHV bio-oil per kg pyrolysis feed / HHV_{wet} of biomass in per kg pyrolysis feed

Table 4.15 show both these yields for miscanthus and SRC willow. These yields relate to the feed to the pyrolysis unit; consequently the biomass feedstock moisture content is 8%.

Table 4.15 bio-oil energy yields

	miscanthus		
Ash	1%	2%	3%
HHV_{wet}/HHV_{wet}	68.9%	60.8%	52.8%
LHV/HHV_{wet}	61.5%	54.0%	46.5%
	SRC willow		
Ash	1%	2%	3%
HHV_{wet}/HHV_{wet}	69.3%	61.2%	53.2%
LHV/HHV_{wet}	61.9%	54.3%	46.9%

4.6 Diesel engine

4.6.1 Diesel engine size

Diesel generators are frequently used as back up generation units but this duty is not relevant to this study. Surveys of power stations which use diesel engines as their main generators have been carried out for the World Bank [166] and VTT [165]. These units vary in size up to 50 MWe. Although the vast majority of 1-2 MWe installations use distillate fuel oil those above 5MWe frequently use heavy fuel oil (HFO). HFO has a similar range of viscosity to bio-oil and also contains a small amount of ash. There are also compression ignition engines that run on gas with a pilot fuel of distillate oil. Consequently although there is limited experience of operating diesel engines on bio-oil (mainly due to the lack of supply of bio-oil) there is considerable experience of some of the techniques that will be needed to produce a commercial diesel generator that runs on bio-oil.

4.6.2 Pilot fuel ratio

Bio-oil does not auto-ignite in a diesel engine, but will ignite from the combustion of a separately injected pilot fuel. It has been assumed that this will be diesel oil. The amount of diesel oil used increases the net carbon emitted by the process. As such it would be desirable to minimise the amount of pilot fuel used.

Trials on a 64 kW 1500 rpm Valmet 420 DS engine by VTT [61] quoted the pilot diesel fraction as 7.9 % but did not say if this was on an energy, mass or volume basis.

Early reports of tests at Ormrod Diesel on a modified 250 kWe engine state that it has successfully run with a pilot diesel energy input of 5% [62-63]; however a later more detailed report on the trials stated that the diesel pilot oil needed to be between 7% and 17% by mass to obtain reasonable emission results [66]. The Ormrod trials did suffer from consistency problems with the bio-oil used [50] and Ormrod thought that the combustion could be improved by reduction of the injector droplet size, consequently the pilot oil ratios used in this trial may not represent the performance of an optimised engine.

A more recent installation of a 300kW engine in a German CHP plant that uses bio-oil made by the PYTEC ablative pyrolysis process was reported to be operating with a pilot oil ratio of 4% by volume [41]. As this is a commercial scale prototype plant it is considered to give a better indication of the amount of pilot oil required than a test engine. Consequently this ratio is used in this study. Although injectors may be set up in terms of volume flow to investigate to costs the pilot ratio is needed in energy terms.

Assuming that diesel oil has a density of 0.87 kg/l and a LHV of 43.3 MJ/kg [168] the net heating value of diesel oil expressed in volume terms is 37.7 MJ/l. So 1 litre of engine fuel including 4% pilot diesel will have 1.5 MJ of diesel energy in it.

Using the LHV value for bio-oil made from 2% ash feedstock from Table 4.11 and the average density of bio-oil from Table 1.2 the heating value of bio-oil expressed in volume terms is 17.6 MJ/l. So 1 litre of engine which is 96% bio-oil will contain 16.9 MJ of bio-oil energy in it. Consequently the pilot fuel ratio in energy terms is 8%.

4.6.3 Efficiency

Both the Ormrod and Valmet engine trials reported a drop in engine efficiency when operating on bio-oil. The efficiency of the engine is not commented on in the PYTEC paper. Given the lack of data from a diesel engine with an injection system specifically designed for bio-oil it is not possible to estimate an efficiency value. In a report on diesel power plant efficiencies of 38 - 47 % are quoted for HFO diesel engines [164]. On the basis of this an efficiency of 42% will assumed for diesel engines in this study.

4.6.4 Capacity factor

As most diesel power stations are not operated at base load their historic capacity factors may not be relevant. The Companhia de Electriccidade de Macau have published performance data from their Coloan Power Station from 1987 - 1992 when they were running HFO fuelled diesel units on base load. Their units achieved capacity factors between 75 - 89% over 16 machine years of operation (two machines were commissioned in 1990) with an average capacity factor of 81% [165]. Although bio-oil is more corrosive than HFO it should be possible to obtain similar capacity factors if appropriate materials are used.

The engines installed at Coloan are slow speed uniflow scavenged two stroke engines (i.e. air is blown into an inlet pot at the bottom of the cylinder when the piston is at the bottom of its stroke, this air drives the exhaust out through a valve in the cylinder head) .

In a survey [167] that compared the performance and availability of slow speed two stroke and medium speed four stroke diesel generators operating on bunker oil (a grade of HFO) the two stroke engines had an availability of 87% and the four stroke ones achieved 83%.

4.6.5 Works Power

A study of a larger number of diesel generators [167] gives values of 1.0 - 10.9% for the works power on medium speed generators with an average value of 4.1%. The corresponding figures for large slow speed machines are 3.2 - 5.8% with an average of 4.7. The wide spread reflect difference is what is included as works power on different sites. The average value for medium speed engines will be used for calculations in this study.

4.7 Combined cycle gas turbine

4.7.1 Optimum combined cycle gas turbine plant size

The main parameters to consider when determining the optimum size of a generation unit are the specific cost (i.e. the capital cost per MWe installed) and conversion efficiency. Figure 4.14 shows the equipment supply cost per MW of electrical output and the efficiency plotted against electrical output for natural gas fired CCGTs. The data plotted is taken from Gas Turbine World [169] and excludes plants that use aero derivative gas turbines as these are thought to be unsuitable for use with bio-oil [68]. The cost data in Gas Turbine World is the equipment supply cost; this has been used directly when calculating the specific investment for Figure 4.18 rather than update it to Total Plant Cost which will be done in Section 5.7.

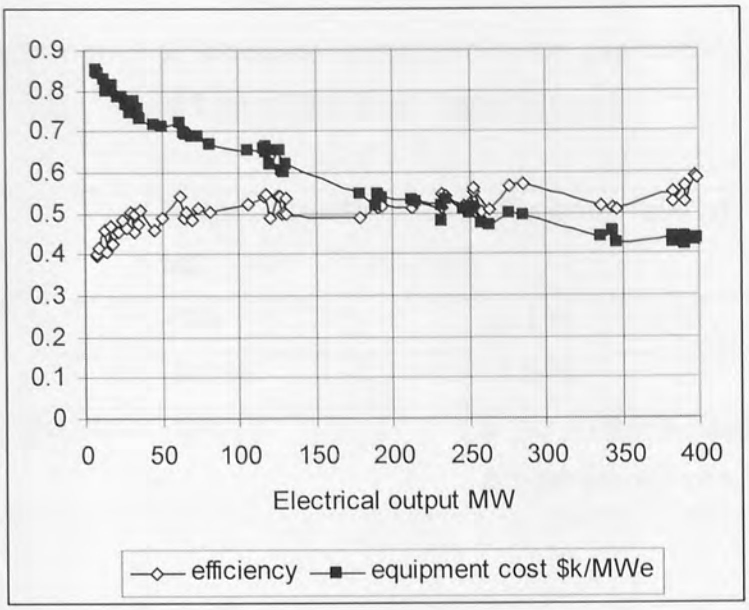

Figure 4.18 Equipment cost and efficiency for gas fired CCGT plants

It should be noted that the GT's employed at the higher loads use more advanced combustion systems (hence their improved efficiencies) and so are less likely to be able to be fired on bio-oil. If advanced technologies are considered to be unsuitable for bio-oil it is reasonable to predict that the efficiency of a gas fired CCGT plant will be around 52% over the power range of 50 - 350 MWe.

The specific investment falls with increasing output but most of the reduction takes place at outputs below 180 MWe. Consequently it would appear that the optimum size for a CCGT would be in the range of 180-350 MWe.

4.7.2 Rating for bio-oil

A plant operating on bio-oil is unlikely to achieve the same output as one burning natural gas. A major supplier of CCGT plant, General Electric (GE), publishes product descriptions for CCGTs which give de-rating factors for CCGT plants using liquid fuels [170]. It is worth comparing these figures with the reported performance figure for the OGT2500 GT that has been modified for use on bio-oil [70]. This has been done in Table 4.16.

Table 4.16 Performance of industrial combined cycle gas turbines running on liquid fuel rather than natural gas.

Fuel	Output relative to NG	Efficiency relative to NG
GE distillate	-3%	-2.1%
GE residual	-9.3%	-7.6%
Orenda OGT2500 bio-oil	-6%	0 to -18.7% depending on actual bio-oil characteristics

The range of values for the efficiency of the Orenda GT results from the fact that Orenda only reports a range of values for bio-oil heat capacity and densities rather than the actual values taken from samples of the oil used.

The efficiency de-ratings are the percentage change in the efficiency, not the actual change in efficiency i.e. if a CCGT has an efficiency of 50% when using natural gas, GE predict that it will have an efficiency of 92.6% of 50% i.e. 46% when operating on residual fuel.

In earlier publications describing the Orenda test program [171] the OGT2500 is quoted as having an output of 2760 kW_e. This is listed in Gas Turbine World Handbook [170] as a re-rating following upgrades. The efficiency of the engine on natural gas has also been increased from 26.7% to 28.3%. Using the re-rated value to calculate the output de-rating for operating on bio-oil it is -9.1%, remarkably close to the GE estimate for residual fuel. Consequently a 9% down rating will be applied to GT and CCGT outputs in this study.

Using the re-rated natural gas efficiency for the OGT2500 the de-rating for bio-oil should be in the range of 5.8 to 23.3%. The GE estimate for residual fuel is in the lower end of this range however the Orenda figures are for single cycle operations where as the GE figures are for combined cycle operation. In a CCGT a drop in GT efficiency can be partially offset by an increase in the amount of heat recovered by the steam cycle.

The difference in values between distillate oils and residual oils is attributed to the ash content of the residuals. Although this is small it can build up in the gas passes reducing heat transfer and restricting gas flow. There is likely to be some char and ash carryover in the pyrolysis plant so there will be some ash in the bio-oil. Distillate fuels have ash contents up to 0.01% by weight where residual fuels can have ash contents up to 0.2% by weight. The bio-oils are reported to have ash contents in the range 0.1-0.2 % mass [48] (the bio-oil specification used by Orenda was for an ash content less than 0.05%) and so it can be assumed that bio-oil is more like residual fuel oil than distillate fuel oil. Consequently a bio-oil CCGT can be expected to have a net efficiency that is only 92.4% of its natural gas rating. In Section 4.7.1 it was concluded that the optimum sized CCGT that is suitable for use with bio-oil would have an efficiency of 52% which would give an efficiency of 48% when burning bio-oil.

It is expected that any bio-oil plant will run at close to base load. When gas fired CCGTs were first built in the UK they were run as base load plants. The capacity figures for all UK plants are given in DUKES Table 5_10 [7]; the maximum annual capacity factor achieved by the GT fleet was 84% (in 1999). The annual capacity factor for an individual CCGT will depend on whether there was a major inspection or overhaul of the GT in the year so the capacity factor for the fleet gives a better indication of the life-time capacity factor. If it is assumed that bio-oil GTs will need a similar maintenance and inspection routine to GTs operating on residual fuel oil or crude oil on the basis that they contain some ash and alkaline metals [174] it is probable that they will need inspecting at 3-4 times the frequency of natural gas machines. GE maintenance notes give a typical outage figure of 1.5% forced outages and 3.5% planned outages.

If it is assumed that the rate of forced outages is independent of the fuel used with an inspection multiplier of 4 (appropriate for residual fuels with low hydrogen content) a bio-oil fired GT is likely to be unavailable due to planned outages for an additional 10.5% of the time when compared to a natural gas machine. This would give a credible maximum capacity factor of 74%.

4.7.3 Works power estimate of gas turbines.

An information paper prepared for the Electricity Supply Industry Planning Council of South Australia [173] quotes the finding of an investigation by Sinclair Knight Merz which gives the works power as 2% of generation for the following CCGTs:

- 2xGE frame 6B with a gross CCGT output of 130 MW;
- GT13E2 with a gross CCGT output of 245.6 MW;
- GE frame 9F with a gross CCGT output of 396.6 MW.

The frame 6B and 13E2 are representative of the type of industrial gas turbine that could be run on bio-oil, so a works power figure of 2% will be used for CCGTS. The same report gives a works power estimate of 1% for a frame 6B operating in open cycle.

4.8 Open cycle gas turbine

4.8.1 Applications of open cycle gas turbines

Open cycle gas turbine generators tend to be used for:

- Peak load or standby duties where the running hours are low;
- In oil rigs and situations where there is abundant gas that would otherwise be flared;

- As a heat source in CHP schemes where the heat load has to be supplied at a high temperature, or where the heat load is too high to be met by a diesel engine but not large enough to justify a combined cycle gas turbine with a back pressure steam turbine.

It has been assumed that the same bio-oil derating factors will apply to OCGT operations as applied to CCGT operations in Section 4.7.2.

OCGTs are only being considered for peak load and CHP applications in this study. In both cases it should be possible to accommodate the reduced inspection period within the annual low load period (i.e. carry out a major inspection and overhaul every summer rather than one in three).

4.9 Combustion plant

It has been established in laboratory and field trials that bio-oil can be successfully burnt in industrial furnaces [53-59,175-176]. A commercial installation would need a fuel handling system that can cope with the corrosive and viscous nature of bio-oil without holding it at elevated temperatures. It is also likely that a start up fuel will be needed to heat up the furnace to aid initial ignition of the bio-oil. As the total combustion time for bio-oil is similar to that for coal or heavy fuel oil [54] it should be relatively simple to convert existing utility scale boilers to burn bio-oil. Key issues for the successful burning of bio-oil have been identified from a number of combustion trials [176] and are listed below:

- Bio-oil has a high moisture content and will not ignite unless the burner surroundings are hot. This means that an alternative fuel to bio-oil will be needed for start up.
- Bio-oil has about a third of the heating value/ litre of mineral oil. This means that 3 times the volume of bio-oil is needed for the same energy input. It is unlikely that this increase could be accommodated in existing oil burner lances.

- Bio-oil needs to be stored at a relatively low temperature to avoid degradation however it needs to be preheated to reduce its viscosity allow it to atomise. The standard practice for HFO is to store the oil at an elevated temperature (typically 50°C) to improve its handling characteristics. This would not be desirable for bio-oil so a new bio-oil storage tank, forwarding pump and pre-heater would be needed before bio-oil firing could be considered.
- Bio-oil is corrosive so the fuel system and burner lances need to be made of stainless steel.
- Bio-oil does not mix with mineral oil so any shared components would need to be flushed with a mutually compatible solvent.

Bio-oil has the following advantages over fossil fuel:

- It is CO_2 neutral;
- It has a very low sulphur content;
- It can have a lower ash content;
- The high moisture content of bio-oil causes it to have a lower flame temperature than fossil fuels which reduces the generation of thermal NO_X.

It has the following advantages over unconverted biomass:

- It is simpler to store and handle, although in practice the biomass handling problems will be transferred to the pyrolysis plant;
- It is homogeneous and has an uniform moisture content and heating value. This means that the flame should be more stable than for unconverted biomass which in turn should allow a lower amount of excess oxygen to be used which will lower the stack losses from the boiler.

- Fast pyrolysis takes place at a temperature below the melting point of the ash in the biomass [177]. Consequently the ash is concentrated in the char. Some of the char will end up in the bio-oil but with good separation techniques it should be able to reduce the ash content to 10% of that of the original biomass. This is significant as biomass ashes have lower melting points than coal ashes and can form corrosive deposits on boiler tubes if the furnace is operated at the same temperature as it would be for coal combustion [178].

Clearly there is an energy cost in the production of bio-oil from biomass. The biomass feedstock used by a pyrolysis plant could be burnt directly in a steam cycle power station. The extra cost involved in producing bio-oil from the biomass can only be justified if it allows the bio-oil to be utilised more efficiently than the unconverted biomass. Existing dedicated biomass combustion plants have efficiencies around 33% [87,126]. It is assumed that the efficiency of biomass combustion units is limited by the need to keep the furnace temperature below the ash fusion temperature and logistic problems with getting sufficient biomass to a very large scale plant. Bio-oil is easier to transport than biomass, so should not suffer the same logistic constraints; this is investigated in Section 6.2. It also has a much lower ash content - so it is possible that bio-oil fired combustion plants could have similar performance to existing coal fired ones. Large sub-critical steam plants should have cycle efficiencies up to 38% [156] and super-critical plant could achieve up to 47% efficiency [179-181]. Consequently it is possible that the cost of converting biomass to bio-oil could be outweighed by the increased efficiency of the higher steam temperature power plants.

Bio-oil can either be the principal fuel or co-fired with fossil fuels. Co-firing has the advantage that the furnace can be warmed up with fossil fuel which will help with ignition of the bio-oil.

Combustion plants tend to have high availability with even high technology supercritical plants achieving 85% availability [181].

In practice combustion plant capacity factors are dependent on the availability of load rather than the plant.

4.9.1 Works power estimation for combustion plant

A 500MWe pulverised coal fired power station uses around 3.1% of the electricity it generates when operating as full commercial load [182]. Around 19% of this is used by the coal mills so a reasonable estimate for a bio-oil fired steam unit would be 2.5%.

4.10 CHP systems

Although these can be considered as sub system of diesel and open cycle gas turbines CHP applications impose their own constraints on the operation of generation plant.

4.10.1 Capacity Factor

The average capacity factors for all the CHP plants in the UK are published in DUKES [185] and are shown in Figure 4.19.

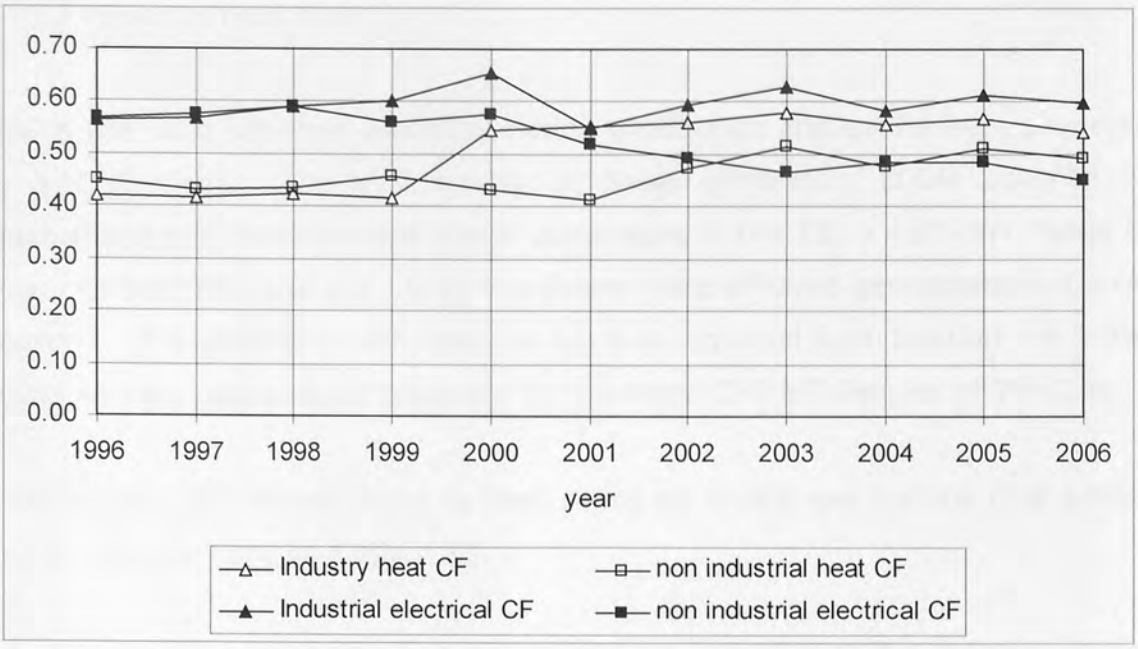

Figure 4.19 Capacity Factors for UK CHP plants

Figure 4.19 shows the capacity factor for different sectors. It is noticeable that the electrical and heat capacity factors are not the same. This can be due to a number of factors including:

- The use of steam bled from a steam turbine to provide heat;
- The use of auxiliary boilers to provide extra heat at times of high demand and to satisfy the low demands;
- changes in the heat/power ratio with generator loads.

The non-industrial sector will be space heating application. The industrial sector will contain some process heating applications which will have a lower seasonal variation than space heating applications hence the higher capacity factor. The survey of Biomass CHP plants in Europe [108] identifies that there is a wide spread of capacity factors between sites but the averages for the different technologies is between 40-60 %. This is consistent with the figures in Figure 4.19.

4.10.2 Power to heat ratio

This is the ratio between electrical power production and useful heat production by a CHP plant. The VTT survey of diesel generators [164] covered CHP applications and reported that diesel generators in the 250 - 450 kWe range had power to heat ratios of 0.8 - 0.95 but larger more efficient generators had a ratio nearer 1. If a generation efficiency of 42 % is assumed from Section 4.6.3 these power to heat ratios would translate to combined CHP efficiencies of 75-82%.

A US report [185] gives power to heat ratios for typical gas turbine CHP systems this is included here as Table 4.17.

Table 4.17 power to heat ratios for gas turbine CHP schemes

GT	Saturn 20	Taurus 60	Mars 100	LM2500+	LM6000PD
size MWe	1	5	10	25	40
p/h	0.48	0.64	0.69	0.89	1.0
electrical efficiency	21.9%	27.1%	29.0%	34.3%	37.0%
CHP efficiency	68%	69%	71%	73%	74%

The efficiencies quoted in this table are on a HHV basis for natural gas. It should be noted that the LM series machines are aero derivatives and so are not representative of the GT that could use bio-oil the other machines are all industrial turbines from Solar Turbines which probably could be modified to use bio-oil. It is noticeable that the CHP efficiencies for the GT based CHP schemes is less than that for the diesel plant this is because it is normal practice on engine based schemes to use the heat from the engines cooling circuits as well as heat extracted from the exhaust gases. In GT based schemes it is normal practice to only extract heat from the hot exhaust gases.

4.11 Bio-oil storage tanks

One of the advantages of pyrolysis over gasification is that it is easier to store bio-oil than it is bio-gas. There are three reasons for wanting to store bio-oil:

- to balance the yields resulting from the use of biomass with different ash content;
- to cover for periods of pyrolysis plant or generator plant non availability;
- to smooth out seasonal loads.

The amount of storage needed to balance the effect of variations in ash content will depend on the number of days' supply of biomass held in each field store and if there is an active programme to take biomass from field stores with different ash contents to balance the ash content over time. This makes it hard to estimate accurately; however the storage capacity needed to cover pyrolysis plant break downs is likely to be sufficient.

There are biomass fired BFB CHP plants used for district heating. These achieve availabilities of around 90% [108]. It is likely that pyrolysis plant based on BFB technology could achieve similar availabilities. Consequently storage of up to 10% of the pyrolysis plant's output should be provided to cover plant non-availability (a lower figure may be appropriate if the planed maintenance on the pyrolysis plant can take place at the same time as the planned maintenance outages of the generation plant).

For CHP plants the storage capacity required will depend on the variation of the electrical load. It has been assumed that these will follow the heat demand. Some industrial CHP systems provide process heat which is relatively constant throughout the year. The storage requirements of these plants will depend on the process plants operating conditions and any contingency storage to cover for possible failure of the pyrolysis plant.

For CHP plants use to supply space heating loads the heat load will be seasonal. If the plant has rated bio-oil consumption Q_R per month then the average monthly consumption over a year Q_A is the rated consumption multiplied by the capacity factor (CF). In a situation where a pyrolysis plant was installed such that when operating under base load condition with an availability of A_P it would provide sufficient bio-oil to satisfy the average loads of the generator with storage being used to buffer the fluctuations in bio-oil demands. The storage requirement will depend on the annual load profile. In this case, if the pyrolysis plant monthly output at base load is Q_P then:

$$Q_R = \frac{Q_P A_P}{CF}$$

Space heating CHP plants (which may supply industrial as well as non industrial clients) are designed to keep something at a fixed temperature throughout the year. The heat input needed to achieve this can be assumed to vary with the number of day light hours and so be considered to be sinusoidal in nature. If the peak and average value of the demand is known it should be possible to predict the seasonal storage requirements. If Q_M is the heat required in month M, where the months are numbered from the spring equinox i.e. month 0 is April

$$Q_M = Q_A - (Q_R - Q_A)\sin\left(\frac{2\pi M}{12}\right)$$

The excess production during the summer months will need to be stored, the bio-oil storage capacity required, Q_S, can be calculated from

$$Q_S = \int_0^6 (Q_A - Q_M)dM = \int_0^6 (Q_R - Q_A)\sin\left(\frac{M\pi}{6}\right)dM$$

$$Q_S = \frac{12(Q_R - Q_A)}{\pi}$$

but

$$Q_A = CFQ_R$$

and

$$Q_R = \frac{Q_P A_P}{CF}$$

so

$$Q_S = \frac{12 Q_P A_P}{\pi}\left(\frac{1}{CF} - 1\right)$$

If a value of 50% is taken as the CF for non industrial applications Figure 4.19 and a pyrolysis plant availability of 90% is assumed the storage capacity for a seasonally variable load comes to 3.4 months production. In practice there will need to be an additional amount to cover non availability of the pyrolysis plant so this may be increased to 4 months production.

It should be noted that the minimum capacity factor for a sinusoidal variation is 50%. Lower values of capacity factor can be modelled by assuming that the year is split up into a sinusoidal heating season and a shut down period in this case if N is the length of the heating season the annual consumption Q_Y is given by:

$$Q_Y = \frac{NQ_R}{2} = 12Q_A$$

$$CF = \frac{Q_A}{Q_R} = \frac{N}{24}$$

$$N = 24CF$$

From Figure 4.19 it would appear that the electrical capacity factor for non industrial installation can fall as low as 45% in this case N would be 10.8 months so an additional storage capacity of 1.2 months production will be needed so the total storage capacity would be around 5 months.

It is desirable to minimise the length of time bio-oil is stored. To achieve this bio-oil needs to be stored in a number of storage tanks that are filled and emptied sequentially.

To avoid mixing old bio-oil with new bio-oil it is necessary to completely empty a tank before starting to draw bio-oil from the next tank so there will be a day at the end of the storage season where one tank must be empty (to take the newly produced bio-oil) and the other tanks full, i.e. the total site storage capacity needs to be one tank more that the storage requirement.

If the number of tanks is increased the capacity of each tank is reduced so the "surplus" capacity caused by the need to have an extra tank is reduced. But the cost per unit volume of smaller tanks will be larger that that for bigger tanks, so there must be an optimum number of tanks.

Assuming that the tanks are cylindrical and standing on their flat base and that the height to diameter ratio is kept constant the capacity of 2 tanks will be determined proportional to the cube of their radiuses but their cost is basically determined by their surface area so:

$$C_2 = C_1 \left(\frac{Q_2}{Q_1} \right)^{\frac{2}{3}}$$

Where C_1 is the cost of a tank with capacity Q_1,
and C_2 is the cost of a tank with capacity Q_2.

The relative costs of providing the required storage capacity using a number of tanks has been calculated and is shown in Table 4.18. The costs are normalised to the cost of a tank that can supply all the required seasonal storage.

Table 4.18 the relative cost of different tank configurations

number of tanks	relative cost of 1 tank	total relative costs of tanks for site
2	1.000	2.000
3	0.630	1.890
4	0.481	1.923
5	0.397	1.984
6	0.342	2.052

It is clear from Table 4.18 that the most economic number of tanks to use is three. The maximum duration of storage will be the tank filling time plus the tank emptying time at the minimum consumption rate. This will happen in the summer. For an installation with a storage capacity of 4 months using 3 tanks the tank filling time will be 2 months. With a 50% CF the summer load is low and it would take nearly 6 months to empty the tank so the maximum storage time is 8 months. If 5 tanks are used the filling time is 1 month and the emptying time is 4.5 months shortening the maximum storage time to 5.5 months.

5 Sub-system capital costs

5.1 Capital cost estimation techniques

There are many different definitions of what the capital cost of a project is, these range from just the cost of the equipment to the full expenditure made by the owner in gaining consent, acquiring the land, developing the site, design and build contract, grid connection charges, commissioning the plant, training personnel, insurance and financing.

Many of the owner's costs are site specific and are generic to developing an industrial site. As such they are highly variable and add little insight into the relative merits of different technologies. Most techno-economic studies (including this one) concentrate on those owner's costs that are technology specific this is known as the Total Plant Cost (TPC). The TPC is made up of direct costs (those which relate to the hardware), indirect costs (those that relate to the construction process) and project costs or owner's costs (the financial cost involved with executing the project) [186]. Direct costs include:

- equipment purchase price;
- transportation to site;
- installation;
- electrical supply;
- piping;
- control and instrumentation;
- water and compressed air services;
- civil works;

The indirect costs include:

- engineering and supervision;
- construction expenses.

Owner's costs include:

- contractors fees;
- contingency;
- working capital.

The indirect costs are normally estimated as a percentage of the Direct Plant Costs (DPC). The sum of the direct cost and the indirect cost are known as the installed plant costs (IPC). The owner's costs are calculated as a percentage of the installed plant cost.

In practice some of these costs remain with the owner and some will be embedded in design and build contracts (also known as engineer, procure and construct contracts or turnkey contracts).

The DPC can be estimated by building it from the bottom up i.e. taking the cost of each plant item, multiplying it by factors to allow for installation, etc then adding up the cost for the complete plant. This approach has the following drawbacks:

- A fairly complete design is needed;
- An up to date database of equipment prices is needed;
- It is time consuming;
- The estimate is for a fixed size of plant;
- The value for the individual factors will vary with the type of plant.

This procedure is used by turnkey contractors but it can cost up to 2% of the project cost to produce a good cost estimate. It has been found that in practice in the initial phase of a project a cost estimate can be made by using a single installation factor (or Lang factor) in place of all the individual factors without an unacceptable loss of accuracy.

This approach has been used where the plant design has been developed to the process flow diagram [86,96]. It was also used for costing combustion based systems in the SUPERGEN programme. However detailed designs of the pyrolysis plants and suitably modified generation equipment are not available for this study. Neither is an up to date data base of equipment prices. An alternative approach is to get indicative estimations from equipment suppliers either directly or from other studies. This approach will be used in this study.

Total plant costs have been used if they are available. These are converted to sterling and indexed to 2006. Where an equipment supply cost has been used in this study the installation factor has either come from the source of the cost estimate (if available) or a textbook [84].

The value of the other factors have been estimated to reflect the complexity of the subsystem.

Equipment supplies can give estimations of the equipment cost (normally ex-works or "free on board" the means of transport use to move the equipment to site) or the cost of the equipment installed on site. If the estimate is for the supplier to install equipment on site it contains elements of indirect costs. This is particularly so if the contractor takes design responsibility in a turnkey contract (one where the client just has to "turn the key" to start the plant). In these cases the owner's costs reduce to those involved with finance and a small contingency to cover the risk of changes to the plant that are the result of events outside the control of the contractor.

All capital cost referred to in this study are Total Plant Costs expressed in pounds sterling at 2006 base data unless specifically stated otherwise.

It is unusual to get a published cost estimate for the exact size of plant that is being considered. Capital costs are sometimes expressed in terms of the Specific Investment, this is the ratio of the Total Plant Cost to the plant's electrical output. This can be used to provide a cost estimate for a given power rating but in most cases the specific investment cost is a function of plant size. A more reliable cost estimate can be obtained by using a sizing equation of the form:

$$Cost_Q = Cost_R \left(\frac{Q}{R} \right)^F$$

Where $Cost_Q$ is the cost for a plant with a throughput of Q, $cost_R$ is the published cost of a known reference plant with a throughput of R, and F is the scaling factor.

The use of scaling factors is appropriate in situations where the increase in throughput is achieved by increasing the size of a plant item rather than adding additional plant items.

Where throughput is increased by adding additional identical process lines (or stream) to operate in parallel it is appropriate to reduce the cost of repeat streams as they do not need fresh engineering and should be some lessons learnt from the first stream which will reduce costs on the subsequent ones. For these reasons the cost of the later streams should be at least 5% lower than for the first stream.

Costs have been taken from sources that were published at different dates. All costs are adjusted to pounds sterling at the base dates of the papers where given (or one year earlier than the published date if a base date was not quoted in the source). The exchange rate used is the average for the year of the monthly average spot exchange rate from the Bank of England's web site [107]. The costs are then indexed up to 2006 level using the US Chemical Engineering magazine Plant Cost Index as this index was used in the papers that the costs have been taken from.

Location factors have not been applied to reported costs from different countries. This is mainly due to the lack of location data in much of the literature. It is worth noting that a 1994 source [184] gives a spread of location factors among the US states (excluding Alaska and Hawaii) of 1.0-1.7 and a factor of 1.13 for the UK so it would appear reasonable to assume that average US and UK costs will be similar.

5.2 Woodchip handling plant

5.2.1 Cost data sources

Costs for woodchip handling equipment have been calculated from the data given in Badger [93]. These are a mixture of equipment supply costs and fully installed equipment costs. Badger states that the cost of installing the plant is 50% of the equipment cost. However this does not give the full TPC.
A more comprehensive list of costs factors is included in an American study on the use of forestry thinning by the Antares Group [121]. These have been used to provide suitable factors for different groups of equipment and contract arrangements. Table 5.1 contains the values used.

Table 5.1 cost multipliers for use with woodchip handling plant

contract type	supply only	turnkey		
	plant	plant	silos	civil work
equipment EC	1	1.00	1.00	1.00
installation	0.5	0.00	0.00	0.00
civil	0.19	0.19	0.19	0.00
electrical	0.16	0.16	0.00	0.00
direct cost	1.84	1.34	1.19	1.00
engineering	0.10	0.00	0.00	0.00
contractor fee	0.07	0.00	0.00	0.00
contingency	0.10	0.05	0.05	0.05
owners	0.10	0.10	0.10	0.10
TPC/EC	2.53	1.55	1.36	1.15

The factors are lower for the turnkey contracts as the turnkey price has been used in place of the equipment cost, (in a turnkey contract the true direct costs are only known to the contractor). It would be possible to use the typical ratios used for equipment only supply contracts to infer an equipment cost from the plant supplied under turnkey contracts and hence arrive at a common TPC/EC ratio for all plant contracts, but this adds an additional level of assumptions without gaining any additional accuracy or insight.

The costs from Badger were converted to sterling at the 2002 exchange rate (\$1.5035 to £1) and inflated using the CE index.

The costs for the supply of the grinders were taken from Lang [125] increased by a factor of 2.43 to get their TPC. These were converted to sterling at the 2004 exchange rate (€1.4739 to £1) and inflated using the CE index.

Although the Antares report includes costs for different size installations there is insufficient definition of the rating of individual plant items to use the data directly.

The estimates given in the papers were used to produce the following sizing equations. for the TPC in £k.

For ground hoppers

$TPC = 16.13\ Q^{0.2939}$
where Q is in t/h

For screens

$TPC = 7.6418\ Q^{0.3904}$
where Q is in t/h

For silos

$$TPC = 3.774\ Q^{0.6787} + 73$$

where Q is in m^3 . The £73k is a fixed price for the silo feeder conveyor.

For dryers

$$TPC = 230.78\ Q^{0.5044}$$

where Q is the dryer output in t/h

For grinders

$$TPC = 0.179Q^2 + 0.0399Q + 84.326$$

where Q is in t/h

Neither the Badger or Antares studies fully defines the conveyors that they have included in their extents of supply; however it is clear that there is relatively little cost increase with increasing capacity. Badger quotes \$34k for a 20 t/hour conveyor and \$35.34 for a 98.5 t/hour one covering the same duty. The Antares report quotes \$35k for a 14 ton/hour conveyor and \$45k for a 44 ton/hour one. The conveyors needed to service the stocking out and reclaim functions are sized to cope with the feed rate from the unloading hopper or reclaim rate achievable by a front end loader; as such they are closer to the size referred to by Badger than those in the Antares report. Consequently they have been estimated on the basis of Badger's costing with a sizing equation of:

$$TPC = 62.33\ Q^{0.0417}$$

where Q is in t/h.

These sizing equations have been used to calculate the cost of components of the wood handling and processing system.

5.2.2 Reception, stocking out and reclaim costs

These costs have been grouped together as they do not scale directly with plant size.

5.2.2.1 Weighbridges

Badger states that both mechanical and electronic weighbridges are in service in the USA.

The electronic ones cost more but have a faster turn round time, and can be interfaced to automatic delivery ticket production, stock control and payment systems. As such they appear to be the best choice for the sizes of plants considered in this study. The report quotes a turnkey cost so a factor of 1.31 has been used to convert the reported turnkey price into a TPC of £144k. Electronic weighbridges can take 3-4 minutes for a weighing operation; if a little extra time is allowed for truck manoeuvring it should be able to handle 10 trucks an hour with one weighbridge. Each delivery needs two weighbridge operations to establish how much biomass has been delivered so a single weighbridge can cope with 5 deliveries an hour. If the effective delivery day is 7.2 hours and each truck load is 26 t then one weighbridge can handle 936 t of woodchips a day or 4680 t a week which at 45% moisture content corresponds to 368 odt/d.

5.2.2.2 Stocking out systems

From Table 4.2 for the 50 odt/d and 100 odt/d plants the incoming deliveries are tipped into an unloading bay and the stocking out is carried out by the stock reclaim front end loader and so there is no capital cost associated with this function. For the 150 odt/d and 200 odt/d a system that can handle 106 t per hour should be able to carry out the stocking out duties. The following costs are associated with this system:

- 1 unloading hopper. This is estimated to cost the same as a self unloading trailer £85k;
- 1 screen £34k;
- 1 stocking out conveyor, £76k;
- 1 Radial stacker conveyor,£77k.

making a total of £271k.

The 400 odt/d plant requires and additional unloading hopper and associated screen to be added to the system to cope with the estimated truck handling rate this increases the cost to £389k for this system.

It has been assumed that the cost of the conveyors and radial stacker can be scaled up to a capacity of 212 t/h (from 98.5 t/h) using the sizing factor for the conveyors. Such a system would be suitable for the 600 odt/day. The following costs are associated with this system:

- 2 unloading hoppers £171k;
- 2 screens £65k;
- 1 stocking out conveyor £78k;
- 1 radial stacker conveyor £80k.

making a total of £393k.

The 800 odt/d plant requires and additional unloading hopper and associated screen to be added to the system to cope with the estimated truck handling rate this increases the cost to £511k for this system.

5.2.2.3 Reclaim systems

The costs for the reclaim system for plants requiring less than 180 odt/day are:

- Front end loader with a $5m^3$ bucket £97k. (The TPC for a front end loader is the purchase price with the owner's costs and contingency added);

- Ground hopper £35k;
- Screen £25k;
- Conveyor £74k.

making a total of £231k

The costs for the reclaim system for plants requiring more than 180 odt/d are:

- Front end loader with a $9m^3$ bucket £243k;
- Ground hopper £43k;
- Screen £34k;
- Conveyor £77k.

making a total of £395k

This system is limited by the ability of the front end loader to reclaim woodchips. If an effective 12 hour working day can be achieved a single front end loader can reclaim 1,440 t/d or 792 odt/d. Consequently this system should be usable for plants with consumption up to 800 odt/d.

An alternative fully automated option has also been quoted in the Antares report. This uses a more sophisticated radial stacker (the one in the Badger report appears to need to be manually slewed) and a pivoting screw auger for recovery. This system is not scaled but is estimated to cost the equivalent of £396k for the radial stacker and £445k for the reclaimer for a 678 ton a day plant. If this equipment was used in place of the Badger radial stacker, recovery ground hopper and front end loader the stocking out and reclaim plant cost would be £1,143k. This is £474k more than the front end loader based system but given the capital equivalent cost of labour calculated in Section 3.3.3 it could be an economic option for those systems where the staffing of the reclaim system exceeds 10 operator shifts a week. Assuming that a shift constitutes 6 hours actual working time and a front end loader can move 120 t in an hour this would represent a weekly reclaim of 72,000 t. If it is assumed that the plant's requirement during the reception day is taken directly from the days deliveries then the plant needs to be supplied from the reclaim system for 64% of the time. This would mean that 10 operator shifts could supply a plant with a demand of 112,500t a week or 16,007t a day which is far more than any installation considered in this study requires. Consequently it is not consider that an automatic system for woodchip handling would be cost effective.

5.2.3 Woodchip store

The woodchip store is sized to hold 4 days supply of fuel. This is considerably less than the American plants but should be sufficient for UK weather conditions and non delivery periods and is consistent with practice on existing UK biomass power stations [126].

The store area was based on a 6m high square pile (the maximum that can be built with a normal front end loader) with sides sloping at 45° with 7m access ways running around its base. Their costs were estimated using £51.5 / m^2 which was derived from the rates in Badger. The costs for the store for plants with consumption up to 800 odt/d are given in Table 5.2.

Table 5.2 Store costs

plant size	odt/d	50	100	150	200	400	600	800
volume	m^3	1536	3072	4608	6143	12287	18414	24557
length	m	26	33	38	42	55	65	74
TPC	£k	35	55	73	91	157	220	282

5.2.4 Woodchip processing systems

These systems consist of the dryer silo, dryer, grinder silo, grinder, and pyrolysis feeder silo. These are all provided on a per pyrolysis reactor basis and can be scaled to fit their duty. The costs of these items are shown in Table 5.3.

Table 5.3 TPC of wood processing plant in £k

size	50 odt/d	100 odt/	150 odt/d	200 odt/d
dryer silo	167	223	269	311
dryer	337	478	586	678
grinder silo	206	286	286	331
grinder	69	99	82	99
pyrolysis silo	206	286	286	331
total	986	1371	1509	1751

The reduction in grinder cost for the 150 odt/d plant compared to the 100 odt/d plant reflects the longer grinding operating hours used on the larger plant.

5.2.5 Total system costs

Table 5.4 summarises the cost from Sections 5.2.2.1, 5.2.2.2, 5.2.2.3, 5.2.3 and 5.2.4.

Table 5.4 TPC in £k of woodchip handling plants for sites with demands up to 800 odt/d

plant size odt/d	50	100	150	200	400	600	800
weighbridge	144	144	144	144	144	287	287
stocking out	0	0	271	271	389	393	511
store	35	55	73	91	157	220	282
reclaim	231	231	249	395	395	395	395
processing	986	1371	1509	1751	3503	5254	7006
total	1395	1800	2246	2652	4587	6550	8481
SI £k/odt	27.9	18.0	15.0	13.3	11.5	10.9	10.6

A 800 odt/d plant is likely to have 4 pyrolysis reactors.

For larger sites it is assumed that the plant will be split up into 600 or 800 odt/d streams. The TPC data in Table 5.4 has been plotted in Figure 5.1; there is a strong linear relationship between the TPC and pyrolysis plant size.

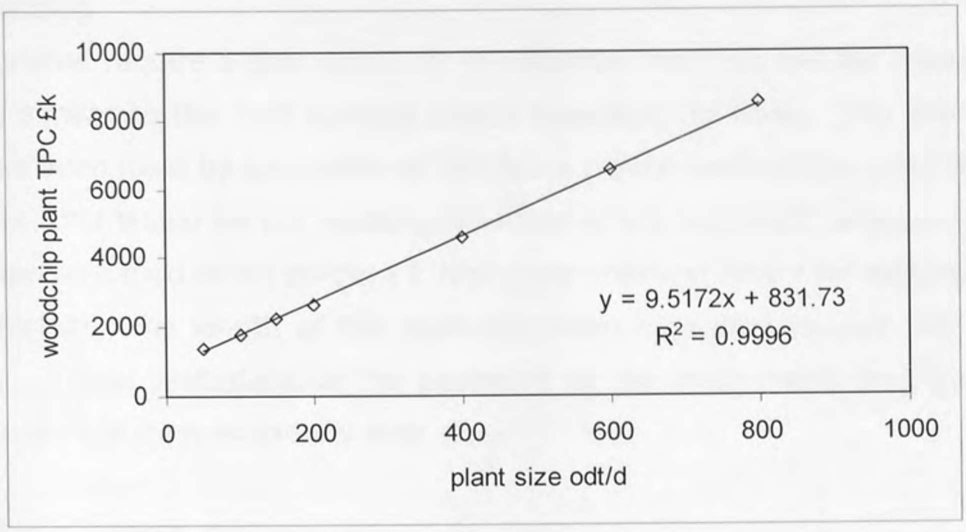

Figure 5.1 Woodchip plant TPC for increasing pyrolysis plant size.

5.3 Miscanthus handling

5.3.1 Cost data sources

The costs for most of the plant items required for miscanthus handling come from Hess [133] which gives turnkey costs. These have been increased by the factors in Table 5.1 to give TPC estimates.

The cost for silos, weighbridges and fork lift trucks (assumed to be the same as a small front end loader) have been taken from the data used for woodchip handling to maintain consistency in pricing between the different systems.

Miscanthus handling plants fall into two groups, manual handling and automatic handling systems.

5.3.2 Costs for items that are required for all systems.

Store building

Both systems require a bale store. It is assumed that this will be inside a basic building similar to the field storage sheds described by Hess. The width of the store has been fixed by the length of the truck trailer combination used to deliver the bales (this would be the working traverse of the automatic crane), the bales have been assumed to be stacked 6 high (the practical limit that can be stacked with a forklift), the length of the store has been increased to give the required capacity. These limitations of the geometry of the store mean that the cost of the bale store increases linearly with size.

TPC = 0.12Q + 38.2 £k

where Q is in t.

Grinders

The cost for the tub grinder used in the Idaho trial covered in the Hess report has been used and scales with a sizing exponent of 0.6. This probably gives a high estimate as these grinders were diesel powered mobile units, where a fixed installation would use lower cost electrical power units.

Dryers

Band dryers have been assumed to be used in these installations. Equipment costs have been taken from [161] and increased by a factor of 2.16 to give the TPC. The following sizing factor has been used:

$TPC = 355.7\ Q^{0.61}$

where Q is the dryer input in t/h.

This sizing factor was estimated by making the following assumptions:

- The cost build up followed the factors given in Table 5.1;
- The mechanical equipment costs increase linearly with throughput;

- The civil cost increases linearly with throughput;
- The installation cost is independent of plant size;
- The electrical cost is independent of plant size,
- The engineering cost is independent of plant size.

5.3.3 Cost unique to manual systems

The unique costs for manual systems are the fork lift trucks and weighbridges (the automatic crane includes a hoist load recorder and moisture meter so the auto systems do not need weighbridges). The fork lift trucks are assumed to cost the same as the small front end loader used for woodchip plants. A single fork lift can cope with the loads on small plants but a second truck is needed on larger plants, it is considered that it is not desirable to have more than two forklifts operating in a single bay.

5.3.4 Cost of the automatic crane system

This has been taken from the Hess report [133]. The system is sized to deal with a truck load at a time; as such it is not really able to increase capacity. It would be possible to reduce the capacity to 1/2 of a layer at a time but this would have an adverse effect on the truck turnaround time and so has not been considered. With a 54 t/h unloading rate a single crane operating for 5 day a week can unload enough miscanthus to supply a 200 odt/d pyrolysis unit in 6.9 hours a day. This is not much less than the effective delivery hours available in a 12 hour day so there is little scope to share cranes between pyrolysis units. If two cranes are mounted on a common rail it should be possible for one crane to service both units provided 24 hour working is allowed; this should give some flexibility to cover breakdown and maintenance but is not a good practice for normal duty.

5.3.5 Total system costs

The total system cost for miscanthus handling and processing systems are shown in Table 5.5.

Table 5.5 TPC in £k of miscanthus handling plants for different pyrolysis plant capacities

size odt/d	50	100	150	200	400	600	800
number of bays	1	1	1	1	2	3	4
weighbridge	144	144	144				
forklifts	97	195	195				
auto cranes				911	1822	2733	3644
store building	70	103	134	165	330	495	660
grinder	186	186	236	281	561	842	1122
dryer silo	126	200	199	243	486	729	972
dryer	667	1017	1294	1544	3089	4633	6178
total	1289	1845	2201	3144	6288	9432	12576
total - discount	1289	1845	2201	3144	6131	9118	12105
SI £k/odt	25.78	18.45	14.67	15.72	15.33	15.20	15.13

If it is assumed that in practice the automatic system will need 1 attendant per bay it should be noted that the forklift based systems at the 100 and 150 odt/d plants require an additional operator. If this additional operator is capitalised at £324k (the sum appropriate for a 10% real discount rate from Section 3.3.3) the effective TPC for the 100 odt/d plant is £2,169k with an SI of £21.7k/odt and the TCP for the 150 odt/d plant is £2,525k with an SI of £16.8k/odt. The estimated TPC for the different pyrolysis plant sizes is plotted in Figure 5.2.

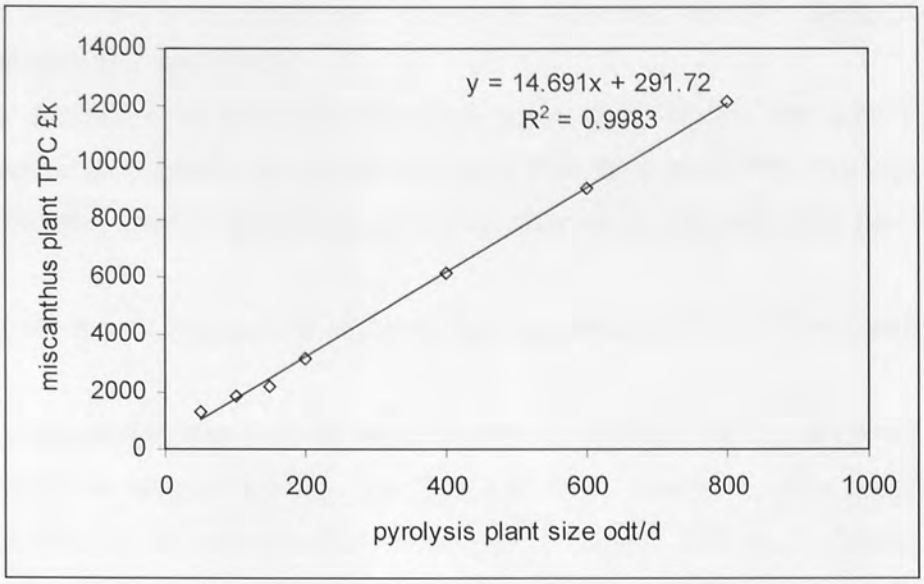

Figure 5.2, Estimated TPC for miscanthus pre-processing plant for different sized pyrolysis plants

It should be noted that although Figure 5.2 shows a straight line characteristic once automatic cranes become economic the cost actually increase in a number of discrete steps. Fortunately these steps correspond in an increase in the pyrolysis plant capacity of 200 odt/d or adding one maximum sized pyrolysis reactor to the plant, so the linear characteristic can be used for this study. In situations where the operation and plant size constraints assumed in this study are not applicable it may be necessary to revert to a stepped characteristic.

5.4 Pyrolysis plant

All of the reviewed techno-economic studies give costs for BFB pyrolysis units (although [86] also includes costs for Rotating Cone Reactors). This type of reactor has the following advantage:

- They have been commercially implemented;
- Much of the experimental investigation into yields have been carried out in BFB rigs;

- The process is scalable (up to a limit imposed by the ability to transfer heat into the reactor);
- The excess char can be removed from the reactor for use as fuel by external processes (in Rotating Cone Reactors and CFB the char is burnt within the reactor and surplus energy has to be extracted as heat).

Consequently it was decided to concentrate on BFB reactor for this study.

As mentioned earlier the size of BFB reactors is limited by the ability to transfer heat through the jacket wall into the fluidised bed. The heat required by the bed will increase with its volume but the heat transfer will be a function of the surface area of the reactor in contact with the bed. The action of the fluid bed will cool the face of the jacket to the bed temperature so the heat transfer will be limited by the temperature limit of the heating gases as discussed in Section 4.4.1.6 and the ability of the jacket wall material to withstand both the thermal gradient across it. The calculation of this limit is outside the scope of this study. In order to ensure that the plants being considered are realisable it has been decided to limit the size of the individual reactors to the largest actually built i.e. 200 odt/d. In the published reports only Ringer [96] considers units that are considerably larger than this; unfortunately he does not discuss the issue of heat transfer. The BESP for 400 odt/d plants using two 200 odt/d reactors or one 400 odt/d reactor will be calculated in Section 7.1.1.4 to see the impact that the imposition of this size limit has on generations costs.

The reported Total Plant Costs from the literature review converted to sterling and indexed to 2006 are given in Table 2.2. These costs include an estimate for woodchip pre-processing plant. This estimate is given separately in all the papers except the Farag, LaClai and Barrett report [89]. All the reported costs are for single reactor installations; it is essential to have separate estimates for the pyrolysis reactors and woodchip handling plants in order to estimate the costs of a multiple reactor site.

The woodchip plant costs from the literature review have been compared with those calculated by the regression equation from Figure 5.1 in Table 5.6.

Table 5.6 Comparison of different estimations for woodchip pre-processing plant TPC in £k.

plant size odt/d	TPC from literature	TPC from Figure 5.1
48	1354	1332
60	1451	1458
120	2418	2091
240	4837	3356

Although there is good agreement at the 48 and 60 odt/d level the estimates diverge at the larger plants sizes. The estimates in the literature are based on Toft's work [82]. He assumed that whole truck tippers would be used on the larger plants. The TPC of these calculated from the data in Badger's report [93] is £350k each compared to the £85k for the ground hoppers assumed in this study. As it is normal practice to have at least 2 tippers on site to avoid a single failure shutting down the plant it may be expected that the estimates using tippers will be multiples of 2 or more times £265k above those using self unloading trucks. It should be noted that the savings made by using ground hoppers will be partially offset be the extra cost of the self unloading trucks.

Farag, LaClair, and Barrett only include turnkey costs for complete plants without giving detailed descriptions of the reception plant. Their report is focussed on plants for New Hampshire so it is reasonable to assume that accepted American practice would be followed in these plants. As such it is reasonable to assume that truck tippers would have been included in the estimate. Consequently the higher of the cost estimates for the woodchip pre-processing plant will be used to infer the cost of the pyrolysis plant. The other papers contained sufficient information for the cost of the pre-processing plant to be estimated; consequently it is possible to strip out the cost of the handling plants to give the cost of the pyrolysis plants.

This has been done in Table 5.7.

Table 5.7 TPC of woodchip pre-processing and pyrolysis plants.

size	Study	cost source	Combined plant TPC	woodchip plant TPC	pyrolysis plant TPC
odt/d			£k	£k	£k
48	Peacock, Bridgwater and Brammer	Wellman	£4,595	£1,354	£3,241
48	Bridgwater, Toft, and Brammer,	Aston	£4,869	£1,354	£3,515
60	Farag, LaClair, and Barrett	Dynamotive	£6,061	£1,451	£4,610
60	Bridgwater, Toft, and Brammer,	Aston	£5,487	£1,451	£4,036
120	Farag, LaClair, and Barrett	Dynamotive	£8,081	£2,418	£5,663
120	Bridgwater, Toft, and Brammer,	Aston	£8,619	£2,418	£6,200
240	Farag, LaClair, and Barrett	Dynamotive	£13,132	£4,837	£8,295
240	Peacock,Bridgewater and Brammer	Wellman	£11,586	£4,837	£6,749

The TPC of the pyrolysis plants have been plotted in Figure 5.3.

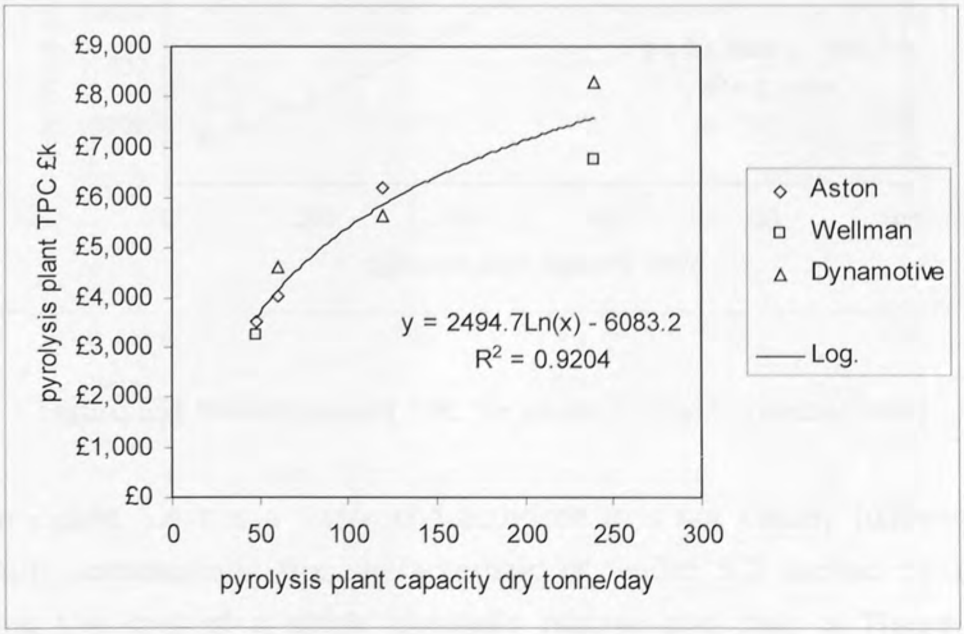

Figure 5.3 estimated TPC of pyrolysis plants

The logarithmic characteristic gives a better fit to the data than the more conventional power characteristic.

The costs for multi-reactor sites have been calculated in Table 5.8. This has been done assuming that the maximum pyrolysis reactor size is 200 odt/d and that repeat reactors cost 5% less than the first stream.

Table 5.8 estimated TPC for multiple reactor sites

plant size odt/d	50	100	150	200	400	600	800
No of reactors	1	1	1	1	2	3	4
TPC £k	3677	5407	6419	7136	13916	20695	27475
SI £k/odt	73.55	54.07	42.79	35.68	34.79	34.49	34.34

The TPC for the different sites have been plotted in Figure 5.4.

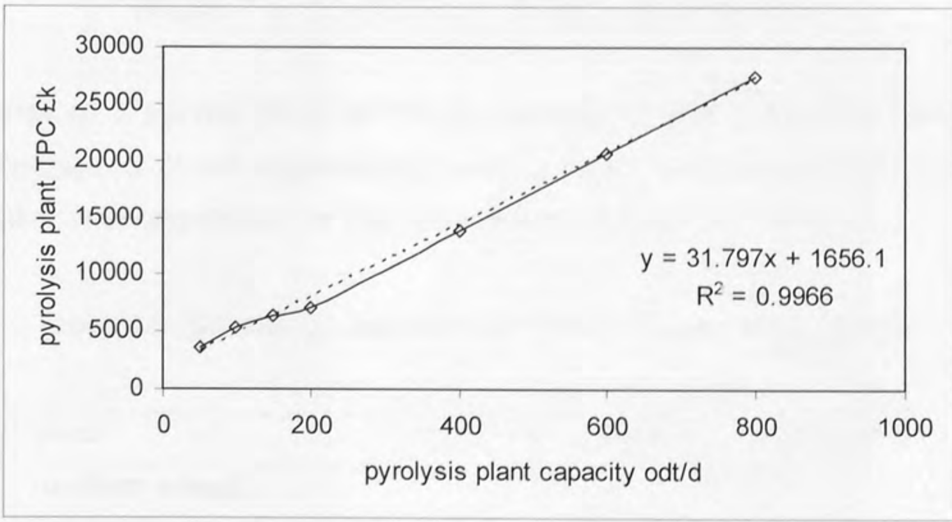

Figure 5.4 the estimated TPC for multi pyrolysis reactor sites

Although Figure 5.4 has a linear characteristic it is not closely followed at the lower end; consequently the characteristic of Figure 5.3 should be used for estimating the cost of a single pyrolysis reactor and that of Figure 5.4 for multiple reactors.

5.5 Diesel Generator

The estimated cost of converted diesel generators from previous studies is shown in Table 2.3. The average of the three estimates comes to £2.19m for a 2.5 MWe diesel generator. This corresponds to a specific investment cost of £876/kWe. Unfortunately only one of the papers [81] gives any indication of the sizing factor for diesel engines, it uses sizing factor is 0.954 which implies that there is little economy of scale for diesel engines. This is largely supported by a study of gas engines (gas engines are frequently based on diesel engines) carried out on US CHP plants with electrical outputs between 0.3 and 5 MWe by the Energy Nexus Group [187] where the TPC in £k for gas engine generators including electrical connections can be found by:

$$TPC = 670\ P^{1.03}$$

Where P is the generator power output in MWe

The findings of a survey [167] of 41 plants that housed a total of 208 medium and 34 low speed diesel engines installed as main duty generators using diesel oil or bunker fuel carried out in the early 80s are shown in Table 5.9

Table 5.9 Specific investment for diesel power plant, £/kWe

class	low	high	average
medium speed			
3-5 MWe	509	928	719
5-8 MWe	389	876	631
8+ MWe	434	581	528
low speed 8+ MWe	852	1091	921

This study defines medium speed engines to be 4 stroke engines with a speed of 300 to 700 rpm. Slow speed engines were 2 stroke cross head engines with speeds up to 300 rpm.

The wide spread of values are considered to reflect differences in extent of supply in terms of plant and services that have been included as capital costs by the plant owners.

The gas engine equation from [187] gives a specific investment of £722/MW_e for 3 MW_e and £733/MW_e for 5 MW_e. These figures compare well with the findings of the power plant survey. On the basis of this agreement it is considered reasonable to use the gas engine equation to produce a TPC estimate for a 1MWe generator this was then used to estimate the specific investment for a 1-3 MW_e generator which was calculated to be around £710/kWe.

At £876/kWe the estimated cost of a 2.5 MW_e diesel engine modified to run on bio-oil from Section 2.2.3 is inside the range of reported values of the 3-5 MW_e from the survey, but it is 23% higher than the average value for that size of diesel engine. This is consistent with an article in Power Engineering magazine which includes a graph of the cost of different types of diesel engines [188]. The figures on the Power Engineering graph are not very clear but it appears that dual fuel medium speed engines are around 20% higher than normal medium speed engines. It is reasonable to assume that an engine that could cope with the corrosive and erosive nature of bio-oil may cost a little more.

The average costs from Table 5.9 increased by 23% to cover the cost of upgrading the engine to run on bio-oil are shown in Table 5.10 and have been used in this study.

Table 5.10 estimated specific investment cost for diesel engines modified to run on bio-oil

plant size	specific investment £/kWe
1-3 MW_e	874
3-5 MW_e	885
5-8 MW_e	776
8 and above MW_e	649

The estimates in Table 5.10 are for medium speed 4 stroke engines.

5.6 Open cycle gas turbine

The capital cost for an open cycle gas turbine can be estimated by taking the published cost for a natural gas fired turbine, multiplying it by a modification cost factor to get a cost for the bio-oil fuelled engine. The output of the GT then needs to be de-rated to the level that can be achieved with a fuel containing ash. The costs of natural gas fired GTs have be obtained from Gas Turbine Would [169] and an estimate of the de-rating for bio-oil has been worked out in Section 4.7.2. However there are no published estimates of the cost of modifying gas turbines to run on bio-oil.

An approximate estimate of $1,700k for a turnkey installed OGT250 GT modified to burn bio-oil was given in Farag et al [89]. This report was written with the support of a memorandum of understanding with Dynamotive who worked closely with Orenda Aerospace in developing the bio-oil fuelled OGT250 so this is close to a manufacturers estimate. If this estimate is indexed to 2006 prices it comes to $2,170k. The equipment cost for a natural gas fired OGT250 in 2006 from Gas Turbine World was $1,469. A 5-10% contingency allowance has been included in the estimate by Farag (this is consistent with the 7% contingency allowance used by Nexus in their report on gas fired GT based CHP schemes [185]).

If an additional allowance of 10% of equipment costs is added to the Farg estimate to cover the cost of capital during construction and other owners cost is added the TPC would be $2,317 or 1.58 times the natural gas equipment cost for packaged gas turbines. The TPC and specific investment have been calculated for a range of GTs using the assumptions discussed in this section and plotted against their estimated outputs when using bio-oil in Figure 5.5 and 5.6.

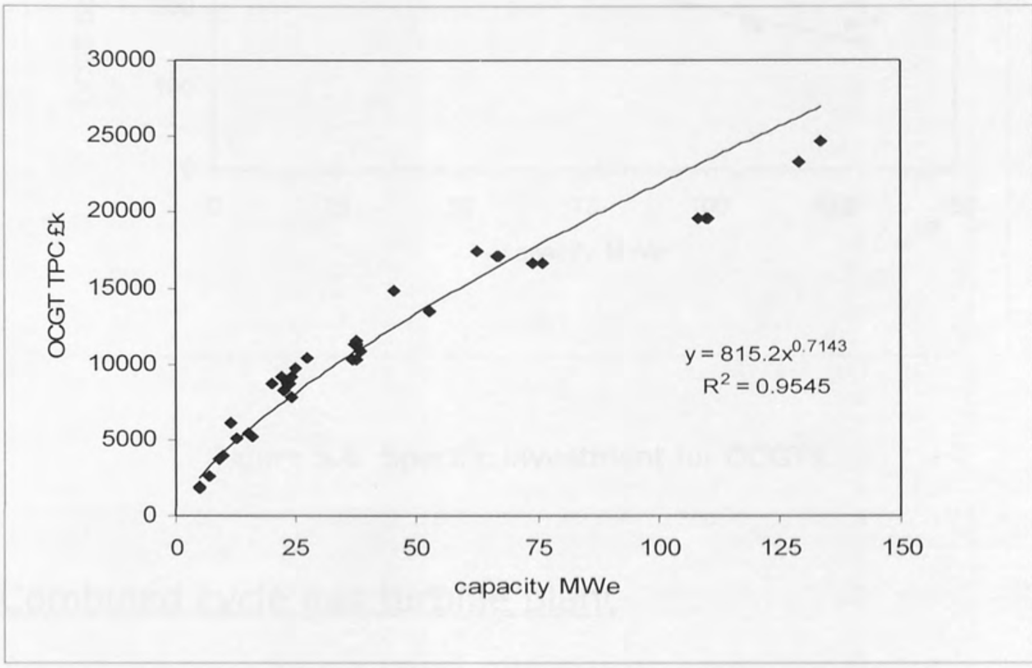

Figure 5.5 Total Plant Cost for bio-oil fuelled open cycle gas turbines

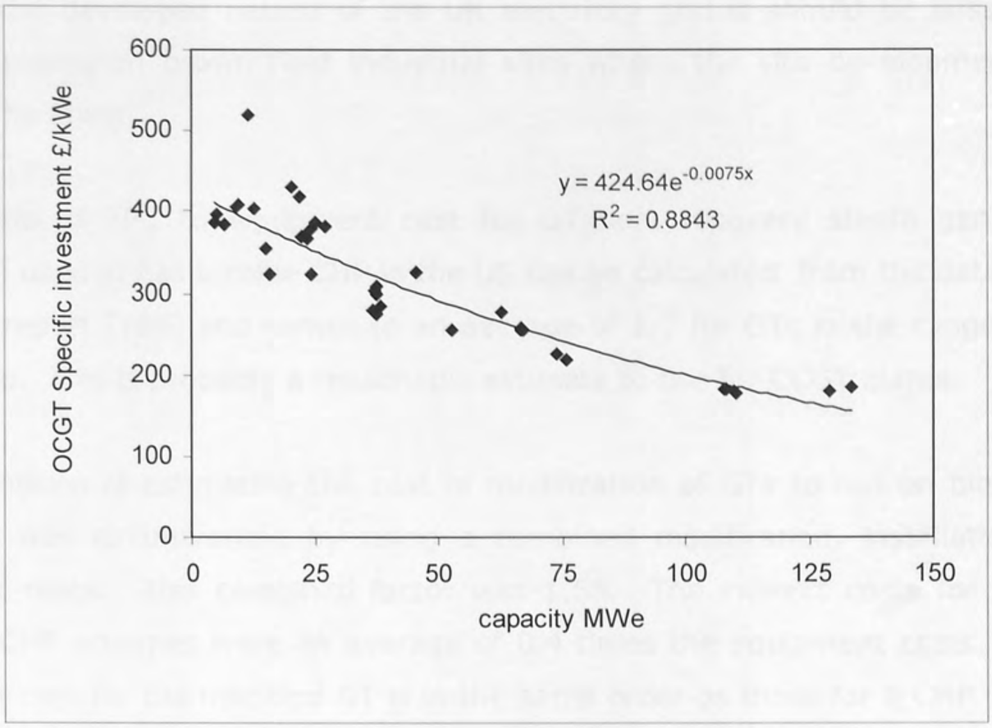

Figure 5.6 Specific investment for OCGTs

5.7 Combined cycle gas turbine plant

The same procedure can be used for estimating the total equipment cost for CCGTs as was used for OCGTs. The problem is getting suitable values for the installation factor, indirect cost and cost of modification of the GT. It is reported in Gas Turbine World [169] that the TPC will be between 1.6 and 2 times the equipment costs. This wide spread is considered to be due to:

- Differing ground conditions;
- Costs variation in different countries;
- Additional buildings and facilities required by the client;
- Differing licensing costs;
- Different electrical grid and gas supply connection costs.

Given the developed nature of the UK electricity grid it should be possible to locate plants on brown field industrial sites where the site development cost should be lower.

The ratio of TPC to equipment cost for GT heat recovery steam generators (HRSG) used in gas turbine CHP in the US has be calculated from the data in the Nexus report [185] and comes to an average of 1.7 for GTs in the range of 5 - 40 MWe. This is probably a reasonable estimate to use for CCGT plants.

The problem of estimating the cost of modification of GTs to run on bio-oil for OCGTs was circumvented by using a combined modification, installation and indirect costs. This combined factor was 1.58. The indirect costs for the GT based CHP schemes were an average of 0.4 times the equipment costs. If the indirect cost for the modified GT is in the same order as those for a CHP scheme the cost for the modification and installation of the OCG250 would be 0.18 times the equipment costs. It should be noted that in common with other small (less than 50MWe) GTs the OGT250 is packaged at works with limited site work required so the installation cost should be modest. A conservative estimation of the modification cost can be made by assuming that all this additional cost was the result of the modifications. The modifications to make a GT run on bio-oil are all carried out at works as such there should be little increase in site costs resulting from the modifications (there is some additional work associated with the need for dual fuel capability and bio-oil flushing facilities). It has been assumed that the steam plant does not need any modification to cope with the use of bio-oil. Consequently it is proposed the TPC is estimated using the following formula:

$$TPC = 1.7\,(ECGT + ECSC) + 1.18(ECGT)$$

where

ECGT is the equipment costs of the gas turbine and

ECSC is the equipment costs of the steam cycle plant.

Clearly the lack of hard data means that this estimate of the modification cost is not accurate but the GT equipment cost accounts for an average of 17% of the TPC on a gas fired CCGT (for CCGTs in the range of 7 - 400 MW_e, the standard deviation on this ratio is 3.7%), so the TPC is not particularly sensitive to the cost of modifying the GTs. The TPC and specific investment for the modified CCGT has been plotted against it's bio-oil rating in Figures 5.7 and 5.8.

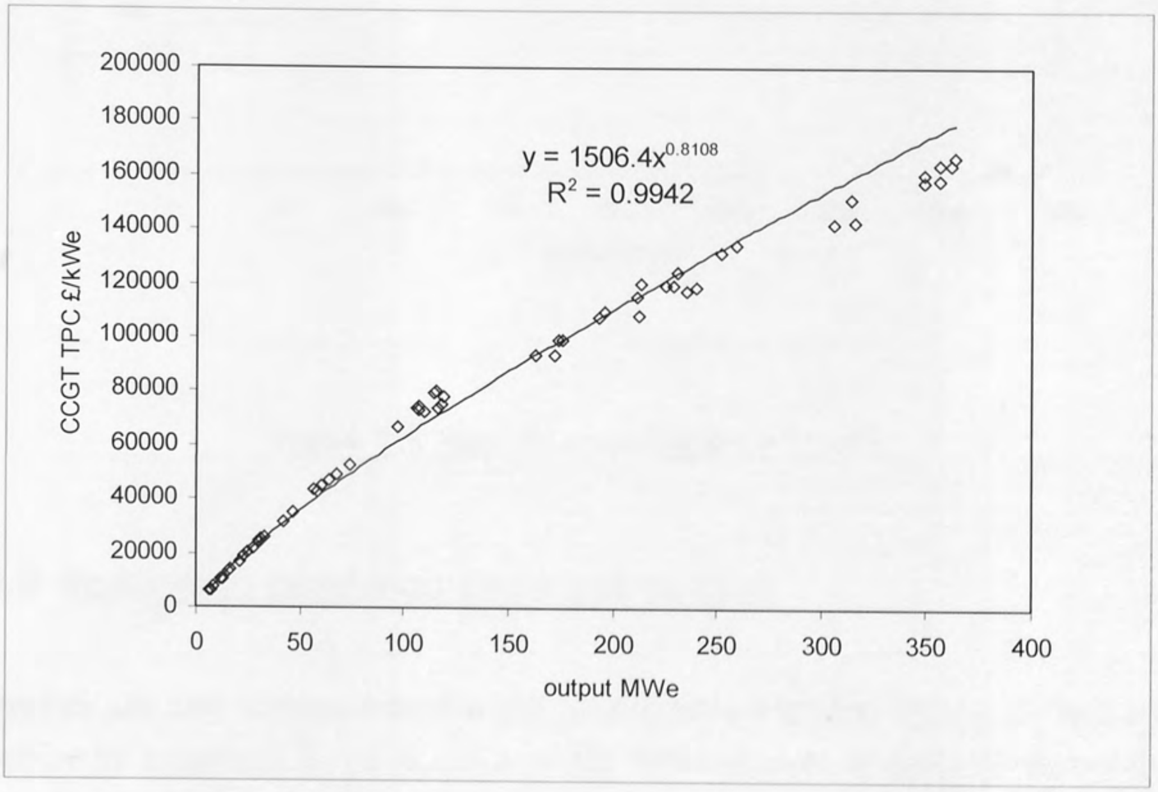

Figure 5.7 Total Plant Cost for bio-oil fuelled combined cycle gas turbines

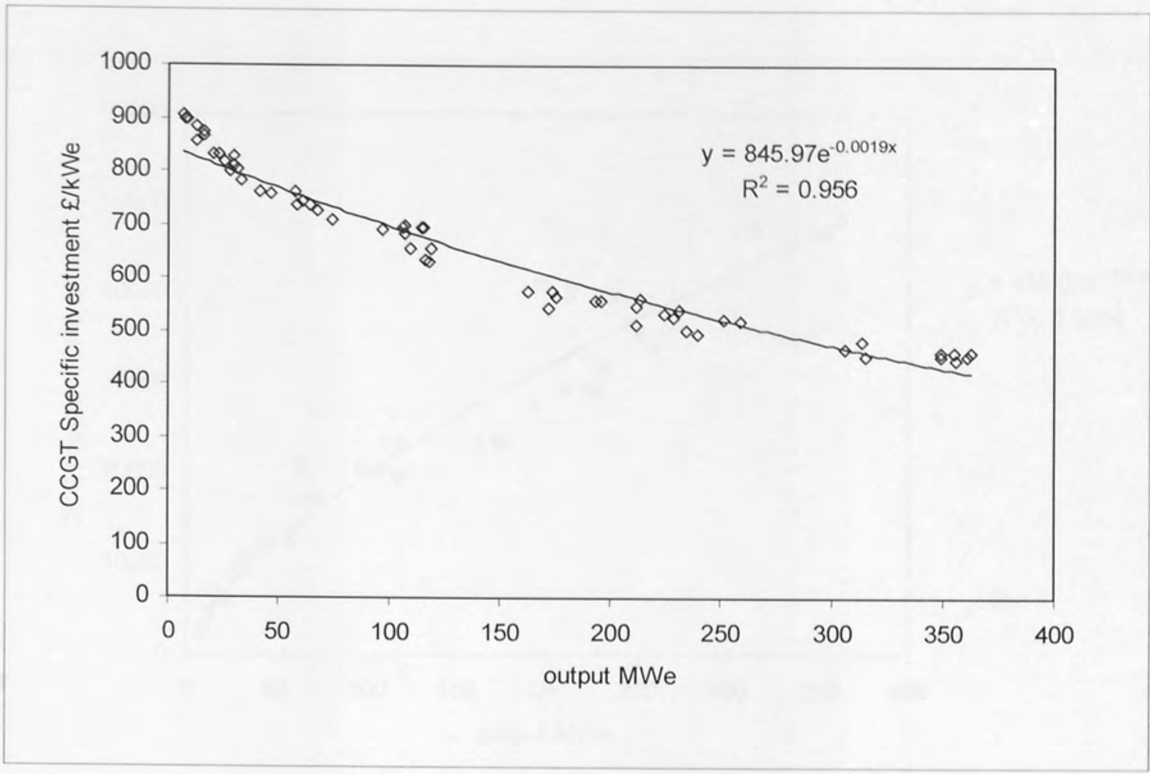

Figure 5.8 Specific investment for CCGTs

5.8 Replanting combined cycle gas turbine

The hot gas path components of a gas turbine have a limited service life and it is frequently necessary to carry out a major refurbishment of the GTs during the life of a CCGT station. An alternative strategy would be to replace the gas fired GT with one modified to burn bio-oil. This would appear to be a lower cost way to acquire a bio-oil CCGT. The TPC and SI for just replacing the GTs is show in Figures 5.9 and 5.10.

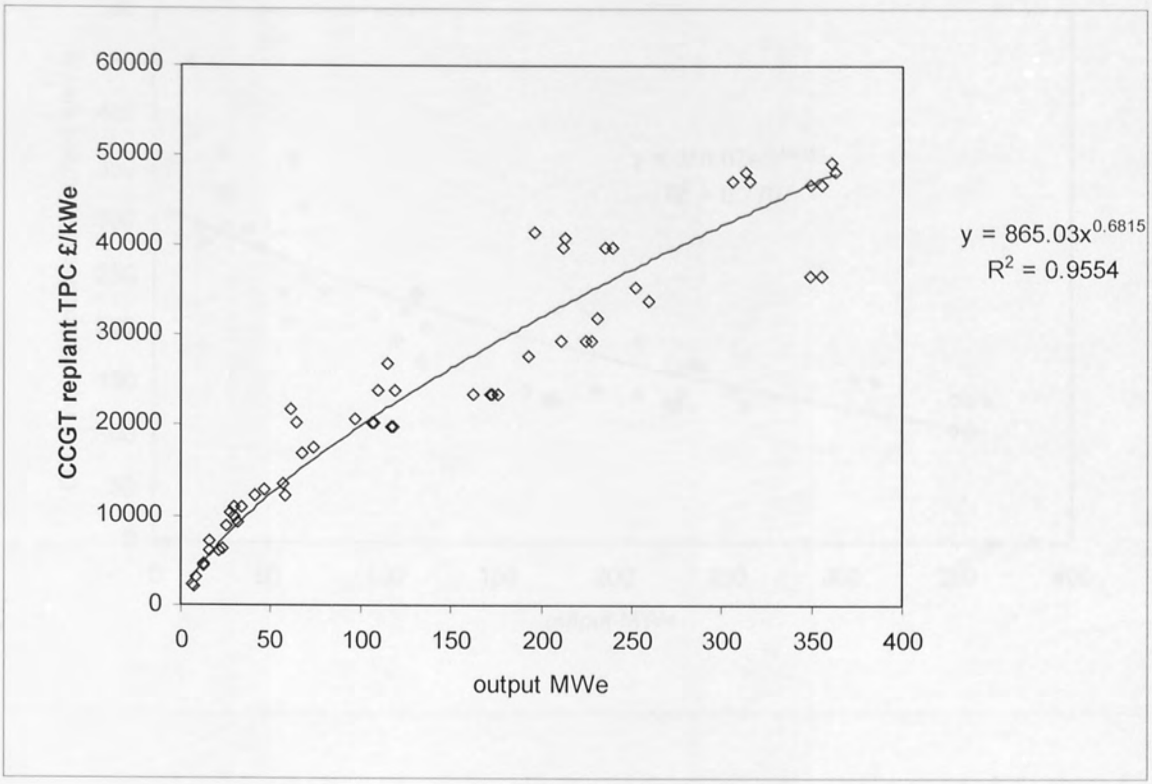

Figure 5.9 TPC for a replanted CCGT

No allowance has been made for the value of the life expired gas fired GT. In practice the generator and auxiliaries will be retained and GT refurbished so the costs in Figure 5.9 will be high, but this will be offset by the need to add an additional fuel system to the installation.

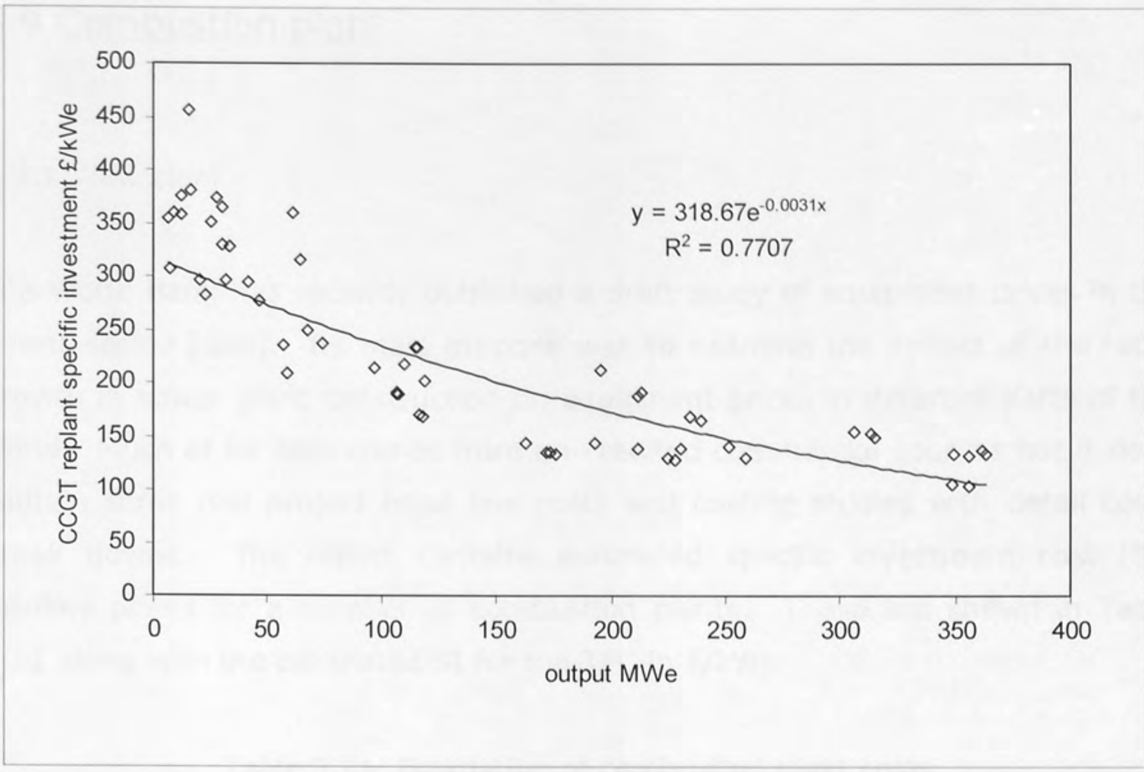

Figure 5.10 Specific investment for a replanted CCGT

It is noticeable that there is a wider distribution of points around the trend line than for the new CCGT case. This reflects the fact that the steam cycle technology is relatively mature and so its cost is less likely to change between plants of similar size. GT technology is still evolving so it is possible to have machines at different levels of engineering sophistication and hence different cost to produce the same output.

The options to replant an existing CCGT stations is clearly limited to the existing stations but may represent a low cost way of proving the technology at a utility scale.

5.9 Combustion plant

5.9.1 New plant

The World Bank has recently published a draft study of equipment prices in the power sector [189]. Its main purpose was to examine the impact of the rapid growth in power plant construction on equipment prices in different parts of the world. Much of its data comes from un-credited commercial sources but it does contain some real project head line costs and costing studies with detail costs break downs. The report contains estimated specific investment cost (SI) turnkey prices for a number of combustion plants. These are shown in Table 5.11 along with the calculated SI for the TPC in £/kWe.

Table 5.11 Estimation of combustion plant costs

type	size MWe	turnkey SI $/kWe	TPC SI £/kWe
coal sub-critical	300	2730	1568
coal sub-critical	500	2290	1315
coal super-critical	800	1960	1126
Oil sub-critical	300	1540	885

An exchange rate of $2.0022 /£ (Bank of England's average spot market rate for 2007) was used to covert the prices to sterling. The turnkey prices were increased by 15% to account for owner's costs; this is more than was applied to the GT cases as the construction period for large combustion plant is longer than that for gas turbine plant.

Coal fired units have coal handling plants, ash handling plants and flue gas desulphurisation plants that are not needed on bio-oil fired ones. The report states that it is reasonable to assume that the ratio of oil fired plant cost to coal fired plant cost will remain reasonably constant. This has been done to obtain the estimates for bio-oil plant shown in Table 5.12.

Table 5.12 Estimated TPC for bio-oil fired combustion plant

type	size MWe	TPC £k	SI £/kWe
sub-critical	300	265000	885
sub-critical	500	371000	742
super-critical	800	508000	635

5.9.2 Co-firing of new plant

To date co-firing has involved utilising the existing coal burners to also burn biomass. It is possible to build a new boiler with both bio-oil burners and coal burners which cannot reach full load on one fuel alone. This would allow the benefits of using supercritical plant to be utilised even if there was insufficient bio-oil available to fully fuel a large unit. For example if an 800MWe unit was fired such that 300 MWe came from bio-oil and 500MWe came from coal the cost of the unit would be

$TPC_{800SUPER}$ = (300 x 635) + (500 x 1126) = £753.3m
with a unit efficiency up to 47%.

If the same capacity was to be provided by a 300 MWe sub-critical bio-oil unit and a 500 MWe coal unit the cost would be

TPC_{300SUB} = 300 x 855 = £265.5m
$TPC_{500SUPER}$= 500 x 1126 = £563m
with a combined TPC for both plants of £828.5m.

In practice the 500 MWe supercritical plant will probably have a higher specific investment cost than the 800 MWe plant so the cost difference will be higher.

The sub-critical unit is likely to have an efficiency of no more than 38% so there is clearly both capital and operating cost advantages by building a large co-fired plant rather than independent bio-oil and coal fired plants.

5.9.3 Refurbished plant

As discussed in Section 1.1.1, a considerable amount of fossil fuel plant is going to be decommissioned as the plant owners do not consider it economic to bring the plant up to new plant emission standards. It may however be worth considering converting some of the old units to burn bio-oil. A converted plant would be require to meet the new plant standard but as the sulphur level of bio-oil is much lower than of fossil fuel a flue gas desulphurisation plants would not be needed. These existing plants have all experienced a considerable number of running hours so many of the pressure parts that operate at high temperature will be near the end of their creep life (running hours before there is an unacceptable risk of component failure due to high temperature creep). Consequently some of the high temperature components of the boiler, steam legs and turbine will need to be replaced in addition to modifying the burners and building a bio-oil handling facility. The extent of this work will vary with each unit being considered. To get an idea of the range of cost involved it has been assumed that the cost of modifying the unit to burn bio-oil and give it a reasonable operation life will be between 10-50 % of the mechanical plant cost of the boiler and turbine. The cost of converting an existing coal fired unit to bio-oil is compared to the cost of building new 500MW sub-critical 500MWe coal and oil fired units in Table 5.15.

Table 5.13 Estimated cost of converting existing 500MWe units to burn bio-oil

	new oil	new coal	low cost modified	high cost modified
cost area	£k	£k	£k	£k
civil	24020	37709	1000	1000
structural steel	12429	20178	0	
boiler	60469	75767	7577	37883
turbine	28070	30167	3017	15083
coal handling	0	27769	0	0
ash handling	0	8391	0	0
dust removal	0	13385	0	0
FGD	0	38957	0	0
SCR NO_X	12289	20428	20428	20428
electrical	23252	33263	0	0
piping	18783	23574	0	0
BOP	49506	92898	6609	6609
direct cost	228818	422485	38630	81003
indirect cost	16758	31415	2872	6023
engineering	23741	43802	43802	43802
contingency	53835	74668	9657	20251
construction cost	323152	572370	94961	151079
owners cost	32315	57237	9496	15108
TPC	355468	629607	104458	166187
SI	711	1259	209	332

Table 5.13 was draw up with the following assumptions:

- The cost of the new coal plant is taken from [189] and converted to sterling at $2.0022/£;
- The owner's costs are assumed to be 10% of the construction cost which is appropriate for a modification programme but low for a new build;
- The new oil plant costs are taken from the costs for a new 300 MW_e oil fired plant multiplied by the ratio of the new coal plant cost at 500 MW_e to new coal plant cost at 300 MW_e [189];

- The BOP (balance of plant) cost for the modified plants are the cost for a basic bio-oil reception and storage plant taken from [92] and scaled using a scaling factor of 0.6;
- The low modification cost is based on the modifications costing 10% of the plant cost of the boiler and turbine for a new 500 MW_e coal plant;
- The high modification cost is based on the modifications costing 50% of the plant cost of the boiler and turbine for a new 500 MW_e coal plant;
- The engineering cost for the modified units is considered to be the same as that for the new build coal to account for the engineering work needed to prove that the retained plant is suitable for its new duty on the modified plant;
- The project contingencies for the modified plants have been set to 25% of the direct cost.

Clearly these are very rough estimates of the type of costs that may be involved with modifying a unit. The real cost will be governed by the condition of the existing unit.

5.10 Bio-oil storage tanks

A 9.4 Mlt epoxy lined steel tank with a floating cover for bio-oil tank was reported to cost an estimated $1M in 2006 [92]. Using the average exchange rate from the bank of England for 2006 of this tank costs £550k.

$$C_t = 550 \times (Q_t /9.4)^{0.666}$$

6 Non-capital Costs

The non capital costs of electricity production are the biomass costs and the costs of running the plant. The biomass costs have been taken from another study. The maintenance costs have been inferred from those in a number of different studies and the staffing costs have been estimated from a staffing scenario as there is no reported staffing level from commercially operating plants.

A detailed analysis of transport costs has been included as these determine the amount that biomass costs increase with increasing biomass demand. The possibility of using a network of pyrolysis plants to supply a centrally located power station has also been investigated.

6.1 Biomass production costs

Biomass costs are clearly an important element of the cost of production of bio-oil. The biomass cost can be considered to have two components, production cost and transport cost. A detailed investigation into the production cost of biomass has not been carried out as part of this study as a detailed survey of energy crop production cost has been carried out by Renwick on behalf of DEFRA [190] in 2005. This covers both SRC willow and miscanthus. The costs were calculated to cover an economic crop life of 16 years (one year to establish the crop then five harvest cycles for coppicing and 15 for miscanthus); this is consistent with the budget assumptions made by two large growers' groups, Renewable Energy Growers Ltd and TV Bioenergy Coppice. This report will be used as the basis for biomass production cost in this study. Taking the cost for both crops from a single study should ensure that any differential between the crops are the result of differences in reported costs rather than differences in study methodologies.

The prices from the Renwick survey inflated from 2004 to 2006 for SRC willow was £69/odt and that for miscanthus was £49/odt. These prices included the farmers estimates of the rental value of the land used to grow the crops (£183/ha for willow and £166/ha for miscanthus). If this is removed from the costs (as it is in other studies), they become £49/odt and £39/odt respectively. Most of the cost of growing biomass relate to the area of land used so any reported cost/odt must be for a specified crop yield. The yields stated in the Renwick report was 9 odt/ha for SRC and 14 odt/ha for miscanthus.

6.1.1 Comparisons with other estimates of production cost

Before using the costs from a single report it is worth checking that its results are consistent with those of other reports. Both SRC and miscanthus are perennial crops with a considerable initial investment that needs to be recouped over a number of harvests. When comparing reported costs it is important to confirm that they are calculated over the same time frame. There can also be differences in the extent of supply which may need accounting for.

6.1.1.1 Woodchip

The economics of SRC production to supply power stations in Yorkshire has been investigated by Hinton [85]. He looks at the costs across 5 harvests. If the effect of establishment grants is removed the break even selling price for woodchips delivered to the end user is £57 /odt for a crop yield of 7 odt/ha/y and £47 /odt with a yield of 10 odt/ha/y.

A similar study has been carried out by Rosenqvist [191] in Northern Ireland give a projection for the likely production cost of woodchips in a mature industry. These have been used to calculate the following break even selling price for different yields of woodchip:

£68 /odt for a yield of 7 odt/ha/y;
£48 /odt for a yield of 10 odt/ha/y.

If the SRC cost from the Renwick report is shared over a yield of 10 odt/yr rather than 9 it would give a woodchip cost of £44 /odt. Both Hinton and Rosenqvist report the delivered cost of the biomass where the Renwick report gives the cost excluding transport to the end user. It will be show in Section 6.2 that the £3-4 difference in reported costs is consistent with the transport costs for a medium size woodchip consumer.

6.1.1.2 Miscanthus

The costs for miscanthus in the Renwick report can be compared with that in the report into the Miscanthus combustion trials at Ely Power Station [126], which gives a delivered miscanthus cost (after indexing by the RPI excluding housing cost) of £50.6/odt. If the Ely report's estimate for loading and transport is subtracted the estimate for farm production costs becomes £35.8/odt. The Renwick report includes an estimate of £3.3/odt for loading. If this is subtracted from the Renwick estimate it gives a farm production cost of £35.8/odt. Unfortunately the Ely report does not give a breakdown of its cost estimation so it is not possible to say if this is a good agreement or co-incidence.

6.1.2 Storage losses

Woodchip Storage losses

There is evidence that woodchips degrade during storage resulting in a loss of dry matter. The rate of dry matter loss is dependent on temperature but it has been found that for an un-compacted ventilated woodchip pile the dry mater loss is roughly 1% a month [90]. The woodchip price paid by the pyrolysis plant operator will need to be increased to take into account the losses during storage. Coppice wood is cut during the winter when the trees are dormant so fresh wood is only available for 4 months a year.

It is desirable that all wood is stored for around 8 weeks to dry naturally so the woodchips will be stored between 2 to 10 months. Consequently the crop will have lost an average of 6% of its dry matter by the time it is required by the pyrolysis plant.

Miscanthus losses

Research into the storage losses in baled miscanthus is ongoing [159] but a report into the production of energy grasses in the UK estimates that the loss for uncovered bale storage is 10% for 6 months storage [196] based on experience with cereal straws.

6.1.3 Expected Yields

SRC

Clearly the crop yield that can be expected has a considerable impact on the cost of woodchips. The Hinton report [85] included yield data for 12 sites. The yields ranged from 5 to 9.5 odt/ha/y with an average value of 7.1 odt/ha/y. A separate report by Wilkingson [192] covers the yields of different willow cultivars at different planting densities at a commercial site in the north of England. It concludes that with the correct mix of cultivars planted at a high density it should be possible to obtain commercial yields in excess of 10 odt/ha/y (it reported that Long Ashton research station had produced yields of up to 17.6 odt/ha/yr). This is consistent with the yield figures given in DEFRA's Guidelines for growing SRC [193]. It is apparent from these reports that a yield of 10 odt/ha/yr could be assumed for a base case but the risk of it falling to 7 odt/ha/yr should be considered in a sensitivity study. When storage losses are taken into account these yields reduce to 9.4 and 6.6 odt/ha.

Miscanthus

The DEFRA guidelines for growing miscanthus [129] states that after three years yields of 10-13 odt/ha should be achievable with yields of 14-16 odt/ha possible as the crop matures.

Yields of 12.4 odt/ha have been reported for late harvested miscanthus at a UK test sites [194], and 10-15 odt/ha reported in [195] which appear to support the DEFRA estimates. When storage losses are considered it would appear reasonable to assume a base case yield of 13.5 odt/ha and a lower case of 9 odt/yr.

6.1.4 Impact of subsides

Although this study is generally concerned with unsubsidised costs, growers do receive subsides for producing energy crops. There are three basic subsides that are relevant to energy crops:

- Single Payment Scheme (SPS) - this is a payment for having land that is or could be used for agriculture [198]. The calculation of the actual payment is dependent on the nature of the farm. The basic payment in 2006 was £110/ha [199], with an average payment of £163/ha [200].
- Energy Crop Scheme - this is an additional annual payment for growing designated energy crops [197]. It was set at €45/ha and subject to modulation (a reduction mechanism that was set to -5% in 2006) and so was worth £29/ha.
- Energy Crop establishment grant - this is set at 40% of the costs associated with the establishment of miscanthus or SRC [198]. In 2006 this averaged £800/ha [200].

The effect of these subsidies on the crop price is shown in Table 6.1.

Table 6.1 Energy crop production cost under different subsidy regimes

Crop	SRC	Miscanthus
yield	9 odt/ha	14 odt/ha
un-subsidised	£69.05/odt	£48.72/odt
after SPS deducted	£56.82/odt	£40.86/odt
after all subsidies	£49.42/odt	£35.91/odt

This study is investigating the unsubsidised costs. However the SPS is a generic farming subsidy, not an energy crop subsidy so it is reasonable to allow it to be deducted from the production costs.

6.1.5 Costs for use in this study

There are two approaches to calculating the biomass cost to the plant operator. One is to consider the grower as being outside the system. In this case the grower's profit should be included in the costs; to do this the rent that the grower could have received for his land if he was not growing biomass should be added to the biomass costs. The alternative is to consider the grower as part of the system. In this case just the grower's costs should be included in the biomass cost. However as the grower is part of the scheme the land cost should be included in the plant capital cost (or the land rental added to the fixed cost). It is proposed to take the first of these options as it reflects the current ownership arrangements for biomass fired plants.

It is proposed that the base cases use the cost of production minus the SPS payment distributed over the target yields minus storage loss. This gives the following cost for biomass:

- Base case SRC £54.41/odt at 9.4 odt/ha;
- Base case miscanthus £42.38/odt at 13.5 odt/ha.

The following costs will be used to test the sensitivity and market competitiveness of selected systems:

- Low yield case SRC £77.49/odt at 6.6 odt/ha;
- Low yield case miscanthus £63.37/od at 9 odt/ha;
- Subsidised case SRC £49.42/odt at 9.4 odt/ha;
- Subsidised miscanthus at £35.91/odt 13.5 odt/ha .

The conversion efficiencies of the pyrolysis plants are expressed in terms of the HHV of the biomass so it is useful to have the costs and yields expressed in energy terms as well as mass terms. Table 4.5 give the average HHV of SRC as 19.5 MJ/kg on a DAF basis. As the average ash content is 2% this would give the HHV for SRC as 19.1 GJ/odt (the value is diluted by the ash in the biomass). The same table gives the DAF HHV of miscanthus as 19.6 MJ/kg with an average ash content of 1.9%; this gives the HHV of miscanthus as 19.2 GJ/odt.

This gives the following cost for biomass:

- Base case SRC £2.85/GJ at 180 GJ/ha;
- Base case miscanthus £2.21/GJ at 259 GJ/ha;
- Low yield case SRC £4.06/GJ at 126 GJ/ha;
- Low yield case miscanthus £3.31/GJ at 173 GJ/ha;
- Subsidised case SRC £2.59/GJ at 180 GJ/ha;
- Subsidised miscanthus £1.87/GJ at 259 GJ/ha.

6.2 Biomass transport cost

The costs associated with transporting energy crops from a farm store to a pyrolysis plant are relatively small compared to the production costs and are frequently considered to be fixed or directly proportional to the distance covered. These approaches are adequate for techno-economic studies that set out to investigate the relative costs of different conversion technologies at a relatively small scale. However a more detailed approach is needed when considering larger systems and when investigating the relative costs of transporting biomass and bio-oil.

It has been assumes that harvested crops are stored in field stores in accordance with the DEFRA best practice guidelines for energy crops [129,90]. The costs associated with growing, harvesting storing and loading crops into trucks have been assumed to be included in the crop production costs. SRC willow is assumed to be transported as woodchips and spring harvested miscanthus transported in 500kg rectangular "Hesston Bales".

The quantity of biomass needed by a plant will depend on its chemical composition and moisture level. In order to compare the transport cost of different bio-fuels the costs have been calculated on the basis of their energy content. In Section 4.5 it was concluded that biomass should be paid for on the basis of its wet HHV. The following HHV_{wet} values are used when calculating the £/GJ cost:

- 13.6 GJ/t for seasoned short rotation coppice willow with a moisture content of 30%;
- 16.7 GJ/t for spring harvested miscanthus with a moisture content of 15%;
- 16.5 GJ/t for fast pyrolysis bio-oil with a moisture content of 28%.

For biomass or biomass with different moisture contents the cost can be found by:

$$C_M = C_R\left(\frac{1-R}{1-M}\right)$$

where C_R is the cost at moisture level R and C_m is the cost at moisture level M.

To be fully consistent crop harvest yields are also expressed in energy units. Using the values from Section 6.1.5 SRC has a HHV of 19.1 GJ/odt and a yield of 9.4 odt/ha giving a SRC energy yield of 180 GJ/ha for SRC; for miscanthus it's HHV is 19.2 GJ/odt and its yield is 13.5 odt/ha giving an energy yield of 259 GJ/ha.

6.2.1 Truck operating costs

Some studies of pyrolysis-based bioenergy systems have included biomass transport costs in their calculations [81,87]. These have been based on commercial freight rates which they acknowledge vary considerably with location. The main features of commercial road haulage operation are:

- High annual distance covered by each truck;
- Low proportion of operating hours being loaded and unloaded;
- Loads managed between different destinations to reduce unloaded running;
- Large proportion of journeys on motorways and major trunk roads.

In contrast, utility scale pyrolysis plants are going to need the equivalent of a dedicated fleet of trucks shuttling between biomass field stores and the plant. The main features of such an operation will be:

- Low annual distances covered by each truck;
- High proportion of time spent loading and unloading;
- Little chance of carrying a commercial load on the return journey;

- Large proportion of journey on rural roads.

The Department for Transport have issued a freight best practice guide [201] which includes a table of costs (at 2003 prices) for operating various types of truck. This has been used to calculate the data in Table 6.2. All costs are brought to a 2006 basis using the average annual retail price of diesel oil for fuel costs [202] and the RPI excluding housing costs [110] for the other costs.

The guide includes sums for capital depreciation but does not explain how they have been calculated. In order to be consistent with the approach normally taken for plant capital costs, a financing charge has been used instead for the capital cost of the vehicle, based on an annual annuity to cover the capital costs of the vehicles over its stated life. A real interest rate of 10% has been used.

Repair and maintenance (R&M) is quoted in the guide as a distance related cost and expressed as a cost per kilometre. However it is likely that the trucks used in these applications will travel much shorter distances in a day than those used for general haulage duties so use of these values will give a low estimate of maintenance cost. Consequently a fixed R&M cost equal to the R&M cost for the type of vehicle covering an average mileage has been used.

Table 6.2 Truck operating costs

	woodchip options				Miscanthus
size	26t rigid	32t rigid	33t artic	44t artic	26t rigid + trailer
payload t	15.5	20	20.5	28	18
life y	6	7	7	6	6
km/y	80500	64400	96600	112700	80500
fixed cost					
Capital					
tractor £			52546	67357	58985
trailer £			32248	36828	19349
total £	58985	77028	84794	104185	78334
discount rate	10%	10%	10%	10%	10%
annuity£/y	13543	15822	17417	23922	17986
R&M £/y	4795	9824	6561	10328	4795
insurance £/y	2133	2336	2698	3413	2133
driver £/y	24259	23098	22761	24653	24259
road tax £/y	686	1267	1267	1267	686
fixed cost	£45,416	£52,347	£50,704	£63,582	£49,859
£/t/y	£2,930	£2,617	£2,473	£2,271	£2,770
days/y	230	230	230	230	230
£/d	£197	£228	£220	£276	£217
variable cost					
fuel	17344	17344	23124	33261	17344
tyres	1554	2516	2413	3136	1554
variables cost	18898	19859	25538	36398	18898
/km	£0.2362	£0.3103	£0.2660	£0.3250	£0.2362
/km/t	£0.0152	£0.0155	£0.0130	£0.0116	£0.0131

The trailers used with the articulated trucks are walking floor self unloading trailers that are suitable for handling woodchips; the payload of these trucks has been reduced to take account of the weight of the walking floor mechanism. The capital cost for self unloading trailers has been calculated by taking the cost for a "standard" trailer from the guide and multiplying it by the ratio of the cost for normal trailers to those for self unloading trailers in the US given in [93].

The rigid truck with trailer is a flat backed truck towing a drawbar trailer for transporting bales.

No business overheads or profits are included in any of these costs.

Costs have been apportioned on the basis of 230 delivery days a year. This has been estimated from the considerations given in Table 6.3.

Table 6.3 Operating days per truck

deliveries days a year based on 5 day week	260
days not available	
plant outage (no deliveries needed)	15
bank holidays	8
truck servicing	7
total days in use	230

6.2.2 Transport zones

In order to optimise the truck loading operation it would make sense to empty a field store before going on to the next one. Consequently it is reasonable to assume that a truck will make several round trips to a single field store in a day. The area that supplies biomass to a plant can be split up into a number of concentric travel zones with each zone defined as the area in which all the field stores can be reached in the same number of round trips a day from the plant. Zone 1 is one round tip, Zone 2 two round trips etc.

The road distance that corresponds to a zone boundary will depend on the total driving time and the average truck speed. The total driving time will be limited by the time taken loading, unloading and weighing the truck. The loading and unloading times will depend on the type of truck used and the form that the biomass is in.

There is no published data on the average speed of trucks on rural journeys, however the speed limit for HGV on single carriageway roads is 64kph and this value has been assumed for the average speed. In practice any journey will involve some travelling below the, speed limit but this will depend on the actual route and traffic conditions. As such this will be site specific. The effect of using a high estimate is to increase the estimates of transport cost.

Trucks have both fixed (time related) and variable (distance related) costs. For any given zone the fixed cost per load will be the day rate for the truck divided by the number of round trips a day. This will need to be added to the distance cost calculated from the round trip distance for a particular store to get the total transport cost per load.

There are limits to the volume of a trailer as well as its loaded weight. The largest practical trailer that is not considered an oversized load in the UK has a capacity of $120m^3$ ($150m^3$ for ridged trucks with drawbar trailers). For $120m^3$ of material to weigh 26 t (the payload of a 44 tonne truck) it must have a minimum bulk density of 216 kg/m^3.

Willow zone costs

Seasoned willow woodchips are likely to have moisture content around 30% [90]. This would give a density of 220 kg/m^3 so the truck payload will be limited by weight. 44 t articulated trucks have the lowest cost per t of load of the trucks listed in Table 6.2 and so are the most economic option for carrying woodchips. The variable costs are a direct function of the driving time. These have been calculated with the following assumptions:

- On any one day a delivery truck shuttles between one field store and one pyrolysis plant;
- The truck must complete a whole number of round trips in an 8 hour day;
- Individual field stores will not have installed loading equipment so it will take about 30 minutes to load 26 t of woodchips into the trailer using a $5m^3$ front end loader and 10 minutes to cover the load to prevent dust spillage during transport;

- From the data given in [93] it takes 10 minutes for a walking floor trailer to unload. The truck will also need to be weighed before and after discharge so it is assumed that the truck will be at the delivery site for 20 minutes;
- Any biomass grown within 2 km of the pyrolysis plant is taken directly to the plant when harvested.

The resulting costs are shown in Figure 6.1.

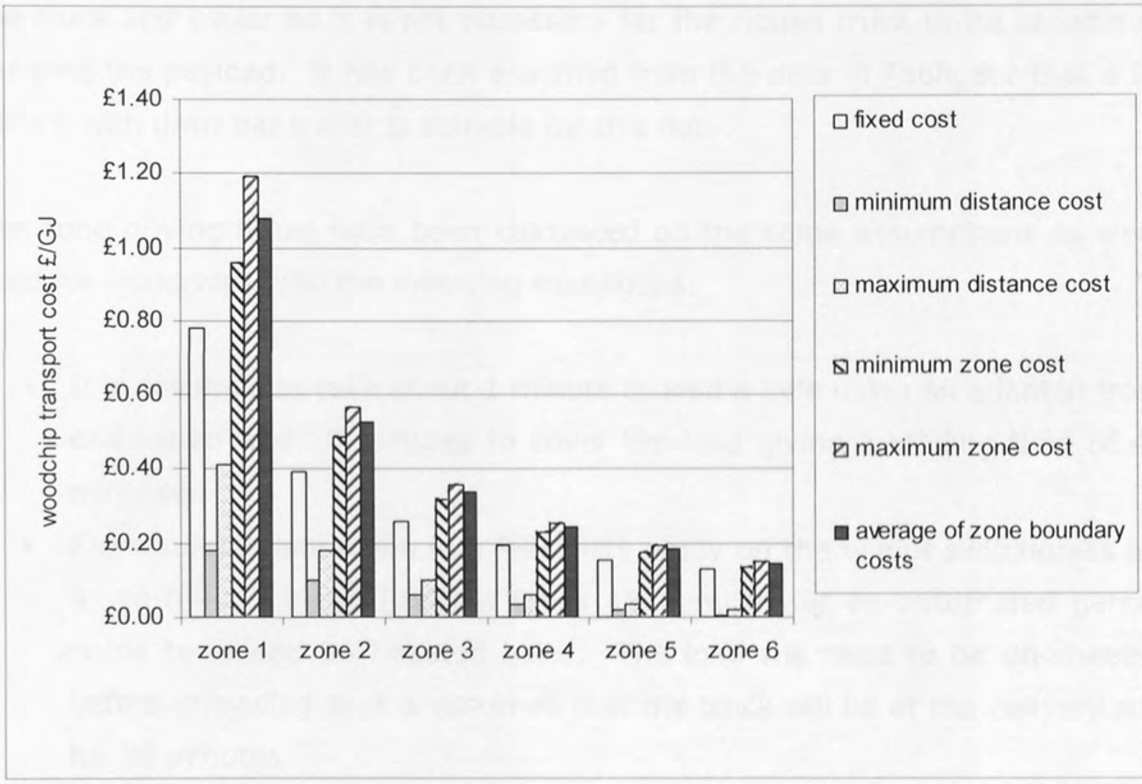

Figure 6.1 Woodchip delivery zone costs

Miscanthus zone cost

High density bales like those produced by a "Hesston" baler have a density between 140 to 170 kg/m^3 for spring harvested miscanthus [158] depending on moisture content. So the truck payload for miscanthus will be limited by its volume. The largest truck and single drawbar trailer combinations that can be used in the UK have a combined load platform length of 15.65m and a maximum width of 2.55m. There is no maximum height for a truck but bridge clearance can limit the choice of routes if the height is more than 4m. From these dimensions a truck and drawbar trailer can carry 36 Hesston bales of miscanthus weighing between 17.1 and 19.4 tonnes. The payload is split equally between the truck and trailer so it is not necessary for the rigged truck to be capable of carrying the payload. It has been assumed from the data in Table 6.2 that a 26 t truck with draw bar trailer is suitable for this duty.

The zone driving times have been calculated on the same assumptions as were used for woodchips with the following exceptions:

- It is assumed to take about 1 minute to load a bale using an adapted front end loader and 10 minutes to cover the load giving a loading time of 46 minutes;
- From survey data given in a feasibility study on the use of switchgrass for a co-firing scheme [132] it takes 18 minutes for an automated gantry crane to unload 36 Hesston bales. The load will need to be un-sheeted before unloading so it is assumed that the truck will be at the delivery site for 30 minutes.

The resulting transport costs for miscanthus are shown in Figure 6.2.

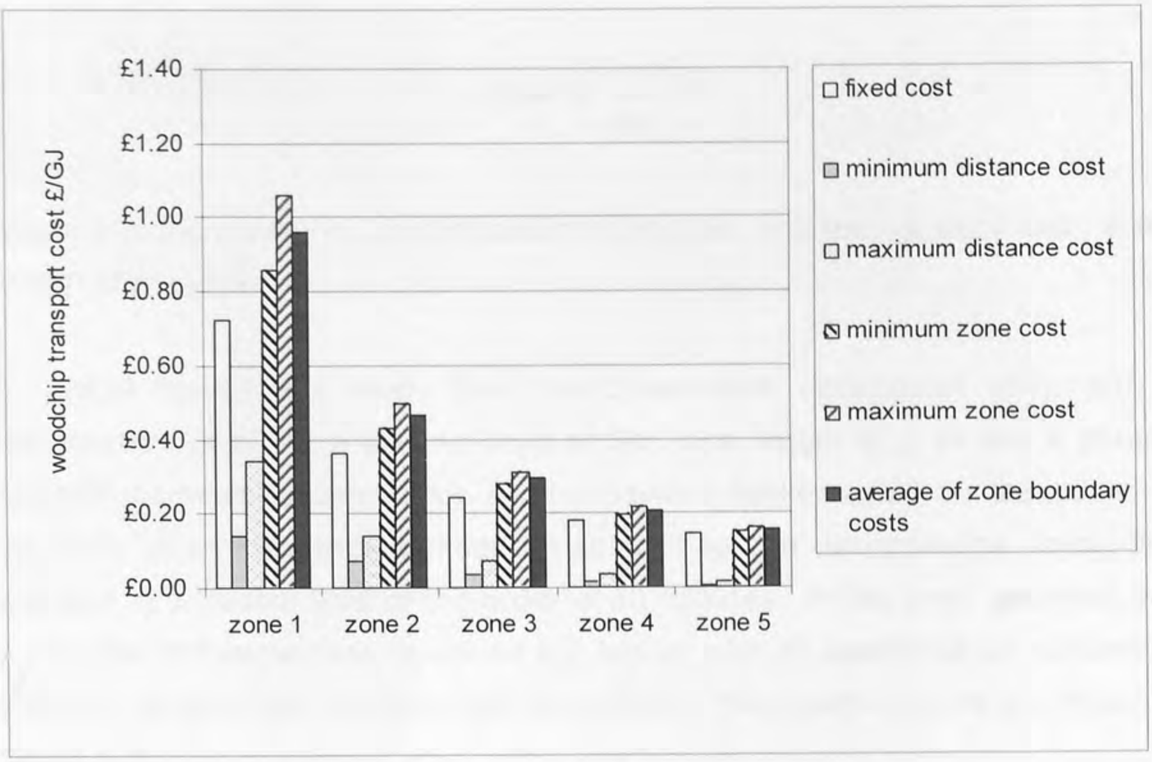

Figure 6.2 Miscanthus delivery zone costs

Bio-oil zone cost

Bio-oil typically has a density of 1,200 kg/m^3 [48] so the truck load will be limited by weight. The costs for a 44 t truck in Table 6.2 include an estimated cost for walking floor trailers. These are reported to be 80% more expensive than flat bed trailers [93]. Bio-oil tankers will also be more expensive than flat bed trailers as they have a stainless steel or lined mild steel tank which will need to be insulated. As the capital cost of the trailer only accounts for 20% of the fixed cost of the truck it is acceptable to assume that the difference in trailer cost between a walking floor trailer and a bio-oil tanker will have little impact on the total truck costs.

The other key factor that affects the zone costs of bio-oil is the loading and unloading times of the tanker. It has been proposed that bio-oil is allowed to flow from delivery tankers into a reception well under gravity [92]. In this situation the unloading time will be governed by the viscosity of the bio-oil and the dimension of the unloading pipe. The Hagen Poiseuille law governs the flow of Newtonian liquids through pipes:

$$\text{Flow} = \frac{\pi P r^4}{8 \eta l}$$

where *P* is the pressure, I is the radius of the pipe, η is the viscosity and *l* is the length of the pipe.

If typical figures are taken from the Dynamotive data sheet [58], with a temperature of 40°C, a loading head of 5m, pipe length of 2 m and 6 parallel 200mm diameter loading pipes a 28 t payload tanker could be loaded in 15 minutes. If an allowance is made for connecting and disconnecting hoses, this will lead to a loading time of the order of 30 minutes. It has been assumed that it will take the same time to unload the tanker with an additional 10 minutes to allow for weighbridge operation and formalities. The resulting costs are shown in Figure 6.3.

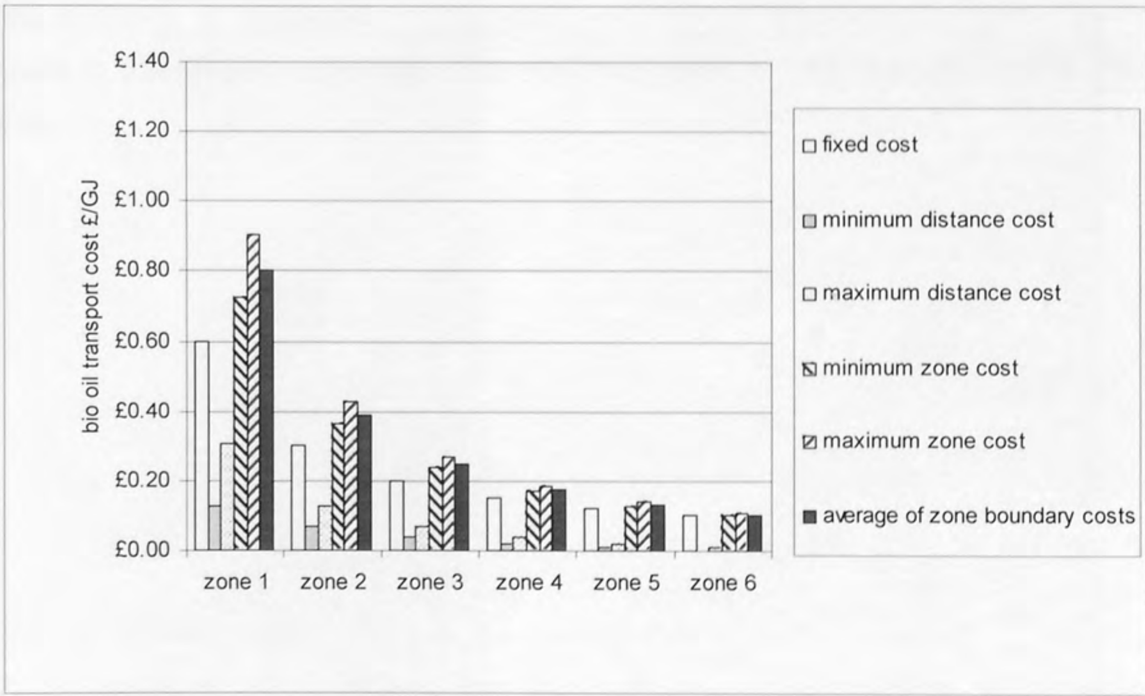

Figure 6.3 Bio-oil delivery zone costs

In Figures 6.1, 6.2 and 6.3 show that the costs are dominated by the fixed cost and that this becomes more pronounced for the inner zones. If a fixed zone cost equal to the average of the costs at the boundaries of the zone is used for the cost of transport from anywhere inside the zone the maximum error would be 12%. This reduces to 7% for zones 3, 4, 5, and 6. Consequently it is acceptable to use a fixed cost for transport for any location within a zone i.e. no assumptions need to be made about the distribution of field stores within the zone or the road speed to estimate the transport costs

The highest variable costs occur in Zone 1 but even here they represent no more than a third of the transport cost, this means that in the worst case if the average speed for a specific site was 50kph this would produce a transport cost that is 7% lower than the cost estimate for 64kph. Consequently the impact of choosing a high estimate for the average speed on the transport cost is small.

A fixed cost per t km has traditionally been used to calculate transport cost [82,87,207]. It is possible to calculate a distance rate that apportions the fixed costs to the distance covered. This has been done for willow woodchips in Figure 6.4.

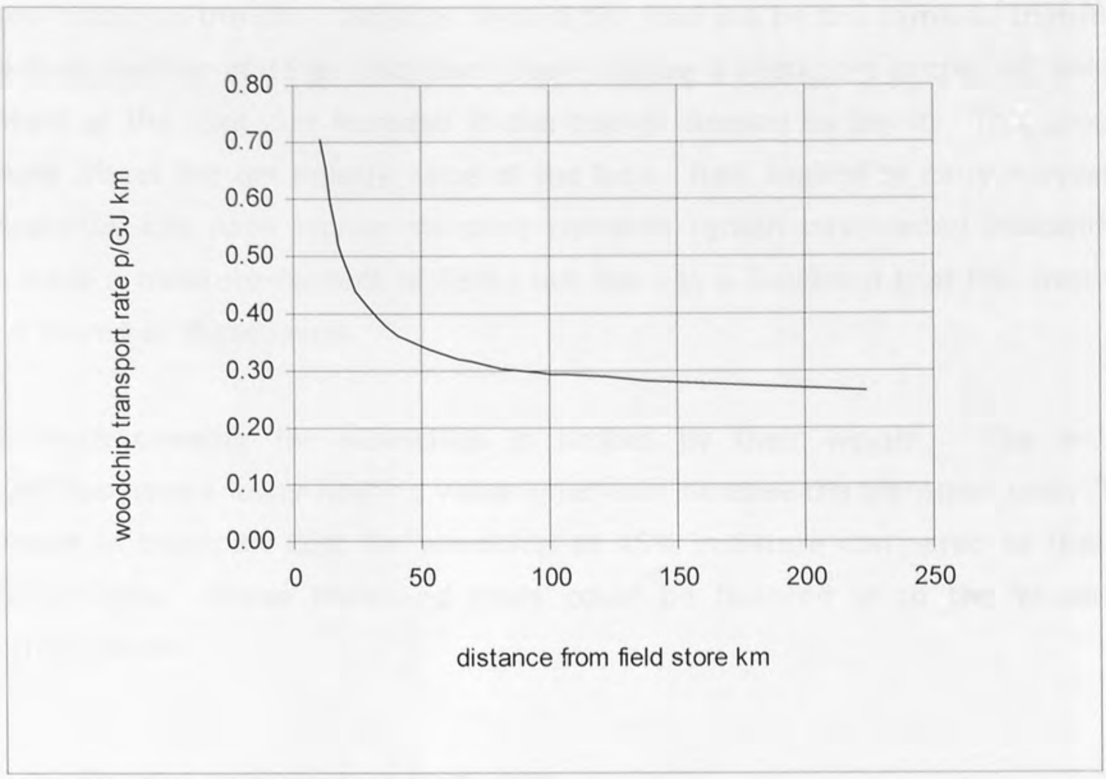

Figure 6.4 Distance rate needed to recover transport costs

From Figure 6.4 it is clear that the use of a single distance rate effectively subsidises the transport of biomass from stores that are close to the pyrolysis plant and penalises those that are further away. Consequently it is not appropriate to use a fixed distance rate for all the stores that supply a plant unless most of the biomass comes from stores that are more than 100km from the pyrolysis plant.

6.2.2.1 Comparison of zone cost for different moisture levels

It is possible that the crops will be wetter than the typical value due to problems with the storage arrangements or the weather. The impact of increasing the moisture level to one and a half time the typical value has been investigated.

The truck capacity for carrying miscanthus is limited by volume not weight. The weight of the bales with an moisture level of 22.5% are still within the load limit of the trailer so the dry matter content of the load will be the same as that for a moisture content of 15%. However there will be a reduction in the net energy content of the load due increase in the energy needed to dry it. This drop is around 2% of the net energy value of the load. Rain soaked or early harvested miscanthus can have higher moisture contents (green havevested miscanthus can have a moisture content of 55%) but there is a likelihood that the crop will rot if stored at these levels.

The truck capacity for woodchips is limited by their weight. The wetter woodchips have a lower heating value which will increase the transport cost. The increase in transport cost for woodchip at 45% moisture compared to that at 30% is 26%. These increased costs could be factored in to the woodchip purchase price.

6.2.2.2 Biomass availability in each zone

In order to calculate the transport costs for a given size of plant it is essential to know how much biomass is available in each zone. The amount of biomass available in a given zone can be estimated from the average crop yield, the fraction of land used for energy crops and the total area of land in the environs of the plant.

The diameter of the zone can be calculated from the average speed and the driving time in the zone, this will give the road distance. The corresponding straight line distance can be found using a winding factor i.e. the ratio between the linear distance and the road distance. Winding factors are route specific but an estimation of the winding factor can be made by assuming that the road runs round two sides of a triangle with a hypotenuse length r and an internal angle of α.

The winding factor W is given by:

$$W = \frac{r\sin(\alpha) + r\cos(\alpha)}{r}$$

the average value of W can be found by

$$W = \frac{\int_0^{0.5\pi} \sin(\alpha) + \cos(\alpha) d\alpha}{0.5\pi}$$

$$W = \frac{4}{\pi} = 1.27$$

This value is only correct for grid road layouts, a study of transport routes would be needed to establish the actual value for a specific site.

Tables 6.4 and 6.5 shows the possible production of biomass for each 1% of total land area used for growing biomass (the Land Use Fraction LUF) assuming:

- Woodchip yields of 9.4 odt/ha/yr with HHV of 19.1 GJ/ha which gives an energy yield of 18 TJ/km^2 ;
- Miscanthus yields of 13.5 odt/ha/yr with HHV of 19.2 GJ/ha which gives an energy yield of 26 TJ/km^2;
- A winding factor of 1.27;
- Average speeds of 64 kph.

These tables show the production from the zone and the cumulative production i.e. the production from the zone and all the zones nesting inside it.

Table 6.4 Zone energy yield in TJ for each 1% of LUF planted with SRC Willow

	zone radius km		production TJ/y	
zone	inner	outer	from zone	cumulative
1	75.6	176.4	14324	17545
2	42.0	75.6	2228	3221
3	25.2	42.0	637	993
4	15.1	25.2	229	357
5	8.4	15.1	89	128
6	1.6	8.4	38	38

Table 6.5 Zone energy yield in TJ for each 1% of LUF planted with miscanthus

	zone radius km		production TJ/y	
zone	inner	outer	from zone	cumulative
1	68.9	169.7	19576	23436
2	35.3	68.9	2849	3859
3	18.5	35.3	735	1010
4	8.4	18.5	221	275
5	2.0	8.4	54	54

It is worth noting that although the yield for miscanthus is higher than that for SRC willow the longer handling times mean that the amount that is available in Zones 6, 5 and 4 is actually less than for SRC willow.

Figures 6.1 and 6.2 show that if the demand can be met from the cumulative production of Zone 3 the transport cost will be under 15% of the base case biomass production cost given in Section 6.1.5. From Table 6.4 and 6.5 the cumulative production of zone 3 is 1000 TJ/%LUF. Consequently detailed analysis of transport cost is only likely to be necessary for sites which need more than 5000 TJ/y of biomass.

6.2.2.3 Estimating transport cost for a plant

An estimate of the average transport cost for a given plant capacity (Ct) can be made by using the following formula:

$$Ct = \frac{\sum_{zone=6}^{zone=1}(Cz.Qz)}{Qt}$$

Where *Cz* is the transport cost per GJ in the zone, *Qz* is the amount of biomass taken from the zone and Qt is the total biomass used by the pyrolysis plant.

The amount of biomass that a plant will need to take from any zone will depend on the fraction of the LUF. There is no "correct" value for LUF; whether a given value is realisable depends on a number of limiting factors:

- The proportion of land that is unsuitable for cultivation (too steep or marshy);
- The proportion of highly productive land where energy crops will never be competitive with traditional agriculture (market gardens and high yielding cereal land);
- The area of woodlands, commons, and nature reserves;
- The proportion of land built over including urban green spaces and sports fields;
- Land used to provide energy crops for other plants including bio-diesel and bio-ethanol production;
- The proportion of land that does not have reasonable road access (i.e. is more than about 2 km from a road that is suitable for heavy goods vehicles).

The National Union of Farmers has been reported as saying that up to 20% of agricultural land could be available for energy crops [5]. Some of this land will probably be used for bio-diesel and bio-ethanol production, so it may be more realistic to assume a lower value of LUF.

The average transport cost has been calculated for woodchip and miscanthus over a range of LUF values in Figures 6.5 and 6.6. This has been done for a truck speed of 64 kph and assuming best practice crop yields.

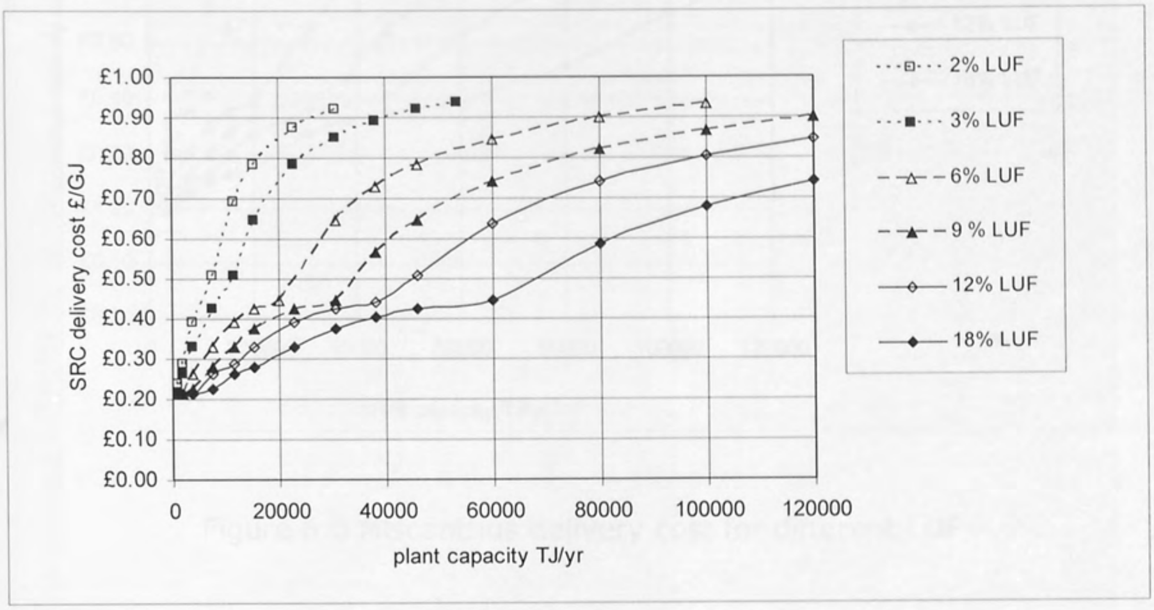

Figure 6.5 Woodchip delivery cost for different LUF

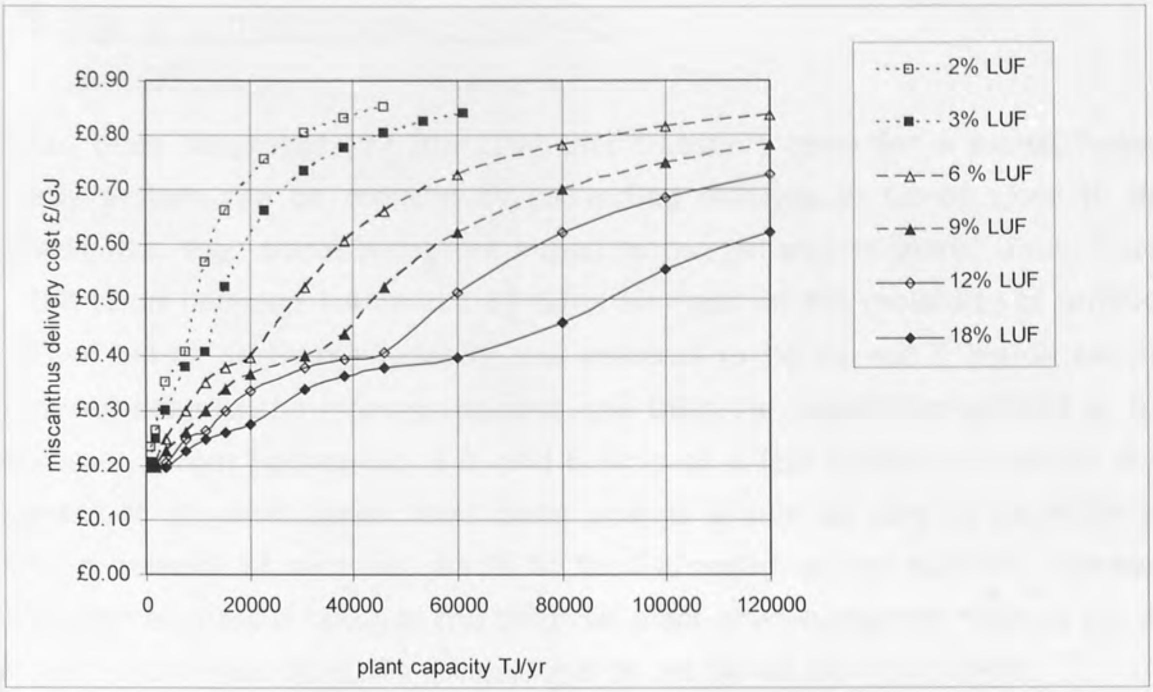

Figure 6.6 Miscanthus delivery cost for different LUF

The shapes of the curves reflect the fact that they are the integral of the zone cost curves which are stepped in nature. The curves have a flattish portion at around £0.40/GJ which corresponds to the use of biomass from Zone 2. The costs rise rapidly once biomass is required to be taken from Zone 1.

The zone sizes were calculated using a speed of 64kph if the speed was 50 kph zone would only be 61% of the size. Likewise if the yields were at the lower values given in Section 6.1.5 the production would be 66% or 70% of the predicted value. Consequently it is credible that the actual production could be 60-70% of that shown in Figures 6.5 and 6.6. This is equivalent to reducing the LUF by around third. The impact of this will depend on the consumption of the plant. It will be particularly significant at consumptions that need a small amount of Zone 1 biomass.

6.3 Use of remote pyrolysis plants

It has been suggested [92,208-209] that transport costs for a bio-oil fuelled energy system can be reduced by converting biomass to bio-oil close to the harvest site, then transporting the bio-oil to the generation plant. From Table 4.10 it takes between 1.44 and 1.89 GJ of biomass (at 8% moisture) to produce 1 GJ of bio-oil so there is clearly less material to be moved if bio-oil can be produced near to the biomass harvest site then the bio-oil transported to the consumer. From Figures 6.1, 6.2, and 6.3 bio-oil is less costly to transport than biomass so it would appear that costs savings should be able to be made by using a network of pyrolysis plants to feed a central power station. However unless the biomass is taken to the pyrolysis plant when harvested there is still an element of biomass transport in additional to the bio-oil transport costs.

Consider the case shown in Figure 6.7.

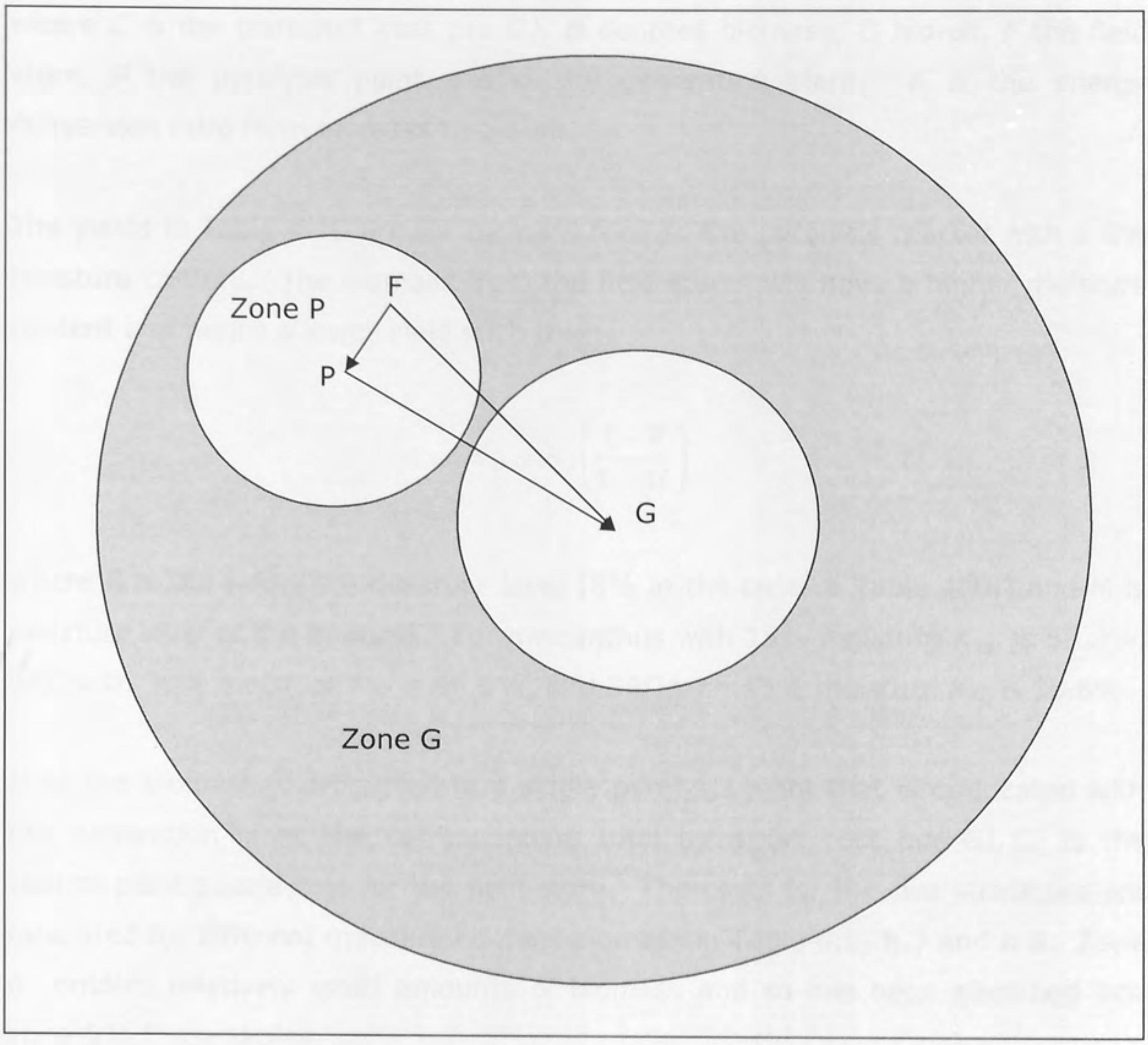

Figure 6.7 Transport options for biomass from field stores

The biomass can be taken directly from the field store F to the central plant G in which case the transport cost, C_D is the zone cost for Zone G. Alternatively the biomass can be processed in a remote pyrolysis plant located at P in which case the total transport cost C_R associated with transporting biomass to the pyrolysis plant and then transporting the bio-oil produced to the centrally located generation stations is:

$$C_R = C_{B,P} + K\, C_{O,G}$$

where C is the transport cost per GJ, B denotes biomass, O bio-oil, F the field store, P the pyrolysis plant and G the generation plant. K is the energy conversion ratio from biomass to bio-oil.

The yields in Table 4.10 are for biomass feed to the pyrolysis reactor with a 8% moisture content. The biomass from the field stores will have a higher moisture content and hence a lower yield such that:

$$K_M = K_R\left(\frac{1-R}{1-M}\right)$$

where R is the reference moisture level (8% in the case of Table 4.10) and M is moisture level of the biomass. For miscanthus with 15% moisture K_{15} is 56.2%, SRC with 30% moisture K_{30} is 46.6%, and SRC with 45% moisture K_{45} is 36.6%.

If all the biomass is processed in a single pyrolysis plant that is co-located with the generation plant the corresponding total transport cost per GJ C_C is the central plant's zone cost for the field store. The costs for the two strategies are tabulated for different moisture content biomass in Table 6.6, 6.7 and 6.8. Zone 6 contains relatively small amounts of biomass and so has been absorbed into zone 5 in these tables.

Table 6.6 Biomass transport costs for 30% moisture woodchips

	transport cost C_C	transport cost C_R			
		F-P zones			
P-G zones		2	3	4	5
1	£1.06	£0.89	£0.71	£0.61	£0.56
2	£0.52	£0.70	£0.51	£0.42	£0.36
3	£0.33	£0.63	£0.45	£0.35	£0.30
4	£0.24	£0.60	£0.41	£0.32	£0.26

Table 6.7 Equivalent biomass transport costs for 45% moisture woodchips

	transport cost C_C	transport cost C_R			
		F-P zones			
P-G zones		2	3	4	5
1	£1.34	£0.95	£0.72	£0.60	£0.52
2	£0.66	£0.80	£0.57	£0.45	£0.37
3	£0.42	£0.75	£0.51	£0.39	£0.32
4	£0.30	£0.72	£0.49	£0.37	£0.30

Table 6.8 Equivalent biomass transport costs for 15% moisture miscanthus

	transport cost C_C	transport cost C_R			
		F-P zones			
P-G zones		2	3	4	5
1	£0.94	£0.91	£0.74	£0.66	£0.60
2	£0.46	£0.68	£0.51	£0.42	£0.37
3	£0.29	£0.60	£0.43	£0.34	£0.29
4	£0.21	£0.56	£0.39	£0.30	£0.25

As the dry matter content of a truck load of miscanthus is independent of its moisture content there is no change in transport cost with moisture content.

From Table 6.10, 6.11 and 6.12 it appears that reasonable savings in combined transport cost can be made but only in limited circumstances, and these saving increases with the moisture content of the biomass.

The maximum transport saving come from the use of a number of small remote pyrolysis plants located in zone one. However Tables 5.4, 5.5 and 5.8 show that there are considerable economies of scale in the capital cost of pyrolysis units and material handling plant. These can generate far larger cost savings than the savings in transport costs associated with using remote pyrolysis units. To take advantage of the economies of scale a pyrolysis plant would need to have at least four 200 odt/day pyrolysis units. This would require around 5000 TJ/y of biomass. From Table 6.4 it would require a minimum LUF of 14% to supply 5000 TJ from inside Zone 4 for willow and 18% for miscanthus; given the pressure on land use from agriculture and other energy crops this is unlikely to be achievable. A 5000tJ/y plant taking biomass from inside its Zone 3 will require a LUF of around 5% which is probably achievable. If this constraint is applicable the only situations where transport costs can be reduced by using remote pyrolysis plants is where the remote plants are situated in the generation stations Zone 1 and the remote pyrolysis plants take biomass from inside their own Zone 2 or Zone 3.

As savings in transport cost can only be made by using remote pyrolysis units in Zone 1 it follows that all the biomass that is inside the other zones should be processed at the central location. Consequently the optimum transport cost can be achieved with a central pyrolysis plant located at the generation plant site with a number of remote satellite pyrolysis plants located in a ring around it. This arrangement is shown in Figure 6.8

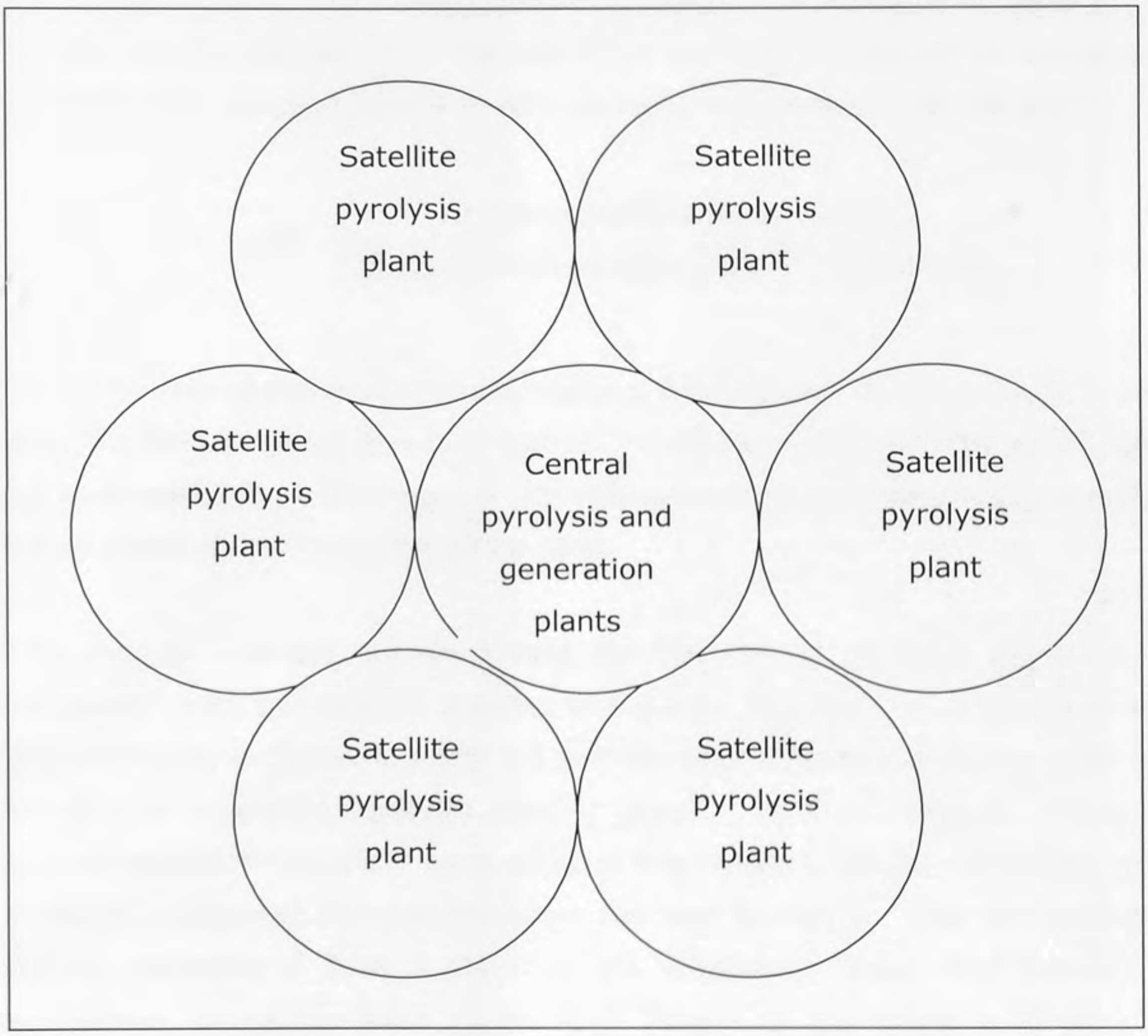

Figure 6.8 Possible network of pyrolysis plants

Figure 6.8 shows all the pyrolysis plants as having the same size environs. This would be the situation if all the pyrolysis plants processed biomass from inside their Zone 2.

From Table 6.4 the 64 kph zone boundaries for willow for Zone 2 has a radius of 76 km so the satellite plants will be located at 152 km from the central plant; this is within the 176 km radius of the central plants Zone 1. It is possible to conceive a second ring of satellites but these would be located at a radius of 304 km from the central plant an so not accessible by a single day round trip.

From Tables 6.6 - 6.8 it would appear that further savings could be made by using satellite plants that only processed biomass from inside their Zone 3. The number of this size satellites that can fit in the ring will depend on the angular extent θ of the satellite plant's environ when viewed from the central plant.

$$\theta = 2\sin^{-1}\left[\frac{\text{radius of satellite outer zone } z_P}{\text{distance from satellite plant to central plant}}\right]$$

The diameters of the zones for each type of biomass are shown in Table 6.4 and 6.5. The formula gives θ as 0.73 radians for woodchip P3 satellites which allows up to 8 satellites in the ring. θ for miscanthus P3 satellites is 0.691 radians which allows up to 9 satellites to be used.

The average biomass transport cost for the central pyrolysis plant can be calculated using the method outlined in 6.2.2.3. The biomass available in each zone is shown in Tables 6.4 and 6.5 and the total transport costs for each zone in used by a satellite pyrolysis plant is given in Table 6.6 or 6.8. Hence the overall transport cost from each plant in the network can be calculated and a production weighted average transport cost can be found. This has been done for the networks of Zone 2 satellites (P2 satellite i.e. those that process the cumulative production from inside their Zones 2) and Zone 3 satellite (P3 satellites) plants using a 9% LUF and the results compared with the cost of a single centralised pyrolysis plant in Figure 6.9 for SRC woodchips.

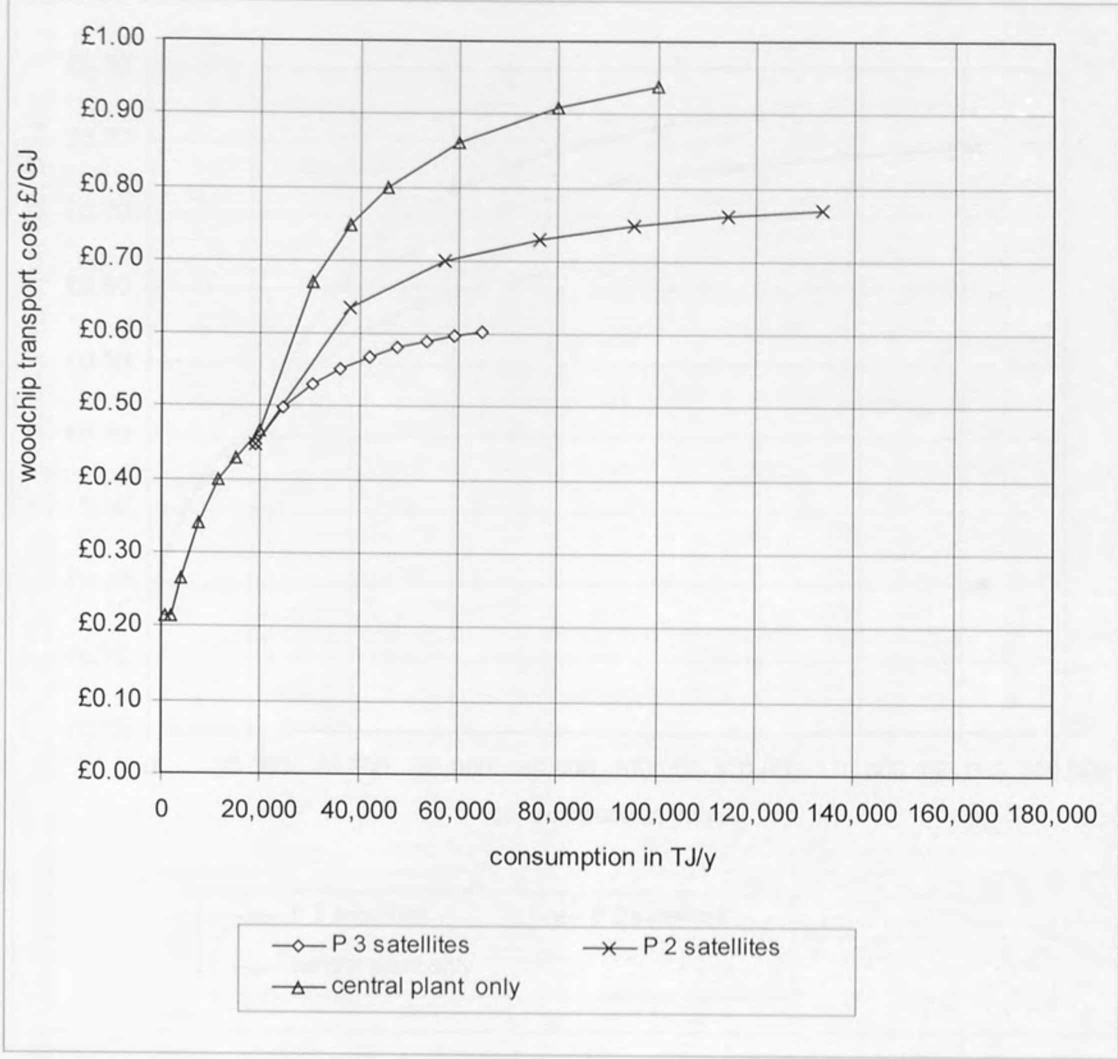

Figure 6.9 Average total transport cost for networks of pyrolysis plants using woodchips assuming a 9% LUF.

The P2 satellites can process biomass that is outside of the central plant's Zone 1 which is why the P2 satellite network has a larger biomass consumption than a centralised plant.

The costs for satellite systems using miscanthus are shown in Figure 6.10.

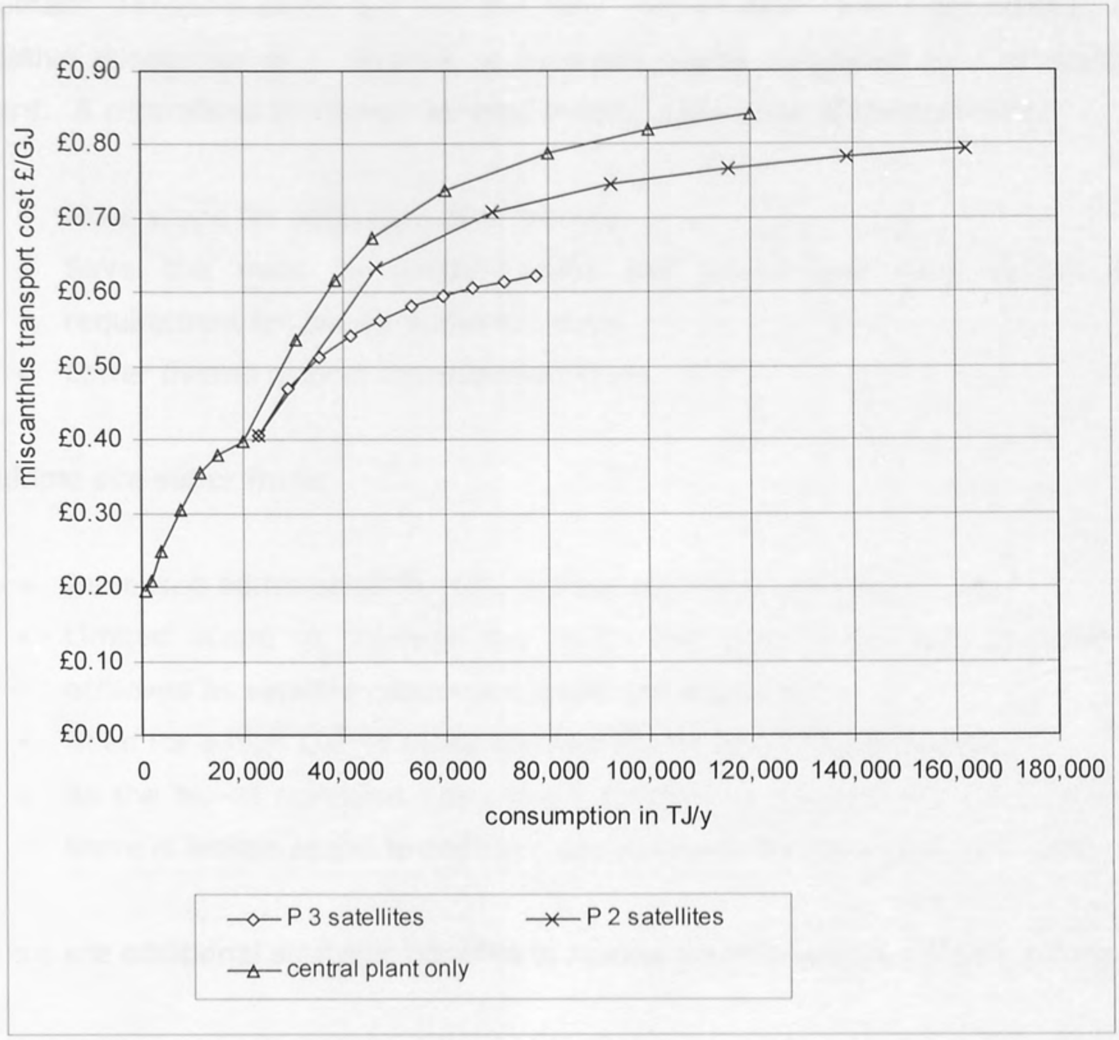

Figure 6.10 Average total transport cost for networks of pyrolysis plants using miscanthus assuming a 9% LUF.

As expected the impact of using satellite plants is lower for the relatively drier miscanthus.

Biomass transport costs are not the only consideration when considering the relative economics of a network of pyrolysis plants compared to a centralised plant. A centralised plant may be able to take advantage of the following:

- More scope for optimisation of labour;
- Save the need to double-handle the bio-oil and may reduce the requirement for bio-oil buffer storage;
- Lower overall project development costs.

Multiple site suffer from:

- Increased administration costs compared to a single site;
- Limited scope to increase the catchment area if the LUF can not be achieved as satellite catchment areas are adjacent;
- Need for a high LUF to make satellite plants of an economic size;
- As the bio-oil transport costs are a function of the satellite plant location there is limited scope to reduce transport costs by increasing the LUF;

There are additional strategic benefits in having satellite plants. These include:

- Reduction in the truck movements at the central site;
- Satellite plants can be owned and operated by different organisations;
- The central site could readily use imported bio-oil;
- The network could contain a mix of woodchip and miscanthus processing sites.

All these points will need considering when comparing real schemes. One point is clear; satellite plants are only worth considering for generators that need more than 25,000 TJ of willow or 29,000 TJ of miscanthus. This corresponds to CCGT plants between 300 and 350 MW_e. It is also clear that the maximum saving that can be made by using satellite plants is £0.25/GJ for willow; this is far less than the difference in biomass price between the low yield and base case prices given in Section 6.1.5.

So although the use of satellite plants may be beneficial for generators with large bio-oil demands, their use is unlikely to alter the viability of a proposed project.

6.3.1 Transport costs for use in study

The range of biomass cost between the base cases and the low yield cases in Section 6.1.5 is £1.21 for SRC and £1.10 for miscanthus. From Figures 6.5 and 6.6 the maximum error that would occur by overestimating the LUF would be £0.50 and the likely uncertainty due to site specific factors would be in the region of £0.20. Consequently it is probably only worth considering a typical transport cost when compiling the overall costs for the project. Therefore the 9% LUF characteristic will be used, as it is in the middle of the estimate of available land for energy crops. It is assumed that satellite plants will be used for larger systems. This means that there are 3 transport cost curves each covering a different consumption range and plant configuration. Figure 6.11 shows the appropriate characteristic for woodchip.

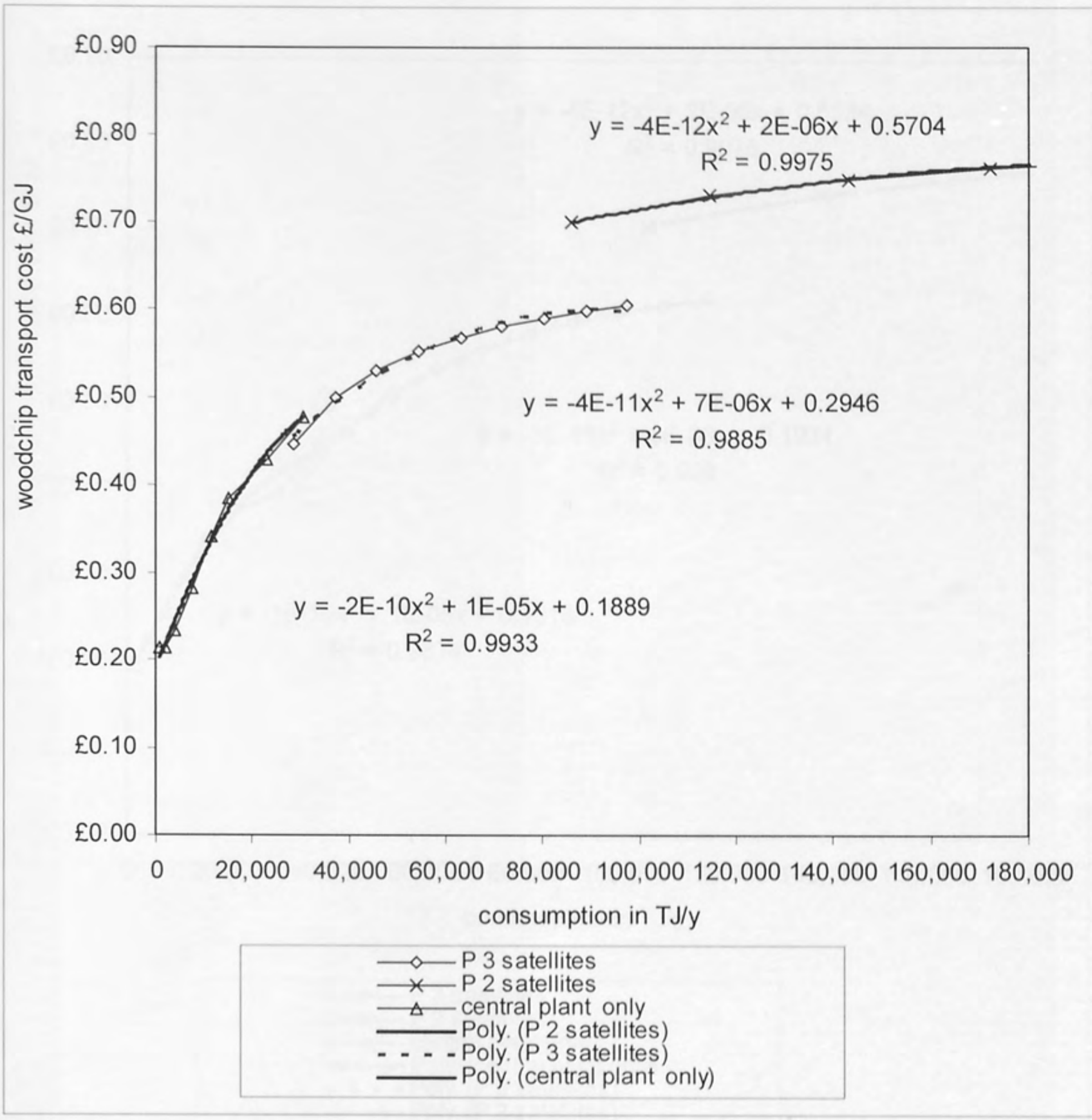

Figure 6.11 Biomass transport costs for willow woodchips

The curves for miscanthus are shown in Figure 6.12.

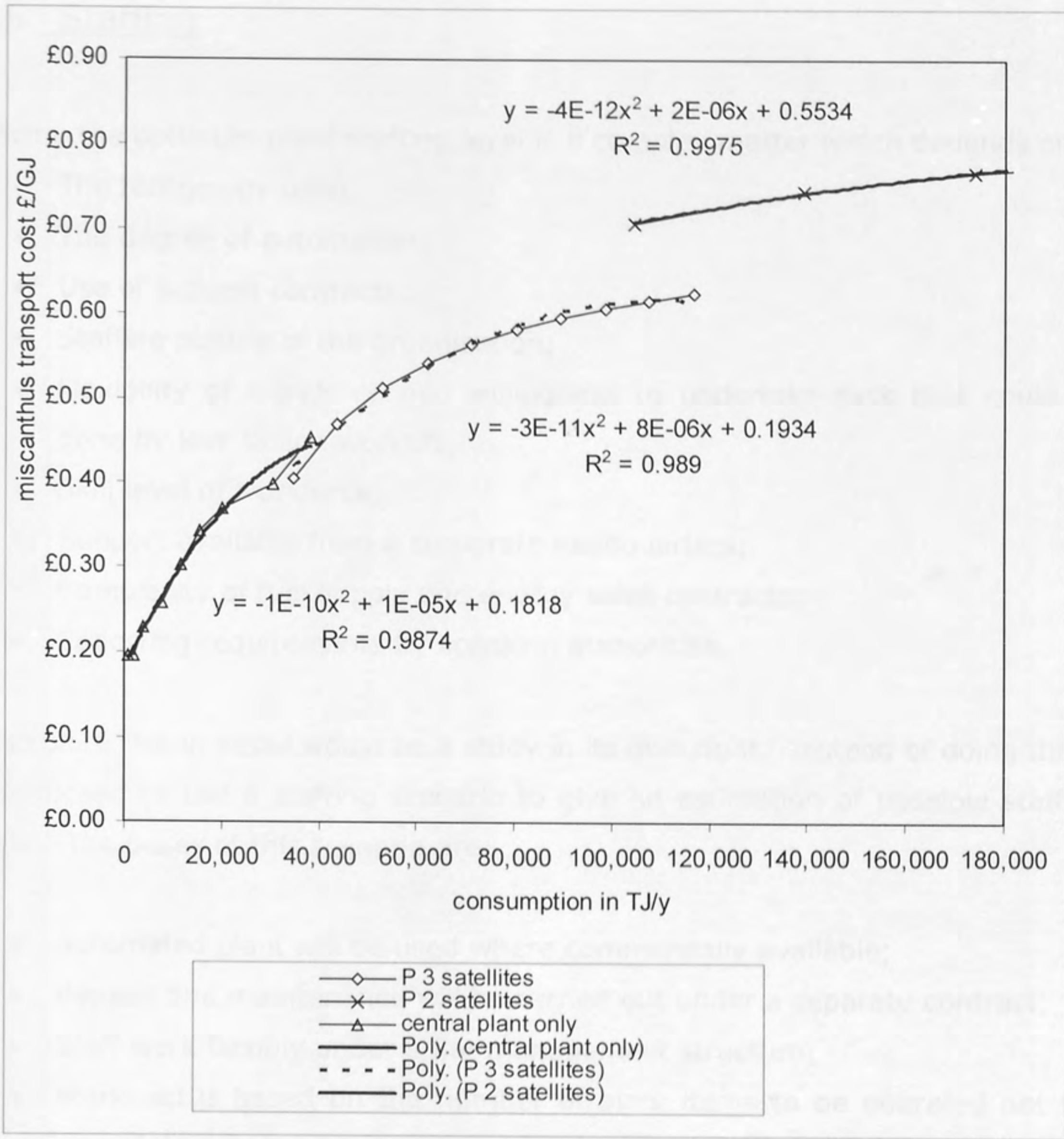

Figure 6.12 Biomass transport costs for miscanthus

6.4 Pilot diesel costs

As stated in Section 3.3.2 the average value for distillate fuel for 2005,2006 and 2007 will be used as the fuel cost. From DUKES Table 3.1.4 [119] the average annual price of gas oil was 3.18 p/kWh or £8.84/GJ.

6.5 Staffing

Finding the optimum plant staffing level is a complex matter which depends on:

- The technology used;
- The degree of automation;
- Use of support contracts;
- Staffing culture of the organisation;
- Flexibility of workforce and willingness to undertake task that could be done by less skilled workers;
- Skill level of workforce;
- Support available from a corporate headquarters;
- Complexity of fuel supply and energy sales contracts;
- Reporting requirements by licensing authorities.

To explore this in detail would be a study in its own right. Instead of doing this it is proposed to use a staffing scenario to give an estimation of possible staffing costs. The bases of this scenario are:

- Automated plant will be used where commercially available;
- Repairs and maintenance will be carried out under a separate contract;
- Staff work flexibly under a flat management structure;
- Workload is based on the number of plant items to be operated not the size of the plant.

Although staff flexibility has been assumed, the staffing numbers have been arrived at by considering the requirements of each subsystem separately. Before doing this the number of shifts that an employee is likely to work needs to be estimated; this has been done in Table 6.9.

Table 6.9 Estimation of the number of shifts worked per employee in a year

days not available for work	
rest days	104
holiday	25
bank holiday	7
sickness [204]	9
training	5
total absence	150
days in a year	356
shifts worked in a year	206

Table 6.9 is based on an employee working 8 hour shifts. The number of staff employed is calculated by estimating the number of shifts worked a year and dividing by the number of shifts an employee is likely to work a year. The results are rounded up to the next whole number on the assumption that part time shift operators cannot be recruited.

6.5.1 Woodchip plant

The materials handling and pre-treatment plants are assumed to need staffing on a two shift basis i.e. most of the plant is shut down at night with the drying processes supervised by the pyrolysis plant staff.

The manual systems used on the 50odt/d and 100 odt/d should be able to be operated by a single operator. These systems will need one shift a day seven days a week.

The reception function of the semi-automatic system should operate without any staff present but it is considered prudent to have an operator supervising operation.

It has been assumed that this operator would be able to supervise up to 4 ground hoppers. The automated reception plant operates for two shifts a day 5 days a week.

The reclaim operation is supervised by the front end loader driver. From Section 5.2.2 one front end loader is needed for plants up to 800 odt/d. Reclaim and stock pile management are done by the same driver. These operations go on for two shifts a day seven days a week.

The total staffing requirement for the woodchip plant is shown in Table 6.10.

Table 6.10 Staffing level required for woodchip handling and pre-processing plant

size odt/d	50	100	150	200	400	800
reception supervisors			1	1	1	1
reception shifts/week			10	10	10	10
front end loader drivers	1	1	1	1	1	1
drivers shifts/week	7	7	14	14	14	14
total shifts worked/week	7	7	24	24	24	24
shifts worked /year	364	364	1248	1248	1248	1248
staff required	2	2	7	7	7	7

Plants at ratings above 800 odt/d are assumed to be made up of multiple 800 odt/d streams.

6.5.2 Miscanthus handling plant

The 50, 100 and 150 odt/y plants all have material handling systems based on fork lift trucks.

The grinder feed is assumed to need one bale at a time where the truck unloading operation requires three bales to be moved at a time. Consequently it has been assumed that these plants will need two operators a shift. The 50odt/d and 100odt/d plants are operated for one shift a day seven days a week the 150 odt/d plant is operated for two shifts a day seven days a week.

The larger plants use automatic cranes: it has been reported in [132] that in practice these cranes are supervised when unloading trucks. It has been assumed that one operator can supervise two cranes installed in a single bay. The automatic bays operate for two shifts seven days a week.

The total staffing requirement for the miscanthus handling plant is shown in Table 6.11.

Table 6.11 Staffing level required for miscanthus handling and pre-processing plant

size odt/d	50	100	150	200	400	800
operators /shift	2	2	2	1	1	2
shifts/week	7	7	14	14	14	14
total shifts worked/week	14	14	28	14	14	28
shifts worked /year	728	728	1456	728	728	1456
staff required	4	4	8	4	4	8

6.5.3 Pyrolysis plant

Although the pyrolysis plant is assumed to be mostly automated it is also assumed to need supervision. There has been insufficient operating experience to establish what the "normal" staffing level should be for a pyrolysis plant. It would be reasonable to assume that they would follow normal power station practice of having control room operators and plant operators.

In a gas fired CCGT power station one desk operator can supervise two gas turbines with heat recovery steam generating boilers and one steam turbine so it has been assumed that one control room operator should be able to control up to four pyrolysis reactors. The plant operator needs to be able to move round the plant in a reasonably short time so it has been assumed that one plant operator can cover two pyrolysis units.

Table 6.12 Staffing level required for pyrolysis plant

size odt/d	50	100	150	200	400	800
operators /shift	2	2	2	2	2	3
shifts/week	21	21	21	21	21	21
total shifts worked/week	42	42	42	42	42	63
shifts worked /year	2184	2184	2184	2184	2184	3276
staff required	11	11	11	11	11	16

6.5.4 Generation

Diesel generators

In the developed world the operation staffing requirement for diesel engines above 3MWe was reported to be between 2 and 5.8 operators per engine [167], this wide range reflects the fact that a number of sites have multiple engines and may share operators between engines. It is expected that diesel generators will be the most suitable generators for sites with one or two pyrolysis reactors. It is likely that at these sites operation staff will be able to undertake some duties related to the diesel generators. Consequently it has been assumed that a single engine will require the employment of two operators.

CCGT and combustion plant

Established practice for CCGT and combustion plants is to have 2 operators per unit on each shift. There appears to be no reason why this practice should not be followed on bio-oil fuelled plant particularly as the fuel reception and storage duties are carried out by the "pyrolysis plant" staff.

6.5.5 Day staff

The number of day staff required will be heavily influenced by the nature of any maintenance and support contracts that are in place. The split of duties between site and headquarters' staff will also affect these numbers. An estimate of possible numbers based on discussions with members of the SUPERGEN consortium and is given in Table 6.13.

Table 6.13 Day staff requirement

plant size x100 odt/d	0.5	1	1.5	2	8	16	24	32	40	48
manager	1	1	1	1	1	1	1	1	1	1
commercial manager					1	1	1	1	1	1
clerical officers	0.5	0.5	1	1	2	3	4	5	6	7
Technical manager	1	1	1	1	1	1	1	1	1	1
engineers				1	3	3	3	3	3	3
technicians	1	1	1	2	3	5	7	9	11	13
day Team total	3.5	3.5	4	6	11	14	17	20	23	26

The low staffing levels for the small plants imply that they have more reliance on off-site expertise. As the plant size increases to 800 odt/y it has been assumed that there is sufficient workload to employ a team of technical professionals. Above this level the additional workload is carried out by technicians working with the engineering team.

It has been assumed that the smaller plants will have relatively simple contract arrangements that can be handled by the site manager or are negotiated by headquarters staff. As the plant size increases above 400 odt/y the site may need multiple bio-mass supply contracts and expensive gas turbine maintenance contracts so a specialist commercial manager has been included in the day team for the larger plants.

It has been assumed that clerical staff can be hired on a part time basis for the smaller sites with a lower clerical workload.

6.5.6 Total staffing levels

The total staffing levels are shown in Tables 6.14 and 6.15. Plants that are over than 800 odt/d are assumed to be made of a number of 800 odt/d streams. Consequently for operation staff the shifts worked per year for these plants will be multiples of that from a single stream. This is then divided by the shifts that each employee works and the number rounder up. Consequently the number of employees is no necessary a direct multiple of the number of streams.

Table 6.14 Staffing levels for a woodchip fuelled pyrolysis plant

plant size	50	100	150	200	800	1600	2400	3200	4000	4800
woodchip handling	2	2	7	7	7	13	19	25	31	37
pyrolysis plant	11	11	11	11	16	32	48	64	80	96
generation	2	2	2	2	11	11	11	11	11	11
day team	3.5	3.5	4	6	11	14	17	20	23	26
total	18.5	18.5	24	26	45	70	95	120	145	170

Table 6.15 Staffing levels for a miscanthus fuelled pyrolysis plant

plant size	50	100	150	200	800	1600	2400	3200	4000	4800
miscanthus handling	4	4	8	4	8	15	22	29	36	43
pyrolysis plant	11	11	11	11	16	32	48	64	80	96
generation	2	2	2	2	11	11	11	11	11	11
day team	3.5	3.5	4	6	11	14	17	20	23	26
total	20.5	20.5	25	23	46	72	98	124	150	176

It appears from Table 6.14 and 6.15 that the choice of feedstock has little impact on site staffing levels.

The largest group of staff is the pyrolysis plant operators. It is likely that with increasing operating experience and plant development the ratio of operators to pyrolysis reactors could be reduced. This will reduce the staff requirement for the larger plants but it is unlikely to impact on the smaller ones due to safety limitations on minimum staffing levels.

As discussed earlier this staffing model is little more than a scenario. It is worth comparing it with the staffing levels from operating biomass fired power stations. Energy Power Resources publish the staffing levels for their plants on their web site [205] these have been listed in Table 6.16.

Table 6.16 Staffing levels at UK biomass fired power station

Plant	type	output MWe	Fuel consumption	employees
Ely	Straw	38	200 kt/y	28
Thetford	poultry litter	38.5	420 kt/y	31
EPR Scotland	chicken litter BFB	9.8	110kt/y	20
Ely Fibpower	chicken litter	12.7	160kt/y	28
Glenford	poultry litter	13.5	not given	21

Although it is not possible to draw a direct comparison the numbers in Table 6.16 are similar to those in Tables 6.14 and 6.15 for the single pyrolysis reactor units. Estimates of full time staff numbers for fully attended biomass plants produced by the Supergen consortium [73] range from 11 to 25 for plants in the range of 2 - 25MW$_e$ depending on technology used.

As notes in Section 2.2.5 Farag includes an estimate of 19 employees for a 240 odt/d plant using forestry woodchips in New Hampshire. This is considerably lower than the present estimate but it appears from his report that he is assuming the plant is only manned on a two shift basis. There are unmanned OCGT generators, land fill gas engines and heating boilers operating in the UK, but the author is not aware of any unmanned refineries and doubt that the public will accept a plant that produces a fuel being left unattended.

The shift manning levels in the reviewed literature is shown in Table 2.4. They are not particularly consistent and range between 2 and 6 operators.

6.6 Repair and maintenance

This item is frequently misnamed as operation and maintenance (true operation cost include fuel and staffing costs which are normally identified separately).

It can be included with overheads and rarely explained in most studies. The work is usually carried out by contractors with such items as the scope of works, supply of consumables, response times, working patterns and cost all subject to negotiation. As such the final costs are commercially confidential. Consequently it is not surprising that there is a wide spread of estimates for this cost. The costs are often expresses as % of the TPC/y. The values used in various studies are shown in Table 6.17.

Table 6.17 Estimate of maintenance costs from different studies

Solantausta Y, Bridgwater T, Beckman D [79]	1.6%
Antares Group [124]	2.0%
Oasmaa A, Solantausta y o, Beckman D [87]	2.0%
Ringer M, Putsche V, Scahill [96]	2.0%
Mitchell C P et al [77]	2.5%
Bridgwater AV, Toft AJ, Brammer JG [81]	2.5%
Toft A J [82]	4.0%
Peacock GVC Bridgwater AV and Brammer JG [86]	4.0%
Farag IH, LaClair CE, Barrett [89]	10.0%

It needs to be recognised that there is very little experience of operating pyrolysis plants commercially. The 1.6% estimate came from experiences of Finnish combustion plant maintenance costs [80] and the 10% one from a chemical engineering text book which is assumed to be a generic allowance for a chemical plant rather than a pyrolysis based power station. Given the lack of firm data it is best to consider these estimates as allowance to cover the cost of maintenance. Consequently it is proposed to use 2% of the TPC for maintenance cost.

Although there is a lack of firm data on the maintenance cost of pyrolysis plant there is some on generators.

In a private report commissioned for Aston University costs associated with gas engines that are suitable for use with bio-gas and land fill gas were obtained in confidence from a number of manufactures [206]. These gases include some corrosive components so engines running on bio-oil should have similar maintenance costs. The cost is expressed as a variable cost with an average value of £ 8.08/MWh_e.

Operation and maintenance costs for gas fire GT's used in CHP plants have been published in [185]; these are separated into a fixed and variable portion. The fixed portion covers staffing costs and the variable portion represents the routine inspection and overhauls carried out by contract. It is expected that any CCGT plant will run on base load so the variable costs have been converted to an annual cost assuming a capacity factor of 0.74 (from Section 4.7.2). It has been reported by GE [174] that machines running on residual fuel oil need inspecting at a third of the interval of natural gas fired machines; consequently the variable costs have been increased by a factor of 3. The same report gives a cost break down and a TPC figure for the GTS. The ratio of the annualised variable costs to the TPC for the gas turbine has been calculated in Table 6.18.

Table 6.18 Gas turbine maintenance costs

size MWe	5	10	25	40
R&M / GT TPC	14%	13%	10%	11%

From the data on CCGT plants in Gas Turbine World [169] the gas turbines are responsible for an average of 33% of the cost of the CCGT. This value will be used to calculate the TPC for the GT. The GTs in Table 6.20 are at the low end of the range considered so it would be appropriate to use the 11% costs from the 40MW machine for all of the GTs considered.

There is no reason to believe that the steam cycle of a CCGT will have similar maintenance cost to the GT.

The GT exhaust conditions are likely to be close to the temperatures found in a biomass fired steam plant but with a lower ash burden. Consequently it is proposed to use the estimate of 1.6% TPC/y from combustion plants quoted by Solantausta [80] to estimate the R&M cost for the steam cycle portion of the CCGT plants. From the equipment cost in Gas Turbine World [169] the steam cycle represents 66% of the cost of a CCGT so the R&M cost of the steam cycle is estimated to be 1% of the total CCGT TPC per year.

The reports on commercial combustion trials discussed in Section 1.2.5.1 do not include any evidence that a bio-oil fired plant needs more maintenance than a fossil fuel fired one. The combustion plants being considered in this study run at higher temperatures than biomass furnaces so an allowance of 2% of TPC has been made to cover R&M for combustion applications.

6.7 Insurance

This is another commercially sensitive issue so there is little published data on this topic. An allowance of 2% a year will be made for insurance, business rates and other external charges.

6.8 Internal electrical loads

The electrical loads of the process will be subtracted from the gross electrical production of the generators. In the case of remote generation the cost of the bio-oil will be in sterling plus an obligation to provide the bio-oil plant with a number of kWh_e equivalent to that used to produce the bio-oil free of charge.

The electrical loads have been taken from Sections 2.2.6. The values for the pyrolysis process in Table 2.5 are taken from different studies and the curve plotted in Figure 2.4 does not have a simple characteristic. Consequently the electrical loads for given plant sizes have been taken from the curve.

The electrical loads for the biomass pre-processing plant and pyrolysis plants are shown in Table 6.19.

Table 6.19 Electrical energy in KWh_e needed to process 1 odt of biomass

size odt/y	50	100	150	200	400
pyrolysis	250	200	190	190	190

The these load estimates are for plants that used woodchips as their feedstock; however from Section 4.1.5 and 4.2.3 it is apparent that the materials handling and processing plants for woodchip and miscanthus take similar amounts of electrical power.

7 Cost of electricity production

This chapter investigates break even selling price (BESP) of electricity i.e. the minimum price that the electricity must sell for to cover the lifetime costs of the project. This has been calculated for a range of plant types operating under a number of different regimes. In addition to calculating the cost under standard condition (base case) the composition of the costs has been investigated to establish the relative sensitivity of the BESP to changes in a major cost area. The impact of changing biomass costs and performance parameters are also investigated.

7.1 Single pyrolysis reactor systems

7.1.1 Diesel power only

7.1.1.1 Base Case

The base case is a set of reasonable values for performance parameters and costs that are used to calculate a reference BESP of electricity. Different technologies can only be compared when they are operating under the same conditions. In this study the base case consists of the following assumptions:

- Performance characteristic appropriate to a 2% ash feedstock;
- Plant financed at a real interest rate of 5% over 20 years;
- Biomass charged at base case cost from Section 6.1.5 of £2.21/GJ for miscanthus and £2.85/GJ for SRC willow woodchips;
- Biomass transport costs from Figure 6.10;

- Pyrolysis units will have similar availability to BFB CHP schemes. From [108] this would appear to be around 90%. All thermal plants need time to warm up and suffer output restrictions due to fouling restricting heat transfer; consequently they do not maintain full output for all operating hours. A de-rating of 5% has been included to cover this loss of output. This gives a maximum capacity factor for pyrolysis units as 85%.
- Char sale price of £2.85/GJ from Section 3.3.4;
- All the electricity used by the plant is subtracted from the annual gross generation to calculate the electricity available for sale;
- From Section 4.6.2 a pilot diesel ratio of 8% by energy has been assumed with the pilot fuel costing £8.84/GJ from Section 6.4;
- Staffing, R&M, and insurance costs are as detailed in Section 6;
- The total bio-oil production is used in a single engine.

The BESP for a pyrolysis plant providing a diesel generator as a function of pyrolysis plant size is shown in Figure 7.1 for both miscanthus and SRC willow.

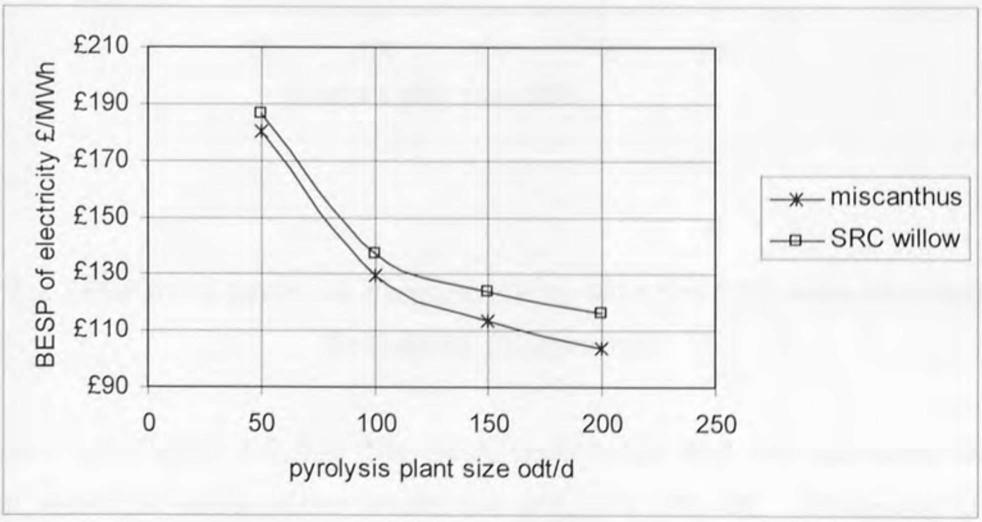

Figure 7.1 Base case BESP for pyrolysis/diesel systems

It is clear that there are considerable economies of scale on single pyrolysis reactor systems.

The biomass production and transport costs of the willow is 28% higher than that for miscanthus so it is not surprising that the BESP is higher for willow at a given plant size. The fact that the difference in BESP increases with plant size reflects the fact that the biomass costs account for only 24% of the cost for a 50 odt/d plant but 39% of the cost for a 200 odt/d plant; consequently the biomass cost advantage has a higher impact with increasing plant size.

The difference in processing costs has been investigated by setting the biomass cost to be the same for both systems in Figure 7.2.

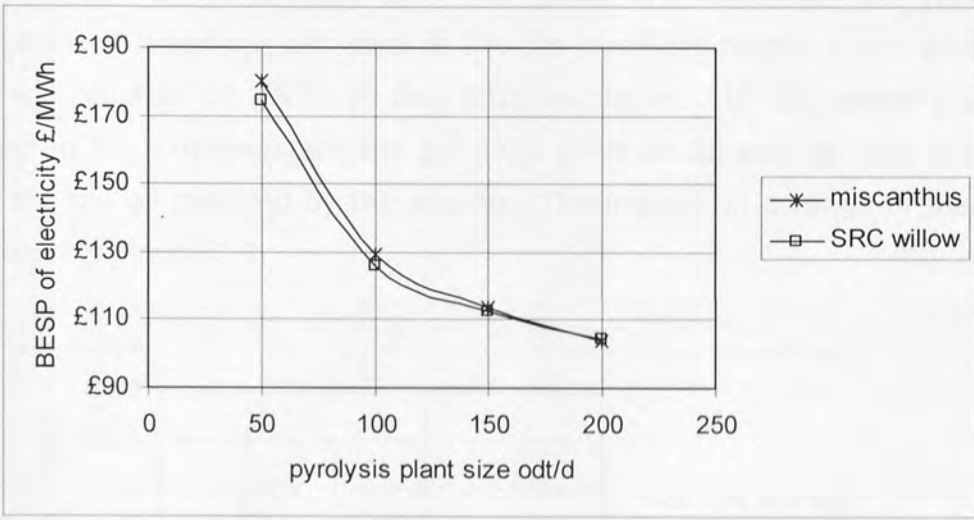

Figure 7.2 BESP form pyrolysis diesel systems with the SRC delivered cost equal to that for miscanthus

It is clear from Figure 7.2 that the basic technology and non-biomass operating costs for systems using either feedstock are very similar. Consequently given that the establishment costs for both crops are similar [190] the lowest costs can be achieved by using the biomass that can achieve the highest yields in the region that the plant is to be located.

Given that miscanthus costs are less in all the scenarios identified in Section 6.1.5, only miscanthus will be considered further for single reactor sites.

7.1.1.2 Generator sizing

Sizing the generator for a particular pyrolysis reactor appears to be a simple matter of using the bio-oil yield and the reactor size to find the rate of bio-oil production. However the yield varies with the ash content of the biomass. If this changes from day to day there will be a mismatch between the generator demand and the pyrolysis reactor's supply. From Table 4.15 it would appear that if both the generator and the pyrolysis plant are sized for the yields that correspond to a feedstock ash level of 2% the pyrolysis reactor could produce all the bio-oil required in 88% of the time available. If the same plant was operating on 3% ash feedstock the pyrolysis plant would only be able to produce 86% of the bio-oil required by the engine. The impact on a range of plant sizes can be seen in Figure 7.3.

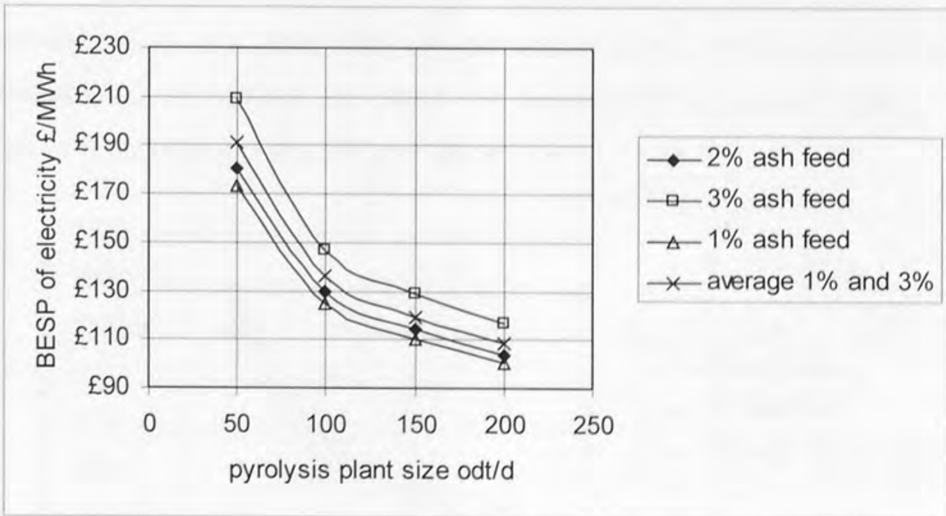

Figure 7.3 Impact of changing feedstock ash content on the BESP for a plant designed for 2% ash feedstock

Figure 7.3 shows that although the change in yields between 1% and 2% is similar to that between 2% and 3%, the impact on the BESP is different. The deterioration in yield caused by going from a 2% to a 3% ash feedstock directly impacts the electricity production, whereas the improvement in yield caused by going from a 2% to a 1% ash feedstock leaves the electrical production constant but directly affects the amount of biomass required. As biomass costs are a fraction of the total cost the impact of these changes is reduced.

In practice the ash content will vary around an average value. It is clear from Figure 7.3 that changes in the BESP resulting from changes in yields will not balance out and the actual BESP will be higher than that calculated for the average ash content feedstock.

The shortfall in bio-oil production that results from lower yields could be rectified by increasing the pilot fuel ratio, but this would reduce the amount of renewable electricity generated by the plant and hence the ROC payments. As diesel engines using distillate fuel are not cost effective for commercial generation on main land UK this option will not be considered further.

From Figure 7.3 it would appear that the impact of a higher yield than the plant was designed for is less than that of too low a yield. Consequently it may be worth considering designing the plant for the lowest expected yield. This has been done and the results shown in Figure 7.4.

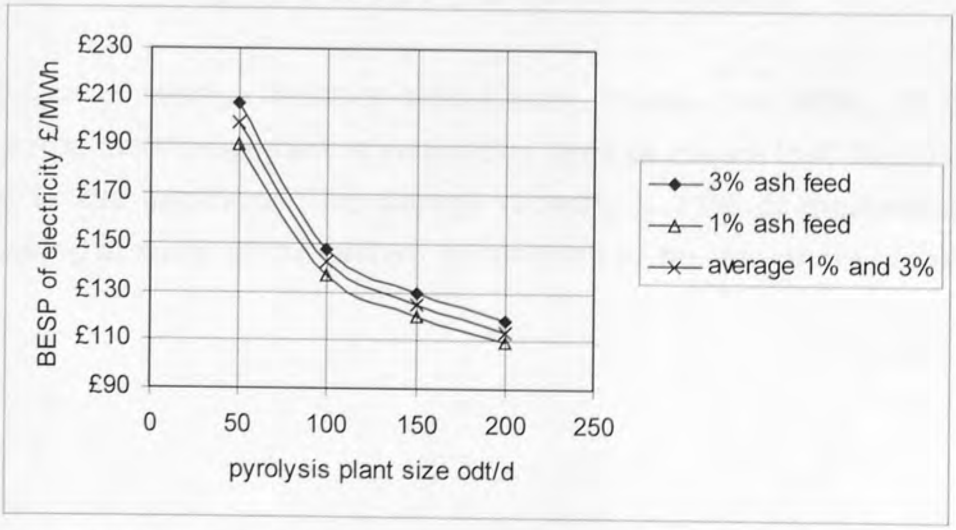

Figure 7.4 Impact of changing feedstock ash content on the BESP for a plant with a design for 3% ash feedstock

As expected the spread between the curves is lower in Figure 7.4 than in Figure 7.3. However the average of the BESP for 1% and 3% is actually higher in Figure 7.4 than in Figure 7.3 consequently this is not a good design option.

Another way of overcoming the variation of yields is to install some buffer storage tanks as described in Sections 4.11 and 5.10. The effect of this is shown in Figure 7.5.

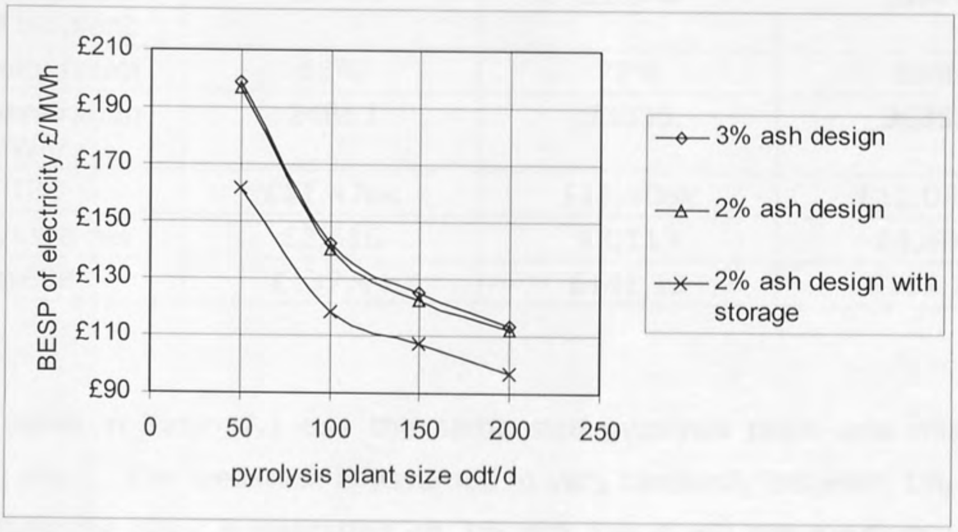

Figure 7.5 Effect of bio-oil storage on BESP

The inclusion of storage facilities dramatically reduces the BESP. It has been assumed that the storage tank is sufficiently large to ensure that bio-oil is always available to the generator (the storage capacity is 15% of production). It is worth looking at some of the system parameters to see why there is this drop in BESP.

Table 7.1 Plant parameters for different generator arrangements for use with 100 odt/d pyrolysis unit.

	sized for 2% ash	sized for 3% ash	sized for 2% ash with storage
Gross Generation MWe	5.44	4.69	5.61
Net Generation MWe	4.4	3.7	4.5
% of generation used by plant	19.4%	21.9%	19.4%
Capacity factor	65%	73%	83%
net generation MWh/y	24863	23395	32855
TPC	£11,476k	£11,400k	£12,045k
SI £/kWe net	£2,616	£3,113	£2,665
BESP	£137.44	£141.13	£117.32

All the cases in Table 7.1 use the same size pyrolysis plant and miscanthus handling plant. The feedstock is assumed to vary randomly between 1% and 3% ash. When the plant is operating on 3% ash fuel it will not produce sufficient bio-oil for the 5.44 MWe generator to be fully loaded so the CF for the system designed for 2% ash feeds is relatively low. The CF for the 3% ash design is higher as it always produces sufficient bio-oil to fully load the generator, but as the generator is smaller the total annual generation for this arrangement is lower.

The use of the buffer tank allows the pyrolysis plant and generation plant to operate independently; this allows a larger generator to be installed (as the pyrolysis plant has a better availability than the diesel generator) and allows the generator to operate at it's maximum CF. Consequently the electrical production from this system is much higher. The improvement in plant utilisation more than compensates for the additional capital cost of the tanks.

This analysis has been based on the assumption that the ash content will vary randomly. One of the factors that can influence ash content is the weather experienced by the crop over its growing and harvest cycle. As the energy crops grown for a particular plant are likely to experience similar weather it is likely that it may take a number of cycles before variations in ash content fully average out. It is not desirable to store bio-oil for more than a few months [50] so the scheme economics must be sufficiently robust to cope with any annual fluctuations in ash content. The BESP has been calculated for the 3 design cases used in Table 7.1 running on 3% ash feedstock and are shown in Figure 7.6.

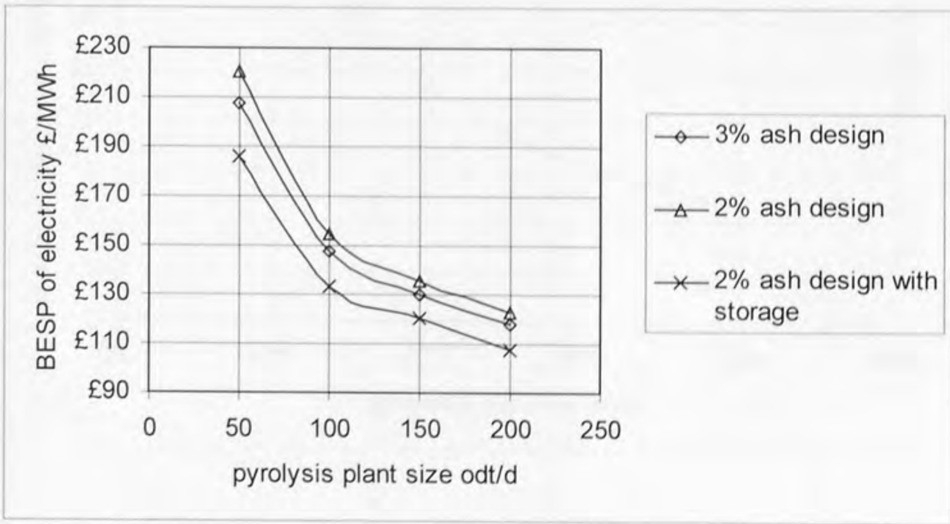

Figure 7.6 BESP for different pyrolysis diesel generators operating for a prolonged period on 3% ash miscanthus

In all cases the BESP in Figure 7.6 is more that those in Figure 7.5.

Although the impact is highest on the 2% ash design with storage it still has the lowest BESP. Consequently the use of buffer storage tanks will be assumed to be the lowest costs option for all the applications considered in this study.

7.1.1.3 Peak load operations

From Figure 3.2 it is clear that in the wholesale electricity market there is a higher price paid for peak time electricity than for base load electricity. In 2006 to 2008 this premium varied between £5/MWh and £25/MWh with an average value of £13/MWh. Diesel engines are suitable for peak load application. If the plant has a suitable bio-oil storage capacity it is possible to oversize the diesel generators and operate the plant as a peak loading power station. The effect this mode of operation has on the generator size for a 200 odt/d pyrolysis unit is shown in Figure 7.7.

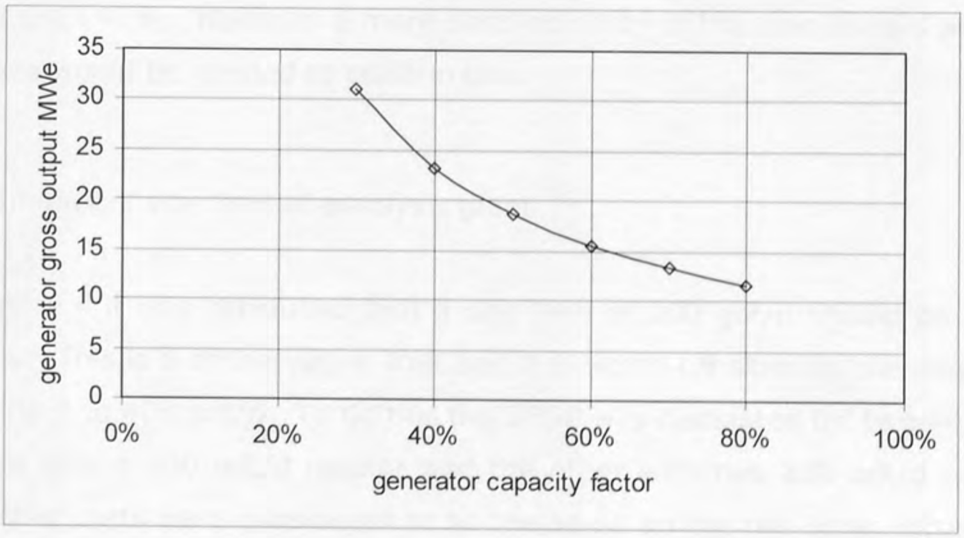

Figure 7.7 Peak load generator size for a 200 odt/d pyrolysis unit

When operating on miscanthus under the base case assumptions the BESP for peak load operations are shown in Figure 7.8.

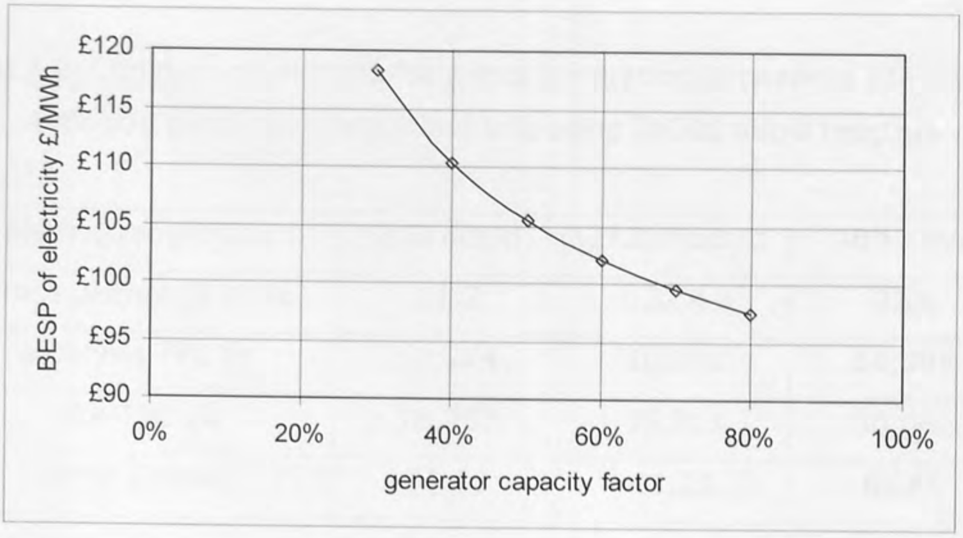

Figure 7.8 BESP for peak load operation

From Figure 7.8 it would appear that if the peak load premium is £13/MWh, peak load could be more profitable than base load operations providing the load factor is higher than 40%. However a more detailed study of the load factors and peak load prices would be needed to confirm this.

7.1.1.4 Impact of size limit of pyrolysis plant

In Section 5.4 it was concluded that a size limit of 200 odt/d should be used in this study. This is a conservative limit and it is worth considering the implication of doubling it to 400 odt/d. To do this the BESP was calculated for two 400 odt/d sites, one with a 400 odt/d reactor and the other with two 200 odt/d reactors. All the other costs were considered to be the same on the two sites. The cost of the 400 odt/d plant was calculated using the sizing curve from Figure 5.3. A 5% discount was applied to the cost of the second reactor in the 2 by 200 odt/d plant. The BESP under the base case conditions given in Section 7.1.1.1 are shown in Table 7.2.

Table 7.2 Comparison of costs for diesel generation between a site using a 400odt/d pyrolysis reactor and one using 2x200 odt/d reactors

plant arrangement	200 odt/d	2x200 odt/d	400 odt/d
gross generator MWe	11.2	22.4	22.4
pyrolysis TPC £k	10,274	20,043	14,995
site TPC £k	18,257	35,711	30,662
BESP £/MWh	96.86	91.23	86.65

The number of significant digits in Table 7.2 are there to highlight the differences; it does not reflect the certainty of the figures. From Table 7.2 it would appear that the cost saving from using a 400 odt/d reactor rather than two 200 odt/d ones is in the order of 5%. This is lower than some of the sensitivities to external cost changes discussed in Section 7.1.1.5 below and as such is unlikely to heavily influence the viability of a particular project.

7.1.1.5 Sensitivities to costs changes

All costs change over time and with location. The effect that changes in any cost item will have on the BESP depends on the proportion of the total that the cost represents. For example if staffing represented 10% of the cost a 20% rise in staffing cost would only give a 2% rise in total costs. The major components of the total annual cost are shown in Figure 7.9.

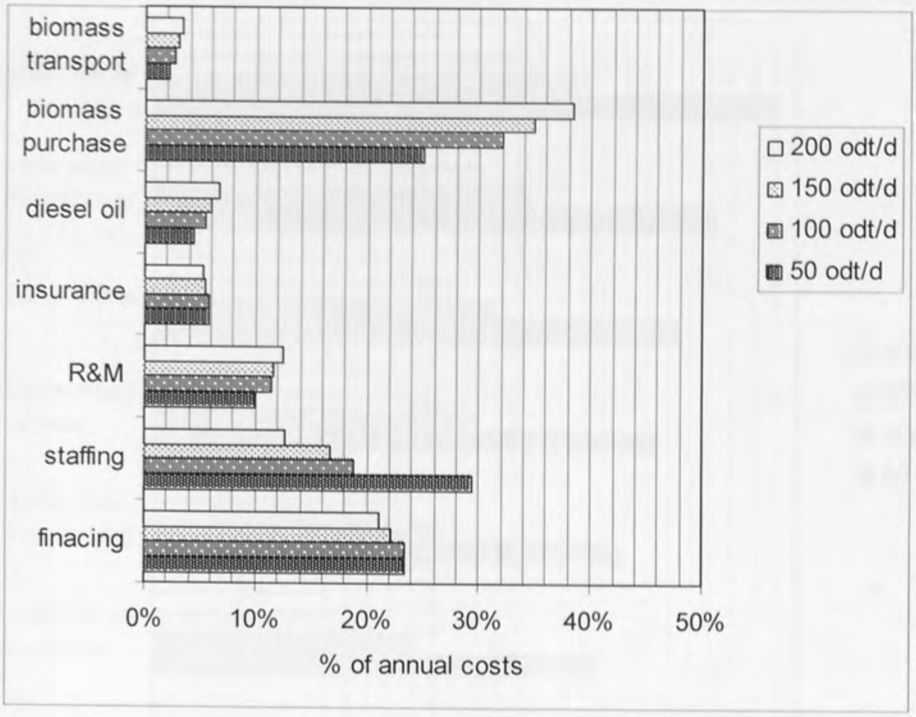

Figure 7.9 Components of the annual costs for a pyrolysis diesel generation plant

For all but the 50 odt/d plant the dominant cost is the biomass feed (the relatively high staffing costs for the 50 odt/d plant reflects the assumed minimum plant attendance requirements). The relatively low significance of the biomass transport cost reflects the assumption that these small systems will be using locally grown biomass.

The range of possible costs for biomass was discussed in Section 6.1.5; the BESP has been calculate for these costs for the 2% ash design with storage and are shown in Figure 7.10. Figure 7.10 also includes the BESP for free biomass; this is not a realistic scenario but is included to gives a measure of the cost of processing the biomass.

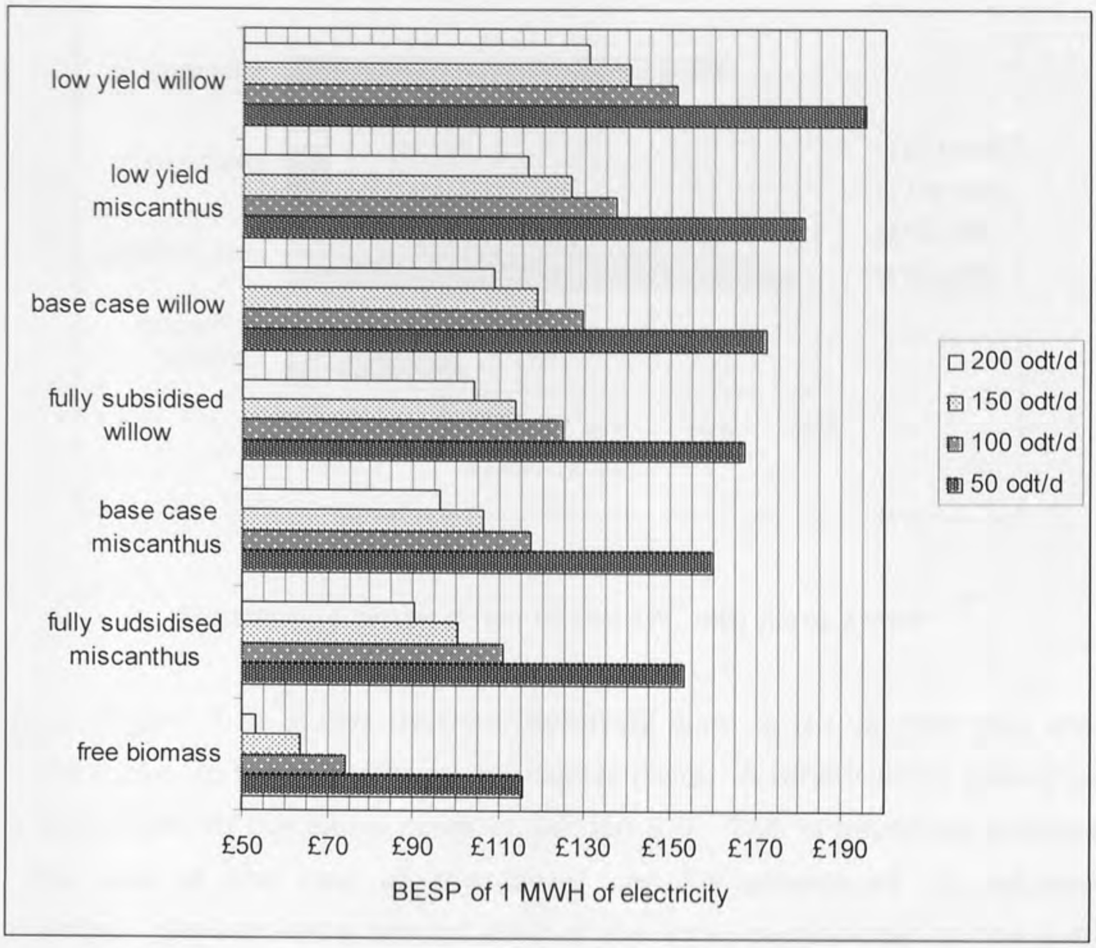

Figure 7.10 Impact of biomass cost on the BESP of electricity

Figure 7.10 gives the spread of possible generation costs for the different biomass cost scenarios. It also gives an indication of the limits that the costs may be reduced to. The biomass component of the bio-oil cost is the BESP for a given scenario minus the free biomass BESP. For the base case miscanthus this comes to £43/MWh (for all but the 50 odt/y plant which is £44/MWh as it has a slightly lower efficiency).

The next most significant cost is the financing charge. The breakdown of the TPC is worth examining in order to consider the volatility of this item; this has been done in Figure 7.11.

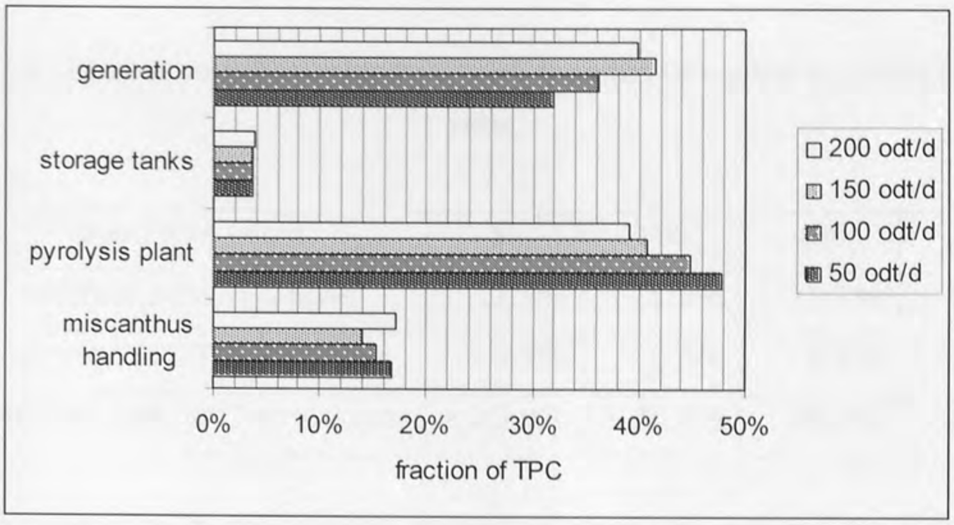

Figure 7.11 break down of the TPC into plant areas

Although Figure 7.11 shows that the pyrolysis plant is the largest cost area it does not make up the majority of the capital costs. A modification allowance of 23% was added to the diesel costs in Section 5.5. This is unproven technology but the rest of the cost of the diesel can be considered as established technology. Consequently around half of the total capital cost of the project relates to established technologies. In Section 2.2.2 it was reported that in practice for well defined projects capital cost estimates can be up to 35% lower than the eventual project cost. With new technologies these estimates should include an increased contingency allowance. If an additional 10% contingency is added to the pyrolysis plant cost the possible overspend could be 40% of the original estimate. The impact of this on the BESP has been calculated at real interest rates of 5% and 10% and normalised to the base conditions in Table 7.3.

Table 7.3 Impact on BESP of electricity of changes to capital cost and interest rate

plant size odt/d	50	100	150	200
interest 10% TPC base	11.4%	11.6%	11.0%	10.6%
interest 5% TPC 40% over	9.9%	10.0%	9.5%	9.2%
interest 10% TPC 40% over	25.9%	26.3%	25.0%	24.0%

The slight decrease in impact with increasing plant size reflects the reduction in the ratio of financing cost to TPC shown in Figure 7.9.

7.1.1.6 Sensitivities to performance changes

Changes in plant performance will result in one of the following:

- Reduction in the amount of feedstock that can be processed in a year, this will reduce the pyrolysis reactor's capacity factor;
- Reduction in the pyrolysis yields which will reduce the amount of bio-oil produced;
- Reduction in the amount of bio-oil that the diesel engine consumes (i.e. a reduction in generation capacity) in a year which will reduce the diesel engine's capacity factor;
- Reduction in the diesel engine's efficiency.

Changes in capacity factors result in falls of both output and biomass consumed whereas changes in conversion ratios result in a fall in electricity production for the same biomass consumption. Each of the four factors identified above have been reduced to 90% of their base value and the BESP calculated; this has been normalised with the BESP under base conditions in Table 7.4.

Table 7.4 Increase in BESP resulting from a 10% reduction in performance

plant size odt/d	50	100	150	200
low bio-oil yield	13.0%	11.9%	11.6%	11.4%
low pyrolysis CF	7.3%	6.1%	5.6%	4.9%
low generator efficiency	13.1%	12.4%	12.3%	12.3%
low generator CF	7.3%	6.1%	5.6%	4.9%

Intuitively one may expect a 10% reduction in bio-oil yield or generator efficiency to produce a 10% fall in production and hence a 10% rise in the BESP. However this ignores the impact of the electricity used by the plant. This is the same in the situation where the plant is underperforming as it is when the plant is working well. Consequently the full reduction in electricity generated is taken from the electricity for sale.

The difference in impact between the drop in yield and the drop in generator efficiency is due to the different impact the two cases have on the pilot diesel consumption. The drop in yield results in a drop in running hours for the generator, so there is a drop in the pilot diesel consumption. A drop in engine efficiency does not affect the running houses so the pilot diesel consumption would also remain the same as the base case.

It is noticeable that although the performance parameters are the same for all the plants, the impact of them varies with plant size. In the case of changes in CF the reduced output has a corresponding reduction in biomass consumed; consequently the impact of the change will depend on the proportion of the cost that is made up by the biomass. Figure 7.9 shows that this increases with plant size and so the impact of CF changes will reduce with plant size.

7.1.1.7 Sensitivity to changes in char price

The percentage of the total costs that is recovered from char sales for a pyrolysis plant generator combination sized for 2% ash feedstock with buffer storage using miscanthus is shown in Table 7.5.

Table 7.5 Proportion of total cost recovered by char sales

plant size odt/d			
50	100	150	200
4.5%	5.8%	6.3%	7.0%

The char income for each unit of biomass processed is constant. As the processing costs are lower on larger plants the char income will represent a higher portion of the total cost on larger plants than on smaller ones.

The char price has been assumed to be linked to the biomass price. If this is the case then any rise in char income is likely to be swamped by the effect of the rise in biomass costs. The main issue is that the char price is similar to the biomass cost and any process that converts one commodity to another of similar value is not worthwhile. If a market can be found for bio-char where it will fetch a premium over the price of biomass the importance of this income stream will increase. From Figure 7.18 bio-oil is at least 3 times the cost of biomass so bio-char would need to have a similar premium to make it worth considering boosting char production at the expense of bio-oil production.

7.1.1.8 System efficiency

The overall system efficiency can be calculated from the amount of electricity sold annually divided the sum of the annual consumption of biomass and pilot diesel fuel. By convention the LHV is used for the energy input of the fuel in combustion based generators.

This has been done for the base case plants in Table 7.6. The pyrolysis process energy efficiencies are also show in Table 7.6. as the electrical efficiencies are functions of the bio-oil efficiency.

Table 7.6 System efficiencies

system size odt/d	50	100	150	200
bio-oil efficiency	58.5%	58.5%	58.5%	58.5%
excess char efficiency	15.3%	15.3%	15.3%	15.3%
useful pyrolysis product efficiency	73.8%	73.8%	73.8%	73.8%
gross electrical efficiency	25.4%	25.4%	25.4%	25.4%
net electrical efficiency	19.5%	20.4%	20.6%	20.6%
marketable product efficiency	34.1%	35.0%	35.2%	35.2%
discounted electrical efficiency	22.8%	23.9%	24.2%	24.2%

The gross electrical efficiency is the total electrical energy generated divided by the total fuel energy used (i.e. biomass plus diesel). It takes no account of the plant's own electrical consumption or of the excess char production.

The net electrical efficiency is the total electrical energy sold divided by the total fuel consumed. This varies slightly with plant size as the internal electrical consumption is slightly higher on smaller plants. This is the most appropriate measure to use when comparing pyrolysis based systems if the char yield is being considered separately.

The excess char can be considered by calculating the marketable product efficiency i.e. the energy content of both the electricity sales and char sales divided by the total of the biomass energy input and the pilot diesel energy input. Although this is a more rigorous scientific definition there is a problem with using it to compare the economic output of two systems.

This is demonstrated in Table 7.7 where the marketable product efficiency increases with the ash content of the biomass but the electrical efficiency falls (this is the result of the reduction in bio-oil yield and increase in excess char yield with increased ash). The problem is that it has been assumed in Section 3.3.4 that the value of char is similar to that of biomass. A process that converts one product into another of similar value has no economic value. Consequently a quality measure that increases when the product mix between high and low value products falls is of little use when comparing the economic performance of two systems.

An alternative approach is to subtract the energy in the excess char from the energy input to the system. This mimics the financial situation where char is considered as a by-product and its sales are offset against the operating costs. The net electrical efficiency when calculated on this basis has been called the "discounted electrical efficiency".

In Section 4.3.2 it was found that the bio-oil yield varies with the biomass ash content and feedstock. Table 7.7 shows the efficiencies for a 200 odt/d plant running on miscanthus with different ash levels and willow.

Table 7.7 Efficiencies for different feedstocks.

feedstock	miscanthus			willow
ash level	1%	2%	3%	2%
bio-oil efficiency	66.6%	58.5%	50.4%	61.9%
excess char efficiency	7.9%	15.3%	22.5%	16.2%
useful pyrolysis product efficiency	74.6%	73.8%	72.9%	78.1%
gross electrical efficiency	28.7%	25.4%	20.3%	28.1%
net electrical efficiency	23.9%	20.6%	17.4%	22.9%
marketable product efficiency	31.37%	35.22%	38.94%	37.2%
discounted electrical efficiency	25.8%	24.2%	22.1%	27.3%

The electrical efficiencies reflect the changes in bio-oil efficiency. The efficiencies are higher for the willow fuelled system than for the miscanthus fuelled system. This is the result of the biomass energy input being measured before the dryer using the lower heating value convention. The after-dryer bio-oil efficiencies calculated on the feed to the pyrolysis plant are 59% for miscanthus and 60% for willow calculated on a LHV basis.

7.1.2 Diesel CHP schemes operated to follow the heat load

7.1.2.1 Base Case

CHP plants that are operated to supply a variable heat load are similar to the peak load applications discussed in Section 7.1.1.3 in that their size is dependent on the capacity factor. The CHP plants have additional capital cost and an additional income from heat sales. The additional capital cost is due to increased storage requirements which were discussed in Section 4.11. In order to reduce the maximum store time of the bio-oil it has been assumed that 5 storage tanks are installed on site. From Section 4.10.2 a power to heat ratio of 1 has been assumed for the base case. The BESP has been calculated for the base condition stated in Section 7.1.1.1 for a range of pyrolysis plants supplying diesel engines that operate at capacity factors of 40%, 50% and 60%, and is shown in Figure 7.12.

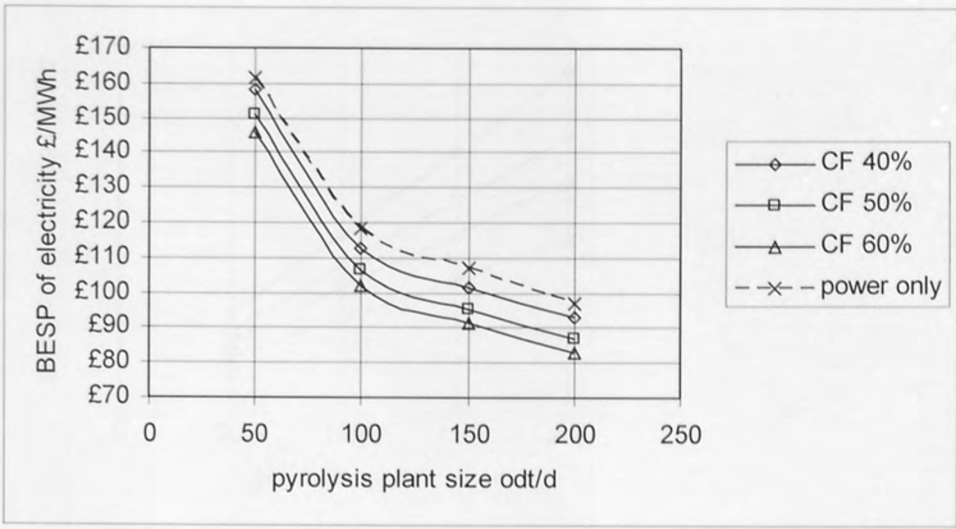

Figure 7.12 BESP for different CHP plants

The power only plot refers to base load operation with an 83% generator capacity factor. The heat income does reduce the BESP of electricity. However as the CF reduces the size of the generator that can be supplied by a given pyrolysis plant increases, this increases the capital cost which must be offset against the heat income.

Figure 7.8 showed that the size of generator that could be supplied by a given pyrolysis plant increased with falling CF. The same is true for CHP plants; this is shown in Figure 7.13.

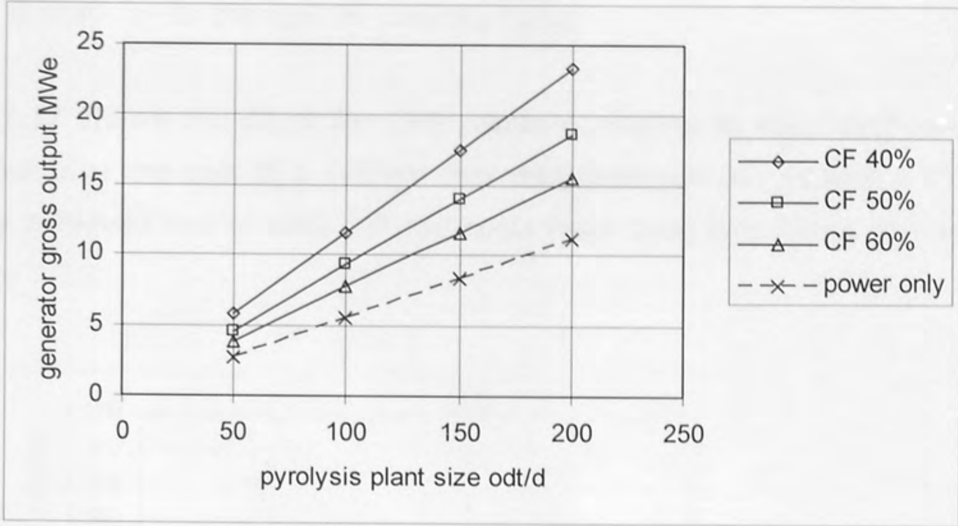

Figure 7.13 Generator size that can be provide by a given pyrolysis plant operating under different capacity factors

Normal practice is to size a CHP plant to match a given heat load so the data in Figure 7.12 and 7.13 have been used to calculate the BESP for different generator output ratings in Figure 7.14.

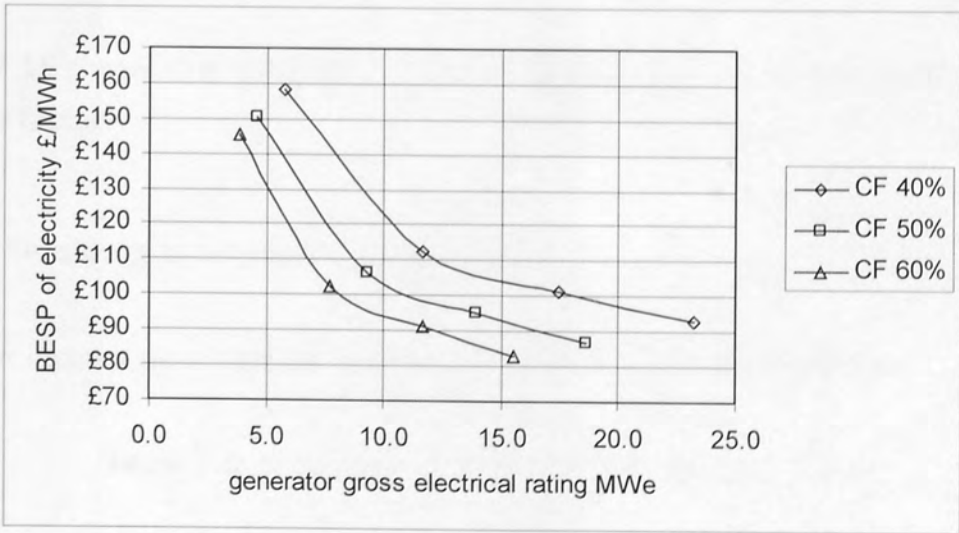

Figure 7.14 BESP of electricity for different generator sizes and capacity factors

7.1.2.2 Sensitivity to changes in capacity factor

Figure 7.12 shows the BESP for CHP plants operating at their designed CF. It would not give the cost of a system that was designed to run with a CF of 50% but only achieved one of 40%. These costs have been calculated and are shown in Figure 7.15.

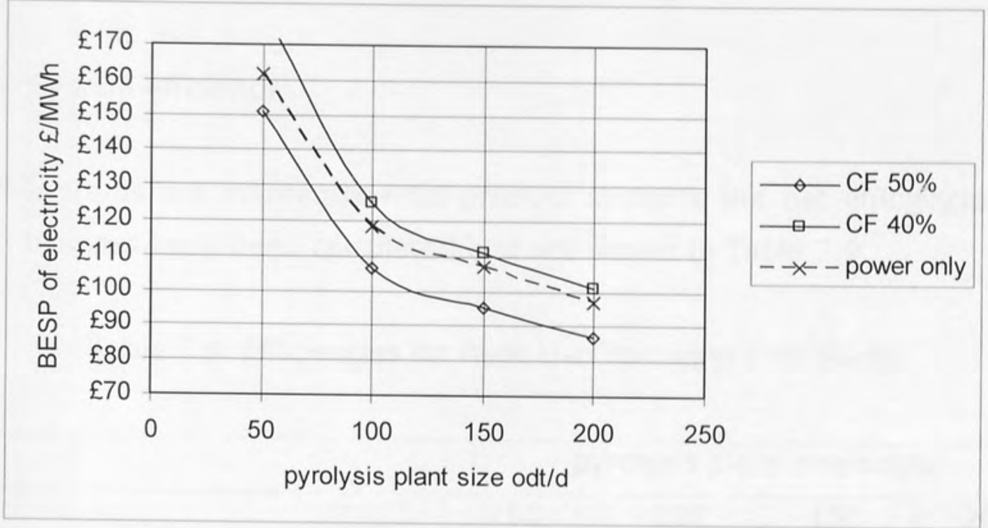

Figure 7.15 BESP for pyrolysis CHP plants designed to run with a 50% CF

Figure 7.15 shows that CHP plants need to be designed for the minimum credible capacity factor.

7.1.2.3 Sensitivity to changes in heat income

The heat income as a fraction of the total costs is shown in Table 7.8

Table 7.8 Proportion of costs covered by heat sales

pyrolysis plant size odt/d			
50	100	150	200
12.6%	16.1%	17.4%	18.7%

Table 7.8 shows that fluctuations in heat prices are unlikely to have a large impact on the BESP of electricity. The increase in the importance of heat price with plant size reflects the fact that the proportion of heat produced is independent of plant size but the total costs/odt are dependent on plant size. The heat to power ratio is fixed by design but may increase with time if the engines efficiency drops and the electrical output falls. Fortunately this should not affect the heat generated.

7.1.2.4 System efficiency

As CHP systems are inherently muti-product systems the net efficiencies for a 2% ash biomass have been calculated and are shown in Table 7.9.

Table 7.9 Efficiencies for heat load following CHP plants

	pyrolysis plant size odt/d			
	50	100	150	200
net electrical efficiency	19.7%	21.1%	21.4%	21.4%
discounted electrical efficiency	23.2%	24.8%	25.2%	25.3%
heat efficiency	26.5%	26.5%	26.5%	26.5%
excess char efficiency	15.3%	15.3%	15.3%	15.3%
marketable products efficiency	62.2%	63.2%	63.4%	63.4%

These values are considerably lower than the nominal total efficiencies found in European biomass fired CHP plants which tend to be in the 80-90% range [108]. The UK government has a policy of promoting good quality CHP schemes [25]. These are ones that have a high overall energy utilisation and relatively high electricity efficiency. In recognition of the fact that high electrical efficiencies are harder to obtain than high heating efficiencies a technology specific weighting system is used to calculate a quality factor [210].

The quality factor is calculated by

$$Q = X\eta_e + Y\eta_h$$

where η is the HHV efficiency and the suffixes e denotes electricity and h heat. These factors use the HHV efficiencies of the scheme but do not take into account the electricity used by the plant itself. The regulations do not refer to pyrolysis plants so no allowances are given for excess char production. To be considered good quality, the CHP scheme must have a *Q* above 100 and an electrical efficiency above 20%. For the base operating condition the HHV efficiency without adjustment for excess char is 23.5% for both electricity and heat generation. For biomass CHP schemes *X* is 370 and *Y* is 120 which gives a Q of 115. There are different values for wood fired plants where *X* is 315 and *Y* is 120 which gives a *Q* of 102. So although the efficiencies are relatively low they can still be considered good quality CHP plants.

7.1.3 Diesel CHP schemes operating under base load

An alternative operation strategy is to operate the diesel engine on base load, sell sufficient of the heat to meet the demand and dump the rest using conventional radiators or by bypassing the exhaust heat recovery boiler. This strategy gives a higher utilisation of the diesel engine and removes the need for seasonal storage of the bio-oil.

This system needs additional cooling plant but smaller storage tanks. The heat exchangers for IC based CHP schemes of over 3 MWe represent about 10% of the capital cost [185]. The capital cost of the diesel engine used for the 2% ash design with buffer storage has been increased by this amount and the BESP of electricity calculated for different heat capacity factors. These are shown in Figure 7.16

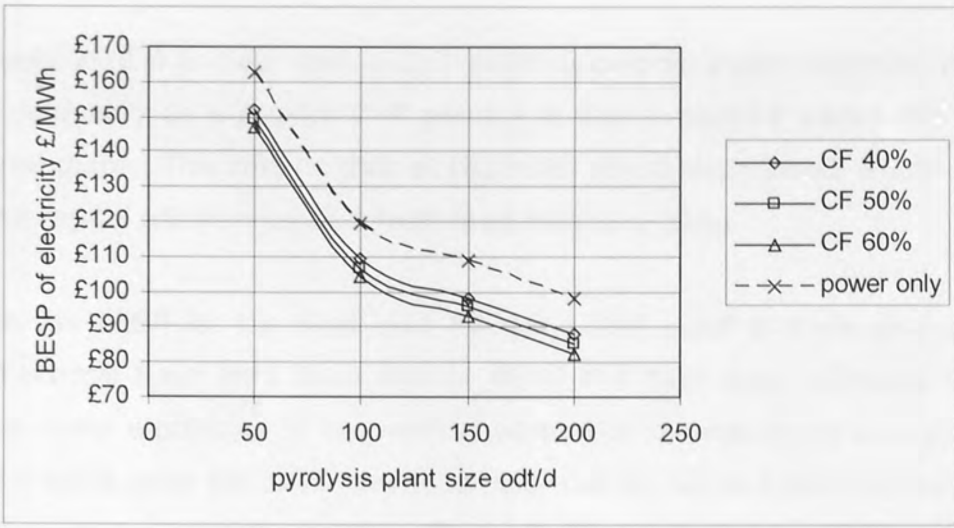

Figure 7.16 BESP of electricity for different heat capacity factors

The values in Figure 7.16 are very similar to those in Figure 7.12; however the generator rating is the same as the power only case shown in Figure 7.13 irrespective of the heat capacity factor. The other major difference between the two schemes is in the heat efficiency. From Table 7.8 the LHV heating efficiency was 26.5% but when operating under electrical base load only the heating efficiencies are:

- 18.7% when operating with a heat CF of 60%;
- 15.5% when operating with a heat CF of 50%;
- 12.4% when operating with a heat CF of 40%;

This reduction in efficiencies has a dramatic impact of the Q factors of the plant as shown in Table 7.10.

Table 7.10 CHP Q factors for different operating regimes

	biomass Q	wood Q
heat load following	115	102
heat CF 60%	107	94
heat CF 50%	103	90
heat CF 40%	100	87

From Table 7.10 it is clear that a CHP plant operating under electrical base load would not qualify as a quality CHP plant if it was evaluated under the rules for wood fired plant. This means that as the rules stand such plants would not have the same capital allowances as a heat load following plant.

Although the BESP for the heat load following CHP plant and the one operating under electrical base load have similar BESP the heat load following plant will generate more electricity in the winter when the market price is higher. The forward market price for base load electricity can be up to £30/MWh more in the winter than in the summer so this effect could make heat load following a more profitable option.

7.1.4 Multiple diesel CHP schemes sharing a remote pyrolysis plant

7.1.4.1 Bio-oil production cost

Figure 7.12 shows that there are considerable economies of scale for CHP plant cost. Figure 7.13 shows that heat loads between 15 to 24 MW are needed to achieve the appropriate savings. The potential for growth area for CHP schemes is for plants that are smaller than this (Section 1.1.5). One way to achieve suitable economies of scale is to use a large pyrolysis plant to provide bio-oil for remote CHP plants that are sized to meet the local heat load. There are two ways of analysing this approach; one is a portfolio approach where it is assumed that a developer has one pyrolysis site and contracts to supply a number of CHP plants, the other is a market approach where pyrolysis plant operators sell bio-oil on an open market to consumers. This latter approach avoids the need to match production and consumption. The break even cost of bio-oil can be calculated using the same procedure as has been used for the BESP of electricity. This has been done for different sized pyrolysis plants in Figure 7.17.

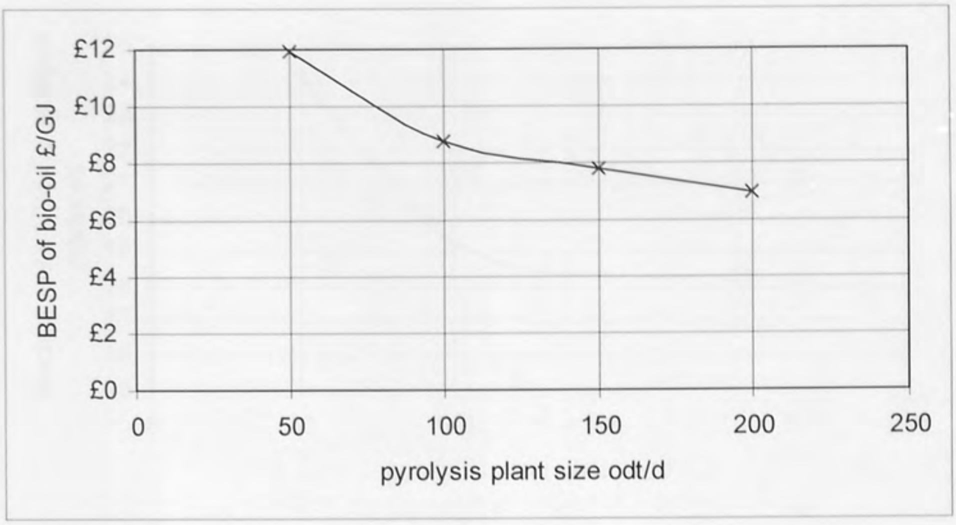

Figure 7.17 BESP of bio-oil

Given the relatively high cost of production from the 50 odt/d unit it is unlikely that a bio-oil production unit would be built at this scale. From Figure 7.17 a 125 odt/d unit is probably near to the smallest credible size.

The BESP of the bio-oil has been calculated without charging for the electricity used to make the bio-oil. It has been assumed that there is an agreement between the pyrolysis plant operator and the CHP plant operator that the CHP plant will supply the pyrolysis plant with sufficient electricity to make the bio-oil he uses free of charge. The amount of electricity required by the bio-oil production plant has been calculated from the yield data in section 4.3 and the combined pyrolysis and biomass handling plant electricity requirements in Table 6.19 and is shown in Figure 7.18.

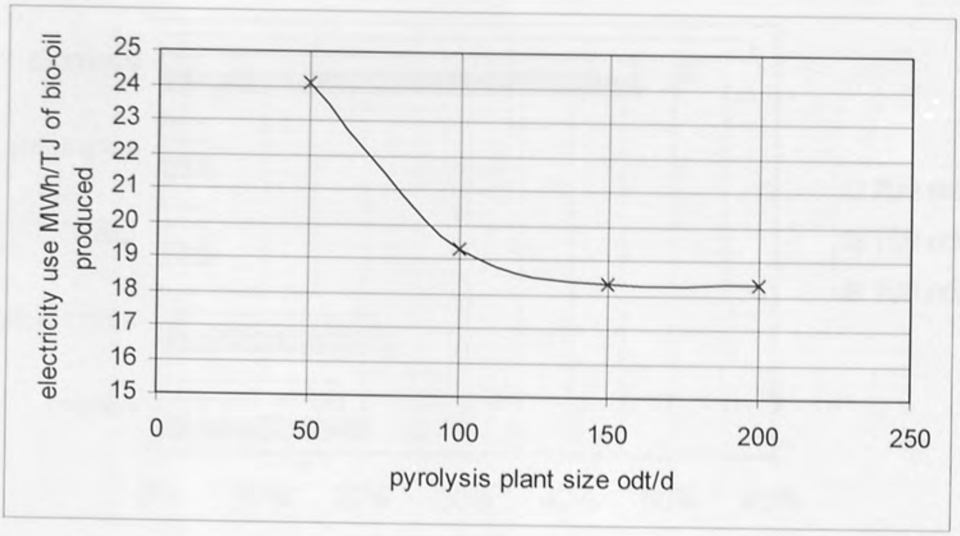

Figure 7.18 electricity to produce a TJ of bio-oil

If pyrolysis units are assumed to be larger than 125 odt/d the electricity requirement can be considered as a constant of 18.5 MWh/TJ of bio-oil. If an electricity price of £90/MWh (from figure 7.21) is assumed for renewable electricity this will add £1.67/GJ to the production cost of bio-oil. Taking the minimum production cost from Figure 7.17 this gives a bio-oil production cost of £8.67/GJ which is in the same order as the distillate fuel cost of £8.84/GJ given in Section 6.4.

As the bio-oil production plant does not include generation plant the relative sizes of the cost will be different from those shown in Figure 7.9. Figure 7.19 shows the break down of the costs into the major components.

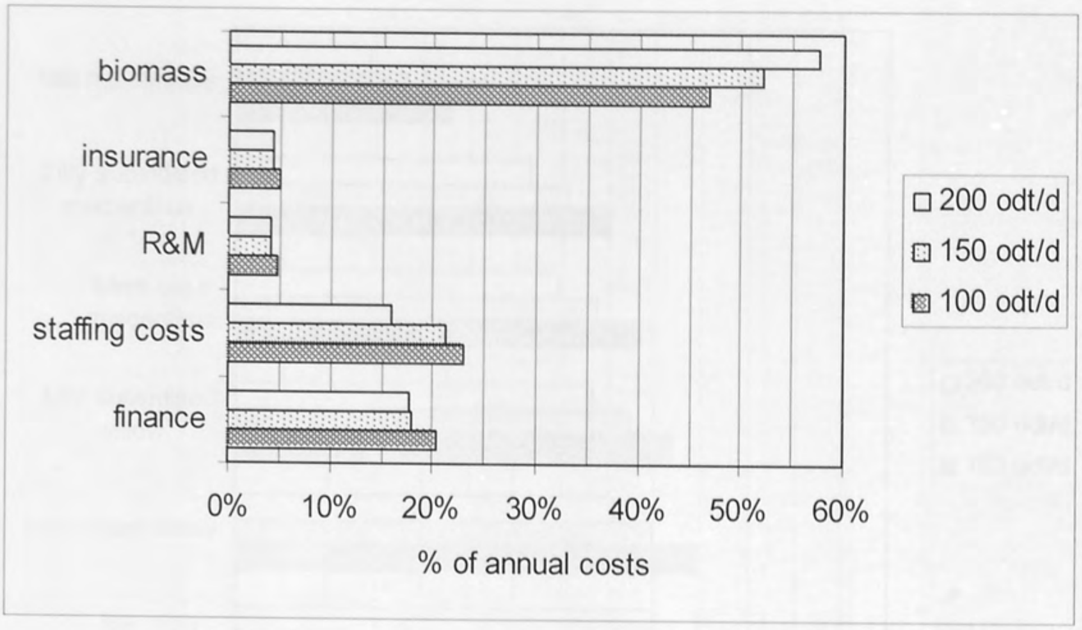

Figure 7.19 Components of the annual costs for a pyrolysis bio-oil production plant

It is clear that the major sensitivity of the bio-oil cost will be to changes in biomass price. The BESP for bio-oil has been calculated for the range of biomass costs identified in Section 6.1.5 and is shown in Figure 7.20.

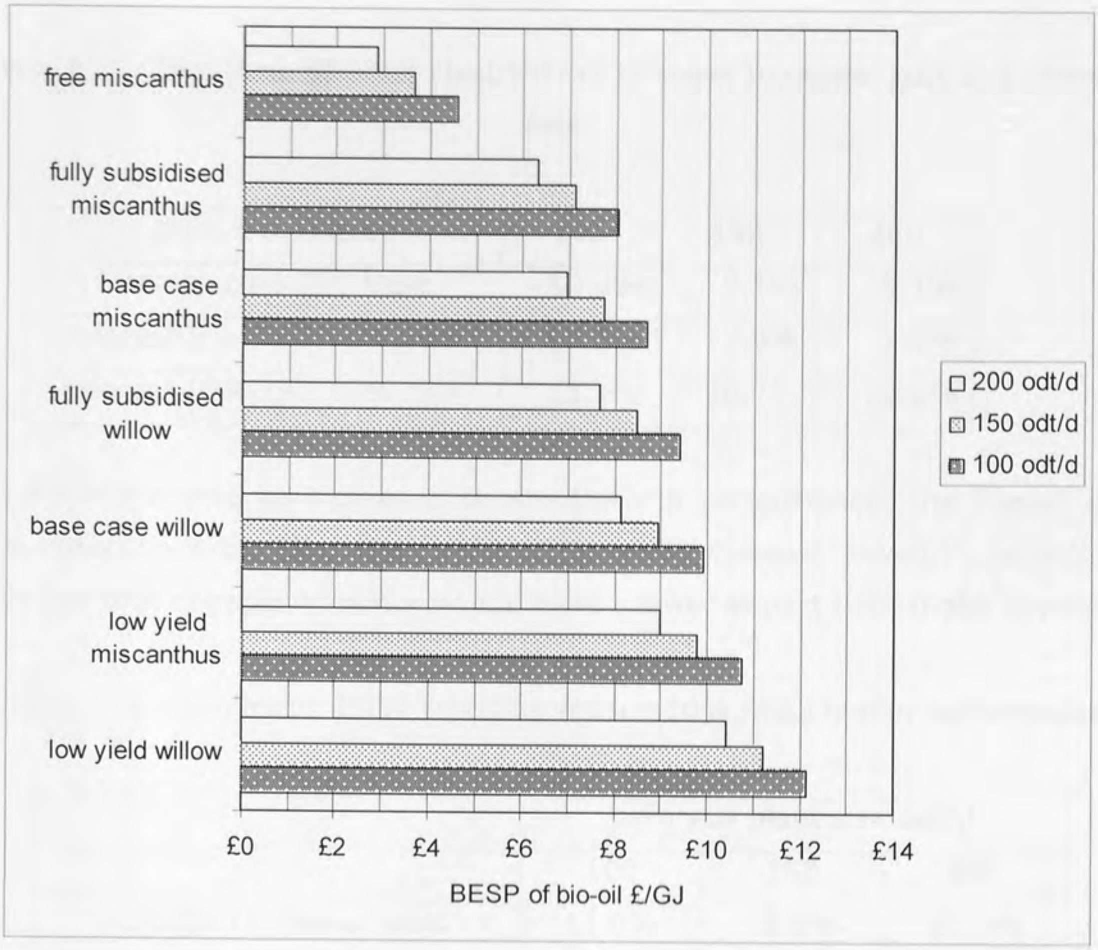

Figure 7.20 Impact of biomass cost on the BESP of bio-oil

From Figure 7.20 it appears that the bio-oil cost may increase by up to 30% with changes in yield. The next most significant cost categories in Figure 7.19 are staffing and finance. The impact of changes in staffing can be calculated from the fraction of the total cost that is accounted for by staff costs. The finance cost can change as the result of changes in interest rate or as a result of capital overspend. The impact of increasing the interest rate to 10% and a 40% overspend on TPC has been calculated and is shown in Table 7.11.

Table 7.11 Impact on BESP of electricity of changes to capital cost and interest rate

plant size odt/d	100	150	200
interest 10% TPC base	10.2%	9.1%	9.1%
interest 5% TPC 40% over	8.8%	7.9%	7.9%
interest 10% TPC 40% over	23.1%	20.7%	20.6%

The BESP can also be increased by shortfalls in performance; the impact of a 10% reduction in bio-oil energy yield and capacity factor is shown in Table 7.12. It is clear that changes in performance have a lower impact than those in yield.

Table 7.12 Increase in BESP resulting from a 10% reduction in performance

	pyrolysis plant size odt/d		
	100	150	200
reduction in bio-oil yield	11.0%	11.0%	11.0%
reduction in capacity factor	6.8%	6.3%	5.6%

7.1.4.2 BESP of electricity

The BESP of electricity has been calculated on the following basis:

- The TPC of the diesel is based on the values given in Table 5.10 with the capital cost of the heat recovery system being recouped as part of the heat price as discussed in Section 3.3.5;
- A total staffing level for the CHP plant of 2 operators has been assumed for the 2 MW_e plant,3 for the 4-6 MW_e plants and 4 for the 10-15MW_e;
- A bio-oil production price of £7.00/GJ from Figure 7.17 and a zone 2 bio-oil transport cost of £0.40/GJ from Figure 6.3;
- All other costs are as given in Section 7.1.1.1.

The results are plotted in Figure 7.21 along with the cost for local CHP plants taken from Figure 7.14.

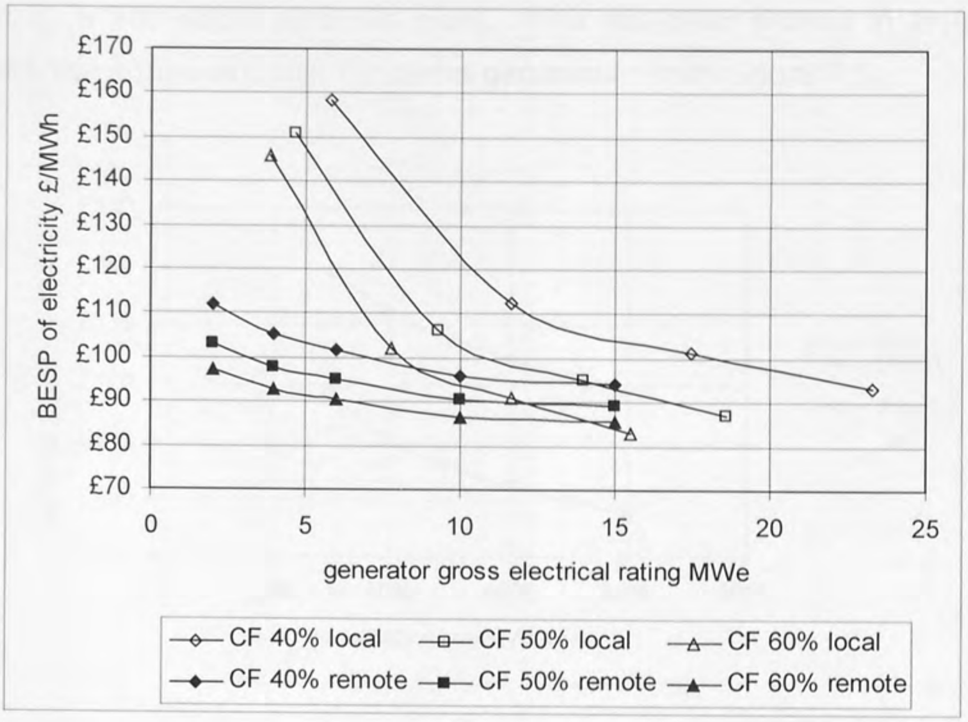

Figure 7.21 BESP of CHP plant with remote and onsite pyrolysis plants

Figure 7.21 shows that for most generator sizes there is a considerable saving to be made by using bio-oil from a large production facility rather than local production on a smaller scale. There are some economies of scale with CHP plants using remote pyrolysis plants, but they are not as significant as those for integrated plants.

7.1.5 Gas turbine power only

Gas turbines cost less than diesel engines but they are less efficient so they tend to be used for peak load operations. The average efficiency of industrial GTs operating on natural gas is around 36%[169] which when derated to run on bio-oil using the figures from 4.7.2 would be around 32%.

This value along with the capital cost from Section 5.6, R&M cost from Section 6.6 and the base assumptions in Section 7.1.1.1 have been used to calculate the BESP for a number of alternative GTs with different capacity factors that can be supplied by a 200 odt/d pyrolysis plant. This has been plotted in Figure 7.22 along with the equivalent cost for diesel generators from Figure 7.8.

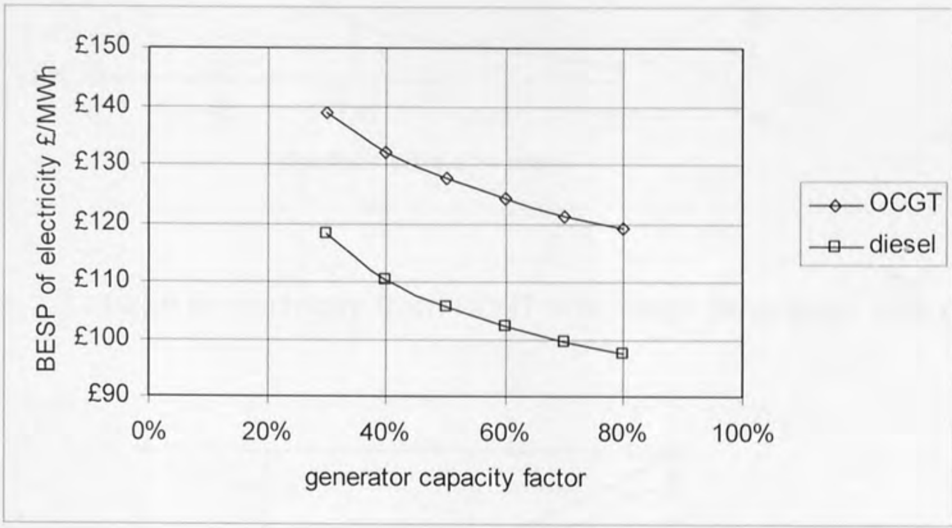

Figure 7.22 BESP of electricity from peak loaded OCGT and diesel generators fed by a 200 odt/d pyrolysis plant

It is clear from Figure 7.22 that open cycle gas turbines are unlikely to be competitive with diesel engines in this application.

7.1.6 Gas turbine combined heat and power

The BESP for a gas turbine based heat load following CHP scheme has been calculated for a range of pyrolysis plant sizes operating under the base condition of Section 7.1.1.1 with an electrical efficiency of 32%, a power to heat ratio of 0.66 from Table 4.12 and a capacity factor of 50%. These costs are shown with the equivalent diesel base CHP plant cost in Figure 7.23 with the size of net electrical power generated and heat reclaimed shown in Figure 7.24.

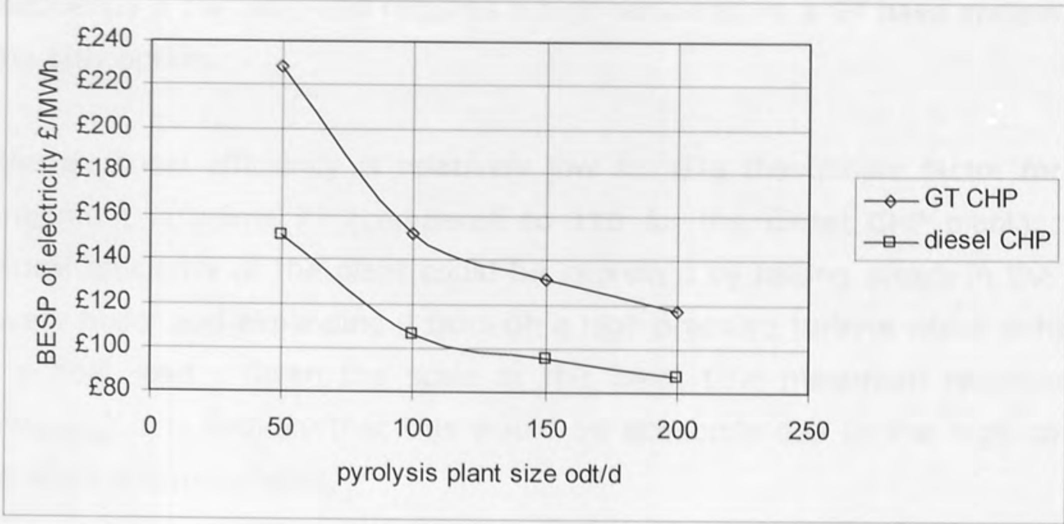

Figure 7.23 BESP of electricity from OCGT and diesel generators CHP plants

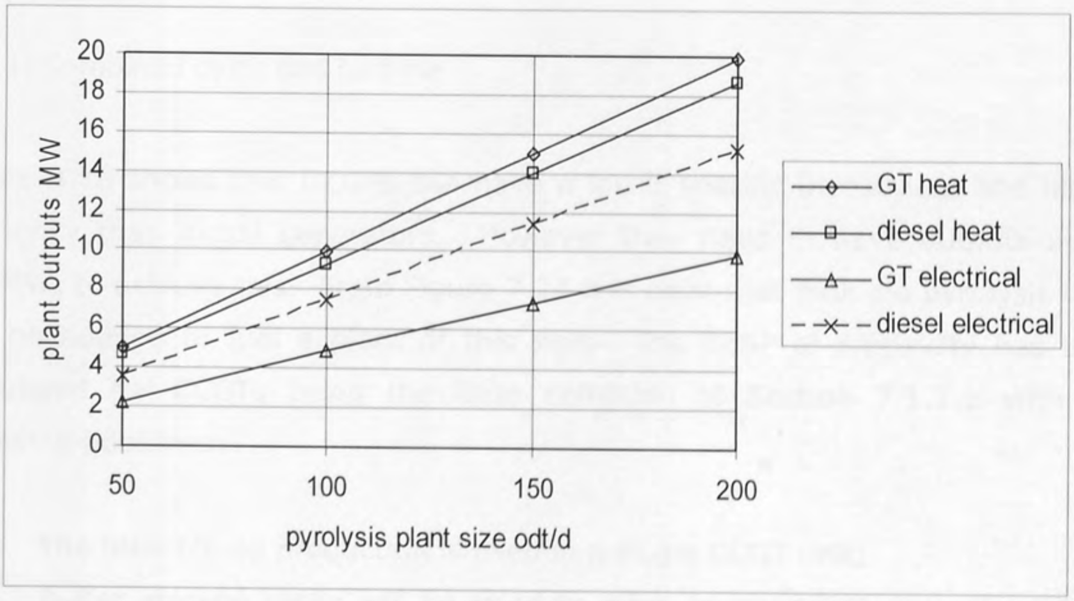

Figure 7.24 CHP loads provided by different sized pyrolysis plants

The impact of the high capital cost of small GTs can be seen in Figure 7.23. The diesel engine option would appear to give the lower cost of generation. However the heat available in the GT based scheme is available at higher temperatures than that in the diesel based ones.

Consequently if the heat load requires a high temperature a GT base system may be the only option.

As the electrical efficiency is relatively low for GTs the quality factor for this arrangement is below 77 (compared to 116 for the diesel CHP plant). The electrical efficiency of the plant could be improved by raising steam in the heat recovery boiler and expanding it through a high pressure turbine which exhausts into a heat load. Given the scale of this plant (the maximum recovered is $20MW_{thermal}$) it is unlikely that this would be economic due to the high cost of small scale steam turbines.

7.2 Sites using multiple pyrolysis reactors

7.2.1 Combined cycle gas turbine

Figure 4.18 shows that CCGTs can have a lower specific investment and higher efficiency than diesel generators. However they need to have outputs above $100MW_e$ to achieve this. From Figure 7.24 it is clear that multiple pyrolysis units will be needed to fuel a plant of this size. The BESP of electricity has been calculated for CCGTs using the base condition of Section 7.1.1.1 with the following additions:

- The total bio-oil production is used in a single CCGT unit;
- Buffer storage tanks will be used to allow independent operation of the pyrolysis and CCGT plant during situations of plant breakdown and to smooth out fluctuation in bio-oil production caused by variations in biomass ash levels;
- The CCGT plant will be run as a base load unit;
- The sites are considered to have a number of identical pyrolysis and material handling plant streams, each stream consisting of 4x200 odt/d pyrolysis units. A 5% discount is applied to the TPC for the second and subsequent streams following the reasoning given in Section 5.1.

The BESP as a function of pyrolysis plant size is shown in Figure 7.25 for both miscanthus and SRC willow.

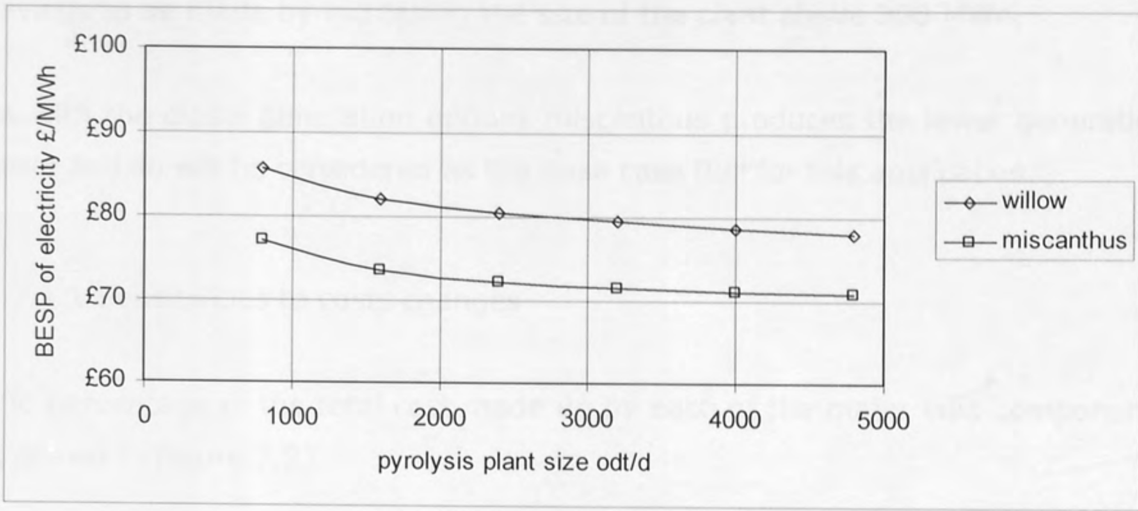

Figure 7.25 Base case BESP for pyrolysis/CCGT systems

The BESP can also be plotted against gross electrical output; this has been done in Figure 7.26.

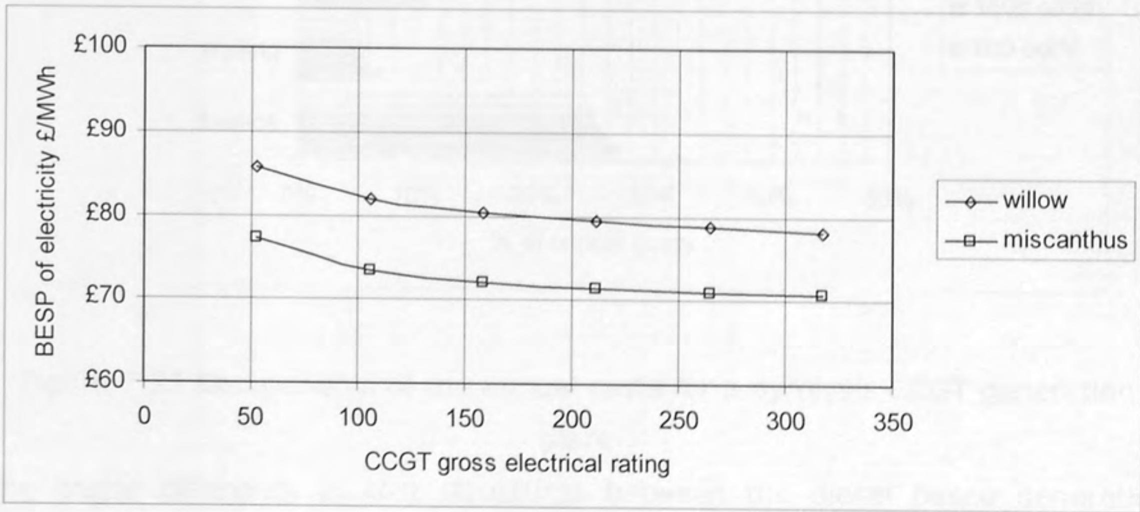

Figure 7.26 Base case BESP for pyrolysis/CCGT systems for different generator size

The BESP for CCGT generators is less than the minimum BESP for diesel power only operation from Figure 7.5 (£92/MWh). The CCGT costs appear to be levelling out as the plant size increases which indicates that that there are few savings to be made by increasing the size of the plant above 300 MWe.

As with the diesel generation options miscanthus produces the lower generation costs and so will be considered as the base case fuel for this application.

7.2.1.1 Sensitivities to costs changes

The percentage of the total cost made up by each of the major cost components is shown in Figure 7.27.

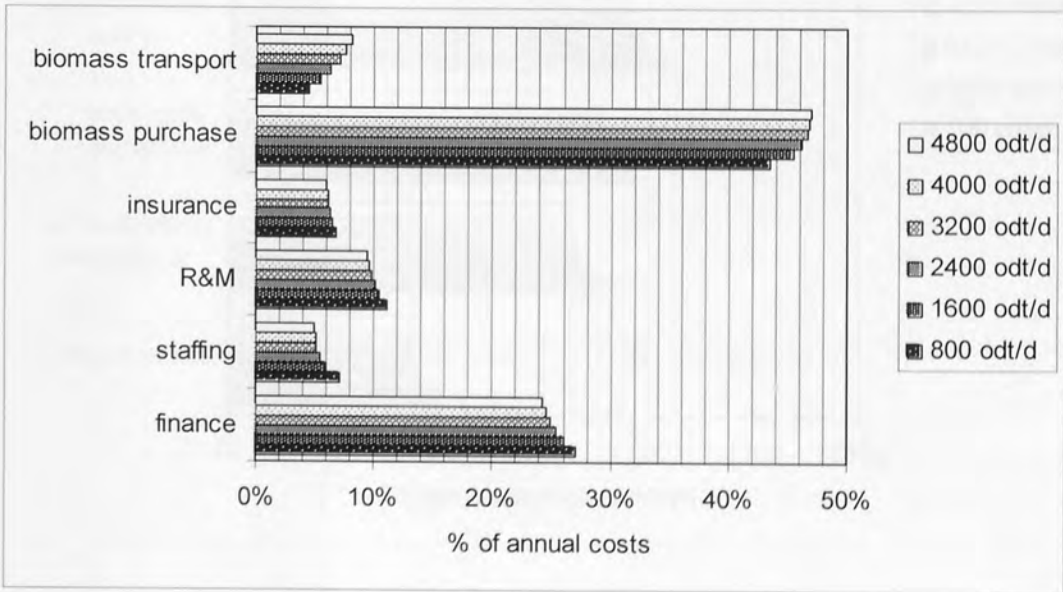

Figure 7.27 Components of the annual costs for a pyrolysis CCGT generation plant

The major difference in cost structures between the diesel based generation systems (Figure 7.9) and the CCGT ones is the reduction in the significance of the staffing cost and increase in the dominance of the biomass costs.

The significance of the transport costs increases with plant size. The reduction in the significance of staffing costs reflects the assumed higher utilisation of staff on the larger plants.

The BESP for the different fuel price scenarios discussed in Section 6.1.5 are shown in Figure 7.28.

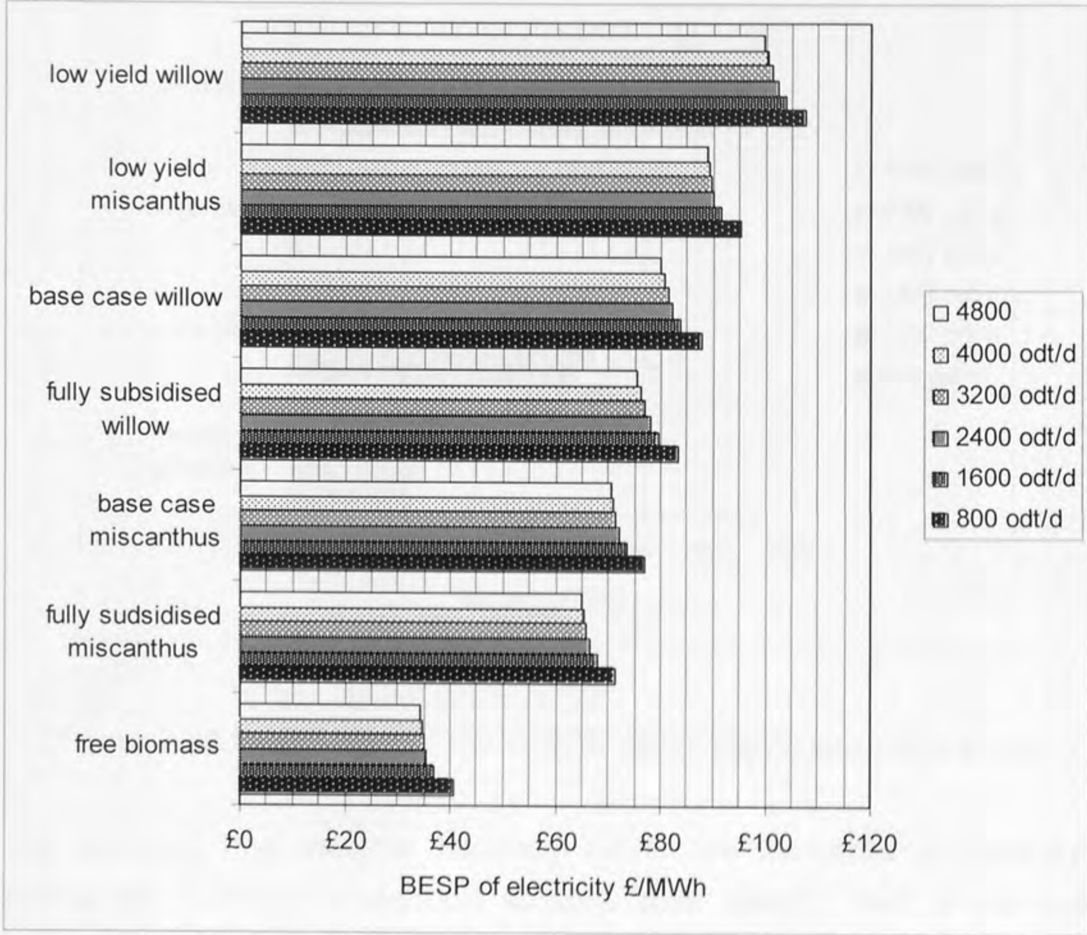

Figure 7.28 Impact of biomass cost on the BESP of electricity from pyrolysis/CCGT plants

The range of BESP values reflect the high proportion of the cost that is represented by biomass. For all the price scenarios covered the BESP in Figure 7.28 is lower than that for the pyrolysis/diesel options shown in Figure 7.10.

However the percentage spread between the highest and lowest cost (excluding free biomass) is higher than for the diesel options.

The breakdown of the capital cost into major plant areas is shown in Figure 7.29. Like the diesel case (Figure 7.11) the majority of the capital expenditure is on established technology.

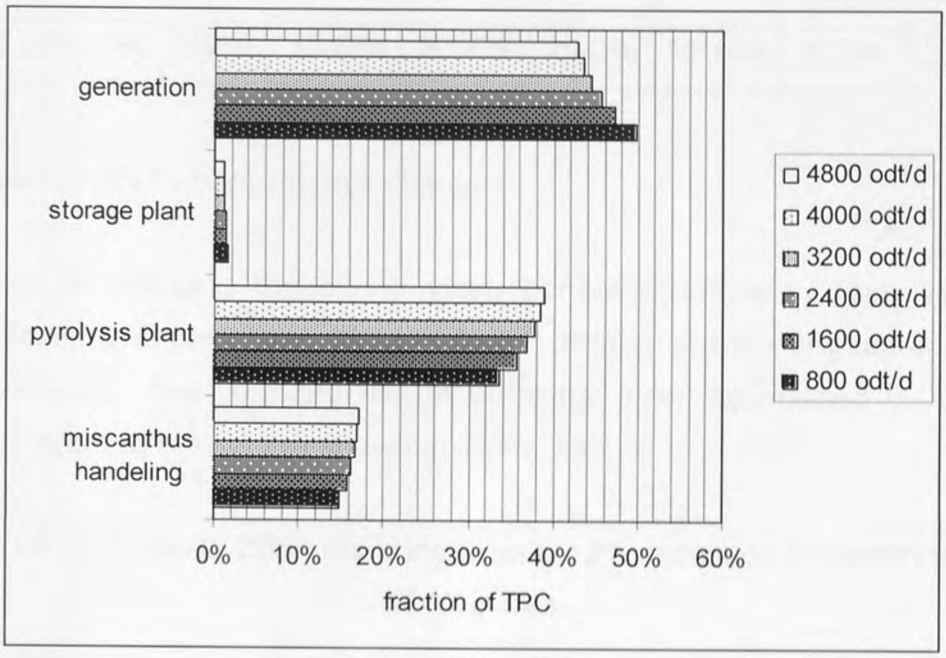

Figure 7.29 break down of the TPC for CCGT plants into plant areas

As the pyrolysis and material handling plants are increased in capacity by increasing the number of identical streams their specific cost is not heavily influenced by plant size. The generation plant does benefit from economies of plant size; consequently the percentage of the TPC that the generation plant represents reduces with increasing plant size.

The impact of increased interest rate and a 40% overspend in TPC is shown in Table 7.13.

Table 7.13 Impact on BESP of electricity of changes to capital cost and interest rate for CCGT plants

plant size odt/d	800	1600	2400	3200	4000	4800
interest 10% TPC base	13.6%	13.2%	12.9%	12.7%	12.5%	12.3%
interest 5% TPC +40%	11.7%	11.4%	11.1%	10.9%	10.7%	10.6%
interest 10% TPC +40%	30.8%	29.8%	29.2%	28.6%	28.2%	27.8%

7.2.1.2 Sensitivity to performance changes

The impact of reducing the bio-oil yield, generator efficiency, pyrolysis plant capacity factor and generator capacity factor to 90% of their original values has been calculated. The resulting rise in BESP has been normalised by the base case BESP and the results are shown in Table 7.14

Table 7.14 Increase in BESP resulting from a 10% reduction in performance of CCGT plants

plant size odt/d	800	1600	2400	3200	4000	4800
low bio-oil yield	13.2%	13.2%	13.2%	13.2%	13.2%	13.2%
low pyrolysis CF	6.2%	5.8%	5.5%	5.3%	5.2%	5.1%
low generator efficiency	13.2%	13.2%	13.2%	13.2%	13.2%	13.2%
low generator CF	6.2%	5.8%	5.5%	5.3%	5.2%	5.1%

As there is no pilot diesel to consider in the CCGT cases the impact of a reduction in yield and a reduction in generation efficiency are the same. Likewise as the works power is independent of plant scale for these applications the reduction in sales is also independent of size.

The reduction in the impact of loss of capacity factor with size is a reflection of the increasing significance of the biomass costs as the plant increases (lowering the CF reduces the biomass requirement).

7.2.1.3 System efficiencies

The system efficiencies have been calculated on the same basis as was used for the diesel generation systems and are shown in Table 7.15. The efficiencies are given for a single plant size as none of the performance characteristics are considered to vary with plant size over the range of plant sizes being considered.

Table 7.15 System efficiencies for bio-oil fired CCGTs

feedstock	2% ash miscanthus	2% ash willow	1% ash willow
bio-oil efficiency	58.5%	61.8%	70.5%
excess char efficiency	15.3%	16.1%	8.1%
useful pyrolysis product efficiency	73.8%	77.9%	78.6%
gross electrical efficiency	28.1%	29.7%	33.8%
net electrical efficiency	23.7%	25.0%	29.1%
discounted electrical efficiency	27.9%	29.8%	31.7%

7.2.1.4 Replanting CCGTs

As discussed in Section 5.8 it would be possible to replace the gas turbines on an existing CCGT plant with ones that are adapted to burn bio-oil. The BESP for electricity from replanted CCGTs has been calculated using bio-oil from miscanthus under the base case conditions and is shown in Figure 7.30. The TPC used to calculate the financing charge was calculated using the characteristic given in Figure 5.9.

However as both the new and retained plant will need maintaining and insuring, the TPC of the same size new plant was used to calculate the R&M and insurance and tax costs.

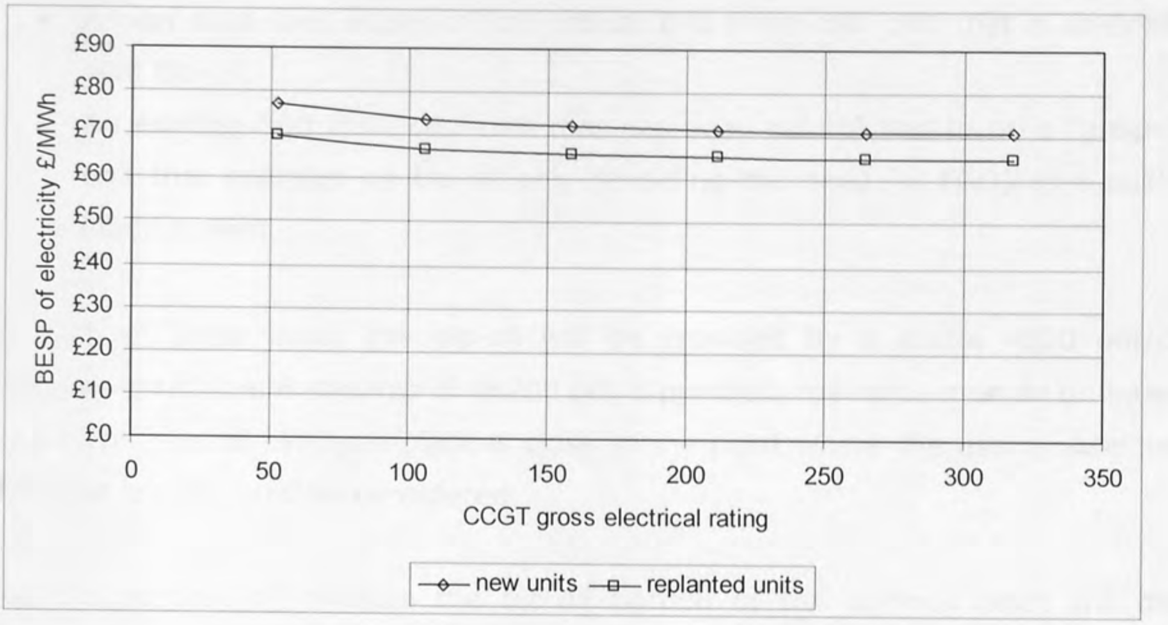

Figure 7.30 BESP for electricity from new and replanted CCGT units

Although the TPC for the replanted unit is 67% of that of the new unit the average saving in the BESP of electricity is around 9%. This reflects the relative significance of financing to the overall cost. The base case uses a 5% real interest rate; however even if this is increased to 10% the savings only increase to 11.5%. It is worth noting that these calculations assume that the retained plant is in a suitable condition to stay in service for another 20 years. This is optimistic and some refurbishment work is likely to be needed which will further reduce the savings.

7.2.2 Combustion steam cycle

Co-firing plant is considered to be a more economic approach than smaller dedicated plants for the reasons outlined in Section 5.9.2.

There are three scenarios that are worth considering:

- A new base load sub-critical 600 MWe coal unit that is co-fired with bio-oil;
- A new base load super-critical critical 800 MWe coal unit that is co-fired with bio-oil;
- An existing 500 MWe coal unit that has been refurbished to be a "green" unit that operates on bio-oil only (avoiding the need for FGD) as a peak loading plant.

In each of these cases the bio-oil will be provided by a onsite 4800 odt/d pyrolysis plant (i.e. 6 streams of 4x200 odt/d pyrolysis reactors) running on base load. This size of pyrolysis plant is close to the point where the use of satellite pyrolysis plants could be considered.

For the purpose of analysis the bio-oil portion of the co-fired plant will be considered as a virtual stand alone unit. This assumes that the coal fired portion is economically viable as an independent unit.

The capital cost for the refurbished 500 MWe unit has been calculated using both the high and low cost estimations from Table 5.13. The R&M and insurance cost for the refurbished plant are based on the capital cost of an equivalent new unit as this represents the value of all the plant that is being maintained and operated.

Two super-critical units have been considered; one with a CF close to the average for a coal fired plant and one with a CF close to the maximum achieved by supercritical plants in commercial operation. The size of the bio-oil portion of the unit will be calculated to use all the bio-oil produced. Large combustion plants initially run on base load and then load cycle as more economic plants are commissioned. It would be desirable for the pyrolysis plant to run at base load throughout its life. This can be achieved by increasing the co-firing ratio as the boilers CF reduces.

The basic techno-economic parameters of the scenarios are shown in Table 7.16.

Table 7.16 Combustion systems costs and performance

scenario	new sub-critical	new super -critical		refurbished	
		low CF	high CF	high cost	low cost
bio-oil rating MWe	295	365	271	500	500
net rating MWe	237	305	226	401	401
CF	63%	63%	85%	37%	37%
co-firing ratio	59.1%	45.7%	33.8%	100%	100%
BESP £/MWh	94.63	74.38	70.09	96.02	92.24
TPC £k	451,231	464,046	404,015	398,108	336,608
net SI £/kWe	1907	1522	1788	994	840
gross efficiency	27.5%	27.5	22.2%	22.2%	22.2%
net efficiency	22.2%	27.5%	27.5%	22.2%	22.2%
discounted efficiency	17.8%	23.0%	23.0%	17.8%	17.8%

The net rating is the electrical export capability of the plant (or bio-oil portion of it) after it has supplied its own load and that of the pyrolysis plant.

It is apparent that the new super-critical units have a clear cost advantage over the sub-critical ones. The BESP of power from the refurbished units could be improved if they had a sufficient bio-oil supply to run at a higher CF.

The lowest BESP came from the 271 MWe co-firing of an 800 MWe unit; this represents a co-firing ratio of 34%. If there were two 800 MWe units on the same site both sharing the bio-oil the co-firing ratio would come down to 17%.

It is credible that this co-firing ratio could be achieved with unconverted biomass at a lower capital cost and at higher net efficiencies than can be achieved with co-firing bio-oil. Consequently it appears that to supply sufficient bio-oil for an optimally sized combustion plant a network of pyrolysis plants is likely to be required.

7.3 Generators using a network of pyrolysis reactor sites

The CCGT sizes in Figure 7.26 are in the range shown to be optimum for cost and efficiency in Figure 4.14 so there appears to be little point in investigating CCGTs fed from networks of pyrolysis plants. From Table 7.16 there would appear to be little advantage in building new sub-critical units. Consequently only new super-critical and refurbished sub-critical plant will be considered in this section.

The bio-oil boiler is in reality a portion of a co-fired boiler so changes in the bio-oil capacity are made by changing the co-firing ratio. As such the technical performance of the steam plant and its specific investment will be independent of size. Consequently the only size dependent costs will be those associated with bio-oil supply.

Given the size of the bio-oil consumption it is likely that a dedicated network of pyrolysis plants will have been built to supply a single plant. The networks have been sized to allow the generation plant to run at either the coal plant average CF or close to maximum CF. The pyrolysis plants are considered to consist of a number of identical 800 odt/d streams (some located at the power station with the rest at satellite locations). It has been assumed that the pyrolysis plants are run under base load conditions and the generation plant operated to burn all the oil they produce.

The staffing scenarios discussed in Section 6.5 do not cover networks of satellite plants. The following staffing levels have been assumed for each stream:

- 8 biomass handling staff;
- 16 pyrolysis plant operators;
- 3 technicians.

These numbers are based on Table 6.13. In addition to the stream staff it has been assumed that there will be a central professional and administration staff of 13 to serve the network, 11 generation plant operators and 3 professional engineers to manage the generation plant.

The base case conditions have been used for the other costs. The main techno-economic parameters for converted 500 MWe units are given in Table 7.17.

Table 7.17 Refurbished combustion system cost and performance

	high refurbishment estimate				low refurbishment estimate			
	average CF		base load CF		average CF		base load CF	
pyrolysis network odt/d	8000	16000	10400	21600	8000	16000	10400	21600
bio-oil rating MWe	500	1000	500	1000	500	1000	500	1000
net rating MWe	401	801	401	801	401	801	401	801
CF %	62.0 %	62.0 %	80.6 %	83.7 %	62.0 %	62.0 %	80.6 %	83.7 %
BESP £/MWh	90.40	93.98	88.75	91.89	88.13	91.71	87.01	90.21
TPC £M	557	1112	674	1384	496	989	612	1261
net SI £/kWe	1390	1388	1682	1728	1237	1234	1528	1574
gross efficiency	22.2 %	22.2 %	22.2 %	22.2 %	22.2 %	22.2 %	22.2 %	22.2 %
net efficiency	17.8 %	17.8 %	17.8 %	17.8 %	17.8 %	17.8 %	17.8 %	17.8 %
discounted efficiency	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %	21.0 %

The increase in the CF that is possible with a larger supply of bio-oil has reduced the BESP of electricity. However as more pyrolysis plants are needed the net SI has risen considerably. The same data for new super-critical steam units is shown in Table 7.18.

Table 7.18 New super-critical combustion system cost and performance

	average CF			base load CF		
pyrolysis network odt/d	5600	10400	20000	7200	14400	28000
bio-oil rating MWe	400	800	1600	400	800	1600
net rating MWe	334	668	1335	334	668	1335
CF %	67.1%	62.3%	59.9%	86.3%	81.5%	83.9%
BESP £/MWh	£75.06	£77.93	£81.17	£71.86	£74.62	£76.83
TPC £M	528	1016	1991	606	1210	2380
net SI £/kWe	1583	1521	1491	1816	1813	1782
gross efficiency	27.5%	27.5%	27.5%	27.5%	27.5%	27.5%
net efficiency	23.0%	23.0%	23.0%	23.0%	23.0%	23.0%
discounted efficiency	27.1%	27.1%	27.1%	27.1%	27.1%	27.1%

The higher efficiencies of the super-critical plant more than compensate for the additional capital expenditure and the BESP for this plant is considerably lower than that for the sub-critical plant. The slight fall in SI with plant size is due to the stream discount on the capital cost of the pyrolysis plants. In practice power stations normally run at base load when new, and then at a reduced CF as plants with a lower cost of electricity production are built. The amount of bio-oil produced by the pyrolysis network is independent of the generator's CF so a higher co-firing ratio can be achieved as the generator CF reduces. Table 7.19 shows the effects of changing the CF on a generation plant for a given pyrolysis network.

Table 7.19 Bio-oil generation from supercritical combustion plants using a fixed size of pyrolysis network

	average CF			base load CF		
pyrolysis network odt/d	5600	10400	20000	5600	10400	20000
generation CF %	62%	62%	62%	85%	85%	85%
bio-oil rating MWe	433	804	1546	316	587	1128
net rating MWE	361	671	1291	264	490	941
co-firing ratio on 2x800MWe site	27%	50%	97%	20%	37%	70%
BESP £/MWh	£75.82	£78.02	£80.59	£75.82	£78.02	£80.59
TPC £M	549	1,018	1,957	549	1,018	1,957
net SI £/kWe	1522	1520	1516	2084	2080	2078
gross efficiency	27.5%	27.5%	27.5%	27.5%	27.5%	27.5%
net efficiency	23.0%	23.0%	23.0%	23.0%	23.0%	23.0%
discounted efficiency	27.1%	27.1%	27.1%	27.1%	27.1%	27.1%

From Table 7.19 there is no change in the BESP with generation CF. This is because it has been assumed that the boiler will be engineered to produce the higher bio-oil rating. The lower bio-oil rating for high generator CF means that the SI is higher for the higher CF. As the BESP will be independent of the CF only the cost for the average CF plant will be considered in the rest of this chapter.

7.3.1.1 Sensitivities to cost changes

Table 7.17 shows that the BESP for refurbished units is not very sensitive to the cost of refurbishment of the unit and is considerably more than the BESP for the new super-critical units; consequently only the super-critical units will be considered for the rest of this chapter. The major components of the total annual cost are shown in Figure 7.31.

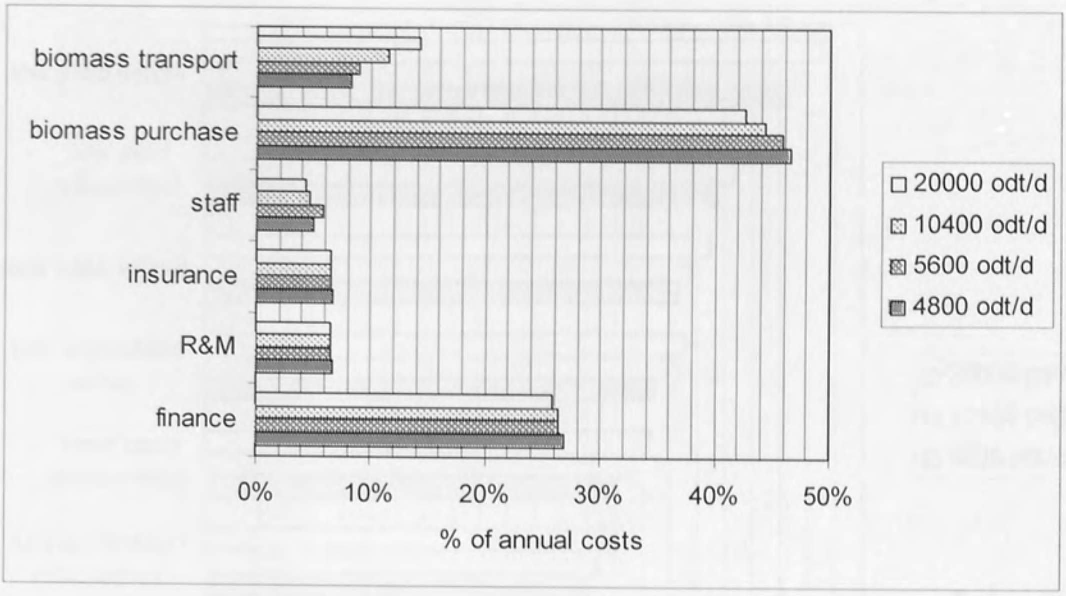

Figure 7.31 Components of the annual costs for a pyrolysis / super-critical steam generation plant with average CF

From Figure 7.31 it is clear that biomass transport costs make up an increasingly significant portion of the costs as the pyrolysis network increases in size. This is also reflected in the increasing BESP with plant size shown in Table 7.18. The impact of the different biomass cost scenarios is shown in Figure 7.32.

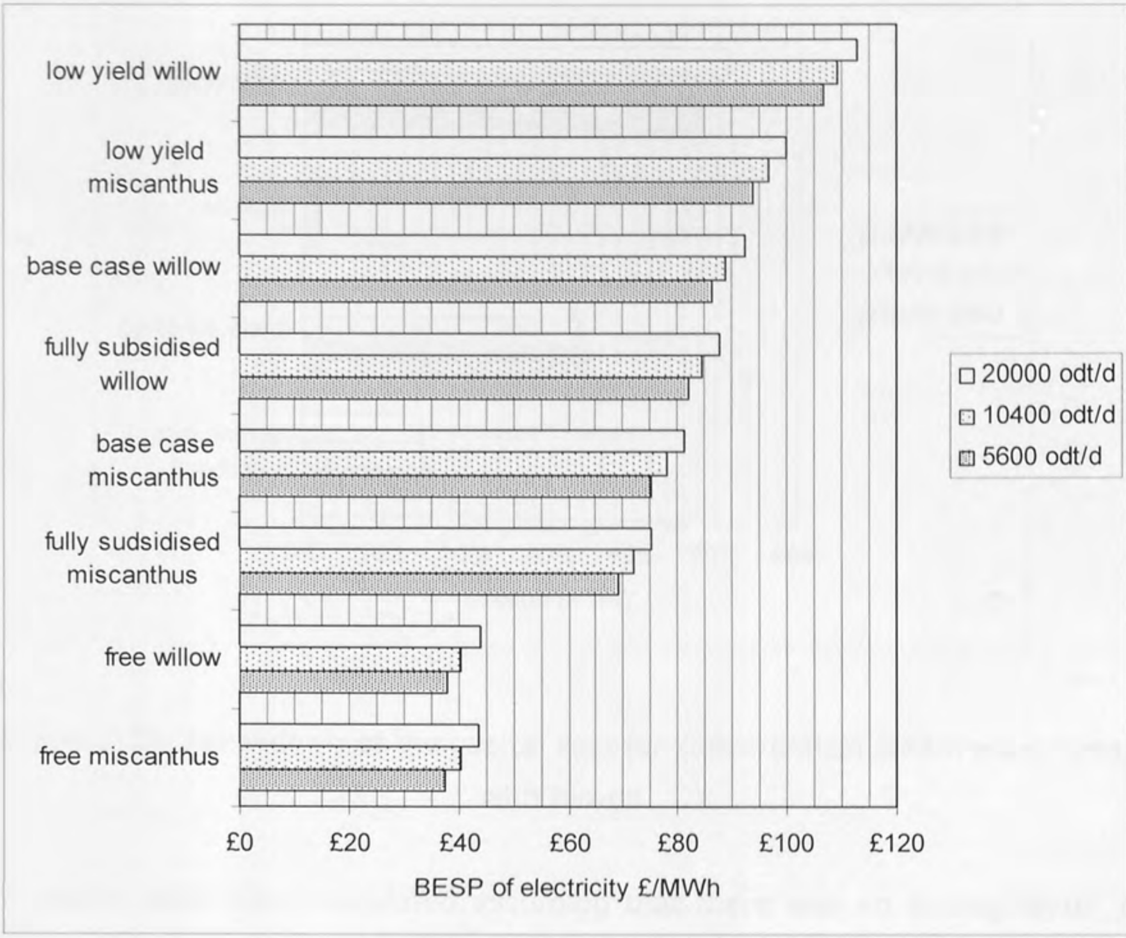

Figure 7.32 BESP of electricity from super-critical steam plants fired with bio-oil operating at average CF

The BESP for generation using free miscanthus and free willow are almost the same. This shows that at large scale as well as small scale the processing costs for miscanthus and woodchips are similar.

The breakdown of the capital cost into major plant areas is shown in Figure 7.33.

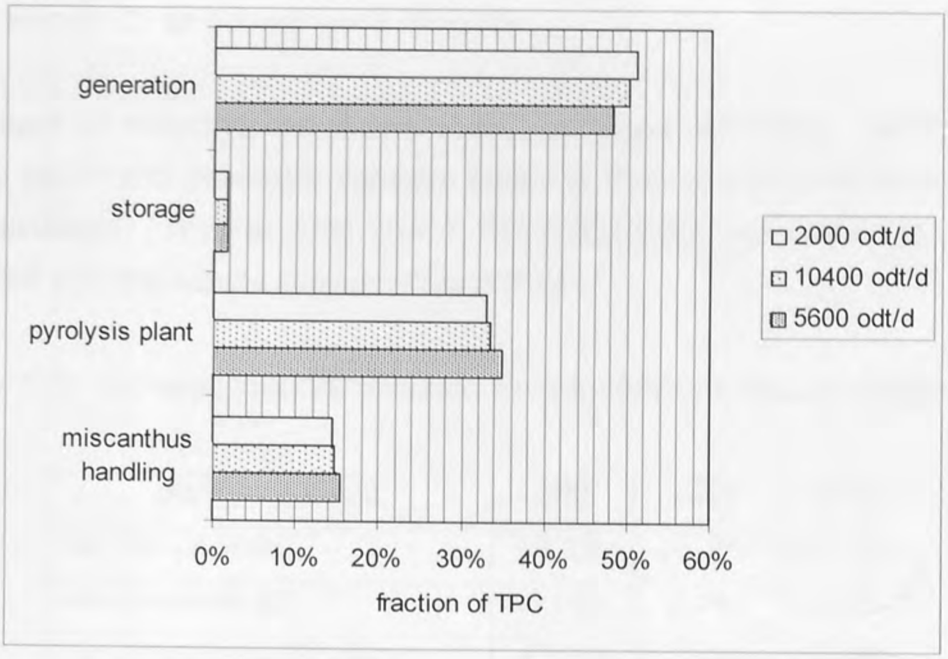

Figure 7.33 Breakdown of the capital cost for super-critical steam plant fired with bio-oil

The capital costs were calculated assuming that there was no scaling factor on the generation plant; consequently the changes in relative proportions shown in Figure 7.33 are due to the assumed stream discount. As with the other systems the bulk of the capital expenditure is on established technology. Consequently 40% is considered to be the maximum credible TPC overspend. The impact of this on the BESP has been calculated at real interest rates of 5% and 10% and normalised to the base conditions in Table 7.20.

Table 7.20 Impact on BESP of electricity of changes to capital cost and interest rate

plant size odt/d	5600	10400	20000
interest 10% TPC base	13.3%	13.3%	13.0%
interest 5% TPC +40%	11.5%	11.5%	11.2%
interest 10% TPC +40%	30.2%	30.1%	29.5%

7.3.1.2 Sensitivity to performance changes

The impact of reducing the bio-oil yield, generator efficiency, pyrolysis plant capacity factor and generator capacity factor to 90% of their original values has been calculated. The resulting rise in BESP has been normalised by the base case BESP and the results shown in Table 7.21

Table 7.21 Increase in BESP resulting from a 10% reduction in performance

plant size odt/d	800	1600	2400
low bio-oil yield	13.2%	13.2%	13.2%
low pyrolysis CF	6.0%	5.7%	6.0%
low generator efficiency	13.2%	13.2%	13.2%
low generator CF	6.0%	5.7%	6.0%

These are similar to those for the CCGT plant in table 7.14 which is not surprising as the generator efficiencies are nearly the same.

7.3.1.3 System efficiency

The system efficiencies have been calculated on the same basis as was used for the diesel generation systems and are shown in Table 7.22. The efficiencies are given for a single plant size as none of the performance characteristics are considered to vary with plant size over the range of plant sizes being considered.

Table 7.22 System efficiencies for supercritical combustion plants

bio-oil efficiency	58.5%
excess char efficiency	15.3%
useful pyrolysis product efficiency	73.8%
gross electrical efficiency	27.5%
net electrical efficiency	23.0%
discounted electrical efficiency	27.1%

7.4 Summary of key findings

This has been a lengthy analysis so it is worth summarising the key findings.

Use of buffer storage

Plant utilisation can be improved by using bio-oil storage to smooth out fluctuation in production caused by variations in bio-oil yield and minor plant breakdowns.

Size of pyrolysis unit

Pyrolysis plants benefit from considerable economies of scale and it is cost effective for smaller generators to buy bio-oil from a central production plant rather than have a small dedicated pyrolysis unit.

Feedstock

The costs of processing willow woodchips and miscanthus are similar.

Char sales

This can cover between 8-22 % of the biomass cost depending on the ash content of the biomass used. However the higher yields come at the expense of the bio-oil yield.

CHP

Diesel based CHP plants following typical heat load CF can produce electricity at lower cost than diesel generators operating on base load. However if the CHP CF is lower than planned this advantage can be lost.

BESP

The lowest BESP is obtained by using CCGT plants of 200-300 MWe and co-firing bio-oil up in 800 MWe in super-critical steam units.

Novelty of plant

In all cases the majority of the capital cost of the plants is spent on established technologies. This proportion increases with plant size.

Sensitivity to cost changes

In all but the smallest system the major cost item is biomass purchase. The significance of this increase with plant size.

Electrical Efficiency

The high works power for the combined pyrolysis/generation process means that the normal method of calculating efficiency if misleading. The co-production of a marketable energy by-product needs to be taken into account when calculating efficiency of pyrolysis systems. The electrical efficiency improves if the pyrolysis plant is operating on a lower ash fuel or on willow rather than miscanthus. Even when this is done the highest discounted electrical efficiency for the systems considered was lower than some biomass combustion plants and considerably lower than co-firing biomass in large coal boilers.

Sensitivity to changes in efficiency and bio-oil yield

As there is a high internal load that must be supplied before any electricity is sold, consequently the systems are disproportionately affected by drops in efficiency of bio-oil yield.

8 Further analysis of promising systems.

The average price of electricity in 2006 (from Section 3.3.6) was £58/MWh for embedded plants and £40/MWh for large plants. At this price level none of the systems considered in Chapter 7 would make a profit without subsidy. The base cases where the required subsidy is less than £40/MWh (the wholesale market price) are shown in Table 8.1.

Table 8.1 BESP of electricity for plant arrangements that require the lowest level of subsidy

Diesel CHP with onsite pyrolysis 50% CF				
gross rating MWe	14.0	18.6		
net rating MWe	11.4	15.1		
subsidy£/MWh	36.98	28.72		
SI £/kWe	1649	1561		
Diesel CHP with remote pyrolysis 50% CF				
gross rating MWe	4	6	10	15
net rating MWe	3.3	4.9	8.1	12.2
subsidy£/MWh	39.55	36.88	32.24	30.82
SI £/kWe	1824	1693	1541	1541
CCGT				
gross rating MWe	106	212	318	
net rating MWe	89	178	268	
subsidy£/MWh	33.49	31.45	30.78	
SI £/kWe	1689	1574	1517	
Super-critical combustion (co-fired with coal) 62% CF				
gross rating MWe	433	804		
net rating MWe	361	671		
subsidy£/MWh	35.82	38.02		
SI £/kWe	1522	1520		

The gross rating is the electrical power rating of the generator, the net rating is the total electricity for sale divided by the generator running hours, i.e. the effective rating of the plant after the pyrolysis and generation plants' electrical loads have been met. In all the cases the pyrolysis plants have been assumed to run with a CF of 85% with the generation plant running at a lower CF. This means that the impact of the subtraction of the pyrolysis plant's electrical consumption from the generator's output will have a greater impact on the generators with the lowest CF.

The SI is based on the net electrical rating.

Although large CHP systems with on site pyrolysis would appear to require the least subsidy there are only a small number of large new space heating loads available so this system is not worth further generic investigation. Consequently the most promising systems which are to be considered for further analysis are diesel CHP with remote pyrolysis plants, combined cycle gas turbine, and co-firing in coal-fired super-critical steam plants.

The analysis in Chapter 7 used historic cost data and assumed that costs and sales price remained constant in real terms. The plants performance was also assumed to be constant throughout their lives. This does not accurately reflect the situation with real power plants. As all of the systems considered have broadly similar cost profiles the inaccuracies caused by these assumptions will affect all the systems in a similar way. Consequently the relative cost between systems should be unaffected. However it would be worth while investigating the possible impact of varying relative costs and production to see what impact it has on the BESP.

8.1 Varying costs over the life of a project

In practice the costs and performance of a plant is likely to change throughout its life for the following reasons:

- Plant testing and teething troubles reduce the CF in the first few years of operation;
- The CF will fall in the last few years of operation due to lack of load as more efficient new plants can offer a lower price than existing ones;
- Biomass yields will increase as the plantations mature which should reduce costs;
- Biomass harvesting costs should reduce due to "learning" effects (Section 8.1.2);
- Operating procedures should improve with practice, reducing staffing costs.

Although these effects are likely to occur the relevant data is commercially sensitive and there is little published data to use. It is however possible to make estimations of these effects and see if they have a significant impact on the BESP. One way of doing this is to estimate the cost and production separately for each year of operation and total them up to provide life time costs. Likewise the generation for each year can be calculated separately and total to give a lifetime generation figure and the BESP calculated. This process will be referred to as variable lifetime costs (VLC) to distinguish it from the constant lifetime costs (CLC) method used in Chapter 7. As the purpose of this exercise is to investigate the significance of possible changes throughout the lifetime of the plant, a scenario approach will be used rather than attempting to predict future costs and operating regimes for the plants.

8.1.1 Capacity factor profile

The following scenario been assumed; the CF will be 50% of its design value for the first year of operation, 75% for the second year, and 100% in the third and subsequent years. It has also been assumed that for the last five years of operation of a power only application the CF will fall due to competition to 80% of its design value (this is consistent with the CF for coal units operating today). CHP plants do not have any competition for their heat load and so their load factors will not taper off towards the end of their operational life.

8.1.2 Biomass costs

Biomass yields increase as the plantations mature but this was considered when estimating the yields in Section 6.1.5. However the management cost of the plantations should reduce with experience. This effect is known as learning; this is an umbrella term for a number of effects which cause costs to reduce with increased production. These effects can be grouped under the following categories:

- Learning by searching - research and development;
- Learning by doing - procedural improvements made as the result of the organisations experience;
- Learning by using - product improvement as the result of users experience;
- Learning by interaction - improvements that are the result of shared experience and research;
- Scaling - cost savings by making the product a different size (normally larger);
- Economies of scale of production - typically mass production but also benefits of using standard designs.

These effects tend to produce a cost curve that reduces by a constant proportion on each doubling of production. Such that:

$$C_{2N} = PR.C_N$$

Where C_{2N} is the cost of the 2Nth unit of production,
PR is the progress ratio and
C_N is the cost of the Nth unit of production.

In many applications the PR remains constant as the process matures until a floor cost is established.

It has been reported that the cost of primary forest fuel (PFF) in Sweden and Finland dropped by 30% with increased production following a classic learning curve with a PR in the range of 85-88% [213]. Unlike energy crops PFF has no set-up costs but it does give a measure of the reduction in harvesting and handling costs. These items represent some 56% of the cost for SRC willow and 54% of the cost for miscanthus [190]. A conservative assessment of the likely reduction in cost can be made by applying the learning factor to the annual cost (i.e. those not associated with establishment of the crop) for a single plantation. A PR of 87% has been used and an establishment cost has been recouped throughout the lifetime harvest of the plantation at a cost of £1.02/GJ. The cost of production with learning is shown in Figure 8.1.

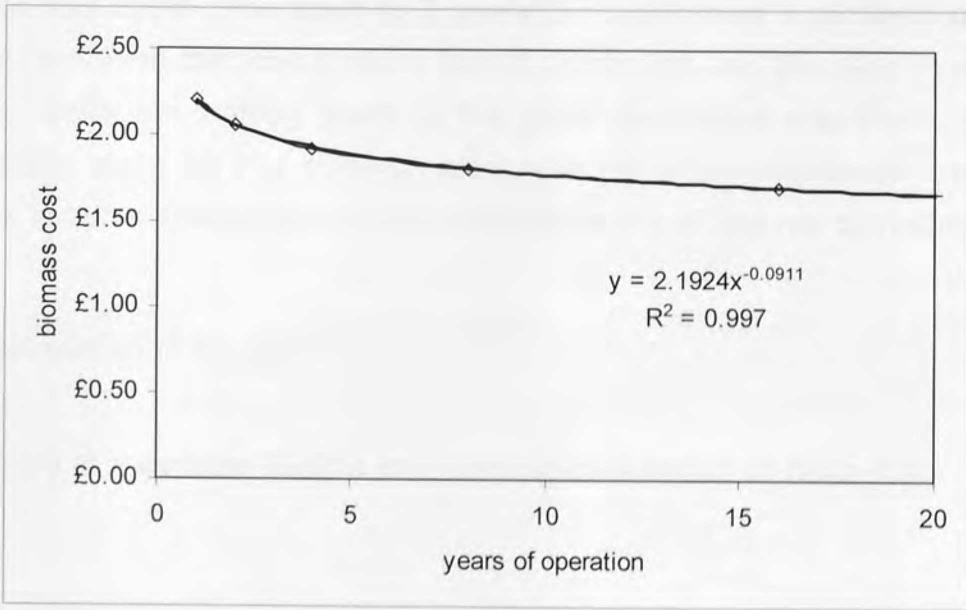

Figure 8.1 Estimated cost of miscanthus production from a single plantation

Year 1 is 2006 the data of the costs survey used to estimate the production cost. Figure 8.1 ignores the production from any new plantations. New plantations will reduce the time period between production doubling and hence speed up the learning process. The establishment costs of new plantations will also benefit from learning effects but there is insufficient published data to predict the impact of increasing the number of plantations or to establish a floor cost for the mature industry.

8.1.3 Staffing costs

All of the systems being considered in this chapter have a high degree of automation with the operation staff supervising the automated systems and dealing with blockages/spillages from the solid and liquid fuel handling plant. It is likely that over time the plant will be modified to reduce the need for such operator intervention and the staffing level can be reduced. The staffing levels proposed for the pyrolysis plants were calculated on the basis of 3 operators supervising 4 pyrolysis units at all times. It is assumed by the 15th year of operation this could come down to 2 operators supervising 4 pyrolysis units. It has been assumed that due to plant layout constraints and the need to maintain particular skills the staffing levels in the other operational areas are constant. The staffing levels for the pyrolysis plant used with the distributed diesel CHP schemes is set by minimum manning constraints and so can not be reduced.

8.1.4 Calculation of the BESP

An example of a variable lifetime cost calculation is shown in Table 8.2.

Table 8.2 BESP of bio-oil from a 200 odt/d pyrolysis plant

year	fixed	CF	biomass use	rate	cost	char sales	bio-oil produced
	£k		GJ	£/GJ	£k	£k	GJ
1	2105	42.5%	595680	2.39	1421	-239	321667
2	2105	63.8%	893520	2.25	2011	-359	482501
3	2105	85.0%	1191360	2.18	2593	-479	643334
4	2105	85.0%	1191360	2.13	2532	-479	643334
5	2105	85.0%	1191360	2.09	2485	-479	643334
6	2105	85.0%	1191360	2.06	2448	-479	643334
7	2105	85.0%	1191360	2.03	2417	-479	643334
8	2105	85.0%	1191360	2.01	2391	-479	643334
9	2105	85.0%	1191360	1.99	2368	-479	643334
10	2105	85.0%	1191360	1.97	2347	-479	643334
11	2105	85.0%	1191360	1.96	2329	-479	643334
12	2105	85.0%	1191360	1.94	2313	-479	643334
13	2105	85.0%	1191360	1.93	2297	-479	643334
14	2105	85.0%	1191360	1.92	2284	-479	643334
15	2105	85.0%	1191360	1.91	2271	-479	643334
16	2105	68.0%	953088	1.90	1807	-383	514668
17	2105	68.0%	953088	1.89	1798	-383	514668
18	2105	68.0%	953088	1.88	1790	-383	514668
19	2105	68.0%	953088	1.87	1782	-383	514668
20	2105	68.0%	953088	1.86	1774	-383	514668
total	42,091				43,458	-8,735	11740853

The staffing level of a single pyrolysis plant is constrained by the minimum staffing levels required for health and safety and so is unlikely to be able to be reduced throughout the life of the plant.

Consequently it is included in the fixed cost along with the financing cost, R&M and insurance. Char sales are shown as negative costs.

The total of the fixed cost, biomass cost and char sales over the 20 year life of the plant is £76,814k giving a BESP of bio-oil of £6.54/GJ (compared to £7.06/GJfor a 200 odt/y plant from Figure 7.18). It should be noted that this cost does not include the cost of the electricity used to make the bio-oil as it has been assumed that this will be provided free of charge by the user of the bio-oil. The same process has been used to calculate the BESP of electricity for the systems identified in Table 8.1 and the results are tabulated in Table 8.3.

Table 8.3 comparison of the BESP calculated by constant life time cost and variable life time cost methods

Diesel CHP with remote pyrolysis 50% CF				
size net MWe	3.3	4.9	8.1	12.2
BESP CLC £/MWh	97.75	95.08	90.44	89.02
BESP VLC £/MWh	97.00	91.68	86.86	85.38
CCGT				
size net MWe	89	178	268	
BESP CLC £/MWh	73.49	71.45	70.78	
BESP VLC £/MWh	71.63	68.17	67.10	
Super-critical combustion (co-fired with coal) 62% CF				
size net MWe	361	671		
BESP CLC £/MWh	75.82	78.02		
BESP VLC £/MWh	73.08	74.38		

From Table 8.3 the BESPs calculated by varying the cost over the lifetime of the plant are lower than the value when considering the cost to be constant and the impact appears to be the same for each type of generation plant.

8.2 Possible cost reductions as more plants are built

In Section 8.1 it was shown that the cost of generation from a single plant would fall as the result of learning effects on the production cost of biomass. Technological learning will also affect the capital cost of the plant and its performance. It is worthwhile considering these to see what the possible BESP would be if fast pyrolysis technologies were implemented in commercial numbers.

8.2.1 Learning effects on capital costs

Pyrolysis based power plants use combinations of new and established process plant. The construction of some bio-oil based power stations is unlikely to alter the cost of the generation plant or biomass handling plants however the cost of the pyrolysis plants should reduce.

A review of studies of technological learning in bioenergy systems was carried out by Junginger et.al [211]. They found that although the capital cost of biomass CHP plants, fluidised bed boilers and anaerobic digesters did reduce as the installed capacity increased it was not possible to accurately calculate PRs for them. This was attributed to the amount of site specific costs involved with these projects. A broader review of learning factors in the energy sector was carried out by McDonald and Schrattenholzer [212], they reported that once the impact of increasing plant size was removed from the calculation the capital cost for coal fired power plants followed a PR of 92.4% (with R^2 of 0.9) Lignite power plants were reported to have a PR of 93.4% (R^2 of 0.96) when calculated on the same basis. The Junginger study gave PR for fluidised beds in the range 90-94% which is consistent with these findings. Consequently it would be reasonable to assume that pyrolysis plants would benefit from a PR of 93%. Other studies have considered the cost of the 10th of a kind plant [81-82]. In the context of this study it is worth considering what constituted the plant. The CCGT and combustion plant all use a number of pyrolysis reactors per plant. If the pyrolysis reactor (and associated quench system) is considered to be the unit of production then the 10th CCGT plant could contain the 160th pyrolysis reactor. However not all the generation plants would be off the same size so it was decided to use the cost of the 128th unit to be the cost of the pyrolysis reactors for mature plants.

8.2.2 Biomass cost

An estimation of the cost reduction of biomass from a single plantation with learning was made in Section 8.1.2. This was based on reduction in harvesting and plantation management cost. If it is assumed that the establishment cost could fall by a similar amount so that energy crops experience the same cost drop as primary forest products did in Scandinavia (30%), the base case cost of miscanthus would be £1.55/GJ.

8.2.3 Performance assumption for later plants

In additional to reduction in costs it is likely that the performance of the plants will also improve with operational experience and minor modification. There is no evidence for the extent that this is likely to happen but the following scenario reflects an optimistic estimate of plant performance:

- Diesel generators' TPC and performance will be assumed to be equal to those for distillate oil;

- A pilot fuel ratio of 5% will be assumed on the basis that with improved injection techniques satisfactory emissions could be reached with a lower pilot fuel ratio, and engines have run with this level of pilot fuel;

- Pyrolysis yields will be assumed to be those for 1% ash miscanthus from Table 4.15. This could be achieved by improved biomass production techniques or biomass pre-treatment and improved pyrolysis plant operations. The corresponding excess char yield will also be used;

- Gas turbine performance will be assumed to be the same as for distillate fuel. This could be achieved by lowering the bio-oil ash content by improved the ash separation or bio-oil filtration techniques;
- The production staff numbers will reduce (subject to minimal staffing limits) to those in Section 8.1.3.

8.2.4 BESP for future plants

The assumptions made in Sections 8.2.1 to 8.2.3 have been used to calculate the BESP for pyrolysis based power plants following significant commercial implementation (i.e. when the technology can be considered mature). The plants are assumed to follow the CF profiles given in Section 8.1.1 and the results are shown in Table 8.4.

Table 8.4 BESP of electricity for mature power

Diesel CHP with remote pyrolysis 50% CF				
size net MWe	3.3	4.9	8.1	12.2
BESP current £/MWh	97.75	95.08	90.44	89.02
BESP mature £/MWh	78.86	74.00	69.71	68.22
subsidy mature £/MWh	40.86	37.08	11.71	10.22
CCGT current technology				
pyrolysis plant size odt/d	1600	3200	4800	
size MWe	89	178	268	
BESP £/MWh	73.49	71.45	70.78	
CCGT mature technology				
pyrolysis plant size odt/d	1600	3200	4800	
size MWe	95	189	284	
BESP £/MWh	51.92	50.01	49.45	
subsidy mature £/MWh	11.92	10.01	9.45	
Super-critical combustion (co-fired with coal) 62% CF current technology				
pyrolysis plant size odt/d	5600	10400		
size net MWe	361	671		
BESP £/MWh	73.08	74.38		
Super-critical combustion (co-fired with coal) 62% CF mature technology				
pyrolysis plant size odt/d	5600	10400		
size net MWe	411	763		
BESP mature £/MWh	60.88	62.30		
subsidy mature £/MWh	20.88	22.30		

The higher oil yields assumed for the mature technology allow for an increase in the size of plant that can be supplied by a given pyrolysis plant; hence the increase in generator size for a given pyrolysis plant. In addition the bio-oil quality improvement reduces the de-rating applied to the CCGT plants.

The improvement in bio-oil yields and quality also improve the system efficiencies as shown in Table 8.5.

Table 8.5 System efficiencies

system	net efficiency		discount efficiency	
	current	mature	current	mature
diesel CHP electricity	20.0%	22.6%	23.6%	24.6%
diesel CHP heat	24.6%	28.0%		
CCGT	23.6%	28.8%	27.9%	31.3%
Combustion	22.9%	26.1%	27.1%	28.3%

The improved bio-oil yields also allow larger generators to be fuelled by a given size of pyrolysis plant thus reducing the specific investment costs. The effects of this are shown in Table 8.6.

Table 8.6 Impact of technology maturity on specific investment

Diesel CHP with remote pyrolysis 50% CF				
size net MWe	3.3	4.9	8.1	12.2
current SI £/MWh	1824	1693	1541	1541
mature SI £/MWh	1343	1234	1107	1107
CCGT				
pyrolysis plant size odt/d	1600	3200	4800	
size net MWe	86	178	269	
current SI £/kWe	1709	1574	1516	
size net MWe	95	186	284	
mature SI £/kWe	1379	1255	1202	
Super-critical combustion (co-fired with coal) 62% CF				
pyrolysis plant size odt/d	5600	10400		
size net MWe	355	659		
current SI £/MWh	1533	1532		
size net MWe	411	773		
mature SI £/MWh	1229	1227		

8.3 Impact of changing the repayment period

Throughout this thesis all the calculations have assumed that the capital for the projects has been provided by 20 year annuity funds. This was done to be consistent with other studies although there is no reason why the annuity fund should run for the life of the plant. In practice most projects are financed from a mixture of equity finance (shareholders cash), long term loans (corporate bonds) and bank loans so portions of the capital cost will be paid off over different terms. The impact of changing the term of the finance can be seen by considering the following example. The TPC for the 178 net MW_e CCGT using current technology is £281M which at a real interest rate of 5% gives a 20 year annuity payment of £22.5M, which in turn gives a lifetime financing cost of £451M. However if the term is reduced to 10 years at the same interest rate the annuity for the first 10 years is £36.4M but it is zero for the last 10 years, giving a lifetime financing cost of £364M which causes a 6% drop in the BESP. Clearly a shorter term should yield a higher profit (at the cost of higher initial annual repayments). One factor that influences the selection of the term is the rate at which the company is allowed to depreciate the plant against corporation tax. If the finance term is longer than the depreciation life of the plant (which may well be shorter than its service life) there will be outstanding debt against a plant with no capital value which will increase the debt to asset ratio for the company.

A shorter finance term has a considerable impact if the BESP is calculated separately for each year of operation rather than over the life of the project. This has been done for the 178 MW_e CCGT for real interest rates of 5 and 10% and for 10 and 20 year term annuities, and the results are plotted in Figure 8.2.

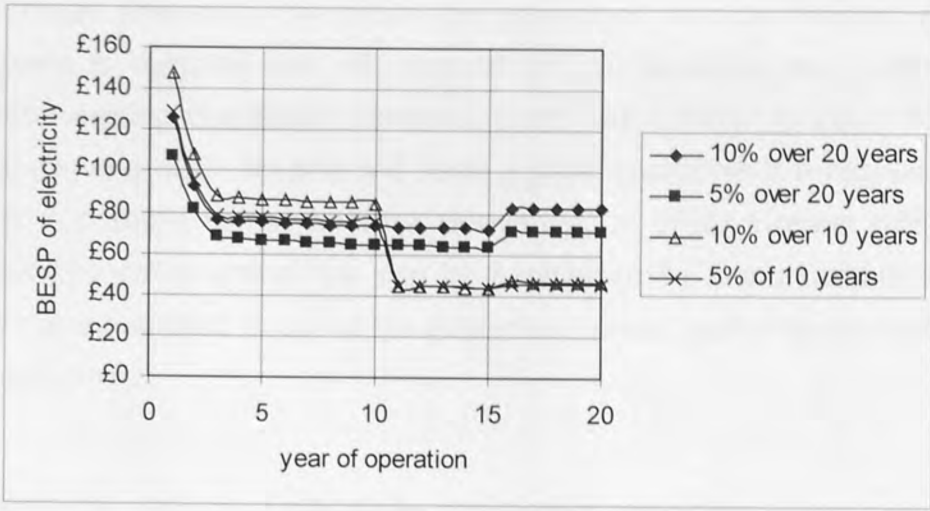

Figure 8.2 Impact of varying the annuity period

The major advantage of using a shorter annuity period can be seen when considering the subsidy regime. Under the current ROC regime as an advanced technology plant in 2006 the plant would received ROC payments of around £90/MWh and a market price around £40/MWh; this would give an income of £120/MWh which would cover the first year's operating cost in all but the 10% interest 10 year term case. However the ROC scheme is only guaranteed to operate until 2027. Although it is likely to be replaced with another support mechanism there is no guarantee that it will be as advantageous to pyrolysis technologies. From Figure 8.2 it can be seen that a plant that is financed over a term that is shorter than the guaranteed life of the ROC scheme will still be profitable even if the ROC scheme is replaced with a far less generous one. Consequently a shorter annuity period reduces the risk that the subsidy regime may become less favourable throughout the life of the project.

8.4 Finacial viability

In common with most European techno-economic studies this thesis has concentrated on the BESP and ignored the fact that the owners will require the plant to make a profit to provide a return to investors.

This is because analysis of the return on investment that the market will expect from a plant is complex and will depend on the structure and nature of the organisation owning the plant. However profit has another function which is to cover the owner's risk. No one will keep a plant operating if it regularly makes losses. It is possible to use financial derivatives to offset interest rate and fuel costs rises and construction risk can be capitalised by using turnkey contracts but once the equipment is out of its guarantee period performance risk remains with the operator.

8.4.1.1 Financial viability of electricity only power production

Working on the principle that the plant should not make a loss and the considerations contained in Chapters 7 it should be possible to estimate a minimum electricity price at which pyrolysis based generation is likely to be considered to be viable. It is proposed that this is calculated from the miscanthus base BESP increased by the sum of the following factors:

- 11% for construction overspend - once construction cost overrun they cannot be reduced over the operational life of the project so it is prudent to assume construction costs will overrun by 40%;
- 26% for high biomass cost - it is likely that over the life of the plants there will be periods of high biomass prices hence it is credible that a miscanthus cost increase to the low yield cost should be allowed for;
- 13% for performance deterioration - the performance of process plants tend to deteriorate with time so it is possible that before a major overhaul the pyrolysis yield could be down by 10%.

This makes the minimum viable price 50% higher than the base BESP. There is a risk that more of the events that cause costs to increases could occur at the same time but without some idea of the likely frequency of their occurrences and possible linkages between factors more detailed calculations would be no more valid than this one.

Given the speculative nature of this calculation it is acceptable to consider the BESP from either CCGT or combustion systems to be the same at around £72/MWh this would give a price at which pyrolysis based systems should be viable at around £108/MWh. From Figure 3.2 the wholesale price of electricity around 2006 was between £40-45/MWh and from Table 1.3 the ROC price was between £40-50/MWh giving a total income from in the range £80-95/MWh this is below the estimated minimum viable price so it is not surprising that no plants were built. With double ROCs (introduced in 2009) the income would be between £120-145/MWh. This is well above the estimated minimum viable price so providing the ROC prices remain at a similar level major utility companies should consider building pyrolysis based power station.

The double ROC payments were introduced to help developing technologies. Inherent in the strategy is the notion that once a technology becomes established its cost reduces and so its subsidy can also be reduced. In this context it is worth applying the same viability criteria to the estimated mature plant BESP from Table 8.3. The BESP for mature combustion in superheated boilers was £62/MWh which would give a minimum viable price of £91/MWh which would have been inside the 2006 single ROC income band that the plant could have expected in 2006 and so may not be viable. The BESP for mature CCGT is £50/MWh which would give a minimum viable price of £75/MWh which is below the income band and so should be viable.

Just because a technology appears to be economically viable does not make it competitive. Comparing pyrolysis based generation with combustion or gasification is outside the scope of this study. However even the discounted efficiencies shown in Table 8.4 are lower than those achievable in large scale combustion plants and the current specific investment figure for both CCGT and combustion from Table 8.5 are similar to those for a 300 MWe coal sub critical combustion unit in Table 5.11. So although this study has showed that pyrolysis based CCGT plants in the 200-300 MWe range should be viable further work is needed to see if they are competitive.

8.4.1.2 Financial viability of combined heat and power

The situation with CHP plants is more complicated than power only ones due to the economies of scale. Assuming that the lowest cost option is to produce pyrolysis oil at a large 200odt/d plant and transport the bio-oil to nearby CHP sites the viability of bio-oil production and CHP operation need to be considered separately. Using the same viability criteria as Section 8.4.1.1 the appropriate factors for bio-oil production from a 200 odt/d site are:

- 9% for a 40% overrun of TPC (Table 7.13);
- 29% for the difference between the cost of low yield miscanthus and the base case;
- 11% for the impact of a 10% reduction in yield.

This gives a viability margin of +49% on the BESP of bio-oil. Applying this to the base case BESP of a delivered bio-oil cost of £7/GJ gives a minimum viable price for bio-oil of £10.4/GJ. The resulting BESP of electricity from a range of remote diesel CHP systems operating at different capacity factors is shown on Figure 8.3.

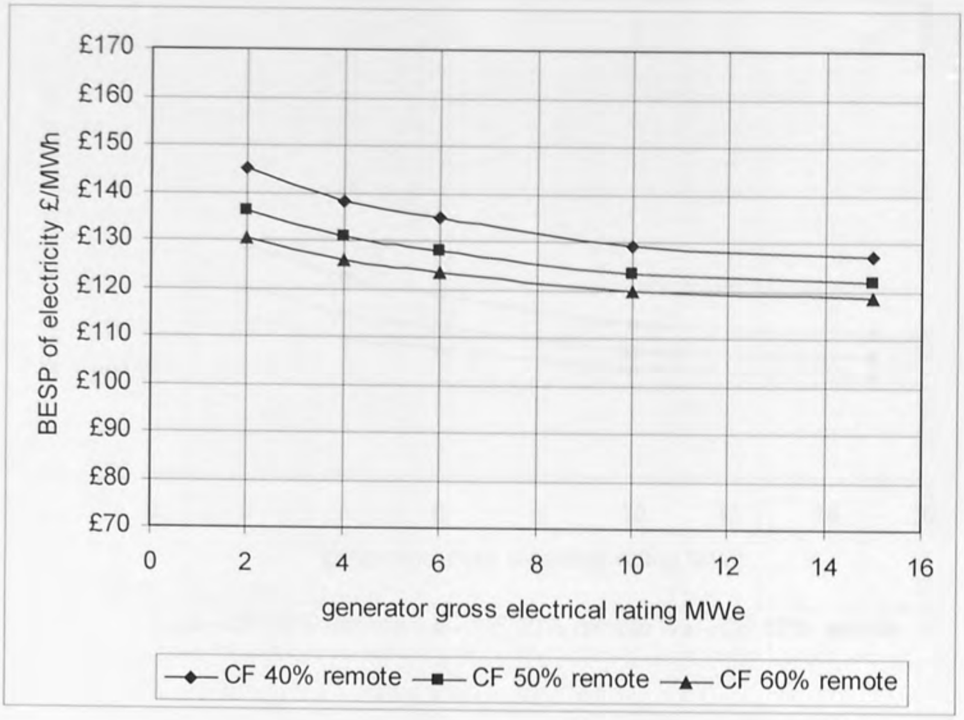

Figure 8.3 BESP of electricity for remote diesel CHP plant calculated using the lowest viable price of bio-oil.

CHP plants sell power directly to consumers so it is appropriate to use the industrial market price and climate change level payment from Section 3.3.6 of £58/MWh when valuing their generation. With double ROC payments this would give an income in the range of £158-138/MWh. This would mean that a CHP system with a CF of at least 40% and a generator rating of more than 4MWe is likely to be viable with smaller schemes being viable provided they have a higher CF.

The bio-oil production cost using the mature plant assumptions from Section 8.2.4 is £5.13/GJ giving a future minimum viable price of £7.64/GJ. This has been used to calculate the BESP of electricity from remote diesel CHP plants in Figure 8.4.

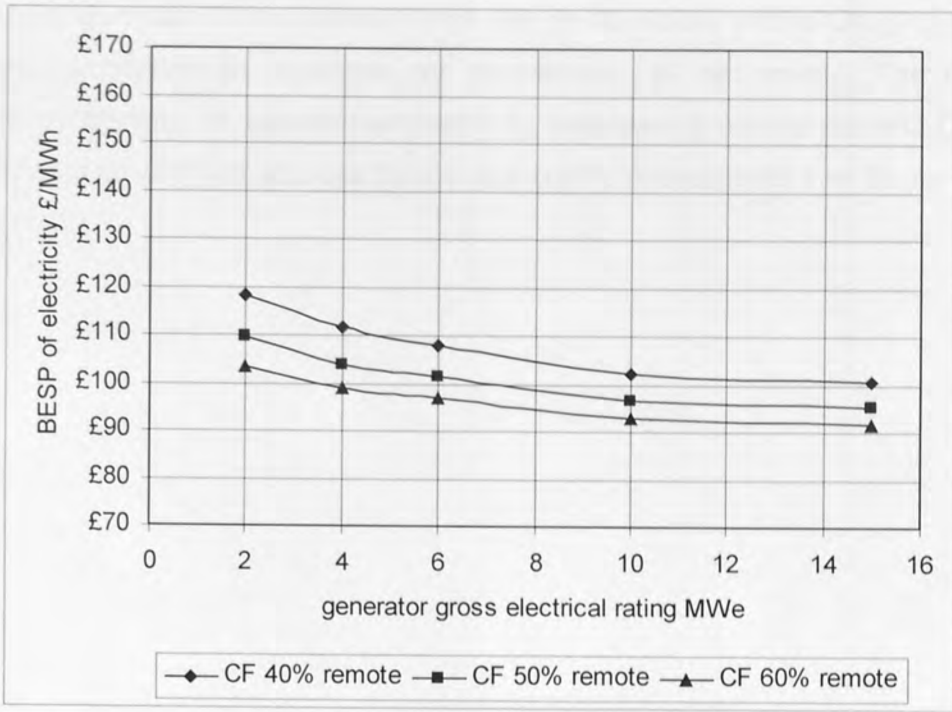

Figure 8.4 BESP of electricity for mature technology remote diesel CHP plant calculated using the lowest viable price of bio-oil

If the subsidy for pyrolysis based CHP were to fall to one ROC/MWh the income from electricity sales would be in the range of £98-108/MWhe. In this situation it would appear that systems with a CF above 60% and generator ratings above 4MWe would be viable so would systems with CF above 50% and generator ratings above 8MWe. However systems with a CF of 40% would not be viable.

This estimation has been carried out assuming a constant heat price. Once the electricity used by the pyrolysis plant is subtracted from the electricity generated the ratio of energy sold as heat to that sold as electricity is 1.2. Using a heat price of £4.8/GJ from Section 3.3.5 heat sales this gives a heat income for each MWh of electricity sold of £21. This price is linked to the gas prices, if this increased by 50% (or if a support mechanise for renewable heat was introduced) it would mean that application with a generator size above 4MWe with a CF above 40% would be viable.

Small scale biomass CHP schemes tend not to be viable in the UK [75] so there is limited completion to pyrolysis for renewable CHP schemes. The relatively high energy density of bio-oil compared to biomass is also a benefit for urban CHP schemes where fuel storage space and traffic movements can be an issue.

9 Conclusions

9.1 Review of the study

9.1.1 Objectives of the study

The main objective of this study was to investigate the cost of electricity production from different generation technologies that used bio-oil when each technology was implemented at its optimum size. Secondary objectives were to investigate:

- The cost differences between plants that used SRC willow and those that used miscanthus as a feedstock;
- The impact of char sales on electricity costs;
- The impact of heat sales on electricity cost.

9.1.2 Review of the study

A review of pertinent reports, legislation and papers was carried out to establish the market environment that any pyrolysis based generation system would operate in. This was done so that the findings could be put into context. A literature review of the potential production process, nature of the bio-oil and use of fast pyrolysis bio-oil was carried out to select a suitable process to model for the study.

A detailed review of previous techno-economic studies which included pyrolysis based generation systems was carried out in Chapter 2. This identified areas that had already been studied, the methods used and those topics where there was a consensus. This was used in Chapter 3 to refine the scope of the study and select an appropriate methodology.

It was decided to carry out a detailed review of the likely technical performance of each major plant subsystem (biomass handling, pyrolysis plant and generation plant). This is reported in Chapter 4. It was concluded from predictions of the bio-oil quality that the performance of generation equipment operating on bio-oil would be similar to those reported for operation on residual fuel oil. Estimations of the electrical power requirements of the various process plants and thermal energy requirements of the pyrolysis plants were also made in this chapter.

The Total Plant Costs of the subsystems were investigated in Chapter 5. The costs of the biomass handling plants were calculated on the basis of assumed plant configurations that could achieve an acceptable truck turn round time and handle the required deliveries without having to have night time or weekend deliveries. The costs for woodchip handling equipment were taken from surveys of US timber fired power stations. Those for miscanthus were taken from US feasibility studies into large co-firing applications and bio-ethanol refineries. It was noted that several of the previous techno-economic studies used a sizing equation derived from equipment supplier's estimation by Bridgwater and Evans [76] which has subsequently been updated to the version used by Bridgwater, Toft and Brammer [81]. This equation was used to provide comparison costs for the size of plants covered in the other techno-economic reports (once extent of supply, currency and base dates differences had been allowed for). These other studies used a mixture of synthetic data [86,96] and supplier's estimates [89] to arrive at their cost estimates. It was found that estimates were in reasonable agreement with each other and a regression line was used to produce a costing equation for use in this study. Cost for diesel generators and combustion plants came from surveys carried out for the World Bank [167,189] and those for Gas Turbines came from Gas Turbine World [169]. In all cases suitable allowances were made for the cost of modification of the equipment to run on bio-oil and the GTs re-rated for RFO duty.

The other costs were considered in Chapter 6. The farm production costs of biomass were taken from a survey of UK energy crop growers. Crop yields for mature plantations were taken from a number of reports. Yields from existing plantations were used to calculate load yield costs for use in sensitivity studies (all the UK plantations are relatively new and it is generally acknowledged that yields increase as the plantations mature). A survey of truck running costs was used to develop a transport cost model which reflected the cost of loading and unloading times as well as driving time. As there was no apparent consensus on staffing levels in the reviewed literature staffing scenarios were developed for the different sized plants using a common set of assumptions. Consensus figures were used for R&M costs, and miscellaneous fixed cost (insurance, utility services and business rates).

The Break Even Selling Price of electricity for the different plant arrangements operating under commercial conditions was calculated in Chapter 7. The sensitivity of the BESP to changes in costs and plant performance was also investigated. The systems that would require the lowest level of subsidy were selected for further analysis that investigated the impact that changes in the performance and biomass cost throughout the life of the plant may have on the BESP. This was reported in Chapter 8 along with a brief investigation into the possible extent of reduction in costs that may occur with technological learning if some plants were built.

9.1.3 Limitations

9.1.3.1 Geographic limitations

This study is based on the energy market in England and Wales so some of its findings may not be relevant to other locations. The study assumes that the generation plant is located in the centre of the area that provided it with biomass; the findings may be different for plants that use imported biomass or biomass from across the country.

9.1.3.2 Problems associated with combining data from multiple sources

Extensive use is made of published survey data. There is no guarantee that any comments or caveats from the original responders have been included in the published work and there was no opportunity to question the original source of the information. This means issues like extent of supply cannot be readily verified.

The bio-oil yields have been taken from a range of published experimental results. All the reports quote a reaction temperature of 450-550°C with a gas residency time of less than 2 seconds. These are the conditions that are quoted as likely to produce the maximum bio-oil yield [28,29] but there could still be difference in yields caused by the nature of individual test rigs rather than the biomass used.

9.1.3.3 Date of RFO performance trials

The performances of GTs and diesel generators burning bio-oil have been assumed to be similar to their performance operating on residual fuel oils (RFO). Interest in using RFO in such applications has declined and much of the data is from a few installations operating between 1970 and 1995. Consequently the impacts of generic improvements to the technologies have not been considered.

9.1.3.4 Pyrolysis Plant TPC estimates

The correct procedure for integrating new data points with an existing regression curve derived from previous studies is to obtain the data points from the previous studies increase the cost using an appropriate index to bring them to the same date as the new data and re-plot the curve. This was not done as the original data points were not all available (some were identified as being commercially confidential [81]). When plotted in Figure 5.3 the predictions from the updated version of the original regression curve were in reasonable agreement with those from the earlier studies so it is possible to say that the sources are in reasonable agreement.

9.1.3.5 Modification cost

Although the cost of modifying GTs and diesel engines to run on bio-oil was inferred from reported costs there is insufficient published data to comment on the accuracy of these estimations or to give any indication of how these costs may vary with generator rating.

9.1.3.6 Staffing costs

The lack of consistent data on staffing levels led to the use of a staffing scenario to estimate labour costs. There is no direct evidence to support the proposed numbers for the plants however in all but the smallest plants (which appear to be very costly) the staffing costs are not a major cost item.

9.1.3.7 Operating regimes

The materials handling systems were sized on an assumption that 24 hour a day 7 day a week deliveries would not be allowed. This is likely to have had little impact on the smaller scale systems that used front end loaders but would allow a higher daily throughput from the automatic systems with less material going to store.

9.1.3.8 The cost for the low yield biomass

The biomass cost for the low yield option reflected the farm production cost. It does not take into account any additional transport cost that may be incurred if the harvest shortfall is made up by buying biomass from outside the normal supply area.

9.2 Principal findings

9.2.1 Pyrolysis modelling

1. *Organic liquid yields* It was found that there is sufficient published experimental data to support the principle that mass yield of the organic liquid can be predicted from the biomass ash content and is inversely proportional to the biomass ash content.

2. *Char yields* It was found that there is sufficient published experimental data to support the principle that mass yield of the char can be predicted from the biomass ash content and is proportional to the biomass ash content.

3. *Total by-product energy yield* There is insufficient evidence to say if the yield of individual gases or their relative concentration depends on the biomass ash level. But if the mass yields of the organic liquid and char are dependent on the biomass ash content then the total mass yield of pyrolysis gases (including water vapour produced by the pyrolysis reactions) must also be dependent on the ash content. It was found that for all reported gas mixtures the total energy in the char and pyrolysis gases was independent of the relative concentration of the individual pyrolysis gases.

4. *Low yield limit* It was estimated that the low organic liquid yields associated with biomass with a high ash content would produce bio-oil with an unacceptably high moisture level. This effectively means that biomass with an ash content above 3.5% is not suitable for bio-oil production.

5. *Electrical power requirement* Estimates for the electrical power requirement were taken from three papers. Plants with capacities above 120 odt/d were found to require 190kWh/odt processed.

6. *Thermal energy requirement* It was shown that the overall thermal requirements of the plant would vary with the combustor temperature and the feedstock moisture level. It was confirmed that there should be sufficient energy in the char and pyrolysis gases to provide the heating requirements of the pyrolysis plant.

7. *Char sales* Tables 7.5 and 8.2 shows that excess char sales do represent an income stream but these sales do not have a major impact on the overall running costs.

9.2.2 Choice of biomass feedstock

1. *Suitability of SRC willow* The ash levels reported for willow with bark are in the 1-3% range; it is predicted that this will result in an average organic liquid mass yield of around 53% rather than the 66% which can be achieved with some sawdust.

2. *Suitability of miscanthus* Miscanthus is suitable for a pyrolysis fuel provided it is harvested whilst dormant in the spring before there is any new growth; if this is done miscanthus has a similar ash level to SRC willow and so will have similar yields.

3. *Cost difference between miscanthus and SRC willow* As baled miscanthus has a lower moisture content than seasoned woodchip it has a 15% lower transport cost per GJ of fuel (Section 6.2.2). However the real advantage of miscanthus over willow is that for similar farm cost per hectare miscanthus is projected to produce higher yields than SRC willow.

4. *Yield difference between miscanthus and SRC willow* Although the organic yields for both feedstocks are similar, SRC willow will produce a higher energy yield of char and pyrolysis gases than miscanthus. But as the willow has a higher moisture content, most of this will be used in the dryer

and there is little difference in the amount of excess char produced from either feedstock.

9.2.3 Transport costs

1. *Zone costs* The costs of running trucks were investigated and it was found that for a pyrolysis plant located in the centre of the area that its feedstock is grown in, the dominant costs were the fixed costs associated with owning the truck rather than the distance related cost associated with driving it. Consequently the cost per load is dominated by the number of round trip a day that the truck can make rather than the actual distance travelled.

2. *Size limitation* For the largest CCGT option considered, biomass transport only accounted for 8% of the total costs and for the largest combustion system for 14%. Consequently transport costs are unlikely to be a limiting factor on the size of a pyrolysis project provided the transport distance allows at least one round trip between the biomass field store and the power station.

3. *Use of satellite pyrolysis plants* The cost of transporting bio-mass from a field store into a pyrolysis plant then transporting the bio-oil to a distant generation site was investigated. It was found that in general this only resulted in transport savings if the trucks making the journey could not do more than one round trip a day between the field store and the generation site. The maximum reduction in transport cost is around 30% of the maximum transport cost.

4. *Network topology of satellite pyrolysis plants* Even if satellite plants are used, the central generation plant should be co-located with a pyrolysis plant that processes biomass that is grown close to the plant. The satellite plants are then located in the one round trip a day travel zone.

9.2.4 Use of buffer bio-oil storage

Storage has not been identified as a feature of bio-oil power plants in previous studies but it has been found to have a significant impact on the BESP of electricity. This is achieved by:

1. *Averaging the effects of varying yields* The mixing of bio-oil from feedstocks with different ash contents allows the generation plant to be sized to the average production rather than the peak production which improves plant capacity factors. This simple facility can result in a 20% fall in the BESP of electricity (Table 7.1). This will also average out the moisture content and so reduce the chances of phase separation associated with low organic yields.

2. *Process separation* Storage allows the decoupling of the production and consumption of bio-oil, and allows the pyrolysis plant to be sized to operate under base load conditions and the generation plant sized to operate under commercial capacity factors. This is particularly significant for CHP plants.

9.2.5 Impact of plant size

1. Although not original it is worth restating the larger the plant size the lower the BESP of electricity. The one exception to this is co-firing in boilers.

9.2.6 Lowest cost of generation

1. *Combustion steam cycle plants* The lowest cost of generation from this study came from co-firing an 800 MWe coal-fired super-critical combustion steam cycle plant with an onsite pyrolysis installation of 4800 odt/d capacity and a generation load factor of 85%. This produced a BESP of

£70/MWh with 271 MWe of bio-oil generation. However it was found that the BESP increased if a higher co-firing ratio was employed. The range of BESP for co-firing applications was £70-£80/MWh

2. *CCGT plants* CCGT plants in the range of 200 to 320 MWe had a BESP around £71/MWh. Consequently in most situations CCGT plants would produce a lower BESP than large scale co-firing in coal-fired supercritical combustion steam cycle plants. This advantage is likely to increase with improving technology as shown in Table 8.3.

9.2.7 Conversion of existing plant

1. *Combustion steam cycle plants* It was found that a lower BESP could be achieved by building new supercritical boilers than could be achieved by converting existing sub-critical units to burn bio-oil.

2. *CCGTs* The situation with CCGTs is different as the new plant offers no technological advantages over existing plant. In this case Figure 7.30 shows a 7% reduction in the BESP as a result of replanting an existing CCGT.

9.2.8 Sensitivities of BESP

1. *Cost Structure* It was found that the cost structure for CCGT and co-firing in new combustion steam plants were similar.

2. *Sensitivity to biomass cost* Biomass purchase makes up some 43-47% of the total costs. This explains the wide spread of BESP with the different biomass cost scenarios with the difference between the base case and low yield case being in the 22-26% range.

3. *Sensitivity to finance cost* Finance accounts for 24-27% of the costs. From Tables 7.13 and 7.20 an increase in interest rate produces an

average of 13% increase in total costs for both CCGT and combustion systems, a 40% increase in TPC produces an 11% increase in costs and the combination of the two produces a 30% increase.

4. *Sensitivity to other costs* For both CCGT and combustion systems staff costs and miscellaneous fixed costs (insurance, utility charges, and local taxes) are under 6% of the total cost. This means that the lack of firm data in these fields will not significantly affect the total cost.

5. *Sensitivity to performance deterioration* From Tables 7.14 and 7.21 both CCGT and combustion plants can suffer a 13% increase in cost as the result of a 10% reduction in conversion efficiency.

6. The sensitivities of the pyrolysis diesel and CHP plants are similar to those for CCGT and combustion with the exception that staffing costs can be of the same order as financing cost for these small systems.

9.2.9 Financial viability

1. *Test for viability* It was found that to cover the operator's risk the electricity price would need to be at least 50% above the BESP for the plant to remain viable.

2. *Current viability* None of the options considered were viable under the subsidy system in place at the study's base date. However as these systems are now entitled to double ROC payments, co-firing in supercritical boilers, large CCGT and distributed diesel CHP systems will be viable (but not necessarily competitive).

3. *Viability if the technology reaches maturity* If the subsidy was reduced back to the single ROC level as pyrolysis technology and energy crop production matured, only the CCGT and diesel CHP schemes with high CF would remain viable.

9.3 Recommendations for future work

9.3.1 Feedstock trials

The use of energy crops is based on the idea that they can be harvested when their alkali metal content is low and then stored until required. This assumes that their composition does not change appreciably with storage. A programme of pyrolysis of samples from energy crops taken at different harvest times and with different storage times is needed to confirm that this strategy in realisable.

9.3.2 Impact of peak and seasonal price

It was identified in Section 7.1.1.3 that the possible premium paid for peak load generation may make this mode of operation more profitable the base load. If these generators are embedded into the distribution systems like CHP plants it is likely that the market price for their electricity would be higher than the wholesale price. If the market premium for peak load electricity is more than 20% (the maximum proportion of cost covered by heat sales) it is possible that peak load operation would have a similar profitability to CHP operation. Further work is needed to establish the average price of electricity for each hour's operation throughout a day for each season of the year. This could then be used to estimate the most profitable load profile to adopt.

9.3.3 Comparative study with other biomass generation

This study has demonstrated that it is practical to supply energy crops to large biomass installations. The techno-economic studies reviewed in Chapter 2 concentrated on small scale projects. It would be worthwhile investigating the relative cost of pyrolysis based CCGT, gasification and combustion in the size range of 100-500 MWe.

9.3.4 Use of imported feedstock and bio-oil

This study was limited the use of energy crops grown in the same region as the generating plant. Although the theoretical availability of these were not found to restrict the size of the options considered there is a real issue with regards to synchronising the establishment of energy crop plantations and construction of power station to use them. One way to avoid this issue is to use biomass that is available from sustainable sources on the world market. This possibility should be explored.

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