
Cofiring high ratios of biomass with coal

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Abstract

As concerns regarding greenhouse gas emissions from coal-fired power plant increase, there is greater focus on the feasibility of cofiring high ratios of biomass. This report first addresses the technical issues which arise when cofiring biomass at high ratios in coal-fired power plant. These principally concern the availability of fuel, storage and handling, milling, slagging, fouling, corrosion and ash disposal. It then describes experience of power plant which have cofired high ratios of biomass over extended periods. These plant are located mainly in the Netherlands and Denmark and a few in the USA, Finland, Belgium and the UK. The report also briefly assesses issues arising when repowering a coal-plant to fire 100% biomass.

Acronyms and abbreviations

ACFB	atmospheric circulating fluidised bed
¢	US\$ cent
c	€ cent
CFB	circulating fluidised bed
CHP	combined heat and power
FBC	fluidised bed combustion
GF	grate fired
HP	high pressure
LCPD	large combustion plant directive
MBM	meat and bonemeal
PAH	polycyclic aromatic hydrocarbon
PCC	pulverised coal combustion
RDF	refuse derived fuel
RH	reheat
ROC	renewable obligation certificates
RPS	renewable portfolio standards
US DOE	US Department of Energy

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I Introduction

It is not surprising as concerns regarding climate change increase, that there is continuing interest in the use of biomass for power generation. This is principally because, if the biomass is grown in a regenerative way, its combustion will not produce any net CO₂ emissions. However, there are some disadvantages when using biomass for power generation, relating to its supply and composition, and these can be reduced if the biomass is cofired with coal. Typical biomass fuels for power generation include wood-based fuels such as wood chips, sawdust bark, tree trimmings, paper and cardboard; agricultural wastes such as straw, rice husks and nut shells; sludges from paper mills and municipal sources and energy crops specially grown for use as biofuels such as switchgrass, eucalyptus, willow and poplar trees. The use of biofuels for power generation varies considerably from country to country. Within OECD countries, Finland utilises the greatest proportion of biomass for power generation at 13.7%. The corresponding figures for some other countries are: Sweden (7.5%), Germany (4.6%), UK (2.8%) and USA (1.7%).

Many countries have initiated incentives in recent years to encourage the use of biomass for power generation. Cofiring biomass in coal-fired power plant invariably incurs additional costs and will generally be feasible only with a financial subsidy. In the USA, a majority of states have enacted renewable energy portfolio standards (RPS) that require electricity providers to procure a portion of their electricity from qualifying renewable sources. Examples include Minnesota, which requires that 25% of power generation must come from renewable sources by 2025 and Colorado which has a 20% requirement by 2020. Whether cofiring qualifies under these programmes varies. A number of states have specifically included cofiring as a qualifying resource, while others have excluded it outright because of its dependence on coal-fired plant (Eisenstat and others, 2009). Based in part on the state level requirements, the US DOE estimates that renewables will increase from 9.5% of total US power generation in 2008 to 13.4% by 2020. The Federal Government also considered a national RPS through the proposed Cap-and-Trade bill or the American Clean Energy and Security Act (ACES) but the likelihood of this has decreased considerably since the 2010 congressional elections. In the UK, generators are issued a renewable obligation certificate (ROC) for each MWh of renewable electricity generated. Cofiring non-energy crops receives only 0.5 ROC/MWh which is a quarter the support available for offshore wind plants (2 ROC/MWh). Cofiring energy crops receives 1 ROC/MWh. In a dedicated biomass plant, the use of non-energy crops attracts 1.5 ROC/MWh and energy crops receive 2 ROC/MWh. The banding is being reviewed and a new structure will apply after April 2013. It is not surprising that a few generators in the UK are considering converting their coal-fired plant to fire entirely biomass. In the Netherlands biomass is envisaged as playing a major part in fulfilling national CO₂ reduction targets and ambitious targets of 25% biomass cofiring levels by 2020 and 40% by 2040 have been set by the Dutch Ministry of Economic Affairs.

There are several drawbacks of using biomass for power generation including the fact that in many countries its supply is widely dispersed and there may not be an established infrastructure for harvesting and transporting it to power plant. The seasonal nature of biomass is problematical in that supplies are readily available during harvesting but scarce during cultivation and growth. The cost of biomass varies considerably. Some types of waste fuels can be virtually free. Energy crops, on the other hand, can be more expensive than coal and the use of such crops for cofiring may only be viable if the additional costs are subsidised. The composition of biomass is very different compared to coal. Biomass can contain much higher moisture levels, up to 50%, which adversely affects combustion by absorbing heat during evaporation. The heating values of biomass are lower than those for coal. Moreover, bulk densities of biomass are much less than coal hence greater volumes of the fuel are needed to be collected, handled, transported and stored. The ensuing costs mean that large biomass units are impractical. The smaller unit sizes and lower heat contents result in biomass plant being less efficient than coal ones. Cofiring biomass in a conventional coal-fired boiler has the potential to overcome some of the drawbacks of firing biomass alone and to derive the benefits of both fuel types.

It is possible to capitalise on the existing investment and infrastructure at a coal-fired power plant and incur only the relatively modest retrofitting cost for biomass cofiring. Retrofitted boilers can fire biomass when biomass supplies are plentiful but switch back to coal when supplies are low. Cofiring increases the efficiency of biomass energy conversion by firing in a larger plant which can accommodate superheaters, economisers and reheaters compared with a smaller plant firing biomass alone. In the present context, the greatest advantage for the coal-fired plant is that biomass cofiring reduces its net CO₂ emissions. Indeed in most cases, cofiring is one of the least costly methods for a coal-fired plant to achieve modest levels of CO₂ reductions. This advantage can be accomplished in a short time scale with little technical risk. In addition to reducing net CO₂ emissions, biomass cofiring enables coal plant to reduce SO₂ emissions as biofuels frequently contain less sulphur than coal. Biofuels also tend to contain less nitrogen and more moisture which leads to lower NO_x emissions. Furthermore, biofuels have higher volatile matter contents than coal which results in less NO_x formation in low NO_x burners. Another advantage is that cofiring diversifies the coal plant's fuel portfolio and it can help to dispose of a solid waste.

More than 150 power plants worldwide have experience of cofiring biomass or waste fuels, at least on a trial basis. There are approximately 40 pulverised coal combustion (PCC) plants that cofire biomass on a commercial basis with an average of 3% energy input from biomass. Though many coal-fired power plant have cofired low percentages of biomass, only about a dozen have cofired high percentages over extended periods. In this report, high cofiring ratios is taken to mean about 15% biomass by weight or 10% by energy output. Cofiring can be direct, where the biomass and the coal are fired in the same boiler or indirect, where the combustion or gasification of the biomass occurs in a separate unit. Direct cofiring is the simplest and most widely applied technology for cofiring biomass. In this process, as all the components of the biomass enter the coal boiler, several technical issues arise which need to be considered. If the proportion of biomass is high, the fuel volume increases considerably and can adversely affect combined grinding and feeding and separate mills may be needed. The lower melting point of the resulting ash can increase the likelihood of slagging and fouling. Some biofuels, such as straw, can contain high chlorine levels which can cause high temperature corrosion. Other biofuels, such as sewage sludge, have high ash contents, which can lead to problems with erosion. The constituents of the ash change during cofiring and this affects ash utilisation and disposal options. These technical issues do not arise during indirect cofiring as the biomass ash and the coal ash are kept separate. However, indirect cofiring is more costly than direct cofiring. Hence though there have been a considerable number of coal-fired plant which have directly cofired biomass, only a handful have incorporated indirect cofiring. Indirect cofiring may be a suitable option for cofiring high ratios of biomass as the biofuel capacity is not limited by the installed equipment in the coal plant.

As concerns regarding climate change increase, as well as greater interest in cofiring high percentages of biomass in coal-fired plant, some operators are considering complete fuel conversion to burn biomass. Both options necessitate detailed consideration of the technical issues discussed above in order to prevent damage to the plant or impairment of its operation. This may be less important if the power plant is approaching the end of its operating life. The Clean Coal Centre have addressed cofiring over many years. *Cofiring of biomass and waste* was discussed by Davidson (1999). Reports entitled *The experience of indirect cofiring of biomass and coal*, *Fuels for biomass cofiring*, *Cofiring coal with waste fuels* and *Co-gasification and indirect cofiring of coal and biomass* have been produced by Fernando (2002, 2005, 2007, 2009). This report will focus on the particular issues which arise when cofiring coal with high percentages of biomass. It will first assess the technical considerations and then describe plant experience.

2 Cofiring technologies

2.1 Direct cofiring

Direct cofiring involves firing the coal and biomass in the same boiler. This is the simplest and most widely applied technology for cofiring biomass. As all the constituents of the biomass enter the coal boiler, several technical issues arise depending on the boiler type. Direct cofiring has been undertaken in stoker, cyclone, fluidised bed combustion (FBC) and pulverised coal combustion (PCC) boilers. In a survey of biomass cofiring in Europe, the proportion of biomass cofired in stoker boilers ranged from 20% to 90%, in FBC boilers from 20 to 90% and in PCC boilers from 3% to 20% (Järvinen and Alkangas, 2001). Clearly, stoker and FBC boilers, which are designed to fully fire biomass, are much more suited for cofiring very high percentages of biomass than PCC boilers.

2.1.1 Stoker firing

In a stoker- or grate-fired boiler, the fuel is fed onto a continuously moving grate while air is blown through the bed of fuel. The two main types of grate are the chain or travelling grate or a vibrating, inclined grate. The smaller particles burn in suspension above the grate while the larger particles burn on the grate as the fuel moves from the back to the front of the boiler. Stoker boilers are capable of firing a wide range of fuels including fairly large pieces, though generally less than 3 cm in length. Stoker boilers are restricted to a maximum capacity of about 100 MWe. Stoker boilers are capable of firing a wide range of fuels including coal, wood, waste fuels, peat and straw. The boiler can be designed to fire even fairly moist fuels of varying sizes but not with too much dust. The efficiency of stoker boilers is less than for that for FBC or PCC boilers and flue gas emissions can be higher. However, investment, operational and maintenance costs for stoker boilers are usually lower. The system is sensitive to changes in fuel quality and moisture and automation of grate combustion is difficult. Such changes also affect fuel handling and feeding. Modern stokers are usually equipped with cyclones or electrostatic precipitators and sometimes gas scrubbers to remove particulates from the stack gases. Problems can arise in stoker firing with low ash melting point fuels but these can be reduced by using mechanical or water-cooled grates and by avoiding the use of preheated combustion air in the final burning region (Juniper, 2000; Van Loo and Koppejan, 2008).

2.1.2 Fluidised bed

The fundamentals of fluidised bed combustion have been discussed by Wu (2006). In a fluidised bed boiler the fuel is burnt in a bed of non-combustible particles suspended by an upward flow of fluidising gas. The temperature in FBC is generally in the range 800–900°C which is lower than for pulverised coal combustion. Efficient combustion is achieved by a relatively long residence time of the fuel in the bed. FBC in either bubbling fluidised bed (BFB) combustion or circulating fluidised bed (CFB) combustion boilers has been commonly utilised for co-combustion of biofuels and coal particularly in Scandinavia. This is due to the high degree of fuel flexibility of this technology in relation to particle size, density, moisture and ash content of the fuel. In a CFB boiler, the circulation of the bed material and high turbulence in the combustion chamber ensures good mixing of the fuel and combustion air. This facilitates the combustion of biofuels with high volatile contents and additionally enables efficient heat transfer in the boiler. The high heat capacity of the bed material allows the use of fuels with high moisture contents and low calorific values such as waste fuels. They can achieve high boiler efficiencies even with challenging, low grade fuels. CFB boilers are flexible with regard to changes to fuel quality and it may be possible to change rapidly from coal to biofuels and vice versa. Though FBC technology is very flexible, if the feeding characteristics of the biofuel vary too much from that of the coal, a separate feeder may be required. FBC boilers designed for coal

combustion can generally switch to waste/coal cofiring with a relatively small investment (ENERGIE, 2000). Though a wide range of biomass fuels has been combusted in CFB boilers, especially in Scandinavia, ash-related problems can arise. The ash composition together with the sulphur and chlorine contents of the fuel are the main factors which affect the risk of bed agglomeration and the rates of boiler fouling, deposit formation, slagging and superheater corrosion. These problems can also arise during cofiring, depending on the type of biomass, especially at high cofiring ratios (Hiltunen and others, 2008).

2.1.3 Cyclones

In a cyclone boiler the burners are large, water-cooled, horizontal, cyclone barrels. The combustion temperature in the external furnaces vary between 1650°C and 2000°C. Cyclone boilers are suitable for fuels in which the mineral matter forms a slag that captures and holds the larger particles. Whereas the larger particles are trapped, the volatile and fine particles burn in suspension providing intense radiant heat for slag layer combustion. Excess slag is drained away. There are specific fuel requirements in that the ash content must be greater than 6%, the volatiles must be greater than 15% and the moisture must be less than 20% unless the fuel is dried. There is less fly ash in the flue gas than in PCC boilers and the fuel only needs to be crushed rather than pulverised. Cyclone boilers are particularly suitable for cofiring as they require minimal modifications for feeding and mixing the secondary fuel and coal. They accept fuels of larger particle size than pulverised coal plant as they combust the fuel in a hot slagging mode. Many waste fuels, such as waste wood and tyres have been cofired in cyclone boilers, particularly in the USA (Costello, 1999).

2.1.4 Pulverised coal

PCC is the dominant method for burning coal for power generation worldwide. In such boilers, the coal is burnt as a fine powder suspension in an open furnace. The burners are conventionally located in the lower portion of the furnace, usually on one or two walls, or in the corners. The combustion temperature is in the range 1300–1700°C. There are four options for directly cofiring biofuels in PCC boilers (Van Loo and Koppejan, 2008):

- 1 The biofuel can be fed with the coal to the coal mills and burnt with coal in the existing coal burners. This is, in principle, the simplest option and involves the lowest capital cost. It is possible to introduce about 3% of the thermal input from the biofuel. However, this approach carries the highest risk of malfunction of the fuel feeding system.
- 2 The second involves the separate handling, metering and comminution of the biofuel which is then injected into the pulverised coal flow upstream of the burners or at the burners. This option requires the installation of a number of biofuel transport pipes across the boiler front, which may also be congested. It may also be difficult to maintain adequate burner performance over the normal boiler load curve.
- 3 The third involves the separate handling and comminution of the biofuel which is then combusted in a number of dedicated burners. This approach will incur the highest capital cost but will pose the least risk to normal boiler operation.
- 4 The final option is to utilise the biofuel as a reburn fuel. This technology is still in the process of development.

The major technical areas of concern when cofiring biofuels directly with coal in PCC boilers are summarised below and described in more detail in Chapter 3. These concerns are increased when cofiring high percentages of biofuels.

- If the proportion of biofuels is high, the total fuel volume may double and this will prevent combined grinding and feeding, and separate mills or burners will be needed. In addition, biofuels with low melting points can lead to caking in the mills and ducts.
- If the moisture content of the biofuel is considerably higher than that of coal, the flue gas volume

increases significantly and this may limit the proportion of biofuel that can be cofired.

- The lower melting points of some ashes resulting from cofiring can increase the likelihood of slagging and fouling on the walls of the combustion chamber and boiler tubes.
- Some biofuels which contain high chlorine levels can lead to high temperature corrosion. The superheaters are most affected due to their high steam temperatures.
- The possibility of erosion increases with biofuels containing high ash levels such as sewage sludge.
- Cofiring can affect SCR catalysts which are upstream of the precipitators in the high dust configuration. Fly ash containing alkali metals, arsenic, phosphorous or fluorine can deactivate the catalyst.
- The change in the composition of the ash formed when cofiring could affect ash utilisation and disposal options.
- The lower sulphur contents of most biofuels reduces the load on the FGD plant. However, any HCl present in the flue gas impairs its performance. An increased presence of heavy metals such as mercury, arsenic or lead in the flue gas could be concentrated in the FGD residues.
- The presence of volatile heavy metals, such as mercury in the biofuel increases emissions from the stack (Hein and Scheurer, 2000).

2.2 Indirect cofiring

Indirect or hybrid cofiring as it is sometimes called involves either pre-gasifying the biofuel in a separate unit or firing the biofuel in a separate combustor and routing the steam produced to the main turbine where it is upgraded to higher conditions. This latter process is also known as parallel firing. Indirect cofiring is much less commonly found than direct cofiring. It has the major advantages that the coal ash is not contaminated by any constituent of the biofuel and that these constituents cannot cause corrosion or slagging in the main plant. These advantages are particularly relevant when cofiring at high ratios of biomass. However, the major disadvantage of indirect cofiring is that installation costs are very much higher than for direct firing. Indirect cofiring usually involves upstream gasification, upstream pyrolysis or separate combustion with steam-side integration. Indirect cofiring is most suitable for biofuels containing relatively difficult components or when it is particularly important to prevent the coal ash being contaminated. For an existing coal-fired boiler, there may be space constraints which prevent the installation of an external gasifier. But if a new coal-fired plant is envisaged which is required to cofire high ratios of a range of different types of biomass and waste, the possibility of indirectly cofiring the biomass should be considered.

3 Technical issues

3.1 Fuel characteristics

The major types of fuels that have been cofired with coal are woody fuels, grassy or straw-derived herbaceous materials, refuse derived fuels (RDF) and sewage sludge. Biomass fuel properties differ significantly from coal and there is a greater variation in these properties compared with typical coals. Fuel characteristics of types of coal and biomass typically utilised in power plant are given in Table 1. The heating values of biomass are typically half that of hard coal. The bulk densities of biomass are also considerably less than coal. The ash content of biomass can vary from 1% to over 20%. The moisture content of biomass is generally much higher than coal and can range from over 25% to over 50%. The biomass fuel nitrogen can vary from 0.1% to over 1% but the sulphur content of biomass is usually very low. Each of these properties need to be considered when cofiring biomass and coal.

3.2 Fuel availability

The availability of biomass is especially important when considering cofiring at high ratios. It is essential that the biomass is cultivated sustainably. It must also not affect food production or tropical rain forests. Some types of waste streams containing biomass are suitable for cofiring. For these streams, continuity and consistency of supply are of paramount concern. Doran (2009) has assessed the availability of biomass in the EU. He first obtained data on the land area in each of the EU countries and identified the agricultural area within each country and the arable land currently under production. He then undertook a more detailed breakdown for the agricultural land in terms of arable land, permanent grassland, permanent crops and set aside land. He has calculated the bioenergy potential in the EU assuming that:

- land currently identified as arable has been included as potential energy crop development;
- areas under set aside are also included;

Table 1 Fuel analysis of coals and selected supplementary fuels (Hein and Scheurer, 2000)

	Hard coal	Brown coal	Wood	Straw	RDF	Dried sewage sludge
LHV, raw, MJ/kg	28	9	12.4	15	23.5	10.6
Moisture, raw, %	5.1	50.4	33	10.6	4.1	3
Volatile matter, dry, %	34.7	52.1	83.2	74.4	82.6	49.5
Ash, dry, %	8.3	5.1	0.34	6.1	12.2	45.1
Fixed C, dry, %	57.1	42.8	16.5	19.9	5.2	2.4
C, dry, %	72.5	65.9	48.7	47.4	56.8	25.0
H, dry, %	5.6	4.9	5.7	4.5	7.9	4.9
N, dry, %	1.3	0.69	0.13	0.4–0.78	0.74	3.2
S, dry, %	0.94	0.39	0.05	0.05–0.11	0.25	1.1
Cl, dry, %	0.13	<0.1	<0.1	0.4–0.73	0.82	<0.1
O, dry, %	11.1	23	45	40.4	21.3	17.7
Ash fusion temperature, °C	1250	1050	1200	850	1120	1200

- removal of large quantities of residues from land which is normally cropped has to be done in a way that does not adversely affect the sustainability of the land;
- residue removal should not lead to increased artificial fertiliser application;
- crops are not transposed in a way requiring additional pesticide;
- the method of cropping must reduce soil erosion and soil compaction;
- crop substitution must be based on environmental benefit.

Based on these assumptions he obtained the data shown in Table 2 on the comparison of the bioenergy potential in the EU with regard to environmental suitability. These data do not take into consideration increased yields that could be obtained from improved plant types or reducing processing waste.

Doran concluded that by 2030 it should be possible to meet up to 20% of the EU-27 energy demand from biomass. This would entail increasing the energy crop production by 800%. This was achievable if the total land area producing energy crops was increased by a factor of three and there was a significant increase in the yield potential as a result of plant breeding.

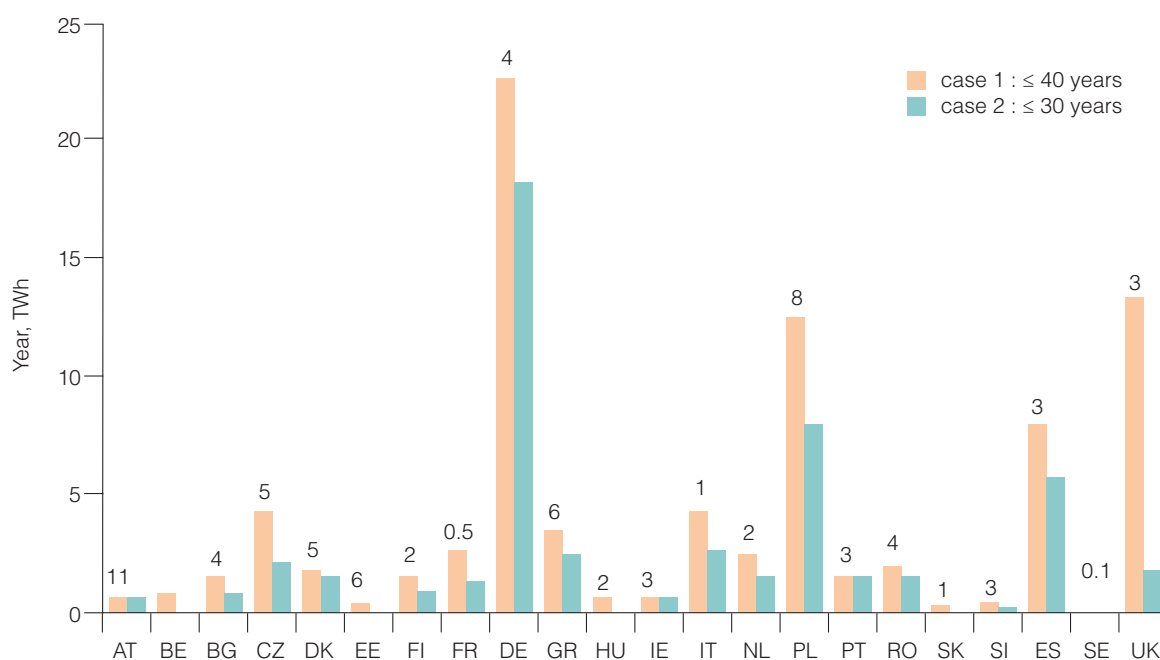
	2010	2020	2030
Austria	6.9	7.8	8.7
Belgium	2.3	2.3	2.3
Cyprus	0.3	0.3	0.3
Czech Republic	3.8	4.5	5
Denmark	2.8	2.5	2.5
Estonia	1.5	2.2	2.6
Finland	9.6	9.8	9.4
France	31.4	37.2	47.4
Germany	26.2	33.8	43.2
Greece	1.6	3.4	3.8
Hungary	3.6	5.5	5.6
Ireland	1.1	1.2	1.3
Italy	16.2	18.7	24.8
Latvia	1.3	1.9	2.4
Lithuania	4.1	7.6	9.9
Malta	0.05	0.05	0.04
Netherlands	2.6	2.2	2.4
Poland	23.8	33	39.3
Portugal	3.6	3.9	4.1
Slovakia	2.2	2.4	3.6
Slovenia	1.8	1.7	1.8
Spain	16.5	22	25.1
Sweden	11.7	13	13.5
UK	13.5	19	24.5
EU	187.95	235.95	283.54

Table 3 Technical potential for biomass cofiring generation in EU, TWh/y (Hansson and others, 2009)		
	Case 1	Case 2
Austria	0.81	0.79
Belgium	0.79	0.1
Bulgaria	1.58	0.86
Czech Republic	4.33	2.25
Denmark	1.86	1.5
Estonia	0.57	–
Finland	1.71	0.94
France	2.63	1.24
Germany	22.8	18.2
Greece	3.47	2.44
Hungary	0.64	–
Ireland	0.66	0.66
Italy	4.49	2.67
Netherlands	2.47	1.62
Poland	12.5	8.1
Portugal	1.56	1.56
Romania	2.17	1.56
Slovakia	0.28	0.07
Slovenia	0.46	0.23
Spain	7.91	5.76
Sweden	0.11	0.03
UK	13.3	1.8
EU	87	52

Hansson and others (2008, 2009) have specifically focused on cofiring biomass with coal for electricity generation and assessed the near-term technical potential for biomass cofiring with coal in existing coal-fired plant in the EU-27 member countries. They obtained data on all coal-fired boilers operating in the EU-27 including those planned and under construction. They assumed that all types of coal-fired boilers are available for cofiring, but as plant age does influence availability they considered two cases. Case 1 included all boilers commissioned in 1967 or later. This contained 90% of boilers. Case 2 included only boilers commissioned since 1977 and corresponded to 50% of installed capacity. They assumed that biomass could replace 15% of coal, in terms of energy, in fluidised bed boilers (FB) and 10% in PCC and grate-fired (GF) boilers. They admitted that future cofiring ratios could be higher but the chosen ratios were judged to be representative of current levels and were considered low risk in relation to technical issues. As the chosen cofiring ratio of biomass was relatively low, they assumed that there was no change in the efficiency or capacity of the plants. The load factors were estimated on a nation by nation basis for both lignite and hard coal plant using data on annual national power generation by fuel and total national power capacity. The technical potential for renewable generation from cofiring in existing power plants was calculated for each

EU-27 country using the available boiler capacity for cofiring, the estimated load factor and the assumed maximum biomass share for each type of boiler included in the database. In this study the estimated demand of biomass was compared with the current national production of biomass for energy production, which is the amount of biomass available in each country for energy production without increased pressure on the environment.

The results demonstrated that the technical potential of renewable generation from biomass cofiring amounts to 87 and 52 TWh/y in EU-27 for Cases 1 and 2 respectively. This corresponds to 2.5% and 1.5% of total gross electricity generation in EU-27. The results for individual countries are shown in Table 3. In all countries the potential renewable energy from cofiring corresponds to less than 10% of total national gross electricity production in 2005 and less than 5% in most countries as shown in Figure 1. Though the potential electricity generated from cofiring is low compared to the total requirement, it could be significant compared to the renewable generation target. The authors compared the renewable electricity generation in 2005 with the then target figure for 2010 and showed that biomass cofiring could produce 20–33% of the gap for the EU-27 countries. The higher figure relates to Case 1 and the lower to Case 2. The potential for cofiring was largest in Germany, UK and Poland for Case 1 and Germany, Poland and Spain for Case 2. However, the need to comply with the LCPD may mean that in the UK, for example, the number of coal-fired plant in operation might be considerably reduced. The authors also compared the estimated technical potential demand for biomass for cofiring with the estimated biomass supply potential. The results for each country are shown in Figure 2. Across the EU-27 as a whole, the biomass demand for cofiring is approximately 10% of the supply but for the UK, Greece and the Czech Republic, the proportion is substantial. Overall, the authors concluded that the implementation of biomass cofiring would depend on several factors such as the availability and cost of the fuel as well as related transport and handling issues. The policies promoting cofiring would also determine its attractiveness but the technology could contribute substantially to the renewable energy development in the EU-27 (Hansson and others, 2008, 2009). Though an individual power plant may be able to substantially reduce its CO₂ emissions by cofiring at high ratios or total conversion to biomass, the availability of biomass will limit this as a universal option for the reduction of CO₂ emissions.



The numbers above the bars are the percentage of gross national electricity production generated from cofiring for Case 1

Figure 1 Technical potential of electricity generation from biomass cofiring the EU (Hansson and others, 2009)

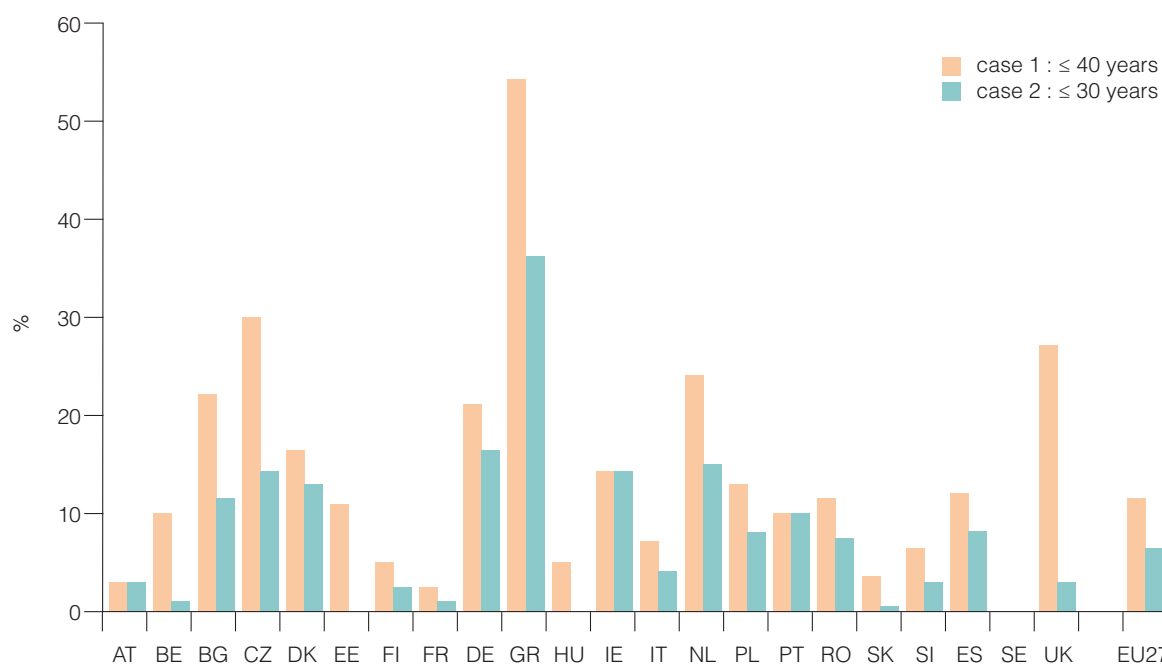


Figure 2 Potential demand for biomass for cofiring as share of maximum national biomass supply (Hansson and others, 2009)

3.3 Fuel delivery, storage and handling

The issues regarding the delivery, storage and preparation of biomass are different from those of coal. Biomass has a much lower bulk density, is generally moist, strongly hydrophilic and is non-friable. The lower heating values and much lower bulk densities mean that the overall fuel densities of biomass in MJ/m³ could be one tenth that of coal. Hence, cofiring biomass at 10% of thermal input requires comparable flows of biomass and coal. Cofiring higher percentages of biomass would require much higher flows of biomass than coal. Hence the on-site delivery, storage and fuel handling demands of biomass are disproportionately high compared with coal. These issues will be particularly apparent when cofiring high biomass ratios. It may also be necessary to add extra flexibility in fuel storage and handling facilities to utilise multiple sources of biomass. The handling and flow properties of biomass are usually more problematical than coal due to the fuel size variation and high fibre and oversized particle content. Biomass is normally delivered by truck, rail or barge and the fuel supplier is often responsible for delivery and unloading. The design of receiving pits and pre-screens need to be as open as possible to enable sufficient unloading for the boiler capacity given the high shear strength and the low energy density of the biomass. The high shear strength and the fibre content determine the design of screening; one of the best screening devices is the disc-screen. The transport capacity of conveyors and reclaimers becomes more important as the fuel quality decreases. The handling of more fibrous fuels affects the design of crossing points, chutes and openings and especially silos and stores. The sizes of the intermediate stores need to be larger due to the lower energy density of the biomass. Though the simplest way to store the biomass is an outdoor stockpile, most biomass materials will need to be stored under cover to control moisture content and prevent microbial degradation. This could be in a large fuel shed or in circular silos. Chipped wood tends to be more easily handled than mulch-like material, long stringy bark or bio-crops such as switchgrass. Large quantities of fine, sawdust-type materials are prone to plugging chutes and hoppers. Chipped wood or wood pellets tend to be the mostly easily handled and is most suitable for high cofiring ratios.

The long-term storage of biofuels such as wood chips can cause difficulties as, if the moisture content exceeds 20%, biological activity can lead to heating of the storage pile, loss of dry matter and

significant deterioration of the physical quality of the fuel. Biomass has a tendency to decay, causing foul odours and, therefore, storage duration is limited. The temperature of stored biomass can rise up to 60°C within a few days but no such increase occurs if the size is more than 20 cm. It is also possible that high dust and spore concentrations in the stored fuels can give rise to dust explosions, resulting in health and safety problems. Where biomass is stored in enclosed structures for long periods, significant release of CO, CO₂ and CH₄ occurs and has to be vented for personnel protection and fire prevention. The location of storage silos in a power plant could make the hazard much more dangerous than in an agricultural setting. To minimise biological activity during long-term storage it is possible to store the wood in larger pieces to reduce surface area, to use fungicides, to pre-dry or cool the fuel. Controlling moisture content is the key. Cereal straws on the other hand have moisture contents below 20% and are not subject to biological activity to the same extent as wet wood fuels. Suggested techniques to prevent any problems include not compacting the biomass piles as this can lead to high moisture concentrations in local areas and to self-heating. Biomass piles should also contain homogeneous materials as with different materials, self-heating can start in a niche. The temperature and the gas composition within the pile should be measured. Temperature measurement points must be widespread as self-heating can start locally. The presence of CO₂ indicates early stages of the process. At later stages of the process, CO can be detected and this suggests the direct threat of a fire and immediate action is necessary. When storing fresh biomass piles indoors, the moisture content can be reduced if there is natural convection. The walls of the storage halls should allow air circulation through the piles. Natural convection is also important to prevent self-ignition, especially with bark and sawdust. In this respect, biomass in the form of uncomminuted material, such as whole logs, can be stored and dried more effectively than biomass in the form of chips. Most biomass materials have the potential to cause dust explosions or deflagration and the risk is dependent on moisture content. It is more likely if the fuel is dry. The use of pelletised materials will significantly reduce the amount of dust present but degradation can take place during storage and handling. It is important to eliminate ignition sources in the vicinity of the fuel. External storage of dry biomass fuels such as straw should be avoided due to possible re-wetting by rainfall. External storage of biofuels with fine particles like sawdust results in dust emissions and is not possible in populated areas.

Dust control needs to be maintained during handling and storage of biofuels, particularly at transfer points and intakes to the system. Biofuels may give off odours and some produce high concentrations of bacterial and fungal spores which raise health concerns. Some may even be carcinogenic. Biomass can be very dusty when dry and this may constitute an explosion hazard. The containment of such dust hazards requires explosion control in accordance with International Codes. Equipment or buildings designed for use with coal may not be suitable for biomass without modification. Careful consideration must be given to containment measures. When wood pellets are delivered by trucks, the reception area can be installed below ground level and pellets discharged onto an enclosed belt conveyor. The tipping hoppers can also be enclosed within a large building of sufficient size to contain the whole vehicle in its tip position. Emissions can be tightly controlled and monitored by maintaining the building under negative pressure and incorporating a two stage filtration system. Mechanical handling equipment should be of enclosed design to prevent dust leakage and spillage. It is more difficult to prevent spillage from the sides of belt conveyors for example due to wind unless the location is fully enclosed. Care must be taken at the loading point, the discharge point and intermediate transfer point. Some biomass materials, such as sewage sludge and meat and bone meal, give off particularly strong odours. The perceived problem can be worse than the actual problem but needs to be addressed for the sake of the workforce and the neighbours. It may be necessary to add odour control as part of the filtration system (Van Loo and Koppejan, 2008; Pethullis, 2010; Koza and Ma, 2011).

3.4 Combustion characteristics

There are significant differences between the combustion characteristics of coal and biomass. The volatile matter content of biomass fuels is higher than typical coals though the specific heating values of volatiles in kJ/kg is lower for biomass than coal. The fraction of heat contributed by volatile

products is about 70% for biomass compared with 30–45% for coal. The ratio of volatile matter to fixed carbon for biomass is typically greater than 4.0 whereas for coal it is less than 1.0. Pyrolysis starts earlier for biomass and yields a much higher proportion of mass through devolatilisation than coal. Typically biomass yields 90–95% of its mass during devolatilisation compared with 55–60% for most coals. As devolatilisation occurs very rapidly in the combustion zone, most biomass fuels should yield this proportion of mass as long as they are entrained in the flue gas. If the biomass particles are too large or too dense for this, however, they could enter the bottom ash stream with little conversion. This should not happen if the fuel preparation is adequate. Furthermore, the low particle densities result in biomass particles oxidising at higher rates than coal. In addition, biomass char contains more oxygen than coal and is more porous and reactive. However, in spite of these favourable factors, if the biomass particles are excessively large or contain excessive levels of moisture, inadequate fuel conversion could take place. The amount of flue gas produced per unit of energy generated when firing biomass is generally much higher than for coal. This could affect the flue gas flow patterns through the boiler and convective areas. Flue gas is not always effectively mixed in the furnace resulting in variations in gas composition at the boiler exit. During cofiring, if the biomass is injected in a few burners and the flue gas does not mix thoroughly, some areas of the boiler will be exposed to a higher biomass cofiring percentage than suggested by the overall value. Striated flow patterns can also affect ash deposition and there may be large local variations in the rate of deposit accumulation (Veijonen and others, 2003; Baxter and Koppejan, 2004).

3.5 Milling and burners

There are several options available for direct cofiring of biomass in coal-fired boilers. The simplest is to pre-mix the biomass with the coal and feed the mixed fuel into the bunkers, processing the fuel through existing coal milling and firing equipment. This involves only modest capital expenditure, principally for biomass reception, storage and handling facilities and the project can be implemented in a reasonable timeframe. This approach is possible for cofiring up to 10% (th), although ratios of only up to 5% are more usual. This limitation is related to the ability of coal mills to co-mill biomass materials. Problems may arise as most mills pulverising coal depend on brittle fracture of the coal particles whereas biomass materials, which are generally fibrous, do not mill by this mechanism. If the biomass does not mill satisfactorily, the cofiring ratio will be limited. In vertical spindle coal mills, there is a tendency for the mill differential pressure and the mill power consumption to increase with cofiring ratio. There may be an increase in particle size of the mill product when cofiring but it may be unnecessary to reduce the biomass to the same size as coal as it is a more reactive fuel. Chipped, pelletised and granular biomass materials are the ones which are most easily milled. Under optimum conditions the coal mills will pulverise wood pellets to the normal size distribution. The utilisation of wet biomass can impact the heat balance in the mill. There is a tendency of biomass to accumulate in the mill and this needs to be considered both during normal operation and when emptying the mill of fuel. Blending small quantities of sawdust with coal has been found to reduce pulveriser capacity due to changes in fuel moisture and Hardgrove Grindability Index. A mill safety issue could also arise in conventional coal mills where hot air is introduced to dry the coal. Biomass tends to release combustible volatile matter into the mill body at temperatures significantly lower than apply when milling bituminous coal. It may be necessary to modify the mill operating procedure to minimise the risks of overheating the coal-wood mixture. It is also possible to modify one or more of the existing coal mills on a boiler to mill the biomass material on its own and fire the milled material through the existing pulverised coal pipe work and burners though this option is only possible for limited types of biomass in certain power plant. Coal mills are generally very robust and have high availability and low maintenance requirements. The mill has to be modified to operate with cold primary air but there is usually no need to modify the grinding elements. The maximum heat input from the mill group is, however, significantly derated, commonly to about 50–70% of that of coal. The level of derate is lower with torrefied materials (*see* Section 3.9). The third option is to install new, dedicated biomass mills and introduce the milled fuel into the existing coal firing system or through new biomass burners (Fernando, 2005; Livingstone, 2009a; Flin, 2009).

As mentioned above, for higher cofiring ratios, it is possible to pre-mill the biomass as this avoids the constraints associated with co-milling. The pre-milled biomass needs to be pneumatically conveyed from the handling/milling facilities to the boilers. It can then be injected directly into the furnace with no flame stabilisation or additional combustion air. This option is simple to install and relatively inexpensive and involves providing new, small diameter, furnace penetrations. This option has been demonstrated in a downshot-fired boiler but its application in wall- or corner-fired boilers is limited. The second option is to install new, dedicated biomass burners with their associated combustion air supplies. This option may be required for cofiring ratios greater than 20%. Though this technique has several advantages (for example, the introduction of the biomass does not affect the pulverised coal system directly) it does create several issues which have to be addressed. New burner locations, generally within the existing burner belt, have to be identified, new furnace penetrations made and support structures installed. The biomass burners require a secondary air supply and this may require significant modifications to the existing draught plant. The impacts on the existing PCC system and furnace and boiler performance need to be addressed. The dedicated biomass burners are based either on conventional PCC burners or cyclone burners and these have not been extensively demonstrated in large multi-burner furnaces in conjunction with conventional systems. The direct firing of biomass is complex both in terms of mechanical and control interfaces with the boiler and is relatively expensive to install but will be needed at very high cofiring ratios.

The final option is to inject the pre-milled biomass into the coal pipework or at the existing burner. The biomass can be injected directly into the coal burner, into the coal pipework just upstream of the burner or into the mill outlet pipework. Injecting directly into the burners necessitates significant modifications to the coal burners but may be required if there are concerns that the biomass might block the pulverised coal pipework. This technique has been applied successfully at both wall-fired and corner-fired furnaces but the quantity of biomass that can be cofired in a single burner is quite modest. The modification of the existing burner does result in additional cost and risk compared to injection into the pulverised coal pipework. This option has been undertaken at the Studstrupværket plant in Denmark where chopped straw is cofired through the core air tubes of the low NO_x burners. The coal is fired through the primary air annulus as usual. Significant modifications of the coal burners were required including relocation of both the oil lance and the flame scanner to clear the core air tube for biomass injection. This approach has the disadvantage that it inevitably involves some interference with the performance of the tertiary air swirlers. If instead the biomass is injected into the pulverised coal pipework, the installation is relatively simple and cheap. The mill air and fuel flow rates can be reduced in line with the biomass conveying air flow rate and the heat input to the mill group from the biomass. Both the mill and burners can be maintained within their normal operating envelopes for both heat input and primary air flow. The maximum heat input from the mill group is not affected, and in some cases increased. If the biomass is introduced upstream of the coal burners, the mixture of the two fuels is carried along the pulverised coal ductwork, through the burner and enters the combustor via the primary air annulus as usual. In this option, if the biomass is introduced just upstream of the non-return valves local to the burner inlet, the point of introduction of the biomass will be readily accessible from the burner galleries for inspection and maintenance. The potential risks of introducing a secondary fuel into the existing pipework are minimised as the mixed fuel stream is present in the pipework for the shortest length. Furthermore, as the introduction point is well away from the mills, the potential impact of mill incidents on the biomass system is reduced. However, routing the biomass pipework through the normally congested region local to the boiler front becomes overly complex and expensive. Hence it may be preferable to introduce the biomass into the mill outlet pipework just downstream of the mill product dampers and upstream of the pulverised coal splitters. This approach is much easier to engineer but has the disadvantage that there are greater risks of interference with the pulverised coal transport and the biomass conveying system could be affected by mill incidents (Livingstone, 2007, 2009a).

Overall, it is apparent that there are a number of viable options for the direct injection of cofiring of pre-milled biomass into conventional PC systems. The preferred option for any particular plant will depend on the type of biomass to be cofired, on the desired cofiring ratio and on a number of

site-specific factors. Some of these systems are in commercial operation and their operational experience to date has been encouraging. The maximum cofiring ratios achieved using this technique thus far have been in the range 10–15%. The main constraints limiting increasing the cofiring ratio have been the availability of biomass supplies, the limitation on fuel storage and handling concerns regarding negative impacts on boiler performance and integrity at elevated ratios. However, in a number of cases, generally to a single small number of mill groups, it has been possible to increase the cofiring ratio to about 50%. It should be possible to replicate this approach to more than one mill group thus increasing the cofiring ratio on a boiler unit basis. Initially, a system to connect a single biomass metering and pneumatic conveying can be added to a second mill group on the same boiler. For a new boiler, it should be possible to have the facility to cofire 50% biomass on all mill groups. In a retrofit project, the maximum cofiring ratio may be limited by site-specific factors and plant constraints. Even for a new boiler with high cofiring capability, the implications on the turndown capability of the mills and the boiler will need to be considered. The direct injection process has several key advantages over alternative systems for both new and retrofit projects:

- There are no requirements for significant modifications to the boiler draught plant and secondary air ductwork.
- The boiler and mills can be started with coal as usual and biomass cofired only when the combustion and boiler systems are functioning properly.
- If there are any problems with coal mills, the biomass system can be switched off and isolated until the problems are resolved.
- The biomass control system only affects the mill controls.
- The biomass combustion is always supported by a stable coal flame. The risks of negative impacts to the boiler are much less than cofiring biomass through dedicated burners.
- The products of the combustion of biomass are always well mixed with coal and hence risks associated with striated flows resulting in localised deposition of biomass combustion products causing corrosion are minimised.

Overall, it is apparent that direct injection of cofiring is a technically robust and cost-effective approach to cofiring pre-milled biomass in large PCC boilers for both retrofit and new applications (Livingstone, 2007, 2009a).

3.6 Slagging and fouling

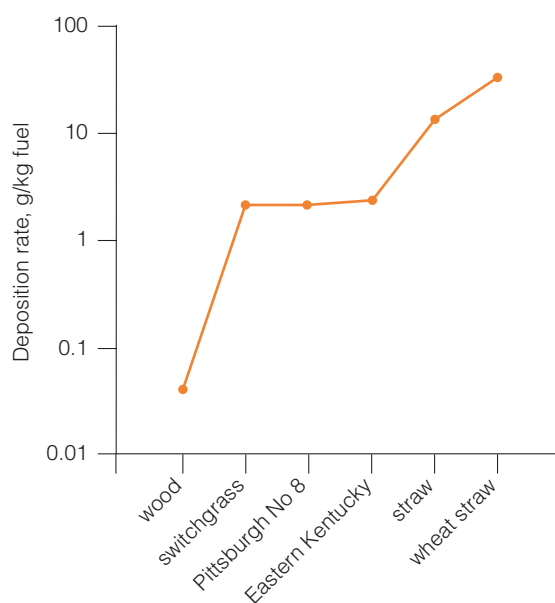
Slagging is defined as the deposition of fly ash on heat transfer surfaces and refractory in the furnace primarily subject to radiant heat transfer. Fouling is the deposition of fly ash at temperatures below its melting point in the heat recovery sections subject mainly to convective heat transfer. Substances which vaporise in the combustion zone condense on heat transfer zones by the condensation of volatiles or sulphation by reacting with SO_3 . These deposits range from light sintering to complete fusion. The degree of slagging and fouling depends on local gas temperatures, tube temperatures, temperature differences, tube orientation, local heat flux and fuel composition. Regarding the last of these factors, deposit formation depends on the release and chemistry of chlorine, sulphur, aluminium, silicates and alkalis during combustion. Biomass fuels can contain a higher proportion of alkaline species compared with coal though the total ash content must also be considered. The constituents of the ash such as alkali metals, phosphorous, chlorine, silicon, aluminium and calcium affect ash melting behaviour. Alkaline metals readily vaporise during combustion. A key reaction that needs to be considered is the release of volatile species, such as alkali metals and phosphate compounds and their subsequent deposition on boiler surfaces and on surfaces of ash particles and deposits. The major proportion of inorganic materials in biomass is in the form of salts or bound in organic matter, whereas in coal they are bound in silicates which are more stable.

Coal ash is composed mainly of alumino-silicates and quartz with the other significant constituents being compounds of iron, calcium, magnesium, potassium and sodium. The sulphur, chlorine and phosphorous contents of coal ash are low. As coal contains relatively low levels of fluxing elements

Table 4 Ash data from Studstrup cofiring trial (Van Loo and Koppejan, 2003)

Constituent	Coal ash, %	Straw ash, min %	Straw ash, max %	Wood ash, typical %
SiO ₂	59.8	19.7	38.9	10
Al ₂ O ₃	19.1	0.24	0.52	2
Fe ₂ O ₃	8.1	0.13	0.19	1
CaO	2	6.35	8.45	35
MgO	1.7	1.5	1.9	5
Na ₂ O	0.6	0.29	1	3
K ₂ O	2.2	28.7	34.6	20
P ₂ O ₅	0.2	2.45	3	12
SO ₃	2.1	3.4	5	12
Cl	<0.1	4.55	7.06	-

such as iron, calcium, potassium, sodium and magnesium, the ash is relatively refractory and has low propensity for slagging and fouling. Straw ash, like most biomass ashes, is not composed of aluminosilicates but of quartz and inorganic salts of potassium, calcium, magnesium and sodium, principally phosphates, sulphates and chlorides. These ashes would have fusion temperatures in the range 750–1000°C compared with fusion temperatures well in excess of 1000°C for coal ash and are hence much more likely to cause slagging and fouling. Wood ash is similar to straw in that it is not composed principally of aluminosilicates. However, it differs from straw in that wood contains very little chloride and lower levels of alkali metals. The fusion temperatures of wood ash can be similar to coal ash. The constituents of typical ashes which arise from the combustion of bituminous coal, straw and wood are listed in Table 4. The ash deposition rates of biomass fuels can greatly exceed or be considerably less than those of coal. Figure 3 illustrates rates of experimental standardised deposit accumulation rates on simulated superheater tubes. Absolute deposition rates of some herbaceous


Figure 3 Rates of ash deposition (Baxter, 2011)

fuels can exceed coal rates by an order of magnitude; those for wood can be an order of magnitude less. This is partly attributable to the ash contents of the fuels but also to ash particle size and chemistry. In general, deposition rates should decrease when cofiring wood or similar low ash, low alkali, low chlorine fuels but should increase when cofiring high alkali, high chlorine, high ash fuels like many herbaceous materials. Cofiring high ratios of herbaceous fuels would be expected to be more troublesome than cofiring similar ratios of woody fuels. It should, however, be noted that the ash content of most types of biomass is less than typical coals.

When biomass is cofired with coal, the effect on deposition is first that the rate of and extent of slag formation increases. This is because, apart from SiO₂, all the significant components of most biomass ashes, principally the alkali and alkaline-earth

metals, are powerful fluxes for alumino-silicate systems. The decrease in fusion temperatures results in fused or partially fused slag deposits which are more likely to incorporate incoming particles and grow. The impact is most dramatic when biomass is cofired with a coal which has a particularly refractory ash. In these cases cofiring biomass at even modest cofiring ratios can have a major impact on ash fusion behaviour. The presence of significant levels of alkali and alkaline-earth compounds in mixed ashes reduces fusion temperatures by 100–200°C and dramatically increases the likelihood of slagging. The effect on slagging of cofiring woody biomass with coals containing low CaO levels in the ash, such as Central Appalachian coals, are much greater than for coals containing high CaO levels, such as Powder River Basin or lignites. The deposition and retention of ash materials can cause operational problems in all types of boilers. These include:

- The partial fusion of ash particles in the beds of fixed beds and fluidised bed combustors leading to poor process conditions, defluidisation of fluidised beds and problems with ash removal and downstream ash handling equipment.
- The deposition of fused or partially fused materials on burner components in PCC furnaces can result in interference with burner light-up, operation and combustion performance.
- The build-up of slag can block ash hopper throats in PCC furnaces. This can result in plant load reductions or unplanned outages for off-load cleaning.
- Slag deposits on furnace heat exchange surfaces reduce furnace heat absorption, increasing gas temperatures within the furnace and furnace exit. This can lead to ash deposition in downstream heat exchangers.
- The formation and subsequent shedding of slag from upper furnace and reactor surfaces can lead to damage to lower furnace components.

Fouling is the accumulation of ash deposits in the convective sections of boilers and other heat exchangers. This takes place at temperatures around 1000°C and is generally a much slower process than slag formation. Convective fouling is one of the most troublesome ash-related problems associated with firing biomass fuels because of their relatively high alkali metal content. Potassium tends to be the most dominant alkali metal for most biomass fuels and, as in the case of sodium, it is in a form that can be released by volatilisation. This differs from coal, where potassium is principally present as a constituent of clay and does not volatilise in the flame. As most types of biomass are high fouling fuels, cofiring biomass with coal in almost all cases increases the likelihood of fouling. The levels of risk depend not only on the nature of biomass and coal ashes and the cofiring ratio but also on site-specific factors. The sensitivity of individual boilers regarding the tendency to accumulate ash, its subsequent effect on reduced heat transfer and the effectiveness of installed cleaning systems varies from plant to plant. In many cases the appropriate response to problems of slagging and fouling during cofiring, is to reduce the cofiring ratio. Experience in Europe suggests that slagging and fouling are unlikely to be a problem for cofiring ratios less than 10%. Clearly issues relating to slagging and fouling must be considered when cofiring at high biomass ratios (Van Loo and Koppejan, 2003, 2008; Livingston, 2009b; Baxter, 2011; Tillman and others, 2010).

In 2005, RWE npower in co-operation with Imperial College, London, in a project partly funded by The Department of Trade and Industry, undertook a two-year project to investigate the effects of high levels of biomass cofiring on large utility boilers. The project aimed at providing boiler operators with greater confidence in using higher levels of biomass up to 50% coal thermal replacement. The specific objectives of the project were:

- Identification of the main areas of the boiler at risk if the biomass is cofired with coal at 50% or more of thermal replacement.
- Determination of the nature of deposits likely to form in the radiant and convective passes of the boiler. Measurement of the physical and mechanical properties of the deposits to determine thermal shock and sootblowing properties.
- Development of a model to predict the thermal impact of fouling deposits and to optimise sootblowing operations.
- Assessment of the use of low cost additives to mitigate the effects of alkali metal fouling from biomass residues.

- A technical and economic assessment of high levels of biomass cofiring including recognition of current CO₂ abatement levels and other environmental constraints.

The range of biomass fuels considered included palm kernel, wood pellets, sawdust, short rotation coppice, miscanthus, switch grass, reed canary grass, maize and olive residue. The Laboratory tests were undertaken at Imperial College using an Entrained Flow Reactor (EFR) which consists of four electrically heated furnaces. Rig trials were performed in RWE npower's Combustion Test Facility (CTF) located at Didcot. This facility represented the flue gas path of a typical 500/660 MWe boiler and created with its single horizontal burner a time-temperature history of a middle row burner in a full-scale boiler with peak temperatures similar to a burner surrounded by other burners. Un-cooled ceramic coolers were inserted into the flue gas stream at positions representing the pendent superheater nose level of a two-pass boiler and these were used to establish the deposition behaviour of the ash in the flue gas stream for each trial.

The cofiring trials showed that flame stability was good for all fuel mixes and test conditions and NO_x emissions decreased with increasing proportions of biomass in the fuel mix. Oily biomass showed more pronounced reductions than dry biomass. SO₂ emissions reduced due to the lower sulphur content in biomass fuels and there was no increase in CO levels. Carbon-in-ash levels increased during cofiring and increased further with increasing levels of biomass in the fuel mix. The highest levels were recorded when cofiring palm kernel and lowest whilst cofiring wood. Slagging increased with increasing biomass cofiring ratio and was worst with palm kernel and olive residue. Dry biomass fuels could be fired at higher levels than oily biomass fuels without causing slagging problems. The slagging tests on the CTF rig demonstrated that with a 15% olive residue mixed with South African coal, the deposition rate increased by approximately 20%. In the case of cofiring 25% wood, the deposition rate reduced slightly. The impact of slagging was also assessed as function of temperature. In the case of South African coal cofired with 40% wood, slagging appeared to become an issue of concern at flue gas temperatures above 1180°C. The same level of concern was reached for a 15% olive residue mix with the same coal at approximately 1150°C. Over the range of trials using South African coal with wood, olive residues and palm kernel, the ash deposits were found to be medium to strongly sintered in the temperature range 1000–1200°C. By comparison for the same temperature range, the resulting slagging from the coal only test would be described as light to medium. Both are shown in Figure 4. The measured thermal conductivities of the cofired deposits were consistent with published results for coal ash deposits, once porosity was taken into account. Cofiring biomass did not alter the thermal conductivity of fuel ash deposits. The measured thermal expansivities of the pure miscanthus deposit were slightly higher than published results for coal ash deposits. Overall, the replacement of coal by biomass did not significantly alter the thermal properties of fuel ash deposits. Woody biomass fuels are less prone to slagging than herbaceous fuels which contain higher levels of inorganic matter and whose ashes have lower fusion temperatures (RWE npower, 2008).



Figure 4 Furnace deposits (RWE npower, 2008)

There are several methods for predicting ash deposition in boilers. The traditional empirical approach is based on empirical slagging and fouling indices. The ash deposition indices are calculated either from the fuel ash content and the ash chemical composition or on the results of the Ash Fusion Test. In the main these indices have been utilised for the assessment of coal ashes but they have been applied, with appropriate modifications to ashes from other solid fuels, such as wastes and biomass fuels, and the ashes resulting from cofiring coal and biomass. The slagging indices are based on the results of the Ash Fusion Test or on the

	SA export coal	Wood pellets	50% blend	Olive residues	50% blend	Distillers grain	50% blend
Ash content, %	14.6	2	7.1	2.9	7.6	4.2	8.6
Slagging index	0.83 (med)	1.09 (high)	1.01 (med/high)	N/A (severe)	1.43 (high)	N/A (severe)	1.63 (high)
Fouling index 1	0.08 (low)	2.3 (severe)	0.5 (low/med)	5.1 (severe)	1.2 (high/severe)	5.9 (severe)	1.6 (severe)
Fouling index 2	0.028 (low)	0.157 (med/high)	0.102 (med)	0.515 (severe)	0.288 (high)	0.804 (severe)	0.418 (severe)

chemical composition of the ash, generally the ratio of the acidic oxides (SiO_2 and Al_2O_3) to the basic oxides (Fe_2O_3 , CaO , MgO , Na_2O and K_2O). These indices provide a general assessment of the likely fusion behaviour of the ash and can be used to rank the likelihood of the ash forming fused or partially fused agglomerates and slag deposits. Despite the recognised technical limitations, these indices are still widely used in industry. Since the slagging indices for coal are based on assessing the fusion behaviour of the alumino-silicates in coal ash, care must be taking when applying them to biomass fuels which are chemically very different. When considering slagging behaviour of cofired ashes, apart from SiO_2 , all the significant constituents of most biomass ashes, principally the alkali and alkaline earth metals, are effective fluxes for alumino-silicate systems. When cofiring biomass with coal at relatively low cofiring ratios (<10–20% on a mass basis), the mixed ash is still predominantly an alumino-silicate system and the conventional slagging assessment can be made. At higher cofiring ratios, the predictions are less reliable. The most commonly used fouling indices for coal ash are based on the sodium content of the fuel. This is because the deposition of sodium compounds in the fuel by volatilisation/condensation mechanism is considered the principal one for heat exchanger fouling. The majority of potassium in coal ash is in the clay and is not considered to volatilise. In biomass, however, potassium is the dominant alkali metal and does volatilise. Hence fouling indices for biomass are based on total alkali content. These indices, with appropriate modifications where necessary, are used to provide an assessment of the potential for slagging and fouling when cofiring. It has to be recognised that the risks of obtaining misleading results will increase with increasing cofiring ratio. More complex approaches to modelling have been attempted over several decades but these have not been widely applied as the predictive capabilities of the best analytical models are limited. Of more practical use, maybe, is the significant improvement in recent years in the available techniques for monitoring ash deposition in operating plant and for the optimisation of the use of on-line cleaning systems (Stam and others, 2009). Livingston has calculated slagging fouling indices for mixed ashes at high cofiring ratios which are given in Table 5. These results demonstrate that for the South African coal, the potential for slagging is medium and fouling low. When cofiring 50% wood pellets, the slagging potential is slightly increased and the fouling potential significantly increased. However, cofiring 50% olive residue or distiller's grain increases considerably the potential for both slagging and fouling (Livingston, 2011).

3.7 Corrosion and erosion

Biomass cofiring can increase both the high and low temperature corrosion rates in utility boilers. Increased high temperature corrosion results from changes in the chemistry of the ash deposited on boiler surfaces. This is caused by the release of increased levels of alkali metal species in the vapour phase and their subsequent condensation on boiler surfaces. This leads to the enrichment of potassium

compounds, in particular, at the metal/oxide/ash deposit interface. The majority of biomass fuels tend to be relatively rich in alkali metals, especially potassium and in some cases phosphates. They also have relatively low sulphur contents. Moreover, some types of biomass contain relatively high chlorine contents, up to 1% which is released as HCl in the boiler flue gas which can lead to the enrichment of chloride at the metal/oxide/ash deposit interface. Biomass ash deposits tend to have relatively high potassium contents and relatively high chloride to sulphate ratios. This can have a significant impact on corrosion, particularly at high metal temperatures on superheater surfaces. Indeed, in dedicated biomass boilers, final steam temperatures are generally lower than in large coal-fired boilers. The HCl can also result in low temperature corrosion in the back end ducting though this problem is generally less serious and more manageable than superheater corrosion. Hence, depending on the cofiring rate, biomass fuels containing high levels of alkali or chlorine such as straw, switchgrass, poultry manure and sewage sludge can create or exacerbate corrosion problems. Increased rates of erosion are also possible with some types of biomass such as poultry manure and sewage sludge (Van Loo and Koppejan, 2008; Kunkel and others, 2004).

The extent of corrosion can be limited if SO₂ is present in the flue gas as this can react with condensed alkali and alkaline-earth chlorides to form less corrosive sulphates. These sulphate compounds, however, are only stable under oxidising conditions and then at lower temperatures than flame temperatures. The conversion of chloride compounds to sulphates is dependent on kinetic and transport factors. Overall corrosion rates depend on fuel properties such as sulphur, chlorine, and alkaline/alkaline earth content, operating conditions, which determine ash deposition and local gas-phase stoichiometry and boiler design which determines tube composition and temperatures. The advantages of the sulphur in the coal in preventing corrosion do not extend to reducing conditions as the sulphates that drive chlorine from surface deposits are not stable under reducing conditions. Hence corrosion may still occur in overfire air systems (Baxter, 2003).

Detailed investigations of corrosion have been conducted at the 80 MWth CFB boiler at Grenå in Jutland, Denmark, which fired a 50:50 mixture of coal and straw. The corrosion rates of the superheater tubes were found to be five to twenty-five times faster than when firing coal alone. For the first six months of operation, while the unit was run below 80% load, there were no reports of superheater fouling or corrosion. However, increasing the load to 100%, which increased the flue gas temperatures in the cyclone from 850°C to 900–1000°C, resulted in excessive fouling on the surfaces of the cyclones and superheaters. After 18 months, the corrosive damage was so serious that the final superheater elements had to be replaced. Selective chloride corrosion was considered to be responsible for the accelerated metal loss. Examination of the superheater tubes showed that the chromium had been selectively removed from the metal surface and along grain boundaries. In many cases, significant enrichment of chlorine was detected at the corrosion front and the great majority of the potassium in the superheater fouling deposits was in the form of potassium chloride and this was considered to be the main agent for selective chlorine corrosion. The suggested mechanism for corrosion involved sulphation of the solid phase KCl, followed by the release of Cl₂ or HCl which acts as a corrodent. The modifications which were undertaken to reduce the extent of corrosion were the addition of a heat transfer surface to reduce furnace temperature, a switch to a lower sulphur coal and the use of a higher quality limestone. The bed temperature was reduced from 900°C to 860°C. This was achieved by installing wing walls to the evaporator and two heat exchangers in the loop seal. As the space between the superheater rows was only 30 cm, it was necessary to soot blow very often to remove deposits. However, excessive soot blowing caused erosion (Wieck-Hansen and Sander, 2003). There were also operational problems resulting from agglomeration when the cofiring ratio exceeded 60% which led to the possibility of defluidisation. This did not take place in the combustor riser, probably due to the high gas velocity. However, severe agglomeration occurred in the external heat exchanger box which resulted in defluidisation and blockage in the return leg. The plant was forced to shut down (Lin and others, 2003).

During investigations at Studstrup, in which straw and coal were cofired in a 152 MWe PCC boiler, the results were very different and the corrosion rates were modest up to 10% cofiring ratio, with a

different mechanism of corrosion. There was a need for additional soot blowing and some slagging, especially at 20% cofiring ratio. Examination of the fly ash indicated that the potassium had reacted with the alumino-silicates in the coal ash and little, or no KCl was present. The chlorine in the straw had formed HCl or possibly Cl₂ in the flue gas. The dominant corrosion mechanism observed in the superheater tubes was oxidation with perhaps some alkali sulphate melt corrosion which is the expected mechanism associated with coal firing. The difference in corrosion mechanisms at Grenå and Studstrup was due to the fact that in a PCC boiler the combustion temperatures are considerably higher than in a CFB boiler which allows the potassium to react with the ash components. The cofiring ratios at Studstrup were also lower than at Grenå. Hence it is apparent that cofiring biomass with coal increases the risk of corrosion of high temperature boiler tubes which is the result of increased levels of alkali species and chlorine in the boiler flue gas. The risks are lower in PCC plant firing biomass fuels with lower ash, potassium and chlorine contents and at low cofiring ratios. The experience for PCC plant shows that when firing only coal, the ash deposits are dominated by alkali metal sulphates. Biomass cofiring may introduce increased levels of chloride into the system but at low cofiring ratios, the ash chemistry is dominated by the alkali metal sulphates. There is also evidence that at the high temperatures within PCC furnaces, volatile potassium species from the biomass fuel react with silicate and alumino-silicate coal ash particles, reducing the likelihood of potassium chloride and sulphate formation local to tube surfaces (Van Loo and Koppejan, 2008).

Erosion and abrasion, when cofiring, tend to be less important than in coal-fired plant because the majority of biomass fuels have relatively low ash contents. There are, however, a number of specific instances where erosion can be a significant issue (Livingston, 2009b):

- The presence in the biomass of small quantities of tramp materials (such as, sand, soil and metal items) can effectively increase the abrasion and erosion potential of the biomass fuel. This is most likely to occur in the particle pneumatic conveying system and materials handling equipment.
- Some biomass fuels (such as rice husks) which have a particularly high quartz content can cause abrasion problems in the fuel and ash handling systems where erosive damage to plant components can be significant.
- The formation of significant quantities of fused ash material, particularly in fixed bed combustors can cause erosion and abrasion damage to the ash handling system.
- In biomass boilers experiencing severe convective section fouling problems, erosive wear on tubes can also occur. Regular use of sootblowers to control the fouling can lead to further erosion.

3.8 Ash-related issues for CFB boilers

There are several factors related to the composition of the fuel ash which can adversely affect the operation of CFB boilers. In most fluidised bed combustors, there is a tendency for fuel ash and bed material to sinter and form agglomerates. Excessive agglomeration can lead to poor air distribution and eventually to defluidisation of the bed and hence must be avoided. The key processes leading to the formation of bonds between bed particles in biomass-fired FBC combustors are (Van Loo and Koppejan, 2008):

- Partial melting of the low ash melting point ash components to form a low viscosity liquid phase which forms necks between the bed particles. This type of sintering mechanism is of fundamental importance for fuels with ashes rich in alkali metals, phosphates and some heavy metals.
- The solid ash bed particles, particularly silicates and alumino-silicate species may be partially soluble in the liquid phase at the sintering temperature. This can contribute to the strength of the particle-particle bonding.
- It is also possible for chemical reactions occurring at surfaces of bed particles to increase the strength of inter-particle bonds. For instance, the reaction of lime on the surfaces of bed particles with SO₂ to form calcium sulphate can lead to sintering of bed particles in FBC combustors firing high calcium biomass fuels.

In terms of their ash composition, biomass fuels can be divided into three groups. The first are biomasses with high Ca and K but low Si levels in the ash. Most woody fuels belong to this group. The second type are ones which have high Si but low levels of Ca and K in the ash. Rice husk, bagasse and spring harvested reed canary grass belong to this group. The third type of biomass produces ash containing high levels of Ca, K and P. Sunflower seed and rapeseed cakes are fuels in this group (Hiltunen and others, 2008).

During the firing of biomass fuels in group one in FBC combustors, the potassium and calcium from the biomass ash can react with the quartz in the bed forming a layer of Ca, K-silicate on the bed particle. This layer becomes thicker increasing the particle size. As the layer is sticky, the bed particles agglomerate, further increasing the bed particle size. If the bed has an occasional excursion to high temperature, it can sinter. The agglomeration can be controlled by regularly discharging the bed ash and feeding fresh sand into the bed. The ash melting point of woody fuels varies widely, depending on the ash composition. In general, the higher the fuel alkali and chlorine contents, the lower are the sintering and initial deformation temperatures. Wood ash starts to form agglomerates and to sinter between 900°C and 1000°C. Coal ash is usually trouble-free at these temperatures. Woody ashes are much more reactive than coal ashes. The lower reactivity of coal ash is due to its composition – mainly quartz, various silicate-based minerals and iron oxide. The calcium and alkali in these minerals are not in free, reactive forms as they are in biomass ashes. Hence the combustion of woody biomass fuels is more challenging than coal. This is especially so in high efficiency boilers with high steam temperatures and pressures as the negative properties of ashes are amplified. The incidence of boiler fouling, deposit formation and corrosion are increased compared to coal-fired boilers; hence, when coal is cofired with woody fuels, especially at high cofiring ratios, the possibility of such occurrences is more likely.

Most fuels containing group two ash are herbaceous or agricultural biofuels. They can be very diverse in chemical composition and combustion properties. Some fuels, like straws or cereals also contain relatively high potassium and chloride levels. The ash melting behaviour of straws and cereals is challenging. The sintering temperatures are in the range 700–900°C and the ash softening points below 1000°C. Complete melting can happen below 1200°C. Straw is a reactive and difficult fuel with high fouling, slagging and corrosive properties. The mechanism of bed agglomeration in type two biomasses is different compared to the type one fuels. Agglomeration in group two fuels is caused by separate sticky and partly molten ash particles and not sticky layers forming on bed particles as in type one fuels. The molten straw ash particles consist of potassium chloride and low melting potassium silicates formed in reactions between potassium and silica present inherently in the fuel ash. Hence, with fuels such as straw, the nature of the bed material does not significantly impact the bed agglomeration rate. The operational problems that arose when straw and coal were cofired in the CFB boiler in Grenå have already been described in Section 3.7. Straw firing in large-scale, industrial CFB boilers is difficult but it can be cofired at low cofiring ratios with coal. Problems could arise at high cofiring ratios. Another fuel in this group is rice husk. Rice husk ash contains over 90% SiO₂ making it very different from ashes of other cereals and even rice straw ash. The potassium and calcium contents in rice husk ash are low compared to rice straw. Because of this ash composition, the ash melting point of rice husk is very high, about 1500°C. When fired alone, rice husk ash does not cause significant slagging or fouling. Indeed, when rice husk is cofired with other fuels, even ones which are prone to fouling, its ash seems to be able to prevent fouling. This cleaning effect is caused by its slightly erosive properties resulting from its large particle size and the presence of sharp-edged SiO₂ particles. Thus rice husk can be cofired quite easily in CFB plant. The two 370 MWth CFB boilers in Tha Toom, Thailand, have successfully cofired up to 50% rice husk and eucalyptus bark with anthracite or bituminous coal.

Biomass fuels containing the third type of ash, namely high in Ca, K and P, are sunflower seed and rapeseed cake. They also contain high chloride levels and their ash melting temperatures are in the same range as straw. Sintering may start at about 700°C and the ash is completely molten at 1200°C. The limited experience of combusting these fuels demonstrates that they are prone to fouling but they

can be cofired with coal in CFB boilers in moderate cofiring ratios. Operational problems are likely to occur at high ratios (Hiltunen and others, 2008).

The increasing requirement for CFB boilers to cofire biomass and waste fuels has increased the stress on refractory systems of the boilers, necessitating more frequent replacement cycles and increased maintenance costs. Many existing CFB boilers which began operation in the late 1980s or early 1990s, were designed for coal firing and the older refractory materials lining the boilers were suitable for coal. Recently they have begun to cofire biomass fuels which has resulted in refractory failures due to erosion and excessive cracking caused by corrosion/erosion associated with the biomass material. The failure mechanism is the result of alkali-related chemical attack creating compounds that can be easily eroded. The corrosion of the refractory involves the reaction of the material matrix and the surface of the alkalis introduced into the unit from the fuel. These mainly consist of sodium, potassium or calcium in the form of carbonates, sulphates and chlorides. These reactions occur within the microscopic pores of the refractory lining causing weakened bonds, volumetric expansion and, ultimately, failure by erosion. The development of low cement alumina silicate-based refractory products increased the life of CFB refractory products and reduced failure rates. More recently, continued advancement of the low cement, castable-based, products has yielded materials with higher strength, abrasion-resistant properties. The improvements in these properties and resistance to alkali attack compared to conventional materials in coal-only boilers have resulted in extended life of the linings and lower cost installations. These material became the linings of choice in CFB boilers. Although these low cement aluminosilicate refractories result in better resistance to low levels of alkalis, it has been found that biomass fuels containing high levels of alkalis have caused rapid degradation of linings. Under these circumstances, in lower erosive zones of the boiler, reducing the refractory alumina content to provide a higher silica to alumina ratio has been found to seal the permeability of the hot face to alkali penetration, thus increasing resistance and reducing failure rates. Though this change has been effective in low erosion areas such as loop seals and outlet ducts, these products may lack the abrasion resistance required in upper cyclone areas. These higher wear areas are more prone to erosive and alkali attack with increased levels of moisture and alkalis found in some biomass fuels. It has been found that changing the type of alumina can provide greater resistance and increase service life. Mullite has been shown to be superior to standard bauxite used traditionally in low cement aluminosilicate products (Rau, 2010).

3.9 Torrefaction

Torrefaction is a thermochemical process which alters the properties of biomass, improving its physical properties for handling and utilisation. It is a process that has been known since the 1930s and heats the biomass to between 200°C and 300°C, typically for about an hour, in a reducing atmosphere. During the process, the biomass partly decomposes, releasing several volatile products. The final solid product can be pelletised. Most types of biomass, such as woody biomass, agricultural residues and mixed waste can be torrefied. Typically, 70% of the mass is retained as a solid product, containing 90% of the initial energy content. The biomass feedstock frequently has a low calorific value, is hydrophilic, heterogeneous, vulnerable to biodegradation and has poor milling and handling properties. The torrefied product has far superior fuel properties. It is friable and less fibrous. The heating value of the torrefied product is typically 19–22 MJ/kg (LHV) which approaches that of bituminous coal. The product is also homogeneous and not prone to degradation. Overall the product has far superior transport, handling, storage, milling and feeding properties than the raw biomass. Torrefied fuel is far more suitable for cofiring at high ratios than untreated biomass.

The processes occurring in a typical torrefaction reactor are:

- Initial heating – the biomass is initially heated until the drying stage is reached. As the temperature is increased the moisture starts to evaporate.
- Pre-drying – free water is evaporated from the biomass at a constant rate. Its temperature remains

practically constant until the critical moisture content is reached and the rate of water evaporation starts to decrease.

- Post-drying and intermediate heating – The temperature is increased to 200°C. Physically bound water is released. The biomass is now practically free of moisture. Some mass loss can be expected as light organic compounds, such as terpenes, start to evaporate.
- Torrefaction – During this stage the biomass is torrefied. This stage commences when the temperature reaches 200°C and ends, after the period of constant temperature, when the temperature dips below 200°C. Devolatilisation and mass loss occurs during the heating period, continues during the period of constant temperature and stops during or after the period of cooling.
- Solids cooling – The product is cooled from 200°C to the desired final temperature. No further mass release takes place but some evaporation of adsorbed reaction products may occur.

The torrefied product can then be pelletised. Torrefaction increases product durability and reduces biological degradation, while pelletisation increases the energy density. It is claimed that the final product can be stored, handled and utilised much like coal (Bergman and others, 2005; Mahr, 2011).

ECN in the Netherlands have studied the process for nearly a decade. Initial bench-scale studies commenced in 2002-03 and investigated the relation between torrefaction conditions and product properties for a broad range of feedstocks, the underlying mechanisms of the process and the pelletisation behaviour of the torrefied biomass. Based on this research, dedicated reactor and process concepts were developed. Heat integration using the energy content of the torrefaction gases was crucial to achieve high energy efficiency. This led to the development of the BO₂ technology which features conventional drying and pelletisation incorporating compact moving bed technology with direct heating and no moving parts. The heat integration ensures high energy efficiency of >90%. A pilot plant based on this technology produces 1–10 t batches of torrefied biomass. The pilot plant operated smoothly and was easy to start and stop. There was high feedstock flexibility, limited pressure drop and no bridging given proper sizing of feedstock. The process was modestly exothermic and the reactor temperature was well controlled to enable good product quality control. The good control of torrefaction conditions was essential for adequate pelletisation performance. ECN are collaborating with Vattenfall to demonstrate the technology (Kiel, 2011).

The Dutch start-up company Topell is intending to produce torrefied ‘biocoal’ pellets on a commercial scale. Topell Energy’s technology combines torrefaction with pelletisation and should enable continuous production of biomass on a industrial scale. The Topell process consists of a series of Torbed reactors which convert fibrous biomass into a torrefied product. After this, the torrefied biomass is cooled and compacted forming the torrefied pellets that can be stored and shipped to customers. This process can be applied to a wide range of fibrous biomasses, not just wood. Even comparatively difficult biomass fuels such as roots and switchgrass can be converted. The features of the Torbed reactor which are particularly advantageous are firstly that it ensures highly efficient heat transfer. The turbulence inside the reactor results in intense contact between the biomass and the process air, thus facilitating efficient heat transfer. This, in combination with the small bed volume provides excellent process control. By recycling a large part of the process air when drying the biomass, large energy savings can be made. As the operation of the reactor is based on displacement of air, it does not feature any moving parts hence there are very low maintenance costs. The final product has a bulk density of 700–750 kg/m³, calorific value of 20–24 MJ/kg (NCV) energy density of 18–20 GJ/m³. The fines content is less than 2%. The pellets are homogenous, hydrophobic, biologically inactive and easy to grind. The only challenges with the fuel are large-scale open storage and transport. In 2008, RWE Innogy took a 25% stake in Toppell. A joint venture of RWE Innogy and Toppell Energy are constructing a commercial-scale biocoal facility in Duiven, Gelderland, the Netherlands. The construction of the plant commenced in June 2010. The plant, which will utilise approximately 135 kt/y of biomass and have a production capacity of 60 kt/y, is under construction (Modern Power Systems, 2008; 2010a; Topell Energy, 2011; Van der Burg, 2011).

3.10 Cofiring assessments

The above sections detail the main factors that need to be assessed before deciding whether biomass at high ratios can be cofired in a given coal-fired boiler. Critically important components of the boiler are affected by cofiring especially at high ratios. The difficult task for plant operators is compounded by the fact that there is relatively little experience of biomass cofiring at high ratios and full-scale tests are expensive and risky. There is clearly a need for an inexpensive means to assess the likely impact of cofiring on various boiler components. ECN have developed a Cofiring TOOLBOX to facilitate such assessments. This process involves a combination of laboratory experiments, full-scale measurement campaigns and modelling, and for given cofiring scenario. From this, it is claimed that it is possible to formulate design rules, operator guidelines and fuel specifications. The grindability of the biomass, for example, is directly measured. Fuel conversion and ash formation are assessed in a laboratory-scale combustion simulator reactor. The reactivity of the fuel is measured and the necessary kinetic parameters are determined for CFD modelling. A deposit probe is placed at the reactor outlet to collect ash samples to provide ash quality information needed to make fouling assessments. ECN claims that the TOOLBOX assessment covers almost all the important technical concerns. The results have been for the large part validated with full-scale data. Moreover, they claim it is possible to generate reliable information prior to and at a fraction of the cost of full-scale cofiring trials (Cieplik and Houkema, 2011).

4 Emissions

Sloss (2010) has reviewed the emissions from cofiring coal, biomass and sewage sludge. In general terms, the majority of studies reviewed in the report demonstrated that, assuming combustion conditions are optimised, the cofiring of biomass with coal resulted in a reduction of major pollutants such as SO₂ and NO_x. This chapter will focus on the emissions of individual pollutants when cofiring.

4.1 CO₂ emissions

The net emissions of CO₂ from the combustion of biomass are less than from coal if the biomass is grown in a sustainable manner. The measured stack emissions of CO₂ when biomass is cofired in a coal plant may increase slightly as the boiler is derated during cofiring. Even if the biomass that is cofired is not an energy crop, such as demolition wood, cofiring still reduces greenhouse gas emissions, as otherwise the waste wood would be left to decay and would produce methane which is a far more potent greenhouse gas than CO₂.

4.2 SO₂ emissions

SO₂ emissions invariably decrease, often in proportion to the amount of biomass used, as most types of biomass contain less sulphur than coal, as shown in Figure 5. Further reductions are sometimes observed as biomass ash frequently contains higher levels of alkali and alkaline earth compounds than coal and can retain a greater fraction of sulphur in the ash. The proportion of sulphur retained in the ash typically increases from 10% in coal to 50% for pure biomass. The sulphur contents in waste fuels are much more variable. The sulphur levels in sewage sludge range are similar or somewhat greater than in coal. Hence, when sewage sludge is cofired with coal, SO₂ emissions would be expected to be similar or increase slightly. Though sewage sludge contains high levels of CaO, tests have shown that this does not reduce SO₂ emissions significantly. The inactivation of CaO could be due to surface sintering at the high combustion temperatures existing in a PCC boiler. Figure 5 shows SO₂ emissions when miscanthus, straw and sewage sludge are cofired with coal. The SO₂ emissions decrease with miscanthus and straw but increase with sewage sludge (Spliethoff and others, 2001).

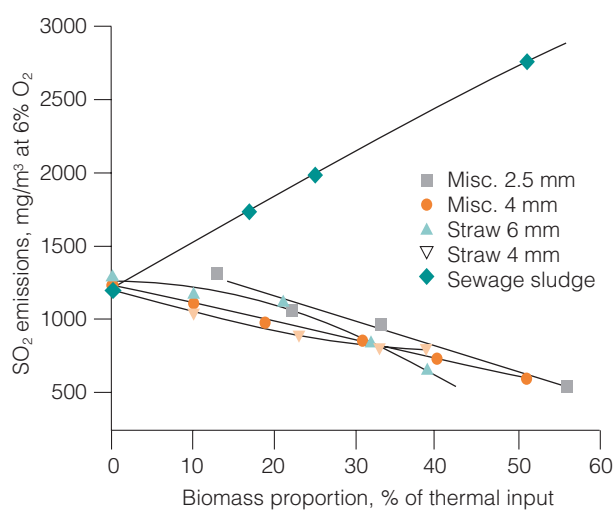


Figure 5 Emissions of SO₂ as a function of biomass ratio for several blends (Spliethoff and others, 2001)

4.3 NO_x emissions

NO_x emissions when cofiring biomass are more difficult to predict and may increase, decrease or remain the same as compared to coal firing depending on the type of biomass, firing conditions and operating conditions. Some biomass fuels, such as woody fuels, have lower nitrogen contents which result in lower NO_x emissions. Other fuels such as alfalfa stalks and rice hulls can contain higher nitrogen contents than typical coals. However, NO_x emissions are not determined purely by fuel nitrogen alone but by the manner in which the nitrogen is released. There is evidence that during devolatilisation, biomass releases more ammonia and less HCN than is found during coal combustion. A greater proportion of the

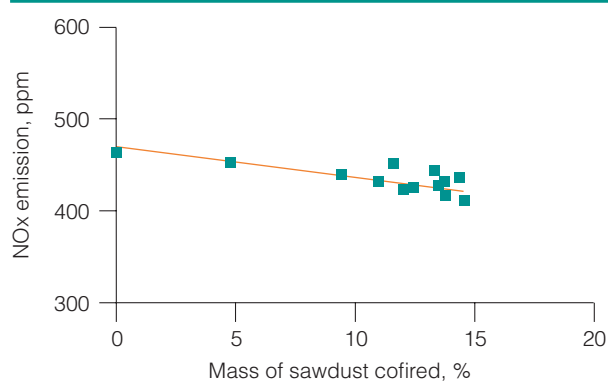


Figure 6 Emissions of NO_x as a function of biomass ratio at the Seward plant (Laux and others, 2000)

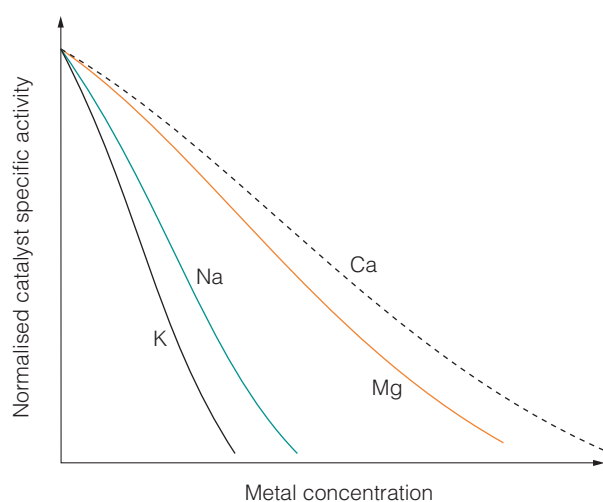


Figure 7 Qualitative effect of alkali and alkaline-earth compounds on SCR catalyst activity (Baxter and others, 2003)

to the deactivation of SCR catalysts during biomass cofiring with chlorides having the higher deactivation potential. Orthophosphates, which are likely to be present at catalyst temperatures also exhibited a significant deactivation potential. In many cases, such as cofiring clean wood, the effect on ash chemistry associated with cofiring is small compared with the natural fluctuations in coal ash. However, when cofiring large amounts of herbaceous biomass, or large amounts of biomass in a single burner, all or some portion of the catalyst may see significant changes in composition and hence more fouling and possibly poisoning (Baxter and Koppejan, 2004 and 2011; Beck and others, 2005).

The effect on SCR when cofiring high ratios of biomass has been investigated by Folkedahl and others (2006). A portable slipstream reactor was installed in a utility boiler cofiring 80% biomass with 20% Power River Basin (PRB) coal. The boiler was a stoker-fired unit and the biomass was primarily hog fuel (tree bark) with some sawdust. A section of the catalyst was removed after 43 days and replaced with a new section. The new section and the two remaining sections were removed after 171 days of operation, thus providing catalyst sections that had been in place for 43, 128 and 171 days. The sections were analysed to determine activity coefficients which were then translated into equivalent rates for a full-scale SCR unit. The initial deactivation rate for a full-scale system was predicted to be

nitrogen is released as volatile compounds and this can result in lower NO_x emissions, particularly in low NO_x burners. Thermal NO_x is dependent on the combustion temperature and NO_x production, when cofiring, can be further reduced as the higher moisture content in the biomass can lower peak flame temperatures (Baxter and Koppejan, 2004). The separate injection of sawdust in a 32 MWe wall-fired boiler has been demonstrated at the Seward plant in the USA. Cofiring ratios up to 20% by mass (10% by heat input) were investigated. NO_x reductions of up to 18% were measured during cofiring as shown in Figure 6. The key to NO_x reduction was flooding the combustion zone with highly volatile sawdust. This was facilitated by the separate injector.

Biomass cofiring can indirectly affect NO_x emissions in that there is evidence that SCR catalysts can be adversely affected by it. This is due to alkali and alkaline-earth metal constituents of biomass poisoning the vanadium-based catalysts in SCR systems. Most biomass fuels contain high levels of alkali and alkaline-earth metals, though the total ash content of some types of biomass are low. The impact of the compounds of these metals on SCR catalyst activity is shown in Figure 7. The most significant mechanisms for catalyst deactivation during biomass cofiring appear to be surface fouling on the catalyst and possibly pore plugging rather than chemical poisoning. Other laboratory and plant investigations have shown that potassium chlorides and sulphates are major contributors

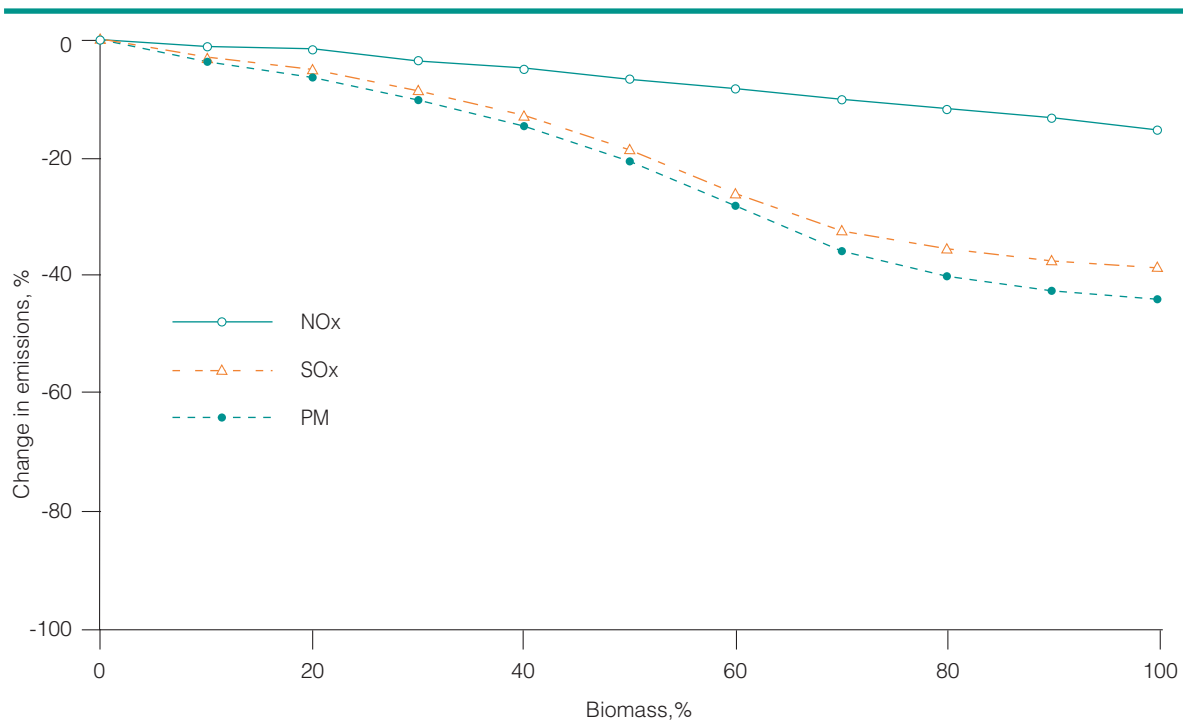


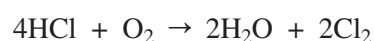
Figure 8 Plots for average emission impacts of cofiring coal with biomass (Demirbas, 2005)

between 6% and 9% per 1000 h, which is an order-of-magnitude greater than normally observed at a coal-fired unit. The mode of catalyst deactivation was combined alkali and calcium sulphate formation and growth at catalyst pore openings. The results indicate that the use of SCR when cofiring high ratios of biomass needs to be carefully evaluated before implementation.

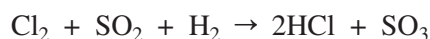
Demirbas (2005) has assessed the average impact on emissions of increasing the biomass cofiring ratio up to full conversion. This is shown in Figure 8. Although the figure should be regarded as a generalisation, the suggested trends are in agreement with the majority of other studies. Namely that, assuming combustion conditions are optimised, the cofiring of biomass with coal results in a reduction of emissions of major pollutants such as SO₂ and NO_x (Sloss, 2010). Thus cofiring high ratios of biomass does not raise particular concerns regarding SO₂ and NO_x emissions.

4.4 HCl emissions

The chlorine content of some types of biomass can be considerably higher than coal. In straw, chlorine levels approaching 1% have been measured which is about ten times greater than typical bituminous coals. Traces of the chlorine can form dioxins and other compounds but the substantial fraction of the fuel chlorine will be released as HCl. The chlorine in the fuel can be reduced by fuel washing and HCl will be readily removed by a FGD scrubber. Some of the fuel chlorine reacts with alkali metals in the fuel to form salts which can cause corrosion as discussed in Section 3.5. There is also a possibility that HCl in the flue gas can cause back-end corrosion. The presence of chlorine affects the speciation of mercury in the flue gas as has been discussed by Davidson (2005). One particular concern about the use of fuels containing chlorine is the production of harmful polychlorinated dibenzo-p-dioxins (PCDDs) and polychlorinated dibenzofurans (PCDFs). Initially the chlorine contained in fuels is released by thermal decomposition to form HCl. This can then be converted to molecular chlorine by the Deacon reaction.



Molecular chlorine reacts with aromatic species in the fuel to form PCDDs and PCDFs, depending on temperature and boiler design. Boiler temperatures are too high for these species to be produced in the boiler but there is a possibility of de novo synthesis (synthesis from smaller precursor species) of these compounds in cooler downstream regions such as the ESP. When chlorine containing biomass fuels are cofired with coal, the formation of PCDDs and PCDFs is inhibited. Results from industrial plant and laboratory investigations have shown that a 16% mass fraction of coal was sufficient to reduce PCDD/F formation by 95%. The possible mechanisms for PCDD/F inhibition include the depletion of molecular chlorine concentration by its reaction with SO₂.



It is also possible that the presence of sulphur reduces the catalytic activity of fly ash or that SO₂ might sulphonate phenolic PCDD/F precursors (Lu and others, 2005). Cofiring high levels of biomass containing a high fuel chlorine content raises mainly concerns regarding corrosion within the plant. There should not be any concerns about HCl in the flue gas assuming that the plant contains an efficient FGD unit. However, as the biomass fraction approaches full conversion, the possibility of dioxin formation will need be considered.

4.5 Particulate and trace emissions

Most biomass fuels have lower ash contents than typical coals but those of some waste fuels such as sewage sludge and poultry litter are significantly higher. However, it has to be remembered that the ash contents of biomass are not as low on an energy equivalent basis because of their lower heating values. In general, cofiring biomass with coal leads to a reduction of the total fly ash burden. The available plant data are contradictory. In some cases, a sharp increase in particulate emissions when cofiring biomass has been measured. In other cases there has been no significant change. The effect is site-specific, depending on the type of biomass and the performance of the installed particulate collection equipment. The properties of the solid products from biomass combustion are very different from those produced by coal combustion. The chemical properties of the ash are different as are the physical characteristics. The inorganic material in biomass can generate a significant amount of submicron fume and vapour in the flame. Hence cofired fly ash can contain a significant quantities of very fine aerosols which may not be collected by conventional particulate abatement equipment. ESPs are not efficient at collecting fine aerosols and fabric filters can be blinded by fine aerosols and fume. Furthermore, as most types of biomass contain lower sulphur levels than coal, the SO₂ and hence the SO₃ levels in the flue gas will be reduced when cofiring. The lower SO₃ levels will adversely affect the resistivity of the fly ash and could impair ESP performance. This possibility must be considered when cofiring biomass (Van Loo and Koppejan, 2008).

The concentrations of some trace elements can be significantly higher in certain biomass materials than in coal. However, there is no evidence that these elevated levels have led to compliance issues in existing plants that have switched to cofiring. However, as emissions standards worldwide are being tightened, the situation could arise that certain types of biomass have difficulties complying with future legislated limits, especially at high cofiring ratios (Sloss, 2010).

4.6 Ash utilisation

About 80% of the ash produced in a PCC plant is in the form of fly ash from the ESP/bag filter, economiser and air heater hoppers. The extent of utilisation of this ash varies considerably from country to country. In the Netherlands, Germany, Belgium, Italy and Denmark, utilisation rates exceed 80%. In the UK, the proportion utilised is less than 50%. The average utilisation for fly ash in the EU-15 in 2008 was 47%. In the USA, 39% of fly ash was utilised in a secondary market in 2009 with the remainder sent for landfill, reclamation and restoration. Fly ash is mainly used for the production

of cement and concrete but the ash needs to comply with standards which specify, for example, the nature and proportion of secondary fuels, chemical properties, such as SO_3 content, and physical properties, such as fineness. The standards may also relate to the pozzolanic behaviour of the ash. Though nearly all fly ashes from coal combustion meet the required standards, the concern is that when biomass is cofired, the fly ashes may not comply. In general, these ashes are enriched in free CaO , K_2O and/or P_2O_5 . They may also contain glass, quartz, haematite/magnetite and phosphates. At high cofiring ratios, the challenge will be to find new applications for fly ash if they do not comply with standards. KEMA and ECN have investigated other options for the use of fly ash which are technically feasible and can handle large volumes. None was economically attractive though the production of lightweight aggregates was the closest to economic viability. The remaining 20% of the ash from a PCC plant is in the form of bottom ash or slags and is collected in the furnace ash hopper. This can be used as structural filler, blended cement and blasting grit in road construction or other infrastructural works. The utilisation rates for bottom ash and slags can be higher than fly ash. In the EU in 2008, the utilisation rates for bottom ash and boiler slag were 48% and 100%. The respective proportions in the USA for 2009 were 44% and 84%. In practice, most bottom ashes from coal-fired plant, with or without cofiring, can be used with little or no restrictions. Even at high cofiring rates few problems would be expected for utilisation of bottom ash (Van Loo and Koppejan, 2008; ACAA, 2011; ECOBA, 2008; Pels and Saraber, 2011).

In some countries, the use of ash from PCC plant in cement or concrete was precluded if the coal was cofired with biomass or waste. For example, the original European EN 450 standard specified that only fly ash from pure coal or anthracite combustion was allowed as an aggregate in the cement or concrete industry. In the USA, the ASTM specification C168 for the use of fly ash in concrete, specified that the ash must be derived entirely from coal combustion. These criteria have been relaxed in the current EN 450-1 standards which deal with definitions, specifications and conformity criteria and EN 450-2 which covers the conformity evaluation of fly ash for concrete. Fly ash from co-combustion of specific secondary fuels such as wood chips, straw, olive pit and other vegetable fibres, green wood and cultivated biomass, animal meal, municipal sewage sludge, petroleum coke and liquid and gaseous fuels can now be used for concrete provided the percentage of secondary fuel does not exceed 20% by mass and if the derived amount of ash from the co-combustion material is not greater than 10%. There are additional limits on the static chemical properties of the ash such as the chloride content has to be less than 0.1% and the total alkali content (normalised as Na_2O) less than 5%. There are dynamic chemical requirements such as carbon-in-ash levels and physical specifications relating to, for example, fineness and setting time for concrete. There are other requirements such as durability of the concrete. Garcia-Galindo and others (2009) investigated ten types of biomass and waste fuels and have estimated the maximum cofiring ratio which would conform to the EN 450-1 criteria for fly ash. The types of biomass considered were: grape prunings, sawdust, forest residues, willow, demolition wood, straw, grass, olive cake, MBM and sewage sludge. The calculations in some cases involved stoichiometric correlations and in others laboratory testing. In general, cofiring blends of up to 30% (th) biomass complied with the requirements of the chemical and physical properties of the EN 450-1 standard. There were additional limitations in some cases. Herbaceous biomass and olive cake incurred restrictions due to their alkali content, that in worst cases constrained cofiring ratios to 15%. The chloride levels in grass and straw, in worst cases, allowed cofiring up to ratios of 10%. Sewage sludge was the only biomass whose use was restricted to a cofiring ratio of 15% due to its $\text{SiO}_2 + \text{Al}_2\text{O}_3 + \text{Fe}_2\text{O}_3$ contents. Other than these restrictions, regarding the dynamic chemical parameters, the physical properties of the fly ash and the properties of the concrete, cofiring ratios of up to 30% met the standard. There are proposals to increase the proportion of biomass which can be cofired to 40% for the specific secondary fuels listed above; indeed to 50% in the case of green wood. These proposals also include raising the permitted proportion of ash derived from co-combustion to 30% (Van den Berg, 2010).

Dutch utilities have been cofiring biomass and coal since the mid 1990s. One issue that needed to be addressed was the effect of cofiring on fly ash utilisation. A programme was undertaken to find out whether the fly ash produced from cofiring met the quality requirements for utilisation as a filler or as

a cement replacement and for the production of concrete. Tests were undertaken at several power plants with up to 10% by mass of secondary fuels. Cofiring took place for at least three days to ensure steady operation. The types of secondary fuels included several types of pellets, sewage sludge, petcoke, wood chips, poultry manure, MBM and liquid hydrocarbons. Extensive characterisations of the fly ashes were performed including analysis of their chemical and physical composition and morphology. Fly ashes produced by cofiring showed no significant difference in chemical composition from that of reference ashes. The original EN 450 limits were met for the carbon-in-ash levels for some ashes. The fly ashes met the technical standards for their use in cement pastes, mortars

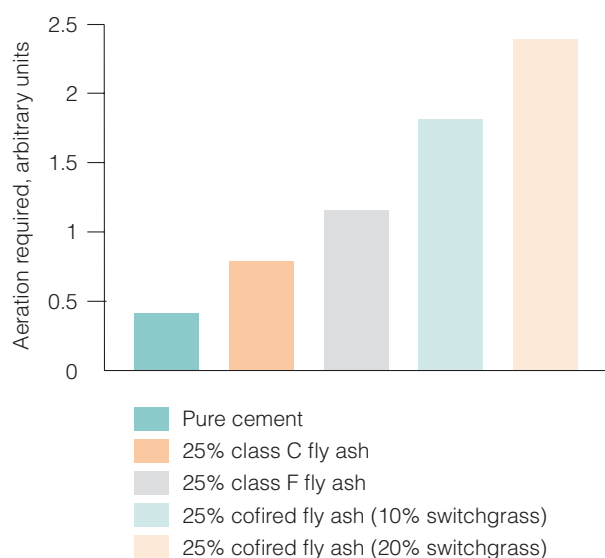


Figure 9 Amount of aerating agent required for a range of specifications of fly ash compositions (Baxter and Koppejan, 2004)

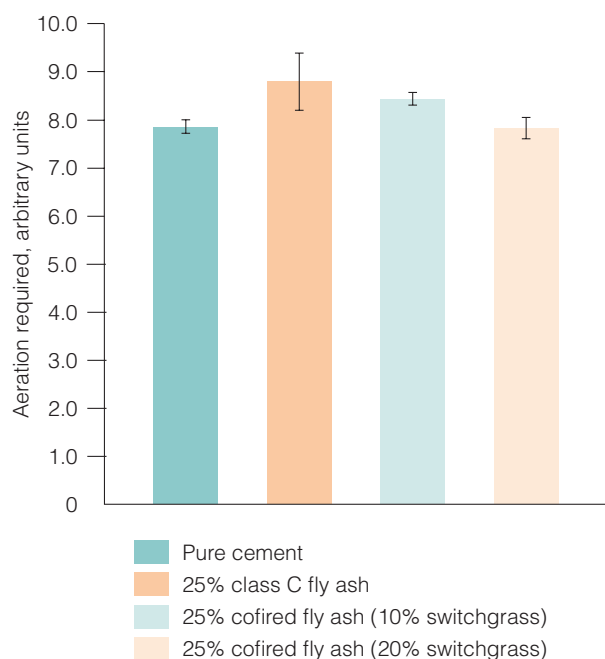


Figure 10 Dependence of flexural strength on fly ash composition (Baxter and Koppejan, 2004)

and concrete. These fly ashes did not show significantly different behaviour when combined with superplasticisers, air-entraining admixtures or retarding admixtures (Lamers and others, 2001). Cofiring ratios in excess of 10% have been investigated by KEMA in their 1 MWth test boiler. In this, up to 25% wood, chicken manure and RDF on a thermal basis was cofired with coal. The results showed that cofiring up to 25% waste wood, a few per cent chicken manure and 15% RDF was possible without significant influence on the properties of the fly ash (Meij and others, 2006). Further investigations on cofired ashes at high cofiring ratios have been conducted by Sarabèr and Van den Berg (2006). Flyash samples produced from cofiring at the KEMA test boiler and samples from Dutch power plant were tested according to EN 450 (1995).

There was additional testing for the concentrations of elemental macro components, reactive SiO_2 and the setting time for cement in accordance with EN 450 (2005). The testing included cofiring 39% SRF, 56% poultry manure and 23% paper sludge by mass. The results indicated that all the fly ash samples generated met the EN 450 standards. The performance tests of concrete confirmed the suitability of these fly ashes (Sarabèr and Van den Berg, 2006).

Investigations have been conducted on the impact of biomass-derived fly ash on concrete properties. The effect of biomass- and coal-derived fly ash containing both subbituminous and bituminous coal fly ash and ash obtained from cofiring herbaceous and woody biomass has been determined. In all cases, 25% of the fly ash used was replaced with fly ash which contained 0–40% biomass-derived material. The effects of the biomass on concrete air entrainment, flexural strength, compressive strength, set time, freeze-thaw behaviour and chlorine permeability were investigated. The focus of the tests was on herbaceous biomasses as woody biomass

contains so little ash that cofiring is much less likely to have a measurable impact on fly ash properties. Results in Figure 9 show the impact of fly ash on the required amount of aerating agent to establish ASTM-compliant air entrainment levels in concrete. Air entrainment is essential to prevent failure during freeze-thaw cycles. The results indicate that the amount of aerating agent increases with herbaceous biomass content. This arises as herbaceous biomass ash contains higher levels of water soluble components than coal ash which interact with aerating agents which are generally surfactants. Hence, if fly ashes from cofired units were treated in the same way as fly ashes from coal units, the resulting concrete would fail under freeze-thaw cycles. Increasing the amount of surfactant to the required level when cofiring biomass costs little but the failure to recognise the need to adjust could have a major impact. The impact of cofired ashes on flexural strength was also investigated and results obtained shown in Figure 10. There was little difference observed among the test samples. Additional data on set time and compressive strength indicated that all fly ashes delayed set times by two to four hours compared with concrete made from only cement, but that biomass cofired fly ashes do not behave differently from coal fly ash. The early compressive strength after one month was found to be compromised by all fly ashes with no difference between those containing biomass and those without. However, later compressive strengths after two months were found to be enhanced by the presence of all fly ashes. In some respects, biomass fly ash outperforms coal fly ash. Biomass enhances the pozzolanic reaction (CaOH with fly ash) significantly, presumably because it contains amorphous rather than crystalline silica, the former being much more rapid to react with CaOH in the mix. This reaction ultimately builds strength in concrete beyond that developed by the cementitious reaction. Experimental studies have shown that biomass containing fly ashes are superior to pure coal fly ash (Baxter and Koppejan, 2004; Van Loo and Koppejan, 2008; Baxter, 2011).

Barnes (2010) has reviewed the impacts on ash utilisation from recent changes in power generation practices. In relation to the quality of ash produced by cofiring, he concluded that the composition of fly ash tends to be dominated by the composition of coal as most co-fuels have a relatively low ash content. However, if the co-fuel is rich in a specific component, for example vanadium and nickel in petcoke, care must be taken to ensure that these do not impact adversely on the use of ash or on its environmental impact. In most cases reported in the literature, adverse effects are rare and cofiring ash may be used without penalty. He also surveyed the use of cofired fly ash as a cement component in concrete. The use of co-fuels results in fly ashes having essentially equal performance characteristics to coal fly ash over a wide range of cofiring ratios. Morphological observations revealed that cofiring gave minor changes in composition. The differences that were noted were, with one or two exceptions, within the range of normal variability of coal ashes. In terms of loss on ignition, there were only minor differences between materials. The main properties of construction application materials did not show any differences between performance for cofired and coal fly ashes of similar fineness. One study was of particular interest as it investigated high cofiring ratios. Johnson and others (2010) evaluated coal fly ash and cofired fly ash obtained at the Atikokan power station in Ontario, Canada, which fired coal or cofired wood pellets up to a cofiring ratio of 66% on a thermal basis. The fly ash produced was characterised and analysed for use as cement admixtures. Cofiring did not markedly change the fly ash composition as the ash content of wood pellets was very low compared to the lignite. The levels of metals and trace elements were within the ranges reported for other coal fly ashes. All the fly ashes had losses on ignition <1% which complied with the ASTM LOI regulations for use in concrete. Partial substitution of cement with fly ashes up to 40 wt% had a moderate effect on the entrained air content of the mortars but this difference disappeared upon addition of air entraining agent. Substituted mortars exceeded 75% of the strength of ash-free mortars after 28 days of curing thus meeting ASTM requirements. By 90 days, they met or surpassed 100% of the strength of ash-free mortars. Modifying the mortars with 20% coal ash or cofired ash had no effect on durability following repeated freeze-thaw cycles.

Overall, these studies indicate that there appear to be only modest impacts of biomass-containing fly ash on concrete properties, with an increased aerating agent requirement being one issue needing further attention. Otherwise, biomass-containing fly ash behaves in a qualitatively similar way to coal fly ash with no biomass, in terms of structural and performance properties when incorporated into concrete.

KEMA have investigated the health aspects of cofired ash. These initially involved tests on the KEMA 1 MWth test boiler in which secondary fuels were cofired up to a cofiring ratio of 10% on a mass basis followed by tests on all seven Dutch coal-fired plant with cofiring ratios up to 40% (mass). The ashes were used as raw materials to make concrete test cubes which were subjected to leaching and other tests and demonstrated that fly ashes generated by high percentage cofiring are able to meet the European EN 450 standards. The health effects were assessed using the KEMA Dust Assessment Methodology (KEMA-DAM) which determines whether, in case of fly ash dust exposure, the TLVs (Threshold Limited Values) or health limit values of particular substances in the dust can be exceeded. The KEMA-DAM procedure was applied to calculated cofired ash compositions at cofiring ratios of 10%, 30% and 50% (mass) for five secondary fuels. The result showed that up to 50% cofiring ratios of paper sludge, sewage sludge, residual wood, chicken manure and RDF of average composition did not lead to individual occupational exposure limits being exceeded at an inhalable dust exposure of 10 mg/m³. The sum of the average concentrations of the potentially carcinogenic trace elements As, Be, Cd, Co, Cr and Ni in the fly ash in all cases was less than 40% of the limit value for carcinogenic components and mixtures of 1000 mg/kg. The concentrations of dioxins and furans were measured in samples of cofired ash up to a cofiring ratio of 37% and were less than 2 pg TEQ/g which is 30 times lower than the limit value for application in soil. The concentrations of PAH in the ashes were also very low. The overall conclusions were that cofired ash did not pose any increased health risk for the ashes tested which were up to a cofiring ratio of 40% and cofired ashes could be regarded as ‘non dangerous substances’ according to the European Waste Catalogue (te Winkel, 2010).

5 Experience of plant cofiring high percentages of biomass

Over the past decade considerable progress has been made in utilising biomass in coal-fired plant. An analysis by Cremers (2009) has shown that over 200 units have either tested or demonstrated cofiring or are currently cofiring on a commercial basis (Table 6). However, only a few have cofired at high percentages, which in this report is taken as a share of biomass greater than about 15% by mass or 10% by energy. This chapter surveys experience worldwide in cofiring high percentages of biomass.

5.1 The Netherlands

As part of its obligations under the Kyoto Protocol, the Netherlands government agreed a coal covenant in 2002 with the six utilities which operated coal-fired plant to reduce CO₂ emissions from coal by 5.8 Mt/y in the period 2008 to 2012. More than half this target, namely 3.2 Mt, would be achieved by substitution of coal by biomass. This equated to installed biomass capacity of 508 MW. To achieve the target, electricity production from clean biomass attracted a subsidy of 4.8 c/kWh and a tax redemption of 2.9 c/kWh (International Energy Agency, 2004). Since then, the EU-27 have adopted a 20% renewable energy target for 2020. In the case of the Netherlands, this would mean a renewable energy target of 14%. Renewable electricity is a major part of the overall renewable energy target. The Dutch Clean and Efficient Program, initiated in 2007, proposed a 35% share of power from

	BFB	CFB	CFB/BFB	Grate	PF	unknown	Total
Australia					8		8
Austria		3		1	1		5
Belgium					1		1
Canada					7		7
Denmark		1		4	7		12
Finland	42	13	6	4	10	6	81
Germany				1	4	22	27
Indonesia	2						2
Italy					6	1	7
Netherlands					6		6
Norway		1					1
Spain		1					1
Sweden	3	7		2	3		15
Taiwan		1					1
Thailand		1					1
UK		2			16		18
USA	1	5		5	29		40
Total	48	35	6	17	98	30	234

Table 7 Current status of cofiring in the Netherlands (Cremers, 2009)					
Plant	Unit	Owner	Plant output, MWe	Plant output, MWth	Cofiring, %
Amercentrale 8	8	Essent	600	250	10–12
Amercentrale 9	9	Essent	600	350	27 +5 (gasifier)
Borselle	12	EPZ	403	–	10–15
Gelderland	13	Electrabel	602	–	5–8
Maasvlakte	1 and 2	E.ON	2x531	–	6

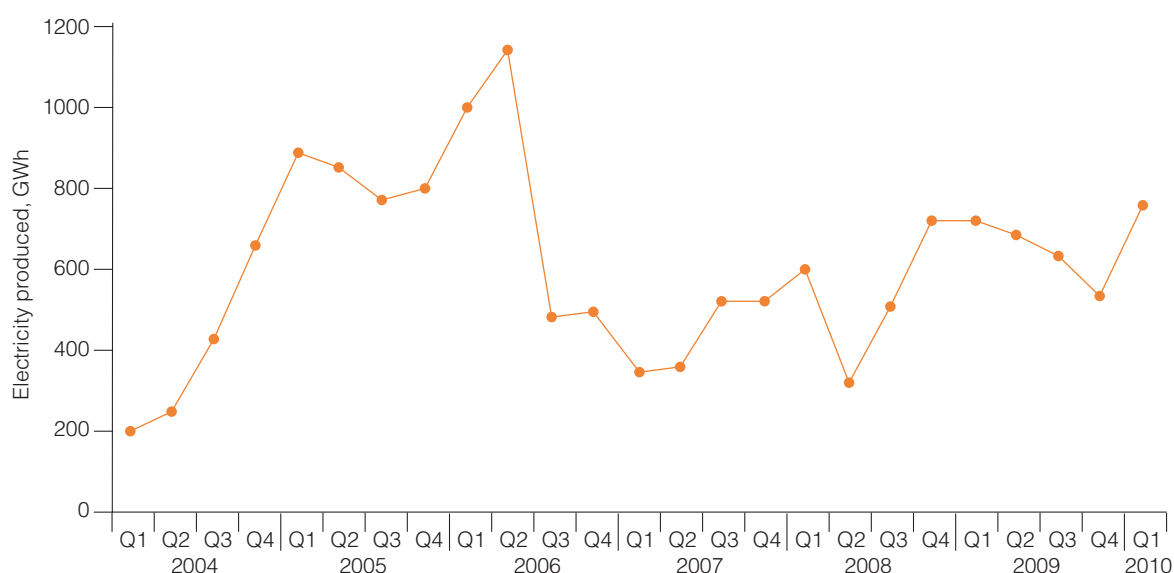


Figure 11 Electricity produced from biomass cofiring in the Netherlands (2002-09)
(Junginger and Jonker, 2010)

renewable sources by 2020. This would entail increasing the amount of renewable power generated in the Netherlands from 9 TWh in 2008 to 55 TWh in 2020 (Seebregts and Van Deurzen, 2010).

Biomass and waste have been cofired extensively in the Netherlands since the mid 1990s. The range of biomass and wastes that have been cofired includes wood pellets, waste wood, paper sludge, cocoa shells, chicken litter, sewage sludge, palm oil, meat and bonemeal, refuse derived fuel and olive kernels. The Netherlands has seven PCC units in five locations and all have cofired biomass, with six cofiring on a commercial basis. In addition, there is the Buggenum IGCC plant. The status of cofiring in the Netherlands is shown in Table 7. The amount of power generated from cofiring is given in Figure 11. This shows that the biomass power production has fluctuated and reached a peak in 2006, then more than halved in 2007 and increased erratically since then. The drastic reduction in 2006 was due to factors affecting use of liquid biofuel, mainly palm oil. Its usage plunged from 15.9 PJ in 2006 to 0.6 PJ in 2007, whereas the usage of solid biomass increased slightly over this period from 13.4 PJ to 15.4 PJ. The main reduction for the cofiring in 2006 was the reduction of the subsidy scheme in July 2006 and sustainability issues concerning palm oil. Until 2007 cofiring was subsidised by the

Dutch MEP subsidy programme. This programme stopped in 2006 and was succeeded by the SDE subsidy programme in 2008, which did not include cofiring. However, the original subsidy still applies for cofiring projects which were included in the pre-2007 MEP programme. All the current coal-fired power plant, excluding Hemweg 8, receive the MEP subsidy when they cofire. After the initial drop in 2007 cofiring of liquid biomass has been slowly increasing again to a consumption of 3 PJ in 2008. In 2009, the main feedstock for cofiring was solid biomass and about 650 GWh of electricity was generated by cofiring power plant. There are proposals for three new USC PCC plant which would cofire biomass. At Maasvlakte, Electrabel have proposed a 800 MWe plant and E.ON have proposed a 1100 MWe plant. The former would cofire 60% biomass and the latter 20%. Two 800 MWe units have been proposed by RWE at Eemshaven which would cofire 10% biomass. The current plants which cofire high ratios of biomass are Amercentrale 8 and 9 located in Geertruidenberg, the Borselle plant and the Gelderland 13 plant (Cremers, 2009; Junginger and Jonker, 2010). The operation of these units is described below.

5.1.1 Amercentrale 8

The unit 8 at the Amercentrale power plant is the second largest coal-fired CHP plant in the Netherlands and has a generating capacity of 645 MWe and a heat production capacity of 250 MW. This is a tangentially-fired PCC plant fitted with FGD and SCR, and the unit has been in operation since 1980 and can switch from coal, natural gas, oil or biomass. The types of biomass that are cofired are wood pellets, citrus pellets, palm kernel chips and olive residues. The unit has the capability to cofire up to 320 kt/y of biomass which is equivalent to a 20% cofiring ratio by mass. The actual amounts of biomass cofired in 2009 and 2010 were 166 kt and 160 kt which corresponds to cofiring ratios of 12.4% and 13.2%. Two separate mills were installed for Unit 8 for biomass. Each has a capacity of 160,000 t/y which corresponds to 37 MWe. The operational issues which are currently of concern are air/flue gas balance, too low a mill capacity, pneumatic transport to burners and fuel quality. The reliability of the hammermills has been poor but modifications have been made improving their performance in 2011 (Essent, 2011; Willeboer, 2008; RWE, 2010a; Van Riel, 2011).

5.1.2 Amercentrale 9

The unit 9 at the Amercentrale power plant is the largest coal-fired CHP unit in the Netherlands generating 600 MWe and has a thermal output of 350 MW. This PCC unit contains a FGD unit and low NO_x burners. The same types of biomass are cofired as at Amercentrale 8. The unit can cofire up to 600 kt/y of biomass. Two coal mills were modified to fire biomass. This involved construction of an inner plate, change of orientation of rolls and closure of some inner holes. The power output with the two mills when cofiring biomass is 136 MWe. Some operational issues arose relating to the grinding and pneumatic transport of the biomass. These included wear of mills and lines and mill capacity, the fibrous structure of the biomass, the particle size distribution, danger of dust explosions and pneumatic transport limitations. The current availability of mills is 99.8%. There were other concerns regarding the combustion behaviour in the furnace. These included longer burnout times, air distribution, low NO_x corrosion and temperature distribution. Other issues of concern were high inlet temperature for the FGD plant and fly ash quality. There are no significant operational concerns at the main plant which is one of Essent's most reliable units. The quantities of biomass cofired at the two units including the gasifier, described below, are shown in Figure 12. The actual quantities of biomass cofired in the main plant in 2009 and 2010 were 595 kt and 580 kt which corresponded to cofiring ratios of 31.7% and 34.2% by mass (Essent, 2011; Willeboer, 2008; Vollebregt, 2009; Van Riel, 2011).

The Amercentrale plant also contains a gasifier which gasifies demolition wood and fires the syngas in Unit 9. The demolition wood that is gasified is waste wood contaminated with paint and glue. Because of the contaminants it contains, the wood ash has to be kept separate from the coal ash. The chipped demolition wood is transported to the plant by truck and stored in a storage silo from which it is

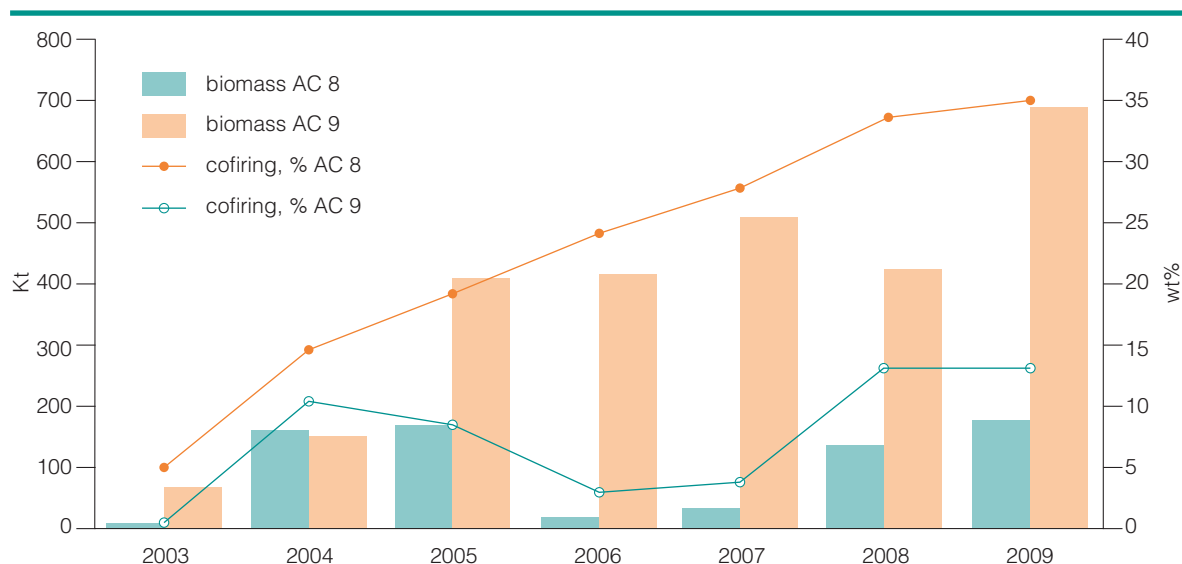


Figure 12 Biomass cofired at Amercentrale 8 and 9 (Vollebregt, 2009)

continuously transferred to a day silo. This feeds the screw conveyor feeding system of the gasifier. The atmospheric circulating fluidised bed gasifier operates at temperatures between 850°C and 950°C. The bed consists of sand and sometimes limestone or dolomite. The product gas passes through a cyclone and was originally cooled to a temperature of 220–240°C. The cooled gas is dedusted in a bag filter, quenched, scrubbed with water to remove ammonia, reheated to 100°C and fed to special burners in the Amercentrale 9 boiler. The output of the gasifier is 29 MWe at an efficiency of 34% net or 26 MWe + 15 MWth in cogeneration mode at an efficiency of 31% electrical and 18% heat (Willeboer, 2000). During early trials the gas cooler clogged up due to fouling and, in spite of modifications, the problems continued. In addition, the fly ash covering the bag filter showed a high sensitivity to oxygen due to the high carbon content of the ash. Hence the bag filters were replaced with cyclones which also meant that it was no longer necessary to cool the syngas to 220°C but to 450°C. Later the bed material was replaced with coarser sand to prevent it being carried along with the syngas. Measures were also needed to prevent agglomeration in the bed. Further problems occurred in the gas cooler due to fouling and pneumatic knockers were installed. A different challenge arose in 2005 when Dutch legislation changed such that it was not possible for uncleaned biomass to be converted to cleaned biomass at an installation. This meant that syngas from the demolition wood would be classified as uncleaned biomass and the plant would need to meet the requirements of waste incinerators. However, following extensive negotiations, Essent persuaded the ministry that the syngas was as clean as syngas produced from clean biomass. The gasification of demolition wood recommenced in 2007. The biomass consumed by both units since 2001 is shown in Figure 13. The operational issues that have arisen since 2007 relate to wood quality. This has been addressed by reduction of metal parts following extensive wood quality control. There have also been instrument trips, for example with O₂ measurements. Instances of refractory damage have occurred due to frequent flushing with cold N₂ as well as bottom ash blockages and partial blockage of gas cooler due to fouling. The existing practice of unplanned outages due to breakdown of non-redundant components and opportunity-based cleaning and repair of the gas cooler has been replaced by three to four planned outages per year combined with preventative maintenance and inspections. The challenges arising in the early years have been addressed and the current concerns relate to plant unavailability caused by iron and other impurities in the fuel. It is hoped to increase the operating hours of the gasifier to over 5000 h/y. This would correspond to gasifying 100 kt/y of demolition wood. The amounts of biomass cofired in the gasifier in 2009 and 2010 were 94 kt and 86 kt respectively. The operators are considering installing a third biomass mill at Amercentrale 9, additional wood feeding to the gasifier, a second gasifier at Amercentrale 9 and additional mills at Amercentrale 8 with the purpose of increasing the cofiring ratio to 50% by 2015 (Hooijmaijers, 2009; Vollebregt, 2009; Van Riel, 2011).

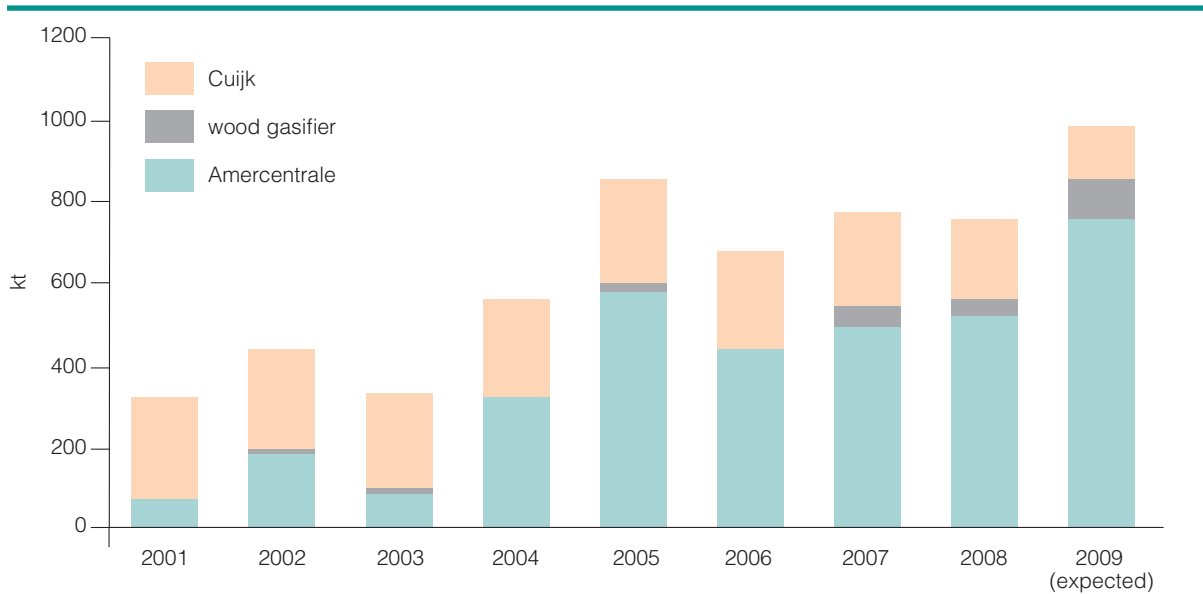


Figure 13 Biomass cofired at Amercentrale 9 in main plant and gasifier (Vollebregt, 2009)

5.1.3 Borselle

The Borselle plant, operated by EPZ is located in Borselle and is a 406 MWe tangentially-fired PCC unit with low NO_x burners and overfire air. The site also contains a 450 MWe nuclear plant, an 18 MWe gas turbine and a number of wind turbines. The coal-fired plant originally started to cofire phosphor gas in 1996. It has cofired biomass since 2000 and currently cofires cocoa residue, palm kernel and citrus pulp. Originally, secondary fuels were simply shovelled on to the coal conveyor belt. The fuel mixture was pulverised in the coal mills and blown into the boiler. This was suitable for cofiring ratios of <5% but the biomass feed to the pulverisers fluctuated, resulting in unstable operation. Hence, a second feeding system for secondary fuels was installed. The secondary fuels were fed from a day silo to two coal pulverisers by means of a screw conveyor. Although this allowed the secondary fuel to be fed in a controlled manner, the capacity of the system was limited to 5–10% of secondary fuel by mass. Therefore, another system was installed in which there were individual feeding lines for the secondary fuel which had been pulverised by a rotary hammer mill or a cruncher and then introduced directly into the boiler through dedicated burners. It was then possible to increase the cofiring ratio to 30% on a mass basis. Though the capacity limitation problem was now solved, other operational challenges arose. The particle size distribution for the pulverised secondary fuel was different from that of coal. Whereas the average particle size for pulverised coal was in the range 0.1 mm, that for secondary fuels was substantially larger at 0.7 mm and also had a larger range of particle size distribution as shown in Figure 14. This difference affected the handling properties of the pulverised fuel mixture with respect to pulveriser flooding, pneumatic transport, burner flame pattern and behaviour in the firebox. The level of change depended on the type of coal, type of secondary fuel and the cofiring ratio. In addition, there were effects on by-products. This was related to the performance of classifiers and mills and could result in high percentages of unburnt carbon as much as 18% carbon-in-ash. There were also effects on the odour, colour and the quantity of ash. The level of contamination could have such an effect on fly ash quality that it had to be disposed of as a waste. This would have considerable financial repercussions. The operators also observed noticeable effects on boiler fouling. The effect of the biomass was to switch the ash type from hard coal to sub-lignite. The normal fouling prediction formulae proved inadequate and a strict observation routine was required. By changing the firing pattern in the furnace and the fuel composition through switching to gas firing or coal-only firing, it was possible to prevent some of the fouling in the furnace or reheaters. As the fuel composition of the secondary fuels varies largely and is very different from coal, the various power plant emissions could increase significantly. The components that are not removed by the usual flue gas treatment were species such as chlorine, phosphorous, fluorine and mercury.

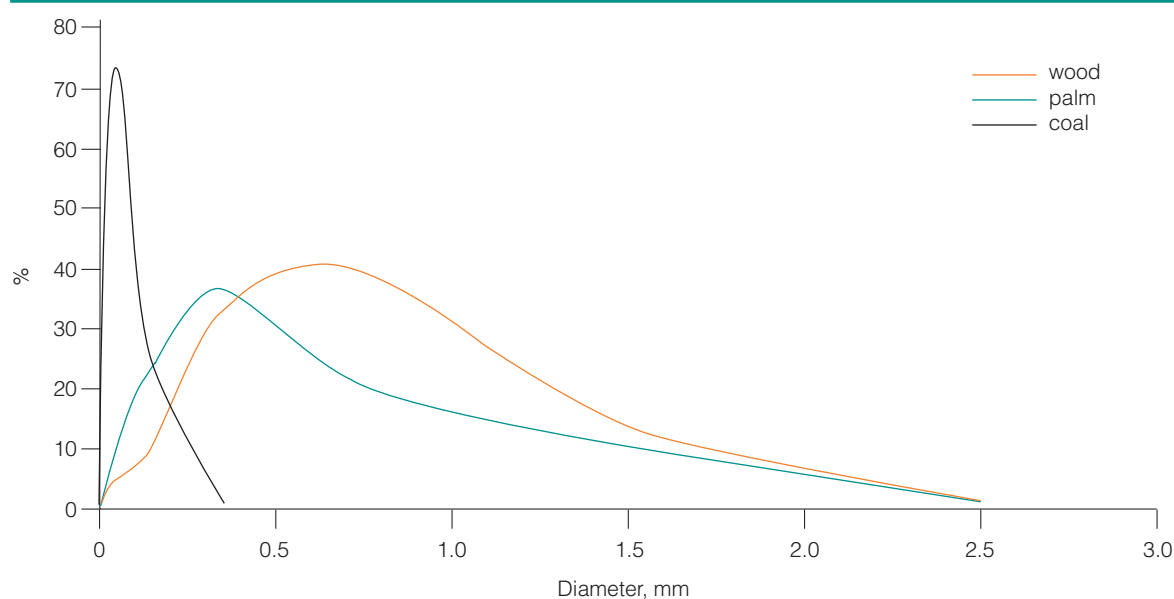


Figure 14 Typical particle size distribution of secondary fuels when pulverised with coal (Dekker and Van Mastrigt, 2006)

In order to assess the long-term effects on the boiler, particularly in relation to corrosion, EPZ initiated a monitoring programme in 2004. At various locations KEMA corrosion probes were exposed to furnace and convective section conditions. After 3000, 5000 and 8000 hours of exposure, the probes were replaced and examined by KEMA. This showed a severe increase in oxidation of the radiant wall tubes. Inspection of the radiant wall tubes during the 2005 shut-down confirmed these findings. The tubes near the dedicated secondary burners had been particularly affected by chlorine attack. During the shutdown 300 m² of Inconel 622 were welded to the radiant wall tubes in order to repair the damage. The effect on the SCR catalyst when cofiring large quantities of secondary fuels was also investigated. During the installation of the SCR unit, a test reactor was also installed. Catalysts with differing vanadium contents of 0.5%, 1.0% and 1.5% were monitored while cofiring 10–15% of secondary fuels such as animal residues, phosphorous rich refinery off gas, cacao, sea nuts, wood pellets and olive pulp. The longest test of 8000 h was undertaken with the 1% V catalyst as this was the type that was installed at the plant. This examination showed that the activity of the catalyst had decreased by 20% which was better than anticipated and in line with expected degradation of catalyst when operating on coal only. Overall, the operators concluded that the experience of cofiring large quantities of secondary fuels with coal was limited. Normal coal-based prediction rules do not apply when cofiring at high cofiring ratios. Strict plant monitoring is required when cofiring in excess of 10% biomass. Based on the composition of the fuel mixture, short-term effects (by-products, emissions, efficiency) and long-term effects (corrosion, catalyst poisoning) must be considered and limits may need to be applied. Setting up a monitoring programme in combination with a blending database, which contains the various parameters and limitations is crucial for successful processing of large quantities of secondary fuels (Dekker and Van Mastrigt, 2006). The Borselle plant had an output of 2.3 TWh in 2009 of which 360 GWh (15%) was generated from biomass. The biomass share increased 40% compared to 2008 (E-Energymarket, 2010).

5.1.4 Gelderland 13

Electrabel Gelderland 13 power plant was the first plant in the Netherlands to cofire biomass. It is a 602 MWe, PCC unit containing 36 low NO_x burners without overfire air but with SCR and FGD. It has been cofiring waste wood originating from demolition activities commercially since 1995. The amount of waste wood originally fired was 60,000 t which is equivalent to a 3% coal replacement. The

wood was originally injected into the boiler through four separate burners located below the coal burners. However, this led to increased carbon-in-ash levels and hence the wood was injected with the pulverised coal. The wood milling capacity was not originally sufficient and there were also high maintenance costs. Hence it was necessary to redesign the milling circuit. The electrical output from the wood was 20 MWe. The wood waste supplies are plentiful and when pulverised, the fuel has the burning characteristics of natural gas or oil. At this modest cofiring ratio, with a relatively high quality fuel, the impacts on operations, environmental performance and plant availability have been small. Though there were initial problems with wood handling and milling, the plant has had no problems maintaining commercial operation. The public acceptance of cofiring was an issue as the plant is located near a residential quarter of Nijmegen. Operations were halted at one stage as the authorities decided that the permit did not allow the combustion of waste (Van Aart and Ramsgaard-Nielsen, 2002; Van Loo and Koppejan, 2003). The cofiring ratio was increased over the years and reached 3–10% by 2008. More recently, the cofiring ratio has been further increased. This involved installation of additional facilities for pellet unloading, transport and pre-cleaning and for storage, milling and transport of the milled wood to the burners. The conversion involves investment of more than €40 million. The wood is co-injected into the primary air coal dust lines. The connection is just before each burner to prevent blockage in splitters. There are 24 blowers and 24 pneumatic lines to each burner. The cofiring capacity of biomass was increased from 44 MWe to 180 MWe. This corresponds to a cofiring ratio of nearly 30% (th) and 470,000 t of wood pellets will be cofired annually (Beekes, 2006; Ryckmans, 2009; NL Agency, 2010).

5.2 The USA

Biomass cofiring is a proven technology in the USA. Several power plant have commercially cofired biomass for some years and there have been many demonstration projects at others. Although in the late 1980s and through the 1990s there were a large number of successful field tests at utility installations in the USA with support from the National Renewable Energy Laboratory, there has been comparatively little new work over the past decade. In 2010, 10.3% of net electricity generation was from renewable sources of which the major components were hydropower (6.2%) and wind (2.3%). Biomass and waste contributed only 1.4%. The use of renewable fuels for power generation is, however, likely to increase due to current and proposed government policies and requirements. Though there is no federal support for cofiring, individual states have Renewable Portfolio Standards (RPS) which provide a mechanism to increase renewable energy generation using a market-based approach. An RPS requires utilities to supply a specified minimum amount of customer load with electricity from eligible renewable energy sources. Over 30 states currently have such standards. The targets for the share of renewable energy vary with California having the highest of 33% by 2020. All states include biofuels and biomass as being eligible but whether cofiring is eligible depends on the individual state. A number of states have explicitly defined cofiring as a qualifying resource, while others have explicitly excluded it. Other programmes are silent and the Governing State Commission may need to determine whether cofiring constitutes a renewable resource on a case-by-case basis (Eisenstat and others, 2009; EPA, 2009; US Energy Information Administration, 2011).

In the USA there have been over 40 commercial cofiring demonstrations. A broad range of fuels, such as, residues, energy crops, herbaceous and woody biomasses have been cofired in PCC, stoker and cyclone boilers. The proportion of biomass in the majority of projects has ranged from 1% to 20% by mass. Currently cofiring is limited to a few dozen plant, many of which use waste biomass from industrial and agricultural production facilities to generate power for those same facilities, rather than to other customers. Though biomass cofiring in utility boilers showed much promise two years ago, supported by encouragement from the new Obama administration and state RPSs, more recent EPA (Environmental Protection Agency) legislation, the recession, low natural gas prices and opposition from environmental groups have significantly reduced the power industry's interest in biomass cofiring. Many of the older coal-fired boilers targeted for cofiring face possible shutdown. The new EPA MACT (Maximum Achievable Control Technology) rules have a severe impact on biomass

cofiring. Industry is reluctant to add new pollution control systems, such as scrubbers and SCR, unless the payback time is short. Biomass cofiring projects which Southern Company and Duke Energy had for biomass cofiring are now on hold. In the future, if RPSs include cofiring, biomass cofiring could play a part in extending the life of marginal coal-fired plant. Biomass cofiring will give efficiency benefits, emissions reductions and provide baseload generation. At low to moderate cofiring ratios, cofiring appears to have the best overall performance for reducing emissions and ensuring trouble-free operation of coal-fired plant (Neville, 2011).

5.2.1 Availability of biomass

Currently biomass is cofired in the USA at a relatively small scale. The availability and sourcing of biomass will be a major consideration for a utility seeking to develop a significant cofiring generating capacity. There are several types of biomass that can be cofired in the USA. Wood-based and agriculturally-based biomass are both potential fuel sources. There are, however, considerable regional differences in the local availability of potential biomass sources. A wood-based fuel may be preferred for a power plant in Southeastern USA due to the abundance of soft woods in the region. In parts of the Midwest, which are agricultural regions, an agricultural product will be a preferable option. Biomass can be cultivated specifically as a fuel or could be a by-product of another process. Purpose-grown agricultural products include miscanthus and switchgrass. By-products include straw, corn stover, bagasse and rice hulls. Primary sources of woody fuels are frequently roundwoods. Residual sources include sawdust, mill residue and hog fuel. The advantage of purpose-grown biomass is stability of supply of the fuel and the increased efficiency in harvesting. The disadvantage is that it can compete with other uses for the fuel. The use of roundwood as a fuel, for example, would compete with the lumber and pulp paper industries. Agricultural biomass could displace food production. Residual biomass fuels are typically less expensive and less likely to compete with other uses but are not always harvested with the primary material, making collection difficult. Biomass can be used as a fuel in its raw state or can be processed by, for example, pelletisation or torrefaction. Pelletisation typically increases the heat content of the fuel by removing moisture and standardises the size and shape. However, the process is energy intensive and adds to the cost of biomass. Torrefaction also increases the heat content of the fuel and makes it more durable.

The sourcing of biomass also requires careful consideration. There may be some sources near a power plant but they may be unable to provide the quantity of biomass to generate 100 MWe or more. A utility may need to find a number of suppliers in different geographic areas to obtain the quantity of fuel necessary. In most cases, these suppliers do not currently exist. Some will be active in the agricultural or wood products industries but they are not active in supplying biomass fuels. In many cases, suppliers of biomass fuels have limited operating history. There are about 50 pellet plants operating in the USA with a combined production of around 1 Mt/y. One of the largest is in Florida and produces 550,000 t/y but many are in the range 50,000–125,000 t/y. A key determinant of the size of the pellet plant is how far the plant is from the raw biomass that will need to be harvested. As raw biomass can have a moisture content of approximately 50%, the transportation costs become an important factor as the distance increases. This will also influence whether the pellet plant is located near the utility or the raw biomass supply. Since the industry is relatively undeveloped, utilities may be able to shape the supply chain before it is fully established (Clair and Fordham, 2009; Akbrut, 2010).

5.2.2 Cofiring plant

Amongst the commercial cofiring demonstrations in the USA, about a dozen trials have fired relatively high cofiring ratios of biomass and these are listed in Table 8. Some of these trials took place over relatively short periods. A collaboration involved the National Energy Technology Laboratory (NETL), US Department of Energy (US DOE) and the Electric Power Research Institute

Table 8 US high biomass cofiring plant experience (Battista and Hughes, 2000; Grabowski, 2004)

Name	Output, MWe	Cofiring ratio, % (mass)	Duration	Biomass
McNeil	50	15	since 1998	wood chips
Hammond	100	13	3 days	sawdust
Dunkirk	90	20	6 months	wood residue
Greenidge	108	30	16h/day	wood chips
BL Station	120	12	2 months	wood waste
Gadsden	60	12	3-4 weeks	switchgrass
Michigan City	469	20	5 days	wood waste
Blount St	100	15		switchgrass
Seward	32	18	2 months	sawdust
Allen	272	20	10-24 tests	sawdust
Jeffries	165	20	6 months	wood chips
Vermilion	75	25	3 hrs	railroad ties
City of Tacoma	42	80	ongoing	wood/RDF

(EPRI) who initiated a co-operative agreement in 1995 to develop biomass cofiring in coal-fired plant. The US DOE/EPRI biomass cofiring programme was initiated in 1996 at seven existing coal-fired utilities and the initial evaluations were at Allen, Kingston and Shawnee plants. These represented a cyclone boiler, a tangentially-fired boiler and a wall-fired boiler. The studies indicated that biomass cofiring was technically feasible and subsequently cofiring has been demonstrated at many US plants both inside and outside the EPRI programme. The experience gained from these trials has provided valuable information on fuel handling, storage and preparation. There is a modest amount of information on efficiency, emissions and economics but less information on fireside behaviour and SCR impacts. By 2001 utility cofiring techniques had largely been evaluated and demonstrated and the emphasis then shifted to gasification-based bioenergy. The cofiring trials that took place have been surveyed by Fernando (2005) and the type of information obtained is given in the examples described below. More recently some work has been undertaken to evaluate the feasibility of firing high cofiring ratios and indeed consideration of total conversion of a coal plant to fire biomass (Tillman and others, 2002; Grabowski, 2004 and Baxter and Koppejan, 2004).

5.2.3 Allen plant

Cofiring tests were undertaken in one unit of TVA's Allen plant, which had three 272 MWe cyclone boilers in 1994-96. The plant is located in Memphis, TN, in a wood producing area with numerous sawmills and furniture mills in the immediate vicinity. The coals fired were Illinois Basin coal and Utah bituminous coal. Both green and dry sawdust were obtained but the best results were achieved with green sawdust containing 40% moisture. The sawdust was stocked in the coal yard and reclaimed for blending with the coal on the belts leading to the bunkers. Cofiring percentages up to 20% by mass (10% th) were tested. Base coals used included both Illinois basin coal and Utah bituminous coal. Tests were conducted varying the particle size of biomass from 6.25 mm to 38 mm and varying the excess oxygen from 2.2% to 3.5%. It was possible to cofire sawdust without loss in boiler capacity. An increase in feeder speed was required but there was sufficient feeder capacity to accommodate

this. There was some loss in boiler efficiency but it was not necessary to increase excess oxygen. The tests demonstrated that it was possible to reduce SO₂, NO_x and CO₂ emissions with modest efficiency penalties. The sawdust had a low fuel nitrogen content (0.1% to 0.3%) and a high volatile to fixed carbon ratio (typically >4) compared to coal. This resulted in lower NO_x emissions. The particle size was found to have significant influence on NO_x levels. Particles larger than 25 mm did not reduce NO_x levels (Tillman and others, 2002; Tillman and Harding, 2004).

5.2.4 Plant Gadsden

Plant Gadsden consists of two 70 MWe tangentially-fired PCC units located in Gadsden, Alabama. The units were fuelled with eastern bituminous coals. Switchgrass was injected directly into the boiler through separate burners up to a cofiring ratio of 7% (th). The tests were supported by extensive pilot-scale studies at the Southern Research Institute. Testing took place in March and April 2001 and forty tests were conducted at different operating conditions and cofiring ratios. Each test lasted one to two hours. The testing was designed to address efficiency and environmental impacts of cofiring, focusing particularly on airborne emissions. The testing showed boiler efficiency loss of 0.3% to 1.0%, depending upon the level of cofiring and boiler conditions. This reduction was partly due to higher dry gas losses associated with introducing cold transport air into the furnace. Additional losses were higher hydrogen and moisture losses. Emissions of SO₂, mercury and fossil CO₂ decreased while cofiring. NO_x emissions did not decrease. This programme showed that it was important not to blend herbaceous materials with coal for pulverising and storing in bunkers and also not to store the switchgrass in the surge bin overnight as this caused handling problems (Tillman and Harding 2004; Zemo and others, 2002).

Southern Company and Alabama Power have conducted more recent tests at Plant Gadsden from October to November 2007. About 1100 t of wood chips were cofired in Unit 2. Green wood chips were successfully cofired in blends at 8%, 10% and 15% by weight. The types of wood cofired included whole trees with needles and clean chips. The wood was deposited on top of the coal on the belt and stored in the bunker. The biomass energy input was about 3–5%. The wood chip moisture varied between 50% and 67%. Pine needles in the wood complicated bunker flow, increasing the tendency of the fuel in the bunker to bridge, to rat hole and to adhere to the walls. The mill amps increased by 10–15% when cofiring green wood chips, believed to be caused by build-up of wood in the pulveriser bowl. The mill motors had to have sufficient reserve, or had to be upgraded, to carry the additional load to avoid derating. Full load required much higher volumes of fuel when cofiring due to the low density and low heating value of the fuel. At a cofiring ratio of 15%, the volume of fuel was 25–30% more than with coal alone. Coal feeders and pulverisers must have sufficient capacity or be upgraded to process this volume of fuel. The operating stability on automatic controls did cause difficulties during the tests but this was thought to be less related to cofiring than to the installation of new controls prior to the tests. Minor adjustments to the control unit reestablished normal operation. The high moisture content of the green wood increased mill under-bowl pressures. At full load, the power output was reduced by about 5% when cofiring 15% green wood due to these mill factors. No blockage of fuel lines or pulveriser raffles was observed. Boiler exit temperatures fell with increased wood in the fuel. This was probably due to the high moisture content of the wood reducing the adiabatic flame temperature. The size of wood chips did not seem to affect mill operation. The boiler efficiency was unchanged when cofiring 10% wood but at 15%, the efficiency was reduced by about 0.3–0.7% depending on load. Mercury and sulphur emissions were reduced during cofiring but NO_x levels were unchanged. Particulate emissions were lower during cofiring while the opacity was essentially unchanged (Boylan and others, 2011).

A second series of tests were carried out in April and May 2008. Cofiring ratios of 8% and 15% were tested but this time with dry, 35% moisture and 65% moisture wood. In addition to the lower moisture content than in the earlier tests, the wood was mainly hardwood. The coal used in this trial was different from the synfuel used in the earlier one. The coal in phase 2 was softer than the synfuel in

Phase 1. Hence the unit was able to achieve full load at 15% cofiring ratio without exceeding mill amp limits. The drier wood in phase 2 also resulted in fewer mill problems. Unlike in the earlier tests, the mill under-bowl pressures and mill temperatures were acceptable and required no unit load derate. Slagging occurred during the tests but this was caused by the coal. The operating instability issues were resolved with simple control tuning. A measurable NO_x reduction was seen in Phase 2 unlike in the earlier tests. This might have been related to the difference in volatile contents of the two coals or to the higher fraction of fines in the phase 2 wood. The CO emissions were similar in both tests (Boylan and others, 2008).

5.2.5 Seward plant

The cofiring test programme at the Seward plant was undertaken by EPRI and the US DOE in December 1996 and July 1997. The tests were performed on the 32 MWe, wall-fired, No 12 boiler which was equipped with a biomass surge bin, metering augers, lock hoppers and transport pipes. These pipes connected the biomass delivery system to unused centre pipes of the top three burners. The initial tests were conducted with green sawdust containing 39% moisture, old sawdust containing 49% and dry sawdust containing 14% moisture. Sawdust was injected utilising this separate injection system up to 18% on a mass basis. The results obtained from the tests are shown in Table 9. During cofiring there was no reduction in boiler capacity, the loss in efficiency was modest equating to about 1% for a cofiring ratio of 10% (mass) but there was significant reduction of NO_x emissions of up to 17%. This reduction was due to fuel volatility. The sawdust ignited rapidly creating fuel-staging conditions for reducing NO_x. The tests showed that carbon conversion was not degraded by cofiring. There were no operational problems with opacity, unburnt carbon or CO emissions. The demonstration at Seward was terminated when the plant was sold as a result of deregulation (Tillman, and others, 2002; Tillman and Harding, 2004).

Other than the trials at Plant Gadsden, current demonstration activities in the USA on cofiring high ratios of biomass with coal are limited. The demonstrations undertaken as part of the DOE/EPRI/NETL

Table 9 Test results at Seward power plant (Tillman and others, 2002)

Wood type	Cofiring, %		Boiler η , %	Carbon-in-ash, %	NO _x , kg/GJ
	mass	thermal			
None	0	0	85.62	6.92	0.41
Fresh sawdust	3.4	1.47	85.79	4.61	0.37
Fresh sawdust	6.4	2.83	85.71	5.86	0.37
Fresh sawdust	9.5	4.31	85.47	6.02	0.36
Fresh sawdust	13	6.04	85.03	7.84	0.36
Fresh sawdust	16.1	7.6	84.21	8.68	0.34
Dry sawdust	13.8	8.11	85.74	5.09	0.35
Dry sawdust	17.2	10.3	84.09	10.16	0.34
Fresh sawdust	17.9	8.53	84.65	5.89	0.34
Old sawdust	4.4	1.61	86.13	5.5	0.37
Old sawdust	8.2	3.05	85.26	6.7	0.37
Old sawdust	11.9	4.31	85.62	3.12	0.36
None	0	0	86.07	6.65	0.37

programme prior to 2002, concentrated on storage, handling, fuel preparation, milling, combustion and environmental aspects. There were no major impediments regarding these aspects. However, some of the trials took place only for a few days or for a few hours per day dispersed over a few months. These would not necessarily show up operational issues related to corrosion, slagging or fouling. No such problems were observed when cofiring woody biomasses. Herbaceous biomass fuels which generally have higher inorganic content and lower ash fusion temperatures would be expected to be more prone to slagging and fouling especially at high cofiring ratios.

5.2.6 US biomass repowering

There are several projects in the USA to take an existing coal-fired plant and repower it to fire biomass. This is considered to be less costly than constructing a new biomass plant, and it directly replaces coal generation capacity and is considered carbon neutral. Southern Company are repowering Plant Mitchell unit 3 located near Albany, GA. Currently it is a 155 MWe, PCC, coal facility. It will become a 96 MWe 100% wood-fired facility with a new stoker grate and suspension firing. Approximately 1.1 Mt/y of biomass will be fired. Once completed it will become the largest operating wood-fired power plant in the USA. In March 2010, Georgia Public Service Commission approved the plant. The retrofit was expected to begin in 2011 and the plant to be in operation in 2012 (Haswell, 2010). Plans were also announced by FirstEnergy Corp to convert two units at the R E Burger plant in Shadyside, OH to burn biomass. Units 4 and 5 at Burger with a combined output of 312 MWe, were to have fired biomass (specifically such as corn stalks, wheat or grass) in a \$200 million retrofit which was to be completed in 2013. However, in November 2010 FirstEnergy Corp announced that the two units would be permanently shut down. The reason given was that the market prices of electricity had fallen significantly and the expected market prices no longer supported a repowered Burger plant (Power-Gen Worldwide, 2010). Another station where a biomass-fired boiler was retrofitted to replace an existing coal-fired one was the Schiller power plant in Portsmouth, NH. This is Public Service of New Hampshire (PSNH)'s third-largest facility and has been in continuous operation for six decades. The first three units were retired decades ago but units 4–6 were installed in the 1950s and in the early 1980s they were refurbished to utilise oil or coal. In 2003, the decision was made to replace Unit 5 with a similarly-sized, 50 MW biomass-fired CFB boiler. Alstom Power Inc were awarded the EPC contract and the contract to supply the CFB boiler island. The existing Unit 5 turbine was overhauled and PSNH were able to use the balance-of-plant already in place such as the generator, cooling water and auxiliary steam systems as well as the feedwater, make-up water and condensate equipment. The biomass consists of wood chips, stumps, brush, low-lying vegetation, low grade woods and other plant materials unusable in timber and paper production. These materials are produced by normal forestry practices such as timber harvesting and fire control and from clearing land for homes, roads and commercial development. Although the CFB unit currently burns wood, it can burn coal if necessary. The plant became operational in December 2006 thus reducing emissions and expanding the local market for low grade wood. The \$75 million project was completed at no cost to the ratepayers (Peltier, 2007).

Not all biomass repowering projects reach fruition. In October 2008, Xcel Energy announced a \$55 million proposal to convert the last remaining coal-fired unit at its Bay Front power plant in Ashland, WI, to fire gasified biomass. Two of the three units at Bay Front contain stoker boilers which have combusted woody biomass since 1979. The third has a coal-fired cyclone boiler. The units all generate about 20 MWe. Syngas from gasified biomass was most suitable for this boiler. The conversion would have entailed the installation of a gasifier and some minor changes to the boiler to maximise heat recovery, as well as new fuel handling equipment such as another hydraulic truck dumper and conveyor belts. Xcel submitted an approval application to the Public Service of Wisconsin in February 2009. Though the application was approved in November 2009, a year later Xcel cancelled the plans. The company said that the cancellation was due to three factors. The first was that the cost increased from \$55 million to \$80 million. In addition, the conversion faced considerable regulatory uncertainty and the declining costs of other generation options (Austin, 2009; Biomass Power and Thermal, 2010).

5.3 UK

Though 15 large coal-fired power plant in the UK have cofired biomass, most have cofired at cofiring ratios of less than about 6% (th). The exceptions are the Drax power station located near Selby, Yorkshire and Fiddler's Ferry power station near Warrington, Merseyside. The 4000 MWe Drax plant owned by Drax Group now has the capability of generating 500 MWe from biomass, which corresponds to a cofiring ratio of 12.5% (th). Scottish and Southern Energy's Fiddler's Ferry plant can cofire up to 20% (th) biomass in two units. RWE have also decided to convert the Thames-side Tilbury plant to fire 100% biomass.

5.3.1 Drax

The Drax power plant consists of 6 x 660 MWe units. Drax first considered biomass cofiring in 2002. It trialled cofiring palm kernels in 2003. By co-milling through existing mills, the plant was able to generate 100 MWe from biomass cofiring in 2004 and by 2005 was cofiring about 162,000 t of biomass per year. The mill power requirements increased when co-milling biomass with coal. In order to significantly increase the cofiring ratio and avoid poor mill performance due to co-milling, it was decided to install a new direct injection system in which the biomass is milled separately and injected into the existing pulverised coal lines upstream of the coal burners as shown in Figure 15. A direct injection pilot was installed in one of the units in 2005 and operated successfully, leading to the decision to adopt this configuration in all six units in 2007. This technique has the advantage that the milling technology can be optimised for biomass and the performance of existing coal mills is unaffected. For wall-fired boilers, as at Drax, cofiring the coal and biomass in existing burners is more economic than installing dedicated biomass burners, though this does limit the cofiring ratio. The capacity of the new direct injection cofiring installation is 1.5 Mt/y of biomass which corresponds to about 400 MWe. This added to the existing capacity of 100 MWe of cofiring capacity through the current mills results in a total cofiring capacity of about 500 MWe.

The contract for the construction of the biomass handing and processing facilities was awarded to Alstom and the contract for providing the direct injection connections to the existing PC feed lines to Doosan Babcock. The installation of the direct injection system posed demanding construction

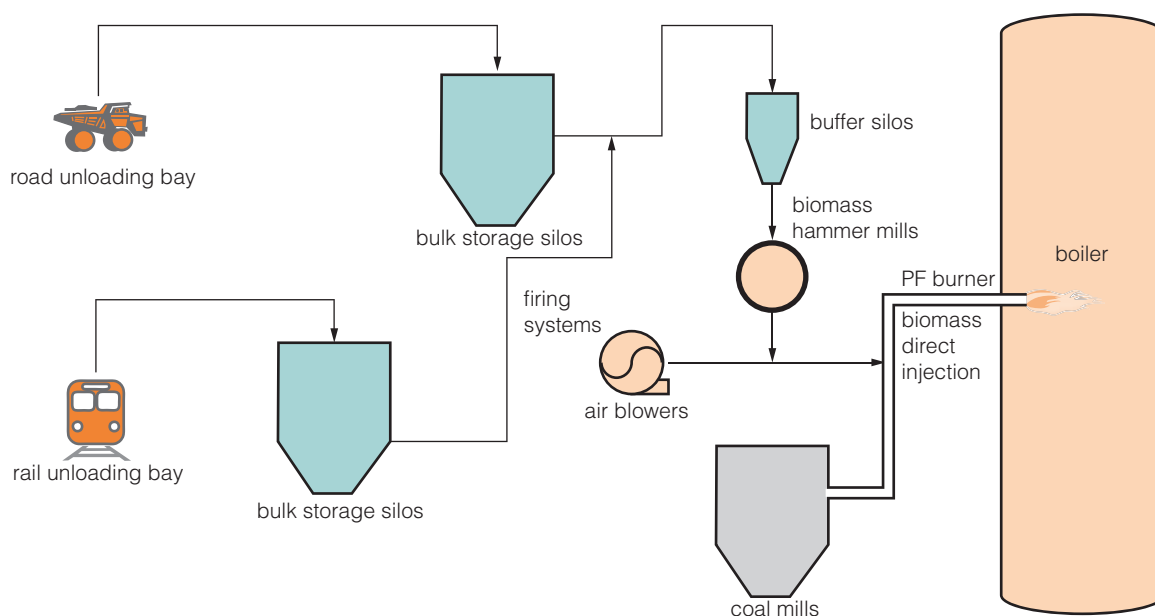


Figure 15 Scheme for direct injection at Drax (Modern Power Systems, 2010)

challenges and constraints due to the need to work within an operating plant. The road unloading, biomass storage and process plant were installed away from the main boiler and the biomass was transported across the power plant to a compact superstructure, located just outside the boiler building, where the final processing and milling takes place. The conveyors are enclosed and of the air-glide type, to achieve smooth flow and reduce dust generation. The biomass is conveyed from the bottom of the screening tower to the top of the bulk storage silos. The biomass bulk storage capability is 36,000 m³, which corresponds to three days' supply at full load and the buffer capacity is 2400 m³. Screw reclaimers extract the biomass from the bottom of the bulk silos and convey it to buffer silos at the top of the processing tower. The hammer mills are located in the processing tower. The milled biomass from the hammer mills is injected into the pulverised coal lines.

Drax cofires three types of biomass: agricultural residues, forestry products and energy crops. Agricultural residues include straw, oat husks, peanut husks, grape flour, cocoa shells and olive cake among many others. As they are by-products of food production, they do not reduce the amount of land available for farming. Forestry products include bark, thinnings, tree tops and branches. Energy crops include short rotation coppice willow and miscanthus. Drax has been for many years at the forefront of encouraging UK farmers to develop a UK biomass supply chain. It launched the 'Green Shoots' programme in 2009 to source energy crops. Drax has built a straw pellet plant in Goole to process straw purchased from local farmers. This was opened in 2009 and can produce 100 kt of straw pellets annually. Drax has considered converting one of its six boilers to run solely on biomass but the UK renewable legislation does not facilitate this. Under the present regulations, any biomass Drax burns is considered to be cofiring because all the boilers use the same chimney. If the rule was changed so that individual boilers could be deemed to be dedicated biomass plants, Drax would receive up to 2 ROCs/MWh for the electricity generated. Drax expects in time to increase the cofiring ratio for the plant from 12.5% to 15% or 20% but they do acknowledge that it would be impossible to convert the whole plant to fire biomass as that would require about 15 Mt of biomass per year which would be impossible to procure or store. If the cofiring ratio at Drax is increased to above 15%, the plant would be entitled to the proposed enhanced cofiring ROC level of 1 ROC/MWh (Department of Energy and Climate Change, 2011). Drax has decided to build three 300 MW biomass plants in Hull in a joint venture with Siemens. This will require 4Mt of feedstock a year (Marshall, 2009; Modern Power Systems, 2010b).

Data showing the usage of fuels at Drax over the past seven years are given in Table 10 and the types and amounts of biomass fired in 2009 are in Table 11. Drax utilises about 9 Mt of coal annually which is typically 50% indigenous. The imports are largely from Colombia, Russia and the USA. It is evident that, in addition to biomass, Drax has cofired significant quantities of petroleum coke. This is a by-product of the oil refining process and is composed mainly of carbon. It also contains high levels of sulphur and heavy metals and its use gives rise to environmental and operational concerns (Fernando, 2001). Drax reports that over the several years it has cofired biomass, there has been little or no reduction in total boiler efficiency. Drax does not report any particular operational issues that have arisen since starting to cofire high proportions of biomass. In general, biomass is more susceptible to spontaneous combustion, and high standards of plant cleanliness are important; any spillage of biomass must be cleared up quickly. The technical areas they are focusing on for further development include prediction and minimisation of slagging, fouling and corrosion resulting from coal/biomass blends. In order to obtain continued expansion of fuel flexibility, they are improving materials handling and coal blending. Boiler performance factors include improved fuel air distribution, measurement and control and flame eyes performance. Drax boilers already have flame eyes to monitor the flames of pc burners. These were not designed for biomass and increasing the cofiring ratio above 12.5% may necessitate improvements to flame monitoring. Drax is also characterising the effects of cofiring on emissions, NO_x optimisation and on by-products such as ash and gypsum. As the cofiring ratio is increased, the effect on ash and gypsum quality will need to be assessed as these are currently sold and will need to meet the EN-450 standard. Recently Drax has successfully trialled cofiring up to 50% (th) biomass in one unit (Wright and Ghent, 2011; Ghent, 2011).

Table 10 Drax fuel usage (Drax Power Ltd, 2010)

Fuel used, kt	2004	2005	2006	2007	2008	2009	2010
Coal	9167	9323	10197	9815	9720	8331	9839
Pet coke		64.05	111.3	140.1	267.9	477	210
Heavy fuel oil	17.1	7.9	19.3	21.9	27.2	48.0	24.9
Renewable oil	26.6	68.87	20.75	9.3	1.46	0.04	0.0
Biomass	76.7	161.6	43.33	187.4	412.1	380.6	907.5

Table 11 Drax biomass usage in 2009 (Drax Power Ltd, 2009)

Biomass	Tonnes burnt, kt
Agricultural residues (straw, cocoa, grape, rape, bagasse, sunflower, peanut)	250
Wood pellets	103
Wood	13
Energy crops (miscanthus, willow)	14
Total	380

5.3.2 Fiddler's Ferry

The SSE's Fiddler's Ferry power plant, located near Warrington Merseyside contains 4 x 500 MWe tangentially-fired PCC boilers. Alstom Power designed and installed two dedicated biomass cofiring systems in units 2 and 4. The types of biomass that are cofired are wood pellets, palm kernels, olive stones and olive cake. The biomass conveyors are enclosed and head ends are maintained under suction to minimise dust emissions. The intermediate storage silo has a capacity of 200 m³ to allow for variations in fuel properties and operational conditions. In order to prevent spontaneous combustion, safety systems are included to detect carbon monoxide or high temperatures. The biomass is fed in two streams from the base of the silo by variable-speed screw feeders into twin hammer mills. The milled product is discharged from the mill hopper by a screw feeder into the fuel line. Dust explosions can be contained within the mill and the temperature is monitored within the mill to detect fires. On each boiler unit, the milled biomass is conveyed by four independent pneumatic transport systems from each mill hopper outlet. Each of the four streams is divided into two by a splitter and passes to two diagonal opposed biomass burners at one level. The biomass burners are located in one of the large auxiliary air compartments. Biomass is injected to the furnace at boiler loads greater than 50%. The cofiring plant has been fully operational since mid-2006 with an availability of 95%. It has consistently delivered a rated output of 100 MWe which corresponds to a cofiring ratio of 20% (th). Each unit is capable of processing 1440 t/d. A wide range of biomass types have been cofired but there is a moisture limit of <15%. No slagging or fouling has been observed (Waldron and Saimbi, 2006; Kelsall, 2011).

5.3.3 Tilbury

The Tilbury 'B' power plant, located east of London, contains 3 x 350 MWe units which were due to close in 2015 after the owner RWE npower opted it out of the Large Combustion Plant Directive (LCPD). At one stage the plant was to be replaced by a supercritical PCC unit with CCS but these plans were abandoned in December 2009. Instead RWE npower has decided to fuel the plant

completely with biomass which will make it the largest biomass-fuelled power plant in the world. As the heat content of biomass is less than coal and the same weight of biomass is intended to be fired, the design capacity of each unit will be reduced from the existing 350 MWe burning coal to about 250 MWe burning biomass. A two-week test programme was carried out in 2010 to demonstrate that the units were capable of total biomass firing with certain modifications to the boiler. These modifications were carried out in the summer of 2011 and the station was fully operational firing biomass in December 2011. The biomass is delivered by ship along the Thames using the existing jetty which can accommodate bulk carriers. Although the weight of the biomass burnt annually will be about the same as coal, the volume of biomass will be considerably greater hence more ship movements can be expected.

The wood pellets which will be fired at Tilbury are friable and easily reduced to fine dust by mechanical handling. Operation of the existing continuous coal unloaders and their associated conveyors and transfer chutes would cause considerable attrition of the wood pellets. Hence vacuum unloaders which are more suitable for handling wood pellets will be installed. The wood pellets also contain fine dust which will tend to be concentrated in the ships' holds. The dust content would become airborne within the exiting conveyor galleries and transfer points between conveyors. This would lead to atmospheric fugitive releases which would constitute both a fire and health and safety risk. Therefore a dust separator will be installed in a new enclosure on the jetty to separate fine dust from the flow of wood pellets. The uneven distribution of fine dust expected in the bulk wood pellet cargoes means that some buffer capacity is needed in the dust handling system. Hence the dust will be stored in silos prior to being blown into the boilers to augment the milled pellet fuel. Regarding the fuel itself, initially it was envisaged that it would be necessary to provide storage capacity for approximately 60,000 t of wood pellets at Tilbury. This would have required the equivalent of 12 silos, each approximately 19 m diameter x 41.5 m high. However, the Tilbury power plant is located near the Tilbury Fort which was built by Henry VIII in the 16th century. The proposed biomass silos and their connecting conveyors would have been significantly closer to the Fort than the existing station. Discussions with the relevant authorities, particularly English Heritage, indicated that there would be opposition to the construction of silos on such a scale. Therefore, RWE npower reconsidered the need for storage capacity and after reviewing the logistics of fuel delivery, decided that it was possible to manage fuel deliveries to enable the biomass to be unloaded direct from the ships into the bunkers in the existing boiler house without the need for intermediate storage. The only silos installed will be the smaller ones for fine dust handling. This would mean that there would be a ship being unloaded most of the time. Each ship would contain about three days' supply for the plant. Though the majority of the pellets will be delivered from the USA, some fuel will be delivered from a port on the near Continent in a shuttle vessel, which will be available if there is any disruption to the transatlantic deliveries.

RWE npower has assessed the implication for emissions following the biomass conversion. Converting Tilbury B from a coal to a dedicated biomass-fired plant will result in considerable reductions of life-cycle CO₂ emissions by 78–87%, other factors being equal. Biomass firing will also reduce NO_x emissions due to lower combustion temperatures and lower nitrogen content of the fuel. The emissions data obtained during the full unit trial indicated that NO_x emissions were more than 50% lower—220 mg/m³ with biomass compared to 480 mg/m³ with coal. The reductions in SO₂ emissions will be even greater due to the lower S content of wood pellets. During the full trial, SO₂ emissions decreased by 70–80% from 800 mg/m³ with coal to 200 mg/m³ with biomass. The particulate emissions when firing biomass are expected to be similar to those from coal at approximately 20–40 mg/m³. Though wood pellets have a lower ash content than coal, the precipitators will not perform as effectively due to the higher temperatures of the flue gas passing through them. The particulate emissions data during the full trial indicated that the emissions would be similar or very slightly higher when burning biomass but within the station's emission limit of 50 mg/m³.

RWE npower estimates that over the remaining LCPD period, Tilbury could burn 2.3 Mt of biomass. Much of this will be obtained from the new RWE pelletising plant in Waycross, Georgia, USA. Wood

pellets will be transferred by ship from Savannah, which has extensive berthing facilities and rail connections. Construction of the 750,000 t/y plant at Waycross started in March 2010 and the first pellets were produced in March 2011. The plant is to be commissioned and officially opened in March 2012. RWE decided to site the pellet factory in the USA as the European wood market is not sufficient to supply the growing market for biomass for power generation. The Waycross facility is costing RWE \$120 million and the target market is Europe where RWE already burns significant quantities of biomass in the Netherlands and Germany. The USA has extensive unused wood resources, and in Georgia alone the rate of timber growth currently far exceeds annual consumption while, during recent years, the decline of the pulp and paper industries has freed up even more timber capacity. Wood grows much more rapidly in the subtropical climate of Georgia than in Scandinavia or Russia. Georgia has adopted the most stringent sustainability standards for the procurement and processing of wood. The Waycross plant consists of three elements. In the wood yard, the pine logs arriving on site are barked and coarsely chopped. The material is then transported on conveyor belts from the yard to dryers where the wood is dehumidified. In the actual pellet plant, the feedstock is further crushed and pressed into pellets. The pellets are then transported by train to the port of Savannah which is about 100 miles from the plant. RWE are hoping that the authorities may allow Tilbury to operate outside the LCPD and may eventually lead to the plant being re-licensed. Given that the UK needs an increase in biomass use to reach its renewable energy targets, the case for re-licensing Tilbury seems strong (RWE, 2010b; Coal UK, 2011).

5.4 Denmark

Denmark has several power plants which can cofire high ratios of coal and biomass. There is one operated by Vattenfall (Amargerværket, Unit 1) and three by DONG Energy (Avedøre, Unit 2; Studstrupværket, Units 3 and 4 and Grenå, Unit 1).

5.4.1 Amargerværket (Amager)

The first unit at the Amager power plant was commissioned in 1971, the second in 1972 and the third in 1989. All three were originally coal/oil fired. Unit 1 was decommissioned in 2004 and has been renovated to become a multi-fuel plant burning coal, oil and biomass. The new unit has a capacity of 80 MWe and 331 MW district heating. During the renovation, a new boiler and turbine plant were installed. The unit has also been equipped with a new stack and emission control technologies to remove NO_x and SO₂. The renovated unit was recommissioned in May 2010. Unit 2, which has a capacity of 95 MWe and 166 MW district heating was converted to biomass firing in 2003 and currently utilises mainly straw pellets. Unit 3, which has a capacity of 263 MWe and 370 MW of district heating continues to fire coal/oil.

The renovation of Unit 1 involved replacing the original coal/oil boiler with a new 500 t/h Benson boiler. The main new auxiliary components were three roller mills and coal pipes, twelve NO_x oil/coal/wood/straw burners, two rotary regenerative air preheaters, ducts and fans. The limited space in the boiler house resulted in a one-and-a-half pass boiler with the economiser placed in the flue gas duct. The supply of two air preheaters was also a consequence of the existing boiler house layout. The boiler is wall-fired with three rows of four burners where each of the three roller mills feed one burner row. The milling plant uses air for transport of both coal and biomass. The mill exit temperature for coal is 90–110°C and the transport air dries the fuel. Self-ignition in the mills is possible with biomass even at low temperatures. The mill inlet temperature for wood and straw is set at 80–90°C to minimise the risk of ignition. The mills and feeders are pressure resistant and there are explosion suppressing devices on mills and dust pipes. Each of the three fuel supply lines operates with one fuel type at a time such that the whole line (mill, coal pipes, burners) can be optimised for the specific fuel in use. This is important for burners that have to fire fuels with major differences in characteristics. The fuel change is handled from the control system using pre-programmed burner settings for internal air

distribution as well as level of swirl. The fuel change from coal to biomass or vice versa will require some minor mechanical changes to the mill such that it will be out of operation for about a day. Full load is possible on coal with the remaining two mills. The secondary and tertiary air for the circular burner are the main combustion air flows and represent 80% of the burner air. Both the level of swirl and the split between secondary and tertiary air can be controlled and optimised for each fuel. The air is introduced in a staged manner to reduce NO_x formation. The staging is further extended by the use of overfire air (OFA) nozzles on both the front and back walls. There were several issues that had to be addressed during cofiring. The mill capacity is mass flow based hence the thermal input decreases with fuels having lower heating values such as wood and straw. However, since the system is designed for full load with two of the three mills in service, biomass firing can also attain full thermal load by using all three mills. There are concerns about slagging and fouling both in the furnace and in between superheater tubes. There is load limitation for straw in order to avoid slag build-up. To assess slag build-up in the second pass, softening temperatures for straw and wood need to be considered. At 50% boiler load the flue gas temperature at the inlet of the second pass reaches the softening temperature of straw ash (650–700°C). The softening temperature of wood ash is above 1000°C which is higher than the full load flue gas temperature at the inlet of the second pass. Hence load limitations must be put on straw and straw mixtures. Another measure that was needed to prevent slag build-up was to increase the pitch in HP (high pressure) and RH (reheat) tube bundles and limit the use of finned tubes. The use of finned tubes is avoided in the boiler and first introduced in the economiser after the coarse fraction of fly ash is removed. There are four water soot blowers in the furnace and steam soot blowers in all superheater, economiser and air preheaters. Corrosion resistance was enhanced by the use of austenitic steel in superheaters and fully enamelling air preheater elements. Coal ash reduces the effect of the troublesome components of the biomass ash. The presence of sulphur, for example, lowers the risk of chlorine corrosion.

The boiler was expected to have a yearly operation of approximately 5000 full load equivalent hours. For 100% coal firing this represents 250,000 t of coal. The yearly biomass consumption was planned to be 40,000 t of wood pellets and 110,000 t of straw pellets. The load ranges of the various fuels are: coal 35–100%, straw pellets 35–90%, wood pellets 35–100%, heavy fuel oil 20–100%. The range restrictions on cofiring are determined by the quality of the ash in combination with boiler load and the capacity of the mills. On commissioning Vattenfall announced that the unit would not be firing coal but would fire about 100,000 t of straw pellets and 300,000 t of wood pellets every year. (Gjernes, 2006; Gjernes and Poulson 2007; Kristensen 2009; Vattenfall, 2010).

5.4.2 Studstrupværket

Several cofiring trials have been conducted at DONG Energy's Studstrup (Studstrupværket) plant. The first was between 1996 and 1998. Unit 1 at the Studstrup plant is a 152 MWe, wall-fired PCC plant. The trials focused on combustion, straw handling, superheater corrosion, fly ash utilisation and SCR catalyst deactivation. The conversion of the unit for cofiring involved establishing a straw pre-processing plant with a capacity of 20 t/h which is equivalent to 20% of the energy input at full load. The boiler contained twelve swirl burners on three levels. The four medium level burners were converted for cofiring. The boiler performance during cofiring was satisfactory though there was a need for additional soot blowing and some slagging occurred, especially at 20% cofiring ratio. Several materials were tested in probes installed in the outlet of the secondary and platen superheaters. No selective corrosion was found and chloride ions were not present in the oxide and deposits. This indicated that gas phase KCl was not present. The potassium in the straw probably reacted with the coal ash to form unreactive K-Al-silicates. Some potassium might also have reacted with SO₂ forming potassium sulphate. Coal ash thus had a substantial beneficial effect on the corrosive elements in straw as the potassium was bound in the ash and the chloride was released as HCl in the flue gas. The levels of unburnt carbon in the bottom ash were higher, and in the fly ash lower, than with coal-only firing. No problems relating to ash deposition, high temperature corrosion or environmental performance were incurred at straw cofiring rates up to 20% on a thermal basis. The quality requirements for

utilising fly ash in the cement and concrete industry were met at 10% cofiring at Studstrup. It was possible to use fly ash from cofiring straw for cement production but not for concrete as the original EN 450 standard prescribed that fly ash for concrete must come from pure coal firing. Leaching and stability tests showed that there were no problems regarding landfill disposal of the ash.

Following the tests on Unit 1, which is no longer in operation, tests were later undertaken on Unit 4 which has an output of 350 MWe and had been commissioned in December 2001. This is boxer-fired with 24 burners arranged with six burners per row in 2 x 2 rows. The four burners in the middle of the upper row of the front wall were converted for cofiring by enabling straw to be introduced into the centre tubes of the burner. The converted burners can each burn up to 5 t/h of straw. Unit 4 was ready for cofiring operation at the start of 2002. Compared with the demonstration on Unit 1, the operation on Unit 4 resulted in low availability of the straw handling equipment. It was only possible to fire 70% of the design capacity in 2002, though the performance improved towards the end of the year. In order to improve availability, new motors and inlet boxes were installed on all four lines. Following damage to one of the shredders in November 2002, it was rebuilt with new shafts. After re-commissioning in December 2002, the straw line operated with high availability at full capacity. The straw consumption in 2003 was 95,916 t. The results of the first two years of 10% cofiring operation at Studstrup 4 showed an acceptable availability of the straw preprocessing unit. The carbon-in-ash levels in fly ash were reduced by cofiring and NO_x emissions were either unchanged or slightly reduced. There was no increase in boiler deposit formation and there was no increase in deactivation of the high dust SCR catalyst at 7% cofiring. These catalysts are poisoned by potassium compounds and are readily deactivated in straw-fired plants. But, when cofired with coal, the potassium is bound in the coal ash and is less harmful. This has been shown in tests at Studstrup where flue gas from cofiring has been passed through a SCR reactor for 15,000 h without impairing catalyst performance. There was no evidence of chloride corrosion. Then the revision of the European Standard EN450 allowed the use of ash from cofiring of specific fuels, including straw to be used for concrete production. Fly ash from Studstrup 4 complied with all the requirements of the revised EN450 and extensive compliance tests were performed in conjunction with the Danish concrete industry. However, to make the ash usable the proportion of straw is limited to 20% by weight (13% by energy). In 2005 it was decided to convert the 350 MWe, Unit 3 for cofiring so that both units at Studstrup are capable of cofiring coal and straw. In 2007, the plant consumed 130 kt of straw. Full-scale commissioning of SCR at Studstrup took place in 2007. Severe catalyst plugging occurred after a few weeks of operation. The plugging was found to be caused by straw char particles. Washing the catalysts removed half the plugging. New catalyst layers were installed and the catalyst is now protected by ash screens. In 2010, Unit 3 cofired 77 kt of straw which corresponds to 6.3% on a thermal basis. The corresponding figures for Unit 4 were 42 kt and 6.9%. There were no particular operational issues at either unit resulting from cofiring (Fernando, 2005; Sander and Skøtt, 2007; Møller, 2010; Sander, 2011).

5.4.3 Grenå

Coal and straw have been cofired at the Grenå CHP plant since 1992. The CFB boiler at Grenå was designed to fire 0–60% straw and 40–100% coal on an energy basis. The plant has a thermal output of 60 MJ/s for district heating and process steam and an electrical output of 17 MW. The mixture of straw and coal is fed into the boiler and combustion takes place in the temperature range 800–920°C. The bed material and unburnt fuel are separated from the flue gas by two parallel cyclones. The boiler was originally fitted with three superheater sections. This design resulted in problems with deposit formation and corrosion when burning straw. This was due to the high concentration of chlorine in the flue gas together with the high particle concentration above the bed. The formation of deposits was initiated by the condensation of potassium chloride. The bed temperature of more than 900°C was found to be too high and, in order to reduce it, wing walls were installed in the evaporator. This lowered the bed temperature by about 30°C but this was still not sufficient to keep the deposit formation under control. In 1996 two heat exchangers were installed in the loop seal to reduce the temperature by an additional 10°C. However, after a year there was such heavy corrosion on the tubes

that it was necessary to replace them with those of another design in which all the tubes were submerged in the bed material. In 2001, superheater 4 had to be changed again due to erosion. A change in the distribution of air helped to reduce the bed temperature to 860°C. In 2000, an extra economiser was installed to lower the flue gas temperature and improve ESP performance. It was necessary to increase the frequency of sootblowing to reduce deposit formation but this was found to increase erosion. Hence soot blowing was performed only when necessary. It was also necessary to protect some of the tubes with steel shells or to increase the wall thickness from 8 mm to 10 mm. The fly ash composition changed when cofiring straw. There was considerably more potassium chloride and potassium sulphate with straw. The soluble salts made the ash more difficult to utilise and it was necessary to dispose of it. Initially Colombian coal was fired successfully, then South African coal was used. Straw has been the main biofuel but its composition varied from year to year and from field to field. It was found that rain during maturing and harvesting had a major effect on the potassium and chlorine content. The chlorine content varied from between 0.1% and 0.5% or even higher and the potassium content varied between 0.8% and 2%. Other fuels such as sunflower shells, shea nut residues, grain screenings and wood chips were also cofired. The sunflower shells and wood chips cofired successfully as they had low potassium chloride contents. Shea pellets did cause problems as they have a high potassium content. Grenå currently fires 40 kt/y of biomass. Though the aim of firing biomass at a rate of 60% proved to be challenging, the necessary changes in plant design and operation were made to enable it. The main modification was to reduce the bed temperature by 60°C. Though fluidised bed boilers are flexible regarding the choice of fuel, difficulties can arise if the ash has a low melting point as with straw ash. Melted ash makes the sand particles in the bed stick together which affects the fluidisation of the bed. Hence the straw proportion is limited to 50% at Grenå. Furthermore, it has not been possible to find a use for the residual product of the bed, which therefore has to be landfilled (Wieck-Hansen and Sander, 2003; Sander and Skøtt, 2007).

5.4.4 Avedøre 2

The Avedøre power plant is located on the outskirts of Copenhagen. Unit 1 at the plant was commissioned in 1990 and is a coal/oil fired CHP plant with an output of 250 MWe or 215 MWe plus 330 MJ/s of district heating. Unit 2 was commissioned in 2001 and is a multi-fuel plant having the flexibility to fire coal/oil/natural gas and biomass and has a capacity at full load of 575 MWe or 495 MWe plus 575 MJ/s of district heating. The plant is described in detail in Fernando (2002). Unit 2 consists of a biomass unit (105 MWth) which fires wood chips or straw, a USC boiler (800 MWth) which can fire natural gas, fuel oil, coal or wood pellets and two gas turbines (2 x 55 MWe). Up to now, the USC unit has not fired significant quantities of coal though coal ash is added to prevent corrosion and deactivation of the SCR catalyst and to produce an ash which can be handled and sold. Permission has been given to fire coal from 2011 and a fourth mill is being installed. Unit 1 will be converted to fire 100% wood pellets in 2013 (Lindberg, 2011).

5.5 Finland

In Finland, large quantities of biomass from forest industries have been fired for many years as the main fuel in grate-fired, BFB and CFB boilers. Fluidised bed boilers are the most commonly ones used for co-combustion.

5.5.1 Kymijärvi

Finland has a few plant which cofire coal and biomass but the only one of these which utilises significant amounts of biomass and coal is the Kymijärvi CHP plant, located near the city of Lahti in southern Finland. The plant is operated by Lahden Lämpövoma Oy, the power company providing power and district heating for the city of Lahti. The plant has been indirectly cofiring coal and

biomass since 1998. Indirect cofiring involves either pre-gasifying the biofuel in a separate plant and firing the syngas in the main boiler or firing the biofuel in a separate combustor and routing the steam produced to the main turbine. Indirect cofiring is much less commonly found than direct cofiring but has the advantage that the coal ash is not contaminated by any constituent of the biofuel and that these constituents cannot cause corrosion or slagging of the main coal plant. Moreover, for operators interested in cofiring high ratios of biomass, the total biofuel capacity is not limited by constraints imposed by the installed components of the existing coal plant. However, the major disadvantage of indirect cofiring is that installation costs are very much higher than for direct cofiring. The Kymijärvi plant has an output of 167 MWe of power and 240 MWth of district heating. The boiler is a Benson, once-through boiler with steam conditions of 125 kg/s, 540°C/4 MPa reheat. The boiler is not operated in the summer when the heat demand is low. In the spring and autumn, the boiler operates at lower load with natural gas as the fuel. The boiler utilises 180 kt/y (1200 GWh/y) of coal and the equivalent of about 800 GWh/y of natural gas. The plant fires low sulphur coal (0.3–0.5% S) and hence does not require a sulphur removal system. The burners have flue gas recirculation and staged combustion for NO_x control. The gasification unit was added to the plant to reduce costs and environmental emissions. This gasifies wet biofuel and feeds the hot, raw, low calorific syngas directly into the existing boiler. The unit enables the biofuels and waste fuels to be fired efficiently with low investment and operational costs. Moreover, only minor modifications were required in the existing boiler and any problems with the gasifier do not affect the main plant (Raskin and others, 2001; Fernando, 2002).

The gasifier at Kymijärvi is of the ACFB type and consists of a refractory-lined steel vessel with a hot fluidised bed. The gasifier operates at a temperature of about 850°C. Its output varies between 35 and 55 MWth depending on the moisture content of the gasifier fuel and the required gasifier load. The system consists of a reactor in which gasification takes place, a uniflow cyclone to separate the bed material from the gas and a return pipe for returning the circulation material to the bottom of the gasifier. Air is fed to the bottom of the reactor via a distribution grid. These biofuels are introduced into the lower part of the gasifier and typically contain 20–60% water, 40–80% combustibles and 1–2% ash. A major difference between the Kymijärvi gasifier and ones used earlier is that it is no longer necessary to dry the fuel even if it has a moisture content up to 60%. Some mechanical modifications have been made to accommodate the types of biofuel fired at Kymijärvi. Fuels such as waste wood and shredded tyres can contain items such as nails and screws and the air distribution grid and bottom ash extraction system have been designed to allow for their presence. The product syngas is fed directly from the gasifier to the boiler through the air preheater to two burners located below the coal burners. The heating value of the syngas is low when the fuel is wet. If the fuel moisture is 50%, its heating value is 2.2 MJ/m³.

The gasifier was connected to the main boiler in 1997 and combustion tests were performed in January 1998. Since then, the gasifier has been in continuous operation other than for maintenance. The reported operating experience has been excellent. On an annual basis, the gasifier availability has been between 96.1% and 99.3%. Figure 16 shows the proportions of different fuels used and energy produced between 1998 and 2006. The few problems that have arisen regarding the gasifier plant have related mostly to the use of shredded tyres. On several occasions, the wire content of the tyres was sufficiently high such that the accumulated wires blocked the ash extraction system and the gasifier had to be shut down. Otherwise, the gasifier has operated satisfactorily with all other fuel combinations. The operating conditions in the gasifier such as, temperature, pressures and flow rates have been as designed and the measurements of the product gas, bottom ash and fly ash composition have been very close to calculated values. The heating value of the syngas is low, typically 1.6–3.2 MJ/m³.

The stability of the main boiler has been excellent. The large openings that were needed to install the gas burners did not cause any disturbance to the water/steam circulations. The product gas composition has been stable in spite of its low heating value. The main coal burners have operated normally in spite of the fact that the gas burners were integrated close to the lowest level coal burners. The residue from gasifier bottom ash is mainly sand and limestone with a small quantity of solid

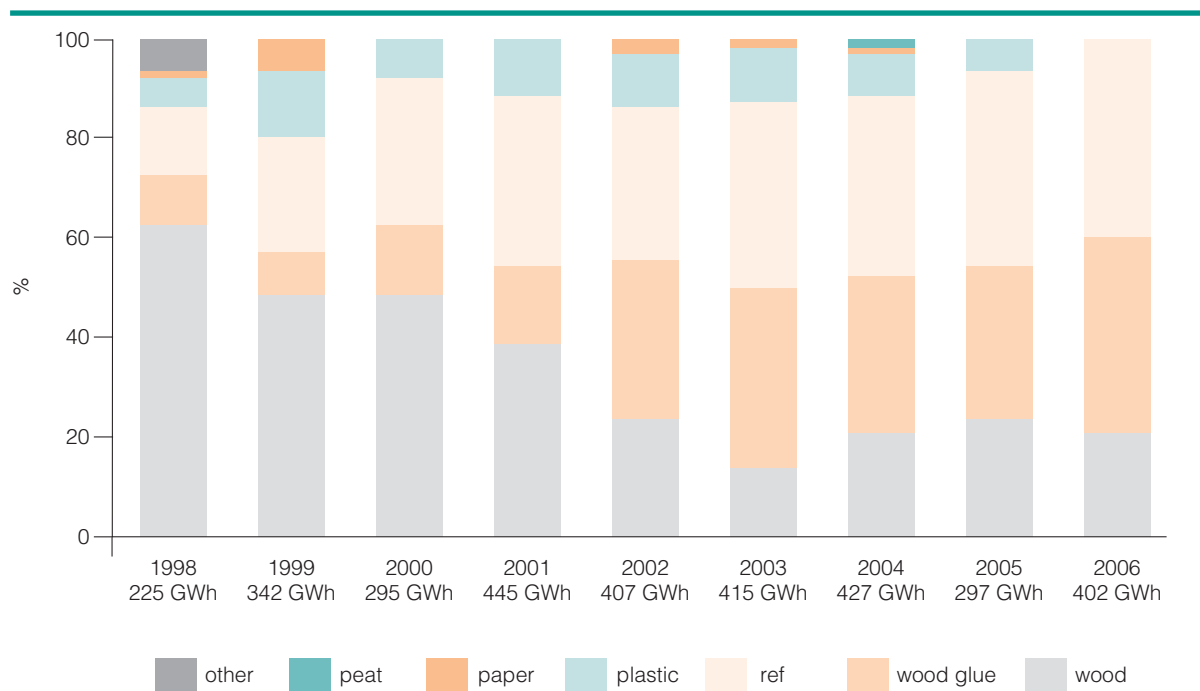


Figure 16 Fuel usage at Lahti gasifier (Kivela, 2007)

Table 12 Effect of Lahti gasifier on coal boiler emissions (Palonen and Nieminen, 1999)	
Emission	Change caused by gasifier
NOx	decrease by 10 mg/MJ
SOx	decrease by 20–25 mg/MJ
HCl	increase by 5 mg/MJ
CO	no change
Particulates	decrease by 15 mg/m ³
Heavy metals	slight increase in some elements from low base level
Dioxins Furans PAH Benzenes Phenols	No change

impurities such as pieces of metal, concrete and glass. The carbon content of the bottom ash is typically less than 0.5%. No trace of chlorine has been found in the ash. Regarding the trace elements in the ash, the only ones found in significant concentrations were chromium, copper and zinc, which were found at levels of hundreds of ppm. If the fuel contained shredded tyres, the concentration of zinc could rise to 3000 ppm. The concentrations of other trace elements were in the range of a few ppms or tens of ppms. Leachability tests have also been conducted and these have demonstrated low values of trace metal leachability. The gasifier bottom ash is landfilled. The main boiler filter ash is used for construction. The emissions from the main boiler during the operation of the gasifier were measured and the results are summarised in Table 12. The NOx content decreased typically by 5–10%. This was due to the

cooling effect of the high moisture product gas in the lower part of the boiler. In addition, due to the low sulphur content of the biofuels, the main boiler SO₂ emissions decreased by approximately 20–25 mg/MJ. In contrast, the HCl emissions increased by approximately 5 mg/MJ due to the high chlorine content in SRF and tyres. The CO emissions were unchanged as was the carbon content of the fly ash from the main boiler. The total particulate emissions decreased by 15 mg/m³. Measurements of the heavy metal content of the stack emissions showed increased levels for some elements but the base levels were low. Hence the changes that were measured in practice were also very low. There were no changes in the concentrations of trace organic species such as dioxins and furans. The Lahti gasifier continues its successful operation with no major problems ten years after

commissioning. It presently utilises clean wood (15%), waste wood (32%), RDF (40%), tyres (10%) and peat (3%) (Nieminen and others, 2004; Palonen and others, 2006; Kivela, 2007; Anttikoski, 2009).

5.6 Belgium

5.6.1 Ruien

Following the successful operation of the Kymijärvi power plant, a gasifier based on a similar concept, which also indirectly cofires biomass, was installed at Unit 5 of the Electrabel Ruien plant in 2003. This plant is located near Oudenaarde city and is the largest fossil fuel plant in Belgium. Unit 5 is a tangentially-fired, once through boiler (18 MPa, 540°C) having a power output of 190 MWe. The gasifier is a Foster Wheeler CFB gasifier and is shown in Figure 17. Only limited space was available around the boiler for the installation of the syngas burners. Based on CFD modelling of the combustion process and allowing for the constraints of the physical boundary conditions, the two burners were installed at opposite sides at the 6 m level, out of the boiler centre line. The existing coal corner burners were above the syngas burners. The reactor temperature is about 900°C. The design fuel for the gasifier is fresh wood chips but the gasifier can utilise other types of fuel such as bark, hard and soft board residues and dry, recycled wood chips. The fuel moisture can vary between 20% and 60%. Depending on the fuel mix, the heat input from the syngas into the boiler ranges from 45 to 70 MWth. Under normal conditions with biomass containing 50% moisture, the gasifier produces syngas with a thermal output of 50 MWth, which at an overall efficiency of 34% produces an electrical output of 17 MWe. If the biomass contains a lower moisture level of 20%, the output increases to 86 MWth. The LHV of the syngas is approximately 3–4 MJ/m³.

The facility has been in commercial operation since May 2003. About 100 kt/y of biomass have been gasified generating 120 GWh. On an annual basis 50 kt of coal were replaced. This was equivalent to 9% of the coal requirement. The effect on the emissions of the main boiler has been monitored which

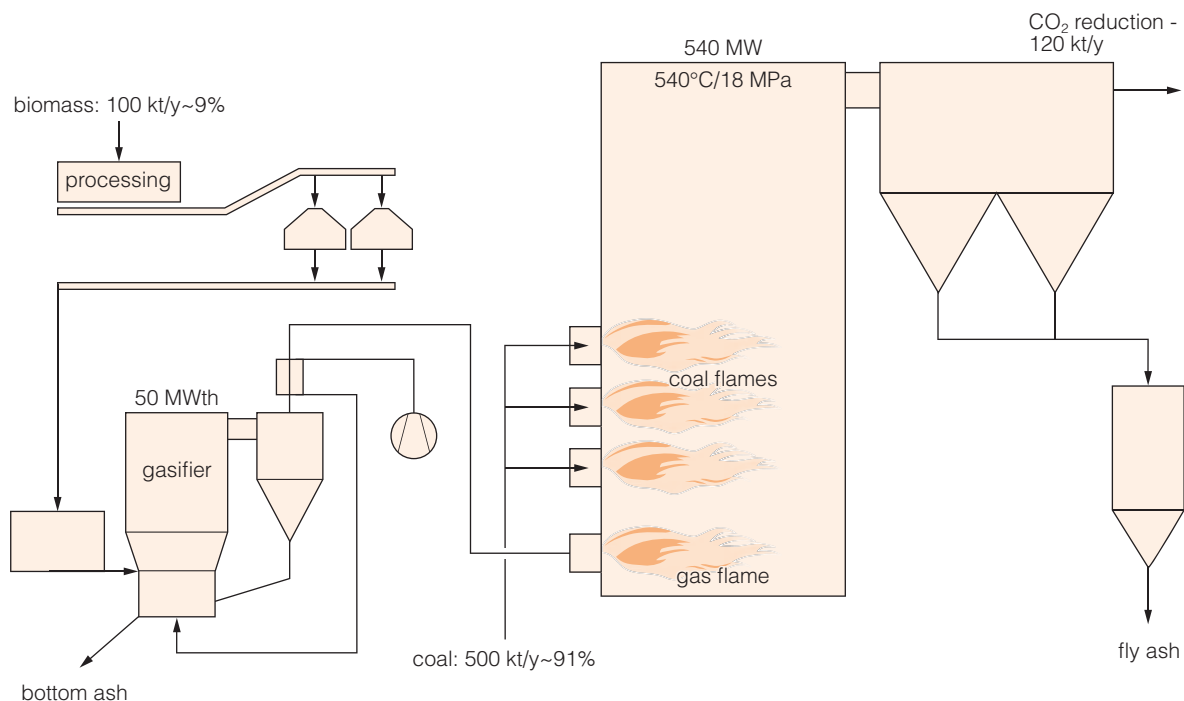


Figure 17 Process diagram of Ruien gasifier (Ryckmans, 2006)

shows that both NO_x and SO₂ decreased. The former was probably due to moisture in the syngas and the latter due to the lower sulphur levels in biomass compared with coal. There were no changes observed in dust or CO emissions. The concentration of heavy metals and levels of unburnt carbon in the ash did not change significantly. Some operational issues did arise initially. The use of wood chips for the gasifier necessitated specific requirements for material quality. The biomass suppliers had to modify their operations to meet stringent conditions regarding the humidity, physical dimensions and the removal of foreign materials from the wood. The bed material consisted of sand and limestone purchased locally. The required quality criteria regarding type and particle distribution were not initially appreciated by the supplier. In addition, the sand was mostly quartz. Agglomeration sometimes occurred and the use of other materials such as alumina was necessary. Other problems included the rupturing of the gasifier preheater on two occasions and blocking of the cyclone return leg. These problems were only to be expected during commissioning and, overall, the gasifier demonstrated that a high efficiency steam cycle could be used in producing green electricity with minor modifications to the existing boiler. The capital cost was low compared to a stand-alone facility as were O&M (operational and maintenance) costs. The gasifier has demonstrated high availability and there are only minor impacts on the operation and availability of the main boiler. At present, dry and wet wood, fresh wood and cleaned waste wood are utilised in the gasifier. Current operational issues include fuel flexibility, operator training, continuing concerns regarding bed agglomeration and consideration of alternatives to quartz sand including high alumina (Savat, 2003; Bartsoen, 2004; Ryckmans, 2006; Van Dijen, 2009).

6 Conclusions

Given the increasing concerns regarding climate change, it is not surprising that there is continuing interest in the use of biomass for power generation. This is principally related to the fact that, if the biomass is grown in a regenerative way, its combustion will not produce any net CO₂ emissions. Cofiring biomass is particularly attractive to coal generators as this is one of the simplest ways of reducing net CO₂ emissions from a coal-fired power plant. However, due to the difference in fuel composition, several technical issues must be addressed when considering cofiring. Recent interest is focusing on biomass cofiring at high cofiring ratios. This can exacerbate the effects of these operational issues and these must be assessed in detail to prevent damage to the plant or impair its operation. These issues may be of less importance if the power plant is approaching the end of its operating life. Though more than 150 power plant worldwide have some experience of cofiring biomass only about a dozen, which were previously coal-fired plant, have cofired high percentages of biomass with coal over extended periods.

The availability of biomass is especially important when considering cofiring at high ratios. It is essential that the biomass is cultivated sustainably. It must also not affect food production or tropical rain forests. A recent study of biomass availability in the EU has concluded that by 2030, it should be possible to meet up to 20% of the EU-27 energy demand from biomass. Another study which specifically focused on cofiring biomass with coal for electricity generation in the EU-27 concluded that in all countries the potential renewable energy from cofiring corresponds to less than 10% of total national gross electricity production and less than 5% in most. Across the EU as a whole, biomass demand for cofiring was approximately 10% of the supply potential but for the UK, Greece and the Czech Republic, the proportion was much greater. Though an individual power plant may be able to reduce its CO₂ emissions substantially by cofiring at high ratios or total conversion to biomass, the availability of biomass will limit this as a universal option for CO₂ reduction.

There are several options available for direct cofiring of biomass in coal-fired boilers. The simplest is to pre-mix the biomass with the coal and feed the mixed fuel into the bunkers and process the fuel through existing coal milling and firing equipment. This approach is possible for cofiring up to 10% on a thermal basis, although ratios of only up to 5% are usually utilised on a commercial basis. This limitation is related to the ability of coal mills to co-mill biomass materials. For higher cofiring ratios, it is possible to pre-mill the biomass as this avoids the constraints associated with co-milling. It can then be injected directly into the furnace with no flame stabilisation or additional combustion air. This option is simple to install and relatively inexpensive and involves providing new, small diameter, furnace penetrations. Another option is to install new, dedicated biomass burners with their associated combustion air supplies. Though this technique has several advantages it is relatively expensive to install but will be needed at very high cofiring ratios. The final option is to inject the pre-milled biomass into the coal pipework or at the existing burner. The biomass can be injected directly into the coal burner, into the coal pipework just upstream of the burner or into the mill outlet pipework. It is generally preferable to introduce the biomass into the mill outlet pipework just downstream of the mill product dampers and upstream of the pulverised coal splitters.

Possible increases in slagging and fouling must be assessed when cofiring biomass. The degree of both depend on many factors including fuel composition. Biomass fuels can contain a higher proportion of alkali species compared with coal though total ash content must also be considered. In general, deposition rates should decrease when cofiring wood or similar low ash, low alkali, low chlorine fuels but should increase when cofiring high alkali, high chlorine, high ash fuels like many herbaceous materials. Cofiring high ratios of herbaceous fuels would be expected to be more troublesome than cofiring similar ratios of woody fuels. It should, however, be noted that the ash content of most types of biomass is less than typical coals.

Biomass cofiring can increase both the high and low temperature corrosion rates in utility boilers. Moreover, some types of biomass contain a relatively high chlorine content which is released as HCl in the boiler flue gas which can lead to back end corrosion. Hence, depending on the cofiring rate, biomass fuels containing high levels of alkali or chlorine can create or exacerbate corrosion problems. Increased rates of erosion are also possible with some types of biomass such as poultry manure and sewage sludge. Biomass cofiring generally does not cause concerns regarding stack emissions.

Torrefaction is a thermochemical process which alters the properties of biomass, improving its physical properties for handling and utilisation. It involves heating the biomass between 200°C and 300°C, typically for an hour, in a reducing atmosphere. The torrefied product can then be pelletised. Torrefaction increases product durability and reduces biological degradation, while pelletisation increases the energy density. The final product can be stored, handled and utilised much like coal. Torrefied fuel is far more suitable for cofiring at high ratios than untreated biomass.

Though there are several dozen coal-fired plant which have cofired biomass only a handful have cofired at high ratios on an extended basis and these are located mainly in the Netherlands, Denmark and the UK. Plants in the Netherlands have the most experience in cofiring high ratios of biomass over extended periods. Unit 8 at the Amercentrale, PCC-fired, CHP plant has a generating capacity of 645 MWe and 250 MWth, and has the capability of cofiring up to a 20% (mass) ratio. A range of biomass fuels have been cofired in 2009 and 2010 at cofiring ratios of 12.4% and 13.2% with mills causing some concern. High ratios of biomass have been cofired at Unit 9 at the Amercentrale, PCC, power plant which is the largest coal-fired CHP unit in the Netherlands generating 600 MWe and has a thermal output of 350 MW. There are currently no serious operational issues at this unit which is one of Essent's most reliable units. The quantities of biomass cofired in 2009 and 2010 were 595 kt and 580 kt which corresponded to cofiring ratios of 31.7% and 34.2% (mass). The Amercentrale plant also contains a gasifier which gasifies demolition wood and fires the syngas in Unit 9. The output of the gasifier is 29 MWe or 26 MWe + 15 MWth in cogeneration mode. The challenges arising in the early years have been addressed and the current concerns relate to plant unavailability caused by iron and other impurities in the fuel. The operators are considering installing a third biomass mill at Amercentrale 9, additional wood feeding to the gasifier, a second gasifier at Amercentrale 9 and additional mills at Amercentrale 8 with the purpose of increasing the cofiring ratio to 50% by 2015. Another power plant in the Netherlands which has cofired high ratios of biomass is the Borselle plant which contains a 406 MWe, PCC unit. It originally cofired phosphor gas but more recently has cofired cocoa shells, palm kernel and citrus pulp. Cofiring at ratios >10% (mass) necessitated the installation of individual feeding lines for the secondary fuel. Several operational challenges had to be addressed such as high percentages of unburnt C and oxidation of radiant wall tubes and fouling in the furnace and reheaters. In 2009, the percentage of output generated from biomass was 15% (th). The Gelderland 13 power plant which consists of a 602 MWe, PCC unit also cofires high ratios of waste wood pellets. The milled wood is co-injected into the primary air coal dust lines. The cofiring capacity of biomass is 180 MWe. The cofiring ratio is nearly 30% (th) and 470,000 t of wood pellets are cofired annually.

Denmark has several power plant which can cofire high ratios of coal and biomass. These are one operated by Vattenfall–Amargerværket (Unit 1) and three operated by DONG Energy – Avedøre (Unit 2), Studstrupværket (Units 3 and 4) and Grenå (Unit 1). Amager Unit 1 was originally a coal/oil fired but was decommissioned in 2004 renovated to become a multi-fuel plant burning coal, oil and biomass. The new unit has capacity of 80 MWe and 331 MW district heating. During the renovation, a new boiler and turbine plant were installed. The renovated unit was recommissioned in May 2010. There are restrictions on the cofiring range which are determined by the quality of the ash in combination with boiler load and the capacity of the mills. On commissioning Vattenfall announced that the unit would not be firing coal but would fire straw and wood pellets. Several cofiring trials have been conducted at DONG Energy's Studstrup (Studstrupværket) plant. The first was between 1996 and 1998 in Unit 1 which is a 152 MWe, wall-fired PCC plant. Straw was cofired up to a cofiring ratio of 20% (th) without any serious operational issues. Following the tests on Unit 1, which

is no longer in operation, tests trials were undertaken on Unit 4 which has an output of 350 MWe to cofire straw starting in 2002. After resolving initial problems with straw handling, it was possible to cofire straw up to a ratio of 10% satisfactorily. In 2005 it was decided to convert the 350 MWe, Unit 3. After commissioning in 2007, there were problems with catalyst plugging but these have been resolved and currently units 3 and 4 are cofiring straw in the range 6–7% (th) without any particular operational issues. Coal and straw have been cofired at the Grenå CHP plant since 1992. The design was to cofire up to 60% (th) straw but there were severe corrosion problems. This necessitated reducing the bed temperature, submerging the boiler tubes in the bed material and limiting the cofiring ratio to 50%.

Biomass cofiring is a proven technology in the USA with over 40 commercial demonstrations. Though there is no federal support for cofiring, individual states have Renewable Portfolio Standards to encourage the use of renewable energy. All states include biofuels and biomass as being eligible but whether cofiring is eligible depends on the individual state. Amongst the commercial cofiring demonstrations in the USA, about a dozen trials have fired relatively high cofiring ratios of biomass. Cofiring tests were undertaken in 1994–96 in one unit of TVA's Allen plant, which has three 272 MWe cyclone boilers. Cofiring percentages up to 20% (mass) were tested. There were no operational issues other than some loss in boiler efficiency. Two series of cofiring trials have been undertaken at the 70 MWe, PCC, Plant Gadsden plant. Switchgrass was injected directly into the boiler through separate burners with no operational issues other than slight reduction of boiler efficiency. More recently in 2007, wood chips were cofired in blends up to 15% (mass). The mill amperage increased and there was slight reduction in boiler efficiency. Cofiring tests were also undertaken at the 32 MWe, PCC unit at the Seward plant in separate months in 1996–97. Sawdust was separately injected up to 18% (mass). There were no operational concerns other than a small reduction in boiler efficiency. Other than the trials at Plant Gadsden, current demonstration activities in the USA on cofiring high ratios of biomass with coal are limited. The demonstrations undertaken as part of the DOE/EPRI/NETL programme prior to 2002, concentrated on storage, handling, fuel preparation, milling, combustion and environmental aspects. There were no major impediments regarding these aspects. However, some of the trials took place only for a few days or for a few hours per day dispersed over a few months. These would not necessarily show up operational issues related to corrosion, slagging or fouling. No such problems were observed when cofiring woody biomasses. Herbaceous biomass fuels which generally have higher inorganic content and lower ash fusion temperatures would be expected to be more prone to slagging and fouling especially at high cofiring ratios.

There are a several projects in the USA to take an existing coal-fired plant and repower it to fire biomass. Southern Company are repowering Plant Mitchell unit 3 in Georgia. Currently it is a 155 MWe, PCC, coal facility. It will become a 96 MWe 100% wood-fired facility with a new stoker grate and suspension firing. Another repowering project was the PSNH's Schiller plant in New Hampshire. In 2003, the existing unit 3 was replaced with a similarly sized 50 MW biomass-fired CFB boiler. Not all repowering projects reach fruition. FirstEnergy Corp's plans to convert two units at the coal-fired R E Burger plant to fire biomass and Xcel's plans to fire gasified biomass at its Bay Front power plant were not implemented.

Though 15 large coal-fired power plant in the UK have cofired biomass, all but one have cofired at cofiring ratios of less than about 6% (th). The exceptions are the Drax and the Fiddler's Ferry power plants. The Drax plant consists of 6 x 660 MWe units. Drax decided to install a new direct injection system in which the biomass is milled separately and injected into the existing pulverised coal lines upstream of the coal burners. The capacity of the new direct injection cofiring installation is 1.5 Mt/y of biomass which corresponds to about 400 MWe. This added to the existing capacity of 100 MWe of cofiring capacity through the existing mills results in the Drax's total cofiring capacity of about 500 MWe. Drax cofires three types of biomass: agricultural residues, forestry products and energy crops. Drax do not report any particular operation issues that have since they have started to cofire high proportions of biomass. Several types of biomass have been cofired successfully in two of the

four 500 MWe units at Fiddler's Ferry power plant up to a ratio of 20% (th). The Tilbury 'B' power plant contains 3 x 350 MWe units and the owner, RWE npower, has decided to fuel the plant completely with wood pellets which will make it the largest biomass fuelled power plant in the world. After the conversion, the design capacity of each unit will be reduced from the existing 350 MWe burning coal to about 250 MWe burning biomass. Much of the fuel, which will be grown sustainably, will be obtained from the new 750,000 t/y, RWE pelletising plant in Waycross, Georgia, USA.

Kymijärvi CHP plant in southern Finland, has been indirectly cofiring coal and biomass since 1998. Indirect cofiring involves either pre-gasifying the biofuel in a separate plant and firing the syngas in the main boiler. For operators interested in cofiring high ratios of biomass, by indirectly cofiring, the total biofuel capacity is not limited by constraints imposed by the installed components of the existing coal plant. The Kymijärvi main plant has an output of 167 MWe of power and 240 MWth of district heating. The gasifier at Kymijärvi has an output which varies between 35 and 55 MWth. The Lahti gasifier has operated successfully with no major problems ten years after commissioning. A similar gasifier has been installed at Unit 5 of Electrabel's Ruien plant in Belgium which gasifies several types of wood and continues to operate satisfactorily.

It is apparent that there are relatively few coal-fired power plant that have cofired high ratios of biomass over extended periods. It has been possible to deal with operational issues that have arisen. Wood pellets or a torrefied fuel are the most suitable fuels for cofiring at high ratios in coal-fired powered plant. As operational experience is sometimes of relatively short duration, there is more information on fuel handing, storage and combustion than on corrosion, slagging and fouling. Issues relating to storage and milling are of particular importance when cofiring at high ratios. Slagging and fouling will need to be addressed if cofiring at high ratios is intended over extended periods. These will be less of a concern if cofiring is intended for a short period at the end of the plant's operating life. The availability of fuels will be a serious impediment if cofiring at high ratios is to be adopted on a large scale but for an individual power plant, cofiring is an attractive option to reduce net CO₂ emissions substantially.

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