

# CHALMERS



**Cofiring: technological option in Romania for promoting cleaner fossil fuels usage**

**Bogdan Marin**

**Supervisor: Associate Professor Lars-Erik Åmand**

Department of Energy and Environment  
Division of Energy Technology  
CHALMERS UNIVERSITY OF TECHNOLOGY  
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**Abstract:** *Co-firing refers to the simultaneous or alternative utilisation of two or more fuels in a combustion unit for the purpose of heat/ power generation and it has been successfully demonstrated in many installations worldwide for most combination of fuels, techniques and boiler types. It is a serious option that addresses the worlds current energy challenges by making use of several types of fuel, ranging from renewable resources to undesired wastes, being based on the already used and well known coal combustion technologies, and increasing the security of supply by using domestic fuel sources. The master thesis investigates the possibility of implementing such a co-firing project, comprising all the various steps needed to be considered in such a project/ venture, in Romania.*

**Keywords:** *Co-firing; Co-combustion; Biomass and/ or waste co-firing along with coal; Promoting cleaner fossil fuels; Retrofitting & Rehabilitating Romanian power plants.*







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# Chapter 1 – NATIONAL EMISSION LIMITS

What will be the emission limit values in the case of a unit burning:

- a) Coal
- b) % Coal + % Biomass
- c) % Coal + % Biomass + % Waste

in a boiler for heat and/or electricity production?

(With Romania as a case study in the context of compliance/implementation of EU environmental regulations)

Addressed topics

- *EU energy situation*
- *RO EU integration*
- *RO energy overview*
- *National Emission Limits under Kyoto + RO plan*
- *Limits for individual combustion units a) b) c)*



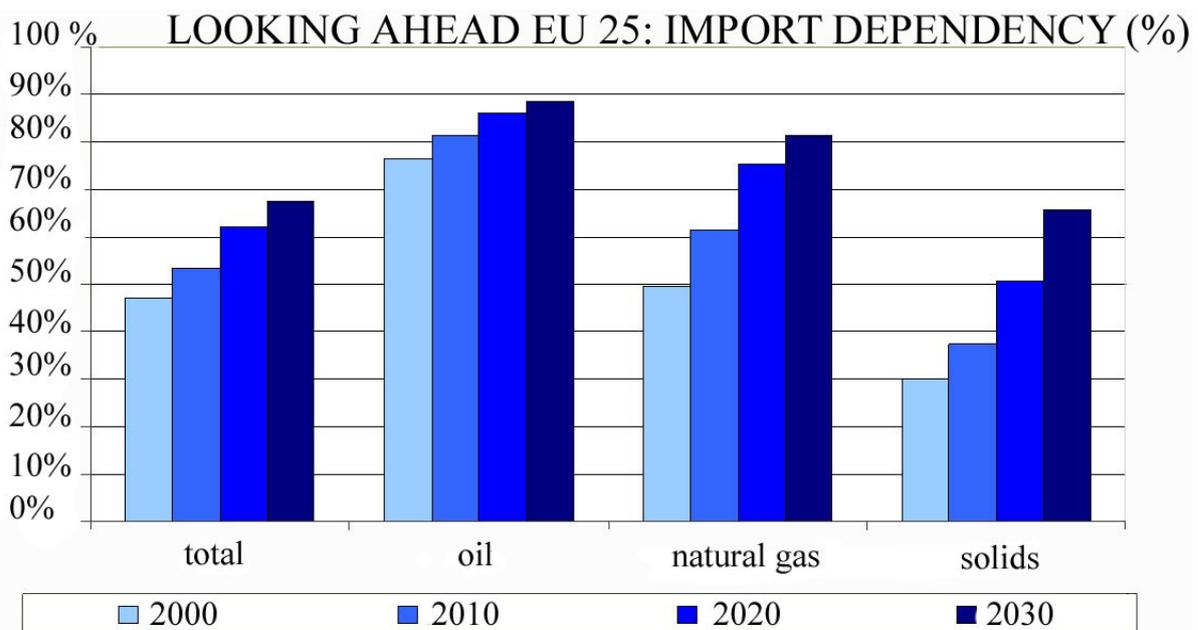




## 1.1 EU energy situation

In recent European events regarding the formulation of a common position on EU energy policy, heads of European States or Governments expressed their interest in revitalising Europe's energy policy having in view the extremely difficult ever growing challenges facing Europe and the world today, particularly with regard to security of energy supply and the necessity to combat climate change. With the release of the Green Paper – EU's long-term energy policy in March 2006, the three pillars of EU energy policy in the next 25 years are set: sustainability, competitiveness and security of supply.

Currently the European energy sector is characterised by a strong reliance on imported fossil fuels associated with increased emission of CO<sub>2</sub> leading to a non-sustainable development governing the entire continent. Looking at the European economy, gradually in need of more energy, it is in essence based on oil, coal and natural gas, which make up to four-fifths of its total energy consumption and almost two-thirds of which it imports. Since at present the EU energy production satisfies almost half of its needs, the common view is that if nothing is done, by 2030 the share of fossil fuels is going to increase making the energy imports much higher, amounting to 70 % of total needs (*Barbaso, 2006*).



**Figure 1.1** EU 25: Import dependency (%) (*Barbaso, 2006*)

The promotion of renewable energy has an important role to play in redefining the European strategy in the energy sector as additional clean fuel sources are investigated, in the terms that the petroleum price is growing in an alarming matter, the combustible fossils fund is limited, consumption is in a continuous rising and matters related to environment protection and among these the climatic changes. Since 1997, the EU has been working towards the ambitious target of a 12 % share of renewable energy in gross inland consumption by 2010. In 1997 the share of renewable energy was 5.4 % and by 2002 it had reached almost 6% (*Table 1.1*).

Table 1.1 Total energy consumption by fuel (%) in 2002							(Europa, 2006)
	Coal and lignite	Oil	Gas	Nuclear	Renewables	Industrial waste	Total energy consumption (1000 TOE)
EEA	18.5	37.6	23.1	13.8	6.8	0.2	1,843,310
EU-25	18.2	38.0	23.1	14.8	5.7	0.2	1,684,042
EU-15 pre-2004	14.7	39.9	23.6	15.6	5.8	0.2	1,482,081
EU-10 new members	43.5	23.8	19.5	8.8	5.0	0.3	201,961

TOE – tonnes of oil equivalent  
 EEA – European Economic Area : Iceland, Liechtenstein, Norway, EU-25  
 EU-25 – EU-15 + EU-10  
 EU-15 pre-2004 – Belgium, France, Germany, Italy, Luxembourg, Netherlands, Denmark, Ireland, United Kingdom, Greece, Portugal, Spain, Austria, Finland, Sweden  
 EU-10 new members – Czech Republic, Cyprus, Estonia, Hungary, Latvia, Lithuania, Malta, Poland, Slovakia, Slovenia.

Legend:

Bio-energy, encapsulating all biomass energy systems that produce heat and/or electricity, already provides 64% of all renewable energy sources (RES) of the European Union, thus leading the way to a sustainable pattern of energy generation. In spite of the advances already gained in the bio-energy sector, the overall development lags far behind the goals fixed in the White Paper of the European Commission. According to this document the contribution of bio-energy should increase from 45 M toe in 1995 to 135 M toe in 2010.

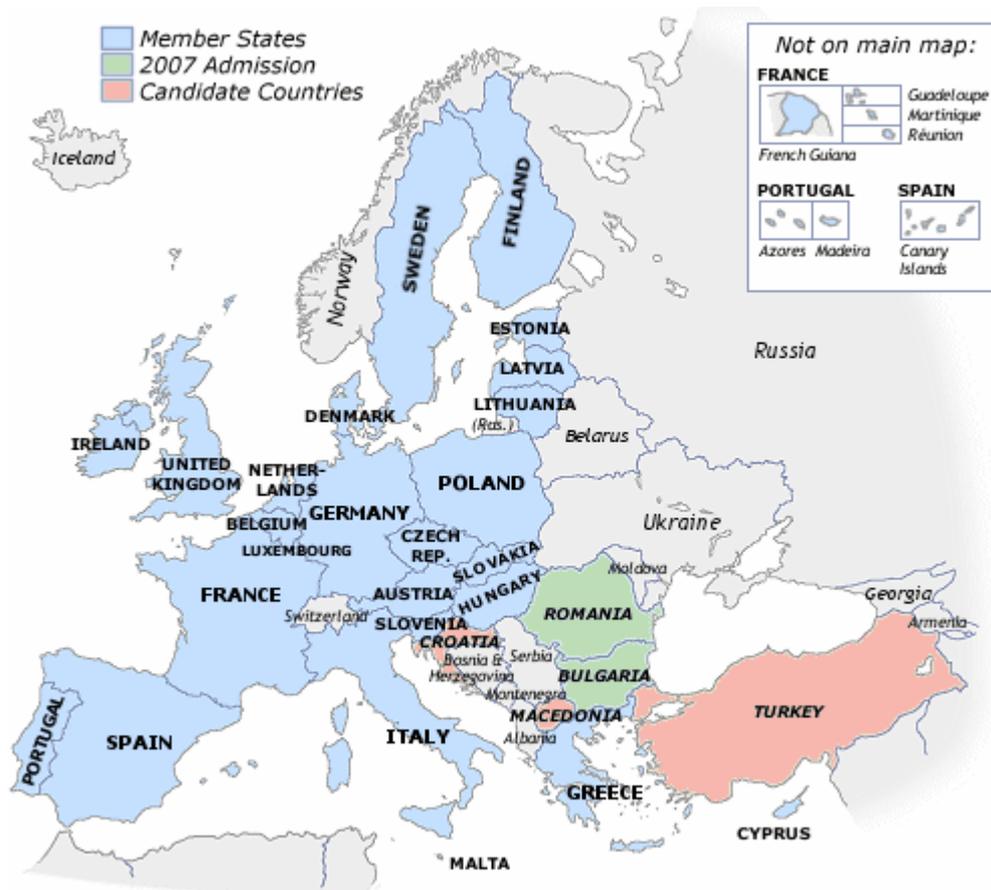


Figure 1.2 Map of EU-EEA member countries (Europa, 2006)

### 1.1.1 RO Biomass potential

With an enlarged EU with ten new members and the upcoming inclusion of two more candidate countries in early 2007, such targets are easier to reach as the New Member States bring to the EU a significant bio-energy potential. Romania possesses a large potential of biomass and is expected to make considerable efforts to make benefit of the European know-how and dissemination of recent technologies in order to use the potential energy accumulated by the biomass. Currently in Romania biomass represents an important energy source, for rural areas especially. Its main utilisation is to supply fuels to many consumer categories such as: population with a share of biomass in total fuel consumption of about 50%; agriculture & forestry sector with the share of biomass in total fuel consumption of 25%; hotels in mountain area, schools and other public buildings located mainly in the rural area for which category the share of biomass in the total fuel consumption represents about 15%.

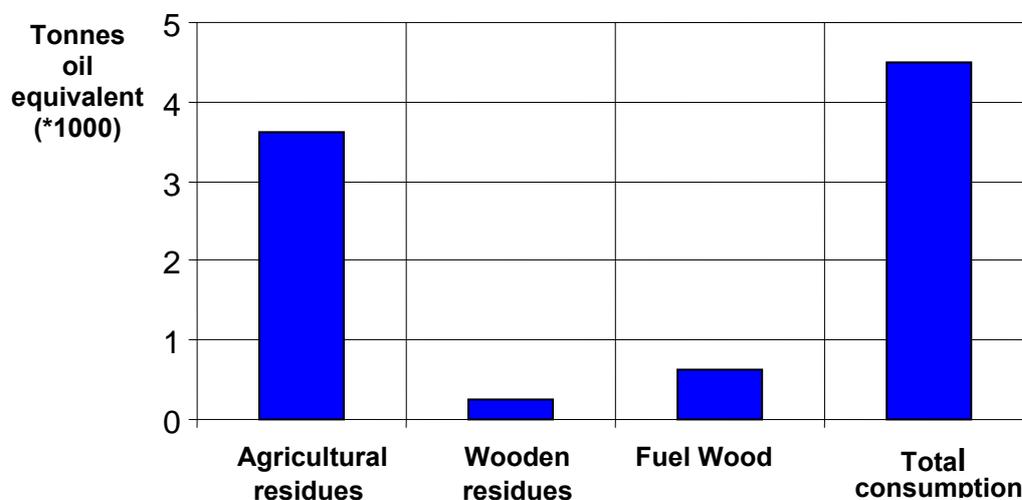
Studies revealed that Romania posses a high energetic biomass potential, evaluated at about 7594 toe/year representing about 19% from the total primary resources consumption at the levels of the year 2000 by the following fuel categories:

- forestry and fire wood wastes, 1175 thousand toe/year;
- wood-sawdust wastes and other wood waste, 487 thousand toe/year;
- agricultural waste resulting from cereals, corn stems, vine wastes, etc. 4799 thousand toe/year; biogas, 588 thousand toe/year;
- waste and urban domestic (household) waste, 545 thousand toe/year.

At present, the different types of combustion units that are used for energy generation from biomass are:

- ~550 steam and/or hot-water industrial boilers for industrial heating (using wood fuel);
- ~10 hot-water boilers covering a range of 0.7 MW to 7 MW for urban heating;
- approx. 14 million wood ovens and/or agricultural waste, for individual house heating. (*Budulan, Rugina 2004*)

*Figure 1.3* is indicating the share of the utilised biomass resources in Romania, representing approx.6.5 % of the total energy consumption.



**Figure 1.3 Utilized biomass resources in Romania** (*Ministry of Environment and Water Management, 2005*)

This considerable current interest in the use of biomass for heat/power generation exists because of several reasons. The capital one is that if biomass is grown in a regenerative manner and its combustion will not produce any net CO<sub>2</sub> emissions, thus reducing current GHG emissions. Other advantages include that it diversifies the power plant's fuel portfolio, it can lead to reductions in SO<sub>2</sub> and NO<sub>x</sub> emissions and it can help dispose of solid wastes. Many countries from the EU have initiated various incentives in recent years to encourage the utilization of biomass for electricity production, trying to answer the present challenges. However, there are some disadvantages of the use of biomass for electricity production which relate to its supply, transportation, composition but these can be reduced if the biomass is cofired with coal.

Cofiring refers to the simultaneous or alternative utilisation of two or more fuels in a combustion unit for the purpose of heat/power generation and it has been successfully demonstrated in many installations worldwide for most combination of fuels, techniques and boiler types. It is a serious option that addresses the current energy challenges by making use of several types of fuel, ranging from renewable resources to undesired wastes, making use of already diffused and well known coal combustion technologies, and increasing the security of supply by using domestic fuel sources.

There are two main attitudes behind cofiring. One regards coal as problem, largely due to quantities of carbon dioxide produced and their enhancement of the greenhouse effect. Cofiring especially with "CO<sub>2</sub>-neutral biomass", is a way of displacing coal as a fuel and thus reducing GHG emissions. The other attitude sees coal as the solution, largely to the increasing problems of waste disposal. Here, the more stable combustion characteristics and lesser environmental impacts of coal are used to deal with wastes that otherwise would be landfilled or, if incinerated alone, would lead to more undesirable emissions to the atmosphere compared to cofiring together with coal (*Davidson, 1999*).

Pointing out the current problematic EU energetic challenges, particularly with regard to security of energy supply and the necessity to combat climate change, and introducing one of the undertaken solutions to address them, cofiring of biomass and/or waste, constitutes the framework governing this analysis.

The current status of the EU family is that it is being enlarged, with 10 recent new members, and the upcoming inclusion of two more candidate countries in early 2007, bringing them together in front of the same challenges.

## 1.2 RO EU integration

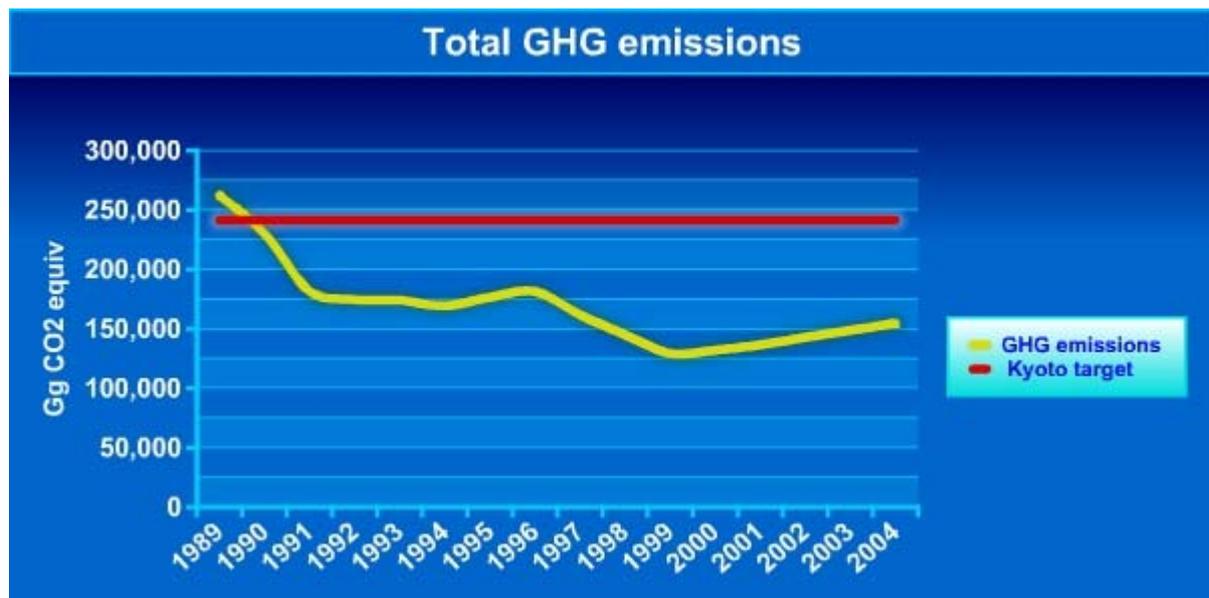
Romania's sustainable development in economic and social terms is directly linked to the development of the energy sector. The development of the national economy and of Romania's society will depend on how energy will be made available, affordable and acceptable.

The power sector contribution to Romania's sustainable development means providing the energy demand coverage in the long run, under various utilisation forms for each consumer at prices that make it accessible to anyone under market conditions, while being also acceptable to society in terms of environmental impact and of other hazards from electricity generation, conversion, transmission and from waste management.

Romania's major objective is to comply with all conditions for its integration into the European Union and to reach to the European development level. The particular effort that has to be made to achieve this goal is not only institutional and legislative. Romania has to be able to successfully manage the economic competition, with economic development realized in the most sustainable and efficient manner. Being its main driver, one crucial role will be played by the development of the energy sector, hence the acknowledgement of modern, clean power generating techniques is vital for avoiding mistakes. Making use of current European experience is an advantage that is going to be made available with the integration process and it should be utilised to its maximum potential.

### 1.2.1 Kyoto Protocol commitment

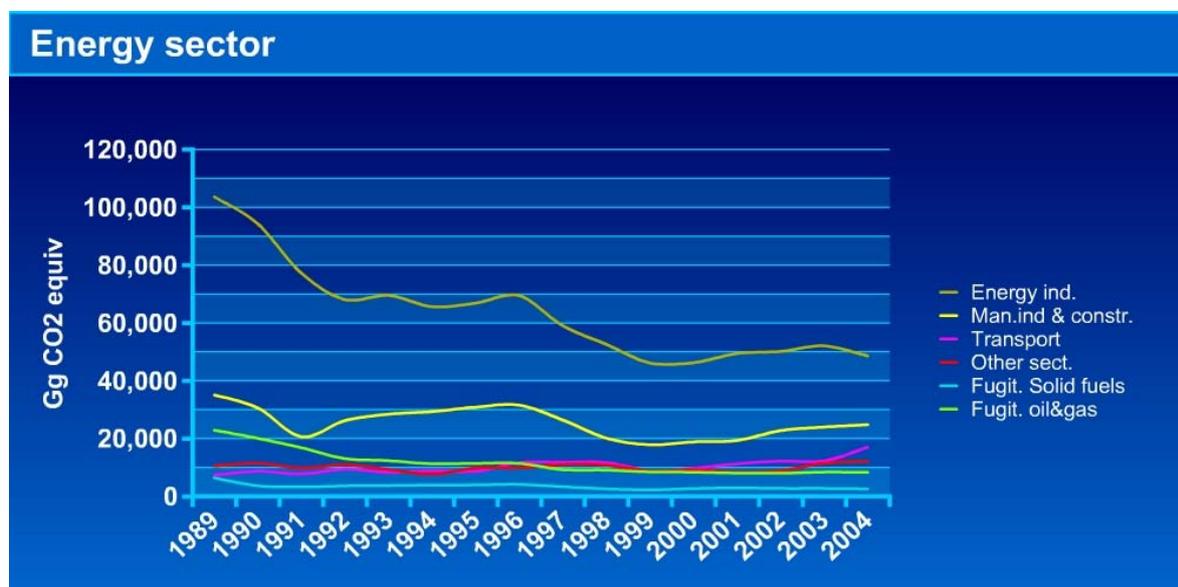
Romania signed the Kyoto Protocol in 1999 and ratified it in January 2001, being the first Annex I country Party that ratified it. With Kyoto Protocol, the Parties to the Convention assumed the obligation to reduce the GHG emissions with a certain rate regarding the base year for each country. Romania committed itself to reduce the greenhouse gas emissions by 8% comparing to 1989 (base year) levels in the first commitment period 2008 - 2012.



**Figure 1.4 Total GHG emissions: Romania** (*National Inventory Report to UNFCCC 2006*)

Figure 1.4 shows the commitment cap on GHG emissions and the evolution of the emissions in CO<sub>2</sub> equivalent in the period 1989-2004. According to this, already there is a great probability for Romania to meet the Kyoto Protocol commitments regarding the limitation of the GHG emissions in the first commitment period (2008-2012).

The GHG emissions have decreased with 41% since the base year. The emissions trend reflects the changes in this period characterized by a process of transition to a market economy. The emissions trend can be split in two parts: the period 1989-1996 and the period 1996-2004. The decline of economic activities and energy consumption in the period 1989-1992 had directly caused the decline in total emissions during that period. With the entire economy in transition, some energy intensive industries reduced their activities and this is reflected in the reduction of GHG emissions. Emissions have started to increase until 1996, because of economy revitalization. Considering the starting of the operation at the first reactor at the Cernavoda nuclear power plant (1996), the emissions started to decrease again. The decrease continued until 1999. The increased trend after 1999 reflects the economic development in the period 1999-2004.



**Figure 1.5 Energy sector GHG emissions: Romania** (*National Inventory Report to UNFCCC 2006*)

The Energy sector represents the largest source of anthropogenic GHG emissions in Romania. In 2004 emissions from the energy sector accounted for 113.4 Tg CO<sub>2</sub> equivalent, which represent 73.3 % of the total GHG emissions. Within the Energy sector, the energy industries are the most significant, followed by manufacturing industries and construction sector.

The Energy sector emissions follow the same pattern of the total emissions revealing its great contribution to them, at present dictating the whole behaviour of the total GHG emissions. The same trend can be observed among the entire period 1989 -2004 mainly caused by the decline in fuel combustion activities and the amount of fossil fuels extracted. The emission trend reflects the changes in this period characterized by a process of transition to a market economy. A similar trend is visible with the 1989-1996 period bringing a significant decrease in all economic activities followed by an increase (1993-1996), the decrease after 1999 as a consequence of bringing into operation of the first reactor at the Cernavoda nuclear power plant, and after 1999 the emissions have started to increase as a consequence of economy revitalization (*UNFCCC - National Inventory Report to UNFCCC, 2006*).

## 1.3 RO Energy overview

The annual power generation in Romania in 2005 was 59.7 TWh. The generation mix and installed capacity are given *Table 1.2* Thermal power producers account for the greatest share in the electricity production, having also the largest installed capacity.

<b>Table 1.2 Romania electricity production and installed capacity</b> <i>(Ministry of Economy and Trade, 2005)</i>		
Generation type	Share (%)	Installed capacity (GW)
Coal/lignite	39.4 %	9.3
Hydro	34 %	6.4
Oil/Gas	17.3 %	6.5
Nuclear	9.3 %	0.75

Much of the thermal capacity is built on the 1960s and 1970s technology and the major power stations are listed in *Table 1.3*

<b>Table 1.3 Romanian large thermal power stations</b> <i>(Ministry of Economy and Trade, 2005)</i>				
Power Station	Installed Capacity (MWe)		Primary Fuel	Year Commissioned
	Units	Total		
Turceni	7 x 330	2310	Lignite	1978-1987
Rovinari	4 x 330	1720	Lignite	1972-1979
Mintia	6 x 210	1260	Black coal	1969-1980
Craiova	2 x 315 2 x 100 1 x 55 3 x 50	1035	Lignite	1965-1976
Braila	1 x 330 3 x 210	960	Oil/Gas	1973-1979
Brazi	2 x 200 2 x 105 6 x 50	910	oil/gas	1961-1986
Ludus	2 x 200 4 x 100	800	gas	1963-1967
Borzesti	2 x 210 1 x 60 2 x 50 3 x 25	655	oil/gas	1955-1969
Bucuresti Sud	2 x 125 2 x 100 2 x 50	550	oil/gas	1956-1975
Galati	3 x 105 1 x 100 2 x 60	535	gas/coke gas/furnace gas	1969-1984
Doicesti	2 x 200 6 x 20	520	lignite	1952-1978
Paroseni	1 x 150 3 x 50	300	coal	1956-1964
Fintinele	1 x 100 1 x 50 4 x 25	250	gas	1954-1966

Some plants use a mixture of natural gas and oil (hydrocarbons) as a fuel therefore it has been represented aggregated in the tables.

It is estimated that approximately 40% of the current total installed thermal capacity will need to be rehabilitated or replaced by 2010 (*Ministry of Economy and Trade, 2005*). Having the right conditions for modernizations set up by the emerging carbon market, it can be speculated that the power industry will be involved in cofiring projects.

## 1.4 National Emission Limits

The first challenge of the power sector is the reduction of the pollutant substance emissions, exhausted into atmosphere through the existent plant stacks.

At the European level the Directive 2001/80/EC is addressing to Large Combustion Plant(s) (LCP) with a rated thermal input exceeding 50 MW, for all type of fossil fuels used and for those which entered under IPPC (Integrated Pollution Prevention and Control).

For the implementation of this EU directive the RO Government issued the Governmental Decision (GD) no. 541/2003, with the modification and addition of GD no. 322/2005, on the limitation of emissions of certain pollutants into the air from large combustion plants, over 50 MW establishing the measures needed to limit the emissions of certain pollutants.

These limits are mandatory for any new plant which will be implemented. For the already running units it's stated that until 2012 the demanded limits should be reached using a gradual programme so through implementing important investments the stated emissions levels can be fulfilled.

These documents also express the Romanian targets regarding reductions in pollutant emissions, part of the National Programme of Emissions Reductions from LCP, and which are presented in the *Table 1.4*.

<b>Table 1.4 Total annual emission limits for sulphur dioxides, nitrogen oxides and particulate matter</b> <i>(Governmental Decision no. 322/2005)</i>			
<b>Year</b>	<b>SO<sub>2</sub></b>	<b>NOx</b>	<b>PM</b>
<b>2007</b>	<b>&lt; 540 tons / year</b>	<b>&lt; 128 000 tons / year</b>	<b>&lt; 38 600 tons / year</b>
<b>2008</b>	<b>&lt; 530 tons / year</b>	<b>&lt; 125 000 tons / year</b>	<b>&lt; 33 800 tons / year</b>
<b>2010</b>	<b>&lt; 336 tons / year</b>	<b>&lt; 114 000 tons / year</b>	<b>&lt; 23 200 tons / year</b>
<b>2013</b>	<b>&lt; 148 tons / year</b>	<b>&lt; 112 000 tons / year</b>	<b>&lt; 15 500 tons / year</b>
<b>2016</b>	-	<b>&lt; 80 000 tons / year</b>	-
<b>2017</b>	-	<b>&lt; 74 000 tons / year</b>	-

Emissions standards in Romania are summarised in *Table 1.5* along side examples of emission limits in other countries in the EU. For SO<sub>2</sub> the Romanian limit is the same with the top value of the limit seen elsewhere in the EU. For NOx the limit appears to be lower in Romania and for particulates the standard is the same with the EU limit value.

<b>Table 1.5 Emission limits in Romania compared to other EU countries, mg/m<sup>3</sup></b> (Governmental Decision no. 322/2005)				
<b>Pollutant</b>	<b>Country</b>	<b>Fuel type</b>	<b>Plant size, MWth</b>	<b>Emission limit, mg/ m<sup>3</sup></b>
<b>SO<sub>2</sub></b>	<b>Romania</b>	<b>Solid</b>	<b>50 &lt; P &lt; 100</b>	<b>2000</b>
			<b>100 &lt; P &lt; 500</b>	<b>2400-4P</b>
			<b>P &gt; 500</b>	<b>400</b>
		<b>Liquid</b>	<b>50 &lt; P &lt; 300</b>	<b>1700</b>
			<b>300 &lt; P &lt; 500</b>	<b>3650-6.5P</b>
			<b>P &gt; 500</b>	<b>400</b>
		<b>Gaseous</b>	<b>All</b>	<b>35</b>
	<b>Blast-furnace gas/gases from steel industry</b>		<b>All</b>	<b>800</b>
	<b>Other EU countries</b>		<b>100 - 500</b>	<b>400-2000</b>
		<b>&gt; 500</b>	<b>400</b>	
<b>NO<sub>x</sub></b>	<b>Romania</b>	<b>Solid</b>	<b>50 &lt; P &lt; 500</b>	<b>600</b>
			<b>P &gt; 500</b>	<b>500/200*</b>
		<b>Liquid</b>	<b>All</b>	<b>450</b>
		<b>Gaseous</b>	<b>50 &lt; P &lt; 500</b>	<b>300</b>
	<b>P &gt; 500</b>		<b>200</b>	
	<b>Other EU countries</b>		<b>&gt; 500</b>	<b>650</b>
<b>Particulates</b>	<b>Romania</b>	<b>Solid</b>	<b>50 &lt; P &lt; 500</b>	<b>100</b>
			<b>P &gt; 500</b>	<b>50</b>
		<b>Liquid</b>	<b>All</b>	<b>50</b>
		<b>Gaseous</b>	<b>All</b>	<b>5</b>
		<b>Blast-furnace gas/gases from steel industry</b>	<b>All</b>	<b>10/50</b>
	<b>Other EU countries</b>		<b>100 – 500</b>	<b>100</b>
			<b>&gt; 500</b>	<b>50</b>

from 1<sup>st</sup> January 2016

**Note:** Emission limits expressed at O<sub>2</sub> content of 6% for solid fuels, 3% for liquid and gaseous fuels respectively.

Referring to cofiring, this document also establishes the manner in which the emission limit values for sulphur dioxide, nitrogen oxides and particulates for LCP with cofiring capability are defined by the authority for environment protection.

On authorizing a LCP, equipped for cofiring, which implies simultaneous using of 2 or more fuel types the competent authority for environment protection sets the emission limit values as follows:

- The **emission limit value** for each pollutant, corresponding to each fuel type is known, related to the thermal nominal power of the LCP (*Table 1.5*).
- The **balanced emission limit values** for each fuel type are defined. These values are obtained through multiplying the individual emission limit values (*Table 1.5*) with the corresponding thermal power of each fuel, the result being divided by the sum of the corresponding thermal powers of all used fuels.
- The **balanced emission limit values** are being **summarised**.

Undertaking cofiring projects implies utilizing a secondary fuel along with the primary fuel which is in most cases coal. The secondary fuel type considered can be biomass and/or waste. In some situations the waste can have a biomass origin; therefore it can be subject to confusion when having to respect and comply with emission regulations.

Different countries from the EU have different definitions regarding what is a biomass waste, and to which category it belongs, biomass or waste. The Romanian legislation defines biomass and its subdivision biomass waste as follows:

*Biomass – product composed partially or totally out of a vegetal, agricultural or forestry matter, which can be utilised as a fuel for the recovery of the energetic content, as well as the following wastes used as fuel:*

- a) vegetal waste, from agriculture and forestry;*
- b) vegetal waste from the food processing industries, if the thermal energy from the combustion process is valued;*
- c) fibrous vegetal waste from the production of natural cellulose pastes and from the paper made from cellulose paste, if these are incinerated on site and if the energy produced by the incineration installation is being valued;*
- d) cork waste;*
- e) wood waste, excepting those which can contain halogenated organic compounds or heavy metals, from applying protection or wood conservation treatments, and which include specially waste from constructions and demolitions*

*(Governmental Decision no. 541/2003)*

It is important to differentiate between a biomass waste, which can be in fact a “clean” biomass without containing toxic compounds, being part of the biomass category (e.g. straw), and a biomass waste that contains toxic compounds and which is regarded as a waste (e.g. painted wood telephone posts), even though with its biomass origins, being treated by a totally different legal framework.

At the European level the Directive 2000/76/EC is addressing the incineration of waste and the transposed Romanian Governmental Decision is GD no. 128/2002 on the incineration of waste.

Because of the cofiring projects manner, when cofiring coal, biomass and waste, both the European Directives (and the Romanian equivalents): 2001/80/EC (GD 541/2003) and 2000/76/EC (GD 128/2002), must be implemented, and an overview of the latter is necessary.

This document lays out the legal framework for plants co-incinerating waste which is needed in cofiring of biomass and waste programmes. The allowed average daily values (calculated using average half an hour values) depending on fuel type, for solid fuels, biomass and liquid fuels are defined, and presented in *Table 1.6* and *Table 1.7*.

<b>Table 1.6 Average daily values for combustion installations that co-incinerate wastes</b> (Governmental Decision no. 128/2005)				
<b>Solid fuels</b>				<b>(mg/ Nm<sup>3</sup> (O<sub>2</sub> content 6%))</b>
<b>Pollutant</b>	<b>&lt; 50 MWth</b>	<b>50-100 MWth</b>	<b>100-300 MWth</b>	<b>&gt;300 MWth</b>
<b>SO<sub>2</sub></b> General case	-	850	850 – 200 (linear decrease from 100 to 300 MWth)	200
<b>Indigenous fuels</b>	-	Or desulphurisation rate ≥ 90%	Or desulphurisation rate ≥ 92%	Or desulphurisation rate ≥ 95%
<b>NOx</b>	-	400	300	200
<b>Dust</b>	50	150	130	130
<b>Biomass</b>				<b>(mg/ Nm<sup>3</sup> (O<sub>2</sub> content 6%))</b>
<b>SO<sub>2</sub></b>	-	200	200	200
<b>NOx</b>	-	350	300	200
<b>Dust</b>	50	150	130	130
<b>Liquid fuels</b>				<b>(mg/ Nm<sup>3</sup> (O<sub>2</sub> content 3%))</b>
<b>SO<sub>2</sub></b>	-	850	850 – 200 (linear decrease from 100 to 300 MWth)	200
<b>NOx</b>	-	400	300	200
<b>Dust</b>	50	50	30	30

Comparing to the European directive allowed values for emissions, the Romanian values for the SO<sub>2</sub> and NOx average daily values are identical, however the dust limits for solid fuels and biomass seem to be much looser in Romania, being greater with about 100 units than the European counterparts for the plants larger than 50 MWth.

The total emission limit values for trace elements that must be respected by plants are given in *Table 1.7*.

<b>Table 1.7 Total emission limit values for combustion installations that co-incinerate wastes</b> (Governmental Decision no. 128/2005)	
<b>Pollutant</b>	<b>(C expressed in mg/Nm<sup>3</sup> (O<sub>2</sub> content 6%))</b>
<b>Cd + Tl</b>	0.05
<b>Hg</b>	0.05
<b>Sb + As + Pb + Cr + Co + Cu + Mn + Ni + V</b>	0.5
All average values measured over the sample period of a minimum of 30 minutes and a maximum of 8 hours	
<b>Pollutant</b>	<b>(C expressed in mg/Nm<sup>3</sup> (O<sub>2</sub> content 6%))</b>
<b>Dioxins and furans</b>	0.1
All average values measured over the sample period of a minimum of 6 hours and a maximum of 8 hours	

## 1.5 Market incentives for cofiring

Besides environmental advantages, cofiring can be appealing to thermal power producers because of the economic advantages it comes with, in the current European energy situation. New instruments to coordinate market mechanisms based on competition, the initiatives related to the achievement of important objectives, either associated with the environment – SO<sub>2</sub>, NO<sub>x</sub> or GHG emissions, or associated with the necessity to diversify the energy resources and to reduce the import dependency were introduced to achieve certain objectives at national, regional or global level: Green Certificates, Kyoto Protocol's Emission Trading and European Union's Emissions Trading Scheme, etc. Cofiring initiatives would benefit from the advantages of all the market based instruments and to underline that, a quick overview of them is necessary.

**Green Certificates:** The Green Certificates System is chosen by the Romanian Government to promote electricity from renewable energy sources (E-RES) on the internal electricity market. The E-RES target established by the Romanian Government is 33% from the national consumption of electricity by 2010 (33% includes both electricity produced large hydro power plants and the electricity produced from other type of technologies, which are using wind sources, solar sources, waves, biomass, geothermal, electricity produced in hydro power plants with a capacity equal or less than 10 MW, and hydrogen produced from RES) (*Romanian Power Market Operator, 2006*).

The trading system of the of green certificates represents a method to stimulate the production of E-RES at the lowest price, and which in the same time can reduce the CO<sub>2</sub> emissions through the replacement of an equivalent quantity of electricity produced from fossils fuels. A green certificate is a document which certifies the production of 1 MWh of E-RES.

The Green Certificates system combines the advantages of the command and control mechanisms with those of the market mechanisms. As a command and control mechanism the green certificates system has a target established at a central level, by the government, and the market determines the behaviour of the participants.

In a green certificates system, the producers receive a certain number of green certificates according to the electricity produced from RES and delivered into the network. The electricity suppliers are obliged to buy a number of green certificates corresponding to the quota imposed by the Government. In such way, the producers sell green certificates to the electricity suppliers and the green certificates price covers the differences between the E-RES and electricity from conventional fuel costs.

The Green Certificates market has begun to function, the first green certificates were issued in August 2005. Up to now, 40 participants have been registered to the green certificates market, 7608 green certificates have been issued and 7241 green certificates have been traded in November, December 2005 and January, February and March 2006. The market clearing price was in November and December 2005, 41.90 Euro, 37.08 Euro in January 2006, 41.90 euro in February 2006 and 42 euro in March 2006. (*Romanian Power Market Operator, 2006*)

By implementing a cofiring project, a thermal plant with two 315 MW boilers, with a 87.3 boiler efficiency, in one year (300 days) cofiring at 10% (electricity base) biomass might generate 446400 green certificates.

**Emission Trading (ET):** According to this mechanism only Annex I parties that have commitments for emissions limitation mentioned in Annex B of Kyoto Protocol can trade emissions. These parties will be prepared to transfer emissions units (AAUs). A unit transferred by means of this mechanism represents 1 metric tone of CO<sub>2</sub> emitted into the atmosphere. (CO<sub>2</sub> equivalent). The acquisition and the transfer of these units are made controlled, by means of a national GHG emissions register. The States Parties can authorize legal entities (companies) to participate in this trading mechanism. Each such entity will have an account in the national GHG emissions register. The main difference between the two other Kyoto Protocol mechanisms Joint Implementation (JI) - Clean Development Mechanism(CDM) and Emission Trading(ET) is that while JI-CDM systems are based on bilateral accords, ET are based on a totally integrated trading system, the participants buying emission permits on a centralized market, where the price will be determined by the demand and the offer of such units.

**European Union Emissions Trading Scheme (EU-ETS):** This mechanism is used in the European Union, between member states, with the framework set by the EU Directive 2003/87/EC and it is already in operation since 1 January 2005. This scheme consists of two main periods 2005-2007 and Kyoto Protocol period 2008-2012. The main difference between the Kyoto Protocol and EU- ETS is that the emissions reductions targets of EU-ETS are included in KP Annex B, but are not the same.

At the core of EU-ETS are the National Allocation Plans (NAP) of each member state, approved by European Commission. In NAP elaboration cycle, the European Union negotiates with each country the national GHG emissions amount of European Union Allowances (EUA), and inside of the country this quantity being divided among the main installations according with Directive 2003/87/EC criteria. Once a company has allocated an annual GHG emissions quantity (for each year between 2008-2012) according with NAP, it has a greater flexibility in order to achieve the emission limits (*Balasoiu, 2006*).

For both these two market instruments, the reductions in CO<sub>2</sub> achieved by biomass cofiring projects would result in financial incentives in the form of tradable emission permits, making them more attractive to be undertaken. Reducing CO<sub>2</sub> emissions is one of the biggest advantages of biomass cofiring, putting the cofiring plants in a favourable position on the electricity market to take advantage of the GHG reduction market mechanisms and remain competitive.

While centralized market instruments for coal cofiring with waste does not exist, the incentives to do so exist on the current European market. Cofiring of coal and waste achieves reduction in GHG emissions in an indirect manner by resulting in a lesser environmental impact than waste disposal or incineration which would lead to more undesirable emissions to the environment. It can be economic attractive because it is seen as a customer service by avoiding high waste disposal costs. Waste cofiring plants can take advantage of the fact that the landfilling spaces are diminishing in densely populated areas, along with the landfill emissions of CO<sub>2</sub>, methane and potential groundwater pollution, and get a financial incentive of providing this end service to the local communities they belong to.







## Chapter 2 – COFIRING

Cofiring: promoting cleaner fossil fuels

Addressed topics

- *Technological options for cofiring*
- *Technical issues regarding cofiring (biomass, wastes)*
- *International cofiring experience*



## 2.1 Why cofiring?

The prospects for coal use in power generation have always been affected by consideration of the energy reserves, price and security of supply of fuels in every region of the world. Environmental issues are playing an increasingly important role in today's energy policy. Alongside with the reduction of air pollutants such as particulates, sulphur dioxide (SO<sub>2</sub>) and nitrogen oxide (NO<sub>x</sub>) emissions, for which there are well-established technical solutions, the climate change issue has been receiving increasing consideration over the last period. The 1997 Kyoto Protocol marked a political decision to take action to mitigate climate change. Coal will be particularly affected because it's the most carbon intensive of all fossil fuels.

Technology transfer is regarded as an important process in emission reduction, much can be achieved by increasing power generating efficiencies in countries where efficiencies are far below the OECD average and where coal is sure to be used in the future. Policies with the aim to reduce GHG emissions and especially CO<sub>2</sub> are expected to affect how the world produces and consumes energy in the coming years with the direct application to coal utilization in the electricity production.

Currently available power generating technologies for using coal with other fuels having lower GHG emission factors or with wastes for their disposal, that otherwise would be landfilled or, if incinerated alone, would lead to more undesirable emissions to the atmosphere, are proving a successful option in several countries with a considerable interest of using biomass for power generation. This is because of several reasons, the capital one being that the combustion of biomass does not produce any net CO<sub>2</sub> emissions because of the regenerative manner in which it is grown being carbon neutral. The term biomass refers to organic matter that stores solar energy. 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 sludges and energy crops specially grown for use as biofuels such as switchgrass, eucalyptus, willow and poplar trees.

Using only biomass for power generation has several drawbacks including the fact that in many countries the biomass supply is widely dispersed and an infrastructure for harvesting, processing and transporting it to the power plant is hard to establish. The seasonal nature of it raises other complications plus the fact that costs of different biomass types are very variable ranging from being virtually free to considerably more expensive than coal, where its utilization depends on economic viability and whether the additional costs are subsidised.

Cofiring biomass along with coal has the potential to overcome some of the drawbacks of firing it alone while maximizing the advantages of its utilization. Cofiring does not involve high capital costs of building a new biomass plant, with a low capacity compared to a coal fired plant, but the significantly lower retrofitting costs of an existing plant maintaining the high capacity of coal fired plants. Retrofitting boilers can fire biomass when biomass supplies are available but switch back to coal when the supplies are running low. When co-fired the biomass efficiency ranges from 30% to 38%, maximizing the biomass energy conversion, in a larger plant than firing it in a smaller plant using biomass alone. Another important advantage is that it diversifies the coal-fired plant's fuel portfolio, increasing energy security. In addition to reducing CO<sub>2</sub> emissions, cofiring enables the coal-fired plant to reduce SO<sub>2</sub> emissions as biomass contains generally less sulphur than coal. Biomass also tends to contain less nitrogen which leads to lower NO<sub>x</sub> emissions. Furthermore, biomass has a higher volatile matter

contents than coal which is likely to form less NO<sub>x</sub> in low-NO<sub>x</sub> burners. Other than reducing atmospheric emissions, cofiring helps to dispose of a solid waste. The operating cost when cofiring are likely to be higher due to the higher biomass cost compared to coal, but, in spite of this, cofiring is often the cheapest form of renewable energy production (*Baxter, 2005*).

For Romania, with the upcoming ascension in the European family, in the context of opening the green certificates market in late 2005 and with the upcoming participation in the EU ETS- European Union Emission Trading Scheme the advantages provided by the cofiring option should become very interesting for Romanian thermal based power plants in the near future.

Reducing GHG, SO<sub>2</sub>, NO<sub>x</sub> emissions, closing material flows, disposing of solid wastes while recovering important energy content, contributing to cleaner fossil fuels utilization, increasing energy security while taking steps to achieve a sustainable development of the energy sector, generating green certificates and participating to the reduction of the GHG emissions on the ET scheme, cofiring is proving to be an opportunity increasing the competitiveness of the thermal power producers.

Cofiring can be direct, where the coal and biomass/waste are fired in the same boiler or indirect when the combustion or gasification of the biomass/waste occurs in a separate unit. In this chapter both possibilities are looked at, assessing the technological options of cofiring, technical issues raised by it and currently available plant experience.

## 2.2 Direct cofiring: technological options

Direct cofiring involves firing the coal and the biomass in the same boiler. This is the simplest and most used technology for cofiring biomass. As the biomass is combusted along with the coal, several technical issues arise depending on the type of boiler used. Coal and biomass have been co-fired in stoker, cyclone, fluidised bed combustion (FBC) and pulverized coal combustion (PCC) boilers. The proportions of the biomass fractions co-fired in respect with the boiler type according to a survey on Europe (*Järvinen, Alkangas, 2001*) are:

Boiler type	Biomass fraction
Stoker	20% - 95%
FBC	20% - 90%
PCC	3% - 20%

### 2.2.1 Stoker firing

The stoker or grate-fired boiler loads the fuel from below or more commonly from above a constantly moving grate while air is blown through the bed of fuel. There are two main types of grate: chain (travelling grate) and inclined (vibrating) grate. The smaller particles combust in suspension above the grate while the larger particles burn on the grate as the fuel moves from the front to the back of the boiler. The following advantages and disadvantages regarding grate-fired boilers can be listed:

- ☑ Stoker boilers are capable of firing a wide range of fuels, fairly large fuel pieces up to 3 cm in length
- ☑ Stoker boilers are suitable for firing a wide range of fuels including coal, wood fuels, waste fuels, peat and straw
- ☑ The boiler can be designed to fire even moderately wet fuels of varying size but not with too much dust
- ☑ Investment, operational and maintenance costs are usually lower than FBC and PCC
- ☑ Modern stoker plants are usually equipped with cyclones and electrostatic precipitators and sometimes gas scrubbers to remove particulates from the stack gasses
  
- ☒ Stoker firing is restricted to a maximum capacity of 100 MWe
- ☒ Efficiency is less than for FBC and PCC and the flue gas emissions can be higher
- ☒ The system is sensitive to changes in fuel quality, moisture thus the automation of the grate combustion is difficult. Such changes affect the fuel handling and feeding
- ☒ Problems can arise when using fuels with low ash melting points, but they can be minimized by using mechanical or water cooled grates avoiding the need to use preheated combustion air in the final burning region (*Juniper, 2000*);

### 2.2.2 Fluidised bed combustion

In fluidised bed boilers the fuel is burned in a bed of hot combustible particles suspended by an upward flow of fluidising gas. The temperature in FBC is lower than in PCC and efficient combustion is achieved by a relatively long residence time of the fuel in the bed. FBC is either bubbling fluidised bed (BFBC) or circulating fluidised bed combustion (CFBC).

- ☑ CFBC offers high degree of fuel flexibility in relation to the particle size, density, moisture and ash contents of the fuel.
- ☑ In a CFBC boiler, the circulation of the bed material and high turbulence in the combustion chamber ensures a good mixing of the fuel and combustion air facilitating the combustion of biofuels with high volatile contents additionally enabling 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 biomass.
- ☑ CFBC achieves high boiler efficiencies even with difficult, low grade fuels
- ☑ CFBC boilers are very flexible with regard to changes in fuel quality and it is possible to change quickly from coal to biomass and vice versa.
- ☑ FBC boilers designed for coal combustion can generally switch to coal/biomass cofiring with a relatively small investment
  
- ☒ When firing biomass, the process of receiving, handling, pre-processing, storage, conditioning, blending, conveying and feeding the fuel to the boiler will require space and equipment specifically designed for the feedstock.
- ☒ Though FBC technology is very flexible, if the feeding characteristics of the biomass differ too much from that of coal, a separate feeder may be required.
- ☒ When firing biomass in FBC boilers other problems may occur related to the modified vertical temperature profile, slagging and fouling on boiler walls when firing fuels with high alkaline contents, bed agglomeration when firing fuels with high alkaline and aluminium contents and chloride corrosion on heat transfer surfaces (*Energie, 2000*).

### 2.2.3 Pulverised coal boilers

PCC is the most diffused technology for burning coal to generate power worldwide. In the pulverised coal boilers the coal is burned as a fine powder suspension in an open furnace. The burners are conventionally located in the lower part of the furnace, usually on one or two walls, or in the corners.

It can be pointed out that there are four options for directly cofiring the biomass in a PCC boiler:

1. **Blending** - The biomass fuel can be fed with the coal to the coal mills and can be burned with the 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 2% of thermal input from biomass utilising such a blend
  - The initial capital cost of this technology is estimated to be 50\$/kW of biomass
  - This approach carries the highest risk of malfunctioning of the fuel feeding system
2. **Separate handling** – involves separate handling, metering and comminution of the biomass which is then injected into the pulverised coal upstream of the burners or at the burners.
  - Necessitates the installation of a number of biomass transport pipes across the boiler front, which may already be congested.
  - It may be difficult to maintain adequate burner performance over the normal boiler load curve.
3. **Separate handling and comminution** – involves separate handling and comminution of the biomass which is then combusted through a number of dedicated burners.
  - This approach will incur the highest capital cost
  - Initial capital cost is about 200 \$/kW biomass
  - Will pose the least risk to normal boiler operation
  - Possible to achieve 10% thermal input from biomass
4. **Biomass as re-burn fuel** – the final option is to utilise the biomass as a re-burn fuel. This technology is still in the process of development. (*Van Loo and Koppejan, 2003*)

Because the Romanian thermal power production is based only on PCC boiler technology at present (this does not mean that interest does not exist to retrofit some of the older plants to competing technologies), with the upstream technology required for pulverising the coal already developed and in place we will summarize the major technological areas of concern when cofiring biomass directly with coal in PCC boilers, and describe the problems in more detail for all the technologies in *Section 2.3*:

- For high proportions of biomass input (for example 10% of thermal input) the fuel volume can almost double and this can prevent combined grinding and feeding resulting the need for separate grinding and feeding mills. As well, biofuels with low melting points can cause caking in the mills and ducts.
- If the moisture degree of the biomass is considerably higher than that of the coal (for example bark or fresh cuttings) the flue gas volume will increase significantly and this can limit the biomass proportion that can be used.
- The lower melting points of some ashes resulting from cofiring can increase the possibility of slagging and fouling on the walls of the combustion chamber and the boiler tubes.
- Some biofuels that contain a high chlorine concentration (straw) can lead to high temperature corrosion. Superheaters are most affected due to their high steam temperatures, and efforts to increase efficiency by raising steam temperatures will aggravate this effect.
- The fouling possibility of convective heating surfaces is greater for fuels with low ash melting points. Cofiring sewage sludges can increase erosion due to their high ash contents but this will not be a problem for biofuels with low ash contents.
- Cofiring can affect the selective catalytic reduction (SCR) catalysts which are upstream of the precipitators in their high dust configuration. Fly ash containing alkali metals, arsenic, phosphorus or fluorine can deactivate the catalyst.
- The change in the composition of the formed ash when cofiring could affect ash utilisation and disposal options.
- The lower sulphur contents of most biofuels will reduce the load on the FGD plant. However, the presence of HCl in the flue gas will impair the operation of the FGD plant. 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 will lead to increased emissions from the stack (Hein and Scheuer, 2000).

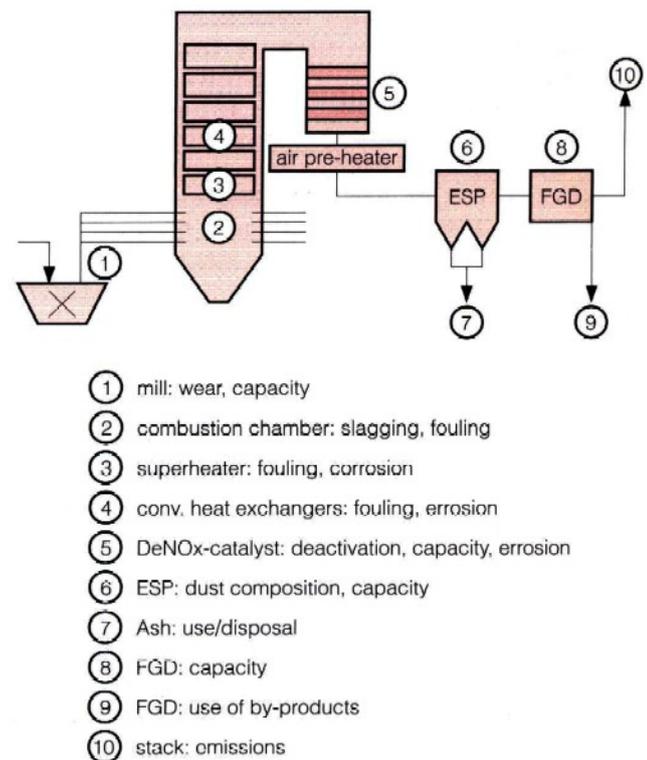


Figure 2.1 Areas of concern in cofiring with PCC (Hein and Scheuer, 2000)

## 2.3 Technical issues regarding direct cofiring biomass

### 2.3.1 Fuel characteristics

The major types of biomass considered are woody fuels and grassy or straw-derived herbaceous materials. The fuel properties of biomass are considerably different from those of coal as represented in *Table 2.1* and there is a greater difference with properties of typical coal types. Generally the heating values of biomass are half than those of 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 25% to even over 50%. The fuel nitrogen of biomass can vary from 0.1% to over 1% but the sulphur content of biomass is usually very low. These properties should be considered when cofiring biomass with coal (*Van Loo and Koppejan, 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	48.5
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	23.0
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

### 2.3.2 Fuel delivery, storage and preparation

Because of the fuel composition the issues regarding delivery, storage and preparation of biomass are different that of coal. Biomass has a much lower bulk density, is generally moist, strongly hydrophilic and is non-friable. The heating values and the particle densities are generally half that of coal and bulk densities about one fifth of coal. Therefore the overall fuel density of biomass in MJ/m<sup>3</sup> is about one tenth of coal. Therefore, cofiring biomass at 10% of thermal input requires comparable volumetric flows of coal and biomass. From this the on-site delivery, storage and fuel handling demands from biomass are disproportionately high compared to coal.

Biomass is normally delivered by truck 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 low energy density of biomass. The high shear strength and the fibre content also determine the design of the screening and 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 intermediate stores need to be larger due to the lower calorific values of biomass. The largest round-bottom store equipped with a slewing screw reclaimer currently available is 5000 m<sup>3</sup>. The volume of a single A-shape store can exceed 10 000 m<sup>3</sup>. The most reliable boiler silo has proved to be a cylindrical silo fitted with

an unloading screw turning at the bottom. This design ensures the most accurate and adjustable discharge of fuel (*Rohan, 2005*).

The long-term storage of wood in chip form, for example, can cause additional difficulties as, if moisture content exceeds 20%, biological activity can lead to heating of the storage pile, loss of dry matter and a significant deterioration of the physical quality of the fuel. It is also possible that high dust and spore concentrations in the stored fuel can give rise to health and safety problems. To minimise biological activity during the long-term storage it is possible to store wood in larger pieces to reduce the exposed surface area, to use fungicides, to pre-dry or cool the fuel. On the other hand cereal straws have moisture contents below 20% and are not subject to biological activity to the same extent as wet wood fuels. KEMA (<http://www.kema.com/>) have investigated the factors leading to spontaneous combustion of biomass and have suggested the following guidelines to prevent it. In addition to storing the biomass as dry as possible, with a moisture content of less than 20%, they suggest that the storage pile should consist of a homogenous material and the biomass pile should not be compacted. They further suggest that the temperature and the gas composition in the pile should be measured. Biomass comminution produces a non-friable fibrous substance. It is not possible, nor necessary to reduce the biomass to the same size and shape as coal. The average aspect ratios of these particles range from three to seven cm or even higher. Such particles have very low packing densities and can be problematic during transportation. (*Baxter and Koppejan, 2004; Veijonen, 2003; Van Loo and Koppejan 2003; Meijer, 2005*)

If the biomass and the coal are pre-blended, the behaviour of the blended fuel in the mills must be considered. Problems may arise as most mills pulverising coal depend on the fragile composition of the coal particles whereas biomass does not mill satisfactory, the biomass/coal cofiring ratio may be limited. The utilisation of wet biomass can modify the heat balance in the mill. There is a tendency for the biomass to accumulate in the mill and 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. Unless there is excess mill throughput and drying capacity, significant capacity losses may occur. Biomass releases combustible volatiles at lower temperatures than bituminous coals. This gives rise to safety issues, which must be addressed particularly during start-ups, shut-downs, loss of coal incidents, mill trips and restarts (*Laux, 2000; Livingstone 2004*).

### 2.3.3 Combustion in the boiler

Adding to the differences in size and shape of the biomass particles and the coal fired in the boiler, other differences in the combustion characteristics of coal and biomass must be considered. As stated above the volatile matter content of biomass is higher than that of coal while the specific heating value of volatiles in kJ/kg is lower for biomass than for coal. The fraction of heat contributed by volatile products is about 70% for biomass compared with 30 to 45% for coal. The ratio of volatile matter to fixed carbon for biomass is in general greater than 4.0, while for coal it is always less than 1.0. Pyrolysis starts earlier for biomass and biomass yields a much higher proportion of mass through devolatilisation than coal. Typically biomass yields 90-95% of its mass during devolatilisation compared to 55-60% for most coals. As devolatilisation occurs very rapidly in the combustion zone, most biomass fuels should yield this proportion mass as long as they are entrained in the flue gas. If the biomass particles are too large or too dense for this, they could enter the bottom ash stream with little conversion. This should not occur 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 containing excessive high levels of moisture, inadequate fuel conversion could take place (*Vejjonen, 2003; Baxter and Koppejan, 2004*).

When biomass is cofired in a PCC boiler, it can be blended with the coal if the proportion of biomass, on a mass basis, is less than about 5%. For greater proportions of biomass it may be necessary to inject the biomass separately. Apart from the secondary storage and handling, other issues need to be addressed when integrating biomass cofiring into existing burner systems both tangentially and wall-fired units. In **tangentially-fired** furnaces, the fuel and air nozzles are mounted in the corners or walls of the furnace. The fuel and the air jets are directed towards a common firing circle in the centre which produces a swirl flow pattern. When cofiring biomass, the biomass injectors must be directed towards the common firing circle to avoid separation of the biofuel from the cycle and ensure sufficient mixing. The four methods of retrofitting the biomass injectors in tangential boilers are:

- Injection through the air compartment in the main windbox;
- Injection coaxial with the coal nozzles;
- Injection with biomass nozzles replacing coal nozzles;
- Injection through separate wall penetrations.

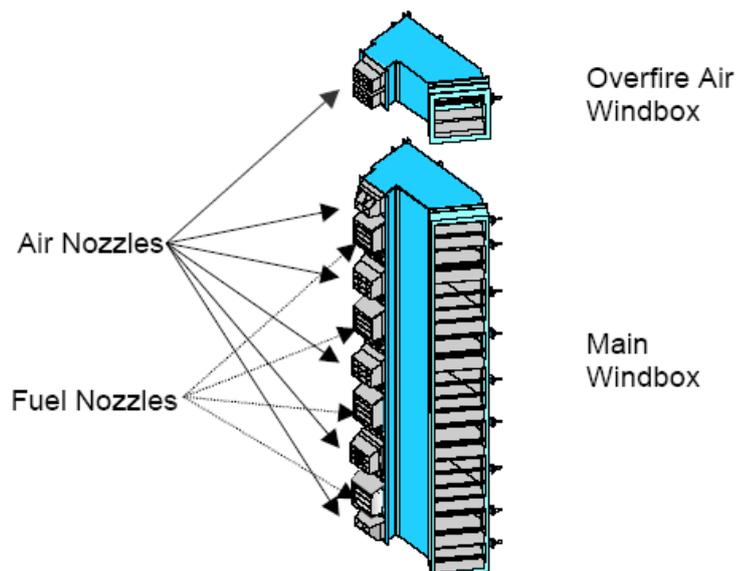
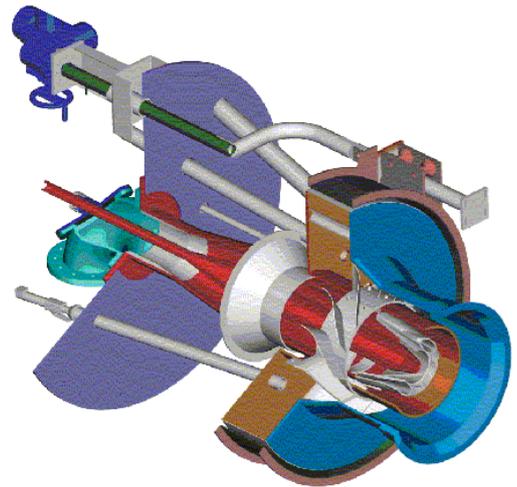


Figure 2.2 FW Tangentially Fired Low NOx system (*Heinz & others, 1999*)

The first two methods require the redesign of the air and fuel nozzles respectively. A customized fuel injector will be needed to be designed to fit in the windbox between the fuel nozzles or to be integrated into the coal fuel nozzles. If there is sufficient milling capacity in the existing firing system, the third option could be used. Either an entire mill could be taken out of service and the respective coal nozzles replaced with biomass nozzles, or a few pipes could be disabled to allow the integration of the biomass nozzles. In low NO<sub>x</sub> tangentially-fired systems part of the secondary air is diverted to an overfire system. This reduces NO<sub>x</sub> production but complete burnout is delayed. The high volatility of biomass generally lowers NO<sub>x</sub> emissions but any imbalance of fuel and air can increase CO and levels of unburned carbon. This is possible when cofiring biomass as high volatile biomass competes with coal for oxygen and if there is insufficient air for the combustion of both fuels, carbon burnout will be delayed.

The installation of biomass cofiring into a **wall-fired** boiler is potentially more complex than with a tangentially-fired boiler as there are many different types of burner designs. Wall-fired systems are installed as either single wall-fired furnaces or opposed wall-fired furnaces. The burners have one, two or three concentric annuli supplying combustion air around a central fuel nozzle. The air is swirled to control the flame stability and local flame mixing. In low NO<sub>x</sub> burners the central core is kept substoichiometric. Biomass can be injected into a wall-fired burner by:

- Injection of biomass coaxial with the coal nozzles;
- Injection with biomass nozzles replacing coal nozzles;
- Injection through separate furnace wall penetration.



**Figure 2.3 FW Vortex Series/Split Flame Low NO<sub>x</sub> Burner** (*Heinz & others, 1999*)

Of these possibilities, mainly the coaxial injection of biomass has been tried successfully. The conversion of entire burners to biomass firing creates the challenge that the burner air control needs to be totally independent from the biomass burners as the air requirements for the two fuels are quite different. It is also possible for striated flow patterns to be formed such that flue gas is not mixed effectively and that the gas composition at the boiler exit is not uniform but reflects burner-to-burner variations in stoichiometry and other properties. If the biomass is injected only into a few burners and the gasses do not mix thoroughly, many regions of the boiler will be exposed to higher cofiring percentages than suggested in the overall figure. This would also affect the extent to which, for example, the sulphur from the coal might react with the components derived from biomass to ameliorate corrosion (*Laux, 2002; Baxter 2000*).

### 2.3.4 Slagging and fouling

**Slagging** is the deposition of fly ash on the heat transfer surfaces and refractory in the furnace principally 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 condensation of volatiles or sulphating by reaction with  $\text{SO}_3$ . These deposits range greatly, the degree of slagging and fouling depending on local gas temperatures, tubes temperatures, temperature differences, tube orientation, local heat flux and fuel composition. Taking into consideration the last of these factors, deposit formation depends on the release and chemistry of chlorine, sulphur, aluminium, silicates, and alkalis during combustion. Compared to coal biomass can contain a higher proportion of alkaline species however the total ash content must be considered. The constituents of ash content such as alkali metals, phosphorus, chlorine, silicon, aluminium and calcium can affect the ash melting behaviour. Alkaline metals readily vaporise during combustion. 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 much more stable.

In *Table 2.2* the constituents of typical ashes which arise from the combustion of coal, straw and wood are listed.

Constituent	Coal ash, %	Straw ash, min %	Straw ash, max%	Wood ash, typical %
$\text{SiO}_2$	59.8	19.7	38.9	10
$\text{Al}_2\text{O}_3$	19.1	0.24	0.52	2
$\text{Fe}_2\text{O}_3$	8.1	0.13	0.19	1
CaO	2	6.35	8.45	35
MgO	1.7	1.5	1.9	5
$\text{Na}_2\text{O}$	0.6	0.29	1	3
$\text{K}_2\text{O}$	2.2	28.7	34.6	20
$\text{P}_2\text{O}_5$	0.2	2.45	3	12
$\text{SO}_3$	2.1	2.4	5	12
Cl	<0.1	4.55	7.06	-

It can be seen that the coal ash is composed mainly of quartz and alumino-silicates with the other major constituents being compounds of iron, calcium, magnesium, potassium and sodium. The sulphur, chlorine and phosphorus contents of coal ash are low. As coal contains relatively low levels of fluxing elements such as iron, calcium, potassium, sodium and magnesium, the ash is relatively refractory and has low predisposition for slagging and fouling.

Straw ash, like most of the biomass ashes, is not composed of alumino-silicates but of quartz and inorganic salts of potassium, calcium, magnesium and sodium, principally phosphates sulphates and chlorides. These ashes have fusion temperatures in the 750-1000C range compared to the fusion temperatures of coal ash in excess of 1000C, and adding up to a greater possibility of slagging and fouling.

The properties of wood ash are similar to those of straw ash. Throughout the data in *Table 2.2* is it not unusual that the levels of these constituents can vary greatly.

When biomass is cofired with coal in low to medium cofiring ratios, the behaviour of the resulting ash will be mainly determined by the behaviour of the coal ash. A key reaction that needs to be considered is the release of volatile species, such as alkali metals and phosphate compounds at flame temperatures and their following deposition on the boiler surfaces and deposits.

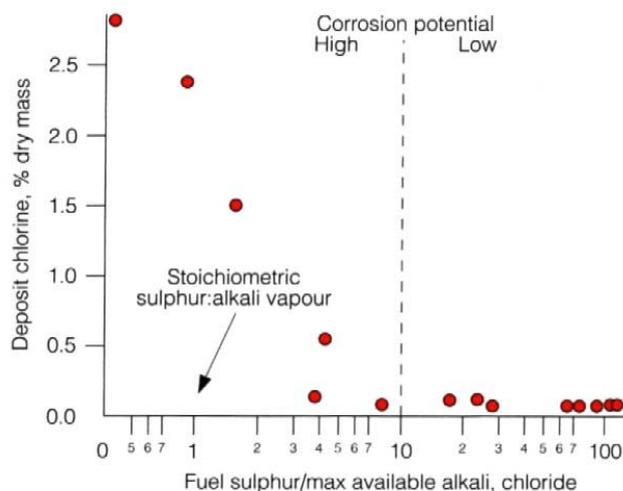
The first effect on deposition, when cofiring biomass with coal, is the increase of the rate and extent of slag formation. This is principally due to the decrease in fusion temperatures of produced ashes during cofiring since fused or partially fused slag deposits are more likely to incorporate incoming particles and grow in size. The most dramatic impact of this process is observed when biomass is cofired with coal which has a particularly refractory ash. In these situations cofiring even at even modest ratios can have a major impact on ash fusion behaviour. The presence of significant levels of alkali and alkali-earth compounds in the mixed ash acts as a very effective flux on the coal ash, reducing the fusion temperatures by 100-200C and dramatically increasing the likelihood of slagging. This effect is less dramatic with coal ashes originally having lower fusion temperatures and already having significant slag formation predispositions.

Secondly the volatilisation and condensation of alkali metals and phosphates when cofiring coal with biomass, is a major mechanism for the initiation and growth of fouling deposits. Most types of biomass are high fouling fuels and cofiring biomass with coal in almost all cases increases the likelihood of fouling. The level of risk depends not only on the nature of biomass and coal ashes and the cofiring ratio but also on site specific factors like the sensitivity of individual boilers regarding the tendency to accumulate ash, its subsequent effect in reduced heat transfer and the effectiveness of installed cleaning systems varying 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% (*Val Loo and Koppejan, 2003*).

### 2.3.5 Corrosion

Cofiring with biomass can increase both the high and the low temperature corrosion rates in utility boilers. Increased high temperature corrosion can occur due to changes in the ash chemistry of the ash materials 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 leading to the enrichment of particularly potassium compounds and the metal/oxide/ash deposit interface. Moreover some types of biomass contain high chlorine levels which result in high HCl concentrations in the boiler flue gas which can lead to the enrichment of chloride at the metal/oxide/ash deposit interface. The HCl can also result in low temperature corrosion in the back end ducting although this problem is generally less serious and more manageable than superheater corrosion. Therefore, depending on the cofiring rate, biomass containing high levels of alkali or chlorine such as straw, switchgrass, poultry manure and sewage sludge can create or exacerbate corrosion problems. (*Van Loo and Koppejan, 2003; Kunkel, 2004*)

The extent of corrosion can be limited if  $\text{SO}_2$  is present in the flue gas because it reacts with condensed alkali and alkaline-earth chlorides to form less corrosive sulphates. However, these sulphate compounds are only stable under oxidising conditions and then at lower temperatures than flame temperatures. The conversion of chloride compounds to sulphates is affecting the corrosion rates which are thus dependant on fuel properties such as sulphur, chlorine and alkali/alkaline earth content, operating conditions (determining ash deposition and local gas phase stoichiometry) and the boiler design (which determines the tube composition and the temperatures). *Figure 2.4* shows that the extent of deposited chloride decreases as the ratio of fuel sulphur to the sum of available alkali plus chloride increases. Cl breaks free from compounds when this ratio exceeds unity but values approaching ten are required to eliminate corrosion. The advantages of the sulphur in the coal in preventing corrosion under oxidising conditions do not extend to reducing conditions (sulphates are not stable under reducing conditions corrosion may still occur in overfire air systems). (*Baxter, 2003*)



**Figure 2.4** Effect of sulphur to alkali ratio on amount of chlorine deposited (*Baxter & others, 2003*)

## 2.3.6 Environmental emissions

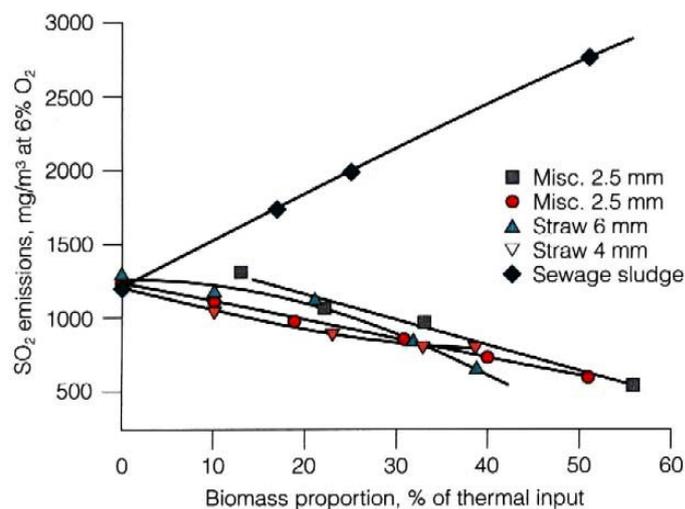
### 2.3.6.1 CO<sub>2</sub>

The combustion of biomass releases about 30 gC/MJ (LHV). However these emissions can be regarded as being carbon neutral if the biomass is grown in a managed forest. The stack emissions of CO<sub>2</sub> may increase when cofiring biomass compared only to coal. Even if the biomass 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 a far more potent gas than CO<sub>2</sub>.

### 2.3.6.2 SO<sub>2</sub>

SO<sub>2</sub> emissions always decrease, often in proportion to the biomass used, as most types of biomass contain far less sulphur than coal (*Table 2.1*). 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. *Figure 2.5* shows SO<sub>2</sub> emissions when wood, straw or miscanthus (misc.) are cofired with coal.

In addition to lower sulphur content of biomass, the proportion of sulphur retained in ash increases from 10% in coal to 50% for pure biomass (*Spliethoff, 2001*).

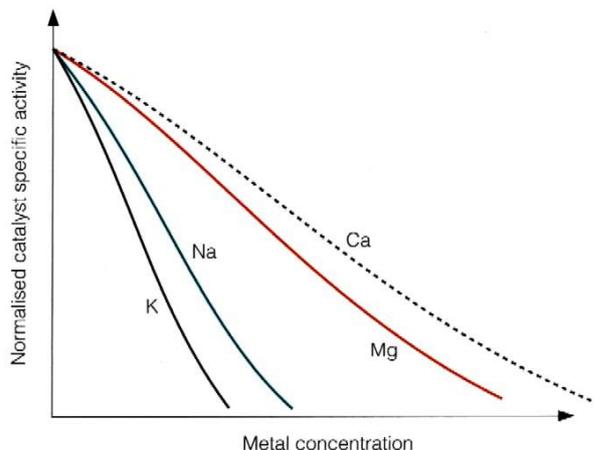


**Figure 2.5 Emissions of SO<sub>2</sub> as a function of biomass ratio for several blends** (*Spliethoff & others, 2000*)

### 2.3.6.3 NO<sub>x</sub>

NO<sub>x</sub> emissions when cofiring biomass are more difficult to predict and may increase, decrease or remain the same as when firing coal depending on particular types of biomass, firing conditions and operating conditions. Some biomass fuels, such as those derived from wood have lower nitrogen contents which result in lower NO<sub>x</sub> emissions. Other fuels, mainly derived from agricultural practices such as rice hulls, can contain higher nitrogen contents than typical coals. However, NO<sub>x</sub> emissions are not determined purely by nitrogen content but on 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 nitrogen in biomass is released as volatile compounds and this can result in lower NO<sub>x</sub> emissions, particularly with low NO<sub>x</sub> burners. Moreover, the higher moisture content of biomass can lower peak flame temperatures thus reducing NO<sub>x</sub> production (*Baxter and Koppejan, 2004*).

Biomass cofiring can indirectly affect NO<sub>x</sub> emissions in that there is evidence that SCR catalysts can be adversely affected by it. It can be due to alkali and alkali-earth metal constituents of biomass poisoning the vanadium-based catalyst in SCR systems. Most biomass fuel contains high levels of alkali and alkali-earth metals although the ash contents of some biomass fuels are low. The impact of the compounds of these metals on SCR catalyst activity is shown in *Figure 2.6*.



The exact mechanism is uncertain but may be related to changes in the surface acidity. (*Baxter & others, 2003*)

**Figure 2.6 Qualitative effect alkali and alkaline-earth compounds on SCR catalyst activity** (*Baxter & others, 2003*)

Biomass can also be used as a reburn fuel. This reburn technique involves introducing a proportion of the fuel (10-30% of heat input usually) at a point above the combustion zone to create a reducing zone in which the NO produced in the primary zone is reduced to N. Most used fuel for reburning is natural gas although coal or oil also have been used. When biomass is utilised as a reburn fuel it is often gasified and then introduced in the coal boiler (indirect cofiring). Tests on pilot scale showed that the resulting gas from alfalfa (high N content) as a reburn fuel increased the NO<sub>x</sub> emissions whereas the resulting gas from switchgrass lowered NO<sub>x</sub> emissions by 35%. There have been some reburn trials introducing biomass directly on laboratory scale facilities with the conclusion that the use of wood as a reburn fuel was just as effective as a reburn fuel as natural gas and achieved NO<sub>x</sub> reductions as high as 60-70% (*Harding and Adams, 2000*).

### 2.3.6.4 HCl

Chlorine content in some types of biomass such as grass and straw can be considerably higher than in coal. In straw the chlorine content can approach 1%, ten times greater than in typical bituminous coals. Some of the fuel chlorine reacts with alkali metals in the fuel such as K and Na to form salts which can lead to corrosion as discussed above in *Section 3.4*. Traces of chlorine can form dioxins and other compounds but a substantial fraction of the fuel chlorine will be released as HCl. The chlorine content of the fuel can be reduced by washing the fuel and HCl will be readily removed by a FGD scrubber. Otherwise the possibility exists that HCl in the flue gas could cause back-end corrosion (*Rohan, 2005*).

### 2.3.7 Ash utilisation

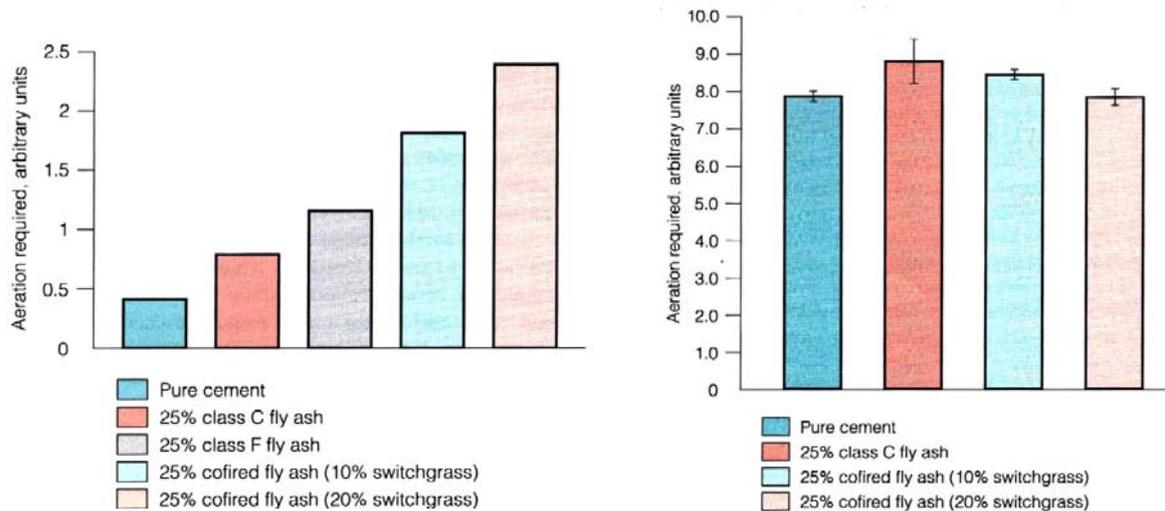
The ESP/bag filter, economiser of air, heat hoppers recover about 80% of the ash produced from a PCC plant in the form of fly ash. The grade of utilisation of this ash varies considerably from country to country: In Holland, Germany, Belgium, Italy and Denmark the utilisation rate exceeds 80% while in the UK the proportion utilised is less than 50% and in the US over a third of the generated fly ash is sold on a secondary market. The rest of the ash is sent to landfill, reclamation and restoration and it is regarded as a non-hazardous waste. 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.

The main utilisation of fly ash is in the production of cement and concrete where needs to comply with some standards (EN450, DIN 1045 or BS3982) that specify the C-in-ash, SO<sub>3</sub> content and fineness. The bottom ash is used for land reclamation, stabilisation and in non-aerated concrete blocks.

In some countries the use of ash from PCC plants in the cement or concrete is not allowed if the coal is cofired with biomass. For example the European standard EN405 specifies that “only the fly ash from pure coal or anthracite combustion is allowed as an aggregate in the cement or concrete industry” and in the USA, the ASTM specification C168, for the use of fly ash in concrete, specifies that “the ash must be derived entirely from coal combustion”. However exceptions can be allowed. In Germany, for example, the utilisation of fly ash from the cofiring of sewage sludge is allowed provided that the input fraction of the sewage sludge, on a mass basis, does not exceed 5%. There are discussions taking place to revise EN450 to allow the utilisation of ash derived from cofiring coal and biomass up to a certain wt% of biomass. Standards in Denmark and Canada have been relaxed recently to allow the use of some biomass fly ash in concrete production (*Van Loo and Koppejan, 2003*).

Although the compositions of biomass and coal ash are quite different, the composition of cofired ash is dominated by alumino-silicates derived from coal ash as the ash content of most biomass fuels is very low and cofiring ratios are also usually low. Investigations have been made on the impact of biomass derived fly ash on concrete properties. The impact of biomass and coal-derived fly ash on concrete involving both subbituminous and bituminous fly ash and ash obtained from cofiring herbaceous and woody biomass has been determined. In all cases, 25% of the fly ash used in the concrete was replaced with fly ash which contained 0-40% biomass derived material. The effect of biomass on concrete air entrainment, flexural strength, compressive strength, set time, freeze-defreeze behaviour and chlorine permeability

were investigated. The focus of the tests was on herbaceous biomasses as woody biomasses contain so little ash that cofiring is much less likely to have measurable impact on fly ash properties. Preliminary results shown in *Figure 2.7* show the impact of the 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-defreeze cycles.



**Figure 2.7 Amount of aerating agent required for a range of specifications of fly ash compositions**

*(Baxter and Koppejan, 2003)*

**Figure 2.8 Dependence of flexural strength On fly ash composition**

*(Baxter and Koppejan, 2003)*

The results indicate that amount of aerating agent increases with herbaceous biomass content. 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-defreeze cycles. This can be solved by increasing the amount of surfactant (favouring film forming that support bubble growth in concrete), costing little but failing to recognize the need to adjust would have major impact.

*Figure 2.8* illustrates the impact of cofired ashes on flexural strength. There was little observable difference among the tests samples. Additional data on concrete set times and compressive strength indicated that all fly ashes delayed set times by two to four hours compared to concrete made from only cement but the 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 presence of all fly ashes (*Baxter and Koppejan, 2004*).

## 2.4 Technical issues regarding direct cofiring of waste

First the concept of waste must be clarified since as pointed out in *Section 1.4*, special attention must be paid to what is considered a waste and what is not, as it may be regulated by different parts of the law.

A waste may be defined as an unwanted solid or liquid residue from some source or process that is unwanted, meaning it has no further value or use to its producer. It may be described as something which has zero or negative value (disposal of the residue having a cost associated with it). Things get complicated when this distinction between a waste and a product is broken. When a waste can be used in some other way by anyone, it has acquired a value and might no longer be considered a waste. Then a distinction must be made to cover this aspect as well. Therefore a waste may be defined as a movable object that has no direct use to its producer and is discarded permanently.

There are many types of wastes, but this report refers to non-hazardous wastes such as agricultural and forestry wastes, construction wastes, industrial wastes, and other urban wastes investigated for cofiring. A classification of the types of waste which may be suitable for cofiring would be:

- Municipal solid waste (municipal sewage sludge, refuse derived fuel, plastic, etc);
- Biomass (forest industry residues, industrial wastes, construction industry wastes, etc);
- Used tires(tire-derived fuel);
- Specialized industrial wastes (petroleum coke, used oil, etc)

The biomass wastes, as they can be considered biomass as long they are “clean”, can be referred to *Section 2.3* regarding the technical issues raised by their cofiring with coal. Matters related to their delivery, storage, preparation, feeding, combustion in the boiler, slagging, fouling and corrosion, environmental emissions and ash utilisation were addressed in *Section 2.3* and will not be repeated in this section.

### 2.4.1 Fuel characteristics

**Municipal solid waste (MSW):** Many types of fuels can be derived from MSW since it contains many types of different wastes. Normally MSW has a heterogeneous composition that can include a wide variety of materials such as metal, glass, paper, plastic containers, waste foods, fabrics disposed by city residents. Its composition varies from country to country, and among regions of the specific country. Its composition also varies with time as a result of changes in lifestyle and packing and is likely to be affected by recycling and reuse initiatives. A subcategory of it would be the refuse derived fuel (RDF) which would be more practical to use. RDF contains only the combustible materials but excludes materials removed for recycling (e.g. newspapers). RDF can be of many types, depending on the degree of preparation it goes through. Out of which packaging-derived fuel (PDF) and plastic packaging-derived fuel (PPDF) are the most significant because their separation from RDF is done for the purpose of creating higher value fuels. PDF can represent over 50% of thermal content of MSW, even though its weight % may be much less due to lower moisture and higher calorific value than the remaining combustible material consisting mainly of moist food wastes. It is difficult to qualify and especially to quantify in general terms the specific wastes included in MSW, RDF, and PDF since they vary according to the locality in which

they are collected. Comparing to glass, plastic containers are lightweight, tough, and near unbreakable. The use of plastic is increasing in the society and it has introduced more disposal problems. Although plastic on average is less than 10% of MSW by weight, it occupies 20% of MSW by volume. The energy content of plastic is 30-44 MJ/kg. Other fuel properties are presented in comparison with biomass fuels in *Table 2.1*.

There are three different ways of treating MSW: landfill, recovery from recycling purpose (paper, plastic, metal, glass fractions and a residue for landfill) and combustion for disposal alone (incineration), or combined with energy recovery. Waste to energy is gaining more and more attention as landfill costs and environmental concerns rise and, at the same time, the landfill area is diminishing. Furthermore, in many countries from the EU, landfilling will soon not be considered as an option.

**Biomass waste:** The term biomass waste should be understood in this section with the distinction from *Section 1.4* in mind. It describes organic matter derived from plants including agricultural wastes, demolition and forestry wood wastes, resulted because of the intervention of man. It retains most of the physical characteristics of its originating biomass presented in *Section 2.3.1*, but the other “alterations” must be taken into account when used for cofiring: using appropriate measuring and control equipment related to type of pollutant contained. Wood waste: can be classified as forestry wood waste (waste from commercial logging and harvested wood from site development); mill residue (waste from companies that create boards, beams, and other primary wood products from whole logs as well as companies that produce products such as flooring, fencing, cabinets, etc); and urban wood waste (construction and demolition wood, and other wood that may be combined with other municipal or solid waste). Other types of biomass wastes that can potentially be cofired with coal can be straw, bagasse (residue from sugar cane processing), elephant grass etc. These types of biomass are regional and in most cases their potential use is related more to economics.

**Specialised industrial wastes:** Other types of waste are suitable for cofiring including used oil, petroleum coke, auto shredder residue (ASR) etc. The energy content of the used oil is about 41-44 MJ/kg. ASR is material left after recycling of cars accounting for about 21% of the car’s original weight. It consists of varying amounts of fibre, fabric, paper, wood, foam rubber, plastics making it generally combustible with an average value of 12.5 MJ/kg. ASR quantities are increasing since more plastic are used as substitutes for metal in car industry. Petroleum coke is produced as a by-product of the oil refining industry and its value is generally not critical to the overall economics of the refinery. It has been successfully cofired in PCC, FBC boilers and cement kilns the calorific value being about 33 MJ/kg.

**Used tires:** Historically, landfilling has been the most popular disposal option, although many used tires are retained by individuals or disposed improperly. However, the increase in environmental regulations led industry to use other options (recycling, retreating, and burning for energy). The calorific value of the tires in the range 27-37 MJ/kg (*Ekman 1996*).

### 2.4.2 Preparation and feeding

**Refuse Derived Fuels:** It is not practical to burn MSW in combustion systems designed for coal because of the non homogenous composition, so it must first be processed to RDF by removing metal, glass, and other non combustible parts. It can take up to 2.6 t of MSW to produce 1 t of RDF. There can be problems in obtaining an adequate supply of RDF based fuel as waste contractors have little experience in providing material of the right quality, so fuel arrangements must be made before modifying the plant for cofiring. One approach would be to a pelletized form of the RDF. Wastes suitable for producing pellets include paper, laminates, board, packing material, non PVC-plastics, fibrous wastes, etc. Once produced the RDF pellets would have versatility to be used in many configurations. Another approach would be the delivery of RDF to the plant where it can be processed on site and fed directly to the boiler. RDF has been commonly burned in stoker and FBC boilers. It was pointed out that if plastic waste are to be burned in a PCC there is a need to find the maximum particle size to minimize the grinding effort (great increase in costs if it is necessary to reach sizes below 1 mm) but guarantee a sufficient burnout, as even coal firing systems in the 100  $\mu\text{m}$  range were capable of burning plastic up to 2 mm in size (*Gerhardt, 1997*).

**Sewage sludge:** A potential advantage of cofiring is that costly preparation of sewage sludge might be avoided. It can be transported to the plant by trucks where it can be mechanically dewatered if necessary, conveyed then pumped. The sewage sludge can be fired in CFB boilers, supplied via the ash recirculation ducts, distributing evenly in the bed, and also with PCC through one of the arrangements discussed in *Section 1.3.3* for low cofiring percentages. The preparation and feeding of waste for cofiring is fuel related and it can be pointed out that many various setups can be encountered, accordingly to fuel characteristics, conditions at the plant, agreements, etc. Also cofiring of wastes can be mixed, using multiple wastes, rather than just one type.

### 2.4.3 Combustion in the boiler

**Sewage sludge:** was cofired with coal in FBC and PCC boilers. For FBC systems it is no problems burning sewage sludge. Due to the small particle size of the sewage sludge granules, smooth dosing is possible resulting in a very stable combustion. Also it is known to lower bed temperature, a positive effect on FBC boilers. Cofiring with PCC boilers at low percentages (up to 15% th) (blending) it was found out that the fuel injection mode has only a marginal effect, the sludge having a lower reactivity than the coal. Cofiring an equal mass of sewage sludge with coal (~26%) through a simple burner extended the flame stability performance limits (*Abbas, 1996*). However flame ignition is delayed when the share of sewage sludge increases, and burner settings may be a critical factor of how the sewage sludge behaves with respect to flame stability. On the other hand, carbon burnout increases with a high share of sewage sludge in the fuel blend, this being attributed to the lower content of fixed carbon in the sewage sludge. Once combustion has started, flames with a high content of sewage sludge (20%) burn quickly, with a fast mixing of reactants and products, reflecting the higher amount of volatiles in comparison with fixed carbon (*Cenni, 1997*).

**Tire Derived Fuels:** TDF is especially suitable for Stoker and CFB combustion technologies and is judged to be an excellent supplemental fuel. For Stoker boilers low cofiring rates of 5 % and 10 % of tire blending are unproblematic. At higher rates air flow adjustments may be necessary to achieve complete burnout of the tires. Unlike coal, tire chips have no internal moisture to facilitate burnout; any moisture is at the surface. In coal, the internal moisture expands in the furnace, shattering the coal and exposing more surface area, thus facilitating a more complete burnout. Cofiring at higher rates of 40% posed problems for Tekniska Verken CHP (*Chapter 2.5.3*) causing vitrification of the mortar in the brick walls inside the furnace, occurring specially around the spreader stoker where the radiation is particularly intense. For CFB boilers the accumulation of steel wires in the combustor is cited as a potential problem but it has been found out that even large wire will oxidise sufficiently to break down in the combustor; the resultant oxide (polystyrene) being easily separated from the ash for possible reclamation.

**Plastic-Derived Fuels:** Commonly plastics are cofired in FBC combustors. In studies it was found out that polyethylene, polypropylene, polystyrene, and polyvinyl chloride (PVC) burn like oil. Except for PVC, they burn completely during the pyrolysis stage leaving no char. PVC produces an ash-free “char”. Any ash produced from the plastics corresponds to the mass of inorganic colouring agents incorporated into the plastics. Depending on the primary fuel used the amount of volatiles would increase significantly dictating how much plastics-derived fuel could be fed to the combustor (*Zevehoven, 1997*).

As a conclusion for all the waste fuels cofired below 20% the penalties on the combustion are insignificant, almost non-existing. Next the potentially damaging effects such as slagging and fouling, and the possibility of associated corrosive effects will be examined.

#### 2.4.4 Slagging, fouling, and corrosion

**Sewage sludge:** Sewage sludge has high ash content. While producing the same thermal output, 25% sewage sludge cofiring leads to an ash mass five times higher than in pure coal combustion, so it can cause operational difficulties. It was found at high cofiring rates (~50%) the slag buildup is significant, even changing the flame shape characteristics, so it is recommended that sewage sludge does not pass 10% of the total fuel input when cofiring with pulverised coal. The high ash content of the sewage sludge can also cause difficulties in fluidised bed firing. The difficulties can be attributed to the ash fusion behaviour and the low sintering point of the fly ash (between 840 and 860 C). These temperatures are generally lower than the temperature at the top of the FBC which is around 950 C (*Probst and Wehland, 1995*).

**Refuse Derived Fuels:** When cofiring RDF with high sulphur coal at the Municipal Electric Plant USA, the corrosion rates were 5-10 times less than those with bulk RDF burning, and approximated those from coal alone. It was suggested that the sulphur in the coal inhibits the corrosive effects of the chlorine in RDF. In other cases extreme levels of slagging and fouling were observed on boiler heat transfer surfaces, causing severe corrosion problems. It is important the consistency of the RDF, also fractions of lower chlorine content being present in the RDF can lead to corrosion problems (*Davidson, 1999*).

## 2.4.5 Environmental emissions

### 2.4.5.1 Particulates

**Tire Derived Fuels:** A decrease of the particulate emission by 50% was achieved during operation at W G Krummrich plant USA cofiring TDF with coal (*Dennis, 1994*). The fly ash analysis revealed that many of the compounds entering the ESP were metals (especially zinc) and the increased conductivity of these particles made charging easier hence a more efficient particle removal from the flue gas stream. A second reason that can be attributed was that a 10% lower air flow through the boiler was observed during TDF cofiring resulting in a longer retention time in the ESP and the better particle removal.

**Sewage sludge:** An improvement of the ESP was observed at Weiher II power station in Germany cofiring dried sewage sludge (*Billotet, 1995*). However the improvement was not attributed directly to the sewage sludge, but to the moist vapour from the sewage sludge drying operation. This vapour was led into the boiler thus integrated in the whole combustion process.

### 2.4.5.2 SO<sub>2</sub>

**Refuse Derived Fuels:** Cofiring RDF or MSW will reduce SO<sub>2</sub> emissions by dilution. SO<sub>2</sub> emissions are decreasing as the cofiring fraction is increased, the sulphur being captured in the ash. Also it was suggested that the chlorine content of PVC in MSW may reduce the emission of SO<sub>2</sub> from AFBC systems, the sulphur contents of the bed ash and fly ash increasing as the PVC/coal ratio (1 wt% - 3.3 wt%) is increased (*Xu, 1998*).

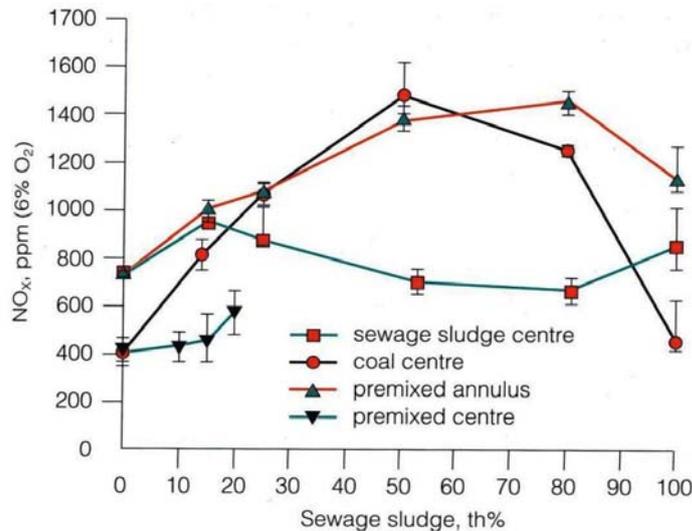
**Sewage sludge:** Comparing to the other considered fuels, sewage sludge has the highest sulphur content usually containing ~1 wt% (*Table 2.1*). In some cases it was seen to increase the SO<sub>2</sub> concentration in the flue gasses, but even so there is a significant sulphur retention in the ash of ~15%-25%. In other cases sewage sludge can decrease the emissions, all dependant of the composition of the sludge and the plant conditions.

**Tire Derived Fuels:** Tires contain ~1-2% sulphur that is introduced during the vulcanisation process. With a sulphur content value which is comparable to the ones of different coal types the SO<sub>2</sub> emissions will vary marginally depending on the type of the coal used. Cofiring TDF with coal will have a small effect on the sulphur dioxide emissions as the two fuels have similar sulphur contents.

### 2.4.5.3 NO<sub>x</sub>

**Refuse Derived Fuels:** Different compositions of RDF/coal blends were examined and the gaseous emissions from cofiring of the briquetted fuel mixture in a stoker boiler were measured (*Gera and Gautam, 1993*) and it was found out that the NO<sub>x</sub> concentrations from 100% coal combustion were less than those from firing briquettes containing 30% RDF.

**Sewage sludge:** Usually sewage sludge contains more nitrogen than coal but this does not mean that increased NO<sub>x</sub> emissions are to be expected every time. NO<sub>x</sub> emissions from cofiring sewage sludge with coal are very dependant on the burner settings. The best results are obtained when the coal and the sewage sludge are premixed and injected through the centre of the burner. In this way increasing the share of sewage sludge has nearly no influence on the NO<sub>x</sub> formation even though there is a larger amount of fuel nitrogen being injected into the furnace. Considering that in practice 10% sewage sludge is the usual maximum, the best way to add it (or any other nitrogen rich material) is to mix it with the main fuels and inject it through a low NO<sub>x</sub> burner. (Gerhard, 1997).



**Figure 2.9 Effect of different burner configurations and share of sewage sludge on measured NO<sub>x</sub> emissions (Gerhard, 1997)**

Sewage sludge has also been found to be effective as a reburning fuel even at high air ratios in the reduction zone ( $>0.9$ ). This was attributed to the nitrogen being released as NH<sub>i</sub> that can reduce the NO<sub>x</sub> already formed. (Kicherer, 1995).

**Tire Derived Fuels:** It was observed that TDF usually lowers the NO<sub>x</sub> emission levels when it is cofired with coal, one big reason being the lower nitrogen content. Typical coals have a nitrogen content of ~1.3 % compared to ~0.2 % for the tires. Cofiring of pulverised coal and tires was seen to result in NO<sub>x</sub> emissions proportional to the weight average of the blends (Atal, 1995). A particle size effect on the NO<sub>x</sub> emissions was also observed (Levendis, 1998). NO<sub>x</sub> formation was seen increased when large particles (180-212 μm) of coal were cofired with TDF particles of any size (small 63-75 μm or large 180-212 μm) comparing to the case when small particles (63-75 μm) of coal were cofired with TDF particles of any size (small 63-75 μm or large 180-212 μm).

#### 2.4.5.4 HCl

**Refuse Derived Fuels:** HCl emissions from RDF or MSW cofiring with coal closely reflect the chlorine input in the process and increased emissions are usually observed. In a 65 MW CFBC, the addition of 11 th% RDF caused the calculated HCl emissions to increase from 47

mg/m<sup>3</sup> for a peat/coal fuel to 130 mg/m<sup>3</sup>, the chlorine input in the process being 25 mg/MJ and 66 mg/MJ respectively. (*Desroches-Durcane, 1998*)

**Sewage sludge:** As with the other emissions from sewage sludge, the HCl emissions vary considerably depending on the chlorine content of the sewage sludge. Comparing to coal which has <~0.1 wt% chlorine content sewage sludge can vary from ~0.01 wt% to as high as ~1.5 wt% the emissions behaving correspondingly (*Davidson, 1999*).

### 2.4.5.5 Trace organic compounds

The perceived problem with chlorine is not the acid gas emissions, but its potential conversion into trace organic compounds, particularly dioxins and furans (polychlorinated dibenzodioxins (PCDD) and polychlorinated dibenzofurans (PCDF)) together abbreviated with PCDD/F.

**MSW/RDF:** Although PCDD/F emissions from municipal waste combustion are a serious concern, coal-fired utility boilers generally do not emit significant amounts of these substances and it is reasonable to suppose that cofiring coal and municipal waste could reduce PCDD/F emissions. (*Air Pollution Consultant, 1995*) One way by which coal cofiring can reduce the formation of PCDD/F is that the combustion temperature, if higher than 816C, will ensure that all organic compounds are destroyed providing there is adequate fuel/air mixing being the case especially for PF firing. Another way is that the sulphur dioxide from the coal combustion suppresses the formation of PCDD/F in MSW combustion. For FBC it was suggested that the lower combustion temperatures would lead to increased PCDD/F emissions but in many cases it was found out that PCDD/F levels for MSW/RDF coal cofiring are well below the 0.1 ng/m<sup>3</sup> EU limit (*Sunderman, 1995*).

**Sewage sludge:** It was observed that the flame type has an influence on the PCDD/F emissions when cofiring sewage sludge with pulverised coal, the better solution being when the coal is injected through the annulus of the burner and the sewage sludge through the centre 0.04 ng/m<sup>3</sup>, compared to the opposite configurations result of 0.3 ng/m<sup>3</sup> (*Morgan and van de Kamp, 1996*).

### 2.4.6 Ash quality

**Sewage sludge:** Cofiring with sewage sludge strongly increases the amount of ash produced. Sewage sludge, with only a third of the heating value of coal, produces five times the amount of ash. So, to substitute the thermal value of coal with sewage sludge means that fifteen times the amount of ash is produced compared with 100% coal combustion. Even at 5 % cofiring, the amount of ash produced doubles. Even so, analysis of the sewage sludge ashes showed that the concentrations of trace elements are very similar to those in coal ash, most of the concentrations remaining in their normal variation range (*Kicherer, 1995*).

**Tire Derived Fuels:** Scrap tires chips cofiring in chain grate stoker boilers was reported to generate ash “amazingly similar to that generated from coal” being used in the main market of cement industry (*Dennis, 1994*).

## 2.5 Direct cofiring plant experience

Biomass and waste biomass have been successfully demonstrated in over 150 installations worldwide for most of fuels and boiler types. A hundred of these demonstrations have been in Europe, twelve in Asia and the rest in the USA. The majority of plants in the USA which have cofired biomass have units larger than 100 MWe, whereas in Europe a significant proportion of cofiring units were smaller. In the following part focus is on the configurations used for direct cofiring of biomass/waste, the results and the experienced gained through these demonstrations. Because of the fact that cofiring configurations are dependant on many factors like, biomass type, coal firing technology, fuel specifications etc., it is not as standardized as coal firing, many solutions of configurations are possible and this section will present some of the most representative examples for each type of coal firing technology.

### 2.5.1 Direct cofiring with PCC

Having considered the options for direct cofiring the biomass/waste in a PCC boiler, their advantages and disadvantages, there will be given plant examples implementing each type of processing technique from *Section 2.2.3*: blending, separate handling, separate handling and comminution.

#### 2.5.1.1 Direct cofiring with PCC - Blending

##### Big Stone Plant #1, South Dakota, USA

**Power Plant Description:** The Harlee Branch Generating Station is located in Milledgeville on Lake Sinclair about 160 km southeast of Atlanta, Georgia and is owned by Southern Company/Georgia Power Company. Plant Branch has four boilers.

- **Unit #1** is a 250 MWe opposed-fired pulverized coal unit manufactured by Babcock & Wilcox (B&W) in 1965. The boiler generates 793,786 kg/hr steam flow at 165 bar and 537°C superheat and reheat. The unit has been furnished with CE journal pulverisers.
- **Unit #2** is a 319 MWe opposed-fired pulverized coal unit manufactured by D. B. Riley Company in 1967. The boiler generates 1,018,768 kg/hr steam flow at 165 bar and 537°C superheat and reheat. Coal is pulverized with Riley Stoker horizontal tubular pulverisers.
- **Unit #3** is a 480 MWe opposed-fired pulverized coal boiler manufactured by B&W in 1968. The boiler generates 1,534,049 kg/hr steam flow at 241 bar and 537°C superheat and reheat.
- **Unit #4** is a 490 MWe opposed-fired pulverized coal boiler manufactured by B&W in 1969. The boiler generates 1,616,149 kg/hr steam flow at 241 bar and 537°C superheat and reheat. Pulverisers for both Units 3 and 4 are B&W ball/race mills.

All four boilers burn bituminous coal and have electrostatic precipitators for particulate control.

**Project Description/Objectives:** The project consists of burning wood sander dust mixed with coal in any of the four pulverized coal boilers at Branch Generating Station. The effort has the dual objectives of producing electric power from a low cost resource and of providing an alternative for a power company customer to landfill disposal of wood residues. A successful program could reduce customer disposal costs, reduce utility fuel costs, and reduce pressures on the local landfill.

**Process Design:** One or two trucks per day of sander dust from a local wood furniture manufacturing business are delivered by truck to the coal stockpile at Plant Branch. There, the wood dust and coal are blended by tractor on the coal pile and the blend is pushed into the plant reclaim system and into the bunker for any one of the four units. The wood and coal blend then passes through the rest of the coal handling system, the feeders, pulverisers, ridders, coal pipes, and through the coal burners into the boiler. The sander dust typically makes up about 1% or less of the fuel for one unit by heat. There is no specific control over the blend percentage but coal pile management of the wood ensures that high percentages don't reach the bunker. The sander dust is very low in moisture (less than 5%) and is a very fine powder.

**Project History/Status:** Cofiring has been conducted at this plant for about eight years, starting in 1992. There have been no major problems with blending the wood with the coal and commingling the blend in the pulveriser prior to entering the boiler. There has been no noticeable effect on flue gas emissions or boiler operation. Additional tests for one day at higher concentrations (approximately 10% by weight) were conducted briefly in 1995. The tests were to obtain fly ash samples for a study of the effects of wood/coal ash on the properties of concrete and cement.

The results of the cement and concrete study are part of an ongoing assessment by the industry. The unit successfully burned the higher concentrations of wood, in this case green sawdust. Higher mill amps were experienced, as well as some fluctuation of feeder speed, but otherwise the presence of the wood in the fuel caused no problems.

**Results/Conclusions:** At low percentages, sander dust can be successfully and regularly commilled with coal as fuel in these pulverized coal units. The units at Plant Branch can accommodate higher percentages if necessary, at least in the short term. Sander dust continues to be burned at Plant Branch. Similar programs have been conducted at several other plants in the Southern electric system with similar success (*IEA Bioenergy Task 32, 2006; Montana-Dakota Utilities, 2006*).

### 2.5.1.2 Direct cofiring with PCC – Separate handling

#### Studstrupvaerket #1, Aarhus, Denmark

**Power Plant Description:** Studstrup Power Plant, near Aarhus in Jutland, is operated by Elsam. Studstrup Unit 1 is a 150 MWe pulverised coal-fired boiler, which was originally commissioned in 1968. The handling, pre-processing, and firing equipment represents the culmination of experience gained over a number of previous projects. A diagram of the system is reproduced in *Figure 2.10*.

**Project Description/Objectives:** The system was installed and commissioned during 1994-5, and a demonstration programme started in 1996, focusing on the performance of the straw-handling and firing system, the boiler performance, the process chemistry, i.e. slagging, fouling and residue characteristics, and the pilot testing of deSO<sub>x</sub> and deNO<sub>x</sub> equipment. This involved long-term operation at 10 and 20% straw on a heat input basis.

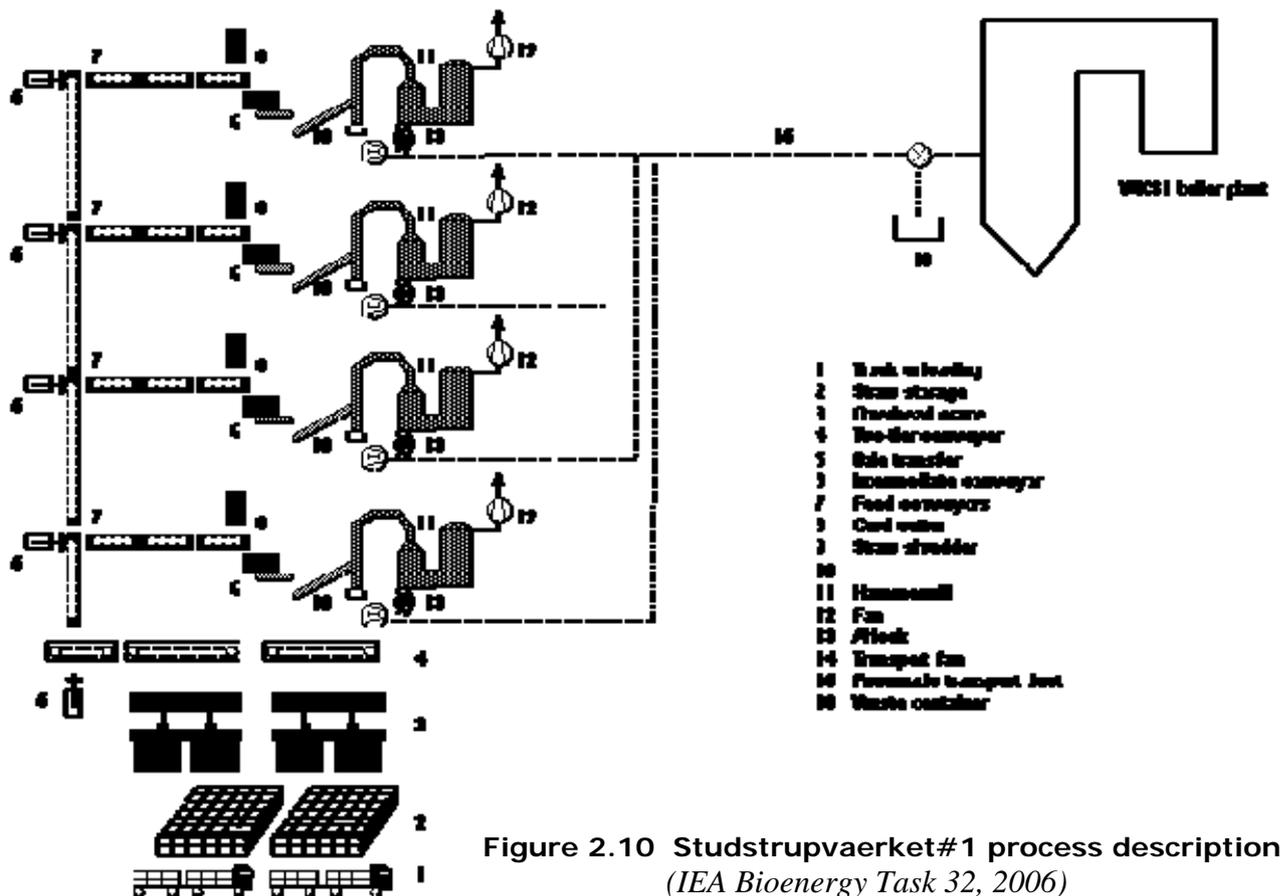


Figure 2.10 Studstrupvaerket#1 process description  
(IEA Bioenergy Task 32, 2006)

**Process Design:** The straw delivery lorries are unloaded by an automatic overhead crane, which is fitted with load cells and microwave pads for the automatic recording of the weight and the moisture content of individual Hesston bales. The crane places bales in the store, or feeds the two-tier conveyor system. The conveyor and bale transport system automatically feed four straw pre-processing lines.

On entry to the straw pre-processing plant, the bale cord is cut and removed. The broken bale then falls into the straw-reducing unit. This has a cutting table with two shafts fitted with a number of curved blades that break up the straw bale and reduce the straw to a top-size of 100-150 mm. The loose straw is then dropped onto an inclined belt conveyor. This helps to even out the flow of straw, and the speed of the belt is used to control the straw feed rate to the burner. From the top of the belt, the straw is dropped to an air classifier, which removes any tramp material that may be included in the bales. The straw is then sucked through a short pneumatic conveying system into the hammer mill. The hammer mill further reduces the straw size depending on the aperture in the outlet screen. At Studstrup, 50 and 75 mm screens are used. From the hammer mill outlet, the chopped straw drops into a collection bin, which is fitted with an aspiration chamber and a rotary airlock. This drops the chopped straw into the pneumatic conveying system to the burners.

The boiler has twelve pulverised fuel (PF) burners, arranged in three rows of four burners in each row on the furnace rear wall, and produces 139 kg s<sup>-1</sup> of steam at 540°C and 143 bar. The four burners in the centre row have been converted to allow straw-coal cofiring. The chopped straw arrives at the burner at a primary air velocity of 25 m s<sup>-1</sup>. This is reduced to 15 m s<sup>-1</sup> at the burner and the straw is fired down the burner core air tube, with the coal being fired through the primary air annulus. With this arrangement, it is possible to co-fire straw at up to 20% of the total furnace heat input at full boiler design load.

**Results/Conclusions:** There were some initial problems with the handling and mechanical conveying of wet straw, and it was found that the system was sensitive to relatively small quantities of straw with moisture content in excess of 25%. The key issue in the solution to this problem was co-operation with the straw suppliers to improve the quality and consistency of the delivered fuel. The combustion system performed reasonably well, provided that the straw injection velocity through the burner was below 15 m/s. Good burnout, even of the more dense components of the straw, was achieved. No particular problems associated with ash deposition, high temperature corrosion, or the environmental performance of the plant were identified at straw cofiring rates up to 20% on a heat input basis.

After successful operation of unit 1 from 1996-1998, the intention was to convert Unit 4 at Studstrup Power Station, a 350 MWe boiler, to straw cofiring. After concerns about the utilisation of the mixed coal/straw ash residues as a component of cement and concrete product were solved in 2001, unit #4 (350 MW) was converted to straw. As of January 2002, Studstrupværket is capable of cofiring approx. 250,000 tonnes of straw and 100,000 tonnes of other biomass fuels (e.g. maize, sunflower seed husks, etc.) with coal annually (*IEA Bioenergy Task 32, 2006; Elsam Kraft A/S, 2006*).

## Kingston Fossil Plant #5, Oakridge, Tennessee, USA

**Power Plant Description:** Kingston Fossil Plant is in Kingston, Tennessee about 56 km west of Knoxville. The station is owned and operated by the Tennessee Valley Authority (TVA). There are nine tangentially-fired, pulverized coal-fired boilers at the station. The nine units began commercial operation sequentially from February, 1954 to December, 1955.

- Boilers #1 through #4 are rated at 139 MWe (net) with four pulverisers supplying the four corners of the single furnace at four elevations on the boilers. Each boiler is a reheat unit with natural circulation and a continuous rating of 462,664 kg/hour steam.
- Boilers #5 through #9 are rated at 180 MWe (net) with six pulverisers supplying the four corners of each twin furnace (superheat furnace and reheat furnace) at three elevations on the boilers. Each boiler is a reheat unit with controlled circulation and a continuous rating of 580,598 kg/hour steam.

All boilers were manufactured by Combustion Engineering (CE) and have CE Raymond Bowl mills. Each unit burns bituminous coal and have electrostatic precipitators for particulate control.

**Project Description/Objectives:** Approximately 600 tons of green, hardwood sawdust from three sawmills in the Kingston area were delivered to the station and burned in Boiler #5 to determine the effects on the boiler of burning a blend of 5% wood by weight with coal. The purpose of the testing was to evaluate the impacts of cofiring low levels of wood waste on: pulveriser operations (coal sizing effects), boiler operations (effects on boiler capacity and efficiency), and airborne emissions (effects on NO<sub>x</sub>, SO<sub>2</sub> and CO<sub>2</sub>). The objective was to reduce fuel costs, to support TVA's forest product and industrial customers, and to reduce emissions.

**Process Design:** The wood fuel handling system was temporary and portable. The handling system included a trommel screen for removing foreign material and assuring a maximum particle size of 1/4", front-end loaders for managing the fuel piles and a variable speed conveyor with an in-feed hopper for blending the wood with the coal on the belt. The system worked well, but the front-end loading was taxed at 5% by weight if the wood pile was too far away from the conveyer. The sawdust was delivered to the station, screened to minus 1/4" and stored in a pile near the Rotary Car Dumper #2. The screened fuel was covered with a tarp for weather protection and to reduce fugitive dust emissions. During blending, a front-end loader was used to load a temporary belt which discharged into the car dumper as rail cars of coal were being unloaded. This blend then went through the primary crusher, into the #5 bunker through the coal feeders and pulverisers, and into the boiler at all firing levels.

**Results/Conclusions:** The ability of the boiler to meet full and minimum load requirements was unaffected by cofiring a blend up to 5% wood by weight. The boiler efficiency was essentially unaffected (less than 0.2% drop due to 40-50% wood moisture). The stability of the boiler was also unaffected. The effect of the blend on SO<sub>2</sub>, NO<sub>x</sub>, and particulate was insignificant. The fineness of the coal which was ground in the pulveriser was degraded with increasing wood content in the blend. There was a significant degradation above the 5% by weight level. However, the fineness was calculated with the wood in the blend so the ultimate effect of this is probably offset by the higher volatility of the wood.

The cofiring tests conducted at Kingston demonstrated that a blend of up to 5% wood by weight could be burned in the Kingston boilers without problems. There were no negative impacts on the handling system. The effects on the pulverisers were neutral and did not appear to affect the boiler operation. The boiler efficiency, stability and emissions were largely unaffected (*IEA Bioenergy Task 32, 2006; Tennessee Valley Authority, 2006*).

### 2.5.1.3 Direct cofiring with PCC – Separate handling and comminution

#### Gelderland plant, Electrabel, Nijmegen, the Netherlands

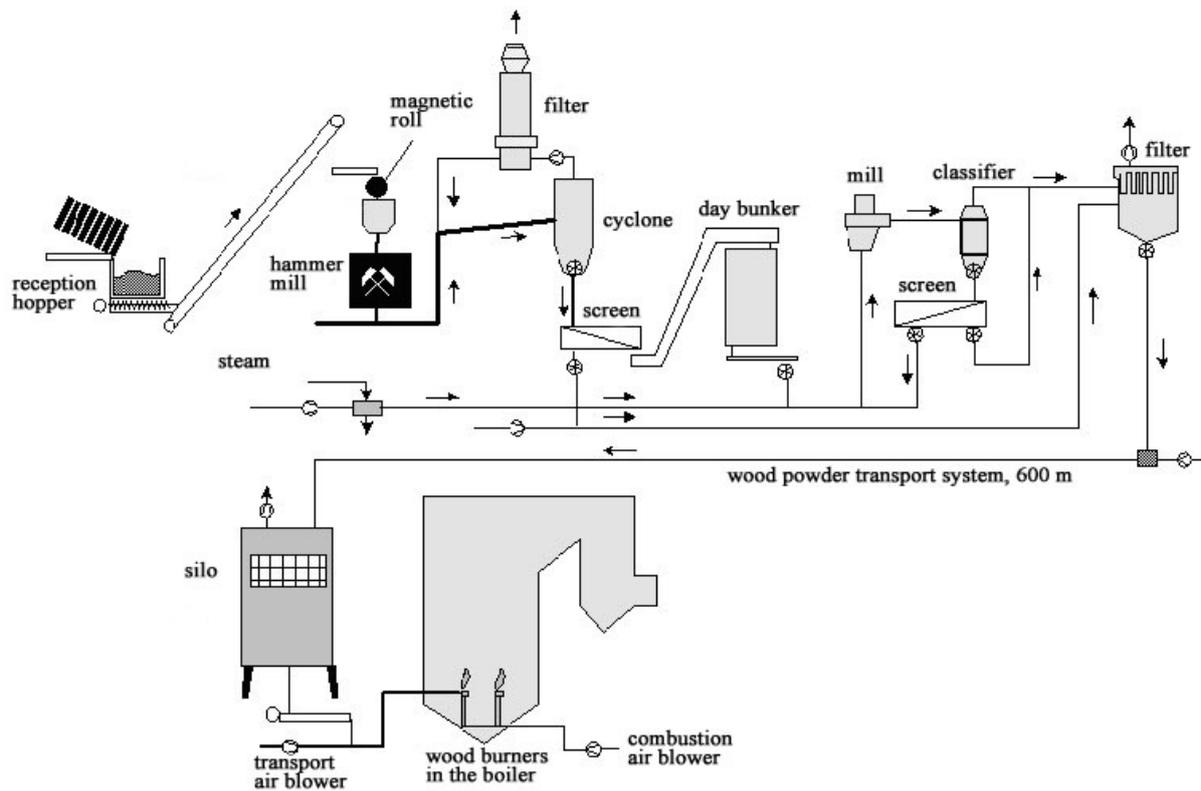
**Project Description/Objectives:** The waste wood cofiring project at Gelderland Power Plant burns demolition wood. The justification for the project was based on the fact that in 1992, 240,000 tonnes of waste and demolition wood was sent for landfill disposal in Holland. It was proposed, therefore, to convert one of the coal-fired power plant boilers to burn 60,000 tonnes per annum of processed waste wood. The boiler unit selected was a 635 MW<sub>e</sub> pulverised coal-fired boiler at Gelderland Power Station, which had been commissioned in 1981. In 1985-1988, the unit had been fitted with a wet limestone FGD system and in 1994 a SCR system had been fitted for NO<sub>x</sub> emission control.

A number of pre-set conditions for the wood cofiring project were established:

- there were to be no significant risks to the availability of the boiler;
- all emissions should remain within the limits set by Dutch environmental legislation; and
- the ability to continue commercial utilisation of 100% of the boiler fly ashes as a component of construction materials should be retained.

The waste wood material is collected and processed into raw wood chips at three sites in the Netherlands. At these sites, large pieces of tramp material are removed manually, and smaller items of high density are removed by air classification and screening. The wood is then chipped to meet the following specifications:

Bulk density	165-185 kg/m <sup>3</sup>
Particle size	0-3 cm
Moisture content	< 20% (dry basis)
Gross Calorific Value	> 16 MJ/kg
Lead content	< 1500mg/kg
Zinc content	< 1400 mg/kg
Chlorine content	< 400 mg/kg



**Figure 2.11 Gelderland process description** (IEA Bioenergy Task 32, 2006)

**Process Design:** The chipped material is delivered to the power station. A diagram of the basic wood fuel handling system at the power station site has been reproduced in *Figure 2.11*. The wood chips are unloaded in the reception area and conveyed to the grinding area. Magnetic separation and air classification equipment are employed to provide additional cleaning of the delivered chips. They are then fed to a hammer mill, which reduces the material to a top size of 4 mm. After screening out the fines, the oversize material is sent to the milling plant. The mill product and the fines from the hammer mill are combined and powdered in a wood-handling system. There are two mills, each with a capability of producing around 1.8 tonnes per hour of final mill product.

The specifications for the powdered wood product are as follows:

Particle size distribution: 90% < 0.80 mm  
 99% < 1.00 mm  
 100% < 1.50 mm  
 Moisture content: < 8% (dry basis)

The powdered wood is conveyed pneumatically to a storage silo, of 1,000 m<sup>3</sup> capacity, located adjacent to the boiler. A powdered wood metering system then delivers the fuel to four burner injection systems, each capable of delivering 1.1-3.5 tonnes of fuel per hour. The four burners, each rated at 20 MW<sub>th</sub>, are located in the side-walls of the furnace. The boiler furnace is opposed-wall-fired with three rows of six burners in both the front and rear walls. The wood/oil burners and the wood combustion control system are independent of the coal-firing system, and there is no interference with the boilers' capability to burn coal at full load.

**Results/Conclusions:** The wood-firing capacity is around 10 tonnes per hour, which is equivalent to 3-4% of the heat input to the furnace. At this cofiring ratio and with a relatively high-quality fuel, the impacts on the operation, the environmental performance, and the availability of the boiler have been small. The system was commissioned in 1995 and, despite considerable initial problems with the wood-handling and milling system, it is now in full commercial operation. On average, around 60,000 dry tonnes of wood are fired per annum, replacing around 45,000 tonnes of coal p.a. There is also a reduction of around 4,000 tonnes p.a. of the fly ash produced, due to the very low ash content of the wood fuel. This is a very important project in that it is the first direct biomass co-combustion demonstration in a large utility boiler in Europe, with long-term experience of commercial operation. At an electrical power output from wood firing of 20 MW<sub>e</sub>, it has an operational scale that is of direct value to future cofiring projects.

**Plans:** The Gelderland power plant is developing plans to increase the percentage of cofiring from 3 to 10 % by expanding the existing cofiring capacity, direct cofiring and upstream gasification using a 150 MW CFB gasifier.

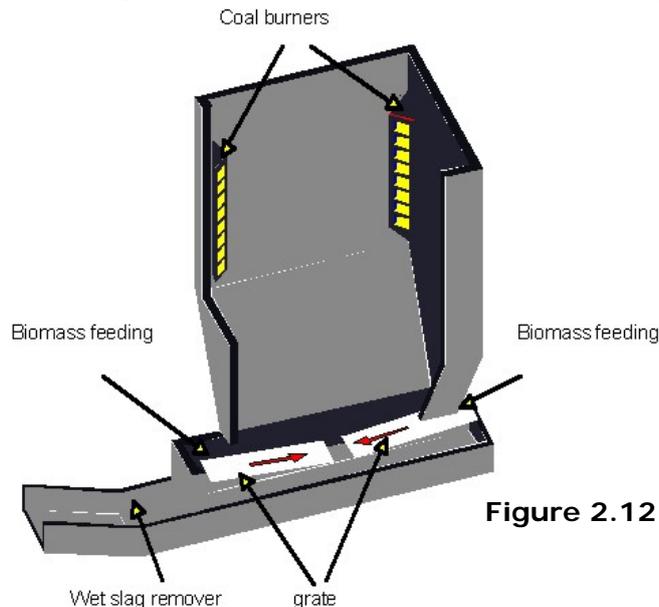
Since the milling plant at the Gelderland power station went into operation, Electrabel has greatly simplified and improved the process of milling wastewood, which can lead to a reduction in specific cost and energy consumption of approx. 50%. The modified pre-treatment chain, which is likely to be implemented on a new location in Belgium, consists of the following process steps:

- Reception and storage of wood chips
- Removal of contaminants from wood chips
- Milling process, consisting of hammermill - sieve - hammermill - sieve (two steps in series).

With this process, drying and storage facilities will not be necessary, and the number of mills is reduced from 7 to 2 (*IEA Bioenergy Task 32, 2006*).

## Lenzing, St. Andrä, Austria

**Process Design:** At the St Andrä power plant, operated by Verbund in Austria, wood fuels can be burned on a new biomass grate which is installed directly under the furnace of a pulverised coal-fired boiler. This is a 124 MWe unit with a pulverised coal-fired radiant furnace. The ash hopper has been modified to include two travelling grates for the firing of chipped wood materials and the handling of the furnace bottom ashes. The arrangement is illustrated schematically in *Figure 2.12*. The nominal thermal capacity of the biomass grates is 10 MWth, which is equivalent to around 3% of the total heat input to the furnace.



**Figure 2.12 Lenzig boiler modification**  
(IEA Bioenergy Task 32, 2006)

**Results/Conclusions:** The cofiring system was commissioned in 1995, and has operated without major problems. Minor problems were experienced with the inclusion of tramp materials in the biomass fuel, which caused some blockages of the fuel-feeding system. The travelling grate and the wet ash handling system have operated well with the mixed biomass ash/coal bottom ash mixture. The burnout of the fuel was good, with carbon in ash levels in the discards from the grate being less than 5%. Biomass cofiring at this level had no significant impact on the performance and availability of the boiler, nor on the environmental performance of the unit.

The principal advantage of this approach to biomass cofiring is that the wood fuel needs minimal pre-processing. The fuel, in this case, is chipped to a top-size of 50 cm, and is wet, at 10-55% moisture, on a wet basis. In this case, the fuel mix includes bark, sawdust, and wood chips, and in principle, this approach secures fuel flexibility.

This approach has the advantage of involving relatively low capital cost (1.45 M€, mainly for the grates and additional conveying components), but is only suitable for biomass cofiring at low cofiring ratios, and can be applied only to furnaces which have sufficient clearance under the ash hopper to allow installation of a fuel-feeding and grate system. In cases in which space is more limited, it is possible to locate the grate system outside the boiler and to introduce the combustion flue gases from the biomass furnace into the coal furnace through hot gas ductwork. This is, of course, a more expensive option.

The other significant drawback of this approach is that the solid residue from the grate is a biomass ash/coal bottom ash mixture. This cannot be recycled as a low-grade fertiliser, as can most ashes from the combustion of biomass alone (IEA Bioenergy Task 32, 2006).

## 2.5.2 Direct cofiring with CFB

### Grenå Kraftvarmeværk, Grenå, Denmark

**Power Plant Description:** The Combined Heat and Power plant (CHP plant) at Grenå Kraftvarmeværk is owned and operated by the electricity Production Company Elsam. The plant has been in commercial operation since 1992 and is designed for combustion of a mixture of fuels like coal, straw and other biofuels. The plant is equipped with a CFB boiler of 88 MWth designed for operation with a fuel mixture up to 60 % straw or with coal alone. The main specifications of the Grenå CHP-plant are:

- Maximum in-feed capacity of fuel to the boiler is approximately 85 MW.
- Steam data: 92 bars and 505 °C steam temperature.
- Electrical output 18,6 MWe
- Thermal output: 60 MWth (maximum of concurrently production of district heating and process steam)
- District heat output: Maximum 35 MWth.
- Process steam output at 8,3 bar/ 210 °C: Maximum 53 MJ/s.

**Process Design:** This boiler is fed with up to 60% straw. Straw is delivered by truck as 450 kg bales, which are lifted, 12 at a time, by automatic crane to storage or directly to the feed system. An automatic drag chain conveying system moves 12 bale batches from storage to the feed line, from where they move on to four parallel shredders. The shredded straw is fed pneumatically through air locks to the boiler injection loop seals.

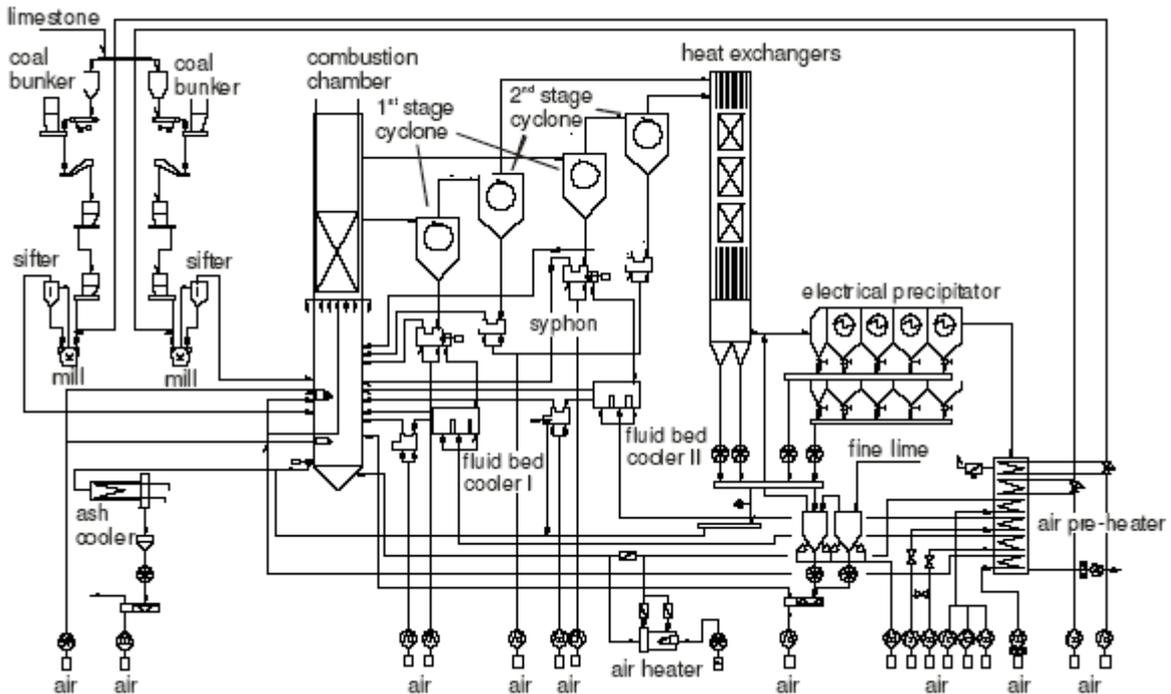
**Results/Conclusions:** Even with this purpose-designed system, several short duration failures occurred during the test, due to excessive cutter wear and compacted bales with wet intrusions. The much longer residence time in circulating fluidised bed combustion systems makes this particular technology more tolerant of feed, in terms of moisture or size. For straw combustion, only pneumatic feeding of prepared feed is employed.

The boiler is designed for operation with a fuel mixture up to 60 % straw or with coal alone. The temperature in the combustion chamber of the fluid bed is kept in the range of 820-830 °C. In order to avoid slagging it is essential that this temperature not becomes too high. In the beginning of the operation of the plant corrosion was observed in some parts of the superheaters. The wall thickness of the tubes in superheater 1 has been increased and that has eliminated the problem.

Flue gas cleaning is carried out in an electrostatic filter divided in three stages, which is located outside the boiler building. The content of dust in the flue gas after the filter is commonly 5-10 mg/normal m<sup>3</sup>. This is conveniently lower than the limit for dust at 50 mg/normal m<sup>3</sup> set by the environmental authorities. The plant also performs a satisfying combustion quality with a low excess air ratio (6-7 % oxygen in flue gas). The biomass system was extended in 1996 with a new separate storage and supply system for dry comminuted and/or pelletized biomass fuels (*IEA Bioenergy Task 32, 2006; Elsam Kraft A/S, 2006*).

## Stadtwerke Duisburg AG, Germany

**Power Plant Description:** the Stadtwerke Duisburg AG plant had the first combustor of CFB type in Germany, commissioned in 1985 with an electric power of 96 MWe. At present, due to some optimization the electrical output was increased to 105 MWe. The flow diagram of the Duisburg combustor is shown in *Figure 2.13*.



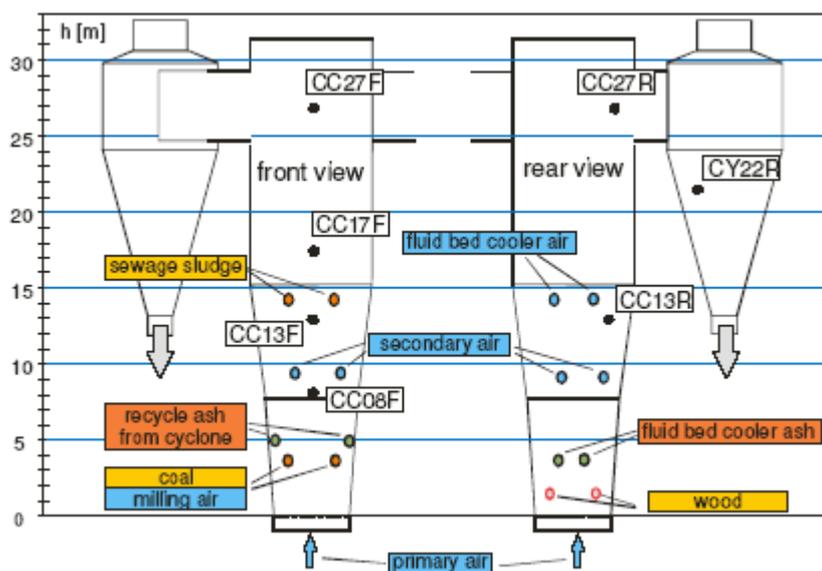
**Figure 2.13** Duisburg plant flow diagram (*Stadtwerke Duisburg AG, 2006*)

The combustion chamber is connected to two first-stage cyclones. The second stage cyclones are no longer in operation being closed at the bottom, therefore filled with ash material in the conical part and serving for additional combustion volume for the flue gases. Coal serves as the main fuel and it is fed to the combustion chamber through two two-stage systems in parallel, each equipped with a bunker and a lock in order to maintain the overpressure in the combustion chamber. After the second stage cyclones the flue gasses are directed to a waste heat boiler, an electrostatic precipitator (EP) and the air pre-heater. Limestone is added with the coal for sulphur capture in the fluid bed reactor. The heat is taken out of the process by two external fluid bed heat exchangers (fluid bed coolers), heat exchangers into the combustion chamber and additional heat exchangers installed in the waste heat boiler (*Stadtwerke Duisburg AG, 2006*).

**Project Description:** The experiment was performed in the framework of the COPOWER project (“Synergy effects of co-processing biomass with coal and non-toxic wastes for heat and power generation”) aimed at investigating fuel mixtures that would provide possible synergy effects in the fields of operating behaviour, emissions, slagging and fouling phenomena, attrition effects and trace metal partitioning. Further the whole supply chain for the fuels is analyzed and characteristics related to the disposal of the remaining ashes (leachability) are taken into account.

The co-combustion test in the 252 MWth CFB combustor Duisburg accounted for the investigation of operating behaviour of cofiring trials on different scales of operation. The operating parameters and stack emissions were recorded during the test in addition to local measurements of gas concentrations, solids and fluxes, suspension velocities, solids volume concentrations and temperatures. Also ash samples were collected at various points in the plant for further investigation (COPOWER, 2006; Gulyurtlu, Leckner, Åmand & others, 2006).

**Process Design/Operating Conditions:** The test accounted for a 12 days period divided into four test periods in which one or more fuels were fired continuously for a 3 day period. In period I and IV the plant was operated on pure coal, the base fuel. The coal used was a low sulphur coal from Colombia. The aim of period IV was to check if the plant returns to the initial operating conditions and emissions of period I. In period II wet sludge was added to the coal as a typical example of waste material. The sludge used for this test is a mixture of municipal sludges from the Duisburg area. It is delivered by truck to a closed waste bunker and delivered to the combustion zone above the secondary air zone by a separate handling system (sludge pump). In period III biomass and sewage sludge were fired in addition to coal. For biomass wood pellets were used, which were supplied from the rear side of the boiler below the fluid bed cooler ash zone. The mass flow for period I was 37.6 t/h coal, 36.9 t/h coal plus 4.1 t/h sludge for period II and 31.3 t/h coal plus 4.3 t/h sludge plus 7.3 t/h wood for period III respectively. During the whole test duration boiler was kept to near 100% load with only small changes necessary for proper operation of the plant (Wischnewski & others, 2006). The boiler diagram with the measuring points and secondary fuels entry areas is represented in Figure 2.14.



**Figure 2.14** Location of measuring points in Duisburg  
(Wischnewski & others, 2006; Stadtwerke Duisburg AG, 2006)

**Results/Conclusions:** the information gathered during the test provided first preliminary conclusions indicated indeed cofiring waste and/or biomass may provide synergies for both the operating behaviour of the plant and the emissions.

- With the co-combustion of wood with sewage sludge a significant decrease in the solids holdup of the combustion chamber can be noticed. As a consequence, the heat transfer characteristics of the boiler are influenced in a positive way.
- The temperatures under cofiring conditions are generally lower than under pure coal firing, one reason being certainly the additional amount of water transported with the sewage sludge. A decrease of the boiler temperature would decrease the boiler load, if all other parameters were to be kept constant, however the load did not change significantly (because of an increased external circulation rate providing a more efficient cooling of the combustion chamber, and a higher bed-to-wall heat transfer caused by a increase of solids volume concentration). As a practical consequence cofiring of a suitable waste may allow the operator to increase the load for given temperature levels or to lower the temperature in the combustion chamber if it is desirable for ash melting reasons as an example.
- A significant reduction of NO<sub>x</sub> emissions was observed for cofiring with sewage sludge compared to pure coal firing although the N-in-fuel mass flow was increased. With an addition of wood to the coal and the sludge the NO<sub>x</sub> emissions increases again. This meant that the negative of the wood towards the NO<sub>x</sub> emissions can be compensated by the positive effect of the sewage sludge, the overall emissions remaining at a level which wouldn't exceed the level of pure coal firing.
- A reduced limestone requirement under cofiring sewage sludge, wood and coal conditions was observed in order to reduce the SO<sub>2</sub> emissions (*Wischniewski & others, 2006; Gulyurtlu, Leckner, Åmand & others, 2006*).

### 2.5.3 Direct cofiring with Stoker

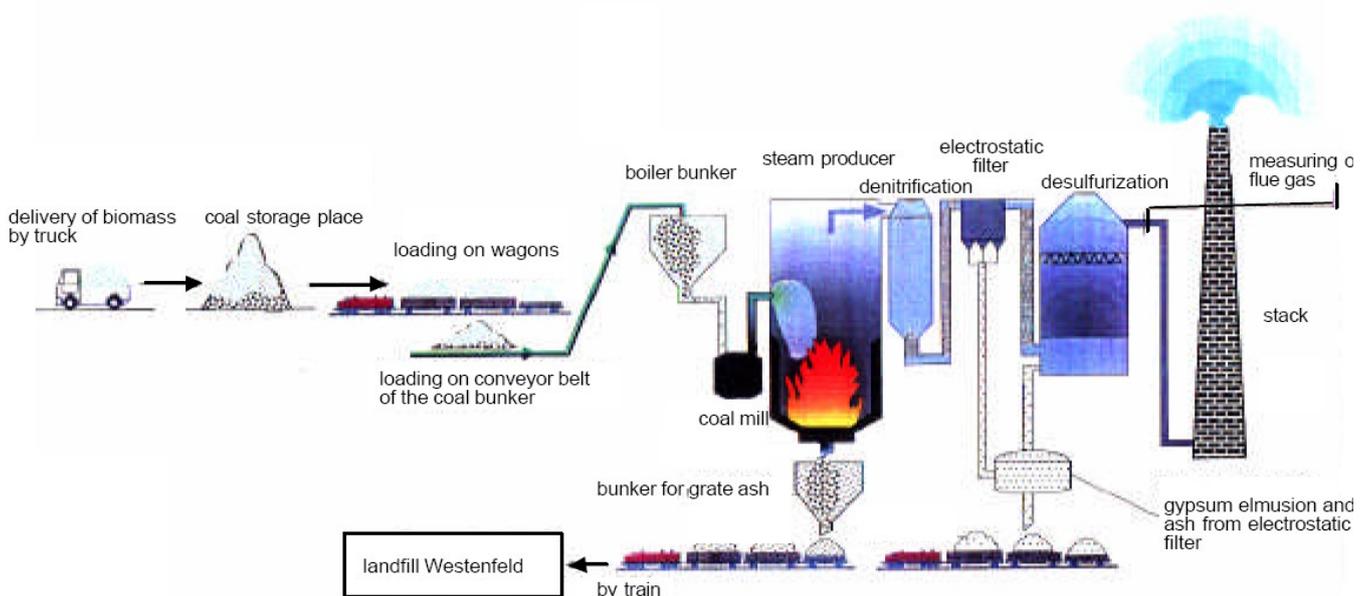
#### Schwandorf power plant, Germany

**Power Plant Description:** The Schwandorf power plant of Bayernwerk AG is a 280 MWth condensing power plant, equipped with a grate and is normally fired with pulverised brown coal.

**Project History/Status:** In 1996, a series of cofiring tests comprising four individual tests of 24 hours and a five day test term test were carried out in Unit B with herbaceous pellets and waste wood:

- 24 hours, in which 80 t straw pellets were fired, corresponding to 5% of the heat value of the brown coal
- 24 hours, in which 320 t straw pellets were fired, corresponding to 20% of the heat value of the brown coal
- 24 hours, in which 160 t cereals were fired, corresponding to 10% of the heat value of the brown coal
- 24 hours, in which 160 t grasses from landscape care were fired, corresponding to 10% of the brown coal
- A continuous test for about one week in 1996 with 1,600 t straw pellets and 5,300 t brown coal (corresponding to 20% of the brown coal)

A diagram of the fuel handling system has been represented in *Figure 2.15*.



**Figure 2.15 Schwandorf plant process description** (*IEA Bioenergy Task 32, 2006*)

**Process Design:** The biomass is mixed with the brown coal in the coal yard using a wheel loader and then conveyed using a normal feeding line into 2 of the 4 existing coal hammermills. The mills could be operated with biomass shares up to 40 %. The mixture is injected into the combustion chamber.

**Results/Conclusions:** Due to insufficient mechanical strength, the pellets caused dust emissions during handling and were difficult to mix well with brown coal at the coal storage. It was therefore concluded that these less mechanically stable pellets would not be suitable in this case.

Hardly any additional slagging was observed during short-term tests. The experiments showed some increased slagging at the grate and at the evaporator, but no critical condition occurred; but due to the mode of operation (standstill during the weekends) the boiler cleaned itself. No chlorine corrosions were noticed.

Because of good results of the cofiring test Bayernwerk obtained a permission to burn waste wood by cofiring. After the shutdown of unit B and C, about 100 kton/annum of waste wood has been cofired on the average in unit D since 15 June 1999. This corresponds to 12% of fuel input on energy basis (8% on mass basis). The waste wood is delivered as chips with sizes of 7 - 60 mm and with low dust content to avoid problems earlier faced. The fuel passed from the boiler bunker into the coal mills and was ground smaller. For waste wood, only very limited dust emissions occurred, and humidification during loading the wagons was found to reduce all dust emissions significantly (*IEA Bioenergy Task 32, 2006; E.ON Bayern AG, 2006*).

### Tekniska Verken CHP plant, Linköping, Sweden

**Power Plant History/Description:** “Tekniska Verken Ltd” is a share holding company where all shares are owned by the Linköping municipality some 200 km south-west of Stockholm. The CHP plant annually produces about 150 GJ of heat and 60 GJ of electricity. The first part of the plant was built in 1964. It comprised two boilers using oil as fuel supplied by “Svenska Maskinverken” from Gothenburg. In the seventies another boiler and a new steam turbine were installed and one of the old turbines from 1964 was also changed to a larger one. In 1984, due to the increased oil prices on the world market, the two original boilers from 1964 were redesigned to utilise solid fuels. One of the boilers was converted to use coal. The boiler was equipped with a Spreader-stoker with a wander grate supplied by Vølund from Denmark. The second boiler was converted to burn biofuels on a moving grate and was supplied by Von Roll from Switzerland. Today, the boilers are integrated in a CHP block: one for coal, one for oil and one for wood-fuels with a total capacity of 240 MW heat and electricity in CHP of 77 MW. The fuel mix is chosen in respect of fuel prices and the national taxation system. The operating time is from September to May with planned revisions and maintenance during the summer.

**Process Design:** In the first boiler, coal and rubber waste are burned together to produce maximum of 28 kg/s of steam (5.9 MPa, 475 °C). The annual supply of 25,000 tonne coal is imported from Poland and shipped over the Baltic Sea to the nearby harbour in Norrköping and transported some 50 km to Linköping by truck. 15,000 tonnes rubber waste from tires and industrial processes is imported the same way. Some of the rubber waste is supplied from domestic sources.

The fuels are delivered chipped and are separately dumped in a hopper and mixed. The mix is up to a maximum of 40% rubber. The fuel mix passes a magnetic separator where iron waste is removed, mostly steel wire from the tire beds. The next step is a crusher where the mix is crushed to a size of 25 mm. The rubber waste is already delivered to the plant at that size, so it's mainly the coal which is being crushed.

A conveyor transports the fuel mix from the crusher to the furnace where the fuel is delivered by a spreader-stoker. When using coal, the boiler has a maximum output of 83 MW<sub>th</sub>. The second boiler for solid fuels is designed for biofuels and has a capacity of 23 k/s of steam (5.9 MPa, 475 °C). The annual supply is 150,000 tonnes of wood-fuels in a mixture of bark from the forest products industry and recycled wood. The latter is mainly imported to the harbour at Norrköping as above. Bark is screened at the plant while other quantities of wood-fuels are delivered at certain grades of screening, size and separation optimal for the boiler. The output of the biofuelled boiler is 65 MW<sub>th</sub> and 20 MW<sub>th</sub> in a flue gas cooler at maximum. The third boiler is an oil-boiler at 154 MW<sub>th</sub> using some 16,000 tonnes oil annually. The oil boiler is mainly used for top-load and as reserve to the other two boilers. There is also an electric boiler at 25 MW in the system.

The plant is equipped with flue gas recirculation and SNCR to reduce NO<sub>x</sub> emission to 31 mg/MJ fuel. Further, cyclones and baghouse filters enable reduction of dust emission to 23 mg/MJ. Hydrated lime is injected to reduce SO<sub>2</sub> emissions.

**Results/Conclusions:** Two traditionally oil-boilers have successfully been converted to solid combustion. A coal fired boiler has been converted to accommodate a mix of some 30% rubber and the rest coal. The biofuelled boiler accommodates different kinds of wood fuels. These moves have been driven by changes in policy instrument i.e. fuel taxation on fossil fuels stated by the Swedish government.

Various biofuels together with rubber waste were used in different tests to find the most cost effective fuel mix. Recycled wood-fuels and rubber waste has been shown to be the most cost effective fuels because of low costs, no fuel taxation and high energy value. Burning biofuels and rubber is not without problems, and significant costs have been incurred. New gas cleaning and scrubbing equipment has been installed and for rubber burning there has been increased corrosion in the furnace and in the sulphur scrubber. Decomposition of the mortar (the material filling the gap between the bricks and binding them) in the brick walls within the furnace has also been a problem in rubber burning.

Different fuel mixes have been tested and during the past years the mixture have been bark and recycled wood with 50% respectively. The problems with this boiler have been less than for the coal/rubber boiler. However, there has been some corrosion in the super-heaters probably because of the content of chlorine in the recycled wood. If the content of recycled wood is less than 50% the problems are possible to handle (*IEA Bioenergy Task 32, 2006; Tekniska Verken, 2006*).

## 2.6 Indirect cofiring: technological options

Indirect cofiring involves pregasifying the biofuel in a separate unit and firing the resulting gas along with coal or firing the biofuel in a separate combustor and routing the steam produced to the main turbine where it is upgraded to higher conditions. The latter process is also known as parallel firing. Indirect cofiring is less common than direct cofiring and it can also be referred as hybrid cofiring.

- ☑ The major advantages that it holds are that the coal ash is not contaminated by any constituent of the biofuel and these constituents cannot cause extra slagging, fouling and corrosion in the main plant.
- ☑ Additionally the total biofuel capacity is not limited by existing constraints imposed by installed hardware and any problems with the biomass plant will not result in the whole power plant being shut down increasing energy security.
- ☒ The major disadvantage of indirect cofiring is that the installation costs are much higher than for direct firing.

Indirect cofiring is most suitable for biofuels containing relative difficult components or when it is particularly important to prevent the coal ash from being contaminated. Indirect cofiring typically involves upstream gasification, upstream pyrolysis or separate combustion with steam-side integration. Another technology is under development, known as upstream hydro thermal upgrading, but it's not commercially available (*Rohan, 2002*).

### 2.6.1 Upstream gasification

This technique involves gasifying the biofuel upstream of the coal fired boiler. The fuel gas which is produced is fired in specific low calorific (bio)gas burners. Up to date there are two approaches to this technology, the concept by Lurgi (Germany) and distributed by Foster Wheeler (Finland) and another concept by Foster Wheeler Oy (Finland).

#### 2.6.1.1 Lurgi (Germany) concept

In the Lurgi concept, the biofuel is gasified in a CFB gasifier at atmospheric pressure and about 850C. The fuel is pre-treated by size reduction and drying to meet the gasifiers specifications of particle size in the mm range and moisture content of <20%. After gasifying, the raw fuel gas is cleaned at low temperatures by a scrubber and a baghouse after which the fuel is fired in low calorific gas burners in the coal boiler. The main advantage of this concept is that more of the contaminants in the fuel are removed before entering the coal boiler and therefore a variety of fuels can be used without causing serious problems regarding emission constrains or ash quality.

### 2.6.1.2 Foster Wheeler Oy (Finland) concept

The alternative gasification concept from Foster Wheeler Oy (Finland) approach is still to gasify the biofuel in an atmospheric pressure CFB gasifier. The maximum moisture fuel specification is less stringent, less than 60%. Hence, for most cases, fuel drying is not necessary and as a consequence the fuel preparation costs can be drastically reduced. The fuel gas is fired in the boiler using very low calorific gas burners without any additional gas clean-up, thus further reducing costs. This design has the advantage of high overall conversion efficiency of the biofuel to produce power but a greater proportion of the biofuels contaminants reach the coal boiler. The range of fuels that can be used will be limited to prevent potential problems with slagging/fouling, emission constraints or ash quality (*Rohan, 2002*).

### 2.6.2 Upstream pyrolysis

It is a variation of the gasification concept where the biofuel is pyrolysed upstream the coal-fired plant. There are three types of pyrolysis processes, slow, fast and flash pyrolysis. Slow and fast pyrolysis produce respectively char and oil as their main products, and have been identified as the most suitable processes for indirect cofiring.

#### 2.6.2.1 Slow pyrolysis

In the case of slow pyrolysis, the biofuel is pre-processed, reducing its size and being dried, and pyrolysed at relatively mild conditions at atmospheric condition and 450C. The produced char is mixed and combusted with coal. Part of the gas produced is used to drive the pyrolysis process and the rest is fired in dedicated gas burners in the coal boiler. What needs to be considered is that depending on the fuel a low temperature gas clean-up system may be part of the system.

#### 2.6.2.2 Fast pyrolysis

Fast pyrolysis refers to paralyzing the pre-processed biofuel, size reduced and dried, at 15 kPa and 500C to produce 70% oil, 15% char and 15% gas. The gas is used to drive the pyrolysis process and both the oil and the char are fired in the coal boiler. This technology also can handle a limited range of biofuels, the majority of contaminants concentrating in the oil and char, so fast pyrolysis is only applicable for relatively clean biofuels (*Rohan, 2002*).

### 2.6.3 Separate combustion with steam-side integration

A different approach for indirect cofiring is to fire the biofuel in a completely separate combustion system and the produced heat to be fed to the steam boiler of the coal-fired plant and used for relatively high efficiency power generation. The main benefit of this approach is that the biofuel is fired without significantly affecting the coal combustion process, and the advantages that this generates.

### 2.6.4 Upstream Hydro Thermal Upgrading (HTU)

In this developing technology a wet biofuel is converted to a biocrude at high pressure (12-18 MPa) and temperature (300-350C). Having similar characteristics to pyrolysis oil this biocrude is cofired in specific burners in the coal boiler. The potential advantage of this process is that it is able to process wet biofuels such as sewage sludge and pig manure without predrying but as mentioned this process is under development and it is not commercially available (*Rohan, 2002*).

## 2.7 Indirect cofiring plants

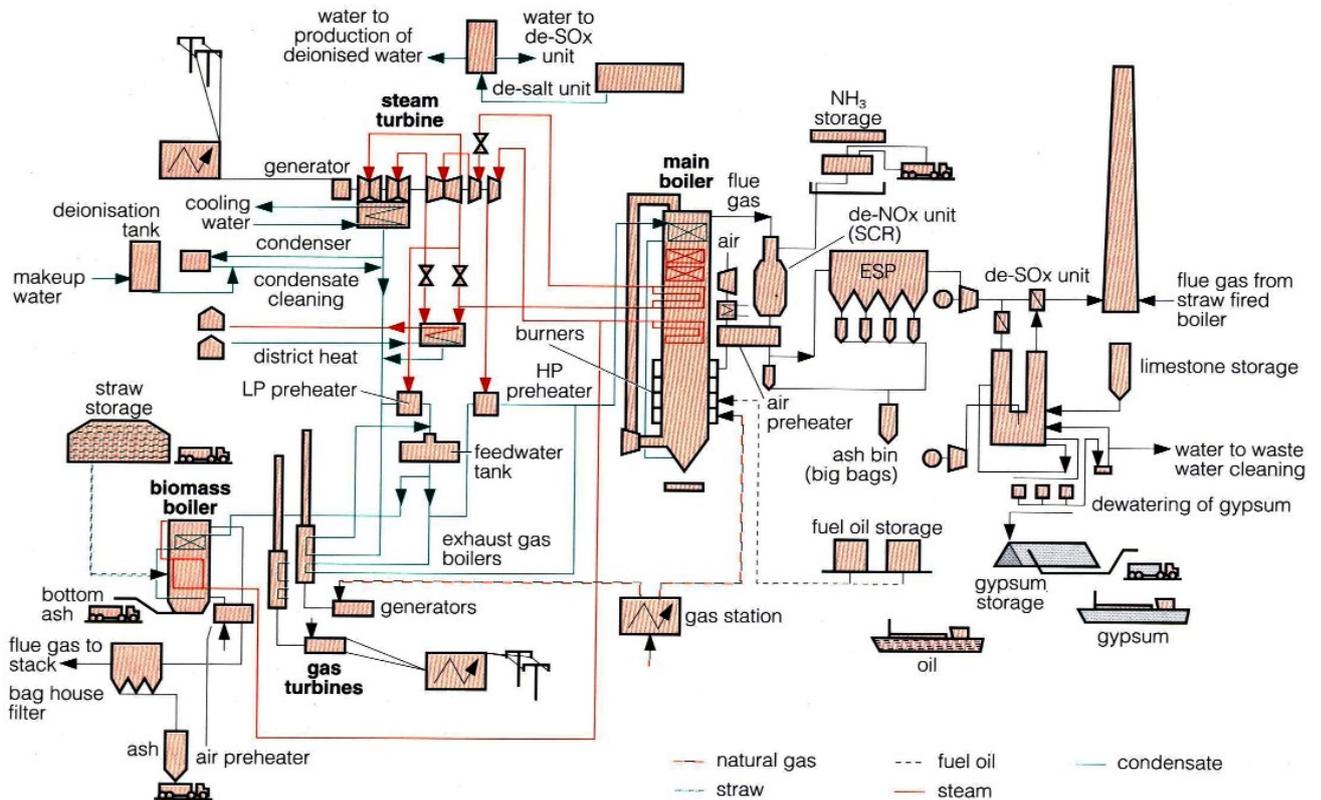
The majority of plants that cofire coal and biomass involve direct cofiring. The ones that indirectly cofire two or more fuels are fewer in number and these will be described in this section. Accordingly to the distinction made in the beginning of *Section 2.6*, between pregasifying the biofuel in a separate unit and combusting the resulting gas along with the coal (upstream gasification), and combusting the biofuel in a separate unit and routing the steam produced to the main turbine to be upgraded to higher conditions (parallel combustion), *Section 2.7* will be divided into two parts describing the two different approaches. The Avedøre plant which combusts the biomass in *Section 2.7.1*, and Kymijärvi plant which gasifies the biomass in *Section 2.7.2*.

### 2.7.1 Parallel combustion plants

#### Avedøre 2, Copenhagen, Denmark

**Plant Description:** Built on reclaimed land south of Copenhagen by a joint venture between ENERGI E2 and Sweden's Vattenfall, the innovative Avedøre 2 is adjacent to the existing Avedøre 1. The purpose of the plant is to meet the growing demand for district heating in the Copenhagen metropolitan region, replacing the output of three old coal-fired plants in eastern Denmark. The existing Avedøre 1 plant is a coal/oil fired combined heat and power (CHP) plant with a rated output of 250 MWe or 215 MWe plus 330 MJ/s of district heating. The Avedøre 2 plant has the flexibility to fire coal/oil/natural gas and biomass and has a capacity at full load of 570 MWe or 485 MWe plus 570 MJ/s of district heating. In cogeneration mode very high fuel conversion efficiencies can be achieved as use is made of waste heat which is normally rejected via cooling tower or water to the environment. The Avedøre 2 plant was designed to fire coal as well as other fuels but, due to government regulations, it will only fire the other fuels, though it could fire coal at a later stage. The construction of the plant is intended to shift generation away from coal, reduce emissions and increase the use of biomass (*Modern Power Systems, 2000; ENERGI E2, 2006*).

**Multifuel design:** The plant contains an innovative multi-fuel design which combines the output from three separate combustion units into one ultra-supercritical (USC) steam turbine system. It consists of a parallel powered combined cycle (PPCC) arrangement with a coal/natural gas/oil USC boiler, a biomass combustion unit able to burn wood chips or straw, and an aeroderivative gas turbine running in an integrated cycle. The plant is schematically represented in *Figure 2.16*.



**Figure 2.16 Avedøre 2 plant schematic** (*Modern Power Systems, 2000*)

The Multifuel concept enables each fuel to be burnt separately. The exhaust gas from the gas turbine is used for preheating part of the condensate and part of the boiler feedwater thereby replacing bleed steam from the steam turbine, meaning it produces more electricity as the steam extracted from it is reduced. The boiler is not affected by whether the gas turbine is in operation or not as the feedwater temperature and flow are unaffected. Hence the gas turbine can be promptly brought in or out of load as required and is suitable for peaking (it has been designed for at least 400 start-ups per year). The linkage from the gas turbine and the USC unit results in more electricity being produced from the gas burnt in the gas turbine than if the same quantity of gas were burnt in a separate gas-fired plant. The effective efficiency of the biomass unit is also increased as its steam is utilised in a larger more efficient steam turbine than if it has its own steam turbine. The multi-fuel concept enables the plant to attain efficiencies of 48% for the main unit, 41–47% for the biomass unit and 56–60% for the gas turbine. These efficiencies are for the condensing option when only electricity is produced. The overall fuel efficiency of the plant in cogeneration mode, with the maximum production of heat and electricity, is predicted to be 94% (gross). The very high efficiencies are possible because of the ultra-supercritical steam conditions and the synergies obtained by connecting the units in a new advanced cycle (*Modern Power Systems, 2000*).

The main plant data is given in *Table 2.3*.

<b>Table 2.3 Avedøre 2 – main plant data</b>		<i>(Modern Power Systems, 2000)</i>	
<b>Overall plant</b>		<b>Steam turbine electrical generator</b>	
Capacity at full load, gross (MWe)	460 (without gas turbines) 600 (with gas turbines)	Type	Ansaldo Energia 50WT23E
Capacity at full load, net Electricity-only mode (MWe)	430 (without gas turbines) 570 (with gas turbines)	Rated output (MVA)	565
CHP mode (MWe/MJ/s heat)	360/480 (without gas turbines) 485/545 (with gas turbines)	Power factor	0.85
Efficiency (%)	49 (without gas turbines) 51 (with gas turbines)	Rated voltage (kV)	19.5
Fuel	Natural gas (USC boiler and gas turbines) Heavy fuel oil (USC boiler) Straw (biomass boiler)	Stator cooling	water
		Rotor cooling	hydrogen
		<b>Gas turbine electrical generator</b>	
		Type	Alstom TR-30/68
		Number	2
		Rated output (MVA)	68.3
		Power factor	0.85
		Rated voltage (kV)	11.5
		Cooling (stator/rotor)	Air/indirect water (TEWAC)
<b>Main boiler</b>		<b>Steam turbine</b>	
Supplier	FLS miliø/BWE	Supplier	Ansaldo Energia
Type	Once through, Benson, corner-fired (originally designed for coal)	Type	Five cylinders, single reheat
Burners	BWE low NOx, type 3AG-LN57	Inlet pressure (bara)	300
Capacity (kg/s)	HP            RH 296.5        284.4	Inlet temp (C)	580
Operating pressure (MPa)	30.5        6.42 (7.39 with biomass boiler)	Reheat inlet temp (C)	600
Operating steam pressure	582        600	Nominal condenser pressure (bara)	0.023
Feedwater temperature (C)	320	Maximum electrical output (MWe)	535
Thermal data		Maximum heat output (MJ/s)	620
Boiler capacity (MJ/s)	800.5	Maximum steam flow (kg/s)	336
Capacity per burner (MJ/s)	57.2	Max final feedwater temp (C)	320
Gas flow (kg/s)	16.6	<b>Gas turbines</b>	
Combustion air flow (kg/s)	289.9	Model	Rolls-Royce Industry, Trent
Flue gas flow (kg/s)	323.3	Number	2
Thermal efficiency (%)	96.0	Capacity, ISO (MWe)	51.2
Emissions		Heat rate, ISO (kJ/KWh)	8662
CO (mg/MJ)	59	Efficiency (%)	41.6
NOx (mg/MJ)	60	Pressure ratio	35
		Exhaust temp (C)	426
		Exhaust mass flow (kg/s)	159.6
		Emissions	
		NOx (mg/MJ)	50
		Co (vppm)	25
<b>Biomass boiler</b>			
Supplier	Ansaldo Vølund/Babcock Borsig Power-AEnergitechnik	Boiler firing capacity (MJ/s)	105
Type	Once through, Benson, grate fired	Fuel (straw) flow (kg/s)	7.2
Outlet steam pressure (MPa)	31 down to 16 at full load	Combustion air flow (kg/s)	40.3
Outlet steam temp (C)	583	Flue gas flow (kg/s)	47.1
Outlet steam capacity (kg/s)	40	Thermal efficiency (%)	93.2
Flue gas outlet (C)	115	Emissions	
Feedwater temp (C)	230 down to 180 at full load	CO (mg/MJ)	625 max
		NOx (mg/MJ)	240 max

**USC unit:** the main unit is a 380 MWe ultra-supercritical, Benson, single pass, boiler and steam turbine generator with a flue gas treatment plant. The boiler is first fired with gas until the load is 20% when coal may be introduced. Above 30% the boiler can be fired with an arbitrary mix of gas, coal or wood pellets from a nearby factory (Inköge). The tangential firing system contains 16 BWE Low NO<sub>x</sub> burners. The boiler contains a flue gas recirculation system, in order to maintain reheat steam temperatures, especially when the biomass boiler is in operation. Hot flue gas is recirculated from the top of the boiler to over burner nozzles. The unit contains an SCR system between the boiler and the air heater which is designed to achieve 95% NO<sub>x</sub> reduction. Particulates are removed downstream of the preheater by an ESP. The ESP is split into four electrical fields and eight parallel bus sections and can process 994 000 m<sup>3</sup>/h at 115-170C. The guaranteed range of outlet dust concentrations is 11-30 mg/m<sup>3</sup>. Downstream of the ESP is a two-step Noel-KRC, limestone/gypsum, wet scrubbing FGD plant. In this system SO<sub>2</sub> absorption takes place in two discrete process loops located in a countercurrent absorbent to produce gypsum (*Modern Power Systems, 2000*).

**Steam turbine:** the steam plant in pure condensation mode without the biomass boiler and the gas turbines can generate 390 MWe with an overall efficiency of 49%. This very high figure is partly due to the low temperature of the cooling water (10C) but mainly due to the design of the steam turbine (high performance blading developed with a 3D steam profile, with the advanced steam conditions in the ultra-supercritical range). The resulting gross heat rate in pure condensing mode, without district heating, biomass boiler and gas turbine is 6680 kJ/kWh. The corresponding gross efficiency is 53.9% and this high efficiency target at Avedøre is guaranteed not for one or two operating points but as many as 26 points. The Avedøre steam turbine consists of one single-flow high-pressure (HP) turbine, one intermediate-pressure (IP1) turbine, one double-flow intermediate-pressure (IP2) turbine and two double-flow low-pressure turbines (LP1 and LP2). The system is designed for full throttling admission and sliding pressure operation (*Modern Power Systems, 2000*).

**Gas turbine plant:** the gas turbine plant at Avedøre contains two Industrial Trent generating sets, supplied and maintained by Rolls Royce plc. These provide peak load generation and also heat condensate and water to the USC unit. In open cycle the sets generate 50-60 MW at 42% efficiency. The turbines incorporate the Dry Low Emissions (DLE) combustion system and atmospheric emissions are limited to NO<sub>x</sub> levels of 50 mg/ m<sup>3</sup> and CO levels of 25 mg/m<sup>3</sup>. The flue gas from the turbine is used to preheat the feed water for the main unit instead of extracting steam from the turbine resulting in synergy level between the two plants. The turbines are housed in custom-built enclosures, designed to comply with ambitious noise targets. The enclosures contain all electrical and mechanical auxiliaries and this modular approach reduces site installation and commissioning times and costs (*Modern Power Systems, 2000*).

**Biomass plant:** the biomass plant consists of an indoor straw store, a boiler plant, an ash separator and a bottom ash and fly ash handling plant. The biomass boiler is the world's largest and most efficient straw fired boiler with a straw consumption of 26.5 t/h, producing 40 MW electricity and 60 MJ/s heat. It has been designed for 100% straw firing or mixed firing, with straw and wood chips. The initial consumption of straw of 150 000 t/y will replace 90 000 t of coal.

The straw combustion system consists of the following components:

- Straw feeding system;
- Fire damper arrangements to prevent burning back;
- Regulating straw feeding table;
- Straw disintegrator to reduce straw density;
- Double stoker screws in water cooled channel to feed straw into furnace;
- Water cooled vibration grate.

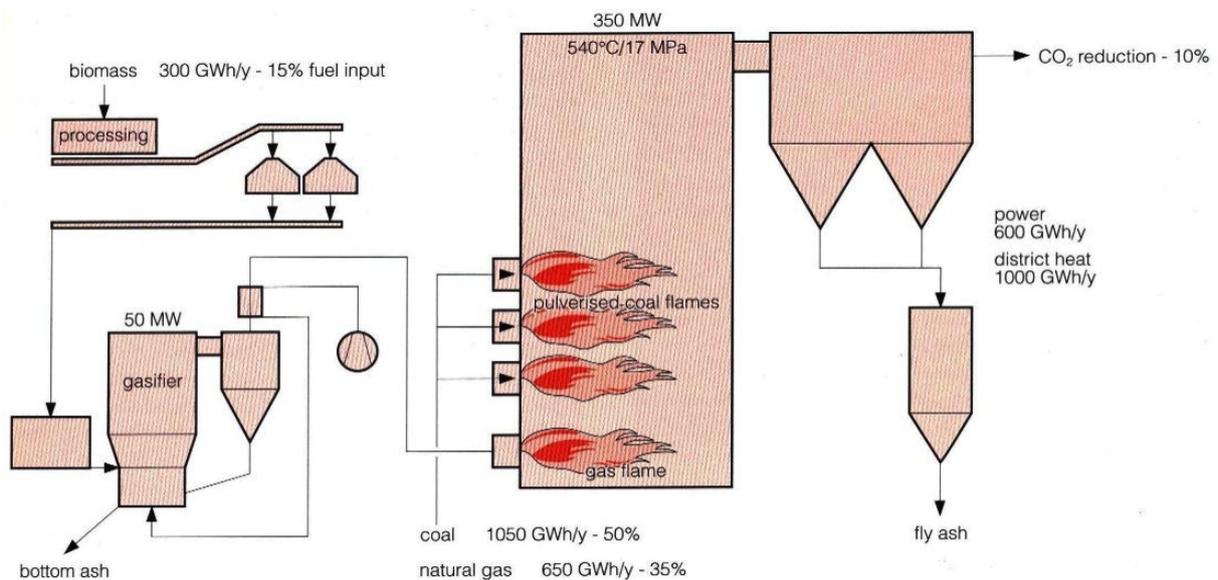
The biomass boiler is a once-through Benson type boiler. As the biomass boiler supplies the same turbine as the main boiler, the steam parameters are the same (31 MPa and 583C). In the boiler, above the feed layer, ignition air is injected into the straw. The ignition air must be blown down into the straw to fix the position of ignition hence the boiler wall above the furnace is at an angle of 45C so that the nozzles face the fed straw. Further up there are secondary air nozzles which push the pyrolysis and gasification products into the furnace. The boiler has vertical tubing in the combustion chamber in several passes each with upward flow. Between the passes are downcomers and in some cases special mixing devices to distribute water and steam evenly. Because of the highly corrosive constituents in straw special care has been taken to avoid fouling and corrosion, especially in the superheater (melting slag layer protecting the superheaters and the water walls of the combustion chamber form the evaporator). The steam from the biomass unit combines with the steam from the main boiler before entering the turbine. Using the biomass steam in the main turbine allows higher efficiencies to be achieved than if it had its own smaller turbine, as the losses for a larger turbine are relatively lower than in a smaller turbine. Having the two boilers separate also allows the ash to be utilised separately. The bottom ash from the biomass boiler will be used as fertiliser. The flue gas from the boiler after passing through the air heater will pass through a bag filter which will remove more than 99% of the ash particles. The maximum emissions from the boiler will be CO-625 mg/ m<sup>3</sup> and NOx – 240 mg/ m<sup>3</sup> (*Modern Power Systems 2000*).

## 2.7.2 Upstream Gasification plants

### Kymijärvi3, Lahti, Finland

**Plant Description:** Kymijärvi power plant which is located near the city of Lahti in southern Finland is operated by Lahden Lämpövoima Oy (consortium between the city of Lahti and the largest utility in Finland Fortum Oy). The power plant was originally oil-fired but it was converted to coal firing in 1982. The maximum power output is 167 MWe with 240 MWth of district heating. The boiler is a Benson, once-through boiler with steam conditions of 125 kg/s, 540°C/17 MPa and 540°C/4 MPa reheat. The boiler is not operated in the summer when the heat demand is low. In the spring and fall, the boiler operates at lower load with natural gas as the fuel. The boiler uses 180,000 t/y (1200 GWh/y) of coal and about 800 GWh/y of natural gas. The plant fires low-S coal (0.3-0.5% S) and does not have any sulphur removal system. The burners have flue gas recirculation and staged combustion for NO<sub>x</sub> control. Different types of biofuels and wastes, corresponding to about 300 GWh/y are available locally and these fuels could substitute 15% of current fuel usage and 30% of coal usage. The biofuels include peat and demolition wood, and the waste is produced from classified refuse from households, offices, shops and construction sites. In order to reduce fuel costs and to reduce environmental emissions, a gasification demonstration project has been undertaken at Kymijärvi to demonstrate a commercial scale gasification of a wet biofuel and the use of hot, raw, very low calorific gas directly in the existing boiler (*Palonen and Nieminen, 1999a; Raskin and others, 2001*).

The plant is schematically represented in *Figure 2.17*.



**Figure 2.17** Lahti project – biomass gasification (*Palonen and Nieminen, 1999*)

**Process Description:** The fuels are transported to the power plant in trucks. There are two receiving halls; one for REF (recycled fuel obtained from refuse produced by households, offices, shops and construction sites.) and one for biofuels. The REF hall also processes coarse biofuels. In the REF hall, the trucks tip REF and coarse biofuels on the floor of the hall or into a pit after which they are crushed in a slowly rotating crusher. Trucks are also used to transport biofuels to the other receiving station. The transport platforms of the trucks have conveyors which discharge the biofuels and the fuel falls through a screen down on to the chain conveyor at the bottom of the bunker. The coarser particles are separated by the screen and moved to the REF hall for crushing. The fuel is transported by conveyors after passing a magnetic separator and further crushing, if needed, to a fuel storage silo. In addition to storing the fuel, the silo is used for homogenisation of the fuel mixture before it is transported to the gasification building. The silo discharger has variable speed controls. Initially, the gasifier fuels consisted of mainly biofuels such as bark, wood chips, sawdust and uncontaminated wood waste. Later on, other fuels have been used and the system for collecting REF was started at the end of 1997. The amounts of REF that have been utilised are less than the capacity of the gasifier but are expected to increase. Other fuels such as railway sleepers and shredded tires have also been used. *Table 2.4* summarises the main fuels that have been used in the first four operating years.

<b>Table 2.4 Fuel processed at the Lahti gasifier</b> (Makkonen and Hotta, 2002)				
<b>Fuel</b>	<b>1998</b>	<b>1999</b>	<b>2000</b>	<b>2001</b>
<b>Biomass, %</b>	<b>71</b>	<b>57</b>	<b>63</b>	<b>61</b>
<b>REF, %</b>	<b>22</b>	<b>23</b>	<b>29</b>	<b>26</b>
<b>Plastics, %</b>	-	<b>13</b>	<b>7.4</b>	<b>12</b>
<b>Paper, %</b>	-	<b>6</b>	<b>0.1</b>	<b>0.3</b>
<b>Railway tires</b>	<b>5.5</b>	<b>0.1</b>	<b>0.3</b>	-
<b>Shredded tires</b>	<b>1.5</b>	<b>0.9</b>	-	-
<b>Total, tonnes</b>	<b>79900</b>	<b>106200</b>	<b>91800</b>	<b>116100</b>

**Operating experience:** Since the gasifier has been connected to the main boiler in December 1997, it has been in continuous operation, other than for maintenance periods. The reliability during the first operational period was excellent and few problems occurred related to the fuel processing plant. The availability of the plant then decreased due to a lack of fuel and fuel processing problems. Regarding the gasifier plant, problems arose relating to the use of shredded tires. The wire content of tires was so high that the accumulated wires blocked the ash extraction system. The gasifier has operated well with other fuels and results have met expectations. The operating conditions regarding temperature, pressure and flow rates have been as designed and process measurements of product gas, bottom ash and fly ash composition have been close to calculated values. The operating temperature of the gasifier has been 830-850°C. The high moisture content of the fuels, which has been between 45% and 58%, has resulted in low heating value of the product gas, typically in the range 1.6-2.4 MJ/m<sup>3</sup>. The gasifier output varied between 35 and 55 MWth depending on the moisture content of the gasifier fuel and the required gasifier load. Minimum levels of pollutants are obtained when gasifying non-contaminated fuels. The use of contaminated materials increases the concentrations of ammonia, hydrogen cyanide and alkalies. There were also modest effects on the emissions from the main boiler when the gasifier was operated. The most

noticeable change was the 5-10% reduction in NO<sub>x</sub> emissions. The most likely reason for this reduction was the cooling effect of the low calorific value, high moisture product gas in the lower part of the boiler.

As the biofuels contain low sulphur levels, the SO<sub>2</sub> emissions decreased by 20-25 mg/MJ, corresponding to a 10% reduction. However, as the chlorine content of biofuels is greater than in coal, HCl emissions are increased by 5 mg/MJ when the gasifier is in operation (REF and shredded tires contain significant chlorine levels). Heavy metal emissions with the gasifier were very low though higher than with coal alone. There was no measurable increase in the emissions of trace organics such as dioxins and polycyclic aromatic hydrocarbons.

The main components of the gasifier bottom ash were the bed materials sand and limestone though there were small amounts of metal pieces and concrete, etc. The carbon content of the ash was typically less than 0.5% and there were negligible levels of chlorine. The ash contained trace levels of several heavy metals such as Cd, Cr and Cu. The concentrations of most metals were less than tens of ppm but Cr, Cu and Zn were found in the hundreds of ppm range. When shredded tires were used as a fuel, the Zn content of the ash reached 3000 ppm. Leachability tests on the bottom ash showed that the trace metal leachabilities were low. The amount of gasifier ash is only a small proportion (3-5%) of total main boiler ash. The operation of the gasifier had only a small effect on the quality of the main boiler ash. There was no change in the levels of unburnt carbon or alkalis. The results of leachability tests on the main boiler ash were satisfactory and it was possible to utilise the ash as before.

Corrosion/deposit formation has been undertaken and the inspection of boiler heat transfer surfaces during annual maintenance showed no evidence of abnormal deposit formation or high temperature corrosion.

The results from the first four years of operation have been very encouraging. During this period 1310 GWh of energy have been generated from the gasifier's product gas. Several different types of fuel have been gasified and a total of 22,006 h of operation under gasification have been achieved. (*Palonen and Nieminen, 1999a; Raskin and others, 2001; Makkonen and Hotta, 2002*).

## 2.8 Cofiring cost comparison

Several theoretical comparison studies between different indirect cofiring options and rival technologies are available in the literature made as feasibility studies to predict costs and justify new investments. Although their results differ slightly when assessing the investment costs (different assumptions, plant sizes, case context, constraints taken into consideration etc), the main picture is visible and their ranking is clear when regarding costs. After taking into consideration their technical advantages and disadvantages it is fair to present the primary financial aspects that need to be addressed before implementing them.

Such an example would be a study (*Van Ree and others, 2001*) comparing a base case PC plant with a representative plant of each type of cofiring. For the base case it was chosen a 600 MWe plant with a net electrical plant efficiency of 40% (LHV) operating 6000 h/year, considering the following cofiring technologies:

- Direct cofiring (same feed) ;
- Direct cofiring (separate feed);
- Indirect cofiring – gasification, Lurgi;
- Indirect cofiring – gasification, Foster Wheeler;
- Indirect cofiring – separate combustion with steam-side integration;
- Indirect cofiring – slow pyrolysis;
- Indirect cofiring – fast pyrolysis;
- Indirect cofiring – HTU.

A 10% and a 40% substitution of coal by biomass were considered and the expected additional investment costs for each of the cofiring technologies are presented in *Table 2.5*.

Concept	Net electrical efficiency with substitute fuel (%LHV)		Specific additional investment cost (€/kWe)	
	10	40	10	40
Co-combustion percentage (energetic base)				
Direct co-combustion	39.5	39.5	40	25
Separate size red., drying, feeding, combustion	38	38	500	285
Upstream gasification (Lurgi)	35.5	35.5	1120	735
Upstream gasification (Foster Wheeler)	38	38	455	300
Upstream slow pyrolysis	32.5	32.5	1240	1240
Upstream fast pyrolysis	36	36	935	935
Upstream HTU	35.5	35.5	620	490
Upstream separate combustion with steam-side integration	38.5	38.5	940	575

The results show that direct cofiring with the same feed is by far the cheapest technology and all the indirect technologies are at least ten times more expensive with the Foster Wheeler gasification technology being the least expensive. It can be said that the costs are inverse proportional to the risks involved when operating these technologies and the costs that might appear in case of malfunctions. The results are focused on and reflect the technological aspects of cofiring. Along the technical constraints, the ones imposed by authorities, financial and legal bodies other technical aspects that need special attention when maximising the proportion of biomass are the operating flexibility, maximum load and unavailability, very important factors in current liberalised markets. Also environmental limitations can play an important role and special attention is needed to be paid. The fly ash quality can be changed when cofiring, and for now some European and domestic legislation is not clear on the status of such by products. The legislation constraining the NO<sub>x</sub>, SO<sub>2</sub>, dust and heavy metal emissions is subject to revision. Solid residues from clean fuels such as waste wood and straw would not exceed emission limits whereas residues from contaminated fuels such as demolition wood and sewage sludge would exceed the limits (*Van Ree and others, 2001*).





## Chapter 3 – CONTINUOUS EMISSION MONITORING

How are the pollutants measured in practice?

- a) What kind of measurement instruments is being used? How are the measurements currently performed?
- b) How are the measurements reported to the authorities for later processing?

Addressed topics:

- *Measurement strategy, measurement planning, reporting and design of measurement sites*
- *Continuous emission monitors*





## 3.1 The need for continuous emission monitoring

To be able to support the various Emission Trading schemes, and create a favourable environment in which the challenges of the EU energy policy can be successfully addressed, accurate monitoring and quantifying of the emissions has to be realized between the partner countries. This necessitates a certain level of standardization of the methods used in all the processes involved in the emission monitoring chain to be reached in the member states.

The Large Combustion Plant Directive (EU 2001/80/EC / RO GD 541/2003) and the Waste Incineration Directive (EU 2000/76/EC / RO GD 128/2002) (*Section 1.4*), which are establishing the measures needed to limit the emissions of certain pollutants from large combustion plants need enforcement and the guarantee that the set emission limit values are successfully met. These documents contain specific reference to air emission limit values in terms of continuous measurements, and the standardization of the procedures involved to realize the continuous emission monitoring are supported at the European level by a range of CEN (Comite Europeen de Normalisation / European Committee for Standardization) standards.

For Romania it was negotiated in October 2004 at Brussels, as a part of Chapter 22 – Environment, the implementation of the EU LCP Directive in the existing power plants where among the main measures of implementing “the best available technique” (BREF-BAT) for boilers, implementing air pollution control technology, and voluntary implementation of Environment Management System, was the requirement to realize measurements for pollutants according with CEN standards, transmit, validate and store these data at national level (*WEC FOREN, 2006*).

The prescribing of CEN standards to comply with the set emission limit values had the basis in the two EU Directives mentioned above. Some CEN standards concern the use of manual methods, such as for dioxins, while others require Continuous Emission Monitors (CEMs) for oxides of sulphur and nitrogen. Where CEM's are required, the legislation is very prescriptive in some circumstances. It has not only prescribed the principle of the method to be used but also the quality (uncertainty) of the instrument to be used when installed (i.e. the minimum 95% Confidence Interval). Furthermore these instruments are to be regarded as essential to the operation of the process, and where limits are exceeded for extended periods it may be required to shut down the process. The use of CEM's as a regulatory tool has been growing over the years, and should eventually replace existing manual methods, where good traceability can be established. They not only provide a continuous record of releases, but enable this information to be read remotely, where telemetry is available. For CEM's to be used effectively however, they must be fit-for-purpose, properly installed and calibrated, and have provision for ongoing quality control (*Munns, 2004*).

Therefore after presenting the legislative framework behind cofiring projects (*Chapter 1*) and the technical possibilities in undertaking such ventures (*Chapter 2*) it is natural to cover what matters have to be considered downstream the cofiring process and overview the procedures and technicalities of continuous emission monitoring for coal/biomass/waste-fired power plants.

## 3.2 Measurement strategy, measurement planning, reporting and design of measurement sites

For the emissions to be quantified in an integrated manner so that they can be traded on the market and the emission reductions to take place where it's cheapest to do so, continuous emission monitoring is needed to be realized. It has been used as a policy instrument in a prescriptive manner and its use has been growing in popularity recently. One of the standards employed to arrange and harmonize the operations at European level is the CEN standard prEN 15259. It is important to plant designers, constructors, plant operators, testing laboratories, accreditation bodies and regulators.

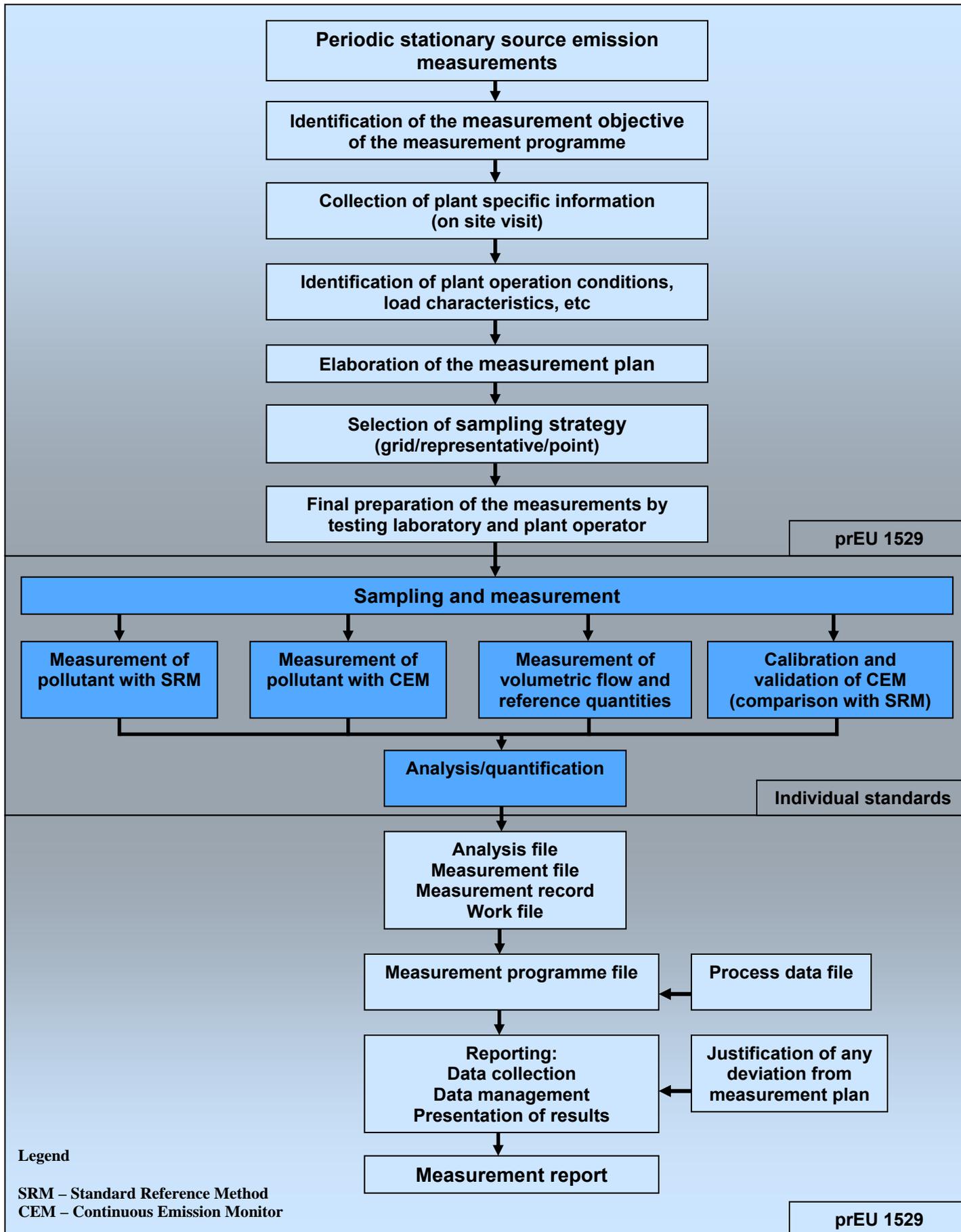
### 3.2.1 CEN - prEN 15259: Air quality - Measurement of stationary source emissions - Measurement strategy, measurement planning, reporting and design of measurement sites

This CEN European Standard specifies:

- minimum requirements for the measurement strategy, measurement planning and reporting of emission measurements of air pollutants and reference quantities to be carried out in exhaust ducts at plants;
- minimum requirements for the design and construction of a plant with respect to performing emission measurements. This specifically applies to the arrangement, number and construction of the measurement ports and measurement sites.

The new European standard prEN 15259 will help to harmonise emission measurement planning, strategy and reporting in Europe. For Romania prEN 1529 was submitted to the local CEN for public inquiry in December 2005, and presently it is fully implemented in Romanian legislation.

The whole process can be visualized in three individual parts, each one taking multiple steps and each one being in the focus of different actors (directives) as in *Figure 3.1*:



## Periodic stationary source emission measurements

This first part is to be implemented by conforming strictly with the European standard by every individual plant and it is normally undertaken by an accredited test laboratory. This stage involves the following main steps in order to assure a successful later operation of the measurements: the identification of the measurement objective, elaboration of a measurement plan and choosing a relevant sampling strategy.

**Measurement objective:** it includes at least the following aspects:

- measurement site
- process and operating conditions, which are relevant for the emission
- measurands (e.g. pollutant concentration, reference quantities, mass flow, volumetric flow)
- measurement uncertainty
- applied measurement methods
- period of measurement campaign
- competence of the testing laboratory

This step requires on site collection of information. The plant operating conditions and load characteristics are determined and then the measurement plan is being elaborated.

**Measurement plan:** It must be formulated in order to specify the following:

- operating conditions of the plant including fuel or feedstock, waste gas components and reference quantities to be measured
- timing and location arrangements of the required individual measurements
- measurement methods to be applied
- measurement sections and measurement sites
- technical supervisor, necessary personnel and auxiliary help for carrying out of the measurements
- measurement dates
- reporting arrangements

**Sampling strategy:** Next a relevant sampling strategy of the gasses must be decided. It may only be necessary to sample at any point when the gas has consistency in composition, or a representative point might be taken in place. At the opposite situation, when the other cases are not relevant it may also be necessitated a grid sampling strategy. The way a sample strategy is decided is based on a newly developed method to determine the homogeneity of concentration distribution in the measurement plane. It gives a clear basis for decision, how to perform the emission measurements, as grid or as point measurements. Assessing the homogeneity according prEN 1529 is only once necessary in the case of a new plant, or if there is no information about the homogeneity assessment from former measurements (*Enlich, 2006*).

## Sampling and measurement

The next stage is the sampling and the actual measurement at the plant level. It is covered by component specific, individual standards dependant on the pollutant type, equipment and used setup. A range of CEN standards covers this level which are directed and organized by prEN 1529 in the way that is represented in *Figure 3.1*. Here, a greater degree of flexibility is needed to be able to accommodate the various technologies employed to sample and analyze the emissions monitored (*Section 3.3*). The framework comprises the actions needed to be taken to realize a standardized, robust sampling and measurement. Accordingly to the pollutant type it is measured using a standard reference method (SRM). Then the pollutant is measured with a chosen continuous emission monitor (CEM) (or automated measuring system (AMS) (portable systems)). Measurements of volumetric flow and reference quantities also take place, in order for the calibration and validation of the CEM by comparison with the result from the SRM. The purpose of the SRM is crucial as valid calibration functions (the relationship between the true value of the determinand in the stack, and the output of the CEM) depends on the validity of data, thus accurate and precise application of the SRMs. All these steps build up to the analysis and quantification of the emissions in a format compatible with the next stage where the report is to be submitted.

## Measurement report

This stage is dedicated to report the status of the emissions to a dedicated institution. It is organized by the prEU 1529 standard in the following manner. The information is gathered into an analysis file, a measurement file, a measurement record and a work file and these are compiled into a measurement programme file along with the process data file in order to be reported. The reporting stage comprises of the data collection, management and the presentation of results along with eventual deviations from the measurement plan. The measurement report is the end result which enables the emissions to be quantified making emission trading possible in an enforced manner.

As a conclusion it can be pointed out that certain steps from this process are crucial to the reliability of the emission measurements. The sample point must be representative for the plant situation because from this stage depend all the following. Further on, several actors are involved in the functioning of this directive (accredited test laboratories, regulator/authority, process operator) and agreements need to be reached in order to align the measurement strategy to reach the measurement objective before the measurements are carried out.

After presenting the legislative background, the next section is focused on the actual “Sampling and measurement” step from the directive, focusing on the continuous emission monitoring which is important especially for plant operators. An overview follows of the current available possibilities when carrying out emission monitoring in coal-firing designed power plants.

## 3.3 Continuous emissions monitoring

Continuous emissions monitors (CEMs) are automated systems which continuously sample and analyse emissions of one or more chemical species from a stationary source. The principal components in stack gases from coal-fired power plants which may require monitoring are particulates, SO<sub>x</sub> and NO<sub>x</sub>, with O<sub>2</sub> and/or CO<sub>2</sub> being measured for reference purposes. For cofiring projects, depending on the fuel utilized along with coal, additional components may require monitoring and control.

The most common use of CEMs is for regulatory purposes to ensure that emissions from an individual source do not exceed the legislative set values. By measuring the emission of particular flue gas components, the information from CEMs can be used to enhance process data or to allow feedback control. They also provide useful information for the boiler operators allowing eventual reductions in raw material input, power consumption or emissions. CEMs also provide valuable data for studies on atmospheric pollution, deposition and environmental effects. With the emergence of emission reduction strategies and emission trading schemes much more is dependant on CEMs so therefore there is need for accurate, robust and reliable CEM equipment.

This part of the chapter is an overview of the current available continuous emission monitoring systems for measurement of pollutant emissions for power plants. Technological options are investigated along with CEM equipments advantages and disadvantages.

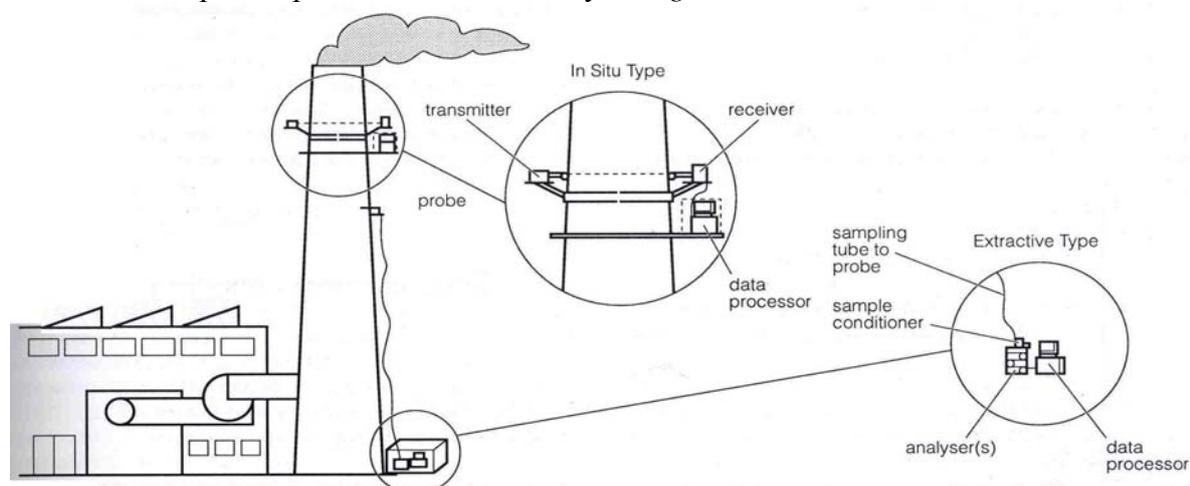
CEMs are composed of a sampling system, an analysis system and a data acquisition system and this section will be structured accordingly.

### 3.3.1 Sampling systems

Considering the sampling method used there are two types of CEMs:

- “in-situ” – where the sample is analysed in the stack or duct with little or no sampling treatment;
- extractive – where a sample is withdrawn for analysis elsewhere;

The two concepts are presented schematically in *Figure 3.2*:



**Figure 3.2** Two source emissions-monitoring configurations (SRI, 1994)

### 3.3.1.1 In-situ systems

In-situ CEMs are essentially analysers placed within the stack or duct. They commonly comprise an optical transmitter and receiver mounted on the inner stack walls to analyse the flue gases directly within the gas stream. Because the measured gas is not removed or conditioned, there are no potential losses in the sampling system. These systems have fast response times and may be suited for control applications. They must be quite rugged systems in order to withstand high flue gas temperatures, water vapour, acid gas corrosion and high particulate burdens. Also they must be able to withstand a large amount of vibration. Progressive fouling of the optics by particles and condensates in the flue gas is a problem. Although these systems require less intensive preventive maintenance than extractive systems, they are difficult to service since their removal is difficult and hazardous to personnel when the boiler or process is on-line.

One of the major disadvantages of in-situ systems is that they are difficult to validate. The whole stack cannot be filled with a certified calibration gas and therefore it is not possible to determine fully whether the systems are running correctly or not. In practice the systems are calibrated with small samples of dry gas while the measurements are performed on a wet basis (*Venni, 1992*).

In-situ systems are subdivided into two main groups:

- cross duct (path systems) – the detection paths are longer, up to the full width of the flue gas stream;
- insertion probes (point systems) – the detection paths are a fraction of the diameter of the flue gas stream;

**Cross duct monitors:** are composed out of an optical/radiation source and a receiver mounted directly onto the duct walls (as shown in *Figure 3.1*). The receiver may be diametrically opposite the transmitter or the beam may be reflected back to the transmitter by a retro-reflector. Maintenance, when required, is simple and measurement is immediate and continuous. Air curtains may be used to stop the hot flue gas from contacting the optical surfaces. Several gas species can be measured by each analyser. Wet and dry analysis is possible by multi-gas analysers if water vapour is one of the measured species. The area of stack chosen for the placing of the monitor must contain a representative portion of the flue gas. Severe duct warping may cause ray misalignment and high vibration can cause interference. Cross-stack systems are not well suited for applications involving gases with high humidity content such as those encountered downstream of FGD systems (*Venni, 1992*).

**Insertion probes:** may be used to approximate cross-stack samplers. Here a short optical path is established within a probe mounted in the duct at a small percentage of the duct diameter. They are multi gas devices which measure within a porous tube. An energy ray is passed from an analyser to a reflector and folded back to be measured after passing through the sample gas and gas specific filters. The short measurement path may limit sensitivity. Insertion probes have the advantage over cross-duct monitors in that they can be periodically flushed with calibration gas. Inserted cold, probes may cause condensation and filter blockage. Corrosive flue gases could cause expensive damage to components of the system (*Clark, 1996*).

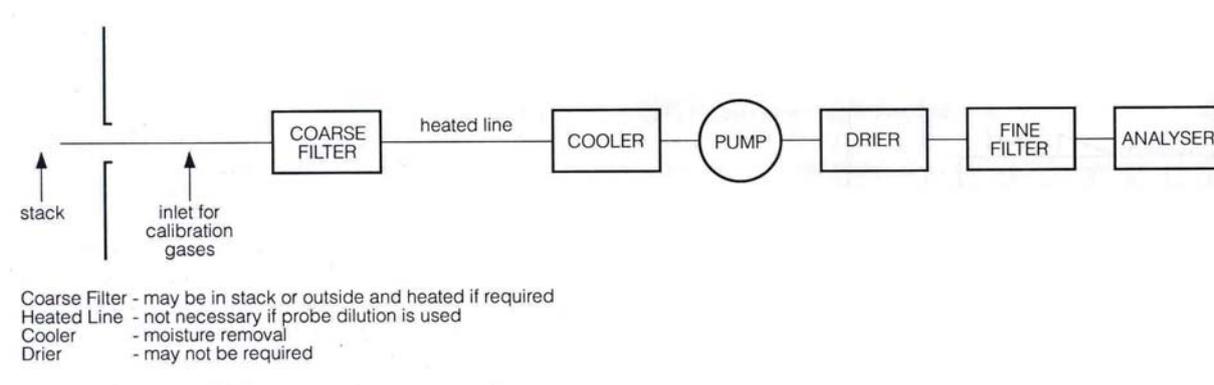
### 3.3.1.2 Extractive systems

Extractive (or “ex-situ”) CEMs remove samples from the gas stream and analysis is performed elsewhere. These systems are commonly demanded by European regulatory bodies for monitoring gaseous emissions from large complex processes. However CEMs for particulates are rarely based on extractive systems.

Extractive systems have the advantage over in-situ systems that little or no sensitive equipment is mounted within the stack and the sample can be withdrawn from almost anywhere, allowing them to be used in a greater number of locations than in-situ systems. Extractive CEMs are easier to reach to maintain, check, calibrate and repair. They also allow for future changes in legislation as they are easier to modify or replace than in-situ systems.

Extractive sampling systems have also inherent problems. Flue gases entering extractive systems are hot, may be heavily loaded with particulate matter, may contain water vapour, SO<sub>2</sub> and NO<sub>x</sub> and other oxidation products. Particulates can be abrasive and adhesive and can block the probe and can damage the analytical system. Water vapour condensing in a sampling system can lead to formation of acidic solutions and depositions, problems accentuated downstream the FGD and scrubbers. To avoid these problems, extractive sampling systems normally incorporate filters and are heated, if necessary, to avoid condensation. Sample line transmit time may cause an unacceptable delay before measurement and they can be affected by potential in-leakages which dilute the sample. Further disadvantages of extractive systems include their complexity and high investments required for purchase and installation also requiring labour intensive preventive maintenance (Clark, 1996).

A generic extractive sampling system is shown schematically in *Figure 3.3* showing also optional components.



**Figure 3.3** Typical gas extractive system, (Sloss L L, 1996)

**Hot-wet monitors:** In hot-wet systems the sample is drawn through a heated probe and then through a heated line to a remote analyser. In this way species such as SO<sub>2</sub>, HCl and NH<sub>3</sub> can be measured directly by maintaining the sample temperature high. The main advantage of such systems is that no water removal system is required and there are no problems with water and/or species in solution condensing within the sampling equipment. Because of the requirements for heated lines and probes these systems are commonly expensive to buy and install. Technical problems can lead to condensation and blocked sample lines. Some of the sample may be lost by condensation forming at unheated junctions in the line. The majority of extractive CEM monitors in use on coal-fired power plants in Europe are hot-wet monitors.

**Cold-dry monitors:** In Cold-dry systems condition the gas by filtering and condensing it to eliminate particles and water vapour prior to analysis is necessary. This improves the quality of the sample gas and avoids the need for constant temperature. These systems commonly require considerable maintenance, and are susceptible to probe blockage, freezing and require the condensate to be disposed in an acceptable manner. These systems are not used commonly in coal-fired power plants as some pollutant gases, especially soluble gases such as SO<sub>2</sub>, NO and NO<sub>2</sub> may condensate out with the water. SO<sub>2</sub> and NO can be measured as dry gases while NO<sub>2</sub>, NH<sub>3</sub> and HCl can only be measured on a wet basis.

**Super-dry monitors:** A permeable membrane is used in super-dry monitors to move moisture to adjacent pure dry air which is then vented. This means virtually all the water in the sample can be removed. The sample gas has to be filtered down to 0.3 µm to avoid blocking the membrane and a heated probe is required. The sample collection is slow and therefore the measurement time is long. Only a dry basis measurement is possible. If the water content of the sample gas is greater than 40% then the drying system may not be able to manage to dry the gas properly. Super-dry monitors as CEMs are not yet commonly used on coal-fired power plants.

**Dilution monitors:** The dilution systems collect the sample with a dilution probe through an unheated line to an analyser. The analysers used, commonly those designed for measurements in ambient air, must be sensitive to low concentration ranges. The gas used in the dilution process must be highly pure and an appropriate dilution factor must be used. The advantages of dilution systems include the fact that no heated line or moisture removal system is required and the system has relatively low maintenance requirements. Dilution systems have low possibilities for in-leakages as they are maintained at a positive pressure. They have limited use in high moisture applications and the effects of barometric pressure and stack temperature must be corrected. Because of the dilution stage, the method is not applicable to pollutants already in low concentrations in the stack gases (VOC and CO). Also a single dilution ratio may not be suitable for all pollutants and only wet gas measurements can be made. Because these systems are normally less complex than normal extractive systems they are cheaper to purchase and operate, and they are mostly used in the US (*Sloss L L, 1996*).

#### 3.3.2 Analysis systems

CEM analysers may be fitted on a generic coal-fired power plant in various key points as before/after dust filters, FGD plants, stacks, etc in points that are of interest. Different monitors can be used, accordingly to the principle they function on, and the analysis systems available in such applications are the subject of this section. CEM covered perform monitoring of important atmospheric pollutants (particulates, SO<sub>x</sub> and NO<sub>x</sub>), however in order to produce valid emission values for different process rates and at different pressures and temperatures, it is necessary to measure other parameters such as O<sub>2</sub> or CO<sub>2</sub>, H<sub>2</sub>O, temperature, pressure, and gas flow. The reference value monitors, gas and particles monitor techniques will be covered next.

##### 3.3.2.1 Gas monitors

Most stack emissions analysers are either based on ultraviolet or infrared processes and the choice of analyser mainly depends on which emissions should be monitored. Most analysers can measure more than one chemical species, though not necessarily simultaneously. A short overview of the analytical techniques employed in measurement of different chemical species is following.

##### Ultraviolet

Ultraviolet (UV) absorption spectroscopy is based on the absorption of UV light at specific wavelengths by the gaseous component to be monitored. UV systems can be used to measure O<sub>3</sub>, SO<sub>2</sub>, H<sub>2</sub>S, NO, NO<sub>2</sub>, NH<sub>3</sub> and Cl<sub>2</sub>. UV systems can be used in either in-situ or extractive applications (more common). Three basic types of UV systems are available (*Venni, 1992*).

**NDUV:** Non-Dispersive UV – the radiation passes through the sample gas and then splits into two rays of equal intensity. The rays are filtered which allows the transmission of specific wavelengths only. The first wavelength is equal to the gas absorption wavelength, the second is one where the gas has minimal absorption. The detected signals are converted into concentration values. The sample gas must be completely free of particles which would affect the transmittance. NDUV systems are simple and free from interferences due to other gaseous components. NDUV is the preferred method for NO measurement at large combustion plants where the NO concentration is low (*HMIP, 1994*).

**SDAS:** Second Derivative of Absorption Spectra – after passing through the sample gas, the UV ray is passed through an oscillating scanner and diffracted to give a continuous oscillating spectrum. A detector is set to measure the signal at the appropriate wavelength for the target pollutant. If well compensated, the detection is unaffected by broad band absorption from other gases and particulates. SDAS systems are complex and can monitor more than one gaseous component (*Venni, 1992*).

**DOAS:** Differential Optical Absorption Spectroscopy – both UV and visible light absorption are used on many inorganic and organic compounds. These systems, based on fibre optics are used throughout Europe (*White, 1993*).

## Infrared

The principle of infrared (IR) systems is the comparison of the sample gas directly against the reference gas. IR systems can analyse a greater number of gases (CO, CO<sub>2</sub>, SO<sub>2</sub>, NO, NO<sub>2</sub>, N<sub>2</sub>O, HCN, HCl, CH<sub>4</sub>, some hydrocarbons and water vapour) than UV systems. This makes them more applicable to coal-fired power plants than other systems.

Some IR measurements are sensitive to water vapour, which absorbs IR radiation over a broad spectrum. The different IR systems manage this problem in different ways. They can provide the measurements on a wet basis, dry basis or normalised CO<sub>2</sub> level. Three types of IR systems which may be applied to power plant CEM are available.

**GFCIR:** Gas Filter Correlation IR incorporated systems are the most flexible IR systems available. In such systems the IR ray is modulated by two cells mounted on a rotating wheel. The first cell is filled with the sample gas, the second with a gas which does not absorb IR at the same wavelength. The sample gas only absorbs the modulated beam during the second half of the modulating period. GFCIR systems are relatively insensitive to interferences from other gases or particles and can monitor several different gaseous components such as SO<sub>2</sub>, CO, NO<sub>x</sub> and HCl (*Venni, 1992*).

**NDIR:** Non-Dispersive IR uses a mechanical chopper to modulate the IR source. Concentrations of the target species are measured against a standard reference gas and therefore NDIR systems only measure a single species at a time. NDIR can measure CO, CO<sub>2</sub>, hydrocarbons, SO<sub>2</sub>, NH<sub>3</sub>, and NO. NDIR is used most often for CO but CO<sub>2</sub> and SO<sub>2</sub> are also frequently measured. These systems can also be used for the measurement of N<sub>2</sub>O as long as CH<sub>4</sub>, SO<sub>2</sub>, H<sub>2</sub>O and NH<sub>3</sub> are either removed from the sample content or their interferences are taken into account. They are commonly used in extractive systems although in-situ configurations are possible. The interference from water vapour can pose particular problems with NDIR systems as water vapour has a very broad absorption spectrum in the IR region. Water must be removed by condensation prior to gas analysis. The detection ranges for CO and NO are from 0-20 000 ppm and for SO<sub>2</sub> the range is around 0-100 ppm. NDIR instruments are among the least expensive and most reliable analysers (*HMIP, 1993*).

**FTIR:** Fourier transform IR is becoming more popular as these are robust instruments which can withstand dirt, high temperatures and vibration. FTIR systems use an interferometer which aligns and splits the light ray which then passes through the sample to the detector. The signal is translated from a spectral form into a digital form for analysis. The time period between the scan and the results is commonly 2-60 seconds, depending on the application. The system is not truly continuous as the response times are up to one minute. FTIR can be used in both in-situ and extractive CEM systems to measure SO<sub>2</sub>, NO<sub>2</sub>, NO, CO<sub>2</sub> and CO, water and various hazardous trace pollutants such as NH<sub>3</sub> and HF at ppm levels or lower. One of the major advantages of FTIR is the ability to quantify numerous compounds simultaneously. FTIR also offers different sampling strategies depending on the type of analysis required. In-situ FTIR transmission measurements can be used to determine the temperature of the gases, density, particle size and composition of particulates in the flue gas. FTIR is intrinsically a low-maintenance measurement method with most of the components having a lifetime of one year or more. Detection limits for most species are commonly below 5 ppm. However FTIR systems are among the most expensive but are cited as the most suitable for the use in power plants (*Sloss L L, 1996*).

#### 3.3.2.2 Particulate monitors

The measurement of particulates poses specific problems as the optical properties of the particulates (the base of most CEMs for particulates) may not remain constant over time with different operating conditions. As mentioned in *Section 3.1.2* CEMs for particles and dust are rarely based on extractive systems, instead particle measurements being performed by in-situ instruments. The following sections cover the different particle measurement systems.

**Opacity devices:** Opacity meters or optical transmissometers are in-situ systems which measure the decrease in light intensity due to absorption and scattering as the beam crosses the stack. Opacity systems are insensitive to interferences from other flue gas components since the beam spectrum is photopic (400-700 nm) and most other flue gas constituents do not absorb radiation in this spectral region. However, opacity analysers are generally not suitable for measurements following FGD systems unless the flue gas has been reheated. Opacity measurements are dependent on particle size, composition, shape, colour and refractive index. These properties may change with fuel type and recalibration may be necessary. These monitors are generally only accurate within narrow limits of these parameters and it is necessary for each instrument to be calibrated on the stack and process for which is intended.

There are two formats for opacity devices: single path and double ray. Single path monitors simply project a ray across a duct to a receiver. Air flow may be used to clean the optical windows since window contamination can be the major source of errors in such devices. Double ray devices project the ray between two transceivers. This enables each transceiver to compensate for gradual window contamination by using clean mirrors inserted periodically in the ray path.

Opacity devices can measure opacity as a %, Ringelmann values (a form of dark/light grading) or, if calibrated against an isokinetic sample test, can give results in mg/m<sup>3</sup>. The most accurate devices can measure  $\pm 5$  mg/m<sup>3</sup> over a 1 m path ( $\pm 0.2$  opacity). They have an upper limit of around 2000 mg/m<sup>3</sup> and a lower detection limit not much lower than 10 mg/m<sup>3</sup> making such instruments not suitable for measuring low concentration particle emissions. There are no moving parts in most opacity devices contributing to a low capital and operating cost (*HMIP, 1993*).

**Backscatter devices:** Light in an angle ray projected into the duct will be back scattered to a detector if particles are present in the duct. Backscatter instruments can be accurate down to 1 mg/m<sup>3</sup> and therefore these instruments are superior to opacity devices for monitoring low emission concentrations. Therefore backscatter instruments are commonly used in power stations.

Backscatter devices are particularly suited to in-situ applications in small ducts where low levels of dust are present. However, in larger ducts the device will only measure wall proximate samples. Another drawback of these monitors is that there is no standard gravimetric method for calibration. Special precautions have to be taken to prevent reflection of the light ray from the duct wall interfering with the measurement. Measurement in some systems may also be influenced by water droplets unless the sample is treated prior to analysis by an extractive system. Extractive light scattering CEM have been used at many large combustion plants with FGD in Europe. Backscatter devices can only measure dust and are quite expensive (*HMIP, 1993*).

**Flicker devices:** The modulation of an optical system caused by particulates passing through a flue gas duct is proportional to the particulate concentration. Only the change in the light signal is measured and therefore lens contamination does not affect the measurement. However the actual relationship between the dust load and the measurement may not be true across the full measurement range since dust alone does not generate flicker. Also the gas velocity, turbulence and temperature gradients may also affect the results (*Clark, 1996*).

**Triboelectric devices:** Triboelectric devices, or particle impingement probes, detect the charge transfer which occurs when a particle in a flowing gas stream impinges on the in-situ probe. This system has to be calibrated against an extractive method at each individual site since the electrical effect is dependent on the particle size distribution and composition. Since the response of the probe is sensitive to gas velocity, these systems are most suited to situation where the gas flow is fairly constant. Triboelectrostatic CEMs are also precise instruments measuring particulate concentrations of 1 mg/m<sup>3</sup>. They are inexpensive, can only measure dust density in location close to the wall (in large ducts since the probe has a limited length). Measurement verification is not possible unless independent extractive methods are adopted. Wet conductive solids will bridge the insulation between the duct walls and the probe causing a change in output (*Clark, 1996*).

### 3.3.2.3 Reference value monitors

Continuous monitors for O<sub>2</sub> and also H<sub>2</sub>O, gas velocity, temperature, pressure may be required for process control purposes and normalisation (the correction of data to standard reference conditions). These reference value measurements can be commonly found integrated in devices that measure several other pollutants.

Oxygen can be measured with electrocatalytic zirconia probes (most common). These are usually in-situ devices based on the movement of oxygen ions through the solid electrolyte zirconium. At 850C a layer of zirconium oxide (ZrO<sub>2</sub>) becomes porous to oxygen ions. By letting this movement occur between two cells a partial pressure is created which can be measured. This type of analyser is sensitive to the presence of combustible CO and hydrocarbons. The equipment is simple but a constant supply of clean dry air is required for reference cell (*Venni, 1992*).

In paramagnetic systems the O<sub>2</sub> molecules are drawn into an inhomogeneous magnetic field towards the higher field strength. A pressure difference occurs when two gases with different O<sub>2</sub> concentrations (the sample gas and a reference gas) come together in the field. Response times can be short to around one second. Vibrations can affect O<sub>2</sub> analysis and these systems must be either well housed or have a built in vibration detector which may be used to compensate the system.

O<sub>2</sub> can also be measured using electrochemical cells. The molecules diffuse through a membrane towards a gold electrode, the current being proportional to the concentration (*HMIP, 1994*).

#### 3.3.3 Reporting requirements

Once a CEM is selected and installed properly, the most important considerations are the calibration and other quality control procedures required to ensure the accuracy of data. This section focuses on the production and application of the data produced from CEM systems.

Maintenance of CEMs is paramount to maintaining the accuracy and validity of the data produced. In order to remain accurate, the analyser part of CEMs equipment is subject to specific checks some of them, specified in ISO guidelines, being:

- Cycle response time – the time it takes to achieve a 95 % step change in the response of a monitoring system to a known stimulus.
- System linearity check – characterise the linearity of the monitors deviation from a calibration standard by challenging the system at non-zero concentration levels within the expected measurement range. Deviation of the instruments response curve from an ideal response curve is being tested. (max 5 %)
- System drift (7-day calibration error) – the drift of the system from the calibrated point over a period of seven days. (max 2.5 %)
- Relative accuracy – test the entire measurement system independently against an standard reference method (SRM),

Calibration is the most important check for a reliable CEM being required at regular intervals and also after replacement of any part or the CEM or relocation of the CEM. For reasons discussed in *Section 3.2.1* under “Sampling and measurement” calibration of the CEM is realized against a SRM.

Calibration for dust monitors must determine and compensate for optical contamination and also include linearity checks. Particulate monitoring devices are only as accurate as the calibration is undertaken with a manual extractive system.

Gas analysers must be able to introduce test gases automatically while in-situ in order to confirm their calibration. In-situ gas analysers are commonly calibrated during manufacture stage. With CEM systems approved by the German TÜV, a single standard gas cell of known concentration is introduced into the measurement path within the unit every two hours to ensure accuracy, overcoming the need for a calibration gas. Gas analysers are usually supplied with a pre-programmed calibration curve for different calibration gases and systems which self-calibrate during normal service commonly have alarms which indicate excess deviation of the known standard and manual recalibration of the analyser is necessary (*Sloss L L, 1996*).



## Chapter 4 – CONCLUSIONS

Addressed topics:

- *General suggestions for co-firing technology choice for typical Romanian PCC boilers*
- *Environmental issues for co-firing*



## 4. Conclusions

Throughout the report all international available co-firing capabilities were reviewed along side with configurations and gained experience. When undertaking in the near future a co-firing initiative, it is important for Romanian power plant operators to take full advantage of the international co-firing experience in order to avoid normal occurring problems in the development process that have been already solved previously elsewhere. Special attention must be paid to sensitive aspects encountered in such projects and for these reasons international experience is a valuable part of technology transfer in order to be successful in the process of emissions reduction. Furthermore the international co-firing experience has to be correctly applied in concordance with the Romanian regional conditions to be able to capitalize at maximum the available co-firing potential, and build steps to achieve a sustainable development of the thermal energy sector. On these considerations a conclusion has to be drawn in a suggestions form underlining the examples from the international co-firing projects examples most suitable to be implemented in Romania along side with the environmental issues that need special attention to be successfully solved.

### 4.1 General suggestions for co-firing technology choice for typical Romanian PCC boilers

With the integration in the EU and the adhesion to common goals with respect to European energy policy, the share of the renewable energy resources in total Romanian energy consumption, especially biomass, having high potential, is expected to grow through investments with the purpose of utilizing untapped resources at this moment. That is why it is important to point out the relevant configurations of plant examples from Europe and US presented in *Chapter 2.5* and *Chapter 2.7* that are most suited to be successfully implemented in the Romanian thermal power generation sector as first co-firing initiatives.

Based on the co-firing fuel availability, type, characteristics, and the coal firing technology used, some presented international co-firing plant configurations and experience may prove to be useful for Romanian power plant operators in service under similar conditions. In that respect the following set of co-firing projects presents interest as having the highest potential for being implemented successfully under Romanian conditions.

- the Netherlands - Gelderland plant, Nijmegen
- Denmark - Studstrupvaerket #1, Aarhus
- Finland - Kymijärvi3, Lahti

## the Netherlands - Gelderland plant, Nijmegen

The project can be relevant because of the similarities in plant configuration with typical Romanian ones: PCC unit, commissioned in the 1980s, later fitted with a wet limestone FGD and SCR for NO<sub>x</sub> emission control. The reason for implementing the co-firing project was the availability of large quantities of landfill demolition wood, situation highly emergent in Romania as modernizations in the railway system, constructions sector, etc are taking place. In this case the co-firing initiative can be justified as the co-firing of the demolition wood together with the coal in a large power plant leads to far less, and controlled, undesired emissions than the landfill disposal method, also making use of the fuel the best possible way, coal power plants having a higher efficiency than incineration plants. The established pre-set Dutch conditions for the wood co-firing project will probably be kept or have correspondents, in the eventuality of implementing such a design in Romania as plant owners do not want significant risks to the availability of the boiler (Romanian ones are commonly used in CHP configurations for district heating), and the boiler fly ashes are used 100% as component in construction materials, while emissions are to be maintained within the limits set by the Romanian legislation.

The low risk on the combustion and post combustion equipment was achieved in this case by employing a separate handling and comminution facility for the secondary fuel. The waste wood material was collected and processed into raw wood chips off site. Then, a wood fuel handling and processing system (detailed process description in *Chapter 2.5.1.3* ) was configured on site to deliver the powdered wood to the dedicated boilers burners. The wood/oil burners and the wood combustion control system are independent from the coal firing system thus are not interfering with the capability to burn coal at full load, assuring the boiler availability. The co-firing ratio was set to 3-4% (10 tones per hour) of the heat input to the furnace for ash quality considerations. At this co-firing ratio and with a relatively high-quality fuel, the impacts on the operation, the environmental performance, and the availability of the boiler have been small.

The system was commissioned in 1995 and, despite considerable initial problems with the wood-handling and milling system, is presently in full commercial operation. On average, around 60,000 dry tonnes of wood are fired per annum, replacing around 45,000 tonnes of coal p.a. There is also a reduction of around 4,000 tonnes p.a. of the fly ash produced, due to the very low ash content of the wood fuel. It is a very important project in that is the first direct biomass co-combustion demonstration in a large utility boiler in Europe (electrical power output from wood firing of 20 MW<sub>e</sub>), with long-term experience of commercial operation.

*The advantages of such an approach are that the highest direct co-firing ratio for PCC technology can be achieved posing the least risk to normal boiler operation, at the price of the highest capital cost of the other direct co-firing options for PCC. It can be chosen a model with high potential to be implemented in Romanian power plants because of possible fuel availability and of plant configurations distribution, where large spaces are available (most plants are off city) and large installed capacities (some unused) of coal processing installations are available that can be converted for biomass processing.*

## Denmark - Studstrupværket #1, Århus

This project is seen as relevant because of the fuel type (straw) employed for co-firing (Romania having a large agricultural sector) and that the handling, pre-processing, and firing equipment represents the culmination of experience gained over a number of previous Danish projects in co-firing straw. Also, as an important factor for suggesting it as a project with high potential to be implemented in Romania are the resemblances in plant configuration with typical Romanian ones: medium sized PCC units, commissioned in the 1960s-1970s, later fitted with deSO<sub>x</sub> and deNO<sub>x</sub> equipment for emission control.

The co-firing system was installed and commissioned during 1994-1995, and a demonstration programme started in 1996, focusing on the performance of the straw-handling and firing system, the boiler performance, the process chemistry, i.e. slagging, fouling and residue characteristics, and the pilot testing of equipment for SO<sub>x</sub> and NO<sub>x</sub> control, involving long-term operation at 10 and 20% straw on a heat input basis.

In the Danish projects, the main argument was to make use of large quantities of available straw. The approach of the Aarhus power plant was to implement a separate handling co-firing arrangement (involving separate handling, metering and comminution of the biomass which is then injected into the pulverised coal upstream of the burners or at the burners). The description and the design of the process are detailed in *Chapter 2.5.1.2*.

As lessons learned, initial problems with the handling and mechanical conveying of wet straw were determined by the sensitivity of the system to relatively small quantities of straw with moisture content in excess of 25%. The key issue in the solution to this problem was co-operation with the straw suppliers to improve the quality and consistency of the delivered fuel. The combustion system performed reasonably well, provided that the straw injection velocity through the burner was reduced (below 15 m/s). Good burnout, even of the more dense components of the straw, was achieved. No particular problems associated with ash deposition, high temperature corrosion, or the environmental performance of the plant were identified at straw co-firing rates up to 20% on a heat input basis.

After successful operation of unit 1 from 1996-1998, the intention was to convert Unit 4 at Studstrup Power Station, a 350 MWe boiler, to straw co-firing. After concerns about the utilisation of the mixed coal/straw ash residues as a component of cement and concrete product were solved in 2001, unit #4 (350 MW) was converted to straw. As of January 2002, Studstrupværket is capable of co-firing approx. 250,000 tonnes of straw and 100,000 tonnes of other biomass fuels (e.g. maize, sunflower seed husks, etc.) with coal annually.

This approach also has the advantage of the highest direct co-firing ratio for PCC technology that can be achieved with little risk to normal boiler operation at a more moderate capital cost of direct co-firing options for PCC. Since biomass/coal are co-fired with the same burner (being injected upstream or at the burner, it may be difficult to maintain adequate burner performance over the normal boiler load curve and also necessitating the installation of a number of biomass transport pipes across the boiler front, which may already be congested.

*The Aarhus co-firing project can be seen as a model with high potential to be implemented at Romanian thermal power plants situated in the southern part of the country (plains areas where there is a tradition in agriculture), where there can be made available a yearly, constant, available fuel supply. As well the power plants current configurations can overcome*

*the space and equipment related shortcomings of the separate handling direct co-firing approach in constructing and operating the separate handling system.*

## Finland - Kymijärvi3, Lahti

Another co-firing project that is relevant and a model with high potential to be implemented in Romanian plants in the near future is the Finnish power plant from Lahti, Kymijärvi3 example. This is resulted from the main argument of power plant similarities in configuration with Romanian ones (medium sized coal-fired power plant commissioned in the early 1980s with PCC boiler). Another contributing factor is the operation mode of the power plant, Kymijärvi3 not operating in periods when heat demand is low. This aspect makes the example more important from the perspective of the plant operating experience, as Romanian coal-fired plants are also switched from providing base electricity (operating full time on a yearly basis) to providing marginal electricity (only periods when there is demand). Unlike the first suggested configurations, the Finnish approach is involving indirect co-firing, pregasifying the biofuels in a separate unit and firing the resulting gas along with the coal in the main boiler. This way the fuel flexibility is increased, because many types of fuels can be gasified, while ensuring there's no risk posed to the coal boiler and the ash is not mixed, making it the most desirable co-firing configuration from the perspective of maintenance of ash properties, and zero risk on boiler and post combustion equipment, though at the highest capital cost.

The boilers fuel consumption was 180,000 t/y (1200 GWh/y) of coal and about 800 GWh/y of natural gas (during low demand periods, operating at lower load). The main drive of the project was the local availability of different types of biofuels and wastes, corresponding to about 300 GWh/y, being able to substitute 15% of current fuel usage and 30% of coal usage. The biofuels include peat and demolition wood, and the waste is produced from classified refuse from households, offices, shops and construction sites. In order to reduce fuel costs and to reduce environmental emissions, a gasification demonstration project has been undertaken at Kymijärvi demonstrating a commercial scale gasification of a wet biofuel and the use of hot, raw, very low calorific gas directly in the existing boiler. Detailed process description is available in *Chapter 2.7.9*.

Operating experience has showed that since the gasifier has been connected to the main boiler in December 1997, it has been in continuous operation, other than for maintenance periods. The reliability during the first operational period was excellent and what few problems arose related to the fuel processing plant (decreased plant availability due to lack of fuel and processing problems) were easily solved. Regarding the gasifier plant, problems arose relating to the use of shredded tires (high wire content of tires was accumulated and blocked the ash extraction system). The gasifier has operated well with other fuels and results have met expectations. The operating conditions regarding temperature, pressure and flow rates have been measured as designed and process measurements of product gas, bottom ash and fly ash composition have been close to calculated values. The results of leachability tests on the main boiler ash were satisfactory and it was possible to utilise the ash as before co-firing. Corrosion/deposit formation has been undertaken and the inspection of boiler heat transfer surfaces during annual maintenance showed no evidence of abnormal deposit formation or high temperature corrosion.

The results from the first four years of operation have been very encouraging, generating 1310 GWh of energy from the gasifier's product gas and gasifying several different types of fuel, and gaining a total of 22,006 h of operation under gasification.

*The Lahti co-firing project can be seen as a model with high potential, most suitable to be implemented Romanian power plants situated near densely populated cities especially in the plains area where a wide range of fuels (biofuels/wastes) can be locally made available. The main advantage of this approach of preventing the coal ash to be contaminated when it's particularly important to do so (high standards for quality cement production) is available for operating with a variety of biofuels even containing relative difficult components such as wastes, constituting the main driver behind such an initiative. When employed, the in-direct co-firing approach will assure that any biofuel/waste constituent will not cause extra slagging, fouling and corrosion in the main plant and the total biofuel capacity will not be limited by existing constraints imposed by installed hardware. Energy security is increased with this approach as problems with the biomass plant will not result in the whole power plant being shut down. If the major disadvantage of highest capital cost can be surpassed the indirect co-firing approach is the best technical solution for biomass/waste coal co-firing.*

Further on, when analyzing a co-firing configuration with the scope of re-habilitating a specific Romanian thermal power plant an important role will be played by the site specific conditions that were not the subject of this analysis. Engineering and design issues presented in the report, and are well understood for most applications in the international experience, but the optimum design for a given power plant will be site-specific and will vary depending on a number of key aspects including site location, site layout, boiler type, biomass type and moisture content, level of co-firing, type of existing pulverizer, pulverizer excess capacity, pollution control equipment etc.

## 4.2 Environmental issues for co-firing

The most important emissions from coal-fired plants are particulates, sulphur dioxide and oxides of nitrogen, which are carefully monitored and are subject to environmental regulation through national emission limits (*Chapter 1.4 Table 1.5*). When co-firing the coal with a secondary fuel, the emission values will change according to the chemical composition of the fuels, combustion, absorption mechanisms and pollution control equipment employed, so it is important to note the main issues that may appear after the co-combustion process.

### SO<sub>2</sub> emissions

Most forms of biomass contain very small amounts of sulphur compared to coal. (*Chapter 2.3.1. Table 2.1*). For this reason, the co-firing fraction which is substituting biomass for coal will be resulted in possible reductions in sulphur dioxide (SO<sub>2</sub>) emissions. This aspect becomes a very important co-firing strong-point as typical Romanian thermal power plants were not originally designed with sulphur capture technologies and the domestic brown coal utilized has relatively high sulphur content. So, for the typical domestic potential biofuels (straw, wood etc) co-fired with coal, the sulphur content will be lower than for coal so this will tend to reduce the overall SO<sub>2</sub> emissions.

For the sulphur control purposes all the plants are/will be fitted with limestone/gypsum FGD systems so that the sulphur emission limits are respected and it is important to determine the effect of co-firing on the performance of the FGD plant. Co-firing of biomass was found out to have no occurrences of harmful effects on the overall performance of the FGD plants although reports of decreased limestone reactivity were observed during laboratory tests. This topic is currently under research, for understanding better the long time effects of co-firing biomass over the FGD plant.

The SO<sub>2</sub> retention mechanism by the biomass ashes (*Chapter 2.3.6.2*) has not been observed in pulverised coal systems because of the high combustion temperatures. As well the high combustion temperatures in pulverised coal systems generally prevent any increase in the emission of dioxins, despite the chlorine that is often present in some biomass feedstock (miscanthus, straw).

Other potential fuels for co-firing with coal are classified as wastes (sewage sludge, RDF, etc.). Sewage sludge contains high sulphur levels and it can increase the SO<sub>2</sub> and heavy metals concentration in the flue gasses when co-fired although emissions are not typically increased to unacceptable levels, while ash quality is largely maintained. Total ash content is increased and there is significant sulphur retention in the resulted ash. In other cases sewage sludge can decrease the emissions, all dependant of the composition of the sludge and the plant conditions. Normally sewage sludge is best limited to ~10% to avoid problems with increased ash content and slagging.

*As a conclusion, judged by the experiences provided by international co-firing experiences, by employing modern FGD solutions for sulphur removal from the flue gases, tough emission limits can be hold for biomass/waste co-firing plants with pulverised coal, been demonstrated at commercial scale in units larger than 600 MWe.*

## NO<sub>x</sub> emissions

When co-firing a secondary fuel with coal there is some uncertainty regarding the outcome of the NO<sub>x</sub> emissions levels. For biomass co-firing with coal, NO<sub>x</sub> emissions may increase, decrease or remain the same, the effect varying with the type of biomass, firing and operating conditions at each plant. For example bio-fuels containing relatively little nitrogen, like wood, tend to decrease the total NO<sub>x</sub> emissions while others, mostly derived from agricultural practices, can contain higher nitrogen contents translating into higher NO<sub>x</sub> emissions if unchecked.

However emissions of NO<sub>x</sub> cannot be predicted exclusively from the fuels nitrogen content but on the manner in which the nitrogen is released during combustion resulting from the plant design and operation. Changes in the boiler configuration to accommodate biomass firing have an impact on the NO<sub>x</sub> emissions release, especially if a set of dedicated burners are introduced in the boiler. International plant experience shows that burner configuration has a considerable influence on the formation of nitrogen oxides during co-firing. The high volatile content of biomass offers an enhanced capacity for limiting NO<sub>x</sub> by combustion measures converting the coal plant to co-firing. In the case of pulverized coal co-combustion, the NO<sub>x</sub> emissions from higher rank coals are improved most noticeably, with some impressive reduction results for staged combustion comparing with coal alone. Best general practice is the addition of the coal in the substoichiometric zone, and the biomass in the more air-rich zones. For waste fuels like sewage sludge, co-firing with coal showed a greater sensitivity regarding NO<sub>x</sub> emissions comparing to conditions for biomass, as sewage sludge has a higher nitrogen content than biomass. Therefore to minimize the NO<sub>x</sub> formation, sewage sludge addition is made centrally, through the oxygen-deficient burner zone, through a low NO<sub>x</sub> burner.

Biomass/sewage sludge have also proved to be suitable for reburning applications with the scope of NO<sub>x</sub> mitigation. By utilizing a gasifier, a low calorific value gas is being injected with the coal in conventional pulverized coal plants. With this technique boilers can be retrofitted for reburning, where a layer of fuel rich substoichiometric combustion is generated high up in the boiler furnace. Some of the NO<sub>x</sub> and NO, precursors passing through this region, are transformed into N<sub>2</sub>. Additional air is injected downstream of the fuel-rich zone to complete combustion. If the flue gas is coming from low NO<sub>x</sub> burners fitted low in the boiler, this system in combination with reburning can result in significant reductions in NO<sub>x</sub> levels.

*As a conclusion regarding the NO<sub>x</sub> emissions for co-firing in Romanian pulverized coal thermal power plants, by using low NO<sub>x</sub> burners combined with appropriate air staging (air injection at two levels) and fuel staging (fuel feeding in the furnace at two different levels), below national emission levels are attainable for biomass/waste coal co-firing, without additional employing of de-NO<sub>x</sub> units for fuel gas treatment.*

## Dust/particulates emissions

By incorporating biomass/waste, the properties of the coal ash may be modified so another area to be regarded with attention is the ash disposal and/or utilization. In both these areas an environmental issue to be had in mind on a co-firing project is the dust/particulate emissions, as biomass/waste as a co-feedstock for coal could introduce elements into the ash that could present an environmental hazard, so careful attention and the use of pollution control measures is imposed.

Repeated and rough handling of biomass materials can liberate significant quantities of dust. Dry biomass particles tend to have a low density and large drag coefficient and can be easily suspended in air. Generally, the greatest risk posed by biomass to personnel is the exposure to dust, primarily through inhalation.

Also particulate ash collection is an important part of plant operation to minimise dust emissions as co-firing plant experience showed that there can be a slight increase in particulate emissions when co-firing with biomass (wood especially). Particulate control equipments can be employed such as existing, conventional electrostatic precipitators or bag filters. These measures have high collection efficiencies and the increase in emitted dust/particles levels proved to have only a marginal change in performance. FGD equipment also has a positive effect on the particles emission, part of the incoming particles after the ESP being retained while the FGD system is in operation.

However when co-firing wastes that can contain difficult components (such as sewage sludge or tainted biomass) care must be exerted that the pollution control equipment in case is able to handle the extra stress can retain the difficult components. In such cases, close continuous monitoring of emissions and extra awareness measures are required so that the emission limits are not passed as this type of co-firing falls into the scope of another directive (*Chapter 1.4*).

*It can be concluded that the observed changed levels of dust/particles emission when co-firing do not pose any difficulty in maintaining the particle emission below the national limit and that the impact of co-firing biomass on boiler particulate emission levels is not considered significant. Co-firing of difficult fuels & wastes can be sought after a certain co-firing experience is nationally achieved and after a quality controlled infrastructure for the waste collection is established.*

## HCl for co-firing waste

Chlorine induced corrosion is the most important corrosion process in thermal power plants, firing coal or coal with biomass/waste. The chlorine is released mainly as HCl entrapped in gas form increasing the corrosion of the superheater tubes. Damage to superheater tubes causes in the first steps decreased process efficiency, up to full process stop with associated plant downtime. For these reasons, as co-firing of coal with waste especially is seen to increase the HCl emissions relative to the content of chlorine in waste/coal, this procedure is regarded as risky, and not undertaken if corrosion problems are solved previously.

For co-firing high-chlorine content biomass type fuels (straw, switchgrass) which can cause severe corrosion, front-end measures can be applied such as precipitation exposure/washing the fuels where these are appropriate, limiting the corrosion to acceptable levels. As the most used Romanian coal is relatively high sulphur content brown coal, it can be speculated that the extent of corrosion will be limited as some of the fuel chlorine will react with the alkali metals in the biomass fuel such as K and Na to form salts leading to less corrosive sulphates as discussed in *Section 2.3.5.*, and the remaining chlorine traces not released as HCl will be inhibited to form dioxins by the high combustion temperatures in PCC boilers.

For co-firing with waste fuels the HCl emissions from sewage sludge, RDF or MSW closely reflect the chlorine input in the process and increased emissions are usually observed. The extent of increased HCl emissions varies considerably depending on the chlorine content of the input fuels, comparing to coal which has  $< \sim 0.1$  wt% chlorine content sewage sludge can vary from  $\sim 0.01$  wt% to as high as  $\sim 1.5$  wt% . To be able to cope with the increased HCl emissions advanced flue gas treatment plants (FGD units) are necessary to scrub the HCl gas, such as plant back-end corrosion is avoided.

To be able to withstand aggressive HCl corrosion, the best practice is to upgrade the superheater materials to more corrosion-resistant alloys, however where it's proving to be an incentive to do so, where the efficiency is not affected adversely and upgrading is an economical solution to the problem.

*Concluding, it is uncertain that waste co-firing will be pursued as the first steps of full scale co-firing trials as it's necessary to build an own experience base with co-firing, argument being coupled with the high biomass co-firing potential, which sets the priority. As experience is built, European-Romanian emission standards aligned, and also the period given to older plants to conform to strict emission limits expires (instalment of advanced pollution control equipment) the incentive of coal-waste co-firing is strong as an alternative to landfilling and can be seen viable where populated urban areas provide constant large quantities of wastes periodically, as a landfilling alternative.*



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