Reduction of fuel side costs due to biomass co-combustion

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ARTICLE INFO

ABSTRACT

The feasibility and influence of co-combustion of woody biomass on the fuel side costs is discussed for three hard coal power plants located in Berlin, Germany. Fuel side costs are defined as the costs resulting from flue gas cleaning and by-products. To have reliable data, co-firing tests were conducted in two power plants (i.e. slag tap furnace and circulating fluidising bed combustion). The amount of wood which was co-fired varied at levels below 11% of the fuel heat input. Wood chips originating from landscape management were used. The analyses show that co-combustion of woody biomass can lower the fuel side costs and that the co-combustion at a level below 10% of the thermal capacity is technically feasible without major problems. Furthermore, a flexible spreadsheet tool was developed for the calculation of fuel side costs and suggestions for operational improvements were made. For example, the adaptation of the Ca/S ratio (mass ratio of calcium in limestone to sulphur in the fuel) in one plant could reduce the fuel side costs up to $135 \, k{\in}yr^{-1}$ $(0.09 \, {\in}MWh^{-1})$.

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1. Introduction

Renewable energies play an increasing role in the German energy supply. In 2009, their share in total final energy supply (power, heat and fuel) was 10.1%, around 238 TWh [1]. Meanwhile, more than hundred field demonstrations of biomass co-combustion exist in 16 countries, utilizing many types of biomass in combination with various types of coals and boilers [2]. At present, Vattenfall AB investigates whether co-combustion of biomass in hard coal power plants is feasible and economically and environmentally worthwhile. One factor of the total costs of a power plant is its fuel side costs. Fuel side costs are the side costs resulting from flue gas cleaning and by-products. The fuel side costs are expressed as $\in MWh^{-1}$ fuel heat input and represent 1–5% of the total costs.

This work focused on direct co-combustion, the combustion of biomass and coal in one combustor and the most common type of co-firing. In general, biomass consists of more oxygen, silica, and potassium than coal and less carbon, sulphur, nitrogen, aluminium and iron. The chlorine content can be lower (e.g. residual wood) or higher (e.g. straw). Biomass has lower volumetric energy density and heating value. The moisture content can be lower or higher depending on possible pre-treatment (e.g. drying). Biomass is non-friable and contains much more volatiles. These characteristics can affect preparation, handling and storage properties. Advantages of co-combustion are: higher efficiencies are possible in coal-fired power plants, variations in biomass supply can be compensated by a higher firing ratio of coal, emissions (e.g. CO_2 and SO_x) are reduced, fossil fuel reserves are saved and installation costs are lower compared to the installation of a new biomass mono-combustion plant if an existing plant is used. Problems associated with biomass co-combustion can contain deposit formation (slagging and fouling), corrosion and erosion, deactivation of the catalysts in the $DeNO_x$ unit and agglomeration of bed material. Furthermore, problems can occur with fuel preparation, handling, storage, milling, feeding and ash utilisation. The combustion behaviour can change and the overall efficiency can decrease. Not all coal mills are suitable for the grinding of biomass-coal mixtures because of the fibrous nature and non-friability of biomass [2–6].

The objective of this investigation was to evaluate the feasibility of co-combustion (of woody biomass) and its impact on the fuel side costs in three hard coal power plants in Berlin, Germany. This included the identification of operational data and calculation of material flows relevant for an analysis of fuel side costs. It was necessary to determine the specific costs of materials consumed or generated in the power plants and related to the fuel side costs. A flexible spreadsheet tool was developed for the assessment of the impact of an offered (bio-)fuel on the side costs. Suggestions for operational improvements were made, based on the side cost analysis.

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2. Materials and methods

This study focused on three coal-fired power plants in Berlin, Germany. They correspond to the three different types of coal combustion (dry furnace, slag tap furnace and fluidised bed combustion (FBC)). An overview of these combined heat and power (CHP) plants is given in Table 1.

The flue gas cleaning in the CHP plants Reuter and Reuter West consists of an electrostatic precipitator (ESP) for dust removal, a denitrogenation (DeNO$_x$) unit (ammonia as additive) to lower the NO$_x$ emissions and a flue gas desulphurisation (FGD) unit (lime or limestone as additive, gypsum as product) to reduce SO$_x$ emissions. In CHP plant Moabit, no DeNO$_x$ unit is necessary because the lower combustion temperature leads to lower NO$_x$ emissions. Instead of using a separate FGD unit, the limestone for desulphurisation is added directly to the combustor. This is typical for FBC. The flue gas cleaning is described in detail, e.g. by Effenberger, Parker and Strauß [7–9].

2.1. Fuel side costs

Fuel side costs cover all costs resulting from flue gas cleaning and by-products. They are expressed as €MWh^{-1} fuel heat input. Relevant for the calculation of fuel side costs are the following additives and by-products: ammonia, limestone, gypsum, fly ash, bottom ash, boiler slag, FBC ash.

2.2. Experimental study

2.2.1. Mono-combustion

Data of coal mono-combustion within the power plants Reuter, Reuter West and Moabit was collected on a monthly basis and then assessed based on weighted mean values. The composition of by-products (ashes, gypsum) was analysed at least 1 to 2 times a year (routine testing). The data from the CHP plants Reuter and Reuter West was collected in 2007, the data of Moabit in 2005. Based on this the mass flows of carbon, nitrogen and sulphur were determined.

2.2.2. Co-combustion

At CHP plant Reuter, co-combustion tests with untreated wood chips from landscape management and a co-firing ratio ≤3.5% of fuel heat input (≤100 t d^{-1}) were conducted from January to April 2009. The wood chips had an edge length ≤30 mm and a moisture content of ~40% by weight. One sample of boiler slag, fly ash and gypsum was taken at a co-firing ratio of ~1.0% of fuel heat input and another at a co-firing ratio of ~1.9% of fuel heat input.

Two failures caused a service interruption of the power plant during the testing period. These failures made it impossible to achieve higher co-firing ratios under stable conditions. Neither of the two failures was caused by co-firing biomass.

In addition, data of co-combustion tests in CHP plant Moabit was analysed. The tests were conducted with wood chips (length ~25 mm, moisture content ~11–31% by weight) made of untreated wood residues. They lasted 5 days in 1997, each day with different biomass ratios of the heating value. The co-firing ratios were 8–11% of the fuel heat input. Several samples (one sample every 2 h) were taken over the course of the day and they were blended to get a representative sample for the corresponding biomass ratio. The fuel composition (raw) of the tests in the CHP plants Reuter and Moabit can be found in Table 2.

2.3. Analytical methods

The following analyses of coal, biomass, fly ash, bottom ash, boiler slag and FBC ash were made: moisture content, loss on igni-
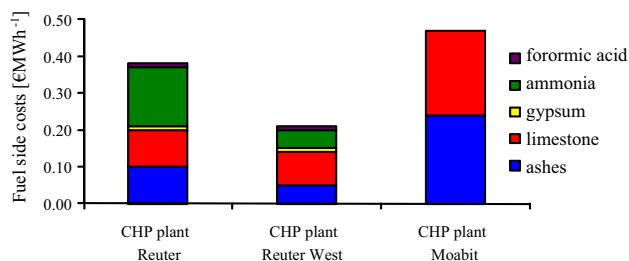

Fig. 1. Distribution of fuel side costs (coal mono-combustion).

tion (LOI), carbon content (fuels only), hydrogen content (fuels only), nitrogen content, sulphur content, heating value (fuels only), concentration of free CaO (fly ash only), concentration of oxides and X-ray diffraction (fly ash and boiler slag only). The generated gypsum was tested for pH value and for the amount of MgO and Na$_2$O. All analyses followed the corresponding German standards (Table 3).

For statistical data evaluation, the Principal component analysis (PCA) was applied. PCA is a Multivariate data analysis (MVDA) which illustrates differences between variables graphically. It is described in detail, e.g. by Henrion et al., Ecke and Wold et al. [10–12]. The statistics program STATISTICA version 8 was used [13].

3. Results

Coal mono-combustion at the CHP plants Reuter, Reuter West and Moabit served as reference cases. The determination of mass balances revealed that the majority of nitrogen and sulphur was kept in the flue gas cleaning system. For example, CHP plant Reuter West emitted ≤1% of the initial sulphur and nitrogen as SO$_2$ and NO$_x$ emissions. The calculated fuel side costs are listed in Table 4. Fig. 1 shows the distribution of fuel side costs during coal mono-combustion. Ca/S is the mass ratio of calcium in limestone to sulphur in the fuel, NH$_3$/N the mass ratio of ammonia to nitrogen in the fuel.

The stated value (target value of Ca in limestone per S in fuel for the desulphurisation process) for the Ca/S ratio in CHP plant Moabit was 1.75 compared to the calculated value of 2.57. The calculated value indicates that more limestone than necessary was added. The fuel side costs of coal mono-combustion calculated with the stated value would be 0.38 €MWh^{-1} which corresponds to a cost reduction of ~135 k€yr^{-1} (~0.09 €MWh^{-1}).

The co-combustion tests in CHP plant Reuter with a co-firing ratio ≤3.5% of fuel heat input indicated no changes of emissions and the composition of by-products. The co-combustion test at CHP plant Moabit with a co-firing ratio between 8 and 11% of fuel heat input revealed an increase of the LOI and carbon content in FBC ash (from the ESP). The LOI was 14.6% (±5.1%; n = 5) by weight for coal combustion and 24.7% (±1.4%; n = 4) by weight during co-combustion. All other results of the co-combustion tests were within normal ranges.

The statistical evaluation with a principal component analysis (PCA) showed a proportional correlation of the amount of coal fired and the flue gas temperature in the stack.

An Excel spreadsheet tool was developed to estimate the fuel side costs depending on different fuel properties. For this purpose an existing spreadsheet tool was extended towards the co-combustion of woody biomass. It was based on the assumption that composition and properties of the generated by-products remain unaffected by the co-combustion, e.g. the generated fly ashes fulfil the criteria of EN450 [14] as concrete additive (to keep the specific costs for disposal). The spreadsheet tool was designed to document type, amount and costs of fuels and auxiliary materi-

Table 1
The CHP plants Reuter, Reuter West and Moabit.

Power plant	Furnace type	Capacity [MW_el]	Temperature [°C]	Mills	Additives and by-products
Reuter	Slag tap furnace	132	1500	Beater mills	Ammonia, limestone, gypsum, boiler slag, formic acid
Reuter West	Dry furnace	600	1200	Roller-type bowl mills	Ammonia, limestone, gypsum, fly ash, bottom ash, formic acid
Moabit	Circulating FBC	100	800	Hammer mills	Limestone, FBC ash

Table 2
Fuel composition (raw) during co-combustion tests.

Parameter	Unit	CHP plant Reuter		CHP plant Moabit	
		Hard coal	Wood chips	Hard coal	Wood chips
Heating value	[MJ kg^{-1}]	26	9–12	28–29	13–18
Ash	[% by weight]	14.6	1.6–4.7	6.6–8.2	1.3–2.4
Water	[% by weight]	8.3	32.9–40.1	6.9–9.8	11.3–31.0
Volatiles	[% by weight]	27.0	40.9–50.8	24.9–29.2	54.5–65.5
C	[% by weight]	65.5	28.5–33.5	70.6–73.2	35.4–45.8
H	[% by weight]	4.2	3.1–4.3	4.3–4.6	4.0–5.2
N	[% by weight]	1.2	0.2–0.9	1.3–1.5	0.2–0.4
S	[% by weight]	0.61	0.04–0.07	0.96–1.15	0.05–0.52

Table 3
Analytical methods.

Parameter	Sample	Analysis	German standard
Moisture content	Coal, biomass, fly ash, bottom ash, boiler slag, FBC ash	Drying ($T = 106 °C$)	DIN 51718
LOI	Coal, biomass, fly ash, bottom ash, boiler slag, FBC ash	Heating ($T = 815 °C$)	DIN 51719
C	Coal, biomass	Infrared (IR) detection	DIN 51732
H	Coal, biomass	IR detection	DIN 51732
N	Coal, biomass, fly ash, bottom ash, boiler slag, FBC ash	Thermal conductivity	DIN 51732
S	Coal, biomass, fly ash, bottom ash, boiler slag, FBC ash	IR detection	DIN 51724-3
Heating value	Coal, biomass	Calorimetric measurement	DIN 51900
Free CaO	Fly ash	Titration	DIN EN 451-1
Oxides	Coal, biomass, fly ash, bottom ash, boiler slag, FBC ash	XRF[a], OES-ICP[b]	DIN 51729-10
Mineralogical structure	Fly ash, boiler slag	X-ray diffraction (XRD)	–
PH	Gypsum	PH measurement	–
MgO	Gypsum	Atomic absorption spectroscopy (AAS)	–
Na$_2$O	Gypsum	AAS	–

[a] X-ray fluorescence analysis.
[b] Optical emission spectroscopy with inductively coupled plasma.

als that are purchased and used in a power plant. The expenditures were correlated with the costs for generated by-products. The specific costs were calculated under consideration of stoichiometric factors (e.g. Ca/S ratio and NH$_3$/N ratio) as well as plant specific operation factors. The results were the basis for the calculation of the fuel side costs caused by the chemical fuel composition.

4. Discussion

The evaluation of the operational data and specific costs originating from coal mono-combustion provided a basis for the calculation of the fuel side costs of coal-mono combustion and the co-combustion with woody biomass. Furthermore, it revealed preconditions for the application of the analysis tool, for example criteria for ash compositions, and visualised that the majority of sulphur and nitrogen originating from the fuel was captured in the flue gas cleaning system. The fuel side costs are ~0.38 €MWh^{-1} at CHP plant Reuter, ~0.21 €MWh^{-1} at CHP plant Reuter West and

~0.47 €MWh^{-1} at CHP plant Moabit (calculated with exemplary values). The fuel side costs depend very much on the fuel composition (e.g. higher nitrogen content in the fuel leads to more ammonia necessary for the denitrogenation process) and are dominated by the costs for limestone, ammonia and the ashes (Fig. 1). Those have the highest potential for cost savings. The biomass co-fired in CHP plants Reuter and Moabit had a lower nitrogen and sulphur content than coal (Table 2).

Biomass co-combustion benefits from the high efficiencies achievable in large coal power plants (biomass mono-combustion plants have a lower efficiency) and improves the combustion process due to the higher amount of volatiles in biomass [2,15]. On the other hand, e.g. high moisture content of biomass and an increased temperature of the flue gas due to co-combustion can lead to efficiency losses [3,6,16–18].

The existing mills in CHP plant Reuter are beater mills; CHP plant Reuter West has roller-type bowl mills and CHP plant Moabit hammer mills. The mills in Reuter and Moabit are suitable for grinding

Table 4
Fuel side costs in the CHP plants Reuter, Reuter West and Moabit with calculated values for Ca/S and NH$_3$/N.

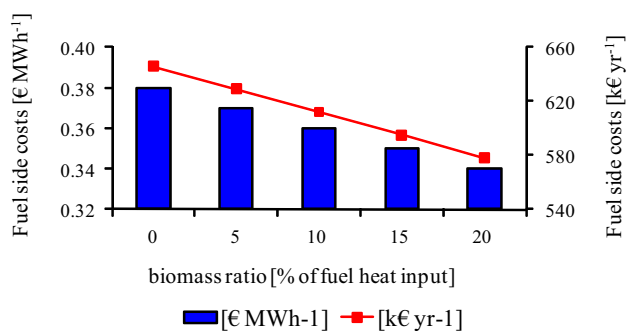| Value	Unit	Reuter	Reuter West	Moabit
Ca/S	t t^{-1}	1.23 ± 0.28 ($n = 11$)	1.21 ± 0.07 ($n = 11$)	2.57 ± 0.62 ($n = 12$)
NH$_3$/N	t t^{-1}	0.24 ± 0.08 ($n = 12$)	0.07 ± 0.02 ($n = 12$)	–
Fuel side costs 0% biomass[a]	€MWh^{-1}	0.38	0.21	0.47
Fuel side costs 10% biomass[a]	€MWh^{-1}	0.36	–	0.45

[a] Of fuel heat input.

Fig. 2. Influence of co-combustion on fuel side costs in CHP plant Reuter. The fuel side costs are expressed as €MWh^{-1} and k€yr^{-1}.
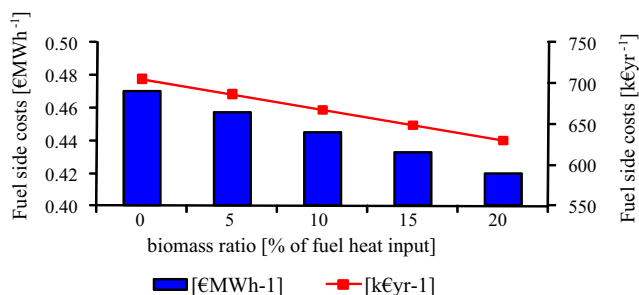

Fig. 3. Influence of co-combustion on fuel side costs in CHP plant Moabit. The fuel side costs are expressed as €MWh^{-1} and k€yr^{-1}.

of a biomass-coal mixture and thus for direct co-combustion, the roller-type bowl mills in Reuter West are not. At a biomass share of <10% of fuel heat input, common coal milling and feeding systems are considered as appropriate [3–5]. The low volumetric energy density of biomass is the restricting factor for the co-firing ratio. In Reuter West, a separate milling and feeding system for biomass and additional investment costs would be necessary for co-combustion.

The majority of by-products are used in the construction industry, e.g. fly ash is used as concrete additive according to standard EN 450-1 [14]. To keep the fuel side costs low, it is crucial that the ash composition and properties remain unaffected by the co-combustion. According to van Loo and Koppejan [3], co-combustion of woody biomass has no harmful effect on the fly ash properties as concrete additive.

The analysis of the ashes and limestone during co-combustion showed no irregularities beside the increase of the LOI of FBC ash in Moabit. The higher LOI could be caused by an incomplete burnout because of the different particle size of the wood chips. This could be avoided by a reduction of the particle size. No change of emissions was detected during the co-combustion tests in both power plants. In our view, the possible emission reduction caused by the lower content of N and S in the biomass was overlaid by the normal variations.

Co-combustion of woody biomass can reduce fuel side costs at the CHP plants Reuter and Moabit (Figs. 2 and 3). For example, at a co-firing ratio of 10% of fuel heat input, the possible cost savings are ~34 k€yr^{-1} in CHP Reuter and ~37.5 k€yr^{-1} in CHP Moabit.

The increase of the flue gas temperature in the stack with increasing amounts of coal fired showed problems with the adaptation of the heat exchanger behind the DeNO$_x$ unit to the heat flow in CHP plant Reuter. The result was an overall efficiency loss. Furthermore, the Ca/S ratio at CHP plants Reuter and Moabit had a large standard deviation. A better adaptation of the limestone supply gives the opportunity for limestone savings and thus lower fuel side costs. The large margin between the real Ca/S ratio and the stated Ca/S ratio in CHP plant Moabit was noticeable. The adapta-

tion of this value can reduce the fuel side costs about 135 k€yr^{-1}. The NH$_3$/N ratio at CHP plants Reuter and Reuter West had a large standard deviation, too. A better adjustment of the DeNO$_x$ unit can lead to lower fuel side costs. An inspection of the respective plant units and, if possible, an adjustment can improve the whole process and can reduce the fuel side costs.

Co-combustion can be economically worthwhile. This is the case if the power producer has to pay for NO$_x$, SO$_x$ and CO$_2$ emissions (e.g. as in Denmark) or receives subsidies for the generation of renewable energies through biomass co-combustion. Baxter [2] mentions co-combustion installation costs (for modifications in an existing plant) of ~50–300 $ kW^{-1} biomass capacity, another source [19] describes additional investment costs for co-combustion of ~300 €kW$_{el}$$^{-1}$ in a PC boiler (dry furnace and slag tap furnace) compared to ~2500–3000 €kW$_{el}$$^{-1}$ to build a biomass mono-combustion plant.

It should be considered to also co-fire other types of biofuels such as leaves or straw, which are more likely to have a negative impact on the power plant operation, such as corrosion, deposits or catalyst deactivation. If the co-firing ratio is <5%, the risks for problems such as corrosion and deposits should be low. Especially in autumn, large amounts of leaves accumulate in the Berlin area. Co-combustion offers a high flexibility of the co-firing ratio. This is very appropriate for the co-combustion of seasonal biofuels. The co-combustion of leaves is not accomplished on a large scale yet and offers a field for future research (i.e. preparation, handling, deposits, deactivation of DeNOx catalysts, influence on by-products). To reduce the negative effects of co-combustion of herbaceous biomass (i.e. deposits), it might be necessary to develop appropriate additives, which neutralise the critical components in the biomass. The higher the share of biomass in the fuel, the more important are remedial measures.

The developed spreadsheet tool is applicable for coal mono-combustion and co-combustion of woody biomass and co-firing ratios ≤10% of fuel heat input. Precondition for this is that the by-product utilisation remains unaffected by the co-combustion. Van Loo and Koppejan [3] report that co-combustion of woody biomass has no harmful effect on the fly ash properties as concrete additive. The fuel side costs would strongly increase if this utilisation became impossible due to co-combustion.

5. Conclusions

Co-combustion of woody biomass has a positive impact on fuel side costs. The lower contents of ash, sulphur and nitrogen reduce the amounts of generated by-products and the amounts of limestone and ammonia necessary for flue gas cleaning. The main factors of fuel side costs are the costs for limestone, ammonia and the ashes. Therefore, they have the highest potential for possible cost savings. The substitution of 10% of fuel heat input by woody biomass can reduce the fuel side costs by ~34 k€yr^{-1} at CHP plants Reuter and by 37.5 k€yr^{-1} at CHP plant Moabit (exemplary values). The fuel side costs during coal mono-combustion are ~0.38 €MWh^{-1} at CHP plant Reuter, ~0.21 €MWh^{-1} at CHP plant Reuter West and ~0.47 €MWh^{-1} at CHP plant Moabit (calculated with exemplary values).

The CHP plants Reuter and Moabit are most suitable for biomass co-combustion. Both have mill types that allow grinding of biomass-coal mixtures at small co-firing ratios. They allow direct co-combustion of up to 10% of the fuel heat input with the existing mill and feeding system. Furthermore, they generate no certified EN450 fly ashes which must fulfil strict criteria. This allows variations in ash composition. The co-combustion tests in Reuter and Moabit showed no significant alternations of the composition and properties of ashes and gypsum. The small alternations that

occurred are avoidable through an optimisation of the milling or combustion process.

The risks for deposits, corrosion, deactivation of the SCR catalysts and increased emission values due to co-combustion of un-treated woody biomass are low.

The analyses of this work detected several possibilities for improvements at the three power plants. To reduce the fuel side costs and efficiency losses, it is recommended, if possible, to adjust the heat exchanger behind the DeNO$_x$ unit of CHP plant Reuter, the Ca/S ratio in the FGD units of CHP plants Reuter and Moabit, and the NH$_3$/N ratio in the DeNO$_x$ units of CHP plants Reuter and Reuter West. In CHP plant Moabit, this can reduce the fuel side costs up to 135 k€yr^{-1} (0.09 €MWh^{-1}).

The developed Excel spreadsheet tool is applicable for coal mono-combustion and biomass co-combustion of woody biomass with co-firing ratios ≤10% of fuel heat input.

It might be useful to co-combust herbaceous biomass such as leaves, too. They are available in large quantities during autumn. Their co-combustion is not accomplished on an industrial scale yet.

Acknowledgements

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