

LOW GRADE FUEL - OIL SHALE AND BIOMASS CO-COMBUSTION IN CFB BOILER

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Abstract. Estonia has two of the world's largest oil shale firing circulating fluidized bed (CFB) units with a designed electrical capacity of 215 MW each. The units are based on double boiler CFB technology provided by Foster Wheeler Energia OY. The units are located at Eesti and Balti power plants (EPP and BPP). The paper presents analyses of data obtained from tests of oil shale and biomass co-combustion in the full-scale CFB boiler located at BPP. The tests were conducted at nominal boiler load: 100% (314 t/h), with a biomass thermal input of 15%. During the experiments ash samples from the furnace chamber (bottom ash), INTREX, super-/reheater (SH, RH), economizer (ECO), and air preheater (APH), and from all four fields of the electrostatic precipitator (ESP) were taken. Samples of fly ash for determining the mass division (total suspended particulates PM10 and PM2.5) were taken after the ESP. The gas analysis was performed at the ESP inlet. Analysis of the chemical composition of ash was carried out. The specific consumption of oil shale per useful heat and gross electricity were found and other techno-economic characteristics determined.

It was found that oil shale and biomass co-combustion reduced CO₂ emission by 14.6% and ash formation by 16% when compared with conventional oil shale CFB combustion. The SO₂ emissions remained in the limits of 20–30 mg/Nm³. Total suspended particulates PM10 and PM2.5 did not change compared to conventional oil shale CFB firing. The CFB boiler efficiency even increased slightly, when it is known that in case of coal and biomass co-combustion it decreases. Therefore, oil shale and biomass co-combustion can be considered as a viable option and near-term solution for reducing the environmental impact of oil shale-based power production.

Keywords: oil shale, biomass, co-combustion, TSP PM 10/2.5, ash composition, CO₂ emission reduction.

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1. Introduction

Estonian oil shale (OS) is a very difficult-to-burn fuel due to its unique properties. The high alkali and chlorine content of OS ash has caused significant corrosion and fouling problems in pulverized firing (PF) units, resulting in decreased availability. Gaseous emissions, especially SO₂ and particulate emission, have been high. Since in Estonia almost 90% of electricity is produced from OS [1, 2], the co-combustion of biomass and OS can be the quickest, easiest and cheapest way to reduce the environmental impact of OS-based power production [3, 4].

Estonia is implementing two different combustion technologies for OS-based power production: PF and circulating fluidized bed (CFB) technologies. A recent study describing PF and vortex combustion technologies are presented in [5, 6]. Some of the results of tests on CFB technology and CFB boiler reliability are presented in [7–12].

In the OS CFB boilers, fouling and corrosion problems in the convective superheaters have been prevented by a careful choice of the steam temperature for each superheating stage and by using effective heat surface cleaning methods. INTREX superheaters are used as the last super/reheating stage, and refractory lined separators as the second superheating stage, allowing lower steam temperature to be used in convective super/reheater (SH, RH) sections where the risk of high-temperature corrosion is the highest. The existing CFB boilers use pneumatic fuel feeding with many feeding points, resulting in good fuel mixing and providing favorable conditions for sulfur binding in the lower furnace. SO₂ emission is considerably reduced due to the inherent limestone content of oil shale ash, which favors sulfur capture in CFB conditions. SO₂ and NO_x emissions are reduced by 99% and 30%, respectively, while particulate emission decreased significantly compared to the old PF units with lower efficiency electrostatic precipitators (ESP). The improved efficiency and decreased carbonate decomposition in CFB has decreased the CO₂ emission per produced power unit by nearly 24% [8].

The careful CFB boiler design has resolved problems related to oil shale combustion, and no signs of significant fouling or corrosion of heat exchangers have occurred in the CFB boilers at Narva Power Plants. Still, air pre-heater corrosion has been noticed in CFB units, but it has been caused by too low temperatures at the air preheater (APH) inlet, which has been an operational fault [9].

Improved availability, lower maintenance costs and higher efficiency of CFB units have significantly improved the unit's economics. According to the performance tests, the net efficiency of CFB units is 38–39%, whereas in the PF units it is in the range of 29–30%.

Higher efficiency was obtained by implementing higher live and reheat steam temperature, reducing flue gas heat losses by applying better control of excess air and reducing the flue gas temperature at the outlet.

Another significant part of efficiency improvement comes from the lower carbonate decomposition and higher sulfation rate during CFB combustion, the effect of which is about 0.4 MJ/kg or 5% compared with those in PF reported by Hotta et al. [8].

Recent studies point out that utilization of biomass fuels in CFB boilers may cause operational problems, such as agglomeration, deposit formation, and corrosion [13–17]. However, such problems can be limited with proper boiler design, suitable boiler operation, alternative bed materials or additives, and most effectively by co-combustion with coal or peat that can capture problematic elements from biomass/wastes. Since OS powered CFB units have been carefully designed to avoid such operational problems, OS and biomass co-combustion in CFB seems the most promising option to reduce the environmental impact of OS-based power production.

The current paper deals with the study of OS and biomass co-combustion in a CFB boiler with 15% of biomass thermal contribution. Previous studies on coal and biomass co-combustion point out that 20% is the optimum amount, which can be burnt in a CFB boiler without following drawbacks. If the biomass contribution is higher, the boiler thermal efficiency decreases, NO_x and other flue gas components exceed the allowed environmental legislation limits and there have been noticed problems with heating surface fouling [18]. The aim of this paper is to investigate the effect of OS and biomass co-combustion on CFB boiler thermal efficiency, emissions, distribution of particulate matter, ash chemical composition and CO_2 reduction.

2. Experimental set-up

The major goal of tests was to carry out analyses of ash and flue gas, as well as to determine the boiler efficiency. The tests were performed with the following fuel shares (as of thermal input): 85% of OS and 15% of wood chips. OS was of class P3 (particle size 0–40 mm) from the screening before enrichment from Aidu open-pit mine. Wood chips from stem wood and branches were used as the biomass fuel. The main characteristics of the fuels used are presented in Table 1.

The main characteristics of the boiler during the tests are given in Table 2. The variations of steam pressure and mass flow during all tests are shown as well. It can be seen that the variations are smaller than the marginal values given in the standard EN 12952-15 (2003) [19].

Table 1. Fuel characteristics

	Wood chips	Oil shale
W_i^r , moisture, as received fuel, %	43.5	12.6
Q_b^d , heating value, dry fuel in calorimetric bomb, MJ/kg	20.2	11.3
Q_i^r , heating value, as received fuel, MJ/kg	9.6	8.9
A^r , ash content, as received fuel, %	1.6	49.1
$(\text{CO}_2)_m^r$, carbonate CO_2 content, as received fuel, %	–	18.2

Table 2. Boiler characteristics at nominal load

Boiler load, MW _{th}	245.7
Electrical load of unit, MW _e	197.9
Steam temperature (live/superheated), °C	534.2/535.7
Steam pressure (live/superheated), MPa	12.82/2.16
Pressure variation of live steam, %	0.8
Steam mass flow (live/superheated), kg/s	86.95/76.2
Mass flow variation of live steam, %	2.6
Flue gas temperature (after ESP), °C	178

During the tests the analyses of fuel, ash and flue gas were carried out. The location of ports (1–9) for collecting samples is shown in Fig. 1. Fuel samples were taken on daily average basis. The ash samples were taken from several ports located in the furnace chamber, INTREX, super-/reheater (SH, RH), economizer (ECO), and air preheater (APH), and from all four fields of the electrostatic precipitator (ESP). Samples of fly ash for determining the mass division (total suspended particulates PM10 and PM2.5) were taken after the ESP. The samples were used for determining a detailed chemical composition of ashes. In the frame of the tests the boiler efficiency was calculated as well.

The results of sample analyses were averaged to reach a representative estimate. Also, during the tests the major process parameters of the boiler and unit as a whole were recorded using the plant's standard data acquisition system. The temperature and composition of flue gas were measured before the ESP.

The total of 9 ash samples were taken from several ports located in the furnace, INTREX, super heater, ECO, and APH, and from all four fields (ESP1, ESP2, ESP3 and ESP4) of the ESP. The ash was taken from the dry flow to ensure the representativeness of samples.

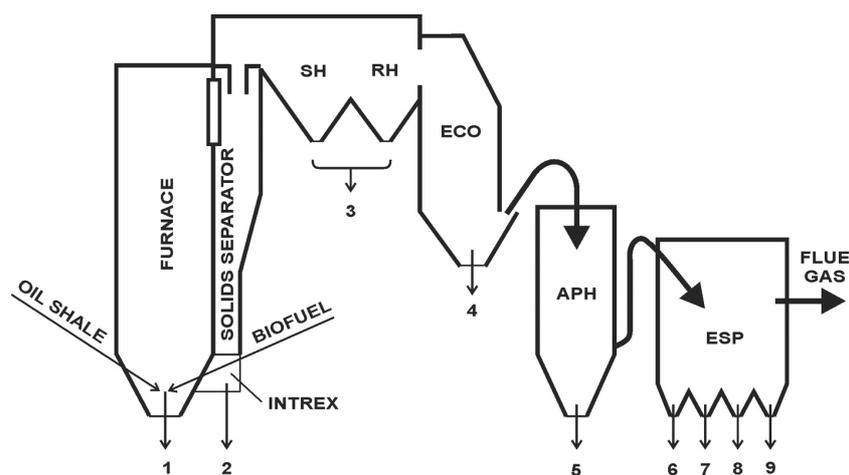


Fig. 1. CFB boiler sampling points.

The analysis of flue gas was carried out from the sampling ports before the ESP. The composition of flue gas was determined applying an FTIR type analyzer for wet gas, at a temperature of 180 °C. The flue gas moisture content was also determined by a FTIR spectrometer.

Fly ash samples were taken after the ESP to determine the division of finest particles (PM10 and PM2.5) in flue gas.

3. Results and discussion

3.1. Fuel – oil shale

The oil shale samples were analyzed in the laboratories of the Department of Thermal Engineering (DTE) of Tallinn University of Technology and BPP. The local laboratory of BPP determined the daily average heating value and moisture content (W_i^f) of the OS used. The DTE laboratory performed the ultimate and proximate analyses of wood chips and OS. Table 1 presents the heating values determined in a calorimetric bomb (Q_b^d) and as received fuel (Q_i^f) calculated by general moisture content.

3.2. The chemical composition of ash samples

The samples were taken at nominal (100%) boiler load (steam flow rate about 314 t/h). The composition of ash (at 815 °C) is presented in Table 3. The nitrogen content in ash samples was below detection limit.

Table 3. Chemical composition of ash, %

	Furnace	INTREX	SH	ECO	APH	ESP 1	ESP 2	ESP 3	ESP 4
CO ₂	21.03	5.54	5.09	4.69	4.33	4.49	4.22	3.76	7.13
C (CO ₂)	5.74	1.51	1.39	1.28	1.18	1.22	1.15	1.03	1.94
C _{elem}	5.93	1.50	1.39	1.33	1.19	1.26	1.17	1.10	1.92
S _{elem}	3.99	7.38	3.84	3.09	4.14	2.23	2.36	2.33	2.59
SO ₃ total	9.98	18.65	9.60	7.73	10.35	5.6	5.98	5.83	6.48
S _{sulphate}	3.37	7.04	3.51	2.90	3.84	2.20	2.29	2.30	2.60
SO ₃ sulphate	8.43	17.60	8.78	7.24	9.61	5.50	5.73	5.75	6.50
S _{sulphide}	0.62	0.34	0.33	0.19	0.30	0.03	0.07	0.03	0.01
SiO ₂	7.21	10.27	28.82	32.09	27.62	34.56	35.37	36.18	30.43
Fe ₂ O ₃	2.76	3.21	4.43	4.78	4.82	4.97	4.93	5.30	5.30
Al ₂ O ₃	3.12	3.87	9.26	8.48	7.17	9.69	10.72	11.60	11.38
CaO	53.20	58.16	42.67	36.23	40.10	31.68	31.85	30.21	30.35
CaO _{free}	15.65	26.93	16.06	14.84	17.44	13.79	12.52	10.30	3.60
MgO	1.21	1.79	0.81	4.34	3.42	3.64	3.57	4.00	3.24
K ₂ O	0.52	0.95	2.58	3.19	2.45	3.67	3.76	4.06	3.45
Na ₂ O	0.17	0.13	0.23	0.47	0.25	0.28	0.3	0.29	0.27
Cl	0.16	0.24	0.35	0.47	0.36	0.45	0.44	0.71	1.44
Loss on ignition _{815 °C}	21.2	6.10	5.20	5.10	4.30	4.60	4.40	4.40	10.0

The extent of carbonate minerals decomposition in various ash samples is presented in Table 4 and the results are compared with those of a previous CFB study [2].

Table 4. The extent of carbonate minerals decomposition (k_{CO_2})

Sampling point Fuel	Furnace	INTREX	SH-RH	ECO	APH	ESP 1	ESP 2	ESP 3	ESP 4
BIO + OS	0.51	0.88	0.85	0.86	0.88	0.84	0.85	0.86	0.74
OS 8.5	0.47	0.97	0.79	0.80	0.85	0.82	0.83	0.84	0.81
OS 11.1	0.68	0.97	0.82	0.83	0.88	0.82	0.83	0.85	0.70

The tests indicated that the extent of carbonates decomposition (k_{CO_2}) at the nominal load is in the range of 0.51–0.88. The weighted average is between 0.72–0.75 when using ash balance data obtained by Plamus et al. [2]. When firing OS with biomass or firing OS with higher heating value, the extent of carbonates decomposition increases.

For characterizing ashes the bulk densities were determined. Table 5 presents the bulk densities determined for ashes from the furnace, INTREX, superheater, economizer, air preheater and ESP 1–4. For comparison, previous results of CFB firing tests, where OS with a heating value of 8.5 and 11.1 MJ/kg was used, are also given [2].

Table 5. Bulk density of ash flows, g/cm^3

Sampling point Fuel	Furnace	INTREX	SH-RH	ECO	APH	ESP 1	ESP 2	ESP 3	ESP 4
BIO + OS	1.503	1.286	0.908	0.791	0.919	0.698	0.681	0.543	0.412
OS 8.5	1.483	1.28	0.787	0.668	0.841	0.652	0.666	0.564	0.431
OS 11.1	1.647	1.3	0.758	0.71	0.841	0.598	0.565	0.515	0.447

3.3. Boiler heat balance

The heat balance and thermal efficiency estimations of the considered full-scale experimental study of the CFB boiler were performed on the basis of the standard [19] by the indirect method taking into account the specific nature of oil shale as a fuel. The amount of heat released, ash content and flue gas amount during combustion of 1 kg of oil shale depends strongly on the endothermic and exothermic processes taking place in the mineral part of the fuel [5]. These processes include the decomposition of calcite and dolomite, oxidation of FeS_2 , sulfating of CaO and formation of new minerals. A more detailed description of the calculation of heat amount and

ash content can be found in [20]. Combustion flue gas mass and volume were calculated. Flue gas content (dry gas), kg/kg, was found as follows:

$$\mu_{\text{God}} = 12.5122\gamma_{\text{C}} + 26.3604\gamma_{\text{H}} - 3.3212\gamma_{\text{O}} + 1.0\gamma_{\text{N}} \\ + [(1 - \eta_{\text{S}})1.9953 + 3.2947]\gamma_{\text{S}} + k_{\text{CO}_2}\gamma_{\text{CO}_2},$$

where η_{S} is desulfurization efficiency (p. 8.3.5 in [19]); k_{CO_2} is the extent of carbonate mineral decomposition [21]; γ_{C} , γ_{H} , γ_{O} , γ_{N} , γ_{S} , γ_{CO_2} are carbon, hydrogen, oxygen, nitrogen, sulfur and carbonate carbon dioxide contents in fuel, respectively, kg/kg.

Flue gas volume (dry gas), m³/kg, was calculated as follows:

$$V_{\text{God}} = 8.8930\gamma_{\text{C}} + 20.9724\gamma_{\text{H}} - 2.6424\gamma_{\text{O}} + 0.7997\gamma_{\text{N}} \\ + [(1 - \eta_{\text{S}})0.68172 + 2.6325]\gamma_{\text{S}} + 0.509\gamma_{\text{CO}_2}k_{\text{CO}_2}.$$

Carbon dioxide content (dry gas), kg/kg, was found as follows:

$$\mu_{\text{CO}_2} = 3.6699\gamma_{\text{C}} + 0.0173\gamma_{\text{H}} - 0.0022\gamma_{\text{O}} \\ + [(1 - \eta_{\text{S}})0.001 + 0.0017]\gamma_{\text{S}} + k_{\text{CO}_2}\gamma_{\text{CO}_2}.$$

All calculations for heat balance were made for normal conditions: $t_{\text{r}} = 0$ °C, $p_{\text{r}} = 101\,325$ Pa. The boiler efficiency at nominal load according to the EN standard was 88.8% (Table 6).

Table 6. Boiler efficiency

Item	Value	
	kW	%
Heat input		
Heat from fuel combustion	266 654	96.0
Physical heat of fuel	1118	0.4
Input heat of combustion air	10 133	3.6
Total	277 905	100.0
Useful heat capacity	245 689	
Loss with flue gas	25 620	9.3
Loss due to unburned fuel (CO)	5	0.0
Bottom ash loss	3605	1.3
Fly ash loss	913	0.3
Loss due to radiation	854	0.3
Total	30 997	11.2
Heat efficiency		88.8

3.4. Flue gas

The composition of flue gas was determined before the ESP. The values of average concentration of major emission gases are given in Table 7, presenting for comparison also OS and biomass firing test results obtained by

Plamus et al. [1]. We can conclude that co-combustion reduces CFB boiler emissions.

Table 7. Concentration of main pollutants in flue gas before ESP (6% O₂)

Fuel used	CO ₂ , %	CO, mg/Nm ³	NOx, mg/Nm ³	SO ₂ , mg/Nm ³
OS+BIO	13.8	20–30	140–200	0
OS 8.5	14.4	20–45	200	15.0
OS 11.1	11.2	20–45	200	15.0

The content of finest particles of fly ash together with its mass division (PM10/2.5) after the ESP is an important indicator of flue gas composition. The fly ash cannot be caught by the final section of the ESP and as a result, it is emitted into the ambient air.

The mass division of fly ash after the ESP was determined in three parallel tests (Fig. 2). The content of finest ash particles remained in the same limits when firing OS with biomass compared to pure OS firing [12].

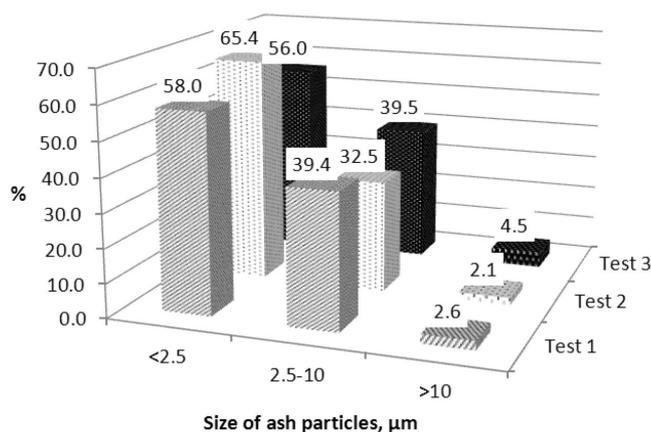


Fig. 2. Fly ash mass distribution after ESP.

3.5. Specific consumption and emission of the energy unit

Specific mass flow indicators of fuel and ash, CO₂, CO and SO₂ emissions both per useful heat (MWh_{th}) and gross electricity production (MWh_e^{br}) are given in Table 8. The specific indicators of fuel and ash per production unit obtained experimentally for the first boiler of the energy unit were assumed to be applicable to the second boiler as well. In Table 9 there are two values of CO₂ emission – based on sample measurements, and calculated on the basis of fuel composition.

The heat rate of the unit was 2.36 MWh_{th}/MWh_e^{br}, corresponding to the gross energy efficiency of 42.37%.

Table 8. Specific indicators of fuel consumption and ash emissions

Indicator	Unit	Value
Oil shale consumption per useful heat	g/kWh _{th}	375
Biomass consumption per useful heat	g/kWh _{th}	56
Ash formation per useful heat	g/kWh _{th}	182
Oil shale per electricity (gross)	g/kWh _e ^{br}	882
Biomass per electricity (gross)	g/kWh _e ^{br}	132
Ash formation per electricity (gross)	g/kWh _e ^{br}	428

Table 9. Specific emission indicators

Pollutant	Per useful heat, kg/MWh _{th}	Per electricity (gross), kg/MWh _e ^{br}
CO ₂ ¹	334	788
CO ₂ ²	393	927
CO	0.045	0.111
SO ₂	0	0

¹ – calculation based on measured percentage of CO₂ with calculated volume of dry gas;

² – calculation based on fuel composition.

4. Conclusions

The data from experimental tests conducted on CFB boiler indicate that the thermal gross efficiency of the boiler is 88.8%. Regarding emission into air, the average concentration of CO, NO_x and SO₂ at stable load varied insignificantly. The test with biomass thermal share of 15% showed that the specific emission of SO₂, CO and NO_x remained the same or slightly decreased compared with the values reported by Plamus et al. in [2] where only OS was fired with LHV of 8.5 MJ/kg. The ash content was decreased by 16% and CO₂ emissions were 14.6% lower. The content of fine particles (< 2.5 μm) of ash after the ESP remained in the same limits compared to the results obtained by Parve et al. [12].

The specific consumption of oil shale per useful heat and gross electricity was 0.375 t/MWh_{th} and 0.882 t/MWh_e^{br}, respectively. The specific consumption of biomass per useful heat and gross electricity was 0.056 t/MWh_{th} and 0.132 t/MWh_e^{br}, respectively. The same indicators for total ash formation were 0.182 t/MWh_{th} and 0.428 t/MWh_e^{br}, respectively.

The heat rate of the unit was 2.36 MWh_{th}/MWh_e^{br}, corresponding to the gross energy efficiency of 42.37%.

The test results encouraged OS and biomass co-combustion in a CFB boiler. Therefore additional biomass feeding system has been installed which allows increasing biomass share up to 50% of thermal input. Preliminary test results indicate that there is no effect on fouling, however, boiler efficiency may decrease, but it mainly depends on fuel moisture content (based on unpublished data by T. Pihu et al.).

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