BIOMASS CCS STUDY

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TECHNO-ECONOMIC EVALUATION OF BIOMASS FIRED OR CO-FIRED POWER PLANT WITH POST-COMBUSTION CO_2 CAPTURE

Background to the Study

The use of biomass in power generation is one of the important ways in reducing greenhouse gas emissions. Specifically, the co-firing of biomass with coal could be regarded as a common feature to any new build power plant if a sustainable supply of biomass fuel is readily accessible.

Currently, there is an on-going discussion on what could be the pros and cons of incorporating CO_2 capture and storage (CCS) to any type of biomass fired power plant. The discussion has primarily centred on how to consider the CO_2 emitted from biomass fired power plants, if it is counted as "CO_2 neutral" and if stored could be considered as a "negative" CO_2 emission.

This report is the first part of a sequence of studies planned under the biomass with CCS series which aims to address this discussion by investigating the potential application and feasibility of incorporating CO_2 capture technologies to a biomass fired power plant. Most importantly, this series of studies are aimed to address the discussion on biomass CCS viability and the relation to CO_2 price.

One of the main questions addressed in this study was "What should the CO_2 emission cost be to make CCS an attractive option to be incorporated into a biomass fired power plant assuming that the stored CO_2 from a biomass fired power plant could generate an additional revenue from a CO_2 credit"

This study has been carried out to estimate the performance and costs of "standalone" biomass fired power plants or coal co-fired with biomass power plants with CO_2 capture based on standard MEA post-combustion capture technologies. The study was carried out for IEA Greenhouse Gas R&D Programme (IEA GHG) by Foster Wheeler Italiana.

This overview summarises the results of the study and highlights those results that could aid the discussion about the biomass CCS option. More detailed technical information is included in the Executive Summary in the main report and the main report itself.

Study Basis

The study aimed to investigate options and evaluate the techno-economic performance of a biomass fired, or coal co-fired with biomass, power plant based on current state of the art boiler and steam generation equipment incorporating CO_2 capture technology. It is expected that the study should provide the performance of the plant assuming the need to capture at least 90% of the total CO_2 emissions.

Currently, the state of the art largest standalone biomass fired combustion power plant (i.e. between 100 to 250 MW_e net) offered commercially is based on circulating fluidized bed (CFB) technology. In the mid-range (i.e. between 30 to 90MW_e net), the commercially offered state of the art technology would be based on a bubbling bed fluidized bed (BFB) technology. For less than 50MW_e net, a stoker fired (fixed bed) system is still considered competitive compared to any fluidized bed technology. For direct co-firing of biomass and coal, the technical operating limit of co-firing biomass is about 10-20% of the total thermal input.

The current study evaluated the techno-economic performance of incorporating CO_2 capture and storage in a biomass fired power plant on the following four cases namely:

- Case 1: nominal 500 MW_e (net) co-firing of biomass and coal in PF power plant.
- Case 2: nominal 500 MW_e (net) co-firing of biomass and coal in CFB power plant.
- Case 3: nominal 250 MW_e (net) circulating fluidized bed standalone biomass power plant.
- Case 4: nominal 75 MW_e (net) bubbling fluidized bed standalone biomass power plant.

The capture technologies to be evaluated were limited to post-combustion capture using a standard MEA solvent. The main considerations were:

(a.) Economics (CAPEX and OPEX),
(b.) Overall mass and energy balance,
(c.) Impact of the CCS to the Overall Efficiency,
(d.) Environmental performance.

Power Plant Performance and Cost Assessments

Assessment Criteria

The performance and costs of power plants with CO_2 capture were estimated based as far as possible on IEA GHG's standard assessment criteria. The plants were assumed to operate at base load with a load factor of 90% (for reference power plant without CO_2 capture cases) and 88% (for power plant with CO_2 capture). The economic evaluation was based on a 10% annual discount rate and 25 years operating life.

The biomass fuel used for this study is based on virgin wood and assumed to be supplied sustainably. Nonetheless, a brief discussion of the possible impact of other types of biomass fuel on the performance of the power plant has been included in the report. For the co-firing option, the coal used for this study is based on Eastern Australian Coal which is used in the IEA GHG standard assessment criteria. The reference coal price was assumed to be €2.90/GJ, whilst for biomass fuel price was assumed to be €8.39/GJ (bone dry basis). Due to local variations of biomass price, the sensitivity of power cost to fuel price was assessed in the report.

The location of the power plant for this study was assumed to be built at the coastal site in The Netherlands.

The plant costs were estimated in Euros (May 2009). Conversion of Euros to US Dollars was assumed to be 1.35$ to 1.00€. The accuracy of the cost estimate is set at ±30%.

Further details of the assessment criteria are included in the main study report.

Economic Assessment and Consideration to the Impact of the Green Certificate and ETS Mechanism

The economic assessment incorporated the potential benefit of a Green Certificate and the benefit or penalty of the CO_2 ETS price (assuming that power plant operator will be required to buy the ETS certificates necessary for the plant).

To evaluate the potential impact of any incentives from the Green Certificate or the ETS Mechanism, four different scenarios for all cases were assumed, which are briefly described below.

[1] Scenario 01 – The calculation of the Levelised Cost of Electricity does not include any revenues from the Green Certificate nor from ETS mechanism.

[2] Scenario 02 – The calculation of the Levelised Cost of Electricity only allows the revenues from the Green Certificate. For the reference case, the Green Certificate is given a price of 50 € / MWh.

[3] Scenario 03 – The calculation of the Levelised Cost of Electricity only allows the revenues from the ETS mechanism. For the reference case, the Green Certificate is given a price of 14 € / t CO_2.

[4] Scenario 04 – The calculation of the Levelised Cost of Electricity considers the revenues from both the Green Certificate and ETS mechanism.

For the reference cases, the Green Certificate is assumed to be €50 per MWh, whilst for the CO_2 ETS price was assumed to be fixed at € 14 per tonnes of CO_2 emitted. It should be noted that for simplicity, the revenues from the Green Certificate and ETS mechanism were assumed to be constant over the whole 25 years economic life of the power plant. This should reflect the average revenues necessary during the economic life of the power plant to achieve the breakeven cost. The levelised cost of electricity were calculated based on these values setting the net present value of the power plant to zero (i.e. NPV = € 0).

Case Descriptions

Table 1 (overleaf) presents the key features of the power plants and the choice of technology for the flue gas clean up necessary to achieve the regulatory requirements related to emissions or requirements of the CO_2 capture plant.

It should be noted that for all cases evaluated, it was assumed that the same size boiler would be used for power plants both with or without CO_2 capture. As a consequence, the power plant with CO_2 capture units would produce less electricity at the gate as compared to power plants without CO_2 capture.

Overview of Results

Summary of the Performance and Cost of the Power Plant

The performances and cost of the biomass fired or co-fired power plants are summarised in Tables 2 and 3.

Summary of Results – Presenting the Cost Impact of the Green and ETS Certificates

Figures 1 and 2 present the levelized cost of electricity (based on NPV = 0) for Cases 1A to 2B and Cases 3A to 4B respectively without any consideration for the possible benefit of the Green Certificate or the possible benefit or penalty of the ETS CO_2 price.

Table 4 presents a summary of the CO_2 emissions of the power plant which indicates the CO_2 contribution from biomass and coal. The overall capture efficiency based on the total CO_2 emission is also provided. The amount of CO_2 avoided was also presented and this was calculated based on the CO_2 emissions from both coal fired and NGCC without CO_2 capture as reference plant.

Table 5 presents a summary of the CO_2 credit and potential revenues that could be obtained from the Green Certificate and ETS mechanism. It should be noted that it was assumed that no free ETS certificate allowance will be provided to the power plant operator; therefore any subsequent CO_2 emissions from coal would require the purchase of the ETS certificate. Table 6 summarises the results from the different scenarios for the reference cases.

Figures 3 and 4 illustrate the levelized cost of electricity for Case 1 and Case 3 indicating the price of ETS that would make CO_2 capture from a biomass fired or co-fired power plants on cost parity to the non-CO_2 capture cases and the impact of the Green Certificate to the levelised cost of electricity (assuming a combine incentives provided).

Summary of Results – Presenting the Sensitivity to the Fuel Cost

Figures 5 and 6 present the sensitivity of the levelised cost of electricity to the biomass fuel price, both with and without the consideration of the benefits gained from the Green or ETS certificates (Scenario 1 and 4 respectively). Whilst Figures 7 and 8 present the sensitivity of the levelised cost of electricity to the coal price for Cases 1A, 1B, 2A and 2B under the Scenario 1 and 4 respectively.

Table 1: Summary and Key Features of the Power Plants Evaluated in this Study

Case	Boiler Technology	Steam Parameter	Fuel	Key Technology Features	CO_2 Capture	DeSOx	DeNOx
1A	PC	supercritical	90% Coal / 10% Biomass	None	No	FGD	SCR
1B	PC	supercritical	90% Coal / 10% Biomass	None	Yes	FGD	SCR
2A	CFB	supercritical	90% Coal / 10% Biomass	Inclusion of special plastic HEX for flue gas heat recovery	No	Limestone Injection in Furnace	None
2B	CFB	supercritical	90% Coal / 10% Biomass	None	Yes	Limestone Injection in Furnace & FGD	None
3A	CFB	subcritical	100% Biomass	Inclusion of special plastic HEX for flue gas heat recovery	No	None	None
3B	CFB	subcritical	100% Biomass	None	Yes	Limestone Injection in Furnace	None
4A	BFB	subcritical	100% Biomass	None	No	None	None
4B	BFB	subcritical	100% Biomass	None	Yes	Limestone Injection in Furnace	None

Table 2: Summary of Performance and Cost of the Biomass Fired or Co-Fired Power Plants

	Biomass Thermal Input	Net Power Output	Net Efficiency (LHV)	Total Investment Cost	Capital Cost
	%	MW	%	MM €	€/kWe net
SC PC boiler co-fired with biomass					
Case 1A (without CO_2 capture)	10	518.9	44.8	657.2	1266.5
Case 1B (with CO_2 capture)	10	398.9	34.5	824.3	2066.5
SC CFB boiler co-fired with biomass					
Case 2A (without CO_2 capture)	10	521.4	45.1	707.3	1356.5
Case 2B (with CO_2 capture)	10	390.5	33.8	918.4	2351.8
Sub CFB boiler fired with biomass					
Case 3A (without CO_2 capture)	100	273.0	41.7	370.3	1356.4
Case 3B (with CO_2 capture)	100	168.9	25.8	519.7	3077.2
Sub BFB boiler fired with biomass					
Case 4A (without CO_2 capture)	100	75.8	36.0	185.4	2446.1
Case 4B (with CO_2 capture)	100	48.9	23.2	256.2	5240.1

Table 3: Summary of Power Plant Performance of the Biomass Fired or Co-Fired Power Plants

FOSTER WHEELER

CLIENT: IEA GHG
PROJECT: Biomass Fired Plant
LOCATION: The Netherlands

Plant Data		**500MW supercritical-PC**		**500MW supercritical CFB**		**250MW CFB**		**75MW BFB**	
Case		**1a**	**1b**	**2a**	**2b**	**3a**	**3b**	**4a**	**4b**
Coal flowrate	t/h	145	145	145	145				
Coal thermal input	MW_{th}	1,042	1,042	1,040	1,040				
Biomass flowrate	t/h	57	57	57	57	323	323	104	104
Biomass thermal input	MW_{th}	116	116	116	116	654	654	211	211
Total fuel flowrate	t/h	202	202	202	202	323	323	104	104
Total thermal Input, LHV	MW_{th}	1,158	1,158	1,156	1,156	654	654	211	211
Steam Turbine Gross Power Output	kW_e	**545,227**	**474,084**	**553,403**	**473,697**	**289,953**	**224,626**	**83,407**	**68,453**
Auxiliary Load									
Fuel receiving, handling & storage	kW_e	1,400	1,400	1,400	1,400	900	900	300	300
Limestone unloading, storage and handling	kW_e	26	27	75	40		5		2
Boiler auxiliary consumption	kW_e	7,526	7,526	19,500	20,960	10,500	10,967	3,535	3,676
Flue gas desulphurisation (FGD)	kW_e	1,767	2,071		1,593				
Gypsum loading, storage and handling	kW_e	157	168		78				
DeNOx system	kW_e								
Ash loading, storage and handling	kW_e	1,164	1,164	1,805	1,514	211	245	68	76
Steam Turbine auxiliaries and condenser	kW_e	1,141	1,013	1,176	1,012	620	480	177	145
Baghouse filter	kW_e	350	400						
Induced Draft fan	kW_e	4,834	4,979						
Condensate pumps and feed water system (1)	kW_e	865	441	818	445	476	177	1,694	1,607
Machinery cooling water system	kW_e	140	1,550	141	1,575	80	1,690	25	550
Sea water system	kW_e	3,630	5,025	3,724	5,051	2,130	3,790	700	1,260
Miscellaneous Balance-of-Plant	kW_e	2,188	2,111	2,213	2,110	1,373	1,289	857	838
Step-Up Transformer Losses	kW_e	1,100	950	1,100	950	700	550	260	170
CO_2 capture plant	kW_e		9,909		9,827		7,844		2,390
CO_2 compression and drying	kW_e		36,518		36,671		27,750		8,617
Total Auxiliaries	kW_e	**26,288**	**75,252**	**31,952**	**83,225**	**16,990**	**55,687**	**7,617**	**19,631**
Performance									
Net Plant Power	kW_e	**518,939**	**398,832**	**521,451**	**390,472**	**272,964**	**168,939**	**75,790**	**48,822**
Gross Plant Efficiency (LHV)	%	47.1	41.0	47.9	41.0	44.3	34.3	39.6	32.5
Net Plant Efficiency (LHV)	%	44.8	34.5	45.1	33.8	41.7	25.8	36.0	23.2
Energy Efficiency Penalty (LHV)	%	-	10.3	-	11.3	-	15.9	-	12.8

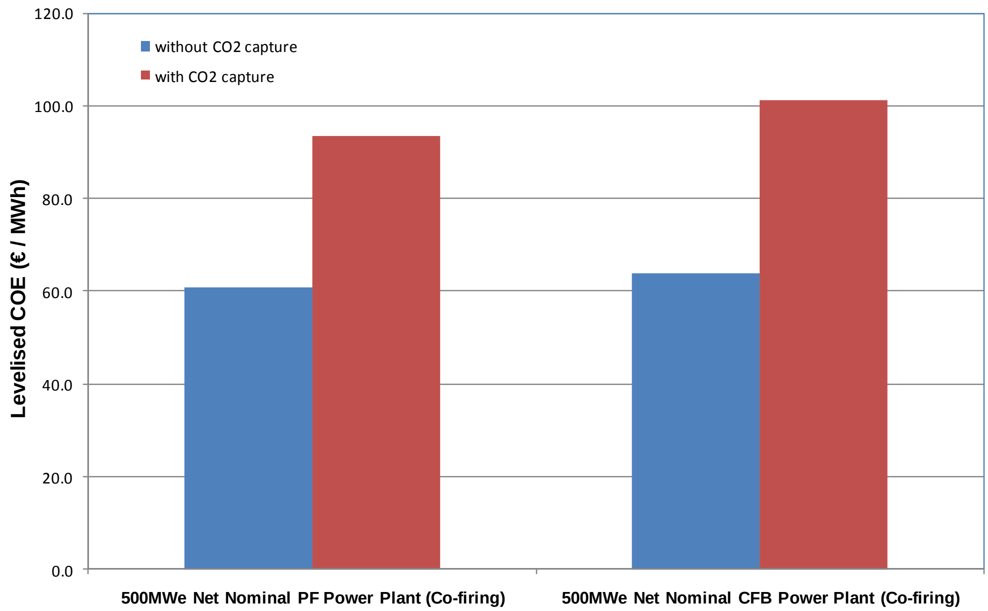

Figure 2: Levelised Cost of Electricity (COE) at 10% IRR for Coal Co-Fired with Biomass Power Plants (COE does not include any incentives or penalty from ETS CO_2 price or Green Certificate)

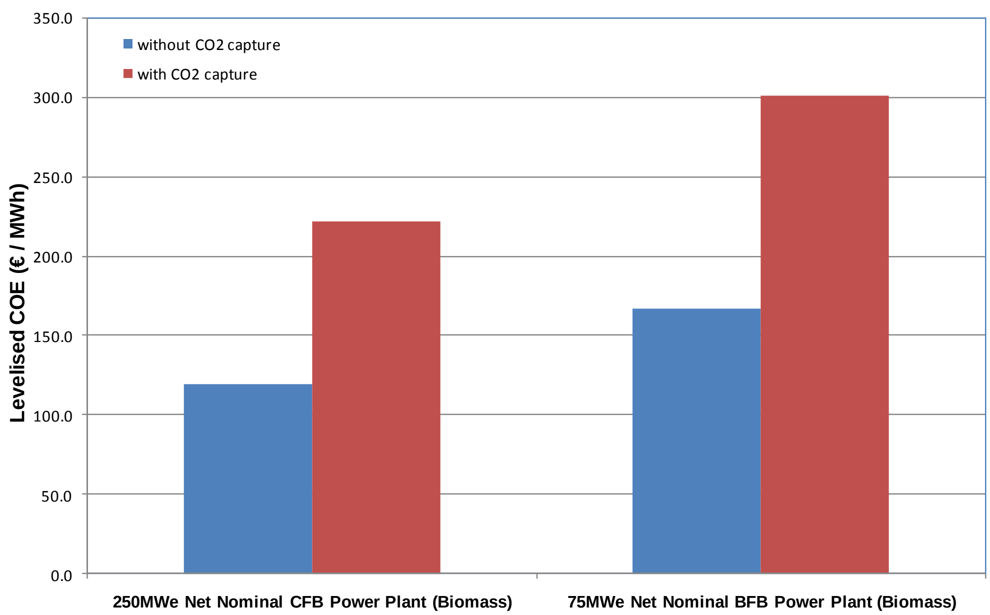

Figure 3: Levelised Cost of Electricity (COE) at 10% IRR for "Standalone" Biomass Fired Power Plants (COE does not include incentives or penalty from ETS CO_2 price or Green Certificate)

Table 4: Summary of CO_2 Emissions of the Biomass Fired or Co-Fired Power Plant

	Actual CO_2 Emissions	CO_2 from Coal	CO_2 from Biomass	Total CO_2 Captured	Equivalent CO_2 Emissions	CO_2 avoided wrt conventional coal	CO_2 avoided wrt NGCC
	g/kWh	g/kWh	g/kWh	g/kWh	g/kWh	g/kWh	g/kWh
SC PC Coal fired boiler (w/o CO2 capture)	722.8	722.8	-	-	722.8	-	-
NGCC (without CO2 capture)	359.0	359.0	-	-	359.0	-	-
SC PC boiler co-fired with biomass							
Case 1A (without CO_2 capture)	748.5	649.7	98.8	0.0	649.7	73.1	-290.7
Case 1B (with CO_2 capture)	973.7	845.2	128.5	876.4	-31.3	754.1	390.3
SC CFB boiler co-fired with biomass							
Case 2A (without CO_2 capture)	748.2	649.4	98.8	0.0	649.4	73.4	-290.4
Case 2B (with CO_2 capture)	999.0	867.1	131.9	899.1	-32.0	754.8	391.0
Sub CFB boiler fired with biomass							
Case 3A (without CO_2 capture)	1081.3	0.0	1081.3	0.0	0.0	722.8	359.0
Case 3B (with CO_2 capture)	1747.8	0.0	1747.8	1573.1	-1573.1	2295.9	1932.2
Sub BFB boiler fired with biomass							
Case 4A (without CO_2 capture)	1257.3	0.0	1257.3	0.0	0.0	722.8	359.0
Case 4B (with CO_2 capture)	1948.9	0.0	1948.9	1754.6	-1754.6	2477.4	2113.7

Table 5: Summary of the Annual Credit from ETS or Green Certificate for Biomass Fired or Co-Fired Power Plants

	Net Power	Operating Hours	Power from Biomass	Annual Green Certificate Credit[1]	Total CO_2 Emissions (Overall)	CO_2 Emission Credit	CO_2 Emission Penalty	Annual ETS Credit (Penalty)[2,3]
	MW	h	MW	MM €	t/h	t/h	t/h	MM €
SC PC boiler co-fired with biomass								
Case 1A (without CO_2 capture)	518.9	7884	51.9	**20.5**	388.4	0.0	337.1	**-37.2**
Case 1B (with CO_2 capture)	398.8	7710	39.9	**15.4**	38.8	12.5	0.0	**1.4**
SC CFB boiler co-fired with biomass								
Case 2A (without CO_2 capture)	521.5	7884	52.1	**20.6**	390.1	0.0	338.6	**-37.4**
Case 2B (with CO_2 capture)	390.5	7710	39.0	**15.1**	39.0	12.5	0.0	**1.4**
Sub CFB boiler fired with biomass								
Case 3A (without CO_2 capture)	273.0	7784	273.0	**107.6**	295.2	0.0	0.0	**0.0**
Case 3B (with CO_2 capture)	168.9	7710	168.9	**65.1**	29.5	265.7	0.0	**28.7**
Sub BFB boiler fired with biomass								
Case 4A (without CO_2 capture)	75.8	7784	75.8	**29.9**	95.3	0.0	0.0	**0.0**
Case 4B (with CO_2 capture)	48.8	7710	48.8	**18.9**	9.5	85.8	0.0	**9.3**

[1] Green Certificate = 50 € /MWh
[2] ETS Price = 14 € / t CO_2
[3] If value is (-) then this indicates that the power plant operator is required to buy the ETS certificate.

Table 6: Summary of Results – Levelised Cost of Electricity (based on IRR = 10%)

	Scenario 01	Scenario 02	Scenario 03	Scenario 04
Green Certificate (€/MWh)	**0.0**	**50.0**	**0.0**	**50.0**
ETS CO2 Certificate Price (€/t CO_2)	**0.0**	**0.0**	**14.0**	**14.0**
	Levelised Cost of Electricity (COE)			
	€ / MWh	€ / MWh	€ / MWh	€ / MWh
SC PC boiler co-fired with biomass				
Case 1A (without CO_2 capture)	60.95	55.95	70.05	65.05
Case 1B (with CO_2 capture)	93.50	88.50	93.07	88.07
SC CFB boiler co-fired with biomass				
Case 2A (without CO_2 capture)	63.85	58.85	72.95	67.95
Case 2B (with CO_2 capture)	101.24	96.24	100.79	95.79
Sub CFB boiler fired with biomass				
Case 3A (without CO_2 capture)	119.61	69.61	119.61	69.61
Case 3B (with CO_2 capture)	221.43	171.43	199.41	149.41
Sub BFB boiler fired with biomass				
Case 4A (without CO_2 capture)	167.03	117.03	167.03	117.03
Case 4B (with CO_2 capture)	300.95	250.95	276.39	226.39

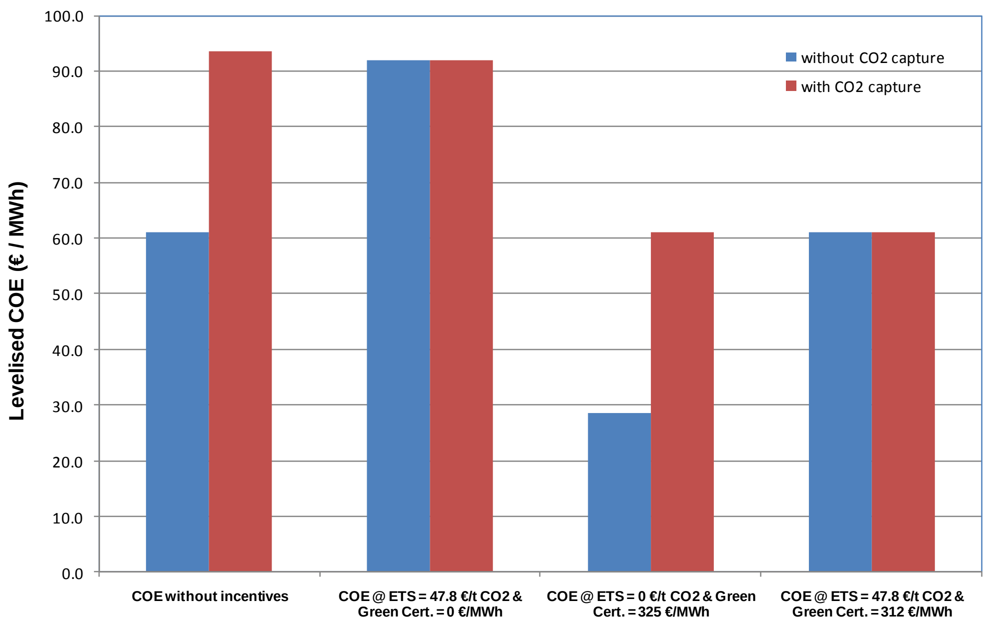

Figure 3: Levelised COE at 10% IRR for a nominal 500MWe Pulverised Coal Power Plants Co-Fired with Biomass (Figure illustrating the impact of ETS and Green Certificates)

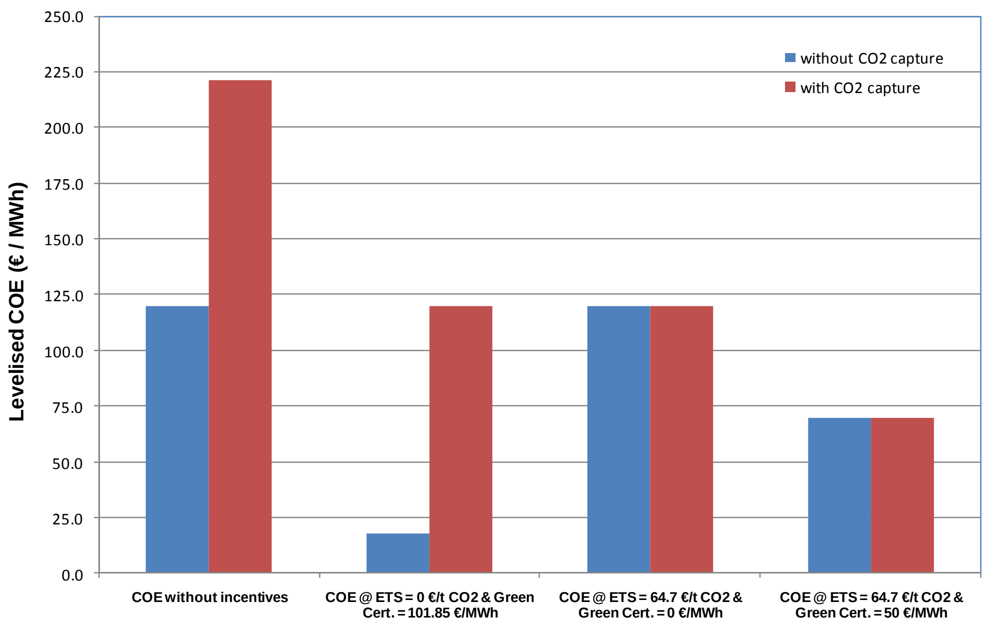

Figure 4: Levelised COE at 10% IRR for a nominal 250MWe Biomass Fired CFB Power Plant (Figure illustrating the impact of ETS and Green Certificates)

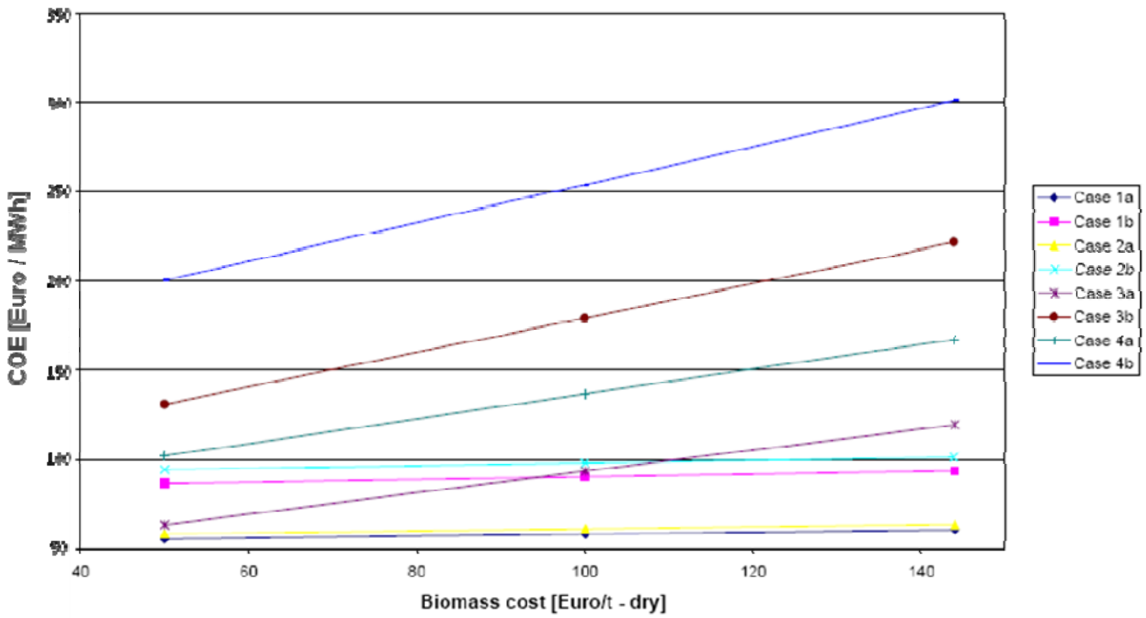

Figure 5: Levelised COE at 10% IRR for all cases illustrating the sensitivity to biomass fuel price for Scenario 1 – assuming no benefit from the Green or ETS certificates

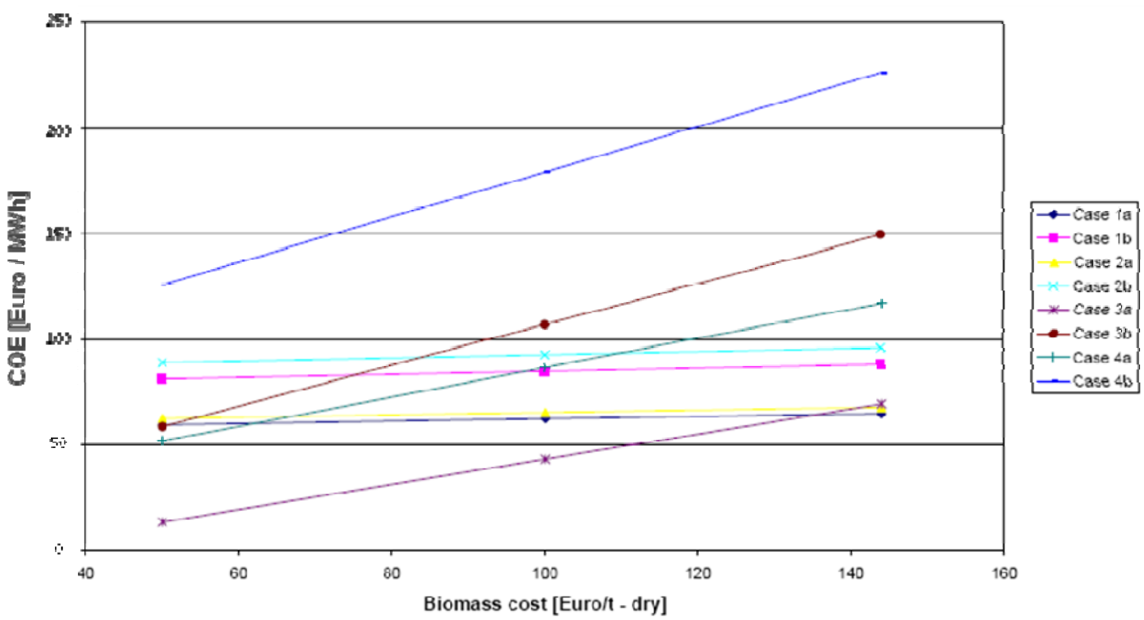

Figure 6: Levelised COE at 10% IRR for all cases illustrating the sensitivity to biomass fuel price for Scenario 4 – assuming to include the benefit to be gained from the Green or ETS certificates

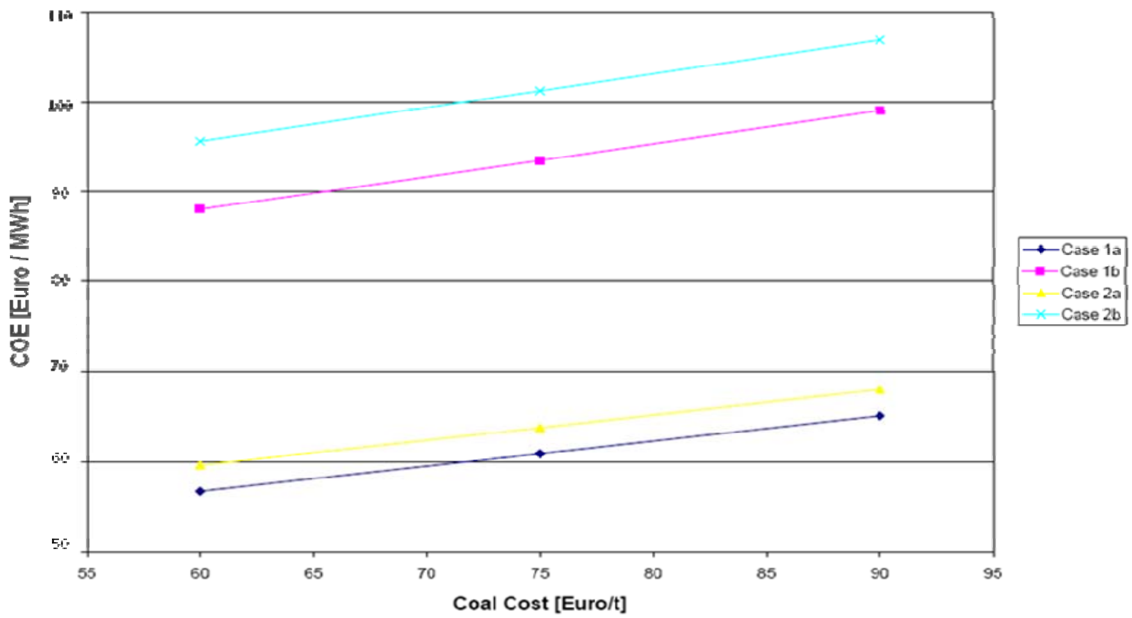

Figure 7: Levelised COE at 10% IRR for all cases illustrating the sensitivity to coal fuel price for Scenario 1 – assuming that no benefits to be gained from the Green or ETS certificates

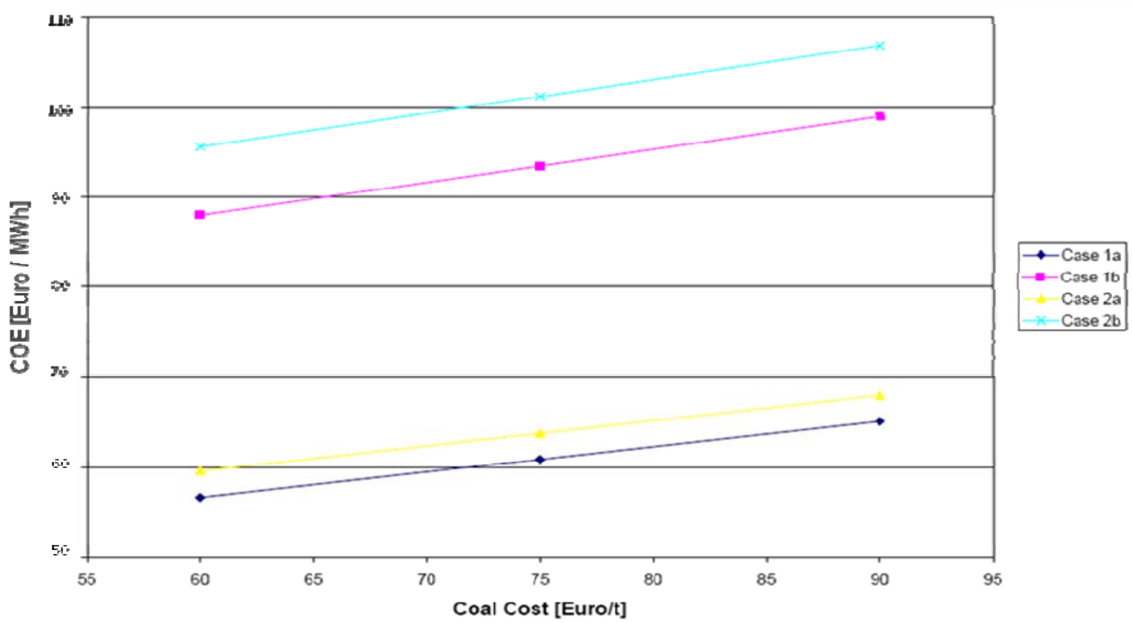

Figure 8: Levelised COE at 10% IRR for all cases illustrating the sensitivity to coal fuel price for Scenario 4 – assuming to include the benefits to be gained from the Green or ETS certificates

Discussion of Results

Power Plant Performance – Impact of the CO_2 Capture Plant

The net power outputs of the power plants are lower in all CO_2 capture cases (Cases 1B, 2B, 3B and 4B). This is due to the installation of the same size boiler as compared to their corresponding power plants without CO_2 capture, thus the lower power output reflects the energy penalty of the CO_2 capture unit.

The thermal efficiencies for the power plants without CO_2 capture were all within the range of 36 - 45% based on a lower heating value (LHV), which are consistent with the expected performance of state of art power plants for supercritical and subcritical units.

For power plants with CO_2 capture, the thermal efficiency ranges from as low as 23% for the smaller bubbling fluidized bed boiler to 34.5% for the supercritical PC boiler co-fired with biomass. This reflects the significant penalty incurred by the subcritical units (a penalty ranging between 12-16% based on LHV) vs the supercritical units (a penalty ranging between 10-12% based on LHV).

The following points summarised the key features that affects the performance of the power plant evaluated in this study:

- It should be noted that for Case 1A, a supercritical boiler for the pulverised coal fired power plant was used instead of the more advanced ultra-supercritical units. The primary concern was due to the slagging and fouling issues which are common with co-firing of biomass. Currently, there is no experience or a reference plant where co-firing of biomass in an ultra-supercritical PC boiler has been demonstrated; therefore this study concluded that the use of supercritical PC boiler co-fired with biomass would be more conservative in design to maintain the confidence in achieving the necessary availability.

- It could be illustrated in this study that for a coal fired power plant co-fired with biomass at nominal 500MWe net output, the CFB case – Case 2A (45.1%) – would have higher net efficiency than the PC case – Case 1A (44.8%). The better performance of Case 2A than Case 1A was due to the absence of the external FGD and the introduction of the special plastic heat exchanger that could maximise the heat recovery from the flue gas downstream the ID fan for Case 2A. It should be noted that this type of heat exchanger cannot be applied if an external FGD or CO_2 capture units are installed. Therefore this type of equipment, that helped improved the performance of the power plant, was only implemented for Case 2A and 3A. For the BFB case (Case 4A), the special heat exchanger was not installed due to its high cost and minimal benefits in relation to its possible performance gain.

- As presented in Tables 2 and 3, it could be noted that a significant loss in net efficiency for all cases when the CO_2 capture units were installed. This should be expected due to the steam and power requirements for CO_2 capture units and the compressors to deliver the CO_2. However, it should be further noted that a higher loss in net efficiency could be observed for cases using a "standalone" biomass fired power plants (i.e. Case 3B and 4B). The higher loss in net efficiency could only be due to the following factors:

    - Installation of additional flue gas clean up equipment (i.e. for Case 2B – addition of an external FGD; introduction of limestone injection into the furnace for Case 3B and 4B) to achieve the required quality of the flue gas before introduction to the CO_2 capture units increases the loss of net efficiency of the power plant.

    - The installation of the Direct Contact Cooler, which is necessary to reduce the particulate matter introduce to the CO_2 capture plant, does not allow the recovery of low grade heat that could be used by the power plant.

- It should be highlighted that due to lower LHV of the biomass with respect to coal has its impact to the exhaust flue gas. The fact that biomass fired power plants make more heat at low temperature therefore penalising any power plants with CO_2 capture units where low temperature heat recovery cannot be introduced.

- Furthermore, the volume of flue gas from a "standalone" biomass fired power plant to be handled by the CO_2 capture unit are proportionally larger than a similar sized coal fired boiler. Therefore, requiring larger process equipment which increased the auxiliary power requirements. Additionally, the amount of CO_2 from a "standalone" biomass power plant is more dilute than that of the CO_2 concentration of flue gas from a same sized coal fired boiler.

Cost Implication of the CO_2 Capture Plant

Power Plant Co-Fired with Biomass

As shown in Figure 2, the difference in the levelised cost of electricity (COE) between the PC and CFB case with CO_2 capture is higher than its corresponding cases without CO_2 capture. The COE for the PC with CO_2 capture is about 7% lower as compared to the CFB case with CO_2 capture. This result is a consequence of a lower investment cost of the PC boiler in addition to the small advantage in efficiency when CO_2 capture unit was installed.

In terms of the specific capital cost, as shown in Table 2, the installation of the CO_2 capture unit resulted to an increase of ~63% for the PC case comparing both with or without CO_2 capture (Case 1A and 1B); and a ~73% increase for the CFB case (Cases 2A and 2B). Most of the increase in the specific capital cost could be attributed to the installation of the CO_2 capture unit and the compression unit. However, the higher increase in the capital cost in the CFB case as compared to the PC case could be attributed to the additional cost associated to the installation of the external flue gas desulphurisation which was not required for the CFB power plant without CO_2 capture.

Power Plant Fired with 100% Biomass

As shown in Figure 3, the percentage increase in the COE for both CFB and BFB power plants with CO_2 capture are almost similar as compared to their corresponding cases without CO_2 capture (about 80-85% increase). However, if compared to co-fired cases, which has about 50-60% increase to their COE when capturing the CO_2, the increase in COE for "standalone" biomass power plants are significantly greater; and could be a primary consequence of the higher cost of the biomass fuel as compared to coal (on energy basis). Likewise, to some extent, the increase in COE is also due to the increase in the capital cost. Additionally, the higher performance penalty when capturing CO_2 from "standalone" biomass power plants also contributed to the higher increase in the COE.

In terms of specific capital cost as shown in Table 2, an increase of 126% and 114% could be noted for the "standalone" 250MWe CFB (Cases 3A and 3B) and 75MWe BFB (Cases 4A and 4B) biomass power plants respectively. For both cases, the increase in the specific capital cost is primarily due to the cost associated to the CO_2 capture unit and the compression unit. The magnitude of the increase in the capital cost of a "standalone" biomass cases as compared to the co-fired cases are higher could be also be due to the proportionally larger volume of flue gas and slightly diluted CO_2 concentration needed to be processed by the CO_2 capture unit.

Impact of ETS and Green Certificate

To evaluate the benefits that could be gained from the ETS Certificate, it was assumed that there will be no free allocation of ETS credit provided. Thus, for all cases, the power plant would need to buy the necessary ETS credit to cover their CO_2 emissions. The calculation of the CO_2 emissions and annual revenues for the ETS and Green Certificates is illustrated in Tables 4 and 5.

For the four reference scenarios, it was assumed that ETS and Green Certificates will have a reference price of 14€/t CO_2 and 50€/MWh respectively. Furthermore, it was assumed that these prices would be constant over the whole economic life of the power plant. This means that if the price goes below the assumed value, then you will end up a negative NPV value.

The cost implication of the ETS and Green Certificate could be illustrated in Figures 3 and 4. These figures clearly show that both the Green and ETS certificate are needed to make the capture of CO_2 from a biomass fired or co-fired power plant to be competitive.

Also, it could be noted that the price of the ETS certificate could provide the benefits to make the COE of the power plant with CO_2 capture comparable to the COE of the power plants without CO_2 capture but will also need the benefit of the Green Certificate to bring down the COE of the power plant with or without CO_2 capture and make it comparable to the COE of the power plant without CO_2 capture for Scenario 1 - if no incentives from ETS or Green Certificate are considered.

A case in point (as shown in Figure 3), for the PC co-fired with biomass case (Case 1A and 1B), the price of the ETS certificate should be about 48€/t CO_2 to make the power plant with CO_2 capture comparable to the power plant without CO_2 capture. Furthermore, Figure 3 also illustrates that both the ETS (at 48€/t CO_2) and the Green Certificate (at 312€/MWh) would be needed to bring down the COE of the power plant to the same level to the COE of the power plant without capture when no incentives are considered (i.e. Scenario 1).

Impact of the Cost of Fuel

For power plants without CO_2 capture, as shown in Figure 2 and 3, the COE is about twice for the 250MWe CFB (Case 3A) and thrice for the 75MWe BFB (Case 4A) as compared to the 500MWe PC or CFB co-fired with biomass cases (Case 1A or 2A). This is primarily due to the higher cost of the biomass fuel per unit energy basis.

Without any incentives included (Scenario 1) as shown in Figure 5, the 250MWe biomass fired CFB power plant (Case 3A) could only be competitive as compared to their co-fired biomass counterpart (Case 1A or 2A) when the cost of biomass fuel would drop down to around 50 €/t dry basis. On the other hand, 75MWe biomass fired BFB power plant without CO_2 capture would need a biomass price down to around 30€/t dry basis to make it comparable to their co-fired biomass cases.

For power plants with CO_2 capture, as illustrated in Figure 6, it could be clearly noted that the COE from the 250MWe biomass fired CFB power plant with CO_2 capture (Case 3B) would only be competitive as compared to the COE of the co-fired biomass power plants without CO_2 capture (Case 1A and 2A) when both incentives are included (Scenario 4 – i.e. ETS Certificate at 14€/t CO_2, and Green Certificate at 50€/MWh) and in addition to a low price of biomass fuel at 50€/t dry basis. However, given this condition, the COE for Case 3A - from the 250MWe full biomass fired CFB plant without capture - is significantly lower than the COE for Case 3B –biomass fired CFB power plant with CO_2.

Comments from Expert Reviewers

Comments on the draft study report were received from a number of expert reviewers. The reviewers' comments were taken into account as far as possible in the final version of the contractor's report or in the overview. In general the reviewers thought the report was comprehensive and of high quality.

There were some specific comments about the technologies selected for the study, in particular, the use of a supercritical boiler instead of the more highly efficient ultra-supercritical boiler. It was noted by the reviewer that although currently there are no power plants co-fired with biomass operating at ultra-supercritical condition, a boiler could be easily adapted to co-fire biomass in the near future. Several reviewers recommended that more discussion on the impact of the fuel especially lower grade biomass fuel with respect to the boiler performance and its economics was required.

Furthermore, the reviewers recommended that the investigation of a higher percentage (with levels up to 40%) of biomass co-firing should be evaluated in future studies. In this regard, it was agreed that this recommendation would be implemented by monitoring R&D work related to high percentage co-firing of biomass.

In terms of the economic assumptions used in this report, several reviewers have been critical with the assumption of €14 per tonnes of CO_2 for the ETS certificate in the reference scenario. They considered this assumption as very conservative.

Additional comments focused on the price of the biomass fuel at €144 per tonnes on bone dry basis used in the study which was considered to be very high. Reviewers noted that this price is considered appropriate for virgin wood which could make the economics of the biomass fired power plants less attractive. It was accepted that any future study should focus on lower grade biomass fuel which could be more readily available than the biomass fuel assumed in this study.

Particular to the CFB boiler, reviewers noted that the efficiency of the CFB appears on the high side especially when considered in context of a multi-fuel plant operating on lower quality biomass. The authors of this report agreed that the current efficiency presented in this report could only be realised when pure wood pellet would be used for fuel. The use of lower quality fuel was not evaluated since this was not within the scope of the study. It was recommended that any future study on Biomass CCS application would be broader and consider lower grade fuels possibly in niche applications.

Further comments noted that the use of the LCPD standard, in terms of emissions, may not be appropriate for power plants operating beyond 2015. It was therefore recommended that any future study should be based on the appropriate new legislation that will be published by 2010-2011.

Major Conclusions

This study evaluated the techno-economics of four different cases of power plants fired with biomass under four different economic scenarios considering the impact of ETS and Green Certificates. The following could be concluded from this study:

Power Plant Performance

a. For the PC co-fired with biomass cases, the study examined the use of a supercritical boiler instead of the more advanced ultra-supercritical boiler due to the concern of the plant's availability and reliability. The study has indicated that there is a significant technology gap that needs to be overcome when using ultra-supercritical power plant co-fired with biomass. This is still to be demonstrated in the larger scale to achieve the necessary confidence. Specifically, the technology gaps exist in the slagging and fouling area when a boiler is co-fired with biomass and operated under ultra-supercritical conditions.

b. Without CO_2 capture, the net efficiency of the 500MWe CFB co-fired with biomass is higher than its counterpart PC case. However, this was reversed when CO_2 capture units were installed. This is due to the higher performance penalty incurred by the CFB because of the additional FGD needed and the absence of advanced flue gas heat recovery equipment downstream of the ID fan.

c. This study illustrated that "standalone" biomass fired cases experience a higher performance penalty when CO_2 capture was included. It was noted that the main reasons for the additional performance penalty in the full biomass fired power plant was due to the larger volume needed to be processed by the CO_2 capture plant, a slightly diluted CO_2 concentration, and in some cases, the additional flue gas clean up equipment required.

Cost of the Power Plant

a. The higher cost of the biomass fuel as compared to the coal price on a unit energy basis has a significant impact to the cost of electricity of the "standalone" biomass fired power plants. This study illustrated that for power plants without CO_2 capture, the COE is about twice for the 250MWe CFB (Case 3A) and triple for the 75MWe BFB (Case 4A) when compared to the 500MWe PC or CFB co-fired with biomass cases (Case 1A or 2A).

b. In terms of the specific capital cost, the installation of the CO_2 capture unit resulted in an increase of ~63% for the PC case when comparing both with or without CO_2 capture (Case 1A and 1B); and a ~73% increase for the CFB case (Cases 2A and 2B); an increase of ~126% and ~114% for both "standalone" biomass fired power plants (Cases 3A vs. 3B and 4A vs. 4B) respectively. Most of the increase in the capital cost was due to the CO_2 capture units and the compression units. However, additional capital cost increase was also due to the equipment needed for flue gas clean up, especially for the CFB and BFB cases.

Cost of Electricity with ETS and Green Certificate

a. There are three factors that could make the biomass fired or co-fired power plant with CO_2 capture competitive as compared to power plants without CO_2 capture, this includes the benefits that could be gained from the ETS and the Green Certificate; and the sensitivity to the price of the biomass fuel.

b. To make the biomass fired or co-fired power plant comparable to their counterparts without CO_2 capture, an ETS price of ~48 – 55€/t CO_2 is necessary for the 500MWe co-fired with biomass cases (Case 1 and 2). Whilst, ETS prices of ~65€/t CO_2 and ~76€/t CO_2 are necessary for the "standalone" biomass fired 250MWe CFB (Case 3) and 75MWe BFB (Case 4) respectively.

c. It can be concluded that Green Certificates alone will not make biomass fired power plants with CO_2 capture cost competitive. Both ETS and Green Certificate mechanisms need to be in place to make the COE for CO_2 capture cases comparable to non-CO_2 capture cases.

Recommendations

IEA GHG should investigate the possible applications of CO_2 capture in some niche industries where biomass is normally used as fuel for power and heat generation. This includes, but is not limited to, the following industries:

- Biomass CHP application
- Sugar refineries (the use of Baggasse)
- Pulp and paper industries
- Oleo petrochemical industries
- Corn / rice processing industries

IEA GHG should continue to monitor the developments in the use of biomass for power and heat generation. Most importantly, continue its participation in the discussion of the potential advantage of installing CO_2 capture and its feasibility with respect to the possible gain from "negative" emissions.

CLIENT	:	IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME	:	TECHNO-ECONOMIC EVALUATION OF CAPTURING CO_2 FROM BIOMASS FIRED POWER PLANT
DOCUMENT NAME	:	BIOMASS FIRED POWER PLANT REPORT

ISSUED BY	:	S. CAVEZZALI
CHECKED BY	:	P. COTONE
APPROVED BY	:	F. GASPARINI

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BIOMASS FIRED POWER PLANTS REPORT

I N D E X

General Index

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : TECHNO-ECONOMIC EVALUATION OF CAPTURING CO_2 FROM BIOMASS FIRED POWER PLANT
DOCUMENT NAME : EXECUTIVE SUMMARY

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SECTION A

EXECUTIVE SUMMARY

I N D E X

SECTION A

SECTION A

1.0 Scope of the Study

IEA Greenhouse Gas R&D Programme (IEA GHG) retained Foster Wheeler to investigate different power generation plant designs, fired with biomass and coal, aimed at assessing the potential advantage of biomass fired power plants with post combustion capture of CO_2.

The primary purpose of this study is, therefore, the evaluation of feasibility and costs of CO_2 capture in biomass fired power plants. The study will focus on techno-economic evaluation of four different cases of biomass fired power plants establishing the cost of electricity when the CO_2 capture is incorporated into a standalone biomass fired or co-fired (with coal) power plant.

The study evaluates the following four alternative biomass fired power plants:

- Case 1: 500 MWe (net) Pulverised Coal (PC) power plant with co-firing of biomass and coal
- Case 2: 500 MWe (net) Circulating Fluidised Bed (CFB) power plant with co-firing of biomass and coal
- Case 3: 250 MWe (net) CFB power plant with standalone biomass firing
- Case 4: 75 MWe (net) Bubbling Fluidised Bed (BFB) power plant with standalone biomass firing

For the four sizes, the cases with and without CO_2 capture are evaluated.

The study is based on the current state-of-the-art technologies, evaluating costs and performance of plants which can be presently engineered and built.

The study is finally completed with a comparison of the various alternative designs, confronting for the various technology combinations cost and performance data.

In order to evaluate the benefit of the CO_2 removal, four scenarios have been evaluated. The scenarios evaluate the following:

- Benefits of the green certificates. It has been considered an additional benefit on the electric energy selling price added to the quote of electricity produced by the biomass (based on duty fired in the boiler); this benefit is applied to all the cases, depending on the percentage of duty fired on biomass;
- ETS market. It has been considered that no free CO_2 allowances have been assigned to any plant, in accordance with European Directive 2009/29/EC, where it is specified that from 2013 no free allocations will be given to CCS activities of the power sector. Moreover, the CO_2 emitted to

atmosphere from the firing of biomass has been considered as neutral. The ETS is applied as a cost to the CO_2 emissions derived from coal firing and therefore as a penalty on the plant economics. For coal and biomass co-fired cases with CO_2 capture, if the overall CO_2 captured on mass bases is higher than the CO_2 emitted from coal firing, the net CO_2 emitted results negative and the ETS is applied as a revenue to the plant economics on the negative flowrate of CO_2 emitted. For the fully biomass fired cases, all the CO_2 captured results as negative emission and the ETS is applied positively on all the CO_2 captured, impacting on the economics of the plants as a revenue;
- benefit of green certificates and ETS market. The economical analysis considers both benefits from Green Certificate and ETS mechanism.

FWI like to acknowledge the following companies for their fruitful support to the preparation of this study:

- *FW Energy Oy* for the support on the performance and costs of CFB and BFB boilers
- *FW North America* for the support on the performance and costs of PC boiler
- *MHI* for the support on the performance of CO_2 capture unit
- *GTC Technology* for the support on the performance of CO_2 capture unit
- *Amine Expert* for the support on the performance of CO_2 capture unit.

2.0 Bases of Design

The Power Plants are designed to process, in an environmentally acceptable manner, a wood chips of clean virgin biomass and (for the co-firing cases) a coal from eastern Australia and produce electric energy to be delivered to the local grid.
The cost of the coal delivered to site is 75 €/t, while the cost of the biomass, on an absolute dry basis, delivered to site is 144 €/t.

The capacities of each case are defined in terms of net power output and they are referred to the cases without CO_2 capture. For the cases with CO_2 capture, the boiler sizes remain constant having as a consequence the reduction of the plant net power output due to the impact of the CO_2 removal and compression units in terms of power and steam consumptions.

The CO_2 capture is made in an amine based Acid Gas Removal Unit, located downstream the flue gas treatment unit of the boiler. The "post-combustion" CO_2 capture rate is fixed at 90%. This target can be easily achieved in the post-combustion CO_2 capture unit slightly increasing the unit consumptions of steam and electricity.

The plant main product is electric energy. By-products are:

- Carbon Dioxide for the Alternatives recovering CO_2
- Solid by-products: bottom ash, fly ash and gypsum, depending on the boiler alternative.

The environmental limits set up for the plants are outlined hereinafter.
The overall gaseous emissions from the plant referred to dry flue gas with 6% volume O_2 shall not exceed the following limits (European directive 2001/80):

	500 MWe Coal Power Station with Cofiring (1) mg/Nm^3 @ 6% O_2 vol.	**250 MWe Biomass Combustion mg/Nm^3 @ 6% O_2 vol.**	**75 MWe Biomass Cofiring mg/Nm^3 @ 6% O_2 vol.**
NO_x	200	200	200
SO_x	200	200	300
Particulate	30	30	30

Note 1: Applicable both to PC Boiler and to CFB Boiler.

For the cases with CO_2 capture the SOx and particulate emissions achieved will be lower due to specific constrains of the CO_2 removal technology.

Characteristics of waste water discharged from the plant shall comply with the limits stated by the EU directives.
The bases of design of the plants, such as capacity, required availability, location, climatic data etc... are defined in Section B, of the Report.

3.0 Alternative design of power plant

Several power plant design alternatives have been developed in the Study. The selected alternatives attempt to compare the following key process aspects:

- Different power plant technologies for processing coal and/or biomass;
- Impact of co-firing of coal and biomass in power plants;
- Different power plant technologies and sizes fully fired on biomass;
- Performance penalties for the capture of CO_2 to reduce environmental impact.

The following Table A.3.1 provides a summary of the 8 cases with some of the most significant performance data.
Cases identified with “a” do not consider the CO_2 capture, while cases identified with “b” include the CO_2 capture.

It is interesting to note the following:

- Only the PC boiler technology needs the use of an SCR system for NOx removal. In the CFB/BFB technologies, the NOx control can be achieved directly in the firing system of the boiler with low temperature at furnace exit.
- In the CFB co-fired boiler, the environmental limits can be achieved just with the addition of limestone in the furnace bed. A further external stage of FGD is needed when CO_2 capture is applied due to the lower SOx content required at CO_2 capture unit inlet.
- In the CFB/BFB fully biomass fired boilers, the environmental limits can be achieved without the addition of limestone in the furnace bed and without external FGD. Due to the low sulphur content of the biomass, the use of limestone as bed material and the CaO content in the biomass ashes is enough to achieve the required SOx capture. In the cases with CO_2 capture, the injection of limestone in the furnace bed is required due to the high SOx removal efficiency required.

Table A.3.1 – Most significant data for all the process alternatives

CASE	Boiler Technology	Fuel	Nominal electric power output	CO_2 Capture	DeNOx	DeSOx
1a	PC	90% Coal + 10% biomass (1)	500 MW	NO	YES	FGD
1b	PC	90% Coal + 10% biomass (1)	500 MW	YES	YES	FGD
2a	CFB	90% Coal + 10% biomass (1)	500 MW	NO	NO	Limestone injection in furnace
2b	CFB	90% Coal + 10% biomass (1)	500 MW	YES	NO	Limestone injection in furnace + FGD
3a	CFB	100 % Biomass	250 MW	NO	NO	NO
3b	CFB	100 % Biomass	250 MW	YES	NO	Limestone injection in furnace
4a	BFB	100 % Biomass	75 MW	NO	NO	NO
4b	BFB	100 % Biomass	75 MW	YES	NO	Limestone injection in furnace

Note (1): Based on fired duty (LHV)

4.0 Performance Data

The most important performance data of the different power plants, with and without CO_2 capture, are summarized in the following Table A.4.1. Table A.4.2 shows the overall performance data for each power plant case.

An important feature introduced in the CFB cases is a special plastic heat exchanger that allows to maximise heat recovery downstream of the ID fan without suffering from corrosion resistance and preheating the combustion air. The air is heated through a heating medium (water) that circulates from the plastic heat exchanger to the air heater. The air exiting this exchanger goes to the rotary air preheater and requires a smaller amount of heat to reach the final temperature. In this way it leaves some free thermal power from flue gases that is used to preheat the condensate of the steam cycle. This concept is implemented in the plant putting the rotary air preheater in parallel to a condensate preheater, improving the performance of the plant.

The cases where the plastic heat exchanger is foreseen are case 2a (500 MW CFB boiler without CCS) and case 3a (250 MW CFB boiler without CCS). In the cases where an external FGD system is needed (cases 1a, 1b and 2b) and cases with CCS, the temperature of flue gases does not allow a significant heat recovering without the formation of a strongly visible plume at stack outlet, requiring the installation of a plume abatement (reheat) system.
Based on the experience of boiler vendor, the small amount of heat recoverable and the installation of the plume abatement system in these cases make the plastic heat exchanger not cost effective and do not justify its introduction into the boiler.

Based on the above-mentioned considerations, the plastic heat exchanger makes the net efficiency of the 500 MWe CFB case without CO_2 capture (case 2a) slightly higher than the 500 MWe PC case (case 1a). This is because in the CFB boiler, when no CO_2 capture is considered, the SOx removal is performed with the addition of limestone in the furnace bed only and no external FGD is needed, and the low-temperature heat recovery is performed.

When the CO_2 capture is considered, in the CFB (case 2b) the necessity of an external FGD system and the presence of CO_2 capture unit (Direct Contact Cooler and CO_2 absorption tower) sensibly decreases the flue gas temperature. This makes therefore impossible the introduction of the plastic heat exchanger. For this reason the efficiency loss in the cases with CO_2 capture is higher in the CFB boiler (11.3 percentage points) than in the PC boiler (10.3 percentage points). Due to this lower impact of the CO_2 capture on performance, the net efficiency of the PC boiler results in slightly higher than the CFB boiler when capturing the CO_2.

In the BFB case, the flue gas line does not include the special plastic heat exchanger as the high cost of such an exchanger in relation to the performance increase achieved does not justify the addition of this equipment in the small plant. Moreover, it is important to highlight that the combustion of the biomass strongly affects the exhaust gases of the boiler. In fact, the lower LHV of the biomass with respect to the coal makes available more heat at low temperature, thus further penalising the cases with CO_2 capture where the low-temperature heat recovery exchanger can not be introduced.
Finally, in the biomass fired cases due to the lower LHV of biomass with respect to coal and the different biomass composition (50% of water content), the flue gases at boiler outlet are proportionally higher than in co-fired cases and the CO_2 is much more diluted.

In the 250 MWe biomass fired CFB boiler, the introduction of the CO_2 capture leads to a decrease in net electrical efficiency of about 16 percentage points. As per 500 MWe CFB, in fact, the plastic heat exchanger cannot be applied in the CO_2 capture case. Although in the fully biomass fired CFB the SOx removal is achieved with direct injection of limestone in the boiler, without any external FGD, the presence of CO_2 capture unit (Direct Contact Cooler and CO_2 absorption tower) still decreases the flue gas temperature making impossible the use of such a heat exchanger.
The efficiency decrease related to the CO_2 capture in 250 MWe (case 3b vs. 3a) is much higher with respect to 500 MWe CFB case (2b vs. 2a) although in both cases the CO_2 capture leads to the plastic heat exchanger removal. This is because of the different heat available at low temperature. In the biomass fired case with respect to the co-fired cases, the plastic heat exchanger has more heat available, internally used to increase the overall plant efficiency. Therefore the absence of such exchanger causes a higher loss of efficiency in the 250 MWe case.

In the 75 MWe case, the flue gas line does not include the plastic heat exchanger neither in the case without CO_2 capture nor in the one with CO_2 capture. This leads to a loss of efficiency lower compared with the 250 MWe case when capturing CO_2 (about 13 percentage points).
Nevertheless, the efficiency loss is higher than the 500 MWe CFB case due to the higher quantity of low temperature heat dissipated in the Direct Contact Cooler and CO_2 absorption tower.

Finally, in the two biomass fired cases (case 3 and 4) the flue gases at boiler outlet are proportionally higher than in 500 MWe co-fired cases and the CO_2 is much more diluted. For this reason, the electrical consumption related to CO_2

capture and compression and therefore the impact on the overall performance, is much higher than in the coal and biomass co-fired cases.

Table A.4.1

Performance Data

Case	Boiler Technology	Coal t/h	Biomass t/h	Gross Power Output MW	Auxiliary Consumptions MW	Net Power Output MW	Net Electrical Efficiency (1) %
1a	PC	145	57	545.2	26.3	518.9	44.8
1b	PC	145	57	474.0	75.2	398.8	34.5
2a	CFB	145	57	553.4	32.0	521.4	45.1
2b	CFB	145	57	473.7	83.2	390.5	33.8
3a	CFB	0	323	290.0	17.0	273.0	41.7
3b	CFB	0	323	224.6	55.7	168.9	25.8
4a	BFB	0	104	83.4	7.6	75.8	36.0
4b	BFB	0	104	68.4	19.6	48.8	23.2

Note (1): Based on fired duty (LHV)

Coal LHV = 25.87 MJ/kg
Biomass LHV = 7.3 MJ/kg

TABLE A.4.2 - Overall performance summary

Client	IEA GHG
Project	Biomass fired Power Plants
Date	November 2009 REV. 2

Plant Data		500MW PC		500MW CFB		250MW CFB		75MW BFB	
Case		**1a**	**1b**	**2a**	**2b**	**3a**	**3b**	**4a**	**4b**
Coal flowrate	t/h	145	145	145	145				
Coal thermal input	MW_{th}	1,042	1,042	1,040	1,040				
Biomass flowrate	t/h	57	57	57	57	323	323	104	104
Biomass thermal input	MW_{th}	116	116	116	116	654	654	211	211
Total fuel flowrate	t/h	202	202	202	202	323	323	104	104
Total thermal Input, LHV	MW_{th}	1,158	1,158	1,156	1,156	654	654	211	211
Steam Turbine Gross Power Output	kW_e	**545,227**	**474,084**	**553,403**	**473,697**	**289,953**	**224,626**	**83,407**	**68,453**

Auxiliary Load

		1a	1b	2a	2b	3a	3b	4a	4b
Fuel receiving, handling & storage	kW_e	1,400	1,400	1,400	1,400	900	900	300	300
Limestone unloading, storage and handling	kW_e	26	27	75	40		5		2
Boiler auxiliary consumption	kW_e	7,526	7,526	19,500	20,960	10,500	10,967	3,535	3,676
Flue gas desulphurisation (FGD)	kW_e	1,767	2,071		1,593				
Gypsum loading, storage and handling	kW_e	157	168		78				
Ash loading, storage and handling	kW_e	1,164	1,164	1,805	1,514	211	245	68	76
Steam Turbine auxiliaries and condenser	kW_e	1,141	1,013	1,176	1,012	620	480	177	145
Baghouse filter	kW_e	350	400						
Induced Draft fan	kW_e	4,834	4,979						
Condensate pumps and feedwater system (1)	kW_e	865	441	818	445	476	177	1,694	1,607
Machinery cooling water system	kW_e	140	1,550	141	1,575	80	1,690	25	550
Sea water system	kW_e	3,630	5,025	3,724	5,051	2,130	3,790	700	1,260
Miscelaneous Balance-of-Plant	kW_e	2,188	2,111	2,213	2,110	1,373	1,289	857	838
Step-Up Transformer Losses	kW_e	1,100	950	1,100	950	700	550	260	170
CO2 capture plant	kW_e		9,909		9,827		7,844		2,390
CO2 compression and drying	kW_e		36,518		36,671		27,750		8,617
Total Auxiliaries	kW_e	**26,288**	**75,252**	**31,952**	**83,225**	**16,990**	**55,687**	**7,617**	**19,631**

Performance

		1a	1b	2a	2b	3a	3b	4a	4b
Net Plant Power	kW_e	**518,939**	**398,832**	**521,451**	**390,472**	**272,964**	**168,939**	**75,790**	**48,822**
Gross Plant Efficiency (LHV)	%	47.1	41.0	47.9	41.0	44.3	34.3	39.6	32.5
Net Plant Efficiency (LHV)	%	44.8	34.5	45.1	33.8	41.7	25.8	36.0	23.2

5.0 Investment Cost Data

The investment cost data of the different power plants are reported in the attached Table A.5.1 and A.5.2.

Since capacity is not the same for all the alternatives, it is better to compare these technologies, from the point of view of the investment, on the base of the specific investment (euro/kW), rather than the total investment cost.

Table A.5.1
Investment Cost Data

CASE	Boiler Technology	MAIN SECTIONS INVESTMENT												Total Investment 10^6 Euro	Specific Investment Euro/kW
		Storage and Handling		Boiler Island and Flue Gas Treatment		Power Island		CO_2 capture Plant		CO_2 Compression		Utilities and Offsites			
		10^6 €	%	10^6 €	%	10^6 €	%	10^6 €	%	10^6 €	%	10^6 €	%		
1A	PC	47.1	7	360.3	55	149.3	23	0.0	0	0.0	0	100.5	15	657.2	1267
1B	PC	47.1	6	360.9	44	137.3	17	122.8	15	33.1	4	123.1	14	824.3	2067
2A	CFB	47.2	7	401.7	57	150.6	21	0.0	0	0.0	0	107.7	15	707.2	1356
2B	CFB	47.1	5	434.0	47	137.2	15	123.3	13	33.1	4	143.6	16	918.3	2352

Table A.5.2
Investment Cost Data

CASE	Boiler Technology	MAIN SECTIONS INVESTMENT												Total Investment 10^6 Euro	Specific Investment Euro/kW
		Storage and Handling		Boiler Island and Flue Gas Treatment		Power Island		CO2 capture Plant		CO2 Compression		Utilities and Offsites			
		10^6 €	%	10^6 €	%	10^6 €	%	10^6 €	%	10^6 €	%	10^6 €	%		
3A	CFB	49.0	13	204.1	55	60.8	16	0.0	0	0.0	0	56.4	16	370.3	1356
3B	CFB	49.0	9	205.4	40	52.4	10	102.8	20	28.0	5	82.1	16	519.7	3077
4A	BFB	22.5	12	103.9	56	30.3	16	0.0	0	0.0	0	28.7	16	185.4	2446
4B	BFB	22.6	9	104.5	41	27.2	11	49.1	19	13.9	5	39.0	15	256.3	5252

6.0 Electricity Production Costs

The Table A.6.2 provides the cost of electricity (C.O.E.) and the cost of the CO_2 recovery for the cases designed for the capture of CO_2. In order to evaluate this cost, a calculation of the CO_2 specific emission has been carried out; the Table A.6.1 summarizes the specific emissions for each case and clarifies the CO_2 emissions data used for COE calculation.

The following Table summarizes the economic analyses performed on each alternative in order to evaluate the electric power production cost, based on the following main assumptions:

- 7,884 equivalent hours of operation (90%) in normal conditions at 100% capacity for the cases without CO_2 capture;
- 7,710 equivalent hours of operation (88%) in normal conditions at 100% capacity for the cases with CO_2 capture;
- Total investment cost as evaluated in para 3.0 of this Section;
- O&M costs as evaluated in para 4.0;
- 10% discount rate on the investment cost over 25 operating years;
- No selling price is attributed to the CO_2 in the base case with CO_2 capture; different scenarios with different evaluation of potential benefits related to CO_2 capture are analysed;
- Cost of coal delivered to site is 75 €/t;
- Cost of biomass delivered to site is 144 €/t (on an absolute dry basis).

In order to evaluate the benefit of the CO_2 removal, the following scenarios have been evaluated:

- ❑ Scenario 1: Base case, neither selling price nor any benefit is attributed to CO_2;
- ❑ Scenario 2: benefits of the green certificates. It has been considered an additional benefit on the electric energy selling price added to the quote of electricity produced by the biomass (based on duty fired in the boiler); this benefit is applied to all the cases, depending on the percentage of duty fired on biomass;
- ❑ Scenario 3: ETS market. It has been considered that no free CO_2 allowances have been assigned to any plant. Moreover, the CO_2 emitted to atmosphere from the firing of biomass has been considered as neutral.
  The ETS is applied as a cost to the CO_2 emissions derived from coal firing and therefore as a penalty on the plant economics. For coal and biomass co-fired cases with CO_2 capture, if the overall CO_2 captured on mass bases is higher than the CO_2 emitted from coal firing, the net CO_2 emitted results in an overall negative emission of CO_2 and the ETS is applied as a revenue to the plant economics on the

negative flowrate of CO_2 emitted. For the fully biomass fired cases, all the CO_2 captured results as negative emission and the ETS is applied positively on all the CO_2 captured, impacting on the economics of the plants as a revenue.

- Scenario 4: benefit of green certificates and ETS market. The calculation of the economic analysis considers both benefits from Green Certificate and ETS mechanism..

The figures considered for the Green Certificates and ETS are the following:
- Green certificates: 50 €/MWh;
- ETS: 14 €/t CO_2 captured

The Green Certificates and ETS values have been considered constant all along the life of the project.

Table A.6.2 summarizes the electric power cost for all the cases and all the above-mentioned scenarios.

In order to evaluate the impact of the most important parameters on the economics of the plants, the following sensitivity analyses have been performed:

- Biomass cost: 50 – 100 – 144 €/t (dry basis);
- Coal cost: 60 – 75 – 90 €/t;
- Green certificates: +/- 25% (40 and 65 €/MWh);
- ETS: +100% / +200% (30 and 45 €/t CO_2 captured)

Sensitivity to coal and biomass costs have been performed without considering any incentive (neither green certificates nor ETS) and with the maximum incentive (both Green certificates, 50 €/MWh, and ETS, 14 €/t CO_2 captured). Sensitivity to incentives (Green Certificates and ETS) have been performed by considering the single effect of each incentive and the combined effects of the two incentives.

Sensitivities are shown in the figures A.6.1 to A.6.8 attached at the end of this section.

In the attached table is also listed the cost of CO_2 removal, calculated as follows:

$$\frac{\Delta\,\text{Electric Power Cost}}{\Delta\,\text{Specific }CO_2\text{ emission}}\,[=]\,\frac{\text{Euro}}{\text{t of }CO_2\text{ captured}}$$

Where:

Δ Electric Power Cost = Electric Power Cost with CO_2 capture - Electric Power Cost without CO_2 capture. The unit of measurement is Euro/kWh.

Δ Specific CO_2 emission = Ratio of (CO_2 emission/unit of power production) without capture- ratio of (CO_2 emission/unit of power production) with capture. The unit of measurement is tonne CO_2/kWh.

The cost of CO_2 removal is calculated for each case and scenario with reference to the same scenario of the relevant case without CO_2 capture.

For the 500 MWe co-fired cases, the cost of electricity for cases without CCS falls in a very narrow range of values. The cost of electricity for the PC case results in slightly lower than the case of CFB (by approximately 5%). This result is a consequence of the lower investment cost of the PC boiler which compensates the small advantage of CFB in efficiency.

The fully biomass fired cases are strongly penalised by the very high cost of biomass that is approximately three times more expensive than the coal on an energy basis. They become economically attractive only with incentives that take into account the green fuel and which are related to the CO_2 capture.

Table A.6.1: Summary of CO_2 Emissions of the Biomass Fired or Co-Fired Power Plant

	Actual CO_2 Emissions	CO_2 from Coal	CO_2 from Biomass	Total CO_2 Captured	Equivalent CO_2 Emissions	CO_2 avoided with resp to conventional coal	CO_2 avoided with resp. to NGCC
	g/kWh	g/kWh	g/kWh	g/kWh	g/kWh	g/kWh	g/kWh
SC PC Boiler with coal (without CO2 capture)	722.8	722.8	-	-	722.8	-	-
NGCC (without CO2 capture)	359.0	359.0	-	-	359.0	-	-
SC PC boiler co-fired with biomass							
Case 1A (without CO_2 capture)	748.5	649.7	98.8	0.0	649.7	73.1	-290.7
Case 1B (with CO_2 capture)	973.7	845.2	128.5	876.4	-31.3	754.1	390.3
SC CFB boiler co-fired with biomass							
Case 2A (without CO_2 capture)	748.2	649.4	98.8	0.0	649.4	73.4	-290.4
Case 2B (with CO_2 capture)	999.0	867.1	131.9	899.1	-32.0	754.8	391.0
Sub CFB boiler fired with biomass							
Case 3A (without CO_2 capture)	1081.3	0.0	1081.3	0.0	0.0	722.8	359.0
Case 3B (with CO_2 capture)	1747.8	0.0	1747.8	1573.1	-1573.1	2295.9	1932.2
Sub BFB boiler fired with biomass							
Case 4A (without CO_2 capture)	1257.3	0.0	1257.3	0.0	0.0	722.8	359.0
Case 4B (with CO_2 capture)	1948.9	0.0	1948.9	1754.6	-1754.6	2477.4	2113.7

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TABLE A.6.2 - Electric power costs summary

Client	IEA GHG
Project	Biomass fired Power Plants
Date	July 2009 REV. 1

Case		**1a - 500 MWe PC w/o CCS**				**1b - 500 MWe PC with CCS**			
Scenario		**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**
Green Certificate	[Euro/MWh]	**0**	**50**	**0**	**50**	**0**	**50**	**0**	**50**
ETS	[Euro/t CO2]	**0**	**0**	**14**	**14**	**0**	**0**	**14**	**14**
IRR		**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**
Coal Florate	[t/h]	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0
Coal Fired Duty		90%	90%	90%	90%	90%	90%	90%	90%
Biomass Florate (1)	[t/h]	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5
Biomass Fired Duty		10%	10%	10%	10%	10%	10%	10%	10%
Net Power Out.	[MW]	518.9	518.9	518.9	518.9	398.9	398.9	398.9	398.9
Total Inv. Cost	[MM Euro]	657.2	657.2	657.2	657.2	824.3	824.3	824.3	824.3
CO2 Produced	[t/h]	337.1	337.1	337.1	337.1	337.1	337.1	337.1	337.1
CO2 Captured	[t/h]	0.0	0.0	0.0	0.0	349.6	349.6	349.6	349.6
CO2 Emitted	[t/h]	337.1	337.1	337.1	337.1	-12.5	-12.5	-12.5	-12.5
Revenues / year, Electricity	[MM Euro/y]	249.4	228.9	286.6	266.1	287.6	272.2	286.2	270.8
Revenues / year, Green Certif	[MM Euro/y]	0.0	20.5	0.0	20.5	0.0	15.4	0.0	15.4
Revenues / year, ETS	[MM Euro/y]	0.0	0.0	-37.2	-37.2	0.0	0.0	1.3	1.3
Total Revenues / year	[MM Euro/y]	249.4	249.4	249.4	249.4	287.6	287.6	287.6	287.6
Electricity Prod Cost	[Euro/kWh]	**0.061**	**0.056**	**0.070**	**0.065**	**0.094**	**0.089**	**0.093**	**0.088**
NPV	[MM Euro]	0	0	0	0	0	0	0	0
CO_2 Specific Emission	[10^{-3} Kg/kWh]	649.7	649.7	649.7	649.7	-31.3	-31.3	-31.3	-31.3
CO_2 Removal Cost	[Euro/t]	-	-	-	-	**47.8**	**47.8**	**33.8**	**33.8**

Case		**2a - 500 MWe CFB without CCS**				**2b - 500 MWe CFB with CCS**			
Scenario		**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**
Green Certificate	[Euro/MWh]	**0**	**50**	**0**	**50**	**0**	**50**	**0**	**50**
ETS	[Euro/t CO2]	**0**	**0**	**14**	**14**	**0**	**0**	**14**	**14**
IRR		**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**
Coal Florate	[t/h]	144.8	144.8	144.8	144.8	144.8	144.8	144.8	144.8
Coal Fired Duty		90%	90%	90%	90%	90%	90%	90%	90%
Biomass Florate (1)	[t/h]	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5
Biomass Fired Duty		10%	10%	10%	10%	10%	10%	10%	10%
Net Power Out.	[MW]	521.4	521.4	521.4	521.4	390.5	390.5	390.5	390.5
Total Inv. Cost	[MM Euro]	707.3	707.3	707.3	707.3	918.4	918.4	918.4	918.4
CO2 Produced	[t/h]	338.6	338.6	338.6	338.6	338.6	338.6	338.6	338.6
CO2 Captured	[t/h]	0.0	0.0	0.0	0.0	351.1	351.1	351.1	351.1
CO2 Emitted	[t/h]	338.6	338.6	338.6	338.6	-12.5	-12.5	-12.5	-12.5
Revenues / year, Electricity	[MM Euro/y]	262.5	241.9	299.9	279.3	304.8	289.7	303.4	288.4
Revenues / year, Green Certif	[MM Euro/y]	0.0	20.6	0.0	20.6	0.0	15.1	0.0	15.1
Revenues / year, ETS	[MM Euro/y]	0.0	0.0	-37.4	-37.4	0.0	0.0	1.3	1.3
Total Revenues / year	[MM Euro/y]	262.5	262.5	262.5	262.5	304.8	304.8	304.8	304.8
Electricity Prod Cost	[Euro/kWh]	**0.064**	**0.059**	**0.073**	**0.068**	**0.101**	**0.096**	**0.101**	**0.096**
NPV	[MM Euro]	0	0	0	0	0	0	0	0
CO_2 Specific Emission	[10^{-3} Kg/kWh]	649.4	649.4	649.4	649.4	-32.0	-32.0	-32.0	-32.0
CO_2 Removal Cost	[Euro/t]					**54.9**	**54.9**	**40.9**	**40.9**

Case		**3a - 250 MWe CFB without CCS**				**3b - 250 MWe CFB with CCS**			
Scenario		**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**
Green Certificate	[Euro/MWh]	**0**	**50**	**0**	**50**	**0**	**50**	**0**	**50**
ETS	[Euro/t CO2]	**0**	**0**	**14**	**14**	**0**	**0**	**14**	**14**
IRR		**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**
Coal Florate	[t/h]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal Fired Duty		0%	0%	0%	0%	0%	0%	0%	0%
Biomass Florate (1)	[t/h]	161.3	161.3	161.3	161.3	161.3	161.3	161.3	161.3
Biomass Fired Duty		100%	100%	100%	100%	100%	100%	100%	100%
Net Power Out.	[MW]	273.0	273.0	273.0	273.0	168.9	168.9	168.9	168.9
Total Inv. Cost	[MM Euro]	370.3	370.3	370.3	370.3	519.7	519.7	519.7	519.7
CO2 Produced	[t/h]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2 Captured	[t/h]	0.0	0.0	0.0	0.0	265.7	265.7	265.7	265.7
CO2 Emitted	[t/h]	0.0	0.0	0.0	0.0	-265.7	-265.7	-265.7	-265.7
Revenues / year, Electricity	[MM Euro/y]	257.4	149.8	257.4	149.8	288.3	223.2	259.7	194.6
Revenues / year, Green Certif	[MM Euro/y]	0.0	107.6	0.0	107.6	0.0	65.1	0.0	65.1
Revenues / year, ETS	[MM Euro/y]	0.0	0.0	0.0	0.0	0.0	0.0	28.7	28.7
Total Revenues / year	[MM Euro/y]	257.4	257.4	257.4	257.4	288.3	288.3	288.3	288.3
Electricity Prod Cost	[Euro/kWh]	**0.120**	**0.070**	**0.120**	**0.070**	**0.221**	**0.171**	**0.199**	**0.149**
NPV	[MM Euro]	0	0	0	0	0	0	0	0
CO_2 Specific Emission	[10^{-3} Kg/kWh]	0.0	0.0	0.0	0.0	-1573.1	-1573.1	-1573.1	-1573.1
CO_2 Removal Cost	[Euro/t]	-	-	-	-	**64.7**	**64.7**	**50.7**	**50.7**

Case		**4a - 75 MWe BFB without CCS**				**4b - 75 MWe BFB with CCS**			
Scenario		**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**
Green Certificate	[Euro/MWh]	**0**	**50**	**0**	**50**	**0**	**50**	**0**	**50**
ETS	[Euro/t CO2]	**0**	**0**	**14**	**14**	**0**	**0**	**14**	**14**
IRR		**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**
Coal Florate	[t/h]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal Fired Duty		0%	0%	0%	0%	0%	0%	0%	0%
Biomass Florate (1)	[t/h]	51.9	51.9	51.9	51.9	51.9	51.9	51.9	51.9
Biomass Fired Duty		100%	100%	100%	100%	100%	100%	100%	100%
Net Power Out.	[MW]	75.8	75.8	75.8	75.8	48.9	48.9	48.9	48.9
Total Inv. Cost	[MM Euro]	185.4	185.4	185.4	185.4	256.2	256.2	256.2	256.2
CO2 Produced	[t/h]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2 Captured	[t/h]	0.0	0.0	0.0	0.0	85.8	85.8	85.8	85.8
CO2 Emitted	[t/h]	0.0	0.0	0.0	0.0	-85.8	-85.8	-85.8	-85.8
Revenues / year, Electricity	[MM Euro/y]	99.8	69.9	99.8	69.9	113.5	94.6	104.2	85.3
Revenues / year, Green Certif	[MM Euro/y]	0.0	29.9	0.0	29.9	0.0	18.9	0.0	18.9
Revenues / year, ETS	[MM Euro/y]	0.0	0.0	0.0	0.0	0.0	0.0	9.3	9.3
Total Revenues / year	[MM Euro/y]	99.8	99.8	99.8	99.8	113.5	113.5	113.5	113.5
Electricity Prod Cost	[Euro/kWh]	**0.167**	**0.117**	**0.167**	**0.117**	**0.301**	**0.251**	**0.276**	**0.226**
NPV	[MM Euro]	0	0	0	0	0	0	0	0
CO_2 Specific Emission	[10^{-3} Kg/kWh]	0.0	0.0	0.0	0.0	-1754.6	-1754.6	-1754.6	-1754.6
CO_2 Removal Cost	[Euro/t]					**76.3**	**76.3**	**62.3**	**62.3**

Note (1): Absolute dry basis

7.0 Summary and Conclusions

The most important conclusions of the study are summarized in the following paragraphs:

7.1 Technical conclusions (power plant performance)

A. The net efficiency of the 500 MWe CFB case without CO_2 capture (case 2a) is slightly higher than the 500 MWe PC case (case 1a). This behaviour is reversed when applying the capture of CO_2 due to the higher decrease of performance of the CFB.

B. The fully fired biomass cases see the highest performance decrease when considering the capture of the CO_2.

7.2 Economical conclusions

Cost of electricity

A. For the 500 MWe co-fired cases, the cost of electricity for cases without CO_2 capture falls in a very narrow range of values. Cost of electricity for the PC case is slightly lower than the one of CFB (approximately 5%). This result is a consequence of the lower investment cost of the PC boiler which compensates the small advantage of CFB in efficiency.

B. The fully biomass fired plants without CO_2 capture show very high cost of electricity. With respect to 500 MWe cases, the COE in 250 MWe is about twice and in 75 MWe about three times higher. They are strongly penalised by the very high cost of biomass that is approximately three times more expensive than the coal on an energy basis. The 250 MWe becomes economically attractive only with incentives that take into account the green fuel and related to the CO_2 emissions.

C. For the 500 MWe co-fired cases, the COE difference for cases with CO_2 capture is higher than the relevant cases without CO_2 capture: COE for the PC case is lower than the case of CFB by approximately 7%. This result is a consequence of the lower investment cost of the PC boiler in addition to the small advantage in efficiency.

D. In absence of incentives (scenario 1) the fully biomass fired plants with CO_2 capture result further more penalised with respect to the 500 MWe cases. The COE in 250 MWe is more than twice and in 75 MWe more than three times higher than in 500 MWe cases. In addition to the high cost of biomass, they are also affected by the higher auxiliary consumptions related to the introduction of the CO_2 capture.

Sensitivity analysis

E. In absence of incentives (scenario 1) the fully biomass fired cases without CO_2 capture can be considered competitive with co-fired alternatives only in case the biomass cost drops down to the same cost of coal on energy bases, 50 €/t (dry basis).

F. In presence of full incentives market (scenario 4) the 250 MWe fully biomass fired case becomes more attractive than the co-fired alternatives in case of a biomass cost lower than about 140 €/t dry basis (which is similar to biomass cost considered in present study). The 75 MWe case becomes competitive only in case the biomass cost drops down to around 60 €/t (dry basis).

G. The 500 MWe cases are much less sensitive than the fully biomass fired cases to the green certificates as they apply only to the amount of electricity generated from biomass.

H. The wide difference in Cost of electricity between co-fired cases and biomass cases is significantly reduced by the incentives relevant to the use of green fuel although the COE in the co-fired cases still results lower than in the fully biomass fired cases.

I. In absence of incentives (scenario 1) the fully biomass fired cases with CO_2 capture cannot be considered competitive with co-fired alternatives also in case the biomass cost drops down to the same cost of coal on energy bases, 50 €/t (dry basis).

J. In presence of full incentives market (scenario 4) the 250 MWe fully biomass fired case with CO_2 capture becomes better than co-fired alternatives only in case the biomass cost drops down to about 85 €/t (dry basis). The 75 MWe case also in case biomass cost drops down to the same cost of coal on energy bases, 50 €/t (dry basis), cannot be considered competitive with co-fired alternatives.

K. For coal and biomass co-fired cases, the cost of CO_2 capture become negligible only in case the ETS value rises up to about 45-50 €/t of CO_2 independently from the green certificates. Only in this case, in fact, the COE for cases without and with CO_2 capture results comparable.

L. For the 250 MWe case, the cost of CO_2 capture become negligible only in case the ETS value rises up to about 65 €/t of CO_2 independently from the green certificates. While for the 75 MWe case, this happens only in case the ETS value rises up to about 75 €/t of CO_2.

Figure A.6.1: Biomass cost Sensitivity - Scenario 1

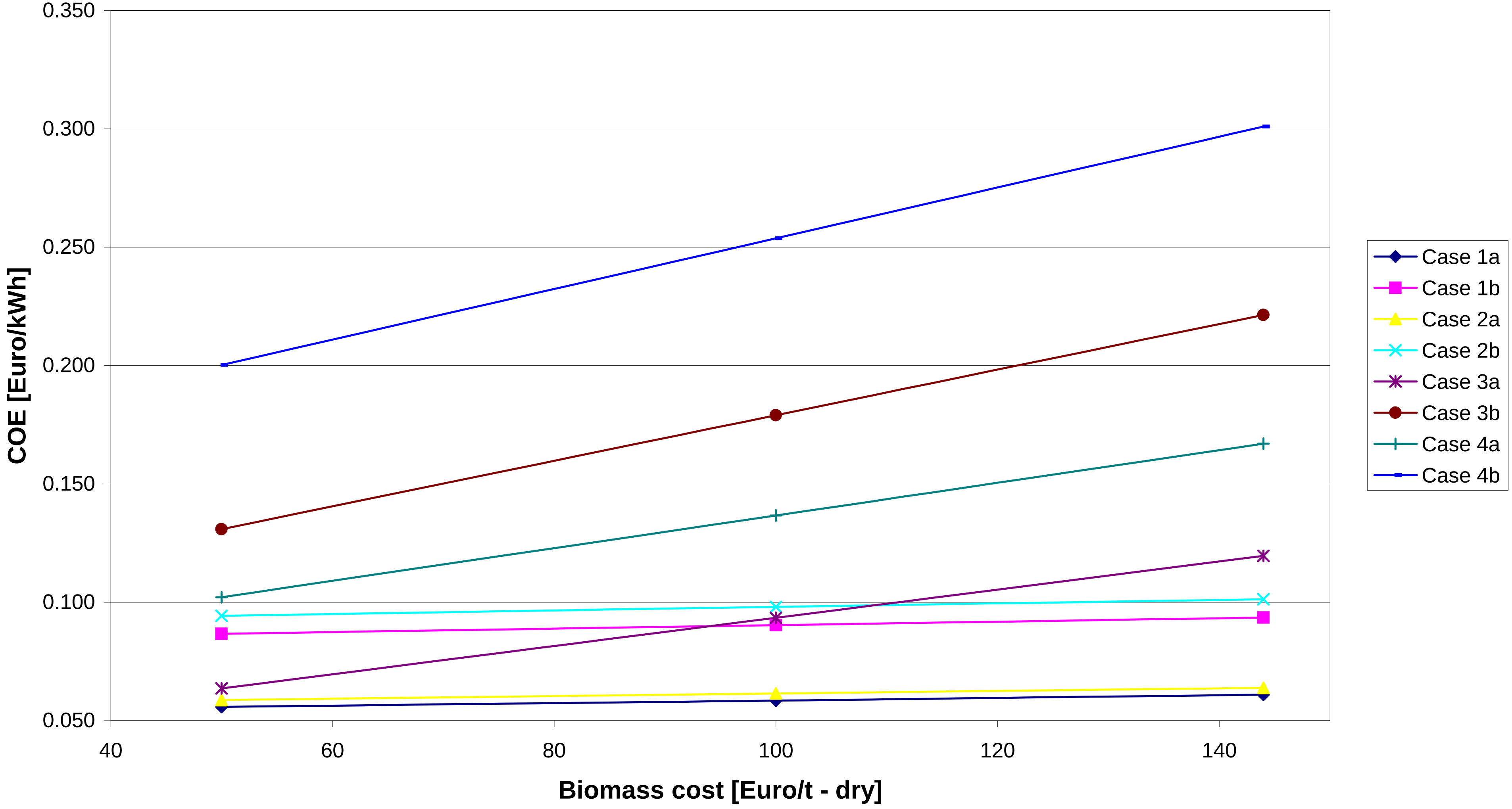


Figure A.6.2: Biomass cost Sensitivity - Scenario 4

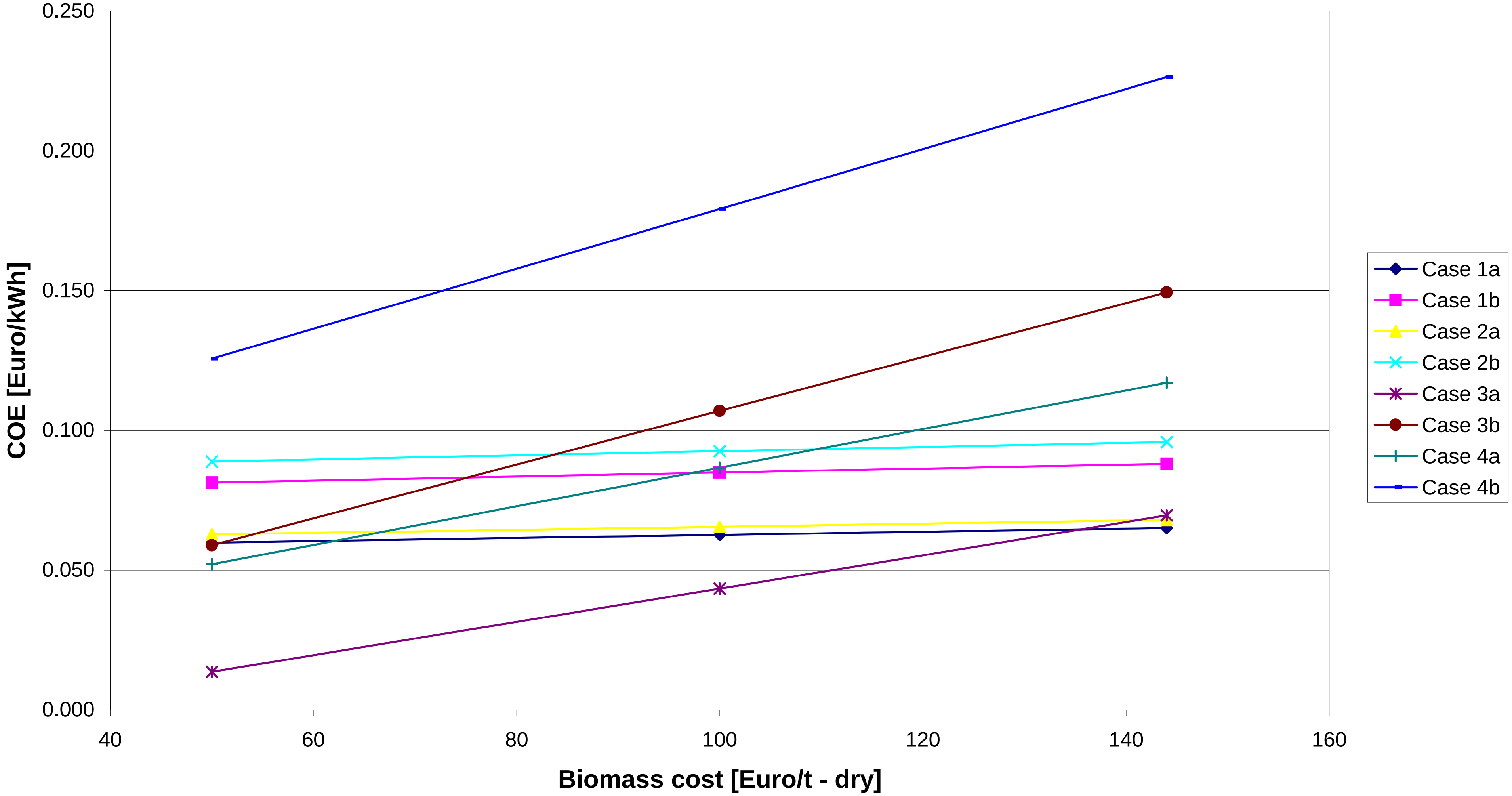


Figure A.6.3: Coal Cost sensitivity - Scenario 1

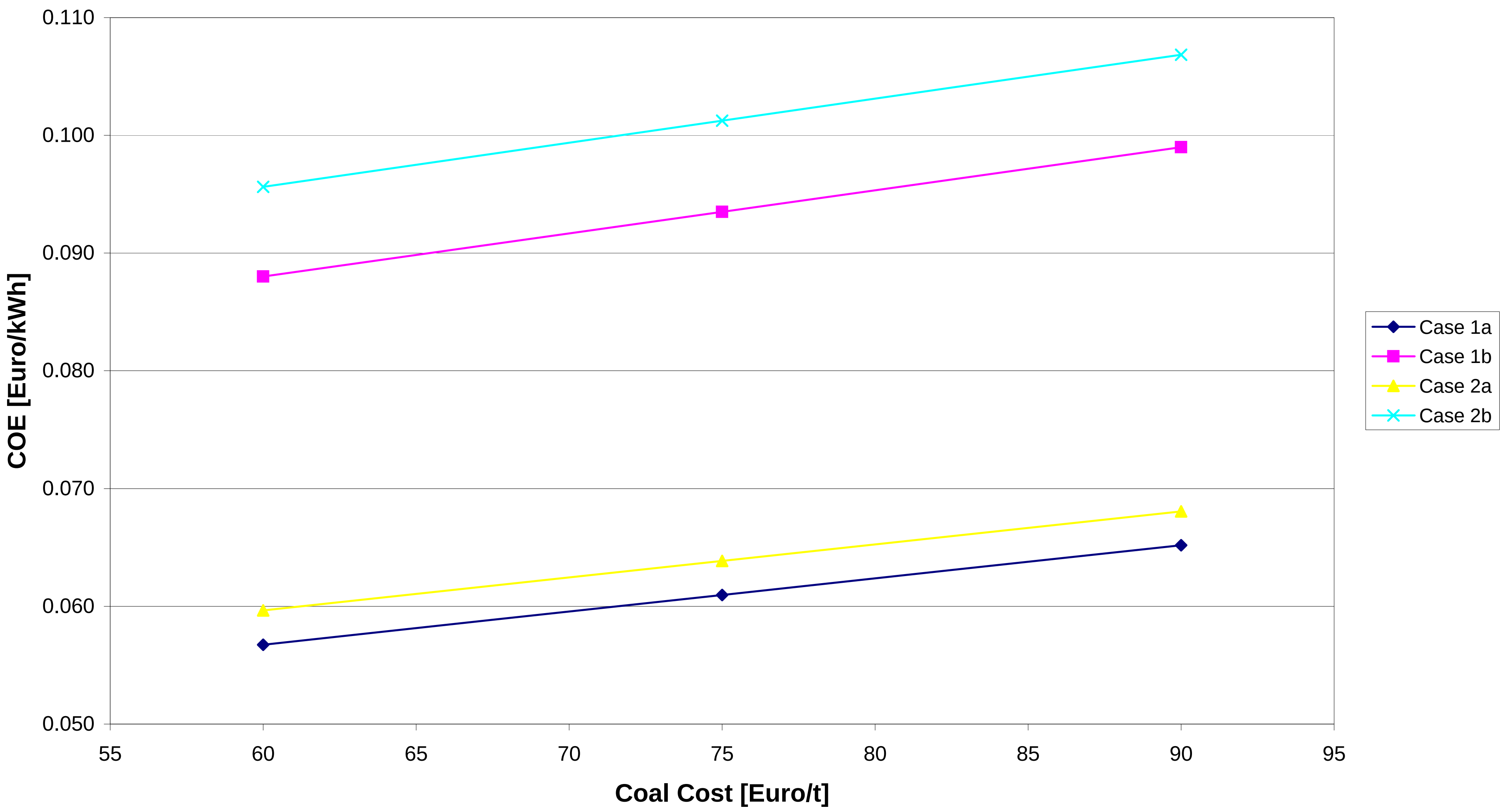


Figure A.6.4: Coal Cost sensitivity - Scenario 4

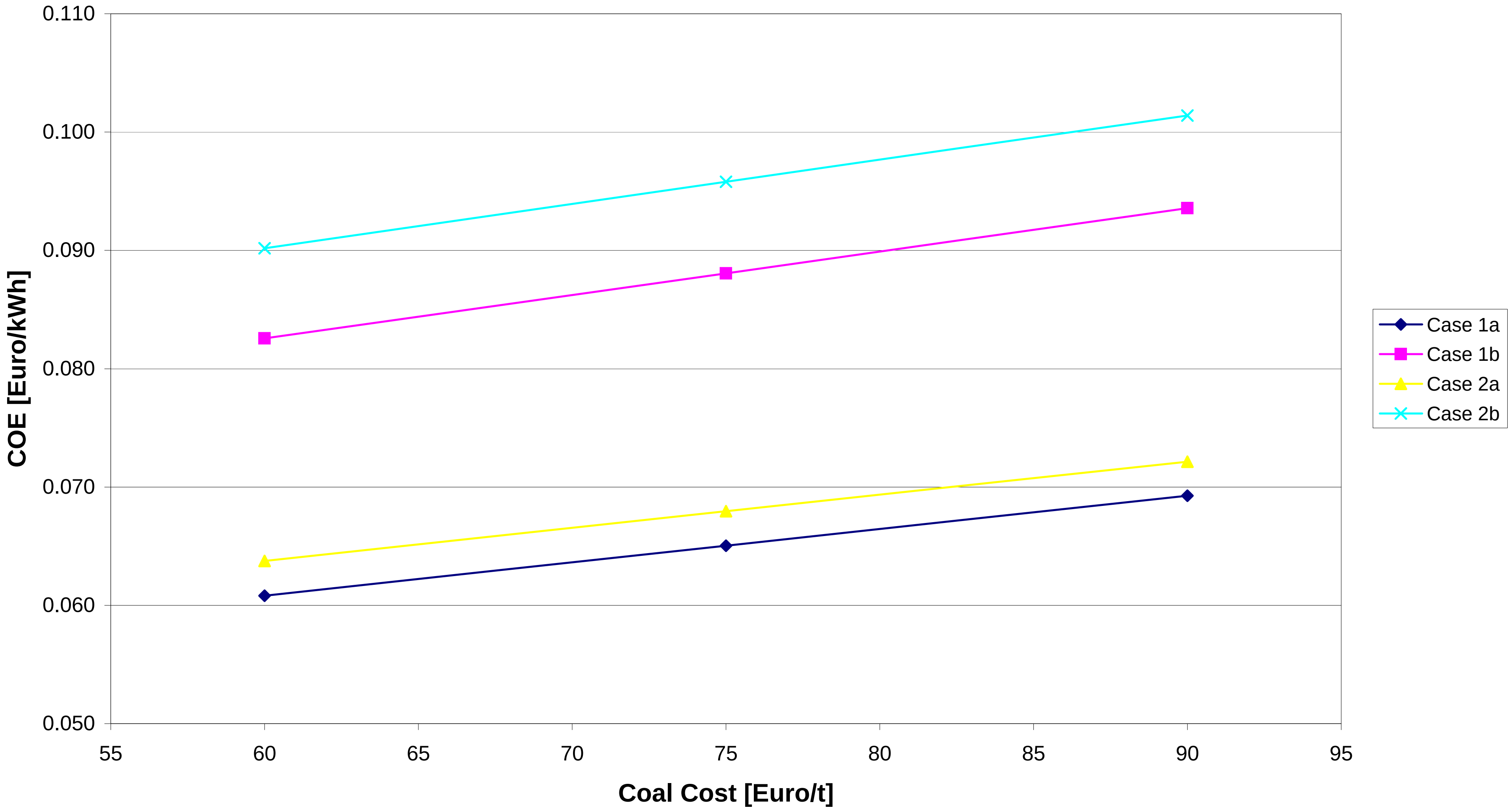


Figure A.6.5: ETS Sensitivity (Scenario 3, GC = 0 €/MWh)

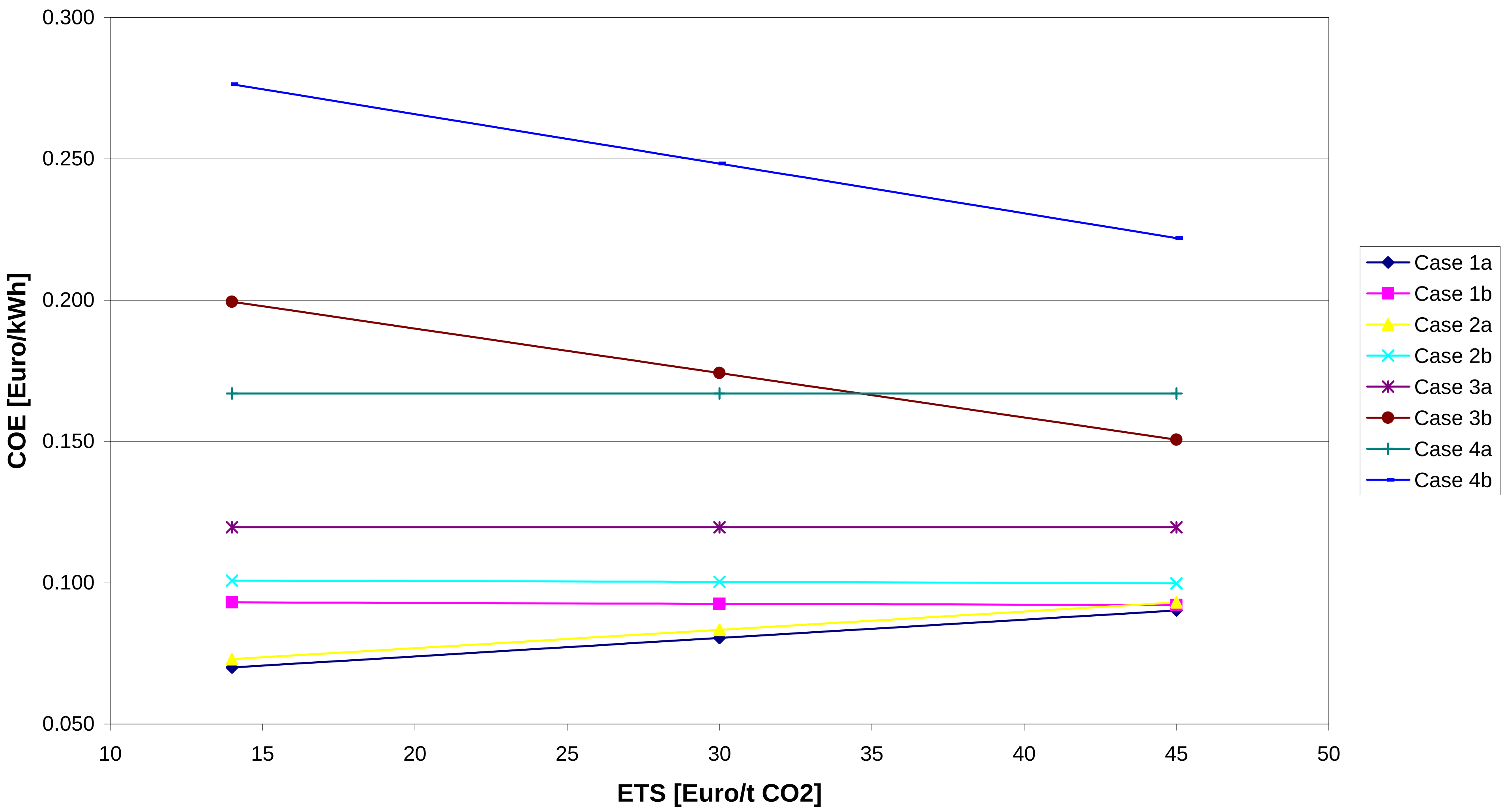


Figure A.6.6: ETS Sensitivity (Scenario 4, GC = 50 €/MWh)

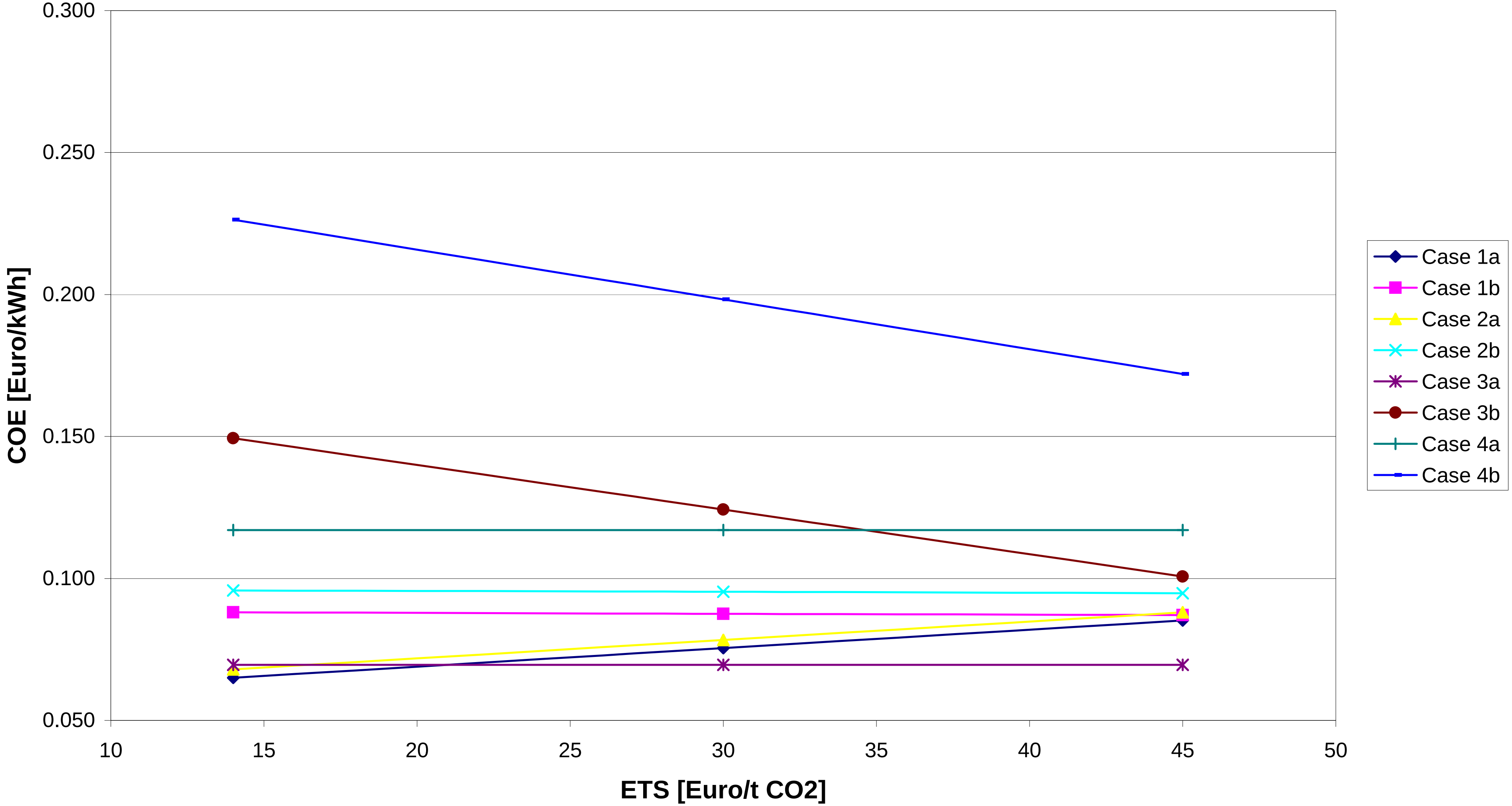
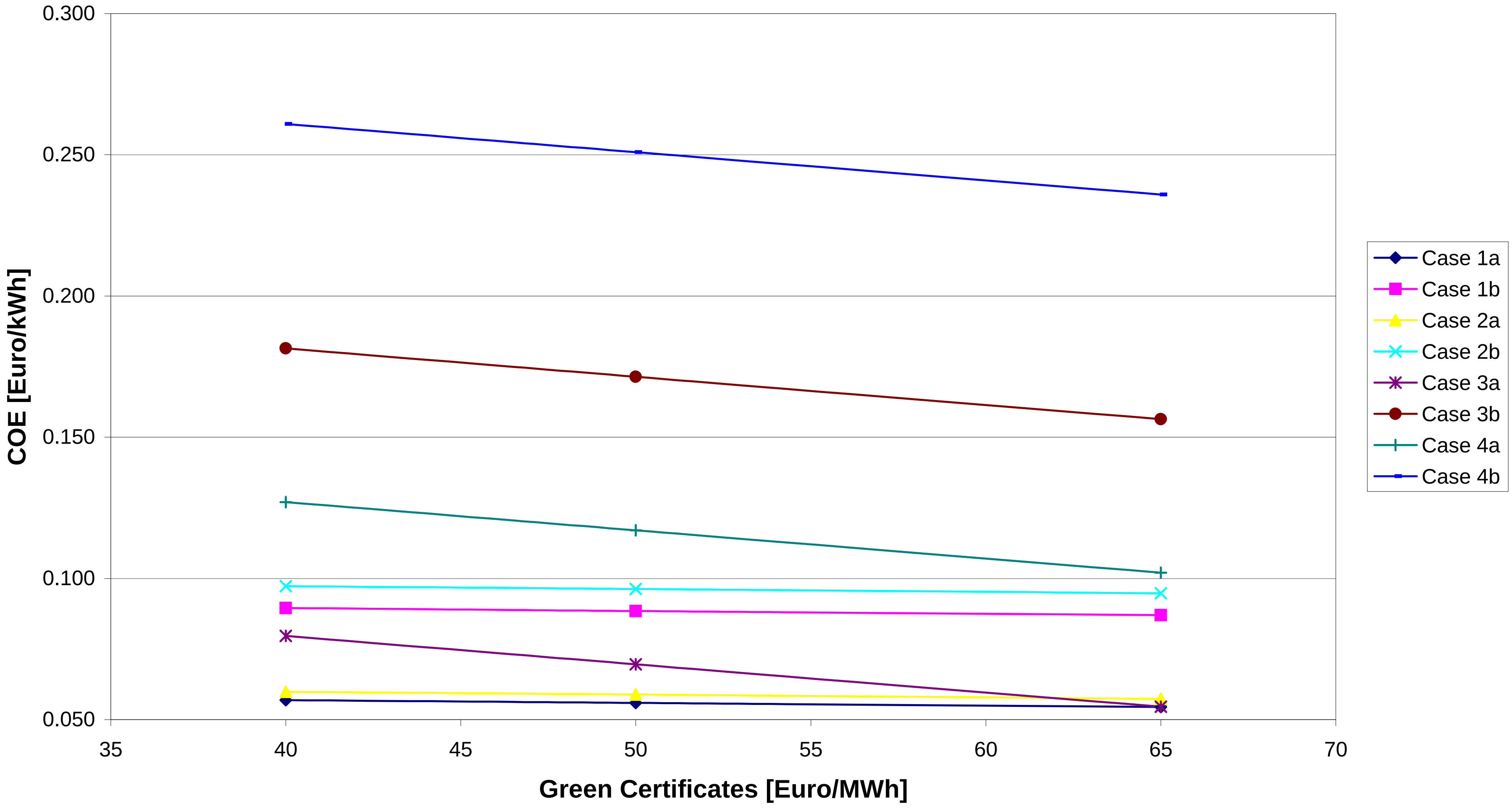


Figure A.6.7: Green Certificates sensitivity (Scenario 2, ETS = 0 €/t CO_2)



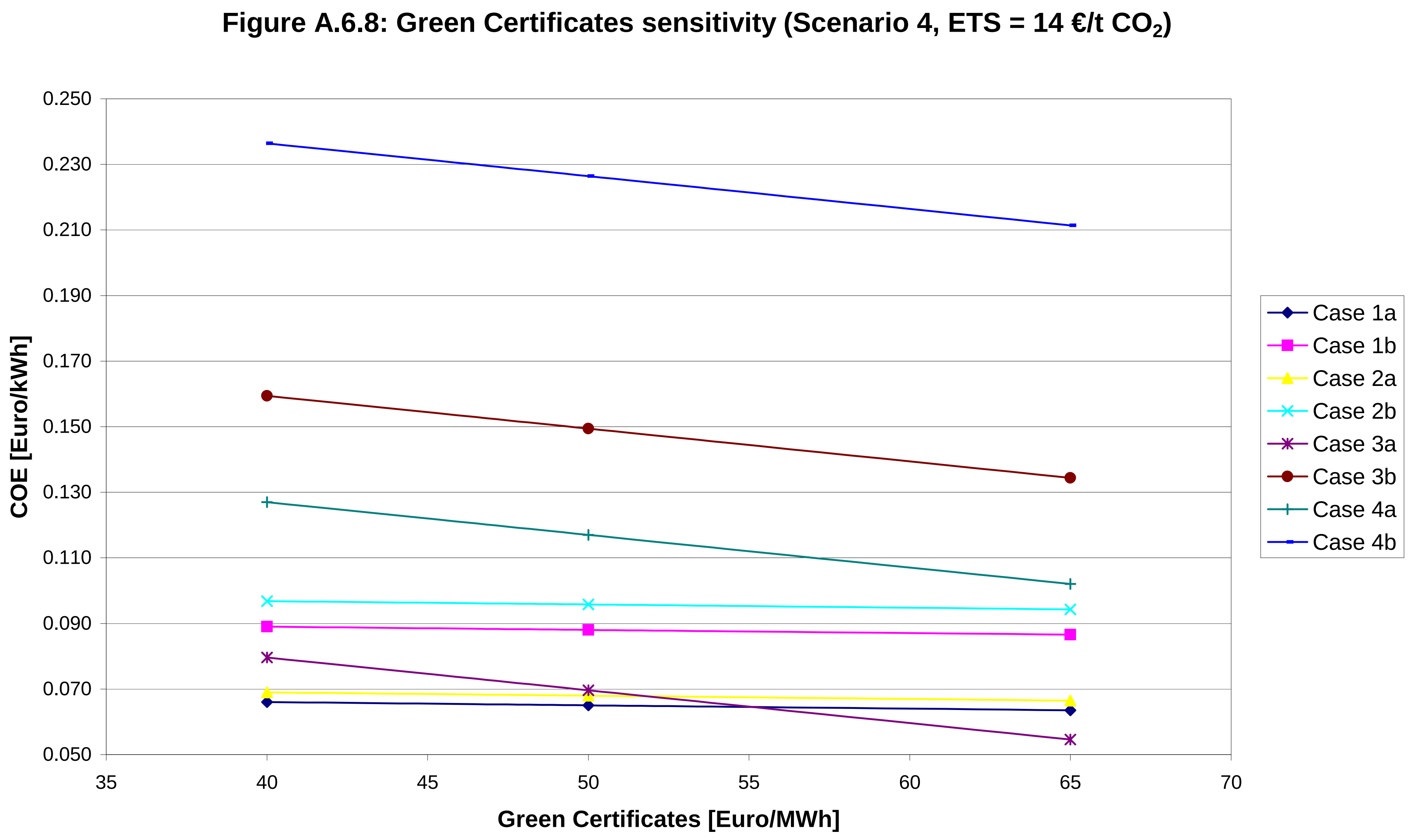


Figure A.6.8: Green Certificates sensitivity (Scenario 4, ETS = 14 €/t CO_2)
COE [Euro/kWh]
0.250
0.230
0.210
0.190
0.170
0.150
0.130
0.110
0.090
0.070
0.050
35
40
45
50
55
60
65
70
Green Certificates [Euro/MWh]
Case 1a
Case 1b
Case 2a
Case 2b
Case 3a
Case 3b
Case 4a
Case 4b

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : TECHNO-ECONOMIC EVALUATION OF CAPTURING CO_2 FROM BIOMASS FIRED POWER PLANT
DOCUMENT NAME : GENERAL INFORMATION

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GENERAL INFORMATION

I N D E X

1.0 Purpose of the Study

IEA Greenhouse Gas R&D Programme (IEA GHG) retained Foster Wheeler to investigate different power generation plant designs, fired with biomass and coal, aimed at assessing the potential advantage of biomass fired power plants with post combustion capture of CO_2.

The primary purpose of this study is, therefore, the evaluation of feasibility and costs of CO_2 capture in biomass fired power plants. The study will focus on techno-economic evaluation of four different cases of biomass fired power plants establishing the cost of electricity when the CO_2 capture is incorporated into a standalone biomass fired or co-fired (with coal) power plant.

The study evaluates the following four alternative biomass fired power plants:

- Case 1: 500 MWe (net) Pulverised Coal (PC) power plant with co-firing of biomass and coal
- Case 2: 500 MWe (net) Circulating Fluidised Bed (CFB) power plant with co-firing of biomass and coal
- Case 3: 250 MWe (net) CFB power plant with standalone biomass firing
- Case 4: 75 MWe (net) Bubbling Fluidised Bed (BFB) power plant with standalone biomass firing

For the four sizes, the cases with and without CO_2 capture are evaluated.

The study is based on the current state-of-the-art technologies, evaluating costs and performance of plants which can be presently engineered and built.

2.0 Project Design Bases

The Power Plants are designed to process, in an environmentally acceptable manner, a wood chips of clean virgin biomass and (for the co-firing cases) a coal from eastern Australia and produce electric energy to be delivered to the local grid.

2.1 Feedstock Specification

The feedstock characteristics are listed hereinafter.

2.1.2 Coal

	Eastern Australian Coal Proximate Analysis, wt%
Inherent moisture	9.50
Ash	12.20
Coal (dry, ash free)	78.30
Total	100.00

	Ultimate Analysis, wt% (dry, ash free)
Carbon	82.50
Hydrogen	5.60
Nitrogen	1.77
Oxygen	9.00
Sulphur	1.10
Chlorine	0.03
Total	100.00

Ash Fluid Temperature at reduced atm., °C	1350
HHV (Air Dried Basis), MJ/kg (*)	27.06
LHV (Air Dried Basis), MJ/kg (*)	25.87
Grindability, Hardgrove Index	45

(*) based on Ultimate Analysis, but including inherent moisture and ash.

Coal Ash Analysis, wt%

SiO_2	50.0
Al_2O_3	30.0
TiO_2	2.0
Fe_2O_3	9.7
CaO	3.9
MgO	0.4
Na_2O	0.1
K_2O	0.1
P_2O_5	1.7
SO_3	1.7

2.1.2 Biomass

	Clean virgin wood, wood chips		
	Unit	**Design (Average)**	**Range**
Fuel As Received			
Lower heating value	MJ/kg	7.3	6 – 10
Total moisture	%	50	40 – 55
Bulk density	kg/m3	300	250 – 350
Ash softening point (reducing conditions)	ºC		> 1 100
Analysis of dry solids (%-weight)			
Carbon	%	50	50 – 52
Hydrogen	%	5.4	5.4 – 7
Oxygen	%	42.2	41.5 – 43.2
Nitrogen	%	0.3	0 – 0.5
Sulfur	%	0.05	0 – 0.05
Ash	%	2	0.5 – 3
Chlorine	%	0.02	0 – 0.02
Total	%	100.0	
Volatiles (Moisture and Ash Free basis)	%	80	70 – 85

Alkaline in ash (weak acid soluble)			
(Na+K)	%	≤4.5	≤4.5
Biomass Ash analysis (%-weight)			
SiO_2	%		15 – 50
TiO_2	%		0.1 – 0.4
Al_2O_3	%		4.0 – 10
FeO_3	%		1.0 – 4.0
MgO	%		1.0 – 5.0
CaO	%		20 – 30
Na_2O	%		0.5 – 2.3
K_2O	%		1.0 – 6.5
P_2O_5	%		0.5 – 2.5
MnO	%		1.0 – 3.0
SO_3	%		0.5 – 2.0
Particle size requirements			
Screen Analysis:			
100 %	mm	< 75	< 75
90 %	mm	< 50	< 50
90 %	mm	> 3	> 3
Max. particle size: Sum of all sides (W+H+D)	mm	< 200	< 200

Fuel shall not contain ice, soil, stones and metal objects.

2.1.3 Start-up fuel

Natural gas is used as start-up fuel.

	Composition, vol%
- Nitrogen	0.4
- Methane	83.9
- Ethane	9.2
- Propane	3.3
- Butane and C5	1.4
- CO_2	1.8
Total	100.0
- Sulphur content (as H_2S), mg/Nm^3	4
LHV, MJ/Nm^3	40.6
Molecular weight	19.4

The gas specification is based on a pipeline quality gas from the southern part of the Norwegian off-shore reverses.

2.2 Products and by-products

The main products and by-products of the Plant are listed here below with their specifications.

2.2.1 Electric Power

Net Power Output	:	depending on alternatives	
Voltage	:	380	kV
Frequency	:	50	Hz
Fault duty	:	50	kA

2.2.2 Carbon Dioxide

The Carbon Dioxide characteristics at plant B.L. are the following:

Status	:	supercritical
Pressure	:	110 bar g
Temperature	:	32 °C
Purity:		
Moisture	:	<10 ppmv
N_2 content	:	to be minimized (1)

(1) High N_2 concentration in the CO_2 product stream has a negative impact for CO_2 storage, particularly if CO_2 is used for Enhanced Oil Recovery (EOR). N_2 seriously degrades the performance of CO_2 in EOR, unlike H_2S, which enhances it.

Capture rate	:	90% molar basis

2.2.3 Solid By-products

The plant produces Gypsum as solid by-product that is potentially saleable to the building industry.

2.3 Environmental Limits

The environmental limits set up for the plant are outlined hereinafter.

2.3.1 Gaseous Emissions

The overall gaseous emissions from the plant referred to dry flue gas with 6% volume O_2 shall not exceed the following limits:

	500 MWe Coal Power Station with Cofiring (1) mg/Nm^3 @ 6% O_2 vol.	**250 MWe Biomass Combustion** mg/Nm^3 @ 6% O_2 vol.	**75 MWe Biomass Cofiring** mg/Nm^3 @ 6% O_2 vol.
NO_x	200	200	200
SO_x	200	200	300
Particulate	30	30	30

Note 1: Applicable both to PC Boiler and to CFB Boiler.

For the cases with CO_2 capture the emissions achieved will be lower due to specific constrains of the CO_2 removal technology.

2.3.2 Liquid Effluent

Characteristics of waste water discharged from the plant shall comply with the limits stated by the EU directives:

- 1991/271/EU
- 2000/60/EU

The main continuous liquid effluent from the plant is the seawater return stream.

2.3.3 Solid Wastes

The plant produces the following solid wastes:

- Bottom ash
- Fly Ash

2.3.4 Noise

All the equipment of the plant will be designed to obtain a sound pressure level of 85 dB(A) at 1 meter from the equipment.

2.4 Plant Operation

2.4.1 Capacity

Depending on the different cases the nominal capacity is fixed as follows:

- Case 1: 500 MWe (net) Pulverised Coal (PC) power plant with co-firing of biomass and coal
- Case 2: 500 MWe (net) Circulating Fluidised Bed (CFB) power plant with co-firing of biomass and coal
- Case 3: 250 MWe (net) CFB power plant with standalone biomass firing
- Case 4: 75 MWe (net) Bubbling Fluidised Bed (BFB) power plant with standalone biomass firing

The above mentioned capacities are defined in terms of net power output and they are referred to the cases without CO_2 capture. For the cases with CO_2 capture, the boiler sizes remain constant with the consequence that the plant net power output is reduced, due to the impact of the CO_2 removal and compression units as power and steam consumer.

A minimum equivalent availability of 90% corresponding to 7,884 hours of operation in one year at 100% capacity is assumed for all the alternatives without CO_2 capture starting from the second year of commercial operation. Same equivalent availability has been selected for all the cases as different critical aspects are present in each alternative (Boiler for CFB cases, FGD for PC case etc…).
For the cases with CO_2 capture a minimum equivalent availability of 88% corresponding to 7,710 hours of operation in one year at 100% capacity is assumed for all the alternatives with CO_2 capture due to the introduction of the CO_2 capture plant.
During the first year of commercial operation, when the plants need final tunings, the equivalent availability will be lower than the normal one (i.e.: 80%, corresponding to 7,000 hours for cases without CO_2 capture, 75%, corresponding to 6,570 h/y for the cases with CO_2 capture).
A lower load factor is considered for the plants with CO_2 capture due to the capture and compression units. The availability of the capture unit shall be confirmed once

the first demonstration plant can provide more detailed information on the unit operation.

The units actually operating in the existing plants are designed for applications that are different from the post-combustion CO_2 capture. The characteristics of the flue gases coming from boilers are different from the ones in the existing units, as typically the pressure is lower and the CO_2 is more diluted

In case the solvent cannot tolerate the expected impurity contents, the risk is more related to an higher solvent degradation and therefore to higher operating and maintenance costs associated to the CO_2 capture rather than to lower demonstrated service factor.

2.4.2 Unit Arrangement

The plant is a single train facility with the following arrangement:

1000	Storage and Handling of solid materials, including: Coal storage and handling Biomass storage and handling Limestone storage and handling
2000	Boiler Island and flue gas treating including: DeNOx, Flue Gas Desulphurisation (FGD) Baghouse filter Ash and solid removal
3000	Power Island, consisting of: Steam Turbine Preheating Line
4000	Utility and Offsite Units
5000	CO_2 capture plant (for cases with CO_2 capture)
6000	CO_2 compression and drying (for cases with CO_2 capture)

2.4.3 Turndown

The plant is designed to operate with a good degree of flexibility in terms of turndown capacity and feedstock characteristics.

The minimum turndown of the boiler is 50% as far as duty is concerned. Such turndown is achieved with a decrease of the steam parameters (i.e. RH temperature).

The minimum turndown of the Steam Turbine is around 20% as far as electrical generation is concerned. The Steam Turbine can stably maintain such load if the rated steam conditions are maintained.

The minimum turndown of the CO_2 capture plant is between 30% and 40% on the basis of the flue gases inlet flowrate. At low flue gases flowrate will not correspond a proportional reduction of the circulating MEA as the internals of the column need to be properly wetted by the solvent. Therefore the unit consumptions (in terms of

MEA circulation and steam consumption for MEA regeneration) will be higher than 30%-40%.

In conclusion, even if the minimum turndown of the Steam Turbine and the CO_2 capture plant is much lower, due to the higher turndown of the boiler, the overall plant turndown is some less than 50%. This is due to the reduced steam characteristics at boiler turndown and the higher specific steam consumption in the CO_2 capture plant that have as a consequence the reduction of the Steam Turbine efficiency and an overall power production lower than 50%.

2.5 Location

The site is a green field located on the NE coast of The Netherlands.
No special civil works implications are assumed. The plant area is assumed to be close to a deep sea, thus limiting the length of the sea water lines (both the submarine line and the sea water pumps discharge line). The site is also close to an existing harbor equipped with a suitable pier and coal bay to allow coal transport by large ships and a quick coal handling.

2.6 Climatic and Meteorological Information

The conditions marked (*) shall be considered reference conditions for plant performance evaluation.

- atmospheric pressure: 1013 mbar (*)

- relative humidity
  - average: 60 % (*)
  - maximum: 95 %
  - minimum: 40 %

- ambient temperatures
  - minimum air temperature: -10 °C
  - maximum air temperature: 30 °C
  - average air temperature: 9 °C (*)

2.7 Economic/Financial Factors

2.7.1 Design and Construction Period

Plant design and construction will be completed in 30 months starting from issue of Notice to Proceed to the EPC contractor. Overnight construction will be applied. The curve of capital expenditure during construction is assumed to be:

Year	Investment Cost %
1	20
2	45
3	35

2.7.2 Capital Charges

Discounted cash flow calculations will be expressed at a discount rate of 10% and to illustrate sensitivity at 5%.

2.7.3 Cost of Debt

All capital requirements will be treated as debt at the same discount rate used to derive capital charges. This is equivalent to assuming 100% equity. No interest during construction is applied but the timing of capital expenditure is taken into account in the discounted cash flow analysis.

2.7.4 Inflation

No inflation shall be applied to the economical analysis.

2.7.5 Commissioning

Plant commissioning will take a 6 month period: two months will be during the last phases of the construction and the remaining four once the construction has been completed. No allowance will be made for receipts from sales in this period.

2.7.6 Working Capital

Sufficient storage for 30 days operation at rated capacity will be allowed for raw materials, products, and consumables.

2.7.7 Land purchase, surveys, general site preparation

5% of the installed plant cost is assumed.

2.7.8 Fees

2% of the installed plant cost is assumed to cover process/patent fees, consultant services other than EPC Contractor's services, fees for agents, legal and planning costs. This item is part of the capital cost.

2.7.9 Operation and Maintenance

Labour and Maintenance data used for the economical evaluation are summarized in Section E.

2.7.10 Taxation and Insurance

1% of the installed plant cost per year is assumed to cover local taxation. Taxation on profits is not included. The same percentage of the installed plant cost per year is assumed for insurance.

2.7.11 Fuel Costs

Cost of coal delivered to site is 75 €/t.
Cost of biomass delivered to site is 144 €/t (dry basis).

2.7.12 By-Products Price

No selling price is attributed to Gypsum. It is treated as neutral.

2.7.13 Currency exchange rate

The estimate was developed in Euro.
The following exchange Euro to US $ rate has been used:

1.35 US $ equivalent to 1 Euro.

2.7.14 CO_2 price

No selling price is attributed to CO_2 in the base case; different scenarios with different evaluations of benefits related to CO_2 capture are analyzed in section E.

The figures considered for the Green Certificates and ETS are the following:
- Green certificates: 50 €/MWh;
- ETS: 14 €/t CO_2 captured

2.8 Software Codes

For the development of the Study, two software codes will be mainly used:

- PROMAX v2.0 (by Bryan Research & Engineering Inc.): flue gas amine sweetening process for CO_2 removal.
- Gate Cycle v6.0 (by General Electric): Simulator of Power Island used for Steam Turbine and Preheating Line simulation.
- Aspen HYSYS 2006 (by AspenTech): Process Simulator used for CO_2 compression and drying.

3.0 Basic Engineering Design Data

Scope of the Basic Engineering Design Data is the definition of the common bases for the design of all the units included in the plant to be built on the east coast area of Netherlands.

Process Units:
- 1000: Storage and Handling of solid materials, including:
  - 1100: Coal storage and handling
  - 1200: Biomass storage and handling
  - 1300: Limestone storage and handling
- 2000: Boiler Island and flue gas treating, including:
  - 2100: Boiler
  - 2200: DeNOx
  - 2300: Flue Gas Desulphurisation
  - 2400: Baghouse filter
  - 2500: Ash and solid removal and handling
- 5000: CO_2 capture plant (for cases with CO_2 capture)
- 6000: CO_2 compression and drying (for cases with CO_2 capture)

Power Island including:
- 3100: Steam Turbine;
- 3200: Preheating Line;
- 3300: Electrical Power Generation.

Utility and Offsite Units providing services and utility fluids to all the units of the plant; including:
- 4100: Sea Cooling Water/Machinery Cooling Water Systems;
- 4200: Demineralized, Condensate Recovery, Plant and Potable Water Systems;
- 4300: Back-up fuel system
- 4400: Plant/Instrument Air Systems;
- 4500: Waste Water Treatment;
- 4600: Fire fighting System;
- 4700: Chemicals;
- 4800: Ash storage and handling;
- 4900: Interconnecting (instrumentation, DCS, piping, electrical, 400 kV substation).

3.1 Units of Measurement

All calculations are and shall be in SI units, with the exception of piping typical dimensions, which shall be in accordance with ANSI.

3.2 Site conditions

- Site elevation
  plant area : 6 m above mean sea level.
- Atmosphere type : coastal area with salt pollution.

3.3 Climatic and Meteorological Information

Reference is made to para. 2.6 for main data.

Other data:

- Rainfall
  design : 25 mm/h
  50 mm/day
- Wind
  maximum speed : 35 km/h
- Snow
  : 50 kg/m^2
- Winterization
  winterization is required.
- Sea water supply temperature and salinity
  average (on yearly basis) : 12 °C
  maximum average (summer) : 14 °C
  minimum average (winter) : 9 °C

  salinity : 22 g/l

3.4 Soil data

- Earthquake
  earthquake factor : negligible

- Geology
  green field site with no special civil works implications.

3.5 Project Battery Limits design basis

3.5.1 Electric Power

High voltage grid connection:	380 kV
Frequency:	50 Hz
Fault duty:	50 kA

3.5.2 Process and Utility Fluids

The streams available at plant battery limits are the following:

- Coal;
- Biomass;
- Natural gas;
- Sea water supply;
- Sea water Return;
- Plant/Raw/Potable water;
- Gypsum product;
- CO_2 rich stream.

3.6 Utility and Service fluids characteristics/conditions

In this paragraph are listed the utilities and the service fluids distributed inside the Plant.

3.6.1 Cooling Water

The plant primary cooling system is sea water in once through system.

Sea Cooling Water (primary system)

Source : sea water in once through system
Service : for steam turbine condenser and CO_2 compression and drying exchangers, machinery cooling water-cooling.
Type : clear filtered and chlorinated, without suspended solids and organic matter.

Supply temperature:

- average supply temperature (on yearly basis) : 12 °C
- max supply temperature (average summer) : 14 °C
- min supply temperature (average winter) : 9 °C
- max allowed sea water temperature increase : 7 °C

Return temperature:

- average return temperature : 19 °C
- max return temperature : 21 °C

Operating pressure at Users inlet : 0.9 barg

Max allowable ΔP for Users : 0.5 barg

Design pressure for Users : 4.0 barg
Design pressure for sea water line : 4.0 barg
Design temperature : 55 °C
Cleanliness Factor (for steam condenser) : 0.9
Fouling Factor : 0.0002 h °C m^2/kcal

Machinery Cooling Water (secondary system)

Service : for machinery cooling and for all plant users other than steam turbine condenser and CO_2 compression and drying exchangers.
Type : demiwater stabilized and conditioned.

Supply temperature:

- max supply temperature : 17 °C
- min supply temperature : 13 °C
- max allowed temperature increase : 12 °C
- design return temperature for fresh cooling water

cooler	: 29	°C
Operating pressure at Users	: 3.0	barg
Max allowable ΔP for Users	: 1.0	bar
Design pressure	: 5.0	barg
Design temperature	: 50	°C
Fouling Factor	: 0.0002 h °C m^2/kcal	

3.6.2 Waters

Potable water

Source	: from grid	
Type	: potable water	
Operating pressure at grade	: 0.8	barg (min)
Operating temperature	: Ambient	
Design pressure	: 5.0	barg
Design temperature	: 38	°C

Raw water

Source	: from grid	
Type : potable water		
Operating pressure at grade	: 0.8	barg (min)
Operating temperature	: Ambient	
Design pressure	: 5.0	barg
Design temperature	: 38	°C

Plant water

Source	: from storage tank of raw water	
Type : raw water		
Operating pressure at grade	: 3.5	barg
Operating temperature	: Ambient	
Design pressure	: 9.0	barg
Design temperature	: 38°C	

Demineralized water

Type : treated water (mixed bed demineralization)

Operating pressure at grade	:	5.0 barg
Operating temperature	:	Ambient
Design pressure	:	9.5 barg
Design temperature	:	38 °C

Characteristics:

- pH		6.5÷7.0	
- Total dissolved solids	mg/kg	0.1	max
- Conductance at 25°C	μS	0.15	max
- Iron	mg/kg as Fe	0.01	max
- Free CO_2	mg/kg as CO_2	0.01	max
- Silica	mg/kg as SiO_2	0.015	max

3.6.3 Steam and BFW

Steam

The main characteristics of the Steam at Boiler B.L. are shown in the following table.

Table B.3.1 – steam conditions.

	HP SH		**Cold RH**	**Hot RH**	
	P, bar	**T, °C**	**T, °C**	**P, bar**	**T, °C**
Case 1 – 500 MWe (PC)	275	580	340	55	600
Case 2 – 500 MWe (CFB)	275	580	350	60	600
Case 3 – 250 MWe	169	565	354	39	565
Case 4 – 75 MWe	115	540	-	-	-

Boiler Feed Water

The main characteristics of the Boiler Feed Water at Boiler B.L. are shown in the following table.

Table B.3.2 – Boiler Feed Water at units B.L.

	T, °C
Case 1 – 500 MWe (PC)	290
Case 2 – 500 MWe (CFB)	290
Case 3 – 250 MWe	290
Case 4 – 75 MWe	225

3.6.4 Instrument and Plant Air

Instrument air

Operating pressure			
- normal	:	7.0	barg
- minimum	:	5.0	barg
Operating temperature	:	40	°C (max)
Design pressure	:	10.0	barg
Design temperature	:	60	°C
Dew point @ 7 barg	:	-30	°C

Plant air

Operating pressure	:	7.0	barg
Operating temperature	:	40	°C (max)
Design pressure	:	10.0	barg
Design temperature	:	60	°C

3.6.5 Natural Gas

Characteristics of Natural Gas are listed at para 2.1.2, Project Design Bases.

Type : natural gas.
Service : boiler start-up fuel

Operating pressure at Users	:	3.5	barg
Operating temperature at Users	:	30	°C
Design pressure	:	6.0	barg
Design temperature	:	60	°C

3.6.6 Limestone

The Limestone is used both as the fluidised bed material and in the FGD with the following characteristics.

Composition:
- $CaCO_3$ % wt. (dry) >95
- $MgCO_3$ % wt. (dry) = 1.5
- Inert % wt. (dry) = 3.5

The Limestone is available at plant B.L. as pebbles and need to be milled to the required sizes.

3.6.7 Chemicals

Caustic Soda

A concentrated (50% by wt) NaOH storage tank is foreseen and used to unload caustic from trucks.
Concentrated NaOH is then pumped and diluted with demineralized water to produce 20% by wt NaOH accumulated in a diluted NaOH storage tank.
The NaOH solution is distributed within plant with the following characteristics:

Supply temperature, °C	Ambient
Design temperature, °C	70
Supply pressure (at grade) at unit BL barg	3.5
Design pressure barg	9.0
Soda concentration wt %	20

Hydrochloric Acid

Two concentrated (20% by wt) HCl storage vessels are foreseen and used to unload hydrochloric acid from trucks.
Concentrated HCl is pumped to users where is firstly diluted if necessary.

Supply temperature, °C	Ambient
Design temperature, °C	70
Supply pressure (at grade) at unit BL barg	2.5
Design pressure barg	5.0
Hydrochloric concentration wt %	20

Chemical for DeNOx

Aqueous ammonia will be used as reducing agent in this application with the following characteristics:

NH_4OH: with NH_3 concentration 25% by weight (commercial grade)

3.6.8 Electrical System

The voltage levels foreseen inside the plant area are as follows:

	Voltage level (V)	*Electric Wire*	*Frequency (Hz)*	*Fault current duty (kA)*
Primary distribution (1)	33000 ± 5%	3	50 ± 0.2%	31.5 kA
MV distribution and utilization	10000 ± 5% 6000 ± 5%	3 3	50 ± 0.2% 50 ± 0.2%	31.5 kA 25 kA
LV distribution and utilization	400/230V±5%	3+N	50 ± 0.2%	50 kA
Uniterruptible power supply	230 ± 1% (from UPS)	2	50 ± 0.2%	12.5 kA
DC control services	110 + 10%-15%	2	-	-
DC power services	220 + 10%-15%	2	-	-

Note (1): Applicable for Case 1 and 2 only. To be confirmed during the study development.

3.7 Plant Life

The Plant is designed for a 25 years life, with the following considerations:

- Design life of vessels, equipment and components of equipment will be as follows:
  - 25 years for pressure containing parts;
  - 5 years for replaceable parts internal to static equipment.

- Design life of piping will be 10 years.

- For rotating machinery a service life of 25 years is to be assumed as a design criterion, taking into account that cannot be applicable to all parts of machinery for which replacement is recommended by the manufacturer during the operating life of the unit, as well as to small machinery, machines on special or corrosive/erosive service, some auxiliaries and mechanical equipment other than rotating machinery.

3.8 Codes and standards

The project shall be in accordance to the International and EU Standard Codes.

CLIENT	:	IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME	:	TECHNO-ECONOMIC EVALUATION OF CAPTURING CO_2 FROM BIOMASS FIRED POWER PLANT
DOCUMENT NAME	:	DESCRIPTION OF THE MAJOR BLOCKS COMMON TO THE POWER GENERATION ALTERNATIVES

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CHECKED BY	:	P. COTONE
APPROVED BY	:	F. GASPARINI

Date	Revised Pages	Issued by	Checked by	Approved by
May 2009	Rev 0	S. Cavezzali	P. Cotone	F. Gasparini
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SECTION C

DESCRIPTION OF THE MAJOR PROCESS BLOCKS COMMON TO THE ALTERNATIVES

INDEX

SECTION C

1.0 Storage and Handling of solid materials

1.1. Coal

The coal is delivered to the power station by ship.
The coal is unloaded by a continuous unloading system, composed essentially by a bucket elevator supported by a boom structure which can travel alongside the ship.
The boom is equipped with an hydraulic luffing system which adjusts the elevator position during the unloading operation.
The elevator unloads the coal onto a number of consecutive conveyors and hoppers which eventually discharge the coal to the conveyor travelling along the pier.
From here, the coal is transported to the coal storage by belt conveyors. The system is enclosed to avoid spillages to the environment; the transfer from one conveyor to the other is in "transfer towers", equipped with filters and exhausting blowers.
The coal storage is sized for 21 days of operations. The storage volume is sufficient to accommodate the full inventory of one ship, while still storing the coal needed for one week of operation, thus allowing for the harbour downtime.

At the plant site the coal is stored in a dome, internally equipped with a stacker-reclaimer system which both distributes the coal in the dome and reclaims it for feeding the boiler.

The coal from the reclaimer is discharged onto enclosed belt conveyors to 2 elevated feed hoppers each sized for a capacity equivalent to 2 hours. Before the entrance to the feed hoppers a magnetic separator is provided to remove tramp iron.
Coal is discharged from the feed hoppers, at controlled rate, and transported by belt feeders to 2 parallel crushers, each sized for 100% of the full capacity. The crushers are designed to break down big lumps and deliver a coal with lump size not exceeding 35 mm (Case 1: 500 MW PC boiler) or 8mm (Case 2: 500 MW CFB boiler).
Coal from the crushers is transferred by enclosed belt conveyors to the day silos close to the process area.

Enclosed belt conveyors, storage hoppers and silos, flow control feeders and other equipment handling coal lignite are potential source of air pollution due to dispersion of fine powder. To control the plant environment all this equipment are connected to a bag filters and exhaust fans that permit the capture of any coal powder generated in the coal handling area.

1.2. Biomass

The biomass is delivered to the power station by ship and or trucks.
The biomass is unloaded by a grab unloading system, composed essentially by a grab crane mounted on a boom structure which can travel alongside the ship.
The grab discharges the biomass into a hopper and then through a discharge feeder onto a belt conveyor which eventually discharges the biomass to the conveyor travelling along the pier.
From here, the biomass is transported to the storage building by belt conveyors and then distributed by a tripper .
The building has a rectangular footprint and is sized for 21 days of operation.
The reclaim of the biomass from the storage building is by means of screws, which load a belt conveyor.
The system is enclosed to avoid spillages to the environment; the transfer from one conveyor to the other is in “transfer towers”, equipped with filters and exhausting blowers.

1.3. Limestone

The limestone is delivered to the power station by ship and or trucks.
The limestone is unloaded by the same grab unloading system used for the biomass and delivered to the storage silos.
From the storage the limestone is sent to the crusher and then to the boiler day silo or to the FGD slurry preparation system.

2.0 Boiler Island

For the boiler description reference shall be made to each case where a specific description of the boiler considered is made.

3.0 Ash and By-Products Handling

3.1. Ash

Power generation from PC/CFB Boilers involves the handling of two types of ash:

- Bottom ash
- Fly ash

Bottom ash is produced during the process of total or partial combustion and is the result of fuel ash melting and subsequent cooling. Consequently it is a coarse product of lumps of various sizes, and is collected at the bottom of the combustion furnace.
Fly ash is also derived from the melting and cooling of the ash contained in the coal, but, due to the micron and submicron particles size, is entrained out of the combustion chamber by the flue gas and collected in downstream equipment: electrostatic precipitators or bag filters.
Bottom ash is generally disposed in a landfill while fly ash can be used in the cement industry as a valuable cement formulation component.
The bottom ash is crushed by a grinder to reduce the lump size, thus making handling and transportation easier.
The fly ash is discharged from the collecting hoppers by star valves into a dense phase, pneumatic transport, which carries the fly ash to storage silos. From the silos the fly ash is loaded by gravity to trucks for transportation. Cyclones and exhaust filter bags are used to prevent air contamination.

3.2. Gypsum

Gypsum is produced only in the alternatives where an external FGD is foreseen.
The gypsum (in paste form) is discharged onto belt conveyors and sent to the storage building, where it is distributed by a tripper.
The gypsum is reclaimed by a portal type reclaimer, able to travel the full length of the building, transported by belt conveyors and loaded onto ships through a continuous loader.

4.0 Flue Gas Denitrification (DeNOx)

The combustion of fossil fuels produces nitrogen oxide (NO) and dioxide (NO_2), collectively called NO_x. The monoxide (NO) is the predominant species.
Selective catalytic reduction (SCR) is a process that catalytically reduces NO_x to N_2 in presence of NH_3.

SCR is today the dominant technology for the control of NO_x in the power generation industry.
An SCR system consists mainly of an ammonia storage, evaporation and injection by mean of a distribution grid followed by the SCR catalytic reactor schematically shown in Figure 4.1.

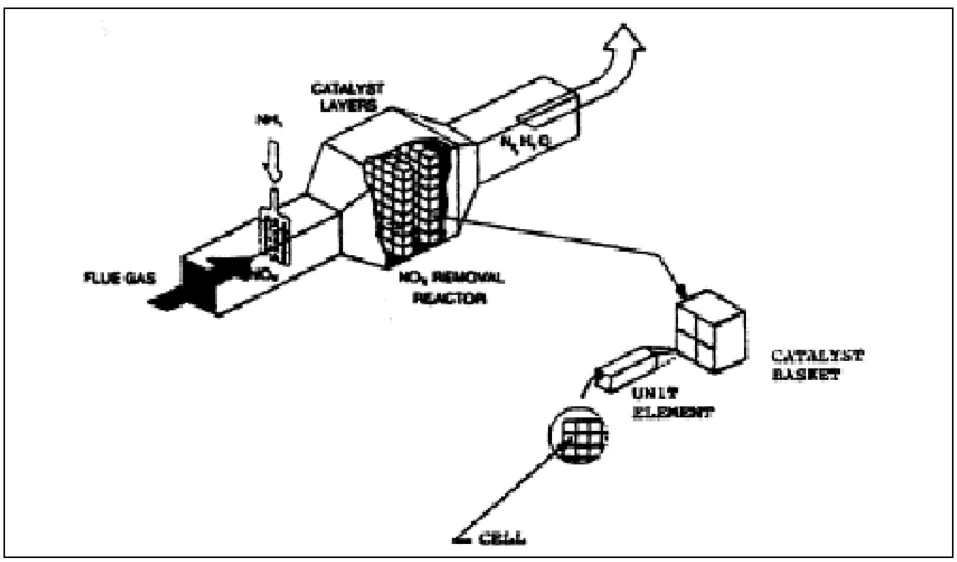

Figure 4.1 SCR System

The honeycomb catalyst cells are contained in square catalytic baskets. The ceramic cells support the active catalyst components, V_2O_5, T_iO_2 and WO_3. V_2O_5 is the most active but promotes also SO_2 oxidation to SO_3 and may be the cause of catalyst sintering at high temperature. Therefore the catalyst formulation is different for different applications. As an alternative, plate-type catalysts are used, which are mainly constituted by a stainless steel carrier and ceramic material rolled on. TiO_2, V_2O_2 and WO_3 are the active catalytic materials.

Cell size varies from 3 to 8 mm. Smaller cells are used in clean gas service; larger cells in dirty gas service.
In absence of SO_2 SCR can operate at low temperature, as low s 200°C. When SO_2 is present in the flue gas also SO_3 is present, in small quantities, but sufficient to react with excess NH_3 to form ammonium sulphate and bisulfate. The first is powdery but the second is sticky and can plug catalyst and equipment. The lower the temperature the higher is the probability of sulphate/bisulphate formation. For this reason SCR in presence of SO_2/SO_3 must operate at high temperature: minimum 300-310°C if SO_3 is less than 5 ppm; higher temperatures, 310-330°C for higher SO_3 concentration. To obtain these temperatures the SCR is normally located between the economizer and the air preheater (Figure 4.2).
In clean gas service the flue gas flow can be horizontal or vertical. In dirty gas service the flow is vertical downward and assisted by soot blowers between the catalyst layers to keep the catalyst clean.

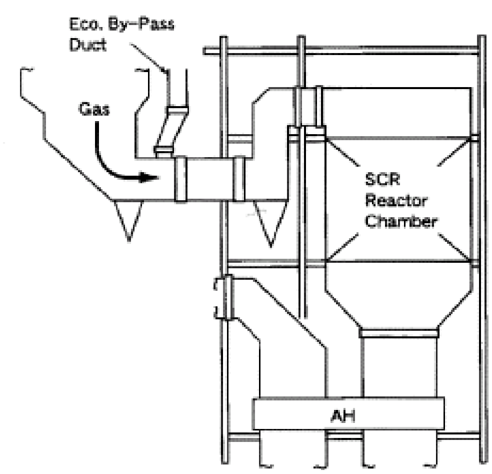

Figure 4.2 SCR in conventional boilers

As shown in Figure 4.2 the catalyst temperature is kept under control at reduced capacities by bypassing a portion of the flue gas around the last economizer bank.

Two types of ammonia injection are in use. The first uses liquid ammonia, which is vaporized then mixed with air and fed to the distribution grid, inside the flue gas duct. The second system uses aqueous ammonia (25-30% NH_3), which is vaporised by means of steam, then mixed with air and heated up to 150°C into a dedicated steam heat exchanger or in a dedicated coil in the boiler duct. The diluted ammonia gas/air mixture is fed to the distribution grid. This second system is generally preferred because of the easier and safer handling and transportation of aqueous ammonia.

As an alternative, gaseous ammonia can be produced via the hydrolysis of urea (NH_2 CO NH_2) water solution by heating in a pressurised reactor (hydrolyser). Gases (NH_3, CO_2, and H_2O) exiting the hydrolyser are mixed with the hot conveying air, heated up to 150°C in a steam heat exchanger and then sent to the ammonia injection grid.
The urea is a common fertilizer and can be transported and handled easily being neither toxic nor explosive.

SCR systems are operated with a careful management of the catalyst and a close control of the NH_3 slip (excess NH_3). At start-up only 50-70% of the catalyst is loaded and NH_3 slip is kept at minimum (0.5 ppm) to meet the required NO_x. With the aging of the catalyst the NH_3 slip is increased progressively up to a maximum, usually 1-3 ppm. At this point, normally 1-2 years after start-up, the remaining portion of the fresh catalyst is loaded and the NH_3 slip can go back to a minimum value and then progressively increased to compensate further catalyst aging until the end of catalyst life.

5.0 Flue Gas Desulphurization (FGD)

Over the last 40 years there have been several significant advancements in the design and performance of FGD systems.
Early demonstrations in USA, Japan and Europe took place in the 1960s. By the mid-1970s the technology was already wide spread in the three areas, but was plagued by a number of problems: relatively high capital and operating costs, poor reliability, scaling and fouling of equipment.

Two alternative FGD systems were proposed:

- wet FGD
- dry FGD

Wet FGD employs to capture SO_2, a scrubbing process, based on a water slurry or a water solution of an alkaline reagents: lime, limestone, sodium carbonate, magnesium oxide, ammonia, dual alkali. Some proposed the use of seawater, others, such as Wellman-Lord developed a regenerable wet process based on sodium sulfite. Most of these reagents have been largely abandoned in favour of the less costly lime-limestone.

The dry FGD involves the spraying of finely atomized droplets of hydrated lime slurry in the flue gas stream, in an optimum temperature window, 150-180°C, which evaporates the water and maximize the utilization of the reagent. An alternative version of the dry FGD involves the injection of a dry sorbent powder, lime, limestone or sodium carbonate. In both cases, downstream the injection point, a bag filter captures the solid particles. The solid particle layer on the bag surface still contains some unreacted reagents, thus, providing an effective second stage of contact between the alkali and the residual SO_2 in the flue gas.

Wet FGD, based on limestone-lime, is today the dominant technology. This position is the result of a number of advancements accomplished in the past 30 years. These advancements are described in the following paragraphs.

a. Forced Oxidation

Early calcium-based systems experienced severe scaling-fouling problems, causing an increase of capital cost (spare equipment) and maintenance cost.
To resolve this problem two processes were proposed: inhibited oxidation and forced oxidation. The first attempted to reduce conversion of sulfite to sulphate, with the addition of a reducing agents (thiosulphate or sulphur). The second achieved full oxidation of SO_2 to SO_3 with the addition of air. Both processes reduced or eliminated fouling but the forced oxidation

became the preferred route because the solid by-product, gypsum, was a saleable product rather than the throwaway sulfite-sulphate mixture made by the inhibited process.

b. Organic acids

The addition of organic acids, adipic acid, formic acid, to the slurry was found to be an effective way to improve mass transfer and achieve higher SO_2 removal efficiency (95-99%) at a lower liquid to gas ratio.

c. Contacting Trays

Special dual flow and sieve trays have been developed for the absorber, to improve gas-liquid contact and mass transfer.

d. Design and layout of spray nozzles and use of wall rings

Adjusting the configuration and positioning of the spray nozzles in the absorber improved the capture of SO_2. Further the use of wall rings inside the absorber redirected the gas flow along the walls toward the middle of the tower, where the spray density is higher, and redistributed the liquid along the walls back into the spray zone.

e. Mist Eliminators

Design of mist eliminators was improved to permit mist collection efficiency at high gas velocity.

f. Computational fluid dynamic (CFD)

CFD was a key tool to improve the design of FGD systems. This modelling technique permitted a better knowledge of the performance of a counter current open spray tower, which produced the following benefits:

- higher flue gas velocity; in excess of 5 m/s, vs. the 2-3 m/s of the early designs;
- Smaller absorbers;
- Single module for large power generation capacity.

g. Hydrocyclones

The gypsum-limestone slurry, leaving the absorber, in the early wet FGD systems was treated in very large thickeners to separate a solid rich mud from clean water, recycled back to the absorber. In the more recent designs the thickeners have been substituted by the more effective and less costly hydrocyclones. The hydrocyclones rely on centrifugal forces to separate solids from water; further they achieve a better separation between the larger gypsum particles, ending in the underflow, and the smaller limestone particles, ending in the overflow recycled back to the absorber. The final result is a superior gypsum quality, less contaminated with unreacted limestone, and a better utilization of limestone reagent, recycled back to the absorber.

The limestone specification is:

$CaCO_3$	% wt	95.00 min
MgO	% wt	0.15 max
Inerts	% wt	4.85 max
Average lump size		10 cm

The wet FGD process, shown in the attached flowsheet of Fig. 5.1 is a typical configuration of a modern, large capacity module, with minimum use of spare or stand-by equipment. To overcome pressure drops a blower is installed at the unit entrance, followed by a regenerative heat exchanger (Ljungstroem type) to reheat the flue gas going to the stack. As an alternative, when high SOx removal is required, a “zero leakage” heat exchanger can be used. In this case, two different exchangers are foreseen: one for clean gas side and one for raw gas side. A closed cycle water circuit performs heat transfer between the exchangers.

A water prescrubber, used to reduce particulates, halogens and to saturate and cool the flue gas can be optionally installed.

The limestone scrubber is a countercurrent, open spray tower, possibly with one or two contact trays. As an alternative, a bubbling reactor can be used.

The mist separator at the top is a lamella shape bundle, periodically flushed with water. The bottom sump of the tower is divided into an oxidation zone, receiving air from a blower, and a crystallization zone to grow the size of gypsum crystals.

The overall reaction, taking place, is:

$$CaCO_3 + SO_2 + \frac{1}{2} O_2 + 2H_2O \rightarrow CaSO_4 \times 2H_2O + CO_2$$

The scrubber bottom slurry is dewatered in hydrocyclones. The overflow is recycled back to the scrubber. The underflow is dewatered in a vacuum belt filter or, alternatively, in centrifuges.

A fraction of the hydrocyclones overflow is discharged to remove from the circulating system dissolved salts (chlorides, fluorides, etc.) which, otherwise, would continuously grow in concentration. This blowdown, before discharge to sewer, is treated with soda and sodium sulphide, for metal precipitation, and then passed to a thickener, pressfilter and sandfilter.

It should be noticed that, if the FGD is followed by CO_2 amine scrubbing, the SO_2 content at the FGD outlet should be as low as possible, close to 10 ppmv or 30 mg/Nm^3 to reduce amine consumption. This is a challenge for today available FGD technology, but probably not an impossible target for the cases considered in this study in view of the low S content of the design coal and/or biomass feed.

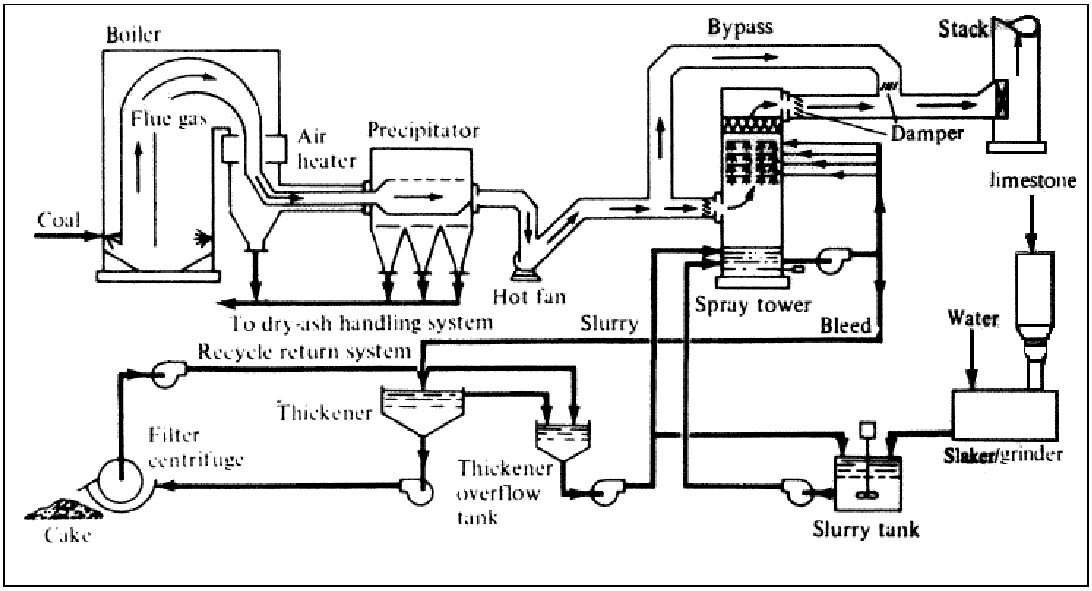

Figure 5.1 FGD Flow Scheme

6.0 MERCURY, HEAVY METALS AND MINOR IMPURITIES REMOVAL

The removal of mercury and heavy metals (Ni, V, etc.) from flue gas is a relatively recent requirement to improve the environmental performance of the power generation industry.

The industrial experience accumulated so far is limited with respect to other emissions control technologies. Even legislation is not well established in many countries or still waiting for a final assessment of the status of the technologies.
EPRI has been active in this area and have participated to development and testing of the most promising technology that is based on the use of active carbon injection followed by a bag house filter, capturing the submicron particulate, where heavy metals are concentrated. Mercury is absorbed on the active carbon injected and trapped by the filter. Mercury removal rates as high as 90% has been demonstrated, with the residual Hg in the flue gas in the 1-3 $\mu g/Nm^3$ range. Oxidized forms of Hg are hardly captured.

Halogens can be present in the flue gases, especially from the CFB/BFB boilers. Calcium oxide passes from the bed and it helps the removal of halides.

7.0 CO_2 Postcombustion Capture

The CO_2 capture technology is mainly used today to purify syngas used in the chemical industry (ammonia, hydrogen), to remove CO_2 from natural gas, to supply CO_2 to the merchant market (beverage, dry-ice, etc.) and for use in enhanced oil recovery (EOR). There is as yet no commercial market for its use in the power industry for the post combustion capture of CO_2.

Several technologies are available for the capture of CO_2:

- Solvent absorption
- Pressure swing adsorption on molecular sieve
- Selective membrane
- Cryogenic processing.

Several solvents can be used: physical, chemical, and intermediate. The chemical solvents (amine) seem to be the best candidate because the CO_2 partial pressure in the flue gas is extremely low and chemical solvents, contrary to physical solvents, are less dependent on CO_2 partial pressure to achieve a satisfactory solvent CO_2 loading.
On the other side chemical solvents require, during solvent regeneration, more energy (steam) to break the relatively strong chemical link between CO_2 and the solvent.
Sterically hindered amines are chemical solvents, that display a weaker link with CO_2, intermediate between a standard amine, like MEA and a physical solvent, like methanol, showing the interesting compromise of lowering the consumption of regeneration steam.

Because of the advanced state of development of amine absorption it is likely that the first generation of CO_2 post combustion capture is going to be based on amine. However the flue gas amine scrubbing is confronted with the problem of the presence of oxygen, which causes solvent degradation and equipment corrosion. This requires incorporation in the solvent of inhibitors to counteract O_2 activity. Three companies offering, the solvent formulation with special inhibitors are:

Fluor : formulated MEA
ABB Lummus : formulated MEA
MHI : formulated sterically hindered amine.

The process scheme and equipment used by these three processes are standard and do not have any novel or proprietary know-how content.

Transferring the formulated amine scrubbing process to the power industry, for CO_2 capture from the flue gas, involves an important scale up issue. However this is not considered to be a big problem because the equipment used permit large scale up in capacity without great risk. Two 12 m diameter absorbers and one regenerator can be designed comfortably and could accommodate a flue gas flow of 2,200,000 Nm^3/h containing 12% CO_2, which corresponds to a coal fired station with a net power generation of 660 MW.

The energy consumption of the amine CO_2 recovery is very high. Electric energy is consumed by flue gas blowers to overcome the system pressure drop; additionally thermal energy is lost in making available LP steam for amine regeneration by extraction from the steam turbine. Another indirect cost, involved by the amine CO_2 removal, is the additional expenditure in the upstream FGD facility, to meet the extremely low levels of residual SO_x in the flue gas, before entering the amine scrubbing. In fact, SO_x and NO_2 react with MEA to form a stable and non regenerable salt, thus causing a continuous loss of solvent. For this reason the flue gas fed to amine scrubbing should not exceed the following limits:

NO_2	20 ppmv	(40 mg/Nm^3) @ 6% O_2 vol dry
SO_X	10 ppmv	(30 mg/Nm^3) @ 6% O_2 vol dry

The percentage of NO_2 in NO_x can vary, depending on the technology, from 3-5% in PC boilers to 15-20% in CFB/BFB boilers. The use of low NO_x burners together with SCR generally permits to meet the required NO_x specification, but the SO_x limit (10 ppm) is a serious challenge for today FGD technology. Some amine technologies may require sulphur content even lower than 10 ppmv in order to further reduce the solvent degradation. In this case an additional stage of desulphurisation is needed.

Another risk issue of post combustion CO_2 removal is the effect on amine solution of other types of impurity (halogens, metals etc.), which may be present in coal fired plant flue gas. Despite the fact that technical solutions for the removal of all these impurities can be found, the demonstration of their effectiveness is an important step before investing in a large capacity plant.

In case the solvent cannot tolerate the expected impurity contents, the risk is related to an higher solvent degradation and therefore to higher operating and maintenance costs associated to the CO_2 capture.

The process flowsheet of the CO_2 amine removal is shown in Figure 7.1.

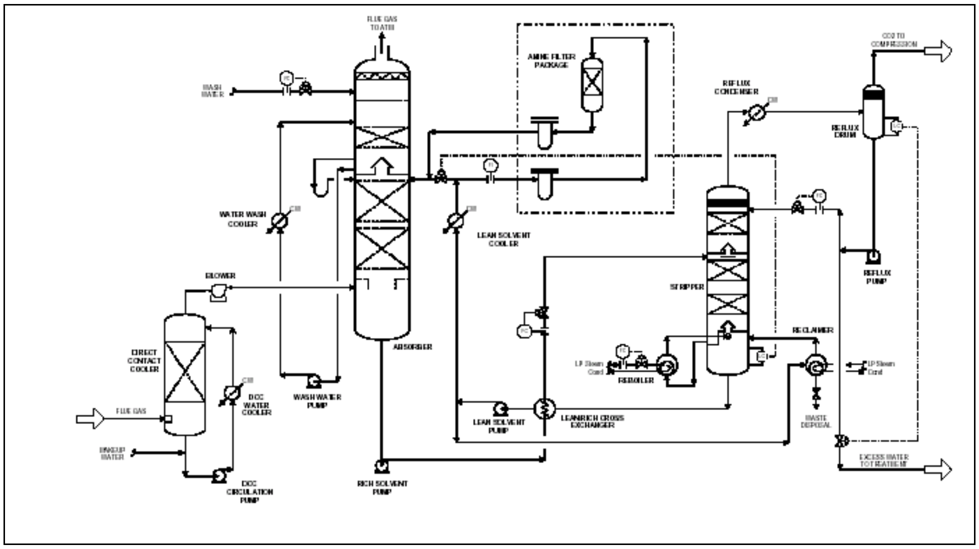

Fig 7.1 – CO_2 postcombustion capture; typical flow scheme

Treated flue gas flows to the direct quench tower where it is contacted with circulating water. The flue gas is cooled and cleaned and then flows to the MEA absorber.
In the absorber the flue gas is first contacted with a semi-lean MEA solution, in the lower section of the tower, and with a fully stripped lean solution in the upper part of the tower.
The scrubbed syngas is then washed and cooled in the tower top section with a stream of circulating water, cooled in an external heat exchanger. Reaction heat between MEA and CO_2 is removed by the top and bottom pump-around.
Make-up water scrubbing in the demister, at the top of the tower, captures any MEA entrainment. The flue gas leaves the top of the tower and goes to the stack after being reheated with the hot flue gases at unit inlet to avoid an excessive plume at stack outlet.

Rich amine from the bottom is pumped to the regeneration section. Before heat exchange with the stripped, hot, amine from the stripper, rich MEA is split into two streams: one flows to the stripper and the remaining to the flash drum. The flashed MEA becomes the semi-lean solution used in the absorber bottom section, while the MEA stripped in the regenerator is the lean MEA used in the absorber top section.

A slipstream of the circulating lean solvent is passed through a mechanical filter to control the suspended solids concentration in the solvent. Suspended solids are considered to be a major cause of foaming in absorbers and regenerators. This mechanical filtration can be supplemented by filtration through an activated carbon bed to remove surface-active contaminants.

The amine solvent circulation system is essentially a closed loop, thus, degradation products and contaminants build up in the system overtime. These undesired compounds decrease the capacity of the solvent in the acid gas removal process and can cause severe operational problems (foaming, emulsion formation, etc.) and impact equipment integrity by increasing the corrosion rate.

A solvent reclaimer unit is a separate unit used to maintain a suitably low concentration of degradation products and contaminants in the solvent.

A demonstration plant has been built in Esbjerg (Denmark) on a coal 420MWe power plant for the CASTOR Project. In this plant a 30% wt MEA solution has been tested on a flue gas flow of 5000 Nm^3/h.
Other demonstrative plants are in the engineering phase, always considering MEA as solvent type.

The content of MEA in the flue gases at stack it is expected to be around 1-3 ppmv, while the content of MEA in the CO_2 pure stream it is expected to be lower than 1 ppmv.

8.0 CO_2 COMPRESSION AND DRYING

CO_2, as produced in the various power generation alternatives described in Section D, must be compressed up to 110 bar g, prior to export for sequestration, as per the battery limit definition.
CO_2, at these conditions is a supercritical fluid (critical point: 31.1°C; 73.9 bar). Although compression to supercritical will be used, this is not an essential requirement, but it depends on the final use of the CO_2 and the CO_2 pipeline length.

All the equipment involved in the process are proven technology, amply demonstrated also for the capacity required by this study.

As a general description, incoming CO_2 at low pressure is saturated with water at temperature close to atmospheric temperature. After separation of possible liquid entrainments, the CO_2 stream is compressed in the first and second stage of a centrifugal compressor. Interstage cooling and water separation are provided at the outlet of the first two stages of compression. Cooling is obtained by preheating of cold condensate followed by air or water trim cooling.

CO_2 from the 2nd stage is routed through the dehydration unit, where humidity water is removed and the gas is dried. The driers are designed to produce CO_2 product with a final water content less than 10 ppmv. The dehydration is carried out via a solid desiccant, like Activated Alumina and Molecular Sieves.

The solid adsorbent bed is contained in a vessel through which wet gas passes and water is adsorbed into the bed. A sequenced valve system switches the duties of the two vessels as one bed is exhausted. In normal operation one bed is used for drying, while the water-saturated bed is regenerated using a small part (ca.10%) of the dry product gas.
Activated alumina meets water specifications of 10 ppm in dried gas while mol sieves achieve less than 1 ppm

CO_2 is then further compressed in a two stages compressor equipped with intercoolers between stages. Supercritical CO_2 at 74 bar is pumped by the CO_2 pump at 110 bar to the pipeline for delivery to the sequestration site.
The adopted centrifugal compressors operate at high speed (9600 r.p.m.), requiring a gearbox. Two 50% capacity compression lines, operating in parallel, are provided with a common drier.

An alternative dehydration system is a triethylene glycol (TEG) system. In this alternative, the wet gas stream enters from the bottom of the absorber and is contacted with descending glycol which absorbs the water from the gas. Dry gas leaves the top of the absorber. The glycol then passes to a regeneration section where a reboiler operating around 180 °C vaporizes the water and water free glycol returns to the absorber. This is a continuous circulating process.

A significant disadvantage of the TEG system is that the circulating TEG absorbs approx. 10% of the carbon dioxide passing through the contactor tower. This carbon dioxide is released from the reboiler system and must be recovered if the project's CO_2 capture target is to be met. Thus the reboiler vent can be routed to the first stage suction of the CO_2 compressors. The CO_2 compressors and dehydration system therefore increases proportionately in size taking into account this recycle stream. Furthermore, significant quantities of CO_2 in the circulating glycol necessitate the use of corrosion resistant alloys in the reboiler system. The specification set for the water content of the export gas is 30 ppm.

9.0 UTILITY AND OFFSITE UNITS

9.1 Cooling water system (Unit 4100)

Unit 4100 includes the Plant primary cooling system, sea water in once through circuit, and the plant secondary cooling system, fresh cooling water in closed circuit with relevant distribution system.

Electric driven operating pumps are provided to pump sea water from the Sea Water Basin, located on the beach, to the plant site, and back to the sea. The sea water intake and the discharge to the sea, connected to the beach facilities by means of submarine lines, are located at a suitable distance in order not to mix the two streams, supply and return.

Inside the plant, sea water is used directly to condense steam in the steam turbine condenser and as cooling medium of the CO_2 compression and drying Unit, and in a separate branch, after further pumping, to cool the Machinery Cooling Water. The machinery cooling water system produces fresh cooling water, circulating in a closed circuit, used as cooling medium for all plant users other than steam turbine condenser, CO_2 compression.

The max allowed sea water temperature increase is 7°C. The temperature increase for the closed circuit of Machinery Cooling water is 12°C.

A plate heat exchanger type is selected to cool the machinery cooling water by means of sea water, in order to minimize the plot area, surface and pressure drop.

Self cleaning backflushing filters will be provided to protect plate exchangers from excessive sea water fouling.

A machinery cooling water expansion drum is installed to compensate the fluctuation of the water volume, due to the temperature variations.
Electric driven pumps are provided to keep the machinery cooling water circulation.
Demineralized water is used as first filling of the machinery cooling water circuit and to compensate water losses.
A chemical injection system is provided in order to add the oxygen scavanger to the machinery cooling water circuit.

9.2 Demi Water (Unit 4200)

Raw water from the nearby river is generally used as make up water for the power plant. Raw water is also used to produce demineralized water. Raw water flows through the Demineralized Water Package that supplies make up water with adequate physical-chemical characteristics to the thermal cycle.
Multiple lines work alternatively to allow periodic resin regeneration. Adequate demi water storage is provided by means of a dedicated Demineralized Water Tank.
The demineralized water make-up supplies the make-up water to the thermal cycle, whilst the demineralized water distribution pump supplies demineralized water to the other plant users or to the plant circuits for first filling.

9.3 Natural Gas system (Unit 4300)

Natural gas is derived from an external network and fed to a metering station, before distribution.
From the metering station, natural gas is distributed to the boilers as start-up/back-up fuel.

9.4 Plant and Instrument air system (Unit 4400)

The air compression system supplies air to the plant. Air is directly taken from the ambient and compressed by means of two air compressors, one in operation and the other one in stand-by.
Compressed air is stored in an air receiver in order to guarantee the hold-up required for emergency shutdown.
Plant air is directly taken from the air receiver, whilst air from instrumentation is previously sent to the air dryer where air is dried up to ensure an adequate dew point (- 40 °C at 7 barg).

9.5 Fire fighting system (Unit 4600)

This unit consists of all the systems able to locate possible fire and all the equipments necessary to its extinction. The Fire Detection and Extinguishing System shall essentially include the automatic and manual fire detection facilities, as well as the detection devices with relevant alarm system. Appropriate fire detection and suppression system shall be installed in each fire hazard area according to the applicable protection requirements. The fire fighting water is supplied by water pumping station via looping piping network consisting in a perimetrical circuit fed by water pumped from cooling tower basin.

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : TECHNO-ECONOMIC EVALUATION OF CAPTURING CO_2 FROM BIOMASS FIRED POWER PLANT
DOCUMENT NAME : CASE 1A – 500 MWE PC BOILER WITHOUT CO_2 CAPTURE

ISSUED BY : S. CAVEZZALI
CHECKED BY : P. COTONE
APPROVED BY : F. GASPARINI

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SECTION D

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D BASIC INFORMATION FOR EACH ALTERNATIVE

1.0 Case 1a - 500 MWe PC Boiler without CO_2 capture

Summary

Case 1 a is based on a SuperCritical PC boiler co-fired with coal and biomass. The boiler is equipped with SCR + FGD based on wet limestone. No capture of CO_2 is considered.

- The size of the plant considered for this configuration is 500 MWe net power output nominal.
- The boiler is co-fired with coal and biomass. The biomass fired corresponds to 10% of total fired duty (based on LHV).
- No drying of biomass is needed.
- The boiler technology for co-firing coal and biomass considered in this study is commercially available in the market.
- In the flue gas line of the boiler downstream the air preheating the flue gases are directly fed to the FGD without the possibility to include any other heat recovery. This is because the FGD system sensibility decreases the flue gas temperature making difficult the introduction of any low temperature heat recovery without the formation of a strongly visible plume at stack outlet. It is necessary to install a plume abatement (reheat) system, therefore the low temperature heat recovery is not cost effective.
- The steam parameters (HP steam 580°C, RH Steam 600°C) and boiler efficiency (approx 93%) selected for the study are slightly lower than the actual commercial state of the art for PC Boiler fully fired on coal (HP Steam 600°C; RH Steam 600°C; boiler efficiency 95%). For the complete steam conditions at the boiler battery limit, see Table B.3.1 in Section B. This prudent approach is due to the cofiring of biomass and the associated problems of potential higher boiler fouling.
- The limit of NO_x emissions are met with the addition of an SCR system based on ammonia injection.

- The limit of SOx emissions are met with the addition of a wet limestone based FGD system.

1.1 Introduction

The Case 1a of the study is a coal and biomass co-fired Super Critical steam plant without carbon dioxide capture.

The configuration of the complex is based on a once through steam generator with superheating and single steam reheating.

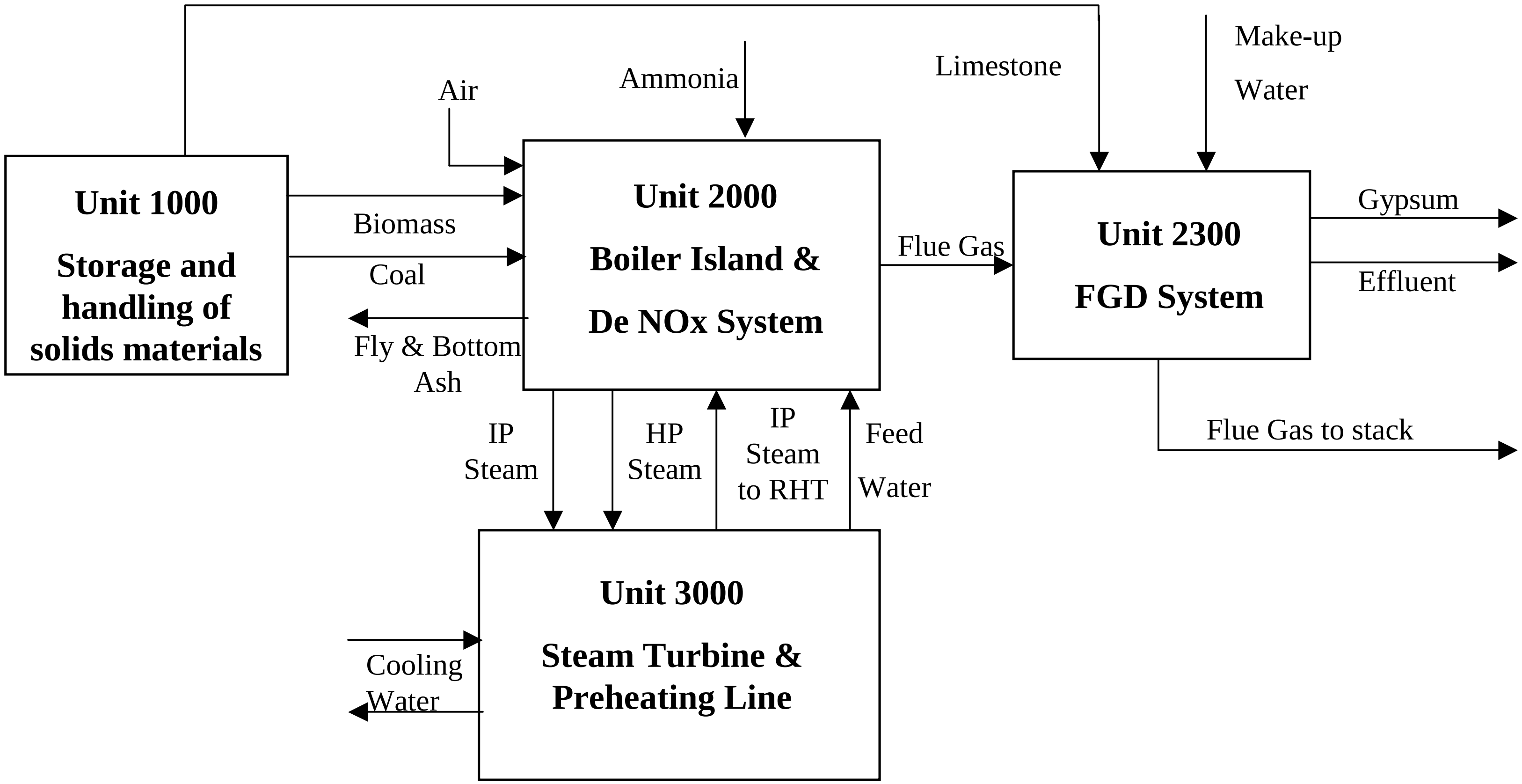
Reference is made to the attached Block Flow Diagram of the plant.
The arrangement of the process units is :

Unit

1000 Storage and Handling of solid materials, including:
- 1100 Coal storage and handling
- 1200 Biomass storage and handling
- 1300 Limestone storage and handling

2000 Boiler Island and flue gas treating, including:
- 2100 Boiler
- 2200 DeNOx
- 2300 Flue Gas Desulphurisation
- 2400 Baghouse filter
- 2500 Ash and by-products removal and handling

3000 Power Island including:
- 3100 Steam Turbine
- 3200 Preheating Line
- 3300 Electrical Power Generation.


Unit 1000
Storage and handling of solids materials
Unit 2000
Boiler Island &
De NOx System
Unit 2300
FGD System
Unit 3000
Steam Turbine & Preheating Line
Air
Ammonia
Limestone
Make-up
Water
Biomass
Coal
Fly & Bottom
Ash
Flue Gas
Gypsum
Effluent
Flue Gas to stack
IP
Steam
HP
Steam
IP
Steam
to RHT
Feed
Water
Cooling
Water

1.2 Process Description

Unit 1000: Storage and handling of solids materials

Please refer to Section C para. 1.0 for a process description of this unit.

This unit is made up of standard equipment in use, to receive the coal, biomass and limestone from outside the plant boundary, store, reclaim and transport them to the boiler plant.

The expected coal consumption is 3500 t/d approximately. In case of 100% coal feed the consumption increases to 3800 t/d approximately.
The expected Biomass consumption is 1370 t/d; this biomass flowrate represents the 10% of the total duty fired in the boiler and represent around the 30% of the total mass fuel consumption.

Unit 2000: Boiler Island

The block flow diagram of this section is attached to paragraph 1.3.

The boiler is a single reheat, two pass type boiler designed for supercritical pressure. The first pass is the furnace with radiant superheaters and the second pass includes convective superheater, reheater and economizer heating surface. The burners are mounted on the front and rear walls of the furnace with overfire airports on the walls above the primary combustion zone for staging of the combustion to minimize formation of thermal NOx.

Please refer to Figure 1 for the arrangement of a typical PC boiler.

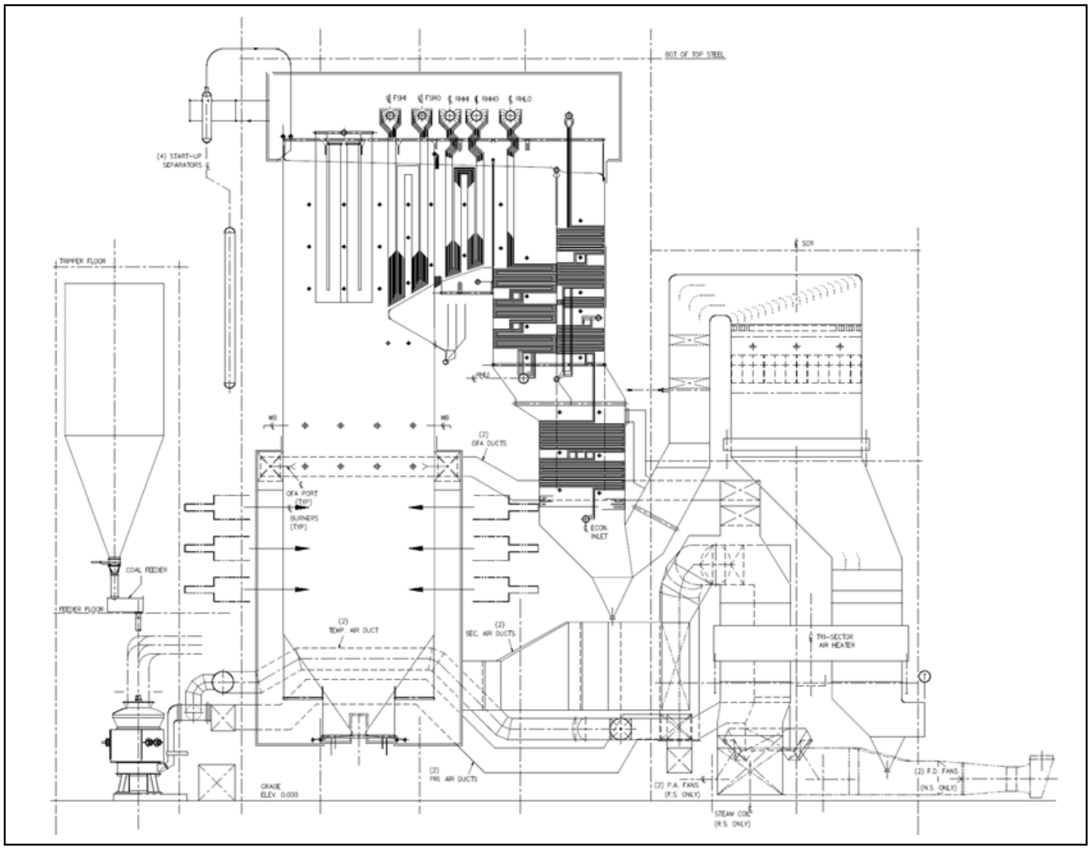


Figure 1 – PC Boiler arrangement

Fuel Preparation

Coal from the day silos is discharged via gravimetric feeders to the coal pulverizers.
Vertical spindle pulverizers grind the coal from the 35 mm feedsize to approximately 74 micron (70% passing). Hot primary air from two 50% capacity primary air fans is used to dry the coal in the pulverizer and to convey the coal from the pulverizer to the burner.

Wood with a particle size 100% less than ¼” (6mm) and 87% (maximum) less than 1/8” (3 mm) is conveyed to the Wood Feeding System. Two 50% capacity systems are provided to feed the prepared wood to the furnace. Each system consists of a prepared wood surge bin (45 to 60 minutes of storage) with a live discharge device, a weigh belt feeder, a drag chain conveyor,

several live screw feed bins and pneumatic conveying systems to feed the wood to each of the coal/wood burners.
Please refer to Figure 2 for the schematic of the Wood Feeding System.

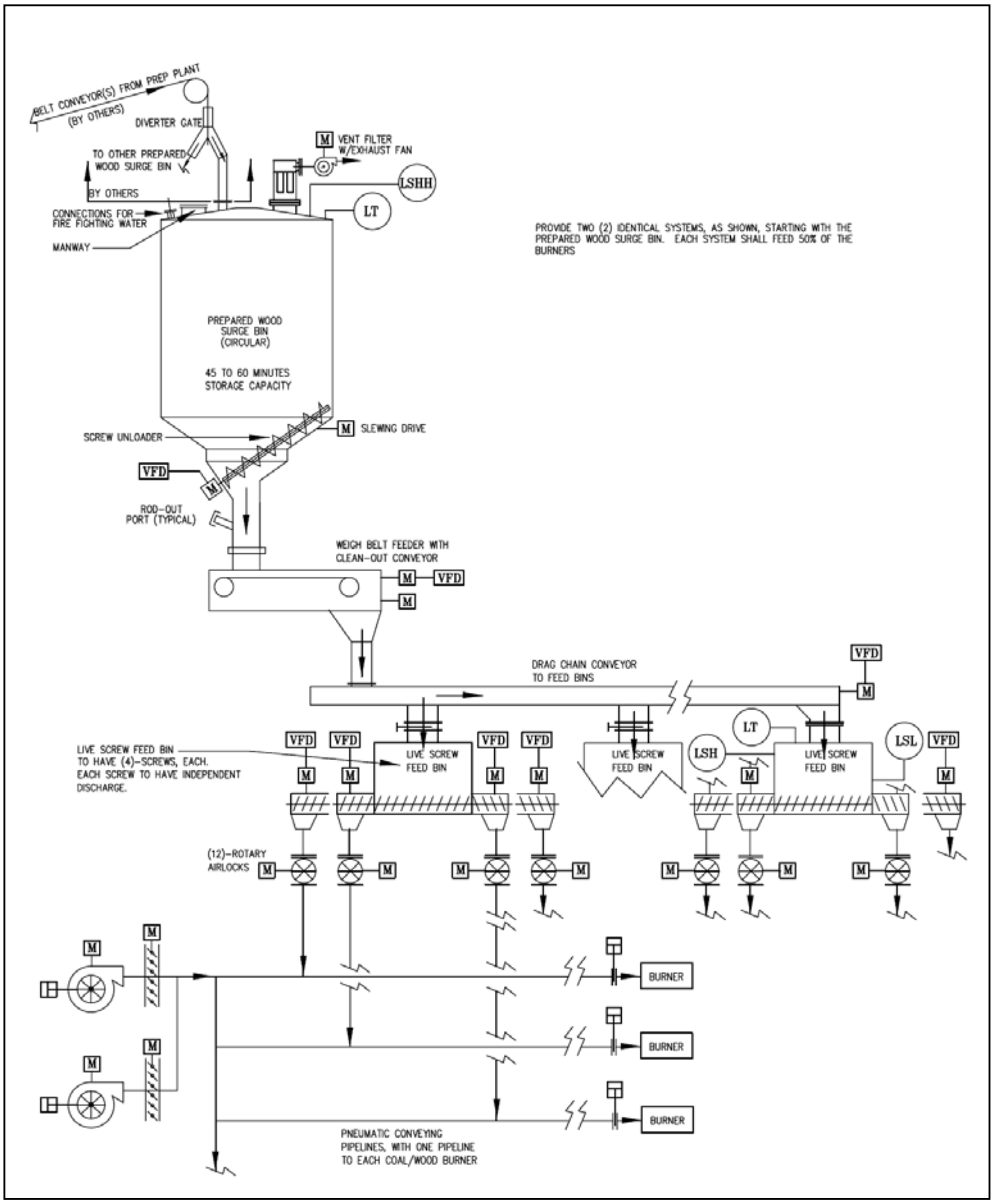


Figure 2 – Wood feeding system

Burners

The fuels, coal and wood biomass, would be fired in horizontal PC type, low NOx burners. The PC burners are modified to allow a biomass injection lance down the centre axis of the burner. Thus, the biomass would be fired separately, but concentrically with the coal, in the same burner.

Flue gas circuit

The flue gases from the furnace are cooled against the radiant superheaters, the convective superheaters and reheaters, the economizer, then pass through the SCR section, the regenerative air heater and finally through the fabric filter before being sent by the I.D. fan to the Flue Gas Desulphurisation (FGD) unit.

Water circuit

The high pressure preheated BFW enters the economizer where is further preheated against the flue gases and then is vaporized in the furnace tubes.
The steam at supercritical conditions is directly sent to the already mentioned superheater banks and then to the steam turbine.

Unit 2200 - De-NOx System

A Selective Catalytic Reduction (SCR) system is provided for further NOx reduction beyond the capabilities of the low NOx burners and overfire air system. The SCR is located between the boiler and the regenerative air heater. The location of the SCR and the provision of an economizer bypass duct provides the needed temperature for the NOx reduction process through a relatively wide load range. Vaporized ammonia injected into the flue upstream of the catalyst reacts with the NOx compounds to reduce them to N_2 and water.

The fuel analysis of the 90% coal / 10% biomass blend was reviewed with a SCR catalyst supplier. With proper selection of catalyst to match the fuels, a 2 – 3 year life of catalyst should be possible. However, testing of the catalyst with the coal / biomass blend should be conducted to determine potential impact on poisoning and deactivation of the catalyst with corresponding reduction in catalyst life.

For Process Description of the De-NO_x system, refer to Section C.

Unit 2300: FGD System

For further description, reference is to be made to Section C para. 5.0 for Wet limestone based FGD system.

The function of the FGD System is to scrub the boiler exhaust gases to remove most of the SO_2 content prior to release the flue gases to atmosphere meeting the environmental limits. The FGD system includes also a flue gas heat recovery system, to discharge the flue gases to atmosphere at minimum temperature of about 90°C (plume abatement).
The system is based on a gas-gas heater (GGH). Basically the untreated flue gas (140°C) is cooled before it enters the absorber (100°C), and the treated gas (50°C) is heated before entering the stack (90°C).

Unit 2400: Baghouse filter

A baghouse filter is provided to remove particulate content in the flue gases to meet the environmental limits. Fly ash are collected from the baghouse filter bottom.

Unit 2500: Ash Handling Plant

The ash handling system, takes care of conveying the ash generated in the boiler plant: both the furnace bottom ash and the fly ash from the various hoppers. (Reference to Section C – para 3.0).

Unit 3000: Steam Turbine and Preheating Line

The block flow diagram of this section is attached to paragraph 1.3.

The power island is a single train, mainly composed of one supercritical steam turbine and one preheating line. Supercritical steam from the boiler is sent to the steam turbine, which consists of a HP, IP and LP section, all connected to the generator on a single shaft. The steam turbine is a condensing type, with multiple extractions for the preheating of the condensate and boiler feedwater.

Main steam from the boiler, generated at 275 bar and 580°C, passes through the stop valves and control valves and enters the turbine. Steam from the exhaust of the HP turbine is returned to the boiler gas path for reheating at 55 bar, 600°C and is then throttled into the double flow IP turbine. Exhaust steam from IP flows into a double casing, double flow LP turbine and then downward into the condenser at 0.03 bar, 24°C.

Different extractions from the IP section at different conditions of steam pressure/temperature allow the preheating of the boiler feed water, while the low-pressure extraction is used to provide the steam necessary for the degassing of the condensate. Steam condensate recovered into the boiler feed water heaters is recovered back to the deaerator.

Part of the exhaust steam from the IP ST section, together with three extractions from the LP steam turbine, provide heat to the four condensate heaters downstream the condensate pumps, before entering the deaerator.

Boiler feedwater exiting the deaerator is pumped to the economizers of the boiler by means of the boiler feedwater pump steam turbine driven.

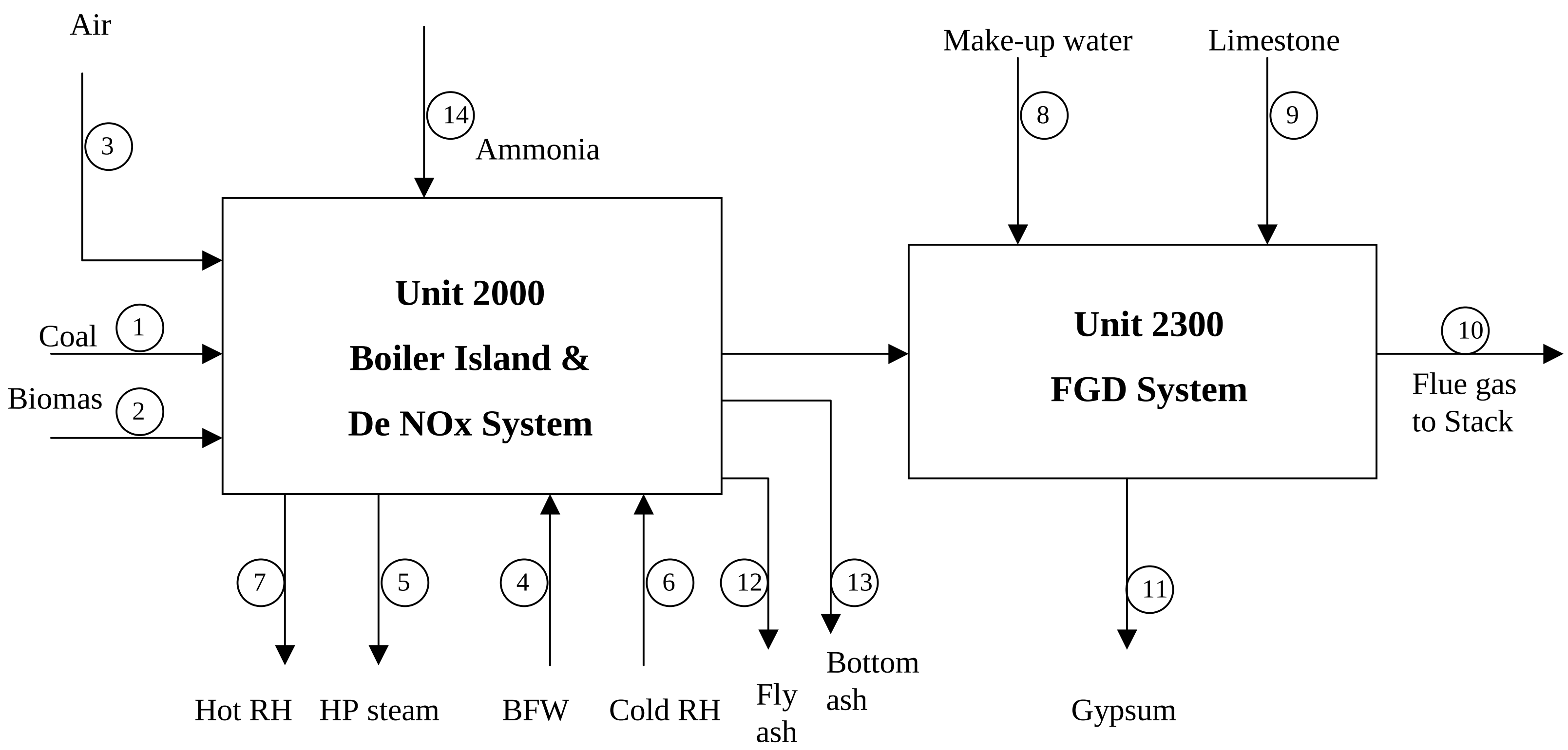
Chemical injection for control of the water quality is made by dedicated packages on the suction of the boiler feedwater pumps and at the inlet of the boilers.

1.3 Block Flow Diagrams

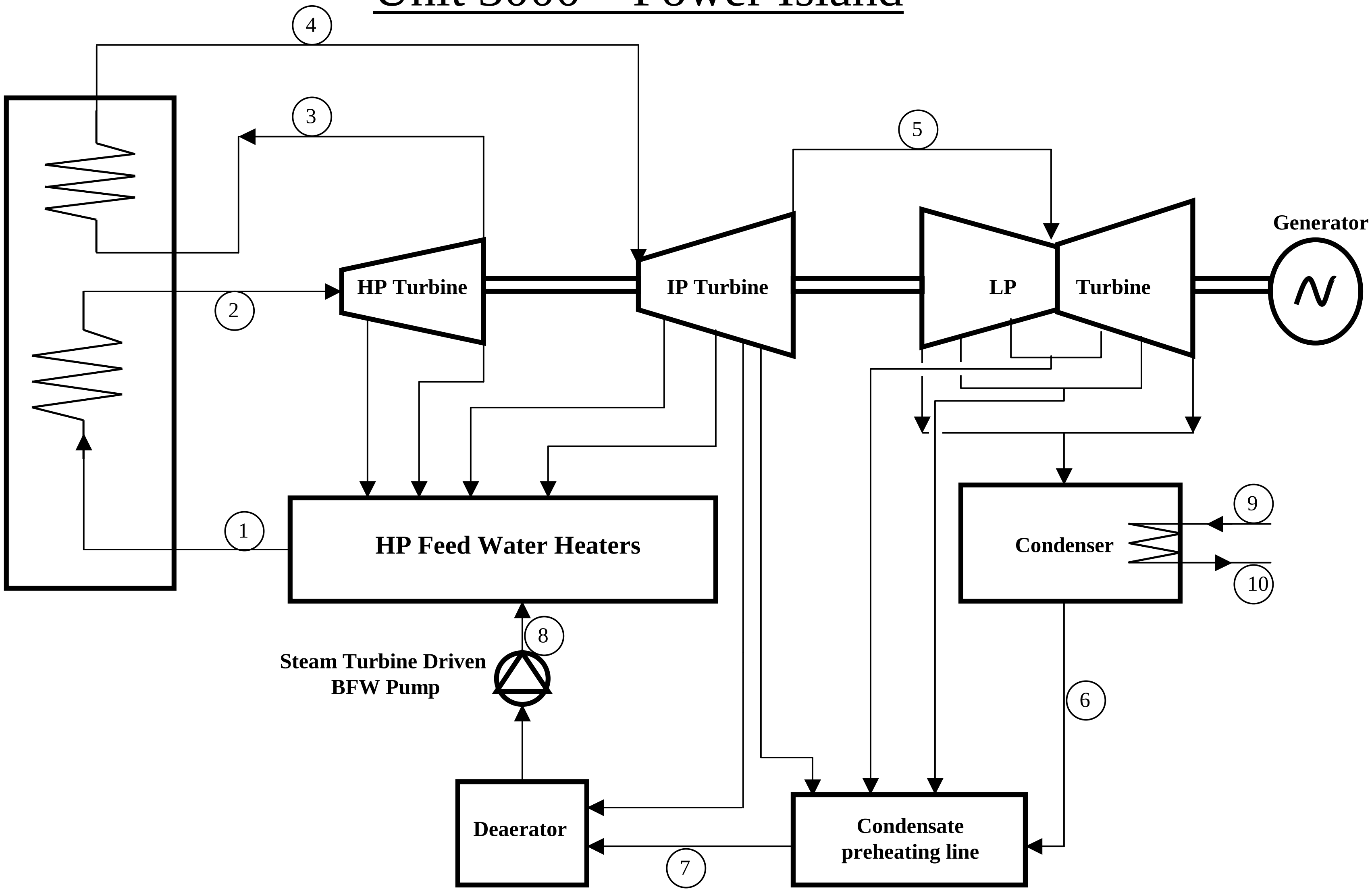
The Block Flow Diagrams of the following process units are attached to this paragraph:

- Unit 2000: Boiler Island
- Unit 3000: Power Island

Unit 2000 – Boiler Island



Unit 3000 – Power Island



1.4 Heat and Material Balances

The Heat & Material Balances of the following process units are attached to this section:

- UNIT 2000: Boiler Island and flue gas treating
- UNIT 3000: Power Island

Stream numbers are as shown on the Block Flow Diagrams attached to paragraph 1.3 of this Section.

PC-USC HEAT AND MATERIAL BALANCE

CLIENT: IEA GREEN HOUSE R & D PROGRAMME
CASE: CASE 1A - 500MW PC boiler without CCS
UNIT: 2000 Boiler Island and Flue gas treating

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a
1	Coal	145	amb.	amb.
2	Biomass	57	amb.	amb.
3	Air intake from Atmosphere	1678	amb.	amb.
4	Feed Water from Preheating line UNIT 3000	1450	290	304
5	HP Steam from boiler	1450	580	275
6	Cold reheat to boiler	1230	340	57.4
7	Hot reheat from boiler	1230	600	55
8	Make up water	60.0	amb.	amb.
9	Limestone	4.1	amb.	amb.
10	Flue Gas to Stack (1)	2046	90	1.005
11	Gypsum	7.1	amb.	amb.
12	Fly ash	14.7	amb.	amb.
13	Bottom Ash	3.7	amb.	amb.
14	Ammonia	0.50	amb.	amb.

Notes:
(1) For gas composition see Paragraph 1.7.1

PC-USC HEAT AND MATERIAL BALANCE

CLIENT: IEA GREEN HOUSE R & D PROGRAMME
CASE: CASE 1A - 500MW PC boiler without CCS
UNIT: 3000 Power Island

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	HP Water to Boiler Island	1450	290	304	1278
2	HP Steam from boiler	1450	580	275	3405
3	Cold reheat to boiler	1230	340	57.4	3022
4	Hot reheat from boiler	1230	600	55.4	3660
5	MP Steam Turbine exhaust	1031.5	282	6.21	3025
6	Condensate	974.6	24	0.03	101
7	LP Preheated Condensate	1395	165.6	13.5	700
8	Condensate to HP FWH	1450	193	305	834
9	Cooling Water Inlet	64043	12	1.9	42
10	Cooling Water Outlet	64043	19	1.4	71

1.5 Utility Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Tables.

FOSTER WHEELER	CLIENT: IEA GREEN HOUSE R & D PROGRAMME PROJECT: BIOMASS FIRED POWER PLANT LOCATION: THE NETHERLANDS	Rev 0 May 09 ISSUED BY: SC CHECKED BY: PC APPR. BY: FG

ELECTRICAL CONSUMPTION SUMMARY - CASE 1A - 500MW PC boiler without CCS

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
1000	SOLID RECEIVING, HANDLING AND STORAGE	
	Fuel Receiving, Handling and Storage	1400
	Limestone unloading, storage and handling	26
2000	BOILER ISLAND AND FLUE GAS TREATING	
	Boiler auxiliary consumption	7526
	Flue gas desulphurization plant (FGD)	1767
	Gypsum loading, storage and handling	157
	Ash loading, storage and handling	1164
	Baghouse filter	350
	Induced draft fan	4834
3000	POWER ISLAND	
	Steam turbine auxiliaries and condenser	1141
	Condensate pumps and feedwater system	865
	Step-Up transformer losses	1100
4000	UTILITIES AND OFFSITE UNITS	
	Machinery cooling water system	140
	Sea water system	3630
	Miscellaneous Balance-of-Plant	2188
	BALANCE	26288

CLIENT:	IEA GREEN HOUSE R & D PROGRAMME	Rev 0
PROJECT:	BIOMASS FIRED POWER PLANT	May 09
LOCATION:	THE NETHERLANDS	ISSUED BY: SC
		CHECKED BY: PC
		APPR. BY: FG

WATER CONSUMPTION SUMMARY - CASE 1A - 500MW PC boiler without CCS

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	Solid receiving, handling and storage			45	
2000	Boiler Island			59	
2300	Flue gas desulphurization plant (FGD)	60	1		
	POWER ISLANDS UNITS				
3000	Surface condenser				64043
	Miscellanea		5	2237	
	UTILITY and OFFSITE				
4100	Machinery Cooling Water System				
4200	Demineralized Water System	6.6	-6		4099
	Miscellanea			50	
	BALANCE	66.6	0	2391	68142

1.6 Overall Performance

The following Table shows the overall performance of the Plant.

IEA GHG		
CASE 1A: 500MW PC boiler without CO_2 capture		
OVERALL PERFORMANCE OF THE COMPLEX		
Coal Flowrate	t/h	145
Coal LHV	kJ/kg	25870
Biomass Flowrate	t/h	57
Biomass LHV	kJ/kg	7300
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1158**
Steam turbine power output (@gen. Terminals)	MWe	545.2
GROSS ELECTRIC POWER OUTPUT (D)	**MWe**	**545.2**
Solid Receiving, Handling and Storage	MWe	1.4
Boiler Island and flue gas treating	MWe	15.8
CO2 Plant incl. Blowers	MWe	0
CO2 Compression	MWe	0
Power Island	MWe	3.1
Utilities	MWe	6.0
ELECTRIC POWER CONSUMPTION	**MWe**	**26.3**
NET ELECTRIC POWER OUTPUT (C)	**MWe**	**518.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**47.1**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**44.8**

1.7 Environmental Impact

The plant is designed to process coal and biomass, whose characteristics are defined in the Basic Engineering Design Data and produce electric power. The advanced technology allows to reach a high efficiency and to minimise environmental impact.

The gaseous emissions, liquid effluents and solid wastes from the plant are summarised in this section.

1.7.1 Gaseous Emissions

Main Emissions

In normal operation at full load, the main continuous emissions are the combustion flue gases leaving the boiler at stack.

Table 1.1 summarises expected flow rate and concentration of the combustion flue gas released to atmosphere from the stack.

	Normal Operation
Wet gas flow rate, kg/s	568.3
Flow, Nm^3/h	1,576,500
Temperature, °C	90
Composition	(%vol)
N_2+Ar	71.1
O_2	4.5
CO_2	12.5
H_2O	11.9
Emissions	mg/Nm^3 (1)
NOx	200
N_2O	not detectable
SOx	200
CO	200
Particulate	Less than 30
NH_3	1 (2)

Table 1.1 – Expected gaseous emissions from plant

(1) Dry gas, O_2 Content 6% vol
(2) Due to ammonia slippage into the flue gas downstream the SCR

Minor Emissions

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). They are prevented by proper design and operation.

1.7.2 Liquid Effluent

All the liquid effluents are treated in the wastewater treatment system in order to be discharged in accordance with the current regulations.

The liquid effluents generated in the power plant are mainly the following:
- Rain water contaminated by powder;
- Wash water contaminated by oil and powder;
- FGD system blowdown;
- Eluates from demineralizing water system;
- Sanitary water.

Sea water in open circuit is used for cooling.
The return stream water is treated with meta-bisulphite in the Dechlorination System to reduce the Cl_2 concentration. Main characteristics of the water are listed in the following:

- Maximum flow rate : 68,142 m^3/h
- Temperature : 19 °C

1.7.3 Solid Effluent

No solid waste other than those produced by a real industrial activity.
The power plant is expected to produce the following solid by-products:

Fly Ash

Flow rate	:	14.7	t/h
Unburned Carbon	:	6.0	%wt

Bottom Ash

Flow rate	:	3.7	t/h
Unburned Carbon	:	3.1	%wt

Fly and bottom ash could be theoretically dispatched to cement industries. For the purposes of present study they are considered as a waste to be disposed.

Solid Gypsum

Flow rate	:	7.1	t/h

Solid gypsum keeping Euro Gypsum restrictions can be delivered to the market. For the purposes of present study it is considered as neutral: neither as a revenue nor as a disposal cost.

CLIENT	:	IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME	:	TECHNO-ECONOMIC EVALUATION OF CAPTURING CO_2 FROM BIOMASS FIRED POWER PLANT
DOCUMENT NAME	:	CASE 1B – 500 MWE PC BOILER WITH CO_2 CAPTURE

ISSUED BY	:	S. CAVEZZALI
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APPROVED BY	:	F. GASPARINI

Date	Revised Pages	Issued by	Checked by	Approved by
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SECTION D

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D BASIC INFORMATION FOR EACH ALTERNATIVE

SECTION D BASIC INFORMATION FOR EACH ALTERNATIVE

2.0 Case 1b - 500 MWe PC Boiler with CO_2 capture

Summary

Case 1b is based on a SuperCritical PC boiler co-fired with coal and biomass. The boiler is equipped with SCR + FGD based on wet limestone. CO_2 capture and compression is considered.

- The size of the plant considered for this configuration is 500 MWe net power output nominal. The boiler is the same as the case without CO_2 capture having as a consequence the reduction in net power output of the plant due to the impact of the CO_2 removal and compression units as power and steam consumer.
- The boiler is co-fired with coal and biomass. The biomass fired corresponds to 10% of total fired duty (based on LHV).
- No drying of biomass is needed.
- The boiler technology for co-firing coal and biomass considered in this study is commercially available in the market.
- The steam parameters (HP steam 580°C, RH Steam 600°C) and boiler efficiency (approx 93%) selected for the study are slightly lower than the actual commercially state of the art for PC Boiler fully fired on coal (HP Steam 600°C; RH Steam 600°C; boiler efficiency 95%). For the complete steam conditions at the boiler battery limit, see Table B.3.1 in Section B. This prudent approach is due to the cofiring of biomass and the associated problems of potential higher boiler fouling.
- The limit of NO_x emissions are met with the addition of an SCR system based on ammonia injection.
- The amine based CO_2 absorption system, requires a very low level of NO_2 in the flue gas. Being the content of NO_2 in NOx ranging from 3% to 5%, this low content of NO_2 is achieved without the need of addition of further denitrification in flue gas treatment. On the other hand due to the removal of the CO_2 from the flue gases, the NOx concentration at stack results slightly higher than the one at CO_2 capture unit inlet. For this reason the NOx level at SCR system outlet shall be lower than in the

case without CO_2 capture by approximately 15% in order to maintain 200 mg/Nm^3 (@6% O_2 dry) at stack. Actually on the basis of the overall annual NOx flow rates, there could be an allowance for the more concentrated stack gases as the absolute NOx flow rate remains constant. Anyhow in the basis of design of the present study there is no any reduction on the emission limit and 200 mg/Nm^3 (@6% O_2 dry) at stack is considered for all cases.

- Production of N_2O in the boiler is expected to be negligible due to the high temperature reached. Moreover, a production of N_2O can also be expected because of the use of an SCR system. In fact, the catalytic decomposition of ammonia yields both NO and N_2O, the former as primary product, the latter as a secondary product. Both products, further undergo catalytic decomposition. This possible emission of N_2O has been investigate with an SCR's Supplier that stated that the N_2O emission is not detectable from an SCR system using ammonia. Finally, it is expected that the N_2O in flue gas will not be absorbed into MEA and pass through unchanged to the stack. However, it is possible that some of the N_2O could form heat-stable salts, and be removed in the reclaimer / filter system. This shall be further investigated with the MEA supplier.

- The amine based CO_2 absorption system, requires a very low level of SO_2 in the flue gas (much lower than the emission limits). This calls for a high SO_2 capture efficiency in the FGD to reach 10 ppm levels of SO_2 at the exit. Such low absolute figures are not presently met in similar size FGD systems, though it can be achieved in the existing plants, with a further level of washing with the reagents. It would be a technical challenge, which needs to be further demonstrated in a large size plant.

- All the heat required for the CO_2 capture plant is provided from the low temperature steam extracted from the turbines. This results in a significant loss of power in the turbine generator. Further, a significant optimisation of heat within the CO_2 capture plant is also considered with adequate heat exchanges between various streams within the plant.

- CO_2 is dried and compressed up to supercritical phase at 110 bar for use in EOR or for geological disposal.

2.1 Introduction

The Case 1b of the study is a coal and biomass co-fired Super Critical steam plant with carbon dioxide capture.

The configuration of the complex is based on a once through steam generator with superheating and single steam reheating.

Reference is made to the attached Block Flow Diagram of the plant.
The arrangement of the process units is :

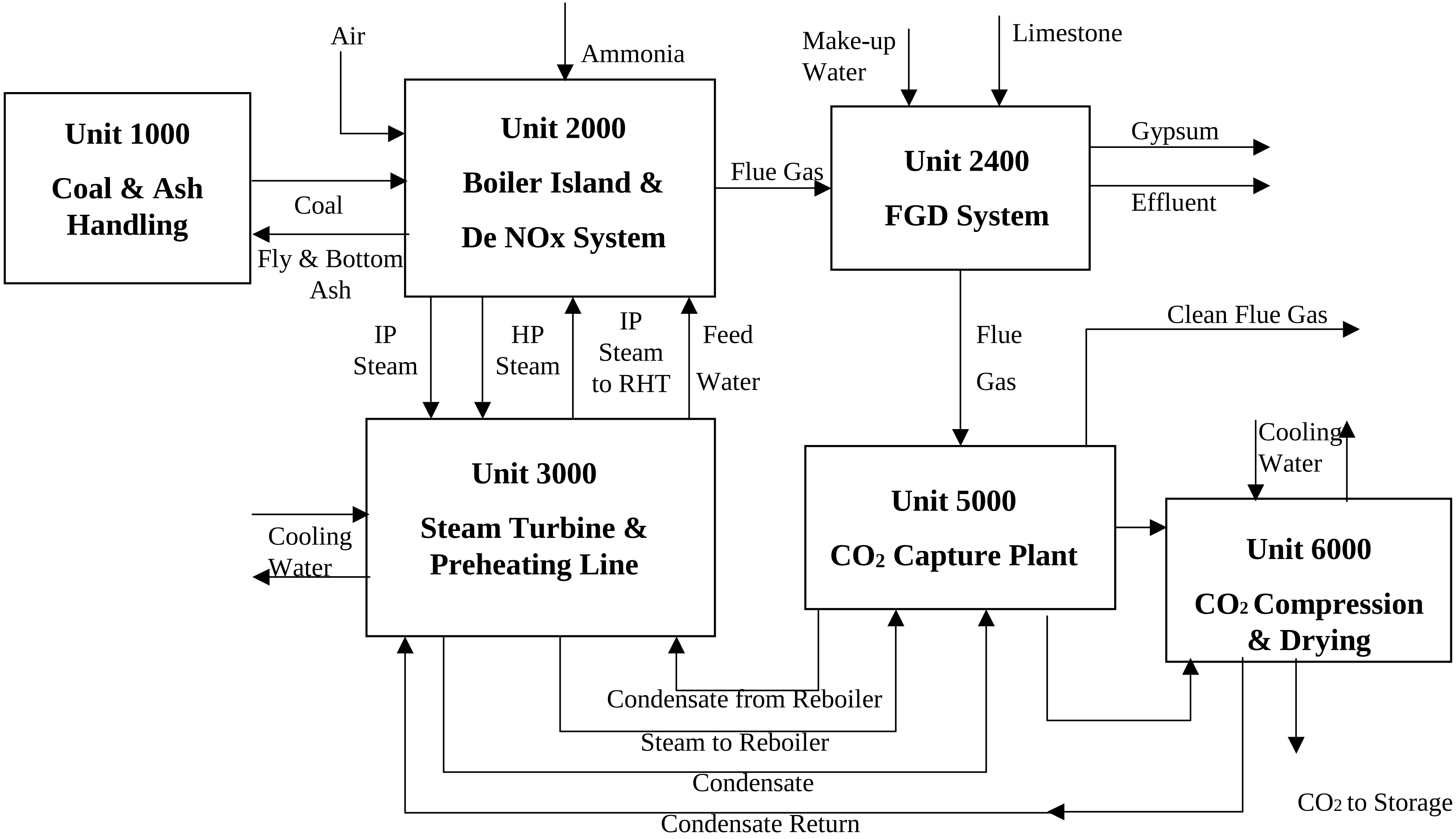
Unit

1000 Storage and Handling of solid materials, including:
- 1100 Coal storage and handling
- 1200 Biomass storage and handling
- 1300 Limestone storage and handling

2000 Boiler Island and flue gas treating, including:
- 2100 Boiler
- 2200 DeNOx
- 2300 Flue Gas Desulphurisation
- 2400 Baghouse filter
- 2500 Ash and by-products removal and handling

3000 Power Island including:
- 3100 Steam Turbine
- 3200 Preheating Line
- 3300 Electrical Power Generation.

5000 CO_2 capture unit
6000 CO_2 compression and drying unit



Air
Ammonia
Make-up Water
Limestone
Unit 1000
Coal & Ash Handling
Unit 2000
Boiler Island &
De NOx System
Coal
Fly & Bottom Ash
Flue Gas
Unit 2400
FGD System
Gypsum
Effluent
IP Steam
HP Steam
IP Steam to RHT
Feed Water
Flue Gas
Clean Flue Gas
Cooling Water
Unit 3000
Steam Turbine & Preheating Line
Cooling Water
Unit 5000
CO_2 Capture Plant
Unit 6000
CO_2 Compression & Drying
Condensate from Reboiler
Steam to Reboiler
Condensate
Condensate Return
CO_2 to Storage

2.2 Process Description

Unit 1000: Storage and handling of solids materials

The unit is exactly the same as case 1a being equal the boiler. For unit description, reference shall be made to paragraph 1.2, section D2.

Unit 2000: Boiler Island

The boiler is exactly the same as case 1a. For unit description, reference shall be made to paragraph 1.2, section D2.

The block flow diagram of this section is attached to paragraph 2.3.

Unit 2200 - De-NOx System

The amine based CO_2 absorption system, requires a very low level of NO_2 in the flue gas: 20 ppmv (@6%O_2, dry basis) as mentioned in section C, para 6.0.

The NOx emissions achieved to meet the environmental limits are 200 mg/Nm^3 (@6% O_2 dry basis, corresponding to approx 100 ppm @6% O_2 dry basis). The content of NO_2 in NOx is expected to range from 3% to 5%; therefore, the expected level of NO_2 at CO_2 capture unit is ranging from 5 to 10 ppmv (@ 6% O_2, dry basis). In the CO_2 capture plant, where flue gas temperatures are lower, it is not expected to have an increase of the NO_2 content, although conversion of NO to NO_2 is promoted by low temperatures, because the kinetics of the reaction that converts NO into NO_2 is too slow with respect to the residence time of gases in the system.

For this reason there is no need of addition of further denitrification in flue gas treatment.

On the other hand due to the removal of the CO_2 from the flue gases, the NOx concentration at stack results slightly higher than the one at CO_2 capture unit inlet. For this reason the NOx level at SCR system outlet shall be lower than in the case without CO_2 capture by approximately 15% in order to maintain 200 mg/Nm^3 (@6% O_2 dry) at stack.

The DeNOx system is similar to case 1a with an higher removal efficiency. For system description, reference shall be made to paragraph 1.2 section D2.

Unit 2300: FGD System

For further description, reference is to be made to Section C para. 5.0 for Wet limestone based FGD system.

The function of the FGD System is to scrub the boiler exhaust gases to remove most of the SO_2 content prior to feed the gases to the CO_2 capture unit.

The downstream amine based CO_2 absorption system, requires a very low level of SO_2 in the flue gas (much lower than the emission limits). This calls for a high SO_2 capture efficiency in the FGD to reach 10 ppm levels of SO_2 at the exit. Such low absolute figure is not presently met in similar size FGD systems, though it can be achieved in the existing plants, with a further level of washing with the reagents. It would be a technical challenge, which needs to be further demonstrated in a large size plant.
The SO_2 level obtained is much lower than the environmental limits fixed in section B.

Unit 2400: Baghouse filter

A baghouse filter is provided to remove particulate content in the flue gases to meet the requirements of the downstream CO_2 capture unit. Fly ash are collected from the baghouse filter bottom.

An excessive amount of particulate in the flue gases fed to the CO_2 capture unit can cause foam formation that can compromise the correct unit operation.
For this reason the particulate content at CO_2 capture unit inlet is fixed at 5 mg/Nm^3 (@6% O_2 dry basis). This value is much lower than the environmental limits fixed in section B.

Unit 2500: Ash Handling Plant

The unit is exactly the same as case 1a. For unit description, reference shall be made to paragraph 1.2, section D2.

Unit 3000: Steam Turbine and Preheating Line

The block flow diagram of this section is attached to paragraph 2.3.

The power island is a single train, mainly composed of one supercritical steam turbine and one preheating line. Supercritical steam from the boiler is sent to the steam turbine, which consists of a HP, IP and LP section, all connected to the generator on a single shaft. The steam turbine is a condensing type, with multiple extractions for the preheating of the boiler feedwater. The LP steam is also extracted for the use in the reboiler and stripping unit in the CO_2 capture plant.

Main steam from the boiler, generated at 275 bar and 580°C, passes through the stop valves and control valves and enters the turbine. Steam from the exhaust of the HP turbine is returned to the boiler gas path for reheating at 55 bar, 600°C and is then throttled into the double flow IP turbine. Exhaust steam from IP flows into a double casing, double flow LP turbine and then downward into the condenser at 0.03 bar, 24°C.

Different extractions from the IP section at different conditions of steam pressure/temperature allow the preheating of the boiler feed water

Recycled condensate from the condenser is pumped to the carbon dioxide capture plant and preheated in the amine stripper overhead condenser and the carbon dioxide compressor intercoolers. An optimisation of the integration between power plant and CO_2 capture plant allows to maximize the efficiency of the process. This also reduces the necessity of LP steam extractions to preheat condensate in LP preheating line. Only one condensate preheater is therefore needed downstream the condensate heating in the process units. The preheated feed water stream is routed to the deaerator, along with condensate returned from the amine stripper reboiler.

Boiler feedwater exiting the deaerator is pumped to the economizers of the boiler by means of the boiler feedwater pump steam turbine driven.

The plant configuration studied considers the following integrations between the Process Units and the Power Island:

- A part of the heat recovered in the CO_2 capture plant (overhead stripper condenser) and in the compression line is recovered by preheating the condensate, partially avoiding the use of LP feed water heaters.
- All the LP steam required for the CO_2 absorption plant is provided by extraction from the LP stage of the steam turbine.

Chemical injection for control of the water quality is made by dedicated packages on the suction of the boiler feedwater pumps and at the inlet of the boilers.

Unit 4000: CO_2 Capture Plant

Clean flue gas with NO_2 less than 20 ppmv and SO_x less than 10 ppm is sent to the CO_2 absorption tower.
Refer to Section C para. 6.0 for this section.

90% capture of CO_2 from the flue gas is considered.
The block flow diagram of this section is attached to paragraph 2.3.

Unit 5000: CO_2 Compression and Drying

Refer to Section C, para. 8.0 for the general description of the Unit. The block flow diagram of this section is attached to paragraph 2.3.

CO_2 can be handled as a liquid in pipe lines at conditions beyond its critical point (P_{CR}=73.9 bar; T_{CR}=31.1°C). The present configuration studied, assumes, CO_2 to be delivered at a pressure of around 110 bara.

The product stream sent to final storage is mainly composed of CO_2. The main properties of the stream are as follows:

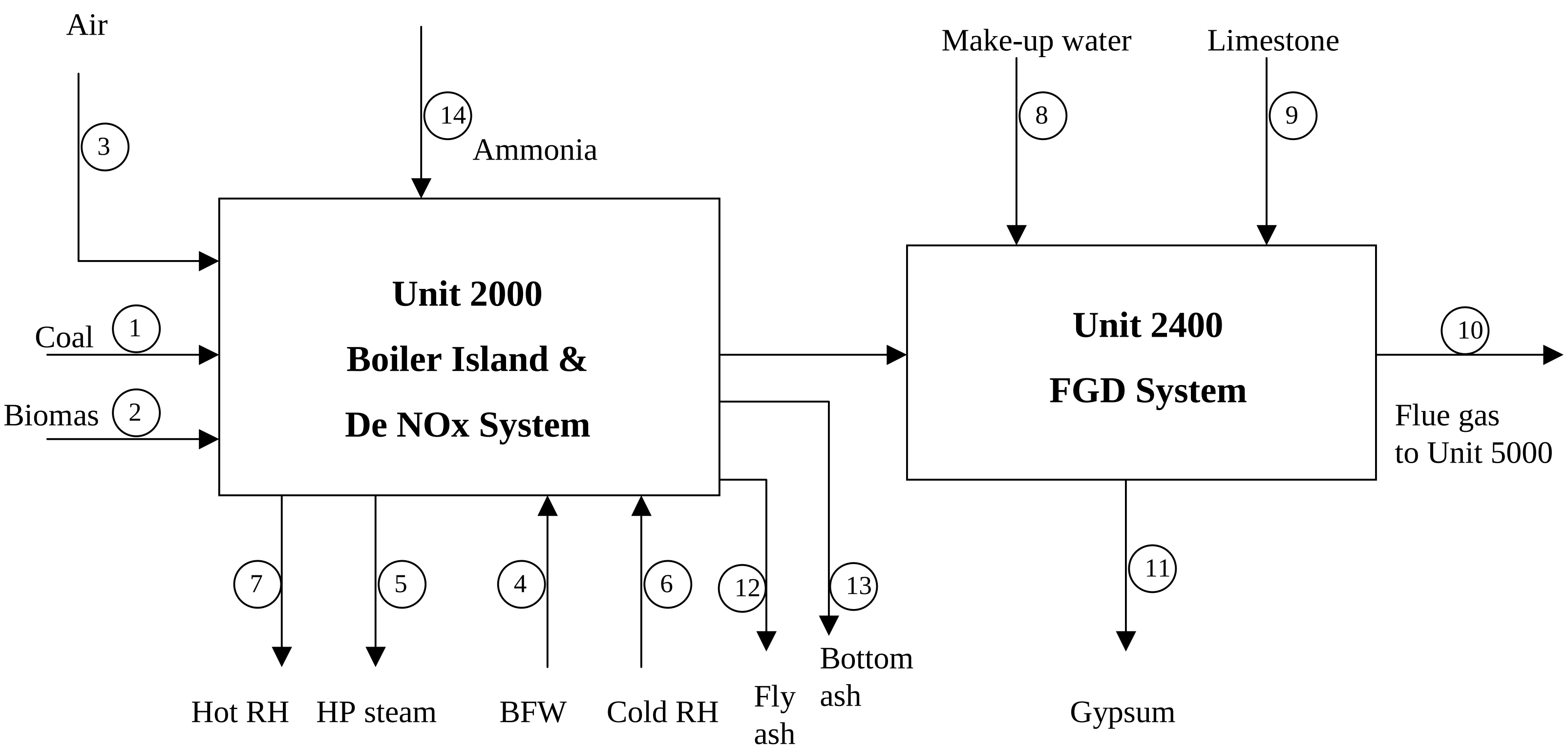
Product stream	:	350.5 t/h.
Pressure	:	110 bar.
Temperature	:	32 °C
CO_2 purity	:	>99.9 % wt.

2.3 Block Flow Diagrams

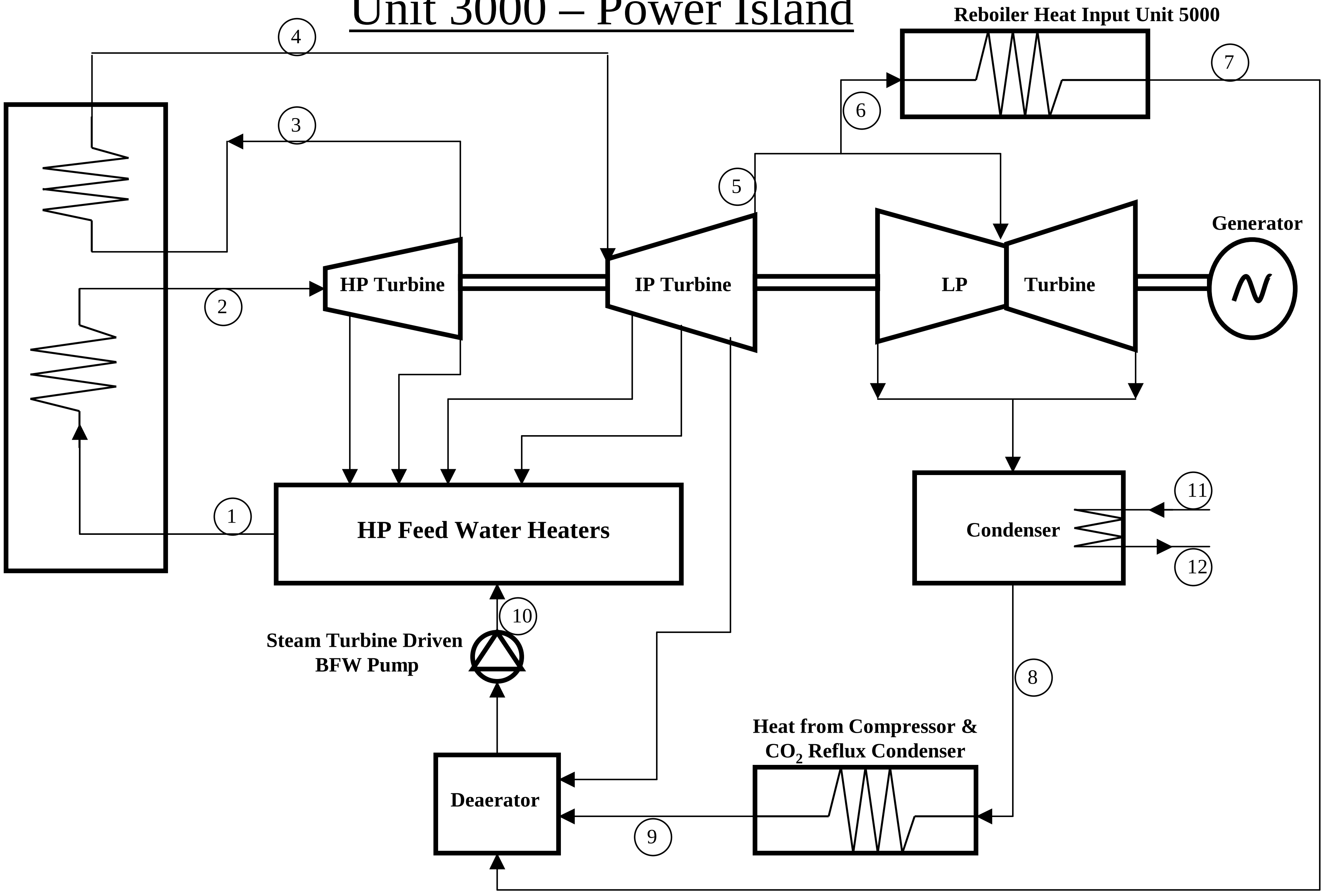
The Block Flow Diagrams of the following process units are attached to this paragraph:

- Unit 2000: Boiler Island and flue gas treating
- Unit 3000: Power Island
- Unit 5000: CO_2 capture
- Unit 6000: CO_2 compression and drying

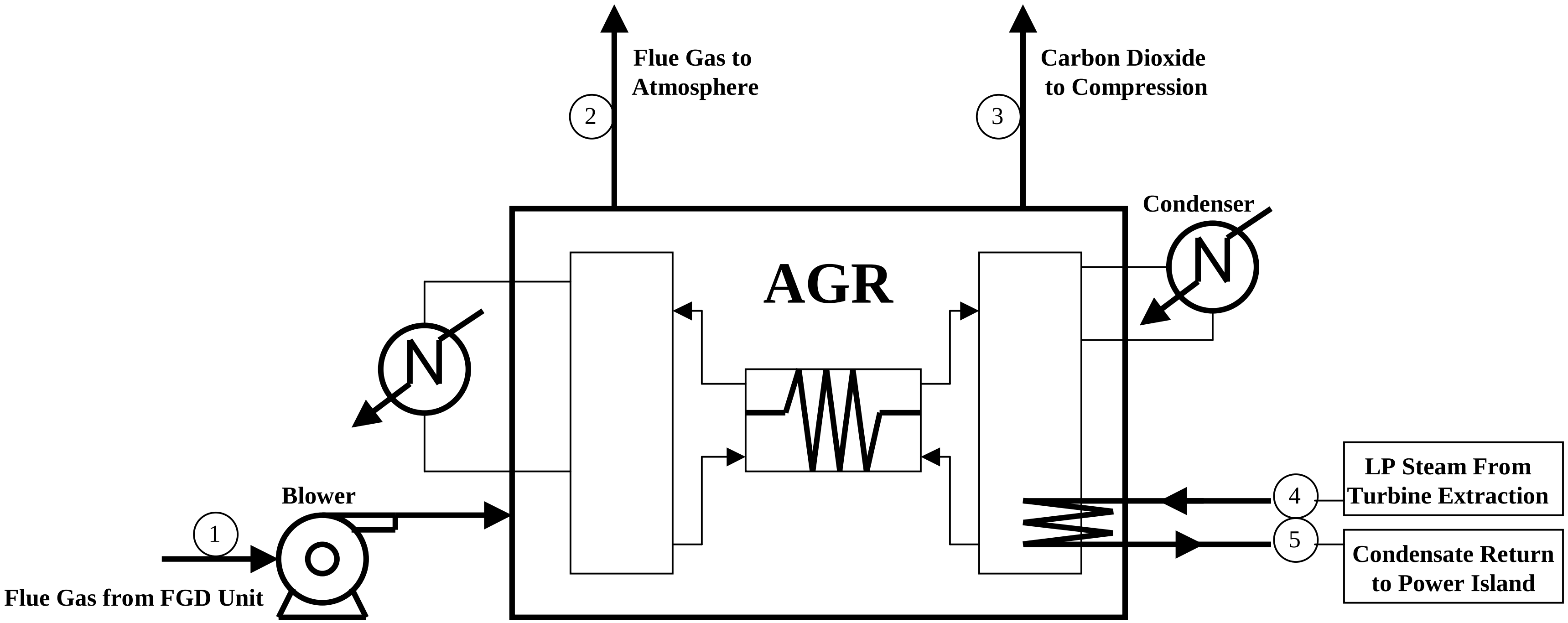
Unit 2000 – Boiler Island



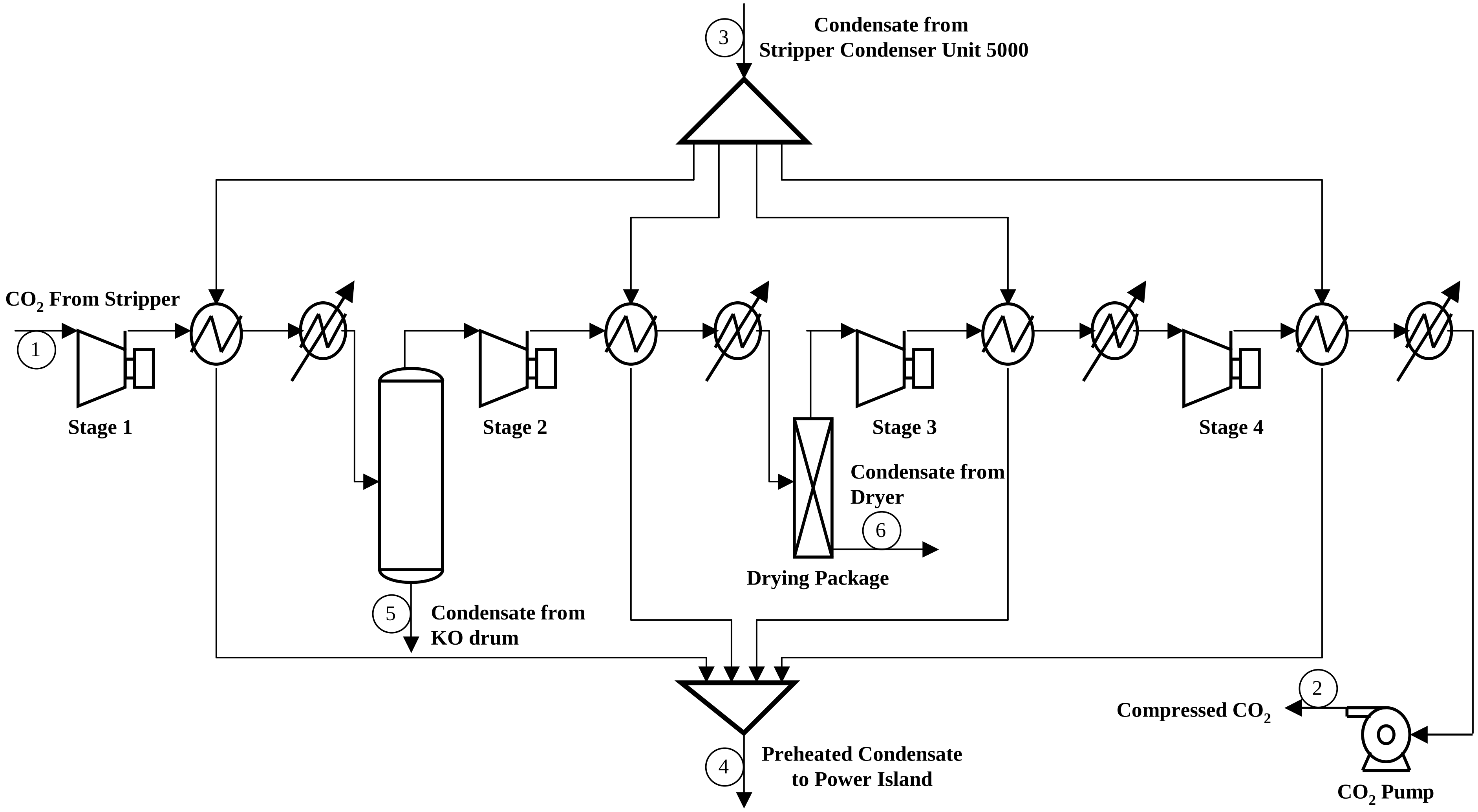
Unit 3000 – Power Island



UNIT 5000 - CO_2 Capture Plant



UNIT 6000 - CO_2 Compression & Drying



2.4 Heat and Material Balances

The Heat & Material Balances of the following process units are attached to this section:

- UNIT 2000: Boiler Island and flue gas treating
- UNIT 3000: Power Island
- UNIT 5000: CO_2 capture
- UNIT 6000: CO_2 compression and drying

Stream numbers are as shown on the Block Flow Diagrams attached to paragraph 2.3 of this Section.

PC-USC HEAT AND MATERIAL BALANCE	
CLIENT:	IEA GREEN HOUSE R & D PROGRAMME
CASE:	CASE 1B - 500MW PC boiler with CCS
UNIT:	2000 Boiler Island and Flue gas treating

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a
1	Coal	145.0	amb.	amb.
2	Biomass	57.0	amb.	amb.
3	Air intake from Atmosphere	1678	amb.	amb.
4	Feed Water from Preheating line UNIT 3000	1450	290	304
5	HP Steam from boiler	1450	580	275
6	Cold reheat to boiler	1230	340	57.4
7	Hot reheat from boiler	1230	600	55
8	Make up water	60.0	amb.	amb.
9	Limestone	4.5	amb.	amb.
10	Flue Gas to CO_2 capture plant (1)	2046	50	1.010
11	Gypsum	7.9	amb.	amb.
12	Fly ash	14.7	amb.	amb.
13	Bottom Ash	3.7	amb.	amb.
14	Ammonia	0.50	amb.	amb.

Notes:
(1) For gas composition see stream #1 of Unit 5000 H&M balance

PC-USC HEAT AND MATERIAL BALANCE

CLIENT: IEA GREEN HOUSE R & D PROGRAMME
CASE: CASE 1B - 500MW PC boiler with CCS
UNIT: 3000 Power Island

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	HP Water to Boiler Island	1450	290	304	1278
2	HP Steam from boiler	1450	580	275	3405
3	Cold reheat to boiler	1230	340	57.4	3022
4	Hot reheat from boiler	1230	600	55.4	3660
5	MP Steam Turbine exhaust	1049.6	233	4.00	2929
6	LP Steam to Reboiler	489.6	233	4.00	2929
7	LP Condensate from Reboiler	489.6	136	16.9	573
8	Condensate	555.5	24	0.03	101
9	LP Preheated Condensate	1395	165.6	13.5	700
10	Condensate to HP FWH	1450	193	305	834
11	Cooling Water Inlet	40568	12	1.9	42
12	Cooling Water Outlet	40568	19	1.4	71

	PC-USC HEAT AND MATERIAL BALANCE				
	CLIENT: IEA GREEN HOUSE R & D PROGRAMME				
	CASE: CASE 1B - 500MW PC boiler with CCS				
	UNIT: 5000 CO_2 Capture Plant				
STREAM	1	2	3	4	5
	Flue gas from FGD Unit	Flue gas to atmosphere	CO_2 to Compression	LP steam from turbine extraction	Condensate return to Power Island
Temperature (°C)	50	100	35	232	136
Pressure (bar)	1.01	1.005	1.5	3.50	16.9
TOTAL FLOW					
Mass flow (t/h)	2046	1619	356.2	490	490
Molar flow (kgmole/h)	70538	58448	8280		
LIQUID PHASE					
Mass flow (t/h)					490
GASEOUS PHASE					
Mass flow (t/h)	2046	1619	356.2	490	
Molar flow (kgmole/h)	70538	58448	8280		
Molecular Weight	29.00	27.7	43.02		
Composition (vol %)					
CO					
CO_2	12.6	1.5	96.2		
$Ar+N_2$	71.1	85.6	0.0		
O_2	4.5	5.4			
H_2O	11.9	7.5	3.8		

The LP steam consumption corresponds to a specific duty to the reboiler of the regenerator column of about 140 kJ/mol of CO_2 captured.

PC-USC HEAT AND MATERIAL BALANCE

CLIENT: IEA GREEN HOUSE R & D PROGRAMME
CASE: CASE 1B - 500MW PC boiler with CCS
UNIT: 6000 CO_2 Compression and Drying

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a
1	CO_2 from Stripper	356.2	35	1.5
2	Compressed CO_2	350.5	32.7	110
3	Condensate from Stripper Condenser	563.2	85	19.9
4	Preheated Condensate to Power Island	563	111.4	19.4
5	Condensate from KO drum	3.2	35	35.5
6	Condensate from Drying package	2.5	177	94.0

2.5 Utility Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Tables.

CLIENT:	IEA GREEN HOUSE R & D PROGRAMME	Rev 2
PROJECT:	BIOMASS FIRED POWER PLANT	November 09
LOCATION:	THE NETHERLANDS	ISSUED BY: SC
		CHECKED BY: PC
		APPR. BY: FG

ELECTRICAL CONSUMPTION SUMMARY - CASE 1B - 500MW PC boiler with CCS

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
1000	SOLID RECEIVING, HANDLING AND STORAGE	
	Fuel Receiving, Handling and Storage	1400
	Limestone unloading, storage and handling	27
2000	BOILER ISLAND AND FLUE GAS TREATING	
	Boiler auxiliary consumption	7526
	Flue gas desulphurization plant (FGD)	2071
	Gypsum loading, storage and handling	168
	Ash loading, storage and handling	1164
	Baghouse filter	400
	Induced draft fan	4979
3000	POWER ISLAND	
	Steam turbine auxiliaries and condenser	1013
	Condensate pumps and feedwater system	441
	Step-Up transformer losses	950
4000	UTILITIES AND OFFSITE UNITS	
	Machinery cooling water system	1550
	Sea water system	5025
	Miscellaneous Balance-of-Plant	2111
5000	CO_2 PLANT INCL. BLOWERS	
	Blower	6045
	Pumps	3865
6000	CO_2 COMPRESSION	36740
	BALANCE	75475

CLIENT:	IEA GREEN HOUSE R & D PROGRAMME	Rev 0
PROJECT:	BIOMASS FIRED POWER PLANT	May 09
LOCATION:	THE NETHERLANDS	ISSUED BY: SC
		CHECKED BY: PC
		APPR. BY: FG

WATER CONSUMPTION SUMMARY - CASE 1B - 500MW PC boiler with CCS

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	Solid receiving, handling and storage			45	
2000	Boiler Island			59	
2300	Flue gas desulphurization plant (FGD)	60	1		
5000	CO_2 capture plant			24542	
6000	CO_2 compression				5445
	POWER ISLANDS UNITS				
3000	Surface condenser				40568
	Miscellanea		5	1945	
	UTILITY and OFFSITE				
4100	Machinery Cooling Water System				45670
4200	Demineralized Water System	6.6	-6		
	Miscellanea			50	
	BALANCE	66.6	0	26641	91683

2.6 Overall Performance

The following Table shows the overall performance of the Plant.

IEA GHG		
CASE 1B: 500MW PC boiler with CO_2 capture		
OVERALL PERFORMANCE OF THE COMPLEX		
Coal Flowrate	t/h	145.0
Coal LHV	kJ/kg	25870
Biomass Flowrate	t/h	57.0
Biomass LHV	kJ/kg	7300
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1158**
Steam turbine power output (@gen. Terminals)	MWe	474.1
GROSS ELECTRIC POWER OUTPUT (D)	**MWe**	**474.1**
Solid Receiving, Handling and Storage	MWe	1.4
Boiler Island and flue gas treating	MWe	16.3
CO2 Plant incl. Blowers	MWe	9.9
CO2 Compression	MWe	36.5
Power Island	MWe	2.4
Utilities	MWe	8.7
ELECTRIC POWER CONSUMPTION	**MWe**	**75.2**
NET ELECTRIC POWER OUTPUT (C)	**MWe**	**398.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.0**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.5**

The following Table shows the overall CO_2 removal efficiency of the Complex:

	Equivalent flow of CO_2 kmol/h
Coal (Carbon = 64.6%wt)	7805
Biomass (Carbon = 25 % wt)	1188
Limestone	45
Carbon in ash	-75
Net Carbon flowing to Process Units (A)	8963
Liquid Storage CO CO_2 Total to storage (B)	 0.0 8050 8050
Emission CO CO_2 Total Emission	 13 900 913
Overall CO_2 removal efficiency, % (B/A)	90

Note: N_2O not included in the table.

2.7 Environmental Impact

The plant is designed to process coal and biomass, whose characteristics are defined in the Basic Engineering Design Data and produce electric power. The advanced technology allows to reach a high efficiency and to minimise environmental impact.

The gaseous emissions, liquid effluents and solid wastes from the plant are summarised in this section.

2.7.1 Gaseous Emissions

<u>Main Emissions</u>

In normal operation at full load, the main continuous emissions are the combustion flue gases leaving the boiler at stack.

Table 2.1 summarises expected flow rate and concentration of the combustion flue gas released to atmosphere from the stack.

	Normal Operation
Wet gas flow rate, kg/s	449.7
Flow, Nm^3/h	1,310,000
Temperature, °C	100
Composition	(%vol)
N_2+Ar	85.6
O_2	5.4
CO_2	1.5
H_2O	7.5
Emissions	mg/Nm^3 (1)
NOx	200
N_2O	not detectable
SOx	43
CO	230
Particulate	Less than 5
NH_3	1 (2)

Table 1.1 – Expected gaseous emissions from plant

(1) Dry gas, O_2 Content 6% vol
(2) Due to ammonia slippage into the flue gas downstream the SCR.

Minor Emissions

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). They are prevented by proper design and operation.

2.7.2 Liquid Effluent

All the liquid effluents are treated in the wastewater treatment system in order to be discharged in accordance with the current regulations.

The liquid effluents generated in the power plant are mainly the following:
- Rain water contaminated by powder;
- Wash water contaminated by oil and powder;
- FGD system blowdown;
- Effluents from CO_2 capture plant (Direct contact cooler and blowdown)
- Eluates from demineralizing water system;
- Sanitary water.

The CO_2 capture plant blowdown water contains a significant amount of MEA and therefore implies the introduction of a further biological section with aerobical and anaerobical treatment.

Sea water in open circuit is used for cooling.
The return stream water is treated with meta-bisulphite in the Dechlorination System to reduce the Cl_2 concentration. Main characteristics of the water are listed in the following:

- Maximum flow rate : 91,683 m^3/h
- Temperature : 19 °C

2.7.3 Solid Effluent

No solid waste other than those produced by a real industrial activity.
The power plant is expected to produce the following solid by-products:

Fly Ash

Flow rate	:	14.7	t/h
Unburned Carbon	:	6.0	%wt

Bottom Ash

Flow rate	:	3.7	t/h
Unburned Carbon	:	3.1	%wt

Fly and bottom ash could be theoretically dispatched to cement industries. For the purposes of present study they are considered as a waste to be disposed.

Solid Gypsum

Flow rate	:	7.9	t/h

Solid gypsum keeping Euro Gypsum restrictions can be delivered to the market. For the purposes of present study it is considered as neutral: neither as a revenue nor as a disposal cost.

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : TECHNO-ECONOMIC EVALUATION OF CAPTURING CO_2 FROM BIOMASS FIRED POWER PLANT
DOCUMENT NAME : CASE 2A – 500 MWE CFB BOILER WITHOUT CO_2 CAPTURE

ISSUED BY : S. CAVEZZALI
CHECKED BY : P. COTONE
APPROVED BY : F. GASPARINI

Date	Revised Pages	Issued by	Checked by	Approved by
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July 2009	Rev 1	S. Cavezzali	P. Cotone	F. Gasparini
November 2009	Rev 2	S. Cavezzali	P. Cotone	F. Gasparini

SECTION D

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D BASIC INFORMATION FOR EACH ALTERNATIVE

SECTION D BASIC INFORMATION FOR EACH ALTERNATIVE

3.0 Case 2a - 500 MWe CFB Boiler without CO_2 capture

Summary

Case 2a is based on a SuperCritical CFB boiler co-fired with coal and biomass. No capture of CO_2 is considered.

- The size of the plant considered for this configuration is 500 MWe net power output nominal.
- The boiler is co-fired with coal and biomass. The biomass fired corresponds to 10% of total fired duty (based on LHV).
- No drying of biomass is needed.
- The boiler technology for co-firing coal and biomass considered in this study is commercially available in the market.
- The flue gas line of the boiler includes a special plastic heat exchanger to maximise heat recovery downstream the ID fan without suffering from corrosion problem. Such heat exchangers are also commercially used for low temperature heat recovery in similar plants.
- The limits of NO_x emissions can be met with just the firing system of the boiler with low temperature at furnace exit. On the basis of experience of CFB boiler suppliers, no addition of a DeNOx system is needed. In case different CFB boiler technology is selected could be necessary the installation of a DeNOx system (SNCR type).
- On the basis of experience of CFB boiler suppliers, flue gas desulphurization is not required to meet SO_x emission limits. SO_x are captured by a limestone injection directly in the combustion chamber. The limestone reacts with the sulphur released from the fuel. The amount of limestone that is required is dependent on a number of factors such as the amount of sulphur in the fuel, the desired SOx target, the temperature of the bed and physical and chemical characteristics of the limestone. A Ca/S ratio of 2.84 is needed to meet the SOx environmental limits with a total sulphur removal in the furnace bed. In case different CFB boiler technology is selected could be necessary the installation of a FGD system.

3.1 Introduction

The Case 2a of the study is a CFB coal and biomass co-fired Super Critical steam plant without carbon dioxide capture.

The configuration of the complex is based on a once through steam generator with superheating and single steam reheating.

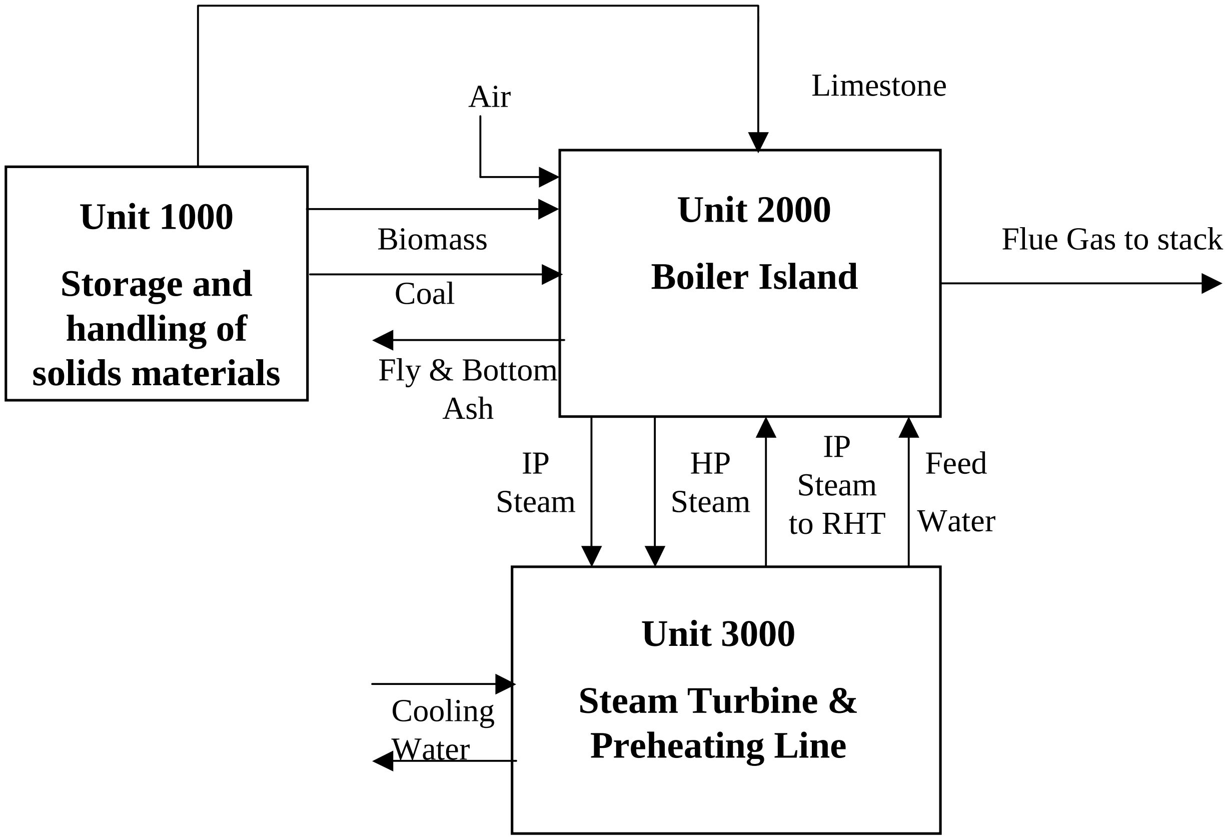
Reference is made to the attached Block Flow Diagram of the plant.
The arrangement of the process units is :

Unit

1000 Storage and Handling of solid materials, including:
- 1100 Coal storage and handling
- 1200 Biomass storage and handling
- 1300 Limestone storage and handling

2000 Boiler Island and flue gas treating, including:
- 2100 Boiler
- 2400 Baghouse filter
- 2500 Ash and by-products removal and handling

3000 Power Island including:
- 3100 Steam Turbine
- 3200 Preheating Line
- 3300 Electrical Power Generation.



Unit 1000
Storage and handling of solids materials
Unit 2000
Boiler Island
Unit 3000
Steam Turbine & Preheating Line
Air
Limestone
Biomass
Coal
Fly & Bottom Ash
Flue Gas to stack
IP Steam
HP Steam
IP Steam to RHT
Feed Water
Cooling Water

3.2 Process Description

Unit 1000: Storage and handling of solids materials

Please refer to Section C para. 1.0 for a process description of this unit.

This unit is made up of standard equipment in use, to receive the coal, biomass and limestone from outside the plant boundary, store, reclaim and transport them to the boiler plant.

The expected coal consumption is 3500 t/d approximately. In case of 100% coal feed the consumption increases to 3800 t/d approximately.
The expected Biomass consumption is 1370 t/d; this biomass flowrate represents the 10% of the total duty fired in the boiler and represent around the 30% of the total massive fuel consumption.

Unit 2000: Boiler Island

The block flow diagram of this section is attached to paragraph 3.3.

The boiler is a Foster Wheeler “Compact” tower supercritical CFB with the solid separators integrated with the combustion chamber.
The boiler includes the fuel feeding systems, the furnace, the solid separators with the solid return channels and INTREX superheaters, back pass, fans and air heater.

Fuel feeding system

Coal/biomass feeding system consists of multiple feeders located at the long walls of the furnace.
Each feeder consists of a day silo, drag chain feeder, drag chain conveyor and discharge to the feeding point.
Each feeding point has a dosing screw, slide gate and wall feeding screw.

Furnace

The furnace has a single fluidising grid, under which there are separate air plenums introducing primary air to the furnace.
The primary air is measured and controlled to insure equal flow to all sections of the grid and uniform fluidisation.

The lower furnace is tapered so that the grid area is smaller than the furnace cross section, to provide high internal turbulence and efficient fuel secondary air mixing.
Secondary air is introduced on the long furnace walls at different elevations to provide staged combustion and minimize NOx emissions.

The combustion chamber works at a relative low temperature (850-880 °C), which corresponds to the optimum condition to remove the sulphur and control the NOx emissions. Therefore neither SCR nor SNCR are required to meet the NOx emissions, for both the case without and with CO_2 capture.

The bottom of the bed, close to the distribution grate, is a high density and a high turbulence zone, where most of the combustion process occurs. The bed material is mainly made of support material like sand and limestone (approximately 95%), the remaining part being the burning coal. The main function of the bed material is to act as a thermal stabilizer, to allow the uniformity of the distribution temperature in the boiler.

Limestone is fed to the furnace to reduce the SO_2 content of the flue gases and to maintain the necessary furnace solids inventory as well. The required amount of limestone depends on a number of factors such as the amount of sulphur in the fuel, the required SOx target, the temperature of the bed and physical and chemical characteristics of the limestone. A Ca/S ratio of 2.84 provides a total sulphur capture in the furnace and allows meeting the environmental requirement on SOx emissions without the addition of an external FGD section.

Solid separators and return

The solid separators (cyclones) are arranged in parallel on two opposite furnace walls.
The separators tubes are steam cooled and are covered by a thin layer of refractory for protection against the erosion. They provide the third steam superheater stage.
The solids collected in the cyclones flow in the solid return legs ending into the INTREX chamber; there is one leg and one INTREX for each cyclone.
The INTREX is a Fluidised solid heat exchanger and is used as a final superheater/reheater stage.

Water and steam circuit

The high pressure preheated BFW enters the economizer where is further preheated against the flue gases, then divided in the enclosure walls of the INTREX heat exchanger and further to the headers of the evaporator (furnace) walls.
The water is heated in the evaporator tubes and eventually converted to superheated steam before the evaporator outlet.
Therefore the dry out occurs at a certain elevation.
Dry steam is superheated in the furnace roof, the convective superheater I, the superheater II in the upper furnace, the solid separators (III) and finally in the INTREX heat exchanger (IV).
The steam is reheated in the convective reheaters (I) and the INTREX heat exchangers (II).

Auxiliary systems

Combustion air system consists of primary and secondary air fans and a separate high pressure air fan for fluidising the INTREX heat exchangers and sealing devices.
A flue gas recirculation system is also provided.

Flue gas system

The flue gases from the boiler economizer is further cooled in a regenerative heat exchanger for preheating the combustion air, filtered and finally cooled to come 90°C in a special heat exchanger made of PF-plastic tubes located downstream of the ID fan.
The available heat is transferred to a primary water circuit which in turn preheats the combustion air (upstream of the regenerative air heaters).

A track list of CFB boilers with and without plastic heat exchanger for reference is attached hereinafter.

Includes heat recovery system

Order Date	Start-Up Date	Client	Plant	Plant Country	Boiler Type	Steam Capacity MWth	Main Steam Flow kg/s	Main Steam Pressure bar(g)	Main Steam Temp. C	Reheat Steam Flow kg/s	Reheat Steam Pressure bar(g)	Reheat Steam Temp. C	Primary Fuel	Secondary Fuel
2009	2012	PAK, S.A.	Konin	Poland	CFB	154	59.7	97	540				Biomass - Wood (80%) Biomass - Crop Waste (20%)	
2008	2012	Isolux Ingenieria S.A. y Tecna Proyectos y Operaciones, S.A.	Rio Turbio Power Project	Argentina	CFB	340	118	129	538				Coal - Bituminous	Coal - Bituminous
2008	2012	Isolux Ingenieria S.A. y Tecna Proyectos y Operaciones, S.A.	Rio Turbio Power Project	Argentina	CFB	340	118	129	538				Coal - Bituminous	Coal - Bituminous
2008	2010	Hanwha Engineering & Construction Corporation (HENC)	HENC GP Project	Korea	CFB	210	69	125	540				Coal	
2008	2010	Prokon Nord Energiesysteme GmbH	HENC GP Project	Korea	CFB	210	69	125	540				Coal	
2008	2010	Prokon Nord Energiesysteme GmbH	A & S Oostrozebeke	Belgium	CFB	71	28	90	500				Biomass - Demo Wood	
2008	2009	Arsmeta Captive Power Company Pvt. Ltd.	Jhangir-Champa, Chattisgarh	India	CFB	135	190	88	515				Coal	
2008	2008	Jin Shan Thermal Power Station	Shenyang	China	CFB	745	207	137	540	162	26	312	Coal - Bituminous	
2008	2008	Jin Shan Thermal Power Station	Shenyang	China	CFB	745	207	137	540	162	26	312	Coal - Bituminous	
2007	2011	Shaw Group, Inc.	Dominion Virginia City Hybrid Energy	USA	CFB	900	271	173	568	240	1	568	Coal	Biomass - Wood
2007	2011	Shaw Group, Inc.	Dominion Virginia City Hybrid Energy	USA	CFB	900	271	173	568	240	1	568	Coal	Biomass - Wood
2007	2010	Central Térmica Mejillones S.A.	Andino Power Plant	Chile	CFB	351	125	172	563	113	33	561	Coal, Coke - Petroleum	Biomass
2007	2010	Central Térmica Mejillones S.A.	Andino Power Plant	Chile	CFB	351	125	172	563	113	33	561	Coal, Coke - Petroleum	Biomass
2007	2010	Fortum Heat Polska sp. Z o.o.	Czestochowa CHP	Poland	CFB	182	72	110	515				Coal	Biomass
2007	2010	Harbin Power Engineering Company, Ltd. (HPE)	Campha	Vietnam	CFB	450	152	180	540	126			Coal - Anthracite Culm	Coal - Slurry
2007	2010	Harbin Power Engineering Company, Ltd. (HPE)	Campha	Vietnam	CFB	450	152	180	540	126			Coal - Anthracite Culm	Coal - Slurry
2007	2010	Jyväskylän Energia Oy	Jyväskylä	Finland	CFB	455	160	164	560	143	43	560	Peat	Biomass - Forest Residual
2007	2009	Hanwha International Corporation	Yeosu	South Korea	CFB	300	111	127	540				Coal	
2007	2009	Hanwha International Corporation	Yeosu	South Korea	CFB	300	111	127	540				Coal	
2007	2009	Hanwha International Corporation	Yeosu	South Korea	CFB	300	111	127	540				Coal	
2007	2009	Söderenergi AB	Igelsta	Sweden	CFB	240	91	89	540				Biomass	Waste - REF, Biomass - Demo Wood
2007	2008	BILT Power Limited	Bhigwan, Maharashtra	India	CFB	129	49	102	525				Coal, Coke - Petroleum	
2006	2009	Harbin Power Engineering Company, Ltd. (HPE)	Campha	Vietnam	CFB	450	152	180	540	126			Coal - Anthracite Culm	Coal - Slurry
2006	2009	Harbin Power Engineering Company, Ltd. (HPE)	Campha	Vietnam	CFB	450	152	180	540	126			Coal - Anthracite Culm	Coal - Slurry
2006	2008	Bhushan Power & Steel Ltd.	Rengali, Orissa	India	CFB	144	58	104	535				Coal - Washery Rejects/Coal - Char	
2006	2008	Bhushan Power & Steel Ltd.	Rengali, Orissa	India	CFB	144	58	104	535				Coal - Washery Rejects/Coal - Char	
2006	2008	Bhushan Power & Steel Ltd.	Rengali, Orissa	India	CFB	144	58	104	535				Coal - Washery Rejects/Coal - Char	
2006	2008	Bhushan Power & Steel Ltd.	Rengali, Orissa	India	CFB	144	58	104	535				Coal - Washery Rejects/Coal - Char	
2006	2008	Bhushan Steel & Strips Ltd.	Meeramandali	India	CFB	172	70	104	545				Coal - Washery Rejects/Coal - Char	
2006	2008	Bhushan Steel & Strips Ltd.	Meeramandali	India	CFB	172	70	104	545				Coal - Washery Rejects/Coal - Char	
2006	2008	Nippon Paper Co., Ltd.	Shiraoi Mill	Japan	CFB	206	78	127	536				Coal	Biomass, Waste - RDF, Waste - Paper Sludge
2006	2008	Nirma Ltd.	Kalatalav, Bhavnagar, Gujarat	India	CFB	160	56	104	510				Lignite	Coal
2006	2008	NV Huisvuilcentrale Noord-Holland (HVC-NH)	HVCBio-energiecentrale, Alkmaar	Netherlands	CFB	71	28	89	500				Biomass - Demo Wood	
2006	2007	Bhushan Steel & Strips Ltd.	Meeramandali	India	CFB	172	70	104	545				Coal - Washery Rejects/Coal - Char	

FW Reference List: All Units Includes heat recovery system

Revised on: 12.11.2009

Order Date	Start-Up Date	Client	Plant	Plant Country	Boiler Type	Steam Capacity MWth	Main Steam Flow kg/s	Main Steam Pressure bar(g)	Main Steam Temp. C	Reheat Steam Flow kg/s	Reheat Steam Pressure bar(g)	Reheat Steam Temp. C	Primary Fuel	Secondary Fuel
2006	2007	Bhushan Steel & Strips Ltd.	Meeramandali	India	CFB	172	70	104	545				Coal - Washery Rejects/Coal - Char	
2005	2008	PKE – Elektrownia Lagisza	Lagisza	Poland	CFB-OTU	966	361	282	563	308	51	582	Coal - Bituminous	Coal - Slurry
2004	2008	Nippon Daishowa Paperboard Tohoku Co. , Ltd		Japan	CFB	135	50	102	505				Coal	Biomass - Wood Residual
2004	2006	Corn Products Intl, Inc	Argo	USA	CFB	293	139	45	399				Coal - Bituminous	
2003	2008	PLN Labuhan Angin Sibolga	Labuhan	Indonesia	CFB	293	117	103	542				Coal	
2003	2008	PLN Labuhan Angin Sibolga	Labuhan	Indonesia	CFB	293	117	103	542				Coal	
2003	2007	Fengyuan Group Co., Ltd.	Fengyuan	China	CFB	150	72	98	540				Coal - Bituminous	
2003	2007	Fengyuan Group Co., Ltd.	Fengyuan	China	CFB	150	72	98	540				Coal - Bituminous	
2003	2007	Fengyuan Group Co., Ltd.	Fengyuan	China	CFB	150	72	98	540				Coal - Bituminous	
2003	2007	HINDALCO Industries Ltd.	Indal	India	CFB	99	39	50	460				Coal	
2003	2007	HINDALCO Industries Ltd.	Indal	India	CFB	99	39	50	460				Coal	
2003	2007	HINDALCO Industries Ltd.	Indal	India	CFB	99	39	50	460				Coal	
2003	2007	Nippon Paper Industries Co., Ltd.	Fuji Mill	Japan	CFB	165	64	104	505				Coal	Biomass - Wood Residual, Waste - RDF
2003	2005	Longyu Power Plant	Longyu Power Plant	China	CFB	150	72	98	540				Coal - Bituminous	
2003	2005	Longyu Power Plant	Longyu Power Plant	China	CFB	150	72	98	540				Coal - Bituminous	
2002	2007	Yuen Foong Yu Paper Manufacturing Co., Ltd.		China	CFB	138	56	127	538				Coal - Bituminous	Coal - Sub-Bituminous, Waste - Tires, Waste -
2002	2006	Bundersforste Biomasse Kraftwerk GmbH & Co KG	Simmering	Austria	CFB	61	20	124	520	17	16	520	Biomass - Wood Chips	
2002	2006	Chuetsu Pulp & Paper Co., Ltd.	Futatsuka	Japan	CFB	90	36	124	530				Coal	Biomass - Wood Residual, Waste - TDF, Waste - Paper Sludge
2002	2006	Hokuetsu Paper Mills Ltd.	Katsuta	Japan	CFB	150	54	102	513				Coal	Biomass - Waste Residual, Waste - TDF, Waste -
2002	2006	Jindal Steel & Power, Ltd.		India	CFB	119	42	71	493				Coal - Bituminous Gob	Coal - Washery Rejects, Coal - Char
2002	2006	Prokon Nord Energiesysteme GmbH	BMHKW Emlichheim	Germany	CFB	67	27	90	500				Biomass - Demo Wood	
2002	2006	Prokon Nord Energiesysteme GmbH	BMHKW Borigstraße, Hambug	Germany	CFB	63	25	90	500				Biomass - Demo Wood	
2002	2006	United Pulp and Paper Co., Ltd (UPPC)		Philippines	CFB	99	37	85	504				Coal	
2002	2003	Zhonghe Thermal Power Co., Ltd.	Zhonghe	China	CFB	150	72	98	540				Coal - Bituminous	
2001	2005	Dragon Special Resin Co., Ltd.		China	CFB	158	61	98	541				Coal - Anthracite	
2001	2005	Dragon Special Resin Co., Ltd.		China	CFB	158	61	98	541				Coal - Anthracite	
2001	2005	Dragon Special Resin Co., Ltd.		China	CFB	158	61	98	541				Coal - Anthracite	
2001	2005	Harpen Energie Contracting GmbH	BMHKW Bergkamen	Germany	CFB	58	23	90	500				Biomass - Demo Wood	Biomass - Forest Residual
2001	2005	Huayue Thermal Power Plant Co., Ltd.		China	CFB	150	72	98	540				Coal - Bituminous	
2001	2005	Huayue Thermal Power Plant Co., Ltd.		China	CFB	150	72	98	540				Coal - Bituminous	
2001	2005	MVV Energie AG	BMHKW Königswusterhausen	Germany	CFB	60	18	90	480	16	16	487	Biomass - Demo Wood	
2001	2005	Stora Enso Kvarnsveden AB	Kvarnsveden	Sweden	CFB	130	45	40	490				Biomass - Bark	Waste - Sewer Sludge, Coal -Bituminous
2001	2004	Yibin Power Plant	Yibin	China	CFB	300	114	98	540				Coal - Anthracite	
2001	2003	Guangdong Yunfu Hengdali Power Plant	Hengdali Power Plant	China	CFB	150	61	98	540				Coal - Anthracite	
2001	2003	Haihua Group Co., Ltd.		China	CFB	150	61	98	540				Coal - Bituminous	
2001	2003	Lubei Group Co.	Indal	China	CFB	150	61	98	540				Coal - Bituminous	
2001	2003	Zouping Power Co.		China	CFB	150	61	98	540				Coal - Bituminous	
2001	2003	Zouping Power Co.		China	CFB	150	61	98	540				Coal - Bituminous	

Includes heat recovery system

Order Date	Start-Up Date	Client	Plant	Plant Country	Boiler Type	Steam Capacity MWth	Main Steam Flow kg/s	Main Steam Pressure bar(g)	Main Steam Temp. C	Reheat Steam Flow kg/s	Reheat Steam Pressure bar(g)	Reheat Steam Temp. C	Primary Fuel	Secondary Fuel
2001	2002	Wusuotun Power Plant	Wusuotun Power Plant	China	CFB	150	72	98	540				Coal - Bituminous	
2000	2004	BOT Elektrownia Turow S.A.	Turow	Poland	CFB	557	196	170	568	181	39	568	Coal - Brown	Lignite
2000	2004	BOT Elektrownia Turow S.A.	Turow	Poland	CFB	557	196	170	568	181	39	568	Coal - Brown	Lignite
2000	2004	ESB Lough Ree Power	Lough Ree	Ireland	CFB	216	78	144	563	66	34	563	Peat	
2000	2004	ESB West Offaly Power	West Offaly	Ireland	CFB	318	113	170	563	98	35	563	Peat	
2000	2004	Longyu Power Plant	Longyu Power Plant	China	CFB	150	72	98	540				Coal - Bituminous	
2000	2004	Longyu Power Plant	Longyu Power Plant	China	CFB	150	72	98	540				Coal - Bituminous	
2000	2004	Summit Myojyo Power		Japan	CFB	125	54	102	513				Biomass - Demo Wood	Coal - Anthracite
2000	2004	Vinacoal		Vietnam	CFB	125	57	128	541				Lignite	
2000	2004	Vinacoal		Vietnam	CFB	125	57	128	541				Lignite	
2000	2002	Zibo Thermal Power Co., Ltd.		China	CFB	150	61	98	540				Coal - Bituminous	
1999	2003	Baoding Thermal Power Plant	Baoding	China	CFB	330	125	98	540				Coal - Bituminous	
1999	2003	BOT Elektrownia Turow S.A.	Turow	Poland	CFB	557	196	170	568	181	39	568	Coal - Brown	Lignite
1999	2003	EC Chorzow Elcho Sp.zo.o.	Elcho	Poland	CFB	274	112	135	538				Coal - Bituminous	
1999	2003	EC Chorzow Elcho Sp.zo.o.	Elcho	Poland	CFB	274	112	135	538				Coal - Bituminous	
1999	2003	Heizkraftwerk Kehl GmbH	BioMasse-HKW Kehl	Germany	CFB	44	16	90	500				Biomass - Demo Wood	
1999	2003	Prokon Nord Energiesysteme GmbH	BMHKW Papenburg	Germany	CFB	63	25	90	500				Biomass - Demo Wood	
1999	2003	Shijiazhuang Thermal Power Plant	Shijiazhuang Thermal Power Plant	China	CFB	300	114	98	540				Coal - Bituminous	
1999	2003	Shijiazhuang Thermal Power Plant	Shijiazhuang Thermal Power Plant	China	CFB	300	114	98	540				Coal - Bituminous	
1999	2003	Southern Illinois Power Cooperative	Marion Station	USA	CFB	349	144	60	485				Coal - Bituminous Gob	
1999	2002	Baoding Thermal Power Plant	Baoding	China	CFB	330	125	98	540				Coal - Bituminous	
1999	2002	Shijiazhuang Thermal Power Plant	Shijiazhuang Thermal Power Plant	China	CFB	300	114	98	540				Coal - Bituminous	
1999	2002	Shijiazhuang Thermal Power Plant	Shijiazhuang Thermal Power Plant	China	CFB	300	114	98	540				Coal - Bituminous	
1998	2002	Jämtkraft AB	KVV Lugnvik Östersund	Sweden	CFB	125	51	145	545				Biomass - Wood Residual	Peat, Biomass - Bark, Biomass - Sawdust, Biomass - Demo Wood
1998	2002	Nirma Ltd.		India	CFB	79	28	105	510				Lignite	Coal
1998	2002	Vattenfall SCA	Munksund	Sweden	CFB	98	34	80	480				Biomass - Bark	Biomass - Wood Residual, Waste - Paper
1997	2001	Mälarenergi AB	KVV Västerås P5	Sweden	CFB	157	56	171	540	50	40	540	Biomass - Wood Residual	Peat, Coal
1997	2001	Skellefteå Kraft AB	KVV Skogsbacka	Sweden	CFB	47	17	87	520				Biomass - Wood Residual	Biomass - Bark, Peat, Coal
1996	2000	BOT Elektrownia Turow S.A.	Turow	Poland	CFB	520	186	132	540	165	24	540	Coal - Brown	Lignite
1996	2000	Hornitex Energie GmbH	BMHKW Horn Bad Meinberg	Germany	CFB	94	33	89	480				Biomass - Demo Wood, Biomass - Wood	
1996	2000	Taiwan Cogeneration Corp. (TCC)		Taiwan R.O.C.	CFB	138	56	127	541				Coal - Bituminous	Coal - Sub-Bituminous, Waste - Tires, Waste - Sewer Sludge
1995	1999	COCO	Block 2	Thailand	CFB	360	121	182	568				Coal	
1995	1999	COCO	Block 1	Thailand	CFB	360	121	182	568				Coal	
1995	1999	EC Katowice S.A.	EC Katowice BCF-100	Poland	CFB	352	134	138	540				Coal - Bituminous	Coal - Slurry
1995	1999	Elektrownia Jaworzno III	Jaworzno III	Poland	CFB	180	72	138	540				Coal	
1995	1999	Elektrownia Jaworzno III	Jaworzno III	Poland	CFB	180	72	138	540				Coal	
1994	1998	Ban Yu Paper Mill Co., Ltd.		Taiwan R.O.C.	CFB	144	56	127	541				Coal - Bituminous	Coal - Anthracite, Waste - Paper Sludge
1994	1998	BOT Elektrownia Turow S.A.	Turow	Poland	CFB	520	186	132	540	165	24	540	Coal - Brown	Lignite
1994	1998	BOT Elektrownia Turow S.A.	Turow	Poland	CFB	520	186	132	540	165	24	540	Coal - Brown	Lignite

FW Reference List: All Units
Revised on: 12.11.2009

Includes heat recovery system

Order Date	Start-Up Date	Client	Plant	Plant Country	Boiler Type	Steam Capacity MWth	Main Steam Flow kg/s	Main Steam Pressure bar(g)	Main Steam Temp. C	Reheat Steam Flow kg/s	Reheat Steam Pressure bar(g)	Reheat Steam Temp. C	Primary Fuel	Secondary Fuel
1994	1998	CEZ a.s. Porici Power Plant	Porici Power Plant	Czech Republic	CFB	178	70	100	520				Coal - Bituminous	Coal - Brown
1994	1998	Dalian Xianhai Thermal Power Corp.	Dalian	China	CFB	160	61	102	541				Coal - Bituminous	
1994	1998	Dalian Xianhai Thermal Power Corp.	Dalian	China	CFB	160	61	102	541				Coal - Bituminous	
1994	1998	Mondi Packaging Paper Steti a.s.		Czech Republic	CFB	176	61	94	535				Coal	Biomass - Bark, Waste Paper Sludge
1994	1998	Moravskoslezske Teplarny a.s.		Czech Republic	CFB	141	53	134	535				Coal - Brown	Coal - Bituminous
1994	1998	Mysore Paper		India	CFB	71	25	62	449				Coal	Lignite, Biomass - Bagasse, Waste - Paper Sludge
1994	1998	National Power Supply Co., Ltd.		Thailand	CFB	370	134	161	542	122	35	542	Coal - Anthracite	Coal - Bituminous, Biomass - Rice Husk, Biomass - Bark
1994	1998	National Power Supply Co., Ltd.		Thailand	CFB	370	134	161	542	122	35	542	Coal - Anthracite	Coal - Bituminous, Biomass - Rice Husk, Biomass - Bark
1994	1998	Sichuan Fuling Aixi Power Generating Co., Ltd.	Aixi	China	CFB	160	61	99	540				Coal	
1994	1998	Zaozhuang Coal Mine Bureau		China	CFB	26	10	38	450				Coal - Washery Rejects	
1993	1997	CEZ a.s. Hodonin Power Station	Hodonin Power Station	Czech Republic	CFB	132	47	96	510				Coal - Brown	
1993	1997	Indah Kiat Pulp and Paper Corp.		Indonesia	CFB	171	61	65	455				Coal	Biomass - Bark, Peat, Biomass Wood, Waste - Sewer Sludge
1993	1997	Indah Kiat Pulp and Paper Corp.		Indonesia	CFB	171	61	65	455				Coal	Biomass - Bark, Peat, Biomass Wood, Waste - Sewer Sludge
1993	1997	P.T. Riau Andalan Pulp & Paper Corp.		Indonesia	CFB	314	130	140	540				Biomass - Bark	Coal
1993	1997	Sonoco Products		USA	CFB	37	15	86	510				Coal	Biomass - Bark, Waste - Paper
1992	1997	CEZ a.s. Hodonin Power Station	Hodonin Power Station	Czech Republic	CFB	132	47	96	510				Coal - Brown	
1992	1996	Brista Kraft AB		Sweden	CFB	122	50	144	540				Biomass - Forest Residual	Coal
1992	1996	CEZ a.s. Porici Power Plant	Porici Power Plant	Czech Republic	CFB	178	70	100	520				Coal - Bituminous	Coal - Brown
1992	1996	CMIEC/Neijiang Thermal Power Plant	Neijiang	China	CFB	285	114	98	540				Coal	
1992	1996	Hangzhou Thermoelectric Plant	Hangzhou Thermoelectric Plant	China	CFB	160	61	99	541				Coal	
1992	1996	Hornitex Werke Beeskow Kunststoffe und Holzwerkstoffe GmbH		Germany	CFB	86	31	89	480				Biomass - Demo Wood, Biomass -	
1992	1996	Taiheiyo Cement Co., Ltd.	Saiki Works	Japan	CFB	69	27	103	541				Coal - Bituminous	Coal - Anthracite, Coke - Petroleum, Waste - RDF, Waste - TDF
1992	1996	Thai Kraft Paper Industry Co., Ltd.		Thailand	CFB	140	53	108	505				Coal	Lignite, Waste - Sewer Sludge, Biomass - Bark
1992	1996	University of Iowa	Univ. of Iowa	USA	CFB	50	21	32	404				Coal	
1992	1996	Växjo Energi AB		Sweden	CFB	100	41	142	540				Peat	Biomass - Forest Residual
1991	1995	Colver Power Project, Inter Power/ AhlCon Ptns	Colver	USA	CFB	270	99	174	541	87	37	541	Coal - Bituminous Gob	
1991	1995	Dalian Industrial Chemical Co.		China	CFB	157	61	100	541				Coal	
1991	1995	Dalian Industrial Chemical Co.		China	CFB	157	61	100	541				Coal	
1991	1995	Fortum Engineering Ltd. Oulun Energia	Toppila	Finland	CFB	291	103	156	540	89	20	540	Peat	Coal
1991	1995	Indian Rayon and Industries Ltd.		India	CFB	35	14	88	510				Coal	Lignite, Oil, Gas
1991	1995	Indian Rayon and Industries Ltd.		India	CFB	35	14	88	510				Coal	Lignite, Oil, Gas
1991	1995	Northampton Energy	Northampton	USA	CFB	277	100	174	541	92	40	541	Coal - Anthracite Culm	
1991	1995	Panjin Liaohe Thermal Power Co.	Laiohe	China	CFB	153	61	124	540				Coal	
1991	1995	Takasaki Sanko Co., Ltd	Sobue Works	Japan	CFB	88	33	121	540				Coal - Bituminous	
1990	1994	Cedar Bay Cogeneration Facility	Cedar Bay	USA	CFB	240	88	136	541	69	29	541	Coal - Bituminous	
1990	1994	Cedar Bay Cogeneration Facility	Cedar Bay	USA	CFB	240	88	136	541	69	29	541	Coal - Bituminous	
1990	1994	Cedar Bay Cogeneration Facility	Cedar Bay	USA	CFB	240	88	136	541	69	29	541	Coal - Bituminous	
1990	1994	Fortum Engineering Ltd.		Finland	CFB	98	33	61	510				Peat	Coal
1990	1994	Hunosa	La Pereda Power Station	Spain	CFB	145	52	113	530				Coal - Anthracite Culm	Coal - Washery Rejects

Unit 2400: Baghouse filter

A baghouse filter is provided to remove particulate content in the flue gases to meet the environmental limits. Fly ash are collected from the baghouse filter bottom.

Unit 2500: Ash Handling Plant

The ash handling system, takes care of conveying the ash generated in the boiler plant: both the furnace bottom ash and the fly ash from the various hoppers. (Reference to Section C – para 3.0).

Unit 3000: Steam Turbine and Preheating Line

The block flow diagram of this section is attached to paragraph 3.3.

The power island is a single train, mainly composed of one supercritical steam turbine and one preheating line. Supercritical steam from the boiler is sent to the steam turbine, which consists of a HP, IP and LP section, all connected to the generator on a single shaft. The steam turbine is a condensing type, with multiple extractions for the preheating of the condensate and boiler feedwater.

Main steam from the boiler, generated at 275 bar and 580°C, passes through the stop valves and control valves and enters the turbine. Steam from the exhaust of the HP turbine is returned to the boiler gas path for reheating at 60 bar, 600°C and is then throttled into the double flow IP turbine. Exhaust steam from IP flows into a double casing, double flow LP turbine and then downward into the condenser at 0.03 bar, 24°C.

Different extractions from the IP section at different conditions of steam pressure/temperature allow the preheating of the boiler feed water, while the low-pressure extraction is used to provide the steam necessary for the degassing of the condensate. Steam condensate recovered into the boiler feed water heaters is recovered back to the deaerator.

Part of the exhaust steam from the IP ST section, together with three extractions from the LP steam turbine, provide heat to the four condensate heaters downstream the condensate pumps, before entering the deaerator.

Boiler feedwater exiting the deaerator is pumped to the economizers of the boiler by means of the boiler feedwater pump steam turbine driven.

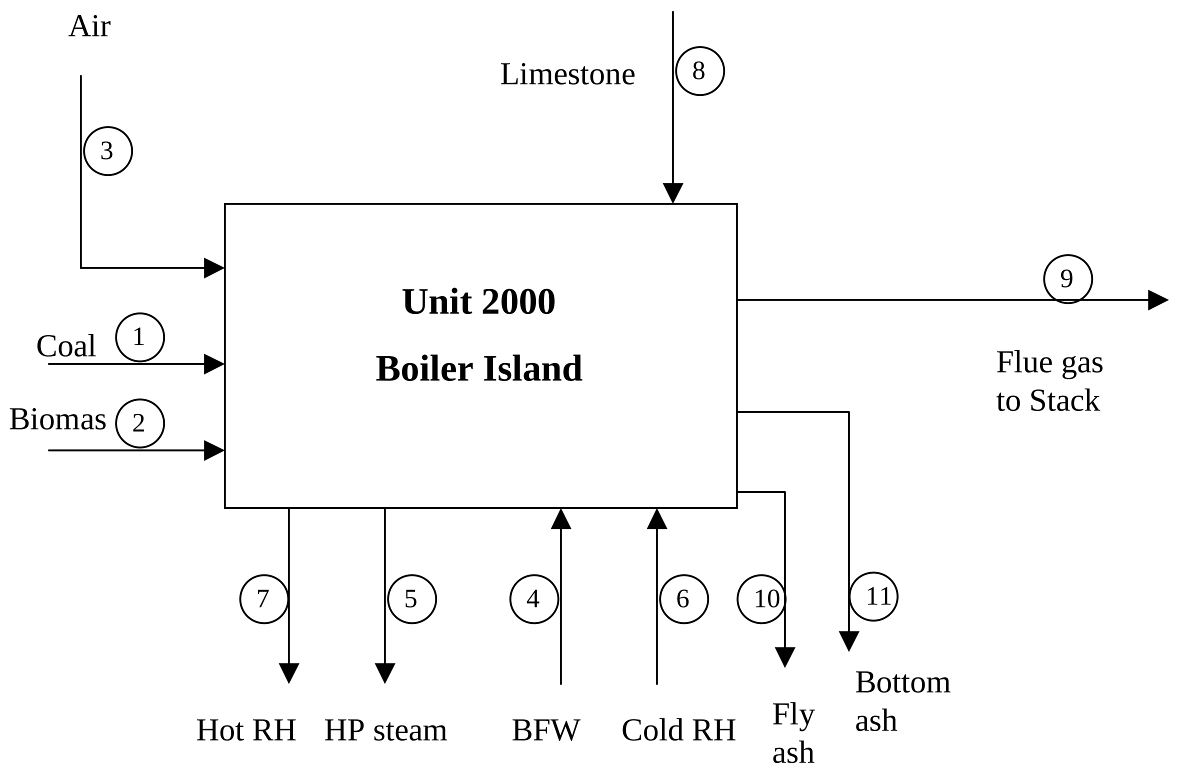
Chemical injection for control of the water quality is made by dedicated packages on the suction of the boiler feedwater pumps and at the inlet of the boiler.

3.3 Block Flow Diagrams

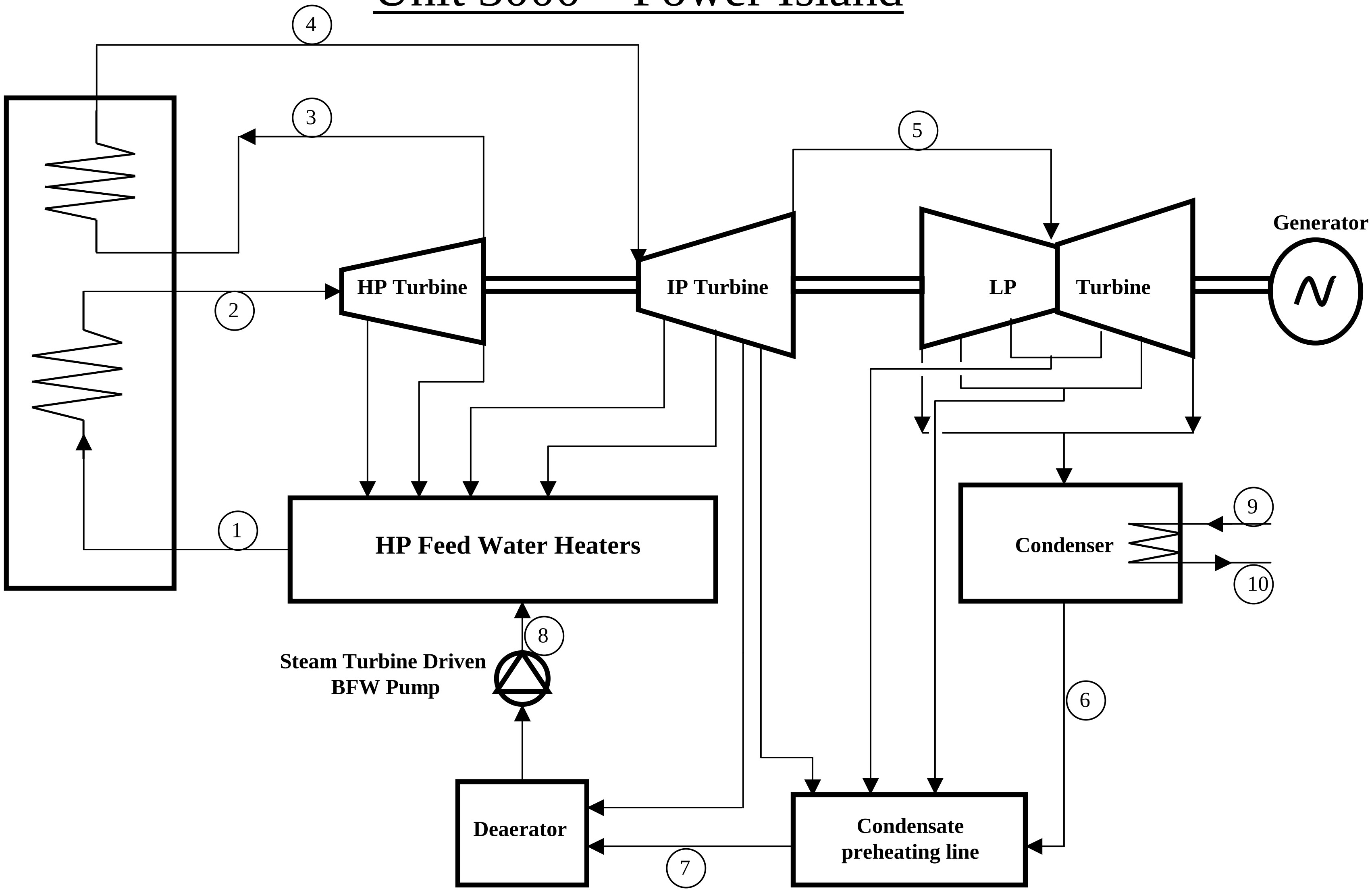
The Block Flow Diagrams of the following process units are attached to this paragraph:

- Unit 2000: Boiler Island
- Unit 3000: Power Island

Unit 2000 – Boiler Island



Unit 3000 – Power Island



3.4 Heat and Material Balances

The Heat & Material Balances of the following process units are attached to this section:

- UNIT 2000: Boiler Island and flue gas treating
- UNIT 3000: Power Island

Stream numbers are as shown on the Block Flow Diagrams attached to paragraph 3.3 of this Section.

PC-USC HEAT AND MATERIAL BALANCE

CLIENT: IEA GREEN HOUSE R & D PROGRAMME
CASE: CASE 2A - 500MW CFB boiler without CCS
UNIT: 2000 Boiler Island and Flue gas treating

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a
1	Coal	145	amb.	amb.
2	Biomass	57	amb.	amb.
3	Air intake from Atmosphere	1907	amb.	amb.
4	Feed Water from Preheating line UNIT 3000	1450	290	318
5	HP Steam from boiler	1450	580	275
6	Cold reheat to boiler	1248	350	62
7	Hot reheat from boiler	1248	600	60
8	Make up water	60.0	amb.	amb.
9	Limestone	11.5	amb.	amb.
10	Flue Gas to Stack (1)	2070	90	1.005
11	Gypsum	0.0	amb.	amb.
12	Fly ash	23.3	amb.	amb.
13	Bottom Ash	6.7	amb.	amb.

Notes:
(1) For gas composition see Paragraph 3.7.1

PC-USC HEAT AND MATERIAL BALANCE

CLIENT: IEA GREEN HOUSE R & D PROGRAMME
CASE: CASE 2A - 500MW CFB boiler without CCS
UNIT: 3000 Power Island

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	HP Water to Boiler Island	1450	290	317.5	1278
2	HP Steam from boiler	1450	580	275	3405
3	Cold reheat to boiler	1248	350	62.0	3039
4	Hot reheat from boiler	1248	600	59.8	3656
5	MP Steam Turbine exhaust	1063.8	273	6.21	3006
6	Condensate	1004.1	24	0.03	101
7	LP Preheated Condensate	1416.5	166.7	12.4	705
8	Condensate to HP FWH	1450	193	319	836
9	Cooling Water Inlet	65590	12	1.9	42
10	Cooling Water Outlet	65590	19	1.4	71

3.5 Utility Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Tables.

CLIENT:	IEA GREEN HOUSE R & D PROGRAMME	Rev 0
PROJECT:	BIOMASS FIRED POWER PLANT	May 09
LOCATION:	THE NETHERLANDS	ISSUED BY: SC
		CHECKED BY: PC
		APPR. BY: FG

ELECTRICAL CONSUMPTION SUMMARY - CASE 2A - 500MW CFB boiler without CCS

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
1000	SOLID RECEIVING, HANDLING AND STORAGE	
	Fuel Receiving, Handling and Storage	1400
	Limestone unloading, storage and handling	26
2000	BOILER ISLAND AND FLUE GAS TREATING	
	Boiler auxiliary consumption	7526
	Flue gas desulphurization plant (FGD)	1767
	Gypsum loading, storage and handling	157
	Ash loading, storage and handling	1164
	Baghouse filter	350
	Induced draft fan	4834
3000	POWER ISLAND	
	Steam turbine auxiliaries and condenser	1141
	Condensate pumps and feedwater system	865
	Step-Up transformer losses	1100
4000	UTILITIES AND OFFSITE UNITS	
	Machinery cooling water system	140
	Sea water system	3630
	Miscellaneous Balance-of-Plant	2188
	BALANCE	26288

CLIENT:	IEA GREEN HOUSE R & D PROGRAMME	Rev 0
PROJECT:	BIOMASS FIRED POWER PLANT	May 09
LOCATION:	THE NETHERLANDS	ISSUED BY: SC
		CHECKED BY: PC
		APPR. BY: FG

WATER CONSUMPTION SUMMARY - CASE 2A - 500MW CFB boiler without CCS

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	Solid receiving, handling and storage			45	
2000	Boiler Island			59	
2300	Flue gas desulphurization plant (FGD)	60	1		
	POWER ISLANDS UNITS				
3000	Surface condenser				65590
	Miscellanea		5	2237	
	UTILITY and OFFSITE				
4100	Machinery Cooling Water System				4099
4200	Demineralized Water System	6.6	-6		
	Miscellanea			50	
	BALANCE	66.6	0	2391	69689

3.6 Overall Performance

The following Table shows the overall performance of the Plant.

IEA GHG		
CASE 2A: 500MW CFB boiler without CO_2 capture		
OVERALL PERFORMANCE OF THE COMPLEX		
Coal Flowrate	t/h	145
Coal LHV	kJ/kg	25870
Biomass Flowrate	t/h	57
Biomass LHV	kJ/kg	7300
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1156**
Steam turbine power output (@gen. Terminals)	MWe	553.4
GROSS ELECTRIC POWER OUTPUT (D)	**MWe**	**553.4**
Solid Receiving, Handling and Storage	MWe	1.5
Boiler Island and flue gas treating	MWe	21.3
CO2 Plant incl. Blowers	MWe	0
CO2 Compression	MWe	0
Power Island	MWe	3.1
Utilities	MWe	6.1
ELECTRIC POWER CONSUMPTION	**MWe**	**32.0**
NET ELECTRIC POWER OUTPUT (C)	**MWe**	**521.4**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**47.9**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**45.1**

3.7 Environmental Impact

The plant is designed to process coal and biomass, whose characteristics are defined in the Basic Engineering Design Data and produce electric power. The advanced technology allows to reach a high efficiency and to minimise environmental impact.

The gaseous emissions, liquid effluents and solid wastes from the plant are summarised in this section.

3.7.1 Gaseous Emissions

Main Emissions

In normal operation at full load, the main continuous emissions are the combustion flue gases leaving the boiler at stack.

Table 3.1 summarises expected flow rate and concentration of the combustion flue gas released to atmosphere from the stack.

	Normal Operation
Wet gas flow rate, kg/s	575.0
Flow, Nm^3/h	1,577,000
Temperature, °C	90
Composition	(%vol)
N_2+Ar	73.0
O_2	4.9
CO_2	12.6
H_2O	9.5
Emissions	mg/Nm^{3} (1)
NOx	200
N_2O	12
SOx	200
CO	200
Particulate	Less than 30

Table 3.1 – Expected gaseous emissions from plant

(1) Dry gas, O_2 Content 6% vol

Minor Emissions

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). They are prevented by proper design and operation.

3.7.2 Liquid Effluent

All the liquid effluents are treated in the wastewater treatment system in order to be discharged in accordance with the current regulations.

The liquid effluents generated in the power plant are mainly the following:
- Rain water contaminated by powder;
- Wash water contaminated by oil and powder;
- Eluates from demineralizing water system;
- Sanitary water.

Sea water in open circuit is used for cooling.
The return stream water is treated with meta-bisulphite in the Dechlorination System to reduce the Cl_2 concentration. Main characteristics of the water are listed in the following:

- Maximum flow rate : 69,689 m^3/h
- Temperature : 19 °C

3.7.3 Solid Effluent

No solid waste other than those produced by a real industrial activity.
The power plant is expected to produce the following solid by-products:

Fly Ash

Flow rate	:	23.3	t/h
Unburned Carbon	:	8.5	%wt

Bottom Ash

Flow rate	:	6.7	t/h
Unburned Carbon	:	2.7	%wt

Fly and bottom ash could be theoretically dispatched to cement industries. For the purposes of present study they are considered as a waste to be disposed.

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : TECHNO-ECONOMIC EVALUATION OF CAPTURING CO_2 FROM BIOMASS FIRED POWER PLANT
DOCUMENT NAME : CASE 2B – 500 MWE CFB BOILER WITH CO_2 CAPTURE

ISSUED BY : S. CAVEZZALI
CHECKED BY : P. COTONE
APPROVED BY : F. GASPARINI

Date	Revised Pages	Issued by	Checked by	Approved by
May 2009	Rev 0	S. Cavezzali	P. Cotone	F. Gasparini
July 2009	Rev 1	S. Cavezzali	P. Cotone	F. Gasparini
November 2009	Rev 2	S. Cavezzali	P. Cotone	F. Gasparini

SECTION D

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D BASIC INFORMATION FOR EACH ALTERNATIVE

4.0 Case 2b - 500 MWe CFB Boiler with CO_2 capture

Summary

Case 2b is based on a SuperCritical CFB boiler co-fired with coal and biomass. The boiler is equipped with FGD based on wet limestone. CO_2 capture and compression is considered.

- The size of the plant considered for this configuration is 500 MWe net power output nominal. The boiler is the same as the case without CO_2 capture having as a consequence the reduction in net power output of the plant due to the impact of the CO_2 removal and compression units as power and steam consumer.
- The boiler is co-fired with coal and biomass. The biomass fired corresponds to 10% of total fired duty (based on LHV).
- No drying of biomass is needed.
- The boiler technology for co-firing coal and biomass considered in this study is commercially available in the market.
- The flue gas line of the boiler does not include the special plastic heat exchanger foreseen in the case without CO_2 capture. This is because of the necessity of the FGD system and the presence of CO_2 capture unit (Direct Contact Cooler and CO_2 absorption tower) that sensibility decrease the flue gas temperature making impossible the introduction of such heat exchanger without the formation of a strongly visible plume at stack outlet.
- The environmental limits on NOx can be met with just the firing system of the boiler with low temperature at furnace exit. On the basis of experience of CFB boiler suppliers, no addition of a DeNOx system is needed. In case different CFB boiler technology is selected could be necessary the installation of a DeNOx system (SNCR type).
- The amine based CO_2 absorption system, requires a very low level of NO_2 in the flue gas. Being the content of NO_2 in NOx ranging from 15% to 20%, this low content of NO_2 is achieved without the need of addition of further denitrification in flue gas treatment. On the other hand due to

the removal of the CO_2 from the flue gases, the NOx concentration at stack results slightly higher than the one at CO_2 capture unit inlet. For this reason the NOx level at boiler outlet shall be lower than in the case without CO_2 capture by approximately 15% in order to maintain 200 mg/Nm^3 (@6% O_2 dry) at stack. Actually on the basis of the overall annual NOx flow rates, there could be an allowance for the more concentrated stack gases as the absolute NOx flow rate remains constant. Anyhow in the basis of design of the present study there is no any reduction on the emission limit and 200 mg/Nm^3 (@6% O_2 dry) at stack is considered for all cases. It is expected that the CFB can meet this specification without the need of SCR or SNCR. In any case it is foreseen the possibility to inject ammonia in the furnace in case the NOx emissions should exceed the environmental limits. The impact of such system on investment and operating costs is considered negligible as it would be on discontinuous basis only.

- Production of N_2O in the CFB boiler are not insignificant because of the combustion temperature. Nitrous oxide (N_2O) is a greenhouse gas with 300 time the impact of CO_2. It is expected that the N_2O in flue gas will not be absorbed into MEA and pass through unchanged to the stack. The behaviour of N_2O is in fact the same of oxygen and therefore its impact on MEA can be considered negligible, due to its very low content with respect to the oxygen.

- The amine based CO_2 absorption system, requires a very low level of SO_2 in the flue gas (much lower than the emission limits). This figure is not achievable only with limestone injection in the furnace bed and an external FGD is needed, therefore SOx capture is made partially in the furnace and partially in the external FGD. Based on FW experience, in a traditional coal fired CFB boiler, the optimum split of SOx removal is considered with a Ca/S ratio of 1 in the furnace bed and the remaining SOx removal duty to the downstream FGD. Wet FGD limestone base type has been selected as it is the most referenced and with the highest SO_2 removal efficiency DeSOx system, anyway different alternatives could be selected. In present study, despite of the presence of the biomass with a very low sulphur content, the overall sulphur content is still too high to allow the complete SOx removal in the furnace bed, therefore a double SOx removal shall be carried out.

- All the heat required for the CO_2 capture plant is provided from the low temperature steam extracted from the turbines. This results in a significant loss of power in the turbine generator. Further, a significant optimisation of heat within the CO_2 capture plant is also considered with adequate heat exchanges between various streams within the plant.

- CO_2 is dried and compressed up to supercritical phase at 110 bar for use in EOR or for geological disposal.

4.1 Introduction

The Case 2b of the study is a CFB coal and biomass co-fired Super Critical steam plant with carbon dioxide capture.

The configuration of the complex is based on a once through steam generator with superheating and single steam reheating.

Reference is made to the attached Block Flow Diagram of the plant.
The arrangement of the process units is :

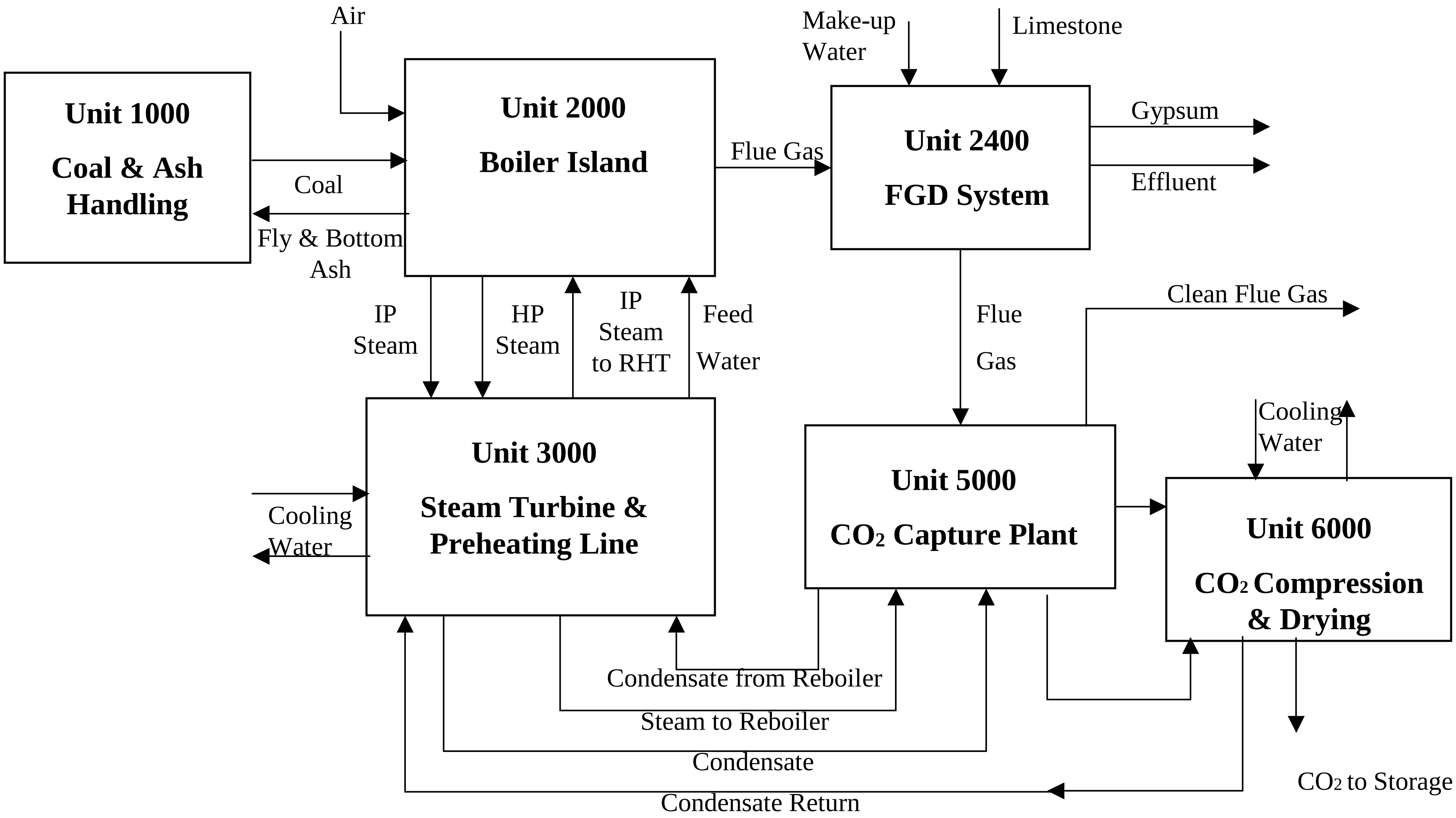
Unit

1000 Storage and Handling of solid materials, including:
- 1100 Coal storage and handling
- 1200 Biomass storage and handling
- 1300 Limestone storage and handling

2000 Boiler Island and flue gas treating, including:
- 2100 Boiler
- 2300 Flue Gas Desulphurisation
- 2400 Baghouse filter
- 2500 Ash and by-products removal and handling

3000 Power Island including:
- 3100 Steam Turbine
- 3200 Preheating Line
- 3300 Electrical Power Generation.

5000 CO_2 capture unit
6000 CO_2 compression and drying unit



Air
Make-up Water
Limestone
Unit 1000
Coal & Ash Handling
Unit 2000
Boiler Island
Coal
Fly & Bottom Ash
Flue Gas
Unit 2400
FGD System
Gypsum
Effluent
IP Steam
HP Steam
IP Steam to RHT
Feed Water
Flue Gas
Clean Flue Gas
Cooling Water
Unit 3000
Steam Turbine & Preheating Line
Cooling Water
Unit 5000
CO_2 Capture Plant
Unit 6000
CO_2 Compression & Drying
Condensate from Reboiler
Steam to Reboiler
Condensate
Condensate Return
CO_2 to Storage

4.2 Process Description

Unit 1000: Storage and handling of solids materials

The unit is exactly the same as case 2a being equal the boiler. For unit description, reference shall be made to paragraph 3.2, section D3.

Unit 2000: Boiler Island

The boiler is exactly the same as case 2a. For unit description, reference shall be made to paragraph 3.2, section D3.

The amine based CO_2 absorption system, requires a very low level of SO_2 in the flue gas (much lower than the emission limits). This figure is not achievable only with limestone injection in the furnace bed and an external FGD is needed. Therefore the SOx capture is made partially in the furnace and partially in the external FGD. Based on FW experience, in a traditional coal fired CFB boiler the optimum split of SOx removal is considered with a Ca/S ratio of 1 in the furnace bed and the remaining SOx removal duty to the downstream FGD.
In present study, despite of the presence of biomass with a very low sulphur content, the sulphur content is still too high to allow the complete SOx removal in the furnace bed, therefore a double SOx removal shall be carried out.

With a Ca/S ratio of 1, the SOx content in the flue gas leaving the boiler is therefore 840 mg/Nm^3 (@6% O_2 dry basis), with a removal efficiency of 50%.

The block flow diagram of this section is attached to paragraph 4.3.

Unit 2300: FGD System

For further description, reference is to be made to Section C para. 5.0 for Wet limestone based FGD system.

The function of the FGD System is to scrub the boiler exhaust gases to complete the SOx removal prior to feed the gases to the CO_2 capture unit.

The flue gases entering the scrubber have a SOx content is 840 mg/Nm^3 (@6% O_2 dry basis). The overall removal efficiency required, in order to have 30 mg/Nm^3 (@6% O_2 dry basis) at scrubber outlet, is therefore 96.4%.

The SO_2 level obtained is much lower than the environmental limits fixed in section B.

Unit 2400: Baghouse filter

A baghouse filter is provided to remove particulate content in the flue gases to meet the requirements of the downstream CO_2 capture unit. Fly ash are collected from the baghouse filter bottom.

An excessive amount of particulate in the flue gases fed to the CO_2 capture unit can cause foam formation that can compromise the correct unit operation.
For this reason the particulate content at CO_2 capture unit inlet is fixed at 5 mg/Nm^3 (@6% O_2 dry basis). This value is much lower than the environmental limits fixed in section B.

Unit 2500: Ash Handling Plant

The unit is exactly the same as case 2a. For unit description, reference shall be made to paragraph 3.2, section D3.

Unit 3000: Steam Turbine and Preheating Line

The block flow diagram of this section is attached to paragraph 4.3.

The power island is a single train, mainly composed of one supercritical steam turbine and one preheating line. Supercritical steam from the boiler is sent to the steam turbine, which consists of a HP, IP and LP section, all connected to the generator on a single shaft. The steam turbine is a condensing type, with multiple extractions for the preheating of the condensate and boiler feedwater. The LP steam is also extracted for the use in the reboiler and stripping unit in the CO_2 capture plant.

Main steam from the boiler, generated at 275 bar and 580°C, passes through the stop valves and control valves and enters the turbine. Steam from the exhaust of the HP turbine is returned to the boiler gas path for reheating at 60 bar, 600°C and is then throttled into the double flow IP turbine. Exhaust steam from IP flows into a double casing, double flow LP turbine and then downward into the condenser at 0.03 bar, 24°C.

Different extractions from the IP section at different conditions of steam pressure/temperature allow the preheating of the boiler feed water

Recycled condensate from the condenser is pumped to the carbon dioxide capture plant and preheated in the amine stripper overhead condenser and the carbon dioxide compressor intercoolers. An optimisation of the integration between power plant and CO_2 capture plant allows to maximize the efficiency of the process. This also reduces the necessity of LP steam extractions to preheat condensate in LP preheating line. Only one condensate preheater is therefore needed downstream the condensate heating in the process units. The preheated feed water stream is routed to the deaerator, along with condensate returned from the amine stripper reboiler.

Boiler feedwater exiting the deaerator is pumped to the economizers of the boiler by means of the boiler feedwater pump steam turbine driven.

The plant configuration studied considers the following integrations between the Process Units and the Power Island:

- A part of the heat recovered in the CO_2 capture plant (overhead stripper condenser) and in the compression line is recovered by preheating the condensate, partially avoiding the use of LP feed water heaters.
- All the LP steam required for the CO_2 absorption plant is provided by extraction from the LP stage of the steam turbine.

Chemical injection for control of the water quality is made by dedicated packages on the suction of the boiler feedwater pumps and at the inlet of the boilers.

Unit 4000: CO_2 Capture Plant

Clean flue gas with NO_2 less than 20 ppmv and SO_x less than 10 ppm is sent to the CO_2 absorption tower.
Refer to Section C para. 6.0 for this section.
In the CO_2 capture plant, where flue gas temperatures are lower, it is not expected to have an increase of the NO_2 content, although conversion of NO to NO_2 is promoted by low temperatures, because the kinetics of the reaction that converts NO into NO_2 is too slow with respect to the residence time of gases in the system.
90% capture of CO_2 from the flue gas is considered.
The block flow diagram of this section is attached to paragraph 4.3.

Unit 5000: CO_2 Compression and Drying

Refer to Section C, para. 8.0 for the general description of the Unit. The block flow diagram of this section is attached to paragraph 4.3.

CO_2 can be handled as a liquid in pipe lines at conditions beyond its critical point (P_{CR}=73.8 bar; T_{CR}=31°C). The present configuration studied, assumes, CO_2 to be delivered at a pressure of around 110 bara.

The product stream sent to final storage is mainly composed of CO_2. The main properties of the stream are as follows:

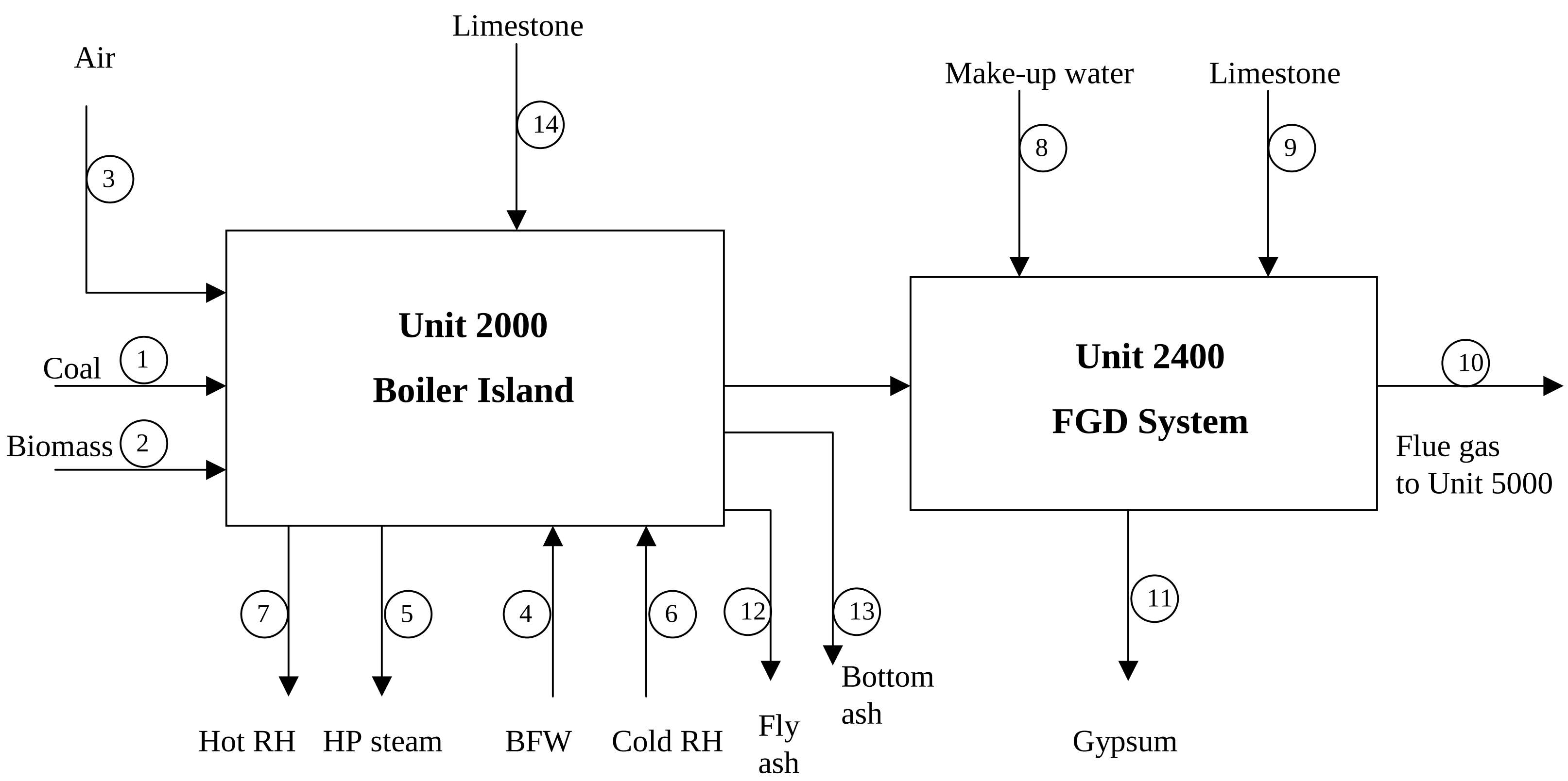
Product stream	:	351.3 t/h.
Pressure	:	110 bar.
Temperature	:	32 °C
CO_2 purity	:	>99.8 % wt.

4.3 Block Flow Diagrams

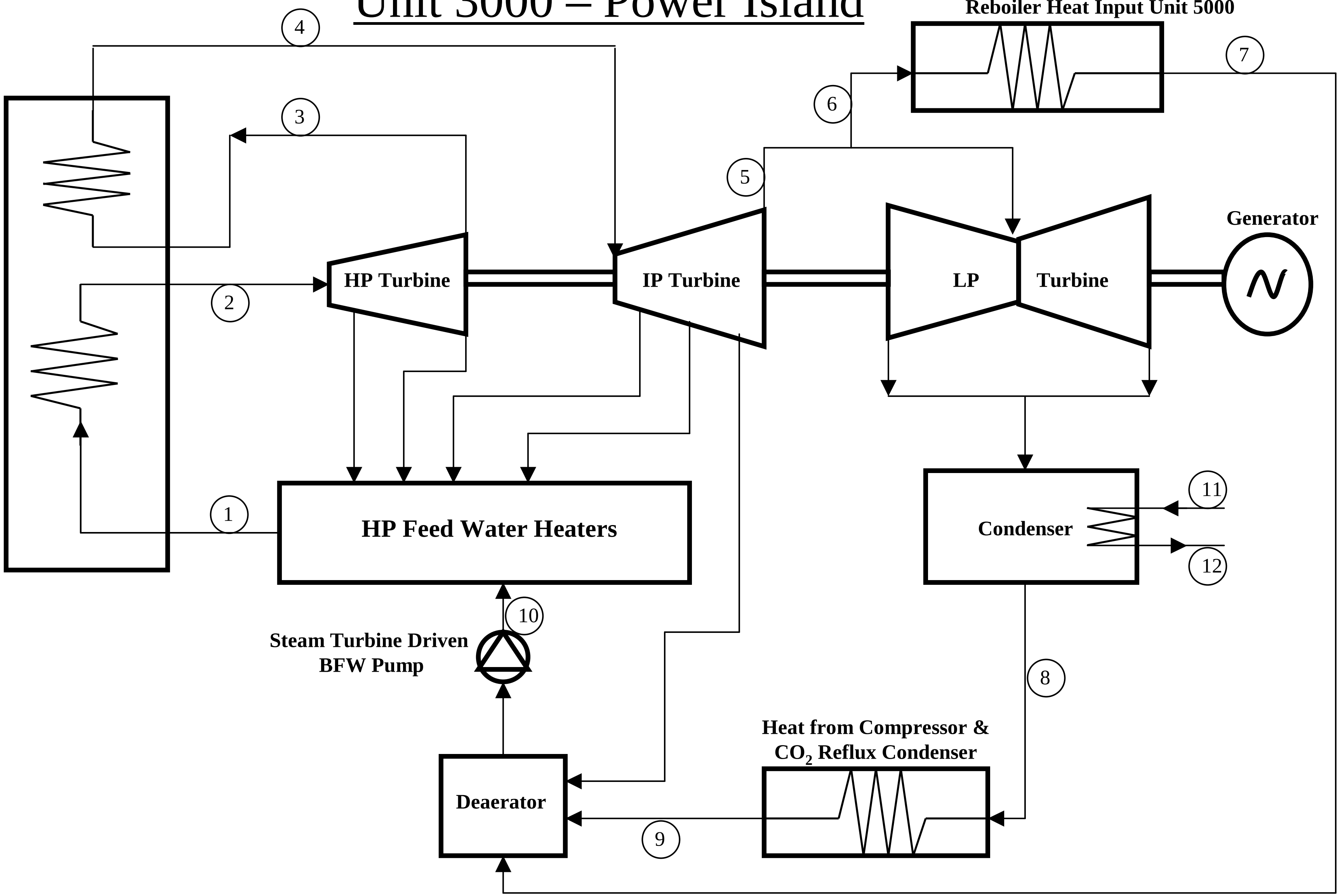
The Block Flow Diagrams of the following process units are attached to this paragraph:

- Unit 2000: Boiler Island and flue gas treating
- Unit 3000: Power Island
- Unit 5000: CO_2 capture
- Unit 6000: CO_2 compression and drying

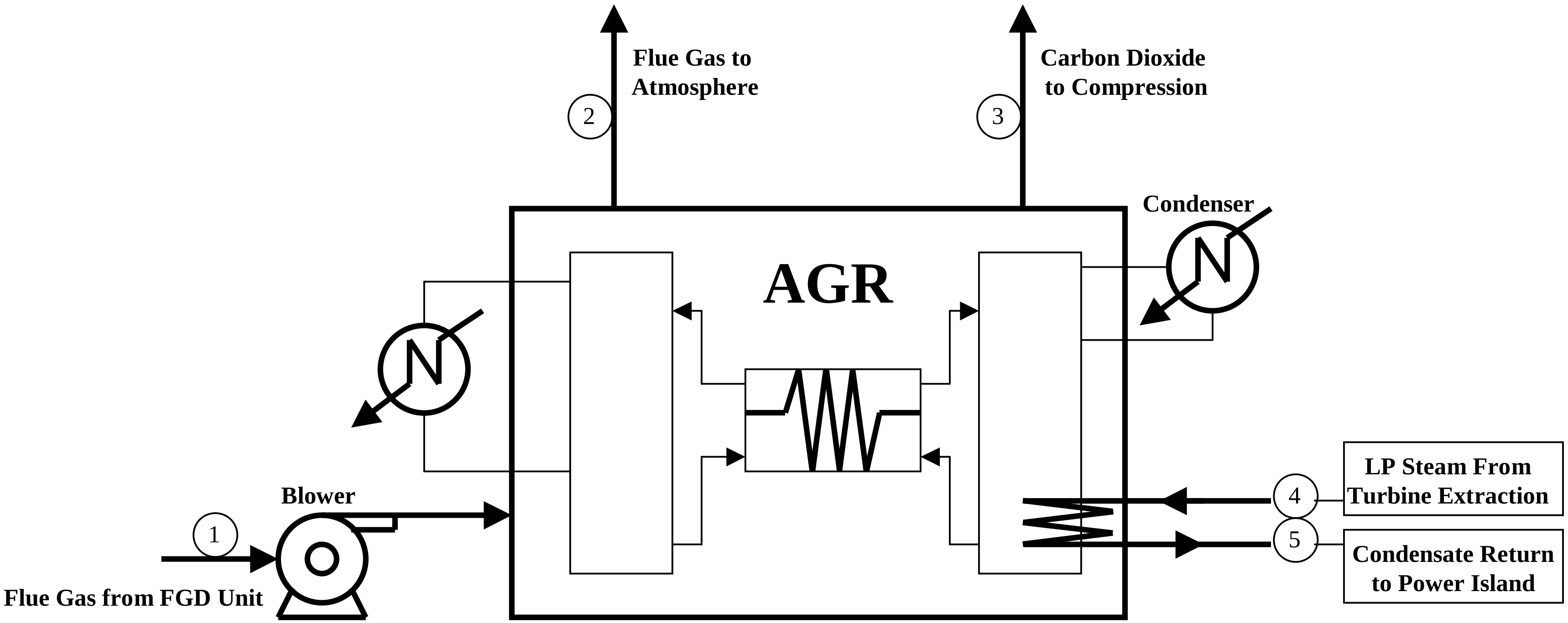
Unit 2000 – Boiler Island



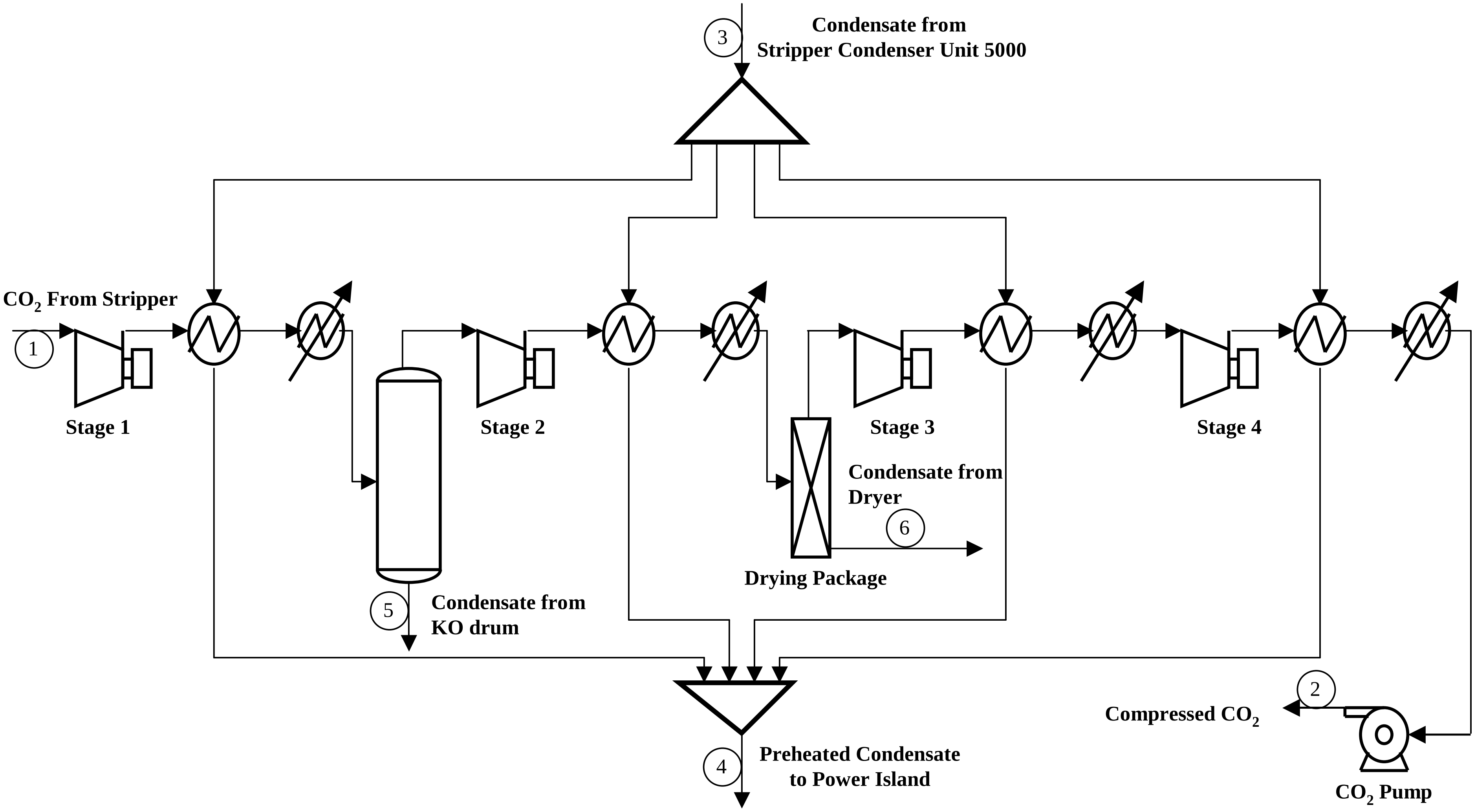
Unit 3000 – Power Island



UNIT 5000 - CO_2 Capture Plant



UNIT 6000 - CO_2 Compression & Drying



4.4 Heat and Material Balances

The Heat & Material Balances of the following process units are attached to this section:

- UNIT 2000: Boiler Island and flue gas treating
- UNIT 3000: Power Island
- UNIT 5000: CO_2 capture
- UNIT 6000: CO_2 compression and drying

Stream numbers are as shown on the Block Flow Diagrams attached to paragraph 4.3 of this Section.

	PC-USC HEAT AND MATERIAL BALANCE
	CLIENT: IEA GREEN HOUSE R & D PROGRAMME
	CASE: CASE 2B - 500MW CFB boiler with CCS
	UNIT: 2000 Boiler Island and Flue gas treating

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a
1	Coal	144.8	amb.	amb.
2	Biomass	57.0	amb.	amb.
3	Air intake from Atmosphere	1886	amb.	amb.
4	Feed Water from Preheating line UNIT 3000	1450	290	318
5	HP Steam from boiler	1450	580	275
6	Cold reheat to boiler	1248	350	62
7	Hot reheat from boiler	1248	600	60
8	Make up water	60.0	amb.	amb.
9	Limestone to FGD	2.1	amb.	amb.
10	Flue Gas to CO_2 capture plant (1)	2118	50	1.010
11	Gypsum	3.6	amb.	amb.
12	Fly ash	19.9	amb.	amb.
13	Bottom Ash	4.8	amb.	amb.
14	Limestone to boiler	4.1	amb.	amb.

Notes:
(1) For gas composition see stream #1 of Unit 5000 H&M balance

PC-USC HEAT AND MATERIAL BALANCE					
CLIENT:	IEA GREEN HOUSE R & D PROGRAMME				
CASE:	CASE 2B - 500MW CFB boiler with CCS				
UNIT:	3000 Power Island				
Stream	**Description**	**Flowrate t/h**	**Temperature °C**	**Pressure bar a**	**Entalphy kJ/kg**
1	HP Water to Boiler Island	1450	290	317.5	1278
2	HP Steam from boiler	1450	580	275	3405
3	Cold reheat to boiler	1248	350	62.0	3039
4	Hot reheat from boiler	1248	600	59.8	3656
5	MP Steam Turbine exhaust	1061.0	224.6	4.00	2912
6	LP Steam to Reboiler	497.9	224.6	4.00	2912
7	LP Condensate from Reboiler	497.9	136	16.9	573
8	Condensate	521.8	24	0.03	101
9	LP Preheated Condensate	1413.8	165.6	12.4	700
10	Condensate to HP FWH	1470	187	319.3	836
11	Cooling Water Inlet	37901	12	1.9	42
12	Cooling Water Outlet	37901	19	1.4	71

	PC-USC HEAT AND MATERIAL BALANCE				
	CLIENT: IEA GREEN HOUSE R & D PROGRAMME				
	CASE: CASE 2B - 500MW CFB boiler with CCS				
	UNIT: 5000 CO_2 Capture Plant				
STREAM	1	2	3	4	5
	Flue gas from FGD Unit	Flue gas to atmosphere	CO_2 to Compression	LP steam from turbine extraction	Condensate return to Power Island
Temperature (°C)	50	97.5	35	224	136
Pressure (bar)	1.01	1.005	1.5	3.50	16.9
TOTAL FLOW					
Mass flow (t/h)	2118	1682	356.9	498	498
Molar flow (kgmole/h)	73122	60664	8295		
LIQUID PHASE					
Mass flow (t/h)					498
GASEOUS PHASE					
Mass flow (t/h)	2118	1682	356.9	498	
Molar flow (kgmole/h)	73122	60664	8295		
Molecular Weight	28.96	27.7	43.02		
Composition (vol %)					
CO					
CO_2	12.2	1.5	96.2		
$Ar+N_2$	71.0	85.2	0.0		
O_2	4.9	5.9			
H_2O	11.9	7.4	3.8		

The LP steam consumption corresponds to a specific duty to the reboiler of the regenerator column of about 140 kJ/mol of CO_2 captured.

PC-USC HEAT AND MATERIAL BALANCE

CLIENT: IEA GREEN HOUSE R & D PROGRAMME
CASE: CASE 2B - 500MW CFB boiler with CCS
UNIT: 6000 CO_2 Compression and Drying

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a
1	CO_2 from Stripper	356.9	35	1.5
2	Compressed CO_2	351.3	32.7	110
3	Condensate from Stripper Condenser	568.2	85	22.0
4	Preheated Condensate to Power Island	568.2	110.2	21.5
5	Condensate from KO drum	3.2	35	35.5
6	Condensate from Drying package	2.4	177	94.0

4.5 Utility Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Tables.

CLIENT:	IEA GREEN HOUSE R & D PROGRAMME	Rev 2
PROJECT:	BIOMASS FIRED POWER PLANT	November 09
LOCATION:	THE NETHERLANDS	ISSUED BY: SC
		CHECKED BY: PC
		APPR. BY: FG

ELECTRICAL CONSUMPTION SUMMARY - CASE 2B - 500MW CFB boiler with CCS

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
1000	SOLID RECEIVING, HANDLING AND STORAGE	
	Fuel Receiving, Handling and Storage	1400
	Limestone unloading, storage and handling	40
2000	BOILER ISLAND AND FLUE GAS TREATING	
	Boiler auxiliary consumption	20960
	Flue gas desulphurization plant (FGD)	1593
	Gypsum loading, storage and handling	78
	Ash loading, storage and handling	1514
3000	POWER ISLAND	
	Steam turbine auxiliaries and condenser	1012
	Condensate pumps and feedwater system	445
	Step-Up transformer losses	950
4000	UTILITIES AND OFFSITE UNITS	
	Machinery cooling water system	1575
	Sea water system	5051
	Miscellaneous Balance-of-Plant	2110
5000	CO_2 PLANT INCL. BLOWERS	
	Blower	6052
	Pumps	3775
6000	CO_2 COMPRESSION	36671
	BALANCE	83226

CLIENT:	IEA GREEN HOUSE R & D PROGRAMME	Rev 0
PROJECT:	BIOMASS FIRED POWER PLANT	May 09
LOCATION:	THE NETHERLANDS	ISSUED BY: SC
		CHECKED BY: PC
		APPR. BY: FG

WATER CONSUMPTION SUMMARY - CASE 2B - 500MW CFB boiler with CCS

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	Solid receiving, handling and storage			45	
2000	Boiler Island			58	
2300	Flue gas desulphurization plant (FGD)	60	1		
5000	CO_2 capture plant			24952	
6000	CO_2 compression				5567
	POWER ISLANDS UNITS				
3000	Surface condenser				37902
	Miscellanea		5	1944	
	UTILITY and OFFSITE				
4100	Machinery Cooling Water System				46335
4200	Demineralized Water System	6.6	-6		
	Miscellanea			30	
	BALANCE	66.6	0	27029	89804

4.6 Overall Performance

The following Table shows the overall performance of the Plant.

IEA GHG		
CASE 2B: 500MW CFB boiler with CO_2 capture		
OVERALL PERFORMANCE OF THE COMPLEX		
Coal Flowrate	t/h	144.8
Coal LHV	kJ/kg	25870
Biomass Flowrate	t/h	57.0
Biomass LHV	kJ/kg	7300
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1156**
Steam turbine power output (@gen. Terminals)	MWe	473.7
GROSS ELECTRIC POWER OUTPUT (D)	**MWe**	**473.7**
Solid Receiving, Handling and Storage	MWe	1.4
Boiler Island and flue gas treating	MWe	24.1
CO2 Plant incl. Blowers	MWe	9.8
CO2 Compression	MWe	36.7
Power Island	MWe	2.4
Utilities	MWe	8.8
ELECTRIC POWER CONSUMPTION	**MWe**	**83.2**
NET ELECTRIC POWER OUTPUT (C)	**MWe**	**390.5**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**41.0**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33.8**

The following Table shows the overall CO_2 removal efficiency of the Complex:

	Equivalent flow of CO_2 kmol/h
Coal (Carbon = 64.6%wt)	7795
Biomass (Carbon = 25 % wt)	1188
Limestone	62
Carbon in ash	-180
Net Carbon flowing to Process Units (A)	8865
Liquid Storage	
CO	0.0
CO_2	7979
Total to storage (B)	7979
Emission	
CO	11
CO_2	875
Total Emission	886
Overall CO_2 removal efficiency, % (B/A)	90

Note: N_2O not included in the table.

4.7 Environmental Impact

The plant is designed to process coal and biomass, whose characteristics are defined in the Basic Engineering Design Data and produce electric power. The advanced technology allows to reach a high efficiency and to minimise environmental impact.

The gaseous emissions, liquid effluents and solid wastes from the plant are summarised in this section.

4.7.1 Gaseous Emissions

Main Emissions

In normal operation at full load, the main continuous emissions are the combustion flue gases leaving the boiler at stack.

Table 4.1 summarises expected flow rate and concentration of the combustion flue gas released to atmosphere from the stack.

	Normal Operation
Wet gas flow rate, kg/s	467.2
Flow, Nm^3/h	1,360,000
Temperature, °C	100
Composition	(%vol)
N_2+Ar	85.2
O_2	5.9
CO_2	1.5
H_2O	7.4
Emissions	mg/Nm^3 (1)
NOx	200
N_2O	14
SOx	35
CO	230
Particulate	Less than 5

Table 4.1 – Expected gaseous emissions from plant

(1) Dry gas, O_2 Content 6% vol

Minor Emissions

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). They are prevented by proper design and operation.

4.7.2 Liquid Effluent

All the liquid effluents are treated in the wastewater treatment system in order to be discharged in accordance with the current regulations.

The liquid effluents generated in the power plant are mainly the following:
- Rain water contaminated by powder;
- Wash water contaminated by oil and powder;
- FGD system blowdown;
- Effluents from CO_2 capture plant (Direct contact cooler and blowdown)
- Eluates from demineralizing water system;
- Sanitary water.

The CO_2 capture plant blowdown water contains a significant amount of MEA and therefore implies the introduction of a further biological section with aerobical and anaerobical treatment.

Sea water in open circuit is used for cooling.
The return stream water is treated with meta-bisulphite in the Dechlorination System to reduce the Cl_2 concentration. Main characteristics of the water are listed in the following:

- Maximum flow rate : 89,804 m^3/h
- Temperature : 19 °C

4.7.3 Solid Effluent

No solid waste other than those produced by a real industrial activity.
The power plant is expected to produce the following solid by-products:

Fly Ash

Flow rate	:	19.9	t/h
Unburned Carbon	:	10.2	%wt

Bottom Ash

Flow rate	:	4.8	t/h

Unburned Carbon : 2.6 %wt

Fly and bottom ash could be theoretically dispatched to cement industries. For the purposes of present study they are considered as a waste to be disposed.

Solid Gypsum

Flow rate : 3.6 t/h

Solid gypsum keeping Euro Gypsum restrictions can be delivered to the market. For the purposes of present study it is considered as neutral: neither as a revenue nor as a disposal cost.

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : TECHNO-ECONOMIC EVALUATION OF CAPTURING CO_2 FROM BIOMASS FIRED POWER PLANT
DOCUMENT NAME : CASE 3A – 250 MWE CFB BOILER WITHOUT CO_2 CAPTURE

ISSUED BY : S. CAVEZZALI
CHECKED BY : P. COTONE
APPROVED BY : F. GASPARINI

Date	Revised Pages	Issued by	Checked by	Approved by
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5.0 Case 3a - 250 MWe CFB Boiler without CO_2 capture

Summary

Case 3a is based on a SubCritical CFB boiler fully fired with biomass. No capture of CO_2 is considered.

- The size of the plant considered for this configuration is 250 MWe net power output nominal.
- No drying of biomass is needed.
- The flue gas line of the boiler includes a special plastic heat exchanger to maximise heat recovery downstream the ID fan without suffering from corrosion problem. Such heat exchangers are also commercially used for low temperature heat recovery in similar plants.
- The limits of NO_x emissions can be met with just the firing system of the boiler with low temperature at furnace exit. The fuel composition (e.g. higher water content), besides, helps to maintain the combustion temperature low, implying a lower NOx production. No addition of an SCR system is needed.
- External flue gas desulphurization and limestone injection in the combustion chamber are not required to meet SO_x emission limits because of the low sulphur content in biomass.

5.1 Introduction

The Case 3a of the study is a CFB biomass fired Sub Critical steam plant without carbon dioxide capture.

The configuration of the complex is based on a steam generator with superheating and single steam reheating.

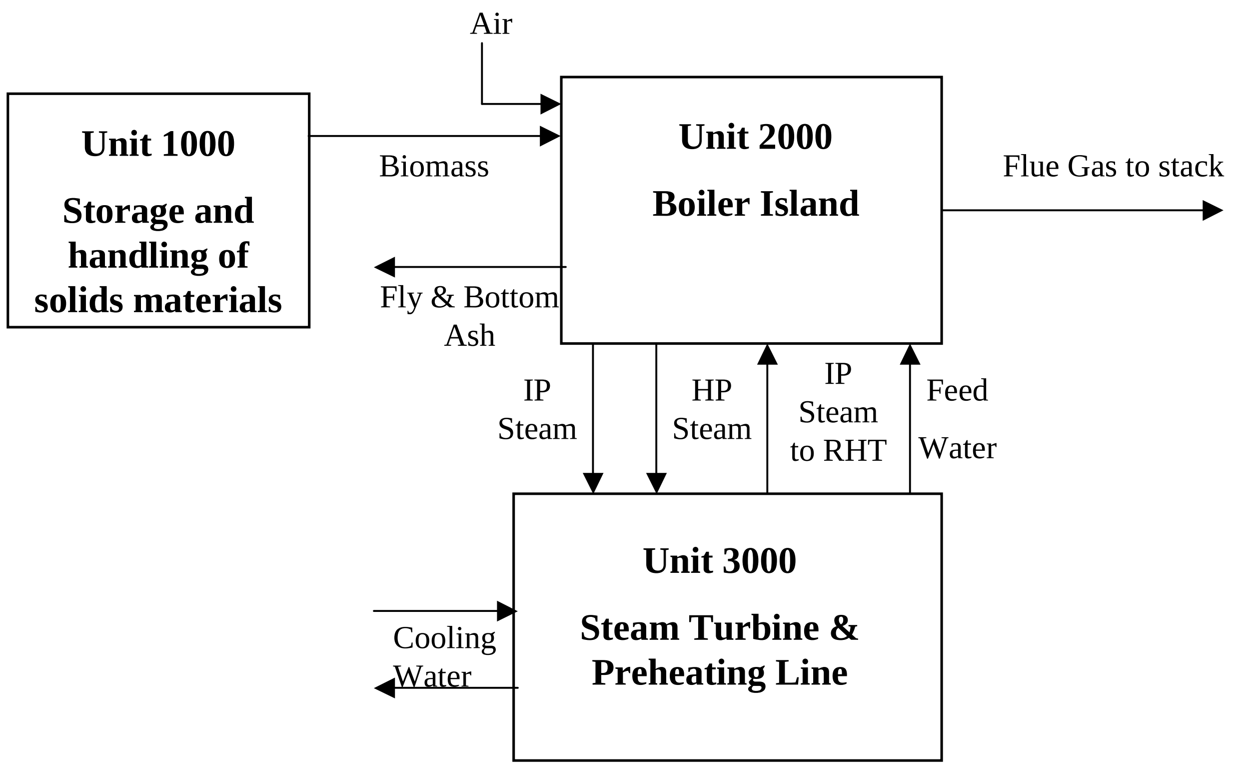
Reference is made to the attached Block Flow Diagram of the plant.
The arrangement of the process units is:

Unit

1000 Storage and Handling of solid materials, including:
- 1100 Coal storage and handling
- 1200 Biomass storage and handling
- 1300 Limestone storage and handling

2000 Boiler Island and flue gas treating, including:
- 2100 Boiler
- 2400 Baghouse filter
- 2500 Ash and by-products removal and handling

3000 Power Island including:
- 3100 Steam Turbine
- 3200 Preheating Line
- 3300 Electrical Power Generation.


Air
Unit 1000
Storage and handling of solids materials
Biomass
Unit 2000
Boiler Island
Flue Gas to stack
Fly & Bottom Ash
IP Steam
HP Steam
IP Steam to RHT
Feed Water
Unit 3000
Steam Turbine & Preheating Line
Cooling Water

5.2 Process Description

Unit 1000: Storage and handling of solids materials

Please refer to Section C para. 1.0 for a process description of this unit.

This unit is made up of standard equipment in use, to receive the biomass from outside the plant boundary, store, reclaim and transport it to the boiler plant.

The expected Biomass consumption is about 7750 t/d.

Unit 2000: Boiler Island

The block flow diagram of this section is attached to paragraph 5.3.

The boiler is a Foster Wheeler "Compact" tower subcritical CFB with the solid separators integrated with the combustion chamber.
The boiler includes the fuel feeding system, the furnace, the solid separators with the solid return channels and INTREX superheaters, back pass, fans and air heater.
Please refer to Figure 1 for the arrangement of a typical CFB boiler.

Fuel feeding system

Biomass feeding system consists of multiple feeders located at the long walls of the furnace.
Each feeder consists of a day silo, drag chain feeder, drag chain conveyor and discharge to the feeding point.
Each feeding point has a dosing screw, slide gate and wall feeding screw.

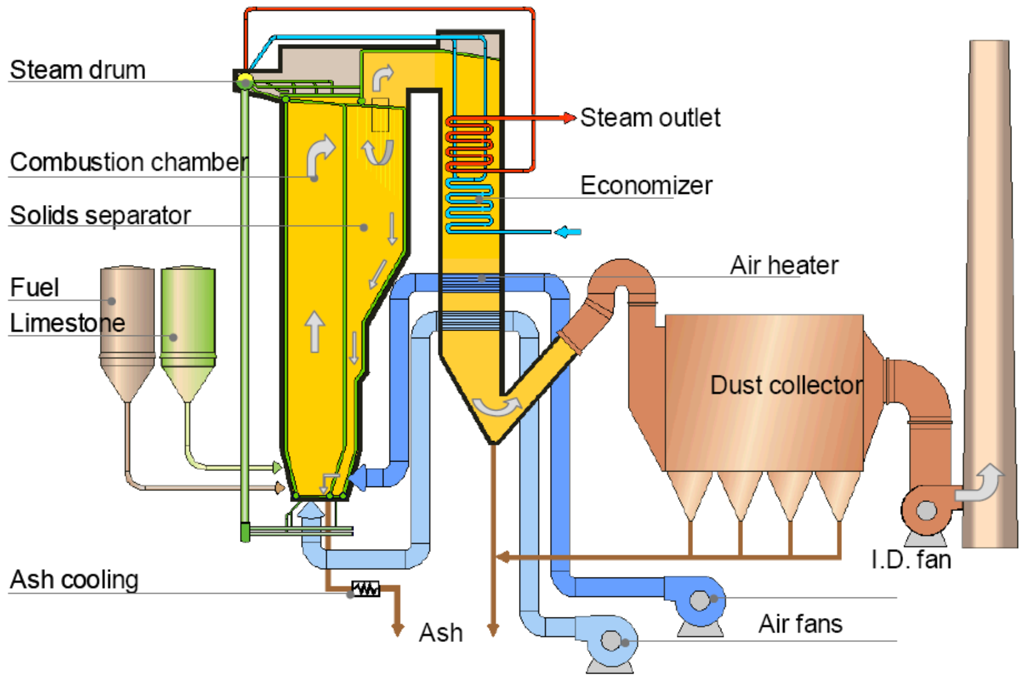


Figure 1 - CFB Boiler arrangement

The boiler is a Foster Wheeler "Compact" tower subcritical CFB with the solid separators integrated with the combustion chamber.
The boiler includes the fuel feeding systems, the furnace, the solid separators with the solid return channels and INTREX superheaters, back pass, fans and air heater.
The CFB subcritical boiler does not differ conceptually from the ultrasupercritical CFB described in paragraph 3.2, except for the water/steam circuit which includes a drum and a natural circulation system.
The solid separators are water cooled and integrated in the evaporation system.
Also in this alternative a PF-plastic tubes heat exchanger is provided for maximum heat recovery.

Water and steam circuit

The high pressure preheated BFW enters the economizer where is further preheated against the flue gases and sent to the steam drum under level control.
The water flows into external downcamers and is heated in the evaporator (furnace and cyclones) wall where is partly converted to superheated steam.
The difference in density between the boiler water and the steam/water mixture provides the driving force to the natural circulation.

The steam/water mixture is sent back to the drum where steam disengages from water and is dried (internally to the drum).
Dry steam is superheated in the furnace roof, the convective superheater I, the superheater II in the upper furnace and finally in the INTREX heat exchanger (III).
The steam is reheated in the convective reheaters (I) and the INTREX heat exchangers (II).

Auxiliary systems

Combustion air system consists of primary and secondary air fans and a separate high pressure air fan for fluidising the INTREX heat exchangers and sealing devices.
A flue gas recirculation system is also provided.

Flue gas system

The flue gases from the boiler economizer is further cooled in a regenerative heat exchanger for preheating the combustion air, filtered and finally cooled to 90°C in a special heat exchanger made of PF-plastic tubes located downstream of the ID fan.
The available heat is transferred to a primary water circuit which in turn preheats the combustion air (upstream of the regenerative air heaters).

Fouling problems are important in 100% biomass fired boilers, because the alkalis in the fuel vaporize at combustor temperatures and can recombine with other ash and fuel constituents (especially sulphate, chloride, silica and phosphorus) to produce low melting compounds that can cause sintering and agglomeration on the furnace and back pass surfaces. High potassium content is especially associated with back pass fouling, while sodium is more often associated with in-furnace sinter formation. Sintering resulting from fuel bound alkalis can be at least partially mitigated by the addition of compounds high in alumina and to a lesser extent by the addition of compounds high in calcium and magnesium. High ash drain rates will also reduce sintering problems.

Unit 2400: Baghouse filter

A baghouse filter is provided to remove particulate content in the flue gases to meet the environmental limits. Fly ash are collected from the baghouse filter bottom.

Unit 2500: Ash Handling Plant

The ash handling system, takes care of conveying the ash generated in the boiler plant: both the furnace bottom ash and the fly ash from the various hoppers. (Reference to Section C – para 3.0).

Unit 3000: Steam Turbine and Preheating Line

The block flow diagram of this section is attached to paragraph 5.3.

The power island is a single train, mainly composed of one steam turbine and one preheating line. Superheated steam from the boiler is sent to the steam turbine, which consists of a HP, IP and LP section, all connected to the generator on a single shaft. The steam turbine is a condensing type, with multiple extractions for the preheating of the condensate and boiler feedwater.

Main steam from the boiler, generated at 169 bar and 565°C, passes through the stop valves and control valves and enters the turbine. Steam from the exhaust of the HP turbine is returned to the boiler gas path for reheating at 39 bar, 565°C and is then throttled into the IP turbine. Exhaust steam from IP flows into a single casing, double flow LP turbine and then downward into the condenser at 0.03 bar, 24°C.

Different extractions from the IP section at different conditions of steam pressure/temperature allow the preheating of the boiler feed water, while the low-pressure extraction is used to provide the steam necessary for the degassing of the condensate. Steam condensate recovered into the boiler feed water heaters is recovered back to the deaerator.

Part of the exhaust steam from the IP ST section, together with three extractions from the LP steam turbine, provide heat to the four condensate heaters downstream the condensate pumps, before entering the deaerator.

Boiler feedwater exiting the deaerator is pumped to the economizers of the boiler by means of the boiler feedwater pump steam turbine driven.

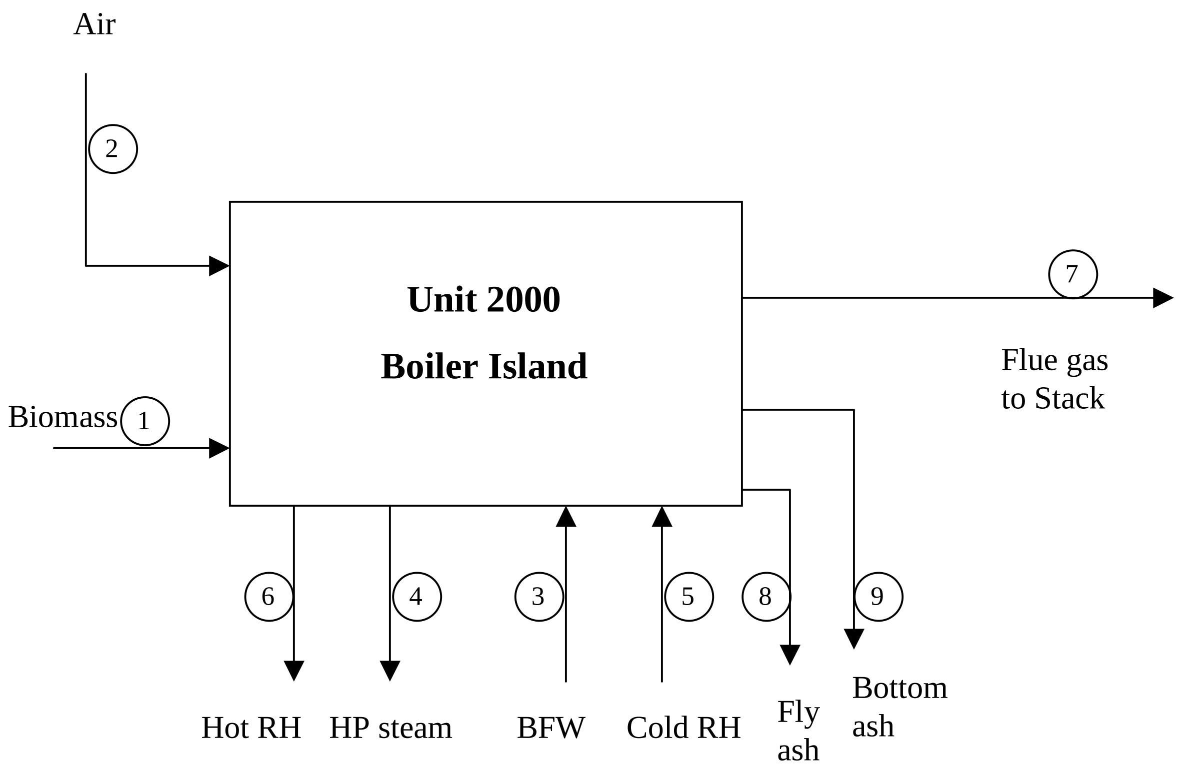
Chemical injection for control of the water quality is made by dedicated packages on the suction of the boiler feedwater pumps and at the inlet of the boiler.

5.3 Block Flow Diagrams

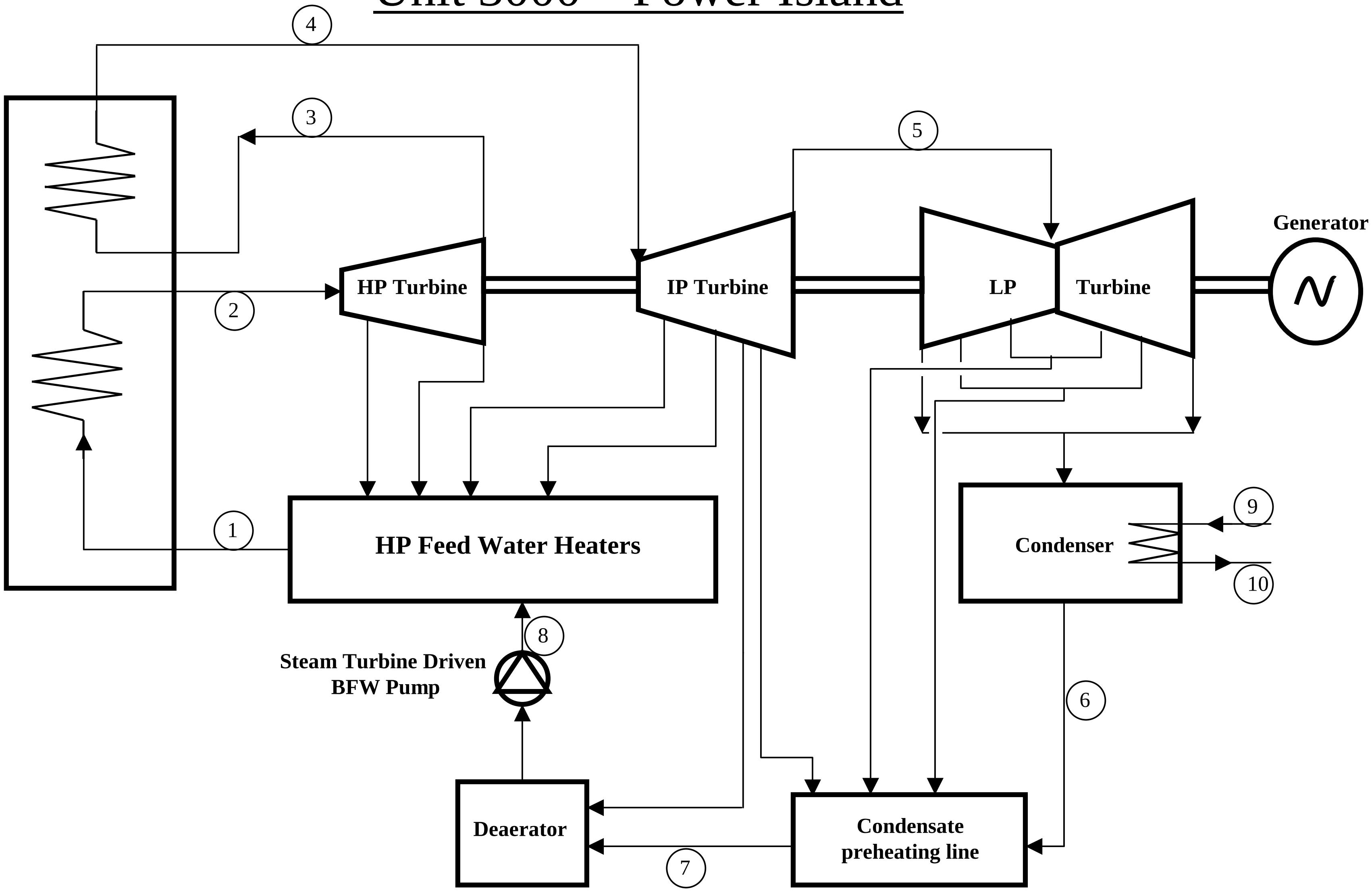
The Block Flow Diagrams of the following process units are attached to this paragraph:

- Unit 2000: Boiler Island
- Unit 3000: Power Island

Unit 2000 – Boiler Island



Unit 3000 – Power Island



5.4 Heat and Material Balances

The Heat & Material Balances of the following process units are attached to this section:

- UNIT 2000: Boiler Island and flue gas treating
- UNIT 3000: Power Island

Stream numbers are as shown on the Block Flow Diagrams attached to paragraph 5.3 of this Section.

PC-USC HEAT AND MATERIAL BALANCE	
CLIENT:	**IEA GREEN HOUSE R & D PROGRAMME**
CASE:	**CASE 3A - 250MW CFB boiler without CCS**
UNIT:	**2000 Boiler Island and Flue gas treating**

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a
1	Biomass	323	amb.	amb.
2	Air intake from Atmosphere	879	amb.	amb.
3	Feed Water from Preheating line UNIT 3000	836	290	205
4	HP Steam from boiler	828	565	169
5	Cold reheat to boiler	711	354	41
6	Hot reheat from boiler	711	565	39
7	Flue Gas to Stack (1)	1563	90	1.005
8	Fly ash	2.9	amb.	amb.
9	Bottom Ash	0.6	amb.	amb.

Notes:
(1) For gas composition see Paragraph 5.7.1

PC-USC HEAT AND MATERIAL BALANCE

CLIENT: IEA GREEN HOUSE R & D PROGRAMME
CASE: CASE 3A - 250MW CFB boiler without CCS
UNIT: 3000 Power Island

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	HP Water to Boiler Island	836.3	290	205.0	1282
2	HP Steam from boiler	828	565	169	3469
3	Cold reheat to boiler	710.5	354	41.0	3103
4	Hot reheat from boiler	710.5	565	38.8	3594
5	MP Steam Turbine exhaust	613.3	312	6.21	3087
6	Condensate	587.5	24	0.03	101
7	LP Preheated Condensate	817.2	174.1	12.4	737
8	Condensate to HP FWH	836.3	191	207	821
9	Cooling Water Inlet	38700	12	1.9	51
10	Cooling Water Outlet	38700	19	1.4	80

5.5 Utility Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Tables.

	CLIENT: IEA GREEN HOUSE R & D PROGRAMME	Rev 0
	PROJECT: BIOMASS FIRED POWER PLANT	May 09
	LOCATION: THE NETHERLANDS	ISSUED BY: SC
		CHECKED BY: PC
		APPR. BY: FG

ELECTRICAL CONSUMPTION SUMMARY - CASE 3A - 250MW CFB boiler without CCS

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
1000	SOLID RECEIVING, HANDLING AND STORAGE	
	Fuel Receiving, Handling and Storage	900
	Limestone unloading, storage and handling	0
2000	BOILER ISLAND AND FLUE GAS TREATING	
	Boiler auxiliary consumption	10500
	Flue gas desulphurization plant (FGD)	0
	Gypsum loading, storage and handling	0
	Ash loading, storage and handling	211
3000	POWER ISLAND	
	Steam turbine auxiliaries and condenser	620
	Condensate pumps and feedwater system	476
	Step-Up transformer losses	700
4000	UTILITIES AND OFFSITE UNITS	
	Machinery cooling water system	80
	Sea water system	2130
	Miscellaneous Balance-of-Plant	1373
	BALANCE	16990

CLIENT:	IEA GREEN HOUSE R & D PROGRAMME
PROJECT:	BIOMASS FIRED POWER PLANT
LOCATION:	THE NETHERLANDS

Rev 0
May 09
ISSUED BY: SC
CHECKED BY: PC
APPR. BY: FG

WATER CONSUMPTION SUMMARY - CASE 3A - 250MW CFB boiler without CCS

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	Solid receiving, handling and storage			72	
2000	Boiler Island			33	
2300	Flue gas desulphurization plant (FGD)				
	POWER ISLANDS UNITS				
3000	Surface condenser				38700
	Miscellanea		10	1190	
	UTILITY and OFFSITE				
4100	Machinery Cooling Water System				2271
4200	Demineralized Water System	11.0	-10		
	Miscellanea			30	
	BALANCE	11.0	0	1325	40971

5.6 Overall Performance

The following Table shows the overall performance of the Plant.

IEA GHG		
CASE 3A: 250MW CFB boiler without CO_2 capture		
OVERALL PERFORMANCE OF THE COMPLEX		
Coal Flowrate	t/h	0
Coal LHV	kJ/kg	25870
Biomass Flowrate	t/h	323
Biomass LHV	kJ/kg	7300
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**654**
Steam turbine power output (@gen. Terminals)	MWe	290.0
GROSS ELECTRIC POWER OUTPUT (D)	**MWe**	**290.0**
Solid Receiving, Handling and Storage	MWe	0.9
Boiler Island and flue gas treating	MWe	10.7
CO2 Plant incl. Blowers	MWe	0
CO2 Compression	MWe	0
Power Island	MWe	1.8
Utilities	MWe	3.6
ELECTRIC POWER CONSUMPTION	**MWe**	**17.0**
NET ELECTRIC POWER OUTPUT (C)	**MWe**	**273.0**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**44.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**41.7**

5.7 Environmental Impact

The plant is designed to process biomass, whose characteristics are defined in the Basic Engineering Design Data and produce electric power. The advanced technology allows to reach a high efficiency and to minimise environmental impact.

The gaseous emissions, liquid effluents and solid wastes from the plant are summarised in this section.

5.7.1 Gaseous Emissions

<u>Main Emissions</u>

In normal operation at full load, the main continuous emissions are the combustion flue gases leaving the boiler at stack.

Table 5.1 summarises expected flow rate and concentration of the combustion flue gas released to atmosphere from the stack.

	Normal Operation
Wet gas flow rate, kg/s	434.2
Flow, Nm^3/h	1,266,000
Temperature, °C	90
Composition	(%vol)
N_2+Ar	60
O_2	3.9
CO_2	11.9
H_2O	24.1
Emissions	mg/Nm^3 (1)
NOx	200
N_2O	7.5
SOx	160
CO	200
Particulate	Less than 30

Table 5.1 – Expected gaseous emissions from plant

(1) Dry gas, O_2 Content 6% vol

Minor Emissions

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). They are prevented by proper design and operation.

5.7.2 Liquid Effluent

All the liquid effluents are treated in the wastewater treatment system in order to be discharged in accordance with the current regulations.

The liquid effluents generated in the power plant are mainly the following:
- Rain water contaminated by powder;
- Wash water contaminated by oil and powder;
- Eluates from demineralizing water system;
- Sanitary water;
- Blowdown from the boiler.

Sea water in open circuit is used for cooling.
The return stream water is treated with meta-bisulphite in the Dechlorination System to reduce the Cl_2 concentration. Main characteristics of the water are listed in the following:

- Maximum flow rate : 40,970 m^3/h
- Temperature : 19 °C

5.7.3 Solid Effluent

No solid waste other than those produced by a real industrial activity.
The power plant is expected to produce the following solid by-products:

Fly Ash			
Flow rate	:	2.9	t/h
Unburned Carbon	:	6.2	%wt
Bottom Ash			
Flow rate	:	0.6	t/h
Unburned Carbon	:	6.0	%wt

Fly and bottom ash could be theoretically dispatched to cement industries. For the purposes of present study they are considered as a waste to be disposed.

CLIENT	:	IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME	:	TECHNO-ECONOMIC EVALUATION OF CAPTURING CO_2 FROM BIOMASS FIRED POWER PLANT
DOCUMENT NAME	:	CASE 3B – 250 MWE CFB BOILER WITH CO_2 CAPTURE

ISSUED BY	:	S. CAVEZZALI
CHECKED BY	:	P. COTONE
APPROVED BY	:	F. GASPARINI

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SECTION D

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6.0 Case 3b - 250 MWe CFB Boiler with CO_2 capture

Summary

Case 3b is based on a SubCritical CFB boiler fired with biomass. CO_2 capture and compression is considered.

- The size of the plant considered for this configuration is 250 MWe net power output nominal. The boiler is the same as the case without CO_2 capture having as a consequence the reduction in net power output of the plant due to the impact of the CO_2 removal and compression units as power and steam consumer.

- No drying of biomass is needed.

- The flue gas line of the boiler does not include the special plastic heat exchanger foreseen in the case without CO_2 capture. This is because of the presence of CO_2 capture unit (Direct Contact Cooler and CO_2 absorption tower) that sensibility decreases the flue gas temperature making impossible the introduction of such heat exchanger without the formation of a strongly visible plume at stack outlet.

- The environmental limits on NOx can be met with just the firing system of the boiler with low temperature at furnace exit. No addition of an SCR system is needed.

- The amine based CO_2 absorption system, requires a very low level of NO_2 in the flue gas. Being the content of NO_2 in NOx ranging from 15% to 20%, this low content of NO_2 is achieved without the need of addition of further denitrification in flue gas treatment. On the other hand due to the removal of the CO_2 from the flue gases, the NOx concentration at stack results slightly higher than the one at CO_2 capture unit inlet. For this reason the NOx level at boiler outlet shall be lower than in the case without CO_2 capture by approximately 15% in order to maintain 200 mg/Nm^3 (@6% O_2 dry) at stack. Actually on the basis of the overall annual NOx flow rates, there could be an allowance for the more concentrated stack gases as the absolute NOx flow rate remains constant. Anyhow in the basis of design of the present study there is no any reduction on the emission limit and 200 mg/Nm^3 (@6% O_2 dry) at stack is considered for all cases. It is expected that the CFB can meet this specification without the need of SCR or SNCR. In any case it is foreseen the possibility to inject ammonia in the furnace in case the NOx emissions should exceed the environmental limits. The impact of such system on investment and operating costs is considered negligible as it would be on discontinuous basis only.

- Production of N_2O in the CFB boiler are not insignificant because of the combustion temperature. Nitrous oxide (N_2O) is a greenhouse gas with 300 time the impact of CO_2. It is expected that the N_2O in flue gas will not be absorbed into MEA and pass through unchanged to the stack. The behaviour of N_2O is in fact the same of oxygen and therefore its impact on MEA can be considered negligible, due to its very low content with respect to the oxygen.

- The amine based CO_2 absorption system, requires a very low level of SO_2 in the flue gas (much lower than the emission limits). Due to the very low level of sulphur contained in the biomass, this figure is achievable only with limestone injection in the furnace bed and an external FGD is not needed. The Ca/S considered to inject limestone is 2.8. Such low absolute figures of SOx emissions are not presently met in a full SOx capture in furnace, though the overall SOx capture efficiency can be achieved in the existing plants. Moreover, biomass typically includes CaO itself thus leading to some amount of inherent retention. The avoiding of the external FGD is one of the main advantages of the biomass fired CFB for CO_2 capture plants. Therefore, it would be a technical challenge, which needs to be further demonstrated in a large size plant.

- All the heat required for the CO_2 capture plant is provided from the low temperature steam extracted from the turbine. This results in a significant loss of power in the turbine generator. Further, a significant optimisation of heat within the CO_2 capture plant is also considered with adequate heat exchanges between various streams within the plant.

- CO_2 is dried and compressed up to supercritical phase at 110 bar for use in EOR or for geological disposal.

6.1 Introduction

The Case 3b of the study is a CFB biomass fired Sub Critical steam plant with carbon dioxide capture.

The configuration of the complex is based on a steam generator with superheating and single steam reheating.

Reference is made to the attached Block Flow Diagram of the plant.
The arrangement of the process units is:

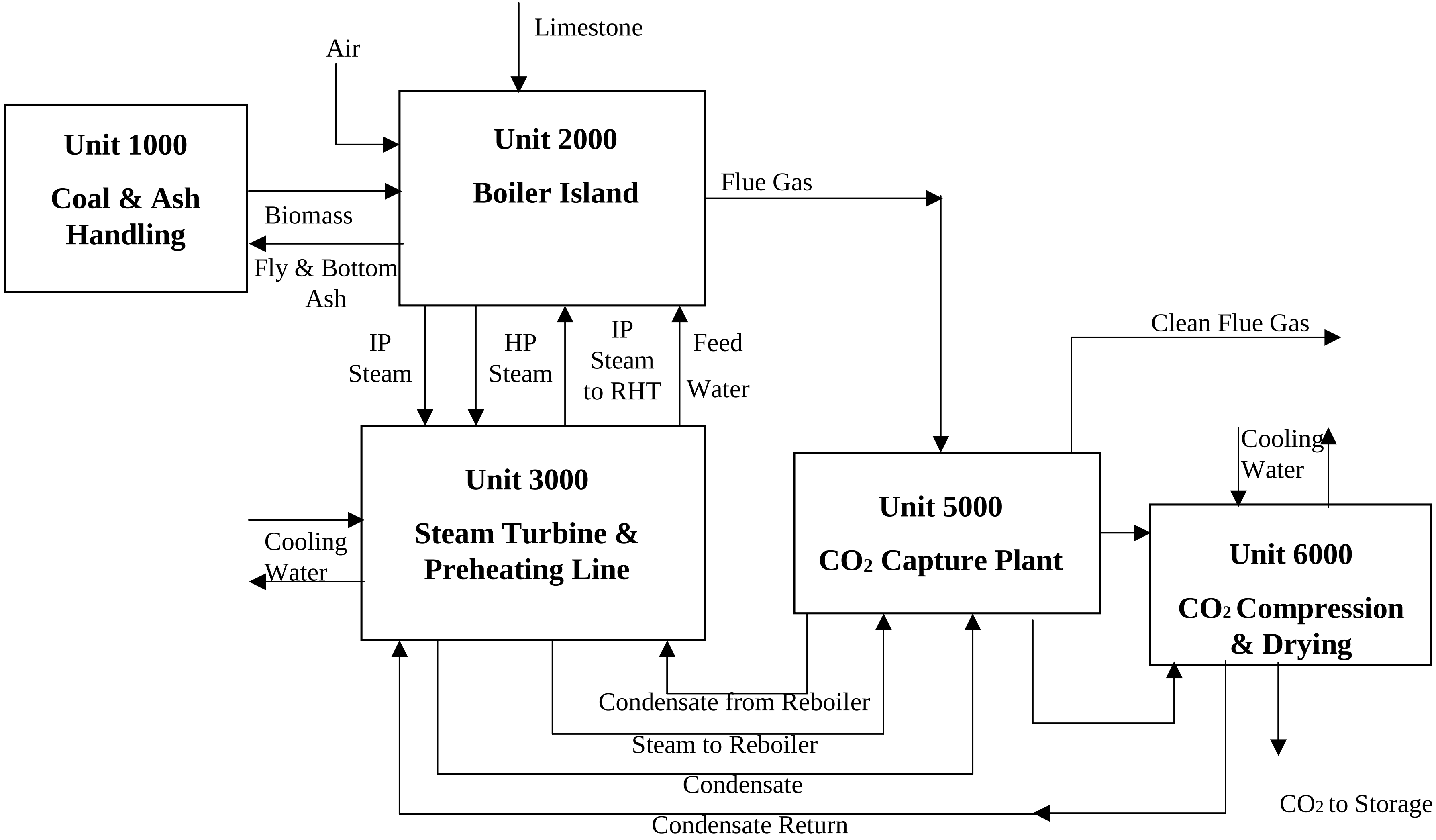
Unit

1000 Storage and Handling of solid materials, including:
- 1100 Coal storage and handling
- 1200 Biomass storage and handling
- 1300 Limestone storage and handling

2000 Boiler Island and flue gas treating, including:
- 2100 Boiler
- 2400 Baghouse filter
- 2500 Ash and by-products removal and handling

3000 Power Island including:
- 3100 Steam Turbine
- 3200 Preheating Line
- 3300 Electrical Power Generation.

5000 CO_2 capture unit
6000 CO_2 compression and drying unit


Limestone
Air
Unit 1000
Coal & Ash Handling
Unit 2000
Boiler Island
Biomass
Fly & Bottom Ash
Flue Gas
IP Steam
HP Steam
IP Steam to RHT
Feed Water
Clean Flue Gas
Cooling Water
Unit 3000
Steam Turbine & Preheating Line
Unit 5000
CO_2 Capture Plant
Unit 6000
CO_2 Compression & Drying
Cooling Water
Condensate from Reboiler
Steam to Reboiler
Condensate
Condensate Return
CO_2 to Storage

6.2 Process Description

Unit 1000: Storage and handling of solids materials

The unit is exactly the same as case 3a being equal the boiler. For unit description, reference shall be made to paragraph 5.2, section D5.

Unit 2000: Boiler Island

The boiler is exactly the same as case 3a. For unit description, reference shall be made to paragraph 5.2, section D5.

The block flow diagram of this section is attached to paragraph 6.3.

Unit 2400: Baghouse filter

A baghouse filter is provided to remove particulate content in the flue gases to meet the requirements of the downstream CO_2 capture unit. Fly ash are collected from the baghouse filter bottom.

An excessive amount of particulate in the flue gases fed to the CO_2 capture unit can cause foam formation that can compromise the correct unit operation.
For this reason the particulate content at CO_2 capture unit inlet is fixed at 5 mg/Nm^3 (@6% O_2 dry basis). This value is much lower than the environmental limits fixed in section B.

Unit 2500: Ash Handling Plant

The unit is exactly the same as case 3a. For unit description, reference shall be made to paragraph 5.2, section D5.

Unit 3000: Steam Turbine and Preheating Line

The block flow diagram of this section is attached to paragraph 6.3.

The power island is a single train, mainly composed of one steam turbine and one preheating line. Superheated steam from the boiler is sent to the steam turbine, which consists of a HP, IP and LP section, all connected to the generator on a single shaft. The steam turbine is a condensing type, with multiple extractions for the preheating of the condensate and boiler feedwater. The LP steam is also extracted for the use in the reboiler and stripping unit in the CO_2 capture plant.

Main steam from the boiler, generated at 169 bar and 565°C, passes through the stop valves and control valves and enters the turbine. Steam from the exhaust of the HP turbine is returned to the boiler gas path for reheating at 39 bar, 565°C and is then throttled into the IP turbine. Exhaust steam from IP flows into a single casing, double flow LP turbine and then downward into the condenser at 0.03 bar, 24°C.

Different extractions from the IP section at different conditions of steam pressure/temperature allow the preheating of the boiler feed water.

Recycled condensate from the condenser is pumped to the carbon dioxide capture plant and preheated in the amine stripper overhead condenser and the carbon dioxide compressor intercoolers. An optimisation of the integration between power plant and CO_2 capture plant allows to maximize the efficiency of the process. This also reduces the necessity of LP steam extractions to preheat condensate in LP preheating line. Only one condensate preheater is therefore needed downstream the condensate heating in the process units. The preheated feed water stream is routed to the deaerator, along with condensate returned from the amine stripper reboiler.

Boiler feedwater exiting the deaerator is pumped to the economizers of the boiler by means of the boiler feedwater pump steam turbine driven.

The plant configuration studied considers the following integrations between the Process Units and the Power Island:

- A part of the heat recovered in the CO_2 capture plant (overhead stripper condenser) and in the compression line is recovered by preheating the condensate, partially avoiding the use of LP feed water heaters.
- All the LP steam required for the CO_2 absorption plant is provided by extraction from the LP stage of the steam turbine.

Chemical injection for control of the water quality is made by dedicated packages on the suction of the boiler feedwater pumps and at the inlet of the boilers.

Unit 4000: CO_2 Capture Plant

Clean flue gas with NO_2 less than 20 ppmv and SO_x less than 10 ppm is sent to the CO_2 absorption tower.
Refer to Section C para. 6.0 for this section.
In the CO_2 capture plant, where flue gas temperatures are lower, it is not expected to have an increase of the NO_2 content, although conversion of NO to NO_2 is promoted by low temperatures, because the kinetics of the reaction that converts NO into NO_2 is too slow with respect to the residence time of gases in the system.
90% capture of CO_2 from the flue gas is considered.
The block flow diagram of this section is attached to paragraph 6.3.

Unit 5000: CO_2 Compression and Drying

Refer to Section C, para. 8.0 for the general description of the Unit. The block flow diagram of this section is attached to paragraph 6.3.

CO_2 can be handled as a liquid in pipe lines at conditions beyond its critical point (P_{CR}=73.8 bar; T_{CR}=31°C). The present configuration studied, assumes, CO_2 to be delivered at a pressure of around 110 bara.

The product stream sent to final storage is mainly composed of CO_2. The main properties of the stream are as follows:

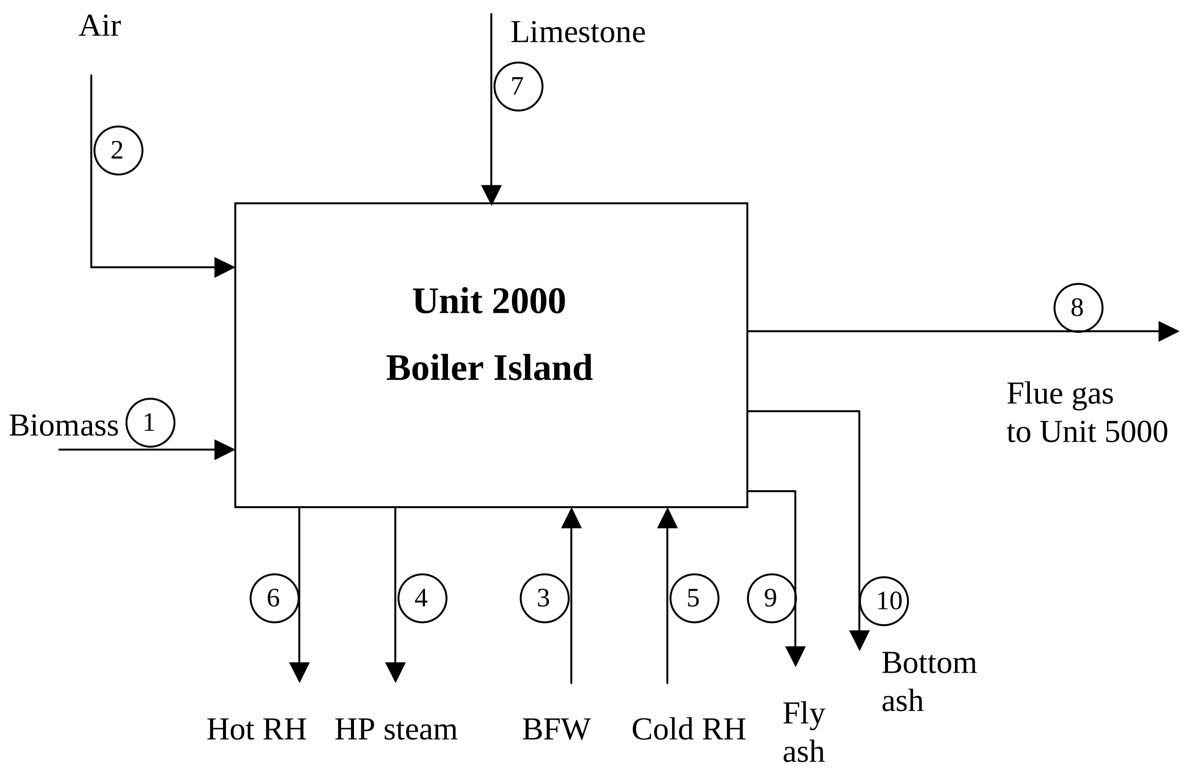
Product stream	:	265.8 t/h.
Pressure	:	110 bar.
Temperature	:	32 °C
CO_2 purity	:	>99.9% wt.

6.3 Block Flow Diagrams

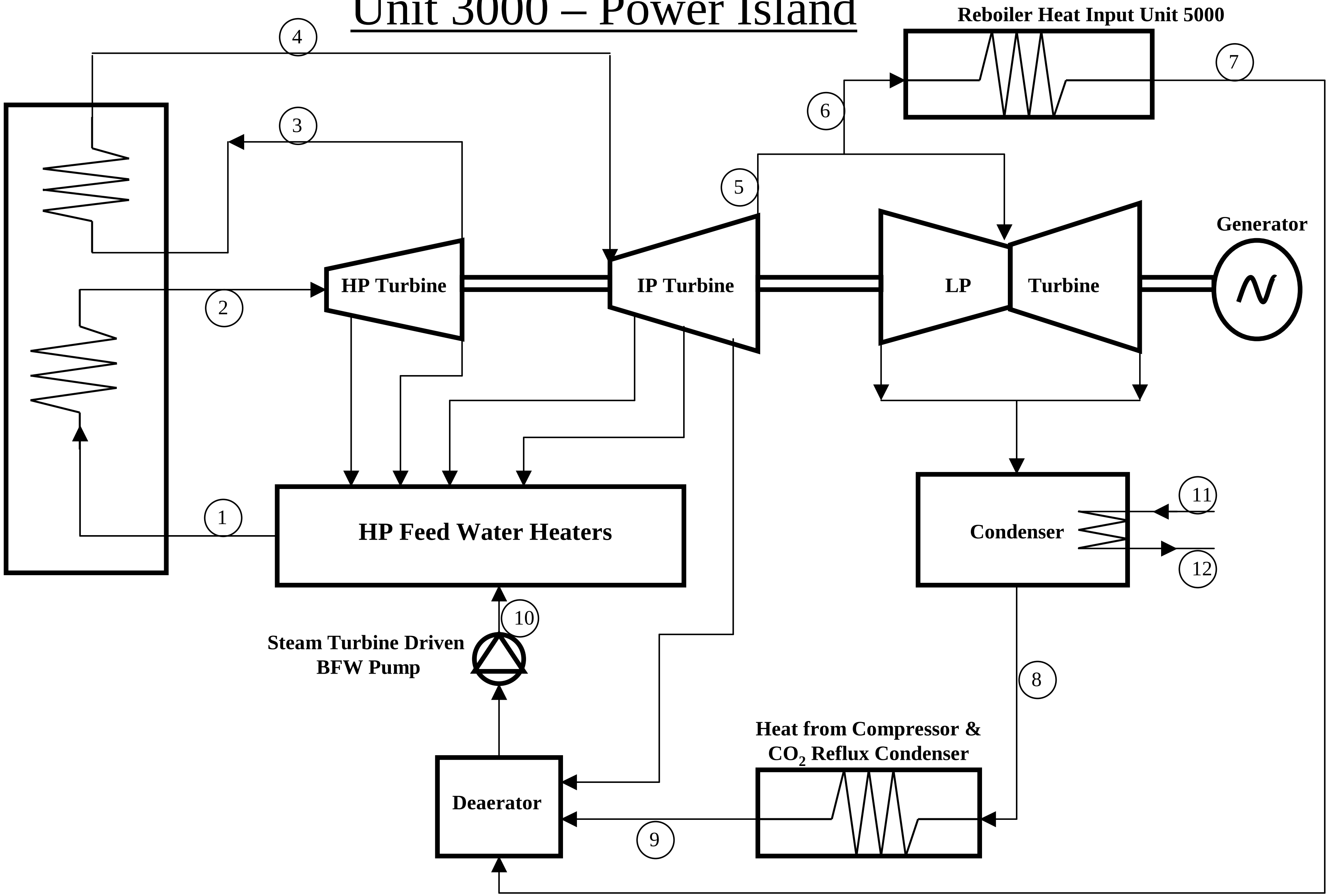
The Block Flow Diagrams of the following process units are attached to this paragraph:

- Unit 2000: Boiler Island and flue gas treating
- Unit 3000: Power Island
- Unit 5000: CO_2 capture
- Unit 6000: CO_2 compression and drying

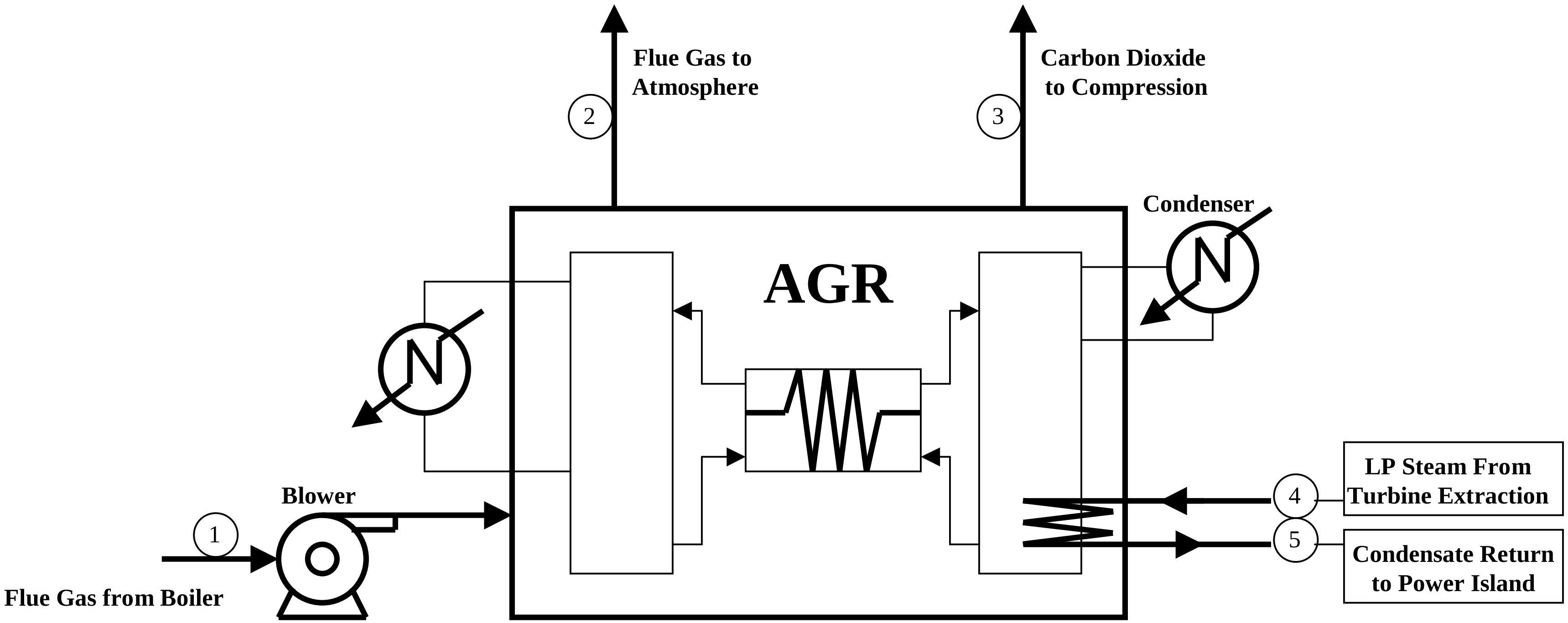
Unit 2000 – Boiler Island



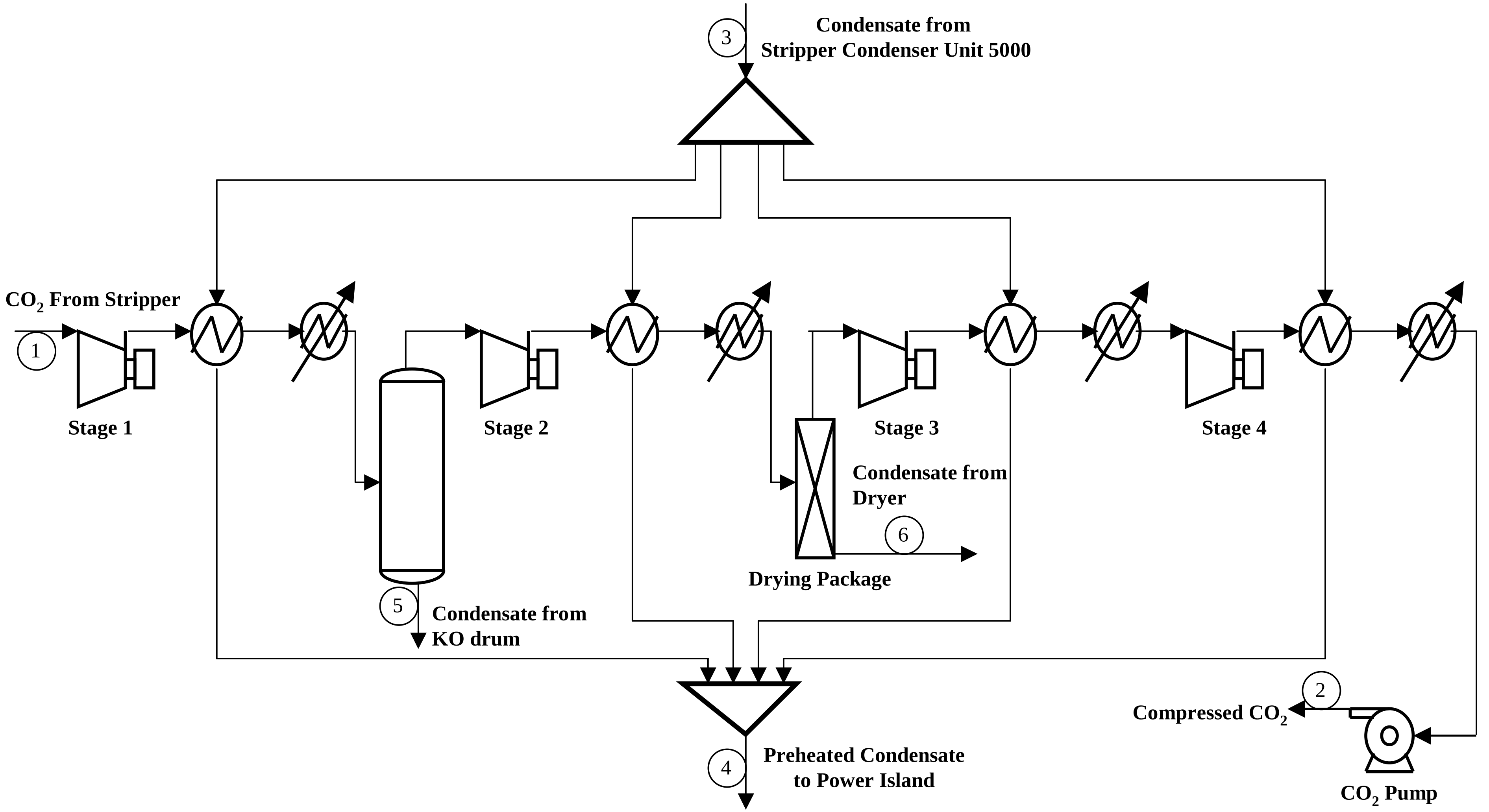
Unit 3000 – Power Island



UNIT 5000 - CO_2 Capture Plant



UNIT 6000 - CO_2 Compression & Drying



6.4 Heat and Material Balances

The Heat & Material Balances of the following process units are attached to this section:

- UNIT 2000: Boiler Island and flue gas treating
- UNIT 3000: Power Island
- UNIT 5000: CO_2 capture
- UNIT 6000: CO_2 compression and drying

Stream numbers are as shown on the Block Flow Diagrams attached to paragraph 6.3 of this Section.

PC-USC HEAT AND MATERIAL BALANCE	
CLIENT:	IEA GREEN HOUSE R & D PROGRAMME
CASE:	CASE 3B - 250MW CFB boiler with CCS
UNIT:	2000 Boiler Island and Flue gas treating

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a
1	Biomass	323	amb.	amb.
2	Air intake from Atmosphere	1249	amb.	amb.
3	Feed Water from Preheating line UNIT 3000	836	290	205
4	HP Steam from boiler	828	565	169
5	Cold reheat to boiler	711	354	41
6	Hot reheat from boiler	711	565	39
7	Limestone	0.7	amb.	amb.
8	Flue Gas to CO_2 capture plant (1)	1563	102	1.015
9	Fly ash	3.3	amb.	amb.
10	Bottom Ash	0.7	amb.	amb.

Notes:
(1) For gas composition see stream #1 of Unit 5000 H&M balance

PC-USC HEAT AND MATERIAL BALANCE	
CLIENT:	IEA GREEN HOUSE R & D PROGRAMME
CASE:	CASE 3B - 250MW CFB boiler with CCS
UNIT:	3000 Power Island

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	HP Water to Boiler Island	836.3	290	205	1282
2	HP Steam from boiler	828	565	169	3469
3	Cold reheat to boiler	710.5	354	41.0	3103
4	Hot reheat from boiler	710.5	565	39.2	3594
5	MP Steam Turbine exhaust	604.2	261.5	4.00	2988
6	LP Steam to Reboiler	362.4	261.5	4.00	2988
7	LP Condensate from Reboiler	362.4	136	16.9	573
8	Condensate	300.0	24	0.03	101
9	LP Preheated Condensate	804.5	165.0	12.4	697
10	Condensate to HP FWH	836.3	191	207.0	821
11	Cooling Water Inlet	16436	12	1.9	51
12	Cooling Water Outlet	16436	19	1.4	80

	PC-USC HEAT AND MATERIAL BALANCE				
	CLIENT: IEA GREEN HOUSE R & D PROGRAMME				
	CASE: CASE 3B - 250MW CFB boiler with CCS				
	UNIT: 5000 CO_2 Capture Plant				
STREAM	1	2	3	4	5
	Flue gas from Boiler	Flue gas to atmosphere	CO_2 to Compression	LP steam from turbine extraction	Condensate return to Power Island
Temperature (°C)	102	102	35	262	136
Pressure (bar)	1.015	1.005	1.5	3.50	16.9
TOTAL FLOW					
Mass flow (t/h)	1563	1104	270.1	362	362
Molar flow (kgmole/h)	56551	39824	6279		
LIQUID PHASE					
Mass flow (t/h)					362
GASEOUS PHASE					
Mass flow (t/h)	1563	1104	270.1	362	
Molar flow (kgmole/h)	56551	39824	6279		
Molecular Weight	27.64	27.7	43.02		
Composition (vol %)					
CO					
CO_2	11.88	1.70	96.17		
$Ar+N_2$	60.05	85.10	0.03		
O_2	3.89	5.50			
H_2O	24.18	7.70	3.80		

The LP steam consumption corresponds to a specific duty to the reboiler of the regenerator column of about 140 kJ/mol of CO_2 captured.

PC-USC HEAT AND MATERIAL BALANCE

CLIENT: IEA GREEN HOUSE R & D PROGRAMME
CASE: CASE 3B - 250MW CFB boiler with CCS
UNIT: 6000 CO_2 Compression and Drying

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a
1	CO_2 from Stripper	270.1	35	1.5
2	Compressed CO_2	265.8	32.7	110
3	Condensate from Stripper Condenser	230.0	85	22.1
4	Preheated Condensate to Power Island	230.0	120.3	21.6
5	Condensate from KO drum	2.4	35	35.5
6	Condensate from Drying package	1.9	177	94.0

6.5 Utility Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Tables.

CLIENT:	IEA GREEN HOUSE R & D PROGRAMME	Rev 2
PROJECT:	BIOMASS FIRED POWER PLANT	November 09
LOCATION:	THE NETHERLANDS	ISSUED BY: SC
		CHECKED BY: PC
		APPR. BY: FG

ELECTRICAL CONSUMPTION SUMMARY - CASE 3B - 250MW CFB boiler with CCS

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
1000	SOLID RECEIVING, HANDLING AND STORAGE	
	Fuel Receiving, Handling and Storage	900
	Limestone unloading, storage and handling	5
2000	BOILER ISLAND AND FLUE GAS TREATING	
	Boiler auxiliary consumption	10967
	Flue gas desulphurization plant (FGD)	0
	Gypsum loading, storage and handling	0
	Ash loading, storage and handling	245
3000	POWER ISLAND	
	Steam turbine auxiliaries and condenser	480
	Condensate pumps and feedwater system	177
	Step-Up transformer losses	550
4000	UTILITIES AND OFFSITE UNITS	
	Machinery cooling water system	1690
	Sea water system	3790
	Miscellaneous Balance-of-Plant	1289
5000	CO_2 PLANT INCL. BLOWERS	
	Blower	4113
	Pumps	3731
6000	CO_2 COMPRESSION	27750
	BALANCE	55687

	CLIENT: IEA GREEN HOUSE R & D PROGRAMME	Rev 0
	PROJECT: BIOMASS FIRED POWER PLANT	May 09
	LOCATION: THE NETHERLANDS	ISSUED BY: SC
		CHECKED BY: PC
		APPR. BY: FG

WATER CONSUMPTION SUMMARY - CASE 3B - 250MW CFB boiler with CCS

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	Solid receiving, handling and storage			72	
2000	Boiler Island			33	
2300	Flue gas desulphurization plant (FGD)				
5000	CO_2 capture plant			27969	
6000	CO_2 compression				4600
	POWER ISLANDS UNITS				
3000	Surface condenser				16436
	Miscellanea		10	922	
	UTILITY and OFFSITE				
4100	Machinery Cooling Water System				49759
4200	Demineralized Water System	11.0	-10		
	Miscellanea			30	
	BALANCE	11.0	0	29026	70795

6.6 Overall Performance

The following Table shows the overall performance of the Plant.

IEA GHG		
CASE 3B: 250MW CFB boiler with CO_2 capture		
OVERALL PERFORMANCE OF THE COMPLEX		
Coal Flowrate	t/h	0.0
Coal LHV	kJ/kg	25870
Biomass Flowrate	t/h	322.6
Biomass LHV	kJ/kg	7300
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**654**
Steam turbine power output (@gen. Terminals)	MWe	224.6
GROSS ELECTRIC POWER OUTPUT (D)	**MWe**	**224.6**
Solid Receiving, Handling and Storage	MWe	0.9
Boiler Island and flue gas treating	MWe	11.2
CO2 Plant incl. Blowers	MWe	7.8
CO2 Compression	MWe	27.8
Power Island	MWe	1.2
Utilities	MWe	6.8
ELECTRIC POWER CONSUMPTION	**MWe**	**55.7**
NET ELECTRIC POWER OUTPUT (C)	**MWe**	**168.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**34.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**25.8**

The following Table shows the overall CO_2 removal efficiency of the Complex:

	Equivalent flow of CO_2 kmol/h
Coal (Carbon = 64.6%wt)	-
Biomass (Carbon = 25 % wt)	6721
Limestone	7
Carbon in ash	-18
Net Carbon flowing to Process Units (A)	6710
Liquid Storage	
CO	0.0
CO_2	6039
Total to storage (B)	6039
Emission	
CO	7
CO_2	664
Total Emission	671
Overall CO_2 removal efficiency, % (B/A)	90

Note: N_2O not included in the table.

6.7 Environmental Impact

The plant is designed to process biomass, whose characteristics are defined in the Basic Engineering Design Data and produce electric power. The advanced technology allows to reach a high efficiency and to minimise environmental impact.

The gaseous emissions, liquid effluents and solid wastes from the plant are summarised in this section.

6.7.1 Gaseous Emissions

Main Emissions

In normal operation at full load, the main continuous emissions are the combustion flue gases leaving the boiler at stack.

Table 6.1 summarises expected flow rate and concentration of the combustion flue gas released to atmosphere from the stack.

	Normal Operation
Wet gas flow rate, kg/s	306.7
Flow, Nm^3/h	893,000
Temperature, °C	102
Composition	(%vol)
N_2+Ar	85.1
O_2	5.5
CO_2	1.7
H_2O	7.7
Emissions	mg/Nm^3 (1)
NOx	200
N_2O	8.5
SOx	49
CO	230
Particulate	Less than 5

Table 6.1 – Expected gaseous emissions from plant

(1) Dry gas, O_2 Content 6% vol

Minor Emissions

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). They are prevented by proper design and operation.

6.7.2 Liquid Effluent

All the liquid effluents are treated in the wastewater treatment system in order to be discharged in accordance with the current regulations.

The liquid effluents generated in the power plant are mainly the following:
- Rain water contaminated by powder;
- Wash water contaminated by oil and powder;
- Effluents from CO_2 capture plant (Direct contact cooler and blowdown)
- Eluates from demineralizing water system;
- Sanitary water;
- Blowdown from the boiler.

The CO_2 capture plant blowdown water contains a significant amount of MEA and therefore implies the introduction of a further biological section with aerobical and anaerobical treatment.

Sea water in open circuit is used for cooling.
The return stream water is treated with meta-bisulphite in the Dechlorination System to reduce the Cl_2 concentration. Main characteristics of the water are listed in the following:

- Maximum flow rate : 70,795 m^3/h
- Temperature : 19 °C

6.7.3 Solid Effluent

No solid waste other than those produced by a real industrial activity.
The power plant is expected to produce the following solid by-products:

Fly Ash

Flow rate	:	3.3	t/h
Unburned Carbon	:	5.5	%wt

Bottom Ash

Flow rate	:	0.7	t/h
Unburned Carbon	:	5.1	%wt

Fly and bottom ash could be theoretically dispatched to cement industries. For the purposes of present study they are considered as a waste to be disposed.

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : TECHNO-ECONOMIC EVALUATION OF CAPTURING CO_2 FROM BIOMASS FIRED POWER PLANT
DOCUMENT NAME : CASE 4A – 75 MWE BFB BOILER WITHOUT CO_2 CAPTURE

ISSUED BY : S. CAVEZZALI
CHECKED BY : P. COTONE
APPROVED BY : F. GASPARINI

Date	Revised Pages	Issued by	Checked by	Approved by
May 2009	Rev 0	S. Cavezzali	P. Cotone	F. Gasparini
July 2009	Rev 1	S. Cavezzali	P. Cotone	F. Gasparini
November 2009	Rev 2	S. Cavezzali	P. Cotone	F. Gasparini

SECTION D

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D BASIC INFORMATION FOR EACH ALTERNATIVE

SECTION D BASIC INFORMATION FOR EACH ALTERNATIVE

7.0 Case 4a - 75 MWe BFB Boiler without CO_2 capture

Summary

Case 4a is based on a SubCritical BFB boiler fired with biomass. No capture of CO_2 is considered.

- The size of the plant considered for this configuration is 75 MWe net power output nominal.
- No drying of biomass is needed.
- The flue gas line does not include the special plastic heat exchanger considered in the 500 MWe and 250 MWe CFB boilers without CO_2 capture. In fact, the high cost of such exchanger in relation to the performance increase achieved does not justify the addition of this equipment in the small 75 MWe BFB boiler.
- The limits of NO_x emissions can be met with just the firing system of the boiler with low temperature at furnace exit. The fuel composition (e.g. higher water content), besides, helps to maintain the combustion temperature low, implying a lower NOx production. No addition of a DeNOx system is needed.
- Flue gas desulphurization and limestone injection in the combustion chamber are not required to meet SO_x emission limits because of the low sulphur content in biomass.

7.1 Introduction

The Case 4a of the study is a BFB biomass fired Sub Critical steam plant without carbon dioxide capture.

The configuration of the complex is based on a steam generator with superheating.

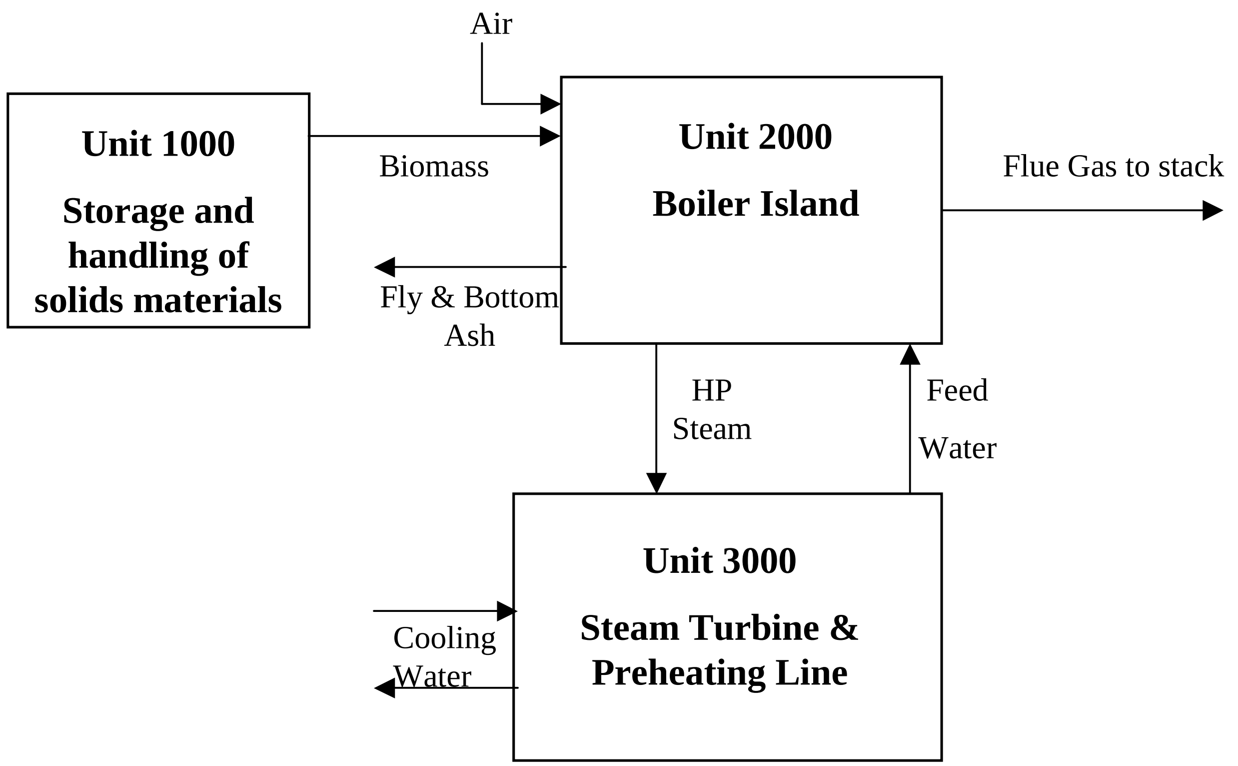
Reference is made to the attached Block Flow Diagram of the plant.
The arrangement of the process units is:

Unit

1000 Storage and Handling of solid materials, including:
- 1100 Coal storage and handling
- 1200 Biomass storage and handling
- 1300 Limestone storage and handling

2000 Boiler Island and flue gas treating, including:
- 2100 Boiler
- 2400 Baghouse filter
- 2500 Ash and by-products removal and handling

3000 Power Island including:
- 3100 Steam Turbine
- 3200 Preheating Line
- 3300 Electrical Power Generation.



Air
Unit 1000
Storage and handling of solids materials
Biomass
Unit 2000
Boiler Island
Flue Gas to stack
Fly & Bottom Ash
HP Steam
Feed Water
Unit 3000
Steam Turbine & Preheating Line
Cooling Water

7.2 Process Description

Unit 1000: Storage and handling of solids materials

Please refer to Section C para. 1.0 for a process description of this unit.

This unit is made up of standard equipment in use, to receive the biomass from outside the plant boundary, store, reclaim and transport it to the boiler plant.

The expected Biomass consumption is about 2500 t/d.

Unit 2000: Boiler Island

The block flow diagram of this section is attached to paragraph 7.3.

The boiler is a Foster Wheeler tower BFB.
The boiler includes the fuel feeding systems, the furnace, the superheaters, the boiler banks, the back pass, the fans and air heater.

Furnace

The main difference of the bubbling fluid bed with respect to the circulating fluid bed is that the velocity in the furnace is just above the fluidisation velocity; the fluidised bed is then confined in a defined volume below the so called freeboard.
As a consequence the combustion takes place in a reducing atmosphere.
Overfire (secondary) air is injected above the freeboard to complete the combustion, providing staged combustion and minimizing NOx emissions.
Also for the BFB boiler, neither SCR nor SNCR are required to meet the NOx emissions, for both the case without and with CO_2 capture.

Flue gas cooling

The flue gases from the furnace are cooled in the boiler banks, the economizer and the tubular air heater.
No special PF-plastic heat exchanger has been provided due to the small size of this boiler.

A picture of the Foster Wheeler BFB boiler is included here below, in figure 1.

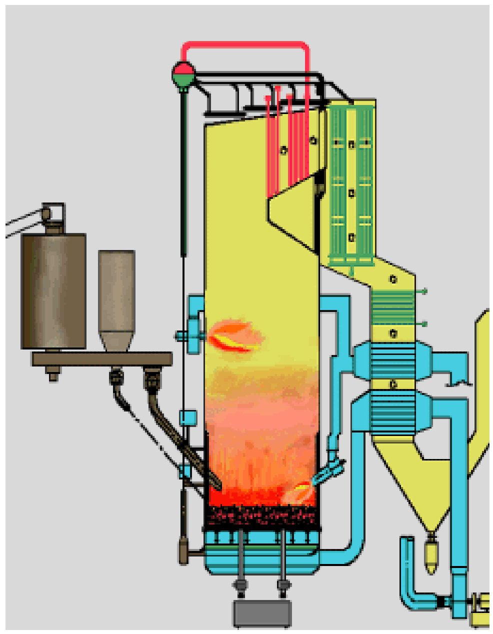


Figure 1 - BFB Boiler arrangement

Fouling problems are important in 100% biomass fired boilers, because the alkalis in the fuel vaporize at combustor temperatures and can recombine with other ash and fuel constituents (especially sulphate, chloride, silica and phosphorus) to produce low melting compounds that can cause sintering and agglomeration on the furnace and back pass surfaces. High potassium content is especially associated with back pass fouling, while sodium is more often associated with in-furnace sinter formation. Sintering resulting from fuel bound alkalis can be at least partially mitigated by the addition of compounds high in alumina and to a lesser extent by the addition of compounds high in calcium and magnesium. High ash drain rates will also reduce sintering problems.

Unit 2400: Baghouse filter

A baghouse filter is provided to remove particulate content in the flue gases to meet the environmental limits. Fly ash are collected from the baghouse filter bottom.

Unit 2500: Ash Handling Plant

The ash handling system, takes care of conveying the ash generated in the boiler plant: both the furnace bottom ash and the fly ash from the various hoppers. (Reference to Section C – para 3.0).

Unit 3000: Steam Turbine and Preheating Line

The block flow diagram of this section is attached to paragraph 7.3.

The power island is a single train, mainly composed of one steam turbine and one preheating line. Superheated steam from the boiler is sent to the steam turbine, which consists of a HP, LP section, all connected to the generator on a single shaft. The steam turbine is a condensing type, with multiple extractions for the preheating of the condensate and boiler feedwater.

Main steam from the boiler, generated at 115 bar and 540°C, passes through the stop valves and control valves and enters the turbine. Exhaust steam from HP flows into the LP turbine and then downward into the condenser at 0.03 bar, 24°C.

Different extractions from the HP section at different conditions of steam pressure/temperature allow the preheating of the boiler feed water, while the low-pressure extraction is used to provide the steam necessary for the degassing of the condensate. Steam condensate recovered into the boiler feed water heaters is recovered back to the deaerator.

Part of the exhaust steam from the HP ST section, together with three extractions from the LP steam turbine, provide heat to the four condensate heaters downstream the condensate pumps, before entering the deaerator.

Boiler feedwater exiting the deaerator is pumped to the economizers of the boiler by means of the boiler feedwater pump electrical motor driven.

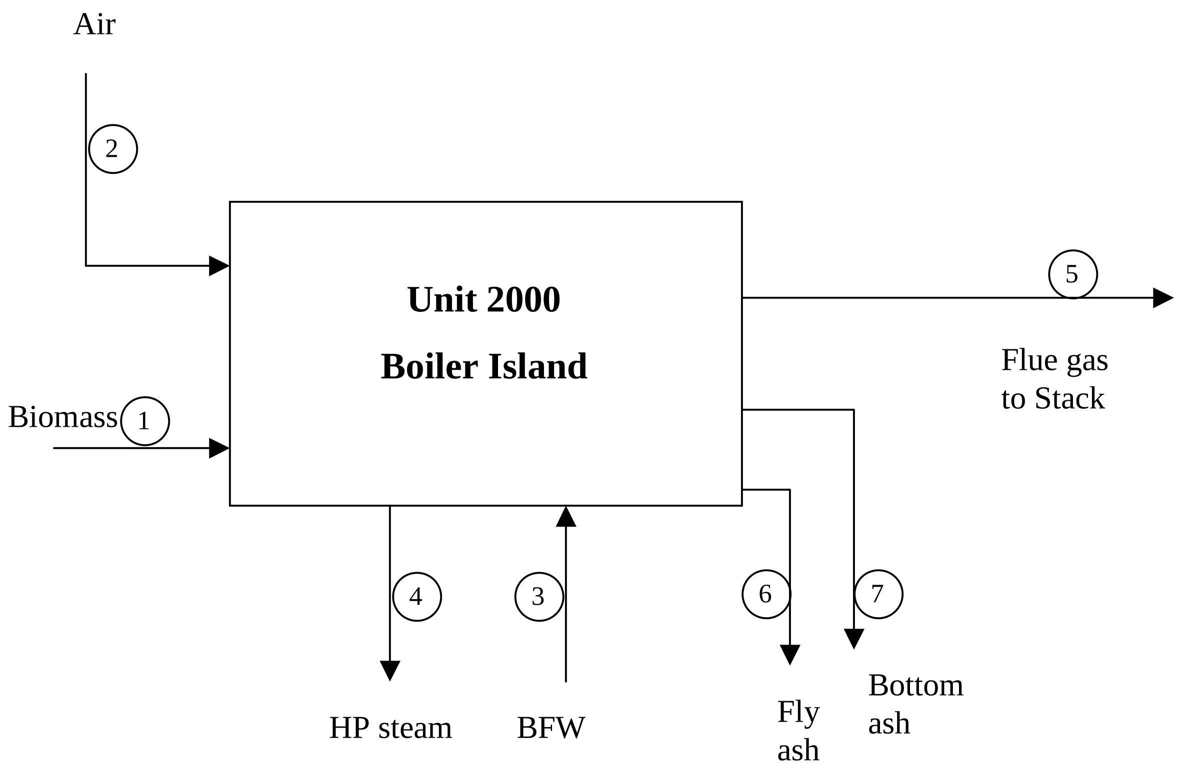
Chemical injection for control of the water quality is made by dedicated packages on the suction of the boiler feedwater pumps and at the inlet of the boiler.

7.3 Block Flow Diagrams

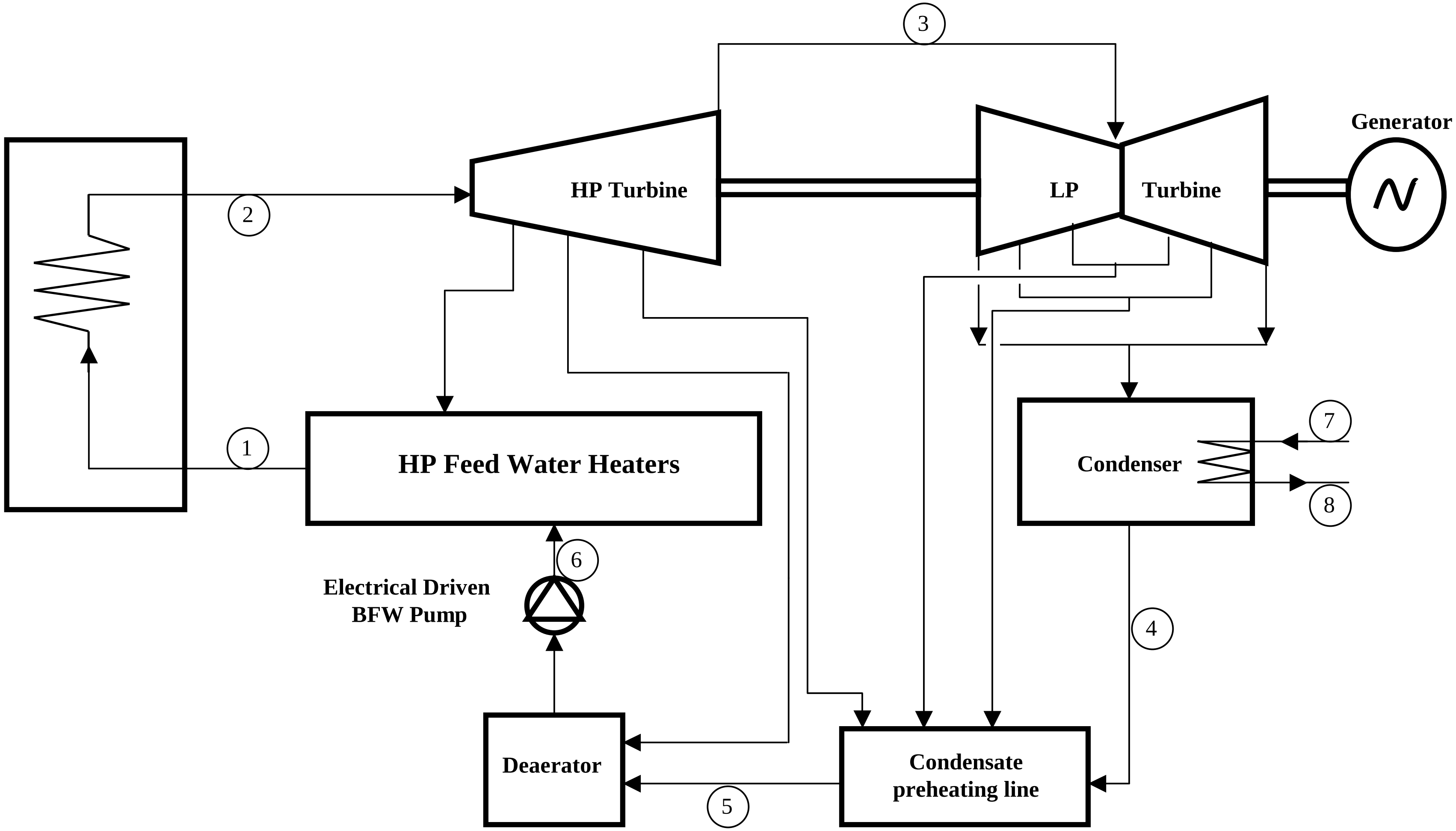
The Block Flow Diagrams of the following process units are attached to this paragraph:

- Unit 2000: Boiler Island
- Unit 3000: Power Island

Unit 2000 – Boiler Island



Unit 3000 – Power Island



7.4 Heat and Material Balances

The Heat & Material Balances of the following process units are attached to this section:

- UNIT 2000: Boiler Island and flue gas treating
- UNIT 3000: Power Island

Stream numbers are as shown on the Block Flow Diagrams attached to paragraph 7.3 of this Section.

PC-USC HEAT AND MATERIAL BALANCE	
CLIENT:	IEA GREEN HOUSE R & D PROGRAMME
CASE:	CASE 4A - 75MW BFB boiler without CCS
UNIT:	2000 Boiler Island and Flue gas treating

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a
1	Biomass	104	amb.	amb.
2	Air intake from Atmosphere	286	amb.	amb.
3	Feed Water from Preheating line UNIT 3000	281	226	138
4	HP Steam from boiler	278	540	115
5	Flue Gas to Stack (1)	469	90	1.005
6	Fly ash	0.9	amb.	amb.
7	Bottom Ash	0.2	amb.	amb.

Notes:
(1) For gas composition see Paragraph 7.7.1

PC-USC HEAT AND MATERIAL BALANCE	
CLIENT:	IEA GREEN HOUSE R & D PROGRAMME
CASE:	CASE 4A - 75MW BFB boiler without CCS
UNIT:	3000 Power Island

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	HP Water to Boiler Island	280.8	226	137.6	973
2	HP Steam from boiler	278	540	115	3459
3	MP Steam Turbine exhaust	222.9	176	6.21	2794
4	Condensate	207.8	24	0.03	101
5	LP Preheated Condensate	265.9	160.0	11.8	676
6	Condensate to HP FWH	280.8	187	11.8	795
7	Cooling Water Inlet	12527	12	1.9	51
8	Cooling Water Outlet	12527	19	1.4	80

7.5 Utility Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Tables.

CLIENT:	IEA GREEN HOUSE R & D PROGRAMME	Rev 0
PROJECT:	BIOMASS FIRED POWER PLANT	May 09
LOCATION:	THE NETHERLANDS	ISSUED BY: SC
		CHECKED BY: PC
		APPR. BY: FG

ELECTRICAL CONSUMPTION SUMMARY - CASE 4A - 75MW BFB boiler without CCS

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
1000	SOLID RECEIVING, HANDLING AND STORAGE	
	Fuel Receiving, Handling and Storage	300
	Limestone unloading, storage and handling	0
2000	BOILER ISLAND AND FLUE GAS TREATING	
	Boiler auxiliary consumption	3535
	Flue gas desulphurization plant (FGD)	0
	Gypsum loading, storage and handling	0
	Ash loading, storage and handling	68
3000	POWER ISLAND	
	Steam turbine auxiliaries and condenser	177
	Condensate pumps and feedwater system	1694
	Step-Up transformer losses	260
4000	UTILITIES AND OFFSITE UNITS	
	Machinery cooling water system	25
	Sea water system	700
	Miscellaneous Balance-of-Plant	857
	BALANCE	7616

	CLIENT:	IEA GREEN HOUSE R & D PROGRAMME	Rev 0
	PROJECT:	BIOMASS FIRED POWER PLANT	May 09
	LOCATION:	THE NETHERLANDS	ISSUED BY: SC
			CHECKED BY: PC
			APPR. BY: FG

WATER CONSUMPTION SUMMARY - CASE 4A - 75MW BFB boiler without CCS

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	Solid receiving, handling and storage			23	
2000	Boiler Island		3	11	
2300	Flue gas desulphurization plant (FGD)				
	POWER ISLANDS UNITS				
3000	Surface condenser				12527
	Miscellanea		2	342	
	UTILITY and OFFSITE				
4100	Machinery Cooling Water System				675
4200	Demineralized Water System	5.5	-10		
	Miscellanea			18	
	BALANCE	5.5	-5	394	13202

7.6 Overall Performance

The following Table shows the overall performance of the Plant.

IEA GHG		
CASE 4A: 75MW BFB boiler without CO_2 capture		
OVERALL PERFORMANCE OF THE COMPLEX		
Coal Flowrate	t/h	0
Coal LHV	kJ/kg	25870
Biomass Flowrate	t/h	104
Biomass LHV	kJ/kg	7300
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**211**
Steam turbine power output (@gen. Terminals)	MWe	83.4
GROSS ELECTRIC POWER OUTPUT (D)	**MWe**	**83.4**
Solid Receiving, Handling and Storage	MWe	0.3
Boiler Island and flue gas treating	MWe	3.6
CO2 Plant incl. Blowers	MWe	0
CO2 Compression	MWe	0
Power Island	MWe	2.1
Utilities	MWe	1.6
ELECTRIC POWER CONSUMPTION	**MWe**	**7.6**
NET ELECTRIC POWER OUTPUT (C)	**MWe**	**75.8**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**39.6**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**36.0**

7.7 Environmental Impact

The plant is designed to process biomass, whose characteristics are defined in the Basic Engineering Design Data and produce electric power. The advanced technology allows to reach a high efficiency and to minimise environmental impact.

The gaseous emissions, liquid effluents and solid wastes from the plant are summarised in this section.

7.7.1 Gaseous Emissions

<u>Main Emissions</u>

In normal operation at full load, the main continuous emissions are the combustion flue gases leaving the boiler at stack.

Table 7.1 summarises expected flow rate and concentration of the combustion flue gas released to atmosphere from the stack.

	Normal Operation
Wet gas flow rate, kg/s	130.2
Flow, Nm^3/h	380,000
Temperature, °C	90
Composition	(%vol)
N_2+Ar	58.7
O_2	2.8
CO_2	12.8
H_2O	25.7
Emissions	mg/Nm^3 (1)
NOx	200
N_2O	6
SOx	160 (2)
CO	200
Particulate	Less than 30

Table 7.1 – Expected gaseous emissions from plant

(1) Dry gas, O_2 Content 6% vol
(2) The sulphur content in the biomass is almost negligible and typically biomass includes CaO itself thus leading to some amount of inherent retention, therefore the SO_2 emissions in the fully biomass fired cases results lower then 200 mg/Nm3.

Minor Emissions

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). They are prevented by proper design and operation.

7.7.2 Liquid Effluent

All the liquid effluents are treated in the wastewater treatment system in order to be discharged in accordance with the current regulations.

The liquid effluents generated in the power plant are mainly the following:
- Rain water contaminated by powder;
- Wash water contaminated by oil and powder;
- Eluates from demineralizing water system;
- Sanitary water;
- Blowdown from the boiler.

Sea water in open circuit is used for cooling.
The return stream water is treated with meta-bisulphite in the Dechlorination System to reduce the Cl_2 concentration. Main characteristics of the water are listed in the following:

- Maximum flow rate : 13,202 m^3/h
- Temperature : 19 °C

7.7.3 Solid Effluent

No solid waste other than those produced by a real industrial activity.
The power plant is expected to produce the following solid by-products:

Fly Ash

Flow rate	:	0.9	t/h
Unburned Carbon	:	5.3	%wt

Bottom Ash

Flow rate	:	0.2	t/h
Unburned Carbon	:	6.3	%wt

Fly and bottom ash could be theoretically dispatched to cement industries. For the purposes of present study they are considered as a waste to be disposed.

CLIENT	:	IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME	:	TECHNO-ECONOMIC EVALUATION OF CAPTURING CO_2 FROM BIOMASS FIRED POWER PLANT
DOCUMENT NAME	:	CASE 4B – 75 MWE BFB BOILER WITH CO_2 CAPTURE

ISSUED BY	:	S. CAVEZZALI
CHECKED BY	:	P. COTONE
APPROVED BY	:	F. GASPARINI

Date	Revised Pages	Issued by	Checked by	Approved by
May 2009	Rev 0	S. Cavezzali	P. Cotone	F. Gasparini
July 2009	Rev 1	S. Cavezzali	P. Cotone	F. Gasparini
November 2009	Rev 2	S. Cavezzali	P. Cotone	F. Gasparini

SECTION D

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D BASIC INFORMATION FOR EACH ALTERNATIVE

SECTION D BASIC INFORMATION FOR EACH ALTERNATIVE

8.0 Case 4b - 75 MWe BFB Boiler with CO_2 capture

Summary

Case 4b is based on a SubCritical BFB boiler fired with biomass. CO_2 capture and compression is considered.

- The size of the plant considered for this configuration is 75 MWe net power output nominal. The boiler is the same as the case without CO_2 capture having as a consequence the reduction in net power output of the plant due to the impact of the CO_2 removal and compression units as power and steam consumer.
- No drying of biomass is needed.
- The environmental limits on NOx can be met with just the firing system of the boiler with low temperature at furnace exit. No addition of an SCR system is needed.
- The amine based CO_2 absorption system, requires a very low level of NO_2 in the flue gas. Being the content of NO_2 in NOx ranging from 15% to 20%, this low content of NO_2 is achieved without the need of addition of further denitrification in flue gas treatment. On the other hand due to the removal of the CO_2 from the flue gases, the NOx concentration at stack results slightly higher than the one at CO_2 capture unit inlet. For this reason the NOx level at boiler outlet shall be lower than in the case without CO_2 capture by approximately 15% in order to maintain 200 mg/Nm^3 (@6% O_2 dry) at stack. Actually on the basis of the overall annual NOx flow rates, there could be an allowance for the more concentrated stack gases as the absolute NOx flow rate remains constant. Anyhow in the basis of design of the present study there is no any reduction on the emission limit and 200 mg/Nm^3 (@6% O_2 dry) at stack is considered for all cases. It is expected that the N_2O in flue gas will not be absorbed into MEA and pass through unchanged to the stack. The behaviour of N_2O is in fact the same of oxygen and therefore its impact on MEA can be considered negligible, due to its very low content with respect to the oxygen.
- Production of N_2O in the CFB boiler are not insignificant because of the combustion temperature. Nitrous oxide (N_2O) is a greenhouse gas with

300 time the impact of CO_2. It is expected that the N_2O in flue gas will not be absorbed into MEA and pass through unchanged to the stack. However, it is possible that some of the N_2O could form heat-stable salts, and be removed in the reclaimer / filter system. This shall be further investigated with the MEA supplier.

- The amine based CO_2 absorption system, requires a very low level of SO_2 in the flue gas (much lower than the emission limits). Due to the very low level of sulphur contained in the biomass, this figure is achievable only with limestone injection in the furnace bed and an external FGD is not needed. The Ca/S considered to inject limestone is 2.8. Such low absolute figures of SOx emissions are not presently met in a full SOx capture in furnace, though the overall SOx capture efficiency can be achieved in the existing plants. Moreover, biomass typically includes CaO itself thus leading to some amount of inherent retention. The avoiding of the external FGD is one of the main advantages of the biomass fired CFB for CO_2 capture plants. Therefore, it would be a technical challenge, which needs to be further demonstrated in a large size plant.

- All the heat required for the CO_2 capture plant is provided from the low temperature steam extracted from the turbine. This results in a significant loss of power in the turbine generator. Further, a significant optimisation of heat within the CO_2 capture plant is also considered with adequate heat exchanges between various streams within the plant.

- CO_2 is dried and compressed up to supercritical phase at 110 bar for use in EOR or for geological disposal.

8.1 Introduction

The Case 4b of the study is a BFB biomass fired Sub Critical steam plant with carbon dioxide capture.

The configuration of the complex is based on a steam generator with superheating and single steam reheating.

Reference is made to the attached Block Flow Diagram of the plant.
The arrangement of the process units is:

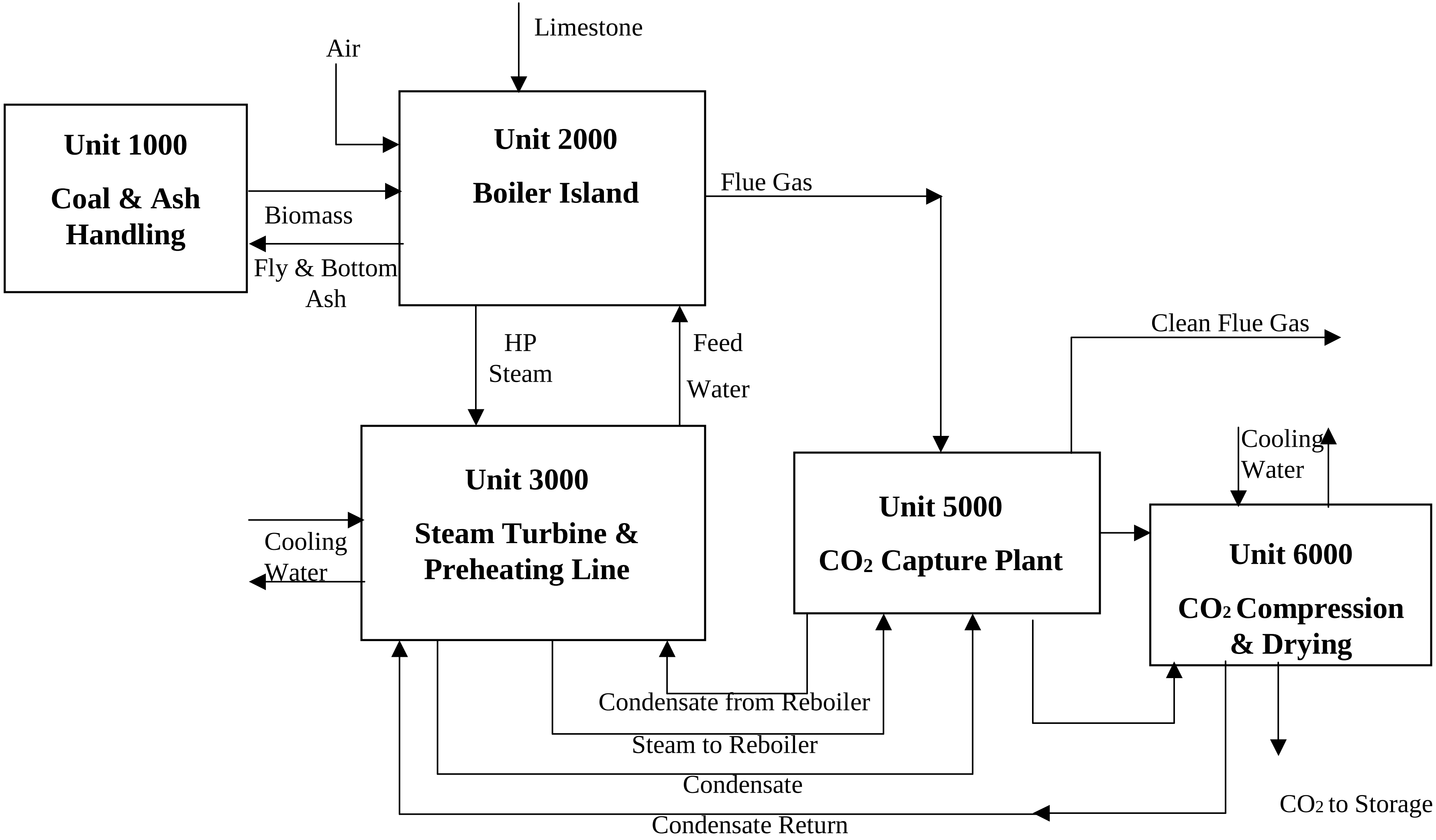
Unit

1000 Storage and Handling of solid materials, including:
- 1100 Coal storage and handling
- 1200 Biomass storage and handling
- 1300 Limestone storage and handling

2000 Boiler Island and flue gas treating, including:
- 2100 Boiler
- 2400 Baghouse filter
- 2500 Ash and by-products removal and handling

3000 Power Island including:
- 3100 Steam Turbine
- 3200 Preheating Line
- 3300 Electrical Power Generation.

5000 CO_2 capture unit
6000 CO_2 compression and drying unit


Limestone
Air
Unit 1000
Coal & Ash Handling
Unit 2000
Boiler Island
Biomass
Fly & Bottom Ash
Flue Gas
HP Steam
Feed Water
Clean Flue Gas
Unit 3000
Steam Turbine & Preheating Line
Cooling Water
Unit 5000
CO_2 Capture Plant
Cooling Water
Unit 6000
CO_2 Compression & Drying
Condensate from Reboiler
Steam to Reboiler
Condensate
Condensate Return
CO_2 to Storage

8.2 Process Description

Unit 1000: Storage and handling of solids materials

The unit is exactly the same as case 4a being equal the boiler. For unit description, reference shall be made to paragraph 7.2, section D7.

Unit 2000: Boiler Island

The boiler is exactly the same as case 4a. For unit description, reference shall be made to paragraph 7.2, section D7.

The block flow diagram of this section is attached to paragraph 6.3.

Unit 2400: Baghouse filter

A baghouse filter is provided to remove particulate content in the flue gases to meet the requirements of the downstream CO_2 capture unit. Fly ash are collected from the baghouse filter bottom.

An excessive amount of particulate in the flue gases fed to the CO_2 capture unit can cause foam formation that can compromise the correct unit operation.
For this reason the particulate content at CO_2 capture unit inlet is fixed at 5 mg/Nm^3 (@6% O_2 dry basis). This value is much lower than the environmental limits fixed in section B.

Unit 2500: Ash Handling Plant

The unit is exactly the same as case 4a. For unit description, reference shall be made to paragraph 7.2, section D7.

Unit 3000: Steam Turbine and Preheating Line

The block flow diagram of this section is attached to paragraph 6.3.

The power island is a single train, mainly composed of one steam turbine and one preheating line. Superheated steam from the boiler is sent to the steam turbine, which consists of a HP and LP section, all connected to the generator on a single shaft. The steam turbine is a condensing type, with multiple extractions for the preheating of the condensate and boiler feedwater. The LP steam is also extracted for the use in the reboiler and stripping unit in the CO_2 capture plant.

Main steam from the boiler, generated at 115 bar and 540°C, passes through the stop valves and control valves and enters the turbine. Exhaust steam from HP flows into the LP turbine and then downward into the condenser at 0.03 bar, 24°C.

Different extractions from the HP section at different conditions of steam pressure/temperature allow the preheating of the boiler feed water.

Recycled condensate from the condenser is pumped to the carbon dioxide capture plant and preheated in the amine stripper overhead condenser and the carbon dioxide compressor intercoolers. An optimisation of the integration between power plant and CO_2 capture plant allows to maximize the efficiency of the process. This also reduces the necessity of LP steam extractions to preheat condensate in LP preheating line. Only one condensate preheater is therefore needed downstream the condensate heating in the process units. The preheated feed water stream is routed to the deaerator, along with condensate returned from the amine stripper reboiler.

Boiler feedwater exiting the deaerator is pumped to the economizers of the boiler by means of the boiler feedwater pump steam turbine driven.

The plant configuration studied considers the following integrations between the Process Units and the Power Island:

- A part of the heat recovered in the CO_2 capture plant (overhead stripper condenser) and in the compression line is recovered by preheating the condensate, partially avoiding the use of LP feed water heaters.
- All the LP steam required for the CO_2 absorption plant is provided by extraction from the LP stage of the steam turbine.

Chemical injection for control of the water quality is made by dedicated packages on the suction of the boiler feedwater pumps and at the inlet of the boilers.

Unit 4000: CO_2 Capture Plant

Clean flue gas with NO_2 less than 20 ppmv and SO_x less than 10 ppm is sent to the CO_2 absorption tower.
Refer to Section C para. 6.0 for this section.
In the CO_2 capture plant, where flue gas temperatures are lower, it is not expected to have an increase of the NO_2 content, although conversion of NO to NO_2 is promoted by low temperatures, because the kinetics of the reaction that converts NO into NO_2 is too slow with respect to the residence time of gases in the system.
90% capture of CO_2 from the flue gas is considered.
The block flow diagram of this section is attached to paragraph 8.3.

Unit 5000: CO_2 Compression and Drying

Refer to Section C, para. 8.0 for the general description of the Unit. The block flow diagram of this section is attached to paragraph 8.3.

CO_2 can be handled as a liquid in pipe lines at conditions beyond its critical point (P_{CR}=73.8 bar; T_{CR}=31°C). The present configuration studied, assumes, CO_2 to be delivered at a pressure of around 110 bara.

The product stream sent to final storage is mainly composed of CO_2. The main properties of the stream are as follows:

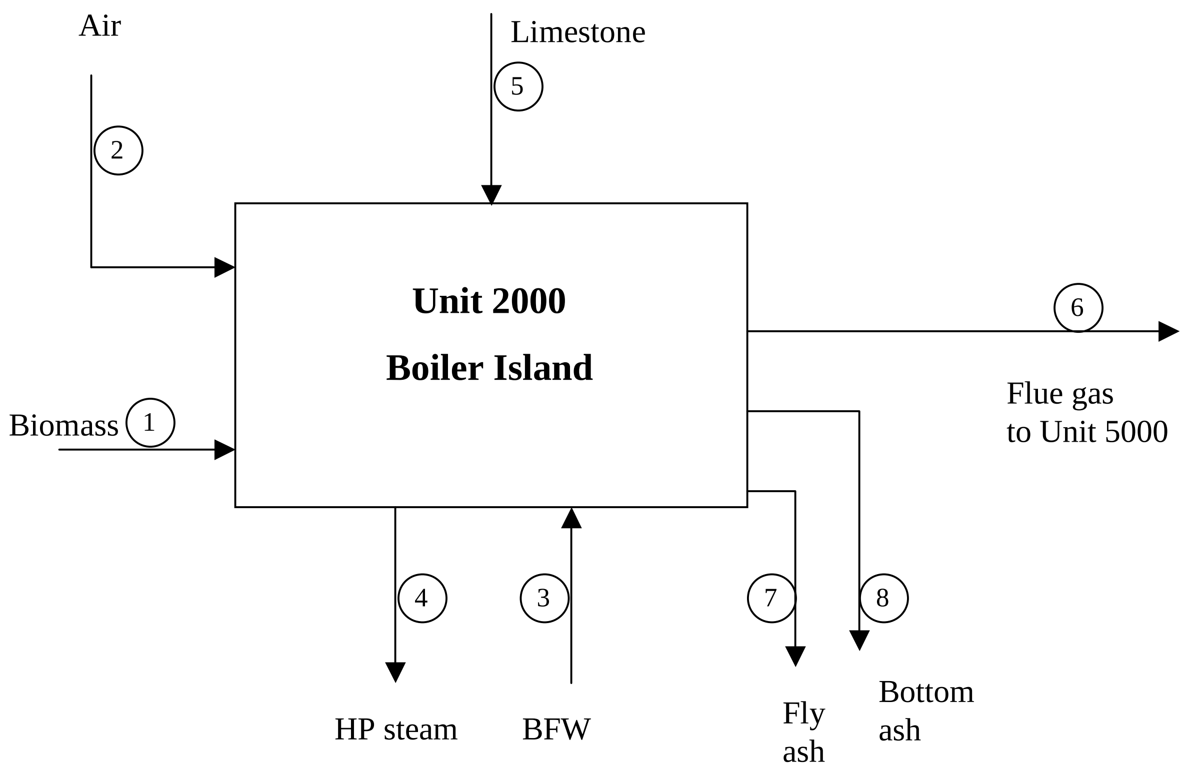
Product stream	:	85.9	t/h.
Pressure	:	110	bar.
Temperature	:	32 °C	
CO_2 purity	:	>99.9% wt.	

8.3 Block Flow Diagrams

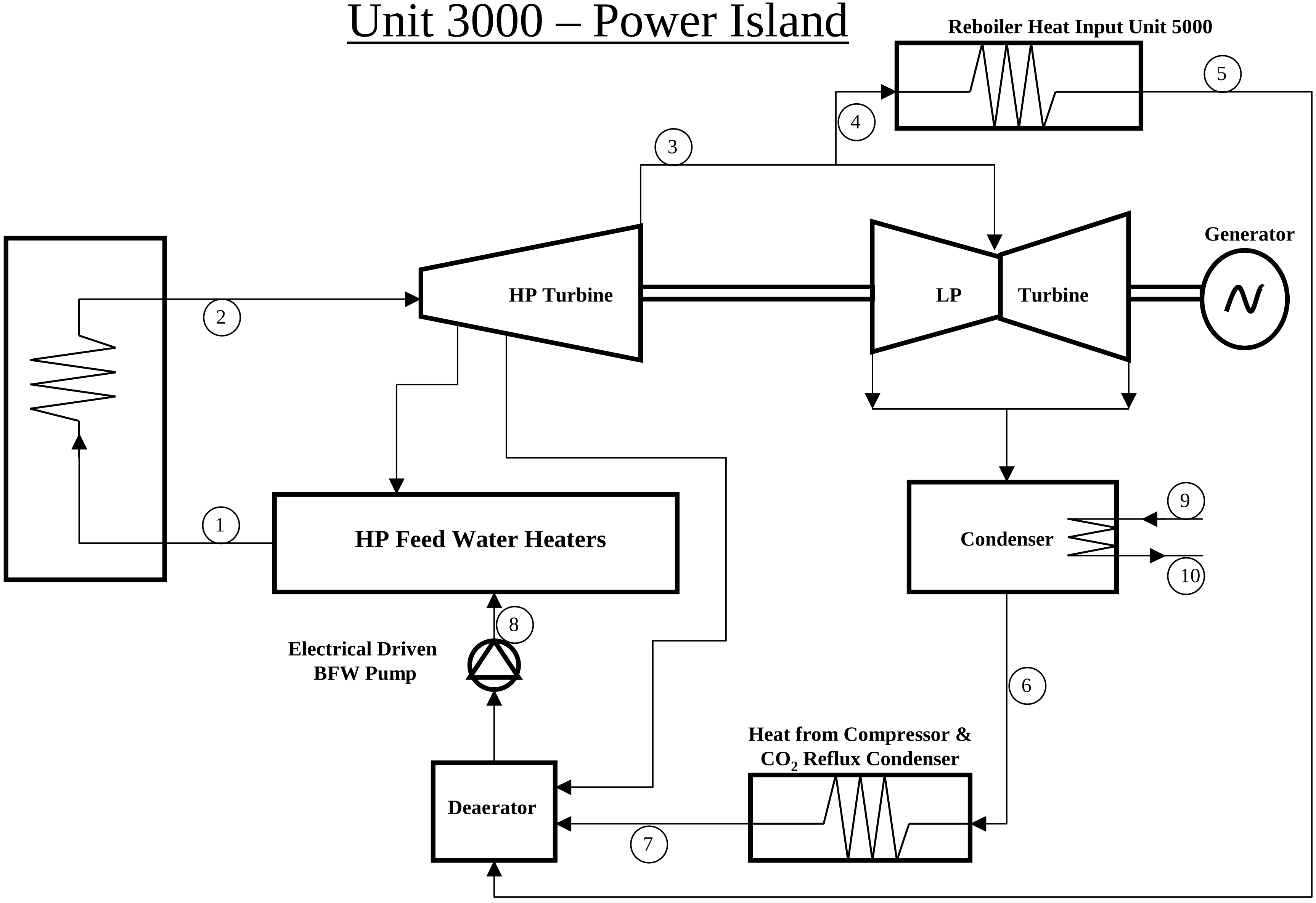
The Block Flow Diagrams of the following process units are attached to this paragraph:

- Unit 2000: Boiler Island and flue gas treating
- Unit 3000: Power Island
- Unit 5000: CO_2 capture
- Unit 6000: CO_2 compression and drying

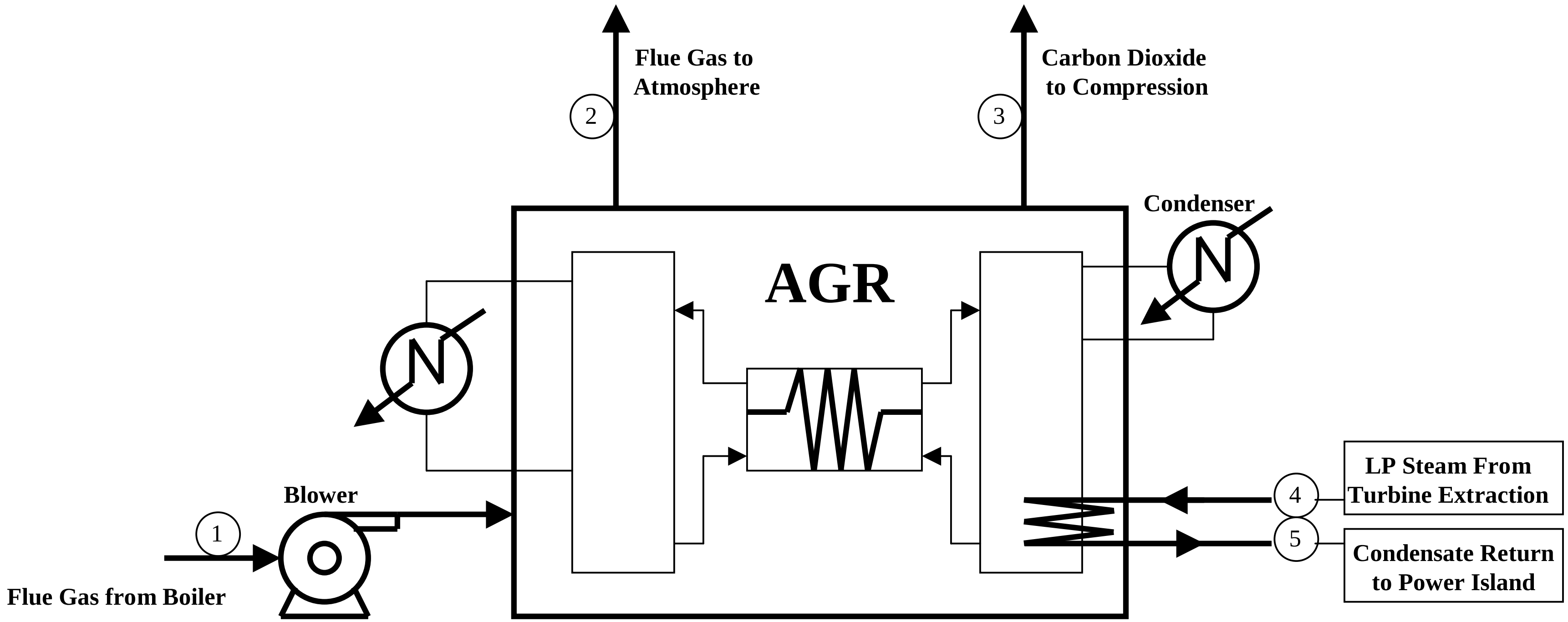
Unit 2000 – Boiler Island



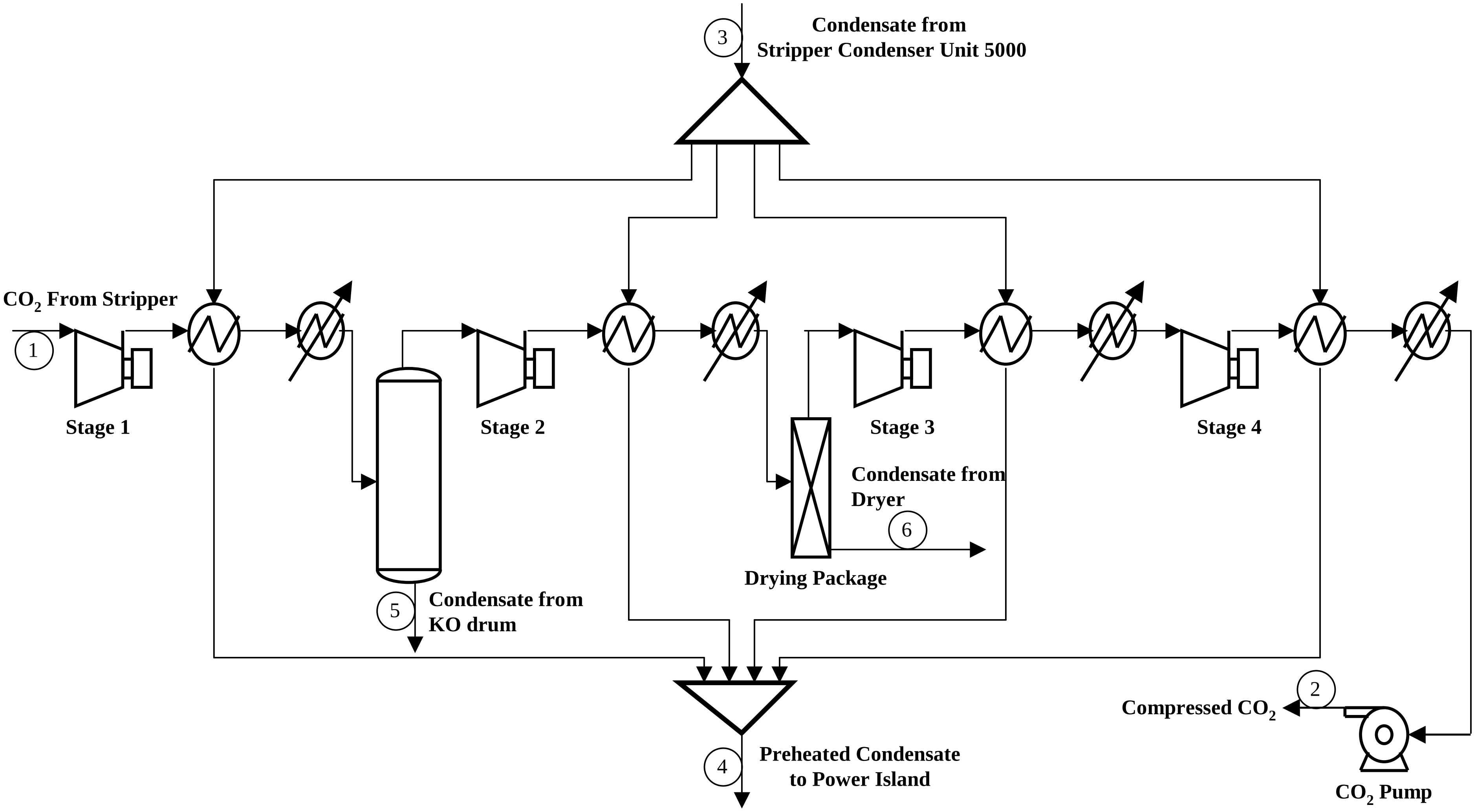
Unit 3000 – Power Island



UNIT 5000 - CO_2 Capture Plant



UNIT 6000 - CO_2 Compression & Drying



8.4 Heat and Material Balances

The Heat & Material Balances of the following process units are attached to this section:

- UNIT 2000: Boiler Island and flue gas treating
- UNIT 3000: Power Island
- UNIT 5000: CO_2 capture
- UNIT 6000: CO_2 compression and drying

Stream numbers are as shown on the Block Flow Diagrams attached to paragraph 8.3 of this Section.

PC-USC HEAT AND MATERIAL BALANCE

CLIENT: IEA GREEN HOUSE R & D PROGRAMME
CASE: CASE 4B - 75MW BFB boiler with CCS
UNIT: 2000 Boiler Island and Flue gas treating

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a
1	Biomass	104	amb.	amb.
2	Air intake from Atmosphere	286	amb.	amb.
3	Feed Water from Preheating line UNIT 3000	281	226	138
4	HP Steam from boiler	278	540	115
5	Limestone	0.3	amb.	amb.
6	Flue Gas to CO_2 capture plant (1)	469	148	1.015
7	Fly ash	1.1	amb.	amb.
8	Bottom Ash	0.2	amb.	amb.

Notes:
(1) For gas composition see stream #1 of Unit 5000 H&M balance

PC-USC HEAT AND MATERIAL BALANCE

CLIENT: IEA GREEN HOUSE R & D PROGRAMME

CASE: CASE 4B - 75MW BFB boiler with CCS

UNIT: 3000 Power Island

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	HP Water to Boiler Island	280.8	226	138	973
2	HP Steam from boiler	278	540	115	3459
3	MP Steam Turbine exhaust	226.4	143.6	4.00	2723
4	LP Steam to Reboiler	126.1	143.6	4.00	2723
5	LP Condensate from Reboiler	126.1	137	15.0	577
6	Condensate	99.0	24	0.03	101
7	LP Preheated Condensate	274.2	175.5	12.9	744
8	Condensate to HP FWH	280.8	190	138.2	814
9	Cooling Water Inlet	6571	12	1.9	51
10	Cooling Water Outlet	6571	19	1.4	80

	PC-USC HEAT AND MATERIAL BALANCE				
	CLIENT: IEA GREEN HOUSE R & D PROGRAMME				
	CASE: CASE 4B - 75MW BFB boiler with CCS				
	UNIT: 5000 CO_2 Capture Plant				
	1	2	3	4	5
STREAM	**Flue gas from Boiler**	**Flue gas to atmosphere**	**CO_2 to Compression**	**LP steam from turbine extraction**	**Condensate return to Power Island**
Temperature (°C)	148	107	35	144	137
Pressure (bar)	1.015	1.005	1.5	3.50	15
TOTAL FLOW					
Mass flow (t/h)	469	313	87.3	126	126
Molar flow (kgmole/h)	16998	11192	2029		
LIQUID PHASE					
Mass flow (t/h)					126
GASEOUS PHASE					
Mass flow (t/h)	469	313	87.3	126	
Molar flow (kgmole/h)	16998	11192	2029		
Molecular Weight	27.59	28.0	43.02		
Composition (vol %)					
CO					
CO_2	12.79	1.90	96.17		
$Ar+N_2$	58.72	88.90	0.03		
O_2	2.81	4.30			
H_2O	25.68	4.90	3.80		

The LP steam consumption corresponds to a specific duty to the reboiler of the regenerator column of about 140 kJ/mol of CO_2 captured.

PC-USC HEAT AND MATERIAL BALANCE

CLIENT: IEA GREEN HOUSE R & D PROGRAMME
CASE: CASE 4B - 75MW BFB boiler with CCS
UNIT: 6000 CO_2 Compression and Drying

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a
1	CO_2 from Stripper	87.3	35	1.5
2	Compressed CO_2	85.9	25.9	110
3	Condensate from Stripper Condenser	99.0	85	14.0
4	Preheated Condensate to Power Island	99.0	109.1	13.5
5	Condensate from KO drum	1.1	35	35.5
6	Condensate from Drying package	0.3	177	94.0

8.5 Utility Consumption

The utility consumption of the process / utility and offsite units are shown in the attached Tables.

CLIENT:	IEA GREEN HOUSE R & D PROGRAMME	Rev 2
PROJECT:	BIOMASS FIRED POWER PLANT	Novemeber 09
LOCATION:	THE NETHERLANDS	ISSUED BY: SC
		CHECKED BY: PC
		APPR. BY: FG

ELECTRICAL CONSUMPTION SUMMARY - CASE 4B - 75MW BFB boiler with CCS

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
1000	SOLID RECEIVING, HANDLING AND STORAGE	
	Fuel Receiving, Handling and Storage	300
	Limestone unloading, storage and handling	2
2000	BOILER ISLAND AND FLUE GAS TREATING	
	Boiler auxiliary consumption	3676
	Flue gas desulphurization plant (FGD)	0
	Gypsum loading, storage and handling	0
	Ash loading, storage and handling	76
3000	POWER ISLAND	
	Steam turbine auxiliaries and condenser	145
	Condensate pumps and feedwater system	1607
	Step-Up transformer losses	170
4000	UTILITIES AND OFFSITE UNITS	
	Machinery cooling water system	550
	Sea water system	1260
	Miscellaneous Balance-of-Plant	838
5000	CO_2 PLANT INCL. BLOWERS	
	Blower	1214
	Pumps	1176
6000	CO_2 COMPRESSION	8617
	BALANCE	19631

	CLIENT:	IEA GREEN HOUSE R & D PROGRAMME	Rev 0
	PROJECT:	BIOMASS FIRED POWER PLANT	May 09
	LOCATION:	THE NETHERLANDS	ISSUED BY: SC
			CHECKED BY: PC
			APPR. BY: FG

WATER CONSUMPTION SUMMARY - CASE 4B - 75MW BFB boiler with CCS

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery Cooling Water [t/h]	Sea Cooling Water [t/h]
	PROCESS UNITS				
1000	Solid receiving, handling and storage			23	
2000	Boiler Island			11	
2300	Flue gas desulphurization plant (FGD)				
5000	CO_2 capture plant			9093	
6000	CO_2 compression				1553
	POWER ISLANDS UNITS				
3000	Surface condenser				6571
	Miscellanea		4	281	
	UTILITY and OFFSITE				
4100	Machinery Cooling Water System				16159
4200	Demineralized Water System	4.5	-4		
	Miscellanea			18	
	BALANCE	4.5	0	9426	24283

8.6 Overall Performance

The following Table shows the overall performance of the Plant.

IEA GHG		
CASE 4B: 75MW BFB boiler with CO_2 capture		
OVERALL PERFORMANCE OF THE COMPLEX		
Coal Flowrate	t/h	0.0
Coal LHV	kJ/kg	25870
Biomass Flowrate	t/h	103.9
Biomass LHV	kJ/kg	7300
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**211**
Steam turbine power output (@gen. Terminals)	MWe	68.5
GROSS ELECTRIC POWER OUTPUT (D)	**MWe**	**68.5**
Solid Receiving, Handling and Storage	MWe	0.3
Boiler Island and flue gas treating	MWe	3.8
CO2 Plant incl. Blowers	MWe	2.4
CO2 Compression	MWe	8.6
Power Island	MWe	1.9
Utilities	MWe	2.6
ELECTRIC POWER CONSUMPTION	**MWe**	**19.6**
NET ELECTRIC POWER OUTPUT (C)	**MWe**	**48.9**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**32.5**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**23.2**

The following Table shows the overall CO_2 removal efficiency of the Complex:

	Equivalent flow of CO_2 kmol/h
Coal (Carbon = 64.6%wt)	-
Biomass (Carbon = 25 % wt)	2169
Limestone	3
Carbon in ash	-5
Net Carbon flowing to Process Units (A)	2167
Liquid Storage	
CO	0.0
CO_2	1950
Total to storage (B)	1950
Emission	
CO	2
CO_2	215
Total Emission	217
Overall CO_2 removal efficiency, % (B/A)	90

Note: N_2O not included in the table.

8.7 Environmental Impact

The plant is designed to process biomass, whose characteristics are defined in the Basic Engineering Design Data and produce electric power. The advanced technology allows to reach a high efficiency and to minimise environmental impact.

The gaseous emissions, liquid effluents and solid wastes from the plant are summarised in this section.

8.7.1 Gaseous Emissions

Main Emissions

In normal operation at full load, the main continuous emissions are the combustion flue gases leaving the boiler at stack.
Table 8.1 summarises expected flow rate and concentration of the combustion flue gas released to atmosphere from the stack.

	Normal Operation
Wet gas flow rate, kg/s	86.9
Flow, Nm^3/h	251,000
Temperature, °C	107
Composition	(%vol)
N_2+Ar	88.9
O_2	4.3
CO_2	1.9
H_2O	4.9
Emissions	$mg/Nm^{3\ (1)}$
NOx	200
N_2O	7
SOx	49
CO	230
Particulate	Less than 5

Table 8.1 – Expected gaseous emissions from plant

(1) Dry gas, O_2 Content 6% vol

Minor Emissions

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). They are prevented by proper design and operation.

8.7.2 Liquid Effluent

All the liquid effluents are treated in the wastewater treatment system in order to be discharged in accordance with the current regulations.

The liquid effluents generated in the power plant are mainly the following:
- Rain water contaminated by powder;
- Wash water contaminated by oil and powder;
- Eluates from demineralizing water system;
- Effluents from CO_2 capture plant (Direct contact cooler and blowdown)
- Sanitary water;
- Blowdown from the boiler.

The CO_2 capture plant blowdown water contains a significant amount of MEA and therefore implies the introduction of a further biological section with aerobical and anaerobical treatment.

Sea water in open circuit is used for cooling.
The return stream water is treated with meta-bisulphite in the Dechlorination System to reduce the Cl_2 concentration. Main characteristics of the water are listed in the following:

- Maximum flow rate : 24,283 m^3/h
- Temperature : 19 °C

8.7.3 Solid Effluent

No solid waste other than those produced by a real industrial activity.
The power plant is expected to produce the following solid by-products:

Fly Ash			
Flow rate	:	1.1	t/h
Unburned Carbon	:	4.3	%wt
Bottom Ash			
Flow rate	:	0.2	t/h
Unburned Carbon	:	6.3	%wt

Fly and bottom ash could be theoretically dispatched to cement industries. For the purposes of present study they are considered as a waste to be disposed.

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : TECHNO-ECONOMIC EVALUATION OF CAPTURING CO_2 FROM BIOMASS FIRED POWER PLANT
DOCUMENT NAME : ECONOMICS

ISSUED BY : S. CAVEZZALI
CHECKED BY : P. COTONE
APPROVED BY : F. GASPARINI

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SECTION E

ECONOMICS

I N D E X

SECTION E

1.0 Introduction

This section summarises the economic data evaluated for each alternative of the study, including:

a. Investment cost;
b. Operation & Maintenance costs;
c. Electric power production cost.

For quick reference, these are the main technical parameters considered for each cases:

Case	Plant type	Nom.Size	SCR	FGD	CO_2 capture	Net efficiency	Net output
1a	S/C PF boiler	500 MWe	Yes	Yes	0	44.8%	518.9 MWe
1b	S/C PF boiler	500 MWe	Yes	Yes	90%	34.5%	398.9 MWe
2a	S/C CFB boiler	500 MWe	No	No	0	45.1%	521.4 MWe
2b	S/C CFB boiler	500 MWe	No	No	90%	38.8%	390.5 MWe
3a	CFB boiler	250 MWe	No	No	0	41.7%	273.0 MWe
3b	CFB boiler	250 MWe	No	No	90%	25.8%	168.9 MWe
4a	BFB boiler	75 MWe	No	No	0	36.0%	75.8 MWe
4b	BFB boiler	75 MWe	No	No	90%	23.2%	48.9 MWe

2.0 Basis of Investment Cost Evaluation

2.1 Basis of the Estimate

The basis of the estimate for each alternative is the technical documentation collected in Sections C and D of the report.

Depending on the alternative considered, the investment cost of the following main Units or blocks of Units is detailed:

Unit 1000:	Storage and Handling of solid materials
Unit 2000:	Boiler Island and flue gas treating
Unit 3000:	Power Island
Unit 4000:	Utilities and Offsite
Unit 5000:	CO_2 capture plant (for cases with CO_2 capture)
Unit 6000:	CO_2 compression and drying (for cases with CO_2 capture)

The overall investment cost of each Unit or block of Units is split into the following items:

- Direct Materials, including equipment and bulk materials;
- Construction, including mechanical erection, instrument and electrical installation, civil works and, where applicable, buildings and site preparation;
- Other Costs, including temporary facilities, solvents, catalysts, chemicals, training, commissioning and start-up costs, spare parts etc.;
- EPC Services including Contractor's home office services and construction supervision.

2.2 Estimate Methodology and Cost Basis

2.2.1 Direct Materials

The direct materials cost estimate of the main Units or Blocks of Units listed at para. 2.1 is developed according to the following general criteria:

Storage and Handling of solid materials

The cost of equipment delivered and erected is based on a budget quotation received from a qualified Vendor, detailing direct materials and construction costs.
The investment cost of the unit is calculated on the basis of the capacity of each alternative, as detailed in Section D.

Boiler Island and flue gas treating

PC Boiler (Case 1)
The Foster Wheeler Power Group (North America office) provided investment cost data of the main equipment, specifically referred to the coal and biomass co-firing of this study and to the actual required flow rate.

The cost of equipment excluded from the estimate (ID Fan, Baghouse filter and FGD) is derived from competitive bids received and technically evaluated by Foster Wheeler Italiana in the past for similar projects. The figure taken as a reference has been adjusted on the basis of electric power consumption (for ID Fan), flue gas flowrate and particulate content (for baghouse filter) and flue gas flowrate and SOx removal efficiency (for FGD).

<u>CFB Boiler (Case 2, 3 and 4)</u>
The Foster Wheeler Power Group (Finland office) provided investment cost data of the main equipment, specifically referred to the coal and biomass fired boiler and to the fully biomass fired boilers of this study and to the actual required flow rate.

The cost of equipment excluded from the estimate (Baghouse filter and FGD, where necessary) is derived from competitive bids received and technically evaluated by FWI in the past for similar projects. The figure taken as a reference has been adjusted on the basis of flue gas flowrate and particulate content (for baghouse filter) and Flue gas flowrate and SOx removal efficiency (for FGD).

Power Island

The direct materials cost is based on competitive bids received in the past for similar equipment (mainly Steam turbine) and on proprietary software output for other equipment and bulk materials.

CO_2 Capture Unit and CO_2 Compression and Drying Unit

The investment cost is derived from competitive bids received and technically evaluated by FWI in the past for similar projects.
For each alternative the figure taken as a reference has been adjusted on the basis of flue gas flowrate and CO_2 captured flowrate (for CO_2 capture unit) and CO_2 flowrate and composition and electric power consumption (for CO_2 compression and Drying Unit).

Utilities and Offsite

Cost of each Unit is evaluated based on in house data for similar Units and adjusted on the basis of unit capacity.
These units also include DCS, ESD, EMS, Electrical Systems and HV substation.

2.2.2 Construction, Other Costs and EPC Services

Per each Unit (if necessary, for each Technology), or block of Units, the remaining costs (i.e. Construction, Other Costs and EPC Services) are calculated multiplying the cost of direct materials by factors, built up by FW from statistics based on cost estimates of similar plants.

2.2.3 Contingencies

The estimating contingency is a provisional sum that will give to an estimate equal chance of overrun or underrun within certain limits and it is meant to cover:
- Estimating errors.
- Estimating omissions.

Contingency is included in the estimate as a percentage of the estimated costs on the basis of:
- definition of the technical documentation in term of quality and completeness;
- estimate quality;
- methodology adopted to develop the estimate.

Different percentages of contingency are applied to the different sections on the basis of historical data. In absence of a more detailed assessment, 10% is considered as reference contingency.

2.2.4 Estimate Currencies

The estimate was developed in Euro.
The following exchange Euro to US $ rate has been used:

1.35 US $ equivalent to 1 Euro.

2.2.5 Inflation

No escalation is applied to the estimated installed cost.

2.2.6 Miscellaneous Costs

Land purchase, surveys and general site preparation are taken into account at a cost equal to 5% of the installed plant cost.
Additional costs for process/patent fees, fees for agents and consultants, legal and planning activities, are taken into account at a cost equal to 2% of the installed plant

cost. Where the cost of license fee is more than 2% of the installed plant cost, it is separately indicated in the calculation.

The sum of the installed plant cost plus the miscellanea costs is the Total Investment Cost.

2.3 Estimate Accuracy

The estimate accuracy is within the range +/- 30%.

3.0 Investment Cost of the Alternatives

3.1 500 MWe PC boiler (Cases 1a and 1b)

The following Tables E.3.1/2 show the investment break down and the total figures for each alternative investigated.

TABLE E.3.1 - ESTIMATE SUMMARY

CASE 1A

Client	IEA GHG
Project	Biomass fired Power Plants
Date:	Nov 2009 REV. 2

FIGURE IN EURO

POS	DESCRIPTION		UNIT 1000 €	2000 €	3000 €	4000 €	5000 €	6000 €	TOTAL €	REMARKS
1	DIRECT MATERIALS		28,086,300	189,926,100	79,981,200	35,280,000			333,273,600	1) ESTIMATE ACCURACY +/- 30%
2	CONSTRUCTION		6,195,600	88,514,100	33,326,100	37,044,000			165,079,800	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		2,891,700	9,463,500	3,998,700	2,646,000			18,999,900	
4	EPC SERVICES		4,130,100	28,129,500	15,996,600	13,230,000			61,486,200	**1000 Storage and Handling of solid materials**
										2000 Boiler island and flue gas treating
										3000 Power Island
										4000 Utilities&Offsites
A	**Installed costs** (contingency excluded)		**41,303,700**	**316,033,200**	**133,302,600**	**88,200,000**	**0**	**0**	**578,839,500**	**5000 CO_2 capture plant**
										6000 CO_2 Compression&Drying
B	Contingency	%	7	7	5	7	7	7	6.5	
		Euro	2,891,259	22,122,324	6,665,130	6,174,000	0	0	37,852,713	
C	Fees (2% of A)		826,074	6,320,664	2,666,052	1,764,000	0	0	11,576,790	
D	Land Purchases; surveys (5% of A)		2,065,185	15,801,660	6,665,130	4,410,000	0	0	28,941,975	
	TOTAL INVESTMENT COST		**47,086,218**	**360,277,848**	**149,298,912**	**100,548,000**	**0**	**0**	**657,210,978**	

TABLE E.3.2 - ESTIMATE SUMMARY

CASE 1B

Client	IEA GHG
Project	Biomass fired Power Plants
Date:	Nov 2009 REV. 2

FIGURE IN EURO

POS	DESCRIPTION		UNIT 1000 €	2000 €	3000 €	4000 €	5000 €	6000 €	TOTAL €
1	DIRECT MATERIALS		28,086,300	190,183,500	73,547,100	43,200,000	59,258,700	17,445,600	411,721,200
2	CONSTRUCTION		6,195,600	88,679,700	30,645,000	45,360,000	32,323,500	7,269,300	210,473,100
3	OTHER COSTS		2,891,700	9,505,800	3,677,400	3,240,000	3,231,900	872,100	23,418,900
4	EPC SERVICES		4,130,100	28,167,300	14,709,600	16,200,000	12,929,400	3,489,300	79,625,700
A	**Installed costs** (contingency excluded)		**41,303,700**	**316,536,300**	**122,579,100**	**108,000,000**	**107,743,500**	**29,076,300**	**725,238,900**
B	Contingency	%	7	7	5	7	7	7	6.7
		Euro	2,891,259	22,157,541	6,128,955	7,560,000	7,542,045	2,035,341	48,315,141
C	Fees (2% of A)		826,074	6,330,726	2,451,582	2,160,000	2,154,870	581,526	14,504,778
D	Land Purchases; surveys (5% of A)		2,065,185	15,826,815	6,128,955	5,400,000	5,387,175	1,453,815	36,261,945
	TOTAL INVESTMENT COST		**47,086,218**	**360,851,382**	**137,288,592**	**123,120,000**	**122,827,590**	**33,146,982**	**824,320,764**

REMARKS

1) ESTIMATE ACCURACY +/- 30%

2) TODAY COSTS (ESCALATION NOT INCLUDED)

1000	**Storage and Handling of solid materials**
2000	**Boiler island and flue gas treating**
3000	**Power Island**
4000	**Utilities&Offsites**
5000	**CO_2 capture plant**
6000	**CO_2 Compression&Drying**

3.2 500 MWe CFB boiler (Cases 2a and 2b)

The following Tables E.3.3/4 show the investment break down and the total figures for each alternative investigated.

TABLE E.3.3 - ESTIMATE SUMMARY

CASE 2A

Client	IEA GHG
Project	Biomass fired Power Plants
Date:	Nov 2009 REV. 2

FIGURE IN EURO

POS	DESCRIPTION		UNIT 1000 €	2000 €	3000 €	4000 €	5000 €	6000 €	TOTAL €	REMARKS
1	DIRECT MATERIALS		28,179,000	223,331,400	80,698,500	37,800,000			370,008,900	1) ESTIMATE ACCURACY +/- 30%
2	CONSTRUCTION		6,216,300	79,497,000	33,624,900	39,690,000			159,028,200	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		2,900,700	16,807,500	4,034,700	2,835,000			26,577,900	
4	EPC SERVICES		4,143,600	32,705,100	16,139,700	14,175,000			67,163,400	**1000 Storage and Handling of solid materials**
										2000 Boiler island and flue gas treating
										3000 Power Island
										4000 Utilities&Offsites
A	**Installed costs** (contingency excluded)		**41,439,600**	**352,341,000**	**134,497,800**	**94,500,000**	**0**	**0**	**622,778,400**	**5000 CO_2 capture plant**
										6000 CO_2 Compression&Drying
B	Contingency	%	7	7	5	7	7	7	6.6	
		Euro	2,900,772	24,663,870	6,724,890	6,615,000	0	0	40,904,532	
C	Fees (2% of A)		828,792	7,046,820	2,689,956	1,890,000	0	0	12,455,568	
D	Land Purchases; surveys (5% of A)		2,071,980	17,617,050	6,724,890	4,725,000	0	0	31,138,920	
	TOTAL INVESTMENT COST		**47,241,144**	**401,668,740**	**150,637,536**	**107,730,000**	**0**	**0**	**707,277,420**	

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TABLE E.3.4 - ESTIMATE SUMMARY

CASE 2B

Client	**IEA GHG**
Project	**Biomass fired Power Plants**
Date:	**Nov 2009 REV. 2**

FIGURE IN EURO

POS	DESCRIPTION		UNIT 1000 €	2000 €	3000 €	4000 €	5000 €	6000 €	TOTAL €
1	DIRECT MATERIALS		28,076,850	238,067,100	73,510,200	50,400,000	59,469,300	17,424,900	466,948,350
2	CONSTRUCTION		6,216,300	87,072,300	30,629,700	52,920,000	32,437,800	7,260,300	216,536,400
3	OTHER COSTS		2,900,700	18,225,900	3,675,600	3,780,000	3,243,600	871,200	32,697,000
4	EPC SERVICES		4,143,600	37,346,400	14,702,400	18,900,000	12,975,300	3,484,800	91,552,500
A	**Installed costs** (contingency excluded)		**41,337,450**	**380,711,700**	**122,517,900**	**126,000,000**	**108,126,000**	**29,041,200**	**807,734,250**
B	Contingency	%	7	7	5	7	7	7	6.7
		Euro	2,893,622	26,649,819	6,125,895	8,820,000	7,568,820	2,032,884	54,091,040
C	Fees (2% of A)		826,749	7,614,234	2,450,358	2,520,000	2,162,520	580,824	16,154,685
D	Land Purchases; surveys (5% of A)		2,066,873	19,035,585	6,125,895	6,300,000	5,406,300	1,452,060	40,386,713
	TOTAL INVESTMENT COST		**47,124,693**	**434,011,338**	**137,220,048**	**143,640,000**	**123,263,640**	**33,106,968**	**918,366,687**

REMARKS

1) ESTIMATE ACCURACY +/- 30%

2) TODAY COSTS (ESCALATION NOT INCLUDED)

1000	**Storage and Handling of solid materials**
2000	**Boiler island and flue gas treating**
3000	**Power Island**
4000	**Utilities&Offsites**
5000	**CO_2 capture plant**
6000	**CO_2 Compression&Drying**

3.3 250 MWe CFB boiler (Cases 3a and b)

The following Tables E.3.5/6 show the investment break down and the total figures for each alternative investigated.

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TABLE E.3.5 - ESTIMATE SUMMARY

CASE 3A

Client	IEA GHG
Project	Biomass fired Power Plants
Date:	Nov 2009 REV. 2

FIGURE IN EURO

POS	DESCRIPTION		UNIT 1000 €	2000 €	3000 €	4000 €	5000 €	6000 €	TOTAL €
1	DIRECT MATERIALS		29,209,500	118,201,500	32,552,100	19,800,000			199,763,100
2	CONSTRUCTION		6,443,100	36,194,400	13,563,900	20,790,000			76,991,400
3	OTHER COSTS		3,006,900	8,297,100	1,627,200	1,485,000			14,416,200
4	EPC SERVICES		4,295,700	16,371,000	6,510,600	7,425,000			34,602,300
A	**Installed costs** (contingency excluded)		**42,955,200**	**179,064,000**	**54,253,800**	**49,500,000**	**0**	**0**	**325,773,000**
B	Contingency	%	7	7	5	7	7	7	6.7
		Euro	3,006,864	12,534,480	2,712,690	3,465,000	0	0	21,719,034
C	Fees (2% of A)		859,104	3,581,280	1,085,076	990,000	0	0	6,515,460
D	Land Purchases; surveys (5% of A)		2,147,760	8,953,200	2,712,690	2,475,000	0	0	16,288,650
	TOTAL INVESTMENT COST		**48,968,928**	**204,132,960**	**60,764,256**	**56,430,000**	**0**	**0**	**370,296,144**

REMARKS

1) ESTIMATE ACCURACY +/- 30%

2) TODAY COSTS (ESCALATION NOT INCLUDED)

1000	**Storage and Handling of solid materials**
2000	**Boiler island and flue gas treating**
3000	**Power Island**
4000	**Utilities&Offsites**
5000	**CO_2 capture plant**
6000	**CO_2 Compression&Drying**

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TABLE E.3.6 - ESTIMATE SUMMARY

CASE 3B

Client IEA GHG
Project Biomass fired Power Plants
Date: Nov 2009 REV. 2

FIGURE IN EURO

POS	DESCRIPTION		UNIT 1000 €	2000 €	3000 €	4000 €	5000 €	6000 €	TOTAL €	REMARKS
1	DIRECT MATERIALS		29,234,700	118,633,500	28,095,300	28,800,000	49,615,200	14,742,000	269,120,700	1) ESTIMATE ACCURACY +/- 30%
2	CONSTRUCTION		6,443,100	36,702,900	11,706,300	30,240,000	27,063,000	6,142,500	118,297,800	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		3,006,900	8,351,100	1,404,900	2,160,000	2,706,300	737,100	18,366,300	
4	EPC SERVICES		4,295,700	16,457,400	5,618,700	10,800,000	10,825,200	2,948,400	50,945,400	**1000 Storage and Handling of solid materials**
										2000 Boiler island and flue gas treating
										3000 Power Island
										4000 Utilities&Offsites
A	**Installed costs** (contingency excluded)		**42,980,400**	**180,144,900**	**46,825,200**	**72,000,000**	**90,209,700**	**24,570,000**	**456,730,200**	**5000 CO2 capture plant**
										6000 CO2 Compression&Drying
B	Contingency	%	7	7	5	7	7	7	6.8	
		Euro	3,008,628	12,610,143	2,341,260	5,040,000	6,314,679	1,719,900	31,034,610	
C	Fees (2% of A)		859,608	3,602,898	936,504	1,440,000	1,804,194	491,400	9,134,604	
D	Land Purchases; surveys (5% of A)		2,149,020	9,007,245	2,341,260	3,600,000	4,510,485	1,228,500	22,836,510	
	TOTAL INVESTMENT COST		**48,997,656**	**205,365,186**	**52,444,224**	**82,080,000**	**102,839,058**	**28,009,800**	**519,735,924**	

3.4 75 MWe BFB boiler (Cases 4a and 4b)

The following Tables E.3.7/8 show the investment break down and the total figures for each alternative investigated.

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TABLE E.3.7 - ESTIMATE SUMMARY

CASE 4A

Client IEA GHG
Project Biomass fired Power Plants
Date: Nov 2009 REV. 2

FIGURE IN EURO

POS	DESCRIPTION		UNIT 1000 €	2000 €	3000 €	4000 €	5000 €	6000 €	TOTAL €	REMARKS
1	DIRECT MATERIALS		13,446,000	60,090,300	16,229,700	10,080,000			99,846,000	1) ESTIMATE ACCURACY +/- 30%
2	CONSTRUCTION		2,966,400	18,394,200	6,762,375	10,584,000			38,706,975	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		1,384,200	4,239,900	811,485	756,000			7,191,585	
4	EPC SERVICES		1,977,300	8,372,700	3,245,940	3,780,000			17,375,940	**1000 Storage and Handling of solid materials**
										2000 Boiler island and flue gas treating
										3000 Power Island
										4000 Utilities&Offsites
A	**Installed costs** (contingency excluded)		**19,773,900**	**91,097,100**	**27,049,500**	**25,200,000**	**0**	**0**	**163,120,500**	**5000 CO2 capture plant**
										6000 CO2 Compression&Drying
B	Contingency	%	7	7	5	7	7	7	6.7	
		Euro	1,384,173	6,376,797	1,352,475	1,764,000	0	0	10,877,445	
C	Fees (2% of A)		395,478	1,821,942	540,990	504,000	0	0	3,262,410	
D	Land Purchases; surveys (5% of A)		988,695	4,554,855	1,352,475	1,260,000	0	0	8,156,025	
	TOTAL INVESTMENT COST		**22,542,246**	**103,850,694**	**30,295,440**	**28,728,000**	**0**	**0**	**185,416,380**	

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TABLE E.3.8 - ESTIMATE SUMMARY

CASE 4B

Client IEA GHG
Project Biomass fired Power Plants
Date: Nov 2009 **REV. 2**

FIGURE IN EURO

POS	DESCRIPTION		UNIT 1000 €	2000 €	3000 €	4000 €	5000 €	6000 €	TOTAL €	REMARKS
1	DIRECT MATERIALS		13,457,700	60,332,400	14,548,500	13,680,000	23,702,400	7,299,900	133,020,900	1) ESTIMATE ACCURACY +/- 30%
2	CONSTRUCTION		2,966,400	18,678,600	6,062,400	14,364,000	12,928,500	3,042,000	58,041,900	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		1,384,200	4,269,600	727,200	1,026,000	1,292,400	365,400	9,064,800	
4	EPC SERVICES		1,977,300	8,421,300	2,909,700	5,130,000	5,171,400	1,459,800	25,069,500	**1000** **Storage and Handling of solid materials**
										2000 **Boiler island and flue gas treating**
										3000 **Power Island**
										4000 **Utilities&Offsites**
A	**Installed costs** (contingency excluded)		**19,785,600**	**91,701,900**	**24,247,800**	**34,200,000**	**43,094,700**	**12,167,100**	**225,197,100**	**5000** **CO_2 capture plant**
										6000 **CO_2 Compression&Drying**
B	Contingency	%	7	7	5	7	7	7	6.8	
		Euro	1,384,992	6,419,133	1,212,390	2,394,000	3,016,629	851,697	15,278,841	
C	Fees (2% of A)		395,712	1,834,038	484,956	684,000	861,894	243,342	4,503,942	
D	Land Purchases; surveys (5% of A)		989,280	4,585,095	1,212,390	1,710,000	2,154,735	608,355	11,259,855	
	TOTAL INVESTMENT COST		**22,555,584**	**104,540,166**	**27,157,536**	**38,988,000**	**49,127,958**	**13,870,494**	**256,239,738**	

4.0 Operation and Maintenance Cost of the Alternatives

Operating and Maintenance (O&M) costs include:

- Feedstock
- Chemicals
- Catalysts
- Solvents
- Raw Water make-up
- Direct Operating labour
- Maintenance
- Overhead Charges

O&M costs are generally allocated as variable and fixed costs.
Variable operating costs are directly proportional to the amount of kilowatt-hours produced and are referred as incremental costs. They may be expressed in €/kWh.
Fixed operating costs are essentially independent of the amount of kilowatt-hours produced. They may be expressed in €/h or €/year.
However, accurately distinguishing the variable and fixed operating costs is not always simple. Certain cost items may have both, variable and fixed, components; for instance the planned maintenance and inspection of the gas turbine, that are known to occur based on number of running hours, should be allocated as variable component of maintenance cost.

4.1 Variable Costs

The variable costs of the different alternatives (Case 1 to 4) are summarized in the attached Tables E.4.1/2.

The consumption of the various items and the corresponding costs are yearly, based on the expected equivalent availability of 7,884 equivalent hours of operation (90%), in one year, for the cases without CO_2 capture, while 7,710 equivalent hours of operation (88%), in one year, for the cases with CO_2 capture.

The chemical consumption due to CO_2 capture plant is mainly constituted by soda ash and activated carbon. These items have a different impact on the total cost due to chemicals in the coal and biomass co-fired cases compared to the fully biomass fired cases.
In the first group the impact is around 15% of the total cost of chemicals and in the second group is around 50%. This is related to the limestone consumption that raises the total cost of chemicals for the coal and biomass co-fired cases. In any case, the cost of chemicals related to the CO_2 capture plant is proportional to the CO_2 removed.

4.1.1 Coal and Biomass co-fired alternatives

The attached Table E.4.1 shows the Variable Costs for Case 1a, 1b, 2a and 2b.

		TABLE E.4.1 - YEARLY VARIABLE COSTS										**Client** IEA GHG **Project** Biomass fired Power Plants **Date** Nov 2009 REV. 2		
		Case 1A			**Case 1B**			**Case 2A**			**Case 2B**		
		Yearly Operating hours =		7884	Yearly Operating hours =		7710	Yearly Operating hours =		7884	Yearly Operating hours =		7710
Consumables	**Unit Cost** Euro/t	**Consumption** Hourly kg/h	 Yearly t/y	**Oper. Costs (yearly basis)**	**Consumption** Hourly kg/h	 Yearly t/y	**Oper. Costs (yearly basis)**	**Consumption** Hourly kg/h	 Yearly t/y	**Oper. Costs (yearly basis)**	**Consumption** Hourly kg/h	 Yearly t/y	**Oper. Costs (yearly basis)**
Feedstock													
Coal	75.0	145,000	1,143,180	85,738,500	145,000	1,117,950	83,846,250	144,756	1,141,256	85,594,223	144,756	1,116,069	83,705,157
Biomass (dry basis)	144.0	28,495	224,655	32,350,260	28,495	219,696	31,636,289	28,499	224,689	32,355,255	28,499	219,730	31,641,174
Auxiliary feedstock													
Make-up water	0.1	66,600	525,074	52,507	66,600	513,486	51,349	5,500	43,362	4,336	66,600	513,486	51,349
Solvents													
MEA	2000.0	0	0	0	875	6,747	13,494,889	0	0	0	880	6,784	13,568,861
Catalyst				1,887,144			1,845,494			1,883,968			1,539,418
Chemicals				1,803,947			2,158,125			2,851,971			1,848,018
Waste Disposal	40.0	18,400	145,066	5,802,624	18,400	141,864	5,674,560	30,096	237,277	9,491,075	24,678	190,267	7,610,695
TOTAL YEARLY OPERATING COSTS, Euro/year				**127,634,981**			**138,706,956**			**132,180,828**			**139,964,672**

4.1.2 Fully biomass fired alternatives

The attached Table E.4.2 shows the Variable Costs for alternatives Case 3a, 3b, 4a and 4b.

FOSTER WHEELER		TABLE E.4.2 - YEARLY VARIABLE COSTS									Client: IEA GHG Project: Biomass fired Power Plants Date: Nov 2009 REV. 2		
		Case 3A			Case 3B			Case 4A			Case 4B		
		Yearly Operating hours = 7884			Yearly Operating hours = 7710			Yearly Operating hours = 7884			Yearly Operating hours = 7710		
Consumables	**Unit Cost** Euro/t	**Consumption** Hourly kg/h	Yearly t/y	**Oper. Costs (yearly basis)**	**Consumption** Hourly kg/h	Yearly t/y	**Oper. Costs (yearly basis)**	**Consumption** Hourly kg/h	Yearly t/y	**Oper. Costs (yearly basis)**	**Consumption** Hourly kg/h	Yearly t/y	**Oper. Costs (yearly basis)**
Feedstock													
Coal	75.0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass (dry basis)	144.0	161,298	1,271,673	183,120,974	161,298	1,243,608	179,079,492	51,930	409,416	58,955,921	51,930	400,380	57,654,763
Auxiliary feedstock													
Make-up water	0.1	11,000	86,724	8,672	11,000	84,810	8,481	5,500	43,362	4,336	4,500	34,695	3,470
Solvents													
MEA	2000.0	0	0	0	666	5,134	10,268,433	0	0	0	214	1,648	3,295,508
Catalyst				0			0			0			0
Chemicals				72,549			468,543			25,098			156,258
Waste Disposal	40.0	3,463	27,304	1,092,155	3,989	30,754	1,230,146	1,109	8,742	349,671	1,309	10,091	403,634
TOTAL YEARLY OPERATING COSTS, Euro/year				**184,294,351**			**191,055,094**			**59,335,027**			**61,513,633**

4.2 Fixed Costs

The fixed costs of the different Power Plants operation include the following items:
- Direct labour.
- Administrative and general overhead.
- Maintenance.

For maintenance, variable element of cost, have been treated as part of fixed costs, on the assumption that Complex operates at the design capacity and with the expected design service factor.

4.2.1 Direct Labour

The yearly cost of the direct labour is calculated assuming, for each individual, an average cost equal to 60,000 Euro/year. The number of personnel engaged is shown hereinafter.

For all the cases, the number of personnel engaged is considered to be constant.
It has been assumed that the number of personnel engaged for the plant operation is constant among all the cases. On the other hand the personnel engaged for the plant maintenance might be slightly different and therefore the only impact of plant size has been considered on maintenance cost, evaluated as percent of the investment cost of the plant as reported in para. 4.2.3.
No impact of the CO_2 capture system on the personnel has been considered, because responsibilities of this unit can be handled by operators dedicated to the "Power Island & Utilities", without requiring new resources.

The Owner's personnel engaged in the Operation and Maintenance for all the alternatives is shown in Table E.4.3. The Complex has been divided into 2 areas of operation: Boiler Island, including flue gas processing and CO_2 capture plant (when present), and Power Island with common Utilities. The same division will be reflected in the design of the centralized Control Room, which will have, correspondingly, 2 main DCS control groups, each one equipped with a number of control stations, from where the operation of the plants of each of the two areas will be controlled.

The Area Responsible and his Assistant will supervise each area of operation; both are daily positions. The Shift Superintendent and the Electrical Assistant are common for the 2 areas; both are shift positions. The rest of the Operation staff is structured around the standard positions: shift supervisors, control room operators and field operators.

The maintenance personnel are based on large use of external subcontractors for all medium-major type of maintenance work. Maintenance costs described at para. 4.2.3 take into account the service outsourcing. Plant Maintenance personnel, like the instrument specialists, perform routine maintenance and resolve emergency problems.

Table E.4.3 – Personnel.

OPERATION	Boiler Island	Power Island & Utilities	TOTAL	NOTES
Area Responsible	1	1	2	daily position
Assistant Area Responsible	1	1	2	daily position
Shift Superintendent	5		5	1 shift position
Electrical Assistant	5		5	1 shift position
Shift Supervisor	5	5	10	2 shift position
Control Room Operator	10	10	20	4 shift position
Field Operator	15	25	40	8 shift position
Subtotal			**84**	
MAINTENANCE				
Mechanical group	6		6	daily position
Instrument group	6		6	daily position
Electrical group	5		5	daily position
Subtotal			**17**	
LABORATORY				
Superintendent + Analysts	4		**4**	daily position
TOTAL			**105**	

4.2.2 Administrative and General Overheads

All other Company services not directly involved in the operation of the Complex fall in this category, such as:

- Management.
- Administration.
- Personnel services.
- Technical services.
- Clerical staff.

These services vary widely from company to company and are also dependent on the type and complexity of the operation.
Based on EPRI, Technical Assessment Guide for the Power Industry, an amount equal to 30% of the direct labour cost has been considered.

4.2.3 Maintenance

A precise evaluation of the cost of maintenance would require a breakdown of the costs amongst the numerous components and packages of the Complex. Since these costs are all strongly dependent on the type of equipment selected and statistical maintenance data provided by the selected Supplier, this type of evaluation of the maintenance cost is premature at this stage of the study.

For this reason the annual maintenance cost of the Complex has been estimated, as suggested by EPRI Technical Evaluation Guide, as a percentage of the installed capital cost of the facilities.
In accordance with EPRI recommendations the Complex has been divided into three major sections, applying to each section different percentages of the capital cost of the section to determine the relative cost of maintenance, as shown in the attached tables.

The total yearly maintenance cost of the Complex is assumed subcontracted to external firms under the supervision of the maintenance staff of the Owner, included in the fixed cost as direct labour.
The overall cost of maintenance could be statistically split as follows:

- Maintenance materials: 60% of total maintenance cost;
- Maintenance labour: 40% of total maintenance cost.

Attached Tables E.4.4 and 5 summarize overall maintenance costs for all the alternatives.

FOSTER WHEELER	**TABLE E.4.4 - Maintenance Costs**	**Client:**	**IEA GHG**
		Project:	**Biomass fired Power Plants**
		Date:	**Nov 2009 REV. 2**

		Case 1A		Case 1B		Case 2A		Case 2B	
Complex section	**Maintenance** %	**Capital Cost** Euro x 10^3 (1)	**Maintenance** 10^3 Euro/Year	**Capital Cost** Euro x 10^3 (1)	**Maintenance** 10^3 Euro/Year	**Capital Cost** Euro x 10^3 (1)	**Maintenance** 10^3 Euro/Year	Capital Cost Euro x 10^3 (1)	Maintenance 10^3 Euro/Year
FUEL HANDLING, MILLING, BOILER ISLAND, POWER ISLAND	4	490,640	19,630	480,419	19,220	528,278	21,130	544,567	21,780
CO_2 CAPTURE PLANT, CO_2 COMPRESS. AND DRYING	2.5	0	0	136,820	3,420	0	0	137,167	3,430
Common facilities (Utilities, Offsite, etc.)	1.7	88,200	1,499	108,000	1,836	94,500	1,607	126,000	2,142
TOTAL		578,840	21,129	725,239	24,476	622,778	22,737	807,734	27,352
		Maint. % =	3.7	Maint. % =	3.4	Maint. % =	3.7	Maint. % =	3.4

	TABLE E.4.5 - Maintenance Costs								
		Client: IEA GHG							
		Project: Biomass fired Power Plants							
		Date: Nov 2009 REV. 2							
		Case 3A		Case 3B		Case 4A		Case 4B	
Complex section	**Maintenance** %	**Capital Cost** Euro x 10^3 (1)	**Maintenance** 10^3 Euro/Year	**Capital Cost** Euro x 10^3 (1)	**Maintenance** 10^3 Euro/Year	**Capital Cost** Euro x 10^3 (1)	**Maintenance** 10^3 Euro/Year	**Capital Cost** Euro x 10^3 (1)	**Maintenance** 10^3 Euro/Year
FUEL HANDLING, MILLING, BOILER ISLAND, POWER ISLAND	4	276,273	11,050	269,951	10,800	137,921	5,520	135,735	5,430
CO2 CAPTURE PLANT, CO2 COMPRESS. AND DRYING	2.5	0	0	114,780	2,870	0	0	55,262	1,380
Common facilities (Utilities, Offsite, etc.)	1.7	49,500	842	72,000	1,224	25,200	428	34,200	581
TOTAL		325,773	11,892	456,730	14,894	163,121	5,948	225,197	7,391
		Maint. % =	3.7	Maint. % =	3.3	Maint. % =	3.6	Maint. % =	3.3

4.3 Summary

The following tables summarize the total Operating and Maintenance Costs on yearly basis for all the alternatives.

Table E.4.6 – Coal and Biomass co-fired alternatives – Total O&M Costs

		Case 1A Euro/year	Case 1B Euro/year	Case 2A Euro/year	Case 2B Euro/year
Fixed Costs	direct labour	6,300,000	6,300,000	6,300,000	6,300,000
	adm./gen overheads	1,890,000	1,890,000	1,890,000	1,890,000
	maintenance	21,129,000	24,476,000	22,737,000	27,352,000
	Subtotal	29,319,000	32,666,000	30,927,000	35,542,000
Variable Costs		127,635,000	138,707,000	132,181,000	139,965,000
TOTAL O&M COSTS		156,954,000	171,373,000	163,108,000	175,507,000

Table E.4.7 – Fully biomass fired alternatives – Total O&M Costs

		Case 3A Euro/year	Case 3B Euro/year	Case 4A Euro/year	Case 4B Euro/year
Fixed Costs	direct labour	6,300,000	6,300,000	6,300,000	6,300,000
	adm./gen overheads	1,890,000	1,890,000	1,890,000	1,890,000
	maintenance	11,892,000	14,894,000	5,948,000	7,391,000
	Subtotal	20,082,000	23,084,000	14,138,000	15,581,000
Variable Costs		184,294,000	191,055,000	59,335,000	61,514,000
TOTAL O&M COSTS		204,376,000	214,139,000	73,473,000	77,095,000

5.0 Evaluation of the Electric Power Cost of the Alternatives

5.1 Electric Power Cost

The following Tables summarize the economic analyses performed on each alternative in order to evaluate the electric power production cost, based on the following main assumptions:

- 7,884 equivalent hours of operation (90%) in normal conditions at 100% capacity for the cases without CO_2 capture;
- 7,710 equivalent hours of operation (88%) in normal conditions at 100% capacity for the cases with CO_2 capture;
- Total investment cost as evaluated in para.3.0 of this Section;
- O&M costs as evaluated in para 4.0;
- 10% discount rate on the investment cost over 25 operating years;
- No selling price is attributed to the CO_2 in the base case; different scenarios with different evaluation of potential benefits related to CO_2 capture are analysed;
- Cost of coal delivered to site is 75 €/t;
- Cost of biomass delivered to site is 144 €/t (on an absolute dry bases).
- Other financial parameters as per Project Design Basis, Section B.

In order to evaluate the benefit of the CO_2 removal, the following scenarios have been evaluated:

- ❑ Scenario 1: Base case, neither selling price nor any benefit is attributed to CO_2;
- ❑ Scenario 2: benefits of the green certificates. It has been considered an additional benefit on the electric energy selling price added to the quote of electricity produced by the biomass (based on duty fired in the boiler); this benefit is applied to all the cases, depending on the percentage of duty fired on biomass;
- ❑ Scenario 3: ETS market. It has been considered that no free CO_2 allowances have been assigned to any plant. Moreover, the CO_2 emitted to atmosphere from the firing of biomass has been considered as neutral.

  The ETS is applied as a cost to the CO_2 emissions derived from coal firing and therefore as a penalty on the plant economics. For coal and biomass co-fired cases with CO_2 capture, if the overall CO_2 captured on mass bases is higher than the CO_2 emitted from coal firing, the net CO_2 emitted results negative and the ETS is applied as a revenue to the plant economics on the negative flowrate of CO_2 emitted. For the fully biomass fired cases, all the CO_2 captured results as negative emission and the ETS is applied positively on all the CO_2 captured, impacting on the economics of the plants as a revenue.

- Scenario 4: benefit of green certificates and ETS market. It has been considered the combination of the above scenarios.

The figures considered for the Green Certificates and ETS are the following:
- Green certificates: 50 €/MWh;
- ETS: 14 €/t CO_2 captured

The Green Certificates and ETS values have been considered constant all along the life of the project.

Table E.5.1 summarizes the electric power cost for all the cases and all the above-mentioned scenarios.

In order to evaluate the impact of the most important parameters on the economics of the plants, the following sensitivity analyses have been performed:

- Biomass cost: 50 – 100 – 144 €/t (dry basis);
- Coal cost: 60 – 75 – 90 €/t;
- Green certificates: +/- 25% (40 and 65 €/MWh);
- ETS: +100% / +200% (30 and 45 €/t CO_2 captured)

Sensitivity to coal and biomass costs have been performed without considering any incentive (neither green certificates nor ETS) and with the maximum incentive (both Green certificates, 50 €/MWh, and ETS, 14 €/t CO_2 captured).
Sensitivity to incentives (Green Certificates and ETS) have been performed by considering the single effect of each incentive and the combined effects of the two incentives.

Sensitivities are shown in the figures E.6.1 to E.6.8 attached at the end of this section.

In the attached table is also listed the cost of CO_2 removal, calculated as follows:

$$\frac{\Delta \text{ Electric Power Cost}}{\Delta \text{ Specific } CO_2 \text{ emission}} [=] \frac{\text{Euro}}{\text{t of } CO_2 \text{ captured}}$$

Where:
Δ Electric Power Cost = Electric Power Cost with CO_2 capture - Electric Power Cost without CO_2 capture. The unit of measurement is Euro/kWh.
Δ Specific CO_2 emission = Ratio of (CO_2 emission/unit of power production) without capture- ratio of (CO_2 emission/unit of power production) with capture. The unit of measurement is tonne CO_2/kWh.

The cost of CO_2 removal is calculated for each case and scenario with reference to the same scenario of the relevant case without CO_2 capture.

The main conclusion that can be drawn from the previous tables and figures are:

- For the 500 MWe co-fired cases, the cost of electricity for cases without CO_2 capture falls in a very narrow range of values. Cost of electricity for the PC case is slightly lower than the one of CFB (circa 5%). This result is a consequence of the lower investment cost of the PC boiler which compensates the small advantage of CFB in efficiency.

- The fully biomass fired plants without CO_2 capture show very high cost of electricity. With respect to 500 MWe cases, the COE in 250 MWe is about twice and in 75 MWe about three times higher. They are strongly penalised by the very high cost of biomass that is approximately three times more expensive than the coal on an energy basis. The 250 MWe becomes economically attractive only with incentives that take into account the green fuel and related to the CO_2 emissions.

- In absence of incentives (scenario 1) the fully biomass fired cases without CO_2 capture can be considered competitive with co-fired alternatives only in case the biomass cost drops down to the same cost of coal on energy bases, 50 €/t (dry basis).

- In presence of full incentives market (scenario 4) the 250 MWe fully biomass fired case becomes better than co-fired alternatives in case of a biomass cost lower than about 140 €/t dry basis corresponding to almost the actual biomass cost considered in present study. The 75 MWe case becomes competitive only in case the biomass cost drops down to around 60 €/t (dry basis).

- For the 500 MWe co-fired cases, the COE difference for cases with CO_2 capture is higher than the relevant cases without CO_2 capture: COE for the PC case is lower than the one of CFB by circa 7%. This result is a consequence of the lower investment cost of the PC boiler in addition to the small advantage in efficiency.

- In absence of incentives (scenario 1) the fully biomass fired plants with CO_2 capture result further more penalised with respect to the 500 MWe cases. The COE in 250 MWe is more than twice and in 75 MWe more than three times higher than in 500 MWe cases. In addition to the high cost of biomass, they are also affected by the higher auxiliary consumptions related to the introduction of the CO_2 capture.

- The 500 MWe cases are much less sensible than the fully biomass fired cases to the green certificates as they apply only to the amount of electricity generated from biomass.

- The wide difference in Cost of electricity between co-fired cases and biomass cases is significantly reduced by the incentives relevant to the use of green fuel although the COE in the co-fired cases still results lower than in the fully biomass fired cases.

- In absence of incentives (scenario 1) the fully biomass fired cases with CO_2 capture cannot be considered competitive with co-fired alternatives also in case the biomass cost drops down to the same cost of coal on energy bases, 50 €/t (dry basis).

- In presence of full incentives market (scenario 4) the 250 MWe fully biomass fired case with CO_2 capture becomes better than co-fired alternatives only in case the biomass cost drops down to about 85 €/t (dry basis). The 75 MWe case also in case biomass cost drops down to the same cost of coal on energy bases, 50 €/t (dry basis), cannot be considered competitive with co-fired alternatives.

- For coal and biomass co-fired cases, the cost of CO_2 capture become negligible only in case the ETS value rises up to about 45-50 €/t of CO_2 independently from the green certificates. Only in this case, in fact, the COE for cases without and with CO_2 capture results comparable.

- For the 250 MWe case, the cost of CO_2 capture become negligible only in case the ETS value rises up to about 65 €/t of CO_2 independently from the green certificates. While for the 75 MWe case, this happens only in case the ETS value rises up to about 75 €/t of CO_2.

TABLE E.5.1 - Electric power costs summary

Client	IEA GHG
Project	Biomass fired Power Plants
Date	July 2009 REV. 1

Case		**1a - 500 MWe PC w/o CCS**				**1b - 500 MWe PC with CCS**				**2a - 500 MWe CFB without CCS**				**2b - 500 MWe CFB with CCS**			
Scenario		**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**
Green Certificate	[Euro/MWh]	**0**	**50**	**0**	**50**	**0**	**50**	**0**	**50**	**0**	**50**	**0**	**50**	**0**	**50**	**0**	**50**
ETS	[Euro/t CO2]	**0**	**0**	**14**	**14**	**0**	**0**	**14**	**14**	**0**	**0**	**14**	**14**	**0**	**0**	**14**	**14**
IRR		**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**
Coal Florate	[t/h]	145.0	145.0	145.0	145.0	145.0	145.0	145.0	145.0	144.8	144.8	144.8	144.8	144.8	144.8	144.8	144.8
Coal Fired Duty		90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Biomass Florate (1)	[t/h]	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5	28.5
Biomass Fired Duty		10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%
Net Power Out.	[MW]	518.9	518.9	518.9	518.9	398.9	398.9	398.9	398.9	521.4	521.4	521.4	521.4	390.5	390.5	390.5	390.5
Total Inv. Cost	[MM Euro]	657.2	657.2	657.2	657.2	824.3	824.3	824.3	824.3	707.3	707.3	707.3	707.3	918.4	918.4	918.4	918.4
CO2 Produced	[t/h]	337.1	337.1	337.1	337.1	337.1	337.1	337.1	337.1	338.6	338.6	338.6	338.6	338.6	338.6	338.6	338.6
CO2 Captured	[t/h]	0.0	0.0	0.0	0.0	349.6	349.6	349.6	349.6	0.0	0.0	0.0	0.0	351.1	351.1	351.1	351.1
CO2 Emitted	[t/h]	337.1	337.1	337.1	337.1	-12.5	-12.5	-12.5	-12.5	338.6	338.6	338.6	338.6	-12.5	-12.5	-12.5	-12.5
Revenues / year, Electricity	[MM Euro/y]	249.4	228.9	286.6	266.1	287.6	272.2	286.2	270.8	262.5	241.9	299.9	279.3	304.8	289.7	303.4	288.4
Revenues / year, Green Certif	[MM Euro/y]	0.0	20.5	0.0	20.5	0.0	15.4	0.0	15.4	0.0	20.6	0.0	20.6	0.0	15.1	0.0	15.1
Revenues / year, ETS	[MM Euro/y]	0.0	0.0	-37.2	-37.2	0.0	0.0	1.3	1.3	0.0	0.0	-37.4	-37.4	0.0	0.0	1.3	1.3
Total Revenues / year	[MM Euro/y]	249.4	249.4	249.4	249.4	287.6	287.6	287.6	287.6	262.5	262.5	262.5	262.5	304.8	304.8	304.8	304.8
Electricity Prod Cost	[Euro/kWh]	**0.061**	**0.056**	**0.070**	**0.065**	**0.094**	**0.089**	**0.093**	**0.088**	**0.064**	**0.059**	**0.073**	**0.068**	**0.101**	**0.096**	**0.101**	**0.096**
NPV	[MM Euro]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO_2 Specific Emission	[10^{-3} Kg/kWh]	649.7	649.7	649.7	649.7	-31.3	-31.3	-31.3	-31.3	649.4	649.4	649.4	649.4	-32.0	-32.0	-32.0	-32.0
CO_2 Removal Cost	[Euro/t]	-	-	-	-	**47.8**	**47.8**	**33.8**	**33.8**					**54.9**	**54.9**	**40.9**	**40.9**

Case		**3a - 250 MWe CFB without CCS**				**3b - 250 MWe CFB with CCS**				**4a - 75 MWe BFB without CCS**				**4b - 75 MWe BFB with CCS**			
Scenario		**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**
Green Certificate	[Euro/MWh]	**0**	**50**	**0**	**50**	**0**	**50**	**0**	**50**	**0**	**50**	**0**	**50**	**0**	**50**	**0**	**50**
ETS	[Euro/t CO2]	**0**	**0**	**14**	**14**	**0**	**0**	**14**	**14**	**0**	**0**	**14**	**14**	**0**	**0**	**14**	**14**
IRR		**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**	**10%**
Coal Florate	[t/h]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Coal Fired Duty		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Biomass Florate (1)	[t/h]	161.3	161.3	161.3	161.3	161.3	161.3	161.3	161.3	51.9	51.9	51.9	51.9	51.9	51.9	51.9	51.9
Biomass Fired Duty		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
Net Power Out.	[MW]	273.0	273.0	273.0	273.0	168.9	168.9	168.9	168.9	75.8	75.8	75.8	75.8	48.9	48.9	48.9	48.9
Total Inv. Cost	[MM Euro]	370.3	370.3	370.3	370.3	519.7	519.7	519.7	519.7	185.4	185.4	185.4	185.4	256.2	256.2	256.2	256.2
CO2 Produced	[t/h]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2 Captured	[t/h]	0.0	0.0	0.0	0.0	265.7	265.7	265.7	265.7	0.0	0.0	0.0	0.0	85.8	85.8	85.8	85.8
CO2 Emitted	[t/h]	0.0	0.0	0.0	0.0	-265.7	-265.7	-265.7	-265.7	0.0	0.0	0.0	0.0	-85.8	-85.8	-85.8	-85.8
Revenues / year, Electricity	[MM Euro/y]	257.4	149.8	257.4	149.8	288.3	223.2	259.7	194.6	99.8	69.9	99.8	69.9	113.5	94.6	104.2	85.3
Revenues / year, Green Certif	[MM Euro/y]	0.0	107.6	0.0	107.6	0.0	65.1	0.0	65.1	0.0	29.9	0.0	29.9	0.0	18.9	0.0	18.9
Revenues / year, ETS	[MM Euro/y]	0.0	0.0	0.0	0.0	0.0	0.0	28.7	28.7	0.0	0.0	0.0	0.0	0.0	0.0	9.3	9.3
Total Revenues / year	[MM Euro/y]	257.4	257.4	257.4	257.4	288.3	288.3	288.3	288.3	99.8	99.8	99.8	99.8	113.5	113.5	113.5	113.5
Electricity Prod Cost	[Euro/kWh]	**0.120**	**0.070**	**0.120**	**0.070**	**0.221**	**0.171**	**0.199**	**0.149**	**0.167**	**0.117**	**0.167**	**0.117**	**0.301**	**0.251**	**0.276**	**0.226**
NPV	[MM Euro]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CO_2 Specific Emission	[10^{-3} Kg/kWh]	0.0	0.0	0.0	0.0	-1573.1	-1573.1	-1573.1	-1573.1	0.0	0.0	0.0	0.0	-1754.6	-1754.6	-1754.6	-1754.6
CO_2 Removal Cost	[Euro/t]	-	-	-	-	**64.7**	**64.7**	**50.7**	**50.7**					**76.3**	**76.3**	**62.3**	**62.3**

Note (1): Absolute dry basis

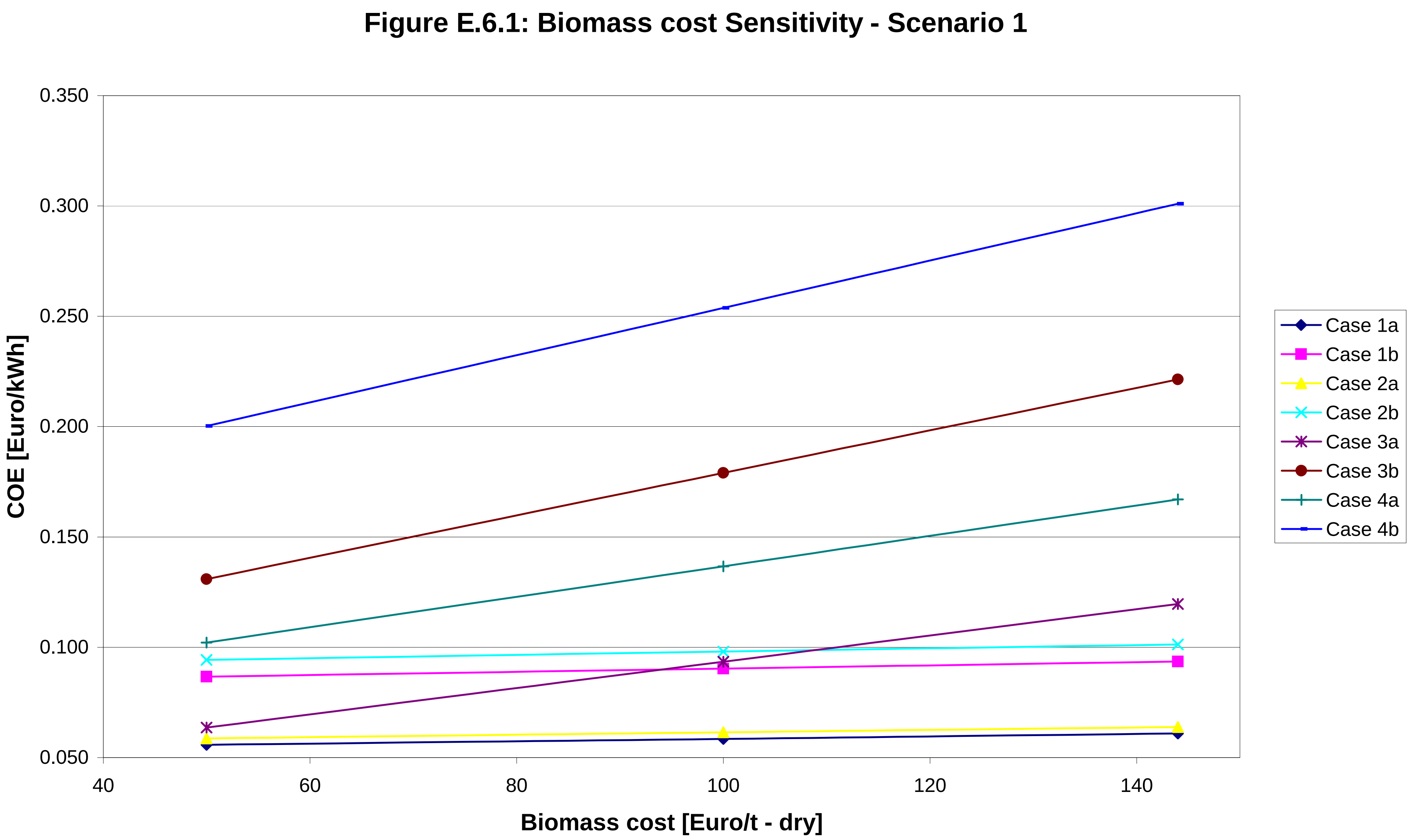


Figure E.6.1: Biomass cost Sensitivity - Scenario 1
COE [Euro/kWh]
0.350
0.300
0.250
0.200
0.150
0.100
0.050
40
60
80
100
120
140
Biomass cost [Euro/t - dry]
Case 1a
Case 1b
Case 2a
Case 2b
Case 3a
Case 3b
Case 4a
Case 4b

Figure E.6.2: Biomass cost Sensitivity - Scenario 4

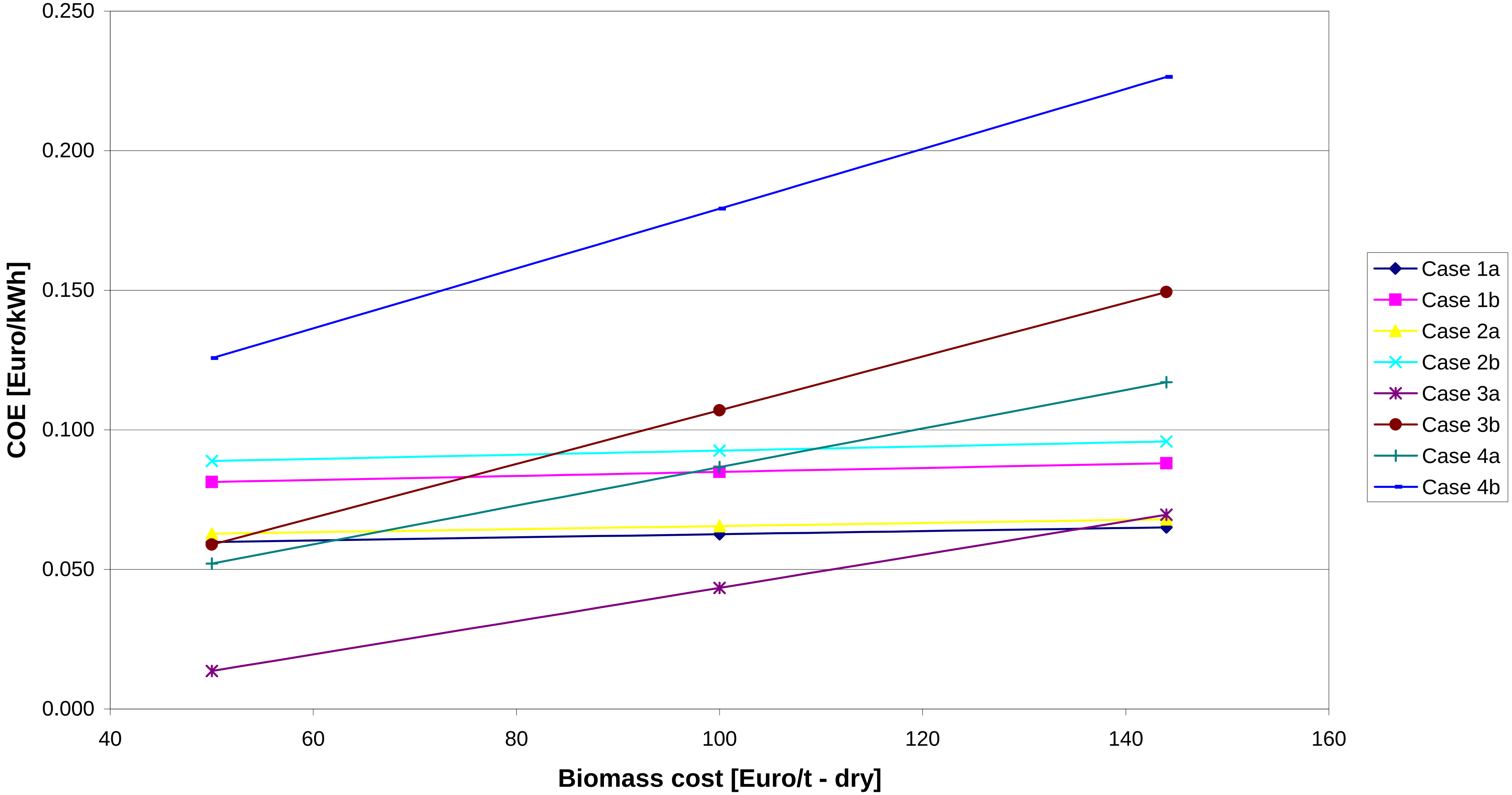
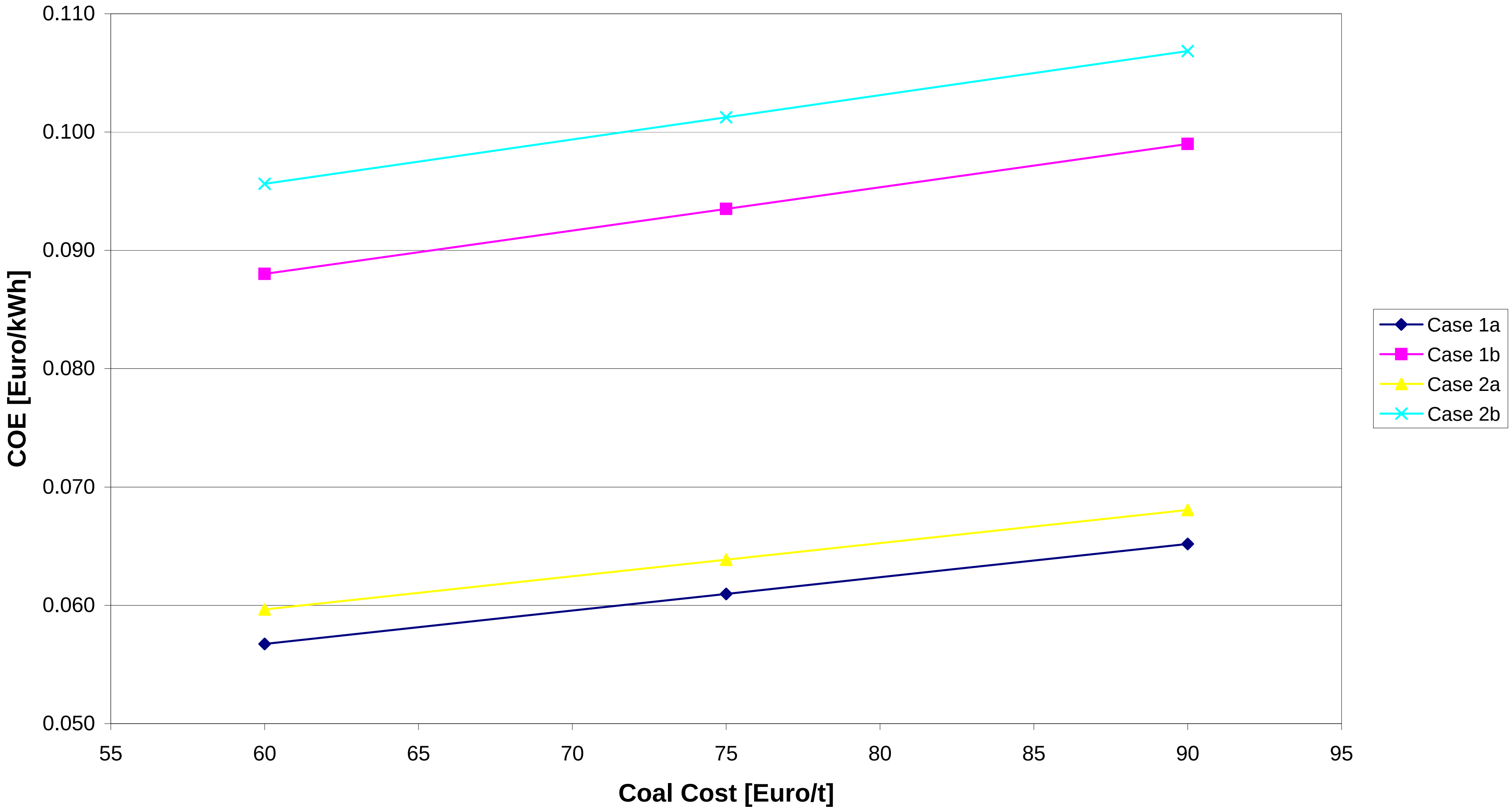


Figure E.6.3: Coal Cost sensitivity - Scenario 1



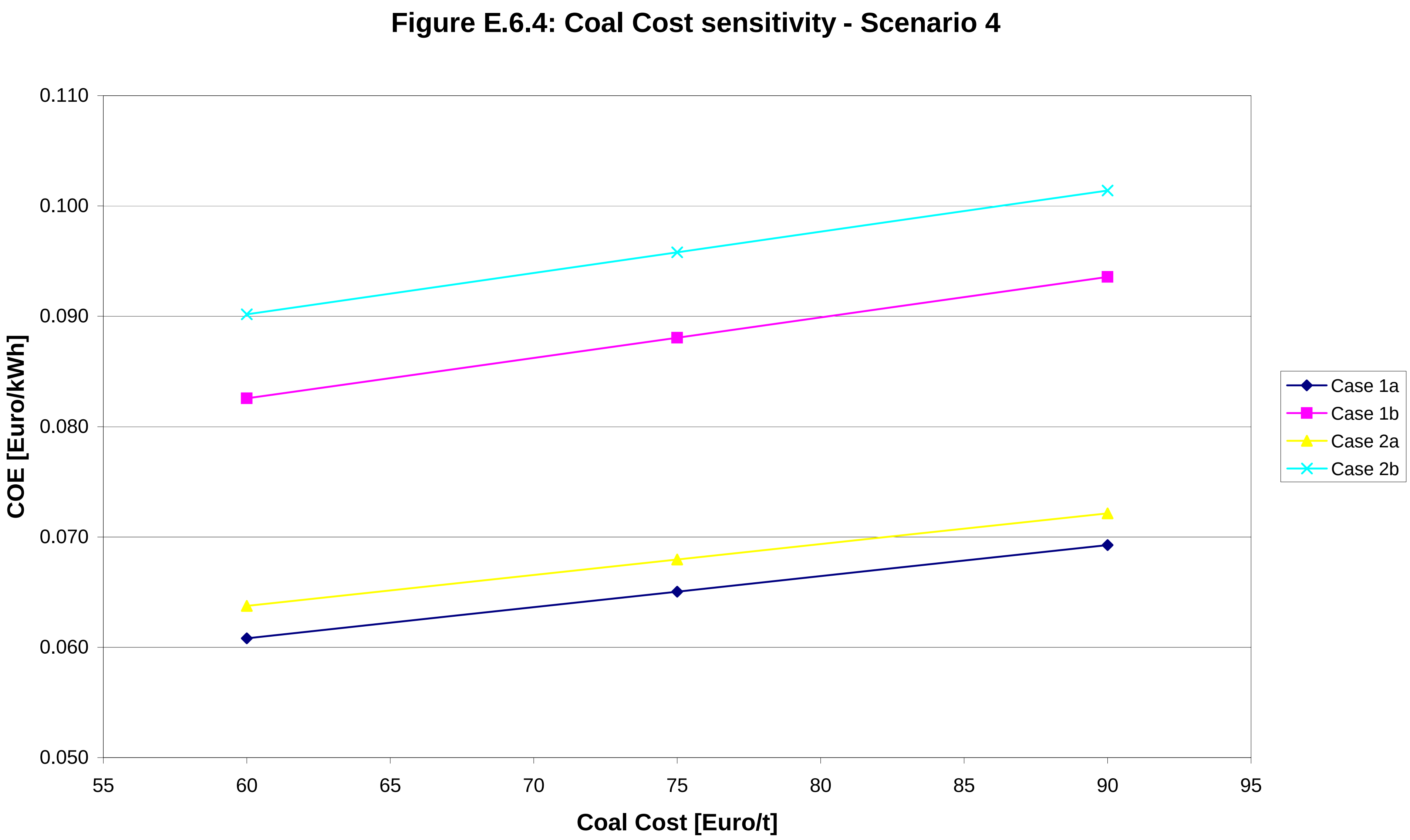


Figure E.6.4: Coal Cost sensitivity - Scenario 4
COE [Euro/kWh]
0.110
0.100
0.090
0.080
0.070
0.060
0.050
55
60
65
70
75
80
85
90
95
Coal Cost [Euro/t]
Case 1a
Case 1b
Case 2a
Case 2b

Figure E.6.5: ETS Sensitivity (Scenario 3, GC = 0 €/MWh)

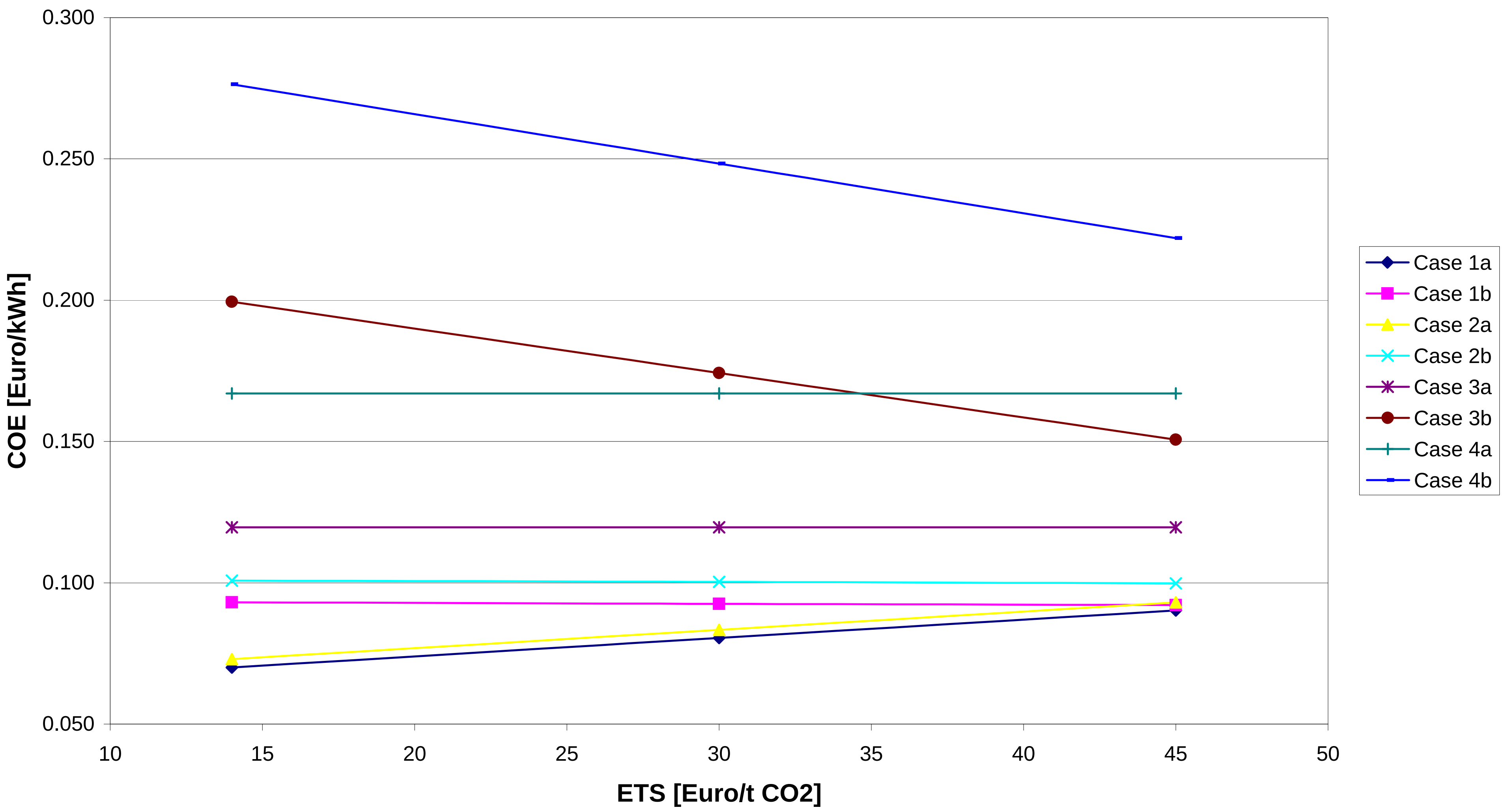


Figure E.6.6: ETS Sensitivity (Scenario 4, GC = 50 €/MWh)

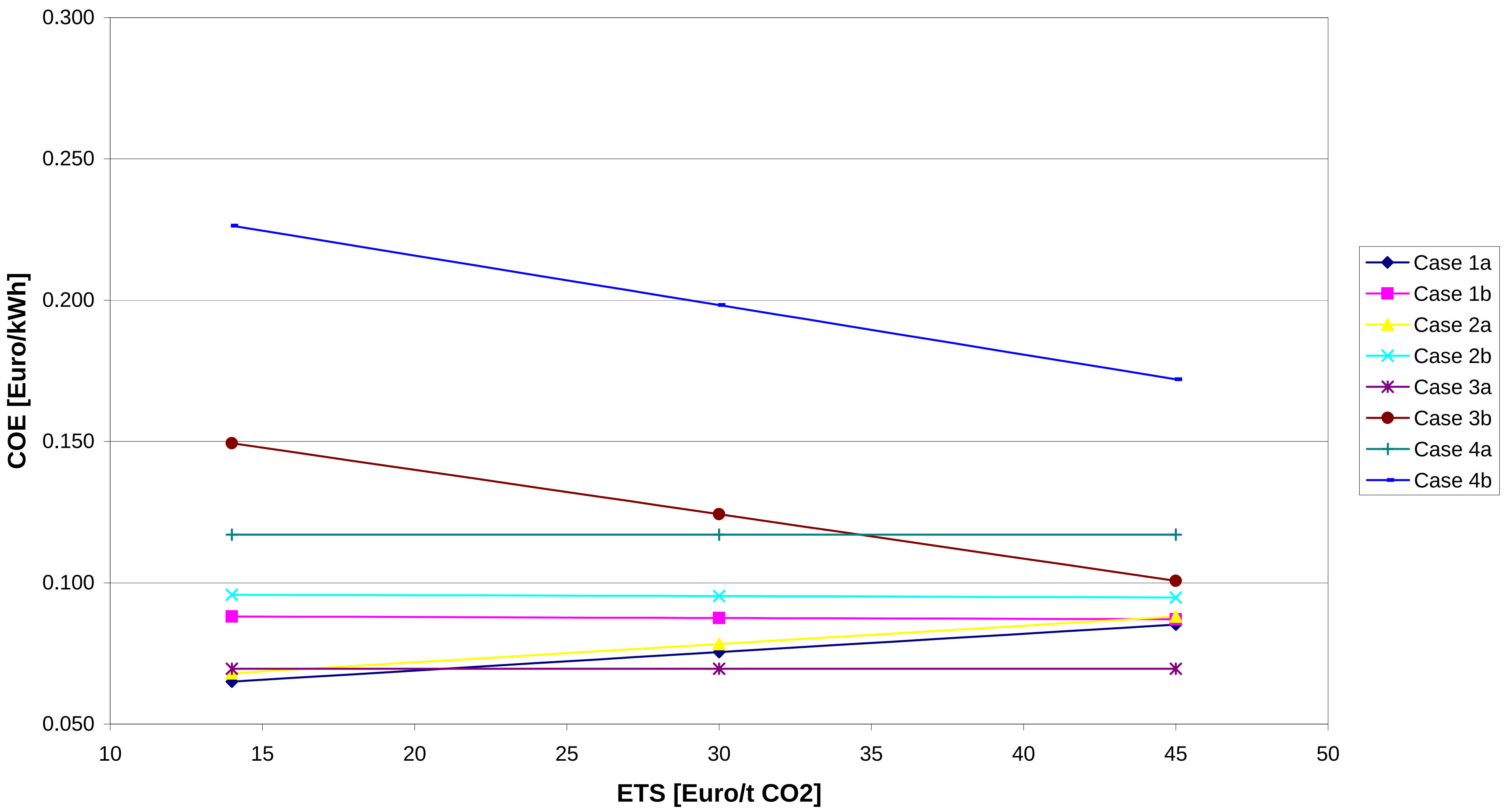


Figure E.6.7: Green Certificates sensitivity (Scenario 2, ETS = 0 €/t CO_2)

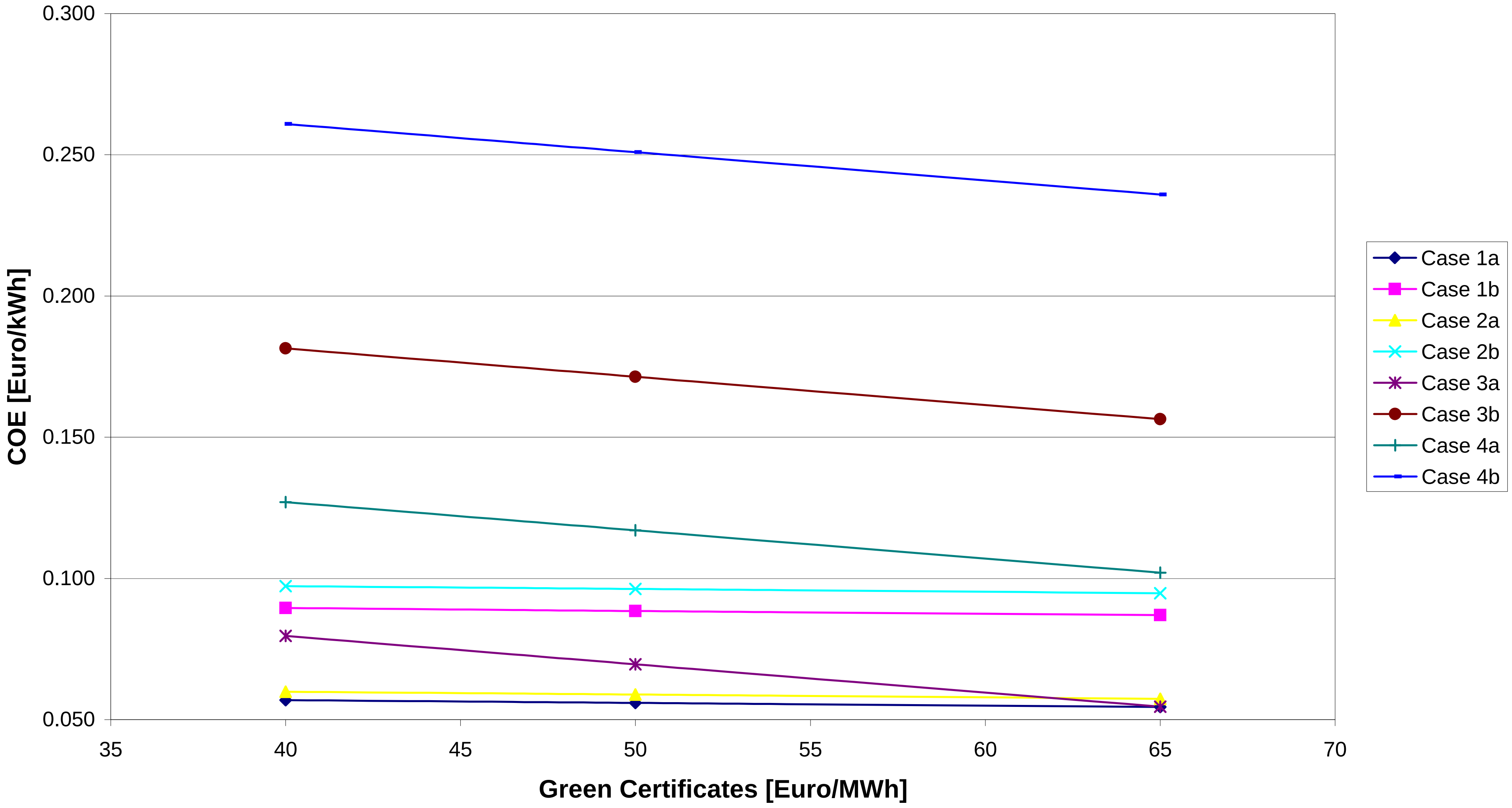
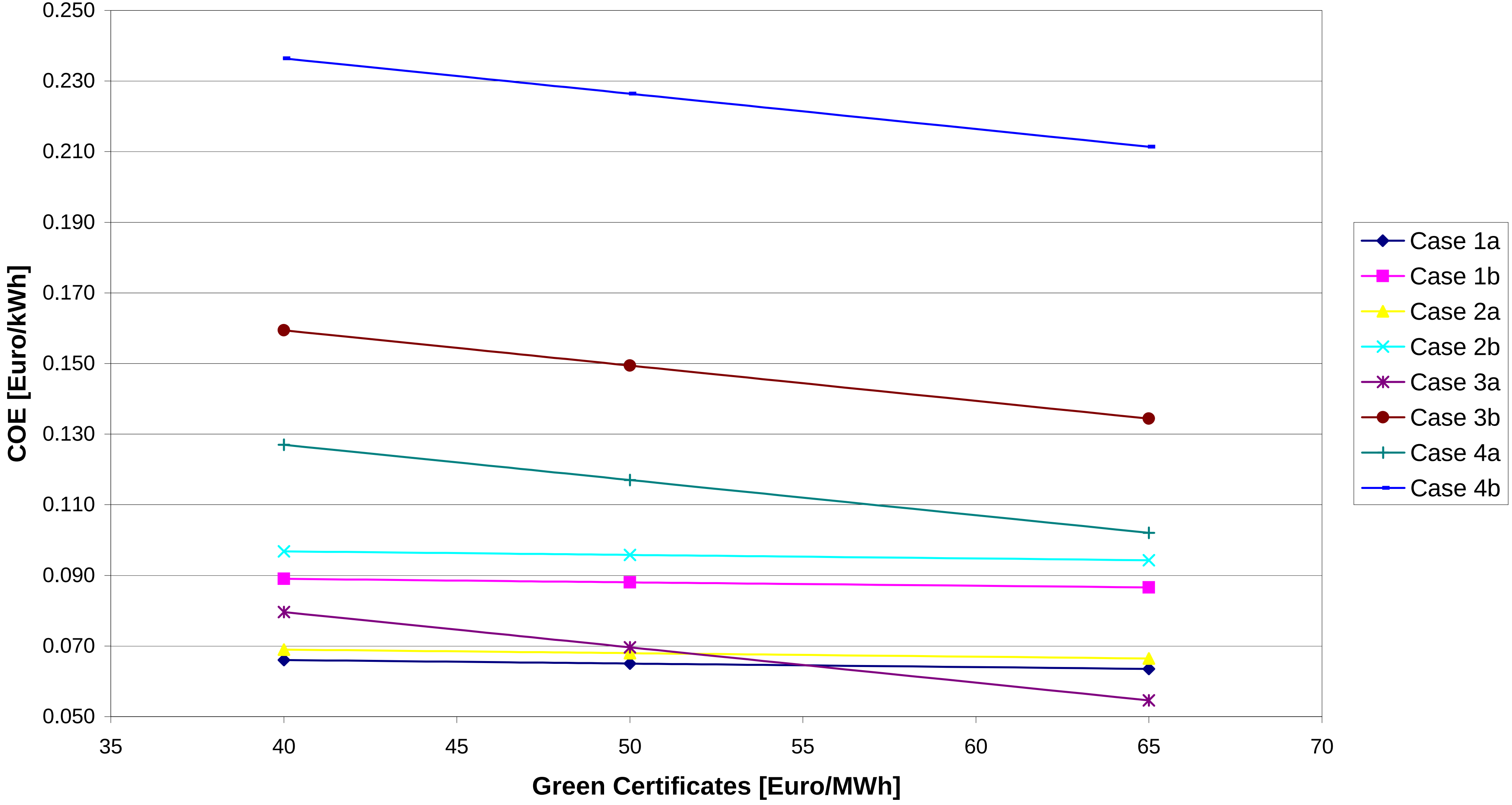


Figure E.6.8: Green Certificates sensitivity (Scenario 4, ETS = 14 €/t CO_2)



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SECTION F

BOILER STATE OF THE ART

INDEX

1.0 Introduction

The demand for biomass is growing and fuel prices are increasing drastically. Thus, all types of biomass will be considered as fuels in the near future. Analyses of national and European policies as well as the targets for renewable energy show that huge amounts of wood will be required in Europe in the future if the targets set by European Commission were to be met.

Compared to conventional fuels like coal and peat, biomass fuels are more difficult and will get even worse, when fuel sources will expand in the future. Fuel quality varies also seasonally and regionally, moisture can be very high, fuel handling and feeding are more demanding, and in biomass-fired boilers fouling, formation of deposits, slagging, and superheater corrosion are common problems.

2.0 Overview of the technology

The equipment for steam production from solid fuels can be generally divided in three main categories:

- Grate (stoker) boilers;
- PC boilers;
- Fluidized bed boilers.

<u>Grate boilers</u>

The fuel is introduced in the furnace where it is dried and the volatile matters is stripped and burnt; the devolatilized fuel drops onto a grate where the burn-out is accomplished.
Various types of grate are available depending on the type of fuel (travelling, stationary, reverse action, rotary etc.).
The combustion air is injected underneath of the grate to provide the also necessary cooling.
This technology is now limited to small size application for biomass and more rarely refuse derived fuel, where the driving force for the investment is getting rid of waste in an environmentally safe manner rather then generating power.

<u>PC boiler</u>

The fuel is pulverized (average particle size around 75 microns) in special mills and injected directly into the furnace together with part of heated primary air; fuel drying takes also place in the mills.
Primary air is introduced simultaneously in the burners to assist the combustion; secondary air is then injected into the furnace to complete the combustion; the staged combustion minimizes the formation of NOx.

In the arch fired boilers, the basic principle is to utilize an enlarged, refractory lined lower furnace to produce a hotter combustion zone with downward fired burners to increase residence time for combustion and allow combustion air to be admitted as the flame develops. This arrangement is particularly suited for hard burning coals.
In the wall fired boilers the burners are installed in the vertical wall with the flame oriented horizontally; this arrangement is suited for bituminous and sub-bituminous coals.
In the tangentially fired boilers the burners are mounted in the corners of the furnace; the overfire air is injected with an "in-windbox" or separate arrangement or a combination of the two. The separate OFA may be injected with a variable angle.
This technology is very widely used for utility boilers in the power and industrial applications when coal is the fuel. Its use with biomass (in co-combustion with coal) is less applied.

Fluidized bed boiler

In a fluidized bed boiler the combustion does not take place in a stationary bed on a grate; rather it takes place in an intensely agitated bed (the fluidized bed) kept in suspension by a flow of air (the primary air).
The fuel is introduced in the furnace through air assisted ports (for flow enhancing and cooling) rather than burners.
In these conditions (which are estabilished when the superficial velocity exceeds the "fluidization velocity") the pressure drop through the bed is no longer depending on the velocity.
The fluid bed combustion is particularly suited for burning difficult, high ash, high moisture fuels in an environmentally friendly manner.
The fluidized bed technology ensures a superior combustion due to the intense mixing and the residence time and the proper temperature, a uniform heat flux and the possibility of in situ capture of the SOx.
Finally, the fluidized bed boiler can be "bubbling" (BFB's) or "circulating" (CFB's).
In the former, the fluidized bed is confined in a defined volume (under the freeboard); in the latter, the fluidized bed moves substantially upward (under the action of air at much higher velocity compared to the BFB) and exits the furnace.
Therefore the solid particles must be captured and reinjected in the furnace to keep the solid inventory.
This means that the solid circulation can be set and is therefore an important design parameters.
The reason to choose CFB instead of BFB was normally the fuel flexibility and the possibility of using also fossil fuels if needed in a later phase or as an emergency fuel. It was also easier to meet the emission requirements with a

CFB than with a BFB and this was an essential advantage of the CFB. This was especially the case with CO and NOx

This technology is now widely used in the power and industrial applications where "difficult" fuels are used (especially biomasses, waste fuels etc.) and a wide fuel flexibility is required.

Areas of development

Extensive research has been done in order to improve both the environmental performance and the economics.
The main area of intervention were:
Size, for scale economy;
Steam parameters, for efficiency increase (environment and economics);
Combustion technique (environment).

3.0 Status of the technology

Bubbling fluidized bed boilers

Bubbling bed technology remained as a technology for the smaller boilers and especially in Finland as a technology for the pulp and paper industry. The steam parameters for these industrial boilers were quite low, pressure approximately 60 to 65 bar(a) and steam temperatures around 500°C as maximum. Also, the size of these boilers was typically rather small, i.e. steam capacity around 50 MWth.

During and after the nineties several bubbling bed biomass plants have been built to the pulp and paper mill integrates overall the world, but also several larger bubbling bed boilers specially designed for power production have been built. The BFB boilers are nowadays available up to 300 MWth with the typical steam parameters of 540°C / 120 bar(a), producing up to approximately 100 MWe electricity.

Circulating fluidized bed boilers

During the eighties emission requirements were still rather low and the CFBs were chosen mainly because of the fuel flexibility. The parameters in the industrial applications were typically: 450-480°C/ 60-70 bar.
During the years the size of the biomass fired CFB boilers has been increased step by step. The range of pure biomass fired CFB units goes up to 300 to 350 MWe electricity with high steam parameters: 565°C / 175 bar(a).
The high steam parameters are possible with an internal heat exchanger as a final super heater (INTREX^{TM}). With this development it is possible to avoid fouling and corrosion of the final super heater and reheater. The final super

heater was placed in the ash return leg and the super heater bundle is covered and protected then by the ash /bed material.

Circulating fluidized bed (CFB) technology has established its position as a utility-scale boiler technology. When considering either new plants or repowering old plants, efficiency and environmental issues are the key issues. High efficiency means lower fuel consumption, and lower levels of ash and air emissions, including lower emissions of carbon dioxide (CO_2). To achieve these coals supercritical steam parameters have been applied.

First CFB power plants to utilize the supercritical steam parameters with once-though steam cycle technology are Łagisza, 460 MWe in Poland, and Novocherkasskaya, 330 MWe Russia.

Steam conditions at Łagisza are 560°C/275 bar and 580°C/55 bar.

Boiler design for both Łagisza and for Novocherkasskaya power plants utilizes low mass flux BENSON vertical once-through technology developed and licensed by Siemens AG, Germany. CFB boiler with low and uniform furnace heat flux is extremely well suited for the Benson technology. These supercritical OTU CFB plants will combine high plant efficiency with the well known benefits of CFB technology, such as superior fuel flexibility, inherently low emissions and high availability.

Although both Łagisza and Novocherkasskaya boilers are designed for the coal and coal slurry firing, the Foster Wheeler CFB boiler designs with supercritical steam parameters are capable of burning 10 to 30% biomass together with coals. The percentage, which can be utilized, is highly dependent of properties of the biomass and coal.

CFB technology and its main design components are well demonstrated in utility scale power production by Foster Wheeler. Scale-up of Foster Wheeler CFB technology with ultrasupercritical steam parameters up to 620°C and plant sizes up to 800 MW_e is feasible in near future.

Pulverized coal boilers

This technology has been the main route for production of power from coal. Today the state of the art of this technology employs the following steam cycle ultrasupercritical conditions:

HP steam pressure		300 bar
Superheating temperature		600°C
Reheating temperature	(1 or 2 stages)	620°C

At these conditions the net efficiency, based on coal LHV, is 45-47%, mainly dependent on the temperature level of the cooling water.

This level of performance is achieved with bituminous/subbituminous coals. With lignite the efficiency drops by about 2% points, due to the water content of lignite.

The largest single module available today is 1000 MW.

Major research and developments are directed to test and commercialize new special alloys for the boiler components, steam turbines, connecting piping and valves, in order to operate the steam cycle at more severe supercritical conditions and thus achieving higher efficiency (50% and higher).
Higher steam conditions would also require a re-design of the steam turbine.

Also, various low NOx burner designs are available, depending on NOx required reduction. Many different arrangements, all based on the Overfire Air (OFA) technology are available.

As noted above, cofiring of biomass and coal is less common in the PC boiler than in the CFB boiler.
Biofuels begin releasing volatiles at a lower temperature, and much more rapidly compared to coals. Also the drying and devolatilization of the biomass happens almost simultaneously.
The increased volatility of the biofuels is among the most critical considerations in cofiring. The biofuel particles volatilize earlier and independently of the fossil fuel particles. This causes some key changes in fuel particle-particle interactions, including reducing the ignition temperature of the mass of the fuel. These changes need to be considered when designing a burner for cofiring of biomass.
Most biofuel co-firing applications on pulverized fuel combustion systems have used a separate injection of fuel and biomass into the boiler. Results show that blending biofuels with coal in the fuel pile had significant adverse impacts on pulverizer performance and this can eventually lead to significant capacity derating of the boilers.
Blending of biomass and/or other opportunity fuels in the coal yard, and utilizing the existing bunkers and firing system has been applied at moderate blending percentages (e.g., <20 percent cofiring on a mass basis).
Separate injection of coal and biomass is most applicable to PC boilers firing more than 10 percent biomass (mass basis). Separate injection permits careful management of fuels with very low bulk densities - fuels that are not readily blended with coals. Apart from secondary fuel storage and handling, integration of the co-firing equipment into the existing burner system has been one of the major tasks when modifying low NOx combustion equipment to include biomass or other co-firing fuels.

4.0 Combustion of different types of biomass

The interest to use biomasses as fuels has increased strongly during the last years as a mean to reduce the CO_2 emissions of energy production. Compared to conventional fuels like coal and peat, biomass fuels are more difficult. Fuel quality varies, moisture can be high, fuel handling and feeding are more demanding. With such problems, the technologies based on fluidized bed (BFB

and CFB) are becoming increasingly popular. As a drawback, biomass-fired B/CFBs may suffer from bed agglomeration. Ash composition together with sulfur and chlorine contents in biomass fuels are the main factors having an impact on the risk of bed agglomeration in fluidized bed boilers, and on the rate of boiler fouling, deposit formation, slagging, and superheater corrosion. On the basis of ash composition, the biomass fuels can be divided into three groups having significant differences in combustion.
Between the three groups fuels have significant differences in combustion properties. The classification is helpful also when ash reactions in multifuel systems are to be predicted.
Biomass ashes are very fine, a few µm in particle size. Ca- and K-containing ashes deposit easily on surfaces, causing fouling of e.g. superheaters, forming CaO, $CaSO_4$ and K_2SO_4 rich deposits that harden if not removed frequently by soot blowing. The deposits can harden in the superheater area. In the economizer section flue gas temperatures are low, below 500ºC, and the deposits remain usually loose and easily removable by soot blowing.
Chlorine in the fuel makes the fouling even worse, and induces the risk of high temperature corrosion in the superheaters.

From the combustion point of view, biomass fuels can be divided into three groups on the basis of their ash composition:
1. Biomasses with Ca, K rich and Si lean ash
2. Biomasses with Si rich and Ca, K lean ash
3. Biomasses with Ca, K and P rich ash

Most woody fuels belong to group 1. Rice husk, bagasse or spring harvested reed canary grass are examples of biomass fuels in group 2, sunflower seed and rapeseed cakes are fuels in group 3.

<u>Biomasses with Ca, K rich and Si lean ash</u>
Wood ash starts to form agglomerates and to sinter between 900 ºC and 1000 ºC in combustion conditions. Coal and peat ashes are usually trouble free at these temperatures, even if the melting point temperatures are in the same range with biomass fuels. Coal or peat is cofired with biomass in many multi-fuel fired boilers.
The woody biomass ashes are in general much more reactive than the ashes of fossil fuels. Lower reactivity of coal and peat ashes is connected to a composition with mainly quartz and various silicate-based minerals, like aluminium silicates, calcium silicates and alkali silicates, and iron oxides.

<u>Biomasses with Si rich and Ca, K lean ash</u>
The fuels in group 2 are very different by chemical composition and combustion properties. Most fuels in this group belong to herbaceous, or

agricultural biofuels. Some of the fuels, like straws of cereals have also relatively high potassium (K) and chlorine (Cl) contents. The composition of biomass ash is strongly dependent on the species and part of the biomass plant.

The ash melting properties of straws of cereals are challenging. The sintering temperatures are in the range 700–900 ºC, and ash softening points below 1000 ºC. Complete melting happens often below 1200 ºC. From experience, straw is known as a reactive but difficult fuel with high fouling, slagging and corrosion properties.

During straw combustion the bed agglomeration is caused by separate sticky and partly molten ash particles, and not by a sticky alkali and calcium silicate layer that is gradually formed on the bed particles like during wood combustion. The molten straw ash particles consist on potassium chloride and low melting potassium silicates formed in reactions between potassium and silica present inherently in the fuel ash.

Biomasses with Ca, K and P rich ash

The ash melting temperatures are in the same range as straw. Sintering may start at about 700 ºC, and the ash is completely molten below 1200 ºC. These fuels are very fouling, but they can be cofired with coal in moderate shares in normal high efficiency CFB boilers.