CO_2 CAPTURE IN LOW RANK COAL POWER PLANTS

Technical Study

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CO$_2$ CAPTURE IN LOW RANK COAL POWER PLANTS

Background to the Study

Until now, IEA GHG's studies on coal-based power plants with CO_2 capture have concentrated mainly on high rank (bituminous) coals but it is recognised that low-rank coals (sub-bituminous coal, lignite and brown coal) are important fuels for power generation in several countries. A study has therefore been carried out to estimate the performance and costs of low rank coal fired power plants with CO_2 capture based on various technologies. The study was carried out for IEA GHG by Foster Wheeler Italiana.

This overview written by IEA GHG summarises the results of the study and puts them in context with results from other studies carried out recently by IEA GHG. More detailed technical information is included in the Executive Summary in Foster Wheeler's report.

Study Basis

Low rank coal availability and analyses
Low rank coals are characterised by relatively high moisture and oxygen contents and low heating values. There is no universal system of classification for low rank coals but the lowest rank coals are normally called lignite and coals which are intermediate between lignite and high rank bituminous coals are called sub-bituminous coals. In some countries the term 'brown coal' is used for low rank coals.

Low rank coal accounts for almost half of the world's proven recoverable coal reserves on a mass basis and 30% of coal production, although in energy terms the proportions are lower because of the relatively low heating values of low rank coals. About 60% of the low rank coal reserves are sub-bituminous coal and the rest is lignite. The country with the world's largest production and proven recoverable reserves of lignite is Germany. A German coal, as shown in table 1, was selected as the basis for this study. The analysis of the standard bituminous coal used in IEA GHG's earlier studies is also shown in table 1 for comparison.

Table 1 Coal analyses

	German brown coal selected for this study	IEA GHG standard bituminous coal
Moisture, % as-received basis	50.70	9.5
Ash, % dry basis	7.10	13.48
Carbon, % dry basis	63.54	71.38
Hydrogen, % dry basis	4.65	4.85
Oxygen , % dry basis	23.44	7.79
Nitrogen, % dry basis	0.74	1.56
Sulphur, % dry basis	0.45	0.95
Chlorine/fluorine, % dry basis	0.08	0.03
HHV, MJ/kg as-received[1]	12.26	27.06
LHV, MJ/kg as-received	10.50	25.87
LHV, MJ/kg C	33.5	40.0

[1] There is no universally recognised relationship between the HHV and LHV of solid fuels. The relationship in this table is based on an equation from the 7th edition of "Technical Data on Fuel" by Rose and Cooper, published by the World Energy Conference. The LHV is the HHV minus the heat of vaporisation of the moisture in the coal and the moisture produced by combustion of the hydrogen in the coal. This definition is normally used in Europe. In North America the LHV is normally calculated by only subtracting the heat of vaporisation of moisture produced by combustion of hydrogen.

IEA GHG participated in a study by the CCPC[2] which considered CO_2 capture power plants based on two Canadian low rank coals; an Alberta sub-bituminous coal, and a Saskatchewan lignite. The Saskatchewan lignite has a significantly higher rank than the German brown coal shown in table 1, for example it has a moisture content of 34% and an oxygen content of 14.6%, dry basis. This study therefore extends the assessment of CO_2 capture to even lower rank coals.

Power plant performance and cost assessments

Assessment criteria
The performances 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 85% and the economic evaluation was based on a 10% annual discount rate and 25 year plant operating life. The reference coal price was assumed to be €1/GJ but the sensitivity of power cost to coal price was assessed, to allow for local variations. Low rank coal is traded on the open market much less than high rank coal and price information is less freely available. Further details of the assessment criteria are included in the main study report.

IEA GHG's standard criteria state that the power plant will be built at a coastal site in the Netherlands but this was not appropriate for this study because low rank coal is normally used at power plants located close to the mine. This study was therefore based on an inland mine site in Germany. The different location resulted in some changes to the plant design criteria, in particular the use of natural draught cooling towers instead of once-through sea water cooling, but in other respects the different location did not significantly affect the performance and costs.

The plant costs were estimated in Euros. Conversion of Euros to US Dollars is currently subject to significant uncertainty, because of recent large fluctuations in the exchange rate. At the start of 2005, one € had the same value as about 1.3 US$ but the value declined to 1.17 $ by December. Between 2001 and 2005 the value of one € has varied within the range of about 0.85 and 1.35$.

Case descriptions
The first stage of the study involved assessment of the performances and costs of power plants with CO_2 capture based on a wide variety of technologies. The following plants were assessed:

1. Pulverised coal boiler with an ultra –supercritical (USC) steam cycle and post combustion CO_2 capture using MEA solvent scrubbing
2. Circulating Fluidised Bed (CFB) boiler with a USC steam cycle and post combustion CO_2 capture using MEA solvent scrubbing
3. Pressurised Circulating Fluidised Bed (PCFB) boiler with a USC steam cycle and post combustion CO_2 capture using MEA solvent scrubbing
4. Oxy-combustion pulverised coal boiler with a USC steam cycle
5. Gasification combined cycle using Future Energy oxygen blown, dry feed, entrained gasifiers, with water quench, sour shift conversion and CO_2 capture by MDEA scrubbing
6. Gasification combined cycle using Shell oxygen blown, dry feed, entrained gasifiers, with heat recovery boilers, sour shift conversion and CO_2 capture by MDEA scrubbing
7. Gasification combined cycle using Foster Wheeler air blown, dry feed, fluidised bed gasifiers, with heat recovery boilers, sour shift conversion and CO_2 capture by MDEA scrubbing

[2] Canadian Clean Power Coalition studies on CO_2 capture and storage, report PH4/27, March 2004.

Plants without capture were not included in the screening assessment, to limit the cost of the study. The assessment did not include the GE (formerly Texaco) gasifier, which had the lowest costs of electricity in IEA GHG's study on bituminous coal gasification combined cycle plants with capture[3]. That gasifier in its current form is considered to be not suitable for high moisture lignite because the water content of the slurry feed to the gasifier would be excessively high, resulting in a low efficiency and high costs.

The IGCC plants produce an impure CO_2 product, containing the sulphur from the coal mainly in the form of H_2S. The oxyfuel plant also produces impure CO_2. In that case the sulphur is mainly present as SO_2. In both cases producing a high purity CO_2 would increase costs.

The technology with the lowest cost (CFB with post combustion capture) was selected for a more detailed assessment, which included assessment of plants with and without CO_2 capture. However, it should be noted that the optimum technology will depend on the fuel analysis and other local circumstances, and criteria other than the base load performance and cost of electricity, such as technology risk.

Results and Discussion

Technology screening

The performances and costs of the power plants with CO_2 capture, from the technology screening, are summarised in table 2.

Table 2: Cost and performance summary, technology screening

	Net power	Efficiency (LHV)	CO_2 capture	Capital cost	Electricity cost
	MW	%	%	€/kW	€c/kWh
Post combustion capture					
Pulverised coal	761.0	35.5	85.0	1645	5.39
CFB	614.4	35.5	85.0	1552	5.34
PCFB	688.4	32.5	85.0	1788	5.55
Oxy-combustion					
Pulverised coal	741.3	37.5	93.0	1882	5.46
Pre-combustion capture					
Future Energy gasifier	665.2	34.7	85.8	1706	5.41
Shell gasifier	628.8	34.5	85.2	1917	5.94
Foster Wheeler gasifier	686.6	34.1	82.9	1795	5.64

The net power outputs of the plants are slightly different in each case because they depend on the sizes of commercially available equipment. The target percentage CO_2 capture is 85%, except for the oxyfuel case, which inherently achieves a higher percentage capture. The other technologies could achieve greater than 85% CO_2 capture if required.

The thermal efficiencies are all within the range of 32.5 - 37.5% on a lower heating value (LHV) basis and the costs of electricity are within the range of 5.34 - 5.94 c/kWh. The oxy-combustion plant has the highest efficiency and percentage CO_2 capture and the CFB plant with post combustion capture has the lowest electricity cost. The differences between the costs of the different technologies are within the limits of uncertainty of the assessment, particularly as none of the technologies is fully proven at commercial scale.

[3] Potential for improvement in gasification combined cycle power generation with CO_2 capture, report PH4/19, May 2003.

Assessment of selected option
The CFB plant with post-combustion capture was assessed in more detail and a reference CFB plant without capture was also assessed for comparison. Costs of avoiding CO_2 emissions were calculated by comparing the plants with and without capture. The results are summarised in table 3.

Table 3: Cost and performance summary, detailed assessment of selected case

	Without capture	With capture	Difference due to capture
Plant performance			
Fuel input, MW (LHV)	1729	1729	0
Gross power output, MW	842	758	-84
Ancillary power consumption and losses, MW[4]	50	148	98
Net power output, MW	792	610	-182
Efficiency and emissions			
Thermal efficiency, % (LHV)	45.8	35.3	10.5
Increase in fuel use per kWh, %			30
CO_2 capture efficiency, %		85.0	
CO_2 emissions, g/kWh	872	170	702
CO_2 captured, g/kWh		962	
Costs			
Capital cost, €/kW net power	1006	1567	561
Electricity cost, €c/kWh (excluding CO_2 storage)	3.46	5.39	1.93
Cost of CO_2 avoidance, €/tCO_2 (excluding storage)			27.5

The CFB plant data in table 3 differ from those in table 2 because Foster Wheeler carried out a more detailed analysis and used more data from equipment vendors, but the overall differences are small. For the technology screening, they scaled the costs of amine scrubbing units from information in Fluor's report for IEA GHG[5]. For the more detailed analysis of the CFB case, they obtained costs of major items of equipment in the amine scrubbing unit from vendors. The resulting costs of the amine scrubbing unit were about 10% higher than the costs obtained by scaling from Fluor's study.

Costs of low rank coal vary considerably between different locations. The relationship between fuel price and the cost of electricity, excluding CO_2 transportation and storage, is shown in figure 1.

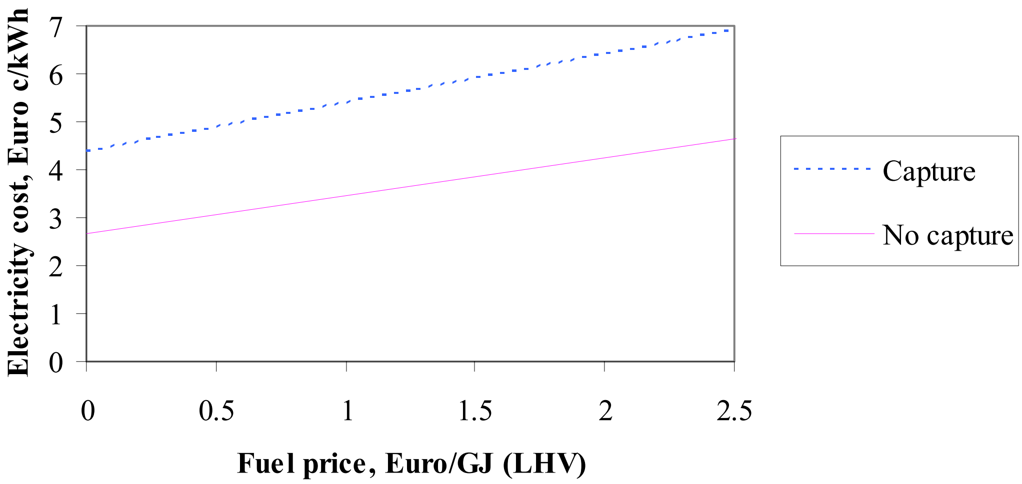

Figure 1 Sensitivity of electricity cost to fuel price

[4] The auxiliary powers exclude boiler feed pumps, which are steam turbine driven, and include transformer losses.
[5] Improvement in power generation with post-combustion capture of CO_2, report PH4/33, November 2004.

The costs in this study exclude CO_2 transportation and storage, which would depend strongly on local circumstances. For illustration, a cost of €10/tonne of CO_2 stored would add 0.96 c/kWh to the cost of electricity and €13.7/tonne to the cost of CO_2 avoided by the CFB plant.

Comparison with bituminous coal fired plants
On a LHV basis, the efficiencies of the brown coal power plants with capture are similar to the efficiencies of bituminous coal plants using the same technology, as reported in other recent IEA GHG studies[6], but on a HHV basis the brown coal plants are less efficient, as shown in table 4.

Table 4: Efficiencies of brown coal and bituminous coal power plants with CO_2 capture

	LHV efficiency, %		HHV efficiency, %	
	Brown coal	Bituminous coal	Brown coal	Bituminous coal
Pulverised coal, MEA scrubbing	35.5	34.8	30.4	33.3
Pulverised coal, oxy-combustion	37.5	35.4	32.1	33.8
IGCC, Shell gasifier	34.5	34.5	29.6	33.0

Low rank coal contains a large amount of moisture, which is evaporated in a drier and within a combustor or gasifier. According to the European definition of LHV (see footnote on page i), the heat of evaporation of this moisture and the moisture produced by combustion of hydrogen in the organic part of the coal has been subtracted from the heating value. Some of the coal drying is carried out using low grade heat from the power generation and CO_2 capture plants, so the high moisture content of the coal can actually be beneficial for the LHV efficiency.

The efficiency penalty for post-combustion CO_2 capture is slightly higher for the low rank coal CFB plants than for the pulverised bituminous coal plants reported in PH4/33 (10.5 compared to 9.2 percentage points), This may be because more CO_2 has to be captured per kWh of electricity in a low rank coal power plant, because the specific energy content of low rank coal is lower in terms of MJ/kgC, as shown in table 1.

It is more difficult to compare the costs in this study with costs from IEA GHG's earlier studies on bituminous coal fired plants, because of the different timing of the studies, varying exchange rates, different locations, different contractors and fuel price uncertainties. However, it appears that the cost of post combustion capture is similar in bituminous coal and brown coal fired plants. In the bituminous coal plant studies the cost of electricity in the optimum IGCC plant was lower than the cost in the post combustion capture and oxyfuel plants but in this study on brown coal the costs are similar for all three technologies. Post combustion capture and oxyfuel combustion appear to become more competitive compared to IGCC for lower rank coals. This is in line with results from studies by the Canadian Clean Power Coalition[7]

Sensitivity to coal analysis
This study was based on a German brown coal. Low rank coal analyses vary considerably, as shown in the main study report. Important factors apart from the rank of the coal are the sulphur and ash contents and the ash composition, particularly the concentration of alkalis which can cause serious operating difficulties in some cases. Quantifying the effects of coal analysis on plant performance, costs and technology selection was outside the scope of this study. However, it is emphasised that the optimum technology for power generation with CO_2 capture will depend on the coal analysis.

[6] Report PH4/19 (IGCC), May 2003, report PH4/33 (post-combustion capture), Nov. 2004 and report 2005/11 (oxy-combustion), July 2005.
[7] Report PH4/27, March 2004.

Comments from Expert Reviewers

Comments on the draft study report were received from various 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 practicality and safety of air drying of low rank coal. Some reviewers would have liked to include assessment of other gasifiers being developed specifically for low-rank coal, in particular the HTW oxygen blown fluidised bed gasifier, the Integrated Drying Gasification Combined Cycle and the next generation ConocoPhillips E-STR gasifier, which they considered may be more competitive. Some reviewers would have liked reference cases without CO_2 capture to be included for all of the technologies and a more detailed assessment of a gasification case. It was also suggested that an oxyfuel CFB boiler may be attractive option. However, it was not possible to include these extra cases within the study budget.

There was some concern about technologies being evaluated by organisations which have a vested interest in them, but this concern is not unique to this study. The main sources of cost data for this and other similar studies carried out for IEA GHG and other agencies are technology and equipment vendors. These organisations have the greatest knowledge about the technologies and their costs but it has to be recognised that they also have a commercial interest in the adoption of their technologies.

Major Conclusions

There is little difference between the costs and thermal efficiencies of low rank coal power plants with CO_2 capture based on post-combustion capture, oxy combustion and IGCC. The optimum technology will depend on the coal analysis and other local circumstances.

Adding post combustion CO_2 capture to a brown coal fired circulating fluidised bed combustion plant reduces the thermal efficiency by 10 percentage points and increases the cost of electricity by about 55%.

Post combustion capture and oxyfuel combustion appear to become more competitive compared to IGCC for lower rank coals.

Recommendations

Criteria other than those considered in this study may influence a utility's choice of technology for power generation with CO_2 capture. IEA GHG is carrying out a study to assess the relative importance to utilities of different criteria.

An oxyfuel CFB case and IGCCs based on other gasifiers should be included in any future assessments of low rank coal power plants with CO_2 capture. Sensitivities to low rank coal analyses should also be included.

IEA GREENHOUSE GAS R&D PROGRAMME

CO_2 CAPTURE IN LOW RANK COAL POWER PLANTS

Final Report

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FOSTER WHEELER

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I N D E X

SECTION D BASIC INFORMATION FOR EACH ALTERNATIVE

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SECTION A
EXECUTIVE SUMMARY

I N D E X

SECTION A EXECUTIVE SUMMARY

SECTION A

1.0 Scope of the study

The IEA Greenhouse Gas R&D Programme has retained Foster Wheeler to investigate different power plant technologies, capable to utilize low rank coal as primary fuel and make the pre-combustion or post-combustion CO_2 capture. The primary purpose of this study is to compare these technologies and analyze benefits and issues associated with the use of low rank coal in the power industry, optimizing efficiency, capital cost and reducing emissions to the atmosphere.

The study begins with the analysis of the distribution and characteristics of the low rank coals deposits from the major producing regions worldwide (reference to Section I, attachment I.1), showing that 47% of the quantity recoverable deposits in the world is mainly composed of lignite and sub-bituminous coal.
Germany is the world's largest brown coal producer/reserve, representing 20% of global production in 2001. This feature led to the selection of a German lignite as reference coal of the study, with a LHV equal to 10,500 kJ/kg and a moisture content of 50.7%.

The nominal capacity of the different power plants is approximately fixed to 750 MWe.

The study initially evaluates costs and performances of seven different power plant technologies, with CO_2 capture, in order to select the most promising process scheme.
After the determination of the most attractive technology, the study also presents a more detailed assessment of performances and costs of the selected technology, comparing the two alternatives with and without CO_2 capture, in order to evaluate the penalties on cost and performances related to the CO_2 sequestration.

Finally, the study is completed with the investigation of possible improvements to the coal firing technology, expected by year 2020.

For the preparation of the study, FWI based part of the work on the study made for IEA-GHG in 2003 ("Gasification Power Generation Study"), which was supported by different companies (Dow, General Electric, Shell, Synetix, Sud-Chemie, Texaco, UOP).

IEA-GHG made also available previous study reports, developed by other companies, for similar plants.
For this specific study, FWI like to acknowledge the following companies for their fruitful support:

- RWE;
- FWOy;
- Future-Energy;
- Shell;
- Siemens;
- Johnson Matthey Catalysts;
- GTC;
- Sulzer;
- Koch-Glitsch;
- FWUS.

2.0 Bases of design

The power plants are designed to process a Western Germany lignite (Rheinbraun) coal (refer to Section B, paragraph 2.1) to produce electric energy.

For the alternatives with post-combustion CO_2 capture, the design capacity of the plant is fixed to approximately provide 750 MWe of power production. For the alternatives with pre-combustion CO_2 capture, the design capacity is fixed to match the appetite of the two gas turbines, General Electric 9FA.
The design capacity for each of the alternatives considered is summarized in paragraph 4.0.

The environmental limits set up for the power plants are outlined hereinafter.

		Post-combustion CO_2 CO_2 capture (1)	Pre-combustion CO_2 capture (2)
NO_x(as NO_2)	:	≤ 200 mg/Nm^3	≤ 80 mg/Nm^3
SO_x(as SO_2)	:	≤ 200 mg/Nm^3	≤ 10 mg/Nm^3
Particulate	:	≤ 30 mg/Nm^3	≤ 10 mg/Nm^3
CO	:	≤ 100 mg/Nm^3	≤ 50 mg/Nm^3

Note: (1) @ 6% O_2 vol dry
(2) @ 15% O_2 vol dry

Characteristics of wastewater discharged from power plants shall comply with the limits stated by the current EU directives.

For the pre-combustion CO_2 capture alternatives (IGCC), the effluent from the wastewater treatment shall be generally recovered and recycled back to the gasification island as process water.

The other bases of design for the power plant, such as capacity, required availability, location, climatic data etc., are defined in Section B of this report.

3.0 Alternative designs of power plants

Several power plant design alternatives were developed in the study. The contemplated alternatives attempt to compare the following key process aspects:

- Different coal power plant technologies for processing of a lignite coal;
- Post-combustion and pre-combustion CO_2 capture in different low rank coal power plants;
- Different CO_2 capture technologies (MEA, MDEA scrubbing or gas liquefaction).
- Performance and cost penalties, due to the CO_2 capture, for the most promising technology amongst the investigated alternatives.

The following alternatives were investigated:

CASE 1 Ultra Super Critical Pulverized Coal (USC-PC) Boiler, with post-combustion CO_2 capture by using MEA as solvent washing.

CASE 2 USC - PC-Oxycombustion Boiler, with post combustion CO_2 capture by means of Gas liquefaction.

CASE 3 Foster Wheeler Circulating Fluidized Bed (CFB) Boiler, with post-combustion CO_2 capture by using MEA as solvent washing.

CASE 4 Foster Wheeler Pressurized Circulating Fluidized Bed (PCFB) Boiler, with post-combustion CO_2 capture by using MDEA as solvent washing.

CASE 5 Future Energy gasification technology, sour shift and CO_2 pre-combustion capture (MDEA scrubbing with combined capture of CO_2 and H_2S).

CASE 6 Shell gasification technology, sour shift and CO_2 pre-combustion capture (MDEA scrubbing with combined capture of CO_2 and H_2S).

CASE 7 Foster Wheeler Air gasification technology, sour shift and CO_2 pre-combustion capture (MDEA scrubbing with combined capture of CO_2 and H_2S).

4.0 Performance data

The most important performance data of the different power plants, with CO_2 capture, are summarized in the following Table A.4.1.

The feature common to all the alternatives is the partial drying of the coal from the initial content of 50.7% to a range varying from 32% for the post-combustion alternatives to 10%-5% respectively for the IGCC alternatives based on Future Energy and Shell technology. The partial drying of the coal lignite is used to enhance the efficiency of the different power plants, utilizing low temperature heat available in the plant at various locations. In the IGCC alternatives, FE and Shell, it is necessary to reduce the moisture content of the lignite to a lower level to permit the operation of the pneumatic transportation system used in these technologies.

Despite the differences of the various technologies involved, the net electrical efficiency falls in a narrow range of values. The Oxycombustion USC-PC boiler is the alternative with the highest electrical efficiency and superior environmental performances.

Table A.4.1 - Performance data.

Case	Power plant tech.	Coal t/h	Coal moisture after drying, %wt	Acid gas removal tech.	CO_2 capture eff., %	Gross power output MWe (1)	Auxiliary cons. MWe	Net power output MWe (2)	Net electrical efficiency %
1	USC-PC	734.0	32	MEA	85.0	932.0	168.8	761.0	35.5
2	Oxy USC- PC	677.6	32	Gas liquefaction	93.0	1039.4	295.8	741.3	37.5
3	CFB FW	592.9	32	MEA	85.0	763.0	146.5	614.7	35.5
4	PCFB FW	727.0	32	MDEA	85.0	816.0	125.5	688.4	32.5
5	IGCC FE	653.3	10	MDEA	85.8	900.3	233.1	665.2	34.7
6	IGCC SHELL	624.2	5	MDEA	85.2	868.7	238.0	628.8	34.5
7	IGCC FW	691.0	25	MDEA	82.9	900.5	211.9	686.6	34.1

Notes: (1) At generator terminals.
(2) At Low Voltage side of the step-up transformers.

5.0 Investment cost data

The investment cost data of the different power plants technologies, with CO_2 capture, are shown in Table A.5.1 and 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. From this comparison it appears that the CFB technology shows the lowest specific investment cost.

Table A.5.1 - Investment Cost Data (Post-combustion alternatives)

Case	Power plant technology.	MAIN POWER PLANT SECTIONS INVESTMENT										Total Investment 10^6 Euro	Specific Investment Euro/kW
		Boiler Island		Process Units		CO_2 Compr.		Power Island		Utilities Offsites			
		10^6 €	%	10^6 €	%	10^6 €	%	10^6 €	%	10^6 €	%		
1	USC-PC	463.1	37	306.4	24	47.6	4	162.5	13	272.2	22	1251.8	1645
2	Oxy USC-PC	451.2	32	416.6(1)	29	92.9	7	174.5	13	260.0	19	1395.2	1882
3	CFB FW	334.0	35	198.2	21	42.0	4	138.6	15	241.0	25	953.8	1552
4	PCFB FW	345.4	28	431.5	35	47.9	4	135.1	11	270.7	22	1230.6	1788

Notes: (1): Including the Air Separation Unit.

Table A.5.2 - Investment Cost Data (Pre-combustion alternatives)

Case	Power plant technology.	MAIN POWER PLANT SECTIONS INVESTMENT										Total Investment 10^6 Euro	Specific Investment Euro/kW
		Air Separation		Process Units		CO_2 Compr.		Power Island		Utilities Offsites			
		10^6 €	%	10^6 €	%	10^6 €	%	10^6 €	%	10^6 €	%		
5	IGCC FE	126.3	11	380.3	34	40.1	3	368.9	33	219.1	19	1134.8	1706
6	IGCC SHELL	114.0	10	472.9	39	38.5	3	367.1	30	212.7	18	1205.1	1917
7	IGCC FW	28.9(1)	2	566.3	46	40.0	3	370.2	30	227.2	19	1232.7	1795

Notes: (1): Air Compression Unit (ASU in not required).

6.0 Production costs and selection of the most promising technology

The following Table A.6.1 provides the cost of electricity (C.O.E.) for the different alternatives, with the CO_2 capture.

The cost of electricity was calculated based on the following main assumptions:

- Cost of coal: 1.0 Euro/GJ (10.5 Euro/t);
- 7446 equivalent operating hours in normal conditions at 100% capacity;
- Total investment cost as given in para. 5.0 of this Section;
- O&M costs as evaluated in Section E;
- 10% discount rate on the investment cost over 25 operating years;
- Other financial parameters as per Section E.

Table A.6.1 - Cost of Electric Power Production.

Case	Power plant technology	C.O.E. (DCF= 10%) Cent/kWh
1	USC-PC	5.39
2	Oxy USC- PC	5.46
3	CFB FW	5.34
4	PCFB FW	5.55
5	IGCC FE	5.41
6	IGCC SHELL	5.94
7	IGCC FW	5.64

The cost of electricity falls in a narrow range of values and the maximum difference between the alternatives is approximately 11%. In particular, the USC-PC, CFB and IGGG-FE display the lowest cost of production of electricity. Amongst these three technologies, CFB is the one with the lowest cost and therefore it is selected for the subsequent more detailed study.

7.0 Detailed information of the most promising technology (CFB)

The selected technology, FW - CFB, has been analyzed with a higher level of detail. The investigation has been extended by obtaining data from critical equipment Suppliers.

CFB technology was also studied without the CO_2 capture, in order to evaluate the cost related to the CO_2 sequestration.

This evaluation is shown in the following Table A.7.1.

Table A.7.1 – Performances of the two CFB alternatives.

ALTERNATIVE		CFB-Boiler without CO_2 capture	CFB-Boiler with CO_2 capture
Lignite Moisture Content After Drying %wt		32	32
OVERALL PERFORMANCES			
Coal Flow Rate A.R.	t/h	592.9	592.9
Thermal Energy of Feedstock	MWth	1729.3	1729.3
Gross Electric Power Output(1)	MWe	841.9	758.2
Auxiliary Consumption	MWe	47.6	146.6
Net Electrical Power Output(2)	MWe	791.8	609.7
Gross Electrical Efficiency	%	48.7	43.8
Net Electrical Efficiency	%	45.8	35.3
ACID GAS REMOVAL TECHNOLOGY		-	MEA Scrubbing
CO_2 Capture Efficiency	%	-	85.0
INVESTMENT COST DATA			
Total Investment	10^6 €	769.3	955.1
Specific Net Investment Cost	€/kW	1006	1567
PRODUCTION COST DATA			
C.O.E. (DCF=10%)	c€/kWh	3.46	5.39

Notes: (1) At generator terminals.
(2) At Low Voltage side of the step-up transformer.

7.1 Cost of avoiding CO_2 emissions

The cost of avoiding CO_2 emissions can be expressed 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 of the alternative with CO_2 capture – Electric Power Cost of alternative w/o CO_2 capture. The Unit of measurement is Euro/kWh.
- Δ Specific CO_2 emission = Ratio of (CO_2 emission/Power production) of alternative with CO_2 capture – ratio of (CO_2 emission/Power production) of the alternative with CO_2 capture. The unit of measurement is ton CO_2/kWh.

Based on the above definition, the cost of avoiding CO_2 emissions, at DCF=10%, is the following:

- Cost of avoiding CO_2 emissions: **27.5 Euro/t**

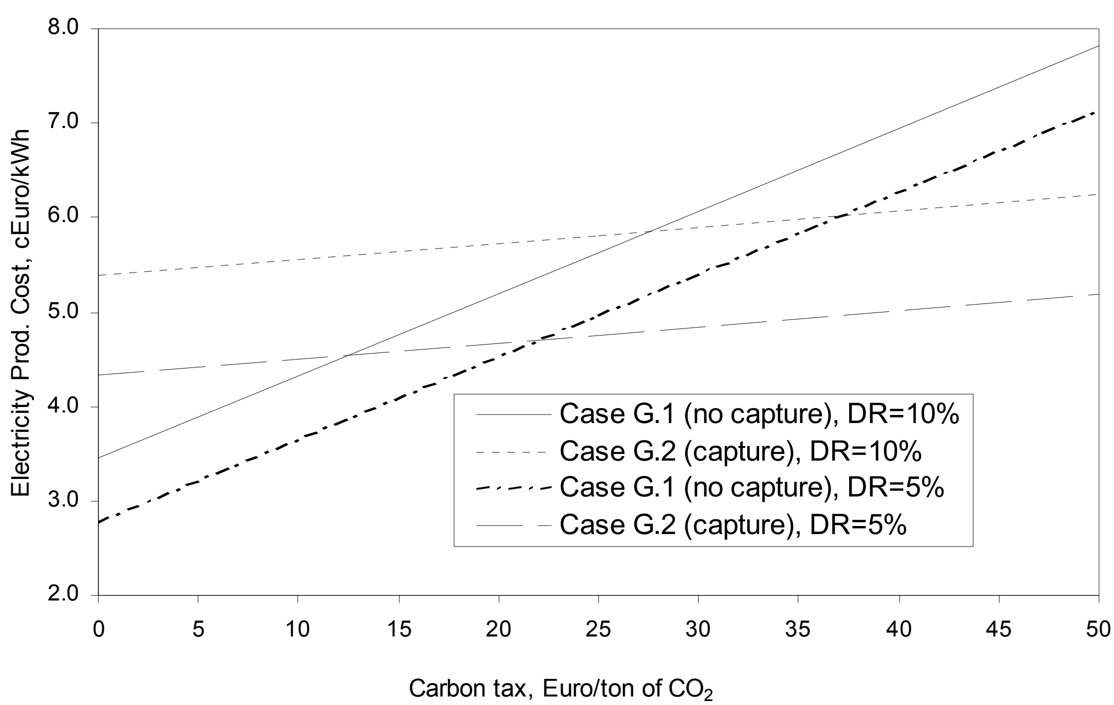
7.2 Electrical power cost in presence of carbon tax

Economic or regulatory mechanisms will be necessary to facilitate development and deployment of CO_2 capture technologies. There are various options, including a carbon tax or emission trading certificates.

The two CFB versions, with and without CO_2 capture, were also compared in presence of a carbon tax. Figure A.7.1 shows this comparison as function of an increasing carbon tax from 0 to 50 Euro/t of CO_2 emitted.

This comparison has also taken into account two different Discount Rates, 10% and 5%. For these two discount rates it appears that the Cost of production (C.O.E.) of these two versions is the same when the carbon tax is respectively 27 and 22 Euro/t of CO_2 emitted.

Fig. A.7.1 - Electricity Production Cost vs. Carbon tax



8.0 Summary and conclusions

The most important conclusions of the study are:

- Partial drying of the lignite is advantageous to increase efficiency, utilizing low temperature heat sources available in the plant at various locations.

- Despite the differences of the various technologies involved, the net electrical efficiency of the various alternatives considered falls in a narrow range of values. The Oxycombustion USC-PC alternative shows the highest electrical efficiency and the superior environmental performances.

- By comparing the different power plant technologies, the specific investment cost (Euro/kW) is the lowest for the CFB technology.

- The cost of electricity of the different alternatives falls in a narrow range of values; the maximum difference between the alternatives is approximately 10%.

- CFB alternative was selected for a more detailed analysis because of its superior specific investment cost and lower C.O.E.. However, the study demonstrated that other technologies utilizing low rank coals are very close in performances and, depending on different local circumstances, may become more competitive with respect to the CFB.

- The cost of CO_2 capture, calculated for the CFB technology is 27.5 Euro/t of CO_2 captured (DCF=10%).

- In an environment with a carbon tax, the CFB with and without CO_2 capture show the same C.O.E. when the carbon tax is 27 and 22 Euro/t of CO_2 emitted, respectively for a DCF of 10% and 5%.

- In the next 15 years, significant improvements of the technologies are expected. The most important improvements are:
  - New alloys to operate in more severe supercritical conditions.
  - Demonstration of Oxyfuel technology.
  - Largest single train capacity for CFB.
  - Various improvements of the IGCC technology on the gas turbines, gasifiers and air separation unit.

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SECTION B
GENERAL INFORMATION

INDEX

SECTION B GENERAL INFORMATION

SECTION B

1.0 Purpose of the Study

The IEA Greenhouse Gas R&D Programme has retained Foster Wheeler to investigate different Power Plant technologies, which use low rank coal as primary fuel and make the pre-combustion or post-combustion CO_2 capture. The primary purpose of this study is, therefore, the analysis of the benefits and issues associated with the use of low rank coal in the power industry, through the evaluation of different power plant technologies, to optimize efficiency, capital cost and reduce emissions to the atmosphere.

The study also analyzes the distribution and characteristics of the low rank coals deposits from the major producing regions worldwide, showing as almost 47% of the quantity recoverable deposits in the world is mainly composed of lignite and sub-bituminous coal (reference to Section I, attachment I.1). The analyses of the low rank coals deposits leads to the selection of a German lignite coal as feedstock for the different power plants, with a LHV equal to 10500 kJ/kg and a moisture content of 50.7%.

The nominal capacity of the different Power Plants is approximately fixed to 750 MWe.

The study evaluates costs and performances of seven different power plants technologies, with CO_2 capture. The description of the different power plant alternatives is made in paragraph 4.0. After the selection of the most attractive technology, the study also presents a more detailed assessment of performances and costs, comparing the alternative with and without the CO_2 capture, to evaluate the penalties related to the CO_2 capture.

Finally, the study investigates possible improvements to the screened technologies, in order to assess the likely performance of a plant in the year 2020.

2.0 Project Design Bases

The power plants are designed to process, in an environmentally acceptable manner, a Western Germany lignite (Rheinbraun) coal to produce electric energy to deliver to the national grid.

For the alternatives with post-combustion CO_2 capture, the design capacity of the plant is fixed to approximately provide 750 MWe of power production.
In case of alternatives with pre-combustion CO_2 capture, the design capacity is fixed to match the appetite of the two selected gas turbines, General Electric 9FA.

2.1 Feedstock Specification

The feedstock characteristics selected for this study (see Section I, attachment I.1) are listed hereinafter.

2.1.1 Design Feedstock

	Germany Garantie Coal Proximate Analysis, wt%
Inherent moisture	50.70
Ash	3.50
Coal (dry, ash free)	45.80
Total	100.00

	Ultimate Analysis, wt% (dry)
Carbon	63.54
Hydrogen	4.65
Nitrogen	0.74
Oxygen	23.44
Sulphur	0.45
Ash	7.10
Chlorine	0.05
Fluorine	0.03
Total	100.00

	Min % wt	Max (*) %wt
SiO_2	4.0	54.0
Al_2O_3	1.7	22.0
TiO_2	0.2	2.5
Fe_2O_3	5.0	16.0
CaO	7.0	34.0
MgO	3.0	17.0
Na_2O	1.0	4.0
K_2O	0.4	1.5
SO_3	11.0	15.0
HHV (as received), kJ/kg (*)	12000	
LHV (as received), kJ/kg (*)	10500	

(*) Refer to Section I, attachment I.1 (paragraph 5.0) for considerations on the ash composition.

2.1.2 Back-up Fuel

	Natural Gas 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/Nm3	4
LHV, MJ/Nm3	40.6
Molecular weight	19.4

2.2 Products and by-products

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

2.2.1 Electric Power

Net Power Output	:	750	MWe	nominal capacity
Voltage	:	380	kV	
Frequency	:	50	Hz	
Fault duty	:	50	kA	

2.2.2 Carbon dioxide

The carbon dioxide characteristics at power plants B.L. are the following:

Status	:	supercritical
Pressure	:	110 bar g
Temperature	:	30 °C
Purity	:	(1)
H_2S content	:	(1)
CO content	:	0.1 % wt (max)
Moisture	:	< 0.1 ppmvd
N_2 content	:	to be minimized (2)

(1) Depending on the process alternative considered (see Section D – Basic information for each alternative).

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

Minimum Capture level	:	80%
Preferred Capture level	:	85%

2.2.3 Solid by-products

The power plants studied produce saleable solid by-products, in particular:

Case 1 (USC-PC) (1)	:	flyash bottom ash gypsum
Cases 2 – 3 – 4 (OXY-PC, CFB, PCFB) (1)	:	flyash bottom ash
Case 5 (IGCC, Future Energy technology) (1)	:	slag (40% wt approx. water content)
Case 6 (IGCC, Shell technology) (1)	:	slag (10% wt approx water content) flyash
Case 7 (IGCC, FW Tecnology)	:	char

(1) : For the description of the different alternatives, see paragraph 4.0.

2.3 Environmental Limits

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

2.3.1 Gaseous Emissions

The overall gaseous emissions from power plants shall not exceed the following limits:

		Postcombustion CO_2 CO_2 capture (1)	Precombustion CO_2 capture (2)
NO_x(as NO_2)	:	$\leq$ 200 mg/Nm^3	$\leq$ 80 mg/Nm^3
SO_x(as SO_2)	:	$\leq$ 200 mg/Nm^3	$\leq$ 10 mg/Nm^3
Particulate	:	$\leq$ 30 mg/Nm^3	$\leq$ 10 mg/Nm^3
CO	:	$\leq$ 100 mg/Nm^3	$\leq$ 50 mg/Nm^3

Note: (1) @ 6% O_2 vol dry
(2) @ 15% O_2 vol dry

2.3.2 Liquid Effluent

Characteristics of wastewater discharged from power plants shall comply with the limits stated by the current EU directives.

For the IGCC cases, the effluent from the wastewater treatment shall be generally recovered and recycled back to the gasification island as process water.

2.3.3 Solid Wastes

The process does not produce any solid wastes, except for typical industrial plant waste e.g. (sludge from waste water treatment etc.).

2.3.4 Noise

All the equipment of the power plants studied are 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

For the alternatives with post-combustion CO_2 capture (conventional power station, CPS) the design capacity of the plant is fixed to approximately provide 750 MWe of power production.
For the alternatives with precombustion CO_2 capture (IGCC), the design capacity is fixed to match the appetite of two General Electric Frame 9FA.

A minimum availability of 85%, corresponding to 7446 hours of operation in one year at 100% capacity is expected for all the alternatives, starting from the second year of commercial operation.

2.4.2 Unit arrangement

Each power plant complex studied is in part a twin or multiple train facility, due to constraints on equipment size and/or to reliability reasons. The arrangement of the process units depends on the process alternative considered (reference to Section D – Basic information for each alternative).

2.4.3 Turndown

The power plants are designed to operate with a large degree of flexibility in terms of turndown capacity and feedstock characteristics. The multiple train configuration of each unit of the power plant (see Section D – Basic information for each alternative) allows to operate at low loads with respect to the design capacity.

This multiple configuration limits the events causing the shutdown of the entire power plant.

For the IGCC alternatives, the minimum turndown of each Gas Turbine on syngas is 20%, i.e. 10% of the design capacity. The minimum turndown of the Power Island, when all the machines are in operation (two Gas Turbines and one Steam Turbine), is about 25% of the IGCC capacity. Even if the operation of the IGCC complex at 25% load is a necessary step of the start-up procedure, its duration is to be limited, being approximately 35% load the expected turn down capacity for the entire IGCC Complex, compatible with a prolonged continuous operation.

For the post-combustion CO_2 capture alternatives, the possibility of turndown of the plants is limited by the capacity of the boilers to work at reduced load. Generally, each boiler can operate in the range of 40 % - 100% load, data depending on the degree of automation considered for the plant and on the equipment installed. The assumed turndown capacity of the conventional power stations is 40%.

2.5 Location

The site an inland area located in the Western Germany, in a greenfield area close the coalmine, without special civil works implications.

The proximity to the coalmine is an essential issue, due to the use of lignite case as primary fuel. In fact, lignite is not often transported long distances because its low heating value makes it relatively expensive to transport and because it often has a great tendency to spontaneously combust.

The plant area is assumed to be close to river water, which is used as make-up water.

2.6 Climatic and Meteorological Information

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

• atmospheric pressure			
	: 1013	mbar	(*)
• relative humidity			
average	: 60	%	(*)
maximum	: 95	%	
minimum	: 40	%	
• ambient temperatures (dry bulb temperatures)			
minimum air temperature	:-10	°C	
maximum air temperature	: 30	°C	
average air temperature	: 9	°C	(*)
• wet bulb temperature at reference conditions:	: 5.6	°C	

2.7 Economic/Financial Factors

2.7.1 Design and Construction Period

Power plants design and construction will be completed in 34 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 the following:

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 Contingency

A contingency of 10% of the installed plant cost will be added to the capital cost in absence of more detailed assessment on the specific unit.

2.7.4 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 assume a 100% equity. No interest during construction is applied.

2.7.5 Inflation

No inflation shall be applied to the economical analysis.

2.7.6 Commissioning

Power plants commissioning will take a 6 month period during the last two months of the third year of construction and the first four months of first year of operation.

2.7.7 Working Capital

Sufficient storage for 30 days operation at rated capacity will be allowed for raw materials, products, and consumables. No allowance will be made for receipts from sales in this period.

2.7.8 Land purchase, surveys, general site preparation

5% of the installed plant cost is assumed.

2.7.9 Taxation and Insurance

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

2.7.10 Fees and owner costs

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.

2.7.11 Operation and Maintenance

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

2.7.12 Fuel Costs

Cost of coal delivered to site is 1.0 $/GJ (LHV basis).
Cost of natural gas delivered by pipeline to site is 1.7 $/GJ (LHV basis).

2.7.13 By-Products Price

No selling price is attributed to CO_2 and other by-products.

2.8 Software Codes

For the development of the Study, two software codes have been mainly used:

- HYSYS v3.0.1 (by Hyprotech Ltd.): Process Simulator used for syngas treatment and for CO_2 capture and compression simulations, downstream the Gasification Island or Power Island.
- Gate Cycle v5.40.0 (by General Electric): Simulator of Power Island units.
- ProMax v1.2 (by BR&E): Simulator for CO_2 capture with amine washing (post-combustion capture)

3.0 Basic Engineering Design Data (BEDD)

3.0 Introduction

Scope of the Basic Engineering Design Data is the definition of the common bases for the design of the units included in the different Power Plants to be built in an inland area of Germany.

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
  Power Plants complex area : 10 m above mean sea level.
- atmosphere type : Industrial.

3.3 Climatic and Meteorological Information

The reference conditions are shown in paragraph 2.6.

Other data:

- rainfall
  design : 25 mm/h
  50 mm/day
- wind
  maximum speed : 35 km/h
- snow : 50 kg/m2
- winterization
  winterization is required.

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 main process and utility fluids at plants battery limits are the following:

- Coal;
- Natural Gas;
- Plant/Raw/Potable water;
- CO_2 rich stream;
- Limestone;
- Chemicals.

3.6 Utility and Service fluids characteristics/conditions

In this paragraph are listed the utilities and the service fluids distributed inside the power plants.
The conditions marked (*) shall be considered reference conditions for the plants performance evaluation.

3.6.1 Cooling Water

Cooling Water for Condenser

Source : raw water in closed loop with cooling towers.
Service : steam turbine condenser.

Supply temperature:			
- average supply temperature (on yearly basis)	: 11	°C	(*)
- max supply temperature (average summer)	: 30	°C	
- max allowed temperature increase	: 10	°C	(*)
Return temperature:			
- average return temperature	: 21	°C	(*)
- max return temperature	: 40	°C	
Operating pressure at Condenser inlet	: 3	barg	
Max allowable ΔP for Condenser	: 0.7	barg	
Design pressure for Condenser (CW side)	: 5.0	barg	
Design temperature	: 70	°C	
Cleanliness Factor (for steam condenser)	: 0.9		

Machinery Cooling Water

Source : raw water in closed loop with cooling towers (same as per condenser)
Service : for machinery cooling (different ΔP at users)

Supply temperature:			
- average supply temperature	: 11	°C	(*)
- max supply temperature	: 30	°C	
- max allowed temperature increase	: 10	°C	(*)
Operating pressure at Users	: 4.0	barg	
Max allowable ΔP for Users	: 1.5	bar	
Design pressure	: 6.0	barg	
Design temperature	: 70	°C	

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	:	40 °C

Raw water

Source	:	from river
Type	:	raw water
Operating pressure at grade	:	0.8 barg (min)
Operating temperature	:	Ambient
Design pressure	:	5.0 barg
Design temperature	:	Ambient

Plant water

Source	:	from storage tank of raw water
Type	:	raw water after filtration
Operating pressure at grade	:	3.5 barg
Operating temperature	:	Ambient
Design pressure	:	9.0 barg
Design temperature	:	40°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	:	40 °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, Steam Condensate and BFW

Steam (IGCC alternatives)

These conditions refer to the Process Units. Inside Power Island the steam levels are different, even if there are interconnected to the Process Units.

Table 3.1 – Process Units steam conditions.

	Pressure, barg			Temperature, °C	
	Max	**Min**	**Design**	**Norm**	**Design**
High Pressure **(HP)** Nominal Pressure: 160 barg	170	160	187	353	370
Medium High Pressure **(MHP)** Nominal Pressure: 80 barg (1)	85	80	93	300	330
Medium Pressure **(MP)** Nominal Pressure: 40 barg	43	40	47	256	270
Low Pressure **(LP)** Nominal Pressure: 6.5 barg	8.0	6.5	12	175	250
Very Low Pressure **(VLP)** Nominal Pressure: 3.2 barg	4.0	3.2	12	152	250

Notes: (1) Only for Cases 6 – 7 (see paragraph 4.0 for definition of the alternatives)

In the table above:
- The maximum value indicates the steam generation pressure to be adopted for steam generators in the Process Units.
- The minimum pressure indicates the steam pressure available for steam users.
- The normal Temperature indicates the *saturation T* corresponding to the Max Pressure indicated.

Steam (Conventional Power Station alternatives)

The only utility steam used inside the Power Plants is VLP steam, whose characteristics are the same of those shown in table 3.1.

Steam Condensate from process, utility and off site units

Steam condensate will be flashed within process units whenever possible to recover steam and piped back to the condensate collection header.
The condensate collection header shall have the following characteristics:

Operating pressure for other Units B.L.	: 1	barg
Operating temperature	: 94	°C
Design pressure	: 12.0	barg
Design temperature	: 250	°C

Boiler Feed Water *(IGCC alternatives)*

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

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

	Pressure Barg	**Temperature °C**
	Normal	**Normal**
Boiler Feed Water, Very Low Pressure **(BWV)**	15	120
Boiler Feed Water, Low Pressure **(BWL)**	15	160
Boiler Feed Water, Medium Pressure **(BWM)**	60	160
Boiler Feed Water, High Pressure **(BWH)**	195	160

3.6.4 <u>Instrument and Plant Air</u>

<u>Instrument air</u>

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

<u>Plant air</u>

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

3.6.5 <u>Nitrogen</u> *(CASES 5 –6, see para. 4.0 for description of the alternatives)*

<u>Low Pressure Nitrogen</u>

Supply pressure	:	6.5	barg
Supply temperature	:	15	°C min
Design pressure	:	11.5	barg
Design temperature	:	70	°C
Min Nitrogen content	:	99.9 % vol.	

<u>Medium Pressure Nitrogen (Syngas dilution)</u>

Supply pressure	:	30	barg
Supply temperature	:	210	°C
Design pressure	:	35	barg
Design temperature	:	240	°C
Min Nitrogen content	:	98 % vol.	

<u>Medium Pressure Nitrogen (GT injection)</u>

Supply pressure	:	26	barg
Supply temperature	:	213	°C
Design pressure	:	35	barg
Design temperature	:	240	°C
Min Nitrogen content	:	98 % vol.	

High Pressure Nitrogen

Supply pressure	:	80 barg (Case 5) 70 barg (Case 6)
Supply temperature	:	15°C (Case 5), 80° C (Case 6)
Design pressure	:	90 barg (Case 5) 80 barg (Case 6)
Design temperature	:	45°C (Case 5), 110° C (Case 6)
Min Nitrogen content	:	99.9 % vol.

3.6.6 Natural Gas

Characteristics of Natural Gas are listed in Project Design Bases (paragraph 2.0).

High Pressure

Type : natural gas.
Service : Gas turbines start-up and back-up fuel.

Operating pressure at Users	:	27.0 barg
Operating temperature at Users	:	30°C above natural gas dew point
Design pressure	:	33.0 barg
Design temperature	:	70 °C

Low Pressure

Type : natural gas.
Service : Boiler start-up and distribution.

Operating pressure at Users	:	3.5 barg
Operating temperature at Users	:	30°C above natural gas dew point
Design pressure	:	6.0 barg
Design temperature	:	60 °C

3.6.7 Oxygen *(for IGCC and PC-Oxycombustion alternatives)*

The Oxygen for the gasification unit has the following characteristics:

Supply pressure	:	(*)
Supply temperature	:	(*)
Design pressure	:	(*)
Design temperature	:	(*)

(*) Depending on the process alternative considered (see Section D – Basic information for each alternative).

Purity	:	95.0	% mol. O_2 min
		3.0	% mol Ar
		2.0	% mol N_2
H_2O content	:	1.0	ppm max
CO_2 content	:	1.0	ppm max
HC as CH_4 (number of times the content in ambient air)	:	5	max

3.6.8 Electrical System Distribution

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)	66000 ± 5%	3	50 ± 0.2%	31.5 kA
Primary distribution (2)	30000 ± 5%	3	50 ± 0.2%	31.5 kA
MV distribution and utilization	11000 ± 5% 6000 ± 5%	3 3	50 ± 0.2% 50 ± 0.2%	31.5 kA 25 kA
Emergency power souce	6000 ± 5%	3	50 ± 0.2%	31.5 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	-	-

Notes: (1) for IGCC Plant
(2) for Coal Power Plants other than IGCCs.

3.7 Plant Life

The Plants are designed for a 25 years life, with the following considerations:

- Design life of vessels, equipment, component 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.

4.0 Alternative Designs of Power Generation

Several power plants alternatives have been developed in the Study.
The contemplated alternatives attempt to compare the following key process aspects:

- Different coal power plant technologies for combustion of a lignite coal;
- Post-combustion and pre-combustion CO_2 capture in alternatives coal power plants;
- Different CO_2 capture technologies (MEA, MDEA scrubbing or gas liquefaction).
- Performance and cost penalties for the capture of CO_2, to reduce environmental impact (only on the most promising technology amongst the investigated alternatives).

The following alternatives are investigated:

CASE 1 Ultra Super Critical Pulverized Coal (USC-PC) Boiler with post-combustion CO_2 capture (using MEA as solvent washing).

CASE 2 USC - PC-Oxycombustion Boiler, with post combustion CO_2 capture by means of Gas liquefaction.

CASE 3 Foster Wheeler Circulating Fluidized Bed (CFB) Boiler, with post-combustion CO_2 capture (using MEA as solvent washing).

CASE 4 Foster Wheeler Pressurized Circulating Fluidized Bed (PCFB) Boiler, with post-combustion CO_2 capture (using MDEA as solvent washing).

CASE 5 Future Energy gasification technology, sour shift (2 stages) and CO_2 capture (MDEA scrubbing with combined capture of CO_2 and H_2S)

CASE 6 Shell gasification technology, sour shift (2 stages) and CO_2 capture (MDEA scrubbing with combined capture of CO_2 and H_2S)

CASE 7 Foster Wheeler Air gasification technology, sour shift (2 stages) and CO_2 capture (MDEA scrubbing with combined capture of CO_2 and H_2S)

The Future Energy gasification technology is based on a dry feed gasifier, with product gas cooling by water quench. The gasifier consists of an outside pressure wall and an inside cooling screen cooled by pressurized water to protect the outside wall against chemical and thermal attacks.

The hot raw synthesis gas and the liquid slag leave the gasifier reaction chamber and flow in parallel vertically downward and discharge directly into the quench section - where the raw gas is cooled down to approximately 220°C by injection of water. Slag produced is granulated in the water bath in the bottom of the Quench system.
The raw gas is saturated with steam (approx. 60%). This water becomes gas condensate in the following cooling steps of the syngas treatment and it will be recycled back as quench water.

The Shell gasification technology is based on a dry feed gasifier, with product gas cooling in a heat recovery boiler. The gasifier consists of a pressure vessel with a gasification chamber inside. Circulating water through the membrane wall to generate saturated steam controls the inner gasifier wall temperature. The membrane wall encloses the gasification zone from which two outlets are provided. One opening at the bottom of the gasifier is used for the removal of slag. The other outlet allows hot raw gas and fly slag to exit from the top of the gasifier.
The hot raw product gas leaving the gasification zone is quenched with cooled, recycled product gas to convert any entrained molten slag to a hardened solid material, prior to entering the syngas cooler. The syngas cooler recovers high-level heat from the quenched raw gas by generating steam. The syngas cooler is water tube type.

The Foster Wheeler gasification technology is based in a CFB gasifier, with air as partial oxidation agent. The gasifier is basically a pressurized CFB unit, completely refractory lined, with no heat transfer surfaces.
The hot syngas leaving the CFB Gasifier is cooled from 930°C to approximately 390°C before filtration. The syngas cooler transfers heat to the steam cycle generating MHP steam. The industry trend for these coolers is a fire tube design, with gas flowing inside the tubes and steam or water outside, on the shell side.

Table B.4.1 provides a summary of the 7 cases with some of the most significant performance data of each alternative. From the comparison of these alternatives, the most attractive technology is selected (see section F) and a more detailed assessment of performances and costs are made for both for the case with and without CO_2 capture (see section G).

Table B.4.1 Most significant performance data for all the process alternatives

ALTERNATIVE		Case 1 USC-PC-Boiler	Case 2 USC-PC-Oxy Combustion	Case 3 FW CFB Boiler	Case 4 FW PCFB Boiler	Case 5 Future Energy Gasifier	Case 6 Shell Gasifier	Case 7 FW Gasifier
Coal Flow rate	**t/h**	734.0	677.6	592.9	727.0	653.3	624.2	691.0
Net Electric Power Output	**MWe**	761.0	741.3	614.4	688.4	665.2	628.8	686.6
Gross Electrical Efficiency	**%**	43.5	52.6	44.1	38.5	47.2	47.7	44.7
Net Electrical Efficiency	**%**	35.5	37.5	35.5	32.5	34.7	34.5	34.1
Acid Gas Removal Technology		MEA Scrubbing	Gas Liquefaction	MEA Scrubbing	MDEA Scrubbing	MDEA Scrubbing (1)	MDEA Scrubbing (1)	MDEA Scrubbing (1)
CO_2 capture efficiency	**%**	85.0	93.0	85.0	85.0	85.8	85.2	82.9

Note: (1): Combined removal of CO_2 and H_2S.

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : CO_2 CAPTURE IN LOW RANK COAL POWER PLANTS
DOCUMENT NAME : DESCRIPTION OF THE MAJOR BLOCKS COMMON TO THE POWER GENERATION ALTERNATIVES

ISSUED BY : G.L. FARINA
CHECKED BY : G.L. FARINA
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by

SECTION C

DESCRIPTION OF THE MAJOR PROCESS BLOCKS COMMON TO THE POWER GENERATION ALTERNATIVES

INDEX

1.0 COAL HANDLING AND STORAGE

The expected net power output from the various power generation alternatives considered in Section D is 750 MW approximately. Depending on the overall efficiency of the generation scheme this net power output corresponds to a supply of low rank coal (lignite) in the range of 800-850 t/h.
The receiving, storage and handling facilities of this coal flowrate are very large and require an extended plot area.

According to the study bases of design the plant is assumed to be located close to a lignite mine to permit delivery to site by belt conveyors or alternatively by a dedicated railway.

At the plant site the coal is stored in dome, providing, a minimum of 5 days storage, which is equivalent to 100,000 ton of coal, which would require a land area of approx. 15,000 m^2.

The coal from the dome is moved by enclosed belt conveyors to 4 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 4 parallel crushers, each sized for 50% of the full capacity. The crushers are designed to break down big lumps and deliver a coal lignite with lump size not exceeding 5 cm.
Coal lignite from the crushes is transferred by enclosed belt conveyors to 4 feed silos close to the process area, where the coal lignite size is further reduced by 4 mills to the level required by the downstream power generation plant. This can be a powder, in the 50-150 micron range, for the technologies requiring a pulverized feed, or a feed or, alternatively, a coal crushed to a maximum size of 2-3 cm for fluid bed technologies.

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.

2.0 DRYING OF LOW RANK COAL-LIGNITE

The efficiency of a power generation plant can be significantly enhanced if the moisture in the feed coal lignite is reduced. But, while there are a lot of studies on low-rank coal drying, there is very limited experience of lignite drying at the level of pilot or demonstration plant.

In spite of the fact that today, there is not yet a commercially proven lignite drying technology, such a process is expected to become shortly available, as the number of users of low rank coal increases worldwide.

It is proposed in the present study to advantageously utilise some low temperature energy available in the plant at various locations, to dry and improve the quality of coal. However only a low temperature drying of coal lignite is attempted. Because when the drying temperature is increased the volatiles from the coal are liberated. As long as the coal temperature is less than 120 °C the part of volatiles that leaves the coal is insignificant. First CO_2 leaves the coal at more than 120 °C, later at about 180°C coal temperature H_2, CO and CH_4**.** Volatiles in coal lignite are very useful and necessary to preserve the good ignition and combustion characteristics. Once the volatiles are removed, the characteristics of coal are significantly changed, with a net loss of the energy content. Hence, in this study, we propose a low temperature drying, controlled in order to reduce moisture as much as possible, but without loosing the volatile content. This means that the moisture content of the design lignite feed is lowered from 50.7% down to 30-32% for the USC PC, CFB boiler and Oxycombustion boiler alternatives, and 5-10% for the IGCC alternatives, except FW Gasifier, to allow the pneumatic transportation of the coal. For the IGCC alternative employing FW Gasifier the moisture content is lowered down to 25%. This will achieve the following advantages:

- increased overall efficiency by a few percent point;
- reduced flow of coal to the mills, by about 30%, directly reducing the power requirement of the mills by about 30%;
- reduction in the flue gas flowrate by about 6%. This has advantages in reducing the power consumption in the flue gas line and reducing the sizing of the FGD and CO_2 absorption plants.

The process alternatives to dry coal lignite are:

- Direct drying with flue gases at the exit of the plant.
- Indirect drying.

Drying by a direct contact of lignite with the flue gas would envisage a bubbling bed of coal, through which the flue gas is pushed. The expected pressure drop of such a system would be very high and consume substantial energy.
Further, a significant entrainment of coal fines into the flue gas should be expected. Few studies have investigated such direct contact drying, because this route appears to be costly and difficult to keep under strict control the drying temperature to prevent loss of volatiles.
For these reasons the "indirect" drying of the low rank coal is the most promising technology.

In USA EPRI is sponsoring a research and development program to dry lignite for the Great River coal program in North Dakota. The process involves the use of a bubbling fluidised bed of lignite. Heat energy to evaporate moisture is supplied by circulating hot water, which preheat air, fed to the bubbling bed and also supply additional heat to the bed by a coil submerged in the bed (see Fig. 2.1). The hot water is heated to 85°C maximum to prevent loss of volatiles contained in the lignite. Hot air carries away part of the coal moisture and, before discharge to the atmosphere, is passed through a bag filter to stop entrained coal powder, which is recycled back to the dried lignite product.
This type of drier is used for all the alternatives of the study, heating the hot water to the maximum temperature of 85°C and feeding air to the bubbling bed at 65°C maximum. Several sources of low temperature heat exist in the plant, depending on the process configuration to heat the circulating water. For the boiler options f.i. the heat recovery is performed on the cold flue gas side and interstage coolers of the CO_2 compressor. For the IGCC alternatives, the heat recovery is performed by using different sources: coolers of the syngas cooling section and N_2 compression section, interstage coolers of the CO_2 compressors, VLP steam generated in the syngas cooling section.
The Great River Energy is in the process of designing a demonstration fluidised bed drier of the locally produced low rank coal.

In parallel, in Germany, RWE is supporting a technology demonstration program to dry Germany lignites. Pilot scale plant of 30 t/h capacity, is in operation; a larger demonstration unit, 240 t/h, is expected to operate in the next 2-3 years, with a target to have this technology available for the design of large new power plants for the year 2008.
This process, known as WTA, is also based on a bubbling bed of fine grain lignite, fluidised by steam. The vapour living the fluidised bed of lignite is cleaned and compressed according to the heat pump principle to such an extent that its thermal energy can be used to heat the lignite bed (see Fig. 2.2).
Shell has just presented at the Gasification Technologies Conference (San Francisco, October 9-12, 2005) this new system based on a steam-fluidised

bed, which uses a vapour electrostatic precipitator in the circulation of the vapour from/to the drier and a dry lignite cooler before going to the downstream storage.

In parallel to the above-described fluidised bed drying technologies, an alternative route, based on mechanical/thermal dewatering, is under development in Germany to reduce the lignite coal water content. Here the coal is first heated; then the water is expelled by means of a press or centrifuge. This process is tested at Rheinbraun, but appears to be not as close to commercialization as the fluid bed techniques.

Figure 2.1- Lignite Indirect Drying

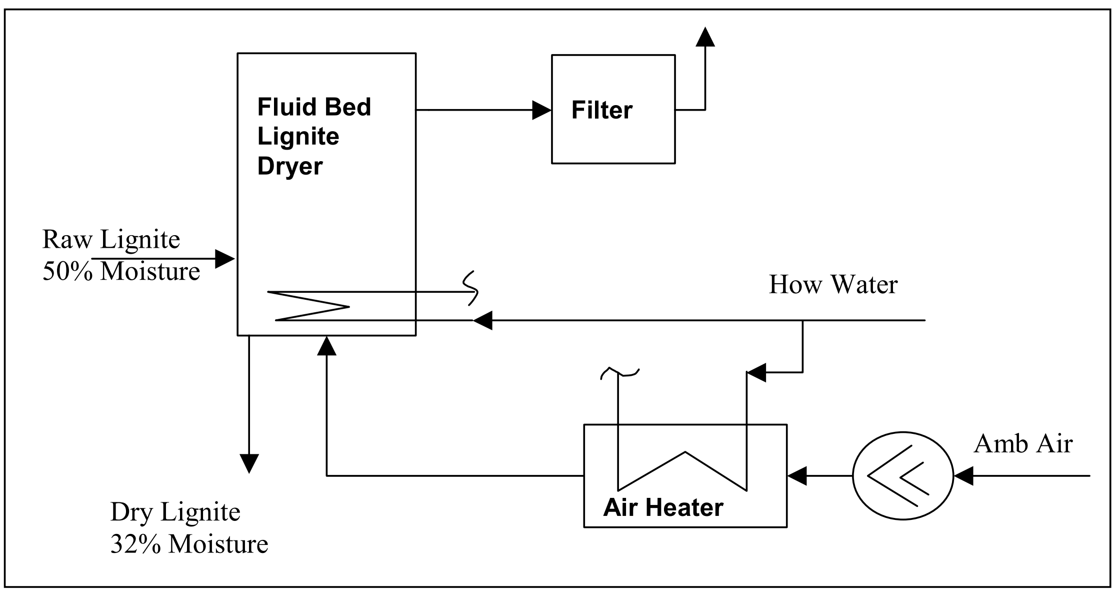
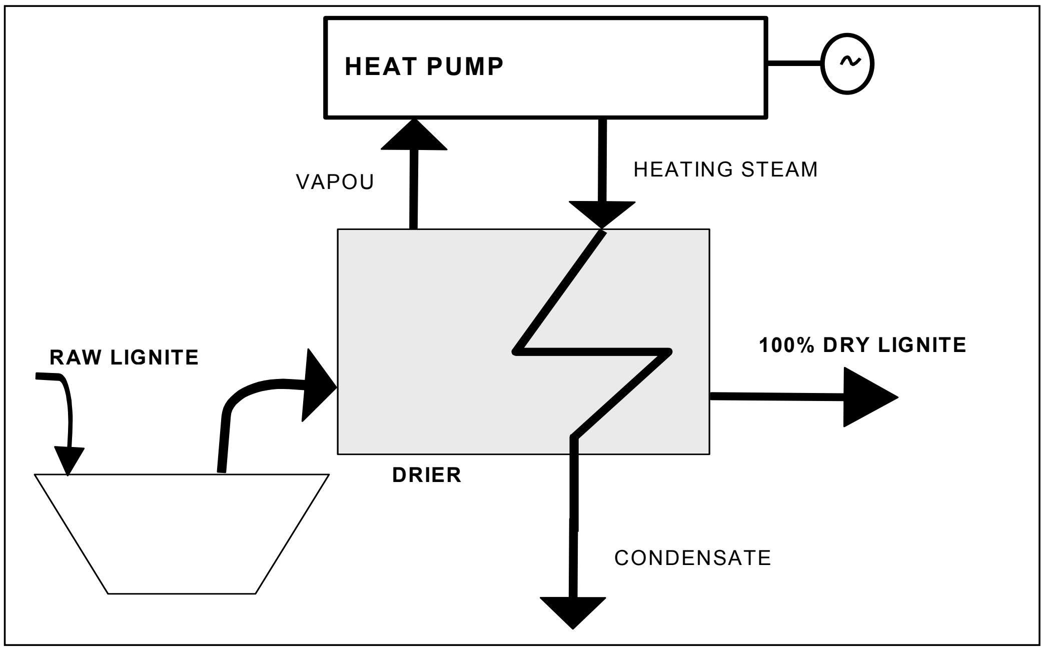


Figure 2.2 - WTA Lignite Drying



3.0 ASH HANDLING

Power generation from coal 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 coal 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 or gasifier vessel.
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 or gasification chamber by the flue gas or syngas and collected in downstream equipment: hoppers, electrostatic precipitators or bag filters.
Bottom ash is generally disposed in a landfill while fly ash is 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.

4.0 FLUE GAS DENITRIFICATION (DeNO$_x$)

The combustion of fossil fuels produces nitrogen oxide (NO) and dioxide (NO_2), collectively called NO_x. The monoxide (NO) is the predominant specie.
Selective catalytic reduction (SCR) is a process that catalytically reduces NO_x to N_2 in presence of NH_3.
An alternative NO_x control route is proposed by BOC, LoTox, which is based on addition of ozone to the flue gas, to oxidize NO and NO_2 to higher nitrogen oxides (N_2O_3 and N_2O_5). These are water-soluble and can be easily captured by a caustic solution to form nitrate and nitrite salts. The atmospheric oxygen is converted to ozone in an alternative generator, supplied as a package by BOC.

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.

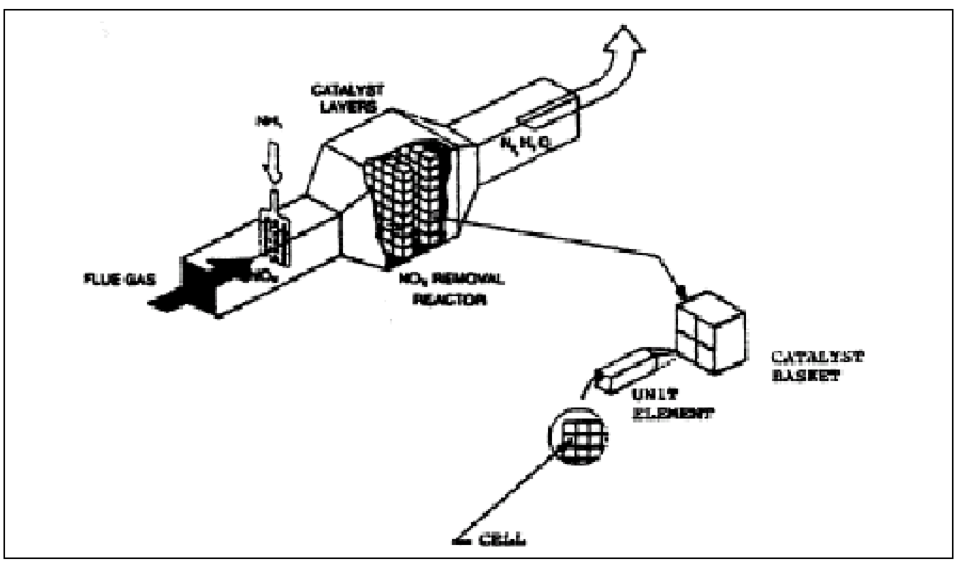


Figure 4.1 SCR System

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. Cell size varies from 4 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 320°C if SO_3 is less than 5 ppm; higher temperatures, 350-400°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.

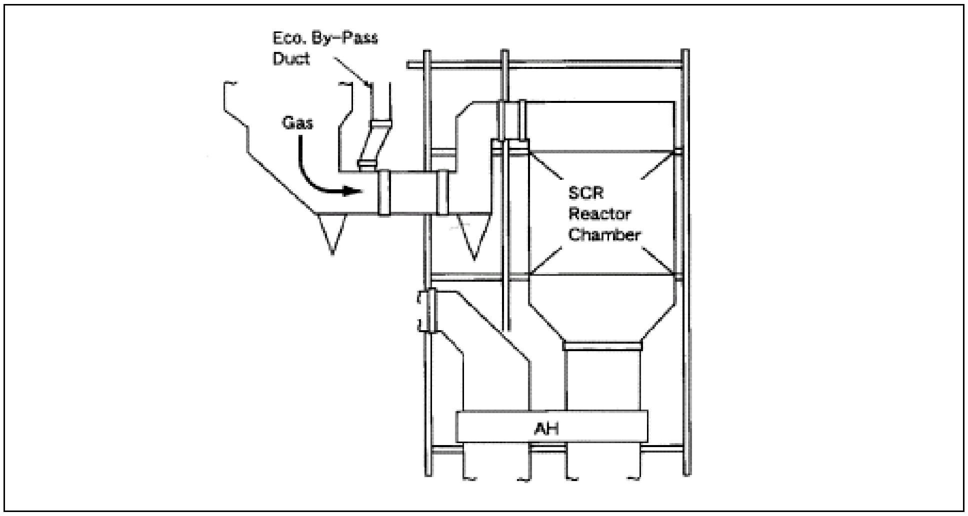


Figure 4.2 SCR in conventional boilers

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 ecomizer 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 mixed with air heated up to 300-450°C in a dedicated coil in the boiler duct. The vaporized 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.

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 (1 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 5-10 ppm. At this point, normally 5-7 years after start-up, the remaining portion of the fresh catalyst is loaded and the NH_3 slip can go back to 1-2 ppm and then progressively increased to compensate further catalyst aging until the end of catalyst life (normally 10 years).

In order to provide a reference for the power generation alternatives described in Section D, the performance and cost of a DeNOx system sized for a coal fired power generation with the following characteristics are given:

Bituminous coal fired	:	210 t/h
Net power output	:	660 MW
Flue gas flowrate	:	2,200,000 Nm^3/h
Flue gas NO_x content	:	300 ppmv (615 mg/Nm^3 6% O_2 – dry)

NO_x content of the exit flue gas is 20 ppmv (40 mg/Nm^3)@ 6% O_2 – dry)
The investment cost of the $DeNO_x$ system is 21 million US$.
The consumption of NH_3 (100%) is 400 kg/h.

The consumption of utilities is negligible.

When the plant includes downstream a CO_2 amine scrubbing, the residual NO_x should be as low as possible to reduce the amine consumption. The 20 ppmv level is a maximum not to be exceeded, otherwise the cost of the amine loss would be too high.

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 has become the dominant technology, as demonstrated by the following Table 5.1, which summarizes a database developed by the International Energy Agency, Coal Research Center in London. This Table 5.1 gives the total MW capacity in service in 1998 with FGD, divided in three categories of FGD technologies.

Table 5.1
Total MW capacity in service with FGD in 1998

Technology	United States	Abroad	Word Total
Wet	82,859	116,374	199,233
Dry	14,836	11,008	25,394
Other	2,798	2,059	4,857
Total FGD	100,043	129,441	229,484

The following Table 5.2 gives the MW capacity in service in 1998 with wet FGD, divided by different reagents. The preference for limestone is evident from these data.

Table 5.2
Breakdown of MW capacity in service with wet FGD in 1998

Technology	United States	Abroad	Word Total
Limestone	55,540	107,790	163,330
Lime	14,196	6,976	21,172
Dolomitic Lime	10,292	50	10,342
Sodium Carbonate	2,756	75	2,831
Seawater	75	1050	1,125
Other	-	433	433
Total FGD	82,856	116,374	199,233

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. Hydroclones

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 hydroclones. The hydroclones 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.

An example of an advanced FGD design, incorporating all the improvements described above, is the single module absorber installed in the 890 MW Tampa Electric Co. Big Band Station, firing a 3.1% sulphur fuel. The main characteristics of this absorber are:

- flue gas flowrate : 4,800,000 m3/h
- gas velocity : 5 m/s
- absorber diameter : 18.3 m
- absorber height : 40 m
- SO_2 removal efficiency: greater than 95%

The investment cost of a today, most advanced large scale FGD design is reported to fall in the range 100-150 US$ per kW, a dramatic drop compared to the 250-300$ per kW of FGD designs of 10-15 years ago.

In order to provide a reference for the power generation alternatives described in Section D, we give, in the following paragraphs, the performance and cost of an FGD system sized for a coal fired power generation with the following characteristics:

Bituminous coal fired	210 t/h
Net power output	660 MW
Overall efficiency	44 %
Flue gas flowrate	2,200,000 Nm^3/h
SO_2 flue gas content	1000 mg/Nm^3 (6% O_2 – dry)
SO_3 flue gas content	10 mg/Nm^3 (6% O_2 – dry)
Flue gas temp. ex. ESP	130 °C

The scrubbed flue gas SO_2 content is 100 mg/Nm^3 (6% O_2 – dry), which corresponds to SO_2 removal efficiency equal to 90%.

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

Gypsum (calcium sulphate de-hydrate) specification, saleable as house building material, is:

$CaSO_4$ x $2H_2O$	% wt dry	95 min
$CaSO_3$	% wt dry	0.25 max
$CaCO_3$	% wt dry	1.5 max
Cl^-	ppm (dry)	100 max
Mg^{++}	ppm (dry)	100 max
Na^+	ppm (dry)	600 max
Colour		white
Humidity	% wt	10 max

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 (Liungstroem type) to reheat the flue gas going to the stack. This reheat is however optional. Optional is also the downstream water prescrubber, used to reduce particulates, alogens, saturate and cool the flue gas.
The limestone scrubber is a countercurrent, open spray tower, possibly with one or two contact trays. Six layers of spray nozzles are located at the top, achieving a total liquid to gas ratio of 15÷20 l per Nm^3 of flue gas, equivalent to a total liquid flow of approximately 40000 m^3/h.
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:

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

Every ton of SO_2 removed generates 0.7 ton of CO_2.
The material of construction of the scrubbing tower is carbon steel lined with rubber or special alloy C-276.
The scrubber diameter is 13 m which corresponds to a flue gas, velocity inside the tower equal to 5 m/s.

The scrubber height is 40 m.
The limestone from the stockpile is crushed and milled to a 50 micron size and dispersed in a water slurry, continuously pumped to the scrubber.
The scrubber bottom slurry is dewatered in hydroclones. 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 hydroclones 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.

The utility and chemical consumptions of this wet FGD module including all auxiliary facilities shown in Figure 5.1, are:

Electrical power	6500	kW
Make-up industrial water	110	m^3/h
Limestone	4	t/h
Gypsum product	6.8	t/h

The delivered and erected investment cost is

$$85 \times 10^6 \text{ US\$}$$

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 lignite.
The particulate leaving the electrostatic separator is predominantly in the submicron range, which does not result in any significant abatement by the wet limestone scrubbing. If the fuel used contains heavy metals (Ni, V, etc.) unfortunately these, after combustion, are in the submicron range, so the electrostatic precipitator and FGD do not stop them effectively. The only way to capture the heavy metals is by active carbon injection followed by bag filtration (see paragraph 6.0).

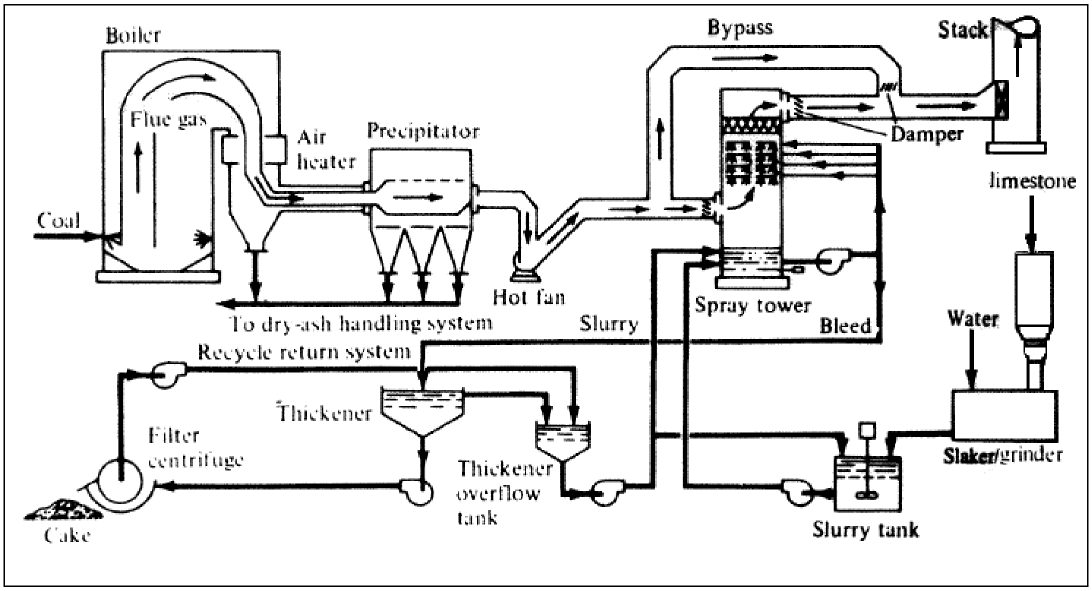


Figure 5.1 FGD Flow Scheme

6.0 MERCURY AND HEAVY METALS 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 fabric bag filter. The best processing scheme is an electrostatic precipitation to remove 99% of particulate (micron range) followed by active carbon injection and pulse jet fabric filter, capturing the submicron particulate, where heavy metals are concentrated. Mercury is absorbed on the active carbon injected and trapped by the fabric 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.

The investment cost of this type of treatment facilities is not available but it falls in the range of the cost of a bag filter house, sized for the flue gas rate.

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.

Should the power industry be obliged to remove CO_2 from flue gas the most likely route is the use of solvent absorption, better suited for the large capacities involved.

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 (see also para. 8.0).
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. Intermediate solvents could offer and interesting compromise, lowering the consumption of regeneration steam. This is the case of sterically hindered amines, which display a weaker link with CO_2, intermediate between a standard amine, like MEA and a physical solvent, like methanol.

Because of the advanced state of development of amine absorption it is likely that the first generation of CO_2 post combustion capture will 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. The solvent formulation with special inhibitors is the basic know-how offered for licence by 3 companies:

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. Energy is consumed by flue gas blowers to overcome the system pressure drop; additionally 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 de-NO_x and FGD facilities, to meet the extremely low levels of residual NO_x and SO_x in the flue gas, before entering the amine scrubbing. In fact, SO_x and NO_x form with amine stable, non regenerable, salts, thus causing a continuous loss of solvent. For this reason the flue gas fed to amine scrubbing should not exceed the following limits:

NO_X	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 use of low NO_x burners together with SCR generally permit to meet the required NOx specification, but the SO_x limit (10 ppm) is a serious challenge for today FGD technology.

Another risk issue of post combustion CO_2 removal is the effect on amine solution of other types of impurity (alogens, 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 stop before investing in a large capacity plant.

As a reference for the power generation alternatives of Section D a CO_2 postcombustion amine scrubbing is presented for a coal fired power generation with the following characteristics as above specified.

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

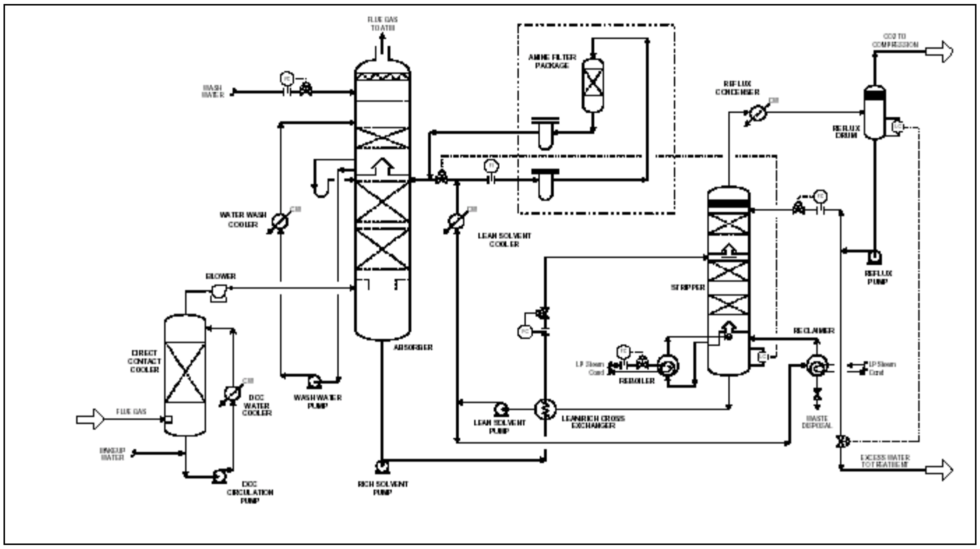


Fig 7.1 – CO_2 postcombustion capture; typical flow scheme

Treated flue gas from FGD 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 at 55°C and goes directly to the stack, which can be mounted on the absorber top.

Rich amine from the bottom is pumped to the regeneration section. After heat exchange with the stripped, hot, amine from the stripper, rich MEA flows in part to the stripper and in part 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 slip stream of the amine circulation is sent to the reclaimer (not shown) where, after addition of sodium carbonate, the amine is distilled with the use of MP steam, to separate the heat stable salts and impurities which are pumped away for disposal.

One module made up by two absorber and one regenerator can process the flue gas of the coal fired power station indicated above. The estimated demand of

LP steam for regeneration, assuming a CO_2 recovery equal to 85%, is 670 t/h.
Power required to drive pumps and blower is 8 MW.
The estimated consumption of MEA plus inhibitor is 1000-1200 kg/h.

8.0 CO_2 PRECOMBUSTION CAPTURE

The CO_2 precombustion capture is applicable to those power generation alternatives (Section D) based on coal lignite gasification. In these processes schemes, after the gasification and sour shift steps, the syngas, before going to combustion in the gas turbine, must be treated for the removal of acid gases, CO_2 and H_2S. This syngas purification is favoured by the fact that syngas is under pressure, which enhances the capture capability of the solvent used in the acid gas removal.

Several different solvents are commercially available for acid gas removal.
They can be grouped in three categories The physical solvents, such as methanol or Selexol, capture the acid gas in accordance with the Henry's law; the chemical solvents, such as amine, capture the acid gas with a chemical reaction; the mixed solvents, such as sterically hindered amine (MDEA) display both types of capture, physical and chemical. The first group is obviously favoured by a high partial pressure of the acid gas in the syngas, while the second group is less sensitive to the acid gas partial pressure.
On the other side physical solvents can be regenerated with minimum energy consumption; usually the bulk of the regeneration duty is done by a simple flashing (pressure reduction). On the contrary chemical solvents require substantial energy (LP steam) for regeneration, because the chemical link between the acid gases and the solvent must be broken.
The mixed solvents display a performance that is a compromise between the first two categories.

The use, for this study, of physical solvent could be attractive because the syngas is under pressure. Further physical solvents display, in general, a better selectivity than chemical solvents, which would permit to separate H_2S from CO_2. This separation permits to convert H_2S to sulphur (Claus process) and to obtain a pure CO_2 by-product.
However a selective acid gas removal, separating H_2S from CO_2, requires higher capital and operating costs than a combined removal of CO_2 and H_2S. An additional important benefit of the combined removal is the elimination of the sulphur recover plant (Claus) and tail gas treatment. On the other side the combined removal produces a CO_2 by-product contaminated with H_2S.
Whether or not it would be acceptable and advantageous to transport and store H_2S along with CO_2 would depend on local circumstances. It may be more expensive to transport and inject CO_2 containing significant concentrations of H_2S and if the CO_2 had to transport long distances, these extra costs may be greater than the reductions in capture costs. It may also be more difficult to obtain permits to transport CO_2, containing H_2S. On the other hand, H_2S can be advantageous for CO_2 enhanced oil recovery (EOR), as it enhances the

miscibility of CO_2. Some of the H_2S injected with the CO_2 would pass through the oil output; if the oil filled is already sour, the additional oil processing costs and environmental impacts may not be significant, but if the oil field is not sour, the H_2S could be a problem. Underground injection of mixtures of CO_2 and H_2S is an established practise.

About 1 million tonnes/year of such gases, separated from natural gas, are injected in western Canada, as described in IEA GHG report PH4/15. In addition, CO_2 containing about 2% H_2S and other sulphur compounds such as mercaptans is used for EOR at the Weyburn oil field in Canada. This gas is transported by pipeline from the Great Plains gasification plant in USA.
If the CO_2 was to be fed into a transmission grid supplying many different users and storage reservoirs, it may be required to have a low impurity concentration, to meet the most stringent requirements of any of the users of CO_2. In this circumstance, combined capture would not be acceptable.

In this study the sulphur content of the selected design feedstock, coal lignite, is rather low, 0.48% wt dry-ash free basis. As a consequence, choosing a combined acid gas removal, the CO_2 by-product would contain approximately 0.28% vol. H_2S. This low concentration encourages the use of combined removal and consequent savings in capital and operating costs, as demonstrated in the previous (2002) study made by FW for IEA GHG R&D Programme.

The use of a combined acid gas removal makes less attractive the use of a physical solvent since selectivity is no longer a requirement. Further physical solvents require in a combined removal process a larger solvent circulation and plant investment cost than chemical solvents; although the latter require more energy for solvent regeneration.
For this study we propose the use of MDEA, a sterically hindered amine, which has been selected for several IGCC projects. MDEA requires a lower solvent circulation rate than physical solvents and the steam consumption for regeneration is lower than the consumption of a true chemical solvent as MEA.

In order to provide a reference for the power generation alternatives of Section D, based on gasification, we provide herebelow a description of a typical H_2S+CO_2 removal plant sized for a coal based IGCC with the following characteristics:

Bituminous coal	270	t/h
Raw syngas (dry)	29,000	kmol/h
Syngas CO_2 content (dry)	60	% vol.
Syngas H_2S content (dry)	0.2	% vol.
Pressure	35	bar

After scrubbing the purified syngas contains less than 3 ppm H_2S because the high solvent circulation required by the simultaneous CO_2 removal, assures an almost total capture of H_2S. The removal efficiency of CO_2 is 90%.
Some H_2 is lost with the CO_2 by-product, equivalent to approximately 0.2-0.3% of the net power output.
The MDEA process is described in the attached process flowsheet shown in Fig. 8.1.
The raw syngas flows to the absorber where it is washed, counter currently, with a water solution of formulated MDEA. The clean solvent is fed to the top tray of the absorber which is equipped with valve trays.
The purified syngas from the top of the absorber is routed to preheating and combustion in the gas turbines.
Rich MDEA from the absorber bottom at 35 bar is expanded to 6-7 bar in an hydraulic turbine for power recovery. The hydraulic turbine supplies power to the lean solvent booster pump. Expanded MDEA flows to a flash drum. The flashed gases join the main acid gas stream leaving the top of the regenerator.
The flashed rich solvent is preheated to about 100°C, by heat exchange with the hot regenerated MDEA, and then enters the regenerator, which is a 3 packing beds tower.
CO_2 and H_2S are stripped by the rising steam, generated in two reboilers, at the bottom of the regenerator, using LP steam as heat source.

Stripping steam containing H_2S and CO_2 flows from the top of the main section of the regenerator tower through a total trap out chimney tray and into the single packed bed direct contact cooling/condensing section that constitutes the upper part of the regenerator. Condensate withdrawn from the chimney tray is pumped firstly through the reflux condensers, to be cooled against cooling water down to 35°C at which temperature it is re-introduced in to the cooling/condensing section of regenerator.
The cooled CO_2+H_2S stream flows to battery limits for transfer to the compression unit.

NH_3 co-absorbed from the raw gas scrubbed in the absorber is also regenerated from the MDEA solvent in the main section and accumulates in the direct cooling/condensing section. The NH_3 is removed from the circulating condensate loop, in the net reflux condensate stream and is passed to the small, single packed bed ammonia stripper. Low pressure steam is injected directly into the base to strip the condensate. The stripped condensate is pumped from

the bottom of tower back to the main section of the MDEA regenerator as reflux.
The overhead vapour, containing ammonia, from ammonia stripper is sent back to the cooling/condensing section of the MDEA regenerator.

The hot regenerated lean MDEA solvent leaving the reboilers is cooled in the lean/rich solvent exchangers then raised in pressure to about 18 bar(a) by means of the lean solvent pumps and passed through the lean solvent coolers, where it is cooled to a maximum of 35°C by heat exchange with cooling water. A 10% slipstream of this cooled lean MDEA solvent is then drawn-off and filtered firstly in a 10 µ mechanical filter, secondly in a carbon filter, and finally in a 5 µ mechanical filter.

In addition 5% of the total lean MDEA solvent circulation of the cooled lean MDEA solvent, following the above filtration/adsorption steps is letdown in pressure and sent to solvent reclaiming package (ion exchange), for removal of the heat stable salts which can otherwise gradually build-up in concentration in the solution.

This reclaimed 5% of the lean MDEA solvent circulation is returned at low pressure to the main suction line of lean solvent pumps.

Finally the cooled lean MDEA solvent is pumped back to the absorber. The unit is also equipped with two solvent storage tanks each capable of storing the entire MDEA solvent inventory. Solvent make-up pumps, withdraw stored solvent and reintroduce it into the main solvent circuit at the suction of lean solvent pumps; a slop drum, fitted with a slop pump receives drains from MDEA containing equipment.

The expected utility consumptions of the MDEA system described above are:

LP steam	150	t/h
Electric Power	12.5	MW
Cooling Water (ΔT= 12°C)	5300	m^3/h

The expected solvent make-up is	62	t/year
The estimated investment cost is:	48	MM US$

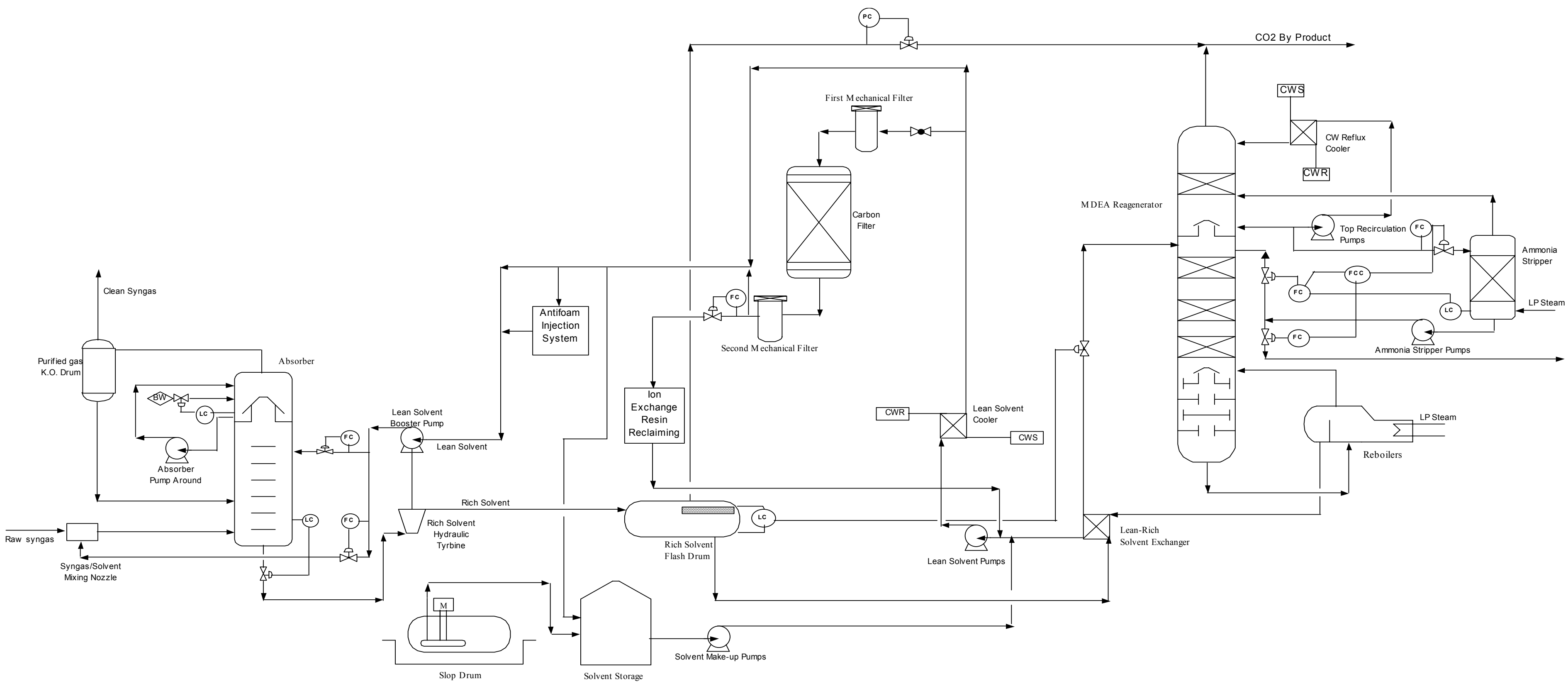


Figure 8.1 CO_2 precombustion capture flow scheme

9.0 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°C-74 bar).

The process configuration of the CO_2 compression and drying depends on the alternative considered (reference to Section D, basic information for each alternative). 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 and/or water used for lignite drying followed by air or water trim cooling.
Compressed CO_2 after the 2nd stage is dried in a molecular sieve multi-bed drier. Regeneration of the drier beds is done by electric energy. Dried CO_2 water content is lower 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 multibed drier.

10.0 UTILITY AND OFFSITE UNITS

10.1 Cooling water system (Unit 4100)

The cooling water system consists of raw water in closed loop with natural draught evaporative towers. Natural draught hyperbolic towers find application because large water quantities are required from the alternative power plants of the study.

In the natural draught cooling towers, air flow through the tower is due to the chimney effect created by the difference in density between the external cold air and the internal warm and humid air. The main advantages of these towers are that there are no problems of fogging and recirculation of air, due to the elevated air discharge, and there is a reduction of windage losses. As a consequence, hyperbolic towers can be located adjacent to users, with a considerable saving in cost of piping for water distribution. Operating and maintenance cost are minimum and service life can be expected to span many years. Investment cost required by hyperbolic towers is higher than mechanical draught towers because of their elevated dimensions.

This system permits to have low water losses limited to evaporation and blowdown. The blowdown is necessary to prevent the concentration of dissolved solids from increasing to the point where it may precipitate and scale up heat exchangers and the cooling tower fill. The best way to reduce water consumption is to reduce evaporation. Evaporation depends on a large number of factors. Some are related to the air ambient conditions on which there is no control (ambient dry bulb temperature, ambient air relative humidity, barometric pressure). Others are related to towers design and operating conditions that can be controlled. In this study the evaporation losses have been calculated taking into account that they are a function of ambient air wet bulb temperature and relative humidity. For the average ambient conditions considered in the study the evaporation losses are 0.285 kg/MJ. The cooling water in closed loop is directly used to condensate steam in the steam turbine condenser of power plants, as cooling medium for the ASU, where this unit is present, and CO_2 capture and compression units, as well as for the cooling of the machinery.

The max allowed cooling water temperature increase is 10°C.

The number of electric driven circulation pumps provided to keep the machinery cooling water circulation depends on the specific alternative.

10.2 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.

10.3 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, gasifiers or gas turbines as start-up/back-up fuel.
In the IGCC plants, the pilots of the flare stacks also use natural gas.

10.4 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).

10.5 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.

Bibliography

While many published literature site studies on drying of coal, the most recent references for such studies are listed below:

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CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : CO_2 Capture in Low-rank Coal Power Pants
DOCUMENT NAME : CASE 1 – PC BOILER WITH POST COMBUSTION CO_2 CAPTURE

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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 1 PC Boiler with Postcombustion CO_2 Capture

Summary

Pulverised Coal fuel Ultra SuperCritical (PC -USC) boiler with SCR + FGD based on wet limestone + Amine wash for CO_2 Absorption + CO_2 compression unit.

- The size of the plant considered for this configuration is based on the size required to provide nearly the same net output for all the other configurations taking into account the additional steam and power requirements of all the equipment in the plant.

- A pre-drying of the coal from a moisture level of 50.7% in as-received coal to about 32% is considered, before it is fed to the boiler plant.
  Drying of coal using low temperature waste heat is used for this alternative (Reference to Section C).

- The boiler technology for firing coal considered in this study is commercially available in the market. The boiler is a tower type boiler. The essential features of the firing system are the flue gas extraction from the furnace and integral fan beater mills for combined drying and grinding of coal, as well as tangential firing system with coal-specific jet burners. The flue gas line of the boiler includes a special plastic heat exchanger to maximise heat recovery between the ESP and the FGD systems, without suffering from corrosion resistance. Such heat exchangers are also commercially used for low temperature heat recovery in similar plants.

- The limits of NO_x emission can be met with just the firing system of the boiler with staged combustion and low temperature at furnace exit. However, an SCR system based on ammonia injection is adopted in the boiler to reduce the NO_x levels to about 20 ppmv, a requirement of the downstream CO_2 capture plant.

- A wet limestone based FGD system is selected for this plant. The downstream amine based CO_2 absorption system, again 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 high efficiencies are not presently met in 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.

- Following the study performed by Fluor, a carbon dioxide capture plant based on solvent scrubbing of flue gas with amine solvents is considered. This is followed by steam stripping and recycle of the solvent and then drying and compression of the captured carbon dioxide. This is a technology commercially available for post combustion capture of carbon dioxide, from more than one supplier, albeit with an acceptable commercial risk for scaling to the size required for this plant. (Reference to Section C para. 7.0).

- The possible effect of any other impurities in the flue gas, even at small concentrations, on the CO_2 capture plant has to be studied further, both theoretically and in pilot operation plants.

- The configuration of the plant considered provides for a good heat integration of the various systems.

- 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.

1.1 Introduction

The Case-1 of the study is a Pulverised Coal (PC) fired Ultra-Super Critical (USC) steam plant fitted with Post-combustion carbon dioxide capture and compression units.

The configuration of the PC USC complex is based on a once through steam generator with superheating and single steam reheating. The boiler has a staged low NO_x burner system with the most advanced gas treatment systems.

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

<u>Unit</u>

1000 Coal handling and storage
Ash and Solid removal
Coal Drying System

2000 Boiler Island with SCR based De NO_x
and Electro Static Precipitators (ESP)

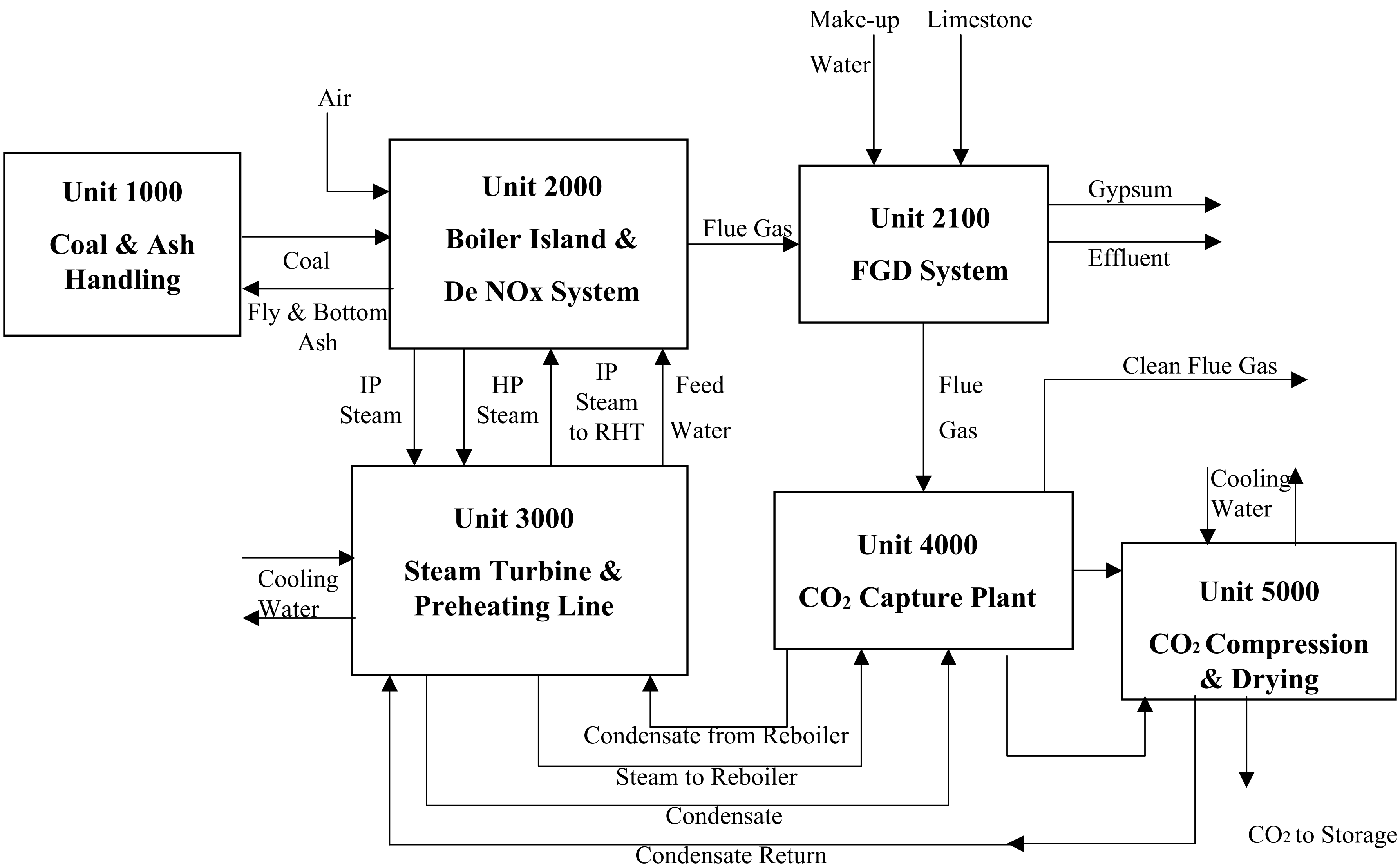
2100 FGD system and Gypsum handling plant

3000 Power Island consisting of
Steam Turbine and Preheating Line

4000 CO_2 Capture Plant (Amine Scrubbing)

5000 CO_2 Compression and Drying

Case: USC – PF Block Flow Diagram



1.2 Process Description

Note: 'Coal' referred to in all the following sections means 'low rank coal' as defined in the BEDD document.

Unit 1000: Coal and Ash Handling

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 from outside the plant boundary, store the coal, reclaim the same and transport to the boiler plant.

Coal Pre-Drying:

This scheme is described in Section C (Basic information for Low Rank Coal Power Plants) para. 2.0 (Drying of low rank coal lignite). A specific block flow diagram showing the main heating sources of this alternative is attached to paragraph 1.3.

The split of the heating sources required for the drying of the lignite is reported in the following table:

Heat source	**Duty**, MWth
Flue gas cooling from Boiler Island	34
CO_2 capture unit	88
CO_2 compression	32
TOTAL HEAT	**154**

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).

Unit 2000: Boiler Island

This Unit is treated as a package supplied by specialised Vendors. USC-PC boilers firing coal of the size proposed for this study are commercially available and have gained a lot of operational experience.

Pulverisation Plant:

Final drying and pulverisation would be performed in the beater mills (fan mills) envisaged in the boiler island due to the soft nature of coal. The Fan Mills create the necessary suction pressure (draft) needed to draw the hot flue gases from near the exit of the furnace into the mills. The coal feed is done into this inlet duct to the mills. The coal and flue gas mixture enters the fan mills and the coal is pulverised by the impact action of the mill impellers. Classifiers at the mill exhausts control the size of the particles by returning larger particles to the mills. The flue gases help transport the pulverised fuel to the burner.
Due to the negative pressure in the mills, ambient air from the atmosphere is used as tempering air to control the temperature required in the pulveriser system.

Tower Type Boiler:

The boiler would be a single pass tower-type ultra super critical boiler, with tangential firing system typical for these type of coals. For reduction of the NO_x emission level, the firing system is provided with air staging in the furnace, incorporating multi-stage supply of combustion air. The integral lower firing temperatures used for this type of coal, further has a tendency to reduce the total NO_x formed in the boiler.
The boiler heating surfaces are arranged in the tower at the exit of the furnace. The second pass of the boiler is only a flue gas duct in which is located the Selective Catalytic Reduction (SCR) based $DeNO_x$.
The flue gases at the exit of the SCR, pass through to the air heater to preheat the incoming combustion air and an Electro Static Precipitator (ESP) to remove the carried over ash particles in the flue gas.
Further, a part of the flue gas at the exit of boiler is re-circulated to maintain the necessary mass flow rates required at the exit of the furnace for good convective heat recovery.

De-NOx System

An SCR system is provided to reduce the NO_x produced by the combustion to a level which does not exceed the inlet requirement of the carbon dioxide capture plant, which corresponds to less than 20 ppmv of NO_2. The catalytic De NO_x reactor is situated in the gas stream between the boiler outlet and the air heaters. This offers a temperature range required for good functioning of the SCR system without the formation of ammonium sulphates. Gaseous ammonia is added to air supplied from a fan in a mixer as the reagent and injected into the flue gas. In the presence of the catalyst, ammonia reacts with nitrogen oxides to reduce it to nitrogen.

An SCR based De-NO_x system is required for this configuration to reduce the NO_x to less than 20 ppmv.
For Process Description of the De-NO_x system, refer to Section C para 4.0.

Flue Gas Coolers:

The flue gas needs to be cooled to about 80°C, as an operational requirement for the downstream FGD system. It is proposed that a part of this heat be recovered for further use in the plant, including heat for drying the coal.

In the first stage, the flue gases are cooled in a plastic heat exchanger to generate hot condensate for further use. Such heat exchangers have been used in commercial coal fired power plants for low temperature heat recovery.

The flue gas needs to be cooled to about 30-35°C, as an operational requirement for the downstream CO_2 capture plant. The flue gas leaves the FGD system at 50 °C and then it passes in a Direct Contact Cooler, performing an adiabatic quench, where it is cooled to 35° C, before entering absorption columns of the CO_2 Capture Plant.

Unit 2100: 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 enter the CO_2 Capture plant. The sulphur dioxide level in the flue gas must be reduced to 10 ppm necessary for efficient operation of the CO_2 capture plant.

Unit 4000: CO_2 Capture Plant

Clean flue gas with NO_x less than 20 ppmv and SO_x less than 10 ppm is now sent to the CO_2 absorption tower.
Refer to Section C para. 7.0 for this section.

Consequent to the detailed study presented by Fluor in its report for a similar technology study, an identical plant is considered for CO_2 capture; a commercial amine (MEA) scrubbing technology. The block flow diagram of this section is attached to paragraph 1.3.

In this study a 85% capture of CO_2 from the flue gas is considered.

Unit 5000: CO_2 Compression and Drying

Refer to Section C, para. 9.0 for the general description of the Unit. The block flow diagram of this section is attached to paragraph 1.3.

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 as a liquid at a pressure of around 110 bara.

Unit 3000: Steam Turbine and Preheating Line

The turbine consists of HP, IP and LP sections all connected to the generator on a single shaft. Main steam from the boiler passes through the stop valves and control valves and enter the turbine at 290 bar, 600°C. Steam from the exhaust of the HP turbine is returned to the boiler gas path for reheating and is then throttled into the double flow IP turbine at 60 bar, 620°C. Exhaust steam from IP flows into a double flow LP turbine and then downward into the condenser at 0.032 bar, 25°C. The LP steam is also extracted for the use in the reboiler and stripping unit in the CO_2 capture plant.

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

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 avoids the necessity of LP steam extractions to preheat condensate in LP preheating line. The preheated feed water stream is routed to the deaerator, along with condensate returned from the amine stripper reboiler. After deaeration the feed-water is heated in HP feed water heaters to 295°C prior to entering the boiler.

Integration Between The Process Units And The Power Island.

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

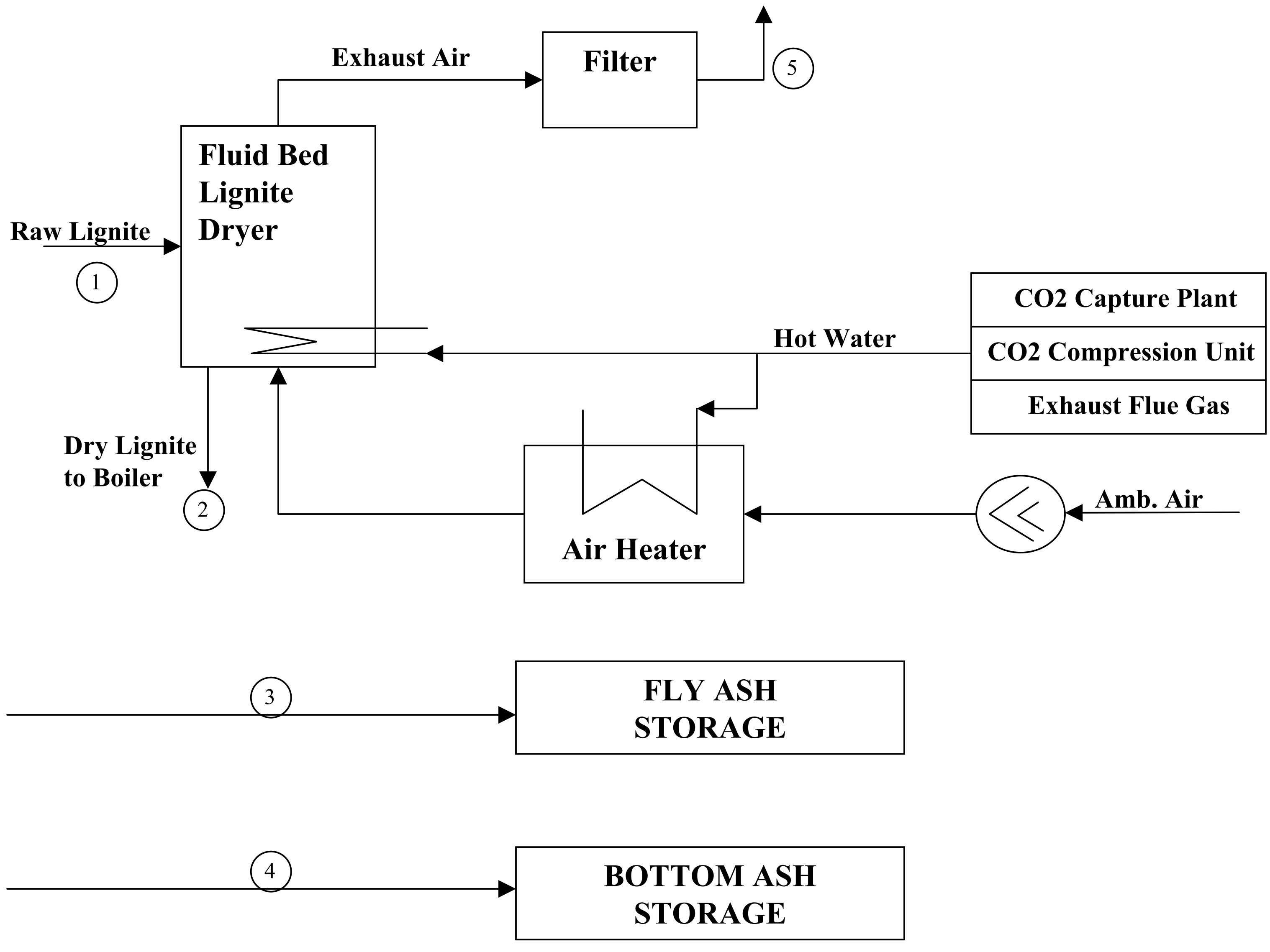
- The heat required for the drying of coal is generated by producing hot water in the flue gas line, before the FGD section, in CO_2 compression unit and in CO_2 capture plant.
- A part of the heat recovered in the CO_2 capture plant (overhead stripper condenser) and in the compression line is recovered by preheating the condensate, totally 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.

1.3 Block Flow Diagrams

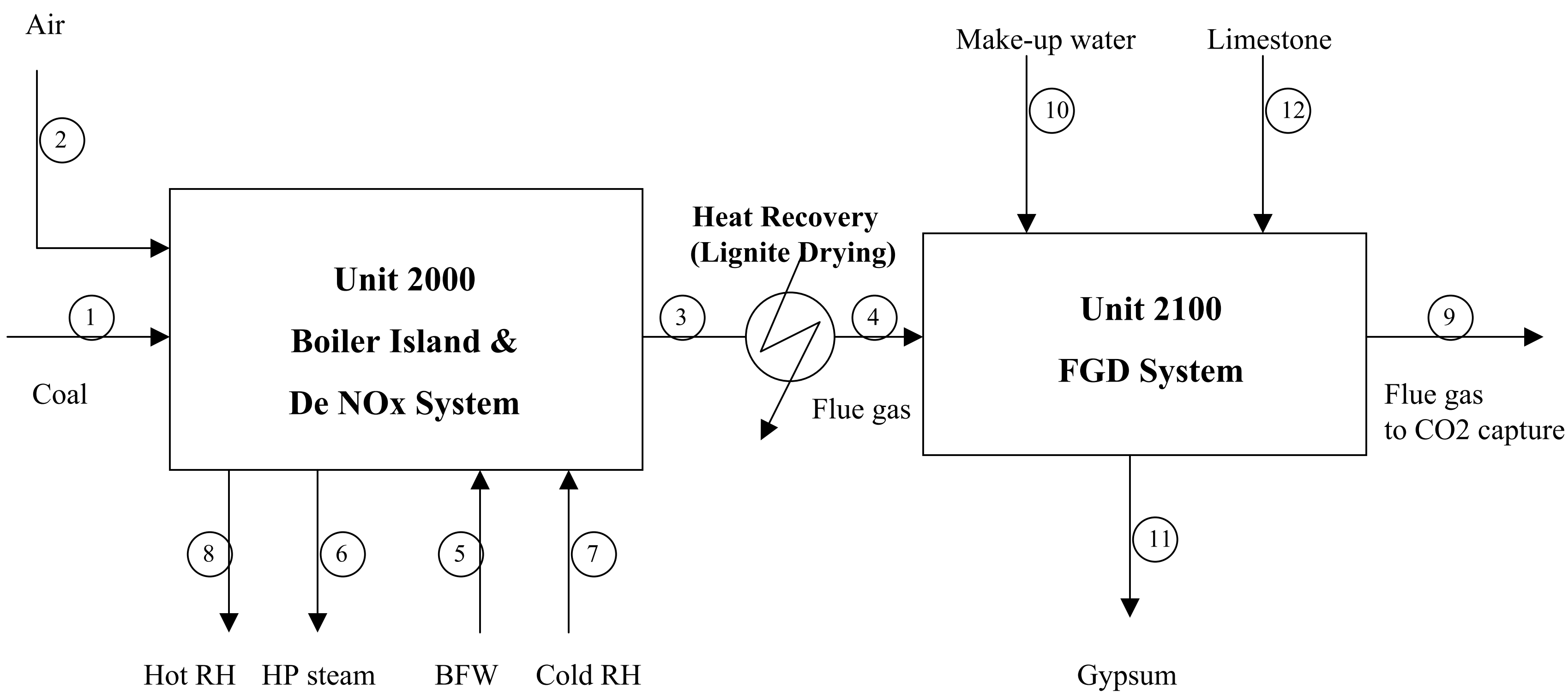
The Block Flow Diagrams of the following process units are attached to this paragraph:

- UNIT 1000: Coal handling and storage
  Ash and Solid removal
  Coal Drying System
- UNIT 2000/2100: Boiler Island with SCR based De NO_x
  Electro Static Precipitators (ESP)
  FGD System
- UNIT 3000: Power Island consisting of
  Steam Turbine and Preheating Line
- UNIT 4000: CO_2 Capture Plant (Amine Scrubbing)
- UNIT 5000: CO_2 Compression and Drying

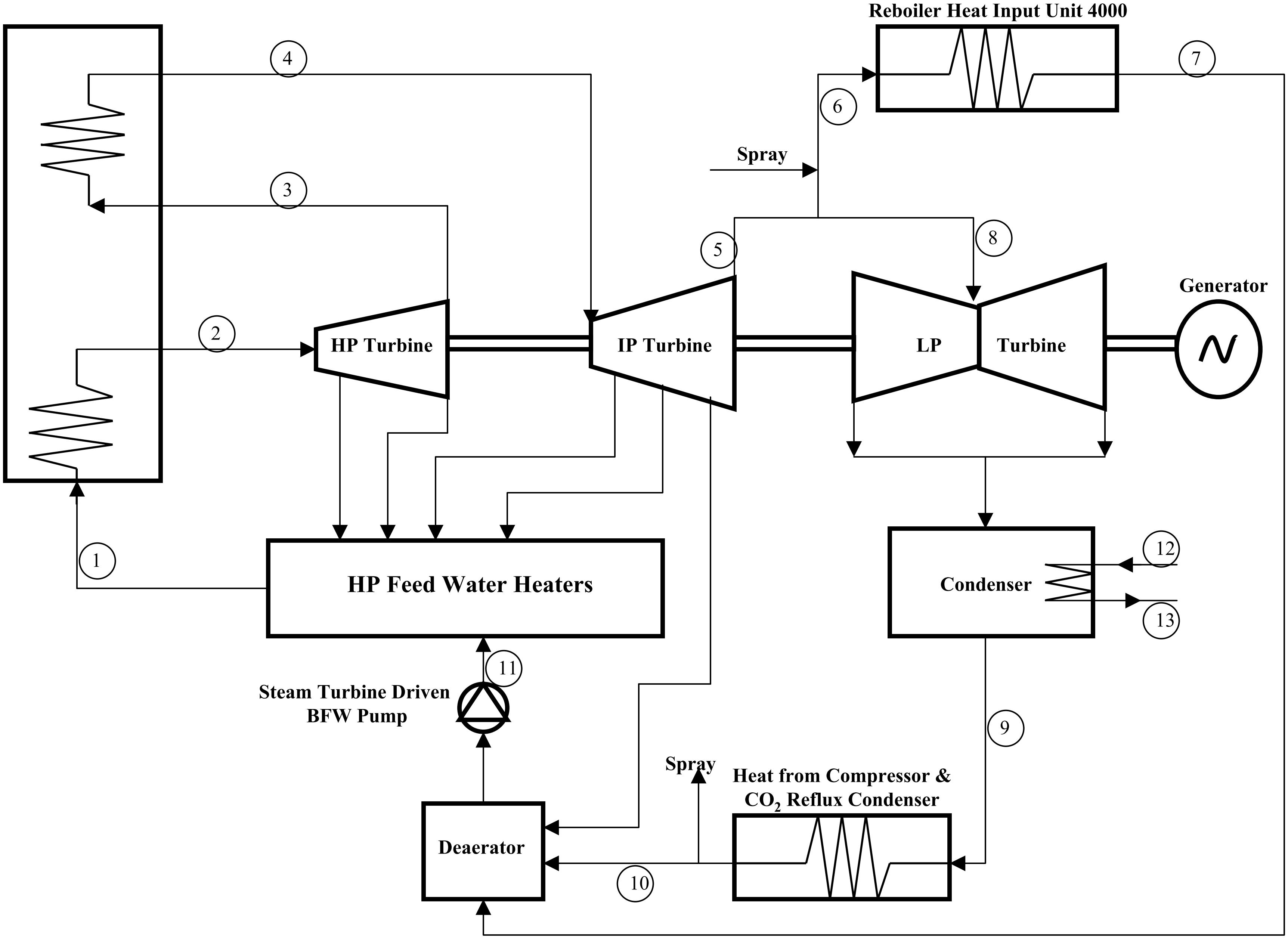
UNIT 1000 - Coal and Ash Handling



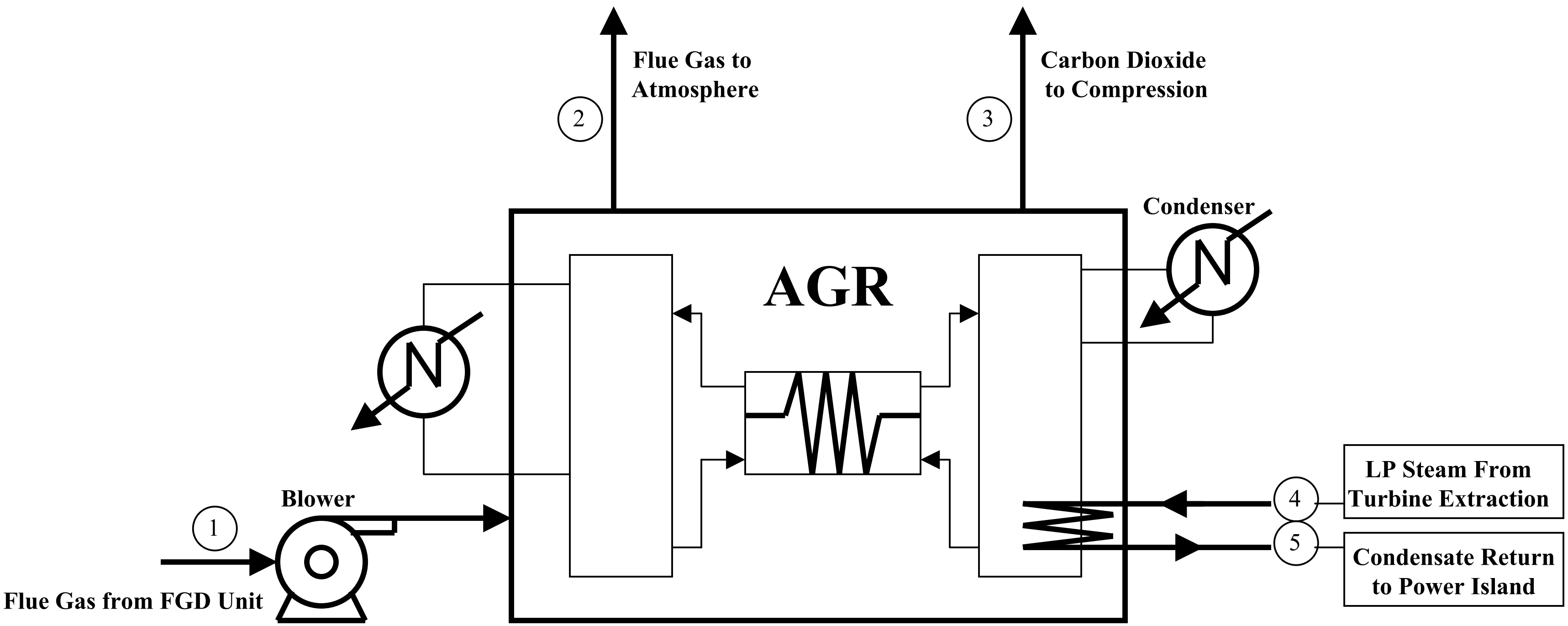
UNITS 2000/2100 – Boiler Island and FGD System



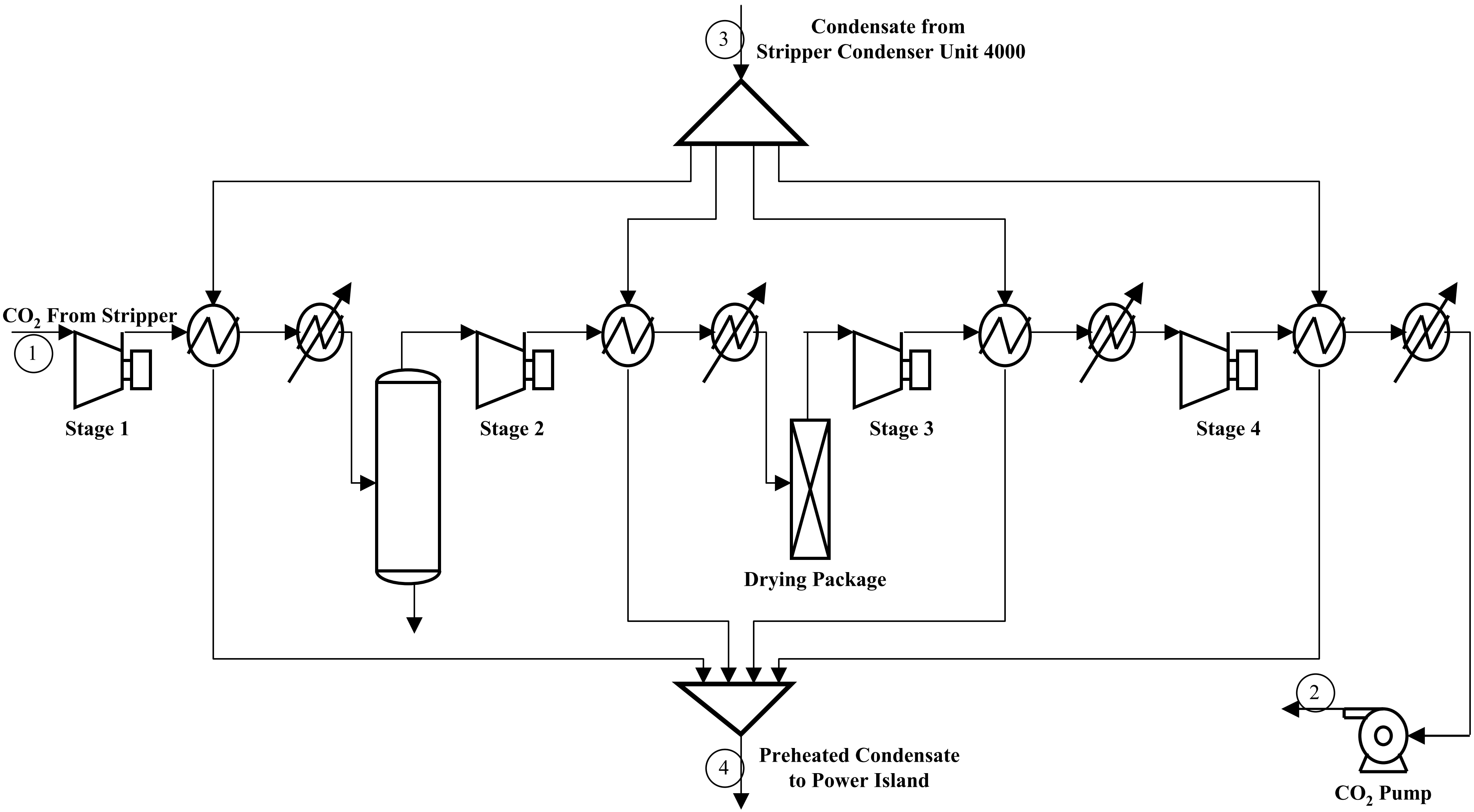
UNIT 3000 - Steam Turbine & Preheating Line



UNIT 4000 - CO_2 Capture Plant



UNIT 5000 - CO_2 Compression & Drying



1.4 Heat and Material Balances

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

- UNIT 1000: Coal handling and storage
  Ash and Solid removal
  Coal Drying System
- UNIT 2000: Boiler Island with SCR based De NO_x
  and Electro Static Precipitators (ESP)
- UNIT 2100: FGD System
- UNIT 3000: Power Island consisting of
  Steam Turbine and Preheating Line
- UNIT 4000: CO_2 Capture Plant (Amine Scrubbing)
- UNIT 5000: CO_2 Compression and Drying

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

FOSTER WHEELER	PC-USC HEAT AND MATERIAL BALANCE					REVISION	0	1	
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME					PREP.	SR		
	CASE : CASE 1					APPROVED	LM		
	UNIT : 1000 Coal & Ash Handling				Sheet 1 of 1	DATE	Feb-05		

STREAM	1	2	3	4	5	6	7	8	9	10
	Coal to Plant	Coal to Boiler Island	Fly Ash	Bottom Ash	Air from Lignite Dryer					
Temperature (°C)	AMB	AMB	AMB	AMB	50					
Pressure (bar)	ATM	ATM	ATM	ATM	ATM					
TOTAL FLOW										
Mass flow (kg/h)	733991	532143	20554	5138	1326973					
Molar flow (kgmole/h)										
	Moisture	Moisture								
	50.70%	32%	0	0						
Composition wt%										
Carbon	31.33%	43.21%								
Hydrogen	2.29%	3.16%								
Oxygen	11.56%	15.94%								
Sulfur	0.22%	0.31%								
Nytrogen	0.37%	0.51%								
Chlorine	0.03%	0.05%								
Moisture	50.70%	32.00%								
Ash	3.50%	4.83%								

FOSTER WHEELER

PC-USC HEAT AND MATERIAL BALANCE

CLIENT : IEA GREEN HOUSE R & D PROGRAMME
CASE : CASE 1
UNITS : 2000 Boiler Island 2100 FGD System

REVISION	0	1	
PREP.	SR		
APPROVED	LM		
DATE	Feb-05		

STREAM	1	2	3	4	5	6	7	8	9	10
	Coal from Coal Dryer	Air intake from Atmosphere	Flue Gas From Boiler	Flue Gas to FGD System	Feed Water from Preheating line UNIT 3000	HP Steam to Steam Turbine	IP Steam from Preheating Line UNIT 3000	IP Reheated Steam to Steam Turbine	Flue Gas to CO2 Capture Plant	Make up Wa
Temperature (°C)	AMB	15	130	80	295	600	358	620	50	30
Pressure (bar)	AMB	1.013	1.01	1.05	337.9	290.0	64.5	60.0	1.12	2.0
TOTAL FLOW										
Mass flow (kg/h)	532143	3436652	3957176	3957176	2760000	2760000	2417870	2417870	3911817	137300
Molar flow (kgmole/h)			136570	136570		153248	134252	134252	133986	
LIQUID PHASE										
Mass flow (kg/h)		0	0	0	2760000	0	0	0	0	137300
GASEOUS PHASE										
Mass flow (kg/h)		3436652	3957176	3957176	0	2760000	2417870	2417870	3911817	
Molar flow (kgmole/h)		560649	136570	136570	0	153248	134252	134252	133986	
Molecular Weight		6.13	28.98	28.98	18.01	18.01	18.01	18.01	29.20	
Composition (vol %)	See UNIT 1000									
N_2		77.57%	69.12%	69.12%	0.00%	0.00%	0.00%	0.00%	70.51%	0.00
CO_2		0.00%	13.93%	13.93%	0.00%	0.00%	0.00%	0.00%	14.24%	0.00
H_2O		0.68%	13.88%	13.88%	100.00%	100.00%	100.00%	100%	12.17%	1.00
O_2		20.86%	3.02%	3.02%	0.00%	0.00%	0.00%	0.00%	3.08%	0.00
Ar		0.89%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00
NOx		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00
SOx		0.00%	0.04%	0.04%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00
CO		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0%	0.00%	0.00

FOSTER WHEELER	PC-USC HEAT AND MATERIAL BALANCE	REVISION	0	1	
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	SR		
	CASE : CASE 1	APPROVED	LM		
	UNIT : 2100 FGD System Sheet 2 of 2	DATE	Feb-05		

STREAM	11	12	13	14	15	16	17	18	19	20
	Product Gypsum	Limestone (1)								
Temperature (°C)	AMB	AMB								
Pressure (bar)	ATM	ATM								
TOTAL FLOW	Solid									
Mass flow (kg/h)	8370	5080								
Molar flow (kgmole/h)										
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)										
Molar flow (kgmole/h)										
Molecular Weight										
Composition (vol %)										
N_2										
CO_2										
H_2O										
O_2										
Ar										
NOx										
SOx										
CO										

Note (1): Limestone Analysis (wt %) $CaCO_3$ = 95% - $MgCO_3$ = 3.4% - Inert = 1.6%

PC-USC HEAT AND MATERIAL BALANCE

CLIENT : IEA GREEN HOUSE R & D PROGRAMME
CASE : CASE 1
UNIT : 3000 Steam Turbine & Preheating Line

Sheet 1 of 1

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	HP Water to Boiler Island	2760	295	338	1298
2	HP Steam from Boiler	2760	600	290	3456
3	IP Steam to Boiler	2418	358	65	3056
4	IP hot reheated steam to Steam Turbine	2418	620	60	3706
5	IP Steam Turbine exhaust	1849	226	3.6	2916
6	LP Steam to Reboiler	1058	146	3.6	2747
7	Hot Condensate returned from Reboiler	1058	134	3	566
8	LP Steam to Steam Turbine	866	226	3.6	2916
9	Condensate	1038	25	0.032	106
10	LP Preheated Condensate	1038	130	12	544
11	Condensate to HP FWH	2760	176	340	765
12	Cooling Water Inlet	53524	11	3	47
13	Cooling Water Outlet	53524	21	2	88

FOSTER WHEELER	PC-USC HEAT AND MATERIAL BALANCE						REVISION	0	1	
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	SR		
	CASE : CASE 1						APPROVED	LM		
	UNIT : 4000 CO_2 Capture Plant					Sheet 1 of 1	DATE	Feb-05		
STREAM	1	2	3	4	5	6	7	8	9	10
	Flue Gas from FGD System	Flue Gas to Atmosphere	Carbon Dioxide to Compression	LP Steam From Turbine Extraction	Condensate from Reboiler to Power Island	Make up Water				
Temperature (°C)	50	46	38	146	134	30				
Pressure (bar)	1.12	1.01	1.6	3.6	3.2	2.0				
TOTAL FLOW										
Mass flow (kg/h)	3911817	3114001	726204	1058060	1058060	190692				
Molar flow (kgmole/h)	133986	113099	16912	58748	58748					
LIQUID PHASE										
Mass flow (kg/h)	0	0	0	1058060	1058060	190692				
GASEOUS PHASE										
Mass flow (kg/h)	3911817	3114001	726204	0	0					
Molar flow (kgmole/h)	133986	113099	16912	0	0					
Molecular Weight	29.20	27.53	42.94	18.01	18.01					
Composition (vol %)										
N_2	70.51%	83.52%	0.01%	0.00%	0.00%	0.00%				
CO_2	14.24%	2.53%	95.88%	0.00%	0.00%	0.00%				
H_2O	12.17%	10.30%	4.11%	100.00%	100.00%	100.00%				
O_2	3.08%	3.65%	0.00%	0.00%	0.00%	0.00%				
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
NOx	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
SOx	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				
CO	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%				

FOSTER WHEELER	PC-USC HEAT AND MATERIAL BALANCE						REVISION	0	1	
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	SR		
	CASE : CASE 1						APPROVED	LM		
	UNIT : 5000 CO_2 Compression & Drying					Sheet 1 of 1	DATE	Feb-05		
STREAM	1	2	3	4	5	6	7	8	9	10
	CO_2 from Stripper	CO_2 to long term Storage	Condensate from Stripper Condenser	Preheated Condensate to Power Island						
Temperature (°C)	38	30	107	130						
Pressure (bar)	1.5	110	12	11						
TOTAL FLOW										
Mass flow (kg/h)	726204	713673	1038012	1038012						
Molar flow (kgmole/h)	16912	16216	57635	57635						
LIQUID PHASE										
Mass flow (kg/h)	0	713673	1038012	1038012						
GASEOUS PHASE										
Mass flow (kg/h)	726204	0	0	0						
Molar flow (kgmole/h)	16912	0	0	0						
Molecular Weight	42.94	44.01	18.01	18.01						
Composition (vol %)										
N_2	0.008%	0.008%	0.00%	0.00%						
CO_2	95.88%	99.99%	0.00%	0.00%						
H_2O	4.11%	0.00%	100.00%	100.00%						
O_2	0.00%	0.00%	0.00%	0.00%						
Ar	0.00%	0.00%	0.00%	0.00%						
NOx	0.00%	0.00%	0.00%	0.00%						
SOx	0.00%	0.00%	0.00%	0.00%						
CO	0.00%	0.00%	0.00%	0.00%						

1.5 Utility Consumption

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

	CLIENT:	IEA GHG	Rev Final
FOSTER WHEELER	PROJECT:	GASIFICATION POWER GENERATION STUDY	Nov 05
	LOCATION:	Germany	ISSUED BY: SR.
	FWI Nº:		CHECKED BY: L.M
			APPR. BY: R.D.

ELECTRICAL CONSUMPTION SUMMARY - CASE 1 - PC - USC

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
1000	**Coal - Ash Storage and Handling**	**343**
1050	**Coal Drying (Air fan consumption)**	**691**
2000	**Boiler Island**	**19200**
2100	**FGD System**	**8100**
4000	**CO_2 Capture Plant**	**31202**
5000	**CO_2 Compression and Drying**	**78400**
	POWER ISLANDS UNITS	
3000	**Steam Turbine and Preheating line**	**1370**
	UTILITY and OFFSITE UNITS	
	Cooling Towers	**20715**
	Others	**8750**
	BALANCE	**168771**

FOSTER WHEELER	CLIENT: IEA GHG PROJECT: GASIFICATION POWER GENERATION STUDY LOCATION: Germany FWI Nº:	Rev 0 Feb-05 ISSUED BY: SR CHECKED BY: L.M. APPR. BY: RD

WATER CONSUMPTION SUMMARY - CASE 1: PC - USC

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water [t/h]
	PROCESS UNITS			
1000	Coal and Ash Handling			99
2000	Boiler Island			123
2100	FGD System		137	
4000	Acid Gas Removal		189	46504
5000	CO_2 Compression and Drying			7850
	POWER ISLANDS UNITS			
	Steam Turbine and Generator auxiliaries		1	53520
	Miscellanea			1510
	UTILITY and OFFSITE			
	Cooling Water (Cooling Towers Make Up)	1610		
	Demineralized/Condensate Recovery/Plant Potable Water System	327	-327	
	Miscellanea			70
	BALANCE	1937	0	109676

FOSTER WHEELER	CLIENT: IEA GHG PROJECT: CO2 Capture in Low rank coal power plants LOCATION: Germany FWI Nº:	Rev 0 Feb-05 ISSUED BY: SR CHECKED BY: LM APPR. BY: R.D.

Chemicals and Consumables Summary CASE 1: PC-USC

	DESCRIPTION	Consumption t/h	Yearly Consumption t/y
	Chemicals and Consumables		
	Make up Water (Power Plant, FGD, CO2 Capture Plant)	1937	14425136
	Limestone	5.08	37826
	Ammonia	0.66	4914
	MEA solvent	1.34	9978
	Activated Carbon	0.05	368
	Soda Ash	0.11	809

1.6 PC-USC Overall Performance

The following Table shows the overall performance of the PC-USC Complex.

PC-USC

Case 1

OVERALL PERFORMANCES OF THE PC-USC COMPLEX		
Coal Flowrate (A.R.)	t/h	734.0
Coal LHV (A.R.)	kJ/kg	10500
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2140.8**
Steam turbine power output (@ gen. terminals)	MWe	932.0
GROSS ELECTRIC POWER OUTPUT OF PC - USC COMPLEX (D)	**MWe**	**932.0**
Coal Storage / Handling / Drying	MWe	1.0
Boiler Island	MWe	19.2
FGD	MWe	8.1
CO2 Plant incl. Blowers	MWe	31.2
CO2 Compression	MWe	78.4
Power Island (1)	MWe	1.4
Utilities	MWe	29.5
ELECTRIC POWER CONSUMPTION OF PC-USC COMPLEX	**MWe**	**168.8**
NET ELECTRIC POWER OUTPUT OF PC-USC (C) **Step-Up Transformer Efficiency (0.997)**	**MWe**	**761.0**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.5%**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**35.5%**

Notes: (1) Boiler Feed Water pumps are steam turbine driven.

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

	Equivalent flow of CO_2 kmol/h
Coal (Carbon = 43.21%wt)	19144
Limestone	51
Slag	118
Net Carbon flowing to Process Units (A)	19077
Liquid Storage	
CO	0.0
CO_2	16215
Total to storage (B)	16215
Emission	
CO	0.0
CO_2	2862
Total Emission	2862
Overall CO_2 removal efficiency, % (B/A)	85.0

1.7 Environmental Impact

The PC-USC Complex is designed to process coal, 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 PC-USC Complex 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 absorber unit of the CO_2 capture plant.

Table 1.1 summarises expected flow rate and concentration of the combustion flue gas after CO_2 capture treatment.

Table 1.1 – Expected gaseous emissions from PC-USC plant integrated with CO_2 capture.

	Normal Operation
Wet gas flow rate, kg/s	865
Flow, Nm^3/h	2535000
Temperature, °C	46
Composition	(%vol)
N_2	83.52
O_2	3.65
CO_2	2.53
H_2O	10.30
Emissions	mg/Nm^3 (1)
NOx	40
SOx	29 (2)
CO	Less than 150
Particulate	Less than 30
NH_3	5 (3)

(1) Dry gas, O_2 Content 6% vol
(2) SOx Emissions upstream AGR unit; after solvent washing, emissions are expected close to zero
(3) Due to ammonia slippage into the flue gas downstream the SCR

In normal operation at full load, the following emission to the atmosphere is foreseen from the Coal Drying Process:

Flow rate	:	1327	t/h
Particulate	:	27.6	kg/h

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

The plant would be designed for zero liquid effluents.

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 : 20.6 t/h

Bottom Ash

Flow rate : 5.1 t/h

Fly and bottom ash can be dispatched to cement industries.

Solid Gypsum

Flow rate : 8.4 t/h

Solid gypsum keeping Euro Gypsum restrictions can be delivered to the market.

1.8 Equipment List

The list of the main equipment and process packages are included in this section.

UNIT 1000 – Coal handling and storage – Ash and Solid removal

Coal Unloading train including:
- Hopper systems
- Coal conveying
- Stacker reclaimer
- Coal delivery equipment

Coal Pre-drying train including:
- Fluid Bed Dryer
- Air fan
- Hot Water based Air Heater
- Filters for exhaust air

Fly ash handling System including:
- Pneumatic Conveying system
- Storage Silo
- Dust suppresion System

Bottom ash systems
- Conveying System
- Clinker Crusher

Miscellaneous equipment

UNIT 2000 – Boiler Island with SCR based De NOx – Electro Static Precipitators (ESP)

Tower type boiler including:
- Fresh Air Fans
- Fan Beater Mills
- SCR DeNOx System
- Air Heaters
- Electro Static Precipitator
- Induced Draft Fans
- Flue Gas Recirculation Fans
- Hot Water Generator
- Miscellaneous equipment

Auxiliary boiler
Structures
Control System

UNIT 2100 – FGD system and Gypsum handling plant

Limestone storage
Limestone feeder
Absorber Tower
Oxydation air blower
Make up water system
Gypsum handling & storage
Reagent feed pumps
Miscellaneous equipment

UNIT 3000 – Power Island consisting of Steam Turbine and Preheating Line

Steam turbine and generator package
Deaerator
HP feedwaterheaters
Condenser Package
Condensate pumps
Steam turbine driven BFW pump
LP pumps

UNIT 4000 – CO_2 Capture Plant

Flue gas blower
Absorption towers
Packing
Stripper tower
Packing for stripper
Stripper reboiler
Overhead stripper condenser
Water wash cooler
Cross exchangers
Lean solvent cooler
Flash preheater
Reclaimer
Soda ash dosing
Amine filter package
MEA storage tank
MEA circulation pumps
Wash water pumps

Surplus water pumps
Reflux pump
Surplus water tankage

UNIT 5000 – CO_2 Compression and Drying

Compression package
Drying package
CO_2 pumps
KO drums
Intercooling heat exchangers
Intercooling Water circulation pumps

Utility and Offsite Units

Cooling Water / Machinery cooling water systems (Unit 4100)
Demineralized, Plant and Potable Water System (Unit 4200)
Natural Gas System (Unit 4300)
Plant / Instrument Air Systems (Unit 4400)
Waste Water Treatment (Unit 4600)
Fire Fighting System (Unit 4700)
Chemicals (Unit 4900)
Interconnecting (Instrumentation, DCS, Piping, Electrical, 400 KV Substation) (Unit 6000)

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : CO$_2$ Capture in Low-rank Coal Power Pants
DOCUMENT NAME : CASE 2 – OXYFUEL PC BOILER

ISSUED BY : S. RIPANI
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by

SECTION D

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D BASIC INFORMATION FOR EACH ALTERNATIVE

2.0 Case 2 - Oxyfuel

Summary

Pulverised Coal Ultra SuperCritical (PC -USC) boiler modified to allow oxycombustion and CO_2 capture and storage.

- The size of the plant considered for this configuration is based on the size required to provide nearly the same net output for all the other configurations.
- A pre-drying of the coal from a moisture level of 50.7% in as-received coal to about 32% is considered, before it is fed to the boiler plant.
  Drying of coal using low temperature waste heat is used for this alternative (Reference to Section C para. 2.0). In this case waste Nitrogen from ASU is used to fluidize the lignite dryer, instead of ambient air. The Nitrogen pressure allows to fluidize the bed without the insertion of a blower.
- The use of oxy-combustion (fossil fuel combusted with near pure oxygen and recycled flue gas or CO_2 and water/steam) to produce a flue gas consisting essentially of CO_2 and water is seen as having potential as a means of disposing of combustion related CO_2. The advantage is that the flue gas is not diluted with nitrogen as when air is used for firing and therefore, can be disposed of with minimal further downstream processing.
- The amount of oxygen required for the plant under study is very high and a single train air separation plant cannot supply the same. Multiple trains of ASU are proposed to supply the required oxygen for combustion. However, the cryogenic technology for separation of oxygen from air is a very well established commercial technology.
- The boiler technology considered in this study with oxygen is an extrapolation of the existing air fired technology. To ensure nearly same conditions of operation, the pure oxygen is mixed with a part of the recycle gas to reach nearly same conditions of the flue gas in the boiler. These effects have to be further understood in detail in a big size plant operation. It is expected that a 500MW boiler using this technology would be demonstrated in the next few years, to understand and establish the design changes required for this boiler.
- The configuration of the boiler considered is a tower type boiler, as with air fired PC boiler considered in the other case of study. The essential features of the firing system are the flue gas extraction from the furnace and integral fan

beater mills for combined drying and grinding of coal, as well as tangential firing system with coal-specific jet burners.

- The limits of NOx emission (European Emission Limits) can be met with just the firing system of the boiler with staged combustion and low temperature at furnace exit. Hence, no SCR system is considered for the boiler. Further, the nitrogen oxides are expected to be condensed into the CO_2 stream in the downstream CO_2 capture and processing plant. Hence, there are no emissions of nitrogen oxides into the atmosphere.

- No FGD system is required for this scheme. All the sulphur oxides are expected to be condensed into the CO_2 stream during the chilling and separation process, and end up in the product CO_2 stream.

- CO_2 plant: The flue gas at the exit of the boiler consists only of the CO_2 and some leakage nitrogen and oxygen. The configuration for CO_2 separation follows the study performed by Mitsui; the flue gases at the exit of the boiler are chilled to separate out the CO_2. The duty for chilling is obtained by partly expanding the compressed CO_2 in the intermediate stages of the plant. CO_2 is eventually compressed to a liquid at 110 bar for final disposal. Present also alternative to clean CO_2 and discuss pros. and cons.

- The possible effect of any other impurities in the flue gas, even at small concentrations, on the CO_2 capture plant has to be studied further, both theoretically and in pilot operation plants.

- The configuration of the plant considered provides for a good heat integration of the various systems.

2.1 Introduction

The Case-2 of the study is a Pulverised Coal (PC) fired Ultra-Super Critical (USC) steam plant modified to allow oxycombustion and CO_2 capture.

The configuration of the PC USC complex is based on once through steam generator with superheating and a single reheating of steam. The boiler has a staged low NOx burner system with the most advanced gas treatment systems including ESP (Electrostatic Precipitators) to capture particulates.

The downstream systems include:
- CO_2 Separation Plant
- CO_2 Compression train.

Previous work from a number of authors as well as pilot and laboratory scale studies have indicated that retrofit of oxy-combustion based technology to existing fossil fuel fired plant is feasible, with more often than not, little or no changes to the existing boiler pressure parts. In case of a new plant, the same philosophy of design as for existing plants can be adopted to ensure ease of design and understanding of the operating principles of the boiler.

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

Unit

1000 Coal handling and storage
Ash and Solid removal
Coal Drying System

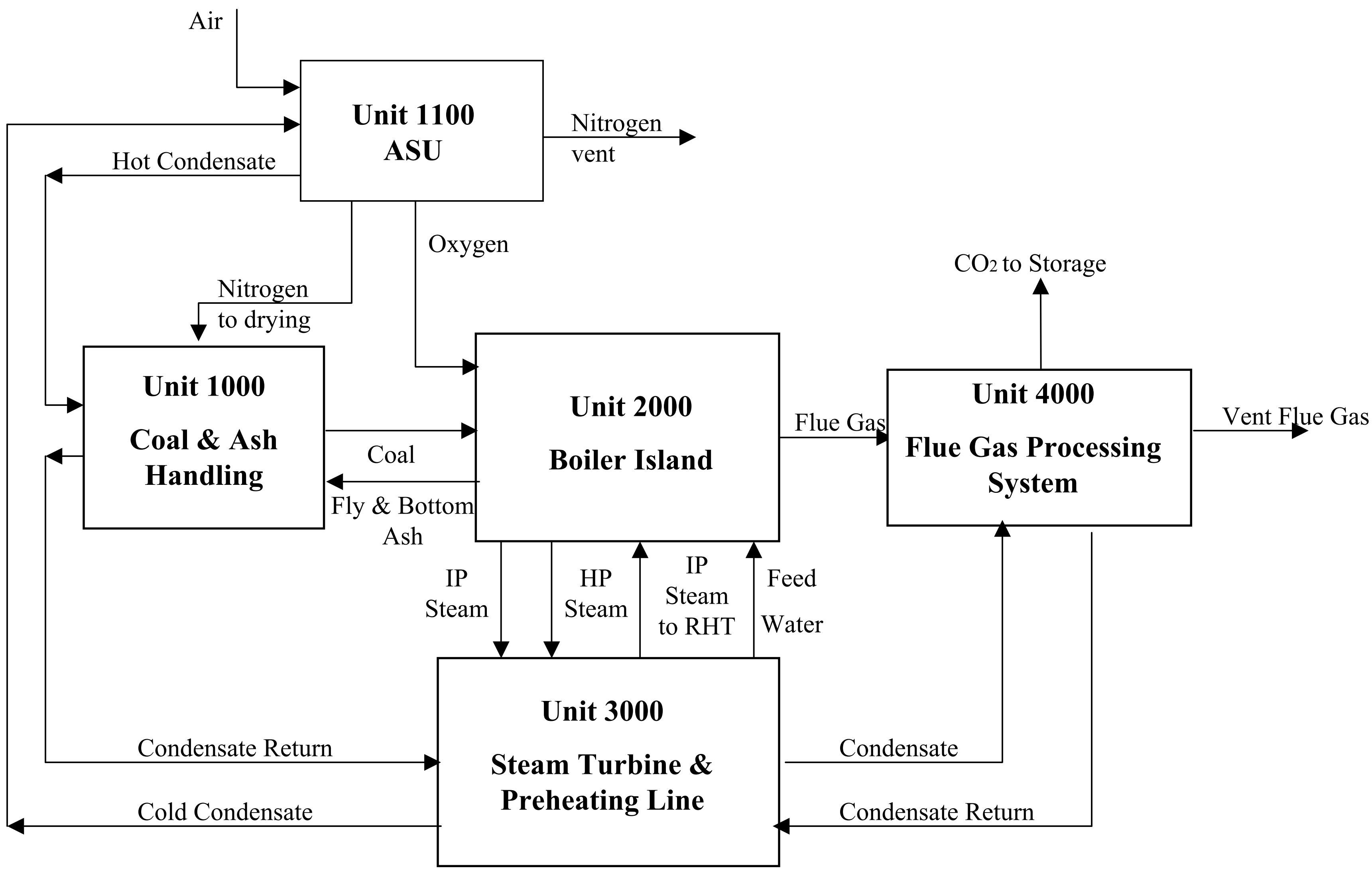
1100 Air Separation Unit (ASU)

2000 Boiler Island with Electro Static Precipitators (ESP)

3000 Power Island consisting of
Steam Turbine and Preheating Line

4000 CO_2 Separation Unit

Case 2: Oxyfuel PC - USC Block Flow Diagram



2.2 Process Description

<u>Note:</u> 'Coal' referred to in all the following sections means 'low rank coal' as defined in the BEDD document.

<u>Unit 1000: Coal and Ash Handling</u>

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 from outside the plant boundary, store the coal, reclaim the same and transport to the boiler plant.

<u>Coal Pre-Drying:</u>

This scheme is described in Section C (Basic information for Low Rank Coal Power Plants) para. 2.0 (Drying of low rank coal lignite). The block flow diagram of the Unit is also attached to paragraph 1.3 of this Section.

The split of the heating sources required for the drying of the lignite is reported in the following table:

Heat source	**Duty**, MWth
ASU	46
Flue gas treatment	96
TOTAL HEAT	**142**

<u>Ash Handling Plant:</u>

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).

<u>Unit 1100: Air Separation Unit (ASU)</u>

The ASU is considered as a typical Package supplied by vendors with clearly defined limits of supply and interfaces.

The configuration selected for the ASU, is a tested and well commercialised cryogenic distillation of air. Considering that the pressure of oxygen required is only at very low pressure to the boiler plant, a low-pressure distillation column is selected.

The typical train of ASU includes:

(1) Air filtration and compression
(2) Cryogenic Heat Exchangers (Cold Boxes)
(3) Cryogenic Distillation Column.

Size of ASU:

The total quantity of oxygen required for this study is much in excess of a single train capacity presently installed. Hence, multiple trains of ASU are considered; three trains in all. The size of each train shall be about 5000 tonnes O_2 per day, which is already about 20% larger than the largest plant presently installed and close to maximum capacity which can be commercially offered nowadays. The limitations of air compressor size and the distillation column size for a single train can be met for larger sizes of ASU.

Purity of Oxygen:

The purity of oxygen affects the downstream CO_2 separation plant, as any impurity in the oxygen gets carried over, along with combustion gases to this plant. However, the combustion gases are also mixed with unavoidable impurities of Nitrogen from air leakage into the boiler, etc.
Consequently, a high purity of oxygen is not an absolute requirement, as the downstream CO_2 separation plant will have to deal with these sources of impurities.
Purity levels of 95% of oxygen are easily generated in the ASU plant. A higher purity level for oxygen imposes a penalty on the energy requirement on the ASU plant.
Hence, the purity level of oxygen requirement defined for the ASU plant is limited to 95%.

Waste Nitrogen:

The ASU also generates a nitrogen stream, which is available at a low pressure (approx. 1.6 bar) and is relatively dry. This is usually vented to the atmosphere as waste gases.
In the present study, this stream is used as the fluidising and drying medium for the lignite drying plant to improve the overall efficiency of the plant.

Unit 2000: Boiler Island

The block flow diagram of the Unit is attached to paragraph 1.3 of this Section.

This Unit is treated as a package supplied by specialised Vendors. Supercritical PC boilers firing coal, of the size proposed for this study, using oxygen are not

developed commercially. However, from a characteristics study, it is expected that the behaviour and design aspects of the boiler would not be different from those of air fired plants.
As pure oxygen is used for combustion, there is a deficient mass flow rate in the boiler due to absence of inert nitrogen present in air fired plants. To make up for this loss in mass flow rates and to reach similar characteristics, a part of the flue gas at the exit of the boiler, is recirculated back through the furnace and convective pass.

At the present level of development of this technology, it is preferable to reach a combustion gas composition whose properties are similar to those for an air fed boiler plant. It is assumed in this study that this can be achieved and hence, the design of an air fired boiler can be extrapolated to those for an oxygen fired boiler. For example, it would be preferable to maintain an oxygen level of about 20% in the gases fed to the boiler. However, it is also understood that the properties of the flue gases and the design of the furnace would be considerably different due to the presence of high level of CO_2 in the gases.
These have been studied by various people and it is expected that a new boiler using O_2/CO_2 mixture can be designed and will perform similar to an air fired boiler.

Pulverisation Plant:

Final drying and pulverisation would be performed in the beater mills (fan mills) envisaged in the boiler island due to the soft nature of coal. The Fan Mills create the necessary suction pressure (draft) needed to draw the hot flue gases from near the exit of the furnace into the mills. The coal feed is done into this inlet duct to the mills. The coal and flue gas mixture enters the fan mills and the coal is pulverised by the impact action of the mill impellers. Classifiers at the mill exhausts control the size of the particles by returning larger particles to the mills. The flue gases help transport the pulverised fuel to the burner.

Tower Type Boiler:

The boiler would be a single pass tower-type super critical boiler, with tangential firing system. For reduction of the NOx emission level, the firing system is provided with staging in the furnace, incorporating multi-stage supply of combustion oxygen and flue gas. The integral lower firing temperatures used for this type of coal, further has a tendency to reduce the total NOx formed in the boiler.
The boiler heating surfaces are arranged in the tower at the exit of the furnace. The second pass of the boiler is only a flue gas duct through which the flue gases pass through to the gas heater (to preheat the incoming mixture of

oxygen and recycled flue gas) and an Electro Static Precipitator (ESP) to remove the carried over ash particles in the flue gas.
Further, a part of the flue gas at the exit of boiler is re-circulated (secondary recycle) to maintain the necessary mass flow rates required at the exit of the furnace for good convective heat recovery.

Flue gas Recirculation (Secondary Recycle):

In comparison with air fired PC fired boilers, the flue gases generated in the boilers are not diluted with the inert nitrogen present in air. To arrive at a similar situation and to provide for adequate mass flow rates for heat pick up and transfer to steam, a part of the product gases at the outlet of the boiler are recirculated into the boiler (secondary recycle). Required adjustments are made in the flow rates to account for the revised composition of the gases and their changed heat capacities of the gases.

As in conventional lignite fired boiler, there is no requirement for air or any other gas to be heated and supplied to the pulveriser plants. A part of the flue gas at the furnace exit is used as the primary recycle stream for final drying and conveying the pulverised fuel to the boiler. Hence, there is only one stream of recycle gas from the boiler exit (in comparison to those for the high rank coal boilers described by Mitsui).

Secondary Recycle Gas location:

In conventional air fired plants, the secondary recycle can be taken at the exit of the ESP, with the temperature of the gases being nearly 130 – 140°C. However, in the case with oxycombustion, the quantity of moisture in the flue gas at the exit of the boiler is very high for conveniently handling this flue gas. Hence, the flue gases are cooled by a water wash to remove the inherent moisture, before recycle back to the boiler. On the way, it is re-heated using the flue gas cooling stream to efficiently return a part of the heat back to the boiler.

Some studies have suggested to recycle the flue gases at the exit of the boilers, before the ESP. This could be disadvantageous, as the gas is still laden with significant dust levels, which could lead to severe erosion of recirculation gas fans. Further, as the ratio of recycle gases is very high (almost 70%), it could lead to a quick build-up of impurities in the boiler.

Excess Oxygen level:

In present day pulverised coal fired boilers, excess air levels of 20% are maintained. There is a continuous effort by boiler designers to reduce this level with a good distribution to about 15% to improve the overall efficiency of the boiler. In any case in the present study is considered an excess oxygen level of 20% at the burner, from all sources (recycle and added oxygen).

Air Leakage into the boiler:

Conventionally, the boilers are operated at a slight vacuum to prevent leakage of hot flue gases at any level, out of the system, for safety reasons. Some smaller boilers are operated at positive pressures, but for big size boilers, maintaining a pressure tight situation is nearly impossible. This leads to unavoidable ambient air leakage into the boiler, affecting the efficiency of the boiler.
This is more harmful for oxy-combustion boilers, as this leakage air effects the downstream equipment and affects the purity of the gases generated in the boiler. This is a big source of nitrogen in the product gases, which is to be removed in the final CO_2 product.
Typically in the design of air fired plants, a 1-2% stoichiometric air leakage into the boiler is considered. A similar air leakage is considered in evaluating the mass flow rates for this study.

De-NOx System

It is expected that all the nitrogen oxides in the flue gases will be condensed along with the CO_2 in the product carbon stream. Hence, no further De-NOx system is required for this option.

Flue Gas Coolers:

The flue gas needs to be cooled to about 30°C, as an operational requirement for the downstream CO_2 system. It is proposed that a part of this heat be recovered for further use in the plant, including heat for drying the coal.

A gas/gas heat exchanger is located in the flue gas path for preheating the flue gases returning to the boiler from the CO_2 plant.
Adequate precaution will be made in the selection of the material of construction of this plant.

As a finish cooler, a direct contact cooler with water is employed to reach the required flue gas temperature for the CO_2 system.

FGD System

All the sulphur oxides will be condensed in the CO_2 plant and end up in the product CO_2 stream. The recycle flue gases to the boiler are re-heated and sent directly to the boiler. As the flue gases do not go through the milling plant, where usually low temperature is encountered, no associated dew point corrosion problems are expected.
Hence, no desulphurisation plant is provided for this case.

Unit 4000: CO_2 Separation Plant

The purpose of this system is to process the flue gas stream leaving the Oxygen Fired Boiler Island to provide a liquid CO_2 product stream for a long term storage.

In this study a minimum of 85% capture of CO_2 from the flue gas is considered.
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 as a liquid at a pressure of around 110 bar a.

The gas at the exit of the boiler, is a CO_2 rich flue gas along with impurities like nitrogen that is present in the feed oxygen and air leakage, moisture of combustion and Oxygen due to the excess of O_2 for combustion and air leakage. These impurities affect the pumping and transport of the product CO_2 streams. Hence, the CO_2 separation section basically consists of a scheme to remove these components to enhance the product CO_2 from the plant.
Different schemes can be used in order to reach the correct CO_2 purity with different costs and electrical consumption. If CO_2 captured is used for EOR it is necessary to have an high purity CO_2 stream (>95%). In case of simple sequestration, it is not important to reach a stringent specification of the CO_2, so the treatment unit can be cheaper and less complicate.
One could look at three possible options for the gas treatment with their own advantages and limitations.

Alternative CO_2 cleaning processes:

- Option 1: Scrubbing of flue gas with amine:

This option can be interesting due to the higher partial pressure of CO_2 in the flue gas, when compared with traditional air fired boiler.
Specific advantages of this scheme could be:

- Smaller towers due to lower volume of flue gas in comparison to air fired boiler.
- Established process of amine wash
- High purity of CO_2 captured stream is possible

However this scheme could have the following limitations

- High cost of amine washing plant
- Need for large steam flow rate to regenerate the amine
- Consequent loss of power

Considering that the final CO_2 product has to be compressed / pumped to a high pressure, this scheme could add additional equipment with consequent loss of power generation and efficiency.

- Option 2: Compression of the gas at high pressure:

Pure CO_2 condenses at 20 °C at about 58 bara and the CO_2 concentration in the flue gas after moisture removal is 78%, to reach the corresponding partial pressure of CO_2 for condensation, it has to be compressed to about 80 bara and cooled till ambient temperature, with cooling water. At this conditions some of the Nitrogen and Oxygen also condense into the CO_2 stream, making it less than 90% purity: a concentration that is not adequate for EOR.
In the case where the final CO_2 is sent for sequestration, this solution is very attractive due to the simple scheme that can be used. The flue gas is only compressed, dried and stored without any stringent specifications required for this case.
A major requirement is that the oxygen concentration should be minimized to meet the current pipelines operating practise, due to the high corrosive nature of oxygen. With this scheme is not possible to reach a low concentration of O_2. Hence corrosion could be a serious problem for pipelines and it could be uneconomic to use special materials.
The effect of other impurities are not fully known.
However it should be emphasized that this treatment would guarantee zero gaseous emissions from the boiler.

- Option 3: Chilling of flue gas, compression and cryogenic separation

This is a modification of Option 2, in that the gases are compressed and chilled to cryogenic temperatures (-60 °C) before separating of product CO_2 and other impurities. At this conditions the solubility of N_2, O_2 and other gases in the

CO_2 stream are low. Hence the product stream of CO_2 is more than 95 % pure. No upstream treatment plant is required. Of course, the scheme calls for big heat exchangers constructed with special material to handle condensed gases in cryogenic conditions and high energy requirements of chilling.
However considering that the product gases anyway have to be compressed to a high pressure, a part of this compressed gases are expanded to generate the required refrigeration.
Optimization with the respect to purity and temperature requirement for separation can be performed to evaluate this process further.

Description of the scheme:

The block flow diagram of the Unit is attached to paragraph 1.3 of this Section.

In the first stage, the flue gases from boiler at 80°C are scrubbed with water in a direct contact scrubber tank. Most of the moisture will be condensed out from the gases. Any carried over particulates in the flue gas is also scrubbed out. A set of moisture separators at the top of this scrubber ensure that the gases leaving the top of the scrubber are almost dry.

A major part of this dry cool gas is recycled back to the boiler to maintain the required mass flow rates by the suction action of the gas recirculation fans. The recycled gases are heated in the flue gas line of the boiler, against the cooling flue gases.

The remaining part of the flue gases is further cooled in a trim cooler before it is sent to the CO_2 separation (purification) section.

The gases are now compressed in multiple stages with inter-stage cooling. The heat of compression is advantageously used to preheat the condensate water to the boiler and also the HP feed water allowing a consistent reduction in size of the preheating line of the power island. Trim coolers are used to further cool the gases at the inlet of each compression stage. The gases are compressed to about 30 bar.

After compression the high pressure gases are dried in a desiccant dryer to reach a low dew point (-60°C) and then they enter the cold box, without problem of ice formation. In the double cold box takes place the inerts removal. The system uses two flash separators tanks, the first at (–26°C) and the second at temperature very close to the freezing temperature of CO_2 (–55°C) by the principle of phase separation between the condensed liquid CO_2 and the insoluble inert gases. The conditions of separation (CO_2 partial pressure and temperature) are set to ensure the required CO_2 purity levels corresponding to at least 85% CO_2 capture overall with a purity higher than

95%. The condensed CO_2 liquid is now evaporated to generate the required refrigeration for the plant operation.
The cold box heat exchanges are optimised by use of reflex heat exchangers. The product CO_2 gases are again compressed to the required pressure of 110 bar. The gases are cooled and condensed to ambient temperature to produce the final product CO_2 liquid for transport in pipelines.

The inert gases leaving the separation tanks are still at a high pressure. These are vented to atmosphere after passing them through an expander to recover some electrical energy from the process.

This section has a huge duty for both compression and cryogenic cooling. The heat exchangers must be constructed in special material due to the problems of corrosion and the very low temperature. An appropriate selection of material of construction is an important issue to be evaluated to guarantee a good operation of the plant.

Unit 3000: Steam Turbine and Preheating Line

The block flow diagram of the Unit is attached to paragraph 1.3 of this Section.

The turbine consists of a HP, IP and LP sections all connected to the generator on a single shaft. Main steam from the boiler passes through the stop valves and control valves and enter the turbine at 290 bar, 600°C. Steam from the exhaust of the HP turbine is returned to the boiler gas path for reheating and is then throttled into the double flow IP turbine at 60 bar, 620°C. Exhaust steam from IP flows into a double flow LP turbine and then downward into the condenser at 0.032 bar, 25°C.

Waste heat from carbon dioxide compressor intercoolers is recovered to preheat boiler feedwater and the condensate from the condenser.
This integration between power plant and CO_2 capture plant allows to maximize the efficiency of the process. This also reduces the MP/LP steam extractions to preheat condensate and BFW in the LP/HP preheating line. The feed-water is finally heated in HP feed water heaters to 295°C prior to entering the boiler.

Integration Between The Various Units Of The Plant.

The plant configuration studied considers the following integrations between the various Units:

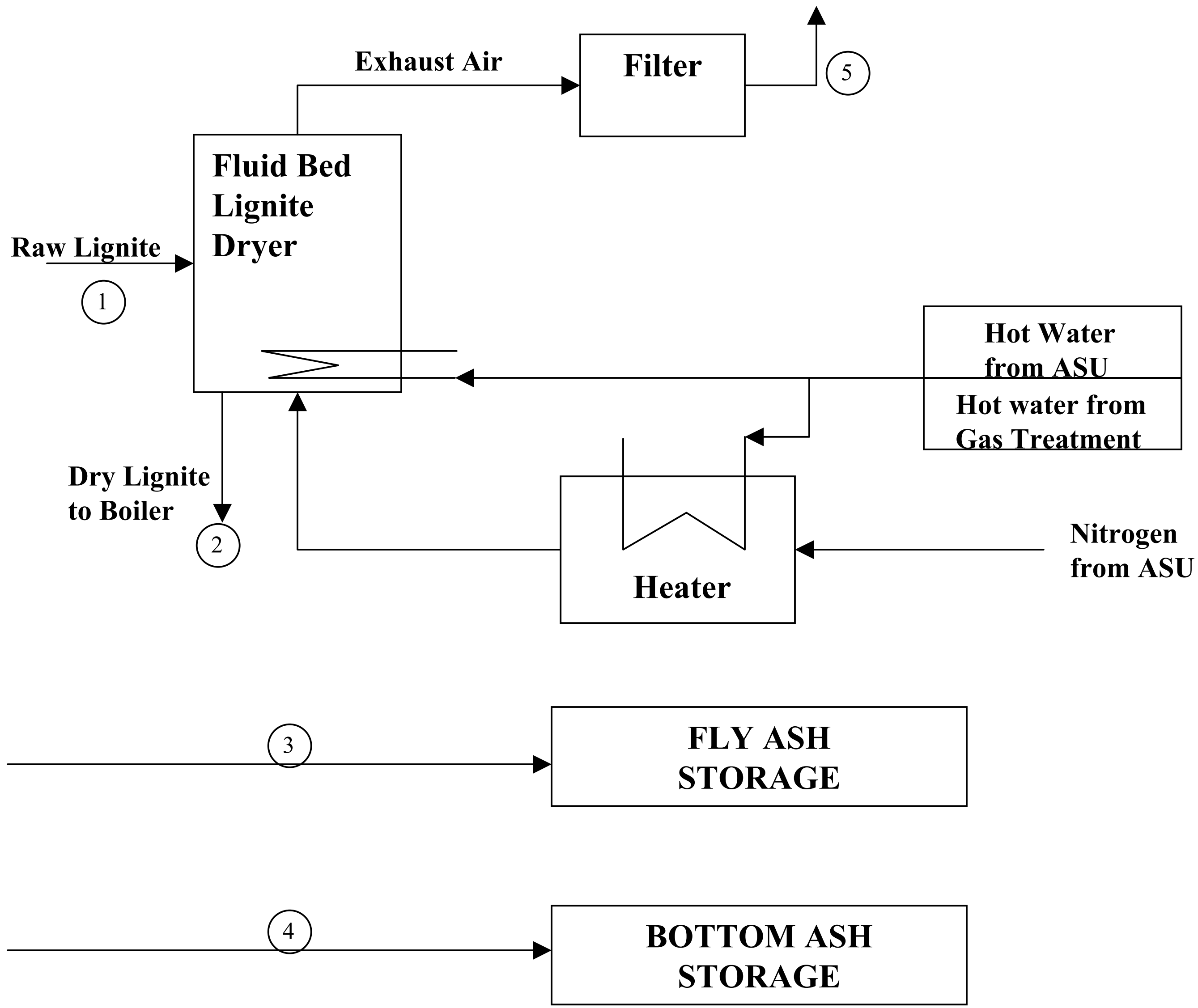
- The heat required for the drying of coal is partially generated by producing hot water in the Air Separation Unit from the inter-stage cooling in the compressors. The missing heat is recoverd from CO_2 compression line.
- The ASU also generates a stream of nitrogen at 1.7 bar. This pressure is more than adequate for the inert medium for fluidising and drying of the input coal. Hence, this stream shall be used for lignite drying process, saving on the power requirements for an independent air blower.
- A part of the heat generated in the CO_2 compression line is recovered by preheating BFW and the condensate, reducing the duty of the HP/LP feed water heaters.

2.3 Block Flow Diagrams

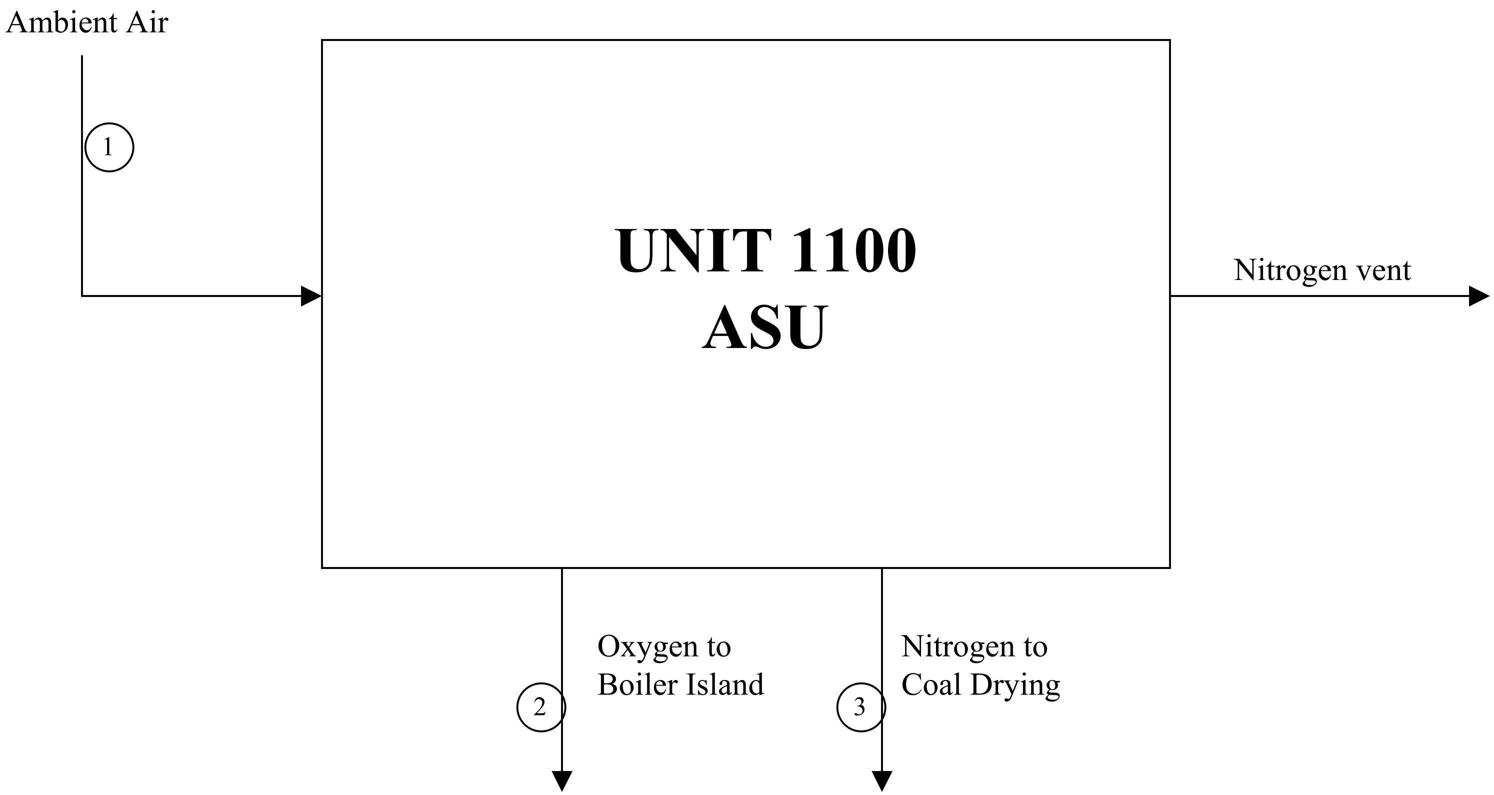
The Block Flow Diagrams of the following process units are attached to this paragraph:

- UNIT 1000: Coal handling and storage
  Ash and Solid removal
  Coal Drying System
- UNIT 1100: Air Separation Unit (ASU)
- UNIT 2000: Boiler Island with Electro Static Precipitators (ESP)
- UNIT 3000: Power Island consisting of
  Steam Turbine and Preheating Line
- UNIT 4000: CO_2 Separation Unit

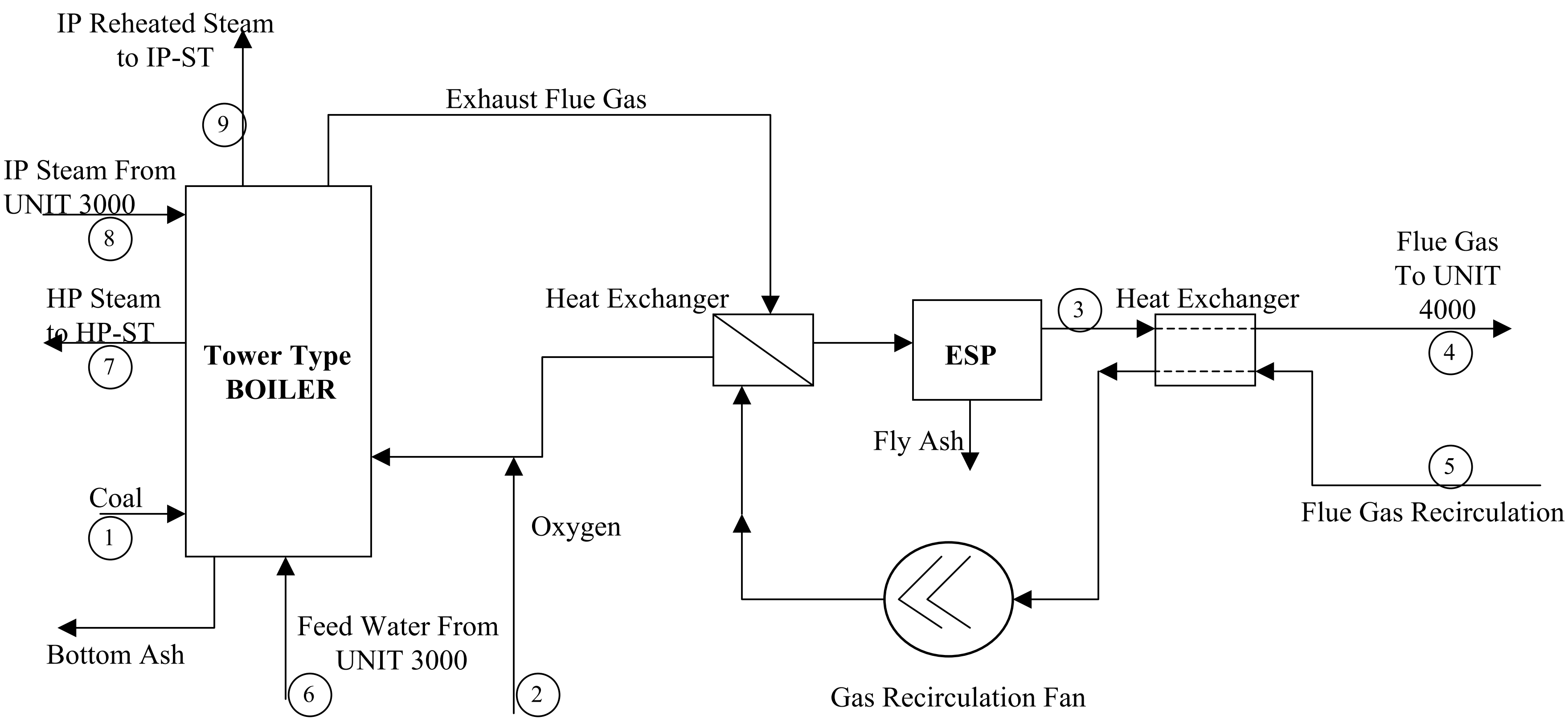
UNIT 1000 - Coal and Ash Handling



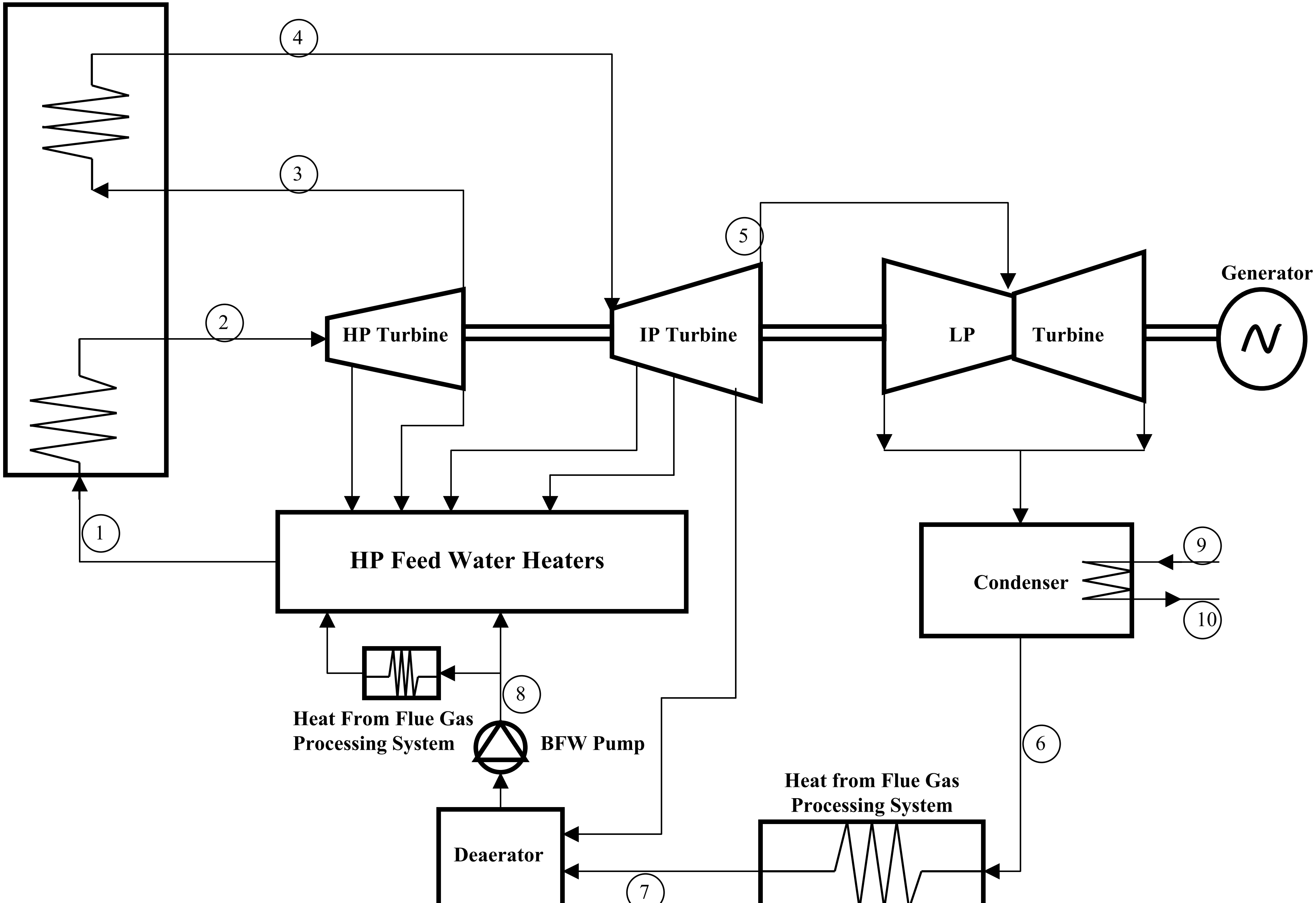
UNIT 1100 - Air Separation Unit ASU



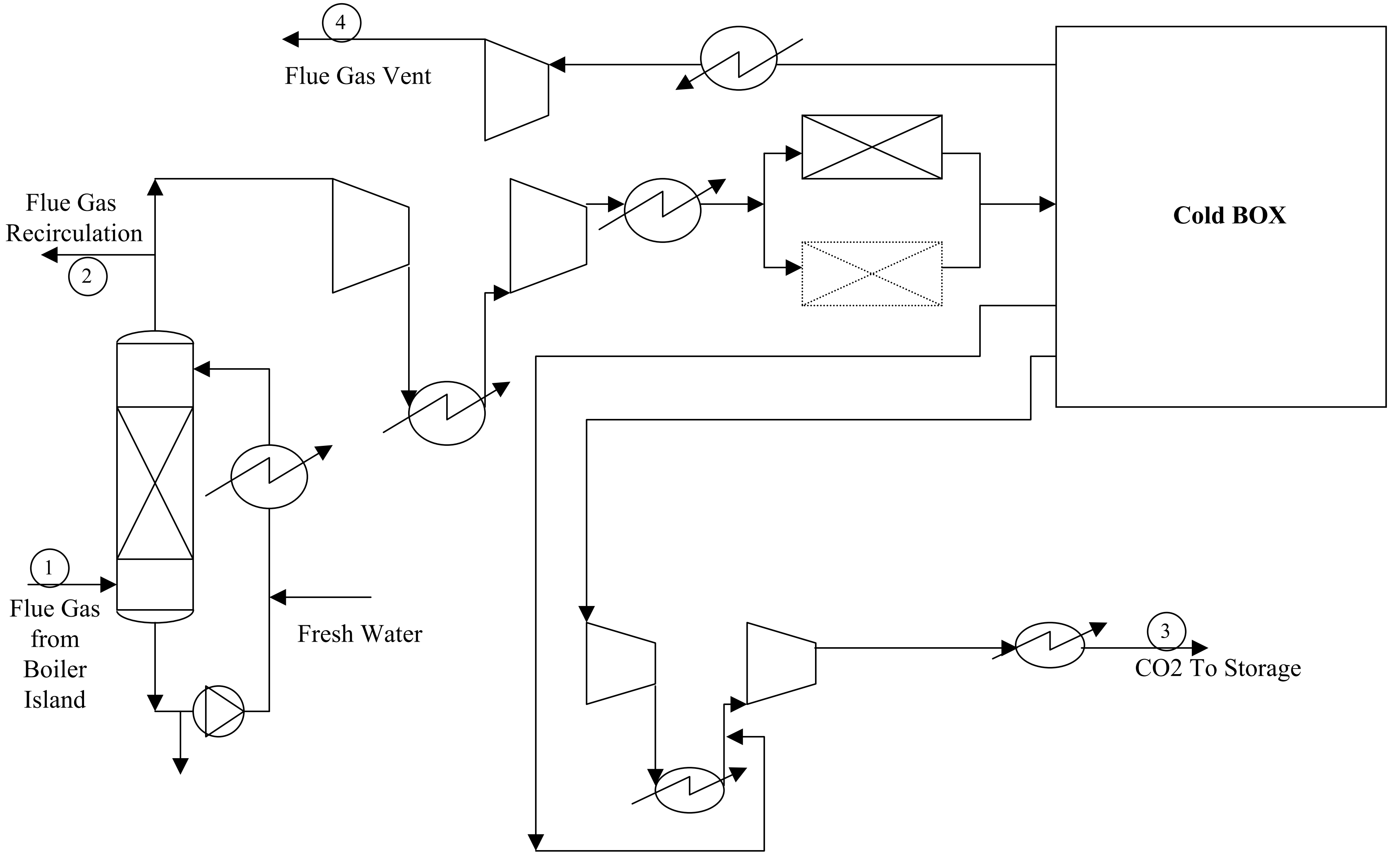
UNIT 2000 - Boiler Island



UNIT 3000 - Steam Turbine & Preheating Line



UNIT 4000 – CO_2 Separation Unit



2.4 Heat and Material Balances

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

- UNIT 1000: Coal handling and storage
  Ash and Solid removal
  Coal Drying System
- UNIT 1100: Air Separation Unit (ASU)
- UNIT 2000: Boiler Island with Electro Static Precipitators (ESP)
- UNIT 3000: Power Island consisting of
  Steam Turbine and Preheating Line
- UNIT 4000: CO_2 Separation Unit

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

FOSTER WHEELER	Oxyfuel PC-USC HEAT AND MATERIAL BALANCE	REVISION	0	1
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	SR	
	CASE : CASE 2	APPROVED	LM	
	UNIT : 1000 Coal & Ash Handling — Sheet 1 of 1	DATE	Feb 05	

STREAM	1	2	3	4	5		6	7	8	9
	Coal to Plant	Coal to Boiler Island	Fly Ash	Bottom Ash	Nitrogen Vent from Lignite Dryer					
Temperature (°C)	AMB	AMB	AMB	AMB	60					
Pressure (bar)	ATM	ATM	ATM	ATM	ATM					
TOTAL FLOW										
Mass flow (kg/h)	677589	491252	18970	4740	1221542					
Molar flow (kgmole/h)										
LIQUID PHASE	Moisture	Moisture								
Mass flow (kg/h)	50.70%	32.0%								
Composition wt% with moisture										
					vol%					
Carbon	31.33%	43.21%			77.31%	Nitrogen				
Hydrogen	2.29%	3.16%			0.27%	Argon				
Oxygen	11.56%	15.94%			0.47%	Oxygen				
Sulfur	0.22%	0.31%			21.94%	Water				
Nytrogen	0.37%	0.51%								
Chlorine	0.03%	0.05%								
Moisture	50.70%	32.00%								
Ash	3.50%	4.83%								

FOSTER WHEELER	Oxyfuel PC-USC HEAT AND MATERIAL BALANCE						REVISION	0	1	
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	SR		
	CASE : CASE 2						APPROVED	LM		
	UNIT : 1100 Air Separation Unit ASU					Sheet 1 of 1	DATE	Feb 05		
STREAM	1	2	3	4	5	6	7	8	9	10
	Ambient Air Inlet	Oxygen	Nitrogen to Drying							
Temperature (°C)	6	16	16							
Pressure (bar)	1.01	1.6	1.4							
TOTAL FLOW										
Mass flow (kg/h)	2830242	677418	1035205							
Molar flow (kgmole/h)	97932	21064	36858							
LIQUID PHASE										
Mass flow (kg/h)	0	0								
GASEOUS PHASE										
Mass flow (kg/h)	2830242	677418	1035205							
Molar flow (kgmole/h)	97932	21064	36858							
Molecular Weight	28.90	32.16	28.09							
Composition (vol %)										
N_2	77.31%	1.98%	99.04%							
CO_2	0.04%	0.00%	0.00%							
H_2O	1.00%	0.00%	0.00%							
O_2	20.73%	94.98%	0.61%							
Ar	0.92%	3.04%	0.35%							
NOx	0.00%	0.00%	0.00%							
SOx	0.00%	0.00%	0.00%							
CO	0.00%	0.00%	0.00%							

FOSTER WHEELER	Oxyfuel PC-USC HEAT AND MATERIAL BALANCE	REVISION	0	1	
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	SR		
	CASE : CASE 2	APPROVED	LM		
	UNIT : 2000 Boiler Island — Sheet 1 of 1	DATE	Feb 05		

STREAM	1	2	3	4	5
	Coal from Coal Dryer	Oxygen from ASU	Exhaust Flue Gas from Boiler	Flue Gas to Processing System	Flue Gas Recirculation
Temperature (°C)	AMB	16	135	30	30
Pressure (bar)	AMB	1.6	1.04	1.02	1.02
TOTAL FLOW					
Mass flow (kg/h)	491252	677418	3529800	907000	1787600
Molar flow (kgmole/h)		21064	113129	22604	44551
LIQUID PHASE					
Mass flow (kg/h)	0	0	0	0	0
GASEOUS PHASE					
Mass flow (kg/h)	491252	677418	3529800	907000	1787600
Molar flow (kgmole/h)		21064	113129	22604	44551
Molecular Weight		32.16	31.20	40.13	40.13
Composition (vol %)	See UNIT 1000				
N_2		1.98%	7.66%	12.90%	12.90%
CO_2		0.00%	45.51%	76.29%	76.29%
H_2O		0.00%	42.91%	4.21%	4.21%
O_2		94.98%	3.80%	6.40%	6.40%
Ar		3.03%	0.00%	0.00%	0.00%
NOx		0.00%	0.00%	0.00%	0.00%
SOx		0.00%	0.12%	0.20%	0.20%
CO		0.00%	0.00%	0.00%	0.00%

STREAM	6	7	8	9	10
	Feed Water from Preheating line UNIT 3000	HP Steam to Steam Turbine	IP Steam from Preheating Line UNIT 3000	IP Reheated Steam to Steam Turbine	
Temperature (°C)	295	600.00	358	620	
Pressure (bar)	339	290	65	60	
TOTAL FLOW					
Mass flow (kg/h)	2610000	2610000	2313600	2313600	
Molar flow (kgmole/h)					
LIQUID PHASE					
Mass flow (kg/h)	2610000	2610000	2313600	2313600	
GASEOUS PHASE					
Mass flow (kg/h)					
Molar flow (kgmole/h)					
Molecular Weight					
Composition (vol %)					
N_2	0.00%	0.00%	0.00%	0.00%	
CO_2	0.00%	0.00%	0.00%	0.00%	
H_2O	100.00%	100.00%	100.00%	100.00%	
O_2	0.00%	0.00%	0.00%	0.00%	
Ar	0.00%	0.00%	0.00%	0.00%	
NOx	0.00%	0.00%	0.00%	0.00%	
SOx	0.00%	0.00%	0.00%	0.00%	
CO	0.00%	0.00%	0.00%	0.00%	

Oxyfuel PC-USC HEAT AND MATERIAL BALANCE

CLIENT : IEA GREEN HOUSE R & D PROGRAMME
CASE : CASE 2
UNIT : 3000 Steam Turbine & Preheating Line

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	HP Water to Boiler Island	2610	295	339	1303
2	HP Steam from Boiler	2610	600	290	3456
3	IP Steam to Boiler	2314	358	65	3056
4	IP hot reheated steam to Steam Turbine	2314	620	60	3706
5	IP Steam Turbine exhaust	1886	283	6	3026
6	Condensate	1994	25	0.032	106
7	LP Preheated Condensate	2516	164	12	703
8	Condensate to HP FWH	2610	189	343	823
9	Cooling Water Inlet	85585	11	2	47
10	Cooling Water Outlet	85585	21	2	88

FOSTER WHEELER	Oxyfuel PC-USC HEAT AND MATERIAL BALANCE	REVISION	0	1	
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	SR		
	CASE : CASE 2	APPROVED	LM		
	UNIT : 4000 CO_2 Separation Unit — Sheet 1 of 1	DATE	Feb 05		

STREAM	1	2	3	4
	Flue Gas from Boiler Island	Flue Gas Recirculation	Carbon Dioxide to Storage	Flue Gas vented to Atmosphere
Temperature (°C)	30	30	35	56
Pressure (bar)	1.02	1.02	110	1.01
TOTAL FLOW				
Mass flow (kg/h)	907000	1787600	725320	164500
Molar flow (kgmole/h)	22604	44551	16642	5011
LIQUID PHASE				
Mass flow (kg/h)			725320	
GASEOUS PHASE				
Mass flow (kg/h)	907000	1787600	725320	164500
Molar flow (kgmole/h)	22604	44551	16642	5011
Molecular Weight	40.13	40.13	43.58	32.83
Composition (vol %)				
N_2	12.90%	12.90%	1.99%	51.60%
CO_2	76.29%	76.29%	96.40%	24.00%
H_2O	4.21%	4.21%	0.00%	0.00%
O_2	6.40%	6.40%	1.34%	24.41%
Ar	0.00%	0.00%	0.00%	0.00%
NOx	0.00%	0.00%	0.00%	0.00%
SOx	0.20%	0.20%	0.27%	0.00%
CO	0.00%	0.00%	0.00%	0.00%

STREAM	5	6	7	8	9	10

2.5 Utility Consumption

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

CLIENT:	IEA GHG	Rev Final
PROJECT:	GASIFICATION POWER GENERATION STUDY	Nov 05
LOCATION:	Germany	ISSUED BY: SR.
FWI Nº:		CHECKED BY: LM
		APPR. BY: RD

ELECTRICAL CONSUMPTION SUMMARY - CASE 2 - PC - USC Oxyfuel

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
1000	Coal - Ash Storage and Handling	340
1050	Coal Drying (Air fan consumption)	638
1100	Air Separation Unit	132000
2000	Boiler Island	11980
4000	CO_2 Separation Unit	112000
	POWER ISLANDS UNITS	
3000	Steam Turbines and Preheating Line	2080
	UTILITY and OFFSITE UNITS 3000 - 4000 - 5000	
	Cooling Towers	25600
	Others	9770
	BALANCE	294408

	CLIENT:	IEA GHG	Rev 0
FOSTER WHEELER	PROJECT:	GASIFICATION POWER GENERATION STUDY	Feb-05
	LOCATION:	Germany	ISSUED BY: SR
	FWI Nº:		CHECKED BY: LM
			APPR. BY: RD

WATER CONSUMPTION SUMMARY - CASE 2: PC - USC Oxyfuel

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water [t/h]
	PROCESS UNITS			
1000	Coal and Ash Handling			91
1100	ASU			9100
2000	Boiler Island			139
5000	CO_2 Compression and Drying			38100
	POWER ISLANDS UNITS			
	Steam Turbine and Generator auxiliaries		1	85584
	Miscellanea			1685
	UTILITY and OFFSITE			
	Cooling Water (Cooling Towers Make Up)	2064		
	Demineralized/Condensate Recovery/Plant Potable Water System	1	-1	
	Miscellanea			78
	BALANCE	2065	0	134777

2.6 PC-USC Overall Performance

The following Table shows the overall performance of the PC-USC Complex.

PC-USC Oxyfuel Combustion		
Case 2		
OVERALL PERFORMANCES		
Coal Flowrate A.R.	t/h	677.6
Coal LHV A.R.	kJ/kg	10500
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1976.3**
Steam turbine power output (@ gen. terminals)	MWe	1027.7
Expander power output	MWe	11.7
GROSS ELECTRIC POWER OUTPUT OF PC - USC COMPLEX (D)	**MWe**	**1039.4**
Coal Storage / Handling / Drying	MWe	1.0
Air Separation Unit	MWe	132.8
Boiler Island	MWe	12.0
CO_2 Separation Unit	MWe	112.6
Power Island (1)	MWe	2.1
Utilities	MWe	35.4
ELECTRIC POWER CONSUMPTION OF PC-USC COMPLEX	**MWe**	**295.8**
NET ELECTRIC POWER OUTPUT OF PC-USC (C) Step-up transformer efficiency (0.997)	**MWe**	**741.3**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**52.6%**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**37.5%**

Notes: (1) Boiler Feed Water pumps are steam turbine driven.

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

	Equivalent flow of CO_2 kmol/h
Coal (Carbon = 43.21%wt)	17674
Slag	426
Net Carbon flowing to Process Units (A)	17248
Liquid Storage	
CO	0.0
CO_2	16044
Total to storage (B)	16044
Emission	
CO	0.0
CO_2	1204
Total Emission	1204
Overall CO_2 removal efficiency, % (B/A)	93

2.7 Environmental Impact

The Oxyfuel PC-USC Complex is designed to process coal, 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 Oxyfuel PC-USC Complex are summarised in this section.

2.7.1 Gaseous Emissions

Main Emissions

In normal operation at full load, the main continuous emission is the gas leaving the CO_2 processing plant.

Table 1.1 summarises expected flow rate and concentration of the combustion flue gas after CO_2 capture treatment.

Table 1.1 – Expected gaseous emissions from Oxyfuel PC-USC plant.

	Normal Operation
Wet gas flow rate, kg/s	45.68
Flow, Nm^3/h	112302
Temperature, °C	56
Composition	(%vol)
N_2	51.60
O_2	24.41
CO_2	24.00
H_2O	0
Emissions	kg/h
NOx	0
SOx	0.95
CO	0
Particulate	NIL

In normal operation at full load, the following emission to the atmosphere is foreseen from the Coal Drying Process:

Air with moisture	:	1222	t/h
Particulate	:	16.1	kg/h

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

The plant is designed for zero liquid effluents

2.7.3 Solid Effluent

Solid waste produced by the process units are typical for these plants
The power plant is expected to produce the following solid by-products:

Fly Ash

Flow rate	:	19	t/h

Bottom Ash

Flow rate : 4.7 t/h

Fly and bottom ash can be dispatched to cement industries.

2.8 Equipment List

The duty specifications of the main equipment and process packages are included in this paragraph.

UNIT 1000 – Coal handling and storage – Ash and Solid removal

Coal Unloading train including:
- Hopper systems
- Coal conveying
- Stacker reclaimer
- Coal delivery equipment

Coal Pre-drying train including:
- Fluid Bed Dryer
- Hot Water based Gas Heater
- Filters for exhaust Gas

Fly ash handling System including:
- Pneumatic Conveying system
- Storage Silo
- Dust suppression System

Bottom ash systems
- Conveying System
- Clinker Crusher

Miscellaneous equipment

UNIT 1100 – Air Separation Unit ASU

Air Filter
Air Compressors
Air Coolers
Air Purification System
Main Exchanger Line
ASU Cold Box
Backup Storage Vessel
Pumps

UNIT 2000 – Boiler Island with – Electro Static Precipitators (ESP)

Tower type boiler including:
- Fresh Air Fans
- Fan Beater Mills
- Gas/Gas Heaters
- Electro Static Precipitator
- Induced Draft Fans
- Flue Gas Recirculation Fans
- Recycle Gas Preheater
- Miscellaneous equipment

Auxiliary boiler
Structures
Control System

UNIT 3000 – Power Island consisting of Steam Turbine and Preheating Line

Steam turbine and generator package
LP feedwaterheaters
Deaerator
HP feedwaterheaters
Condenser Package
Condensate pumps
Steam turbine driven BFW pump
LP pumps

UNIT 4000 – CO_2 Separation Unit

Direct Contact Flue Gas Cooler
Compressors
CO_2 pumps
Drums and Vessels
Heat Exchangers
Water pumps
Flue Gas Expander

Utility and Offsite Units

Cooling Water / Machinery cooling water systems (Unit 4100)
Demineralized, Plant and Potable Water System (Unit 4200)
Natural Gas System (Unit 4300)
Plant / Instrument Air Systems (Unit 4400)
Waste Water Treatment (Unit 4600)
Fire Fighting System (Unit 4700)
Chemicals (Unit 4900)
Interconnecting (Instrumentation, DCS, Piping, Electrical, 400 KV Substation) (Unit 6000)

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : CO_2 Capture in Low-rank Coal Power Pants
DOCUMENT NAME : CASE 3 – FW CFB BOILER WITH POST COMBUSTION CO_2 CAPTURE

ISSUED BY : S. RIPANI
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by

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 3 Foster Wheeler Circulating Fluidized Bed (CFB) Boiler with Postcombustion CO_2 Capture

Summary

SuperCritical CFB boiler with SCR + Amine wash for CO_2 Absorption + CO_2 compression unit.

- The size of the plant considered for this configuration is based on the actual commercial size of CFB boilers. To provide a net power output consistent with other plants studied, two CFB boilers in parallel are employed, taking into account the additional steam and power requirements of all the equipment in the plant.

- The largest CFB boilers are still small in comparison to the largest pulverized coal (PC) boilers, which can be substantially larger than 1000 MWe. However, because CFB boilers are very similar to PC boilers in mechanical design and construction, much of what was learned in scaling up PC boilers can be and is being applied to CFB boiler scale-up. CFB boilers of bigger size are under investigation during these years and they will represent a commercially available technology in the next few years.

- The Boiler technology for firing coal considered in this study is a commercially available unit in the market.

- A pre-drying of the coal from a moisture level of 50.7% in as-received coal to about 32% is considered, before it is fed to the boiler plant.
  Drying of coal using low temperature waste heat is used for this alternative (Reference to Section C).

- CFB Technology is a modern way to burn coals with different characteristics, specifically developed to address today's needs for fuel flexibility and low emissions. The low furnace temperature provide for low NO_x emissions, low SO_x emissions via simple furnace limestone injection and the ability to fire a range of fuels, in particular low rank coals with high moisture content.

- The limits of NO_x emissions can be met with just the firing system of the boiler with low temperature at furnace exit. However, an SCR system based on direct ammonia injection is considered in the boiler to reduce the NO_x levels to about 20 ppmv, a requirement of the downstream CO_2 capture plant.

- Downstream flue gas desulphurization is not required to meet SO_x emission limits. SO_x are captured by a limestone injection 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 temperature of the bed and physical and chemical characteristics of the limestone. The ideal reaction temperature range is 840 – 900 °C. The downstream amine based CO_2 absorption system, again 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 to reach the limit of 10 ppm of SO_2 at the exit of the boiler. With actual technology this limit can't be reached with the only limestone injection. Presently in CFB Boilers the minimum level obtainable is 15 ppm. In any case one of the main advantages of the CFB technology is the possibility to completely avoid the presence of the expensive FGD unit, so 15 ppm of SO_2 in the flue gas are considered acceptable for the CO_2 capture plant. An higher amine degradation in the CO_2 capture plant is also considered. The big advantage of completely avoid the FGD unit, in term of auxiliary power consumption and cost reduction, more than compensate the major amine dagradation.

- Following the study performed by Fluor, a carbon dioxide capture plant based on solvent scrubbing of flue gas with amine solvents is considered. This is followed by steam stripping and recycle of the solvent and then drying and compression of the captured carbon dioxide. This is a technology commercially available for post combustion capture of carbon dioxide, from more than one supplier, albeit with an acceptable commercial risk for scaling to the size required for this plant. (Reference to Section C para. 7.0).

- The possible effect of any other impurities in the flue gas, even at small concentrations, on the CO_2 capture plant has to be studied further, both theoretically and in pilot operation plants.

- The configuration of the plant considered provides for a good heat integration of the various systems.

- 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 exchangers 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.

3.1 Introduction

The Case-3 of the study is a Super Critical CFB steam plant fitted with Post-combustion carbon dioxide capture and compression units.

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

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

Unit

1000 Coal handling and storage
Ash and Solid removal
Coal Drying System

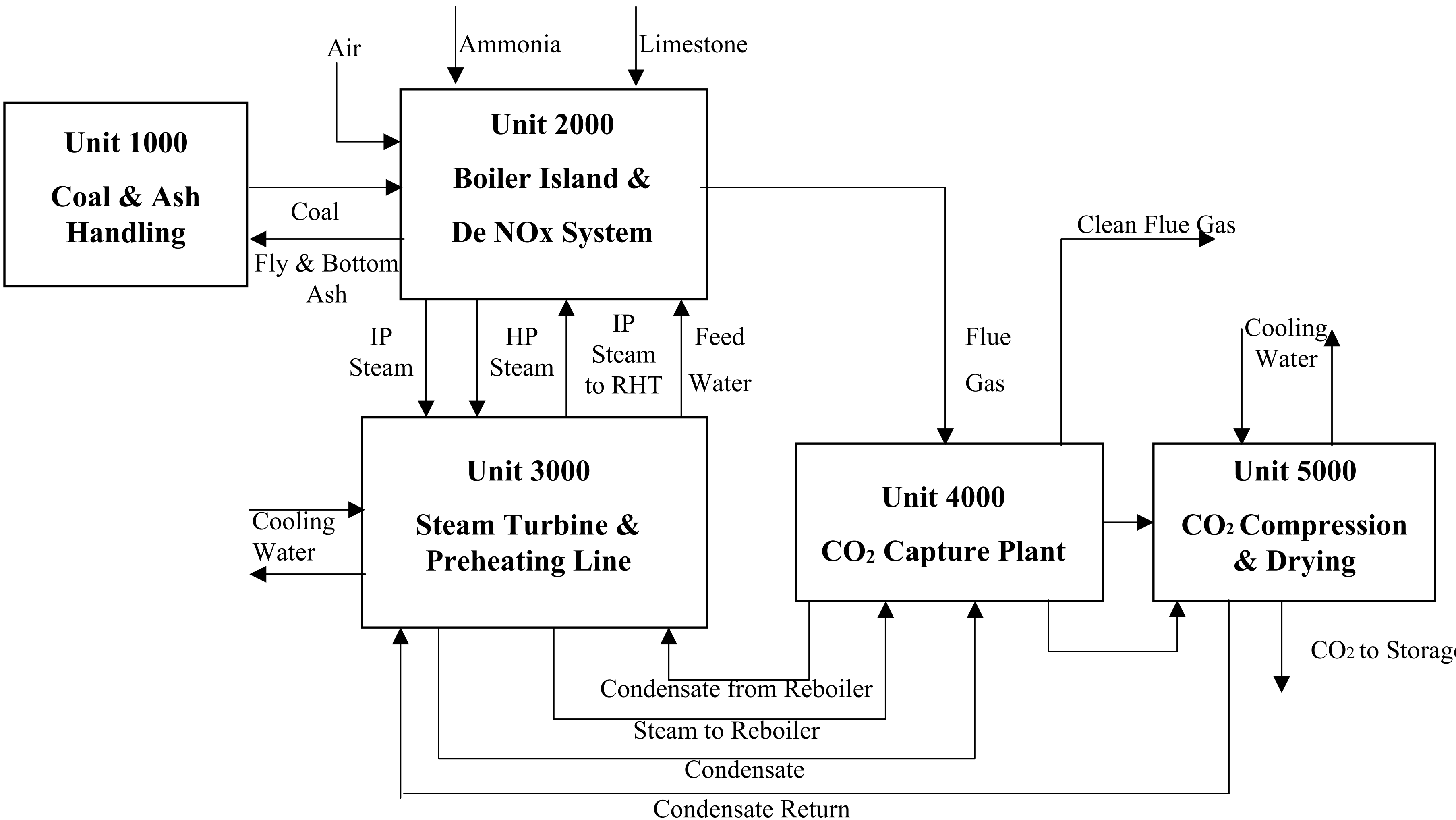
2000 Boiler Island with SCR based De NOx,
Limestone Injection and Electro Static Precipitators (ESP)

3000 Power Island consisting of
Steam Turbine and Preheating Line

4000 CO_2 Capture Plant

5000 CO_2 Compression and Drying

Case 3: CFB Block Flow Diagram



3.2 Process Description

Note: 'Coal' referred to in all the following sections means 'low rank coal' as defined in the BEDD document.

Unit 1000: Coal and Ash Handling

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

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

Coal Pre-Drying:

This Scheme is described in Section C (Basic information for Low Rank Coal Power Plants) para. 2.0 (Drying of low rank coal lignite). A specific block flow diagram showing the main heating sources of this alternative is attached to paragraph 3.3.

The split of the heating sources required for the drying of the lignite is reported in the following table:

Heat source	**Duty**, MWth
Flue gas cooling from Boiler Island	26
CO_2 capture unit	72
CO_2 compression	26
TOTAL HEAT	**124**

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).

Unit 2000: Boiler Island

This Unit is treated as a package supplied by Foster Wheeler. Supercritical CFB boilers firing coal of the size proposed for this study are commercially available and have gained a lot of operational experience.

The CFB Island consists of the boiler proper (furnace, solid separator, back pass), plus the material handling, air handling and other auxiliary equipment.

Milling Plant:

After drying process, the coal is delivered by conveyor belts to the boiler. In this case it is not necessary the pulverisation of coal and the final milling can be avoided. The particles size after drying (<8mm) is already suitable for the CFB boiler operation. The dried lignite is transferred to hoppers for boiler feeding. This system works in pressure to avoid back flow of flue gases from combustion chamber.

Tower Type Boiler:

The boiler would be a tower-type super critical boiler. The main distinguishing feature of a CFB boiler is the separator device at the furnace gas outlet which collect bed material entrained in the flue gas for recycle back to the furnace. The bed material contains fuel ash, unburned fuel, spent limestone and unutilized limestone. Collection and recirculation of this material back to the furnace results in excellent fuel burnout and limestone utilization.
The boiler heating surfaces are arranged in the tower at the exit of the furnace.
The flue gases at the exit of the SCR, pass through to the air heater to preheat the incoming combustion air and an Electro Static Precipitator (ESP) to remove the carried over ash particles in the flue gas.

De-NOx System

An SCR system is provided to reduce the NO_x produced by the combustion to a level which does not exceed the inlet requirement of the carbon dioxide capture plant, which corresponds to less than 20 ppmv of NO_2. The catalytic De NO_x reactor is situated in the gas stream between the boiler outlet and the air heaters. This offers a temperature range required for good functioning of the SCR system without the formation of ammonium sulfates. Gaseous ammonia is added to air supplied from a fan in a mixer as the reagent and injected into the flue gas. In the presence of the catalyst, ammonia reacts with nitrogen oxides to reduce it to nitrogen.

For Process Description of the De-NO_x system, refer to Section C para. 4.0.

Flue Gas Coolers:

The flue gas needs to be cooled to about 30-35°C, as an operational requirement for the downstream CO_2 capture plant. The flue gas leaves the boiler at 128 °C and then is cooled till 85 °C recovering heat for combustion air preheating. Then it passes in a Direct Contact Cooler, performing an adiabatic quench, where it is cooled to 35° C, before entering absorption columns of the CO_2 Capture Plant.

Unit 4000: CO_2 Capture Plant

Clean flue gas with NO_2 less than 20 ppmv and SO_x less than 15 ppm is now sent to the CO_2 absorption tower.
Refer to Section C para. 7.0 for this section.
Consequent to the detailed study presented by Fluor in its report for a similar technology study, an identical plant is considered for CO_2 capture; a commercial amine (MEA) scrubbing technology.
The Block Flow Diagram of this section is attached to paragraph 3.3.

In this study a 85% capture of CO_2 from the flue gas is considered.

Unit 5000: CO_2 Compression and Drying

Refer to Section C, para. 9.0 for the general description of the Unit.
The block flow diagram of this section is attached to paragraph 3.3.

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 as a liquid at a pressure of around 110 bara.

Unit 3000: Steam Turbine and Preheating Line

The turbine consists of a HP, IP and LP sections all connected to the generator on a single shaft. Main steam from the boiler passes through the stop valves and control valves and enter the turbine at 283 bar, 584°C. Steam from the exhaust of the HP turbine is returned to the boiler gas path for reheating and is then throttled into the double flow IP turbine at 48 bar, 602°C. Exhaust steam from IP flows into a double flow LP turbine and then downward into the condenser at 0.032 bar, 25°C. The LP steam is also extracted for the use in the reboiler and stripping unit in the CO_2 capture plant.

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

Recycled condensate from the condenser is pumped to the carbon dioxide capture plant and preheated in the amine stripper overhead condenser and in 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 avoids the necessity of LP steam extractions to preheat condensate in LP preheating line. The preheated feed water stream is routed to the dearator, along with condensate returned from the amine stripper reboiler. After deaeration the feed-water is heated in HP feed water heaters to 272°C prior to entering the boiler.

Integration Between The Process Units And The Power Island.

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

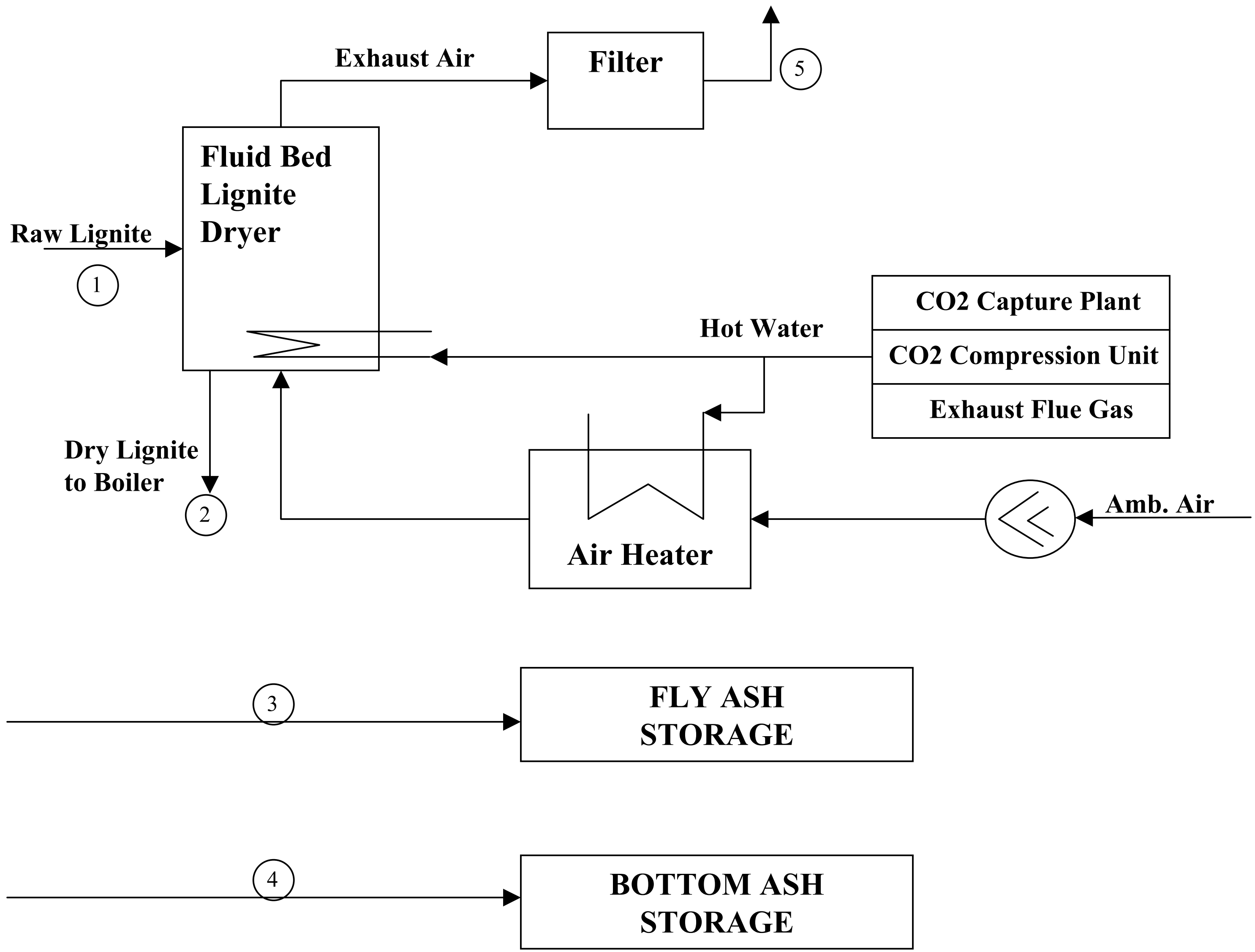
- The heat required for the drying of coal is generated by producing hot water in the flue gas line, in CO_2 compression unit and in CO_2 capture plant.
- A part of the heat recovered in the CO_2 compression line is recovered by preheating the condensate, totally avoiding the use of LP feed water heaters.
- All the LP steam required for the CO_2 absorption plant is provided by extraction from the LP stage of the steam turbine.

3.3 Block Flow Diagrams

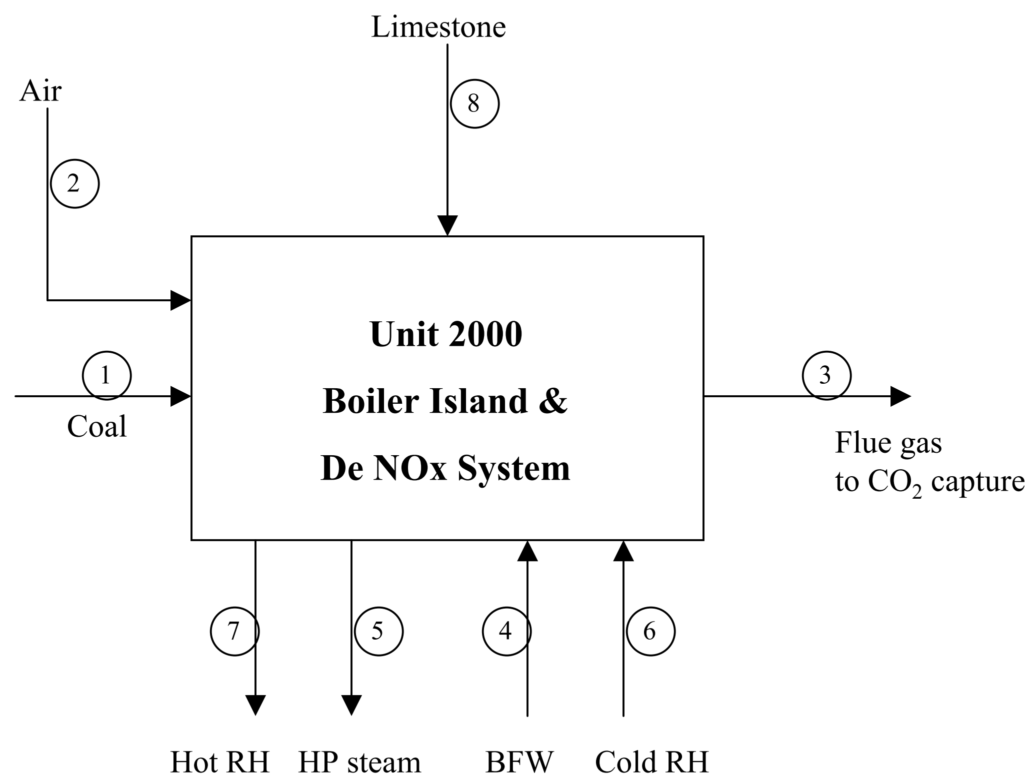
The Block Flow Diagrams of the following process units are attached to this paragraph:

- UNIT 1000: Coal handling and storage
  Ash and Solid removal
  Coal Drying System
- UNIT 2000: Boiler Island with SCR based De-NO_x
  Electro Static Precipitators (ESP)
  Limestone Injection
- UNIT 3000: Power Island consisting of
  Steam Turbine and Preheating Line
- UNIT 4000: CO_2 Capture Plant (Amine Scrubbing)
- UNIT 5000: CO_2 Compression and Drying

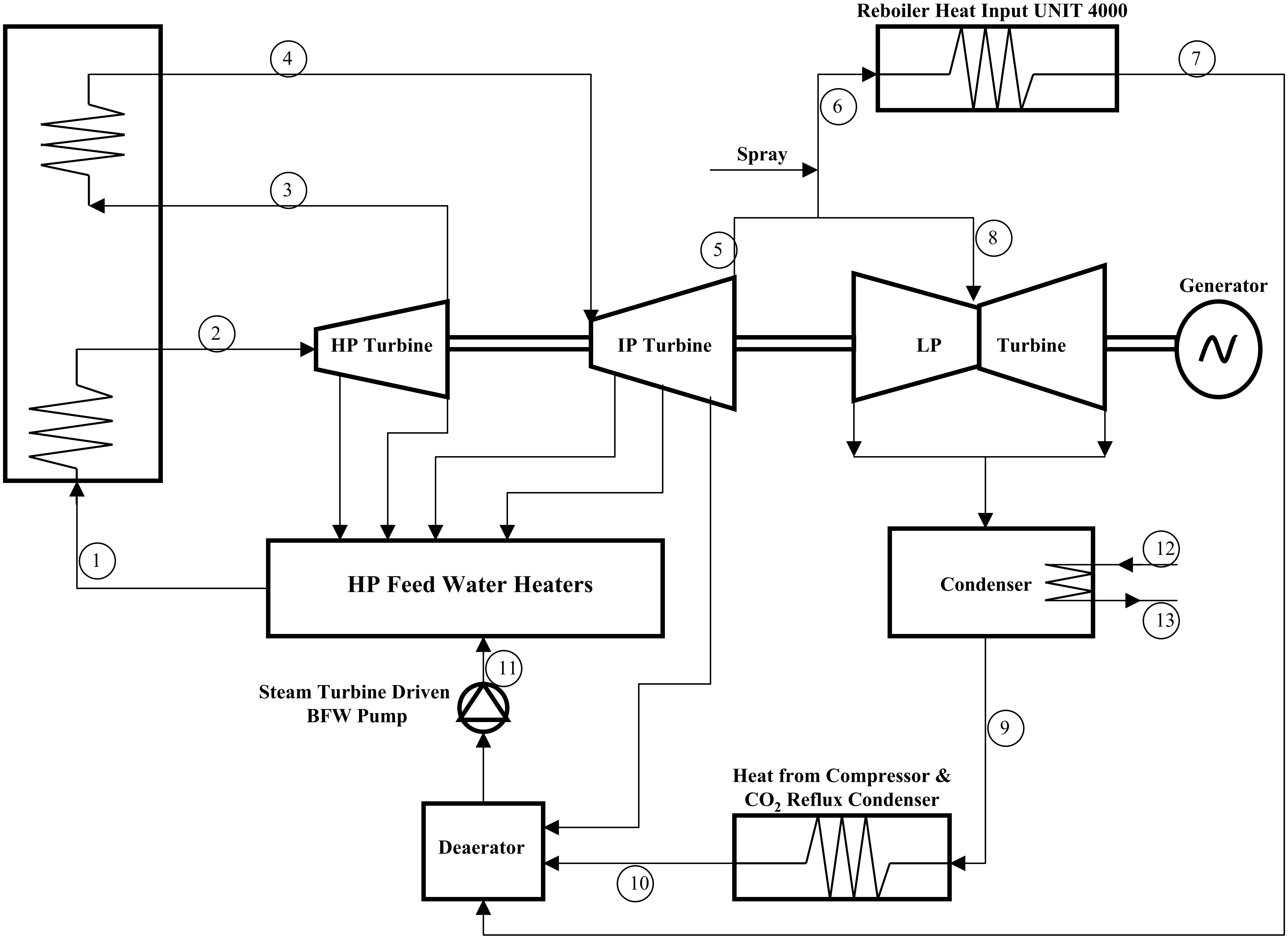
UNIT 1000 - Coal and Ash Handling



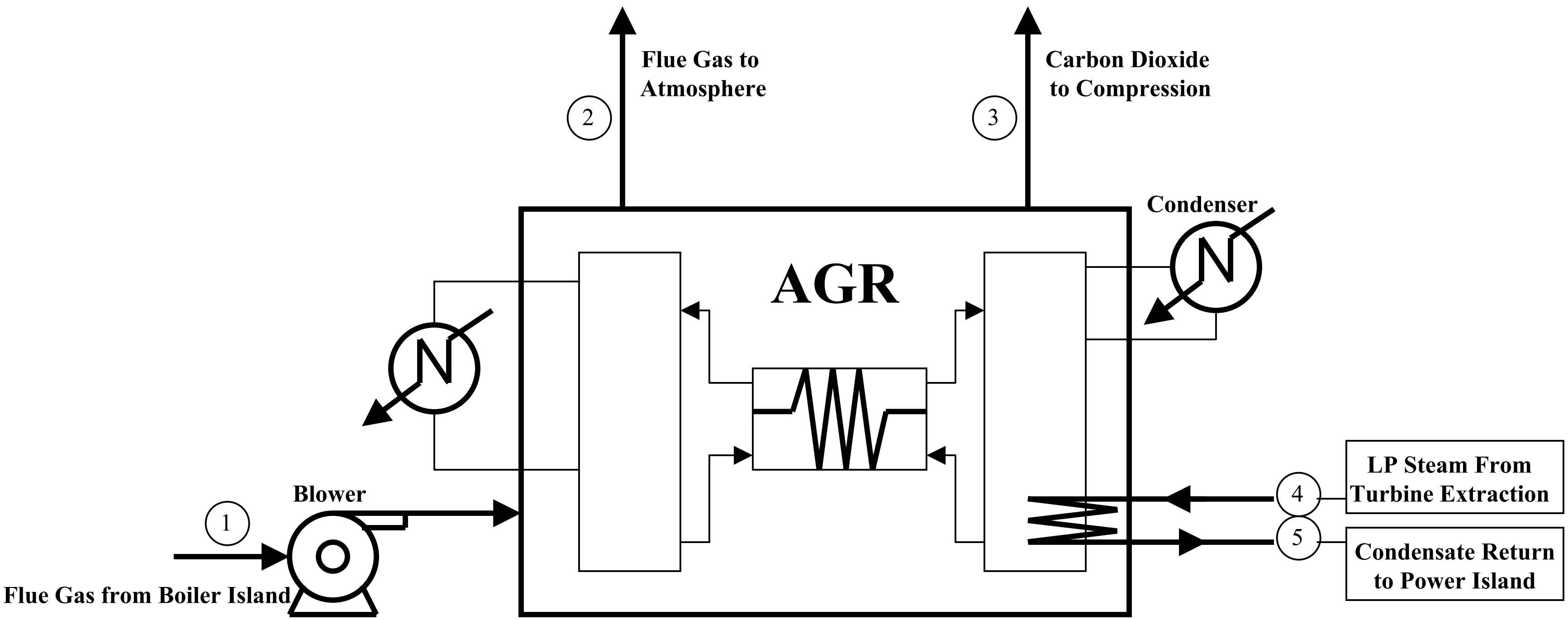
UNIT 2000 – Boiler Island



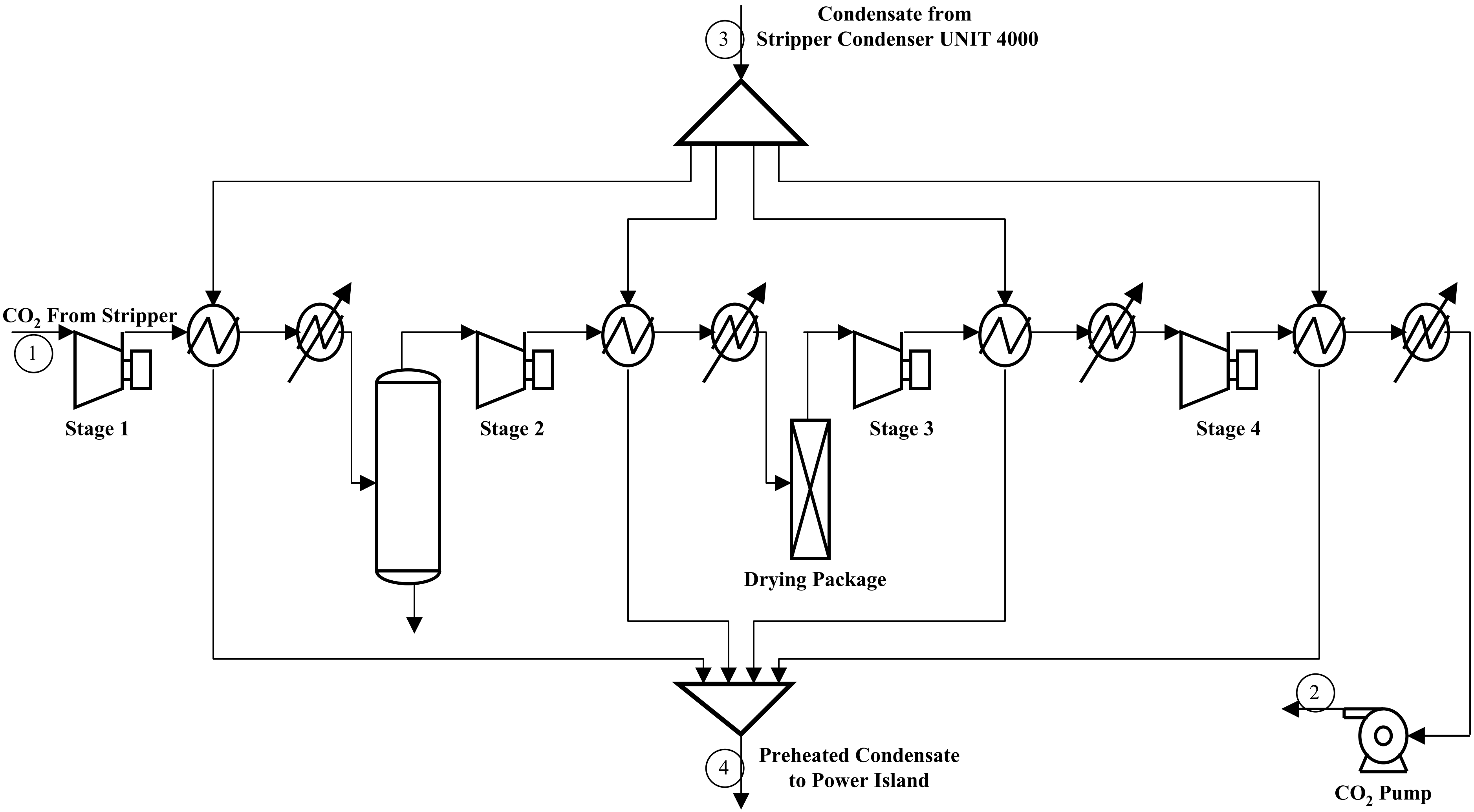
UNIT 3000 - Steam Turbine & Preheating Line



UNIT 4000 - CO_2 Capture Plant



UNIT 5000 - CO_2 Compression & Drying



3.4 Heat and Material Balances

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

- UNIT 1000: Coal handling and storage
  Ash and Solid removal
  Coal Drying System
- UNIT 2000: Boiler Island with SCR based De-NO_x
  Electro Static Precipitators (ESP)
  Limestone Injection
- UNIT 3000: Power Island consisting of
  Steam Turbine and Preheating Line
- UNIT 4000: CO_2 Capture Plant (Amine Scrubbing)
- UNIT 5000: CO_2 Compression and Drying

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

CFB HEAT AND MATERIAL BALANCE							REVISION	0
FOSTER WHEELER	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	SR
	CASE : CASE 3						APPROVED	LM
	UNIT : 1000 Coal & Ash Handling					Sheet 1 of 1	DATE	Feb-05

STREAM	1	2	3	4	5	6	7	8
	Coal to Plant	Coal to Boiler Island	Fly Ash	Bottom Ash	Air from Lignite Dryer			
Temperature (°C)	AMB	AMB	AMB	AMB	65			
Pressure (bar)	ATM	ATM	ATM	ATM	ATM			
TOTAL FLOW								
Mass flow (kg/h)	592883	429840	28800	12240	1071865			
Molar flow (kgmole/h)								
	Moisture	Moisture						
	50.70%	32%						
Composition wt% with moisture								
Carbon	31.33%	43.20%						
Hydrogen	2.29%	3.16%						
Oxygen	11.56%	15.94%						
Sulfur	0.22%	0.31%						
Nytrogen	0.37%	0.51%						
Chlorine	0.03%	0.05%						
Moisture	50.70%	32.00%						
Ash	3.50%	4.83%						

CFB HEAT AND MATERIAL BALANCE			REVISION	0
FOSTER WHEELER	CLIENT : IEA GREEN HOUSE R & D PROGRAMME		PREP.	SR
	CASE : CASE 3		APPROVED	LM
	UNIT : 2000 Boiler Island	Sheet 1 of 1	DATE	Feb-05

STREAM	1	2	3	4	5	6	7	8
	Coal from Coal Dryer	Air intake from Atmosphere	Flue Gas From Boiler	Feed Water from Preheating line UNIT 3000	HP Steam to Steam Turbine	IP Steam from Preheating Line UNIT 3000	IP Reheated Steam to Steam Turbine	Limestone
Temperature (°C)	AMB	15	85	272	584	319	602	AMB
Pressure (bar)	AMB	1.013	1.03	313	283	51	48	ATM
TOTAL FLOW								
Mass flow (kg/h)	429840	2793374	3361176	2182000	2182000	2016000	2016000	27360
Molar flow (kgmole/h)		96690	116023	121155	121155	111938	111938	
LIQUID PHASE								
Mass flow (kg/h)		0		2182000	0	0	0	
GASEOUS PHASE								
Mass flow (kg/h)		2793374	3361176	0	2182000	2016000	2016000	
Molar flow (kgmole/h)		96690	116023	0	121155	111938	111938	
Molecular Weight		28.89	28.97	18.01	18.01	18.01	18.01	
Composition (vol %)	See UNIT 1000							
N_2		77.57%	68.91%	0.00%	0.00%	0.00%	0.00%	
CO_2		0.00%	13.51%	0.00%	0.00%	0.00%	0.00%	
H_2O		0.68%	13.70%	100.00%	100.00%	100.00%	100.00%	
O_2		20.86%	3.88%	0.00%	0.00%	0.00%	0.00%	
Ar		0.89%	0.00%	0.00%	0.00%	0.00%	0.00%	
NOx		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
SOx		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
CO		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

Note (1): Limestone Analysis (wt %) $CaCO_3$ = 95% - $MgCO_3$ = 3.4% - Inert = 1.6%

CFB HEAT AND MATERIAL BALANCE

CLIENT : IEA GREEN HOUSE R & D PROGRAMME
CASE : CASE 3
UNIT : 3000 Steam Turbine & Preheating Line

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	HP Water to Boiler Island	2182	272	313	1191
2	HP Steam from Boiler	2182	584	283	3413
3	IP Steam to Boiler	2016	319	51	2978
4	IP hot reheated steam to Steam Turbine	2016	602	48	3673
5	IP Steam Turbine exhaust	1563	239	3.6	2943
6	LP Steam to Reboiler	873	146	3.6	2747
7	Hot Condensate returned from Reboiler	873	135	3	566
8	LP Steam to Steam Turbine	761	239	3.6	2943
9	Condensate	884	25	0.032	105
10	LP Preheated Condensate	1194	143	9	600
11	Condensate to HP FWH	2182	176	316	762
12	Cooling Water Inlet	45850	11	3	47
13	Cooling Water Outlet	45850	21	3	88

CFB HEAT AND MATERIAL BALANCE								REVISION	0
FOSTER WHEELER	CLIENT :	IEA GREEN HOUSE R & D PROGRAMME						PREP.	SR
	CASE :	CASE 3						APPROVED	LM
	UNIT :	4000 CO_2 Capture Plant				Sheet 1 of 1		DATE	Feb-05
STREAM	1	2	3	4	5	6	7	8	
	Flue Gas from Boiler Island	Flue Gas to Atmosphere	Carbon Dioxide to Compression	LP Steam From Turbine Extraction	Condensate from Reboiler to Power Island	Make up Water			
Temperature (°C)	85	46	38	146	135	30			
Pressure (bar)	1.03	1.01	1.6	3.6	3	2			
TOTAL FLOW									
Mass flow (kg/h)	3361176	2667505	596737	873000	873000	148725			
Molar flow (kgmole/h)	116023	96789	13897	48473	48473	8258			
LIQUID PHASE									
Mass flow (kg/h)	0	0	0	0	873000	148725			
GASEOUS PHASE									
Mass flow (kg/h)	3361176	2667505	596737	873000	0	0			
Molar flow (kgmole/h)	116023	96789	13897	48473	0	0			
Molecular Weight	28.97	27.56	42.94	18.01	18.01	18.01			
Composition (vol %)									
N_2	68.91%	82.60%	0.01%	0.00%	0.00%	0.00%			
CO_2	13.51%	2.43%	95.88%	0.00%	0.00%	0.00%			
H_2O	13.70%	10.31%	4.11%	100.00%	100.00%	100.00%			
O_2	3.88%	4.65%	0.00%	0.00%	0.00%	0.00%			
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
NOx	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
SOx	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			
CO	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%			

FOSTER WHEELER	CFB HEAT AND MATERIAL BALANCE	REVISION	0	1	
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	SR		
	CASE : CASE 3	APPROVED	LM		
	UNIT : 5000 CO_2 Compression & Drying — Sheet 1 of 1	DATE	Feb-05		

STREAM	1	2	3	4	5	6	7	8	9	10
	CO_2 from Stripper	CO_2 to long term Storage	Condensate from Stripper Condenser	Preheated Condensate to Power Island						
Temperature (°C)	38	30	75	124						
Pressure (bar)	1.6	110	12	10						
TOTAL FLOW										
Mass flow (kg/h)	596737	586433	884000	884000						
Molar flow (kgmole/h)	13897	13325	49084	49084						
LIQUID PHASE										
Mass flow (kg/h)	0	586433	884000	884000						
GASEOUS PHASE										
Mass flow (kg/h)	596737	0	0	0						
Molar flow (kgmole/h)	13897	0	0	0						
Molecular Weight	42.94	44.01	18.01	18.01						
Composition (vol %)										
N_2	0.01%	0.01%	0.00%	0.00%						
CO_2	95.88%	99.99%	0.00%	0.00%						
H_2O	4.11%	0.00%	100.00%	100.00%						
O_2	0.00%	0.00%	0.00%	0.00%						
Ar	0.00%	0.00%	0.00%	0.00%						
NOx	0.00%	0.00%	0.00%	0.00%						
SOx	0.00%	0.00%	0.00%	0.00%						
CO	0.00%	0.00%	0.00%	0.00%						

3.5 Utility Consumption

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

CLIENT:	IEA GHG	Rev Final
PROJECT:	GASIFICATION POWER GENERATION STUDY	Nov 05
LOCATION:	Germany	ISSUED BY: SR.
FWI Nº:		CHECKED BY: LM
		APPR. BY: RD

ELECTRICAL CONSUMPTION SUMMARY - CASE 3 - CFB

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
1000	**Coal - Ash Storage and Handling**	**1309**
1050	**Coal Drying (Air fan consumption)**	**561**
2000	**Boiler Island**	**28100**
4000	**CO_2 Capture Plant**	**25400**
5000	**CO_2 Compression and Drying**	**64600**
	POWER ISLANDS UNITS	
3000	**Steam Turbine and Preheating line**	**1140**
	UTILITY and OFFSITE UNITS	
	Cooling Towers	**18270**
	Others	**7200**
	BALANCE	**146580**

	CLIENT:	IEA GHG	Rev 0
	PROJECT:	GASIFICATION POWER GENERATION STUDY	Feb-05
	LOCATION:	Germany	ISSUED BY: SR
	FWI Nº:		CHECKED BY: LM
			APPR. BY: RD

WATER CONSUMPTION SUMMARY - CASE 3: CFB

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water [t/h]
	PROCESS UNITS			
1000	Coal and Ash Handling			80
2000	Boiler Island			104
4000	Acid Gas Removal		149	42704
5000	CO_2 Compression and Drying			7353
	POWER ISLANDS UNITS			
	Steam Turbine and Generator auxiliaries		1	45872
	Miscellanea			1251
	UTILITY and OFFSITE			
	Cooling Water (Cooling Towers Make Up)	1432		
	Demineralized/Condensate Recovery/Plant Potable Water System	150	-150	
	Miscellanea			58
	BALANCE	1582	0	97421

CLIENT:	IEA GHG	Rev 0
PROJECT:	CO2 Capture in Low rank coal power plants	July 05
LOCATION:	Germanie	ISSUED BY: SR
FWI Nº:		CHECKED BY: LM
		APPR. BY: R.D

Chemicals and Consumables Summary CASE 3: CFB

	DESCRIPTION	Consumption t/h	Yearly Consumption t/y
	Chemicals and Consumables		
	Make up Water (Power Plant, CO_2 Capture Plant)	1581	11770323
	Limestone	27.36	203723
	Ammonia	0.5	3467
	MEA solvent	1.5	11169
	Activated Carbon	0.04	308
	Soda Ash	0.09	667.75

3.6 CFB Technology Overall Performance

The following Table shows the overall performance of the CFB Complex.

CFB

Case 3

OVERALL PERFORMANCES OF THE CFB COMPLEX		
Coal Flowrate (A.R.)	t/h	592.9
Coal LHV (A.R.)	kJ/kg	10500
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1729.3**
Steam turbine power output (@gen. Terminals)	MWe	763.0
GROSS ELECTRIC POWER OUTPUT OF CFB COMPLEX (D)	**MWe**	**763.0**
Coal Storage / Handling / Drying	MWe	1.9
Boiler Island	MWe	28.1
CO2 Plant incl. Blowers	MWe	25.4
CO2 Compression	MWe	64.6
Power Island (1)	MWe	1.1
Utilities	MWe	25.5
ELECTRIC POWER CONSUMPTION OF CFB COMPLEX	**MWe**	**146.6**
NET ELECTRIC POWER OUTPUT OF CFB (C) Step-Up Transformer Efficiency (0.997)	**MWe**	**614.6**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**44.1%**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**35.5%**

Notes: (1) Boiler Feed Water pumps are steam turbine driven.

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

	Equivalent flow of CO_2 kmol/h
Coal (Carbon = 43.21%wt)	15466
Limestone	259.7
Slag	50.7
Net Carbon flowing to Process Units (A)	15675
Liquid Storage	
CO	0.0
CO_2	13324
Total to storage (B)	13324
Emission	
CO	0.0
CO_2	2351
Total Emission	2351
Overall CO_2 removal efficiency, % (B/A)	85.0

3.7 Environmental Impact

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

The gaseous emissions, liquid effluents and solid wastes from the CFB Complex 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 absorber unit of the CO_2 capture plant.

Table 3.1 summarises expected flow rate and concentration of the combustion flue gas after CO_2 capture treatment.

Table 3.1 – Expected gaseous emissions from CFB plant integrated with CO_2 capture.

	Normal Operation
Wet gas flow rate, kg/s	741
Flow, Nm^3/h	2169430
Temperature, °C	46
Composition	(%vol)
N_2	82.60
O_2	4.65
CO_2	2.43
H_2O	10.31
Emissions	mg/Nm^3 (1)
NOx	40
SOx	43 (2)
CO	Less than 150
Particulate	Less than 30
NH_3	5 (3)

(1) Dry gas, O_2 Content 6% vol
(2) SOx Emissions upstream AGR unit; after solvent washing, emissions are expected close to zero
(3) Due to ammonia slippage into the flue gas downstream the SCR

In normal operation at full load, the following emission to the atmosphere is foreseen from the Coal Drying Process:

Flow rate	:	1072	t/h
Particulate	:	21	kg/h

Minor Emissions

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). They are prevented by routing all vents to a bag filter.

3.7.2 Liquid Effluent

The plant would be designed for zero liquid effluents

3.7.3 Solid Effluent

The power plant is expected to produce the following solid by-products:

Fly Ash

Flow rate	:	28,8	t/h

Bottom Ash

Flow rate	:	12,2	t/h

The amount of ash produced in a CFB boiler is slightly higher than in a traditional PC boiler because besides the ash in the coal there is also the ash due to the injection of limestone for SO_x removal. This ash consists of Calcium Sulfate, Calcium Oxide not reacted and the inerts included in limestone.
Fly and bottom ash are used as bed filling and/or dispatched to cement industries.

The Calcium Sulfate is not a pure product as in the case of PC boiler and can't be sold as pure gypsum.

3.8 Equipment List

The list of the main equipment and process packages are included in this section.

UNIT 1000 – Coal handling and storage – Ash and Solid removal

Coal Unloading train including:
- Hopper systems
- Coal conveying
- Stacker reclaimer
- Coal delivery equipment

Coal Pre-drying train including:
- Fluid Bed Dryer
- Air fan
- Hot Water based Air Heater
- Filters for exhaust air

Fly ash handling System including:
- Pneumatic Conveying system
- Storage Silo
- Dust suppression System

Bottom ash systems
- Conveying System
- Clinker Crusher

Miscellaneous equipment

UNIT 2000 – Boiler Island with SCR based De NOx – Electro Static Precipitators (ESP)

CFB boiler including:
- Coal and Limestone Silos
- Fresh Air Fans
  - Primary air fan
  - Secondary air fan
- Fluidizing Air Blower
- SCR DeNOx System
- Air Heaters
- Electro Static Precipitator
- Hot Water Generator
- Ash Cooler
- Miscellaneous equipment

Auxiliary boiler
Structures
Control System

UNIT 3000 – Power Island consisting of Steam Turbine and Preheating Line

Steam turbine and generator package
Deaerator
HP feedwaterheaters
Condenser Package
Condensate pumps
Steam turbine driven BFW pump
LP pumps

UNIT 4000 – CO_2 Capture Plant

Flue gas blower
Absorption towers
Packing
Stripper tower
Packing for stripper
Stripper reboiler
Overhead stripper condenser
Water wash cooler
Cross exchangers
Lean solvent cooler
Flash preheater
Reclaimer
Soda ash dosing
Amine filter package
MEA storage tank
MEA circulation pumps
Wash water pumps
Surplus water pumps
Reflux pump
Surplus water tankage

UNIT 5000 – CO_2 Compression and Drying

Compression package
Drying package
CO_2 pumps
KO drums
Intercooling heat exchangers
Intercooling Water circulation pumps

Utility and Offsite Units

Cooling Water / Machinery cooling water systems (Unit 4100)
Demineralized water system (Unit 4200)
Natural Gas System (Unit 4300)
Plant / Instrument Air Systems (Unit 4400)
Raw-Service-Potable water system (Unit 4500)
Fire Fighting System (Unit 4600)
Chemicals
Interconnecting (Instrumentation, DCS, Piping, Electrical, 400 KV Substation) (Unit 6000)

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : CO_2 Capture in Low-rank Coal Power Pants
DOCUMENT NAME : CASE 4 –FW PRESSURIZED CIRCULATING FLUID BED BOILER (PCFB) WITH POSTCOMBUSTION CO_2 CAPTURE

ISSUED BY : G.L. FARINA
CHECKED BY : R. DOMENICHINI
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by

SECTION D

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D BASIC INFORMATION FOR EACH ALTERNATIVE

4.0 CASE 4 Foster Wheeler Pressurized Circulating Fluid Bed Boiler (PCFB) with Postcombustion CO_2 Capture

Summary

Pressurized Circulating Fluid Bed Boiler (PCFB) with Amine wash for CO_2 Absorption + CO_2 Compression Unit.

- The size of the plant considered for this configuration is based on the size required to provide nearly the same net output for all the other configurations taking into account the additional steam and power requirements of all the equipment in the plant.

- A pre-drying of the coal from a moisture level of 50.7% in as-received coal to about 32% is considered, before it is fed to the boiler plant. Drying of coal using low temperature waste heat is used for this alternative (Reference to Section C).

- The boiler technology for firing coal considered in this study is commercially in operation. The boiler is a Pressurized Circulating Fluid Bed type boiler. Limestone is added to the coal, which provides for a 97% sulphur capture and an SO_2 level in the flue gas equal to 38 mg/Nm^3 (dry-6% O_2). After amine scrubbing the SO_2 is further reduced to less than 20 mg/Nm^3 (dry – 6% O_2).

- NOx in the flue gas is kept under control by the combined effect of the low combustion temperature of the fluid bed (870°C) and the use of SNCR to keep in the flue gas 40 mg/Nm3 (dry – 6% O_2).

- CO_2 is captured by solvent scrubbing of the flue gas with 50% MDEA solution (amine Guard FS). MDEA is a sterically hindered amine, which is effective for CO_2 absorption under pressure. The main advantage with respect a MEA washing is the reduction of the solvent stripping steam consumption.

- The configuration of the plant considered provides a heat integration of the various systems.

- All the heat required for the CO_2 capture plant is provided from the low temperature steam extracted from the turbines of a steam cycle based on operation at supercritical conditions.

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

4.1 Introduction

The Case-4 of this study is a Pressurized Circulating Fluidized Boiler (PCFB) steam plant fitted with Post-Combustion carbon dioxide capture and compression units.

The configuration of the Power Plant is based on a PCFB boiler island with steam generator at supercritical conditions with superheating and single steam reheating.

Reference is made to the Process Flow Diagram attached to paragraph 4.3.

The PCFB Complex is divided in the following process units:

Unit

1000	Coal and limestone handling and storage Coal crushing and drying Ash Removal (Multiple modules in parallel)
2000	PCFB boiler island Recuperative exchangers Candle Filter Three modules, each with 33% capacity
3000	Turboexpander and air compression BFW Heater Three modules, each with 33% capacity
4000	Steam power island Two modules, each with 50% capacity
5000	Flue gas water quench CO_2 removal Three modules except amine regenerator which is single module.
6000	CO_2 compression and drying single module

4.2 Process Description

Note: "Coal" referred to in all the following sections means "low rank coal" as defined in the BEDD document.

The technology used in this Case-4 is a circulating fluid bed boiler operating at 16.3 bar (a), thus permitting the capture of CO_2 by scrubbing the flue gas under pressure. The main features of this Case 4 are presented in the following sub paragraphs, to be read in conjunction with the flowsheet (Fig. 1), attached to paragraph 4.3.

a. the net power output of this case is consistent with the capacities of the other cases studied. To achieve this goal the following factors have been taken into account:

   - maximum demonstrated capacity of PCFB boiler. The 360 MW Karita no. 1 plant (Japan), in commercial operation, is the reference point.

   - capacity of Dresser Rand Turboset used in the expansion of the pressurized flue gas.

   The structure of the power plant selected for CASE 4 takes into account the capacities of these two key components and, for an expected net power output of approximately 700 MW, is based on the following number of key-items:

   - 3 PCFB boilers.
   - 3 Dresser Rand Turbosets, each consisting of 2 expanders, 2 low pressure and 1 high pressure air compressors.
   - 3 boiler feedwater heaters, each connected to a D.R. Turboset.
   - 2 x 50% capacity steam turbines
   - 3 CO_2 absorbers and one common amine regenerator
   - 1 CO_2 compression set.

b. Lignite fed to the PCFB boilers needs not to be pulverized, as in PC boilers, but must be reduced to a maximum size of 6 mm, to match the requirements of fluid bed operation. After crushing the lignite is dried to improve the power plant efficiency. A fluid bed drier is used to reduce the moisture from 50.7 to 32%. Low temperature waste heat is the drier energy input, according to the technology described in Section C, paragraph 2, but the

flue gas from the expander, after heat recovery, is used instead of air, as stripping medium.
The split of the heating sources required for the drying of the lignite is reported in the following table:

Heat source	**Duty**, MWth
Flue gas from turboset	76.5
Condensate from quench	75.5
TOTAL HEAT	**152**

Limestone is added to the sized coal to achieve a molar ratio Ca/S equal to 2, which provides for a 97% sulphur capture and an SO_2 level in the flue gas equal to 38 mg/Nm^3 (dry – 6%O_2). After amine scrubbing the SO_2 is further reduced to less than 20 mg/Nm^3 (dry – 6%O_2).
Coal and sorbent (limestone) are fed to PCFB boilers by lock-hoppers and screw feeders, pressurized with air at 35 bar.
NO_x in the flue gas is kept under control by the combined effect of the low combustion temperature of the fluid bed (870°C) and the use of SNCR (injection of NH_3). NO_x in the flue gas is kept below 40 mg/Nm^3 (dry – 6%O_2).
The PCFB boilers combustion air is supplied by the compressor sets driven by the flue gas expanders.
Excess air is 15% vol., achieving a combustion efficiency in excess of 99%.
The boilers heat loss is less than 0.2 % of the coal heat input.

c. The PCFB boiler, in essence, is a conventional, atmospheric pressure, circulating fluidized bed boiler, placed inside a pressure vessel. It consists of a vertical riser, two refractory lined cyclones and 3 Intrex™ fluid bed exchangers (see Fig. 2). The enclosure walls of the riser and the 3 Intrex™ fluid bed exchangers are water cooled tube membrane, containing both evaporative and primary superheat surface.
To minimize the pressure vessel diameter the Intrex™ fluid bed exchangers are stacked vertically. Each exchanger is formed by a tube bundle, submerged in a slow moving fluid bed (0.3-0.4 m/sec), thus minimizing erosion. The top two exchangers superheat HP steam, while the bottom one reheats MP steam. The recirculating bed material from the cyclone is cooled down from 870°C to approximately 700°C by the fluid bed exchangers and then returns to the riser bottom where it mixes with the incoming fresh coal feed. Non mechanical Y valves control the solid flow from the cyclones and from the exchangers to the riser.
The PCFB boiler is approximately 55-60 m tall, with a diameter of 12 m.

Compressed air, 17.3 bar (a) and 232°C, enters at the top of the vessel and flows down through the annular space between the vessel and the internals. Dampers control the distribution of air among the multiple injection points to achieve a staged combustion which minimizes the formation of NO_x.

d. The raw flue gas exits from the top of the PCFB boiler at 870°C and 16,3 bar (a) and is cooled down to 343°C in the no. 1 Recuperative Exchanger. This is a pressure vessel which contains two tube bundles; the first bundle reheats the CO_2 free flue gas from 290°C to 700°C; the second tube bundle partially superheats the HP steam to 510°C. Raw flue gas at 343°C is filtered in a porous metal candle filter to separate entrained ash. Entrained fly ash is approximately 75% of total ash while the remaining 25% is bottom ash collected in the bottom hopper of the PCFB boiler.
The flue gas exiting the filter, is further cooled to 104°C in the Recuperative Exchanger no. 2, which reheats to 290°C the CO_2 free flue gas from the CO_2 absorbers.
The flue gas is further cooled to 38°C by direct contact with cooling water in the quench tower. Hot water (102°) from the quench tower is used as heating medium in a coil inside the lignite fluid bed drier.
Particulate free flue gas, at 38°C and 15.5 bar(a), is contacted with 50% MDEA solution (amine Guard FS). MDEA is a sterically hindered amine, which is an effective solvent for CO_2 absorption under pressure. The main advantage is a reduction of the solvent stripping steam consumption, because a fraction of the CO_2 is dissolved in the solvent under the effect of pressure, and can be released by a pressure reduction, in the flash drum, with no steam demand. The saving of stripping steam is reflected by the expected specific energy consumptions of MEA, operating at pressure close to atmospheric (100% chemical absorption) and MDEA, operating at 15 bar (a) pressure (chemical and physical absorption):

MEA	800-850 kcal/kg of CO_2
MDEA	650-700 kcal/kg of CO_2

The MDEA wash is designed to remove 85% of the CO_2 in the raw flue gas. The rich solvent from the absorbers is first flashed at an intermediate pressure, to release the gas dissolved under the effect of pressure, and then stripped in a common regenerator, which recycles back the lean solvent to the absorber. The CO_2 rich gas from the flash drum and from the regenerator is processed in the CO_2 compression section; a description of this section is given in Section C, paragraph 9. The purity of compressed CO_2 is 99.3% vol.

The CO_2 free flue gas from the absorbers is recycled back to the Recuperative Exchangers no. 1 and no. 2 to recover heat from the raw flue gas. After the Recuperative Exchanger no. 2 some preheated BFW is added to the CO_2 free flue gas stream, to solve pinch point problems in the subsequent exchanger.

The CO_2 free flue gas, at 700°C and 14.8 bar (a) is expanded in the turboset expanders, driving the air combustion compressors and producing, in addition 82,15 MWe. Additional energy could be recovered by increasing the CO_2 free flue gas temperature to 750-800°C. This could be accomplished passing the flue gas from the Recuperative Exchanger no. 1 in a tube bundle in the bed of an Intrex^{TM} exchanger, inside the PCFB boiler. However this possible upgrade of the technology was not used to avoid the recourse to sophisticated alloys and valving in the expander feed line.

The presence of alkali traces in the flue gas could be taken care by spraying in the boiler cyclones exit a water slurry of pulverized emathelyte, which captures alkali vapours. However this is not necessary because the chances of finding alkali vapours in the hot flue gas going to the expander are nil. In fact the flue gas, before reheating, is cooled down to ambient temperature for amine scrubbing and all alkali vapours disappear below 530°C, by condensation on the particulate. Further in this design flue gas is filtered in porous metal candle filter, thus supplying to the expander a clean flue gas, particle free. In this situation the operation of the expander is expected to be easy and problem free.

The expanded flue gas, after heat recovery to preheat the boiler feed water, is compressed by a blower to be used as stripping medium in the lignite fluid bed dryier. The flue gas emerging from the fluid bed drier, at 65°C, is filtered in a bag house filter to stop any entrained carbon particle and then routed to the stack.

e. Steam cycle, shown in Fig. 1, is based on operation at supercritical conditions. HP steam is delivered to the steam turbine at:

290 bar (a)
585 °C

Intermediate pressure, 50 bar (a), IP steam is reheated to 600°C.
Substantial amounts of low pressure steam is used to drive, with a steam turbine, the HP BFW pump and to feed the MDEA reboiler:

HP BFW Pumps :	131 t/h	8 bar steam
MDEA Reboiler :	817 t/h	3.5 bar steam

The plant has a large excess of low temperature heat which cannot be reused. The following low grade heat sources are rejected to cooling water or air:

- CO_2 compression interstage coolers (part of the heat that is not recovered for lignite drying)
- MDEA stripper off-gas
- Lean MDEA solvent cooling
- Ash cooling

4.3 Block Flow Diagrams

The Process Flow Scheme of the plant is attached to this paragraph (Fig. 1).

The General arrangement of the PCFB Boiler is shown in Fig. 2.

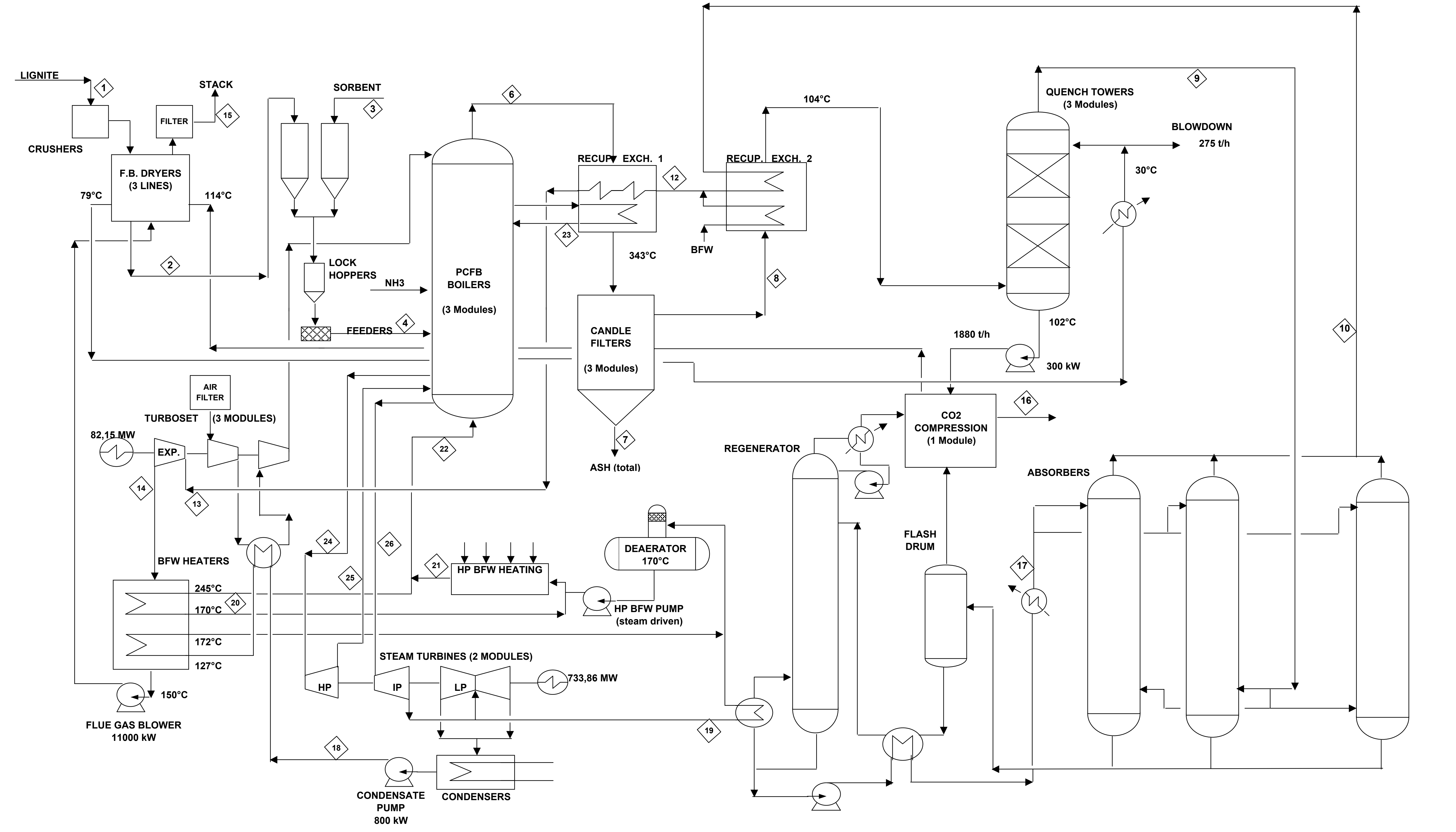


Figure 1 - Plant Process Flow Scheme

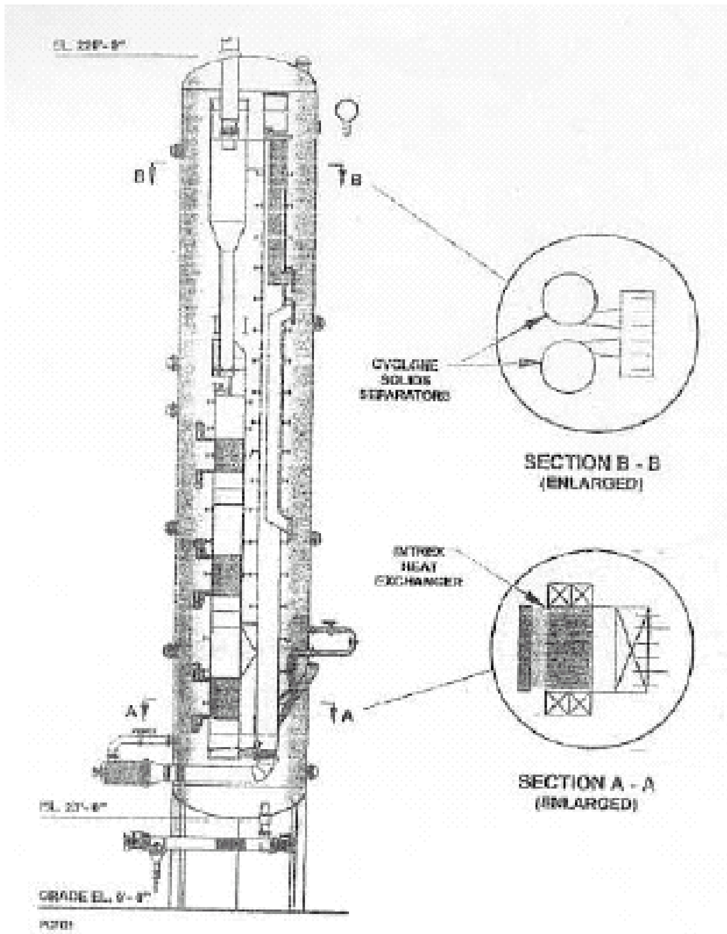


Figure 2 PCFB Boiler General Arrangement

4.4 Heat And Material Balances

The Heat & Material Balances are shown in the following Tables. The stream numbers are those indicated in the process flowsheet of Fig.1, attached to paragraph 4.3. The flowrates shown in the Material Balance are for the entire plant and not for the single modules.

FOSTER WHEELER	HEAT AND MATERIAL BALANCE					REVISION	0
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME					PREP.	GLF
	CASE : CASE 4 - PCFB					APPROVED	RD
	Sheet 1 of 4					DATE	Feb '05

STREAM (Solid)	1	2	3	4	7			
	Raw Lignite	Dry Lignite 32% H2O	Limestone	PCFB Solid Feed	ASH			
Temperature (°C)	9	65	9	38	340			
Pressure (bar a)	1	1	1	24.4	1			
COAL								
Flow (t/h)	727.0	527.1		537.1				
Comp. (% wt)								
C	31.33	43.23		42.43				
H_2	2.29	3.15		3.09				
O_2	11.56	15.94		15.64				
S	0.22	0.30		0.30				
N_2	0.37	0.51		0.50				
Cl	0.03	0.04		0.04				
H_2O	50.70	32.00		31.40				
Ash	3.50	4.83		4.74				
LHV (kgcal/kg)	2508	3460						
SORBENT								
Flow (t/h)			10					
Comp. (% wt)								
CaCO3			98.4	1.83				
MgCO3			0.1					
Inerts			1.5	0.03				
ASH								
Flow (t/h)					38			
Flyash (t/h)					28			
Bottom Ash (t/h)					10			

FOSTER WHEELER	HEAT AND MATERIAL BALANCE						REVISION	0	
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	GLF	
	CASE : CASE 4 - PCFB						APPROVED	RD	
						Sheet 2 of 4	DATE	Feb '05	

STREAM (Gas and Liquid)	5	6	8	9	10	11	12	13	
	Comb. Air to PCFB	Raw Flue Gas	Filtered Flue Gas	Flue Gas to MDEA	CO2 Free Fuel Gas	BFW to R.Ex. 2	CO2 Free F.G. to R.Ex. 1	CO2 Free F.G. to expander	
Temperature (°C)	232	870	343	38	60	65	293	700	
Pressure (bar a)	17.3	16.3	15.7	15.4	15.1	21.0	15.0	14.8	
FLOWRATE									
t/h	3263	3727	3697	3369	2743	200	2943	2943	
10^6 x Nm^3/h	2.532	2.845	2.821	2.444	2.152	-	2.403	2.403	
Comp. (% vol.)									
H_2O	0.68	12.42	12.42	Neg.	1.68		12.06	12.06	
O_2	20.86	2.42	2.42	2.76	3.18		2.84	2.84	
N_2	77.57	69.33	69.33	79.91	91.16		81.54	81.54	
Ar	0.89	0.83	0.83	0.01	1.03		0.92	0.92	
CO_2		15.00	15.00	17.32	2.95		2.64	2.64	
SO_2		Neg.	Neg.	Neg.	Neg.		Neg.	Neg.	
NO		Neg.	Neg.	Neg.	Neg.		Neg.	Neg.	
MW_{AVE}	28.89	29.37	29.37	30.9	28.57		27.45	27.45	
Entrained Solid (t/h) (Ash, $CaCO_4$, CaO)		38.0							

FOSTER WHEELER	HEAT AND MATERIAL BALANCE							REVISION	0
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME							PREP.	GLF
	CASE : CASE 4 - PCFB							APPROVED	RD
	Sheet 3 of 4							DATE	Feb '05

STREAM (Gas and Liquid)	14	15	16	17	18	19	20	21	
	FLUE GAS FROM EXPANDER	FLUE GAS TO STACK	COMPRES. CO2	LEAN MDEA	LP BFW	STEAM TO MDEA REB.	HP BFW TO HRSG	HP BFW TO HP HEATER	
Temperature (°C)	285	65	60	40	25	240	170	170	
Pressure (bar a)	1.04	1.03	110	19	21	3,6	323	323	
FLOWRATE									
t/h	2943	3146	710	9005	944	817	840	1160	
10^6 x Nm^3/h	2.403	2.656	-	-	-	-	-	-	
Comp. (% vol.)									
H_2O	12.06	20.36	0.40						
O_2	2.84	2.57							
N_2	81.54	73.85	0.10						
Ar	0.92	0.83	0.20						
CO_2	2.64	2.39	99.30						
SO_2	Neg.	Neg.							
NO	Neg.	Neg.							
MW_{AVE}	27.45	26.55	43.90						

	HEAT AND MATERIAL BALANCE						REVISION	0	
FOSTER WHEELER	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	GLF	
	CASE : CASE 4 - PCFB						APPROVED	RD	
	Sheet 4 of 4						DATE	Feb '05	
STREAM (Gas and Liquid)	22	23	24	25	26				
	HP BFW TO PCFB	HP STEAM FROM RECUP EX. 1	HP STEAM TO HP TURB.	IP STEAM TO REHEATER	IP STEAM FROM REHEATER				
Temperature (°C)	261	510	585	319	600				
Pressure (bar a)	318	312	290	52.5	50				
FLOWRATE									
t/h	2000	2000	1990	1905	1905				
10^6 x Nm^3/h	-	-	-	-	-				

4.5 Utility consumption

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

CLIENT:	IEA GHG	Rev Final
PROJECT:	GASIFICATION POWER GENERATION STUDY	Nov 05
LOCATION:	Germany	ISSUED BY: SR.
FWI Nº:		CHECKED BY: LM
		APPR. BY: RD

ELECTRICAL CONSUMPTION SUMMARY - CASE 4 - PCFB

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
1000	**Coal - Ash Storage and Handling**	336
1050	**Coal Drying (Air fan consumption)**	684
2000/3000	**Boiler Island & Turboset**	11500
5000	**CO_2 Capture Plant**	7000
6000	**CO_2 Compression and Drying**	79000
	POWER ISLANDS UNITS	
4000	**Steam Turbine and Preheating line**	1500
	UTILITY and OFFSITE UNITS	
	Cooling Towers	20500
	Others	5000
	BALANCE	**125520**

FOSTER WHEELER	CLIENT: IEA GHG PROJECT: GASIFICATION POWER GENERATION STUDY LOCATION: Germany FWI Nº:	Rev 0 Feb-05 ISSUED BY: SR CHECKED BY: LM APPR. BY: RD

WATER CONSUMPTION SUMMARY - CASE 4: PCFB

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water [t/h]
	PROCESS UNITS			
1000	**Coal and Ash Handling**			100
2000/3000	**Boiler Island & Turboset**		50	100
5000	**CO_2 Capture Plant**		100	42300
6000	**CO_2 Compression and Drying**			7700
	POWER ISLANDS UNITS			
4000	**Steam Turbine and Generator auxiliaries**		1	56900
	Miscellanea			1300
	UTILITY and OFFSITE UNITS			
	Cooling Water (Cooling Towers Make Up)	1600		
	Demineralized/Condensate Recovery/Plant Potable Water System	151	-151	
	Miscellanea			100
	BALANCE	1751	0	108500

	CLIENT:	IEA GHG	Rev 0
FOSTER WHEELER	PROJECT:	CO2 Capture in Low rank coal power plants	Feb-05
	LOCATION:	Germany	ISSUED BY: SR
	FWI Nº:		CHECKED BY: LM
			APPR. BY: RD

Chemicals and Consumables Summary CASE 4: PCFB

	DESCRIPTION	Consumption t/h	Yearly Consumption t/y
	Chemicals and Consumables		
	Make up Water (Power Plant, CO2 Capture Plant)	1751	13037946
	Limestone	10	74460
	Ammonia	0.1	745
	MDEA solvent	1.8	13403
	Activated Carbon	0.04	298
	Soda Ash	0.1	745

4.6 PCFB Overall Performance

The following Table shows the overall performance of the PCFB Complex.

Coal Flowrate (A.R.)	t/h	727.0
Coal LHV (A.R.)	kJ/kg	10500
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2120.4**
Steam turbine power output (@gen. Terminals)	MWe	733.86
Turboset Power Output	MWe	82.15
GROSS ELECTRIC POWER OUTPUT OF PC - USC COMPLEX (D)	**MWe**	**816.0**
Coal Storage / Handling / Drying	MWe	1.0
Boiler Island & Turboset	MWe	11.5
Steam Turbine and Preheating Line (1)	MWe	1.5
CO2 Capture Plant	MWe	7.0
CO2 Compression	MWe	79.0
Utilities/Offsites	MWe	25.5
ELECTRIC POWER CONSUMPTION OF PC-USC COMPLEX	**MWe**	**125.5**
NET ELECTRIC POWER OUTPUT OF PC-USC (C) Step-Up Transformer Efficiency (0.997)	**MWe**	**688.4**
Gross electrical efficiency (D/A*100) (based on coal LHV)	**%**	**38.5%**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**32.5%**

Notes: (1) Boiler Feed Water pumps are steam turbine driven.

The following Table shows the overall CO$_2$ removal efficiency of the IGCC Complex:

	Equivalent flow of CO$_2$ kmol/h
Coal (Carbon = 57.19%wt)	18973
Limestone	98
Slag	190
Net Carbon flowing to Process Units (A)	18881
Liquid Storage	
CO	0.0
CO$_2$	16050
Total to storage (B)	16050
Emission	
CO	0.0
CO$_2$	2831
Total Emission	2831
Overall CO$_2$ removal efficiency, % (B/A)	85

4.7 Environmental Impact

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

The gaseous emissions, liquid effluents and solid wastes from the PCFB Complex 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 lignite fluid bed drier.

Table 1 summarises the expected flow rate and composition of the combustion flue gas.

Table 1 – Expected gaseous emissions from PCFB plant integrated with CO_2 capture.

	Normal Operation
Wet gas flow rate, kg/s	874
Flow, Nm^3/h	2656000
Temperature, °C	65
Composition	(%vol)
N_2	73,85
O_2	2,57
CO_2	2,39
H_2O	20,36
Emissions	mg/Nm^3 (1)
NOx	<40
SOx	<38 (2)
CO	Less than 150
Particulate	Less than 30
NH_3	5 (3)

(1) Dry gas, O_2 content 6% vol
(2) SOx Emissions upstream AGR unit; after solvent washing, emissions are expected close to zero
(3) Due to ammonia slippage into the flue gas downstream the SNCR

Minor Emissions

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). They are prevented by routing all vents to a bag filter.

4.7.2 Liquid Effluent

The plant is designed to achieve zero liquid effluents

4.7.3 Solid Effluent

The power plant is expected to produce the following solid by-products:

Fly Ash

Flow rate : 28 t/h

Bottom Ash

Flow rate : 10 t/h

The amount of ash produced is slightly higher than in a traditional PC boiler because besides the ash in the coal there is also the ash due to the injection of limestone for SO_x removal. This ash consists of Calcium Sulfate, Calcium Oxide not reacted and the inerts included in limestone.
Fly and bottom ash are used as bed filling and/or dispatched to cement industries.

The Calcium Sulfate is not a pure product as in the case of PC boiler and can't be sold as pure gypsum.

4.8 Equipment List

The list of the main equipment and process packages are included in this section.

UNIT 1000 – Coal and limestone handling and storage

Coal Unloading train including:
- Hopper systems
- Coal conveying
- Stacker reclaimer
- Coal delivery equipment

Coal Pre-drying train including:
- Fluid Bed Dryer
- Air fan
- Hot Water based Air Heater
- Filters for exhaust air

Fly ash handling System including:
- Pneumatic Conveying system
- Storage Silo
- Dust suppresion System

Bottom ash systems
- Conveying System
- Clinker Crusher

Miscellaneous equipment

UNIT 2000/3000 – Boiler Island & Turboset

3 Pulverized Coal Fluidized Bed boiler including:
- Vertical raiser
- 2 refractory lined cyclone separators
- 3 Intrex fluid bed exchamgers
- Air Distributors
- Miscellaneous equipment

3 Dresser Rand Turbosets (2 expanders, 2 low pressure and 1 high pressure air compressors)
3 Boiler Feed Water Heaters
Structures
Control System

UNIT 4000 – Steam Power Island consisting of Steam Turbine and Preheating Line

Steam turbine and generator package
Deaerator
HP feedwaterheaters
Condenser Package
Condensate pumps
Steam turbine driven BFW pump

UNIT 5000 – CO_2 Capture Plant

Quench Tower
Water pump
Absorption towers
Packing
Flash Drum
Stripper tower
Packing for stripper
Stripper reboiler
Overhead stripper condenser
Cross exchangers
Lean solvent cooler
Reflux Pump

UNIT 6000 – CO_2 Compression and Drying

Compression package
Drying package
CO_2 pumps
KO drums
Intercooling heat exchangers
Intercooling Water circulation pumps

Utility and Offsite Units

Cooling Water / Machinery cooling water systems (Unit 4100)
Demineralized, Plant and Potable Water System (Unit 4200)
Natural Gas System (Unit 4300)

Plant / Instrument Air Systems (Unit 4400)
Waste Water Treatment (Unit 4600)
Fire Fighting System (Unit 4700)
Chemicals (Unit 4900)
Interconnecting (Instrumentation, DCS, Piping, Electrical, 400 KV Substation) (Unit 7000)

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : CO_2 Capture in Low-rank Coal Power Pants
DOCUMENT NAME : CASE 5-IGCC BASED ON FUTURE ENERGY GASIFICATION WITH PRECOMBUSTION CO_2 CAPTURE

ISSUED BY : P. COTONE
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by

SECTION D

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D BASIC INFORMATION FOR EACH ALTERNATIVE

5.0 Case 5 IGCC Based on Future Energy gasification

5.1 Introduction

The IGCC Complex of the study is a very large power production facility, converting coal to electric energy with a minimum impact to the environment.
The key process step of the IGCC Complex is the gasification of coal. Gasification is the partial oxidation of coal, or any other fossil fuel, to a gas, often identified as syngas, in which the major components are hydrogen and carbon monoxide.
The partial oxidation agent used is oxygen, or air, supplemented usually by steam. The choice of oxygen or air depends on the type of gasifier, the final use of the syngas and the reactivity of the feed material. For this study the gasification technology selected is based on oxygen blown gasifier. For Future Energy Gasifier in case of Lignite Gasification, due to the high moisture content, a supplementation of steam is not necessary.
The syngas generated by gasification can be cleaned and then used in a combined cycle that is today the most efficient thermal cycle for power generation. The gasification therefore acts as a bridge between a low quality fossil fuel, coal, and the gas turbine with the target of high-energy efficiency and minimum emissions to the environment.
The gross production capacity of the IGCC Complex of the study is 900 MWe.

The IGCC Complex is a combination of several process units. The main process blocks of the Complex are:

- Coal milling and gasifier feed preparation;
- Air separation;
- Gasification;
- Syngas treatment and conditioning;
- Combined Cycle power generation;
- CO_2 Compression and Drying.

These basic blocks may be supported by other ancillary units, such as Sulphur recovery, Tail gas treatment, and a number of utility and offsite units, such as cooling water, flare, plant/instrument air, machinery cooling water, demineralised water, auxiliary fuels, etc.
Each process unit of the Complex may be a single train for the total capacity or split in two, three or more parallel trains, depending on the maximum capacity

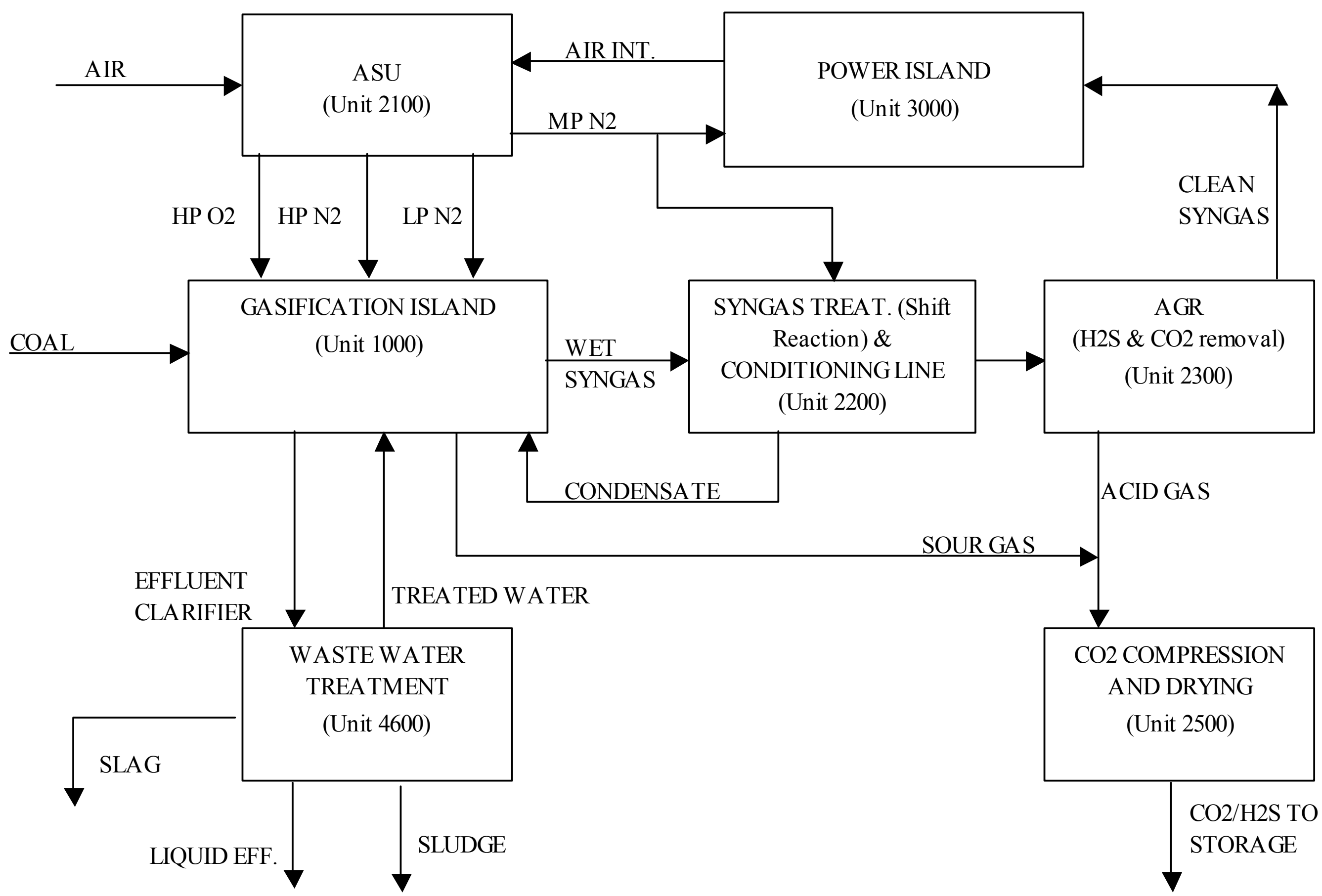
of the equipment involved or on the necessity to assure, through the use of multiple parallel trains, a superior degree of reliability.

The arrangement of the main process units is:

Unit		**Trains**
1000	Gasification	4 x 33%
	Waste Water Pre-treatment	1 x 100%
2100	ASU	2 x 50%
2200	Syngas Treatment and Conditioning Line	2 x 50%
2300	AGR	3 x 33%
2500	CO_2 Compression and Drying	2 x 50%
3000	Gas Turbine (PG 9351 – FA)	2 x 50%
	HRSG	2 x 50%
	Steam Turbine	1 x 100%

Reference is made to the attached overall Block Flow Diagram of the IGCC Complex.

Case 5 – FUTURE ENERGY – IGCC COMPLEX BLOCK FLOW DIAGRAM



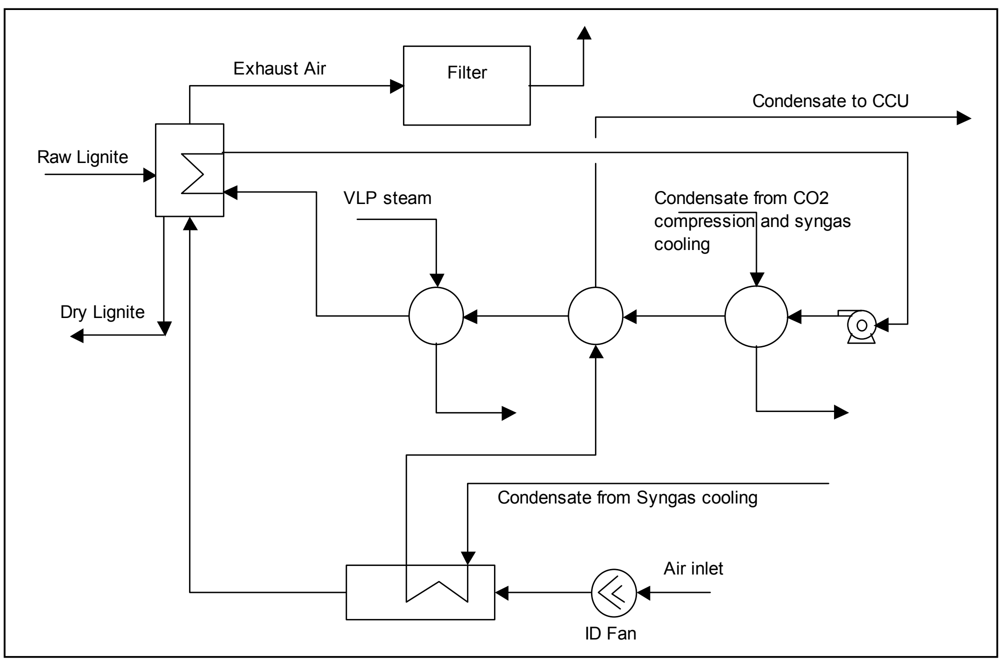
5.2 Process Description

Coal Handling and Storage

This unit is made up of standard equipment in use, to receive the coal from outside the plant boundary, store the coal, reclaim the same and transport to the plant. For more details see section C, paragraph 1.

Coal Drying:

The basic features of this process are shown in Section C, para 2.0.
The process scheme used for this specific alternative is shown in the following scheme.



The indirect Lignite Drying method has been used for this alternative.

This system could be specifically advantageous for the ICGG case, as a lot of source of low temperature heat exists in the plant design that can be used.

For Future Energy gasification the required moisture content in the feedstock is 10%.

The split of the heating sources required for the drying of the lignite is reported in the following table:

Heat source	**Duty**, MWth
Syngas cooling	63
CO_2 compression	38
VLP steam (3.2 barg)	112
N_2 compression	12
TOTAL HEAT	**225**

Unit 1000: Gasification Island

Feeding system:

The coal feeding system consists of four coal silos, four mills and conveyor systems and four dosing unit, one for each gasifier.
The mills reduce the coal lignite size to a fine powder (>55% <100 μm; >99% <500 μm).
By means of conveyor systems the pulverized coal is passed to a dense-flow feeding system consisting of a sequence of an atmospheric fuel bunker, three lock hoppers and a feeder vessel.
The pulverized fuel settles in the fuel bunker, and the carrier gas and purging gas are vented over the bunker top. The full lock hopper is pressurized with purge gas (nitrogen).
The fuel in the feeder vessel is partially fluidised by means of a carrier gas (nitrogen) in the vortex shaft of the feeder vessel, in which the fuel conveying lines are immersed. Finally the fuel is pneumatically transported in a dense flow to the gasifier burners.

Gasifier:

The feedstock is gasified in a patented "Cooling Screen" design gasifier, highly suitable for high-ash containing feedstock. This design lowers the risk of slag attack to a refractory lining and offers long lifetime and low maintenance cost operation. For safe capture of slag and solids a full-quench system is proposed.
The gasifier consists of an outside pressure wall and an inside cooling screen cooled by pressurized water to protect the outside wall against chemical and thermal attacks.

The reactants, pulverized fuel and oxygen are fed into the reaction chamber in parallel flow through the combination burners at gasifier top. The latter are converted in a heterogeneous flame reaction in entrained flow at a pressure of approximately 40 bar and temperatures exceeding slag melting temperatures.

At the top of the reactor one pilot burner and three main burners are arranged. Each main burner is equipped with one feed line. Nitrogen is used to maintain the circuit pressure at 1 bar above the reactor pressure to prevent migration of syngas into the cooling circuit in the event of a leak in the cooling coils or in the cooling shroud of the burner.
In the start-up phase the pilot burner is first run on Natural gas/N_2-mixture.

Once the pilot burner for the ignition of the fuel is in temperature maintenance operation, the gasifier can be brought on line within minutes.
The partial oxidation reaction converts the coal lignite into hydrogen and carbon monoxide. The inert components in the feed are forming a slag.

Quench:

The hot raw synthesis gas and the liquid slag leave the gasifier reaction chamber and flow in parallel vertically downward and discharge directly into the quench section - where the raw gas is cooled down to approximately 220°C by injection of water. Slag produced is granulated in the water bath in the bottom of the Quench system.
The raw gas is saturated with steam (approx. 60%). This water becomes gas condensate in the following cooling steps of the syngas treatment and it will be recycled back as quench water.
The water of the quench, which is not vaporized, is flashed together with suspended solids (slag, fine ash, coke, soot and salts) and sent to the waste water pre-treatment.

Slag Handling:

The slag discharged from the Quench sump falls into a water-filled pressurized lock hopper. When the lock hopper is filled with slag, is cooled, depressurised and the slag and any water remaining in the hopper are discharged into a slag-receiving tank.
The major portion of the slag settles in the slag-receiving tank from where it is discharged by means of a drag chain conveyor. The slag is then washed on a slag wash conveyor to remove fines and quench water and is passed to a conveyor that transports the slag to a slag storage bin/container.
Waters carried out of the slag discharge system are collected in a conveyor overflow wet well and pumped to the waste water treatment plant via a hydro

cyclone. Water that is needed in the slag discharge system is recycled from the waste water treatment plant.

Gas Scrubbing:

The wet raw gas from the quench is cleaned in a venturi scrubber, where fine ash and soot particles are removed from the raw gas by water. Scrubber water is directed to the waste water treatment. Remaining solid particles in the raw syngas are separated from the gas in the course of gas cooling and water condensation.

Waste Water Pre-Treatment:

The liquid effluents from the quench systems, water from the slag separation and overflow of scrubbing water from the venturi scrubbers as well as process condensate, contaminated with fine particulate matter, soot and salts are treated in this section. Waste water from the quench circuit is first pre-treated mechanically by means of a cyclone and filter systems. Most of the pre-cleaned quench water is returned to the quench system.
The remaining part of the pressurized waste water is first sent to a flash vessel to remove all gas components, and then it is routed to the cyanide oxidation after passing a first cooling and neutralization.
During the next step the pre-treated water passes to the precipitation and flocculation tank, where flocculants are added to stimulate the coagulation and settlement of soot and fines. Fine slag and precipitate are removed and further dewatered using a fabric filter to separate the precipitate from the wastewater. The washed and dried filter cake is containerized for appropriate off-site disposal.
The cleared effluent of the thickener and the filtrate of the waste water filter are fed after a neutralisation, to the NH_3 stripping column. The stripped waste water is removed from the column and pumped via a cooler to a waste water tank. Finally the cleaned waste water is recycled to the slag discharge systems and to the quench. The stripper overheads are condensed and the ammonia water is recycled to the NH_3 stripper.
The vapour phase of the flash is cooled and sent together wit the remaining gas of the NH_3 stripping column to the CO_2 compression and drying Unit.

The main process streams of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED (COAL)	HP OXYGEN (95% purity)	HP NITROGEN	LP NITROGEN	SATURATED SYNGAS
Temperature (°C)	AMB.	21	21	21	180
Pressure (bar)		48	55	7.5	39
TOTAL FLOW					
Mass flow (kg/h)	357,900	257,600	74,350	17,570	1,268,500
Molar flow (kmol/h)					64,080
Composition (% vol)					
H_2					10,0
CO					23,9
CO_2					2,7
N_2/Ar					2,7
O_2					-
H_2S + COS					0,07
H_2O					60,50
Others					0,13

Note: Figures referred to the total flowrates

Unit 2100: Air Separation Unit (ASU)

This Unit is treated as a package unit supplied by specialised Vendors.
The Air Separation Unit (ASU, Unit 2100) is installed to produce oxygen and nitrogen through cryogenic distillation of atmospheric air.

The oxygen produced is delivered to the Gasification Island to be used as reaction oxidant.
As a by-product nitrogen is obtained and is used for the pneumatic transport of dried pulverized coal to the gasifiers; the excess is routed to the syngas dilution and to the gas turbines for power augmentation and NOx control.

The Plant consists of two air separation trains and at the same time is able to produce additional oxygen and nitrogen products to maintain the desired inventories in the storage systems of liquid and gaseous products used as back-up; these systems are common to both trains.

ASU is partially integrated with the gas turbines.
When the gasification operates at full load, approx 30% of the air required by the ASU to obtain the design oxygen production is derived from both gas turbine compressors; the integration between the gas turbines operation and the ASU is achieved at a level where approx 70% of the atmospheric air is compressed with a dedicated air compressor and the difference comes already pressurized from the compressors of the gas turbines in the combined cycle.
The air extracted from the gas turbine at high temperature is cooled by exchanging heat with nitrogen for syngas dilution before being fed to the Air Separation Unit.

The main process stream of the Air Separation Unit relevant to this alternative are summarised in following table:

STREAM	TOTAL AIR (1)	OXYGEN TO GASIFIERS (2)	HP NITROGEN (3)	LP NITROGEN (4)	TOTAL NITROGEN TO SYNGAS & GT
Temperature (°C)		21	21	21	100
Pressure (bar)		48	55	7.5	23
TOTAL FLOW					
Mass flow (kg/h)	1,143,000	257,600	74,350	17,570	574,000

Unit 2200: Syngas Treatment and Conditioning Line

This Unit receives the raw syngas from the gasification section, which is hot, humid and contaminated with acid gases, CO_2 and H_2S, and other chemicals, like COS, HCN and NH_3.
Before using this syngas as fuel in the gas turbines it is necessary to remove all the contaminants and prepare the syngas at the proper conditions of temperature, pressure and water content in order to achieve in the combustion process of the gas turbine the desired environmental performance and stability of operation.

Saturated raw syngas from wet scrubbing in Unit 1000, at approximately 40 bar and 180°C, enters Unit 2200. The syngas is first heated by the hot shift effluent and then enters the first stage of Shift Reactor, where CO is shifted to H_2 and CO_2 and COS is converted to H_2S. The exothermic shift reaction brings the syngas temperature up to 419°C.

In order to meet the required degree of CO_2 removal, a double stage shift containing sulphur tolerant shift catalyst (dirty shift) is used. The hot shifted syngas outlet from the first stage is cooled in a series of heat exchangers:

Shift feed product exchanger
HP Steam Generator
MP Steam Generator

Inlet temperature to the second stage shift is controlled to 263 °C. Outlet temperature from second shift is 324°C. The hot shifted syngas outlet from the second stage is cooled in a series of heat exchangers:

MP Steam Generator
LP Steam Generator
VLP Steam Generator
Condensate Preheater A/B

The final cooling step of the syngas takes place in a final cooler, where syngas is cooled with cooling water.
The condensate recovered from the Separator Drums is recycled back to the Gasification Unit.

The first and second stage of the shift reactor is split in two parallel trains, as the remaining equipment of Unit 2200, because of the size limitation of the exchangers involved.
Cold syngas, after CO_2 and H_2S removal, is diluted with Nitrogen in order to achieve 65% max Hydrogen content and then sent to the gas turbines, Unit 3000.

The main process streams of the Syngas treatment and conditioning line relevant to this alternative are summarised in following table:

STREAM	SAT SYNGAS (1)	HP GENERATED STEAM (2)	MP GENERATED STEAM (3a+3b)	LP GENERATED STEAM (4)	VLP GENERATED STEAM (5)	SYNGAS TO GT (6)
Temperature (°C)	221	352	256	175	152	75
Pressure (bar)	39	171	44	9	5	28,5
TOTAL FLOW						
Mass flow (kg/h)	1,268,500	36,000	171,900	160,800	207,000	185,442
Molar flow (kmol/h)	64,080					15,734
Composition (% vol)						
H_2	10,0					65,0
CO	23,9					3,7
CO_2	2,7					4,3
N_2	2,7					26,4
Ar	-					-
O_2	-					0,3
H_2S + COS	0,07					-
H_2O	60,50					0,3
Others	0,13					-

Unit 2300: Acid Gas Removal (AGR)

The removal of acid gases, H_2S and CO_2 is an important step of the IGCC operation. In fact this unit is not only capital intensive and a large consumer of energy, but also is a key factor for the control of the environmental performance of the IGCC. The right selection of the process and of the solvent used to capture the acid gases is important for the performance of the complex.

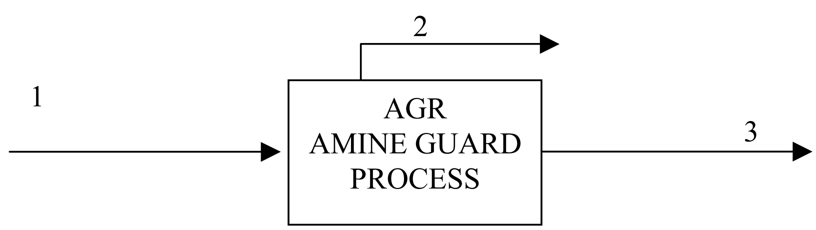
Unit 2300 is characterised by a medium syngas pressure (29.7 bar g) and an extremely high CO_2/H_2S ratio (365/1).
Based on considerations on section C, paragraph 8.0, the combined removal of acid gases, H_2S and CO_2, based on the Amine Guard FS process has been selected.
The product of this process is a single stream to be compressed and delivered to plant B.L.

Entering Streams

1. Untreated Gas from Syngas Treatment & Conditioning Line

Exit Streams

2. Treated Gas to Gas Turbines
3. CO_2 to compression



The Amine Guard FS solvent consumption, to make-up losses, is 64 m^3/year.

The proposed process matches the process specification with reference to H_2S+COS concentration of the treated gas exiting the Unit (H_2S+COS concentration is less than 3 ppm). This is due to the integration of CO_2 removal with the H_2S removal, which makes available a large circulation of the solvent.

The CO_2 removal rate is 91,6% as required, allowing reaching an overall CO_2 capture of 85% with respect to the carbon entering the IGCC.

These performances for the H_2S removal and CO_2 capture are achieved with large steam consumption.

Together with CO_2/H_2S exiting the Unit, the following quantity of hydrogen is lost:

- 97 kmol/h of Hydrogen, corresponding to 0.62% vol and to an overall thermal power of approx 6.6 MWth, i.e. more than 2 MWe.

The feasibility to separate and recover H_2 during the CO_2 compression was investigated. Due to the similar equilibrium constants of CO_2 and H_2 at super-critical CO_2 conditions, this separation is unfeasible.
The main process streams of the AGR Unit relevant to this alternative are summarised in following table:

STREAM	RAW SYNGAS (1)	TREATED SYNGAS (2)	CO2 RICH STREAM (3)
Temperature (°C)	38	38	49
Pressure (bar)	30.7	29.5	1.8
TOTAL FLOW			
Molar flow (kmol/h)	39,500	24,800	15,600
Composition (% vol)			
H_2	52.1	82.6	0.6
CO	3.0	4.7	
CO_2	40.2	5.4	93.3
H_2S + COS	0.1	3 ppm	0.3
Others	4.6	7.3	5.8

Unit 2500: CO_2 Compression and Drying

This Unit is a Package Unit supplied by specialised Vendor. For more details see section C, paragraph 9.0.

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

- Product stream : 647 t/h.
- Product stream : 110 bar
- Composition :

	%vol
CO_2	99.0
H_2S	0.3
Others	0.7
TOTAL	100.0

Unit 3000: Power Island

The power island is based on two General Electric gas turbines, frame 9001 FA, two Heat Recovery Steam Generators (HRSG), generating steam at 3 levels of pressure, and one steam turbine common to the two HRSGs.

The power island configuration is described referring to the Process Flow Diagrams attached to the end of this paragraph.

During normal operation, the clean syngas, coming from Unit 2200 - Syngas Treatment and Conditioning Line, is heated up to 170°C against MP BFW in the syngas final heater dedicated to each Gas Turbine.
Finally, the hot syngas is burnt inside the Gas Turbine to produce electric power; the resulting stream of hot exhaust gas is conveyed to the Heat Recovery Steam Generator located downstream each Gas Turbine.

Compressed air is extracted from the Gas Turbines and delivered to ASU.
MP nitrogen coming from ASU is injected into the Gas Turbines for NO_x abatement and power output augmentation.

The flue gas stream at a temperature of about 570°C flows through the coils inside the HRSG generating steam at three different pressure levels, is cooled down to about 129°C and then discharged to the atmosphere through a stack common to the two HRSG Units.

The turbine consists of HP, IP and LP sections all connected to the generator on a single shaft. HP steam from the HRSG HP section enters the turbine at approx. 156 bar, 550°C. Steam from the exhaust of the HP turbine is returned to the HRSG for reheating after mixing with MP steam, and is then throttled into the IP turbine at approx. 36 bar, 530°C. Exhaust steam from IP flows into a LP turbine after mixing with superheated LP steam from HRSG and then downward into the condenser at 0.032 bar, 25°C.

When the clean syngas production is not sufficient to satisfy the appetite of both Gas Turbines it is possible to cofire natural gas or to switch to natural gas one or both Gas Turbines.
This could happen in case of partial or total failure of the Gasification/Gas Treatment units of the IGCC and during start-up.
The selected machines are suitable to co-fire syngas and natural gas from 20% to 100% load.

During Natural Gas Operation no air extraction is foreseen, while a stream of MP Steam has to be injected into the combustion chambers of the Gas Turbines to reduce the NO_x emissions.

During normal operation on Natural Gas, the Power Island does not export/import to/from IGCC Process Units any steam/water stream and no low temperature heat can be recovered in Process Units. Then all cold condensate coming from Steam Condenser can be directly sent to the deaerator after polishing. In this situation, the degassing steam demand of the deaerator is very high, more than VLP steam produced by HRSG's that needs to be integrated with steam coming from LP and MP headers.

The interfaces considered (during normal operating case) between the power island and the rest of the plant are as follow:

- Compressed Air : Air sent to Unit 2100 – Air Separation Unit;
- MP nitrogen : Nitrogen coming from ASU injected into the Gas Turbines for NO_x abatement and power output augmentation.
- HP steam (160 barg): steam imported from Syngas Treatment and Conditioning Line.
- MP steam (40 barg) : steam imported from Syngas Treatment and Conditioning Line.
- MP steam (40 barg) : steam exported to the Gasification Island users.
- LP steam (6,5 barg): steam imported from Syngas Treatment and Conditioning Line. The steam is also exported to the following Process Units: ASU, Utility and Offsite Unit.
- VLP steam (3,2 barg): the total steam generated in Syngas Treatment and Conditioning Line is used in the Lignite drying section.
- BFW : HP, MP, LP, VLP Boiler Feed Water is exported to the Process Units to generate the above mentioned steam production.
- Process Condensate : All the condensate recovered from the condensation of the steam utilised in the Process Unit is recycled back to the HRSG after polishing in Unit 4200, Demi Water/Condensate Recovery.
- Condensate from ST : All the Condensate from the Condenser is exported to the polishing unit (Unit 4200), pre-heated in the Syngas Cooling and Conditioning Line partially cooled in the Lignite drying section and recycled back to the HRSG.

Flow rate of the steam/water interfaces of the Plant are shown in table attached to para 5.5, Utilities Consumption.

The main process data of the Power Island relevant to this alternative are summarised in following table:

STREAM	SYNGAS (1)	AIR TO ASU (2)	NOX CONTROL N2 (3)	LP STEAM TO ST (4)	HP STEAM TO ST (5)
Temperature (°C)	170	396	213	236	552
Pressure (bar)	26	14,2	22	5,7	156
TOTAL FLOW					
Mass flow (t/h)	185,4 (1)	147,7 (1)	193,0 (1)	92,7	456,4

STREAM	RH MP STEAM TO ST (6)	COND. FROM ST (7)	COOLING WATER TO CND (8)	COOLING WATER FROM CND (9)	FLUE GAS AT STACK (10)
Temperature (°C)	527	25	11	21	129
Pressure (bar)	36	0,03	3	2,3	Amb
TOTAL FLOW					
Mass flow (kg/h)	780,8	873,4	45163	45163	2511,5 (1)

(1): For each GT

Unit 4600: Waste Water Treatment

The part of waste water from the NH_3 stripper that is not recycled back to the quench, flows to the anaerobic section, where a phosphoric acid solution is added to the waste water to support the bacterial growth.

In the Anaerobic Reactor the organic pollutants are biodegraded with production of biological gas and biological sludge. The biogas produced in the reactor is routed to the local flare to be burned.

The biological mass exits the anaerobic reactor and enters the Anaerobic Clarifier where the biomass is separated by gravity from the supernatant.

Effluent from anaerobic section is subject to a further aerobic treatment for the complete removal of ammonia and organic contaminants. The effluent from the anaerobic clarifier is pumped to the denitrification/oxidation tanks where is mixed with the rainwater bleed-off and drainage coming from the deoiling section.

In this deoiling section, the oily drainage mixed with contaminated rainwater is fed by means of pumps from the oil water storage tank to the primary deoiling section, consisting of a Corrugate Plate Interceptor, witch provides gravity separation of free oil and suspended solids carried in the waste water.

The effluent from the separator cells is dosed with polyelectrolyte and is routed by gravity to a secondary deoiling step, consisting of Induced Air Flotation. Air induced by motors driven self-aerating rotors mechanism removes the oil and suspended solids, which are collected in a dense froth to be recycled back to the CPI.

The deoiled water is then pumped to the denitrification/oxidation tanks, where it is mixed with the anaerobic treatment effluent and where the organic contaminants are removed and ammonia is oxidized to nitrates which are further reduced to nitrogen gas in the denitrification section.

The effluent from the oxidation tank enters the aerobic clarifier, where the biomass separates by gravity from the supernatant. The sludge from the bottom of the clarifier is recycled to the anaerobic reactor by the Sludge Pump.

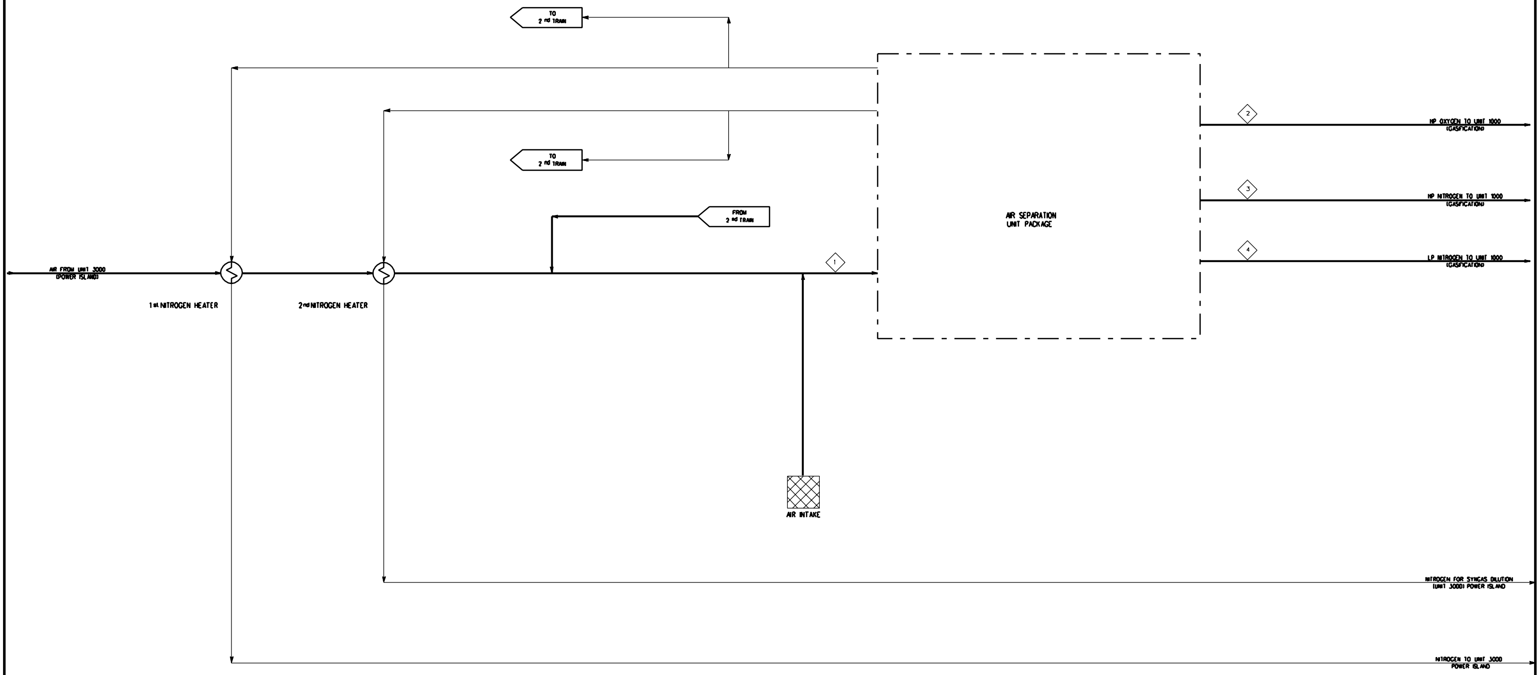
The supernatant from the clarifier is dosed with polyelectrolyte and pumped into Dual Media Filter, which uses sand and anthracite as filter media for the removal of residual hydrocarbons and suspended solids, and into Activated Carbon Filters, for the complete removal of organic contaminants

From the filters the water is recovered back to the Gasification Island as make-up water.

5.3 Process Flow Diagrams

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

- UNIT 2100: Air Separation Unit (PFD n° BD0237A-3-50-2100);
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0237A-3-50-2200);
- UNIT 2300: Acid Gas Removal (PFD n° BD0237A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0237A-3-50-3000; sheet 1 and 2).



LEGEND

STREAM NUMBER

A		ISSUE FOR COMMENTS	P.C.	L.M.	R.D.
			BY	CHD	APP.

REVISIONS

IEA GREEN HOUSE R&D PROGRAMME
CO2 CAPTURE IN LOW RANK COAL POWER PLANTS

FUTURE ENERGY - CASE 5
UNIT 2100-AIR SEPARATION UNIT

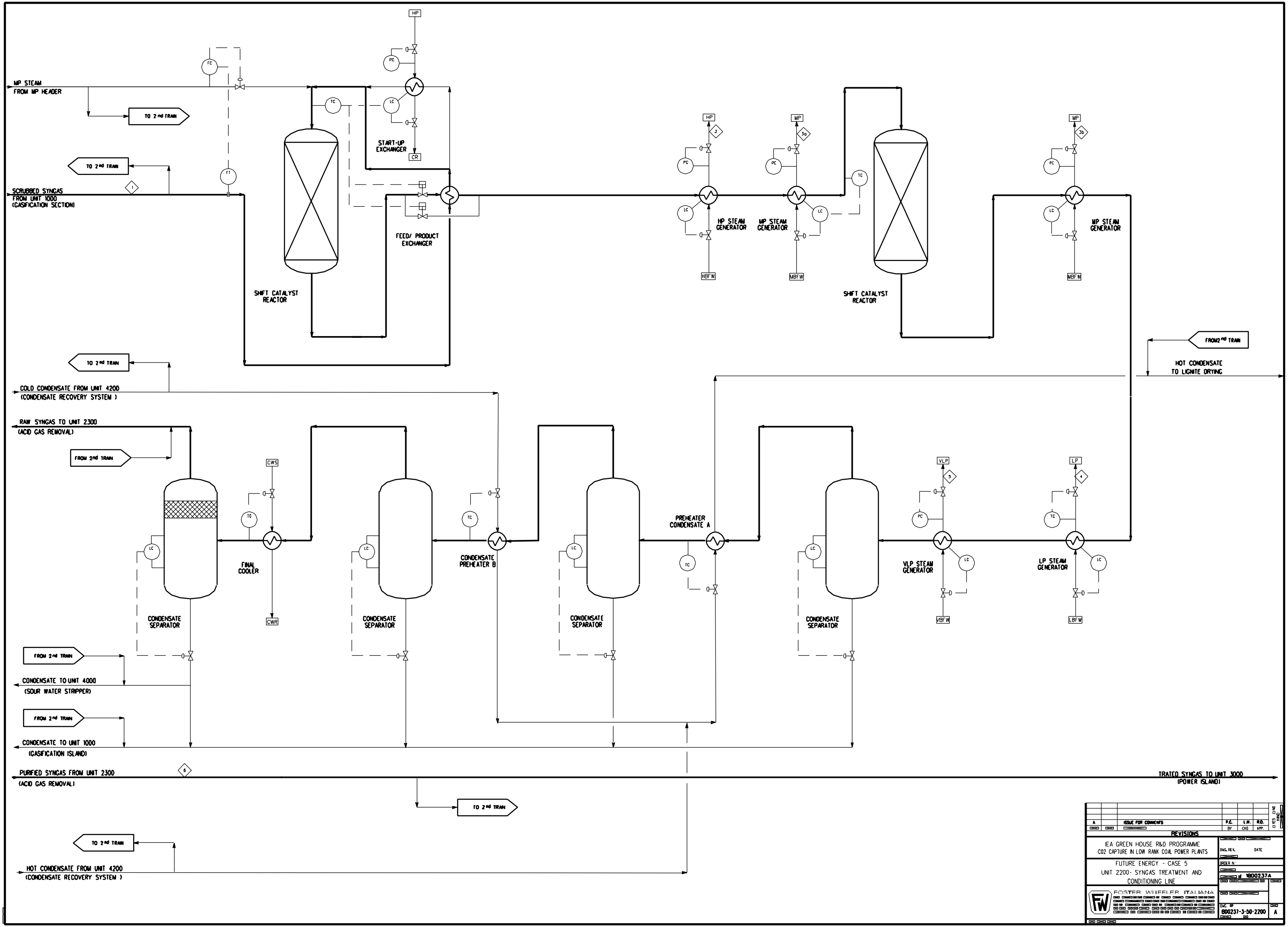
FOSTER WHEELER ITALIANA

DWG. REV. DATE

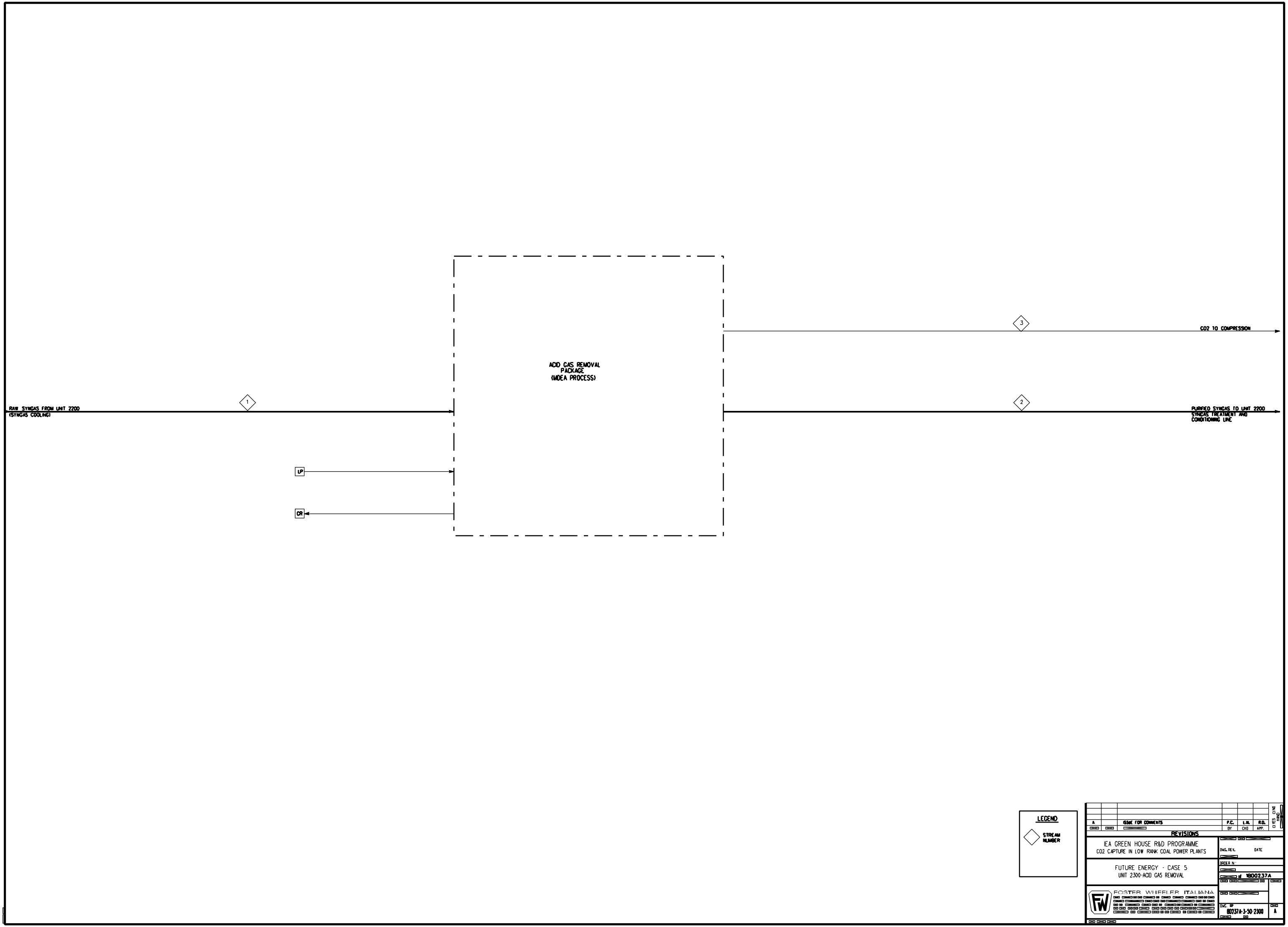
ORDER N°

1BD0237A

DWG. N° 1BD0237A-3-50-2100 A



MP STEAM
FROM MP HEADER
TO 2nd TRAIN
HP
PC
FC
TC
LC
START-UP
EXCHANGER
CR
TO 2nd TRAIN
SCRUBBED SYNGAS
FROM UNIT 1000
(GASIFICATION SECTION)
FT
FEED/ PRODUCT
EXCHANGER
SHIFT CATALYST
REACTOR
HP STEAM
GENERATOR
MP STEAM
GENERATOR
HBFW
MBFW
MP
SHIFT CATALYST
REACTOR
MP STEAM
GENERATOR
FROM 2nd TRAIN
HOT CONDENSATE
TO LIGNITE DRYING
TO 2nd TRAIN
COLD CONDENSATE FROM UNIT 4200
(CONDENSATE RECOVERY SYSTEM)
RAW SYNGAS TO UNIT 2300
(ACID GAS REMOVAL)
FROM 2nd TRAIN
CWS
FINAL
COOLER
CWR
CONDENSATE
PREHEATER B
PREHEATER
CONDENSATE A
VLP
LP
VLP STEAM
GENERATOR
LP STEAM
GENERATOR
VBFW
LBFW
CONDENSATE
SEPARATOR
FROM 2nd TRAIN
CONDENSATE TO UNIT 4000
(SOUR WATER STRIPPER)
FROM 2nd TRAIN
CONDENSATE TO UNIT 1000
(GASIFICATION ISLAND)
PURIFIED SYNGAS FROM UNIT 2300
(ACID GAS REMOVAL)
TRATED SYNGAS TO UNIT 3000
(POWER ISLAND)
TO 2nd TRAIN
TO 2nd TRAIN
HOT CONDENSATE FROM UNIT 4200
(CONDENSATE RECOVERY SYSTEM)
A
ISSUE FOR COMMENTS
P.C.
L.M.
R.D.
BY
CHD
APP.
YES
NO
HAND
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
CO2 CAPTURE IN LOW RANK COAL POWER PLANTS
DWG. REV.
DATE
FUTURE ENERGY - CASE 5
UNIT 2200- SYNGAS TREATMENT AND
CONDITIONING LINE
ORDER N°
1800237A
FOSTER WHEELER ITALIANA
DWG. N°
1800237-3-50-2200
A



ACID GAS REMOVAL PACKAGE (MDEA PROCESS)
RAW SYNGAS FROM UNIT 2200 (SYNGAS COOLING)
CO2 TO COMPRESSION
PURIFIED SYNGAS TO UNIT 2200 SYNGAS TREATMENT AND CONDITIONING LINE
1
2
3
LP
CR
LEGEND
STREAM NUMBER
A
ISSUE FOR COMMENTS
P.C.
L.M.
R.D.
BY
CHD
APP.
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
CO2 CAPTURE IN LOW RANK COAL POWER PLANTS
FUTURE ENERGY - CASE 5
UNIT 2300-ACID GAS REMOVAL
FOSTER WHEELER ITALIANA
DWG. REV.
DATE
ORDER N°
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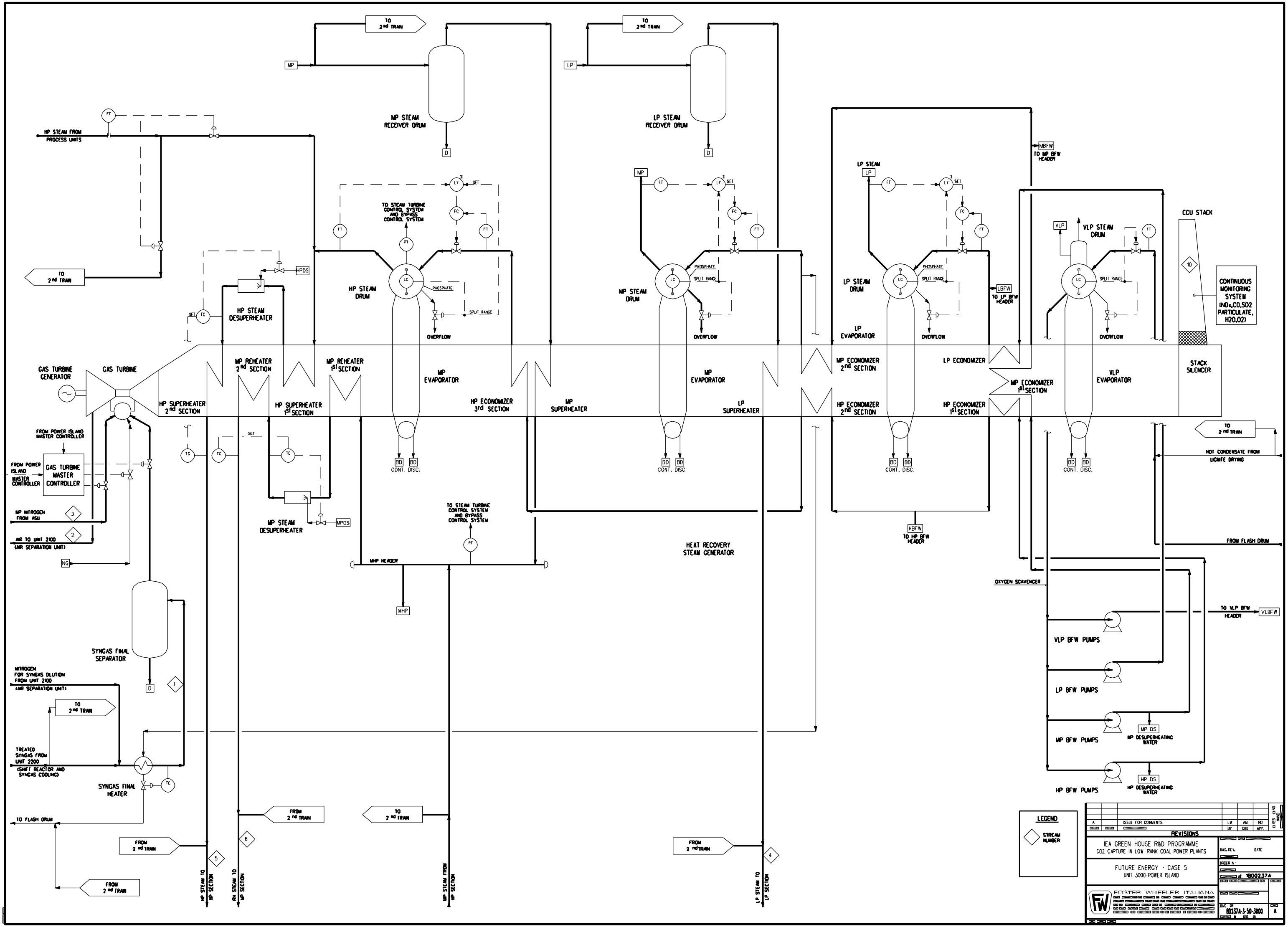
DWG. N°
BD237A-3-50-2300
A



TO 2nd TRAIN
MP
MP STEAM RECEIVER DRUM
LP
LP STEAM RECEIVER DRUM
HP STEAM FROM PROCESS UNITS
TO 2nd TRAIN
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
HPDS
HP STEAM DESUPERHEATER
HP STEAM DRUM
PHOSPHATE
SPLIT RANGE
OVERFLOW
MP STEAM DRUM
LP STEAM
LP STEAM DRUM
MBFW
TO MP BFW HEADER
LBFW
TO LP BFW HEADER
VLP
VLP STEAM DRUM
CCU STACK
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
GAS TURBINE GENERATOR
GAS TURBINE
HP SUPERHEATER 2nd SECTION
MP REHEATER 2nd SECTION
HP SUPERHEATER 1st SECTION
MP REHEATER 1st SECTION
MP EVAPORATOR
HP ECONOMIZER 3rd SECTION
MP SUPERHEATER
LP SUPERHEATER
LP EVAPORATOR
MP ECONOMIZER 2nd SECTION
HP ECONOMIZER 2nd SECTION
LP ECONOMIZER
MP ECONOMIZER 1st SECTION
HP ECONOMIZER 1st SECTION
VLP EVAPORATOR
STACK SILENCER
BD BD CONT. DISC.
TO 2nd TRAIN
HOT CONDENSATE FROM LIGNITE DRYING
FROM POWER ISLAND MASTER CONTROLLER
FROM POWER ISLAND MASTER CONTROLLER
GAS TURBINE MASTER CONTROLLER
MP NITROGEN FROM ASU
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
NG
MP STEAM DESUPERHEATER
MPDS
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
HBFW
TO HP BFW HEADER
HEAT RECOVERY STEAM GENERATOR
MHP HEADER
MHP
FROM FLASH DRUM
OXYGEN SCAVENGER
TO VLP BFW HEADER
VLBFW
VLP BFW PUMPS
LP BFW PUMPS
MP BFW PUMPS
MP DS
MP DESUPERHEATING WATER
HP BFW PUMPS
HP DS
HP DESUPERHEATING WATER
SYNGAS FINAL SEPARATOR
D
NITROGEN FOR SYNGAS DILUTION FROM UNIT 2100 (AIR SEPARATION UNIT)
TREATED SYNGAS FROM UNIT 2200 (SHIFT REACTOR AND SYNGAS COOLING)
SYNGAS FINAL HEATER
TO FLASH DRUM
FROM 2nd TRAIN
TO 2nd TRAIN
HP STEAM TO HP SECTION
RH STEAM TO MP SECTION
MP STEAM FROM MP SECTION
LP STEAM TO LP SECTION
LEGEND
STREAM NUMBER
A ISSUE FOR COMMENTS
LM AM RD
BY CHD APP.
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
CO2 CAPTURE IN LOW RANK COAL POWER PLANTS
FUTURE ENERGY - CASE 5
UNIT 3000-POWER ISLAND
FOSTER WHEELER ITALIANA
1800237A
1800237A-3-50-3000
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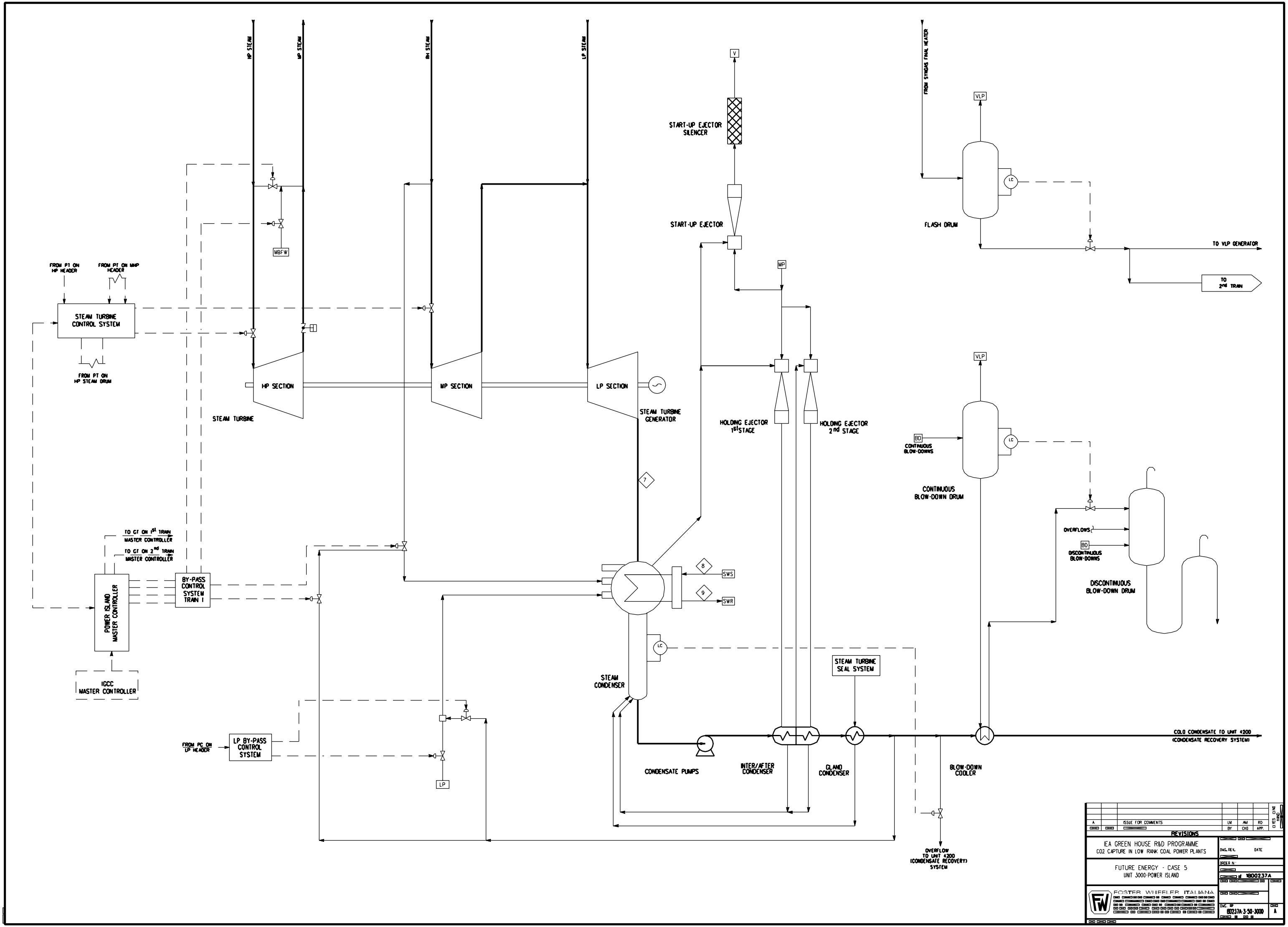
HP STEAM
MP STEAM
RH STEAM
LP STEAM
MBFW
FROM PT ON HP HEADER
FROM PT ON MHP HEADER
STEAM TURBINE CONTROL SYSTEM
FROM PT ON HP STEAM DRUM
HP SECTION
MP SECTION
LP SECTION
STEAM TURBINE
STEAM TURBINE GENERATOR
V
START-UP EJECTOR SILENCER
START-UP EJECTOR
MP
HOLDING EJECTOR 1st STAGE
HOLDING EJECTOR 2nd STAGE
FROM SYNGAS FINAL HEATER
VLP
LC
FLASH DRUM
TO VLP GENERATOR
TO 2nd TRAIN
VLP
BD
CONTINUOUS BLOW-DOWNS
CONTINUOUS BLOW-DOWN DRUM
OVERFLOWS
BD
DISCONTINUOUS BLOW-DOWNS
DISCONTINUOUS BLOW-DOWN DRUM
TO GT ON 1st TRAIN MASTER CONTROLLER
TO GT ON 2nd TRAIN MASTER CONTROLLER
POWER ISLAND MASTER CONTROLLER
BY-PASS CONTROL SYSTEM TRAIN 1
ICCC MASTER CONTROLLER
7
8
9
SWS
SWR
STEAM CONDENSER
STEAM TURBINE SEAL SYSTEM
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
LP
CONDENSATE PUMPS
INTER/AFTER CONDENSER
GLAND CONDENSER
BLOW-DOWN COOLER
COLD CONDENSATE TO UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
OVERFLOW TO UNIT 4200 (CONDENSATE RECOVERY) SYSTEM
A
ISSUE FOR COMMENTS
LM
AM
RD
BY
CHD
APP.
YES
NO
HAND
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
CO2 CAPTURE IN LOW RANK COAL POWER PLANTS
DWG. REV.
DATE
ORDER N°
1BD0237A
FUTURE ENERGY - CASE 5
UNIT 3000-POWER ISLAND
FOSTER WHEELER ITALIANA
DWG. Nº
BD237A-3-50-3000
A

5.4 Heat and Material Balances

For Heat and Material Balances refer to tables attached in paragraph 5.2.

5.5 Utility Consumption

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

	CLIENT:	IEA GHG	REVISION	Rev.0	Rev.1	Rev.2	Rev. 3
			DATE	Feb-05			
	PROJECT:	CO2 capture in low-rank coal power plants	ISSUED BY	P.C.			
	LOCATION:	Germany	CHECKED BY	L.M.			
	FWI Nº:		APPROVED BY	R.D.			

UTILITIES CONSUMPTION SUMMARY - CASE 5 - FUTURE ENERGY LOW PRESSURE GASSIFICATION - MDEA

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MP Steam 40 barg [t/h]	LP Steam 6.5 barg [t/h]	LP Steam ST extr. 4.7 barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS											
900	Lignite Handling, Milling and Drying					207.0					207.0	
1000	Gasification Section			-30.8				44.7			13.9	
2100	Air Separation Unit			20.1							20.1	
2200	Syngas Treatment and Conditioning line	-36.0	-171.9	-160.8		-207.0	36.0	171.9	160.8	207.0		
2300	Acid Gas Removal			157.2							157.2	
3000	POWER ISLANDS UNITS	36.0	171.9	4.9	0.0		-36.0	-216.6	-160.8	-207.0		
4100 to 5300	**UTILITY and OFFSITE UNITS**			9.4							9.4	
	BALANCE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	407.6	0.0

Note: Minus prior to figure means figure is generated

	CLIENT:	IEA GHG	Rev Final
FOSTER WHEELER	PROJECT:	CO2 Capture in Low-rank Coal Power Plants	Nov 05
	LOCATION:	Germany	ISSUED BY: PC.
	FWI Nº:		CHECKED BY: LM
			APPR. BY: RD

ELECTICAL CONSUMPTION SUMMARY - Case 5 - Future Energy - CO_2 capture, combined removal of H_2S and CO_2

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Storage and Handling and Drying**	**703**
950	**Coal Drying (Air fan consumption)**	**1018**
1000	**Gasification Section**	**1292**
2100	**Air Separation Unit**	**129740**
2200	**Syngas treatment and conditioning line**	**1990**
2300	**Acid Gas Removal**	**13349**
2500	**CO_2 Compression and Drying**	**60201**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**960**
3200	**Heat Recovery Steam Generator**	**5630**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**250**
3500	**Miscellanea**	**484**
	UTILITY and OFFSITE UNITS 4100/5200	
4100	**Cooling Water (Cooling Towers Make up / Machinery Water)**	**15985**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**505**
4600	**Waste Water Treatment**	**476**
	Other Units	**555**
	BALANCE	**233,139**

Note: (1) Minus prior to figure means figure is generated

	CLIENT:	IEA GHG	Rev 0
	PROJECT:	CO2 Capture in Low-rank Coal Power Plants	Feb 05
	LOCATION:	Germany	ISSUED BY: PC.
	FWI Nº:		CHECKED BY: LM
			APPR. BY: RD

WATER CONSUMPTION SUMMARY - Case 5 -Future Energy - CO_2 capture, combined removal of H_2S and CO_2

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water [t/h]
	PROCESS UNITS			
1000	**Gasification Section**			**3208**
2100	**Air Separation Unit**			**16327**
2200	**Syngas Treatment and Conditioning line**			**236**
2300	**Acid Gas Removal**			**5598**
2500	**CO_2 Compression and Drying**			**6817**
	POWER ISLANDS UNITS			
3100/3400	**Gas Turbines and Generator auxiliaries**			
3200	**Heat Recovery Steam Generator**			
3300/3400	**Steam Turbine and Generator auxiliaries**		**4**	**45163**
3500	**Miscellanea**			**1629**
	UTILITY and OFFSITE UNITS 4100/5200			
4100	**Cooling Water (Cooling Towers Make Up)**	**1247**		
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**24**	**-24**	
4600	**Waste Water Treatment**	**-16** (1)		
	Other Units		**20**	**410**
	BALANCE	**1255**	**0**	**79388**

Notes: Minus prior to figure means figure is generated

(1) Raw Watewr for Demineralized Water Plant

5.6 IGCC Overall Performance

The following Table shows the overall performance of the IGCC Complex.

FUTURE ENERGY

Low pressure Gasification - MDEA Alternative

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (A.R.)	t/h	653.3
Coal LHV (A.R.)	kJ/kg	10500.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV)	**MWt**	**1905.5**
Natural Gas to gasifiers	kg/h	640.1
NG LHV	kJ/kg	50053.4
TOTAL THERMAL INPUT (A)	**MWt**	**1914.4**
Thermal Power of Raw Syngas exit Scrubber (based on LHV)	MWt	1641.7
Thermal Power of Clean Syngas to Gas Turbines (based on LHV)	MWt	1467.2
Syngas treatment efficiency	%	89.4
Gas turbines total power output (@ gen terminals)	MWe	572.0
Steam turbine power output (@ gen terminals)	MWe	328.3
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**900.3**
ASU power consumption	MWe	129.7
Process Units consumption	MWe	18.4
Utility Units consumption	MWe	17.0
Offsite Units consumption (including cooling tower system)	MWe	0.5
Power Islands consumption	MWe	7.3
CO_2 Compression and Drying	MWe	60.2
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**233.1**
NET ELECTRIC POWER OUTPUT OF IGCC (C) (Step Up transformer efficiency = 0.997%)	**MWe**	**665.2**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**47.2**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.7**

The following Table shows the overall CO_2 removal efficiency of the IGCC Complex.

	Equivalent flow of CO_2, kmol/h
Carbon incoming (Coal carbon = 57.19%wt) Carbon incoming (Natural gas)	17,055.8 34
Slag	42.8
Net Carbon Flowing to Process Units (A)	17,047
Liquid Storage CO CO2 Total to storage (B)	 49 14,584 14,633
Emission CO CO2 Total Emission	 6 2,408 2,414
Overall CO_2 removal efficiency, % (B/A)	85.8

5.7 Environmental Impact

The IGCC Complex is designed to process coal, whose characteristic are shown at Section B - para 2.0, 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 IGCC Complex are summarised in this section.

5.7.1 Gaseous Emissions

Main Emissions

In normal operation at full load, the main continuous emissions are the combustion flue gases of the two trains of the Power Island, proceeding from the combustion of the Syngas in the two gas turbines, and emission from the coal Drying process.

Table 5.1 summarises expected flow rate and concentration of the combustion flue gas from one train of the Power Island.

Table 5.1 – Expected gaseous emissions from one train of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	697.6
Flow, $Nm^3/h^{(1)}$	2,500,200
Temperature, °C	129
Composition	(%vol)
Ar	0.91
N_2	74.83
O_2	11.17
CO_2	1.32
H_2O	11.77
Emissions	$mg/Nm^{3\ (1)}$
NOx	74
SOx	1.2
CO	31.3
Particulate	5

(1) Dry gas, O_2 content 15%vol

Both the Combined Cycle Units have the same flue gas composition and flow rate. The total gaseous emissions of the Power Island are given in Table 5.2.

Table 5.2 – Expected total gaseous emissions of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	1,395.2
Flow, $Nm^3/h^{(1)}$	5,000,400
Temperature, °C	129
Emissions	kg/h
NOx	370.0
SOx	6.0
CO	156.5
Particulate	25.0

(1) Dry gas, O2 content 15%vol

In normal operation at full load, the following emission to the atmosphere is foreseen from the Coal Drying Process:

Flow rate : 1996.7 t/h
Particulate : <10 mg/Nm^3, wet basis.

Minor Emissions

Other minor gaseous emissions are the process vents and fugitive emissions.
Some of the vent points emit continuously; others during process upsets or emergency conditions only. All vent streams containing, potentially, undesirable gaseous components are sent to a flare system. Venting via the flare will be minimal during normal operation, but will be significant during emergencies, process upsets, start up and shutdown.

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). Proper design and operation reduce these emissions to a very low level.

5.7.2 Liquid Effluent

Cooling Water System

Raw water is used for the cooling towers make up.
Main characteristics of the Cooling Towers blowdown are listed in the following:

- Maximum flow rate : 250 m^3/h
- Temperature : 11 °C
- Cooling Tower Concentration factor : 5

5.7.3 Solid Effluent

The plant is expected to produce the following solid by-products:

Slag

Flow rate	:	26	m^3/h
Water content	:	40	%wt

Sludge

Flow rate	:	3,5	m^3/h
Water content	:	80	%wt

Only slag can be sold to be commercially used as major components in concrete mixtures to make road, pads, storage bins. The generated sludge from the waste water cleaning is a waste material and it is necessary to be deposited.

5.8 Equipment List

The list of main equipment and process packages are included in this section.

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		CONTRACT N.	CHECKED BY	L.M.		
			APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2100 - Air Separation Unit - Future Energy - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				shell / tube	shell / tube		
1		**1st Nitrogen heater**	Shell & Tube						
2		**1st Nitrogen heater**	Shell & Tube						
1		**2nd Nitrogen heater**	Shell & Tube						
2		**2nd Nitrogen heater**	Shell & Tube						
		PACKAGES							
		Air Separation Unit Package (two parallel trains, each sized for 50% of the capacity)							

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		DATE	Feb. 05		
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EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - Future Energy -CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				Shell/tube	Shell/tube		
1		**Feed/ Product Exchanger**	Shell & Tube						
2		**Feed/ Product Exchanger**	Shell & Tube						
1		**HP Steam Generator**	Kettle						
2		**HP Steam Generator**	Kettle						
1		**MP Steam Generator**	Kettle						
2		**MP Steam Generator**	Kettle						
1		**MP Steam Generator**	Kettle						
2		**MP Steam Generator**	Kettle						
1		**LP Steam Generator**	Kettle						
2		**LP Steam Generator**	Kettle						

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REVISION	Rev.0	Rev.2	Rev.3
DATE	Feb. 05		
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EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - Future Energy -CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS (Continued)				Shell/tube	Shell/tube		
1		**VLP Steam Generator**	Kettle						
2		**VLP Steam Generator**	Kettle						
1		**Condensate Preheater**	Shell & Tube						
2		**Condensate Preheater**	Shell & Tube						
1		**Final Cooler**	Shell & Tube						
2		**Final Cooler**	Shell & Tube						

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		DATE	Feb. 05		
		ISSUED BY	P.C.		
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EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - Future Energy -CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		DRUMS							
1		**Condensate Separator**	Vertical						
2		**Condensate Separator**	Vertical						
1		**Condensate Separator**	Vertical						
2		**Condensate Separator**	Vertical						
1		**Condensate Separator**	Vertical						
2		**Condensate Separator**	Vertical						
1		**Condensate Separator**	Vertical						
2		**Condensate Separator**	Vertical						

	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.2	Rev.3
FOSTER WHEELER	LOCATION:	DATE	Feb. 05		
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		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - Future Energy -CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		REACTOR							
1		**Shift Catalyst Reactor - 1st Bed**	vertical						
2		**Shift Catalyst Reactor - 1st Bed**	vertical						
1		**Shift Catalyst Reactor - 2nd Bed**	vertical						
2		**Shift Catalyst Reactor - 2nd Bed**	vertical						
		PACKAGE UNITS							
		Catalyst Loading System							
		Shift Catalyst							

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		DATE	Feb. 05		
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EQUIPMENT LIST

Unit 3100 - Gas Turbine - Future Enrgy - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				Shell/tube	Shell/tube		
1		**Syngas Final Heater**	Shell & Tube						
2		**Syngas Final Heater**	Shell & Tube						
		DRUMS							
1		**Syngas Final Separator**	vertical						
2		**Syngas Final Separator**	vertical						
		PACKAGES							
1		**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9531 (FA)	286 MW					
2		**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9531 (FA)	286 MW					

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		DATE	Feb. 05		
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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Future Energy - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PUMPS							
1		**LP BFW Pumps**	centrifugal						One operating, one spare
2		**LP BFW Pumps**	centrifugal						One operating, one spare
1		**MP BFW Pumps**	centrifugal						One operating, one spare
2		**MP BFW Pumps**	centrifugal						One operating, one spare
1		**HP BFW Pumps**	centrifugal						One operating, one spare
2		**HP BFW Pumps**	centrifugal						One operating, one spare
1		**VLP BFW Pumps**	centrifugal						One operating, one spare
2		**VLP BFW Pumps**	centrifugal						One operating, one spare
		MISCELLANEA							
1		**Flue Gas Monitoring System**							NOx, CO, SO_2, particulate, H_2O, O_2
2		**Flue Gas Monitoring System**							NOx, CO, SO_2, particulate, H_2O, O_2
1		**CCU Stack**							
2		**CCU Stack**							
1		**Stack Silencer**							
2		**Stack Silencer**							
1		**MP Steam Desuperheater**							Included in 1-HRSG-3201
2		**MP Steam Desuperheater**							Included in 2-HRSG-3201
1		**HP Steam Desuperheater**							Included in 1-HRSG-3201
2		**HP Steam Desuperheater**							Included in 2-HRSG-3201

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		DATE	Feb. 05		
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		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Future Energy - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
		Fluid Sampling Package							
		Phosphate Injection Package Phosphate storage tank Phosphate dosage pumps							Included in Z - 3202 Included in Z - 3202 One operating , one spare
		Oxygen Scavanger Injection Package Oxygen scavanger storage tank Oxygen scavanger dosage pumps							Included in Z - 3203 Included in Z - 3203 One operating , one spare
		Amines Injection Package Amines Storage tank Amines Dosage pumps							Included in Z - 3204 Included in Z - 3204 One operating , one spare

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		DATE	Feb. 05		
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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Future Energy - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAMGENERATOR							
1		**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple Recovery, Reheated.						
1		**HP steam Drum**							Included in 1-HRS-3201
1		**MP steam drum**							Included in 1-HRS-3201
1		**LP steam drum**							Included in 1-HRS-3201
1		**VLP steam drum with degassing section**							Included in 1-HRS-3201
1		**HP Superheater 2nd section**							Included in 1-HRS-3201
1		**MP Reheater 2nd section**							Included in 1-HRS-3201
1		**HP Superheater 1st section**							Included in 1-HRS-3201
1		**MP Reheater 1st section**							Included in 1-HRS-3201
1		**HP Evaporator**							Included in 1-HRS-3201
1		**HP Economizer 3rd section**							Included in 1-HRS-3201
1		**MP Evaporator**							Included in 1-HRS-3201
1		**LP Superheater**							Included in 1-HRS-3201
1		**MP Economizer 2nd section**							Included in 1-HRS-3201
1		**HP Economizer 2nd section**							Included in 1-HRS-3201
1		**LP Evaporator**							Included in 1-HRS-3201
1		**LP Economizer**							Included in 1-HRS-3201
1		**MP Economizer 1st section**							Included in 1-HRS-3201
1		**HP Economizer 1st section**							Included in 1-HRS-3201
1		**VLP Evaporator**							Included in 1-HRS-3201

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		DATE	Feb. 05		
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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - Future Energy - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAM GENERATOR							
2		**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple Recovery, Reheated.						
2		**HP steam Drum**							Included in 2-HRS-3201
2		**MP steam drum**							Included in 2-HRS-3201
2		**LP steam drum**							Included in 2-HRS-3201
2		**VLP steam drum with degassing section**							Included in 2-HRS-3201
2		**HP Superheater 2nd section**							Included in 2-HRS-3201
2		**MP Reheater 2nd section**							Included in 2-HRS-3201
2		**HP Superheater 1st section**							Included in 2-HRS-3201
2		**MP Reheater 1st section**							Included in 2-HRS-3201
2		**HP Evaporator**							Included in 2-HRS-3201
2		**HP Economizer 3rd section**							Included in 2-HRS-3201
2		**MP Evaporator**							Included in 2-HRS-3201
2		**LP Superheater**							Included in 2-HRS-3201
2		**MP Economizer 2nd section**							Included in 2-HRS-3201
2		**HP Economizer 2nd section**							Included in 2-HRS-3201
2		**LP Evaporator**							Included in 2-HRS-3201
2		**LP Economizer**							Included in 2-HRS-3201
2		**MP Economizer 1st section**							Included in 2-HRS-3201
2		**HP Economizer 1st section**							Included in 2-HRS-3201
2		**VLP Evaporator**							Included in 2-HRS-3201

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		DATE	Feb. 05		
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EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System - Future Energy - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				shell / tube	shell / tube		
		Blow-Down Cooler	Shell & Tube						
		DRUMS							
		Flash Drum	vertical						
		Continuous Blow-down Drum	vertical						
		Discontinuous Blow-down Drum	vertical						
		PACKAGES							
		Steam Turbine & Condenser Package		328 MW					
		Steam Turbine							Included in Z - 3201
		Inter/After condenser							
		Gland Condenser							Included in Z - 3201
		Steam Condenser							Included in Z - 3201
		Steam Turbine Generator							Included in Z - 3201
		Start-up Ejector							Included in Z - 3201
		Holding Ejector 1st Stage							Included in Z - 3201
		Holding Ejector 2nd Stage							Included in Z - 3201
		Condensate Pumps	Centrifugal						Included in Z - 3201 Two operating, one spare
		Start-up Ejector Silencer							Included in Z - 3201

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: PROJ. NAME: CO2 Capture in Low-rank coal Power Plants CONTRACT N.	REVISION: Rev.0 DATE: Feb. 05 ISSUED BY: P.C. CHECKED BY: L.M. APPROVED BY: R.D.

EQUIPMENT LIST

Unit 3400 - Electric Power Generation - Future Energy - with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1		**Gas Turbine Generator**							Included in 1 -Z- 3101
2		**Gas Turbine Generator**							Included in 2 -Z- 3101
		Steam Turbine Generator							Included in Z- 3301

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		DATE	Feb. 05		
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EQUIPMENT LIST

Utility and Offsite Units - Future Energy - with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
	Unit 4100	Cooling Water System							
		Machinery Cooling Water System							
	Unit 4200	Demineralized Water System							
		Plant and Potable Water System							
	Unit 4300	Natural Gas System							
	Unit 4400	Plant and Instrument Air System							
	Unit 4600	Waste Water Treatment							
	Unit 4700	Fire Fighting System							
	Unit 4900	Chemicals							
	Unit 6000	Interconnecting							
		Instrumentation							
		DCS							
		Piping							
		Electrical							
		400 KV Substation							

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : CO_2 Capture in Low-rank Coal Power Pants
DOCUMENT NAME : CASE 6-IGCC BASED ON SHELL GASIFICATION WITH PRECOMBUSTION CO_2 CAPTURE

ISSUED BY : P. COTONE
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by

SECTION D

BASIC INFORMATION FOR EACH ALTERNATIVE

I N D E X

SECTION D BASIC INFORMATION FOR EACH ALTERNATIVE

6.0 Case 6

6.1 Introduction

The main features of the Case 6 configuration of the IGCC Complex are:

- Low pressure (40 bar g) Shell Gasification;
- Coal Nitrogen Dry Feed;
- Gasifier Heat Recovery Type;
- Double stage dirty shift;
- Combined removal of H_2S and CO_2.

The combined removal of acid gases, H_2S and CO_2, is based on the Amine Guard FS process. The product of this process is a single stream to be compressed and delivered to plant B.L.
The degree of integration between the Air Separation Unit (ASU) and the Gas Turbines is approx 30%.
Gas Turbine power augmentation and syngas dilution, for NO_x control, is achieved with injection of compressed N_2 from ASU to the gas turbines.

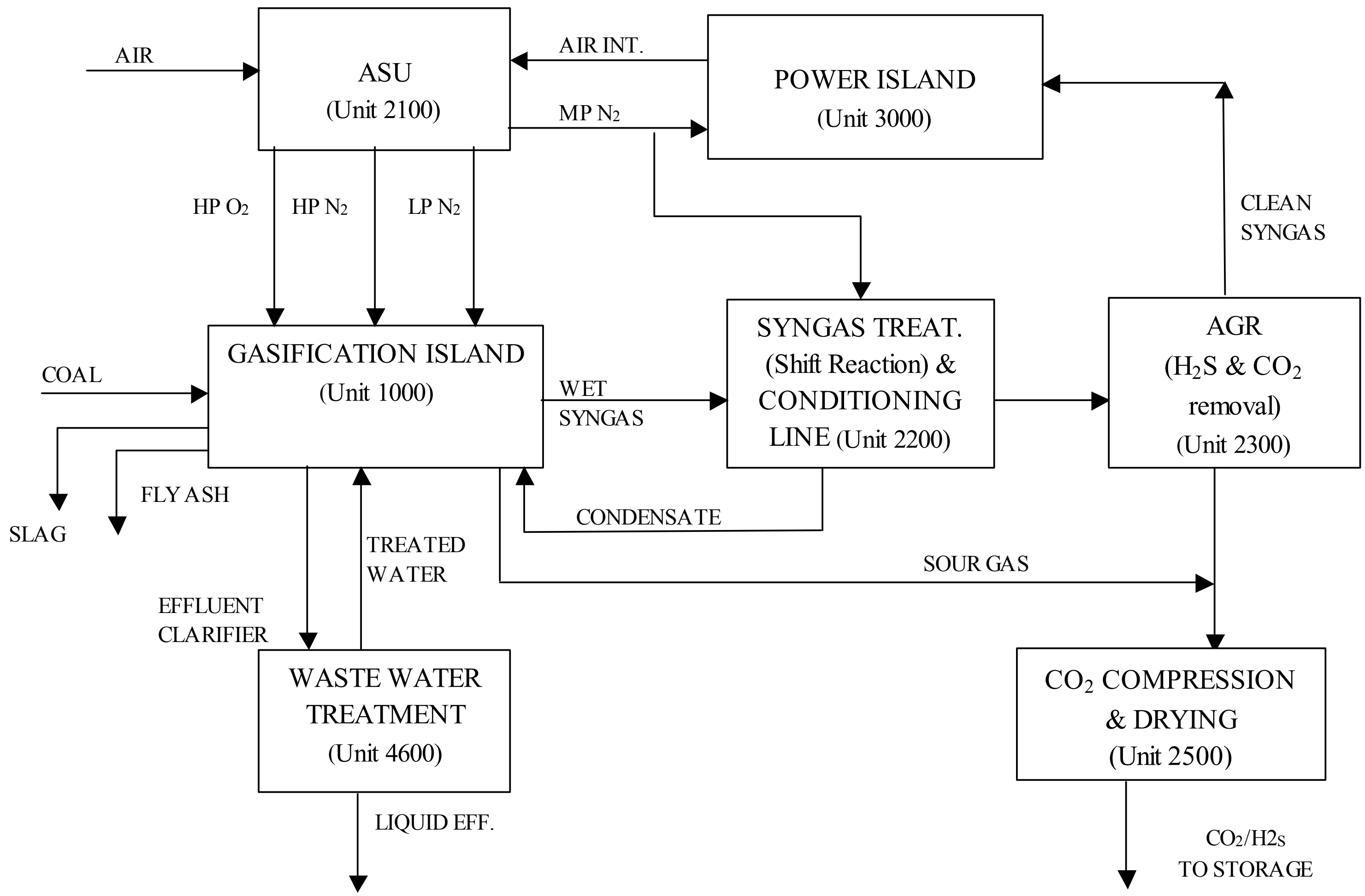
The arrangement of the main process units is:

Unit		Trains
1000	Coal pressurization/feeding	6 x 18.3 %
	Gasification heat recovery	2 x 50 %
	Slag removal	2 x 50 %
	Dry solids removal	2 x 50 %
	Wet scrubbing	2 x 50 %
	Sour slurry and sour water stripper	2 x 50 %
2100	ASU	2 x 50%
2200	Syngas Treatment and Conditioning Line	2 x 50%
2300	AGR	3 x 33%
2500	CO_2 Compression and Drying	2 x 50%

3000	Gas Turbine (PG 9351 – FA)	2 x 50%
	HRSG	2 x 50%
	Steam Turbine	1 x 100%

Reference is made to the attached overall Block Flow Diagram of the IGCC Complex.

Case 6 – SHELL – IGCC COMPLEX BLOCK FLOW DIAGRAM



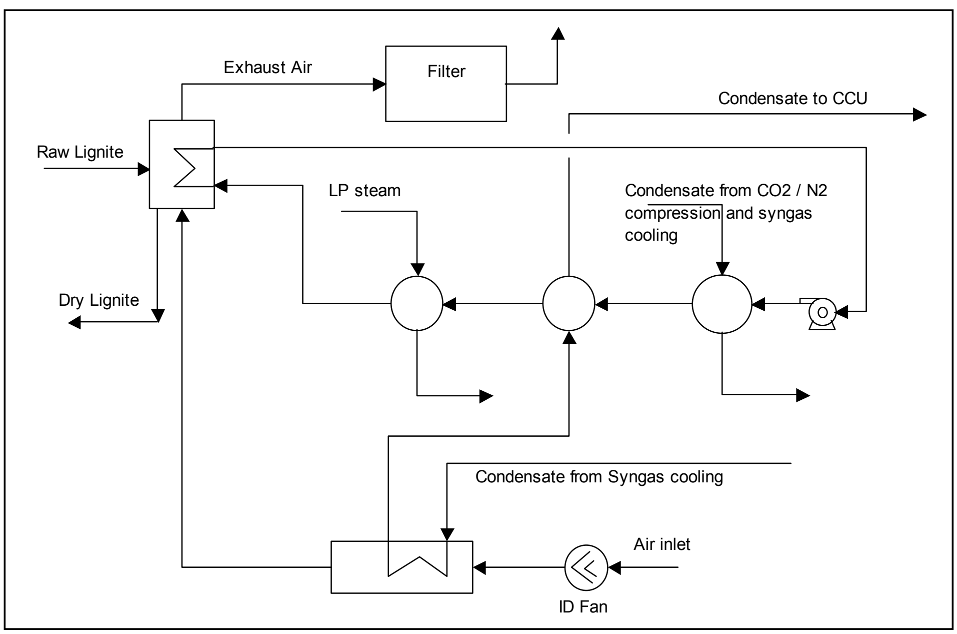
6.2 Process Description

Coal Handling and Storage

This unit is made up of standard equipment in use, to receive the coal from outside the plant boundary, store the coal, reclaim the same and transport to the plant. For more details see section C, paragraph 1.

Coal Drying

The basic features of this process are shown in Section C, para 2.0.
The process scheme used for this specific alternative is shown in the following scheme:



The indirect Lignite Drying method has been used for this alternative.

This system could be specifically advantageous for the ICGG case, as a lot of source of low temperature heat exists in the plant design that can be used.

For Shell gasification the required moisture content in the feedstock is 5%.

The split of the heating sources required for the drying of the lignite is reported in the following table:

Heat source	**Duty**, MWth
Syngas cooling	68
CO_2 compression	38.5
LP steam (5.7 barg)	110
N_2 compression	12
TOTAL HEAT	**228.5**

Unit 1000: Gasification Island

Feeding system

Milled and dried coal is pneumatically transported to the coal pressurisation and feeding system. This system consists of lock hoppers and feed hoppers. Once a lock hopper has been charged with coal, it is pressurised with nitrogen and its contents discharged into a feed hopper.
Pressurised coal is withdrawn from the feed hoppers and pneumatically conveyed with nitrogen to the gasifier's coal burners.
Lock hoppers are widely utilised in materials handling applications. They have proven to be a safe and reliable method for transferring solids under pressure.
The valves required for commercial scale lock hopper systems have been extensively demonstrated.

The coal feeding system consists of four coal silos, four mills and conveyor systems and four dosing unit, one for each gasifier.

Gasifier
The gasifier consists of a pressure vessel with a gasification chamber inside. Circulating water through the membrane wall to generate saturated steam controls the inner gasifier wall temperature. The membrane wall encloses the gasification zone from which two outlets are provided. One opening at the bottom of the gasifier is used for the removal of slag. The other outlet allows hot raw gas and fly slag to exit from the top of the gasifier.
In the top part of the gasifier, a solid-free cold syngas stream is injected to the hot product syngas, so that the product syngas is quenched to a temperature at which the fly ash solidifies. The recycle quench gas is withdrawn from downstream of the dry solids removal unit. A recycle gas compressor is applied for this service.
At the bottom of the gasifier, as the molten slag contacts the water bath, the

slag solidifies into dense, glassy granules. These slag granules fall into a collecting vessel located beneath the slag bath and are transferred to a lock hopper which operates on a timed cycle to receive the slag. After the lock hopper is filled, the slag is washed with clean make-up water to remove entrained gas and any surface impurities. After washing, the lock hopper is de-pressurised and the slag is fed to a de-watering bin. Commercially sized slag sluicing valves have been applied for this service.
The dewatering bin is equipped with a mechanical conveyor (drag chain) to lift the settled solids off the bottom of the vessel and deposit them on a conveyor belt for delivery to intermediate.

High Temperature Gas Cooling

The hot raw product gas leaving the gasification zone is quenched with cooled, recycled product gas to convert any entrained molten slag to a hardened solid material prior to entering the syngas cooler. The syngas cooler recovers high-level heat from the quenched raw gas by generating steam. The gasifier is a water wall membrane type, while the downstream syngas cooler is water tube type.
Each gasifier is coupled with a syngas cooler to maximise the heat recovery while maintaining operability. The steam system has been designed bearing efficiency and intrinsic safety in mind. The choice for two steam levels (HP and MP) ensures a high efficiency. The MP steam pressure level has been selected as high as the HP in order to maximise the overall efficiency.

Dry Solids Removal

The bulk of the flyash contained in the raw gas leaving the syngas cooler is removed from the gas using a commercially demonstrated high pressure, high temperature (HPHT) filter (approx. 350°C). The flyash leaving the process is conveyed to a flyash lock hopper. After the lock hopper is filled, the flyash is purged with high-pressure nitrogen to remove any entrained raw gas; this effluent is disposed to a blow down flare system. After purging the lock hopper, the flyash is pneumatically conveyed to a silo for intermediate storage. All vent gases from the flyash lock hopper and the storage silo are filtered of particles. Flyash is recycled and added to the coal feed.

Wet Scrubbing

The gas leaving the dry solids removal is further purified by passing through a wet scrubbing unit where any residual flyash is removed to a level of less than 1 ppm. This wet scrubbing system also removes other minor contaminants such

as soluble alkali salts and hydrogen halides.
Make-up water is continuously added to the wet scrubbing unit to control the concentration of contaminants. To minimise the water use for the plant, recycle water from the sour water stripper unit is used for this make-up and this comprises the majority of the make-up water stream. A small bleed flow of the contaminated water is sent to the sour slurry-stripping unit to recover the contaminants.
A scrubber outlet temperature of 180 °C has been selected, which corresponds to a 26% water molar content in the syngas.

Sour Slurry Stripper (Waste Water Pre-treatment)

The blow-down water from the wet scrubbing unit and a bleed from the slag bath are fed to a stripper for the removal of hydrogen sulphide, dissolved raw gases and to reduce the ammonia level in the water to an environmentally acceptable level. In this unit, low-pressure steam provides the necessary heat and stripping medium. A large portion of the effluent water from the stripper is recycled after clarification to the slag bath as make-up water. Only a small effluent water stream is sent to the Waste Water Treatment. In this way, the consumption of process water has been minimised.

Sour Water Stripper

Sour water streams from several streams are stripped in this unit. Since the column operates under non-fouling conditions, the necessary stripping steam is supplied via a LP steam reboiler. The vapour leaving the SWS column is sent to an overhead system. In this overhead system the overhead vapours are condensed and the sour gases are separated from the condensate in the gas/liquid separator. The condensed water is routed back to the SWS column as reflux, above the rectifying bed. The sour gases are routed to the battery limit. The SWS effluent has been used as make-up water in the wet scrubbing systems.

The main process streams of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED (COAL)	HP O2 (95% purity)	HP N2	LP N2	HP Steam	MP Steam	SATURATED SYNGAS
Temperature (°C)	AMB.	180	80	70	290	290	180
Pressure (bar)		45	71	7.5	71	71	41
TOTAL FLOW							
Mass flow (kg/h)	323,920	219,800	105,960	41,100	353,200	33,860	711,640
Molar flow (kmol/h)							33,450
Composition (% vol)							
H_2							21,2
CO							42,1
CO_2							5,0
N_2							5,6
Ar							-
O_2							-
H_2S + COS							0,1
H_2O							26,0
Others							-

Note: Figures referred to the total flowrates

Unit 2100: Air Separation Unit (ASU)

This Unit is treated as a package unit supplied by specialised Vendors.
The Air Separation Unit (ASU, Unit 2100) is installed to produce oxygen and nitrogen through cryogenic distillation of atmospheric air.

The oxygen produced is delivered to the Gasification Island to be used as reaction oxidant.
As a by-product nitrogen is obtained and is used for the pneumatic transport of dried pulverized coal to the gasifiers; the excess is routed to the syngas dilution and to the gas turbines for power augmentation and NOx control.

The Plant consists of two air separation trains and at the same time is able to produce additional oxygen and nitrogen products to maintain the desired inventories in the storage systems of liquid and gaseous products used as back-up; these systems are common to both trains.

ASU is partially integrated with the gas turbines.
When the gasification operates at full load, approx 30% of the air required by the ASU to obtain the design oxygen production is derived from both gas turbine compressors; the integration between the gas turbines operation and the ASU is achieved at a level where approx 70% of the atmospheric air is compressed with a dedicated air compressor and the difference comes already pressurized from the compressors of the gas turbines in the combined cycle.
The air extracted from the gas turbine at high temperature is cooled by exchanging heat with nitrogen for syngas dilution before being fed to the Air Separation Unit.

The main process stream of the Air Separation Unit relevant to this alternative are summarised in following table:

STREAM	TOTAL AIR (1)	OXYGEN TO GASIFIERS (2)	HP NITROGEN (3)	LP NITROGEN (4)	TOTAL NITROGEN TO SYNGAS & GT
Temperature (°C)		180	80	70	95
Pressure (bar)		45	71	7.5	23
TOTAL FLOW					
Mass flow (kg/h)	975,220	219,800	105,960	41,100	573,100

<u>Unit 2200: Syngas Treatment and Conditioning Line</u>

This Unit receives the raw syngas from the gasification section, which is hot, humid and contaminated with acid gases, CO_2 and H_2S, and other chemicals, mainly COS, HCN and NH_3.
Before using this syngas as fuel in the gas turbines it is necessary to remove all the contaminants and prepare the syngas at the proper conditions of temperature, pressure and water content in order to achieve in the combustion process of the gas turbine the desired environmental performance and stability of operation.

Saturated raw syngas from wet scrubbing in Unit 1000, at approximately 39 bar and 180°C, enters Unit 2200. The syngas is first heated by the hot shift effluent and then enters the first stage of Shift Reactor, where CO is shifted to H_2 and CO_2 and COS is converted to H_2S. The exothermic shift reaction brings the syngas temperature up to 496°C.

In order to meet the required degree of CO_2 removal, a double stage shift containing sulphur tolerant shift catalyst (dirty shift) is used. In addition, a large amount of MP steam (290 t/h) shall be added to the syngas, coming from the scrubber, to allow reaching the required conversion of the shift reaction. This is a limitation of the gasification technology with waste heat boiler because the water content of the syngas is low if compared to the content of the syngas coming from the quench technology.The large amount of steam added to the syngas corresponds to a loss on the Plant Power production

The hot shifted syngas outlet from the first stage is cooled in a series of heat exchangers:

Shift feed product exchanger
HP Steam Generator
MP Steam Generator

Inlet temperature to the second stage shift is controlled to 263 °C. Outlet temperature from second shift is 297°C. The hot shifted syngas outlet from the second stage is cooled in a series of heat exchangers:
MP Steam Generator
LP Steam Generator
VLP Steam Generator
Condensate Preheater A/B

The syngas exiting from the Condensate Preheater is already at the required temperature (38°C) for the AGR section. Even though a final cooling step of the syngas in a cooling water cooler is foreseen in case of necessity.

Process condensate separated in Separator Drums is recycled back to the Sour Water Stripper of the Gasification Island.

The first and second stage of the shift reactor is split in two parallel trains, as the remaining equipment of Unit 2200, because of the size limitation of the exchangers involved.
Cold syngas, after combined CO_2 and H_2S removal, is diluted with Nitrogen in order to achieve 65% max Hydrogen content, preheated with VLP steam and then sent to the gas turbines, Unit 3000.

The main process streams of the Syngas treatment and conditioning line relevant to this alternative are summarised in following table:

STREAM	SAT SYNGAS (1)	HP GENERATED STEAM (2)	MP GENERATED STEAM (3a+3b)	LP GENERATED STEAM (4)	VLP GENERATED STEAM (5)	SYNGAS TO GT (6)
Temperature (°C)	180	352	256	175	152	135
Pressure (bar)	39	171	44	9	5	28,5
TOTAL FLOW						
Mass flow (kg/h)	711,640	91,800	110,500	69,500	62,500	185,400
Molar flow (kmol/h)	33,450					15,785
Composition (% vol)						
H_2	21,2					65,0
CO	42,1					3,5
CO_2	5,0					4,0
N_2	5,6					26,8
Ar	-					-
O_2	-					0,4
H_2S + COS	0,1					-
H_2O	26,0					0,3
Others	-					-

Unit 2300: Acid Gas Removal (AGR)

The removal of acid gases, H_2S and CO_2 is an important step of the IGCC operation. In fact this unit is not only capital intensive and a large consumer of energy, but also is a key factor for the control of the environmental performance of the IGCC. The right selection of the process and of the solvent used to capture the acid gases is important for the performance of the complex.

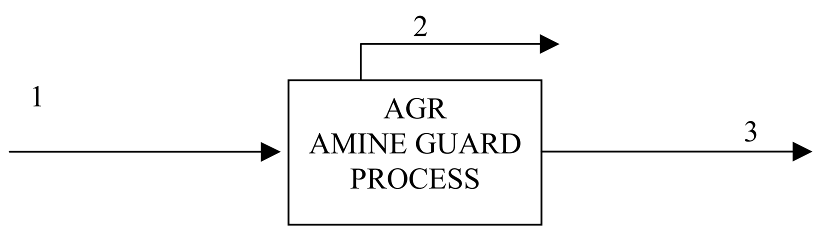
Unit 2300 is characterised by a medium syngas pressure (30 bar g) and an extremely high CO_2/H_2S ratio (387/1).
Based on considerations on section C, paragraph 8.0, the combined removal of acid gases, H_2S and CO_2, based on the Amine Guard FS process has been selected.
The product of this process is a single stream to be compressed and delivered to plant B.L.

Entering Streams

1. Untreated Gas from Syngas Treatment & Conditioning Line

Exit Streams

2. Treated Gas to Gas Turbines
3. CO_2 to compression



The Amine Guard FS solvent consumption, to make-up losses, is 63,5 m^3/year.

The proposed process matches the process specification with reference to H_2S+COS concentration of the treated gas exiting the Unit (H_2S+COS concentration is less than 3 ppm). This is due to the integration of CO_2 removal with the H_2S removal, which makes available a large circulation of the solvent.

The CO_2 removal rate is 91,6% as required, allowing reaching an overall CO_2 capture of approx 85% with respect to the carbon entering the IGCC.

These performances for the H_2S removal and CO_2 capture are achieved with large steam consumption.

Together with CO_2/H_2S exiting the Unit, the following quantity of hydrogen is lost:

- 97 kmol/h of Hydrogen, corresponding to 0.66% vol and to an overall thermal power of approx 6.6 MWth, i.e. more than 2 MWe.

The feasibility to separate and recover H_2 during the CO_2 compression was investigated. Due to the similar equilibrium constants of CO_2 and H_2 at super-critical CO_2 conditions, this separation is unfeasible.
The main process streams of the AGR Unit relevant to this alternative are summarised in following table:

STREAM	RAW SYNGAS (1)	TREATED SYNGAS (2)	CO2 RICH STREAM (3)
Temperature (°C)	38	38	49
Pressure (bar)	30.7	29.5	1.8
TOTAL FLOW			
Molar flow (kmol/h)	38,870	24,900	14,800
Composition (% vol)			
H_2	53.1	82.4	0.7
CO	2.9	4.5	-
CO_2	38.7	5.1	93.3
H_2S + COS	0.1	3 ppm	0.3
Others	5.2	8.0	5.7

Unit 2500: CO_2 Compression and Drying

This Unit is a Package Unit supplied by specialised Vendor. For more details see section C, paragraph 9.0.

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

- Product stream : 609 t/h.
- Product stream : 110 bar
- Composition :

	%vol
CO_2	99.0
H_2S	0.3
Others	0.7
TOTAL	100.0

Unit 3000: Power Island

The power island is based on two General Electric gas turbines, frame 9001 FA, two Heat Recovery Steam Generators (HRSG), generating steam at 3 levels of pressure, and one steam turbine common to the two HRSGs.

The power island configuration is described referring to the Process Flow Diagrams attached to the end of this paragraph.

During normal operation, the clean syngas, coming from Unit 2200 - Syngas Treatment and Conditioning Line, is heated up to 170°C against MP BFW in the syngas final heater dedicated to each Gas Turbine.
Finally, the hot syngas is burnt inside the Gas Turbine to produce electric power; the resulting stream of hot exhaust gas is conveyed to the Heat Recovery Steam Generator located downstream each Gas Turbine.

Compressed air is extracted from the Gas Turbines and delivered to ASU.
MP nitrogen coming from ASU is injected into the Gas Turbines for NO_x abatement and power output augmentation.

The flue gas stream at a temperature of about 570°C flows through the coils inside the HRSG generating steam at three different pressure levels, is cooled down to about 129°C and then discharged through a stack common to the two HRSG Units.

The turbine consists of HP, IP and LP sections all connected to the generator on a single shaft. HP steam from the HRSG HP section enters the turbine at approx. 156 bar, 550°C. Steam from the exhaust of the HP turbine is returned to the HRSG for reheating after mixing with MP steam, and is then throttled into the IP turbine at approx. 36 bar, 530°C. Exhaust steam from IP flows into a LP turbine after mixing with superheated LP steam from HRSG and then downward into the condenser at 0.032 bar, 25°C.

The MHP saturated steam at 70 bar from the gasification island, is superheated in a dedicated coil and sent to a dedicated ST section where is expanded to 5.7 bar. The exhaust steam is mixed with the exhaust steam from the ST IP section and flows to the ST LP main section. This steam turbine is coupled to the same generator of the main steam turbine. A dedicated clutch allows isolating the smaller steam turbine during the start-up of the plant.

When the clean syngas production is not sufficient to satisfy the appetite of both Gas Turbines it is possible to cofire natural gas or to switch to natural gas one or both Gas Turbines.
This could happen in case of partial or total failure of the Gasification/Gas Treatment units of the IGCC and during start-up.
The selected machines are suitable to co-fire syngas and natural gas from 20% to 100% load.

During Natural Gas Operation no air extraction is foreseen, while a stream of MP Steam has to be injected into the combustion chambers of the Gas Turbines to reduce the NO_x emissions.

During normal operation on Natural Gas, the Power Island does not export/import to/from IGCC Process Units any steam/water stream and no low temperature heat can be recovered in Process Units. Then all cold condensate coming from Steam Condenser can be directly sent to the deaerator after polishing. In this situation, the degassing steam demand of the deaerator is very high, more than VLP steam produced by HRSG's that needs to be integrated with steam coming from LP and MP headers.

The interfaces considered (during normal operating case) between the power island and the rest of the plant are as follow:

- Compressed Air : Air sent to Unit 2100 – Air Separation Unit;
- MP nitrogen : Nitrogen coming from ASU injected into the Gas Turbines for NO_x abatement and power output augmentation.
- HP steam (160 barg): steam imported from Syngas Treatment and Conditioning Line.
- MHP steam (70 barg): steam imported from Gasification Island.
- MP steam (40 barg) : steam imported from Syngas Treatment and Conditioning Line.
- MP steam (40 barg) : steam exported from the steam turbine to Syngas Treatment and Conditioning Line to meet the water requirement of the shift reaction.
- LP steam (6,5 barg): steam imported from Syngas Treatment and Conditioning Line. The steam is also exported to the following Process Units: ASU, Utility and Offsite Unit.
- LP steam (6,5 barg): steam exported from the steam turbine to AGR and Lignite Drying section.
- VLP steam (3,2 barg): steam imported from Syngas Treatment and Conditioning Line.

- BFW : HP, MP, LP, VLP Boiler Feed Water is exported to the Process Units to generate the above mentioned steam production.
- Process Condensate : All the condensate recovered from the condensation of the steam utilised in the Process Unit is recycled back to the HRSG after polishing in Unit 4200, Demi Water/Condensate Recovery.
- Condensate from ST : All the Condensate from the Condenser is exported to the polishing unit (Unit 4200), pre-heated in the Syngas Cooling and Conditioning Line partially cooled in the Lignite drying section and recycled back to the HRSG.

Flow rate of the steam/water interfaces of the Plant are shown in table attached to para 6.5, Utilities Consumption.

The main process data of the Power Island relevant to this alternative are summarised in following table:

STREAM	SYNGAS (1)	AIR TO ASU (2)	NOX CONTROL N2 (3)	LP STEAM TO ST (4)	HP STEAM TO ST (5)	RH MP STEAM TO ST (6)	COND. FROM ST (7)
Temperature (°C)	170	396	213	246	552	527	25
Pressure (bar)	26	14,2	22	5,7	156	36	0,03
TOTAL FLOW							
Mass flow (t/h)	185,4 (1)	147,7 (1)	193,0 (1)	144,4	432,9	456,1	970,5

STREAM	COOLING WATER TO CND (8)	COOLING WATER FROM CND (9)	FLUE GAS AT STACK (10)	MP STEAM FROM ST (11)	LP STEAM FROM ST (12)	MHP STEAM TO ST (13)
Temperature (°C)	11	21	129	273	173	507
Pressure (bar)	3	2,3	Amb	40	5,7	69
TOTAL FLOW						
Mass flow (kg/h)	33271	33271	2511,5 (1)	289,1	352,2	387,0

(1): For each GT

Unit 4600: Waste Water Treatment

The effluents from the Gasification Island – Sour water stripper are split in two parts. The flowrate needed as Gasification make-up is recycled back directly to the gasification. The excess part flows to the anaerobic treatment, where a phosphoric acid solution is added to the waste water to support the bacterial growth.

In the Anaerobic Reactor the organic pollutants are biodegraded with production of biological gas and biological sludge. The biogas produced in the reactor is routed to the local flare to be burned.

The biological mass exits the anaerobic reactor and enters the Anaerobic Clarifier where the biomass is separated by gravity from the supernatant.

Effluent from anaerobic section is subject to a further aerobic treatment for the complete removal of ammonia and organic contaminants. The effluent from the anaerobic clarifier is pumped to the denitrification/oxidation tanks where is mixed with the rainwater bleed-off and drainage coming from the deoiling section.

In this deoiling section, the oily drainage mixed with contaminated rainwater is fed by means of pumps from the oil water storage tank to the primary deoiling section, consisting of a Corrugate Plate Interceptor, witch provides gravity separation of free oil and suspended solids carried in the waste water.

The effluent from the separator cells is dosed with polyelectrolyte and is routed by gravity to a secondary deoiling step, consisting of Induced Air Flotation. Air induced by motors driven self-aerating rotors mechanism removes the oil and suspended solids, which are collected in a dense froth to be recycled back to the CPI.
The deoiled water is then pumped to the denitrification/oxidation tanks, where it is mixed with the anaerobic treatment effluent and where the organic contaminants are removed and ammonia is oxidized to nitrates which are further reduced to nitrogen gas in the denitrification section.

The effluent from the oxidation tank enters the aerobic clarifier, where the biomass separates by gravity from the supernatant. The sludge from the bottom of the clarifier is recycled to the anaerobic reactor by the Sludge Pump.

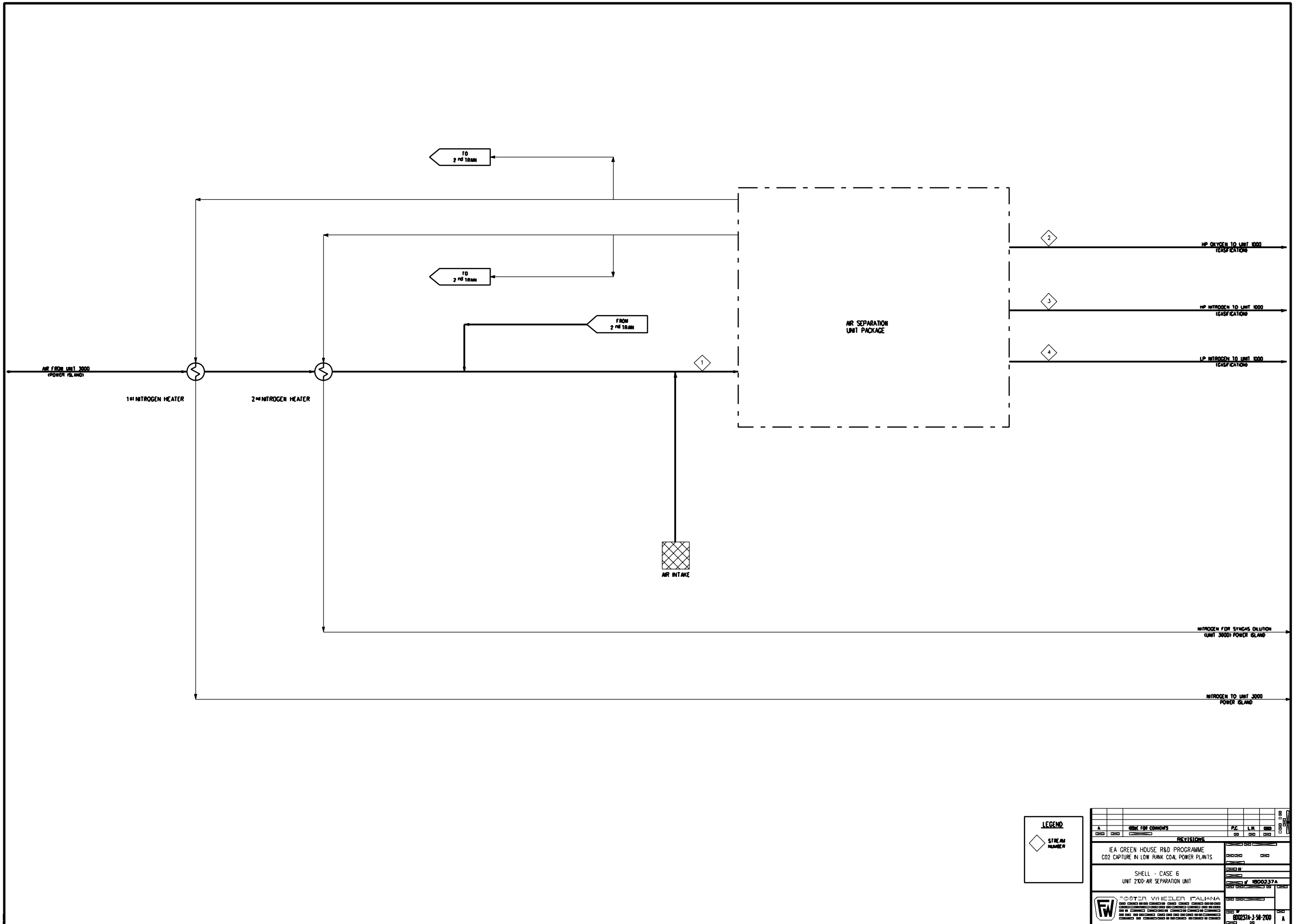
The supernatant from the clarifier is dosed with polyelectrolyte and pumped into Dual Media Filter, which uses sand and anthracite as filter media for the removal of residual hydrocarbons and suspended solids, and into Activated Carbon Filters, for the complete removal of organic contaminants

From the filters the water is sent to a dedicated treatment where the reverse osmosis process allows recovering almost 60% of the treated water. This recovered water is recycled back to the Demi Water System, Unit 4200, and used as raw water for the Demineralised water plant. The remaining 40% of water is discharged together with the cooling towers blowdown.

6.3 Process Flow Diagrams

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

- UNIT 2100: Air Separation Unit (PFD n° BD0237A-3-50-2100);
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0237A-3-50-2200);
- UNIT 2300: Acid Gas Removal (PFD n° BD0237A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0237A-3-50-3000; sheet 1 and 2).


TO 2nd TRAIN
TO 2nd TRAIN
FROM 2nd TRAIN
AIR SEPARATION UNIT PACKAGE
1
2
3
4
HP OXYGEN TO UNIT 1000 (GASIFICATION)
HP NITROGEN TO UNIT 1000 (GASIFICATION)
LP NITROGEN TO UNIT 1000 (GASIFICATION)
AIR FROM UNIT 3000 (POWER ISLAND)
1st NITROGEN HEATER
2nd NITROGEN HEATER
AIR INTAKE
NITROGEN FOR SYNGAS DILUTION (UNIT 3000) POWER ISLAND
NITROGEN TO UNIT 3000 POWER ISLAND
LEGEND
STREAM NUMBER
A
ISSUE FOR COMMENTS
P.C.
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REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
CO2 CAPTURE IN LOW RANK COAL POWER PLANTS
SHELL - CASE 6
UNIT 2100-AIR SEPARATION UNIT
FOSTER WHEELER ITALIANA
1BD0237A
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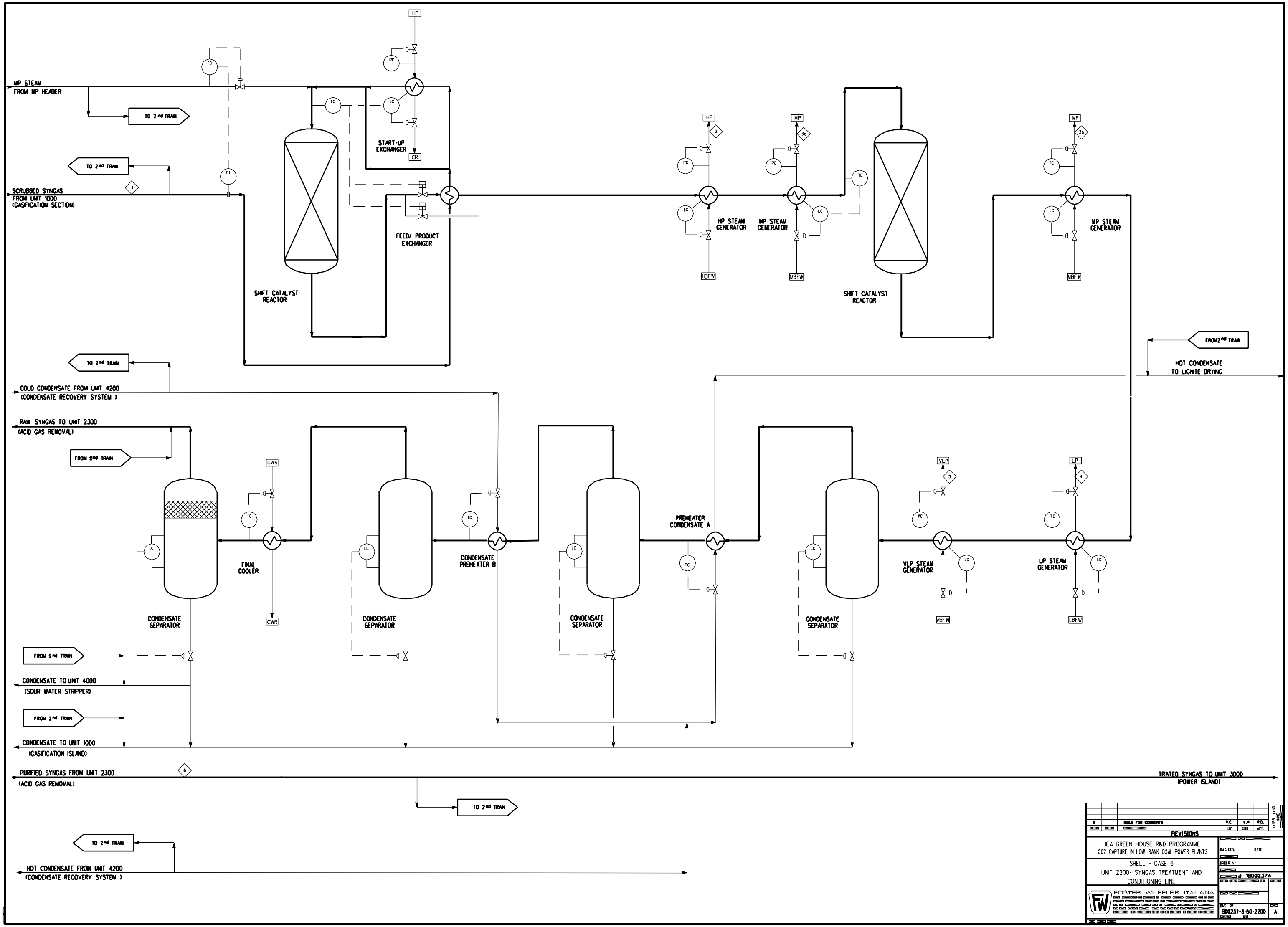
MP STEAM
FROM MP HEADER
TO 2nd TRAIN
FC
FT
TC
PC
LC
HP
START-UP
EXCHANGER
CR
TO 2nd TRAIN
SCRUBBED SYNGAS
FROM UNIT 1000
(GASIFICATION SECTION)
1
FEED/ PRODUCT
EXCHANGER
SHIFT CATALYST
REACTOR
HP
2
MP
3a
HP STEAM
GENERATOR
MP STEAM
GENERATOR
HBFW
MBFW
SHIFT CATALYST
REACTOR
MP
3b
MP STEAM
GENERATOR
MBFW
TO 2nd TRAIN
FROM 2nd TRAIN
HOT CONDENSATE
TO LIGNITE DRYING
COLD CONDENSATE FROM UNIT 4200
(CONDENSATE RECOVERY SYSTEM)
RAW SYNGAS TO UNIT 2300
(ACID GAS REMOVAL)
FROM 2nd TRAIN
CWS
FINAL
COOLER
CWR
CONDENSATE
PREHEATER B
PREHEATER
CONDENSATE A
VLP
5
VLP STEAM
GENERATOR
VBFW
LP
4
LP STEAM
GENERATOR
LBFW
CONDENSATE
SEPARATOR
CONDENSATE
SEPARATOR
CONDENSATE
SEPARATOR
CONDENSATE
SEPARATOR
FROM 2nd TRAIN
CONDENSATE TO UNIT 4000
(SOUR WATER STRIPPER)
FROM 2nd TRAIN
CONDENSATE TO UNIT 1000
(GASIFICATION ISLAND)
PURIFIED SYNGAS FROM UNIT 2300
(ACID GAS REMOVAL)
6
TRATED SYNGAS TO UNIT 3000
(POWER ISLAND)
TO 2nd TRAIN
TO 2nd TRAIN
HOT CONDENSATE FROM UNIT 4200
(CONDENSATE RECOVERY SYSTEM)
A
ISSUE FOR COMMENTS
P.C.
L.M.
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BY
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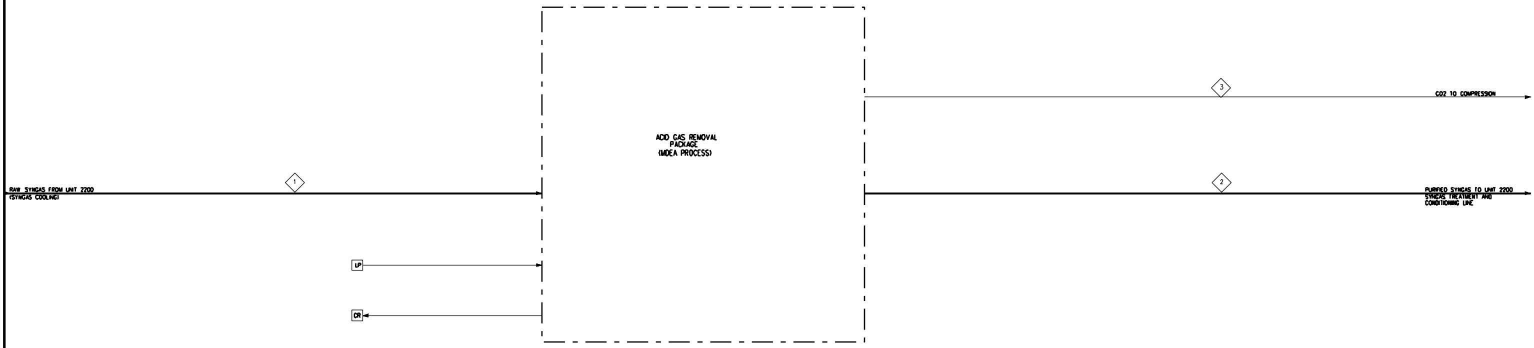
APP.
YES
NO
HAND
REVISIONS
IEA GREEN HOUSE R&D PROGRAMME
CO2 CAPTURE IN LOW RANK COAL POWER PLANTS
DWG. REV.
DATE
SHELL - CASE 6
UNIT 2200- SYNGAS TREATMENT AND
CONDITIONING LINE
ORDER N°
1800237A
FOSTER WHEELER ITALIANA
FW
DWG. N°
800237-3-50-2200
A



LEGEND

STREAM NUMBER

A		ISSUE FOR COMMENTS	P.C.	L.M.	R.O.
			BY	CHD	APP.

REVISIONS

IEA GREEN HOUSE R&D PROGRAMME
CO2 CAPTURE IN LOW RANK COAL POWER PLANTS

SHELL - CASE 6
UNIT 2300-ACID GAS REMOVAL

FOSTER WHEELER ITALIANA

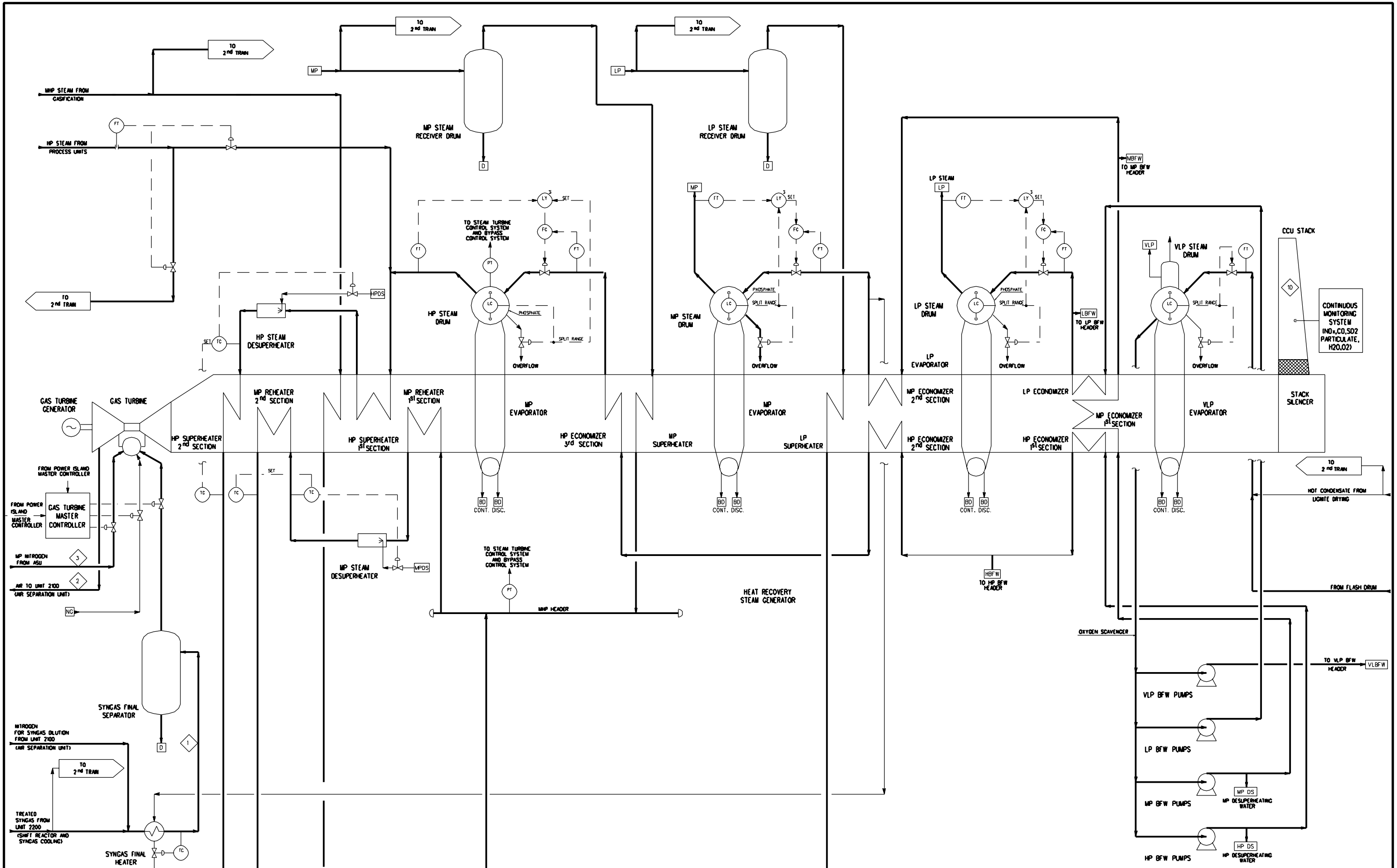
DWG. REV. DATE

ORDER N°

1BD0237A

DWG. N°
BD237A-3-50-2300

A



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		BY	CHD	APP.	YES NO HAND

REVISIONS

IEA GREEN HOUSE R&D PROGRAMME
CO2 CAPTURE IN LOW RANK COAL POWER PLANTS

SHELL - CASE 6
UNIT 3000-POWER ISLAND

FOSTER WHEELER ITALIANA

DWG. REV. DATE
ORDER N°
1BD0237A
DWG. N°
BD237A-3-50-3000
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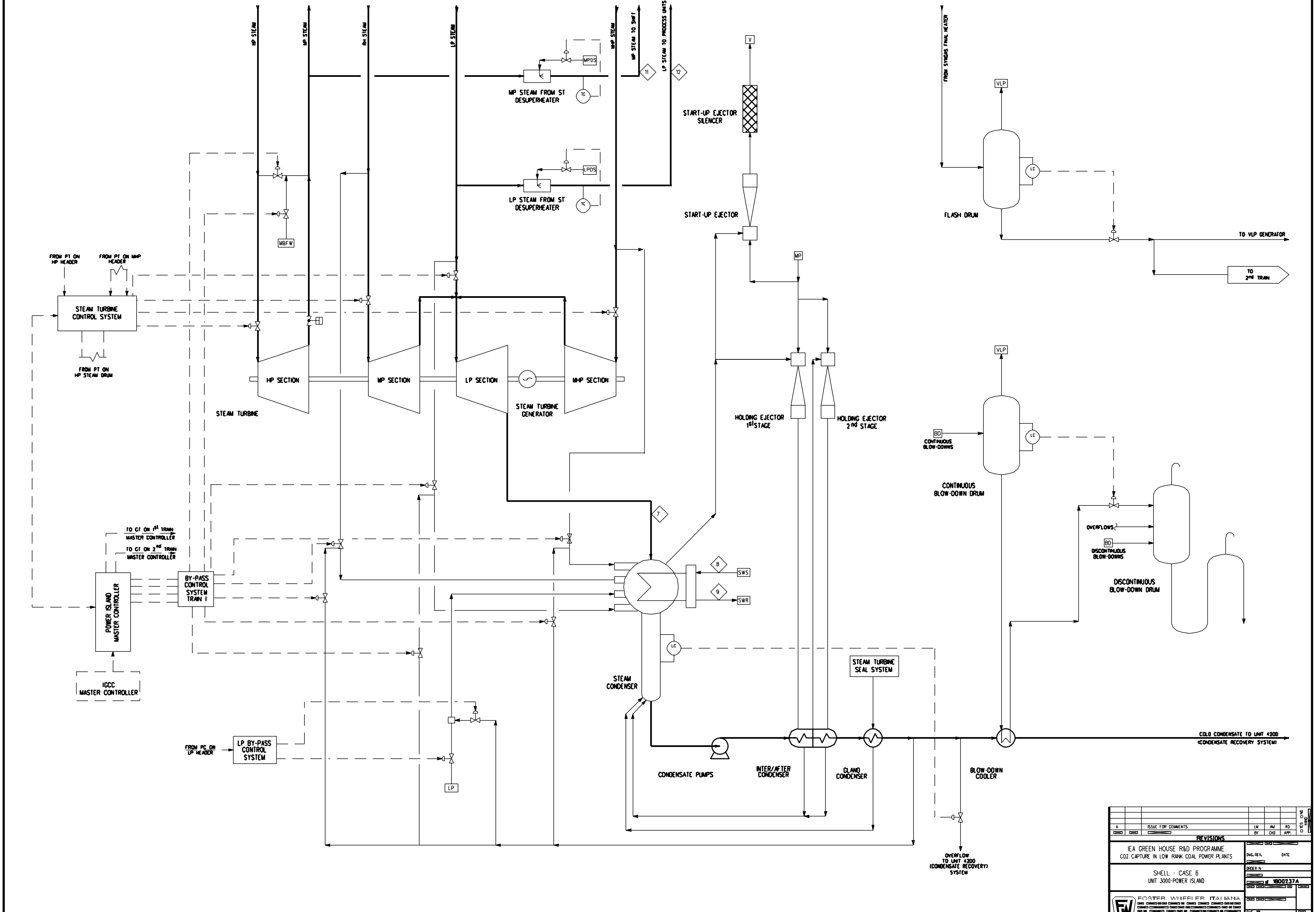

A	ISSUE FOR COMMENTS	LM	AM	RD
		BY	CHD	APP.

REVISIONS

IEA GREEN HOUSE R&D PROGRAMME
CO2 CAPTURE IN LOW RANK COAL POWER PLANTS

SHELL - CASE 6
UNIT 3000-POWER ISLAND

1800237A

FOSTER WHEELER ITALIANA

DWG. Nº 80237A-3-50-3000 A

6.4 Heat and Material Balances

For Heat and Material Balances refer to tables attached in paragraph 6.2.

6.5 Utility Consumption

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

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CLIENT: IEA GHG
PROJECT: CO2 capture in low-rank coal power plants
LOCATION: Germany
FWI Nº:

REVISION	Rev.0	Rev.1	Rev.2	Rev. 3
DATE	Feb-05			
ISSUED BY	P.C.			
CHECKED BY	L.M.			
APPROVED BY	R.D.			

UTILITIES CONSUMPTION SUMMARY - CASE 6 - SHELL LOW PRESSURE GASSIFICATION - MDEA

UNIT	DESCRIPTION UNIT	HP Steam 160 barg [t/h]	MHP Steam 70 barg [t/h]	MP Steam 40 barg sat [t/h]	MP Steam 40 barg SH [t/h]	LP Steam 6.5 barg [t/h]	LP Steam ST extr. 4.7 barg [t/h]	VLP Steam 3.2 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS													
900	Lignite Handling, Milling and Drying						202.0						202.0	
1000	Gasification Section		-387.0						463.1				64.5	11.6
2100	Air Separation Unit					17.1							17.1	
2200	Syngas Treatment and Conditioning line	-91.8		-110.5	289.1	-69.5		-36.2	91.8	110.5	69.5	62.5	26.3	289.1
2300	Acid Gas Removal						150.2						150.2	
3000	**POWER ISLANDS UNITS**	91.8	387.0	110.5	-289.1	42.9	-352.2	36.2	-554.9	-110.5	-69.5	-62.5		
4100 to 5300	**UTILITY and OFFSITE UNITS**					9.4							9.4	
	BALANCE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	469.5	300.7

Note: Minus prior to figure means figure is generated

	CLIENT:	IEA GHG	Rev Final
	PROJECT:	CO2 Capture in Low-rank Coal Power Plants	Nov 05
	LOCATION:	Germany	ISSUED BY: PC.
	FWI Nº:		CHECKED BY: LM
			APPR. BY: RD

ELECTICAL CONSUMPTION SUMMARY - Case 6 - Shell - Combined removal of H_2S and CO_2

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	Coal Storage and Handling and Drying	1009
950	Coal Drying (Air fan consumption)	979
1000	Gasification Section	15906
2100	Air Separation Unit	117752
2200	Syngas treatment and conditioning line	1980
2300	Acid Gas Removal	13144
2500	CO_2 Compression and Drying	56480
	POWER ISLANDS UNITS	
3100/3400	Gas Turbines, Generator auxiliaries and Step-up transformer losses	960
3200	Heat Recovery Steam Generator	8660
3300/3400	Steam Turbines, Generator auxiliaries and Step-up transformer losses	250
3500	Miscellanea	484
	UTILITY and OFFSITE UNITS 4100/5200	
4100	Cooling Water (Cooling Towers Make up / Machinery Water)	18854
4200	Demineralized/Condensate Recovery/Plant and Potable Water Systems	866
4600	Waste Water Treatment	476
	Other Units	245
	BALANCE	**238,046**

CLIENT:	IEA GHG	Rev 0
PROJECT:	CO2 Capture in Low-rank Coal Power Plants	Feb 05
LOCATION:	Germany	ISSUED BY: PC.
FWI Nº:		CHECKED BY: LM
		APPR. BY: RD

WATER CONSUMPTION SUMMARY - Case 6 -Shell - CO_2 capture, combined removal of H_2S and CO_2

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water [t/h]
	PROCESS UNITS			
1000	**Gasification Section**			311
2100	**Air Separation Unit**			13930
2200	**Syngas Treatment and Conditioning line**			0
2300	**Acid Gas Removal**			5512
2500	**CO_2 Compression and Drying**			6455
	POWER ISLANDS UNITS			
3100/3400	**Gas Turbines and Generator auxiliaries**			
3200	**Heat Recovery Steam Generator**			
3300/3400	**Steam Turbine and Generator auxiliaries**		304	33271
3500	**Miscellanea**			1573
	UTILITY and OFFSITE UNITS 4100/5200			
4100	**Cooling Water (Cooling Towers Make Up)**	1495		
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	324	-324	
4600	**Waste Water Treatment**	-71 (1)		
	Other Units		20	352
	BALANCE	1748	0	61404

Notes: Minus prior to figure means figure is generated

(1) Raw Watewr for Demineralized Water Plant

6.6 IGCC Overall Performance

The following Table shows the overall performance of the IGCC Complex.

SHELL

Low pressure Gasification - MDEA Alternative

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (A.R.)	t/h	624.2
Coal LHV (A.R.)	kJ/kg	10500.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1820.5**
Thermal Power of Raw Syngas exit Scrubber (based on LHV)	MWt	1648.5
Thermal Power of Clean Syngas to Gas Turbines (based on LHV)	MWt	1467.5
Syngas treatment efficiency	%	89.0
Gas turbines total power output (@ gen terminals)	MWe	572.0
Steam turbine power output (@ gen terminals)	MWe	296.7
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**868.7**
ASU power consumption	MWe	117.8
Process Units consumption	MWe	32.7
Utility Units consumption	MWe	20.1
Offsite Units consumption (including cooling tower system)	MWe	0.6
Power Islands consumption	MWe	10.3
CO_2 Compression and Drying	MWe	56.5
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**238.0**
NET ELECTRIC POWER OUTPUT OF IGCC (C) (Step Up transformer efficiency = 0.997%)	**MWe**	**628.8**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**47.7**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.5**

The following Table shows the overall CO_2 removal efficiency of the IGCC Complex.

	Equivalent flow of CO_2, kg/h
Carbon incoming (Coal carbon = 57.19%wt)	16,297
Slag	100
Net Carbon Flowing to Process Units (A)	16,197
Liquid Storage	
CO	4
CO2	13,792
Total to storage (B)	13,796
Emission	
CO	6
CO2	2,395
Total Emission	2,401
Overall CO_2 removal efficiency, % (B/A)	85.2

6.7 Environmental Impact

The IGCC Complex is designed to process coal, whose characteristic are shown at Section B - para 2.0, 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 IGCC Complex 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 of the two trains of the Power Island, proceeding from the combustion of the Syngas in the two gas turbines, and emission from the coal Drying process.

Table 6.1 summarises expected flow rate and concentration of the combustion flue gas from one train of the Power Island.

Table 6.1 – Expected gaseous emissions from one train of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	697.6
Flow, $Nm^3/h^{(1)}$	2,500,215
Temperature, °C	129
Composition	(%vol)
Ar	0.91
N_2	74.84
O_2	11.17
CO_2	1.31
H_2O	11.77
Emissions	$mg/Nm^{3\ (1)}$
NOx	74
SOx	1.2
CO	31.3
Particulate	5

(1) Dry gas, O_2 content 15%vol

Both the Combined Cycle Units have the same flue gas composition and flow rate. The total gaseous emissions of the Power Island are given in Table 6.2.

Table 6.2 – Expected total gaseous emissions of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	1,395.2
Flow, $Nm^3/h^{(1)}$	5,000,430
Temperature, °C	129
Emissions	kg/h
NOx	375.0
SOx	6.0
CO	156.5
Particulate	25.0

(1) Dry gas, O2 content 15%vol

In normal operation at full load, the following emission to the atmosphere is foreseen from the Coal Drying Process:

Flow rate : 2029.9 t/h
Particulate : <10 mg/Nm^3, wet basis.

<u>Minor Emissions</u>

Other minor gaseous emissions are the process vents and fugitive emissions. Some of the vent points emit continuously; others during process upsets or emergency conditions only. All vent streams containing, potentially, undesirable gaseous components are sent to a flare system. Venting via the flare will be minimal during normal operation, but will be significant during emergencies, process upsets, start up and shutdown.

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). Proper design and operation reduce these emissions to a very low level.

6.7.2 Liquid Effluent

<u>Waste Water Treatment (Unit 4600)</u>

The expected flow rate, from the Reverse Osmosis, discharged together with the cooling towers blowdown, is as follows:

- Flow rate : 48 m^3/h

Cooling Water System

Raw water is used for the cooling towers make up.
Main characteristics of the Cooling Towers blowdown are listed in the following:

- Maximum flow rate : 300 m^3/h
- Temperature : 11 °C
- Cooling Tower Concentration factor : 5

6.7.3 Solid Effluent

The plant is expected to produce the following solid by-products:

Slag

Flow rate	:	10.8	t/h (dry flow rate)
Water content	:	10	%wt

Slag product can be sold to be commercially used as major components in concrete mixtures to make road, pads, storage bins.

Fly ash

Flow rate	:	12.3	t/h

Fly ash can be dispatched to cement industries.

6.8 Equipment List

The list of main equipment and process packages are included in this section.

		CLIENT:	IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0		
FOSTER WHEELER		LOCATION:		DATE	Feb. 05		
		PROJ. NAME:	CO2 Capture in Low-rank coal Power Plants	ISSUED BY	P.C.		
		CONTRACT N.		CHECKED BY	L.M.		
				APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2100 - Air Separation Unit - SHELL - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				shell / tube	shell / tube		
1		**1st Nitrogen heater**	Shell & Tube						
2		**1st Nitrogen heater**	Shell & Tube						
1		**2nd Nitrogen heater**	Shell & Tube						
2		**2nd Nitrogen heater**	Shell & Tube						
		PACKAGES							
		Air Separation Unit Package (two parallel trains, each sized for 50% of the capacity)							

	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.2	Rev.3
FOSTER WHEELER	LOCATION:	DATE	Feb. 05		
	PROJ. NAME: CO2 Capture in Low-rank coal Power Plants	ISSUED BY	P.C.		
	CONTRACT N.	CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - SHELL -CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				Shell/tube	Shell/tube		
1		**Feed/ Product Exchanger**	Shell & Tube						
2		**Feed/ Product Exchanger**	Shell & Tube						
1		**HP Steam Generator**	Kettle						
2		**HP Steam Generator**	Kettle						
1		**MP Steam Generator**	Kettle						
2		**MP Steam Generator**	Kettle						
1		**MP Steam Generator**	Kettle						
2		**MP Steam Generator**	Kettle						
1		**LP Steam Generator**	Kettle						
2		**LP Steam Generator**	Kettle						

		CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: PROJ. NAME: CO2 Capture in Low-rank coal Power Plants CONTRACT N.	REVISION	Rev.0	Rev.2	Rev.3
			DATE	Feb. 05		
			ISSUED BY	P.C.		
			CHECKED BY	L.M.		
			APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - SHELL -CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS (Continued)				Shell/tube	Shell/tube		
1		**VLP Steam Generator**	Kettle						
2		**VLP Steam Generator**	Kettle						
1		**Condensate Preheater**	Shell & Tube						
2		**Condensate Preheater**	Shell & Tube						
1		**Final Cooler**	Shell & Tube						
2		**Final Cooler**	Shell & Tube						

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: PROJ. NAME: CO2 Capture in Low-rank coal Power Plants CONTRACT N.	REVISION	Rev.0	Rev.2	Rev.3
FOSTER WHEELER		DATE	Feb. 05		
		ISSUED BY	P.C.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - SHELL -CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		DRUMS							
1		**Condensate Separator**	Vertical						
2		**Condensate Separator**	Vertical						
1		**Condensate Separator**	Vertical						
2		**Condensate Separator**	Vertical						
1		**Condensate Separator**	Vertical						
2		**Condensate Separator**	Vertical						
1		**Condensate Separator**	Vertical						
2		**Condensate Separator**	Vertical						

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.2	Rev.3
	LOCATION:	DATE	Feb. 05		
	PROJ. NAME: CO2 Capture in Low-rank coal Power Plants	ISSUED BY	P.C.		
	CONTRACT N.	CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2200 - Syngas Cooling and COS Hydrolisys - SHELL -CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		REACTOR							
1		**Shift Catalyst Reactor - 1st Bed**	vertical						
2		**Shift Catalyst Reactor - 1st Bed**	vertical						
1		**Shift Catalyst Reactor - 2nd Bed**	vertical						
2		**Shift Catalyst Reactor - 2nd Bed**	vertical						
		PACKAGE UNITS							
		Catalyst Loading System							
		Shift Catalyst							

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: PROJ. NAME: CO2 Capture in Low-rank coal Power Plants CONTRACT N.	REVISION	Rev.0	Rev.2	Rev.3
FOSTER WHEELER		DATE	Feb. 05		
		ISSUED BY	P.C.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 3100 - Gas Turbine - SHELL - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				Shell/tube	Shell/tube		
1		**Syngas Final Heater**	Shell & Tube						
2		**Syngas Final Heater**	Shell & Tube						
		DRUMS							
1		**Syngas Final Separator**	vertical						
2		**Syngas Final Separator**	vertical						
		PACKAGES							
1		**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9531 (FA)	286 MW					
2		**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9531 (FA)	286 MW					

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: PROJ. NAME: CO2 Capture in Low-rank coal Power Plants CONTRACT N.	

REVISION	Rev.0	Rev.2	Rev.3
DATE	Feb. 05		
ISSUED BY	P.C.		
CHECKED BY	L.M.		
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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - SHELL - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PUMPS							
1		**LP BFW Pumps**	centrifugal						One operating, one spare
2		**LP BFW Pumps**	centrifugal						One operating, one spare
1		**MP BFW Pumps**	centrifugal						One operating, one spare
2		**MP BFW Pumps**	centrifugal						One operating, one spare
1		**HP BFW Pumps**	centrifugal						One operating, one spare
2		**HP BFW Pumps**	centrifugal						One operating, one spare
1		**VLP BFW Pumps**	centrifugal						One operating, one spare
2		**VLP BFW Pumps**	centrifugal						One operating, one spare
		MISCELLANEA							
1		**Flue Gas Monitoring System**							NOx, CO, SO_2, particulate, H_2O, O_2
2		**Flue Gas Monitoring System**							NOx, CO, SO_2, particulate, H_2O, O_2
1		**CCU Stack**							
2		**CCU Stack**							
1		**Stack Silencer**							
2		**Stack Silencer**							
1		**MP Steam Desuperheater**							Included in 1-HRSG-3201
2		**MP Steam Desuperheater**							Included in 2-HRSG-3201
1		**HP Steam Desuperheater**							Included in 1-HRSG-3201
2		**HP Steam Desuperheater**							Included in 2-HRSG-3201

		CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: PROJ. NAME: CO2 Capture in Low-rank coal Power Plants CONTRACT N.	REVISION	Rev.0	Rev.2	Rev.3
			DATE	Feb. 05		
			ISSUED BY	P.C.		
			CHECKED BY	L.M.		
			APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - SHELL - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
		Fluid Sampling Package							
		Phosphate Injection Package Phosphate storage tank Phosphate dosage pumps							Included in Z - 3202 Included in Z - 3202 One operating , one spare
		Oxygen Scavanger Injection Package Oxygen scavanger storage tank Oxygen scavanger dosage pumps							Included in Z - 3203 Included in Z - 3203 One operating , one spare
		Amines Injection Package Amines Storage tank Amines Dosage pumps							Included in Z - 3204 Included in Z - 3204 One operating , one spare

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: PROJ. NAME: CO2 Capture in Low-rank coal Power Plants CONTRACT N.	REVISION	Rev.0	Rev.2	Rev.3
		DATE	Feb. 05		
		ISSUED BY	P.C.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - SHELL - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAMGENERATOR							
1		**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple Recovery, Reheated.						
1		**HP steam Drum**							Included in 1-HRS-3201
1		**MP steam drum**							Included in 1-HRS-3201
1		**LP steam drum**							Included in 1-HRS-3201
1		**VLP steam drum with degassing section**							Included in 1-HRS-3201
1		**HP Superheater 2nd section**							Included in 1-HRS-3201
1		**MP Reheater 2nd section**							Included in 1-HRS-3201
1		**MHP Superherater**							Included in 1-HRS-3201
1		**HP Superheater 1st section**							Included in 1-HRS-3201
1		**MP Reheater 1st section**							Included in 1-HRS-3201
1		**HP Evaporator**							Included in 1-HRS-3201
1		**HP Economizer 3rd section**							Included in 1-HRS-3201
1		**MP Superheater**							Included in 1-HRS-3201
1		**MP Evaporator**							Included in 1-HRS-3201
1		**LP Superheater**							Included in 1-HRS-3201
1		**MP Economizer 2nd section**							Included in 1-HRS-3201
1		**HP Economizer 2nd section**							Included in 1-HRS-3201
1		**LP Evaporator**							Included in 1-HRS-3201
1		**LP Economizer**							Included in 1-HRS-3201
1		**MP Economizer 1st section**							Included in 1-HRS-3201
1		**HP Economizer 1st section**							Included in 1-HRS-3201
1		**VLP Evaporator**							Included in 1-HRS-3201

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: PROJ. NAME: CO2 Capture in Low-rank coal Power Plants CONTRACT N.	REVISION	Rev.0	Rev.2	Rev.3
		DATE	Feb. 05		
		ISSUED BY	P.C.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - SHELL - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAM GENERATOR							
2		**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple Recovery, Reheated.						
2		**HP steam Drum**							Included in 1-HRS-3201
2		**MP steam drum**							Included in 1-HRS-3201
2		**LP steam drum**							Included in 1-HRS-3201
2		**VLP steam drum with degassing section**							Included in 1-HRS-3201
2		**HP Superheater 2nd section**							Included in 1-HRS-3201
2		**MP Reheater 2nd section**							Included in 1-HRS-3201
2		**MHP Superherater**							Included in 1-HRS-3201
2		**HP Superheater 1st section**							Included in 1-HRS-3201
2		**MP Reheater 1st section**							Included in 1-HRS-3201
2		**HP Evaporator**							Included in 1-HRS-3201
2		**HP Economizer 3rd section**							Included in 1-HRS-3201
2		**MP Superheater**							Included in 1-HRS-3201
2		**MP Evaporator**							Included in 1-HRS-3201
2		**LP Superheater**							Included in 1-HRS-3201
2		**MP Economizer 2nd section**							Included in 1-HRS-3201
2		**HP Economizer 2nd section**							Included in 1-HRS-3201
2		**LP Evaporator**							Included in 1-HRS-3201
2		**LP Economizer**							Included in 1-HRS-3201
2		**MP Economizer 1st section**							Included in 1-HRS-3201
2		**HP Economizer 1st section**							Included in 1-HRS-3201
2		**VLP Evaporator**							Included in 1-HRS-3201

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: PROJ. NAME: CO2 Capture in Low-rank coal Power Plants CONTRACT N.	REVISION DATE ISSUED BY CHECKED BY APPROVED BY	Rev.0 Feb. 05 P.C. L.M. R.D.

EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System - SHELL - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				shell / tube	shell / tube		
		Blow-Down Cooler	Shell & Tube						
		DRUMS							
		Flash Drum	vertical						
		Continuous Blow-down Drum	vertical						
		Discontinuous Blow-down Drum	vertical						
		PACKAGES							
		Steam Turbine & Condenser Package		300 MW					
		Steam Turbine							Included in Z - 3201
		Inter/After condenser							
		Gland Condenser							Included in Z - 3201
		Steam Condenser							Included in Z - 3201
		Steam Turbine Generator							Included in Z - 3201
		Start-up Ejector							Included in Z - 3201
		Holding Ejector 1st Stage							Included in Z - 3201
		Holding Ejector 2nd Stage							Included in Z - 3201
		Condensate Pumps	Centrifugal						Included in Z - 3201 Two operating, one spare
		Start-up Ejector Silencer							Included in Z - 3201
		MISCELLANEA							
1		**LP Steam from ST Desuperheater**							
1		**MP Steam from ST Desuperheater**							

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0		
	LOCATION:	DATE	Feb. 05		
	PROJ. NAME: CO2 Capture in Low-rank coal Power Plants	ISSUED BY	P.C.		
	CONTRACT N.	CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 3400 - Electric Power Generation - SHELL - with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1		**Gas Turbine Generator**							Included in 1 -Z- 3101
2		**Gas Turbine Generator**							Included in 2 -Z- 3101
		Steam Turbine Generator							Included in Z- 3301

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: PROJ. NAME: CO2 Capture in Low-rank coal Power Plants CONTRACT N.	REVISION	Rev.0		
		DATE	Feb. 05		
		ISSUED BY	P.C.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Utility and Offsite Units - SHELL - with CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
	Unit 4100	**Cooling Water System**							
		Machinery Cooling Water System							
	Unit 4200	**Demineralized Water System**							
		Plant and Potable Water System							
	Unit 4300	**Natural Gas System**							
	Unit 4400	**Plant and Instrument Air System**							
	Unit 4600	**Waste Water Treatment**							
	Unit 4700	**Fire Fighting System**							
	Unit 4900	**Chemicals**							
	Unit 6000	**Interconnecting**							
		Instrumentation							
		DCS							
		Piping							
		Electrical							
		400 KV Substation							

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME : CO_2 Capture in Low-rank Coal Power Pants
DOCUMENT NAME : CASE 7 - IGCC BASED ON FOSTER WHEELER GASIFICATION WITH PRECOMBUSTION CO_2 CAPTURE

ISSUED BY : S. RIPANI
CHECKED BY : L. MANCUSO
APPROVED BY : R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by

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 7 IGCC Based on Foster Wheeler gasification

7.1 Introduction

The main features of this alternative for the precombustion CO_2 capture are:
- Low pressure (36.5 barg) FW Gasifier with air as partial oxidation agent;
- CFB Gasifier, Heat Recovery Type;
- Double stage sour Shift;
- Combined removal of H_2S and CO_2, based on the Amine Guard FS process.

The gross production capacity of the IGCC Complex of the study is 900 MWe.

The degree of integration between Air Compression Unit and the Gas Turbines is 30%. The use of air as partial oxidation agent allows the gas turbines working without further syngas dilution with nitrogen, for NO_x control.

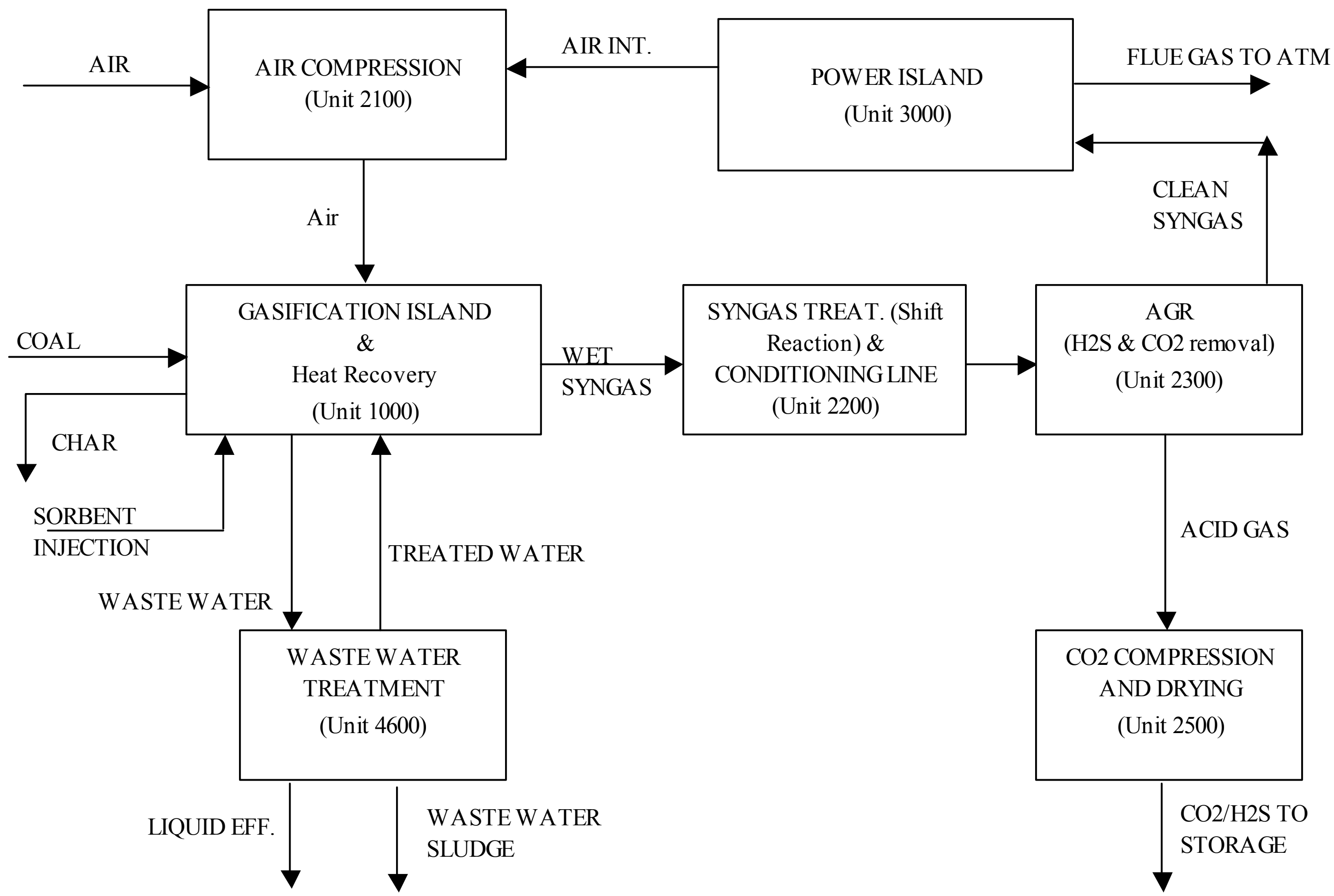
The arrangement of the main process units of the IGCC Complex is as follows:

Unit		Trains
1000	Gasification & Heat Recovery	4 x 33%
	Waste Water Pre-treatment	1 x 100%
2100	Air Compression Unit	2 x 50%
2200	Syngas Treatment and Conditioning Line	3 x 33%
2300	AGR (H_2S and CO_2 Removal)	3 x 33%
2500	CO_2 Compression and Drying	2 x 50%
3000	Gas Turbine (PG 9351 – FA)	2 x 50%
	HRSG	2 x 50%
	Steam Turbine	1 x 100%

Reference is made to the attached overall Block Flow Diagram of the IGCC Complex.

These basic blocks are supported by other ancillary units and a number of utility and offsite units, such as cooling water, flare, plant/instrument air, machinery cooling water, demineralised water, auxiliary fuels, etc.
Each process unit of the Complex may be a single train for the total capacity or split in two, three or more parallel trains, depending on the maximum capacity of the equipment involved or on the necessity to assure, through the use of multiple parallel trains, a superior degree of reliability.

Case 7: FW Gasifier - IGCC COMPLEX Block Flow Diagram



7.2 Process Description

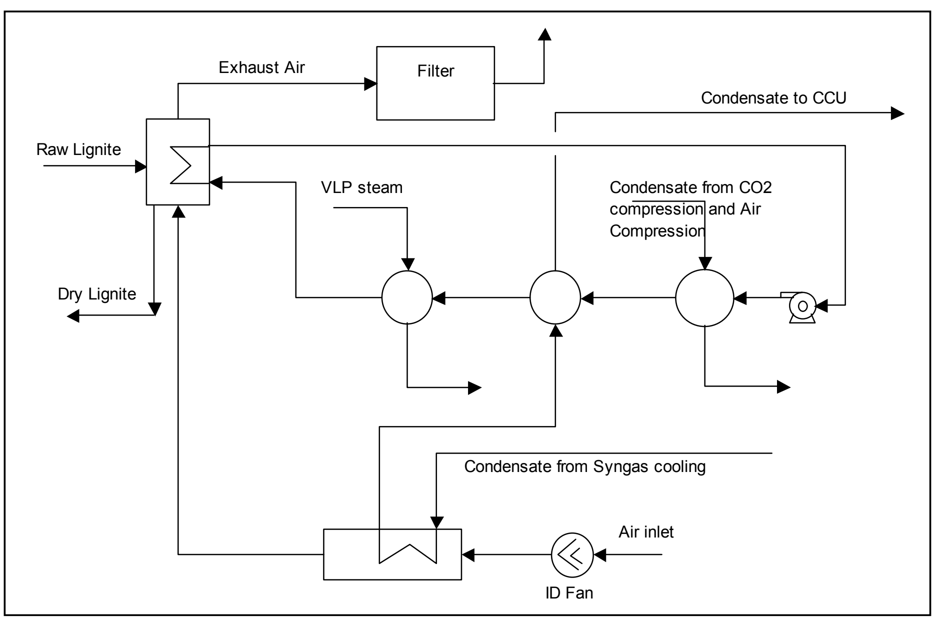
Coal Handling and Storage:

This unit is made up of standard equipment in use, to receive the coal from outside the plant boundary, store the coal, reclaim the same and transport to the plant. For more details see section C, paragraph 1.

Coal Drying:

The FW Gasification technology requires 25% moisture content in the feedstock to the gasifiers. As a lot of low temperature sources exist in plant, the indirect lignite drying method is used for this alternative.

The basic features of this process are shown in Section C, para 2.0.
The process scheme used for this specific alternative is shown in the following scheme.



The split of the heating sources required for the drying of the lignite is reported in the following table:

Heat source	**Duty**, MWth
Syngas cooling	91
CO_2 compression	38
VLP steam (3.2 barg)	16
Air compression	35.5
TOTAL HEAT	**180.5**

Unit 1000: Gasification Island

Feeding system:

The coal feeding system of the CFB Gasifier, operating at pressures ranging between 35 – 40 bara, consists of four coal silos, four mills and conveyor systems and four dosing unit, one for each gasifier.
The recommended particle size is in the range of 1000-2000 μm as larger particle size feed may reduce the carbon conversion and affect the right temperature profile.
By means of conveyor systems, the pulverized coal is passed to a dense-flow feeding system consisting of a sequence of an atmospheric fuel bunker, three lock hoppers and a feeder vessel.
The pulverized fuel settles in the fuel bunker, and the carrier gas and purging gas are vented over the bunker top.
The fuel is pneumatically transported by air in a dense flow to the gasifier burners.

Gasifier:

The feedstock is gasified in a CFB gasifier with air as partial oxidation agent, operating in a temperature range of 900-1000°C. The gasifier is basically a pressurized CFB unit, completely refractory lined, with no heat transfer surfaces. This design lowers the risk of slag attack to a refractory lining and offers long lifetime and low maintenance cost operation. The carbon conversion efficiency is around 97%, lower than the others technologies, thus resulting in a disadvantage of the process. The residual carbon rich char from the gasifier is cooled to approximately 250°C, to avoid auto ignition, depressurized and stored in a dedicated containment vessel. The char residue from the gasifier is suitable for combustion in a PC or CFB boiler; alternatively, the char could also be suitable for landfill disposal, as it is not

classified as a hazardous material. For the development of the present study, it is assumed that char is sent outside for further combustion in a PC or CFB boiler.
CFB gasifiers with 100% carbon conversion efficiency are under investigation and could be patented shortly.

High Temperature Syngas Cooling:

The hot syngas leaving the CFB Gasifier is cooled from 930°C to approximately 390°C before filtration. The syngas cooler transfers heat to the steam cycle generating MHP steam at 80 barg. The industry trend for these coolers is a fire tube design, with gas flowing inside the tubes and steam or water outside, on the shell side. Appropriate design ensures minimum fouling on the gas side, without the need of soot blowing systems.
Downstream the steam generation system, the syngas passes in a cyclone that removes solid particles, then in a ceramic candle filter for the removal of particulate of smaller size. Filtered syngas is used to preheat combustion air up to 316°C, as required by the gasifier, and is further sent to the gas scrubbing at 330°C.

Gas Scrubbing:

Syngas leaving the high temperature cooling section is scrubbed in a wet scrubbing unit to lower the residual fly ash content to a very low level. This system also removes other minor contaminants such as soluble alkali salts and hydrogen halides. To reduce the water consumption of the plant, recycle water from the sour water stripper unit is used. However, make-up water is continuously added to the wet scrubbing unit to control the concentration of the contaminants. The scrubber outlet temperature is lowered down to 160°C, to increase the water content in the syngas (approximately 20%) and reduce the injection of steam for the downstream shift reaction.

Sour Water Stripper:

The Sour Water Stripper separates the sour gases contained in the blow-down water from the Wet Scrubbing unit, as well as other sour water streams like the water condensed from the cooling of the syngas in Unit 2200. Since the column operates under non-fouling conditions, the necessary stripping steam is supplied via a LP steam re-boiler. The vapour leaving the SWS column is sent to an overhead system. In this overhead system the overhead vapours are condensed and the sour gases are separated from the condensate in the gas/liquid separator. The condensed water is routed back to the SWS column, as reflux, above the rectifying bed. The sour gases are routed to Unit 2500 and compressed together with CO_2 captured in the downstream process units. The effluents from the Sour water stripper are split in two parts: the flowrate needed as Gasification make-up is recycled back directly to the gasification, whilst the remaining part flows to the wastewater treatment (Unit 4600).

The main process streams of the Gasification Island relevant to this alternative are summarised in following table:

STREAM	FUEL FEED COAL (25%Moisture)	AIR	STEAM	SORBENT	SATURATED SYNGAS	MHP STEAM GENERATED
Temperature (°C)	AMB.	316	246	15	927	296
Pressure (bar)	38	38	38	38	37	80
TOTAL FLOW						
Mass flow (kg/h)	454200	1064734	32497	8511	1528010	504500
Molar flow (kmol/h)		36868			61458	
Composition (% vol)						
H_2					14.64	
CO					16.65	
CO_2					10.53	
N_2					46.82	
CH_4					1.25	
Ar					0.57	
O_2					0.00	
H_2S + COS					0.05	
H_2O					9.41	
Others					0.08	

Note: Figures referred to the total flowrates.

Unit 2100: Air Compression Unit (ACU)

Compressed air is required by the Gasification Island for the partial oxidation of the coal in the gasifiers. Part of the airflow is also used for the pneumatic transport of dried pulverized coal to the gasifiers.

The Air Compression Unit (Unit 2100) produces air to satisfy the above requirements.

The Plant mainly consists of two air compression trains, integrated with the gas turbines compressors.
When the gasification operates at full load, approx 30% of the air required by the gasifiers is derived from the gas turbine compressors, i.e. the integration between the gas turbines operation and the ACU is achieved at a level where approx 70% of the atmospheric air is compressed with self standing units, being the remaining part coming already pressurized from the compressors of the gas turbines (approx. 14 bars). A second compression stage finally compresses air coming from GTs and first stage up to the required pressure of the gasification island (38 bars).

The air extracted from the gas turbines at high temperature is cooled by exchanging heat with the total airflow rate coming from the last stage of compression, which must be heated to 316°C prior entering the gasifiers.
To reduce the power demand of the compression unit, intercooled stages are used and the heat is recovered for subsequent drying of the lignite.

The main process streams of the Air Compression Unit are summarised in following table:

STREAM	AIR INTAKE FROM ATM (1)	AIR FROM GTs (2)	TOTAL AIR TO GASIFIERS (3)
Temperature (°C)	9	366	316
Pressure (bar)	ATM	14.2	38
TOTAL FLOW			
Mass flow (kg/h)	745314	319420	1064734

Unit 2200: Syngas Treatment and Conditioning Line

This Unit receives the raw syngas from the gasification section, which is contaminated with acid gases, CO_2 and H_2S, and other chemicals, like COS, HCN and NH_3.
Before using this syngas as fuel in the gas turbines it is necessary to remove all the contaminants and prepare the syngas at the proper conditions of temperature, pressure and water content in order to achieve, in the combustion process of the gas turbine, the desired environmental performance and stability of operation.

Saturated raw syngas from wet scrubbing in Unit 1000, at approximately 36 bars and 160°C, enters Unit 2200. The syngas is first heated by the hot shift effluent and then enters the first stage of Shift Reactor, where CO is shifted to H_2 and CO_2, whilst COS is converted to H_2S. In order to meet the required degree of CO_2 removal, a double stage shift containing sulphur tolerant shift catalyst (dirty shift) is used. A large amount of MP steam shall be added to the syngas (227 t/h), before entering the reactors, to allow reaching the required degree of CO conversion. This is a limitation coming from the gasification technology involved, as the air gasification leads to a high nitrogen content in the syngas outlet from the gasification island, thus resulting in a very diluted CO concentration and in a high dry syngas flow rate. In fact, to reach a good CO removal efficiency, a minimum Water on Dry Syngas ratio of approx 0.3 shall be ensured at the outlet of the shift reactors, thus resulting in a high additional steam requirement that corresponds to a considerable loss of power production.

The shift efficiency is 91.4% with respect to the incoming CO and is similar to the other alternatives, but the correspondent CO_2 capture rate of the Plant is less because of the characteristics of the gasification technology involved, being the degree of carbon conversion approximately 97%, instead of more than 99% for the other technologies, and because of the presence of CH_4 in the syngas due to the relatively low combustion temperature.

The exothermic shift reaction brings the syngas temperature outlet from the first stage of the shift reactor up to 350°C. Inlet temperature to the second stage shift is controlled to 275 °C. Outlet temperature from second shift is 305°C. The hot shifted syngas outlet from the second stage is cooled in a series of heat exchangers:
MP Steam Generator
LP Steam Generator
VLP Steam Generator

Condensate Preheater A/B

The final cooling step of the syngas takes place in a cooler, where syngas is cooled with cooling water.

Process condensate collected during the cooling of the condensate is recycled back to the Sour Water Stripper of the Gasification Island.

Unit 2200 is entirely split in three parallel trains, both for the shift reactors and the cooling section, because of the size limitation of the equipment involved.

The main process streams of the Syngas treatment and conditioning line are summarised in following table:

STREAM	SAT SYNGAS (1)	MP GENERATED STEAM (2)	LP GENERATED STEAM (3)	VLP GENERATED STEAM (4)	SYNGAS TO GTs (5)
Temperature (°C)	159	256	175	152	49
Pressure (bar)	36.3	44	9	5	28.5
TOTAL FLOW					
Mass flow (kg/h)	1657187	56300	107800	33060	952848
Molar flow (kmol/h)	68635				50418
Composition (% vol)					
H_2	13.11				36.20
CO	14.90				1.74
CO_2	9.42				2.65
N_2	41.92				56.95
CH_4	1.12				1.52
Ar	0.51				0.69
O_2	0.00				0.00
H_2S + COS	0.05				0.00
H_2O	18.90				0.25
Others	0.07				0.00

Unit 2300: Acid Gas Removal (AGR)

The removal of acid gases, H_2S and CO_2 is an important step of the IGCC operation. In fact, this unit is not only capital intensive and a large consumer of energy, but also is a key factor for the control of the environmental performance of the IGCC. The right selection of the process and of the solvent used to capture the acid gases is important for the performance of the complex.

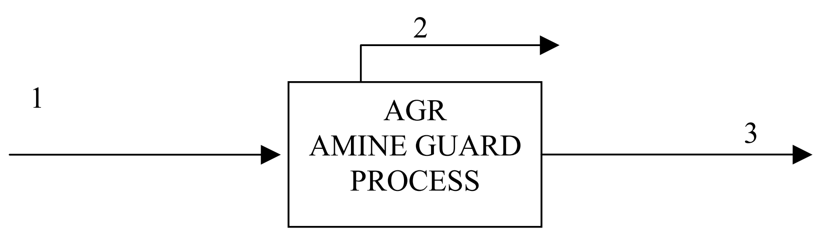
Unit 2300 is characterised by a medium syngas pressure (29 bar g).
Based on considerations of section C, paragraph 8.0, the combined removal of acid gases, H_2S and CO_2, based on the Amine Guard FS process has been selected.
The product of this process is a single stream to be compressed and delivered to plant B.L.

Entering Streams

1. Untreated Gas from Syngas Treatment & Conditioning Line

Exit Streams

2. Treated Gas to Gas Turbines
3. CO_2 to compression



The Amine Guard FS solvent consumption, to make-up losses, is 93 m^3/year.

The proposed process matches the process specification with reference to H_2S+COS concentration of the treated gas exiting the Unit (H_2S+COS concentration is less than 3 ppm). This is due to the integration of CO_2 removal with the H_2S removal, which makes available a large circulation of the solvent.

The CO_2 removal rate is 91.5% as required, allowing reaching an overall CO_2 capture of 82.9% with respect to the carbon entering the Process Units.

These performances for the H_2S removal and CO_2 capture are achieved with large LP steam consumption.

Together with CO_2/H_2S exiting the Unit, the following quantity of hydrogen is lost:

- 86 kmol/h of Hydrogen, corresponding to 0.55% vol and to an overall thermal power of approx 5.8 MWth, i.e. more than 1.8 MWe.

The feasibility to separate and recover H_2 during the CO_2 compression was investigated. Due to the similar equilibrium constants of CO_2 and H_2 at super-critical CO_2 conditions, this separation is unfeasible.

The main process streams of the AGR Unit are summarised in following table:

STREAM	RAW SYNGAS (1)	TREATED SYNGAS (2)	CO_2 RICH STREAM (3)
Temperature (°C)	38	38	49
Pressure (bar)	30	29	1.8
TOTAL FLOW			
Molar flow (kmol/h)	65143	50418	15766
Composition (% vol)			
H_2	28.16	36.20	0.55
CO	1.36	1.74	0.02
CO_2	24.26	2.65	91.77
CH_4	1.18	1.52	0.00
N_2	44.17	56.95	0.74
H_2S + COS	0.05	0.00	0.20
Others	0.82	0.94	6.72

Unit 2500: CO_2 Compression and Drying

This Unit is a Package Unit supplied by specialised Vendors. For more details see section C, paragraph 9.0.

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

- Product stream : 641.4 t/h.
- Product stream : 110 bar
- Composition :

	%vol
CO_2	98.41
H_2S	0.22
Others	1.37
TOTAL	100.0

Unit 3000: Power Island

The Power Island is based on two General Electric gas turbines, frame 9001 FA, two Heat Recovery Steam Generators (HRSG), generating steam at 3 pressure levels, and one steam turbine common to the two HRSGs.

The power island configuration is described referring to the Process Flow Diagrams attached to paragraph 7.3.

During normal operation, the clean syngas, coming from Unit 2100 - Syngas Treatment and Conditioning Line, is heated up to 170°C against MP BFW in the syngas final heater dedicated to each Gas Turbine.
Finally, the hot syngas is burnt inside the Gas Turbine to produce electric power; the resulting stream of hot exhaust gas is conveyed to the Heat Recovery Steam Generator, located downstream each Gas Turbine.

Compressed air is extracted from the Gas Turbines and delivered to Air Compression Unit, reaching 30% of integration.
The flue gas stream at a temperature of about 570°C flows through the coils inside the HRSG, generating steam at three different pressure levels, cooled down to about 129°C and then discharged to the atmosphere through a stack common to the 2 HRSG Units.

The turbine consists of HP, IP and LP sections all connected to the generator on a single shaft. HP steam from the HRSG HP section enters the turbine at approx. 156 bar, 550°C. Steam from the exhaust of the HP turbine is returned to the HRSG for reheating, after mixing with MP steam, and is then throttled into the IP turbine at approx. 36 bar, 530°C. Exhaust steam from IP flows into a LP turbine after mixing with superheated LP steam from HRSG and then downward into the condenser at 0.032 bar (25°C).

The MHP saturated steam (80 bars) from the gasification island is superheated in a dedicated coil and sent to a dedicated ST section where is expanded to 5.7 bar. The exhaust steam is mixed with the exhaust steam from the ST IP section and flows to the ST LP main section. This Steam Turbine is coupled to the same generator of the main steam turbine. A dedicated clutch allows isolating the smaller steam turbine during the start-up of the plant.

When the clean syngas production is not sufficient to satisfy the appetite of both Gas Turbines it is possible to co-fire natural gas or to switch to natural gas one or both Gas Turbines.
This could happen in case of partial or total failure of the Gasification/Gas Treatment units of the IGCC and during start-up.
The selected machines are suitable to co-fire syngas and natural gas from 20% to 100% load.

During Natural Gas Operation no air extraction is foreseen, while a stream of MP Steam has to be injected into the combustion chambers of the Gas Turbines to reduce the NO_x emissions.

During normal operation on Natural Gas, the Power Island does not export/import to/from IGCC Process Units any steam/water stream and no low temperature heat can be recovered in Process Units. Then all cold condensate coming from Steam Condenser can be directly sent to the deaerator after polishing. In this situation, the degassing steam demand of the deaerator is very high, more than VLP steam produced by HRSG's that needs to be integrated with steam coming from LP and MP heaters.

The interfaces considered (during normal operating case) between the power island and the rest of the plant are as follow:

- Compressed Air : Air sent to Unit 2100 – Air Compression Unit.
- MHP steam (80 barg) : Steam imported from Gasification Island.
- MP steam (40 barg) : Saturated Steam imported from Syngas Treatment and Conditioning Line.
- SHMP steam (40 barg): Superheated Steam from the Steam Turbine exported to Syngas Treatment and Conditioning Line to meet the water requirement of the shift reaction.
- LP steam (6,5 barg): Steam imported from Syngas Treatment and Conditioning Line. Steam is also exported to the Utility and Offsite Units.
- LP steam (4.7 barg): Steam exported from the Steam Turbine to the Acid Gas Removal Unit.

- VLP steam (3,2 barg): The total steam generated in Syngas Treatment and Conditioning Line is used in the Lignite drying section.
- BFW : HP, MP, LP, VLP Boiler Feed Water is exported to the Process Units to generate the above mentioned steam production.
- Process Condensate : All the condensate recovered from the condensation of the steam utilised in the Process Unit is recycled back to the HRSG after polishing in Unit 4200, Demi Water/Condensate Recovery.
- Condensate from ST : All the Condensate from the Condenser is exported to the polishing unit (Unit 4200), pre-heated in the Syngas Cooling and Conditioning Line, partially cooled in the Lignite drying section and recycled back to the HRSG.

Flow rate of the steam/water interfaces of the Plant are shown in table attached to para 7.5, Utilities Consumption.

The main process data of the Power Island relevant to this alternative are summarised in following table:

STREAM	SYNGAS (1)	AIR TO ACU (2)	LP STEAM TO ST (3)	MP STEAM TO ST (4)	HP STEAM TO ST (5)	MHP STEAM TO ST (6)
Temperature (°C)	170	396	238	527	550	517
Pressure (bar)	28	14,2	5,7	36	156	77
TOTAL FLOW						
Mass flow (t/h)	476.4 (1)	159.7 (1)	114.4	363.0	377.1	504.5

STREAM	MP STEAM TO SHIFT REACTOR (7)	LP STEAM TO AGR (8)	COND. FROM ST (9)	COOLING WATER TO CND (10)	COOLING WATER FROM CND (11)	FLUE GAS AT STACK (12)
Temperature (°C)	270	170	25	11	21	129
Pressure (bar)	40	5.7	0,03	3	2,3	Amb
TOTAL FLOW						
Mass flow (kg/h)	227.3	222.4	1042.6	38774	38774	2474.7 (1)

(1): For each GT

Unit 4600: Waste Water Treatment

The part of wastewater from the Sour Water stripper, that is not recycled back to the gasification island, flows to the anaerobic treatment, where a phosphoric acid solution is added to the wastewater to support the bacterial growth.

In the Anaerobic Reactor the organic pollutants are biodegraded with production of biological gas and biological sludge. The biogas produced in the reactor is routed to the local flare to be burned.

The biological mass exits the anaerobic reactor and enters the Anaerobic Clarifier where the biomass is separated by gravity from the supernatant.

Effluent from anaerobic section is subject to a further aerobic treatment for the complete removal of ammonia and organic contaminants. The effluent from the anaerobic clarifier is pumped to the denitrification/oxidation tanks where is mixed with the rainwater bleed-off and drainage coming from the deoiling section.

In this deoiling section, the oily drainage mixed with contaminated rainwater is fed by means of pumps from the oil water storage tank to the primary deoiling section, consisting of a Corrugate Plate Interceptor, witch provides gravity separation of free oil and suspended solids carried in the waste water.

The effluent from the separator cells is dosed with polyelectrolyte and is routed by gravity to a secondary deoiling step, consisting of Induced Air Flotation. Air induced by motors driven self-aerating rotors mechanism removes the oil and suspended solids, which are collected in a dense froth to be recycled back to the CPI.
The deoiled water is then pumped to the denitrification/oxidation tanks, where it is mixed with the anaerobic treatment effluent and where the organic contaminants are removed and ammonia is oxidized to nitrates that are further reduced to nitrogen gas in the denitrification section.

The effluent from the oxidation tank enters the aerobic clarifier, where the biomass separates by gravity from the supernatant. The sludge from the bottom of the clarifier is recycled to the anaerobic reactor by the Sludge Pump.

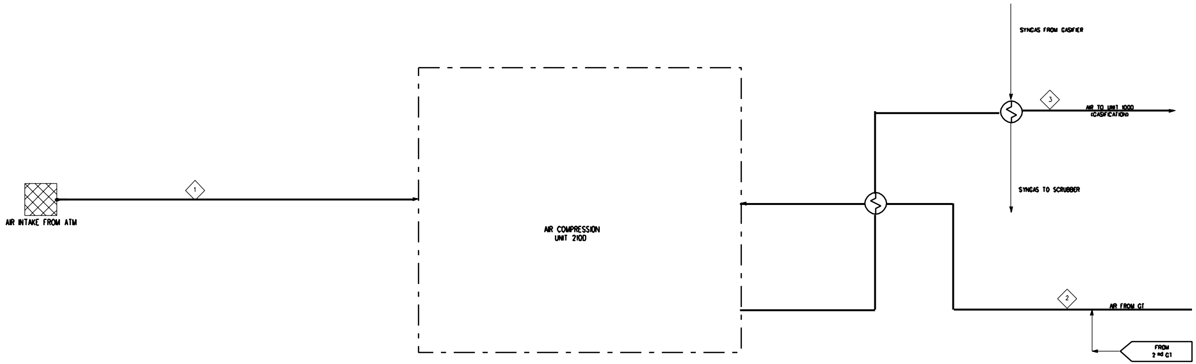
The supernatant from the clarifier is dosed with polyelectrolyte and pumped into Dual Media Filter, which uses sand and anthracite as filter media for the removal of residual hydrocarbons and suspended solids, and into Activated Carbon Filters, for the complete removal of organic contaminants

From the filters the water is sent to a dedicated treatment where the reverse osmosis process allows recovering almost 60% of the treated water. This recovered water is recycled back to the Demi Water System, Unit 4200, and used as raw water for the Demineralised water plant. The remaining 40% of water is discharged together with the cooling towers blowdown.

7.3 Process Flow Diagrams

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

- UNIT 2100: Air Compression Unit (PFD n° BD0237A-3-50-2100)
- UNIT 2200: Syngas Treatment and Conditioning Line (PFD n° BD0237A-3-50-2200);
- UNIT 2300: Acid Gas Removal (PFD n° BD0237A-3-50-2300);
- UNIT 3000: Power Island (PFD n° BD0237A-3-50-3000; sheet 1 and 2).



LEGEND

◇ STREAM NUMBER

A		ISSUE FOR COMMENTS	P.C.	L.M.	R.D.
			BY	CHD	APP.

REVISIONS

IEA GREEN HOUSE R&D PROGRAMME
CO2 CAPTURE IN LOW RANK COAL POWER PLANTS

DWG. REV. DATE

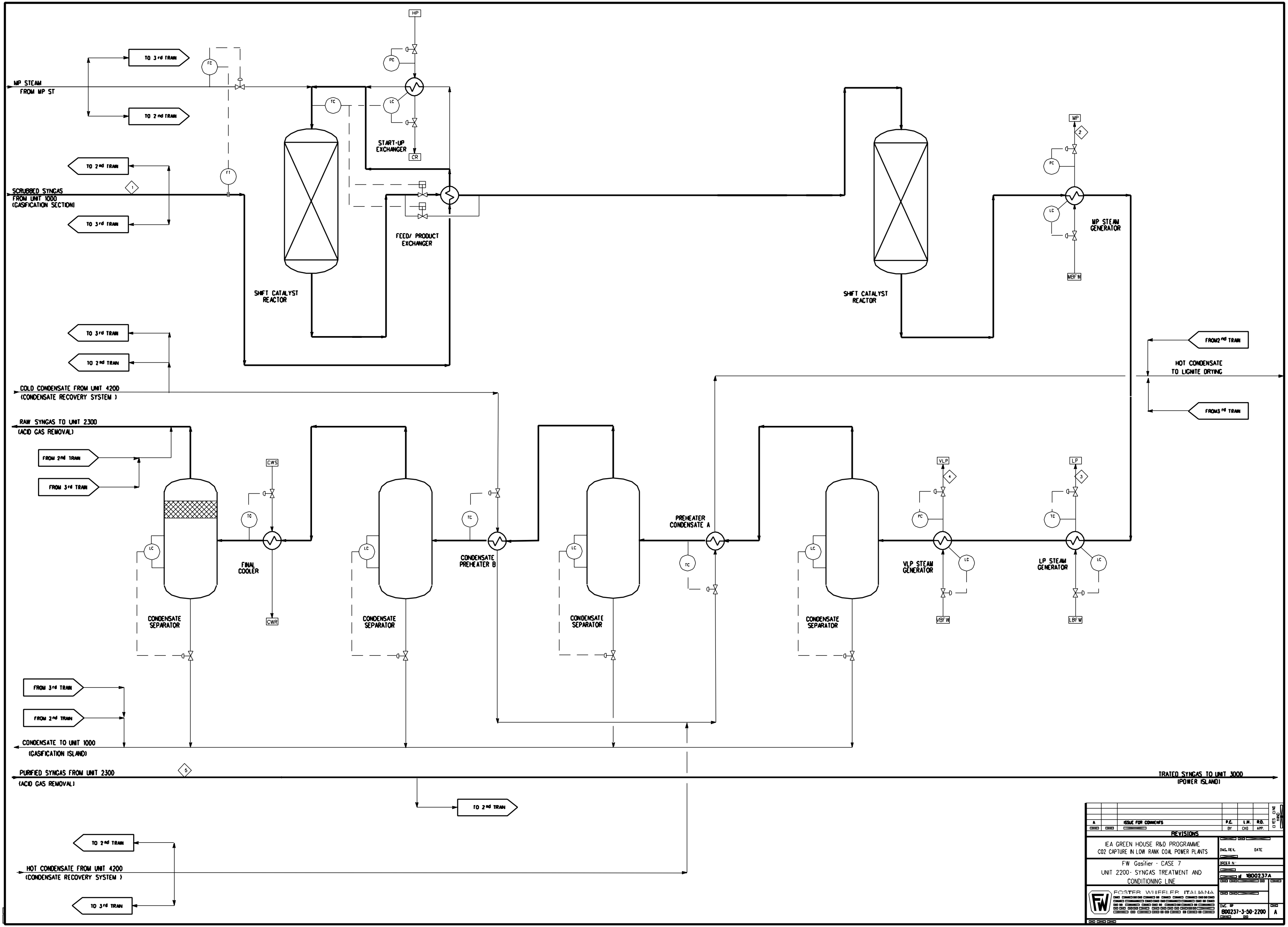
FW GASIFIER - CASE 7
UNIT 2100-AIR COMPRESSION UNIT

ORDER N°

of 1BD0237A

FOSTER WHEELER ITALIANA

DWG. N° 1BD0237A-3-50-2100 A


MP STEAM
FROM MP ST
TO 3rd TRAIN
TO 2nd TRAIN
FC
HP
PC
LC
TC
START-UP
EXCHANGER
CR
FT
TO 2nd TRAIN
SCRUBBED SYNGAS
FROM UNIT 1000
(GASIFICATION SECTION)
TO 3rd TRAIN
FEED/ PRODUCT
EXCHANGER
SHIFT CATALYST
REACTOR
SHIFT CATALYST
REACTOR
MP
PC
LC
MP STEAM
GENERATOR
MBFW
TO 3rd TRAIN
TO 2nd TRAIN
COLD CONDENSATE FROM UNIT 4200
(CONDENSATE RECOVERY SYSTEM)
FROM2nd TRAIN
HOT CONDENSATE
TO LIGNITE DRYING
FROM3rd TRAIN
RAW SYNGAS TO UNIT 2300
(ACID GAS REMOVAL)
FROM 2nd TRAIN
FROM 3rd TRAIN
CWS
TC
FINAL
COOLER
CWR
CONDENSATE
PREHEATER B
PREHEATER
CONDENSATE A
VLP
VLP STEAM
GENERATOR
VBFW
LP
LP STEAM
GENERATOR
LBFW
CONDENSATE
SEPARATOR
CONDENSATE
SEPARATOR
CONDENSATE
SEPARATOR
CONDENSATE
SEPARATOR
FROM 3rd TRAIN
FROM 2nd TRAIN
CONDENSATE TO UNIT 1000
(GASIFICATION ISLAND)
PURIFIED SYNGAS FROM UNIT 2300
(ACID GAS REMOVAL)
TRATED SYNGAS TO UNIT 3000
(POWER ISLAND)
TO 2nd TRAIN
TO 2nd TRAIN
HOT CONDENSATE FROM UNIT 4200
(CONDENSATE RECOVERY SYSTEM)
TO 3rd TRAIN
A
ISSUE FOR COMMENTS
P.C.
L.M.
R.D.
BY
CHD
APP.
REVISIONS
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CO2 CAPTURE IN LOW RANK COAL POWER PLANTS
DWG. REV.
DATE
FW Gasifier - CASE 7
UNIT 2200- SYNGAS TREATMENT AND
CONDITIONING LINE
ORDER N°
1800237A
FOSTER WHEELER ITALIANA
DWG. N°
800237-3-50-2200
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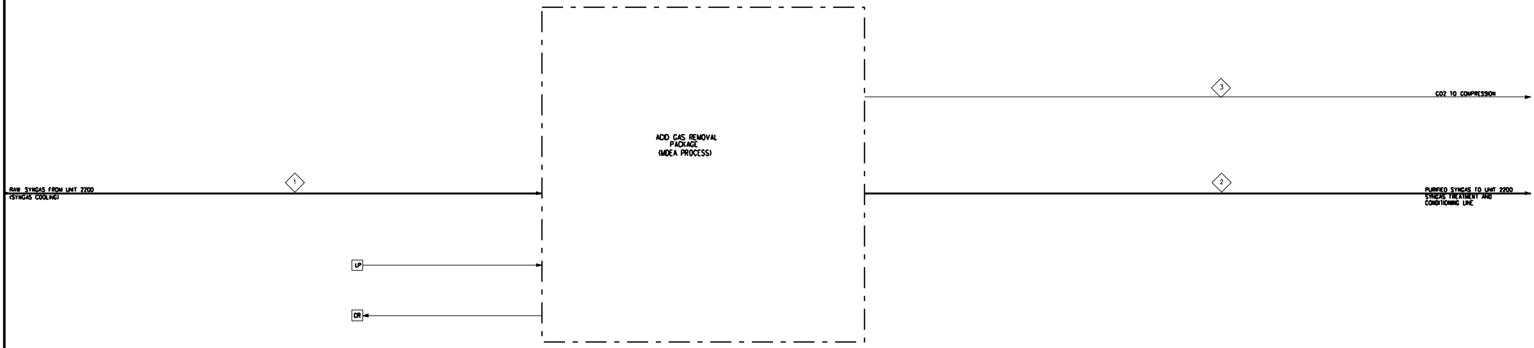

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STREAM NUMBER

A		ISSUE FOR COMMENTS	P.C.	L.M.	R.D.
			BY	CHD	APP.

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CO_2 CAPTURE IN LOW RANK COAL POWER PLANTS

FW GASIFIER - CASE 7
UNIT 2300-ACID GAS REMOVAL

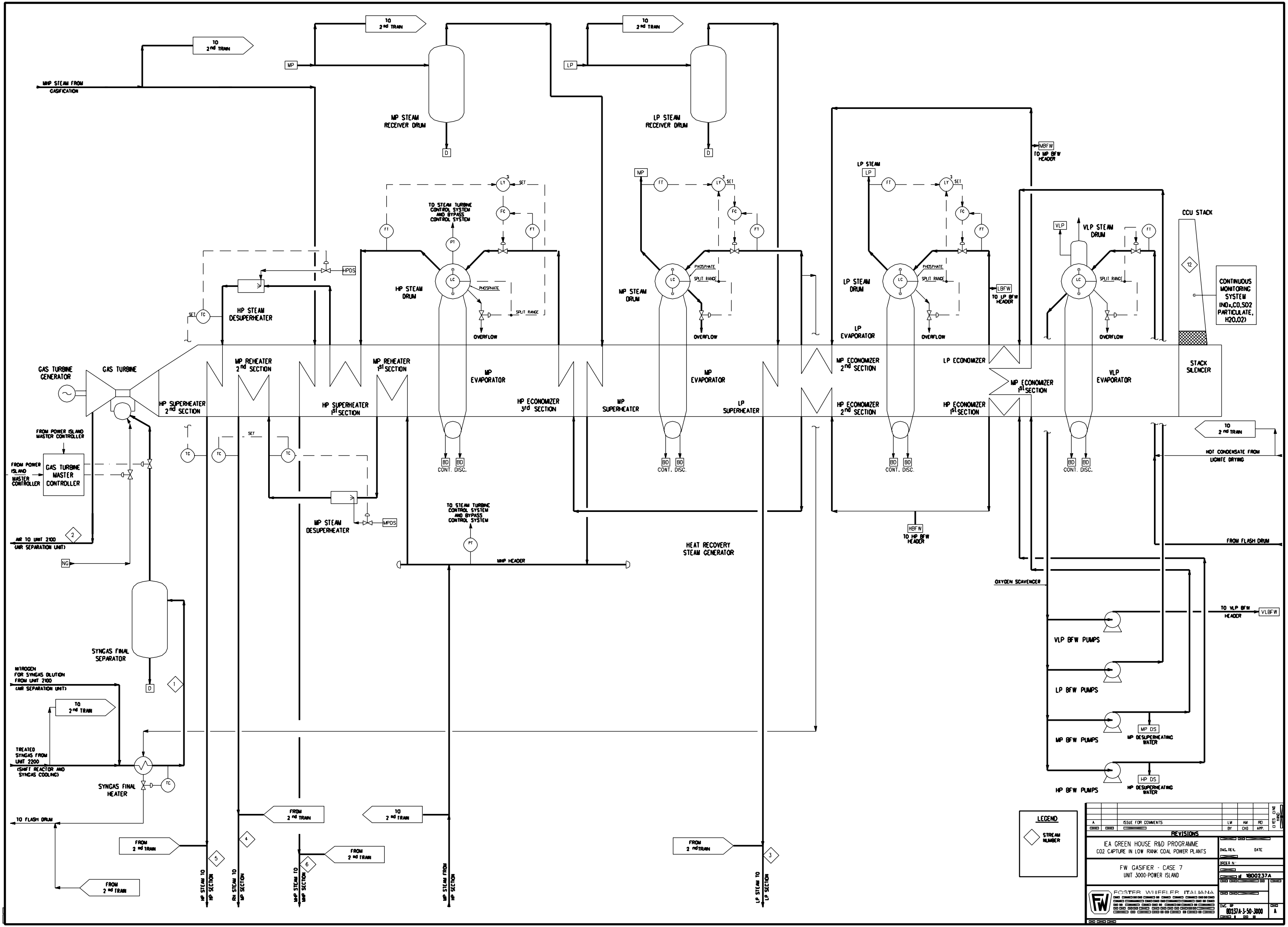
FOSTER WHEELER ITALIANA

DWG. REV. DATE

ORDER N°

1BD0237A

DWG. N° 8D237A-3-50-2300 A



TO 2nd TRAIN
MHP STEAM FROM GASIFICATION
MP
LP
MP STEAM RECEIVER DRUM
LP STEAM RECEIVER DRUM
D
MBFW
TO MP BFW HEADER
LP STEAM
TO STEAM TURBINE CONTROL SYSTEM AND BYPASS CONTROL SYSTEM
HPDS
HP STEAM DESUPERHEATER
HP STEAM DRUM
MP STEAM DRUM
LP STEAM DRUM
VLP STEAM DRUM
VLP
CCU STACK
CONTINUOUS MONITORING SYSTEM (NOx,CO,SO2 PARTICULATE, H2O,O2)
LBFW
TO LP BFW HEADER
PHOSPHATE
SPLIT RANGE
OVERFLOW
LP EVAPORATOR
GAS TURBINE GENERATOR
GAS TURBINE
MP REHEATER 2nd SECTION
MP REHEATER 1st SECTION
HP SUPERHEATER 2nd SECTION
HP SUPERHEATER 1st SECTION
HP EVAPORATOR
HP ECONOMIZER 3rd SECTION
MP SUPERHEATER
MP EVAPORATOR
LP SUPERHEATER
MP ECONOMIZER 2nd SECTION
HP ECONOMIZER 2nd SECTION
LP ECONOMIZER
MP ECONOMIZER 1st SECTION
HP ECONOMIZER 1st SECTION
VLP EVAPORATOR
STACK SILENCER
HOT CONDENSATE FROM LIGNITE DRYING
FROM POWER ISLAND MASTER CONTROLLER
FROM POWER ISLAND MASTER CONTROLLER
GAS TURBINE MASTER CONTROLLER
BD
CONT. DISC.
MP STEAM DESUPERHEATER
MPDS
HBFW
TO HP BFW HEADER
AIR TO UNIT 2100 (AIR SEPARATION UNIT)
NG
MHP HEADER
HEAT RECOVERY STEAM GENERATOR
FROM FLASH DRUM
OXYGEN SCAVENGER
TO VLP BFW HEADER
VLBFW
VLP BFW PUMPS
LP BFW PUMPS
MP BFW PUMPS
MP DS
MP DESUPERHEATING WATER
HP BFW PUMPS
HP DS
HP DESUPERHEATING WATER
SYNGAS FINAL SEPARATOR
NITROGEN FOR SYNGAS DILUTION FROM UNIT 2100 (AIR SEPARATION UNIT)
TREATED SYNGAS FROM UNIT 2200 (SHIFT REACTOR AND SYNGAS COOLING)
SYNGAS FINAL HEATER
TO FLASH DRUM
FROM 2nd TRAIN
HP STEAM TO HP SECTION
RH STEAM TO MP SECTION
MP STEAM TO MP SECTION
MP STEAM FROM HP SECTION
LP STEAM TO LP SECTION
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CO2 CAPTURE IN LOW RANK COAL POWER PLANTS
DWG. REV.
DATE
ORDER N°
FW GASIFIER - CASE 7
UNIT 3000-POWER ISLAND
1BD0237A
FOSTER WHEELER ITALIANA
DWG. Nº
BD237A-3-50-3000
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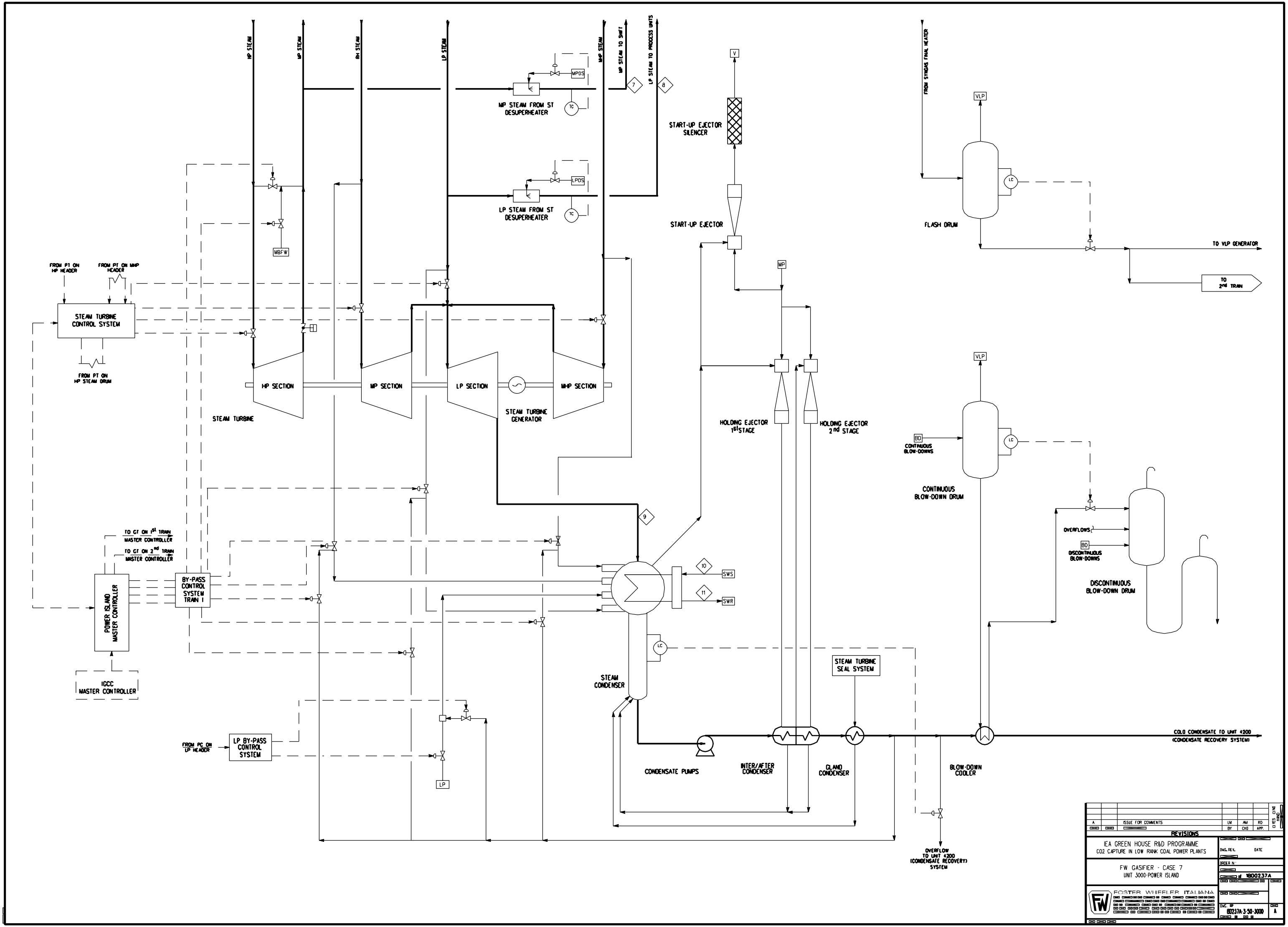

HP STEAM
MP STEAM
RH STEAM
LP STEAM
MHP STEAM
MP STEAM TO SHIFT
LP STEAM TO PROCESS UNITS
7
8
MPDS
TC
MP STEAM FROM ST DESUPERHEATER
LPDS
LP STEAM FROM ST DESUPERHEATER
MBFW
FROM PT ON HP HEADER
FROM PT ON MHP HEADER
STEAM TURBINE CONTROL SYSTEM
FROM PT ON HP STEAM DRUM
HP SECTION
MP SECTION
LP SECTION
MHP SECTION
STEAM TURBINE
STEAM TURBINE GENERATOR
V
START-UP EJECTOR SILENCER
START-UP EJECTOR
MP
HOLDING EJECTOR 1st STAGE
HOLDING EJECTOR 2nd STAGE
FROM SYNGAS FINAL HEATER
VLP
LC
FLASH DRUM
TO VLP GENERATOR
TO 2nd TRAIN
BD
CONTINUOUS BLOW-DOWNS
CONTINUOUS BLOW-DOWN DRUM
OVERFLOWS
DISCONTINUOUS BLOW-DOWNS
DISCONTINUOUS BLOW-DOWN DRUM
TO GT ON 1st TRAIN MASTER CONTROLLER
TO GT ON 2nd TRAIN MASTER CONTROLLER
POWER ISLAND MASTER CONTROLLER
BY-PASS CONTROL SYSTEM TRAIN 1
ICCC MASTER CONTROLLER
9
10
11
SWS
SWR
STEAM CONDENSER
STEAM TURBINE SEAL SYSTEM
FROM PC ON LP HEADER
LP BY-PASS CONTROL SYSTEM
LP
CONDENSATE PUMPS
INTER/AFTER CONDENSER
GLAND CONDENSER
BLOW-DOWN COOLER
COLD CONDENSATE TO UNIT 4200 (CONDENSATE RECOVERY SYSTEM)
OVERFLOW TO UNIT 4200 (CONDENSATE RECOVERY) SYSTEM
A
ISSUE FOR COMMENTS
LM
AM
RD
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CO2 CAPTURE IN LOW RANK COAL POWER PLANTS
FW GASIFIER - CASE 7
UNIT 3000-POWER ISLAND
1800237A
FOSTER WHEELER ITALIANA
80237A-3-50-3000

7.4 Heat and Material Balances

For Heat and Material Balances refer to tables attached in paragraph 7.2.

7.5 Utility Consumption

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

CLIENT:	IEA GHG	REVISION	Rev.0	Rev.1	Rev.2	Rev. 3
PROJECT:	CO_2 capture in low-rank coal power plants	DATE	Jan-05			
LOCATION:	Germany	ISSUED BY	S.R.			
FWI Nº:	1-BD-0237A	CHECKED BY	L.M.			
		APPROVED BY	R.D.			

UTILITIES CONSUMPTION SUMMARY - CASE 7 - FW Gasifier - MDEA

UNIT	DESCRIPTION UNIT	MHP Steam 80 barg [t/h]	MP Steam 40 barg sat [t/h]	MP Steam 40 barg SH [t/h]	LP Steam 6.5 barg [t/h]	VLP Steam 3.2 barg [t/h]	MHP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	VLP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS											
900	Lignite Handling, Milling and Drying					27.0					27.0	
1000	Gasification Section	-504.5	32.5				504.5					32.5
2100	Syngas Treatment and Conditioning line		-56.3	227.3	-107.8	-27.0		56.3	107.8	33.1	6.1	227.3
2200	Acid Gas Removal				222.4						222.4	
3000	POWER ISLANDS UNITS	504.5	23.8	-227.3	-124.4		-504.5	-56.3	-107.8	-33.1		
	UTILITY and OFFSITE UNITS				9.8						9.8	
	BALANCE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	265.2	259.8

Note: Minus prior to figure means figure is generated

	CLIENT:	IEA GHG	Rev Final
FOSTER WHEELER	PROJECT:	CO_2 Capture in Low-rank Coal Power Plants	Nov 05
	LOCATION:	Germany	ISSUED BY: S.R.
	FWI Nº:	1-BD-0237A	CHECKED BY: L.M.
			APPR. BY: R.D.

ELECTICAL CONSUMPTION SUMMARY - Case 7 - FW Gasifier - MDEA

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900-1000	Coal Storage, Handling - Gasification Section	1516
950	Coal Drying (Air fan consumption)	783
2100	Air Compression Unit	106320
2200	Syngas treatment and conditioning line	481
2300	Acid Gas Removal	19465
2500	CO_2 Compression and Drying	59932
	POWER ISLANDS UNITS	
3100/3400	Gas Turbines, Generator auxiliaries and Step-up transformer losses	960
3200	Heat Recovery Steam Generator	6626
3300/3400	Steam Turbines, Generator auxiliaries and Step-up transformer losses	250
3500	Miscellanea	485
	UTILITY and OFFSITE UNITS	
4100	Cooling Water (Cooling Towers Make up / Machinery Water)	13932
4200	Demineralized/Condensate Recovery/Plant and Potable Water Systems	601
4600	Waste Water Treatment	476
	Other Units	50
	BALANCE	**211,877**

	CLIENT:	IEA GHG	Rev 0
FOSTER WHEELER	PROJECT:	CO_2 Capture in Low-rank Coal Power Plants	Jan 05
	LOCATION:	Germany	ISSUED BY: S.R.
	FWI Nº:	1-BD-0237A	CHECKED BY: L.M.
			APPR. BY: R.D.

WATER CONSUMPTION SUMMARY - Case 7 - FW Gasifier - MDEA

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water [t/h]
	PROCESS UNITS			
1000	**Gasification Section**			**3700**
2100	**Air Compression Unit**			**4050**
2200	**Syngas Treatment and Conditioning line**			**7405**
2300	**Acid Gas Removal**			**8162**
2500	**CO_2 Compression and Drying**			**6947**
	POWER ISLANDS UNITS			
3100/3400	**Gas Turbines and Generator auxiliaries**			
3200	**Heat Recovery Steam Generator**			
3300/3400	**Steam Turbine and Generator auxiliaries**		**296**	**38774**
3500	**Miscellanea**			**1630**
	UTILITY and OFFSITE UNITS			
4100	**Cooling Water (Cooling Towers Make Up)**	**1062**		
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**316**	**-316**	
4600	**Waste Water Treatment**	**-89**		
	Other Units		**20**	**504**
	BALANCE	**1289**	**0**	**71173**

Notes: Minus prior to figure means figure is generated

7.6 IGCC Overall Performance

The following Table shows the overall performance of the IGCC Complex.

FW GASIFIER

Case 7

OVERALL PERFORMANCES OF THE IGCC COMPLEX		
Coal Flowrate (A.R.)	t/h	691.0
Coal LHV (A.R.)	kJ/kg	10500.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2015.4**
Thermal Power of Raw Syngas exit Scrubber (based on LHV)	MWt	1585.4
Thermal Power of Clean Syngas to Gas Turbines (based on LHV)	MWt	1467.2
Syngas treatment efficiency	%	92.5
Gas turbines total power output (@ gen terminals)	MWe	580.0
Steam turbine power output (@ gen terminals)	MWe	320.5
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (D)	**MWe**	**900.5**
Air Compression for Gasification	MWe	106
Process Units consumption	MWe	21.9
Utility Units consumption	MWe	14.9
Offsite Units consumption (including cooling tower system)	MWe	0.5
Power Islands consumption	MWe	8.3
CO_2 Compression and Drying	MWe	59.9
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**211.9**
NET ELECTRIC POWER OUTPUT OF IGCC (C) (Step Up transformer efficiency = 0.997%)	**MWe**	**686.6**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**44.7**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**34.1**

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

	Equivalent flow of CO_2 kmol/h
Coal (Carbon = 47.66%wt)	18038
Limestone	84
Slag	661
Net Carbon flowing to Process Units (A)	17461
Liquid Storage	
CO	3.5
CO_2	14471.0
Total to storage (B)	14474.5
Emission	
CO_2	2986.5
CO	0.0
Total Emission	2986.5
Overall CO_2 removal efficiency, % (B/A)	82.9

The removal efficiency of 82.9% of the incoming carbon is lower than the other IGCC technologies, where approx. 85% has been considered. The reasons of this lower efficiency are attributable to the gasification technology of the alternative and are mainly listed in the following:

- Lower carbon conversion of the CFB Gasifier (approx. 97%), compared to more than 99% of the other technologies (see also paragraph 7.2, Unit 1000), which reduces the amount of carbon entering the downstream process units.
- Presence of CH_4 in the syngas generated in the gasifier, because of the low gasification temperature (<1000°C); methane is not affected by the shift reaction and is not captured by the downstream Acid Gas Removal Section.

7.7 Environmental Impact

The IGCC Complex is designed to process coals, whose characteristic are shown at Section B - para 2.0, and produce electric power. The advanced technology allows reaching a high efficiency and minimising environmental impact.

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

7.7.1 Gaseous Emissions

Main Emissions

In normal operation at full load, the main continuous emissions are the combustion flue gases of the two trains of the Power Island, proceeding from the combustion of the Syngas in the two gas turbines, and emission from the coal Drying process.

Table 7.1 summarises expected flow rate and concentration of the combustion flue gas from one train of the Power Island.

Table 7.1 – Expected gaseous emissions from one train of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	687.4
Flow, $Nm^3/h^{(1)}$	2,847,775
Temperature, °C	129
Composition	(%vol)
Ar	0.88
N_2	76.02
O_2	10.09
CO_2	1.67
H_2O	11.34
Emissions	$mg/Nm^{3\ (1)}$
NOx	74
SOx	1.2
CO	31.4
Particulate	5

(1) Dry gas, O_2 content 15%vol

Both the Combined Cycle Units have the same flue gas composition and flow rate. The total gaseous emissions of the Power Island are given in Table 7.2.

Table 7.2 – Expected total gaseous emissions of the Power Island.

	Normal Operation
Wet gas flow rate, kg/s	1,395.2
Flow, $Nm^3/h^{(1)}$	5,695,550
Temperature, °C	129
Emissions	kg/h
NOx	421.5
SOx	6.8
CO	178.8
Particulate	28.5

(1) Dry gas, O2 content 15%vol

In normal operation at full load, the following emission to the atmosphere is foreseen from the Coal Drying Process:

Flow rate : 1601 t/h
Particulate : <10 mg/Nm^3, wet basis.

<u>Minor Emissions</u>

Other minor gaseous emissions are the process vents and fugitive emissions.
Some of the vent points emit continuously; others during process upsets or emergency conditions only. All vent streams containing, potentially, undesirable gaseous components are sent to a flare system. Venting via the flare will be minimal during normal operation, but will be significant during emergencies, process upsets, start up and shutdown.

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). Proper design and operation reduce these emissions to a very low level.

7.7.2 Liquid Effluent

Waste Water Treatment (Unit 4600)

The expected flow rate, from the Reverse Osmosis, discharged together with the cooling towers blowdown, is as follows:

- Flow rate : 268.4 m^3/h

Cooling Water System

Raw water is used for the cooling towers make up.
Main characteristics of the Cooling Towers blowdown are listed in the following:

- Maximum flow rate : 209 m^3/h
- Temperature : 11 °C
- Cooling Tower Concentration factor : 5

7.7.3 Solid Effluent

The plant is expected to produce the following solid by-products:

Char

Flow rate : 40 t/h (dry flow, including 6.8 t/h of unreacted carbon).

The char sorbent residue from the gasifier is sent to an outside plant for further combustion in a PC or CFB boiler.

7.8 Equipment List

The list of main equipment and process packages are included in this section.

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1-BD-0237A	REVISION	Rev.0		
		DATE	Feb. 05		
		ISSUED BY	S.R.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2100 - Air Compression Unit - FW Gasifier - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				shell / tube	shell / tube		
		PACKAGES							
		Air Compression Unit Package (two parallel trains, each sized for 50% of the capacity)							

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1-BD-0237A	REVISION	Rev.0	Rev.2	Rev.3
		DATE	Feb. 05		
		ISSUED BY	S.R.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2200 - Syngas Treatment & Conditioning Line - FW Gasifier - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				Shell/tube	Shell/tube		
1		**Feed/ Product Exchanger**	Shell & Tube						
2		**Feed/ Product Exchanger**	Shell & Tube						
3		**Feed/ Product Exchanger**	Shell & Tube						
1		**MP Steam Generator**	Kettle						
2		**MP Steam Generator**	Kettle						
3		**MP Steam Generator**	Kettle						
1		**LP Steam Generator**	Kettle						
2		**LP Steam Generator**	Kettle						
3		**LP Steam Generator**	Kettle						

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1-BD-0237A	

REVISION	Rev.0	Rev.2	Rev.3
DATE	Feb. 05		
ISSUED BY	S.R.		
CHECKED BY	L.M.		
APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2200 - Syngas Treatment & Conditioning Line - FW Gasifier - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS (Continued)				Shell/tube	Shell/tube		
1		**VLP Steam Generator**	Kettle						
2		**VLP Steam Generator**	Kettle						
3		**VLP Steam Generator**	Kettle						
1		**Condensate Preheater**	Shell & Tube						
2		**Condensate Preheater**	Shell & Tube						
3		**Condensate Preheater**	Shell & Tube						
1		**Final Cooler**	Shell & Tube						
2		**Final Cooler**	Shell & Tube						
3		**Final Cooler**	Shell & Tube						

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1-BD-0237A	REVISION	Rev.0	Rev.2	Rev.3
		DATE	Feb. 05		
		ISSUED BY	S.R.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2200 - Syngas Treatment & Conditioning Line - FW Gasifier - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		DRUMS							
1		Condensate Separator	Vertical						
2		Condensate Separator	Vertical						
3		Condensate Separator	Vertical						
1		Condensate Separator	Vertical						
2		Condensate Separator	Vertical						
3		Condensate Separator	Vertical						
1		Condensate Separator	Vertical						
2		Condensate Separator	Vertical						
3		Condensate Separator	Vertical						
1		Condensate Separator	Vertical						
2		Condensate Separator	Vertical						
3		Condensate Separator	Vertical						

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1-BD-0237A	REVISION	Rev.0	Rev.2	Rev.3
		DATE	Feb. 05		
		ISSUED BY	S.R.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2200 - Syngas Treatment & Conditioning Line - FW Gasifier - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		REACTOR							
1		Shift Catalyst Reactor - 1st Bed	vertical						
2		Shift Catalyst Reactor - 1st Bed	vertical						
3		Shift Catalyst Reactor - 1st Bed	vertical						
1		Shift Catalyst Reactor - 2nd Bed	vertical						
2		Shift Catalyst Reactor - 2nd Bed	vertical						
3		Shift Catalyst Reactor - 2nd Bed	vertical						
		PACKAGE UNITS							
		Catalyst Loading System							
		Shift Catalyst							

		CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1-BD-0237A	REVISION	Rev.0	Rev.2	Rev.3
FOSTER WHEELER			DATE	Feb. 05		
			ISSUED BY	S.R.		
			CHECKED BY	L.M.		
			APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 3100 - Gas Turbine - FW Gasifier - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				Shell/tube	Shell/tube		
1		**Syngas Final Heater**	Shell & Tube						
2		**Syngas Final Heater**	Shell & Tube						
		DRUMS							
1		**Syngas Final Separator**	vertical						
2		**Syngas Final Separator**	vertical						
		PACKAGES							
1		**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9531 (FA)	290 MW					
2		**Gas Turbine & Generator Package** Gas turbine Gas turbine Generator	PG 9531 (FA)	290 MW					

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1-BD-0237A	

REVISION	Rev.0	Rev.2	Rev.3
DATE	Feb. 05		
ISSUED BY	S.R.		
CHECKED BY	L.M.		
APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - FW Gasifier - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PUMPS							
1		**LP BFW Pumps**	centrifugal						One operating, one spare
2		**LP BFW Pumps**	centrifugal						One operating, one spare
1		**MP BFW Pumps**	centrifugal						One operating, one spare
2		**MP BFW Pumps**	centrifugal						One operating, one spare
1		**HP BFW Pumps**	centrifugal						One operating, one spare
2		**HP BFW Pumps**	centrifugal						One operating, one spare
1		**VLP BFW Pumps**	centrifugal						One operating, one spare
2		**VLP BFW Pumps**	centrifugal						One operating, one spare
		MISCELLANEA							
1		**Flue Gas Monitoring System**							NOx, CO, SO_2, particulate, H_2O, O_2
2		**Flue Gas Monitoring System**							NOx, CO, SO_2, particulate, H_2O, O_2
1		**CCU Stack**							
2		**CCU Stack**							
1		**Stack Silencer**							
2		**Stack Silencer**							
1		**MP Steam Desuperheater**							Included in 1-HRSG-3201
2		**MP Steam Desuperheater**							Included in 2-HRSG-3201
1		**HP Steam Desuperheater**							Included in 1-HRSG-3201
2		**HP Steam Desuperheater**							Included in 2-HRSG-3201

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1-BD-0237A	REVISION	Rev.0	Rev.2	Rev.3
		DATE	Feb. 05		
		ISSUED BY	S.R.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - FW Gasifier - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
		Fluid Sampling Package							
		Phosphate Injection Package							
		Phosphate storage tank							Included in Z - 3202
		Phosphate dosage pumps							Included in Z - 3202
									One operating , one spare
		Oxygen Scavanger Injection Package							
		Oxygen scavanger storage tank							Included in Z - 3203
		Oxygen scavanger dosage pumps							Included in Z - 3203
									One operating , one spare
		Amines Injection Package							
		Amines Storage tank							Included in Z - 3204
		Amines Dosage pumps							Included in Z - 3204
									One operating , one spare

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		DATE	Feb. 05		
		ISSUED BY	S.R.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - FW Gasifier - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAMGENERATOR							
1		**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple Recovery, Reheated.						
1		**HP steam Drum**							Included in 1-HRS-3201
1		**MP steam drum**							Included in 1-HRS-3201
1		**LP steam drum**							Included in 1-HRS-3201
1		**VLP steam drum with degassing section**							Included in 1-HRS-3201
1		**HP Superheater 2nd section**							Included in 1-HRS-3201
1		**MP Reheater 2nd section**							Included in 1-HRS-3201
1		**MHP Superheater**							Included in 1-HRS-3201
1		**HP Superheater 1st section**							Included in 1-HRS-3201
1		**MP Reheater 1st section**							Included in 1-HRS-3201
1		**HP Evaporator**							Included in 1-HRS-3201
1		**HP Economizer 3rd section**							Included in 1-HRS-3201
1		**MP Evaporator**							Included in 1-HRS-3201
1		**MP Superheater**							Included in 1-HRS-3201
1		**LP Superheater**							Included in 1-HRS-3201
1		**MP Economizer 2nd section**							Included in 1-HRS-3201
1		**HP Economizer 2nd section**							Included in 1-HRS-3201
1		**LP Evaporator**							Included in 1-HRS-3201
1		**LP Economizer**							Included in 1-HRS-3201
1		**MP Economizer 1st section**							Included in 1-HRS-3201
1		**HP Economizer 1st section**							Included in 1-HRS-3201
1		**VLP Evaporator**							Included in 1-HRS-3201

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1-BD-0237A	REVISION	Rev.0	Rev.2	Rev.3
		DATE	Feb. 05		
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		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator - FW Gasifier - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT RECOVERY STEAM GENERATOR							
2		**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels, Simple Recovery, Reheated.						
2		**HP steam Drum**							Included in 2-HRS-3201
2		**MP steam drum**							Included in 2-HRS-3201
2		**LP steam drum**							Included in 2-HRS-3201
2		**VLP steam drum with degassing section**							Included in 2-HRS-3201
2		**HP Superheater 2nd section**							Included in 2-HRS-3201
2		**MP Reheater 2nd section**							Included in 2-HRS-3201
2		**MHP Superheater**							Included in 2-HRS-3201
2		**HP Superheater 1st section**							Included in 2-HRS-3201
2		**MP Reheater 1st section**							Included in 2-HRS-3201
2		**HP Evaporator**							Included in 2-HRS-3201
2		**HP Economizer 3rd section**							Included in 2-HRS-3201
2		**MP Evaporator**							Included in 2-HRS-3201
2		**MP Superheater**							Included in 2-HRS-3201
2		**LP Superheater**							Included in 2-HRS-3201
2		**MP Economizer 2nd section**							Included in 2-HRS-3201
2		**HP Economizer 2nd section**							Included in 2-HRS-3201
2		**LP Evaporator**							Included in 2-HRS-3201
2		**LP Economizer**							Included in 2-HRS-3201
2		**MP Economizer 1st section**							Included in 2-HRS-3201
2		**HP Economizer 1st section**							Included in 2-HRS-3201
2		**VLP Evaporator**							Included in 2-HRS-3201

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1-BD-0237A	REVISION	Rev.0		
		DATE	Feb. 05		
		ISSUED BY	S.R.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System - FW Gasifier - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		HEAT EXCHANGERS				shell / tube	shell / tube		
		Blow-Down Cooler	Shell & Tube						
		DRUMS							
		Flash Drum	vertical						
		Continuous Blow-down Drum	vertical						
		Discontinuous Blow-down Drum	vertical						
		PACKAGES							
		Steam Turbine & Condenser Package		320 MW					
		Steam Turbine							Included in Z - 3201
		Inter/After condenser							
		Gland Condenser							Included in Z - 3201
		Steam Condenser							Included in Z - 3201
		Steam Turbine Generator							Included in Z - 3201
		Start-up Ejector							Included in Z - 3201
		Holding Ejector 1st Stage							Included in Z - 3201
		Holding Ejector 2nd Stage							Included in Z - 3201
		Condensate Pumps	Centrifugal						Included in Z - 3201 Two operating, one spare
		Start-up Ejector Silencer							Included in Z - 3201
		MISCELLANEA							
1		**LP Steam from ST Desuperheater**							
1		**MP Steam from ST Desuperheater**							

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		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2100 - Electric Power Generation - FW Gasifier - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1		Gas Turbine Generator							Included in 1 -Z- 3101
2		Gas Turbine Generator							Included in 2 -Z- 3101
		Steam Turbine Generator							Included in Z- 3301

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		DATE	Feb. 05		
		ISSUED BY	P.C.		
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EQUIPMENT LIST

Utility and Offsite Units - FW Gasifier - CO_2 capture, dirty shift reaction, combined removal of H_2S and CO_2

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
	Unit 4100	Cooling Water System							
		Machinery Cooling Water System							
	Unit 4200	Demineralized Water System							
		Plant and Potable Water System							
	Unit 4300	Natural Gas System							
	Unit 4400	Plant and Instrument Air System							
	Unit 4600	Waste Water Treatment							
	Unit 4700	Fire Fighting System							
	Unit 4900	Chemicals							
	Unit 6000	Interconnecting							
		Instrumentation							
		DCS							
		Piping							
		Electrical							
		400 KV Substation							

CLIENT	:	IEA GREENHOUSE GAS R&D PROGRAMME
PROJECT NAME	:	CO_2 Capture in Low-rank Coal Power Pants
DOCUMENT NAME	:	ECONOMICS

ISSUED BY	:	L. MANCUSO
CHECKED BY	:	L. MANCUSO
APPROVED BY	:	R. DOMENICHINI

Date	Revised Pages	Issued by	Checked by	Approved by

SECTION E

ECONOMICS

INDEX

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.

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:

Postcombustion CO_2 capture alternatives (Case 1 trough 4):
Coal/Ash Handling & Storage
Coal Drying
Boiler Island with SCR and ESP
FGD Unit (Case 1)
Air Separation Unit (Case 2)
Power Island
CO_2 Capture Plant (MEA or MDEA solvent)
CO_2 Compression and Drying
Utilities and Offsite

Precombustion CO_2 capture alternatives (Case 5 trough 7):
Coal/Ash Handling & Storage
Coal Drying
Gasification Section
Air Separation Unit (Case 5 and 6) or Air Compression Unit (Case 7)
Syngas Treatment and Conditioning Line
Acid Gas Removal (MDEA solvent)
CO_2 Compression and Drying

Power Island
Utilities and Offsite

Further details on the equipment included in the cost estimate of each alternative are shown in the equipment list of each alternative, included in Section D.

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:

Coal/Ash Handling, Storage, Drying

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.

Gasification Island (Precombustion CO_2 capture alternatives)

Gasification Licensors provided investment cost data of the main equipment.
These figures have been adjusted based on the actual coal flowrate resulting from finalization of the IGCC performances of alternatives 5 to 7.
After this adjustment, the investment cost of main equipment has been increased by a factor derived from in-house data, to take into account minor equipment and bulk materials.
The resulting figure is the direct materials cost.

Boiler Island (Postcombustion CO_2 capture alternatives)

USC-PC and Oxy-PC Boiler (Case 1 and 2)
No Supplier provided investment cost data for this alternative; therefore figures have been calculated by using in-house and literature data. Final check of the economical data has been made with figures of the previous IEA reports, used as background.

CFB and PCFB Boiler (Case 3 and 4)
Licensors provided investment cost data of the main equipment, specifically referred to the lignite coal of this study and to the required flow rate of each alternative.

FGD Unit (Case 1)

Reference performance and cost data of an FGD system, designed for a coal fired power generation, are shown in Section C, paragraph 5.0. Economical data are adjusted on the basis of suitable parameters like flue gas flow rate and sulphur concentration.

Air Separation Unit (Case 2, 5, 6 and 7)

The investment cost is derived from competitive bids received and technically evaluated by FW in the past for similar projects.
For each alternative, the figure taken as a reference has been adjusted based on suitable parameters like feedstock flowrate and characteristics, product flowrate, purity and conditions.

Syngas Cooling and Conditioning Line, Acid Gas Removal with MDEA solvent (Precombustion CO_2 capture alternatives)

Investment cost for these units are derived from previous studies that Foster Wheeler made for the IEA, by using suitable parameters like flue gas flowrate and characteristics, product flowrate and purity conditions.

CO_2 Capture Plant with MEA Solvent (Case 1, 3)

Investment cost of this unit is derived from information contained in a previous report made for the IEA. For the two alternatives, the figure taken as a reference has been adjusted based on suitable parameters like flue gas flowrate and characteristics, product flowrate and purity conditions.

CO_2 Compression and Drying

Direct materials cost of CO_2 compressors and drivers are based on a budget quotation received from qualified Vendors. Costs of other equipment are derived from in house data.

Power Island

The direct materials cost is based on competitive bids received in the past for similar equipment (gas turbine, HRSG, steam turbine) and on proprietary software output for other equipment and bulk materials.

Utilities and Offsite

Cost of each Unit is evaluated based on in house data for similar Units.
These units also include DCS, ESD, EMS, Electrical Systems and HV substation.
The overall investment cost evaluated for a reference case selected among the different alternatives is then adjusted case by case, on the basis of the actual coal flowrate.

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 US $ equivalent to 1 Euro.

2.2.5 Inflation

No escalation is applied to the estimated installed cost.

2.2.6 Miscellanea 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 +/- 35%.

3.0 Investment Cost of the Alternatives

3.1 Postcombustion CO_2 capture alternatives (Case 1 through 4)

The following Tables E.3.1/4 show the investment break down and the total figures for each alternative investigated.
Table E.3.5 summarises the results and shows the net specific investment cost for all the alternatives.

Refer : 1-BD-0237A
Client : IEA GREENHOUSE GAS R&D PROGRAMME
Plant : CO_2 capture in low rank coals
Location : GERMANY (Inland)
Date : November 2005 REV. Final

Table E.3.1 - Case 1 - ESTIMATE SUMMARY

USC PC Boiler with post-combustion CO_2 capture

FIGURE IN EURO

POS	DESCRIPTION		1000 €	1050	2000 €	2100 €	3000 €	4000 €	5000 €	UTIL&OFF €	TOTAL €	REMARKS
1	DIRECT MATERIALS		42,069,000	7,201,000	199,730,000	50,547,000	83,268,000	55,420,000	27,373,000	129,053,000	594,661,000	1) ESTIMATE ACCURACY +/- 35%
2	CONSTRUCTION		19,397,000	1,476,000	158,374,000	15,164,000	42,429,000	40,283,000	10,634,000	70,978,000	358,735,000	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		2,763,000	738,000	8,303,000	5,055,000	2,914,000	2,213,000	1,552,000	12,906,000	36,444,000	
4	EPC SERVICES		8,478,000	1,284,000	39,789,000	6,066,000	13,966,000	10,629,000	2,978,000	25,811,000	109,001,000	
A	**Installed costs** (contingency excluded)		**72,707,000**	**10,699,000**	**406,196,000**	**76,832,000**	**142,577,000**	**108,545,000**	**42,537,000**	**238,748,000**	**1,098,841,000**	
B	Contingency	%	7	7	7	7	7	7	5	7	6.9	
		Euro	5,089,490	748,930	28,433,720	5,378,240	9,980,390	7,598,150	2,126,850	16,712,360	76,068,130	
C	Fees (2% of A)		1,454,140	213,980	8,123,920	1,536,640	2,851,540	2,170,900	850,740	4,774,960	21,976,820	
D	Land Purchases; surveys (5% of A)		3,635,350	534,950	20,309,800	3,841,600	7,128,850	5,427,250	2,126,850	11,937,400	54,942,050	
	TOTAL INVESTMENT COST		**82,885,980**	**12,196,860**	**463,063,440**	**87,588,480**	**162,537,780**	**123,741,300**	**47,641,440**	**272,172,720**	**1,251,828,000**	

1000 Coal Handling, Storage, Ash and Solid Removal,
1050 Coal Drying
2000 Boiler Island
Milling
SCR based DeNOx
ESP
2100 FGD System and Gypsum handling
3000 Power Island
4000 CO_2 capture plant
5000 CO_2 Compression & Drying
BOP Utilities&Offsites

Table E.3.2 - Case 2 - ESTIMATE SUMMARY

OXY-USC-PC Boiler with post-combustion CO_2 capture

Refer : 1-BD-0237A
Client : IEA GREENHOUSE GAS R&D PROGRAMME
Plant : CO_2 capture in low rank coals
Location : GERMANY (Inland)
Date : November 2005 REV. Final

FIGURE IN EURO

POS	DESCRIPTION		UNIT 1000 €	1050 €	1100 €	2000 €	3000 €	4000 €	UTIL&OFF €	TOTAL €
1	DIRECT MATERIALS		39,939,000	6,836,000	179,637,000	189,615,000	89,385,000	43,202,000	123,277,000	671,891,000
2	CONSTRUCTION		18,415,000	1,401,000	69,235,000	150,354,000	45,546,000	26,084,000	67,801,000	378,836,000
3	OTHER COSTS		2,623,000	701,000	18,712,000	7,882,000	3,128,000	4,076,000	12,328,000	49,450,000
4	EPC SERVICES		8,048,000	1,219,000	18,712,000	37,774,000	14,992,000	8,151,000	24,656,000	113,552,000
A	**Installed costs** (contingency excluded)		**69,025,000**	**10,157,000**	**286,296,000**	**385,625,000**	**153,051,000**	**81,513,000**	**228,062,000**	**1,213,729,000**
B	Contingency	%	7	7	7	10	7	7	7	8.0
		Euro	4,831,750	710,990	20,040,720	38,562,500	10,713,570	5,705,910	15,964,340	96,529,780
C	Fees (2% of A)		1,380,500	203,140	5,725,920	7,712,500	3,061,020	1,630,260	4,561,240	24,274,580
D	Land Purchases; surveys (5% of A)		3,451,250	507,850	14,314,800	19,281,250	7,652,550	4,075,650	11,403,100	60,686,450
TOTAL INVESTMENT COST			**78,688,500**	**11,578,980**	**326,377,440**	**451,181,250**	**174,478,140**	**92,924,820**	**259,990,680**	**1,395,219,810**

REMARKS

1) ESTIMATE ACCURACY +/- 35%

2) TODAY COSTS (ESCALATION NOT INCLUDED)

1000	**Coal Handling, Storage, Ash and Solid Removal,**
1050	**Coal Drying**
1100	**Air Separation Unit**
2000	**Boiler Island**
	Milling
	ESP
3000	**Power Island**
4000	**CO_2 Separation Unit**
BOP	**Utilities&Offsites**

FOSTER WHEELER

Table E.3.3 - Case 3 - ESTIMATE SUMMARY

CFB Boiler with post-combustion CO_2 capture

Refer	**: 1-BD-0237A**
Client	**: IEA GREENHOUSE GAS R&D PROGRAMME**
Plant	**: CO_2 capture in low rank coals**
Location	**: GERMANY (Inland)**
Date	**: November 2005 REV. Final**

FIGURE IN EURO

POS	DESCRIPTION		UNIT 1000 €	1050 €	2000 €	3000 €	4000 €	5000 €	UTIL&OFF €	TOTAL €	REMARKS
1	DIRECT MATERIALS		36,619,000	6,268,000	144,042,000	70,984,000	51,718,000	24,136,000	114,276,000	448,043,000	1) ESTIMATE ACCURACY +/- 35%
2	CONSTRUCTION		16,884,000	1,284,000	114,216,000	36,170,000	37,592,000	9,377,000	62,851,000	278,374,000	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		2,405,000	643,000	5,988,000	2,484,000	2,065,000	1,369,000	11,428,000	26,382,000	
4	EPC SERVICES		7,379,000	1,118,000	28,695,000	11,906,000	9,919,000	2,625,000	22,856,000	84,498,000	
A	**Installed costs** (contingency excluded)		**63,287,000**	**9,313,000**	**292,941,000**	**121,544,000**	**101,294,000**	**37,507,000**	**211,411,000**	**837,297,000**	
B	Contingency	%	7	7	7	7	7	5	7	6.9	
		Euro	4,430,090	651,910	20,505,870	8,508,080	7,090,580	1,875,350	14,798,770	57,860,650	
C	Fees (2% of A)		1,265,740	186,260	5,858,820	2,430,880	2,025,880	750,140	4,228,220	16,745,940	
D	Land Purchases; surveys (5% of A)		3,164,350	465,650	14,647,050	6,077,200	5,064,700	1,875,350	10,570,550	41,864,850	
TOTAL INVESTMENT COST			**72,147,180**	**10,616,820**	**333,952,740**	**138,560,160**	**115,475,160**	**42,007,840**	**241,008,540**	**953,768,440**	

1000 Coal Handling, Storage, Ash and Solid Removal,
1050 Coal Drying
2000 Boiler Island, SCR based DeNOx, ESP
3000 Power Island
4000 CO_2 capture plant
5000 CO_2 Compression & Drying
BOP Utilities&Offsites

Refer : 1-BD-0237A
Client : IEA GREENHOUSE GAS R&D PROGRAMME
Plant : CO_2 capture in low rank coals
Location : GERMANY (Inland)
Date : November 2005 REV. Final

Table E.3.4 - Case 4 - ESTIMATE SUMMARY

PCFB Boiler with post-combustion CO_2 capture

FIGURE IN EURO

POS	DESCRIPTION		1000 €	1050 €	2000 €	3000 €	4000 €	5000 €	6000 €	UTIL&OFF €	TOTAL €	REMARKS
1	DIRECT MATERIALS		41,808,000	7,156,000	91,240,000	89,040,000	69,210,000	54,026,000	27,509,000	128,345,000	508,334,000	1) ESTIMATE ACCURACY +/- 35%
2	CONSTRUCTION		19,277,000	1,466,000	156,485,000	29,680,000	35,266,000	34,329,000	10,687,000	70,589,000	357,779,000	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		2,745,000	734,000	8,203,000	7,420,000	2,422,000	44,681,000	1,560,000	12,835,000	80,600,000	
4	EPC SERVICES		8,425,000	1,276,000	39,315,000	22,260,000	11,608,000	10,283,000	2,992,000	25,669,000	121,828,000	
A	**Installed costs** (contingency excluded)		**72,255,000**	**10,632,000**	**295,243,000**	**148,400,000**	**118,506,000**	**143,319,000**	**42,748,000**	**237,438,000**	**1,068,541,000**	
B	Contingency	%	7	7	10	10	7	7	5	7	8.2	
		Euro	5,057,850	744,240	29,524,300	14,840,000	8,295,420	10,032,330	2,137,400	16,620,660	87,252,200	
C	Fees (2% of A)		1,445,100	212,640	5,904,860	2,968,000	2,370,120	2,866,380	854,960	4,748,760	21,370,820	
D	Land Purchases; surveys (5% of A)		3,612,750	531,600	14,762,150	7,420,000	5,925,300	7,165,950	2,137,400	11,871,900	53,427,050	
	TOTAL INVESTMENT COST		**82,370,700**	**12,120,480**	**345,434,310**	**173,628,000**	**135,096,840**	**163,383,660**	**47,877,760**	**270,679,320**	**1,230,591,070**	

1000 Coal Handling, Storage, Ash and Solid Removal,
1050 Coal Drying
2000 PCFB Boiler Island, Recuperative Exchanhers, Candle filters
3000 Turbo Expanders and Air Compressors, BFW Heaters
4000 Power Island
5000 Flue Gas Water Quench, CO_2 capture plant
6000 CO_2 Compression & Drying
BOP Utilities&Offsites

Table E.3.5 - ESTIMATE SUMMARY

FOSTER WHEELER

Postcombustion CO_2 capture: Coal Power Plants

Refer: 1-BD-0237A
Client: IEA GREENHOUSE R & D PROJ.
Plant: CO2 CAP. IN LOW RANK COAL P.P.
Location: GERMANY
Date: November 2005 REV. Final

FIGURE IN MM EURO

POS	DESCRIPTION	Case 1 USC-PC		Case 2 OXY-PC		Case 3 CFB		Case 4 PCFB	
		€	%	€	%	€	%	€	%
1	Boiler Island	463.1	37.0	451.2	32.3	334.0	35.0	345.4	28.1
2	Process Units	306.4	24.5	416.6	29.9	198.2	20.8	431.5	35.1
3	CO_2 Compression and Drying	47.6	3.8	92.9	6.7	42.0	4.4	47.9	3.9
4	Power Island	162.5	13.0	174.5	12.5	138.6	14.5	135.1	11.0
5	Utilities and Offsite Units	272.2	21.7	260.0	18.6	241.0	25.3	270.7	22.0
	TOTAL INVESTMENT COST	**1,251.8**	**100.0**	**1,395.2**	**100.0**	**953.8**	**100.0**	**1,230.6**	**100.0**

	Case 1	Case 2	Case 3	Case 4
NET POWER OUTPUT, MWe	761.0	741.3	614.7	688.4
SPECIFIC INVESTMENT COST, Euro/kW	**1645**	**1882**	**1552**	**1788**

3.2 Precombustion CO_2 capture alternatives (Case 5 through 7)

The following Tables E.3.6/8 show the investment break down and the total figures for each alternative investigated.
Table E.3.9 summarises the results and shows the net specific investment cost for all the alternatives.

Refer : 1-BD-0237A
Client : IEA GREENHOUSE GAS R & D PROGRAMME
Plant : CO2 capture in low rank coals
Location : GERMANY (Inland)
Date : November 2005 REV. Final

Table E.3.6 - Case 5 - ESTIMATE SUMMARY

FUTURE ENERGY - IGCC with pre-combustion CO_2 capture

POS	DESCRIPTION		900 €	950 €	1000 €	2100 €	2200 €	2300 €	2500 €	3000 €	UTIL&OFF €	TOTAL €
1	DIRECT MATERIALS		50,792,000	14,530,000	61,500,000	75,693,000	20,866,000	18,874,000	23,054,000	226,311,000	105,737,342	597,357,342
2	CONSTRUCTION		24,414,000	2,978,000	27,675,000	22,712,000	10,074,000	11,993,000	8,956,000	56,577,000	58,155,000	223,534,000
3	OTHER COSTS		3,204,000	1,490,000	9,225,000	3,028,000	14,591,000	15,609,000	1,307,000	22,631,000	10,574,000	81,659,000
4	EPC SERVICES		10,432,000	2,591,000	21,525,000	11,371,000	6,246,000	3,592,000	2,508,000	18,105,000	21,148,000	97,518,000
A	**Installed costs** (contingency excluded)		**88,842,000**	**21,589,000**	**119,925,000**	**112,804,000**	**51,777,000**	**50,068,000**	**35,825,000**	**323,624,000**	**195,614,342**	**1,000,068,342**
B	Contingency	%	7	7	7	5	7	7	5	7	5	6.3
		Euro	6,218,940	1,511,230	8,394,750	5,640,200	3,624,390	3,504,760	1,791,250	22,653,680	9,780,717	63,119,917
C	Fees (2% of A)		1,776,840	431,780	(3) 4,000,000	2,256,080	1,035,540	1,001,360	716,500	6,472,480	3,912,287	21,602,867
D	Land Purchases; surveys (5% of A)		4,442,100	1,079,450	5,996,250	5,640,200	2,588,850	2,503,400	1,791,250	16,181,200	9,780,717	50,003,417
	TOTAL INVESTMENT COST		**101,279,880**	**24,611,460**	**138,316,000**	**126,340,480**	**59,025,780**	**57,077,520**	**40,124,000**	**368,931,360**	**219,088,063**	**1,134,794,543**

REMARKS

1) ESTIMATE ACCURACY +/- 35%

2) TODAY COSTS (ESCALATION NOT INCLUDED)

3) License fee of the proprietary technology exceeds 2% of the plant cost.

900	**Coal Handling, Storage, Milling**
950	**Coal Drying**
1000	**Gasification Section**
2100	**Air Separation Unit**
2200	**Syngas Treat.&Condt. Line**
2300	**Acid Gas Removal**
2500	**CO_2 Compression&Drying**
3000	**Power Island**
4000+	**Utilities&Offsites**

Table E.3.7 - Case 6 - ESTIMATE SUMMARY

FOSTER WHEELER

SHELL - IGCC with pre-combustion CO_2 capture

Refer	**: 1-BD-0237A**
Client	**: IEA GREENHOUSE GAS R & D PROGRAMME**
Plant	**: CO2 capture in low rank coals**
Location	**: GERMANY (Inland)**
Date	**: November 2005 REV. Final**

POS	DESCRIPTION		900 €	950 €	1000 €	2100 €	2200 €	2300 €	2500 €	3000 €	UTIL&OFF €	TOTAL €
1	DIRECT MATERIALS		49,310,000	15,839,000	117,269,000	68,275,000	17,645,000	18,677,000	22,123,000	225,173,000	102,652,000	636,963,000
2	CONSTRUCTION		23,702,000	3,168,000	58,635,000	20,486,000	8,519,000	11,868,000	8,595,000	56,293,000	56,458,000	247,724,000
3	OTHER COSTS		3,111,000	1,585,000	7,036,000	2,732,000	12,339,000	15,447,000	1,254,000	22,517,000	10,265,000	76,286,000
4	EPC SERVICES		10,128,000	2,375,000	29,317,000	10,256,000	5,282,000	3,555,000	2,407,000	18,014,000	20,531,000	101,865,000
A	**Installed costs** (contingency excluded)		**86,251,000**	**22,967,000**	**212,257,000**	**101,749,000**	**43,785,000**	**49,547,000**	**34,379,000**	**321,997,000**	**189,906,000**	**1,062,838,000**
B	Contingency	%	7	7	7	5	7	7	5	7	5	6.4
		Euro	6,037,570	1,607,690	14,857,990	5,087,450	3,064,950	3,468,290	1,718,950	22,539,790	9,495,300	67,877,980
C	Fees (2% of A)		1,725,020	459,340	4,245,140	2,034,980	875,700	990,940	687,580	6,439,940	3,798,120	21,256,760
D	Land Purchases; surveys (5% of A)		4,312,550	1,148,350	10,612,850	5,087,450	2,189,250	2,477,350	1,718,950	16,099,850	9,495,300	53,141,900
	TOTAL INVESTMENT COST		**98,326,140**	**26,182,380**	**241,972,980**	**113,958,880**	**49,914,900**	**56,483,580**	**38,504,480**	**367,076,580**	**212,694,720**	**1,205,114,640**

REMARKS

1) ESTIMATE ACCURACY +/- 35%

2) TODAY COSTS (ESCALATION NOT INCLUDED)

900	**Coal Handling, Storage, Milling**
950	**Coal Drying**
1000	**Gasification Section**
2100	**Air Separation Unit**
2200	**Syngas Treat.&Condt. Line**
2300	**Acid Gas Removal**
2500	**CO_2 Compression&Drying**
3000	**Power Island**
4000+	**Utilities & Offsites**

Table E.3.8 - Case 7 - ESTIMATE SUMMARY

FOSTER WHEELER - IGCC with pre-combustion CO_2 capture

Refer : 1-BD-0237A
Client : IEA GREENHOUSE GAS R & D PROGRAMME
Plant : CO2 capture in low rank coals
Location : GERMANY (Inland)
Date : November 2005 REV. Final

POS	DESCRIPTION		900 €	950 €	1000 €	2100 €	2200 €	2300 €	2500 €	3000 €	UTIL&OFF €	TOTAL €
1	DIRECT MATERIALS		52,679,000	9,516,000	143,512,000	16,617,000	29,217,000	26,126,000	22,979,000	227,097,000	109,664,000	637,407,000
2	CONSTRUCTION		25,321,000	1,950,000	36,716,000	6,456,000	14,106,000	16,601,000	8,927,000	56,774,000	60,314,000	227,165,000
3	OTHER COSTS		3,323,000	976,000	28,179,000	942,000	20,431,000	21,607,000	1,303,000	22,710,000	10,967,000	110,438,000
4	EPC SERVICES		10,820,000	1,697,000	40,268,000	1,808,000	8,746,000	4,973,000	2,500,000	18,168,000	21,933,000	110,913,000
A	**Installed costs** (contingency excluded)		**92,143,000**	**14,139,000**	**248,675,000**	**25,823,000**	**72,500,000**	**69,307,000**	**35,709,000**	**324,749,000**	**202,878,000**	**1,085,923,000**
B	Contingency	%	7	7	7	5	7	7	5	7	5	6.5
		Euro	6,450,010	989,730	17,407,250	1,291,150	5,075,000	4,851,490	1,785,450	22,732,430	10,143,900	70,726,410
C	Fees (2% of A)		1,842,860	282,780	4,973,500	516,460	1,450,000	1,386,140	714,180	6,494,980	4,057,560	21,718,460
D	Land Purchases; surveys (5% of A)		4,607,150	706,950	12,433,750	1,291,150	3,625,000	3,465,350	1,785,450	16,237,450	10,143,900	54,296,150
	TOTAL INVESTMENT COST		**105,043,020**	**16,118,460**	**283,489,500**	**28,921,760**	**82,650,000**	**79,009,980**	**39,994,080**	**370,213,860**	**227,223,360**	**1,232,664,020**

REMARKS

1) ESTIMATE ACCURACY +/- 35%

2) TODAY COSTS (ESCALATION NOT INCLUDED)

900	**Coal Handling, Storage, Milling**
950	**Coal Drying**
1000	**Gasification Section**
2100	**Air Compression Unit**
2200	**Syngas Treat.&Condt. Line**
2300	**Acid Gas Removal**
2500	**CO_2 Compression&Drying**
3000	**Power Island**
4000+	**Utilities & Offsites**

FOSTER WHEELER

Table E.3.9 - ESTIMATE SUMMARY

Precombustion CO_2 capture: IGCC Power Plants

Refer: 1-BD-0237A
Client: IEA GREENHOUSE R & D PROJ.
Plant: CO2 CAP. IN LOW RANK COAL P.P.
Location: GERMANY
Date: November 2005 REV. Final

FIGURE IN MM EURO

POS	DESCRIPTION	Case 5 FUTURE ENERGY €	%	Case 6 SHELL €	%	Case 7 FOSTER WHEELER €	%
1	Air Separation Unit	126.3	11.1	114.0	9.5	28.9	2.3
2	Process Units	380.3	33.5	472.9	39.2	566.3	45.9
3	CO_2 Compression and Drying	40.1	3.5	38.5	3.2	40.0	3.2
4	Power Island	368.9	32.5	367.1	30.5	370.2	30.0
5	Utilities and Offsite Units	219.1	19.3	212.7	17.6	227.2	18.4
	TOTAL INVESTMENT COST	**1,134.8**	**100.0**	**1,205.1**	**100.0**	**1,232.7**	**100.0**

	Case 5	Case 6	Case 7
NET POWER OUTPUT, MWe	**665.2**	**628.8**	**686.6**
SPECIFIC INVESTMENT COST, Euro/kW	**1706**	**1917**	**1795**

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 7) 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 7446 equivalent hours of operation, in one year, based on combustion of the main fuel only.

4.1.1 Postcombustion CO_2 capture alternatives

The attached Table E.4.1 shows the Variable Costs for Case1, 2, 3 and 4.

FOSTER WHEELER	Table E.4.1 - Post-combustion CO_2 capture alternatives- Yearly Variable Costs	Refer : 1-BD-0237A Client : IEA GREENHOUSE R & D PROJ. Date : February 2005 REV. 0

Yearly Operating hours =	7446	Case 1 - USC-PC			Case 2 - OXY-PC			Case 3 - CFB			Case 4 - PCFB		
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 (as received)	10.50	734000	5465364.0	57,386,322	677600	5045409.6	52,976,801	592900	4414733.4	46,354,701	727000	5413242.0	56,839,041
Limestone	20.0	5080	37825.7	756,514	0	0.0	0	27360	203722.6	4,074,451	10000	74460.0	1,489,200
Auxiliary feedstock													
Make-up water	0.100	1937000	14422902.0	1,442,290	2065000	15375990.0	1,537,599	1581000	11772126.0	1,177,213	1751000	13037946.0	1,303,795
Solvents													
MEA	1300	1340	9977.6	12,970,932	0	0.0	0	1466	10918.3	14,193,830	0	0.0	0
MDEA	4500	0	0.0	0	0	0.0	0	0	0.0	0	80	595.7	2,680,560
Catalyst													
DENOx Catalyst	10800	67.5	502.96	5,432,000	0.0	0.00	0	56.4	419.91	4,535,000	20	147.5	1,593,000
Chemicals													
Ammonia	336	660.0	4914.4	1,651,225	0.0	0.0	0	500.0	3723.0	1,250,928	100.0	744.6	250,186
Activated Carbon	1000	50.0	372.3	372,300	0.0	0.0	0	40.0	297.8	297,840	40.0	297.8	297,840
Soda ash	110	110.0	819.1	90,097	0.0	0.0	0	90.0	670.1	73,715	100.0	744.6	81,906
Coordinate phosphate	1.9	5.2	38.9	74	4.2	31.6	60	4.1	30.7	58	3.8	28.0	53
Nalco Eliminox or equivalent	4132	3.5	25.7	106,314	2.8	20.9	86,515	2.7	20.3	84,050	2.5	18.6	76,654
TOTAL YEARLY OPERATING COSTS, Euro/year				**80,208,067**			**54,600,975**			**72,041,785**			**64,612,234**

4.1.2 Precombustion CO_2 capture alternatives

The attached Table E.4.2 shows the Variable Costs for alternatives Case 5, 6, and 7.

FOSTER WHEELER	Table E.4.2 - IGCC alternatives - Yearly Variable Costs									Refer: 1-BD-0237A Client: IEA GREENHOUSE R & D PROJ. Date: February 2005 REV. 0
Yearly Operating hours =	7446	**Case 5 - Future Energy**			**Case 6 - Shell**			**Case 7 - Foster Wheeler**		
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)**
Feedstock										
Coal (as received)	10.50	653300	4864471.8	51,076,954	624200	4647793.2	48,801,829	691000	5145186.0	54,024,453
Limestone	20.0	0	0.0	0	0	0.0	0	8.16	60.8	1,216
Auxiliary feedstock										
Natural Gas	140.7	715.1	5324.6	749,176	75	558.5	78,574	75	558.5	78,574
Make-up water	0.100	1255000	9344730.0	934,473	1748000	13015608.0	1,301,561	1289000	9597894.0	959,789
Solvents										
MDEA	4500	8.60	64.0	288,000	8.85	65.9	296,523	12.96	96.5	434,277
Catalyst										
Sour Shift Catalyst (3-5 years life) (1)	20000	30.349	225.98	4,519,510	20.158	150.10	3,001,912	17.186	127.97	2,559,382
Chemicals										
NaOH (50%)	155.0	480.0	3574.1	553,982	661.6	4926.2	763,559	732.4	5453.4	845,273
HCL (20%)	150.0	974.4	7255.4	1,088,313	1888.4	14061.3	2,109,202	2090.5	15566.1	2,334,922
Coordinate phosphate	1.9	1.3	9.8	19	1.2	8.9	17	1.2	9.1	17
Nalco Eliminox or equivalent	4132.0	0.9	6.5	26,833	0.8	5.9	24,352	0.8	6.0	24,991
Nalco Tri-Act 1801 or equivalent	3615.0	1.3	9.7	35,206	2.5	18.9	68,231	2.8	20.9	75,532
Filter Polyelectrolyte	2580.0	0.3	2.4	6,282	0.6	4.7	12,174	0.7	5.2	13,477
IAF Polyelectrolyte	2580.0	0.3	2.4	6,282	0.6	4.7	12,174	0.7	5.2	13,477
Phosporic acid (20%)	400.0	0.3	2.4	974	0.6	4.7	1,887	0.7	5.2	2,089
TOTAL YEARLY OPERATING COSTS, Euro/year				**59,286,002**			**56,471,994**			**61,367,471**

NOTES: (1) Two catalyst beds are required. 1st bed years life: 3; 2nd bed years life: 5.

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, such as gas turbine inspections (precombustion CO_2 capture alternatives), 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 50,000 Euro/year. The number of personnel engaged for the different alternatives is shown in the following.

Precombustion CO_2 capture alternatives
The Owner's personnel engaged in the Operation and Maintenance of the IGCC Complex (precombustion CO_2 alternatives) is shown in Table E.4.3.1. The Complex has been divided into 3 areas of operation: Air Separation Unit, Gasification, including syngas processing and CO_2 capture plant, and Power Island with common Utilities. The same division will be reflected in the design of the centralized Control Room, which will have, correspondingly, 3 main DCS control groups, each one equipped with a number of control stations, from where the operation of the plants of each of the three areas will be controlled.

The Area Responsible and his Assistant will supervise each area of operation; both are daily position.
The Shift Superintendent and the Electrical Assistant are common for the 3 areas; both are shift position. 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 subcontractor 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.

Personnel shown in Table E.4.3.1 are directly engaged in the Complex. Management, Administration, Technical Services and supporting clerical staff are not included since their composition and strength are very much dependent on Owner's policy.

Table E.4.3.1 – IGCC personnel.

OPERATION	ASU	GASIFICATION	CCU & UTILITIES	TOTAL	NOTES
Area Responsible	1	1	1	3	daily position
Assistant Area Responsible	1	1	1	3	daily position
Shift Superintendent	5			5	1 shift position
Electrical Assistant	5			5	1 shift position
Shift Supervisor	5	5	5	15	3 shift position
Control Room Operator	5	10	10	25	5 shift position
Field Operator	5	25	20	50	10 shift position
Subtotal				**106**	
MAINTENANCE					
Mechanical group	4			4	daily position
Instrument group	7			7	daily position
Electrical group	5			5	daily position
Subtotal				**16**	
LABORATORY					
Superintendent + Analysts	6			**6**	daily position
TOTAL				**128**	

Postcombustion CO_2 capture alternatives

Case 1 – USC PC

The Owner's personnel engaged in the Operation and Maintenance of this alternative is shown in Table E.4.3.2. The Complex has been divided into 2 areas of operation: Boiler Island, including flue gas processing and CO_2 capture plant, 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.

Personnel engaged as Area Responsible, Assistant, as well as the maintenance people follow the considerations made for the previous alternative.

Table E.4.3.2 – USC-PC personnel.

OPERATION	BOILER ISLAND	CCU & 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**	

Case 2 – OXY - USC PC

The Owner's personnel engaged in the Operation and Maintenance of this alternative can be directly derived from the previous case, by simply adding the personnel required for the ASU like for the IGCC alternatives (see table E.4.3.1), i.e. 17 units overall. As a consequence, the total personnel engaged for this alternative are 122 units.

Case 3 & 4 – CFB & PCFB

The Owner's personnel engaged in the Operation and Maintenance of this alternative is shown in Table E.4.3.3. The only difference with the USC-PC case is that the need of multiple boilers results in a higher number of field operators (25 people instead of 15). As a consequence, the total personnel engaged for this alternative are 115 units.

Table E.4.3.3 – CFB & PCFB personnel.

OPERATION	BOILER ISLAND	CCU & 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	25	25	50	10 shift position
Subtotal			**94**	
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			**115**	

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 a percentage of the installed capital cost of the facilities.

Postcombustion CO_2 capture alternatives
Basically, the Complex has been divided in different sections, depending on the material, solid or fluid, handled by the unit. For fluid handling units, the maintenance cost is calculated by considering 2.5% of the installed cost, whilst 4.0% is considered for the solid handling units. For common facilities (utilities and offsite units), 1.7% of the installed cost is considered.

Precombustion CO_2 capture alternatives
Complex has been divided in four major sections, applying to each section the following percentage of the capital cost:
- 4.0% for solid handling units;
- 2.5% for fluid handling units;
- 1.7% for utilities and offsites;
- 5.0% for the Power Island, to take into account the gas turbine maintenance cost based on the assumption of a Long Term Service Agreement (LTSA) with the gas turbine manufacturer.

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 both the postcombustion and precombustion CO_2 capture alternatives.

FOSTER WHEELER	Table E.4.4 - Post-combustion CO_2 capture alternatives - Maintenance Costs								Refer : 1-BD-0237A Client : IEA Date : November 2005	
		Case 1		Case 2		Case 3		Case 4		
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	
COAL HANDLING, DRYING, MILLING, BOILER ISLAND, FGD, POW. ISL.	4.0	709011	28360	617858	24714	487085	19483	645036	25801	
CO_2 CAPUTRE PLANT, CO_2 COMPRESS. AND DRYING, ASU	2.5	151082	3777	367809	9195	138801	3470	186067	4652	
Common facilities (BOP)	1.7	238748	4059	228062	3877	211411	3594	237438	4036	
TOTAL		1098841	36196	1213729	37787	837297	26547	1068541	34489	
		Maint. % =	3.3	Maint. % =	3.1	Maint. % =	3.2	Maint. % =	3.2	

FOSTER WHEELER	Table E.4.5 - IGCC - Maintenance Costs						Refer : 1-BD-0237A Client : IEA Date : November 2005	
		Case 5		Case 6			Case 7	
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
ASU, AGR, SRU & TGT, CO_2 Comp., (Units: 2100,2300,2400,2500)	2.5	198697	4967	185675	4642		130839	3271
Gasification, Syngas Treat., (Units: 900,1000,2200)	4.0	282133	11285	365260	14610		427457	17098
Power Island (Unit: 3000)	5.0 (1)	323624	16181	321997	16100		324749	16237
Common facilities (Utilities, Offsite, etc.)	1.7	195614	3325	189906	3228		202878	3449
TOTAL		1000068	35759	1062838	38581		1085923	40055
		Maint. % =	3.6	Maint. % =	3.6		Maint. % =	3.7

NOTES: (1) Including the Gas Turbine Long Term Service Agreement.

4.3 Summary

The following tables summarize the total Operating and Maintenance Costs on yearly basis for all the alternatives.

Table E.4.6 – Postcombustion CO_2 capture alternatives – Total O&M Costs

		Case 1 Euro/year	Case 2 Euro/year	Case 3 Euro/year	Case 4 Euro/year
Fixed Costs	direct labour	5,250,000	6,100,000	5,750,000	5,750,000
	adm./gen overheads	1,575,000	1,830,000	1,725,000	1,725,000
	maintenance	36,196,000	37,787,000	26,547,000	34,489,000
	Subtotal	43,021,000	45,717,000	34,022,000	41,964,000
Variable Costs		80,208,000	54,601,000	72,042,000	64,612,000
TOTAL O&M COSTS		123,229,000	100,318,000	106,064,000	106,576,000

Table E.4.7 – Precombustion CO_2 capture alternatives – Total O&M Costs

		Case 5 Euro/year	Case 6 Euro/year	Case 7 Euro/year
Fixed Costs	direct labour	6,400,000	6,400,000	6,400,000
	adm./gen overheads	1,920,000	1,920,000	1,920,000
	maintenance	35,759,000	38,581,000	40,055,000
	Subtotal	44,079,000	46,901,000	48,375,000
Variable Costs		59,286,000	56,472,000	61,367,000
TOTAL O&M COSTS		103,365,000	103,373,000	109,742,000

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:

- 7446 equivalent operating hours in normal conditions at 100% capacity;
- 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 CO_2;
- Other financial parameters as per Project Design Basis, Section B.

A sensitivity analysis with 5% discount rate is also developed.

5.1.1 Postcombustion CO_2 capture alternatives

The attached Tables E.5.1/4 show the economic analysis for Case 1, 2, 3 and 4.

The sensitivity analysis with 5% discount rate on the investment cost is shown in Tables E.5.5/8.

Table E.5.9 summarizes the electric power cost for the postcombustion CO_2 capture alternatives, with 10% and 5% discount rate applied on the Total Investment Cost.

Table E.5.9 – Electric Power Cost

ALTERNATIVE		Case 1 USC-PC	Case 2 OXY-USCPC	Case 3 CFB	Case 4 PCFB
Discount rate	**%**	**10**	**10**	**10**	**10**
Coal Flowrate	t/h	734.0	677.6	592.9	727.0
Net Power Output	MWe	761.0	741.3	614.7	688.4
Total Investment Cost	MM Euro	1251.8	1395.2	953.8	1230.6
Specif Net Inv. Cost	**Euro/kW**	**1645**	**1882**	**1552**	**1788**
Revenues/year	MM Euro/year	305.2	301.4	244.3	284.4
Electricity Prod. Cost	**cEuro/kWh**	**5.39**	**5.46**	**5.34**	**5.55**
ALTERNATIVE		**Case 1 USC-PC**	**Case 2 OXY-USCPC**	**Case 3 CFB**	**Case 4 PCFB**
Discount rate	**%**	**5**	**5**	**5**	**5**
Coal Flowrate	t/h	734.0	677.6	592.9	727.0
Net Power Output	MWe	761.0	741.3	614.7	688.4
Total Investment Cost	MM Euro	1251.8	1395.2	953.8	1230.6
Specif Net Inv. Cost	**Euro/kW**	**1645**	**1882**	**1552**	**1788**
Revenues/year	MM Euro/year	242.7	232.0	196.7	223.1
Electricity Prod. Cost	**cEuro/kWh**	**4.28**	**4.20**	**4.30**	**4.35**

5.1.2 Precombustion CO_2 capture alternatives

The attached Tables E.5.10/12 show the economic analysis for Case 5, 6 and 7.

The sensitivity analysis with 5% discount rate on the investment cost is shown in Tables E.5.13/15.

Table E.5.16 summarizes the electric power cost for the precombustion CO_2 capture alternatives, with 10% and 5% discount rate applied on the Total Investment Cost.

Table E.5.16 – Electric Power Cost

ALTERNATIVE		Case 5 IGCC-FE	Case 6 IGCC-SHELL	Case 7 IGCC-FW	Case 5 IGCC-FE	Case 6 IGCC-SHELL	Case 7 IGCC-FW
Discount rate	**%**	**10**	**10**	**10**	**5**	**5**	**5**
Coal Flowrate	t/h	653.3	624.2	691.0	653.3	624.2	691.0
Net Power Output	MWe	665.2	628.8	686.6	665.2	628.8	686.6
Total Investment Cost	MM Euro	1134.8	1205.1	1232.7	1134.8	1205.1	1232.7
Specif Net Inv. Cost	**Euro/kW**	**1706**	**1917**	**1795**	**1706**	**1917**	**1795**
Revenues/year	MM Euro/year	268.1	278.2	288.6	211.5	218.2	227.1
Electricity Prod. Cost	**cEuro/kWh**	**5.41**	**5.94**	**5.64**	**4.27**	**4.66**	**4.44**

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TABLE E.5.1 - USC-PC - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	734.0	t/h
Net Power Output	761.0	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	1098.8
Land purchase; surveys	54.9
Fees	22.0
Average Contingencies	76.1
Total Investment Cost	1251.8

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	57.4
Maintenance	36.2
Waste Disposal	0.0
Chemicals + Consumable	22.8
Insurance and local taxes	22.0

Working Capital	**MM Euro**	
30 days Chemical Storage		2.2
5 days Coal Storage		0.9
Total Working capital		3.1
Labour Cost	**MM Euro/year**	
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.054	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	305.2	MM Euro/year

NPV	0.00
IRR	**10.00%**

CASH FLOW ANALYSYS	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Millions Euro	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electric Energy				161.6	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	305.2	
Operating Costs																													
Fuel Cost				-30.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	
Maintenance				-24.1	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables				-12.1	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	
Waste Disposal				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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance				-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	
Working Capital Cost				-3.1																									3.1
Fixed Capital Expenditures	-250.4	-563.3	-438.1																										
Total Cash flow (yearly)	-250.4	-563.3	-438.1	62.7	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	159.6	3.1
Total Cash flow (cumulated)	-250.4	-813.7	-1251.8	-1189.2	-1029.6	-870.0	-710.4	-550.8	-391.2	-231.6	-72.1	87.5	247.1	406.7	566.3	725.9	885.5	1045.1	1204.7	1364.3	1523.8	1683.4	1843.0	2002.6	2162.2	2321.8	2481.4	2641.0	2644.1
Discounted Cash Flow (Yearly)	-227.6	-465.6	-329.2	42.8	99.1	90.1	81.9	74.4	67.7	61.5	55.9	50.9	46.2	42.0	38.2	34.7	31.6	28.7	26.1	23.7	21.6	19.6	17.8	16.2	14.7	13.4	12.2	11.1	0.2
Discounted Cash Flow (Cumul.)	-227.6	-693.2	-1022.3	-979.6	-880.5	-790.4	-708.5	-634.0	-566.3	-504.8	-448.9	-398.0	-351.8	-309.8	-271.6	-236.8	-205.3	-176.6	-150.5	-126.8	-105.2	-85.6	-67.8	-51.6	-36.8	-23.4	-11.3	-0.2	0.0

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TABLE E.5.2 - OXY-USC-PC - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	677.6	t/h
Net Power Output	741.3	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	MM Euro
Installed Costs	1213.7
Land purchase; surveys	60.7
Fees	24.3
Average Contingencies	96.5
Total Investment Cost	1395.2

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	53.0
Maintenance	37.8
Waste Disposal	0.0
Chemicals + Consumable	1.6
Insurance and local taxes	24.3

Working Capital		MM Euro
30 days Chemical Storage		0.2
5 days Coal Storage		0.9
Total Working capital		1.0
Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.055	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	301.4	MM Euro/year
NPV	0.00	
IRR	10.00%	

CASH FLOW ANALYSYS Millions Euro	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electric Energy				159.6	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	301.4	
Operating Costs																													
Fuel Cost				-28.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	
Maintenance				-25.2	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables				-0.9	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	
Waste Disposal				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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance				-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	
Working Capital Cost				-1.0																									1.0
Fixed Capital Expenditures	-279.0	-627.8	-488.3																										
Total Cash flow (yearly)	-279.0	-627.8	-488.3	73.0	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	177.5	1.0
Total Cash flow (cumulated)	-279.0	-906.9	-1395.2	-1322.2	-1144.7	-967.2	-789.6	-612.1	-434.5	-257.0	-79.4	98.1	275.7	453.2	630.7	808.3	985.8	1163.4	1340.9	1518.5	1696.0	1873.6	2051.1	2228.7	2406.2	2583.7	2761.3	2938.8	2939.8
Discounted Cash Flow (Yearly)	-253.7	-518.9	-366.9	49.8	110.2	100.2	91.1	82.8	75.3	68.5	62.2	56.6	51.4	46.8	42.5	38.6	35.1	31.9	29.0	26.4	24.0	21.8	19.8	18.0	16.4	14.9	13.5	12.3	0.1
Discounted Cash Flow (Cumul.)	-253.7	-772.6	-1139.4	-1089.6	-979.4	-879.1	-788.0	-705.2	-629.9	-561.5	-499.2	-442.7	-391.2	-344.5	-302.0	-263.3	-228.2	-196.3	-167.2	-140.9	-116.9	-95.1	-75.2	-57.2	-40.8	-25.9	-12.4	-0.1	0.0

Rev.	: Final
Date	: November 2005
Page	: 1 of 1

TABLE E.5.3 - CFB - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	592.9	t/h
Net Power Output	614.7	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	837.3
Land purchase; surveys	41.9
Fees	16.7
Average Contingencies	57.9
Total Investment Cost	953.8

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	46.4
Maintenance	26.5
Waste Disposal	0.0
Chemicals + Consumable	25.7
Insurance and local taxes	16.7

Working Capital		**MM Euro**
30 days Chemical Storage		2.5
5 days Coal Storage		0.7
Total Working capital		3.2
Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.053	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	244.3	MM Euro/year

NPV	**0.00**
IRR	**10.00%**

CASH FLOW ANALYSYS Millions Euro	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				129.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3
Operating Costs															
Fuel Cost				-24.5	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4
Maintenance				-17.7	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2
Chemicals & Consumables				-13.6	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7
Working Capital Cost				-3.2											
Fixed Capital Expenditures	-190.8	-429.2	-333.8												
Total Cash flow (yearly)	-190.8	-429.2	-333.8	46.3	121.7	121.7	121.7	121.7	121.7	121.7	121.7	121.7	121.7	121.7	121.7
Total Cash flow (cumulated)	-190.8	-619.9	-953.8	-907.5	-785.7	-664.0	-542.2	-420.5	-298.8	-177.0	-55.3	66.5	188.2	310.0	431.7
Discounted Cash Flow (Yearly)	-173.4	-354.7	-250.8	31.6	75.6	68.7	62.5	56.8	51.6	46.9	42.7	38.8	35.3	32.1	29.1
Discounted Cash Flow (Cumul.)	-173.4	-528.1	-778.9	-747.3	-671.7	-603.0	-540.5	-483.7	-432.1	-385.2	-342.5	-303.7	-268.4	-236.4	-207.2

CASH FLOW ANALYSYS Millions Euro	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	244.3	
Operating Costs														
Fuel Cost	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	
Maintenance	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	
Labour	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	
Waste Disposal	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	
Insurance	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	
Working Capital Cost														3.2
Fixed Capital Expenditures														
Total Cash flow (yearly)	121.7	121.7	121.7	121.7	121.7	121.7	121.7	121.7	121.7	121.7	121.7	121.7	121.7	3.2
Total Cash flow (cumulated)	553.4	675.2	796.9	918.7	1040.4	1162.1	1283.9	1405.6	1527.4	1649.1	1770.9	1892.6	2014.3	2017.6
Discounted Cash Flow (Yearly)	26.5	24.1	21.9	19.9	18.1	16.5	15.0	13.6	12.4	11.2	10.2	9.3	8.4	0.2
Discounted Cash Flow (Cumul.)	-180.7	-156.6	-134.7	-114.8	-96.7	-80.3	-65.3	-51.7	-39.4	-28.1	-17.9	-8.6	-0.2	0.0

Production		
Coal Florate	727.0	t/h
Net Power Output	688.4	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	MM Euro
Installed Costs	1068.5
Land purchase; surveys	53.4
Fees	21.4
Average Contingencies	87.3
Total Investment Cost	1230.6

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	56.8
Maintenance	34.5
Waste Disposal	0.0
Chemicals + Consumable	7.8
Insurance and local taxes	21.4

Working Capital		MM Euro
30 days Chemical Storage		0.8
5 days Coal Storage		0.9
Total Working capital		1.7
Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.055	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	284.4	MM Euro/year

NPV	0.00
IRR	10.00%

CASH FLOW ANALYSYS Millions Euro	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				150.6	284.4	284.4	284.4	284.4	284.4	284.4	284.4	284.4	284.4	284.4	284.4
Operating Costs															
Fuel Cost				-30.1	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8
Maintenance				-23.0	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2
Chemicals & Consumables				-4.1	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4
Working Capital Cost				-1.7											
Fixed Capital Expenditures	-246.1	-553.8	-430.7												
Total Cash flow (yearly)	-246.1	-553.8	-430.7	63.1	156.7	156.7	156.7	156.7	156.7	156.7	156.7	156.7	156.7	156.7	156.7
Total Cash flow (cumulated)	-246.1	-799.9	-1230.6	-1167.5	-1010.7	-854.0	-697.3	-540.6	-383.8	-227.1	-70.4	86.3	243.1	399.8	556.5
Discounted Cash Flow (Yearly)	-223.7	-457.7	-323.6	43.1	97.3	88.5	80.4	73.1	66.5	60.4	54.9	49.9	45.4	41.3	37.5
Discounted Cash Flow (Cumul.)	-223.7	-681.4	-1005.0	-961.9	-864.6	-776.1	-695.7	-622.6	-556.1	-495.7	-440.7	-390.8	-345.4	-304.1	-266.6

CASH FLOW ANALYSYS Millions Euro	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	284.4	284.4	284.4	284.4	284.4	284.4	284.4	284.4	284.4	284.4	284.4	284.4	284.4	
Operating Costs														
Fuel Cost	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	
Maintenance	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	
Labour	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	
Waste Disposal	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	
Insurance	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	
Working Capital Cost														1.7
Fixed Capital Expenditures														
Total Cash flow (yearly)	156.7	156.7	156.7	156.7	156.7	156.7	156.7	156.7	156.7	156.7	156.7	156.7	156.7	1.7
Total Cash flow (cumulated)	713.2	870.0	1026.7	1183.4	1340.1	1496.9	1653.6	1810.3	1967.1	2123.8	2280.5	2437.2	2594.0	2595.6
Discounted Cash Flow (Yearly)	34.1	31.0	28.2	25.6	23.3	21.2	19.3	17.5	15.9	14.5	13.2	12.0	10.9	0.1
Discounted Cash Flow (Cumul.)	-232.5	-201.5	-173.3	-147.7	-124.4	-103.2	-84.0	-66.5	-50.5	-36.1	-22.9	-11.0	-0.1	0.0

TABLE E.5.5 - USC-PC - Cost Evaluation - Discount Rate = 5%

Rev. : Final
Date : November 2005

Production		
Coal Florate	734.0	t/h
Net Power Output	761.0	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	1098.8
Land purchase; surveys	54.9
Fees	22.0
Average Contingencies	76.1
Total Investment Cost	1251.8

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	57.4
Maintenance	36.2
Waste Disposal	0.0
Chemicals + Consumable	22.8
Insurance and local taxes	22.0

Working Capital		**MM Euro**
30 days Chemical Storage		2.2
5 days Coal Storage		0.9
Total Working capital		3.1
Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.043	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	5.00	%
Revenues / year	242.7	MM Euro/year

NPV	**0.00**
IRR	**5.00%**

CASH FLOW ANALYSYS Millions Euro	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				128.5	242.7	242.7	242.7	242.7	242.7	242.7	242.7	242.7	242.7	242.7	242.7
Operating Costs															
Fuel Cost				-30.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4
Maintenance				-24.1	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2
Chemicals & Consumables				-12.1	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0
Working Capital Cost				-3.1											
Fixed Capital Expenditures	-250.4	-563.3	-438.1												
Total Cash flow (yearly)	-250.4	-563.3	-438.1	29.6	97.1	97.1	97.1	97.1	97.1	97.1	97.1	97.1	97.1	97.1	97.1
Total Cash flow (cumulated)	-250.4	-813.7	-1251.8	-1222.2	-1125.1	-1028.0	-930.8	-833.7	-736.5	-639.4	-542.2	-445.1	-348.0	-250.8	-153.7
Discounted Cash Flow (Yearly)	-238.4	-511.0	-378.5	24.3	76.1	72.5	69.0	65.7	62.6	59.6	56.8	54.1	51.5	49.1	46.7
Discounted Cash Flow (Cumul.)	-238.4	-749.4	-1127.9	-1103.5	-1027.4	-954.9	-885.9	-820.1	-757.5	-697.9	-641.1	-587.0	-535.5	-486.4	-439.7

CASH FLOW ANALYSYS Millions Euro	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	242.7	242.7	242.7	242.7	242.7	242.7	242.7	242.7	242.7	242.7	242.7	242.7	242.7	
Operating Costs														
Fuel Cost	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	-57.4	
Maintenance	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	-36.2	
Labour	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	-22.8	
Waste Disposal	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	
Insurance	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	-22.0	
Working Capital Cost														3.1
Fixed Capital Expenditures														
Total Cash flow (yearly)	97.1	97.1	97.1	97.1	97.1	97.1	97.1	97.1	97.1	97.1	97.1	97.1	97.1	3.1
Total Cash flow (cumulated)	-56.5	40.6	137.7	234.9	332.0	429.2	526.3	623.5	720.6	817.7	914.9	1012.0	1109.2	1112.3
Discounted Cash Flow (Yearly)	44.5	42.4	40.4	38.4	36.6	34.9	33.2	31.6	30.1	28.7	27.3	26.0	24.8	0.8
Discounted Cash Flow (Cumul.)	-395.2	-352.8	-312.4	-274.0	-237.4	-202.5	-169.3	-137.7	-107.6	-78.9	-51.6	-25.5	-0.8	0.0

TABLE E.5.6 - OXY-USC-PC - Cost Evaluation - Discount Rate = 5%

Production		
Coal Florate	677.6	t/h
Net Power Output	741.3	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	1213.7
Land purchase; surveys	60.7
Fees	24.3
Average Contingencies	96.5
Total Investment Cost	1395.2

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	53.0
Maintenance	37.8
Waste Disposal	0.0
Chemicals + Consumable	1.6
Insurance and local taxes	24.3

Working Capital		**MM Euro**
30 days Chemical Storage		0.2
5 days Coal Storage		0.9
Total Working capital		1.0

Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.042	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	5.00	%
Revenues / year	232.0	MM Euro/year

NPV	**0.00**
IRR	**5.00%**

CASH FLOW ANALYSYS Millions Euro	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				122.8	232.0	232.0	232.0	232.0	232.0	232.0	232.0	232.0	232.0	232.0	232.0
Operating Costs															
Fuel Cost				-28.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0
Maintenance				-25.2	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2
Chemicals & Consumables				-0.9	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3
Working Capital Cost				-1.0											
Fixed Capital Expenditures	-279.0	-627.8	-488.3												
Total Cash flow (yearly)	-279.0	-627.8	-488.3	36.2	108.1	108.1	108.1	108.1	108.1	108.1	108.1	108.1	108.1	108.1	108.1
Total Cash flow (cumulated)	-279.0	-906.9	-1395.2	-1359.0	-1250.9	-1142.8	-1034.7	-926.7	-818.6	-710.5	-602.4	-494.3	-386.2	-278.1	-170.0
Discounted Cash Flow (Yearly)	-265.8	-569.5	-421.8	29.8	84.7	80.7	76.8	73.2	69.7	66.4	63.2	60.2	57.3	54.6	52.0
Discounted Cash Flow (Cumul.)	-265.8	-835.2	-1257.1	-1227.3	-1142.6	-1061.9	-985.1	-912.0	-842.3	-775.9	-712.7	-652.5	-595.2	-540.6	-488.6

CASH FLOW ANALYSYS Millions Euro	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	232.0	232.0	232.0	232.0	232.0	232.0	232.0	232.0	232.0	232.0	232.0	232.0	232.0	
Operating Costs														
Fuel Cost	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	-53.0	
Maintenance	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	-37.8	
Labour	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	-1.6	
Waste Disposal	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	
Insurance	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	-24.3	
Working Capital Cost														1.0
Fixed Capital Expenditures														
Total Cash flow (yearly)	108.1	108.1	108.1	108.1	108.1	108.1	108.1	108.1	108.1	108.1	108.1	108.1	108.1	1.0
Total Cash flow (cumulated)	-62.0	46.1	154.2	262.3	370.4	478.5	586.6	694.7	802.7	910.8	1018.9	1127.0	1235.1	1236.1
Discounted Cash Flow (Yearly)	49.5	47.2	44.9	42.8	40.7	38.8	36.9	35.2	33.5	31.9	30.4	29.0	27.6	0.2
Discounted Cash Flow (Cumul.)	-439.1	-392.0	-347.1	-304.3	-263.5	-224.7	-187.8	-152.6	-119.1	-87.2	-56.8	-27.8	-0.2	0.0

FOSTER WHEELER

TABLE E.5.7 - CFB - Cost Evaluation - Discount Rate = 5%

Rev. : Final
Date : November 2005
Page : 1 of 1

Production		
Coal Florate	592.9	t/h
Net Power Output	614.7	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	837.3
Land purchase; surveys	41.9
Fees	16.7
Average Contingencies	57.9
Total Investment Cost	953.8

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	46.4
Maintenance	26.5
Waste Disposal	0.0
Chemicals + Consumable	25.7
Insurance and local taxes	16.7

Working Capital		**MM Euro**
30 days Chemical Storage		2.5
5 days Coal Storage		0.7
Total Working capital		3.2
Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.043	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	5.00	%
Revenues / year	196.7	MM Euro/year

NPV	**0.00**
IRR	**5.00%**

CASH FLOW ANALYSYS Millions Euro	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electric Energy				104.1	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	196.7	
Operating Costs																													
Fuel Cost				-24.5	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	
Maintenance				-17.7	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	-26.5	
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables				-13.6	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	
Waste Disposal				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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance				-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	-16.7	
Working Capital Cost				-3.2																									3.2
Fixed Capital Expenditures	-190.8	-429.2	-333.8																										
Total Cash flow (yearly)	-190.8	-429.2	-333.8	21.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	74.1	3.2
Total Cash flow (cumulated)	-190.8	-619.9	-953.8	-932.7	-858.6	-784.5	-710.4	-636.3	-562.2	-488.1	-414.0	-339.9	-265.8	-191.7	-117.6	-43.5	30.6	104.7	178.8	252.9	327.0	401.1	475.2	549.3	623.4	697.5	771.6	845.7	849.0
Discounted Cash Flow (Yearly)	-181.7	-389.3	-288.4	17.3	58.1	55.3	52.7	50.2	47.8	45.5	43.3	41.3	39.3	37.4	35.6	33.9	32.3	30.8	29.3	27.9	26.6	25.3	24.1	23.0	21.9	20.8	19.8	18.9	0.8
Discounted Cash Flow (Cumul.)	-181.7	-571.0	-859.3	-842.0	-783.9	-728.6	-676.0	-625.8	-578.1	-532.6	-489.2	-448.0	-408.7	-371.2	-335.6	-301.7	-269.3	-238.5	-209.2	-181.3	-154.7	-129.4	-105.2	-82.3	-60.4	-39.5	-19.7	-0.8	0.0

Production		
Coal Florate	727.0	t/h
Net Power Output	688.4	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	1068.5
Land purchase; surveys	53.4
Fees	21.4
Average Contingencies	87.3
Total Investment Cost	1230.6

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	56.8
Maintenance	34.5
Waste Disposal	0.0
Chemicals + Consumable	7.8
Insurance and local taxes	21.4

Working Capital	**MM Euro**	
30 days Chemical Storage		0.8
5 days Coal Storage		0.9
Total Working capital		1.7

Labour Cost	**MM Euro/year**	
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.044	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	5.00	%
Revenues / year	223.1	MM Euro/year

NPV	0.00
IRR	**5.00%**

CASH FLOW ANALYSYS Millions Euro	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electric Energy				118.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	223.1	
Operating Costs																													
Fuel Cost				-30.1	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	-56.8	
Maintenance				-23.0	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	-34.5	
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables				-4.1	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	-7.8	
Waste Disposal				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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance				-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	-21.4	
Working Capital Cost				-1.7																									1.7
Fixed Capital Expenditures	-246.1	-553.8	-430.7																										
Total Cash flow (yearly)	-246.1	-553.8	-430.7	30.7	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	95.4	1.7
Total Cash flow (cumulated)	-246.1	-799.9	-1230.6	-1199.9	-1104.5	-1009.1	-913.7	-818.3	-722.9	-627.5	-532.1	-436.7	-341.2	-245.8	-150.4	-55.0	40.4	135.8	231.2	326.6	422.0	517.5	612.9	708.3	803.7	899.1	994.5	1089.9	1091.6
Discounted Cash Flow (Yearly)	-234.4	-502.3	-372.1	25.2	74.8	71.2	67.8	64.6	61.5	58.6	55.8	53.1	50.6	48.2	45.9	43.7	41.6	39.6	37.8	36.0	34.2	32.6	31.1	29.6	28.2	26.8	25.6	24.3	0.4
Discounted Cash Flow (Cumul.)	-234.4	-736.7	-1108.7	-1083.5	-1008.8	-937.6	-869.8	-805.2	-743.7	-685.1	-629.3	-576.2	-525.6	-477.4	-431.5	-387.8	-346.2	-306.5	-268.8	-232.8	-198.6	-166.0	-134.9	-105.3	-77.1	-50.3	-24.7	-0.4	0.0

Production		
Coal Florate	653.3	t/h
Net Power Output	665.2	MW
Sold Sulphur	0.00	t/h
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	1000.1
Land purchase; surveys	50.0
Fees	21.6
Average Contingencies	63.1
Total Investment Cost	1134.8

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	51.1
Maintenance	35.8
Waste Disposal	0.0
Chemicals + Consumable	8.2
Insurance and local taxes	20.0

Working Capital	**MM Euro**	
30 days Chemical Storage		0.8
5 days Coal Storage		0.8
Total Working capital		1.6
Labour Cost	**MM Euro/year**	
# operators		128
Salary		0.05
Direct Labour Cost		6.4
Administration	30% L.C.	1.9
Total Labour Cost		8.3

Electricity Production Cost	0.054	Euro/kWh
Sulphur Price	103.3	Euro/t
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	268.1	MM Euro/year
NPV	0.00	
IRR	**10.00%**	

CASH FLOW ANALYSYS Millions Euro	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				141.9	268.1	268.1	268.1	268.1	268.1	268.1	268.1	268.1	268.1	268.1	268.1
Sulphur				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Costs															
Fuel Cost				-27.0	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1
Maintenance				-23.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8
Labour				-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3
Chemicals & Consumables				-4.3	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0
Working Capital Cost				-1.6											
Fixed Capital Expenditures	-227.0	-510.7	-397.2												
Total Cash flow (yearly)	-227.0	-510.7	-397.2	56.7	144.7	144.7	144.7	144.7	144.7	144.7	144.7	144.7	144.7	144.7	144.7
Total Cash flow (cumulated)	-227.0	-737.6	-1134.8	-1078.0	-933.4	-788.7	-644.0	-499.3	-354.6	-209.9	-65.2	79.5	224.1	368.8	513.5
Discounted Cash Flow (Yearly)	-206.3	-422.0	-298.4	38.8	89.8	81.7	74.2	67.5	61.4	55.8	50.7	46.1	41.9	38.1	34.6
Discounted Cash Flow (Cumul.)	-206.3	-628.4	-926.8	-888.0	-798.2	-716.5	-642.2	-574.7	-513.4	-457.6	-406.9	-360.8	-318.9	-280.8	-246.1

CASH FLOW ANALYSYS Millions Euro	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	268.1	268.1	268.1	268.1	268.1	268.1	268.1	268.1	268.1	268.1	268.1	268.1	268.1	
Sulphur	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	
Operating Costs														
Fuel Cost	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	
Maintenance	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	
Labour	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	
Chemicals & Consumables	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	
Waste Disposal	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	
Insurance	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	
Working Capital Cost														1.6
Fixed Capital Expenditures														
Total Cash flow (yearly)	144.7	144.7	144.7	144.7	144.7	144.7	144.7	144.7	144.7	144.7	144.7	144.7	144.7	1.6
Total Cash flow (cumulated)	658.2	802.9	947.6	1092.3	1236.9	1381.6	1526.3	1671.0	1815.7	1960.4	2105.1	2249.8	2394.4	2396.1
Discounted Cash Flow (Yearly)	31.5	28.6	26.0	23.7	21.5	19.6	17.8	16.2	14.7	13.4	12.1	11.0	10.0	0.1
Discounted Cash Flow (Cumul.)	-214.7	-186.0	-160.0	-136.3	-114.8	-95.3	-77.5	-61.4	-46.7	-33.3	-21.2	-10.1	-0.1	0.0

Production		
Coal Florate	624.2	t/h
Net Power Output	628.8	MW
Sold Sulphur	0.00	t/h
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	1062.8
Land purchase; surveys	53.1
Fees	21.3
Average Contingencies	67.9
Total Investment Cost	1205.1

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	48.8
Maintenance	38.6
Waste Disposal	0.0
Chemicals + Consumable	7.7
Insurance and local taxes	21.3

Working Capital		**MM Euro**
30 days Chemical Storage		0.7
5 days Coal Storage		0.8
Total Working capital		1.5

Labour Cost		**MM Euro/year**
# operators		128
Salary		0.05
Direct Labour Cost		6.4
Administration	30% L.C.	1.9
Total Labour Cost		8.3

Electricity Production Cost	0.059	Euro/kWh
Sulphur Price	103.3	Euro/t
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	278.2	MM Euro/year

NPV	0.00
IRR	10.00%

CASH FLOW ANALYSYS Millions Euro	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	000	00	0	1	2	3	4	5	6	7	8	9	10	11
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%											
Revenues														
Electric Energy				147.3	278.2	278.2	278.2	278.2	278.2	278.2	278.2	278.2	278.2	278.2
Sulphur				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Costs														
Fuel Cost				-25.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8
Maintenance				-25.7	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6
Labour				-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3
Chemicals & Consumables				-4.1	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3
Working Capital Cost				-1.5										
Fixed Capital Expenditures	-241.0	-542.3	-421.8											
Total Cash flow (yearly)	-241.0	-542.3	-421.8	60.6	153.6	153.6	153.6	153.6	153.6	153.6	153.6	153.6	153.6	153.6
Total Cash flow (cumulated)	-241.0	-783.3	-1205.1	-1144.5	-990.9	-837.3	-683.7	-530.1	-376.4	-222.8	-69.2	84.4	238.0	391.7
Discounted Cash Flow (Yearly)	-219.1	-448.2	-316.9	41.4	95.4	86.7	78.8	71.7	65.1	59.2	53.8	48.9	44.5	40.5
Discounted Cash Flow (Cumul.)	-219.1	-667.3	-984.2	-942.8	-847.4	-760.7	-681.9	-610.2	-545.1	-485.8	-432.0	-383.0	-338.6	-298.1

CASH FLOW ANALYSYS Millions Euro	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor															
Revenues															
Electric Energy	278.2	278.2	278.2	278.2	278.2	278.2	278.2	278.2	278.2	278.2	278.2	278.2	278.2	278.2	
Sulphur	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	
Operating Costs															
Fuel Cost	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	
Maintenance	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	
Labour	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	
Chemicals & Consumables	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	
Waste Disposal	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	
Insurance	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	
Working Capital Cost															1.5
Fixed Capital Expenditures															
Total Cash flow (yearly)	153.6	153.6	153.6	153.6	153.6	153.6	153.6	153.6	153.6	153.6	153.6	153.6	153.6	153.6	1.5
Total Cash flow (cumulated)	545.3	698.9	852.5	1006.1	1159.8	1313.4	1467.0	1620.6	1774.2	1927.9	2081.5	2235.1	2388.7	2542.3	2543.9
Discounted Cash Flow (Yearly)	36.8	33.4	30.4	27.6	25.1	22.8	20.8	18.9	17.2	15.6	14.2	12.9	11.7	10.7	0.1
Discounted Cash Flow (Cumul.)	-261.3	-227.9	-197.5	-169.9	-144.8	-121.9	-101.2	-82.3	-65.1	-49.5	-35.4	-22.5	-10.7	-0.1	0.0

TABLE E.5.12 - FOSTER WHEELER - Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	691.0	t/h
Net Power Output	686.6	MW
Sold Sulphur	0.00	t/h
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	1085.9
Land purchase; surveys	54.3
Fees	21.7
Average Contingencies	70.7
Total Investment Cost	1232.7

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	54.0
Maintenance	40.1
Waste Disposal	0.0
Chemicals + Consumable	7.3
Insurance and local taxes	21.7

Working Capital		**MM Euro**
30 days Chemical Storage		0.7
5 days Coal Storage		0.9
Total Working capital		1.6
Labour Cost		**MM Euro/year**
# operators		128
Salary		0.05
Direct Labour Cost		6.4
Administration	30% L.C.	1.9
Total Labour Cost		8.3

Electricity Production Cost	0.056	Euro/kWh
Sulphur Price	103.3	Euro/t
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	288.6	MM Euro/year
NPV	0.00	
IRR	10.00%	

CASH FLOW ANALYSYS Millions Euro	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				152.8	288.6	288.6	288.6	288.6	288.6	288.6	288.6	288.6	288.6	288.6	288.6
Sulphur				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Costs															
Fuel Cost				-28.6	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0
Maintenance				-26.7	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1
Labour				-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3
Chemicals & Consumables				-3.9	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7
Working Capital Cost				-1.6											
Fixed Capital Expenditures	-246.5	-554.7	-431.4												
Total Cash flow (yearly)	-246.5	-554.7	-431.4	62.0	157.1	157.1	157.1	157.1	157.1	157.1	157.1	157.1	157.1	157.1	157.1
Total Cash flow (cumulated)	-246.5	-801.2	-1232.7	-1170.7	-1013.6	-856.4	-699.3	-542.2	-385.0	-227.9	-70.8	86.4	243.5	400.6	557.7
Discounted Cash Flow (Yearly)	-224.1	-458.4	-324.1	42.3	97.6	88.7	80.6	73.3	66.6	60.6	55.1	50.1	45.5	41.4	37.6
Discounted Cash Flow (Cumul.)	-224.1	-682.5	-1006.7	-964.4	-866.8	-778.1	-697.5	-624.2	-557.5	-496.9	-441.9	-391.8	-346.3	-304.9	-267.3

CASH FLOW ANALYSYS Millions Euro	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	288.6	288.6	288.6	288.6	288.6	288.6	288.6	288.6	288.6	288.6	288.6	288.6	288.6	
Sulphur	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	
Operating Costs														
Fuel Cost	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	
Maintenance	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	
Labour	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	
Chemicals & Consumables	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	
Waste Disposal	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	
Insurance	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	
Working Capital Cost														1.6
Fixed Capital Expenditures														
Total Cash flow (yearly)	157.1	157.1	157.1	157.1	157.1	157.1	157.1	157.1	157.1	157.1	157.1	157.1	157.1	1.6
Total Cash flow (cumulated)	714.9	872.0	1029.1	1186.3	1343.4	1500.5	1657.7	1814.8	1971.9	2129.1	2286.2	2443.3	2600.4	2602.0
Discounted Cash Flow (Yearly)	34.2	31.1	28.3	25.7	23.4	21.2	19.3	17.5	16.0	14.5	13.2	12.0	10.9	0.1
Discounted Cash Flow (Cumul.)	-233.1	-202.0	-173.8	-148.1	-124.7	-103.5	-84.2	-66.6	-50.7	-36.2	-23.0	-11.0	-0.1	0.0

TABLE E.5.13 - FUTURE ENERGY - Cost Evaluation - Discount Rate = 5%

Production		
Coal Florate	653.3	t/h
Net Power Output	665.2	MW
Sold Sulphur	0.00	t/h
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	1000.1
Land purchase; surveys	50.0
Fees	21.6
Average Contingencies	63.1
Total Investment Cost	1134.8

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	51.1
Maintenance	35.8
Waste Disposal	0.0
Chemicals + Consumable	8.2
Insurance and local taxes	20.0

Working Capital		**MM Euro**
30 days Chemical Storage		0.8
5 days Coal Storage		0.8
Total Working capital		1.6
Labour Cost		**MM Euro/year**
# operators		128
Salary		0.05
Direct Labour Cost		6.4
Administration	30% L.C.	1.9
Total Labour Cost		8.3

Electricity Production Cost	0.043	Euro/kWh
Sulphur Price	103.3	Euro/t
Inflation	0.00	%
Taxes	0.00	%
Discount rate	5.00	%
Revenues / year	211.5	MM Euro/year

NPV	0.00
IRR	5.00%

CASH FLOW ANALYSYS Millions Euro	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				111.9	211.5	211.5	211.5	211.5	211.5	211.5	211.5	211.5	211.5	211.5	211.5
Sulphur				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Costs															
Fuel Cost				-27.0	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1
Maintenance				-23.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8
Labour				-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3
Chemicals & Consumables				-4.3	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0
Working Capital Cost				-1.6											
Fixed Capital Expenditures	-227.0	-510.7	-397.2												
Total Cash flow (yearly)	-227.0	-510.7	-397.2	26.8	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1
Total Cash flow (cumulated)	-227.0	-737.6	-1134.8	-1108.0	-1019.9	-931.8	-843.7	-755.7	-667.6	-579.5	-491.4	-403.3	-315.2	-227.1	-139.0
Discounted Cash Flow (Yearly)	-216.2	-463.2	-343.1	22.0	69.0	65.7	62.6	59.6	56.8	54.1	51.5	49.1	46.7	44.5	42.4
Discounted Cash Flow (Cumul.)	-216.2	-679.3	-1022.4	-1000.4	-931.4	-865.6	-803.0	-743.4	-686.6	-632.6	-581.1	-532.0	-485.3	-440.8	-398.4

CASH FLOW ANALYSYS Millions Euro	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	211.5	211.5	211.5	211.5	211.5	211.5	211.5	211.5	211.5	211.5	211.5	211.5	211.5	
Sulphur	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	
Operating Costs														
Fuel Cost	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	-51.1	
Maintenance	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	-35.8	
Labour	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	
Chemicals & Consumables	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	-8.2	
Waste Disposal	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	
Insurance	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	-20.0	
Working Capital Cost														1.6
Fixed Capital Expenditures														
Total Cash flow (yearly)	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	88.1	1.6
Total Cash flow (cumulated)	-50.9	37.1	125.2	213.3	301.4	389.5	477.6	565.7	653.8	741.9	829.9	918.0	1006.1	1007.7
Discounted Cash Flow (Yearly)	40.4	38.4	36.6	34.9	33.2	31.6	30.1	28.7	27.3	26.0	24.8	23.6	22.5	0.4
Discounted Cash Flow (Cumul.)	-358.1	-319.6	-283.0	-248.2	-215.0	-183.4	-153.2	-124.6	-97.2	-71.2	-46.5	-22.9	-0.4	0.0

TABLE E.5.14 - SHELL - Cost Evaluation - Discount Rate = 5%

Production		
Coal Florate	624.2	t/h
Net Power Output	628.8	MW
Sold Sulphur	0.00	t/h
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	1062.8
Land purchase; surveys	53.1
Fees	21.3
Average Contingencies	67.9
Total Investment Cost	1205.1

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	48.8
Maintenance	38.6
Waste Disposal	0.0
Chemicals + Consumable	7.7
Insurance and local taxes	21.3

Working Capital		**MM Euro**
30 days Chemical Storage		0.7
5 days Coal Storage		0.8
Total Working capital		1.5
Labour Cost		**MM Euro/year**
# operators		128
Salary		0.05
Direct Labour Cost		6.4
Administration	30% L.C.	1.9
Total Labour Cost		8.3

Electricity Production Cost	0.047	Euro/kWh
Sulphur Price	103.3	Euro/t
Inflation	0.00	%
Taxes	0.00	%
Discount rate	5.00	%
Revenues / year	218.2	MM Euro/year
NPV	0.00	
IRR	5.00%	

CASH FLOW ANALYSYS Millions Euro	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electric Energy				115.5	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	218.2	
Sulphur				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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Operating Costs																													
Fuel Cost				-25.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	-48.8	
Maintenance				-25.7	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	-38.6	
Labour				-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	
Chemicals & Consumables				-4.1	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	-7.7	
Waste Disposal				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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance				-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	-21.3	
Working Capital Cost				-1.5																									1.5
Fixed Capital Expenditures	-241.0	-542.3	-421.8																										
Total Cash flow (yearly)	-241.0	-542.3	-421.8	28.8	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	93.5	1.5
Total Cash flow (cumulated)	-241.0	-783.3	-1205.1	-1176.3	-1082.8	-989.3	-895.8	-802.2	-708.7	-615.2	-521.6	-428.1	-334.6	-241.1	-147.5	-54.0	39.5	133.0	226.6	320.1	413.6	507.2	600.7	694.2	787.7	881.3	974.8	1068.3	1069.9
Discounted Cash Flow (Yearly)	-229.5	-491.9	-364.4	23.7	73.3	69.8	66.5	63.3	60.3	57.4	54.7	52.1	49.6	47.2	45.0	42.8	40.8	38.9	37.0	35.2	33.6	32.0	30.4	29.0	27.6	26.3	25.1	23.9	0.4
Discounted Cash Flow (Cumul.)	-229.5	-721.4	-1085.8	-1062.1	-988.8	-919.0	-852.6	-789.3	-729.0	-671.6	-616.9	-564.8	-515.2	-468.0	-423.0	-380.1	-339.3	-300.5	-263.4	-228.2	-194.6	-162.7	-132.2	-103.2	-75.6	-49.3	-24.2	-0.4	0.0

FOSTER WHEELER

TABLE E.5.15 - FOSTER WHEELER - Cost Evaluation - Discount Rate = 5%

Production		
Coal Florate	691.0	t/h
Net Power Output	686.6	MW
Sold Sulphur	0.00	t/h
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	1085.9
Land purchase; surveys	54.3
Fees	21.7
Average Contingencies	70.7
Total Investment Cost	1232.7

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	54.0
Maintenance	40.1
Waste Disposal	0.0
Chemicals + Consumable	7.3
Insurance and local taxes	21.7

Working Capital		**MM Euro**
30 days Chemical Storage		0.7
5 days Coal Storage		0.9
Total Working capital		1.6
Labour Cost		**MM Euro/year**
# operators		128
Salary		0.05
Direct Labour Cost		6.4
Administration	30% L.C.	1.9
Total Labour Cost		8.3

Electricity Production Cost	0.044	Euro/kWh
Sulphur Price	103.3	Euro/t
Inflation	0.00	%
Taxes	0.00	%
Discount rate	5.00	%
Revenues / year	227.1	MM Euro/year
NPV	0.00	
IRR	5.00%	

CASH FLOW ANALYSYS Millions Euro	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%											
Revenues														
Electric Energy				120.2	227.1	227.1	227.1	227.1	227.1	227.1	227.1	227.1	227.1	227.1
Sulphur				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Costs														
Fuel Cost				-28.6	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0
Maintenance				-26.7	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1
Labour				-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3
Chemicals & Consumables				-3.9	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7
Working Capital Cost				-1.6										
Fixed Capital Expenditures	-246.5	-554.7	-431.4											
Total Cash flow (yearly)	-246.5	-554.7	-431.4	29.4	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7
Total Cash flow (cumulated)	-246.5	-801.2	-1232.7	-1203.2	-1107.6	-1011.9	-916.2	-820.6	-724.9	-629.2	-533.6	-437.9	-342.2	-246.6
Discounted Cash Flow (Yearly)	-234.8	-503.1	-372.7	24.2	75.0	71.4	68.0	64.8	61.7	58.7	55.9	53.3	50.7	48.3
Discounted Cash Flow (Cumul.)	-234.8	-737.9	-1110.6	-1086.4	-1011.4	-940.1	-872.1	-807.3	-745.6	-686.9	-631.0	-577.7	-527.0	-478.7

CASH FLOW ANALYSYS Millions Euro	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	12	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor															
Revenues															
Electric Energy	227.1	227.1	227.1	227.1	227.1	227.1	227.1	227.1	227.1	227.1	227.1	227.1	227.1	227.1	
Sulphur	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	
Operating Costs															
Fuel Cost	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	-54.0	
Maintenance	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	-40.1	
Labour	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	-8.3	
Chemicals & Consumables	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	-7.3	
Waste Disposal	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	
Insurance	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	-21.7	
Working Capital Cost															1.6
Fixed Capital Expenditures															
Total Cash flow (yearly)	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	95.7	1.6
Total Cash flow (cumulated)	-150.9	-55.2	40.4	136.1	231.7	327.4	423.1	518.7	614.4	710.1	805.7	901.4	997.1	1092.7	1094.3
Discounted Cash Flow (Yearly)	46.0	43.8	41.7	39.8	37.9	36.1	34.3	32.7	31.1	29.7	28.3	26.9	25.6	24.4	0.4
Discounted Cash Flow (Cumul.)	-432.6	-388.8	-347.1	-307.3	-269.5	-233.4	-199.1	-166.4	-135.2	-105.6	-77.3	-50.4	-24.8	-0.4	0.0

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SECTION F

COMPARISON OF ALTERNATIVES AND SELECTION OF THE MOST PROMISING TECHNOLOGY

I N D E X

SECTION F

SECTION F COMPARISON OF ALTERNATIVES AND SELECTION OF THE MOST PROMISING TECHNOLOGY

1.0 Introduction

Purpose of this section F is to present the performance and cost data developed for the alternatives studied in the previous sections, in order to bring to evidence the major features and merits of each alternative.

Data used for this comparison are also summarized in Appendix 1, which collects performances, costs and environmental data of all the alternatives. From the first analysis of the table, it is evident that the alternatives have approximately a similar net electrical efficiency, despite the differences of the various technologies involved, which, on the contrary, is reflected in the wide range of both the investment and specific net investment cost. With reference to the production costs, the range of variation falls in a tight range, because the Cost of Energy is simultaneously affected by different factors like the investment cost and the operating/maintenance costs of each alternative.

The following paragraphs present a more detailed analysis of the different alternatives. Due to the number of cases analyzed, the comparison of the alternatives is initially split into two separate groups:

- Post-combustion CO_2 capture alternatives (Case 1 to 4).
- Pre-combustion CO_2 capture alternatives (Case 5 to 7).

This initial comparison allows selecting the two best alternatives, one for each group. Then, the two selected alternatives are compared in order to select the most promising technology of the project.

2.0 Post-combustion CO_2 capture alternatives (Case 1 through 4)

This comparison is mainly aimed at evaluating the effect of the post combustion CO_2 capture on different power plant technologies, by examining plant performances, investment/production cost data and environmental impact.

Table F.2.1 summarises the most important data of the four alternatives.

Table F.2.1 – Performance data.

		Case 1 PC-Boiler		Case 2 PC-Oxycomb.		Case 3 CFB- FW		Case 4 PCFB-FW	
ACID GAS REMOVAL TECHNOLOGY		MEA Scrubbing		Gas Liquefaction		MEA Scrubbing		MDEA Scrubbing	
CO_2 Capture Efficiency	**%**	85.0		93.0		85.0		85.0	
OVERALL PERFORMANCES									
Coal Flow Rate A.R.	**t/h**	734.0		677.6		592.9		727.0	
Coal LHV	**kJ/kg**	10500		10500		10500		10500	
Thermal Energy of Feedstock	**MWth**	2140.8		1976.3		1729.2		2120.4	
Gross Electric Power Output	**MWe**	932.0		1039.4		763.0		816.0	
Auxiliary Consumption	**MWe**	168.8		295.8		146.5		125.5	
Net Electric Power Output	**MWe**	761.0		741.3		614.7		688.4	
Gross Electrical Efficiency	**%**	43.5		52.6		44.1		38.5	
Net Electrical Efficiency	**%**	35.5		37.5		35.5		32.5	
EMISSIONS		g/kWh	mg/Nm3 (6% O_2)	g/kWh	g/h	g/kWh	mg/Nm3 (6% O_2)	g/kWh	mg/Nm3 (6% O_2)
CO_2		166	-	71	-	168	-	181	-
NO_X		0.13	40	0	0	0.14	40	0.15	40
SO_X		0.10(1)	29(1)	0.0013	950	0.15(1)	43 (1)	0.15(1)	38(1)
CO		0.50	150	0	0	0.53	150	0.58	150
Particulate		0.04	30	0.02	Nil	0.03	30	0.03	30
NH_3 (2)		0.02	5	-	-	0.02	5	0.02	5
INVESTMENT COST DATA									
Total Investment	**10^6 €**	1251.8		1395.2		953.8		1230.6	
Specific Net Investment Cost	**€/kW**	1645		1882		1552		1788	
PRODUCTION COST DATA									
C.O.E (DCF=10%)	**c€/kWh**	5.39		5.46		5.34		5.55	
C.O.E. (DCF=5%)	**c€/kWh**	4.28		4.20		4.30		4.35	

Notes: (1) SOx emissions upstream AGR unit; after solvent washing, emissions are expected close to zero.
(2) Due to ammonia slippage into the flue gas downstream the SCR/SNCR.

The feature common to the four alternatives is the drying of the coal from 50.7% to 32%, before feeding the boilers (reference to Section C, paragraph 3.0).

Cases 1 and 3 (USC-PC, CFB), which are established boiler technologies for lignite coal processing, are based on a MEA scrubbing as acid gas removal technology, while the higher pressure of Case 4 (PCFB) makes more advantageous a MDEA washing in order to reduce the steam requirement of the unit.

Both MEA and MDEA washing are widely used for removal of acid gases from streams that are generally oxygen free. No application is presently in operation on large scale for CO_2 capture from power plants exhausts, which contain high oxygen level. However, there are smaller power plants in operation where CO_2 is captured from flue gas, ranging from a few tons per day to a maximum of 200 t/d from a flue gas side stream. These processes have been modified to incorporate inhibitors to limit solvent degradation and equipment corrosion, but only after commercial experience of large-scale coal power plants, a precise estimate of amine losses will be available.

Case 2 is not a well-proven technology because the combustion with pure oxygen has not been used in commercial power plants yet. However, the design of the boiler can be considered as an extrapolation of the existing air fired technology.

The main comments from Table F.2.1 are the following:

- The higher boiler pressure of Case 4 results in a lower Plant auxiliary consumption with respect to the other alternatives, because of the less AGR steam requirement of MDEA with respect to MEA. A further improvement of the AGR performances might be obtained through the selection of a physical solvent (Selexol) instead of MDEA. However, the complexity of the process scheme, specifically the need of cooling and reheating of the flue gas before and after the CO_2 absorption, leads to a low net electrical efficiency of the Plant, which is not expected to be offset, even if Selexol were adopted.
  The complexity of the process scheme also corresponds to a high investment cost and therefore to a high Cost of Electricity.
  As a consequence, Case 4 is the least attractive of the postcombustion CO_2 capture alternatives.

- By comparing Case 1 (USC-PC Boiler) and Case 3 (CFB Boiler), the gross efficiency of the second alternative is higher (+0.6%). This is due to the better combustion efficiency of the fluidized bed technology, mainly related to the homogeneity of the dense phase properties and the coal particle size required by the boiler. In fact, due to the high moisture content of the coal, the conventional PC boiler requires a flue gas extraction from the furnace for final drying and milling of the coal, thus resulting in a reduction of the boiler efficiency.
  With reference to the auxiliary consumption of the two alternatives, Case 3 does not require an FGD unit because the relatively low sulphur content of the coal allows to respect the SOx limit of the downstream AGR unit by adsorption on the limestone used in the fluidized bed. However, this saving of the power consumption is completely offset by the higher auxiliary consumption of the boiler island, because of the air blowers needed for the fluidization of the bed. In fact, the total auxiliary power consumption of Case 3 is higher than Case 1, if considered proportional to the coal flow rate.
  The sum of the above effects leads to the same net electrical efficiency for the two alternatives (35.5%).
  With reference to the investment data, the specific investment cost is lower as the FGD unit and final coal pulverization milling are not required, with a consequent lower Cost of Electricity.

- Case 2 is attractive because the flue gas at the exit of the boiler mainly consists of CO_2 and consequently the downstream flue gas liquefaction allows reaching a high CO_2 capture efficiency with respect to the other alternatives (93% vs. 85%).
  The gross efficiency of the power plant is higher than the other cases because the elimination of AGR avoids its large steam consumption, with a consequent gain on the gross power production. This beneficial effect is partially reduced by the high power requirement of the ASU, which provides oxygen for the coal combustion. In any case, the net electrical efficiency is the best one amongst the four alternatives.
  With reference to the investment cost data, Case 2 is strongly penalized by the cost of the Air Separation Unit that entails the highest investment and highest net specific investment cost of the four alternatives. This result is also reflected in the Cost of Energy at 10% DCF, where figures are higher than the other alternatives. On the other hand, figures at 5% DCF have an opposite trend, because of the low operating costs of this

alternative (see Section E). In any case, 5 % DCF is only a sensitivity analysis of the study, being 10% DCF the design basis of the project. In fact, 5% DCF cannot be considered in line with the actual parameters of the market.
As a consequence of the above economical considerations, Case 2 is less attractive than Case 1 and 3.

- With reference to Case 3, literature data state that the CFB technology is a potential source of N_2O emission, which is a powerful greenhouse gas as 1 kg of N_2O is equivalent to approximately 300 kg of CO_2.

  N_2O emission is much dependent on the combustion temperature, being the N_2O emission decreasing when increasing the combustion temperature. With reference to the specific lignite of the study, the temperatures in the furnace ranges from 875°C (bed temperature) to 880°C (furnace temperature). With these temperatures, the expected N_2O emission from the CFB boiler is approximately 20 mg/Nm^3 (as average value). Therefore, the N_2O production is approximately 0.049 t/h, equivalent to 14.5 t/h of CO_2. In this case, the CO_2 specific emission would increase from 168 to 192 g/kWh.

  Based on some literature data, an additional N_2O emission could also be expected from the SCR system, because of the NH_3 injection, but this is not generally confirmed from catalyst's Suppliers. If additional N_2O emission would be considered for the SCR system, this would be higher for the PC boiler, because the injection system of the CFB is more suitable for a better distribution in the flue gas and the quantity of ammonia injected into the PC boiler is higher, due to the higher combustion temperature, which leads to a higher NOx flowrate entering the SCR system. However, it is not possible to quantify this possible N_2O emission from the SCR system.

  The percentage CO_2 capture could be increased in a CFB plant to offset the higher N_2O emissions: by capturing approximately 87% of the CO_2 entering the AGR unit, instead of the actual 85%, the CO_2 specific emission would decrease from 192 g/KWh to the actual 168 g/kWh. However, the IEA GHG-Fluor study showed that the percentage capture of CO_2 could be increased to 95%, if necessary, without increasing the cost per tonne of CO_2 captured and without affecting significantly the Cost of Electricity.

- With reference to the specific emissions of Case 2, this alternative has the lowest figures, being the pollutant emission close to zero; this is a direct consequence of the combustion with oxygen instead of air. Alternatives other than Case 2 have similar emissions (refer also to the previous point) and their pollutant concentration is in compliance with the current European Directive, as well as the design basis of the project. Therefore, the better environmental performances of Case 2 do not justify considering this alternative the most promising amongst the postcombustion CO_2 capture technologies.

On the basis of the considerations made in this paragraph, Case 3 (CFB) results the most promising technology among the postcombustion CO_2 capture alternatives of the study.

3.0 Pre-combustion CO_2 capture alternatives (Case 5 through 7)

This comparison is mainly aimed at evaluating the effect of the pre-combustion CO_2 capture on different gasification technologies, by examining plant performances, investment/production cost data and environmental impact. The different gasification technologies are: Future Energy (Case 5), Shell (Case 6), FW (Case 7).

Table F.3.1 summarises the most important data of the IGCC alternatives.

Table F.3.1 – Performance data.

		Case 5 Future Energy Gasifier		Case 6 Shell Gasifier		Case7 FW Gasifier	
ACID GAS REMOVAL TECHNOLOGY		MDEA Scrubbing		MDEA Scrubbing		MDEA Scrubbing	
CO_2 Capture Efficiency	**%**	85.8		85.2		82.9	
OVERALL PERFORMANCES							
Coal Flow Rate A.R.	**t/h**	653.3		624.2		691.0	
Coal LHV	**kJ/kg**	10500		10500		10500	
Thermal Energy of Feedstock	**MWth**	1914.4 (1)		1820.5		2015.4	
Gross Electric Power Output	**MWe**	900.3		868.7		900.5	
Auxiliary Consumption	**MWe**	233.1		238.0		211.9	
Net Electric Power Output	**MWe**	665.2		628.8		686.6	
Gross Electrical Efficiency	**%**	47.2		47.7		44.7	
Net Electrical Efficiency	**%**	34.7		34.5		34.1	
EMISSIONS		**g/kWh**	**mg/Nm3 (15% O_2)**	**g/kWh**	**g/h**	**G/kWh**	**mg/Nm3 (15% O_2)**
CO_2		160	-	168	-	191	-
NO_X		0.56	74	0.60	74	0.61	74
SO_X		0.01	1.2	0.01	1.2	0.01	1.2
CO		0.24	31.3	0.25	31.3	0.26	31.4
Particulate		0.04	5	0.04	5	0.04	5
NH_3		-	-	-	-	-	-
INVESTMENT COST DATA							
Total Investment	**10^6 €**	1134.8		1205.1		1232.7	
Specific Net Investment Cost	**€/kW**	1706		1917		1795	
PRODUCTION COST DATA							
C.O.E (DCF=10%)	**c€/kWh**	5.41		5.94		5.64	
C.O.E (DCF=5%)	**c€/kWh**	4.27		4.66		4.44	

(1) Thermal Energy of Feedstock including Natural Gas to Gasifiers

The main common feature of the alternatives is a gasification pressure suitable to feed the gas turbines and the use of a MDEA scrubbing for the acid gas washing, with a combined removal of CO_2 and H_2S.

Cases 5 and 6 (Future Energy and Shell gasification technology) are based on a oxygen-blown entrained bed gasification, whilst Case 7 is based on an air blown fluidized bed gasifier, thus avoiding the presence of the Air Separation Unit.

The main comments from Table F.3.1 are the following:

- By comparing Case 5 and Case 6, the Shell gross electrical efficiency is higher than Future Energy, whilst the net electrical efficiency is lower. This is mainly due to the following reasons:

  - Gasifier efficiency of the Shell Technology is higher, thus resulting in a lower inlet coal flowrate and in a higher gross electrical efficiency of the Plant;
  - Auxiliary consumption of the Shell technology are slightly higher than those of Future Energy. In fact, the higher flowrate of Case 5 corresponds to a higher power consumption of process units (ASU, syngas treatment and conditioning line), but the higher power requirement of the Shell gasification island completely offsets the previous advantage. This leads to the higher net electrical efficiency of the Future Energy Technology.

  With reference to the investment and production cost data, the Shell technology is penalized by the higher investment cost of the Gasification Island, which is explained by the use of Waste Heat Boiler vs. quench adopted by Future Energy. This leads to the highest specific net investment cost and Cost of Energy among the three IGCC alternatives.

- The main advantages of the FW technology are the possibility of avoiding the Air Separation Unit and the capability of gasifying lignite with a high moisture content (25% wt). Future Energy and Shell gasification technologies require, in fact, 10% and 5% of moisture content respectively, thus representing a real challenge of the actual drying technologies for lignite coal (reference to Section C, paragraph 3.0). This high degree of drying required by these two technologies is related to the use of pulverized coal for pneumatic transportation; the low moisture content is necessary to prevent pneumatic transportation plugging.

Both Shell and Future Energy technologies have commercial experience with coal. FW fluid bed gasifier does not have commercial track record, but a design particularly suited for lignite because it does not require lignite pulverisation, but most simply a size reduction and control.
The avoidance of the ASU results in the lowest plant auxiliary consumption. However, the low carbon conversion efficiency (97% vs. more than 99% of the other technologies) leads to the lowest gross efficiency among the three alternatives (44.7% vs. more than 47% of the other technologies). In addition, the low carbon conversion efficiency of the gasifier and the presence of CH_4 in the flue gas, because of the low gasification temperature, reduce the amount of CO that can be economically shifted to CO_2, thus limiting the CO_2 capture efficiency to approximately 83% instead of 85% of the other alternatives.
Another disadvantage of this technology is due to the high gas flowrate of the syngas treatment and conditioning line, as well as of the AGR unit. This is because the gasification with air entails a high nitrogen content in the syngas, and a consequent low concentration of the CO_2 flowing to the AGR, thus increasing the steam requirement and the investment cost of the unit.
Above features of Case 7 result in a relatively high plant investment cost that, together with the low net electrical efficiency, leads to a non attractive cost of electricity.

- With reference to the environmental performances, the three alternatives have similar specific emission levels and the pollutant concentration is in compliance with the current European Directive, as well as the design basis of the project.

The considerations made in this paragraph lead to the conclusion that the Future Energy gasification is the preferred option of the pre-combustion CO_2 capture alternatives.

4.0 Selection of the most promising technology

The considerations made in paragraph 2.0 and 3.0 allowed the selection of the two best alternatives, CFB and IGCC based on Future Energy technology, respectively for the postcombustion and precombustion CO_2 capture case.

Table F.4.1 summarizes the most important performances of the two alternatives.

Table F.4.1 – Performance data.

		Case 3 - CFB-Boiler (FW)		Case 5 - Future Energy Gasifier	
CO_2 capture efficiency, %		85.0		85.8	
Lignite Moisture Content After Drying %wt		32		10	
ACID GAS REMOVAL TECHNOLOGY		MEA Scrubbing		MDEA Scrubbing	
Carbon in Coal Feed	kmol/h	15466.0		17075.0	
Limestone	kmol/h	259.7		0.0	
Slag	kmol/h	50.7		42.7	
CO_2 to Storage	kmol/h	13324.0		14621.0	
CO_2 Capture Efficiency	%	85.0		85.8	
OVERALL PERFORMANCES					
Coal Flow Rate A.R.	t/h	592.9		653.3	
Thermal Energy of Feedstock	MWth	1729.2		1914.4 (1)	
Gross Electric Power Output	MWe	763.0		900.3	
Auxiliary Consumption	MWe	146.5		233.1	
Gross Electrical Efficiency	%	44.1		47.2	
Net Electrical Efficiency	%	35.5		34.7	
EMISSIONS		g/kWh	mg/Nm^3 (VD 6% O_2)	g/kWh	mg/Nm^3 (VD 15% O_2)
CO_2		168	-	160	-
NO_X		0.14	40	0.56	74
SO_X		0.15 (2)	43 (2)	0.01	1.2
CO		0.53	150	0.24	31.3
Particulate		0.03	30	0.04	5
NH_3 (3)		0.02	5	-	-
INVESTMENT COST DATA					
Total Investment	10^6 €	953.8		1134.8	
Specific Net Investment Cost	€/kW	1552		1706	
PRODUCTION COST DATA					
C.O.E. (DCF=10%)	c€/kWh	5.34		5.41	
C.O.E. (DCF=5%)	c€/kWh	4.31		4.27	

(1) Thermal Energy of Feedstock including Natural Gas to Gasifiers
(2) SOx emissions upstream AGR unit; after solvent washing, emissions are expected close to zero.
(3) Due to ammonia slippage into the flue gas downstream the SCR.

The IGCC alternative has a higher gross electrical efficiency (47.2% vs. 44.1%) due to the presence of the gas turbines and to the possibility of using an AGR unit based on a MDEA solvent, which allows saving a considerable quantity of thermal power for the stripper reboilers.

On the other hand, the MDEA washing unit and the need of an ASU entail a high auxiliary power requirement of the IGCC technology, which leads to a lower net electrical efficiency (34.7% vs. 35.5%).

Another advantage of the CFB technology, not negligible, is the possibility of processing a lignite coal with 32% moisture content instead of the 10% required by the Future Energy gasification technology. Current technologies have not yet proven the capability of reach such a low moisture content for a lignite coal.

With reference to the environmental performances, no significant difference is noted amongst the two alternatives.

The comparison of the investment and production cost data are also in favour of the CFB technology, due to the complexity of the IGCC plant, which requires capital intensive units like the ASU and the syngas treatment and conditioning line. On the other hand, the Cost of Energy at 5% DCF is slightly in favour of the IGCC alternative, being the operating cost of the CFB case high because of the higher consumption of the MEA solvent. In any case, as already stated in paragraph 2.0, 5% DCF cannot be considered in line with the actual parameters of the current market.

With reference to the Cost of Energy, it has to be remarked that the availability of the CFB technology should be considered higher than the IGCC Plant. The comparison made in this paragraph is based on 7446 hours of operation, after the commissioning period, for both the alternatives. If 7884 operating hours (90% load factor) for the CFB alternative were considered, the Cost of Energy would be as follows:

- 5.17 c€/kWh at 10% DCF.
- 4.18 c€/kWh at 5% DCF.

Therefore, the considerations made in this section bring to evidence that the most promising technology of the CO_2 capture in low rank coal power plants is the CFB alternative.

Appendix 1

Summary of Performance, Cost and Environmental data of all the alternatives

Appendix 1 – Summary of performance, cost and environmental data of all the alternatives

COMPARISON OF THE ALTERNATIVES

		Post-combustion CO_2 Capture				Pre-combustion CO_2 Capture		
		Case 1 PC-Boiler	**Case 2 PC-Oxy Combustion**	**Case 3 CFB-Boiler (FW)**	**Case 4 PCFB-Boiler (FW)**	**Case 5 Future Energy Gasifier**	**Case Shell Gasifier**	**Case 7 FW Gasifier**
CO_2 capture efficiency, %		85.0	93.0	85.0	85.0	85.8	85.2	82.9
Lignite Moisture Content After Drying %wt		32	32	32	32	10	5	25
ACID GAS REMOVAL TECHNOLOGY		MEA Scrubbing	Gas Liquefaction	MEA Scrubbing	MDEA Scrubbing	MDEA Scrubbing	MDEA Scrubbing	MDEA Scrubbing
Carbon in Coal Feed	**kmol/h**	19144.0	17674.0	15466.0	18973.0	17075.0	16283.0	18038.0
Limestone	**kmol/h**	51.0	0.0	259.7	98.0	0.0	0.0	84.0
Slag	**kmol/h**	118.0	426.0	50.7	190.0	42.7	99.9	661.0
CO_2 to Storage	**kmol/h**	16215.0	16044.0	13324.0	16050.0	14621.0	13785.0	14474.5
CO_2 Capture Efficiency	**%**	85.0	93.0	85.0	85.0	85.8	85.2	82.9
OVERALL PERFORMANCES								
Coal Flow Rate A.R:	**t/h**	734.0	677.6	592.9	727.0	653.3	624.2	691.0
Coal LHV	**kJ/kg**	10500	10500	10500	10500	10500	10500	10500
Thermal Energy of Feedstock	**MWth**	2140.8	1976.3	1729.2	2120.4	1914.4 (1)	1820.5	2015.4
Gross Electric Power Output	**MWe**	932.0	1039.4	763.0	816.0	900.3	868.7	900.5
Auxiliary Consumption	**MWe**	168.8	295.8	146.5	125.5	233.1	238.0	211.9
Gross Electrical Efficiency	**%**	43.5	52.6	44.1	38.5	47.2	47.7	44.7
Net Electrical Efficiency	**%**	35.5	37.5	35.5	32.5	34.7	34.5	34.1

EMISSIONS	g/kWh	mg/Nm^3 (VD 6% O_2)	g/kWh	g/h	g/kWh	mg/Nm^3 (VD 6% O_2)	g/kWh	mg/Nm^3 (VD 6% O_2)	g/kWh	mg/Nm^3 (VD 15% O_2)	g/kWh	mg/Nm^3 (VD 15% O_2)	g/kWh	mg/Nm^3 (VD 15% O_2)
CO_2	166	-	71	-	168	-	181	-	160	-	168	-	191	-
NO_x	0.13	40	0	0	0.14	40	0.15	40	0.56	74	0.60	74	0.61	74
SO_x	0.10[(2)]	29[(2)]	0.0013	950	0.15[(2)]	43[(2)]	0.08[(2)]	38[(2)]	0.0 1	1.2	0.01	1.2	0.01	1.2
CO	0.50	150	0	0	0.53	150	0.58	150	0.24	31.3	0.25	31.3	0.26	31.4
Particulate	0.04	30	0.02	Nil	0.03	30	0.03	30	0.04	5	0.04	5	0.04	5
NH_3 [(3)]	0.02	5	-	-	0.02	5	0.02	5	-	-	-	-	-	-

		Case 1	Case 2	Case 3	Case 4	Case 5	Case	Case 7
INVESTMENT COST DATA								
Total Investment	**10^6 €**	1251.8	1395.2	953.8	1230.6	1134.8	1205.1	1232.7
Specific Net Investment Cost	**€/kW**	1645	1882	1552	1788	1706	1917	1795
PRODUCTION COST DATA								
C.O.E. (DCF=10%)	**c€/kWh**	5.39	5.46	5.34	5.55	5.41	5.94	5.64
C.O.E. (DCF=5%)	**c€/kWh**	4.28	4.20	4.30	4.35	4.27	4.66	4.44

NOTES: (1) Thermal Energy of Feedstock including Natural Gas to Gasifiers. (2) SOx emissions upstream AGR unit; after solvent washing, emissions are expected close to zero. (3) Due to ammonia slippage into the flue gas downstream the SCR/SNCR.

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SECTION G

DETAILED INFORMATION FOR THE SELECTED TECHNOLOGY

I N D E X

G.3 Economics

SECTION G DETAILED INFORMATION FOR THE SELECTED TECHNOLOGY

Purpose of this Section G is to present a detailed assessment of performances and costs of the most attractive technology, the CFB boiler based on the Foster Wheeler's technology, which was selected on the basis of the technical/economical analysis made in section D, E and F of this study.

Section G provides technical and economical information both for the alternative with and without the CO_2 capture, in order to evaluate the penalties on performances and investment cost, due to the CO_2 sequestration.

Section G.1 presents a complete technical report for the CFB technology without the CO_2 capture, providing a detailed process description, heat and material balances, process flow diagrams, sized equipment list, utility consumption and performances.

The same information are also provided for the CFB alternative with the CO_2 capture, in section G.2, with a higher level of detail with respect to same case already developed in section D.3.

In this phase, further investigation was made with Siemens on the steam turbine, leading to some marginal modifications on both the design and the performances with respect to the assumption made in section D.3. As a consequence, the plant performances developed in section G.2 are slightly different from those already shown in section D.3 for the same case, but the analysis made for the comparison of the different alternatives (section F) is not affected. Further details of these modifications are given in section G.2.

Following the technical information of these two cases, a detailed economical analysis is developed in section G.3, evaluating the investment cost, with an accuracy of +/-30%, and the cost of energy for both the alternatives. From the comparison of the two cases, the cost of CO_2 avoidance is also determined.

SECTION G.1 CFB boiler without CO_2 Capture

1.0 Summary

The power plant is based on two SuperCritical CFB boilers, based on the Foster Wheeler's technology. Main features of the plant are summarized herebelow:

- The size of the plant considered for this configuration is based on the actual commercial size of CFB boilers, with the same capacity of Case 3, studied in section D.
- A pre-drying of the coal from a moisture level of 50.7% in as-received coal to about 32% is considered, before feeding the boiler plant. Drying of the coal allows to increase the overall performances of the plant.
- The limits of NO_x emissions, established by regulations, can be achieved with a firing system integrated with a SNCR package.
- Flue gas desulphurization, downstream the boiler, is not required to meet SO_x emission limits. SO_x are captured by a limestone injection in the combustion chamber. The limestone reacts with the sulphur released from the fuel.
- Partial heat recovery from the flue gas from boiler, to preheat water for drying of the coal, is made to improve the plant electrical efficiency.

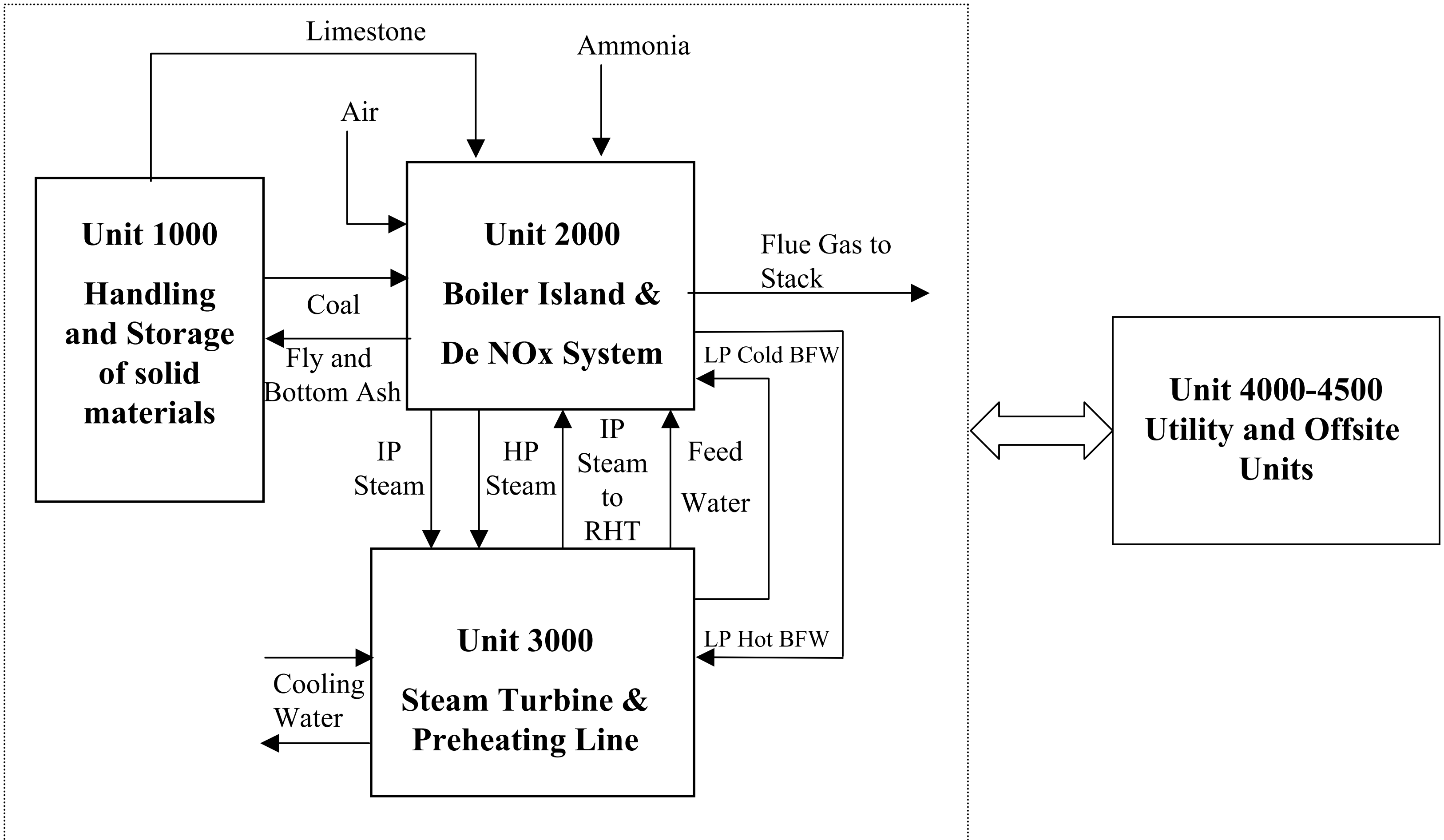
1.1 Process Description

The configuration of the CFB complex is based on two supercritical once through steam generators, with superheating and steam reheating.

Reference is made to the attached Overall Block Flow Diagram of the CFB power plant.

The arrangement of the process units is the following:

CFB Overall Block Flow Diagram



Unit

1000	Storage and Handling of solid materials, including Coal handling and storage Limestone handling and storage
2000	Boiler Island with SNCR based De NOx, Limestone injection and Electro Static Precipitators (ESP) Ash and solid removal
3000	Power Island, consisting of one Steam Turbine and Preheating Line
4100-4500	Utility and Offsite Units

Note: 'Coal' referred to in the following section means 'low rank coal' as defined in the BEDD document.

1.1.1 Unit 1000: Storage and Handling of solid materials

Coal Handling and Storage

The process flow diagram of the coal handling unit is attached to paragraph 1.2 of this section (PFD: 1000-1-50-1001).

According to the study basis, the plant is assumed close to the lignite mine, so the delivery of the coal is made by a railway that discharges the coal in dedicated coal conveyors (CR-1001 A/B) below the railway track. The coal conveyors move the coal to the coal elevators (CR-1002 A/B) and then to the coal storage dome (X-1002) by means of dedicated coal conveyors (CR-1009 A/B).

The dome provides a minimum of 5 days storage, equivalent to approximately 72,000 tons of coal. A series of coal conveyors (CR-1010 A/B, CR-1011, CR-1012) and one coal bucket elevator (CR-1013) take the coal from the dome and transport this to the screen grinder (SCR-1001 A/B) for milling down to a maximum size of 2 cm.

The crushed coal is transported to the drying unit by a series of coal conveyors (from CR-1003 A/B to CR-1007 A/B) before feeding the CFB boilers of the power island.

The whole system is designed to avoid fine powder dispersion to the ambient. Exhaust air blowers are equipped with dedicated coal dust filters for the collection of powder, before discharge of the air to the atmosphere.

Limestone Handling and Storage:

The process flow diagram of the limestone handling unit is attached to paragraph 1.2 of this section (PFD: 1000-1-50-1002).

Limestone is transported to the plant in big lumps, by using the railway. It is transferred to the limestone storage building (X-1004) by using a system similar to that used for the coal, basically made of a series of limestone conveyors and elevators. The storage building is by the coal storage area, with an autonomy of approximately 30 days of operation, corresponding to about 40,000 m^3 of limestone.

The limestone feeding system, from the storage building, is the same of that employed for coal, with conveyors that bring the limestone to the crusher for its pulverization. The pulverization is useful to increase the surface area and consequently the sulphur removal efficiency of the boiler. After milling, limestone is transported by conveyors to the silos next to the boilers. All the conveyors are placed inside a metallic tunnel in order to avoid dispersion of fines. Conveyors are preferred to the pneumatic system to avoid possible problems of plugging, because of the capacity of limestone to absorb humidity.

Coal Pre-Drying:

The process flow diagram of the drying unit is attached to paragraph 2.2 (PFD: 1000-1-50-1003).

This unit is mainly compose of two parallel trains, each sized for 50% of rated capacity.

Pre-drying of the coal is used to improve the plant performances, making use of some low energy temperature heat and taking advantage from the increase of the boiler efficiency due to a lower inlet water content of the coal.

The coal from the coal handling unit is conveyed to the lignite drying system and fed to the fluidized bubbling bed. The air necessary to fluidize the bed and drying the lignite is blown by a dedicated air fan (B-1001 A/B). Air is first pre-heated in the air preheater (E-2001) and then fed to the bubbling bed (FB-1001).

Air is preheated against hot water that circulates in closed loop through the different units of the plant, recovering heat from the following sources.

- Part of the flue gases leaving the CFB boiler after the SNCR system (E-2005) (26 MWth);
- Condensate from the pre-heating line of the power island, before entering the deaerator (98 MWth).

Part of the hot water in closed loop is also sent to the water coils submerged in the fluidized bed. The heat contained in the hot water completes the lignite drying and allows to maintain the bed at constant temperature.

The air that crosses the fluid beds partially removes the moisture content of the coal and is then directed to a dust filter, which reduces the entrained amount of ash, before discharging to the atmosphere. The coal ash collected in the filter is finally sent to the fly ash handling and storage system.

The dry coal at 32% wt of moisture content is discharged in the hopper (X-1001) and sent to the CFB boiler island, by using dedicated coal conveyors (CR-1001 A/B).

1.1.2 Unit 2000: Boiler Island

The boiler island consists of two parallel CFB boilers, for the generation of superheated and reheated steam.

The following description makes reference to the process flow diagram of the boiler island, attached to paragraph 1.2 of this section (PFD: 2000-1-50-2001).

Supercritical Tower Type Boiler:

Each boiler is a tower-type super critical boiler. The boiler is once through type, without steam generator. The steam generation is fixed by the coal feeding system to the boiler, whilst the steam temperature is as consequence of the thermal power of the combustion process.

Coal from the storage and handling system (Unit 1000) is discharged into the coal silos and then fed to the boilers by dedicated pressurized coal feeders. This system is pressurized to avoid possible back flows of gas from the combustion chamber of the boiler. Coal is then mixed with the combustion air in a high turbulence zone to increase the process combustion efficiency.

Limestone is added into the boilers through the dedicated limestone silos, close to the boiler. The presence of the limestone makes the desulphurization of the exhaust gas and allows to have a uniform temperature of the bed.

Part of the fine particles of the bed are entrained by the flue gas into the convective section of the boiler island. The convective section of the boiler recovers heat from the exhaust gas to preheat boiler feedwater, generate superheated HP steam and reheat the cold steam flow rate coming from the steam turbine. Part of the exhaust energy of the exhaust gas is also used to preheat the combustion air in the regenerative air preheater (E-2001). The remaining part of the flue gas is used to partially heat the water necessary for the lignite drying (E-2005), thus increasing the overall efficiency of the plant.

The flue gas from the air preheater and the LP economizer are mixed together, with a resulting temperature of approximately 130°C. The flue gas then flows to the electrostatic precipitator (ESP-2001), for the removal of the fly ash carried out from the CFB boiler. Downstream the ESP, a flue gas induced draught fan (B-2003 A/B) blows the flue gas to the gas cooler (E-2004), where part of the low energy heat is used to preheat water, which is further sent to air preheaters of the CFB Boilers (E-2002 A/B).

Flue gases are finally discharged to the atmosphere at a temperature of approximately 85°C. The buoyancy for dispersion of the flue gas out from the stack could be improved by using a natural draft cooling tower instead of a dedicated stack. This alternative has been already implemented in some German brown coal power station and would not significantly affect the investment cost of the plant.

The heat recovery made on the low energy exhaust gas leads to an improvement of the plant electrical efficiency.

The main components of the circulating fluidized bed steam generator are described in the following paragraphs.

<u>Combustion chamber</u>
The main components of the combustion chamber are:
- Distribution grate;
- Water tubes combustion chamber.

The primary air comes to the distribution grate through the inner tube. The grate is made up by water tubes with several air nozzles, suitably oriented to fluidize the bed material, to prevent back flows and to move the spent bed material towards the drain. These operations are made by an airflow rate above the minimum fluidization velocity of the bed. At partial load of the boiler, the primary airflow cannot be reduced under this minimum value, to make a proper fluidization of the solids bed.

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 NO_x emissions. For a further reduction of NO_x emissions, ammonia is injected into the bed by means of dedicated nozzles, located above the combustion chamber.

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.

Part of the combustion air is also sent above the grate. This is the secondary air, used to complete the staged combustion process and further reduce the NO_x formation.

Water tubes cover the walls of the combustion chamber, in order to improve the heat transfer from flue gas and bed material to the water, generating steam at supercritical conditions.

Separators

The flue gas leaves the top of the combustion chamber and enters the solid separators cyclones located on both sides of the furnace, made of steam cooled refractory panels. The flue gas enters the cyclones with a whirling flow and the solid particles are separated by a centrifugal force. The particles of bigger size flow down along the walls toward the discharge section. A seal system allows the recirculation of these particles to the furnace or, alternatively, to the convective section. The ashes are fluidized by high-pressure air coming from the high-pressure blowers.

Convective heat recovery

Downstream solid separators, flue gas enters the convective heat recovery section, passing through the superheater, the reheater, the economizer and the combustion air preheater.
The superheater consists of different sections, suitable spaced, to avoid fouling problems and to allow a good ash discharge into the downstream hoppers. Spray

water desuperheaters control the steam temperature, using boiler feed water as moderator. After the superheating section, flue gas passes through the counter current reheaters, which increase the temperature of the steam from the HP section of the steam turbine. After the reheating section, flue gas flows to the economizer section and finally to the air preheater, which preheats both the primary and secondary air for the combustion process. This flue gas heat is recovered in a rotating tube bundles and transferred counter currently to the combustion air. The density of the heating surfaces is made to minimize pressure drop and avoid fouling.

Combustion air system

The primary air is taken from the atmosphere by means of two centrifugal fans (design capacity of each fan is 60% of the maximum load) and is blown to the distribution grate in order to fluidize the bed and to provide the required amount of combustion air. The control of the airflow rate is made by a Venturi tube and a control valve. A minimum airflow rate is necessary to allow a continuous fluidization of the bed, also at partial load.

The secondary air is blown by two dedicated blowers (design of each fan is 60% of the maximum load) above the distribution grate, in order to complete the combustion process and maintain a low NO_x emission level. The secondary air is also partially used to pressurize the coal feeders and allow the inlet of the coal in the furnace.

For a proper combustion process, the oxygen content in the flue gas is maintained at 3% vol., dry basis.

High-pressure air is used to fluidize the solid material coming from the solid separation system, allowing the recirculation of the solids in the combustion chamber.

Auxiliary burners

Natural gas auxiliary burners are used during the start-up of the boiler.
Burning natural gas, the bed material is preheated up to the ignition temperature. From this temperature on, the coal can be continuously fed to the combustion chamber and the auxiliary burners can be turned off. The start-up burners are placed in the combustion chamber walls, close to the fluid bed.

Soot Blowers

The soot blowers are used in the boilers to allow the cleaning of the heat exchange surfaces. Soot blowers are located in the convective section of the boiler and can be either fixed or retractable. The soot blowers are motors driven. The ash removed is drag in the flue gas and falls in the hoppers, or is separated by the ESP.

The flue gas exits the furnace and crosses the convective heat recovery by the suction action of the two induced draft fans. At the top of the furnace, the pressure is maintained at 0.5 mbar below the ambient pressure.

A flue gas analysis is performed in order to control the composition (O_2, CO, NO_x, SO_x) and check possible combustion inefficiencies.

De-NOx System

The SNCR system is provided to reduce the NO_x produced during the combustion process to a level that does not exceed the limits of regulations. The possibility to use a water-ammonia solution at 25% weight allows to reduce the NO_x emissions to a low level, without the use of a catalyst. The ammonia solution atomized by air is directly injected at the top of the furnace and in the solid separators via dedicated nozzles. This technical solution is simple and cheap. The ammonia solution is not dangerous and can be transported and handled in the plant.

Ash Handling:

The ash handling system takes care of conveying the ash generated in the boiler plant, e.g. the furnace bottom and fly ash from different hoppers.
The bottom ash are mainly made of calcium sulphate, unreacted calcium oxide, coal ash and unburned carbon coming from the bottom of the boilers. Bottom ash is humidified and transported by dedicated conveyors to the storage building, before final destination for disposal to the outside plant battery limits. Ashes are humidified to avoid dispersion in the ambient.

The fly ash are mainly made of unburned carbon, unreacted calcium oxide and coal ash. The Electro Static Precipitators (ESP) separates fly ash from exhaust flue gas. Fly ash is collected in hoppers and then pneumatically transported to the storage silos. Fly ash is fluidized by high-pressure air coming from the pressurization system. All the fly ash handling units are equipped with a filtration system in order to be insulated from ambient, thus avoiding dispersion to the atmosphere.

1.1.3 Unit 3000: Steam Turbine and Preheating Line

The following description makes reference to the process flow diagram of the power island attached to paragraph 1.2 of this section (PFD: 3000-1-50-3001).

The power island is a single train, mainly composed of one supercritical steam turbine and one preheating line. Supercritical steam from the two boilers is sent to the steam turbine (ST-3001), which consists of a HP, IP and LP section, all connected to the generator (SG-3001) 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 passes through the stop valves and control valves and enters the turbine at 283 bar, 584°C. Steam from the exhaust of the HP turbine, except the flow extracted for the heating of the boiler feed water, is returned to the boiler gas path for reheating, and then throttled into the double flow IP turbine at 48 bar, 602°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 (from E-3006 to E-3009) is recovered back to the deaerator (D-3001).

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 (P-3001 A/B), before entering the deaerator.

Hot condensate from E-3004 is used to pre-heat the water in closed loop, which makes the pre-drying of the coal. Steam condensate from the first two preheaters (E-3002/3) is recovered back to the condenser. Condensate from the gland steam condenser (E-3001), upstream the condensate preheaters, is also recovered back to the condenser.

All the steam that is not used for preheating of the boiler feedwater/condensate flows to the LP steam turbine section and then downward into the water-cooled condenser (E-3010), at 0.032 bar (25°C).

Boiler feedwater exiting the deaerator is pumped to the economizers of the boilers by means of the boiler feedwater pumps (P-3003 A/B/C, two in operation and one common spare). The two pumps in normal operation are steam turbine driven, while the remaining one is motor driven.

Chemical injection for control of the water quality is made by dedicated packages (Z-3001/Z-3002) on the suction of the boiler feedwater pumps and at the inlet of the boilers.

1.1.4 Unit 4100 to 4500: Auxiliary units

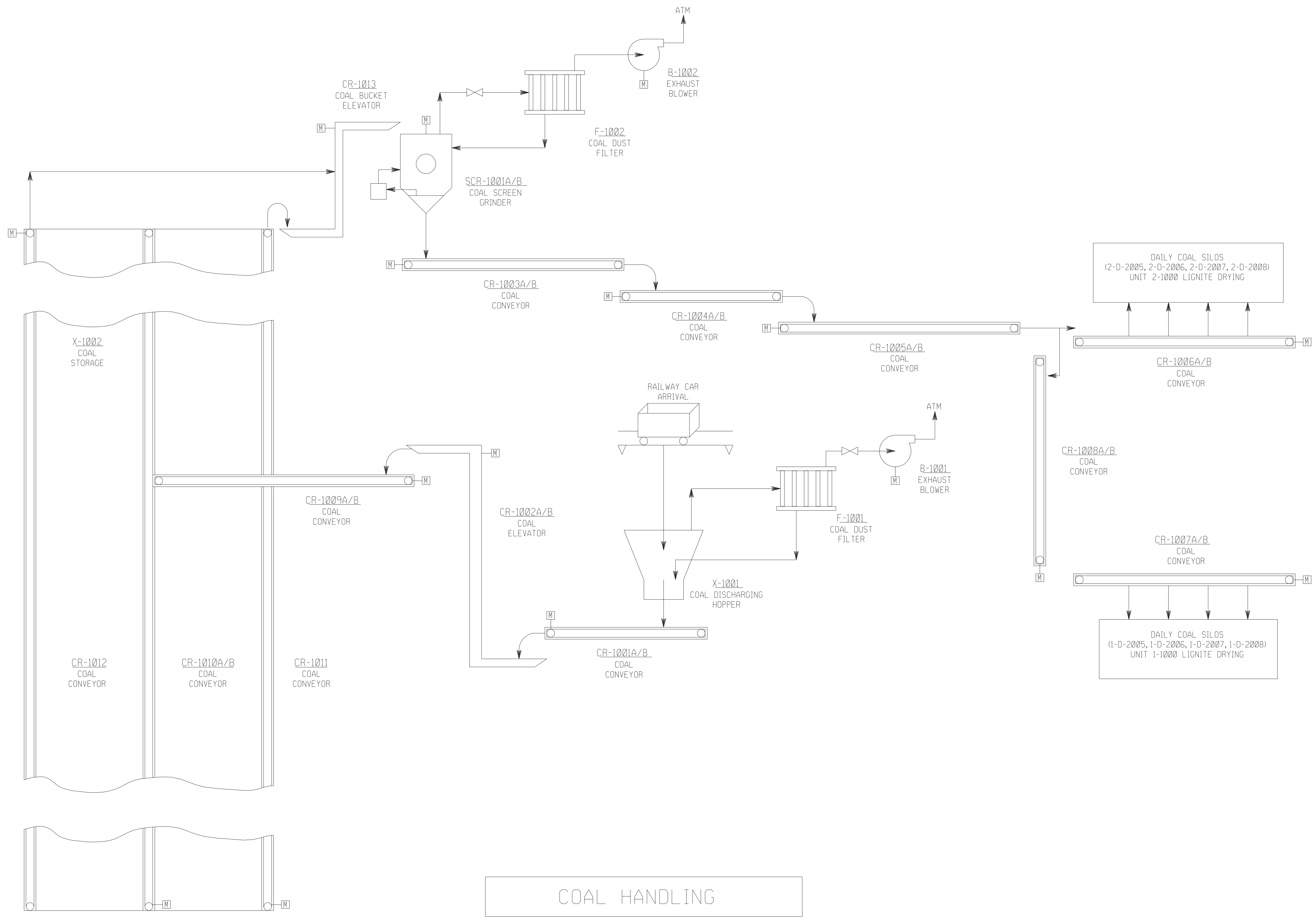
The process description of the auxiliary units is made in section C, paragraph 10.

The process flow diagram of the main auxiliary units is attached to paragraph 1.2 of this section (PFD 4100-1-50-4101).

1.2 Process Flow Diagrams

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

- UNIT 1000:	Coal handling and storage	(PFD: 1000-1-50-1001)
	Limestone handling and storage	(PFD: 1000-1-50-1002)
- UNIT 2000:	Boiler Island with SNCR	
	Electro Static Precipitators	
	Limestone Injection	(PFD: 2000-1-50-2001)
- UNIT 3000:	Power Island consisting of	
	Steam Turbine and Preheating Line	(PFD: 3000-1-50-3001)
- UNIT 4100-4500:	Utility and Offsite Units	(PFD: 4100-1-50-4001)



COAL HANDLING

A		FIRST ISSUE	SF			
REV.	DATE	DESCRIPTION	DRAW	BY	CHD	APP.

REVISIONS

CFB BOILER WITHOUT
CO_2 CAPTURE
IEA GHG R&D PROGRAMME

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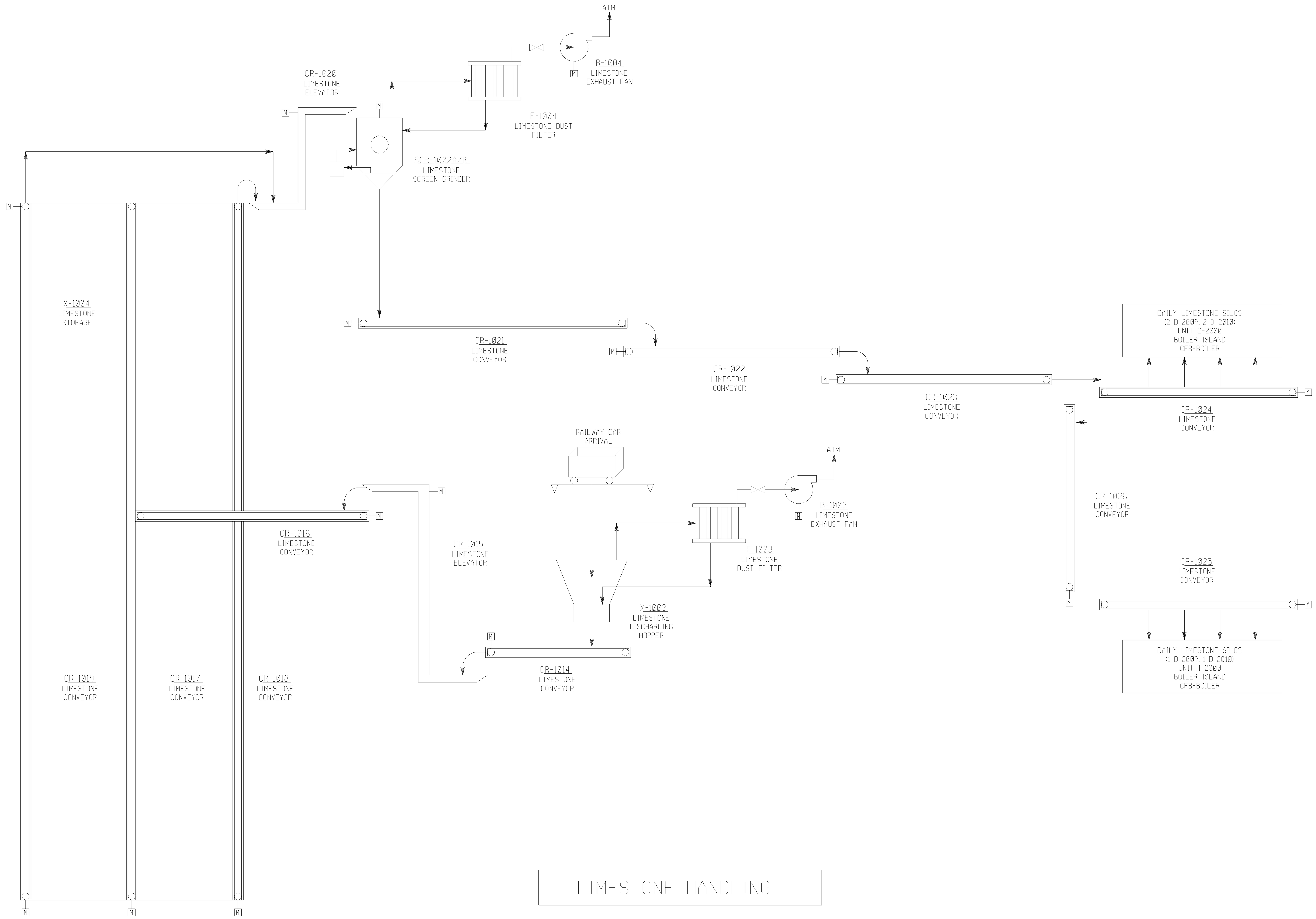
PROCESS FLOW DIAGRAM
COAL HANDLING UNIT 1000

ORDER N°
SUPPLIER
CONTRACT N°
FRAME N°
CLIENT DWG N°
SHEET OF
SCALE

FOSTER WHEELER

FWI DWG N° 1000-1-50-1001
SHEET OF
REV. A

CAD FILE NAME



A		FIRST ISSUE	SF			
REV.	DATE	DESCRIPTION	DRAW	BY	CHD	APP.

REVISIONS

CFB BOILER WITHOUT
CO_2 CAPTURE
IEA GHG R&D PROGRAMME

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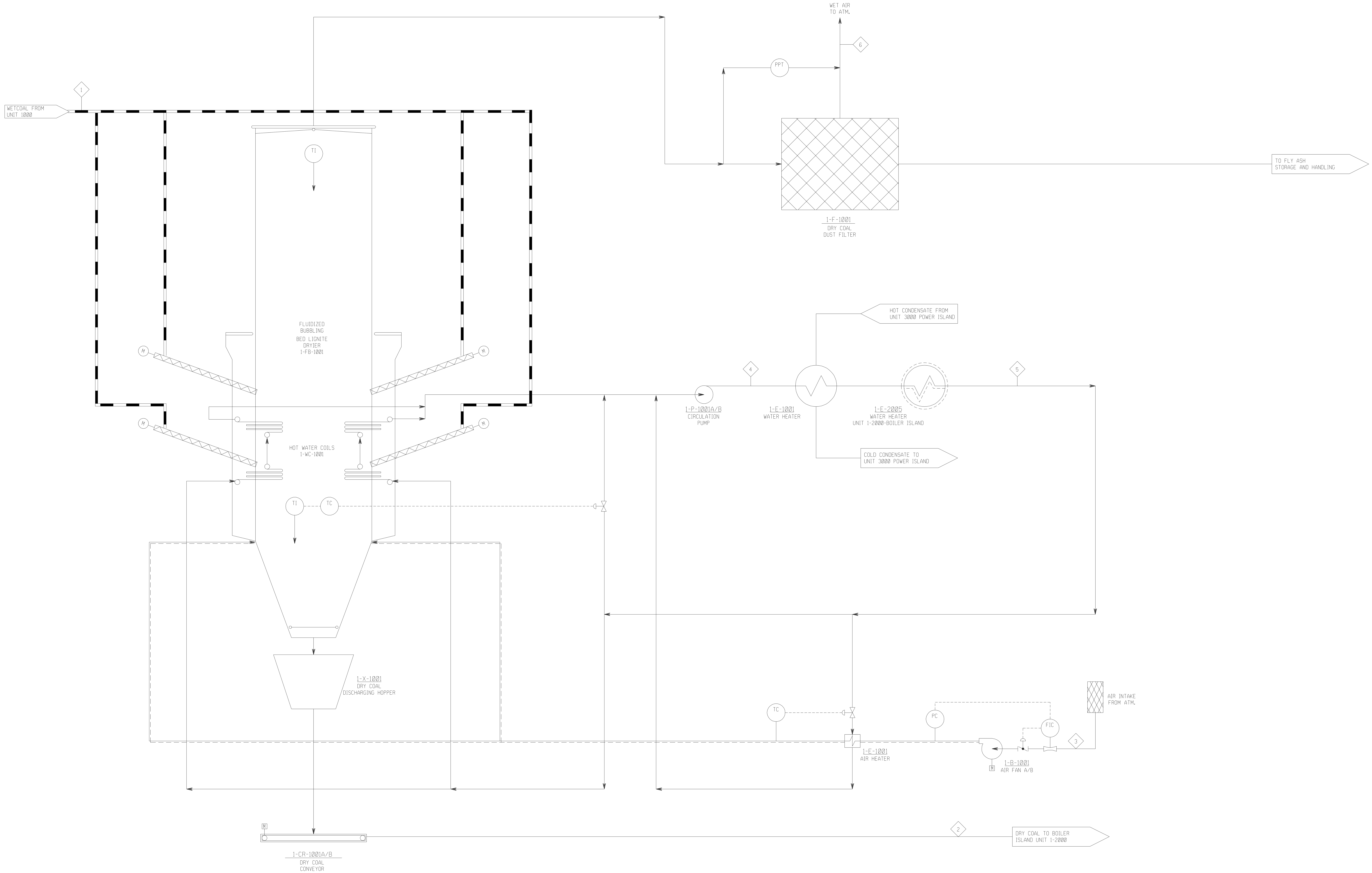
PROCESS FLOW DIAGRAM
LIMESTONE HANDLING UNIT 1000

ORDER N°
SUPPLIER
CONTRACT N°
FRAME N°

FOSTER WHEELER

CLIENT DWG N°
SHEET OF
SCALE
FWI DWG N° 1000-1-50-1002
SHEET OF
REV. A

CAD FILE NAME



LIGNITE DRYING

REV.	DATE	DESCRIPTION	DRAW	BY	CHD	APP.
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REVISIONS

CFB BOILER WITHOUT
CO_2 CAPTURE
IEA GHG R&D PROGRAMME

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PROCESS FLOW DIAGRAM
LIGNITE DRYING SYSTEM
UNIT 1000

ORDER N°
SUPPLIER
CONTRACT N°
FRAME N°

FOSTER WHEELER

CLIENT DWG N° SCALE
SHEET OF

FWI DWG N° 1000-1-50-1003 REV. A
SHEET OF

CAD FILE NAME

FLUE GAS DUCT
CONVECTIVE SECTION
REHEATER
SUPERHEATER
ECONOMIZER
1-D-2005 COAL SILO
1-D-2006 COAL SILO
1-D-2009 LIMESTONE SILO
1-D-2010 LIMESTONE SILO
1-D-2007 COAL SILO
1-D-2008 COAL SILO
SEPARATOR
NH3
COMBUSTION CHAMBER
1-C-2001 CFB BOILER
1-BR-2001A/B/C/D/E/F/G/H/I/L/M/N
START-UP BURNER
1-FD-2002A/B/C/D/E/F COAL SCREW FEEDER
1-FD-2001A/B/C/D/E/F COAL SCREW FEEDER
NATURAL GAS
1-E-2001 REGENERATIVE AIR PREHEATER
IP REHEATER STEAM TO UNIT 3000 IP ST
IP STEAM FROM UNIT 3000 TO REHEATER
HP SUPERHEATED STEAM TO UNIT 3000 HP ST
COLD BOILER FEED WATER FROM UNIT 3000
1-E-2005 LIGNITE DRYING EXCHANGER
COLD WATER FROM LIGNITE DRYING UNIT 1000
HOT WATER TO LIGNITE DRYING UNIT 1000
COLD WATER FROM 1-E-2002A/B
HOT WATER TO 1-E-2002A/B
1-ESP-2001 ELECTROSTATIC PRECIPITATOR
1-B-2003A/B FLUE GAS INDUCED DRAUGHT FANS
1-E-2004 FLUE GAS COOLER
X-2001 CONTINUOUS EMISSION MONITORING SYSTEM
1-CA-2001 STACK
BOTTOM FLY ASH HANDLING
1-B-2004A/B/C/D HIGH PRESSURE BLOWERS
COOLING WATER INLET
COOLING WATER OUTLET
1-E-2003A/B/C/D/E/F/G/H/I/L BOTTOM ASH COOLERS
GRID
1-E-2002A HOT WATER AIR PREHEATER
1-B-2002A/B SECONDARY AIR FAN
1-E-2002B HOT WATER AIR PREHEATER
1-B-2001A/B PRIMARY AIR FAN
HOT WATER FROM 1-E-2004
COLD WATER TO 1-E-2004
BOTTOM AND FLY ASH HANDLING
TI
PDI
PDT PDI
AIC
TC
PC
FIC
HS
M
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
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REVISIONS
CFB BOILER WITHOUT CO_2 CAPTURE
IEA GHG R&D PROGRAMME
PROCESS FLOW DIAGRAM
BOILER ISLAND
CFB-BOILER
UNIT 1-2000
APPROVED FOR CONSTRUCTION
DWG.REV. DATE
SIGNATURE
ORDER N°
SUPPLIER
CONTRACT N°
FRAME N°
CLIENT DWG N°
SCALE
SHEET OF
FW DWG N°
REV.
2000-1-50-2001
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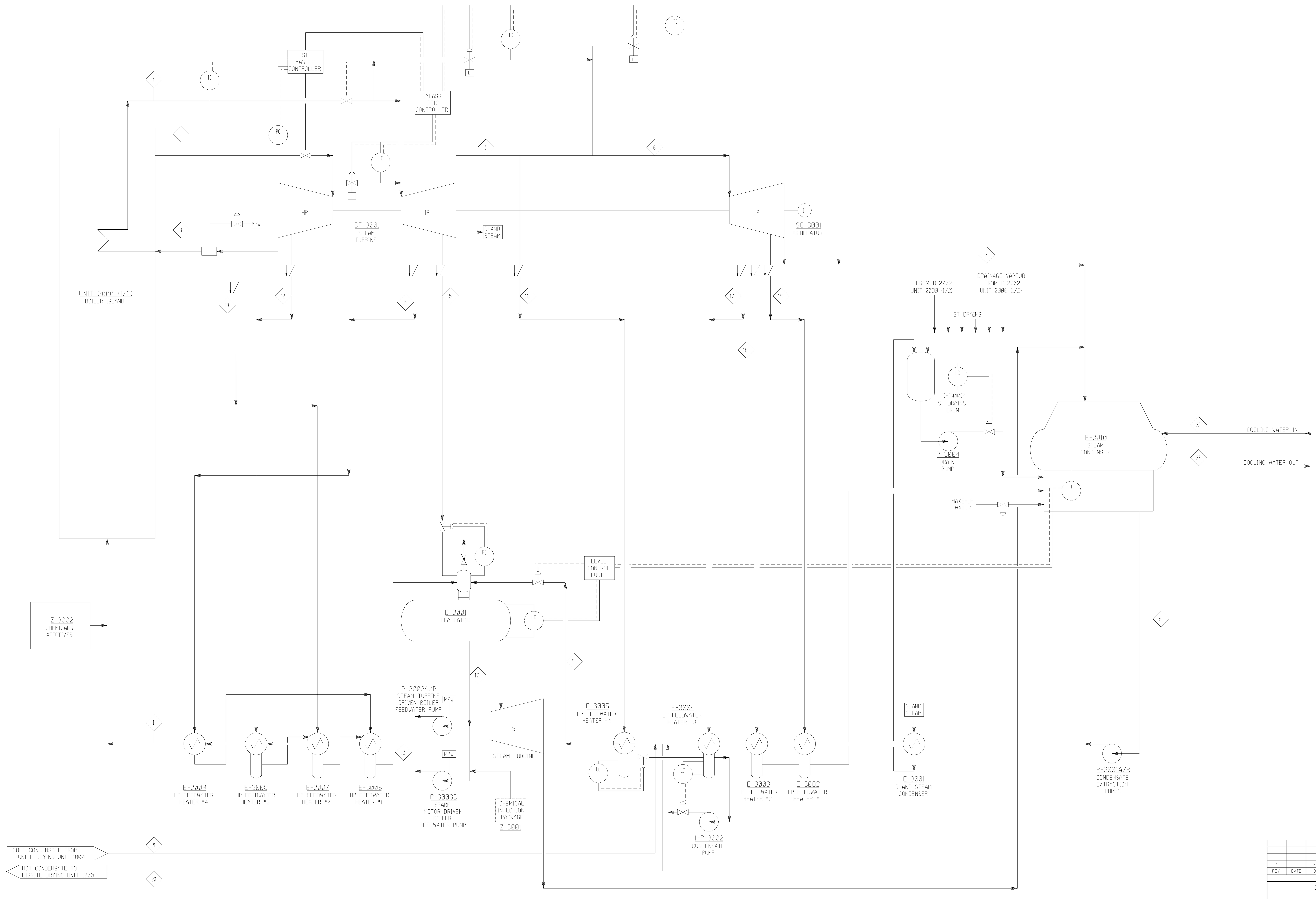
FOSTER WHEELER
CAD FILE NAME



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CFB BOILER WITHOUT CO_2 CAPTURE
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PROCESS FLOW DIAGRAM
POWER ISLAND
UNIT 3000

ORDER N°
SUPPLIER
CONTRACT N°
FRAME N°

FOSTER WHEELER

CLIENT DWG N°
SHEET OF
SCALE
FWI DWG N° 3000-1-50-3001
SHEET OF
REV. A
CAD FILE NAME

RAW-SERVICE-POTABLE WATER SYSTEMS
(UNIT 4500)
DEMI WATER SYSTEM
(UNIT 4200)
PK-4503
ADDITIVIES PACKAGE
P-4501A/B/C
RAW WATER PUMP
PK-4501
CLARIFLOCCULATION SYSTEM
SLUDGE
RAW WATER INTAKE
BA-4501
RAW WATER PUMPING BASIN
PK-4502
WATER CONDITIONING SYSTEM
P-4505A/B
SERVICE WATER PUMP
F-4501A/B
SAND FILTER
LSHL
D-4501
SERVICE WATER COLLECTION DRUM
P-4504A/B
WATER BOOSTER PUMP
TO USERS
PK-4201
DEMI WATER PRODUCTION SYSTEM
D-4201
DEMI WATER COLLECTION DRUM
P-4202
FILLING PUMP
TO START-UP BOILERS
P-4201A/B
DEMI WATER DISTRIBUTION PUMP
1-TR-4101
NATURAL DRAUGHT COOLING TOWER
TO 2nd TRAIN
FROM 2nd TRAIN
USERS
WATER CONDENSER
COOLING WATER AND MACHINERY COOLING WATER SYSTEMS
(UNIT 4100)
P-4503A/B
COOLING TOWER MAKE UP WATER PUMP
F-4502A/L
SAND FILTER
LC
1-PK-4101
WATER CONDITIONING PACKAGE
1-BA-4101
COOLING WATER BASIN
P-4102A/B
MACHINERY COOLING WATER PUMP
P-4101A-D
COOLING WATER PUMP
FC
SUMP PIT
COOLING WATER BLOWDOWN DISCHARGE TO RIVER
1-F-4001
FILTER
POTABLE WATER FROM GRID
POTABLE WATER
PCV
ACP
ACI
QR-4401
AIR DRYER
AIR
K-4401A/B
AIR COMPRESSOR
D-4401
COMPRESSED AIR DRUM
PLANT INSTRUMENT AIR SYSTEM
(UNIT 4400)
ELUATES FROM DEMINERALIZATING PLANT
WATER TREATMENT
SANITARY WATER
PHISICAL PRETREATMENT
- DECANTATION
- DEOILING
- FILTRATION
POTENTIALLY DUSTY AND OILY WATER
BIOLOGICAL OXIDATION PLANT
SUMP PIT
CONDUCT A
CHEMICAL-PHISICAL TREATMENT
- DECANTATION
- CLARIFLOCCULATION
- FILTRATION
POTENTIALLY DUSTY AND METEORIC WATER
CONDUCT B
NATURAL GAS PIPE NETWORK
PK-4301
NATURAL GAS REDUCTION AND METERING STATION
UNIT 2000 (1/2)
START-UP NATURAL GAS
(UNIT 4300)
A FIRST ISSUE SF
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REVISIONS
CFB BOILER WITHOUT
CO2 CAPTURE
IEA GHG R&D PROGRAMME
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DWG. REV. DATE
SIGNATURE
PROCESS FLOW DIAGRAM
AUXILIARY EQUIPMENT
UNIT 4100
ORDER N°
SUPPLIER
CONTRACT N°
FRAME N°
CLIENT DWG N°
SCALE
FOSTER WHEELER
SHEET OF
FW DWG N°
4100-1-50-4001
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1.3 Heat and Material Balances

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

- UNIT 1000: Storage and Handling of solid materials

- UNIT 2000: Boiler Island with SNCR based De-NO_x
  Electro Static Precipitators (ESP)
  Limestone Injection

- UNIT 3000: Power Island, consisting of
  Steam Turbine and Preheating Line

Stream numbers are as shown on the process flow diagrams attached to paragraph 1.2 of this section.

FOSTER WHEELER	CFB HEAT AND MATERIAL BALANCE						REVISION	0	1	
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	SR		
	CASE : CFB without CO_2 Capture						APPROVED	LM		
	UNIT : 1000 Solid materials storage and handling					Sheet 1 of 1	DATE	Nov-05		

STREAM	1	2	3	4	5	6	7	8	9	10
	Wet Coal to Lignite Drying System (1)	Dry Coal to Boiler Island UNIT 2000 (1)	Air intake from atmosphere for Lignite Drying (1)	Cold Water in Close Loop (1)	Hot Water in Close Loop (1)	Wet Air to Atmosphere				
Temperature (°C)	AMB	AMB	6	65	85	65				
Pressure (bar)	ATM	ATM	AMB	3	3	ATM				
TOTAL FLOW										
Mass flow (kg/h)	592883	429840	908820	5290600	5290600	1071865				
Molar flow (kgmole/h)			31458	293759	293759	40513				
	Moisture	Moisture								
	50.70%	32%								
Composition wt% with moisture										
Carbon	31.33%	43.20%								
Hydrogen	2.29%	3.16%								
Oxygen	11.56%	15.94%								
Sulfur	0.22%	0.31%								
Nytrogen	0.37%	0.51%								
Chlorine	0.03%	0.05%								
Moisture	50.70%	32.00%								
Ash	3.50%	4.83%								

Note (1): All the enclosed data are for two CFB boilers in parallel

FOSTER WHEELER	CFB HEAT AND MATERIAL BALANCE	REVISION	0	1	
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	SR		
	CASE : CFB without CO_2 Capture	APPROVED	LM		
	UNIT : 2000 Boiler Island — Sheet 1 of 2	DATE	Nov-05		

STREAM	1-4	5	6	7	8	9	10	11	12	13-14	15	16
	Coal from UNIT 1000 (2)	Primary Air (2)	Secondary Air (2)	High pressure Air (2)	Flue Gas From Boiler to Stack (2)	HP Boiler Feed Water from Preheating line UNIT 3000 (2)	HP Steam to Steam Turbine (2)	IP Steam from Preheating Line UNIT 3000 (2)	IP Reheated Steam to Steam Turbine (2)	Limestone injection (1)-(2)	Cold Water from Lignite Drying UNIT 1000 (2)	Hot Water to Lignite Drying UNIT 1000 (2)
Temperature (°C)	AMB	15	15	15	85	272	584	319	602	AMB	80	85
Pressure (bar)	ATM	1.23	1.13	1.61	1.03	313	283	51	48	ATM	3	3
TOTAL FLOW												
Mass flow (kg/h)	592883	1867900	925400	119750	3361176	2182000	2182000	2016000	2016000	22690	5290600	5290600
Molar flow (kgmole/h)		64656	32032	4145	116023	121155	121155	111938	111938		293759	293759
LIQUID PHASE												
Mass flow (kg/h)	0	0	0	0	0	2182000					5290600	5290600
GASEOUS PHASE												
Mass flow (kg/h)		1867900	925400	119750	3361176	0	2182000	2016000	2016000		0	0
Molar flow (kgmole/h)		64656	32032	4145	116023	0	121155	111938	111938		0	0
Molecular Weight		28.89	28.89	28.89	28.97	18.01	18.01	18.01	18.01		18.01	18.01
Composition (vol %)	See UNIT 1000											
N_2		77.57%	77.57%	77.57%	68.14%	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%
CO_2		0.00%	0.00%	0.00%	13.51%	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%
H_2O		0.68%	0.68%	0.68%	13.70%	100%	100%	100%	100%		100%	100%
O_2		20.86%	20.86%	20.86%	3.88%	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%
Ar		0.89%	0.89%	0.89%	0.77%	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%
NOx		0.00%	0.00%	0.00%	98 ppm VD 6% O2	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%
SOx		0.00%	0.00%	0.00%	70 ppm VD 6% O2	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%
CO		0.00%	0.00%	0.00%	120 ppm VD 6% O2	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%

Note (1): Limestone Analysis (wt%) $CaCO_3$ = 95% - $MgCO_3$ = 3.4% - Inert = 1.6%
Note (2): All the enclosed data are for two CFB boilers in parallel

FOSTER WHEELER	CFB HEAT AND MATERIAL BALANCE						REVISION	0	1	
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME						PREP.	SR		
	CASE : CFB without CO_2 Capture						APPROVED	LM		
	UNIT : 2000 Boiler Island					Sheet 2 of 2	DATE	Nov-05		
STREAM	17	18	19	20	21	22	23	24	25	26
	Cooling Water Inlet (2)	Cooling Water outlet (2)	Bottom Ash to UNIT 1000 (2)	Fly Ash to UNIT 1000 (2)						
Temperature (°C)	11	21	6	6						
Pressure (bar)	3	3	AMB	AMB						
TOTAL FLOW										
Mass flow (kg/h)	104000	104000	12240	28800						
Molar flow (kgmole/h)	5775	5775								
LIQUID PHASE										
Mass flow (kg/h)	104000	104000								
GASEOUS PHASE										
Mass flow (kg/h)	0	0								
Molar flow (kgmole/h)	0	0								
Molecular Weight	18.01	18.01								
Composition (vol %)										
N_2	0.00%	0.00%								
CO_2	0.00%	0.00%								
H_2O	100%	100%								
O_2	0.00%	0.00%								
Ar	0.00%	0.00%								
NOx	0.00%	0.00%								
SOx	0.00%	0.00%								
CO	0.00%	0.00%								

Note (2): All the enclosed data are for two CFB boilers in parallel

CFB HEAT AND MATERIAL BALANCE

CLIENT : IEA GREEN HOUSE R & D PROGRAMME

CASE : CFB without CO_2 Capture

UNIT : 3000 Steam Turbine & Preheating Line

Sheet 1 of 1

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	HP Water to Boiler Island	2182	272	313	1191
2	HP Steam from Boiler	2182	584	283	3413
3	IP Steam to Boiler	2016	319	51	2978
4	IP hot reheated steam to Steam Turbine	2016	602	48	3673
5	IP Steam Turbine exhaust	1620	287	5.5	3037
6	LP Steam to Steam Turbine	1414	287	5.5	3037
7	Steam to Condenser	1286	25	0.032	2288
8	Condensate	1423	25	0.032	106
9	LP Preheated Condensate	1748	156	13	658
10	Condensate to HP FWH (Deaer. Outlet)	2182	175	9	742
11	BFW Pump Delivery	2182	181	315	783
12	1st HP Extraction to E-3008	78	338	59	3011
13	2nd HP Extraction to E-3007	88	318	51	2978
14	1st MP Extraction to E-3009 and E-3006	194	535	32	3535
15	2nd MP Extraction to Deaer. And ST BFW Pump	201	356	9	3172
16	3rd MP Extraction to E-3005	206	287	5.5	3037
17	1st LP Extraction to E-3004	89	220	2.8	2907
18	2nd LP Extraction to E-3003	80	114	0.9	2706
19	3rd LP Extraction to E-3002	86	67	0.3	2533
20	Hot Condensate to Lignite Drying UNIT 1000	1748	130	15	548
21	Cold Condensate from Lignite Drying UNIT 1000	1748	84	13	353
22	Cooling water Inlet	67122	11	3	47
23	Cooling water Outlet	67122	21	2	88

1.4 Utility Consumption

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

	CLIENT:	IEA GHG	Rev 0
FOSTER WHEELER	PROJECT:	GASIFICATION POWER GENERATION STUDY	Nov-05
	LOCATION:	Germany	ISSUED BY: SR.
	FWI Nº:	1BD0237A	CHECKED BY: LM
			APPR. BY: RD

ELECTRICAL CONSUMPTION SUMMARY - CFB without CO_2 Capture

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
1000	Solid Materials Storage and Handling	
	Coal Conveyors and Feeders	630
	Coal Milling and Powder control System	280
	Lignite Drying System	565
	Limestone Conveyors	50
	Limestone Milling and Powder control System	100
	PARTIAL TOTAL	1625
2000	Boiler Island	
	Primary Air Fans	13200
	Secondary Air Fans	3170
	Induced Draught Fans	8950
	High Pressure Blowers	2050
	Bottom Ash Handling	105
	Fly Ash Handling and Storage	140
	Miscellanea	730
	PARTIAL TOTAL	28345
	POWER ISLANDS UNITS	
3000	Steam Turbine and Preheating line	
	Steam Turbine	1000
	Condensate Extraction Pumps	600
	Condensate Pump	30
	PARTIAL TOTAL	1630
	UTILITY and OFFSITE UNITS	
4100	Cooling Water and Machinery Cooling Water System	
	Cooling Towers - Condenser - Process Units - Utilities	12870
	Cooling Towers - Machinery Cooling Water	160
	Cooling Towers - Make-Up	145
4200	Demi Water System	10
4300	Natural Gas Start-Up System	0
4400	Plant and Instrument Air System	1200
4500	Raw / Service / Potable Water System	255
	Miscellanea	1400
	PARTIAL TOTAL	16040
	GRAN TOTAL	47640

	CLIENT:	IEA GHG	Rev 0
FOSTER WHEELER	PROJECT:	GASIFICATION POWER GENERATION STUDY	Nov-05
	LOCATION:	Germany	ISSUED BY: SR
	FWI Nº:	1BD0237A	CHECKED BY: LM
			APPR. BY: RD

WATER CONSUMPTION SUMMARY - CFB without CO_2 Capture

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water [t/h]
	PROCESS UNITS			
1000	**Solid Materials Handling and Storage**			80
2000	**Boiler Island**			104
	POWER ISLANDS UNITS			
3000	**Steam Turbine and Generator auxiliaries**		1	67122
	Miscellanea			1450
	UTILITY and OFFSITE UNITS			
4100	Cooling Water and Machinery Cooling Water System	1057		
4200	**Demi Water System**	1	-1	
4300	**Natural Gas Start-Up System**			
4400	**Plant and Instrument Air System**			50
4500	**Raw / Service / Potable Water System**	50		
4600	**Fire Fighting System**			
	Miscellanea			8
	BALANCE	1108	0	68814

CLIENT:	IEA GHG	Rev 0
PROJECT:	CO2 Capture in Low rank coal power plants	Nov-05
LOCATION:	Germany	ISSUED BY: SR
FWI Nº:	1BD0237A	CHECKED BY: LM
		APPR. BY: RD

Chemicals and Consumables Summary CFB without CO_2 Capture

	DESCRIPTION	Consumption t/h	Yearly Consumption t/y
	Chemicals and Consumables		
	Make up Water (Power Plant)	1108	8250168
	Limestone (Boiler Island SOx Control)	23	168950
	Ammonia (Boiler Island NOx Control)	0.5	4032
	Caustic Soda NaOH (Water Treatment)	0.2	1489
	Corrosion Inhibitors (Cooling Towers)	0.01	42
	Sodium Hypochlorite (Cooling Tower Basin)	0.3	2234

1.5 CFB Overall Performances

The following table shows the overall performance of the CFB complex.

CFB without CO_2 Capture

OVERALL PERFORMANCES OF THE CFB COMPLEX		
Coal Flowrate (A.R.)	t/h	592.9
Coal LHV (A.R.)	kJ/kg	10500
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1729.3**
Steam turbine power output (@gen. Terminals)	MWe	841.9
GROSS ELECTRIC POWER OUTPUT OF CFB COMPLEX (D)	**MWe**	**841.9**
Coal Storage / Handling	MWe	1.6
Boiler Island	MWe	28.3
Power Island	MWe	1.6
Utilities	MWe	16.0
ELECTRIC POWER CONSUMPTION OF CFB COMPLEX	**MWe**	**47.6**
NET ELECTRIC POWER OUTPUT OF CFB (C) **Step-Up Transformer Efficiency (0.997)**	**MWe**	**791.8**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**48.7%**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**45.8%**

1.6 Environmental Impact

The CFB complex is designed to process coal and produce electric power. The advanced technology allows to reach a high efficiency and to minimise the environmental impact.

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

1.6.1 Gaseous Emissions

<u>Main Emissions</u>

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

Table 1.6.1 summarises expected flow rate and concentration of the combustion flue gas.

Table 1.6.1 – Expected gaseous emissions from the CFB plant.

	Normal Operation
Wet gas flow rate, kg/s	934
Flow, Nm^3/h	2600540
Temperature, °C	85
Composition	(%vol)
N_2	68.91
O_2	3.88
CO_2	13.51
H_2O	13.70
Emissions	mg/Nm^{3} (1)
NOx	200
SOx	200
CO	150
Particulate	30

(1) Dry gas, O_2 content 6% vol

In normal operation at full load, the following emission to the atmosphere is foreseen from the coal drying process:

Flow rate : 1072 t/h
Particulate : 21 kg/h

Minor Emissions

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). They are prevented by routing all vents to a bag filter.

1.6.2 Liquid Effluent

The plant would be designed for zero contaminated liquid effluents. 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;
- Cooling towers blowdown;
- Eluates from demineralizing water system;
- Sanitary water.

As the handling and storage systems of the solid materials are insulated from the ambient, to limit the powder dispersion, the meteoric water treatment could be avoided. In any case, it is preferable to collect the rainwater from the buildings and storage areas to the chemical/physical water treatment.

The wash water from the equipment washing is also collected and routed to the water treatment as it can be contaminated by oil and powder.

The cooling towers blowdown and the eluates from the demi water system are not contaminated by any pollutant and therefore can be directly discharged to the receiving basin, without any treatment.

The sanitary water from sanitary fittings, containing biodegradable pollutants, is routed to a collection basin and then to the biological water treatment, for the oxidizing process.

The water treatment includes the physical pre-treatment with settling, deoiling and filtration systems, the biological oxidation and the chemical treatment of clariflocculation. In the settling and deoiling phases the solids (particulate, tar, carbon residues) heavier than water, are collected on the bottom of the collection basin, while oils, lighter than water, are separated on the surface and routed to the oil drain well. The water is then filtered in coke filters and routed, through pumps, to the biological treatment for the biological oxidation. The oxidation process is accelerated by the addition of activated carbons. The water is finally routed to the clariflocculation system for the final purification and then to the plant battery limits.

1.6.3 Solid Effluent

The power plant is expected to produce the following solid by-products:

Fly Ash

Flow rate : 28.8 t/h

Bottom Ash

Flow rate : 12.2 t/h

Fly and bottom ash are used as bed filling and returned back to the mine or dispatched to cement industries, if available in the neighbours.

The Calcium Sulphate is not a pure product and cannot be sold as pure gypsum.

1.7 Equipment List

The list of the main equipment and process packages are included in this section.

		CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0		
FOSTER WHEELER		LOCATION: Germanie	DATE	Nov-05		
		PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants	ISSUED BY	S.R.		
		CONTRACT N.	CHECKED BY	L.M.		
			APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 1000 - Solid Materials Storage and Handling - CFB Boiler without CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		COAL SYSTEM							
		The coal handling and storage system includes: - Stacker reclaimer - Coal conveyors - Coal mills - Filters - Fans		Capacity: 635 t/h					
		BOTTOM ASH SYSTEM							
		The bottom ash handling and storage system includes - Ash storage silos - Ash conveyors - Clinker crusher - Filters - Fans		Capacity: 18 t/h					
		FLY ASH SYSTEM							
		The fly ash handling and storage system includes - Ash storage silos - Pneumatic conveying system - Compressors - Filters - Fans		Capacity: 26 t/h					
		LIMESTONE SYSTEM							
		The limestone handling and storage system includes - Limestone reclaimer area - Limestone conveyors - Limestone mills - Filters - Fans		Capacity: 25 t/h					

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME		REVISION	Rev.0				
	LOCATION: Germanie		DATE	Nov-05				
	PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants		ISSUED BY	S.R.				
	CONTRACT N.		CHECKED BY	L.M.				
			APPROVED BY	R.D.				

EQUIPMENT LIST

Unit 1000 - Solid Materials Storage and Handling - CFB Boiler without CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		CONVEYORS							
		Coal Handling							
1	CR-1001 A/B	Coal Conveyor							
1	CR-1002 A/B	Coal Elevator							
1	CR-1003 A/B	Coal Conveyor							
1	CR-1004 A/B	Coal Conveyor							
1	CR-1005 A/B	Coal Conveyor							
1	CR-1006 A/B	Coal Conveyor							
1	CR-1007 A/B	Coal Conveyor							
1	CR-1008 A/B	Coal Conveyor							
1	CR-1009 A/B	Coal Conveyor							
1	CR-1010 A/B	Coal Conveyor							
1	CR-1011	Coal Conveyor							
1	CR-1012	Coal Conveyor							
1	CR-1013	Coal Bucket Elevator							
		Bottom Ash Handling							
1/2		Bottom Ash Conveyor							
1/2		Bottom Ash Elevator							
2/2		Bottom Ash Conveyor							
2/2		Bottom Ash Elevator							
		Fly Ash Handling							
1/2		Fly Ash Conveyor							
1/2		Fly Ash Roller Transfer to Recirculation Silo							
1/2		Fly Ash Roller Transfer to Storage							
2/2		Fly Ash Conveyor							
2/2		Fly Ash Roller Transfer to Recirculation Silo							
2/2		Fly Ash Roller Transfer to Storage							
		Limestone Handling							
1	CR-1014	Limestone Conveyor							
1	CR-1015	Limestone Elevator							
1	CR-1016	Limestone Conveyor							
1	CR-1017	Limestone Conveyor							
1	CR-1018	Limestone Conveyor							
1	CR-1019	Limestone Conveyor							
1	CR-1020	Limestone Elevator							
1	CR-1021	Limestone Conveyor							
1	CR-1022	Limestone Conveyor							
1	CR-1023	Limestone Conveyor							
1	CR-1024	Limestone Conveyor							
1	CR-1025	Limestone Conveyor							
1	CR-1026	Limestone Conveyor							

		CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germanie PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N.	REVISION	Rev.0		
			DATE	Nov-05		
			ISSUED BY	S.R.		
			CHECKED BY	L.M.		
			APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 1000 - Solid Materials Storage and Handling - CFB Boiler without CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		MILLING							
		Coal Milling							
1	SCR-1001 A/B	Coal Screen Grinder							
		Bottom Ash Crushing							
1/2		Bottom Ash Screen Grinder							
2/2		Bottom Ash Screen Grinder							
		Limestone Milling							
1	SCR-1002 A/B	Limestone Screen Grinder							
		STORAGE							
		Coal Storage							
1	X-1001	Coal Discharging Hopper							
1	X-1002	Coal Storage							
		Bottom Ash Storage							
1/2		Bottom Ash Silo							
1/2		Bed Filling Material Silo							
1/2		Plenum tanks							
2/2		Bottom Ash Silo							
2/2		Bed Filling Material Silo							
2/2		Plenum tanks							
		Fly Ash Storage							
1/2		Fly Ash Storage							
1/2		Fly Ash Recirculation Silo							
2/2		Fly Ash Storage							
2/2		Fly Ash Recirculation Silo							
		Limestone Storage							
1	X-1003	Limestone Discharging Hopper							
1	X-1004	Limestone Storage							
		FILTERS							
1	F-1001	Coal Dust Filter							
1	F-1002	Coal Dust Filter							
1/2	1-F-1001 A/B	Bottom Ash Dust Filter							
2/2		Bottom Ash Dust Filter							
1/2		Fly Ash Exhaust Filter							
2/2		Fly Ash Exhaust Filter							
1	F-1003	Limestone Dust Filter							
1	F-1004	Limestone Dust Filter							

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germanie PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N.	REVISION	Rev.0		
		DATE	Nov-05		
		ISSUED BY	S.R.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 1000 - Solid Materials Storage and Handling - CFB Boiler without CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		FANS							
1	B-1001	Coal Exhaust Fan							
1	B-1002	Coal Exhaust Fan							
1/2		Bottom Ash Exhaust Fan							
2/2		Bottom Ash Exhaust Fan							
1/2		Fly Ash Exhaust Fan							
2/2		Fly Ash Exhaust Fan							
1	B-1003	Limestone Exhaust Fan							
1	B-1004	Limestone Exhaust Fan							
		COMPRESSORS							
1/2		Compressor for Fly Ash pneumatic Handling to Storage							
1/2		Compressor for Fly Ash pneumatic Handling to Recirc. Silo							
2/2		Compressor for Fly Ash pneumatic Handling to Storage							
2/2		Compressor for Fly Ash pneumatic Handling to Recirc. Silo							

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germanie PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N.	REVISION: Rev.0 DATE: Nov-05 ISSUED BY: S.R. CHECKED BY: L.M. APPROVED BY: R.D.

EQUIPMENT LIST

Unit 2000 - Boiler Island - CFB without CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		BOILERS							
1/2	1-C-2001	Supercritical CFB Boiler		MCR: SH: 1090 t/h RH: 1010 t/h		MCR: 285 bar 51 bar	Feed Water 275°C 585 °C 600 °C		Boiler Package including: - Coal Silos - Limestone Silos - Coal Screw Feeders - Coal Burners (1-BR-2001 A-N) - Regenerative Air Preheater - Hot Water Air Preheater - Bottom Ash Coolers - High Pressure Blowers - Air Fans - Flue Gas Induced Draught Fans - Desuperheaters - Start-Up System - Electrostatic Precipitators ESP - Continuous Emission monitoring System - Ammonia Storage and Injection Package - Stack
2/2	2-C-2001	Supercritical CFB Boiler		MCR: SH: 1090 t/h RH: 1010 t/h		MCR: 285 bar 51 bar	Feed Water 275°C 585 °C 600 °C		Boiler Package including: - Coal Silos - Limestone Silos - Coal Screw Feeders - Coal Burners (2-BR-2001 A-N) - Regenerative Air Preheater - Hot Water Air Preheater - Bottom Ash Coolers - High Pressure Blowers - Air Fans - Flue Gas Induced Draught Fans - Desuperheaters - Start-Up System - Electrostatic Precipitators ESP - Continuous Emission monitoring System - Ammonia Storage and Injection Package - Stack

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germanie PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N.	REVISION: Rev.0 DATE: Nov-05 ISSUED BY: S.R. CHECKED BY: L.M. APPROVED BY: R.D.

EQUIPMENT LIST

Unit 2000 - Boiler Island - CFB without CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		FANS							
1/2	1-B-2001 A/B	Primary Air Fans		m=165 kg/s; H=22000 Pa	4000 kW				Included in 1-C-2001
1/2	1-B-2002 A/B	Secondary Air Fans		m=84 kg/s; H=12000 Pa	1100 kW				Included in 1-C-2001
1/2	1-B-2003 A/B	Flue Gas Induced Draught Fans		m=285 kg/s; H=8100 Pa	3700 kW				Included in 1-C-2001
1/2	1-B-2004 A/B/C/D	High Pressure Blowers		m=9 kg/s; H=60000 Pa	580 kW				Included in 1-C-2001
2/2	2-B-2001 A/B	Primary Air Fans		m=165 kg/s; H=22000 Pa	4000 kW				Included in 2-C-2001
2/2	2-B-2002 A/B	Secondary Air Fans		m=84 kg/s; H=12000 Pa	1100 kW				Included in 2-C-2001
2/2	2-B-2003 A/B	Flue Gas Induced Draught Fans		m=285 kg/s; H=8100 Pa	3700 kW				Included in 2-C-2001
2/2	2-B-2004 A/B/C/D	High Pressure Blowers		m=9 kg/s; H=60000 Pa	580 kW				Included in 2-C-2001
		HEAT EXCHANGERS							
1/2	1-E-2001	Regenerative Air Preheater							Included in 1-C-2001
1/2	1-E-2002 A/B	Hot Water Air Preheater							Included in 1-C-2001
1/2	1-E-2003 A/B...I/L	Bottom Ash Coolers							Included in 1-C-2001
1/2	1-E-2004	Flue Gas Cooler							
1/2	1-E-2005	LP-Economizer							
2/2	2-E-2001	Regenerative Air Preheater							Included in 2-C-2001
2/2	2-E-2002 A/B	Hot Water Air Preheater							Included in 2-C-2001
2/2	2-E-2003 A/B...I/L	Bottom Ash Coolers							Included in 2-C-2001
2/2	2-E-2004	Flue Gas Cooler							
2/2	2-E-2005	LP-Economizer							
		SILOS							
1/2	1-D-2005	Coal Silo							Included in 1-C-2001
1/2	1-D-2006	Coal Silo							Included in 1-C-2001
1/2	1-D-2007	Coal Silo							Included in 1-C-2001
1/2	1-D-2008	Coal Silo							Included in 1-C-2001
1/2	1-D-2009	Limestone Silo							Included in 1-C-2001
1/2	1-D-2010	Limestone Silo							Included in 1-C-2001
2/2	2-D-2005	Coal Silo							Included in 2-C-2001
2/2	2-D-2006	Coal Silo							Included in 2-C-2001
2/2	2-D-2007	Coal Silo							Included in 2-C-2001
2/2	2-D-2008	Coal Silo							Included in 2-C-2001
2/2	2-D-2006	Limestone Silo							Included in 2-C-2001
2/2	2-D-2007	Limestone Silo							Included in 2-C-2001

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0		
	LOCATION: Germanie	DATE	Nov-05		
	PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants	ISSUED BY	S.R.		
	CONTRACT N.	CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2000 - Boiler Island - CFB without CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		START-UP SYSTEM							
1/2		Water-Steam Separators							Included in 1-C-2001
1/2		Start-up Tank							Included in 1-C-2001
1/2		Flash Tank							Included in 1-C-2001
1/2		Blow-Down Tank							Included in 1-C-2001
1/2		Drainage Tank							Included in 1-C-2001
1/2		Recirculation Pump							Included in 1-C-2001
1/2		Drainage Transfer Pump							Included in 1-C-2001
2/2		Water-Steam Separators							Included in 2-C-2001
2/2		Start-up Tank							Included in 2-C-2001
2/2		Flash Tank							Included in 2-C-2001
2/2		Blow-Down Tank							Included in 2-C-2001
2/2		Drainage Tank							Included in 2-C-2001
2/2		Recirculation Pump							Included in 2-C-2001
2/2		Drainage Transfer Pump							Included in 2-C-2001
		DESUPERHEATERS							
1/2		HP Steam Desuperheater							Included in 1-C-2001
1/2		By-Pass Desuperheater							Included in 1-C-2001
1/2		Reheated Steam Desuperheater							Included in 1-C-2001
2/2		HP Steam Desuperheater							Included in 2-C-2001
2/2		By-Pass Desuperheater							Included in 2-C-2001
2/2		Reheated Steam Desuperheater							Included in 2-C-2001
		FEEDERS							
1/2	1-FD-2001 A/B...E/F	Coal Screw Feeders							Included in 1-C-2001
1/2	1-FD-2002 A/B...E/F	Coal Screw Feeders							Included in 1-C-2001
2/2	2-FD-2001 A/B...E/F	Coal Screw Feeders							Included in 2-C-2001
2/2	2-FD-2002 A/B...E/F	Coal Screw Feeders							Included in 2-C-2001

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germanie PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N.	REVISION DATE ISSUED BY CHECKED BY APPROVED BY	Rev.0 Nov-05 S.R. L.M. R.D.

EQUIPMENT LIST

Unit 3000 - Power Island - CFB Boiler without CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		STEAM TURBINE							
1	ST-3001	Steam Turbine		886 MWe SH: 285 bar; 585 °C RH: 48 bar; 600°C Cond: 0.032 bar					Steam Turbine Package Including: - Master Controller - By-pass System - By-pass Logic Controller - Ejectors - Silencer
		GENERATOR							
1	SG-3001	Generator		886 MWe					Generator Package Including: - Cooling System with Hydrogen - Start-up System - Vibration Control System
		HEAT EXCHANGERS		**Duty**					
1	E-3001	Gland Steam Condenser		600 kW					
1	E-3002	LP Feedwater Heater 1		47090 kW					
1	E-3003	LP Feedwater Heater 2		44440 kW					
1	E-3004	LP Feedwater Heater 3		58590 kW					
1	E-3005	LP Feedwater Heater 4		60990 kW					
1	E-3006	HP Feedwater Heater 1		63000 kW					
1	E-3007	HP Feedwater Heater 2		64450 kW					
1	E-3008	HP Feedwater Heater 3		50900 kW					
1	E-3009	HP Feedwater Heater 4		82200 kW					
1	E-3010	Steam Condenser		857560 kW					Delta T Cooling Water = 10 °C
		PUMPS							
1	P-3001 A/B	Condensate Extraction Pump		Q=750 m^3/h; H=130 m	355 kW				
1	P-3002 A/B	Condensate Pump		Q=80 m^3/h; H=100 m	30 kW				
1	P-3003 A	Steam Turbine Driven BFW Pump		Q=2180 m^3/h; H=3700 m					In operation - Steam Turbine Driven
1	P-3003 B	Motor Driven BFW Pump		Q=2180 m^3/h; H=3700 m	28000 kW				Spare - Electric Motor Driven
1	P-3004	Drain Pump		Q=25 m^3/h; H=10 m	7.5 kW				
1	P-3005 A/B	Vacuum Pumps							Included in Steam Turbine Auxiliaries
		TANKS							
1	D-3001	Deaerator							
1	D-3002	ST Drain Drum							
		CHEMICAL INJECTION PACKAGE							
1	Z-3001	Chemical Injection Package							
1	Z-3002	Chemical Additives							

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		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 4000 - Cooling Water and Machinery Cooling Water System - CFB Boiler without CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		COOLING TOWERS							
1/2	1-TR-4001	Cooling Towers	Natural Draught						Package Including: - Distribution System - Heat Exchangers - Water Conditioning
2/2	2-TR-4001	Cooling Towers	Natural Draught						Package Including: - Distribution System - Heat Exchangers - Water Conditioning
		PACKAGES							
1/2	1-PK-4001	Water Conditioning Package							Package Including: - Chemical Additives Storage Tanks - Chemical Additives Dosing Pumps
2/2	2-PK-4001	Water Conditioning Package							Package Including: - Chemical Additives Storage Tanks - Chemical Additives Dosing Pumps
		PUMPS		m^3/h x m					
1	P-4001 A/B/C/D	Cooling Water Pump		19400x55	3300 kW				All Operating - Electric Motor Driven
1	P-4002 A/B	Machinery Cooling Water Pump		900x40	80 kW				One operating and one spare- Electric Motor Driven
		BASINS							
1/2	1-BA-4001	Cooling Water Basin							
2/2	2-BA-4001	Cooling Water Basin							
		FILTERS							
1/2	1-F-4001	Filter							
2/2	2-F-4001	Filter							

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EQUIPMENT LIST

Unit 4100 - Demi Water System - CFB Boiler without CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1	PK-4101	Demi Water Production System		2 lines 30 m^3/h each					Package Including: - Neutralized Effluents Discharge Pump - Cationic Column - Decarbonation Tower - Decarbonation Tower Pump - Decarbonation Tower Fan - HCl System - NaOH System - Anionic Column - Neutralization Tank
		PUMPS		m^3/h x m					
1	P-4101 A/B	Demi Water Distribution Pump		30x60	12				
1	P-4102	Filling Pump		125x25	15				During Star-Up
		DRUMS		D(m)xH(m)					
1	D-4101	Demi Water Storage Collection Basin		12x18					Volume = 2000 m^3

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EQUIPMENT LIST

Unit 4200 - Raw-Service-Potable Water System - CFB Boiler without CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1	PK-4201	Clariflocculation System							Package Including: - Clariflocculator - Sludge Pump - Membrane Press - Recirculation Water System - Filtered Water System
1	PK-4202	Water Conditioning System							
1	PK-4203	Additives Package							
		PUMPS		m^3/h x m					
1	P-4201 A/B/C	Raw Water Pump		645x36	75 kW				Two operating - one spare
1	P-4202 A/B	Service Water Pump		50x40	5.5 kW				
1	P-4203 A/B	Cooling Towers Make-Up Pump		620x36	72.5 kW				
1	P-4204 A/B	Service Water Booster Pump		50x40	5.5 kW				
		DRUMS		D(m)xH(m)					
1	BA-4201	Raw Water Pumping Basin							
1	D-4201	Service Water Collection Basin		8x12					Volume = 600 m^3
		FILTERS							
1	F-4201 A/B	Sand Filter							
1	F-4202 A/B...I/L	Sand Filter							

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	CONTRACT N.	CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 4300 - Plant Instrument Air System - CFB Boiler without CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		COMPRESSORS							
1	K-4301 A/B	Air Compressor		52500 Nm^3/h	660 kW				Two operating and one spare - Electrical Motors Included
		DRUMS							
1	D-4301	Compressed Air Drum							
		DRYER							
1	DR-4301	Instrument Air Dryer							

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EQUIPMENT LIST

Unit 4400 - Natural Gas Start-Up System - CFB Boiler without CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1	PK-4401	Natural Gas Reduction and Metering Station							Package Including: - Filter - Preheating System - Flow Indicator - Reduction Valves

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EQUIPMENT LIST

Unit 4500 - Fire Fighting System - CFB Boiler without CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1	PK-4501	Fire Water Distribution System							Package Including: - Pressurization Pump - Fire Fighting Water Pump Electrical Motor Driven Q=610 m^3/h - Fire Fighting Water Pump Diesel Motor Driven Q=610 m^3/h
1	PK-4502	Relieving and Extinguishing System							Package Including: - Deluge System - Outdoor Hydrants - Portable Equipment - Fire Detector - Smoke Detector - No Toxic Gas Flooding System

SECTION G.2 CFB boiler with CO_2 Capture

2.0 Summary

Purpose of this section G.2 is to provide a more detailed set of technical information for the CFB alternative, based on the Foster Wheeler's technology, with the CO_2 capture, which was already investigated in section D.3.

In this case, the performances of the plant are slightly different from those already shown in section D.3, due to the investigation made with one steam turbine supplier, which suggested the following main modifications on the design of the steam turbine:

- Marginal decrease of the efficiency of the LP steam turbine section;
- Reduction of the number of steam extractions from the IP section, so to use a steam turbine design that is similar to that of a conventional power plant.

With reference to the latter point, to reduce the number of steam extractions, part of the heat required for the heating of the boiler feed water is now directly taken from the cold reheat of the HP section, instead of using a dedicated steam extraction from the IP section. This allows to simplify the design of the steam turbine, but results in a loss of power production and a marginal decrease of the plant net electrical efficiency.

The same considerations were also applied to the alternative of the CFB boiler without the CO_2 capture, developed in section G.1.

It has to be noted that, applying these modifications to the USC-PC alternative developed in section D.1, the reduction of the net electrical efficiency of the plant would approximately be 0.6%, as per this case. Therefore, the analysis performed in section F is not affected by the modifications made on the steam turbine design, remaining the CFB alternative the most promising technology for the CO_2 capture in a lignite coal power plant.

2.1 Process Description

The configuration of the CFB complex is based on two supercritical once through steam generators, with amine wash for CO_2 absorption and CO_2 compression unit.

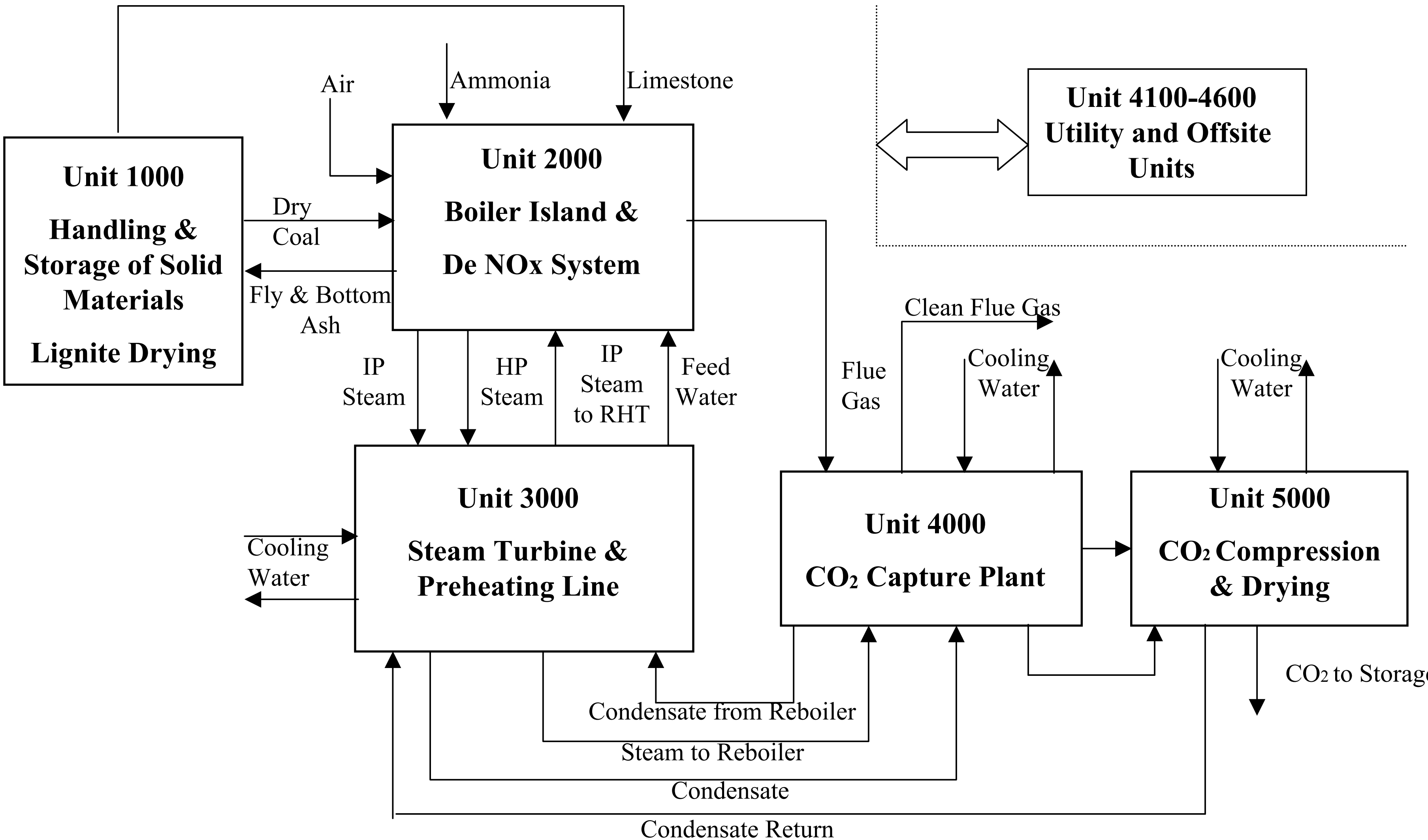
Reference is made to the attached Overall Block Flow Diagram of the CFB power plant.

The arrangement of the process units is the following:

Unit	
1000	Storage and handling of solid materials, including Coal handling and storage Coal pre-drying system Limestone handling and storage
2000	Boiler island with SCR based DeNOx, Limestone injection and Electro Static Precipitators (ESP) Ash and solid removal
3000	Power island, consisting of Steam Turbine and Preheating Line
4000	CO_2 capture plant
5000	CO_2 compression and drying
4100-4500	Utility and Offsite Units

Note: ‘Coal’ referred to in all the following sections means ‘low rank coal’ as defined in the BEDD document.

CFB with CO_2 Capture Overall Block Flow Diagram



2.1.1 Unit 1000: Solid Materials Storage – Handling and Lignite Drying

Coal handling and storage

The process flow diagram of the coal handling unit is attached to paragraph 2.2 of this section (PFD: 1000-1-50-1001).

The process description of this unit does not differ from that made for the alternative without CO_2 capture (section G.1, paragraph 1.1.1).

Coal pre-drying:

The process flow diagram of the drying unit is attached to paragraph 2.2 of this section (PFD: 1000-1-50-1003).

This unit is mainly composed of two parallel trains, each sized for 50% of the rated capacity.

Pre-drying of the coal is made to improve the plant performances, exploiting the large amount of low temperature heat that is available from the downstream CO_2 capture and compression units, also avoiding the use of large cooling water flow rates.

Coal from the coal-handling unit is conveyed to the lignite drying system and fed to the fluidized bubbling bed. The air necessary to fluidize the bed and dry the lignite is blown by a dedicated air fan (B-1001 A/B). Air is first pre-heated in the air preheater (E-2001) and then fed to the bubbling bed (FB-1001). Air is preheated against hot water that circulates in closed loop through the different units of the plant, recovering heat from various sources.
In particular, the exploited low temperature heat sources are:

- Part of the flue gases leaving the CFB boiler after the SCR system (26 MWth);
- Overhead stripper condenser of the CO_2 capture plant; (72 MWth)
- Intercooling system of the CO_2 compression unit (26 MWth).

A more detailed scheme of the heat integration is also shown in the process flow diagram of the CO_2 compression unit, attached to paragraph 2.2 of this section (PFD: 5000-1-50-5001).

Part of the hot water in closed loop is also sent to the water coils submerged in the fluidized bed. The heat contained in the hot water completes the lignite drying and allows to maintain the bed at constant temperature.

The air crossing the fluid beds partially removes the moisture content of the coal and is then diverted to a dust filter, which reduces the entrained amount of ash, before discharge to the atmosphere. The coal ash collected in the filter is finally sent to the fly ash handling and storage system.

The dry coal at 32% wt of moisture content is discharged in the hopper (X-1001) and sent to the CFB boiler island, by using dedicated coal conveyors (CR-1001 A/B).

Limestone handling and storage:

The process flow diagram of the limestone-handling unit is attached to paragraph 2.2 of this section (PFD: 1000-1-50-1002).

The process description of this unit does not differ from that made for the alternative without the CO_2 capture (Section G.1, para. 1.1.1).

The main difference between the two alternatives is the limestone flowrate, because of the more stringent limit on SO_x emission, as a requirement of the downstream CO_2 capture unit, which lead to a higher limestone requirement.

2.1.2 Unit 2000: Boiler Island

The boiler island consists of two parallel CFB boilers, for the generation of superheated and reheated steam, with the same size of the alternative without the CO_2 sequestration.

The process flow diagram of the boiler island is attached to paragraph 2.2 of this section (PFD: 2000-1-50-2001).

The main difference with respect to the description made in section G.1, para 1.1.2, is the use of a SCR system, instead of a SNCR, due to the more stringent NO_x emission level for the downstream CO_2 capture unit.

In a traditional plant, the SNCR system is sufficient to respect the NO_x emission levels of 200 mg/Nm^3 @ 6% O_2, volume dry. For the alternative with CO_2 capture, a SCR system is used to reduce the NO_x produced by the combustion process to a level that does not exceed the inlet requirement of the carbon dioxide capture plant, e.g. less than 20 ppmv of NO_2.

The catalytic $DeNO_x$ reactor is situated in the gas stream between the boiler outlet and the air heaters (PK-2001). This location offers the adequate temperature window, necessary for the good functioning of the SCR system, limiting the formation of ammonium sulphates. Gaseous ammonia is injected into the flue gas and, in presence of the catalyst, reacts with nitrogen oxides to produce nitrogen.

Further details of the SCR $DeNO_x$ system are given in section C, para. 4.0.

2.1.3 Unit 3000: Steam Turbine and Preheating Line

The following description makes reference to the process flow diagram of the power island, attached to paragraph 2.2 of this section (PFD: 3000-1-50-3001).

The power island is a single train, mainly composed of one (1) supercritical steam turbine and preheating line, as per the alternative without the CO_2 capture. The main differences between the two alternatives are the following:

- Large LP steam export from the steam turbine to the AGR unit, for the solvent regeneration of the CO_2 capture plant;
- Preheating of the condensate, which is made by using low sensible heat available from the CO_2 sequestration and compression units (Unit 4000-5000).

The LP steam export to the AGR unit is made by extracting the steam from the crossover between the IP and LP sections of the steam turbine. In order to optimize the plant efficiency, the IP expansion is increased with respect to the case without the CO_2 capture, thus making the design of this turbine different from that of a conventional power plant.

The condensate extracted from the condenser is pumped to the carbon dioxide capture plant for preheating in the amine stripper overhead condenser and then in the carbon dioxide compressor intercoolers.

This optimisation of the integration between the power plant and the CO_2 capture units allows to maximize the efficiency of the process, avoiding the necessity of LP steam extractions to preheat the condensate in the LP preheating line.

As already explained in the summary of this section (para. 2.0), following the investigation made with one steam turbine supplier, the pre-heating of the boiler feed water is made by using part of the cold reheat, flowing to the boiler, and two extractions from the IP steam turbine. This solution partially decreases the performances of the plant, but significantly simplifies the design of the steam turbine.

2.1.4 Unit 4000: CO_2 capture plant

The following description makes reference to the process flow diagram of the CO_2 capture plant, attached to paragraph 2.2 of this section (PFD: 4000-1-50-4001).

This unit is mainly composed of two parallel trains made of one direct contact cooler and one absorption column, followed by a common regeneration stripper.

The flue gas from the boiler island is at approximately 85°C and shall be cooled to about 30-35°C in a dedicated flue gas cooler (DCC-4001), as an operational requirement for the downstream CO_2 absorption. The direct contact cooler makes an adiabatic quench of the flue gas, with the advantage of reducing the particulate concentration to very low level, before entering the absorption column. At the bottom of the quench column, part of the condensed water is recovered and recycled back to the top of the DCC, after cooling with cooling water. The remaining water is sent to the wastewater treatment of the plant.

Downstream the direct contact cooler, the flue gas is fed to the absorption tower (ABS-4001) by a flue gas blower (B-4001A/B). The gas entering the absorption column is contacted firstly with a semi lean MEA stream, secondly with a counter current flow of lean MEA, to allow the 85% CO_2 capture with respect to stream entering the unit.

Some of the heat reaction of MEA with CO_2 is removed by pump around coolers (E-4001, E-4002), located at two different sections of the column. Before leaving the column, the sweet gas is scrubbed with make up water to remove the entrained MEA and to avoid any dispersion of solvent.

The flue gas is then discharged to the atmosphere at the top of the absorption columns at approximately 50°C.

From the bottom of the columns, the rich MEA is splitted into two streams: one is heated in a regenerative cross exchanger (E-4002) against the hot stripper bottom and sent to the regeneration column; the other one is heated in two regenerative exchangers (E-4003, E-4004), before flashing in the flash drum (F-4002). The flash allows to separate steam and CO_2 from the rich MEA stream, generating a stream of semi lean MEA from the bottom of the flash. The flashed vapour flows to the regeneration column, allowing to reduce the amount of steam required for the regeneration of the solvent in the reboiler (E-4008). The separated semi lean MEA stream is pumped back to the first bed of the absorption columns.

The rich solvent is regenerated in the stripping column, which is mainly composed of a stripping and a rectification section. Steam necessary for solvent regeneration comes from the power island, while saturated condensate is recovered back to the deaerator.

The vapour at the top of the column passes through the overhead stripper condenser, where it is cooled first with condensate recycled from the power island and then with water from the lignite drying (E-4006, E-4007). At the overhead stripper condenser outlet the double phase flow is separated in a K.O. drum (D-4001), generating the rich CO_2 stream, which flows to the CO_2 compression (Unit 5000), while condensed water is partially returned to the column as reflux.

The lean MEA at the bottom of the stripping column is pumped back to the absorption, after final cooling against cooling water (E-4005).

A partial flow of the circulating lean amine is periodically sent to the amine reclaimer area to remove the heat stable salts, formed from the reaction of the MEA with gas impurities like SO_2 and NO_2.

2.1.5 Unit 5000: CO_2 Compression and Drying

The following description makes reference to the process flow diagram of the CO_2 compression and drying unit, attached to paragraph 2.2 of this section (PFD: 5000-1-50-5001/2).

This unit is basically made of two parallel trains, each sized for 50% of the total capacity.

The CO_2 rich stream flows from the outlet of the regeneration column (Unit 4000) to the CO_2 compression unit, which is mainly composed of four different stages, with intercooling between them. The intercooling of the compressed CO_2 stream allows to recover heat both for the preheating of the condensate and for the lignite drying system. Cooling water makes final cooling of the CO_2 rich flow gas, between each compression stage.

The condensed water in the intercooling system is separated in the KO drums (D-5001/2). Between the second and the third stage of the compression, the drying system (PK-5001) reduces the water content of the gas to very low levels (less than 1 ppm), by means of a molecular sieve.

The dried gas flows to the last two stages of compression and intercooling, where CO_2 is compressed up to a pressure of 74 bar. Beyond the CO_2 critical conditions (73.8 bar, 31°C) a booster pump (P-5001) is used to deliver a dense phase carbon dioxide to the plant battery limits at 110 bar.

2.1.6 Unit 4100 to 4500: Auxiliary Units

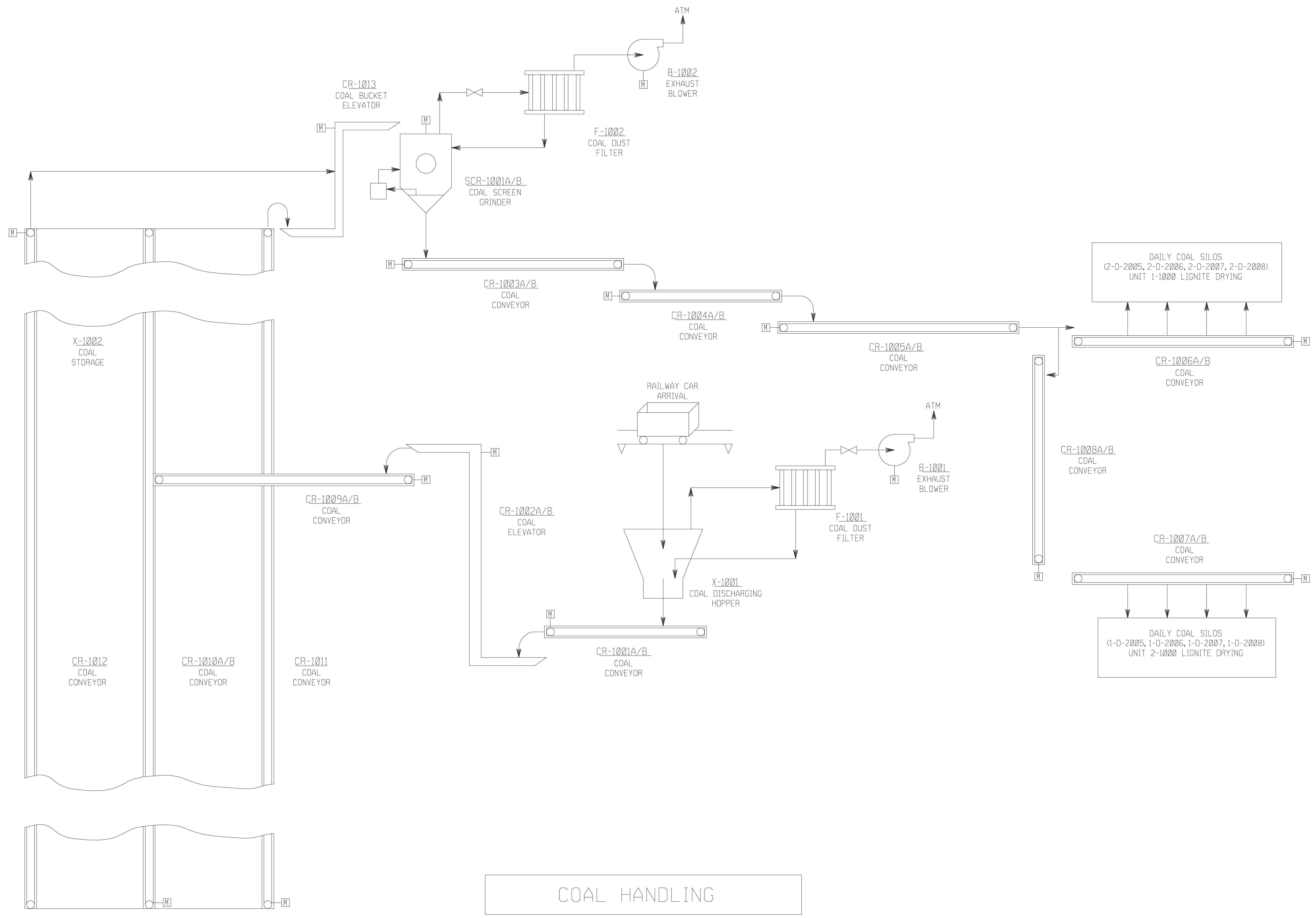
The process description of the auxiliary units is made in section C, paragraph 10.

The process flow diagram of the main auxiliary units is attached to paragraph 2.2 of this section (PFD 4100-1-50-4101).

2.2 Process Flow Diagrams

The process flow diagrams of the following process units are attached to this paragraph:

- UNIT 1000:	Coal handling and storage	(PFD: 1000-1-50-1001)
	Limestone handling and storage	(PFD: 1000-1-50-1002)
	Coal pre-drying system	(PFD: 1000-1-50-1003)
- UNIT 2000:	Boiler island with SCR	
	Electro Static Precipitators (ESP)	
	Limestone injection	(PFD: 2000-1-50-2001)
- UNIT 3000:	Power island consisting of	
	Steam Turbine and Preheating Line	(PFD: 3000-1-50-3001)
- UNIT 4000:	CO_2 capture plant	(PFD: 4000-1-50-4001)
- UNIT 5000:	CO_2 compression and drying	(PFD: 5000-1-50-5001)
- UNIT 4100-4500:	Utility and Offsite units	(PFD: 4100-1-50-4101)



COAL HANDLING

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PROCESS FLOW DIAGRAM
COAL HANDLING UNIT 1000

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CONTRACT N°
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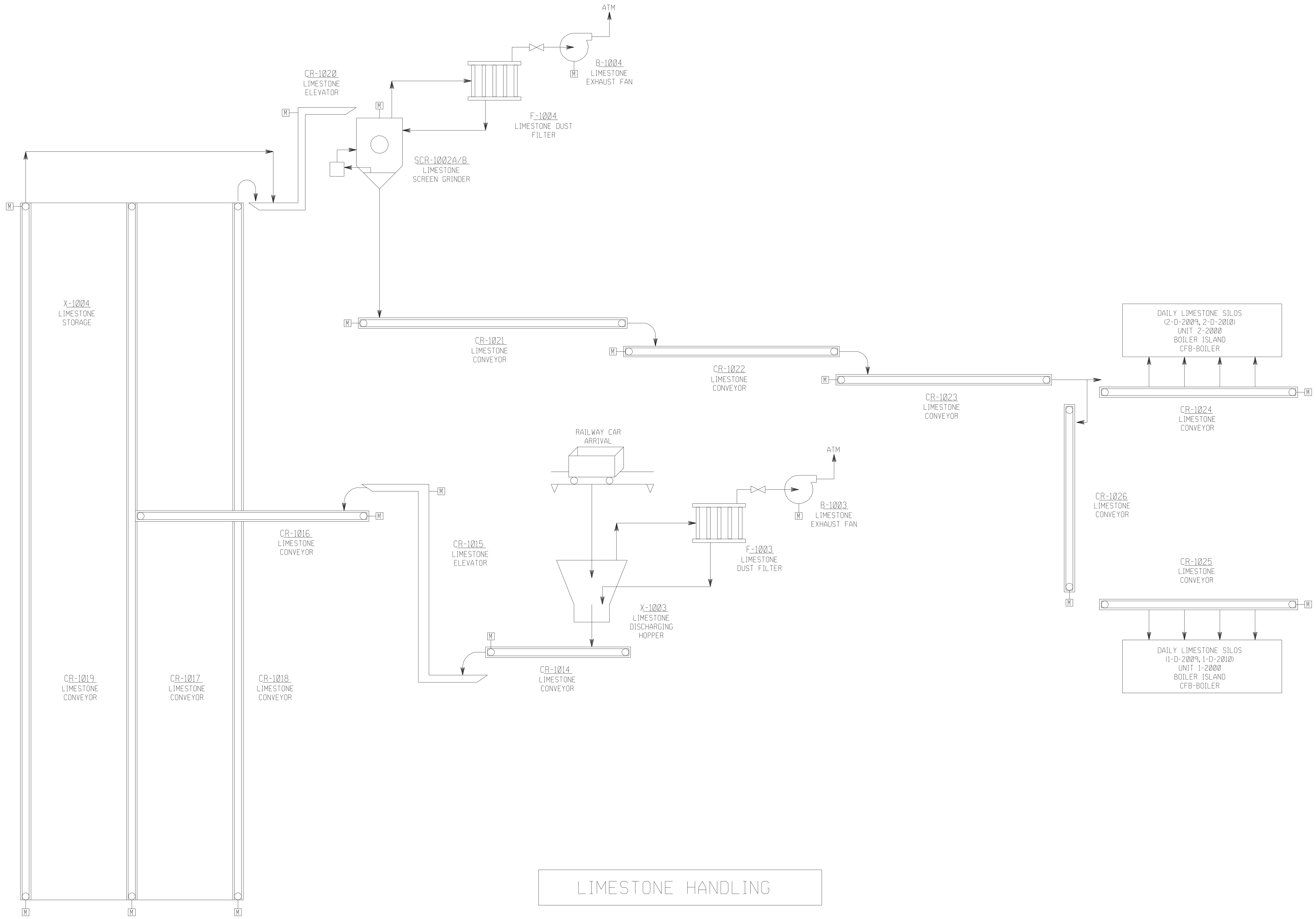

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CFB BOILER WITH CO_2 CAPTURE IEA GHG R&D PROGRAMME	APPROVED FOR CONSTRUCTION DWG. REV. DATE SIGNATURE
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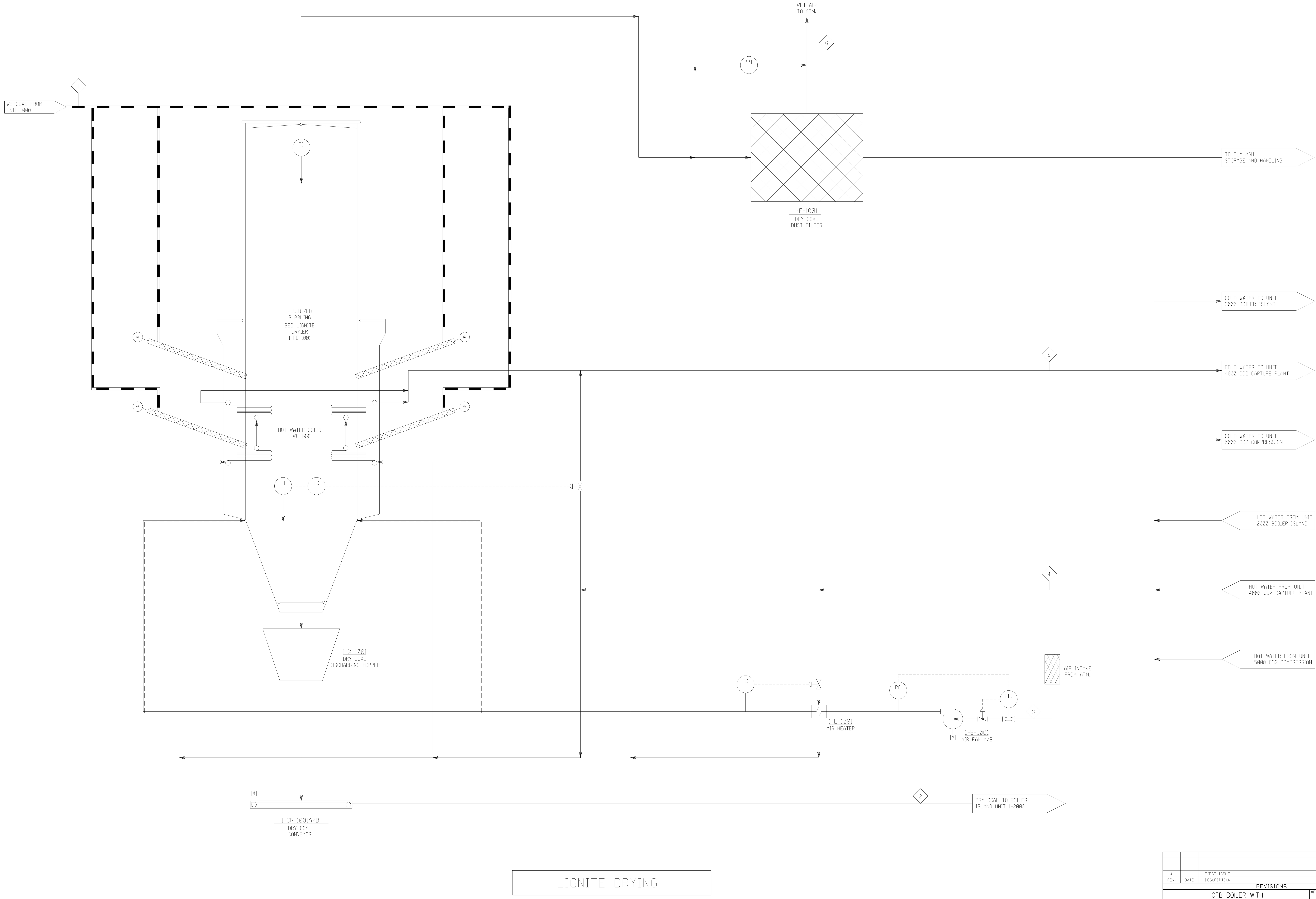

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PROCESS FLOW DIAGRAM
LIGNITE DRYING SYSTEM
UNIT 1000

ORDER N°
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CONTRACT N°
FRAME N°

FOSTER WHEELER

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FLUE GAS DUCT
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1-D-2006 COAL SILO
1-D-2009 LIMESTONE SILO
1-D-2010 LIMESTONE SILO
1-D-2007 COAL SILO
1-D-2008 COAL SILO
SEPARATOR
PDI
COMBUSTION CHAMBER
1-C-2001 CFB BOILER
1-BR-2001A/B/C/D/E/F/G/H/I/L/M/N
START-UP BURNER
1-FD-2002A/B/C/D/E/F COAL SCREW FEEDER
1-FD-2001A/B/C/D/E/F COAL SCREW FEEDER
NATURAL GAS
REHEATER
SUPERHEATER
ECONOMIZER
1-PK-2001 SCR
AMMONIA INJECTION
PDT PDI
IP REHEATER STEAM TO UNIT 3000 IP ST
IP STEAM FROM UNIT 3000 TO REHEATER
HP SUPERHEATED STEAM TO UNIT 3000 HP ST
COLD BOILER FEED WATER FROM UNIT 3000
1-E-2005 LIGNITE DRYING EXCHANGER
COLD WATER FROM LIGNITE DRYING
HOT WATER TO LIGNITE DRYING
1-E-2001 REGENERATIVE AIR PREHEATER
COLD WATER FROM 1-E-2002A/B
1-ESP-2001 ELECTROSTATIC PRECIPITATOR
HS
1-B-2003A/B FLUE GAS INDUCED DRAUGHT FANS
X-2001 CONTINUOUS EMISSION MONITORING SYSTEM
FLUE GAS TO CO2 CAPTURE PLANT UNIT 4000
1-E-2004 FLUE GAS COOLER
HOT WATER TO 1-E-2002A/B
BOTTOM FLY ASH HANDLING
1-B-2004A/B/C/D HIGH PRESSURE BLOWERS
GRID
TC
PC
FIC
1-E-2002A HOT WATER AIR PREHEATER
1-B-2002A/B SECONDARY AIR FAN
COOLING WATER INLET
COOLING WATER OUTLET
1-E-2003A/B/C/D/E/F/G/H/I/L BOTTOM ASH COOLERS
1-E-2002B HOT WATER AIR PREHEATER
HOT WATER FROM 1-E-2004
1-B-2001A/B PRIMARY AIR FAN
COLD WATER TO 1-E-2004
BOTTOM AND FLY ASH HANDLING
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20
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CFB BOILER WITH CO2 CAPTURE IEA GHG R&D PROGRAMME
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CONTRACT N°
FRAME N°
CLIENT DWG N°
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2000-1-50-2001
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CAD FILE NAME

CO2 CAPTURE PLANT

REV.	DATE	DESCRIPTION	DRAW	BY	CHD	APP.
A		FIRST ISSUE	SF			

REVISIONS

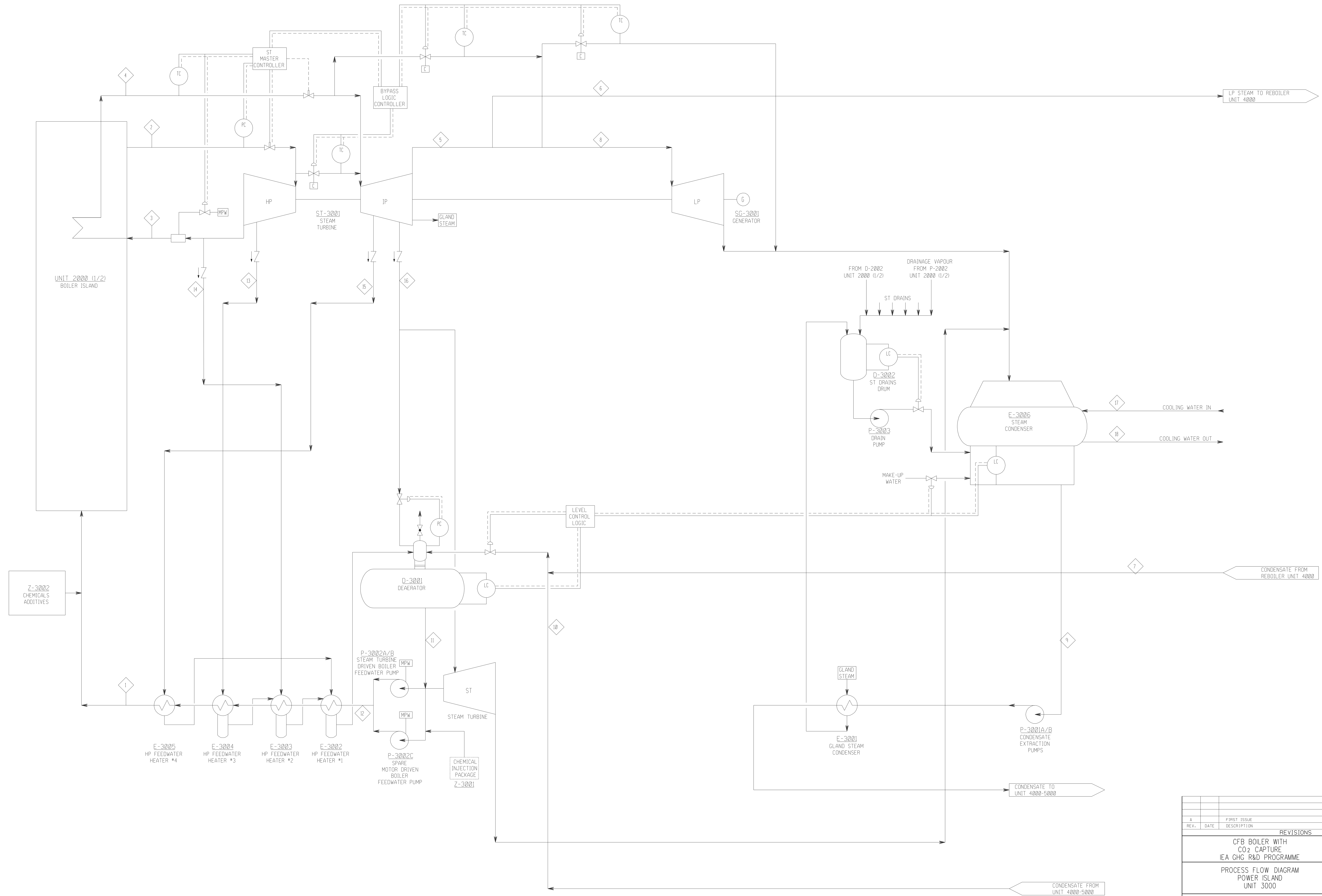
CFB BOILER WITH
CO2 CAPTURE
IEA GHG R&D PROGRAMME

PROCESS FLOW DIAGRAM
CO2 CAPTURE PLANT
UNIT 4000

FOSTER WHEELER

APPROVED FOR CONSTRUCTION
DWG.REV. DATE
SIGNATURE
ORDER N°
SUPPLIER
CONTRACT N°
FRAME N°
CLIENT DWG N° SCALE
SHEET OF
FW DWG N° 4000-1-50-4001 REV. A
SHEET OF

CAD FILE NAME



REV.	DATE	DESCRIPTION	DRAW	BY	CHD	APP.
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CFB BOILER WITH
CO_2 CAPTURE
IEA GHG R&D PROGRAMME

PROCESS FLOW DIAGRAM
POWER ISLAND
UNIT 3000

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DWG. REV. DATE
SIGNATURE
ORDER N°
SUPPLIER
CONTRACT N°
FRAME N°
CLIENT DWG N°
SHEET OF
SCALE
FWI DWG N° 3000-1-50-3001
SHEET OF
REV. A

FOSTER WHEELER

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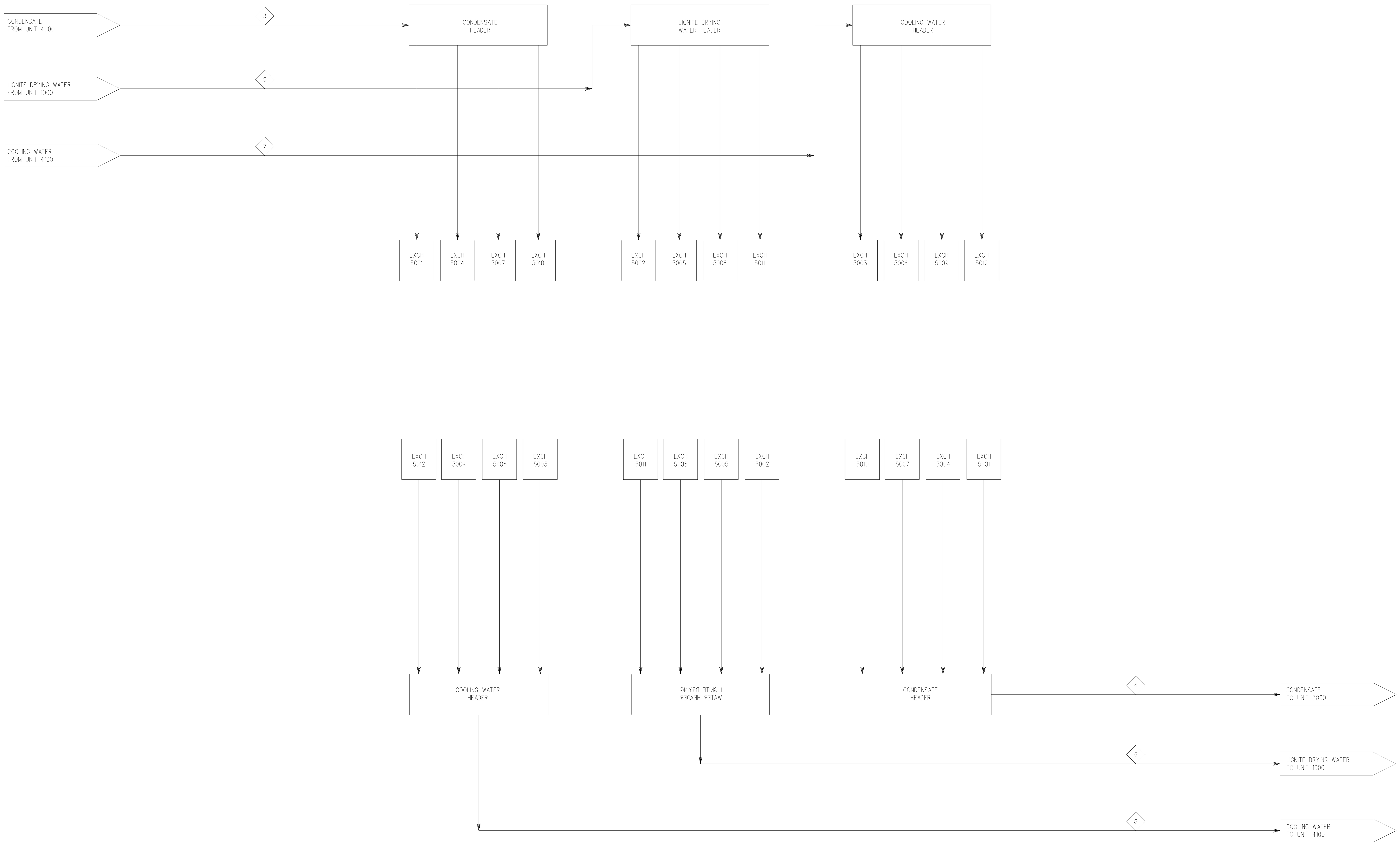

CO2 COMPRESSION & DRYING (HEAT INTEGRATION)

REV.	DATE	DESCRIPTION	DRAW	BY	CHD	APP.
A		FIRST ISSUE	SF			

REVISIONS

CFB BOILER WITH
CO_2 CAPTURE
IEA GHG R&D PROGRAMME

PROCESS FLOW DIAGRAM
CO2 COMPRESSION & DRYING
(HEAT INTEGRATION)
UNIT 5000

APPROVED FOR CONSTRUCTION
DWG. REV. DATE
SIGNATURE
ORDER N°
SUPPLIER
CONTRACT N°
FRAME N°
CLIENT DWG N°
SHEET OF
SCALE

FOSTER WHEELER

FWI DWG N° 5000-1-50-5001
SHEET OF
REV. A

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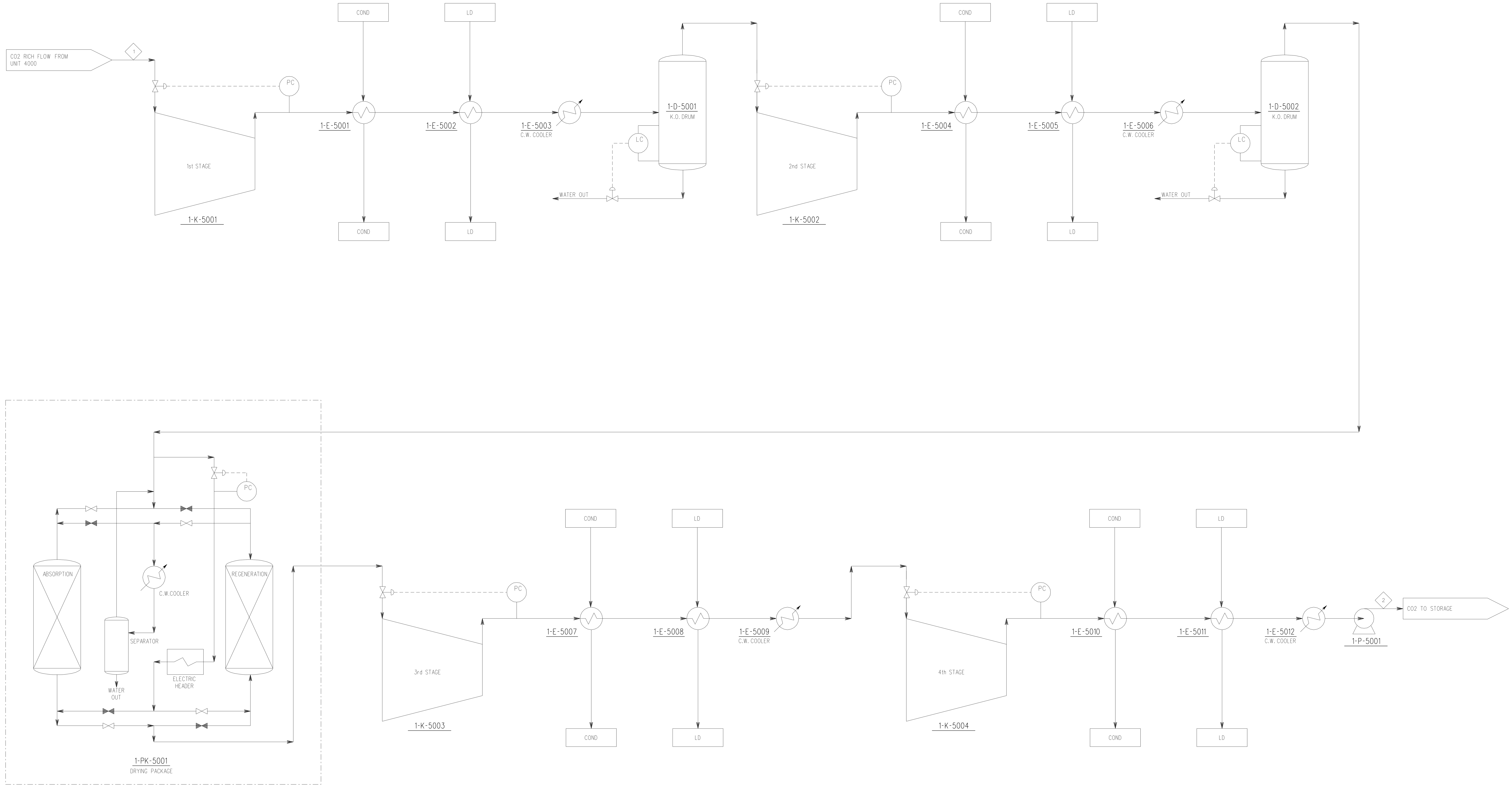

CO2 COMPRESSION AND DRYING PLANT

REV.	DATE	DESCRIPTION	DRAW	BY	CHD	APP.
A		FIRST ISSUE	SF			

REVISIONS

CFB BOILER WITH CO_2 CAPTURE IEA GHG R&D PROGRAMME	APPROVED FOR CONSTRUCTION DWG. REV. DATE SIGNATURE
PROCESS FLOW DIAGRAM CO2 COMPRESSION & DRYING UNIT 5000	ORDER N° SUPPLIER CONTRACT N° FRAME N°
FOSTER WHEELER	CLIENT DWG N° SHEET OF / SCALE
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2.3 Heat and Material Balances

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

- UNIT 1000: Solid materials storage – handling and lignite drying
- UNIT 2000: Boiler island
- UNIT 3000: Steam turbine and preheating line
- UNIT 4000: CO_2 capture plant
- UNIT 5000: CO_2 compression and drying

Stream numbers are as shown on the process flow diagrams attached to paragraph 2.2 of this section.

CFB HEAT AND MATERIAL BALANCE							REVISION	0	1
FOSTER WHEELER	CLIENT : IEA GREEN HOUSE R & D PROGRAMME					Sheet 1 of 1	PREP.	SR	
	CASE : CFB with CO_2 Capture						APPROVED	LM	
	UNIT : 1000 Solid Materials Handling-Storage and Lignite Drying						DATE	Nov-05	
STREAM	1	2	3	4	5	6	7	8	9
	Wet Coal to Lignite Drying System (1)	Dry Coal to Boiler Island UNIT 2000 (1)	Air intake from atmosphere for Lignite Drying (1)	Hot Water from UNITS 2000 - 4000 - 5000 (1)	Cold Water to UNITS 2000 - 4000 - 5000 (1)	Wet Air to Atmosphere (1)			
Temperature (°C)	AMB	AMB	6	85	65	65			
Pressure (bar)	ATM	ATM	ATM	3	3	ATM			
TOTAL FLOW									
Mass flow (kg/h)	592883	429840	908820	5290600	5290600	1071865			
Molar flow (kgmole/h)			31458	293759	293759	40513			
	Moisture	Moisture							
	50.70%	32%							
Composition wt% with moisture									
Carbon	31.33%	43.20%							
Hydrogen	2.29%	3.16%							
Oxygen	11.56%	15.94%							
Sulfur	0.22%	0.31%							
Nytrogen	0.37%	0.51%							
Chlorine	0.03%	0.05%							
Moisture	50.70%	32.00%							
Ash	3.50%	4.83%							

Note (1): All the enclosed data are for two CFB boilers in parallel

CFB HEAT AND MATERIAL BALANCE		REVISION	0	1	
FOSTER WHEELER	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	SR		
	CASE : CFB with CO_2 Capture	APPROVED	LM		
	UNIT : 2000 Boiler Island — Sheet 1 of 2	DATE	Nov-05		

STREAM	1-4	5	6	7	8	9	10	11	12	13-14
	Coal from Coal Drying System (2)	Primary Air intake from Atmosphere (2)	Secondary Air Intake from Atmosphere (2)	High Pressure Air Intake from Atmosphere (2)	Flue Gas From Boiler to CO_2 Capture Plant UNIT 4000 (2)	Feed Water from Preheating line UNIT 3000 (2)	HP SH Steam to Steam Turbine (2)	IP Steam from Preheating Line UNIT 3000 (2)	IP Reheated Steam to Steam Turbine (2)	Limestone Injection (1) - (2)
Temperature (°C)	AMB	15	15	15	85	272	584	319	602	AMB
Pressure (bar)	AMB	1.23	1.13	1.61	1.03	313	283	51	48	ATM
TOTAL FLOW										
Mass flow (kg/h)	429840	1867900	925400	119750	3361176	2182000	2182000	2016000	2016000	27360
Molar flow (kgmole/h)		64656	32032	4145	116023	121155	121155	111938	111938	
LIQUID PHASE										
Mass flow (kg/h)		0	0	0	0	2182000				
GASEOUS PHASE										
Mass flow (kg/h)		1867900	925400	119750	3361176	0	2182000	2016000	2016000	
Molar flow (kgmole/h)		64656	32032	4145	116023	0	121155	111938	111938	
Molecular Weight		28.89	28.89	28.89	28.97	18.01	18.01	18.01	18.01	
Composition (vol %)	See UNIT 1000									
N_2		77.57%	77.57%	77.57%	68.14%	0.00%	0.00%	0.00%	0.00%	
CO_2		0.00%	0.00%	0.00%	13.51%	0.00%	0.00%	0.00%	0.00%	
H_2O		0.68%	0.68%	0.68%	13.70%	100%	100%	100%	100%	
O_2		20.86%	20.86%	20.86%	3.88%	0.00%	0.00%	0.00%	0.00%	
Ar		0.89%	0.89%	0.89%	0.77%	0.00%	0.00%	0.00%	0.00%	
NOx		0.00%	0.00%	0.00%	20 ppm VD 6% O2	0.00%	0.00%	0.00%	0.00%	
SOx		0.00%	0.00%	0.00%	15 ppm VD 6% O2	0.00%	0.00%	0.00%	0.00%	
CO		0.00%	0.00%	0.00%	120 ppm VD 6% O2	0.00%	0.00%	0.00%	0.00%	

Note (1): Limestone Analysis (wt %) $CaCO_3$ = 95% - $MgCO_3$ = 3.4% - Inert = 1.6%
Note (2): All the enclosed data are for two CFB boilers in parallel

FOSTER WHEELER	CFB HEAT AND MATERIAL BALANCE				REVISION	0	1	
	CLIENT : IEA GREEN HOUSE R & D PROGRAMME				PREP.	SR		
	CASE : CFB with CO_2 Capture				APPROVED	LM		
	UNIT : 2000 Boiler Island			Sheet 2 of 2	DATE	Nov-05		
STREAM	15	16	17	18	19	20	21	22
	Cold Water from Lignite Drying UNIT 1000 (2)	Hot Water to Lignite Drying UNIT 1000 (2)	Cooling Water Inlet (2)	Cooling Water Outlet (2)	Bottom Ash to UNIT 1000 (2)	Fly Ash to UNIT 1000 (2)		
Temperature (°C)	65	85	11	21	AMB	AMB		
Pressure (bar)	3	3	3	3	ATM	ATM		
TOTAL FLOW								
Mass flow (kg/h)	1108000	1108000	104000	104000	12240	28800		
Molar flow (kgmole/h)	61521	61521	5775	5775				
LIQUID PHASE								
Mass flow (kg/h)	1108000	1108000	104000	104000				
GASEOUS PHASE								
Mass flow (kg/h)								
Molar flow (kgmole/h)								
Molecular Weight	18.01	18.01	18.01	18.01				
Composition (vol %)								
N_2	0.00%	0.00%	0.00%	0.00%				
CO_2	0.00%	0.00%	0.00%	0.00%				
H_2O	100%	100%	100%	100%				
O_2	0.00%	0.00%	0.00%	0.00%				
Ar	0.00%	0.00%	0.00%	0.00%				
NOx	0.00%	0.00%	0.00%	0.00%				
SOx	0.00%	0.00%	0.00%	0.00%				
CO	0.00%	0.00%	0.00%	0.00%				

Note (1): Limestone Analysis (wt %) $CaCO_3$ = 95% - $MgCO_3$ = 3.4% - Inert = 1.6%

Note (2): All the enclosed data are for two CFB boilers in parallel

CFB HEAT AND MATERIAL BALANCE

CLIENT : **IEA GREEN HOUSE R & D PROGRAMME**

CASE : **CFB with CO_2 Capture**

UNIT : **3000 Steam Turbine & Preheating Line**

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
1	HP Water to Boiler Island	2182	272	313	1191
2	HP Steam from Boiler	2182	584	283	3413
3	IP Steam to Boiler	2016	319	51	2978
4	IP hot reheated steam to Steam Turbine	2016	602	48	3673
5	IP Steam Turbine exhaust	1572	239	3.6	2943
6	LP Steam to Reboiler	873	146	3.6	2747
7	Hot Condensate returned from Reboiler	873	135	3	566
8	LP Steam to Steam Turbine	770	239	3.6	2943
9	Condensate to UNIT 4000 - 5000	889	25	0.032	105
10	LP Preheated Condensate from UNIT 4000 - 5000	889	124	9	522
11	Condensate to HP FWH (Deaer. Outlet)	2182	175	9	742
12	BFW Pump Delivery	2182	181	315	783
13	1st HP Extraction to E-3004	78	338	59	3011
14	2nd HP Extraction to E-3003	88	318	51	2978
15	1st MP Extraction to E-3005 and 3002	194	535	32	3535
16	2nd MP Extraction to Deaer. And ST BFW Pump	250	356	9	3172
17	Cooling water Inlet	46332	11	3	47
18	Cooling Water Outlet	46332	21	2	88

CFB HEAT AND MATERIAL BALANCE

REVISION	0	1	
PREP.	SR		
APPROVED	LM		
DATE	Nov-05		

FOSTER WHEELER

CLIENT : IEA GREEN HOUSE R & D PROGRAMME
CASE : CFB with CO_2 Capture
UNIT : 4000 CO_2 Capture Plant

Sheet 1 of 1

STREAM	1	2	3	4	5	6	7	8	9	10	11	12	13
	Flue Gas from Boiler Island UNIT 2000 (1)	Sweet Gas to Atmosphere	CO_2 Rich Flow to Compression UNIT 5000	LP Steam From Turbine Extraction to Reboiler	Condensate from Reboiler to Power Island	Cold Condensate from UNIT 3000	Hot Condensate to UNIT 5000	Lignite Drying Water from UNIT 1000	Lignite Drying water to UNIT 1000	Cooling Water inlet from UNIT 4100	Cooling water outlet to UNIT 4100	Water Make-Up	MEA Make-Up
Temperature (°C)	85	46	38	146	135	26	75	65	85	11	21	30	
Pressure (bar)	1.03	1.01	1.6	3.6	3	14	12	3	3	3	3	2	
TOTAL FLOW													
Mass flow (kg/h)	3361176	2667505	596737	873000	873000	889000	889000	3074200	3074200	42704000	42704000	148725	
Molar flow (kgmole/h)	116023	96789	13897	48473	48473	49361	49361	170694	170694	2371127	2371127	8258	
LIQUID PHASE													
Mass flow (kg/h)	0	0	0	0	873000	889000	889000	3074200	3074200	42704000	42704000	148725	
GASEOUS PHASE													
Mass flow (kg/h)	3361176	2667505	596737	873000	0	0	0	0	0	0	0	0	
Molar flow (kgmole/h)	116023	96789	13897	48473	0	0	0	0	0	0	0	0	
Molecular Weight	28.97	27.56	42.94	18.01	18.01	18.01	18.01	18.01	18.01	18.01	18.01	18.01	
Composition (vol %)													
N_2	68.14%	81.68%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
CO_2	13.51%	2.43%	95.88%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
H_2O	13.70%	10.31%	4.11%	100%	100%	100%	100%	100%	100%	100%	100%	100.00%	
O_2	3.88%	4.65%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Ar	0.77%	0.93%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
NOx	20 ppm VD 6% O2	<20 ppm VD 6% O2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
SOx	15 ppm VD 6% O2	<15 ppm VD 6% O2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
CO	120 ppm VD 6% O2	<120 ppm VD 6% O2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	

Note (1): All the enclosed data are for two CFB boilers in parallel

CFB HEAT AND MATERIAL BALANCE		REVISION	0	1	
FOSTER WHEELER	CLIENT : IEA GREEN HOUSE R & D PROGRAMME	PREP.	SR		
	CASE : CFB with CO_2 Capture	APPROVED	LM		
	UNIT : 5000 CO_2 Compression & Drying — Sheet 1 of 1	DATE	Nov-05		

STREAM	1	2	3	4	5	6	7	8	9	10
	CO_2 Rich Flow from UNIT 4000	CO_2 to long term Storage	Condensate from UNIT 4000	Preheated Condensate to Power Island UNIT 3000	Lignite Drying Water from UNIT 1000	Lignite Drying Water to UNIT 1000	Cooling Water from UNIT 4100	Cooling Water to UNIT 4100		
Temperature (°C)	38	30	75	124	65	85	11	21		
Pressure (bar)	1.6	110	12	10	3	3	3	3		
TOTAL FLOW										
Mass flow (kg/h)	596737	586433	889000	889000	1108400	1108400	7353000	7353000		
Molar flow (kgmole/h)	13897	13325	49361	49361	61544	61544	408273	408273		
LIQUID PHASE										
Mass flow (kg/h)	0	586433	889000	889000	1108400	1108400	7353000	7353000		
GASEOUS PHASE										
Mass flow (kg/h)	596737	0	0	0	0	0	0	0		
Molar flow (kgmole/h)	13897	0	0	0	0	0	0	0		
Molecular Weight	42.94	44.01	18.01	18.01	18.01	18.01	18.01	18.01		
Composition (vol %)										
N_2	0.01%	0.01%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
CO_2	95.88%	99.99%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
H_2O	4.11%	0.00%	100%	100%	100%	100%	100%	100%		
O_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
NOx	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
SOx	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		
CO	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		

2.4 Utility Consumption

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

FOSTER WHEELER	CLIENT: IEA GHG PROJECT: GASIFICATION POWER GENERATION STUDY LOCATION: Germany FWI Nº: 1BD0237A	Rev 0 Nov-05 ISSUED BY: SR. CHECKED BY: LM APPR. BY: RD

ELECTRICAL CONSUMPTION SUMMARY - CFB with CO_2 Capture

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
1000	Solid Materials Storage - Handling and Lignite Drying	
	Coal Conveyors and Feeders	630
	Coal Milling and Powder control System	280
	Lignite Drying System	565
	Limestone Conveyors	70
	Limestone Milling and Powder control System	130
	PARTIAL TOTAL	1675
2000	Boiler Island	
	Primary Air Fans	13200
	Secondary Air Fans	3170
	Induced Draught Fans	8950
	High Pressure Blowers	2050
	Bottom Ash Handling	105
	Fly Ash Handling and Storage	140
	Miscellanea	730
	PARTIAL TOTAL	28345
4000	CO_2 Capture Plant	25400
5000	CO_2 Compression and Drying	64600
	POWER ISLANDS UNITS	
3000	Steam Turbine and Preheating line	
	Steam Turbine	760
	Condensate Extraction Pump	380
	PARTIAL TOTAL	1140
	UTILITY and OFFSITE UNITS	
4100	Cooling Water and Machinery Cooling Water System	
	Cooling Towers - Condenser - Boiler Island - Utilities	8880
	Cooling Towers - CO_2 Capture and Compression	9390
	Cooling Towers - Make-Up	190
	Cooling Towers - Machinery Cooling Water	280
4200	Demi Water System	60
4300	Natural Gas Start-Up System	0
4400	Plant and Instrument Air System	1500
4500	Raw / Service / Potable Water System	370
	Miscellanea	4800
	PARTIAL TOTAL	25470
	GRAN TOTAL	**146630**

	CLIENT:	IEA GHG	Rev 0
FOSTER WHEELER	PROJECT:	GASIFICATION POWER GENERATION STUDY	Nov-05
	LOCATION:	Germany	ISSUED BY: SR
	FWI Nº:	1BD0237A	CHECKED BY: LM
			APPR. BY: RD

WATER CONSUMPTION SUMMARY - CFB with CO_2 Capture

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water [t/h]
	PROCESS UNITS			
1000	**Solid Materials Handling - Storage and Lignite Drying**			80
2000	**Boiler Island**			104
4000	**Acid Gas Removal**		149	42704
5000	**CO_2 Compression and Drying**			7353
	POWER ISLANDS UNITS			
	Steam Turbine and Generator auxiliaries		1	46332
	Miscellanea			1251
	UTILITY and OFFSITE			
4100	**Cooling Water and Machinery Cooling Water System**	1432		
4200	**Demi Water System**			
4300	**Natural Gas Start-Up System**			
4400	**Plant and Instrument Air System**			50
4500	**Raw / Service / Potable Water System**	150	-150	
	Miscellanea			8
	BALANCE	1582	0	97881

CLIENT:	IEA GHG	Rev 0
PROJECT:	CO2 Capture in Low rank coal power plants	Nov-05
LOCATION:	Germany	ISSUED BY: SR
FWI Nº:	1BD0237A	CHECKED BY: LM
		APPR. BY: R.D

Chemicals and Consumables Summary - CFB with CO_2 Capture

	DESCRIPTION	Consumption t/h	Yearly Consumption t/y
	Chemicals and Consumables		
	Make up Water (Power Plant, CO_2 Capture Plant)	1582	11770323
	Limestone (Boiler Island SOx Control)	27.4	203723
	Ammonia (Boiler Island NOx Control)	0.5	3467
	MEA solvent (CO_2 Capture Plant)	1.66	12345
	Activated Carbon (CO_2 Capture Plant)	0.04	308
	Soda Ash (CO_2 Capture Plant)	0.09	668
	Caustic Soda (Water Treatment)	0.3	1914
	Corrosion Inhibitors (Cooling Towers)	0.01	54
	Sodium Hypochlorite (Cooling Tower Basin)	0.4	2874

2.5 CFB overall performances

The following table shows the overall performance of the CFB complex.

CFB		
CFB with CO_2 Capture		
OVERALL PERFORMANCES OF THE CFB COMPLEX		
Coal Flowrate (A.R.)	t/h	592.9
Coal LHV (A.R.)	kJ/kg	10500
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**1729.3**
Steam turbine power output (@gen. Terminals)	MWe	758.2
GROSS ELECTRIC POWER OUTPUT OF PC - USC COMPLEX (D)	**MWe**	**758.2**
Coal Storage / Handling / Drying	MWe	1.7
Boiler Island	MWe	28.3
CO2 Plant incl. Blowers	MWe	25.4
CO2 Compression	MWe	64.6
Power Island	MWe	1.1
Utilities	MWe	25.5
ELECTRIC POWER CONSUMPTION OF CFB COMPLEX	**MWe**	**146.6**
NET ELECTRIC POWER OUTPUT OF CFB (C) Step-Up Transformer Efficiency (0.997)	**MWe**	**609.7**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**43.8%**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**35.3%**

As already explained in the summary of this section (para 2.0), the plant performances of this alternative are slightly less than those previously developed in section D.3 for the same case. This is for the investigation made with one steam turbine supplier, which led to some modifications on the design of this machine (see para 2.0).

The following table shows the overall CO_2 removal efficiency of the CFB complex:

	Equivalent flow of CO_2 kmol/h
Coal (Carbon = 43.21%wt)	15466
Limestone	259.7
Slag	50.7
Net Carbon flowing to Process Units (A)	15675
Liquid Storage	
CO	0.0
CO_2	13324
Total to storage (B)	13324
Emission	
CO	0.0
CO_2	2351
Total Emission	2351
Overall CO_2 removal efficiency, % (B/A)	85.0

2.6 Environmental Impact

The CFB complex is designed to process coal and produce electric power. The advanced technology allows to reach a high efficiency and to minimise the environmental impact.

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

2.6.1 Gaseous Emissions

Main Emissions

In normal operation at full load, the main continuous emissions are the combustion flue gases leaving the absorber unit of the CO_2 capture plant.

Table 2.6.1 summarises expected flow rate and concentration of the combustion flue gas after CO_2 capture treatment.

Table 2.6.1 – Expected gaseous emissions from CFB plant integrated with CO_2 capture.

	Normal Operation
Wet gas flow rate, kg/s	741
Flow, Nm^3/h	2169430
Temperature, °C	46
Composition	(%vol)
N_2	82.60
O_2	4.65
CO_2	2.43
H_2O	10.31
Emissions	mg/Nm^3 (1)
NOx	40
SOx	43 (2)
CO	Less than 150
Particulate	Less than 30
NH_3	5 (3)

(1) Dry gas, O_2 Content 6% vol
(2) SOx Emissions upstream AGR unit; after solvent washing, emissions are expected close to zero
(3) Due to ammonia slippage into the flue gas downstream the SCR

In normal operation at full load, the following emission to the atmosphere is foreseen from the coal drying process:

Flow rate : 1072 t/h
Particulate : 21 kg/h

Minor Emissions

Fugitive emissions are those emissions caused by storage and handling of materials (solids transfer, leakage, etc.). They are prevented by routing all vents to a bag filter.

2.6.2 Liquid Effluent

The plant would be designed for zero contaminated liquid effluents. All the liquid effluents are treated in the wastewater treatment system in order to be discharged in accordance with the current regulations.

For the description of the wastewater treatment refer to section G.1, para. 1.6.2.

2.6.3 Solid Effluent

The power plant is expected to produce the following solid by-products:

Fly Ash

Flow rate : 28.8 t/h

Bottom Ash

Flow rate : 12.2 t/h

Fly and bottom ash are used as bed filling and returned back to the mine or dispatched to cement industries, if available in the neighbours.

The calcium Sulphate is not a pure product and cannot be sold as pure gypsum.

2.7 Equipment List

The list of the main equipment and process packages are included in this section.

		CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0		
FOSTER WHEELER		LOCATION: Germany	DATE	Nov-05		
		PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants	ISSUED BY	S.R.		
		CONTRACT N. 1BD0237A	CHECKED BY	L.M.		
			APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 1000 - Solid Materials Storage and Handling - CFB Boiler with CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		COAL SYSTEM							
		The coal handling storage and drying system includes: - Stacker reclaimer - Coal conveyors - Coal mills - Filters - Fans		Capacity: 600 t/h					
		LIGNITE DRYING SYSTEM							
		- Fluidized Bubbling Bed Dryer - Air Fan - Hot water based air heater - Filters for exhaust air		Capacity: 600 t/h					
		LIMESTONE SYSTEM							
		The limestone handling and storage system includes - Limestone reclaimer area - Limestone conveyors - Limestone mills - Filters - Fans		Capacity: 30 t/h					

		CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0		
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EQUIPMENT LIST

Unit 1000 - Solid Materials Storage and Handling - CFB Boiler with CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		CONVEYORS							
		Coal Handling							
1	CR-1001 A/B	Wet Coal Conveyor							
1	CR-1002 A/B	Wet Coal Elevator							
1	CR-1003 A/B	Wet Coal Conveyor							
1	CR-1004 A/B	Wet Coal Conveyor							
1	CR-1005 A/B	Wet Coal Conveyor							
1	CR-1006 A/B	Wet Coal Conveyor							
1	CR-1007 A/B	Wet Coal Conveyor							
1	CR-1008 A/B	Wet Coal Conveyor							
1	CR-1009 A/B	Wet Coal Conveyor							
1	CR-1010 A/B	Wet Coal Conveyor							
1	CR-1011	Wet Coal Conveyor							
1	CR-1012	Wet Coal Conveyor							
1	CR-1013	Wet Coal Bucket Elevator							
1/2	1-CR-1001 A/B	Dry Coal Conveyor							
2/2	2-CR-1001 A/B	Dry Coal Conveyor							
		Limestone Handling							
1	CR-1014	Limestone Conveyor							
1	CR-1015	Limestone Elevator							
1	CR-1016	Limestone Conveyor							
1	CR-1017	Limestone Conveyor							
1	CR-1018	Limestone Conveyor							
1	CR-1019	Limestone Conveyor							
1	CR-1020	Limestone Elevator							
1	CR-1021	Limestone Conveyor							
1	CR-1022	Limestone Conveyor							
1	CR-1023	Limestone Conveyor							
1	CR-1024	Limestone Conveyor							
1	CR-1025	Limestone Conveyor							
1	CR-1026	Limestone Conveyor							

	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0
	LOCATION: Germany	DATE	Nov-05
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	CONTRACT N. 1BD0237A	CHECKED BY	L.M.
		APPROVED BY	R.D.

EQUIPMENT LIST

Unit 1000 - Solid Materials Storage and Handling - CFB Boiler with CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		MILLING							
		Coal Milling							
1	SCR-1001 A/B	Coal Screen Grinder							
		Limestone Milling							
1	SCR-1002 A/B	Limestone Screen Grinder							
		STORAGE							
		Coal Storage							
1	X-1001	Wet Coal Discharging Hopper							
1	X-1002	Wet Coal Storage							
		Limestone Storage							
1	X-1003	Limestone Discharging Hopper							
1	X-1004	Limestone Storage							
		FILTERS							
1	F-1001	Wet Coal Dust Filter							
1	F-1002	Wet Coal Dust Filter							
1/2	1-F-1001	Dry Coal Dust Filter							
2/2	2-F-1001	Dry Coal Dust Filter							
1	F-1003	Limestone Dust Filter							
1	F-1004	Limestone Dust Filter							
		FLUIDIZED BUBBLING BED PACKAGE		**Capacity**					
1/2	1-FB-1001	Fluidized Bubbling Bed Lignite Dryer		300 t/h					
1/2	1-WC-1001	Hot water submerged coils		55 MWth					
1/2	1-E-1001	Hot water air heater		7.5 MWth					
1/2	1-X-1001	Dry Coal discharging hopper							
2/2	2-FB-1001	Fluidized Bubbling Bed Lignite Dryer		300 t/h					
2/2	2-WC-1001	Hot water submerged coils		55 MWth					
2/2	2-E-1001	Hot water air heater		7.5 MWth					
2/2	2-X-1001	Dry Coal discharging hopper							
		FANS							
1	B-1001	Wet Coal Exhaust Fan							
1	B-1002	Wet Coal Exhaust Fan							
1/2	1-B-1001 A/B	Air Fan		m=65 kg/s; H=2000 Pa	160 kW				All operating; single design capacity = 60% of the maximum load
2/2	2-B-1001 A/B	Air Fan		m=65 kg/s; H=2000 Pa	160 kW				
1	B-1003	Limestone Exhaust Fan							
1	B-1004	Limestone Exhaust Fan							

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0		
	LOCATION: Germany	DATE	Nov-05		
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	CONTRACT N. 1BD0237A	CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2000 - Boiler Island - CFB with CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		BOILERS							
1/2	1-C-2001	Supercritical CFB Boiler		MCR: SH: 1095 t/h RH: 1010 t/h		MCR: 285 bar 51 bar	Feed Water 275°C 585 °C 600 °C		Boiler Package including: - Coal Silos - Limestone Silos - Coal Screw Feeders - Coal Burners (1-BR-2001 A-N) - Regenerative Air Preheater - Hot Water Air Preheater - Bottom Ash Coolers - High Pressure Blowers - Air Fans - Flue Gas Induced Draught Fans - Desuperheaters - Start-Up System - Electrostatic Precipiatators ESP - Continuous Emission monitoring System - Selective Catalytic Reduction SCR - Ammonia Storage and Injection Package
2/2	2-C-2001	Supercritical CFB Boiler		MCR: SH: 1095 t/h RH: 1010 t/h		MCR: 285 bar 51 bar	Feed Water 275°C 585 °C 600 °C		Boiler Package including: - Coal Silos - Limestone Silos - Coal Screw Feeders - Coal Burners (2-BR-2001 A-N) - Regenerative Air Preheater - Hot Water Air Preheater - Bottom Ash Coolers - High Pressure Blowers - Air Fans - Flue Gas Induced Draught Fans - Desuperheaters - Start-Up System - Electrostatic Precipiatators ESP - Continuous Emission monitoring System - Selective Catalytic Reduction SCR - Ammonia Storage and Injection Package

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1BD0237A	REVISION	Rev.0		
		DATE	Nov-05		
		ISSUED BY	S.R.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 2000 - Boiler Island - CFB with CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		FANS							
1/2	1-B-2001 A/B	Primary Air Fans		m=165 kg/s; H=22000 Pa	4000 kW				Included in 1-C-2001
1/2	1-B-2002 A/B	Secondary Air Fans		m=84 kg/s; H=12000 Pa	1100 kW				Included in 1-C-2001
1/2	1-B-2003 A/B	Flue Gas Induced Draught Fans		m=285 kg/s; H=8100 Pa	3700 kW				Included in 1-C-2001
1/2	1-B-2004 A/B/C/D	High Pressure Blowers		m=9 kg/s; H=60000 Pa	580 kW				Included in 1-C-2001
2/2	2-B-2001 A/B	Primary Air Fans		m=165 kg/s; H=22000 Pa	4000 kW				Included in 2-C-2001
2/2	2-B-2002 A/B	Secondary Air Fans		m=84 kg/s; H=12000 Pa	1100 kW				Included in 2-C-2001
2/2	2-B-2003 A/B	Flue Gas Induced Draught Fans		m=285 kg/s; H=8100 Pa	3700 kW				Included in 2-C-2001
2/2	2-B-2004 A/B/C/D	High Pressure Blowers		m=9 kg/s; H=60000 Pa	580 kW				Included in 2-C-2001
		HEAT EXCHANGERS							
1/2	1-E-2001	Regenerative Air Preheater							Included in 1-C-2001
1/2	1-E-2002 A/B	Hot Water Air Preheater							Included in 1-C-2001
1/2	1-E-2003 A/B...I/L	Bottom Ash Coolers							Included in 1-C-2001
1/2	1-E-2004	Flue Gas Cooler							
1/2	1-E-2005	Lignite Drying Exchanger							
2/2	2-E-2001	Regenerative Air Preheater							Included in 2-C-2001
2/2	2-E-2002 A/B	Hot Water Air Preheater							Included in 2-C-2001
2/2	2-E-2003 A/B...I/L	Bottom Ash Coolers							Included in 2-C-2001
2/2	2-E-2004	Flue Gas Cooler							
2/2	2-E-2005	Lignite Drying Exchanger							
		SILOS							
1/2	1-D-2005	Coal Silo							Included in 1-C-2001
1/2	1-D-2006	Coal Silo							Included in 1-C-2001
1/2	1-D-2007	Coal Silo							Included in 1-C-2001
1/2	1-D-2008	Coal Silo							Included in 1-C-2001
1/2	1-D-2009	Limestone Silo							Included in 1-C-2001
1/2	1-D-2010	Limestone Silo							Included in 1-C-2001
2/2	2-D-2005	Coal Silo							Included in 2-C-2001
2/2	2-D-2006	Coal Silo							Included in 2-C-2001
2/2	2-D-2007	Coal Silo							Included in 2-C-2001
2/2	2-D-2008	Coal Silo							Included in 2-C-2001
2/2	2-D-2006	Limestone Silo							Included in 2-C-2001
2/2	2-D-2007	Limestone Silo							Included in 2-C-2001
		CATALYST							
1/2	1-PK-2001	SCR- Selective Catalytic Reduction							
2/2	2-PK-2001	SCR- Selective Catalytic Reduction							

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1BD0237A	REVISION: Rev.0 DATE: Nov-05 ISSUED BY: S.R. CHECKED BY: L.M. APPROVED BY: R.D.

EQUIPMENT LIST

Unit 2000 - Boiler Island - CFB with CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		DESUPERHEATERS							
1/2		HP Steam Desuperheater							Included in 1-C-2001
1/2		By-Pass Desuperheater							Included in 1-C-2001
1/2		Reheated Steam Desuperheater							Included in 1-C-2001
2/2		HP Steam Desuperheater							Included in 2-C-2001
2/2		By-Pass Desuperheater							Included in 2-C-2001
2/2		Reheated Steam Desuperheater							Included in 2-C-2001
		FEEDERS							
1/2	1-FD-2001 A/B...E/F	Coal Screw Feeders							Included in 1-C-2001
1/2	1-FD-2002 A/B...E/F	Coal Screw Feeders							Included in 1-C-2001
2/2	2-FD-2001 A/B...E/F	Coal Screw Feeders							Included in 2-C-2001
2/2	2-FD-2002 A/B...E/F	Coal Screw Feeders							Included in 2-C-2001
		BOTTOM ASH SYSTEM							
		The bottom ash handling and storage system includes: - Ash storage silos - Ash conveyors - Clinker crusher - Filters - Fans		Capacity: 15 t/h					
		FLY ASH SYSTEM							
		The fly ash handling and storage system includes: - Ash storage silos - Pneumatic conveying system - Compressors - Filters - Fans		Capacity: 30 t/h					
		FILTERS							
1/2	1-ESP-2001	Electrostatic Precipitator ESP							
2/2	2-ESP-2001	Electrostatic Precipitator ESP							
		PACKAGES							
1/2	1-X-2001	Control Emission Monitoring System							
2/2	2-X-2001	Control Emission Monitoring System							

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	
	LOCATION: Germany	DATE	Nov-05	
	PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants	ISSUED BY	S.R.	
	CONTRACT N. 1BD0237A	CHECKED BY	L.M.	
		APPROVED BY	R.D.	

EQUIPMENT LIST

Unit 3000 - Power Island - CFB Boiler with CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		STEAM TURBINE							
1	ST-3001	Steam Turbine		760 MWe SH: 285 bar; 585 °C RH: 48 bar; 600°C Cond: 0.032 bar					Steam Tubine Package Including: - Master Controller - By-pass System - By-pass Logic Controller - Ejectors - Silencer
		GENERATOR							
1	SG-3001	Generator		760 MWe					Generator Package Including - Cooling System with Hydrogen - Start-up System - Vibration Control System
		HEAT EXCHANGERS		**Duty**					
1	E-3001	Gland Steam Condenser		600 kW					
1	E-3002	HP Feedwater Heater 1		142400 kW					
1	E-3003	HP Feedwater Heater 2		48700 kW					
1	E-3004	HP Feedwater Heater 3		40300 kW					
1	E-3005	HP Feedwater Heater 4		15500 kW					
1	E-3006	Steam Condenser		539000 kW					
1	DS-3001	LP-Steam Desuperheater							
		PUMPS							
1	P-3001 A/B	Condensate Extraction Pump		Q=445 m^3/h; H=130 m	210 kW				
1	P-3002 A/B	Steam Turbine Driven BFW Pump		Q=1090 m^3/h; H=3700 m					In operation - Steam Turbine Driven
1	P-3002 C	Motor Driven BFW Pump		Q=2180 m^3/h; H=3700 m	28000 kW				Spare - Electric Motor Driven
1	P-3003	Drain Pump		Q=25 m^3/h; H=10 m	7.5 kW				
1	P-3004 A/B	Vacuum Pumps							Included in Steam Turbine Auxiliaries
		TANKS							
1	D-3001	Deaerator							
1	D-3002	ST Drain Drum							
		CHEMICAL INJECTION PACKAGE							
1	Z-3001	Chemical Injection Package							
1	Z-3002	Chemical Additives							

CLIENT:	IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0	Rev.1	
LOCATION:	Germany	DATE	July - 05	Nov - 05	
PROJ. NAME:	CO_2 Capture in Low-rank coal Power Plants	ISSUED BY	S.R.	S.R.	
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		APPROVED BY	R.D.	R.D.	

EQUIPMENT LIST

Unit 4000 - CO_2 Capture Plant - CFB Boiler with CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		TOWERS		D(m) x H(m)					
1/2	1-ABS-4001	Acid Gas Absorber	Packing Column	15.3 x 33.0		3.5	80		Random packing (PP)
2/2	2-ABS-4001	Acid Gas Absorber	Packing Column	15.3 x 33.0		3.5	80		Random packing (PP)
1/1	STR-4001	MEA Regenerator	Packing Column	12.5 x 25.0		3.5	150		Structured packing (304LSS)
		HEAT EXCHANGERS		Surface Area (m^2)		Shell / Tube	Shell / Tube		
1/1	1-E-4001	DCC Cooling Water Cooler	Shell & Tube	3500		4/4	80/50		
2/2	2-E-4001	DCC Cooling Water Cooler	Shell & Tube	3500		4/4	80/50		
1/1	E-4002	Lean/Rich Exchanger	Plate	10700		5/8	140/130		
1/1	E-4003	Semi Lean MEA cooler	Plate	10600		5/8	90/70		
1/1	E-4004	Flash Preheater	Plate	3500		5/8	150/140		
1/1	E-4005	Lean Solvent Cooler	Shell & Tube	4000		4/8	90/50		
1/1	E-4006	Overhead Stripper Condenser	Shell & Tube	2700		3/5	150/120		
1/1	E-4007	Overhead Stripper Condenser	Shell & Tube	7900		3/5	110/90		
1/1	E-4008	Stripper Reboiler	Thermosyphon	25700		4/5	130/170		
1/1	1-E-4001	Pump around Cooling Water Cooler top	Shell & Tube	4400		3/5	70/50		
2/2	2-E-4001	Pump around Cooling Water Cooler top	Shell & Tube	4400		3/5	70/50		
1/1	1-E-4002	Pump around Cooling Water Cooler bottom	Shell & Tube	3600		3/5	70/50		
2/2	2-E-4002	Pump around Cooling Water Cooler bottom	Shell & Tube	3600		3/5	70/50		
		PUMPS		Q (m^3/h) x H (m)	kW				
1/2	1-P-4001 A/B	Rich MEA Circulation Pump	centrifugal	9600 x 55	2000				One operating and one spare
2/2	2-P-4001 A/B	Rich MEA Circulation Pump	centrifugal	9600 x 55	2000				One operating and one spare
1/2	P-4001 A/B	Lean MEA Circulation Pump	centrifugal	10200 x 25	950				One operating and one spare
1/2	P-4002 A/B	Semi Lean MEA Circulation Pump	centrifugal	8200 x 25	760				One operating and one spare
1/1	P-4003	Overhead Stripper Condenser Reflux Pump	centrifugal	260 x 15	15				
1/2	1-P-4001 A/B	Direct Contact Cooler Recirculation Pump	centrifugal	3000 x 25	280				One operating and one spare
2/2	2-P-4001 A/B	Direct Contact Cooler Recirculation Pump	centrifugal	3000 x 25	280				One operating and one spare
1/2	1-P-4002	Pump around Recirculation Pump top	centrifugal	1200 x 10	40				
2/2	2-P-4002	Pump around Recirculation Pump top	centrifugal	1200 x 10	40				
1/2	1-P-4003	Pump around Recirculation Pump bottom	centrifugal	1050 x 10	35				
2/2	2-P-4003	Pump around Recirculation Pump bottom	centrifugal	1050 x 10	35				
		BLOWERS		Q (Nm^3/h) x H (mmH2O)					
1/2	1-B-4001 A/B/C	Flue Gas Blower	axial	1315000 x 1450	9300				Two blowers operating for each train and one common blower spare
2/2	2-B-4001 A/B	Flue Gas Blower	axial	1315000 x 1450	9300				
		DRUMS		D (m) x H (m)					
1/2	1-DCC-4001	Direct Contact Cooler Drum	vertical						
2/2	2-DCC-4001	Direct Contact Cooler Drum	vertical						
1/1	D-4001	Phase Separator Drum	vertical						
1/1	F-4002	Flash Drum	vertical	5 x 12					
		PACKAGES							
1/1	PK-4001	Amine Reclaimer Area							
		Soda Ash Dosing							Included in PK-4001
		Amine Filter Package							Included in PK-4001
1/1	MU-4001	Solvent Storage Tank							

CLIENT:	IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0		
LOCATION:	Germany	DATE	Nov-05		
PROJ. NAME:	CO_2 Capture in Low-rank coal Power Plants	ISSUED BY	S.R.		
CONTRACT N.	1BD0237A	CHECKED BY	L.M.		
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EQUIPMENT LIST

Unit 5000 - CO_2 Compression and Drying - CFB Boiler with CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		COMPRESSOR							
	1-K-5001	First Stage	Centrifugal	330000 Nm^3/h					
	1-K-5002	Second Stage	Centrifugal	320000 Nm^3/h					
	1-K-5003	Third Stage	Centrifugal	315000 Nm^3/h					
	1-K-5004	Fourth Stage	Centrifugal	315000 Nm^3/h					
		EXCHANGERS		**Duty**		**Shell/Tube**	**Shell /Tube**		
	1-E-5001	Condensate Preheater	Shell & Tube	11000 kWth		6/14	190/150		
	1-E-5002	Lignite Drying Water Heater	Shell & Tube	7000 kWth		6/5	145/120		
	1-E-5003	Cooling Water Exchanger	Shell & Tube	12000 kWth		6/5	110/50		
	1-E-5004	Condensate Preheater	Shell & Tube	11000 kWth		14/14	195/150		
	1-E-5005	Lignite Drying Water Heater	Shell & Tube	7000 kWth		14/5	145/120		
	1-E-5006	Cooling Water Exchanger	Shell & Tube	9000 kWth		14/5	110/50		
	1-E-5007	Condensate Preheater	Shell & Tube	12000 kWth		32/14	200/150		
	1-E-5008	Lignite Drying Water Heater	Shell & Tube	7500 kWth		32/5	145/120		
	1-E-5009	Cooling Water Exchanger	Shell & Tube	10500 kWth		32/5	110/50		
	1-E-5010	Condensate Preheater	Shell & Tube	10000 kWth		76/14	190/150		
	1-E-5011	Lignite Drying Water Heater	Shell & Tube	8500 kWth		76/5	145/120		
	1-E-5012	Cooling Water Exchanger	Shell & Tube	38000 kWth		76/5	110/50		
		DRUMS							
	1-D-5001	K.O. Drum							
	1-D5002	K.O. Drum							
		PUMPS		**Q(m^3/h) / H(m)**					
	1-P-5001	CO_2 Pump	Horizontal	750/540	1200 kW				
		DRYING PACKAGE							
		Drying Package							Package including: - Two Drying beds (1 operating - 1 Regenerating) - Cooling Water Exchanger - Electric Heater - K.O. Drum

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1BD0237A	REVISION	Rev.0		
		DATE	Nov-05		
		ISSUED BY	S.R.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 4100 - Cooling Water and Machinery Cooling Water System - CFB Boiler with CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		COOLING TOWERS		**Duty**					
1/2	1-TR-4101	Cooling Towers	Natural Draught	600 MWth					Package Including: - Distribution System - Heat Exchangers - Water Conditioning
2/2	2-TR-4101	Cooling Towers	Natural Draught	600 MWth					Package Including: - Distribution System - Heat Exchangers - Water Conditioning
		PACKAGES							
1/2	1-PK-4101	Water Conditioning Package							Package Including: - Chemical Additives Storage Tanks - Chemical Additives Dosing Pumps
2/2	2-PK-4101	Water Conditioning Package							Package Including: - Chemical Additives Storage Tanks - Chemical Additives Dosing Pumps
		PUMPS		**m^3/h x m**					
1	P-4101 A/B/C/D/E	Cooling Water Pump		19400x55	3700 kW				All Operating - Electric Motor Driven
1	P-4102 A/B	Machinery Cooling Water Pump		900x40	80 kW				One operating and one spare- Electric Motor Driven
		BASINS							
1/2	1-BA-4101	Cooling Water Basin							
2/2	2-BA-4101	Cooling Water Basin							
		FILTERS							
1/2	1-F-4101	Filter							
2/2	2-F-4101	Filter							

	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1BD0237A	REVISION	Rev.0		
		DATE	Nov-05		
		ISSUED BY	S.R.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 4200 - Demi Water System - CFB Boiler with CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1	PK-4201	Demi Water Production System		2 lines 100 m^3/h each					Package Including: - Neutralized Effluents Discharge Pump - Cationic Column - Decarbonation Tower - Decarbonation Tower Pump - Decarbonation Tower Fan - HCl System - NaOH System - Anionic Column - Neutralization Tank
		PUMPS		**m^3/h x m**					
1	P-4201 A/B	Demi Water Distribution Pump		100x60	40 kW				
1	P-4202	Filling Pump		375x25	45 kW				During Star-Up
		DRUMS		**D(m)xH(m)**					
1	D-4201	Demi Water Storage Collection Basin A/B/C		12x18					Volume = 6000 m^3

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1BD0237A	REVISION	Rev.0		
		DATE	Nov-05		
		ISSUED BY	S.R.		
		CHECKED BY	L.M.		
		APPROVED BY	R.D.		

EQUIPMENT LIST

Unit 4300 - Natural Gas Start-Up System - CFB Boiler with CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1	PK-4301	Natural Gas Reduction and Metering Station							Package Including: - Filter - Preheating System - Flow Indicator - Reduction Valves

FOSTER WHEELER	CLIENT: IEA GREENHOUSE R&D PROGRAMME LOCATION: Germany PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants CONTRACT N. 1BD0237A	REVISION DATE ISSUED BY CHECKED BY APPROVED BY	Rev.0 Nov-05 S.R. L.M. R.D.

EQUIPMENT LIST

Unit 4400 - Plant Instrument Air System - CFB Boiler with CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		COMPRESSORS							
1	K-4401 A/B	Air Compressor		65500 Nm^3/h	750 kW				Two operating and one spare - Electrical Motors Included
		DRUMS							
1	D-4401	Compressed Air Drum							
		DRYER							
1	DR-4401	Instrument Air Dryer							

CLIENT: IEA GREENHOUSE R&D PROGRAMME	REVISION	Rev.0
LOCATION: Germany	DATE	Nov-05
PROJ. NAME: CO_2 Capture in Low-rank coal Power Plants	ISSUED BY	S.R.
CONTRACT N. 1BD0237A	CHECKED BY	L.M.
	APPROVED BY	R.D.

EQUIPMENT LIST

Unit 4500 - Raw-Service-Potable Water System - CFB Boiler with CO_2 Capture

TRAIN	ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
		PACKAGES							
1	PK-4501	Clariflocculation System							Package Including: - Clariflocculator - Sludge Pump - Membrane Press - Recirculation Water System - Filtered Water System
1	PK-4502	Water Conditioning System							
1	PK-4503	Additives Package							
		PUMPS		m^3/h x m					
1	P-4501 A/B/C	Raw Water Pump		800x36	95 kW				Two operating - one spare
1	P-4502 A/B	Service Water Pump		75x40	10 kW				
1	P-4503 A/B	Cooling Towers Make-Up Pump		720x36	86 kW				
1	P-4504 A/B	Service Water Booster Pump		75x40	10 kW				
		DRUMS		D(m)xH(m)					
1	BA-4501	Raw Water Pumping Basin							
1	D-4501	Service Water Collection Basin		10x14					Volume = 880 m^3
		FILTERS							
1	F-4501 A/B	Sand Filter							
1	F-4502 A/B...I/L	Sand Filter							

SECTION G.3 ECONOMICS

3.0 Introduction

Purpose of this section is to summarize the results of the economic analysis made for the CFB technology, with and without the CO_2 sequestration (sections G.1 and G.2).

For the two alternatives, the economic analysis includes:

- Investment cost;
- Operation & Maintenance costs;
- Electric power production costs (C.O.E.);
- Sensitivity analysis:
    - C.O.E. vs. Discount rate (D.R.);
    - C.O.E. vs. Carbon Tax (C.T.).

3.1 Basis of Investment Cost evaluations

The bases of the estimate for the two alternatives are the technical information provided in section G.1 and G.2.

With respect to the analysis already developed in section E, the main features of this investment cost evaluation are the following:

- Direct materials cost estimate of the CO_2 capture plant are based on a detailed design of the equipment and a budget quotation of the columns, as received from qualified Vendors.
- Power Island cost estimate is based on a steam turbine budgetary quotation, as received from Siemens.
- Utilities and Offsite unit costs are based on the design made for the main equipment of the different units.
- Estimate accuracy is within the range +/- 30%.

For all the other bases of investment cost evaluations, refer to section E, para 2.0.

3.2 Investment cost of the two alternatives

The following Tables G.3.1/2 show the investment break down and the total figures respectively for the CFB alternative without and with the CO_2 capture.

Tables G.3.3/4 show the break down of the Utilities and Offsite units for the two alternatives.

Table G.3.5 summarises the results of the estimate and shows the net specific investment cost for the two alternatives.

Refer	: 1-BD-0237A
Client	: IEA GREENHOUSE GAS R&D PROGRAMME
Plant	: CO_2 capture in low rank coals
Location	: GERMANY (Inland)
Date	: July 2005 REV. 0

Table G.3.1 - Case G.1 - ESTIMATE SUMMARY

CFB Boiler without post-combustion CO_2 capture

FIGURE IN EURO

POS	DESCRIPTION		UNIT 1000 €	1050 €	2000 €	3000 €	UTIL&OFF €	TOTAL €
1	DIRECT MATERIALS		33,644,000	6,268,000	145,977,000	85,673,000	97,425,000	368,987,000
2	CONSTRUCTION		15,623,000	1,284,000	115,752,000	43,654,000	57,091,000	233,404,000
3	OTHER COSTS		2,191,000	643,000	6,068,000	2,999,000	8,545,000	20,446,000
4	EPC SERVICES		6,789,000	1,118,000	29,081,000	14,370,000	24,357,000	75,715,000
A	**Installed costs** (contingency excluded)		**58,247,000**	**9,313,000**	**296,878,000**	**146,696,000**	**187,418,000**	**698,552,000**
B	Contingency	%	7	7	7	7	7	7.0
		Euro	4,077,290	651,910	20,781,460	10,268,720	13,119,260	48,898,640
C	Fees (2% of A)		1,164,940	186,260	5,937,560	2,933,920	3,748,360	13,971,040
D	Land Purchases; surveys (5% of A)		2,912,350	465,650	14,843,900	7,334,800	9,370,900	34,927,600
	TOTAL INVESTMENT COST		**66,401,580**	**10,616,820**	**338,440,920**	**167,233,440**	**213,656,520**	**796,349,280**

REMARKS

1) ESTIMATE ACCURACY +/- 30%

2) TODAY COSTS (ESCALATION NOT INCLUDED)

1000	**Storage and Handling of solid materials:**
	Coal handling and storage
	Limestone handling and storage
1050	**Coal Drying**
2000	**Boiler Island**
	SNCR based DeNOx
	ESP
	Ash and Solid Removal
3000	**Power Island**
BOP	**Utilities&Offsites**

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Table G.3.2 - Case G.2 - ESTIMATE SUMMARY

CFB Boiler with post-combustion CO_2 capture

Refer : 1-BD-0237A
Client : IEA GREENHOUSE GAS R&D PROGRAMME
Plant : CO_2 capture in low rank coals
Location : GERMANY (Inland)
Date : Novemeber 2005 REV. Final

FIGURE IN EURO

POS	DESCRIPTION		UNIT 1000 €	1050 €	2000 €	3000 €	4000 €	5000 €	UTIL&OFF €	TOTAL €
1	DIRECT MATERIALS		33,644,000	6,268,000	146,518,000	70,694,000	58,996,000	24,136,000	105,957,500	446,213,500
2	CONSTRUCTION		15,623,000	1,284,000	116,180,000	36,022,000	34,572,000	9,377,000	62,090,000	275,148,000
3	OTHER COSTS		2,191,000	643,000	6,091,000	2,474,000	5,174,000	1,369,000	9,291,000	27,233,000
4	EPC SERVICES		6,789,000	1,118,000	29,189,000	11,857,000	11,799,000	2,625,000	26,490,000	89,867,000
A	**Installed costs** (contingency excluded)		**58,247,000**	**9,313,000**	**297,978,000**	**121,047,000**	**110,541,000**	**37,507,000**	**203,828,500**	**838,461,500**
B	Contingency	%	7	7	7	7	7	5	7	6.9
		Euro	4,077,290	651,910	20,858,460	8,473,290	7,737,870	1,875,350	14,267,995	57,942,165
C	Fees (2% of A)		1,164,940	186,260	5,959,560	2,420,940	2,210,820	750,140	4,076,570	16,769,230
D	Land Purchases; surveys (5% of A)		2,912,350	465,650	14,898,900	6,052,350	5,527,050	1,875,350	10,191,425	41,923,075
TOTAL INVESTMENT COST			**66,401,580**	**10,616,820**	**339,694,920**	**137,993,580**	**126,016,740**	**42,007,840**	**232,364,490**	**955,095,970**

REMARKS

1) ESTIMATE ACCURACY +/- 30%

2) TODAY COSTS (ESCALATION NOT INCLUDED)

1000	**Storage and Handling of solid materials:**
	Coal handling and storage
	Limestone handling and storage
1050	**Coal Drying**
2000	**Boiler Island**
	SCR based DeNOx
	ESP
	Ash and Solid Removal
3000	**Power Island**
4000	**CO_2 capture plant**
5000	**CO_2 Compression & Drying**
BOP	**Utilities&Offsites**

FOSTER WHEELER

Table G.3.3 - Case G.1 - BOP ESTIMATE SUMMARY

CFB Boiler without post-combustion CO_2 capture

Refer : 1-BD-0237A
Client : IEA GREENHOUSE GAS R&D PROGRAMME
Plant : CO_2 capture in low rank coals
Location : GERMANY (Inland)
Date : July 2005 REV. 0

FIGURE IN EURO

POS	DESCRIPTION		UNIT 4100 €	4200 €	4400 €	4500 €	4300/4600/ 4700/4800 €	5000 €	TOTAL €	REMARKS
1	DIRECT MATERIALS		28,714,000	1,158,000	3,852,000	2,700,000	12,812,000	48,189,000	97,425,000	1) ESTIMATE ACCURACY +/- 30%
2	CONSTRUCTION		16,826,000	679,000	2,257,000	1,582,000	7,508,000	28,239,000	57,091,000	2) TODAY COSTS (ESCALATION NOT INCLUDED)
3	OTHER COSTS		2,518,000	102,000	338,000	237,000	1,124,000	4,226,000	8,545,000	
4	EPC SERVICES		7,179,000	290,000	963,000	675,000	3,203,000	12,047,000	24,357,000	
A	**Installed costs** (contingency excluded)		**55,237,000**	**2,229,000**	**7,410,000**	**5,194,000**	**24,647,000**	**92,701,000**	**187,418,000**	
B	Contingency	%	7	7	7	7	7	7	7.0	
		Euro	3,866,590	156,030	518,700	363,580	1,725,290	6,489,070	13,119,260	
C	Fees (2% of A)		1,104,740	44,580	148,200	103,880	492,940	1,854,020	3,748,360	
D	Land Purchases; surveys (5% of A)		2,761,850	111,450	370,500	259,700	1,232,350	4,635,050	9,370,900	
	TOTAL INVESTMENT COST		**62,970,180**	**2,541,060**	**8,447,400**	**5,921,160**	**28,097,580**	**105,679,140**	**213,656,520**	

4100 Cooling Water system
4200 Demineralized water system
4300 Natural Gas System
4400 Plant & Instrument Air System
4500 Raw-Service-Potable water system
4600 Water Treatment
4700 Fire Fighting system
4800 Chemicals
5000 Interconnecting (DCS, piping, HV substation etc.)

FOSTER WHEELER

Table G.3.4 - Case G.2 - BOP ESTIMATE SUMMARY

CFB Boiler with post-combustion CO_2 capture

Refer	: 1-BD-0237A
Client	: IEA GREENHOUSE GAS R&D PROGRAMME
Plant	: CO_2 capture in low rank coals
Location	: GERMANY (Inland)
Date	: July 2005 REV. 0

FIGURE IN EURO

POS	DESCRIPTION		UNIT 4100 €	4200 €	4400 €	4500 €	4300/4600/ 4700/4800 €	5000 €	TOTAL €
1	DIRECT MATERIALS		34,245,000	2,115,000	4,350,000	3,007,500	14,540,000	47,700,000	105,957,500
2	CONSTRUCTION		20,068,000	1,239,000	2,549,000	1,762,000	8,520,000	27,952,000	62,090,000
3	OTHER COSTS		3,003,000	185,000	381,000	264,000	1,275,000	4,183,000	9,291,000
4	EPC SERVICES		8,561,000	529,000	1,088,000	752,000	3,635,000	11,925,000	26,490,000
A	**Installed costs** (contingency excluded)		**65,877,000**	**4,068,000**	**8,368,000**	**5,785,500**	**27,970,000**	**91,760,000**	**203,828,500**
B	Contingency	%	7	7	7	7	7	7	7.0
		Euro	4,611,390	284,760	585,760	404,985	1,957,900	6,423,200	14,267,995
C	Fees (2% of A)		1,317,540	81,360	167,360	115,710	559,400	1,835,200	4,076,570
D	Land Purchases; surveys (5% of A)		3,293,850	203,400	418,400	289,275	1,398,500	4,588,000	10,191,425
	TOTAL INVESTMENT COST		**75,099,780**	**4,637,520**	**9,539,520**	**6,595,470**	**31,885,800**	**104,606,400**	**232,364,490**

REMARKS

1) ESTIMATE ACCURACY +/- 30%

2) TODAY COSTS (ESCALATION NOT INCLUDED)

4100	**Cooling Water system**
4200	**Demineralized water system**
4300	**Natural Gas System**
4400	**Plant & Instrument Air System**
4500	**Raw-Service-Potable water system**
4600	**Water Treatment**
4700	**Fire Fighting system**
4800	**Chemicals**
5000	**Interconnecting (DCS, piping, HV substation etc.)**

Table G.3.5 - ESTIMATE SUMMARY

Refer: 1-BD-0237A
Client: IEA GREENHOUSE R & D PROJ.
Plant: CO2 CAP. IN LOW RANK COAL P.P.
Location: GERMANY
Date: Novemeber 2005 REV. Final

POS	DESCRIPTION	Case G.1 CFB without CO_2 capture		Case G.2 CFB with CO_2 capture	
		€	%	€	%
1	Boiler Island	338.4	42.5	339.7	35.6
2	Process Units	77.0	9.7	203.0	21.3
3	CO_2 Compression and Drying	0	0.0	42.0	4.4
4	Power Island	167.2	21.0	138.0	14.4
5	Utilities and Offsite Units	213.7	26.8	232.4	24.3
	TOTAL INVESTMENT COST	**796.3**	**100.0**	**955.1**	**100.0**

	Case G.1	Case G.2
NET POWER OUTPUT, MWe	**791.8**	**609.7**
SPECIFIC INVESTMENT COST, Euro/kW	**1006**	**1567**

3.3 Operation and maintenance costs

Refer to section E, para 4.0, for general considerations on the operation and maintenance costs.

The variable costs of the two alternatives are summarized in the attached Table G.3.6.

The attached Table G.3.7 summarizes the maintenance costs of the two alternatives.

Below Table G.3.8 summarizes the total operating and maintenance costs of the two alternatives. Direct labor of the CFB alternative with the CO_2 capture is based on 115 total engaged personnel, as shown in section E, para. 4.2, table E.4.3.3. For the alternative without the CO_2 capture and compression units, the number of field operators can be reduced to 15 people (instead of 25), thus leading to a total personnel engaged for this alternative equal to 105.

Table G.3.8 - CFB detailed information - Total O&M Costs

FOSTER WHEELER		Case G.1 Euro/year	Case G.2 Euro/year
Fixed Costs	direct labour	5,250,000	5,750,000
	adm./gen overheads	1,575,000	1,725,000
	maintenance	23,631,000	26,630,000
	Subtotal	30,456,000	34,105,000
Variable Costs		57,372,000	72,043,000
TOTAL O&M COSTS		87,828,000	106,148,000

FOSTER WHEELER	Table G.3.6 - CFB detailed information Yearly Variable Costs				Refer : 1-BD-0237A Client : IEA GREENHOUSE R & D PROJ. Date : July 2005 REV. 0		
Yearly Operating hours =	7446	Case G.1 - CFB without CO_2 capture			Case G.2 - CFB with CO_2 capture		
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)**
Feedstock							
Coal (as received)	10.50	592900	4414733.4	46,354,701	592900	4414733.4	46,354,701
Limestone	20.0	23000	171258.0	3,425,160	27360	203722.6	4,074,451
Auxiliary feedstock							
Make-up water	0.100	1108000	8250168.0	825,017	1582000	11779572.0	1,177,957
Solvents							
MEA	1300	0	0.0	0	1466	10918.3	14,193,830
Catalyst							
DENOx Catalyst	10800	67.5	502.96	5,432,000	56.4	419.91	4,535,000
Chemicals							
Ammonia	336	500.0	3723.0	1,250,928	500.0	3723.0	1,250,928
Activated Carbon	1000	0.0	0.0	0	40.0	297.8	297,840
Soda ash	110	0.0	0.0	0	90.0	670.1	73,715
Coordinate phosphate	1.9	4.1	30.7	58	4.1	30.7	58
Nalco Eliminox or equivalent	4132	2.7	20.3	84,050	2.7	20.3	84,050
TOTAL YEARLY OPERATING COSTS, Euro/yeai				**57,371,913**			**72,042,530**

FOSTER WHEELER	Table G.3.7 - CFB Detailed information Maintenance Costs			Refer : 1-BD-0237A Client : IEA Date : Novemeber 2005	
		Case G.1		Case G.2	
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
COAL HANDLING, DRYING, MILLING, BOILER ISLAND, POW. ISL.	4.0	511134	20445	486585	19463
CO_2 CAPUTRE PLANT, CO_2 COMPRESS. AND DRYING	2.5	0	0	148048	3701
Common facilities (BOP)	1.7	187418	3186	203829	3465
TOTAL		698552	23631	838462	26630
		Maint. % =	3.4	Maint. % =	3.2

3.4 Evaluation of the Electric Power cost and CO_2 removal cost

3.4.1 Electric Power cost

Refer to section E, para 5.0, for general considerations on the operation and maintenance costs.

Tables A.G.1/2, attached to the end of this section, show the economic analysis of the two alternatives.

The sensitivity analysis with 5% discount rate on the investment cost is shown in the attached Tables A.G.3/4.

Below Table G.3.9 summarizes the electric power cost for the two alternatives, with 10% and 5% discount rate applied on the Total Investment Cost.

Table G.3.9 - Electric power cost.

ALTERNATIVE		Case G.1 no capture	Case G.1 no capture	Case G.2 capture	Case G.2 capture
Discount rate	**%**	**10**	**5**	**10**	**5**
Coal Flowrate	t/h	592.9	592.9	592.9	592.9
Net Power Output	MWe	791.8	791.8	609.7	609.7
Total Investment Cost	MM Euro	796.3	796.3	955.1	955.1
Specif Net Inv. Cost	**Euro/kW**	**1006**	**1006**	**1567**	**1567**
Revenues/year	MM Euro/year	203.8	164.1	244.6	196.9
Electricity Prod. Cost	**cEuro/kWh**	**3.46**	**2.78**	**5.39**	**4.34**

3.4.2 CO_2 removal cost

The CO_2 removal cost can be expressed 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 of the alternative with CO_2 capture – Electric Power Cost of alternative w/o CO_2 capture. The Unit of measurement is Euro/kWh.
- Δ Specific CO_2 emission = Ratio of (CO_2 emission/Power production) of alternative with CO_2 capture – ratio of (CO_2 emission/Power production) of the alternative with CO_2 capture. The unit of measurement is ton CO_2/kWh.

The following Table G.3.10 summarizes the CO_2 removal cost with 10% and 5% discount rate applied on the Total Investment Cost.

Table G.3.10 - CO_2 removal cost.

ALTERNATIVE		Case G.1 no capture	Case G.2 capture	Case G.1 no capture	Case G.2 capture
Discount rate	%	**10**	**10**	**5**	**5**
Coal Flowrate	t/h	592.9	592.9	592.9	592.9
Net Power Output	MWe	791.8	609.7	791.8	609.7
Total Investment Cost	MM Euro	796.3	955.1	796.3	955.1
Specif Net Inv. Cost	Euro/kW	**1006**	**1566.5**	**1006**	**1566.5**
Revenues/year	MM Euro/year	203.8	244.6	164.1	196.9
Electricity Prod. Cost	cEuro/kWh	**3.46**	**5.39**	**2.78**	**4.34**
CO_2 emissions	t/h	689.7	103.5	689.7	103.5
CO_2 specific emiss.	10^{-3} kg/kWh	871.1	169.8	871.1	169.8
CO_2 **removal cost**	Euro/t	-	**27.5**	-	**22.2**

3.4.3 Electric Power cost in presence of carbon tax

The following Tables summarize the economic analyses performed in order to evaluate the electric power production cost in presence of a carbon tax, expressed as Euro/t of CO_2 emitted.

The economic analysis is performed respectively at 25 and 50 Euro/t of CO_2 emitted.

The Tables A.G.5/8, attached to the end of this section, show the economic analysis of the two alternatives at the above carbon tax values and 10% discount rate.

The sensitivity analysis with 5% discount rate on the investment cost is shown in the attached Tables A.G.9/12.

Tables G.3.11 and 12 summarize the electric power cost for the two alternatives, with 10% and 5% discount rate applied on the Total Investment Cost at different carbon tax value.

Fig. G.3.1 also reports the results of the economic analysis shown in the previous tables. This figure shows that the taxation level necessary to make the two alternatives economically equivalent are approximately 27 and 22 Euro/t of CO_2 emitted, respectively for a discount rate of 10% and 5%.

Table G.3.11 - Electric power cost at different carbon tax value (DCF=10%).

ALTERNATIVE		Case G.1 no capture	Case G.2 capture	Case G.1 no capture	Case G.2 capture	Case G.1 no capture	Case G.2 capture
Discount rate	**%**	**10**	**10**	**10**	**10**	**10**	**10**
Carbon tax	**Euro/t**	**0**	**0**	**25**	**25**	**50**	**50**
Coal Flowrate	t/h	592.9	592.9	592.9	592.9	592.9	592.9
Net Power Output	MWe	791.8	609.7	791.8	609.7	791.8	609.7
CO_2 emissions	t/h	689.7	103.5	689.7	103.5	689.7	103.5
Total Investment Cost	MM Euro	796.3	955.1	796.3	955.1	796.3	955.1
Specif Net Inv. Cost	Euro/kW	**1006**	**1566.5**	**1006**	**1566.5**	**1006**	**1566.5**
Revenues/year	MM Euro/year	203.8	244.6	203.8	244.6	203.8	244.6
Electricity Prod. Cost	cEuro/kWh	**3.46**	**5.39**	**5.63**	**5.81**	**7.81**	**6.24**

Table G.3.12 - Electric power cost at different carbon tax value (DCF=5%).

ALTERNATIVE		Case G.1 no capture	Case G.2 capture	Case G.1 no capture	Case G.2 capture	Case G.1 no capture	Case G.2 capture
Discount rate	**%**	**5**	**5**	**5**	**5**	**5**	**5**
Carbon tax	**Euro/t**	**0**	**0**	**25**	**25**	**50**	**50**
Coal Flowrate	t/h	592.9	592.9	592.9	592.9	592.9	592.9
Net Power Output	MWe	791.8	609.7	791.8	609.7	791.8	609.7
CO_2 emissions	t/h	689.7	103.5	689.7	103.5	689.7	103.5
Total Investment Cost	MM Euro	796.3	955.1	796.3	955.1	796.3	955.1
Specif Net Inv. Cost	Euro/kW	**1006**	**1566.5**	**1006**	**1566.5**	**1006**	**1566.5**
Revenues/year	MM Euro/year	164.1	196.9	203.8	244.6	203.8	244.6
Electricity Prod. Cost	cEuro/kWh	**2.78**	**4.34**	**4.96**	**4.76**	**7.14**	**5.19**

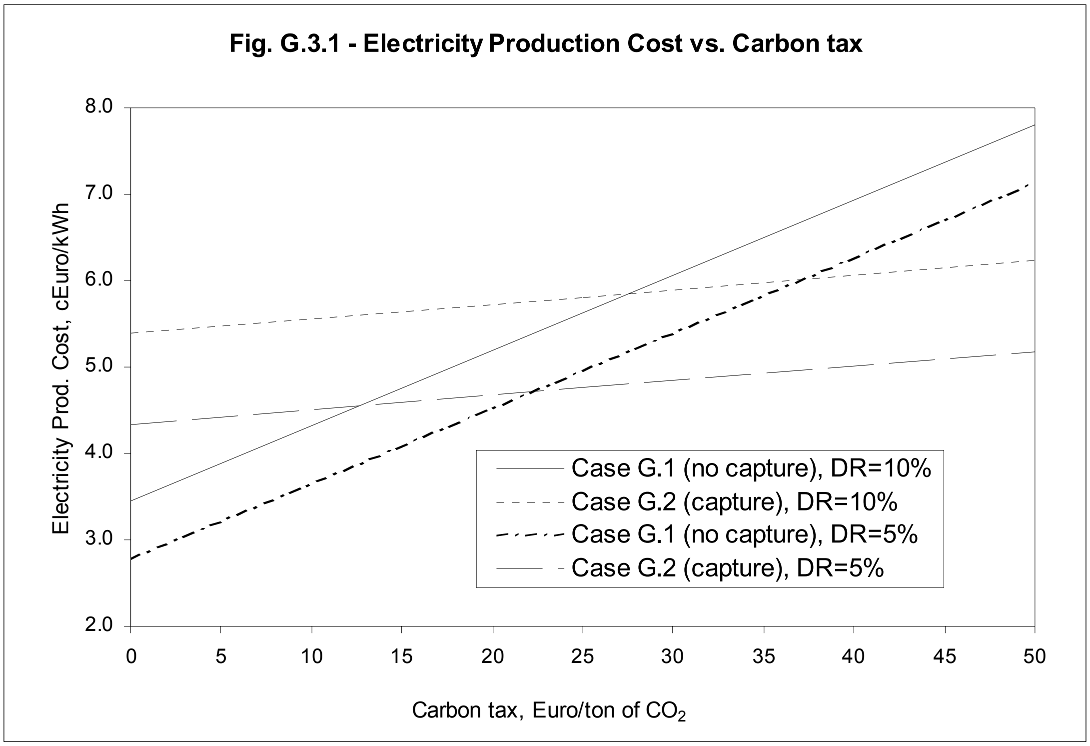
Fig. G.3.1 - Electricity Production Cost vs. Carbon tax
Electricity Prod. Cost, cEuro/kWh
8.0
7.0
6.0
5.0
4.0
3.0
2.0
0
5
10
15
20
25
30
35
40
45
50
Carbon tax, Euro/ton of CO2
Case G.1 (no capture), DR=10%
Case G.2 (capture), DR=10%
Case G.1 (no capture), DR=5%
Case G.2 (capture), DR=5%

TABLE A.G.1 - CFB without CO_2 capture- Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	592.9	t/h
Net Power Output	791.8	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	698.6
Land purchase; surveys	34.9
Fees	14.0
Average Contingencies	48.9
Total Investment Cost	796.3

Operating Costs [MM Euro/year] **at 85% load factor**	
Fuel Cost	46.4
Maintenance	23.6
Waste Disposal	0.0
Chemicals + Consumable	11.0
Insurance and local taxes	14.0

Working Capital		**MM Euro**
30 days Chemical Storage		1.1
5 days Coal Storage		0.7
Total Working capital		1.8
Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.0346	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	203.8	MM Euro/year
NPV	**0.00**	
IRR	**10.00%**	

CASH FLOW ANALYSYS Millions Euro	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electric Energy				107.9	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	203.8	
Operating Costs																													
Fuel Cost				-24.5	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	
Maintenance				-15.8	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables				-5.8	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	
Waste Disposal				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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance				-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	
Working Capital Cost				-1.8																									1.8
Fixed Capital Expenditures	-159.3	-358.4	-278.7																										
Total Cash flow (yearly)	-159.3	-358.4	-278.7	38.8	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	1.8
Total Cash flow (cumulated)	-159.3	-517.6	-796.3	-757.6	-655.9	-554.3	-452.6	-351.0	-249.3	-147.7	-46.1	55.6	157.2	258.9	360.5	462.2	563.8	665.4	767.1	868.7	970.4	1072.0	1173.7	1275.3	1377.0	1478.6	1580.2	1681.9	1683.7
Discounted Cash Flow (Yearly)	-144.8	-296.2	-209.4	26.5	63.1	57.4	52.2	47.4	43.1	39.2	35.6	32.4	29.4	26.8	24.3	22.1	20.1	18.3	16.6	15.1	13.7	12.5	11.4	10.3	9.4	8.5	7.8	7.0	0.1
Discounted Cash Flow (Cumul.)	-144.8	-441.0	-650.4	-623.9	-560.8	-503.4	-451.2	-403.8	-360.7	-321.5	-285.9	-253.5	-224.1	-197.3	-173.0	-150.8	-130.7	-112.4	-95.8	-80.7	-67.0	-54.5	-43.1	-32.8	-23.4	-14.9	-7.2	-0.1	0.0

TABLE A.G.2 - CFB with CO_2 capture- Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	592.9	t/h
Net Power Output	609.7	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	838.5
Land purchase; surveys	41.9
Fees	16.8
Average Contingencies	57.9
Total Investment Cost	955.1

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	46.4
Maintenance	26.6
Waste Disposal	0.0
Chemicals + Consumable	25.7
Insurance and local taxes	16.8

Working Capital		**MM Euro**
30 days Chemical Storage		2.5
5 days Coal Storage		0.7
Total Working capital		3.2
Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.0539	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	244.6	MM Euro/year

NPV	0.00
IRR	**10.00%**

CASH FLOW ANALYSYS
Millions Euro

	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				129.5	244.6	244.6	244.6	244.6	244.6	244.6	244.6	244.6	244.6	244.6	244.6
Operating Costs															
Fuel Cost				-24.5	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4
Maintenance				-17.8	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2
Chemicals & Consumables				-13.6	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8
Working Capital Cost				-3.2											
Fixed Capital Expenditures	-191.0	-429.8	-334.3												
Total Cash flow (yearly)	-191.0	-429.8	-334.3	46.4	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9
Total Cash flow (cumulated)	-191.0	-620.8	-955.1	-908.7	-786.8	-664.9	-543.0	-421.1	-299.2	-177.3	-55.3	66.6	188.5	310.4	432.3
Discounted Cash Flow (Yearly)	-173.7	-355.2	-251.2	31.7	75.7	68.8	62.6	56.9	51.7	47.0	42.7	38.8	35.3	32.1	29.2
Discounted Cash Flow (Cumul.)	-173.7	-528.9	-780.0	-748.3	-672.6	-603.8	-541.3	-484.4	-432.7	-385.7	-343.0	-304.1	-268.8	-236.7	-207.5

	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	244.6	244.6	244.6	244.6	244.6	244.6	244.6	244.6	244.6	244.6	244.6	244.6	244.6	
Operating Costs														
Fuel Cost	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	
Maintenance	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	
Labour	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	
Waste Disposal	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	
Insurance	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	
Working Capital Cost														3.2
Fixed Capital Expenditures														
Total Cash flow (yearly)	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	3.2
Total Cash flow (cumulated)	554.2	676.1	798.0	919.9	1041.9	1163.8	1285.7	1407.6	1529.5	1651.4	1773.3	1895.2	2017.1	2020.4
Discounted Cash Flow (Yearly)	26.5	24.1	21.9	19.9	18.1	16.5	15.0	13.6	12.4	11.3	10.2	9.3	8.5	0.2
Discounted Cash Flow (Cumul.)	-181.0	-156.9	-134.9	-115.0	-96.9	-80.4	-65.4	-51.8	-39.4	-28.2	-18.0	-8.7	-0.2	0.0

FOSTER WHEELER

TABLE A.G.3 - CFB without CO_2 capture- Cost Evaluation - Discount Rate = 5%

Production		
Coal Florate	592.9	t/h
Net Power Output	791.8	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	698.6
Land purchase; surveys	34.9
Fees	14.0
Average Contingencies	48.9
Total Investment Cost	796.3

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	46.4
Maintenance	23.6
Wastee Disposal	0.0
Chemicals + Consumable	11.0
Insurance and local taxes	14.0

Working Capital	**MM Euro**	
30 days Chemical Storage		1.1
5 days Coal Storage		0.7
Total Working capital		1.8
Labour Cost	**MM Euro/year**	
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.0278	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	5.00	%
Revenues / year	164.1	MM Euro/year
NPV	0.00	
IRR	5.00%	

CASH FLOW ANALYSYS Millions Euro	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electric Energy				86.9	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	164.1	
Operating Costs																													
Fuel Cost				-24.5	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	
Maintenance				-15.8	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables				-5.8	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	
Waste Disposal				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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance				-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	
Working Capital Cost				-1.8																									1.8
Fixed Capital Expenditures	-159.3	-358.4	-278.7																										
Total Cash flow (yearly)	-159.3	-358.4	-278.7	17.7	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	1.8
Total Cash flow (cumulated)	-159.3	-517.6	-796.3	-778.6	-716.7	-654.9	-593.0	-531.1	-469.2	-407.3	-345.5	-283.6	-221.7	-159.8	-97.9	-36.1	25.8	87.7	149.6	211.5	273.3	335.2	397.1	459.0	520.9	582.7	644.6	706.5	708.3
Discounted Cash Flow (Yearly)	-151.7	-325.0	-240.8	14.6	48.5	46.2	44.0	41.9	39.9	38.0	36.2	34.5	32.8	31.3	29.8	28.3	27.0	25.7	24.5	23.3	22.2	21.2	20.1	19.2	18.3	17.4	16.6	15.8	0.4
Discounted Cash Flow (Cumul.)	-151.7	-476.7	-717.5	-702.9	-654.4	-608.2	-564.3	-522.4	-482.5	-444.5	-408.3	-373.9	-341.1	-309.8	-280.0	-251.7	-224.7	-199.0	-174.5	-151.2	-129.0	-107.8	-87.7	-68.5	-50.2	-32.8	-16.2	-0.4	0.0

TABLE A.G.4 - CFB with CO_2 capture- Cost Evaluation - Discount Rate = 5%

Production		
Coal Florate	592.9	t/h
Net Power Output	609.7	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	MM Euro
Installed Costs	838.5
Land purchase; surveys	41.9
Fees	16.8
Average Contingencies	57.9
Total Investment Cost	955.1

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	46.4
Maintenance	26.6
Wastee Disposal	0.0
Chemicals + Consumable	25.7
Insurance and local taxes	16.8

Working Capital		MM Euro
30 days Chemical Storage		2.5
5 days Coal Storage		0.7
Total Working capital		3.2
Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.0434	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	5.00	%
Revenues / year	196.9	MM Euro/year

NPV	**0.00**
IRR	**5.00%**

CASH FLOW ANALYSYS Millions Euro	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electric Energy				104.2	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	196.9	
Operating Costs																													
Fuel Cost				-24.5	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	
Maintenance				-17.8	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables				-13.6	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	
Waste Disposal				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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance				-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	
Working Capital Cost				-3.2																									3.2
Fixed Capital Expenditures	-191.0	-429.8	-334.3																										
Total Cash flow (yearly)	-191.0	-429.8	-334.3	21.1	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	3.2
Total Cash flow (cumulated)	-191.0	-620.8	-955.1	-934.0	-859.8	-785.6	-711.4	-637.2	-563.0	-488.8	-414.6	-340.4	-266.2	-191.9	-117.7	-43.5	30.7	104.9	179.1	253.3	327.5	401.7	475.9	550.1	624.3	698.5	772.7	846.9	850.1
Discounted Cash Flow (Yearly)	-181.9	-389.8	-288.8	17.4	58.1	55.4	52.7	50.2	47.8	45.6	43.4	41.3	39.4	37.5	35.7	34.0	32.4	30.8	29.4	28.0	26.6	25.4	24.2	23.0	21.9	20.9	19.9	18.9	0.8
Discounted Cash Flow (Cumul.)	-181.9	-571.8	-860.5	-843.2	-785.0	-729.6	-676.9	-626.7	-578.9	-533.3	-489.9	-448.6	-409.2	-371.8	-336.1	-302.1	-269.7	-238.9	-209.5	-181.5	-154.9	-129.5	-105.4	-82.4	-60.5	-39.6	-19.7	-0.8	0.0

FOSTER WHEELER

TABLE A.G.5 - CFB without CO_2 capture- Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	592.9	t/h
Net Power Output	791.8	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost
CO2 emissions	689.7	t/h

(*) 10.5 Euro/t = 1 \$/GJ (1 Euro= 1 \$)

Capital Expenditures	**MM Euro**
Installed Costs	698.6
Land purchase; surveys	34.9
Fees	14.0
Average Contingencies	48.9
Total Investment Cost	796.3

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	46.4
CO_2 cost	128.4
Maintenance	23.6
Waste Disposal	0.0
Chemicals + Consumable	11.0
Insurance and local taxes	14.0

Working Capital		**MM Euro**
30 days Chemical Storage		1.1
5 days Coal Storage		0.7
Total Working capital		1.8
Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.0563	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	332.2	MM Euro/year
Carbon tax =	25	Euro/t
NPV	**0.00**	
IRR	**10.00%**	

CASH FLOW ANALYSYS Millions Euro	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%											
Revenues														
Electric Energy				175.9	332.2	332.2	332.2	332.2	332.2	332.2	332.2	332.2	332.2	332.2
Operating Costs														
Fuel Cost				-24.5	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4
CO_2				-68.0	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4
Maintenance				-15.8	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2
Chemicals & Consumables				-5.8	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0
Working Capital Cost				-1.8										
Fixed Capital Expenditures	-159.3	-358.4	-278.7											
Total Cash flow (yearly)	-159.3	-358.4	-278.7	38.8	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6
Total Cash flow (cumulated)	-159.3	-517.6	-796.3	-757.6	-655.9	-554.3	-452.6	-351.0	-249.3	-147.7	-46.1	55.6	157.2	258.9
Discounted Cash Flow (Yearly)	-144.8	-296.2	-209.4	26.5	63.1	57.4	52.2	47.4	43.1	39.2	35.6	32.4	29.4	26.8
Discounted Cash Flow (Cumul.)	-144.8	-441.0	-650.4	-623.9	-560.8	-503.4	-451.2	-403.8	-360.7	-321.5	-285.9	-253.5	-224.1	-197.3

CASH FLOW ANALYSYS Millions Euro	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	12	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor															
Revenues															
Electric Energy	332.2	332.2	332.2	332.2	332.2	332.2	332.2	332.2	332.2	332.2	332.2	332.2	332.2	332.2	
Operating Costs															
Fuel Cost	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	
CO_2	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	
Maintenance	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	
Labour	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	
Waste Disposal	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	
Insurance	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	
Working Capital Cost															1.8
Fixed Capital Expenditures															
Total Cash flow (yearly)	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	1.8
Total Cash flow (cumulated)	360.5	462.2	563.8	665.4	767.1	868.7	970.4	1072.0	1173.7	1275.3	1377.0	1478.6	1580.2	1681.9	1683.7
Discounted Cash Flow (Yearly)	24.3	22.1	20.1	18.3	16.6	15.1	13.7	12.5	11.4	10.3	9.4	8.5	7.8	7.0	0.1
Discounted Cash Flow (Cumul.)	-173.0	-150.8	-130.7	-112.4	-95.8	-80.7	-67.0	-54.5	-43.1	-32.8	-23.4	-14.9	-7.2	-0.1	0.0

FOSTER WHEELER

TABLE A.G.6 - CFB without CO_2 capture- Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	592.9	t/h
Net Power Output	791.8	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost
CO2 emissions	689.7	t/h

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	698.6
Land purchase; surveys	34.9
Fees	14.0
Average Contingencies	48.9
Total Investment Cost	796.3

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	46.4
CO_2 cost	256.8
Maintenance	23.6
Waste Disposal	0.0
Chemicals + Consumable	11.0
Insurance and local taxes	14.0

Working Capital		**MM Euro**
30 days Chemical Storage		1.1
5 days Coal Storage		0.7
Total Working capital		1.8
Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.0781	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	460.6	MM Euro/year
Carbon tax =	50	Euro/t
NPV	0.00	
IRR	**10.00%**	

CASH FLOW ANALYSYS Millions Euro	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electric Energy				243.9	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	460.6	
Operating Costs																													
Fuel Cost				-24.5	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	
CO_2				-135.9	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	
Maintenance				-15.8	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables				-5.8	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	
Waste Disposal				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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance				-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	
Working Capital Cost				-1.8																									1.8
Fixed Capital Expenditures	-159.3	-358.4	-278.7																										
Total Cash flow (yearly)	-159.3	-358.4	-278.7	38.8	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	101.6	1.8
Total Cash flow (cumulated)	-159.3	-517.6	-796.3	-757.6	-655.9	-554.3	-452.6	-351.0	-249.3	-147.7	-46.1	55.6	157.2	258.9	360.5	462.2	563.8	665.4	767.1	868.7	970.4	1072.0	1173.7	1275.3	1377.0	1478.6	1580.2	1681.9	1683.7
Discounted Cash Flow (Yearly)	-144.8	-296.2	-209.4	26.5	63.1	57.4	52.2	47.4	43.1	39.2	35.6	32.4	29.4	26.8	24.3	22.1	20.1	18.3	16.6	15.1	13.7	12.5	11.4	10.3	9.4	8.5	7.8	7.0	0.1
Discounted Cash Flow (Cumul.)	-144.8	-441.0	-650.4	-623.9	-560.8	-503.4	-451.2	-403.8	-360.7	-321.5	-285.9	-253.5	-224.1	-197.3	-173.0	-150.8	-130.7	-112.4	-95.8	-80.7	-67.0	-54.5	-43.1	-32.8	-23.4	-14.9	-7.2	-0.1	0.0

FOSTER WHEELER

TABLE A.G.7 - CFB with CO_2 capture- Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	592.9	t/h
Net Power Output	609.7	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost
CO2 emissions	103.5	t/h

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	838.5
Land purchase; surveys	41.9
Fees	16.8
Average Contingencies	57.9
Total Investment Cost	955.1

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	46.4
CO_2 cost	19.3
Maintenance	26.6
Waste Disposal	0.0
Chemicals + Consumable	25.7
Insurance and local taxes	16.8

Working Capital		**MM Euro**
30 days Chemical Storage		2.5
5 days Coal Storage		0.7
Total Working capital		3.2
Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.0581	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	263.8	MM Euro/year
Carbon tax =	25	Euro/t

NPV 0.00
IRR 10.00%

CASH FLOW ANALYSYS Millions Euro	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
	000	00	0	1	2	3	4	5	6	7	8	9	10	11
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%											
Revenues														
Electric Energy				139.7	263.8	263.8	263.8	263.8	263.8	263.8	263.8	263.8	263.8	263.8
Operating Costs														
Fuel Cost				-24.5	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4
CO_2				-10.2	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3
Maintenance				-17.8	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2
Chemicals & Consumables				-13.6	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8
Working Capital Cost				-3.2										
Fixed Capital Expenditures	-191.0	-429.8	-334.3											
Total Cash flow (yearly)	-191.0	-429.8	-334.3	46.4	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9
Total Cash flow (cumulated)	-191.0	-620.8	-955.1	-908.7	-786.8	-664.9	-543.0	-421.1	-299.2	-177.3	-55.3	66.6	188.5	310.4
Discounted Cash Flow (Yearly)	-173.7	-355.2	-251.2	31.7	75.7	68.8	62.6	56.9	51.7	47.0	42.7	38.8	35.3	32.1
Discounted Cash Flow (Cumul.)	-173.7	-528.9	-780.0	-748.3	-672.6	-603.8	-541.3	-484.4	-432.7	-385.7	-343.0	-304.1	-268.8	-236.7

CASH FLOW ANALYSYS Millions Euro	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor															
Revenues															
Electric Energy	263.8	263.8	263.8	263.8	263.8	263.8	263.8	263.8	263.8	263.8	263.8	263.8	263.8	263.8	
Operating Costs															
Fuel Cost	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	
CO_2	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	
Maintenance	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	
Labour	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	
Waste Disposal	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	
Insurance	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	
Working Capital Cost															3.2
Fixed Capital Expenditures															
Total Cash flow (yearly)	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	3.2
Total Cash flow (cumulated)	432.3	554.2	676.1	798.0	919.9	1041.9	1163.8	1285.7	1407.6	1529.5	1651.4	1773.3	1895.2	2017.1	2020.4
Discounted Cash Flow (Yearly)	29.2	26.5	24.1	21.9	19.9	18.1	16.5	15.0	13.6	12.4	11.3	10.2	9.3	8.5	0.2
Discounted Cash Flow (Cumul.)	-207.5	-181.0	-156.9	-134.9	-115.0	-96.9	-80.4	-65.4	-51.8	-39.4	-28.2	-18.0	-8.7	-0.2	0.0

FOSTER WHEELER

TABLE A.G.8 - CFB with CO_2 capture- Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	592.9	t/h
Net Power Output	609.7	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost
CO2 emissions	103.5	t/h

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	838.5
Land purchase; surveys	41.9
Fees	16.8
Average Contingencies	57.9
Total Investment Cost	955.1

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	46.4
CO_2 cost	38.5
Maintenance	26.6
Waste Disposal	0.0
Chemicals + Consumable	25.7
Insurance and local taxes	16.8

Working Capital		**MM Euro**
30 days Chemical Storage		2.5
5 days Coal Storage		0.7
Total Working capital		3.2
Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.0624	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	10.00	%
Revenues / year	283.1	MM Euro/year
Carbon tax =	50	Euro/t
NPV	**0.00**	
IRR	**10.00%**	

CASH FLOW ANALYSYS Millions Euro	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor	20%	45%	35%																										
Revenues																													
Electric Energy				149.9	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	283.1	
Operating Costs																													
Fuel Cost				-24.5	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	
CO_2				-20.4	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	
Maintenance				-17.8	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables				-13.6	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	
Waste Disposal				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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Insurance				-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	
Working Capital Cost				-3.2																									3.2
Fixed Capital Expenditures	-191.0	-429.8	-334.3																										
Total Cash flow (yearly)	-191.0	-429.8	-334.3	46.4	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	121.9	3.2
Total Cash flow (cumulated)	-191.0	-620.8	-955.1	-908.7	-786.8	-664.9	-543.0	-421.1	-299.2	-177.3	-55.3	66.6	188.5	310.4	432.3	554.2	676.1	798.0	919.9	1041.9	1163.8	1285.7	1407.6	1529.5	1651.4	1773.3	1895.2	2017.1	2020.4
Discounted Cash Flow (Yearly)	-173.7	-355.2	-251.2	31.7	75.7	68.8	62.6	56.9	51.7	47.0	42.7	38.8	35.3	32.1	29.2	26.5	24.1	21.9	19.9	18.1	16.5	15.0	13.6	12.4	11.3	10.2	9.3	8.5	0.2
Discounted Cash Flow (Cumul.)	-173.7	-528.9	-780.0	-748.3	-672.6	-603.8	-541.3	-484.4	-432.7	-385.7	-343.0	-304.1	-268.8	-236.7	-207.5	-181.0	-156.9	-134.9	-115.0	-96.9	-80.4	-65.4	-51.8	-39.4	-28.2	-18.0	-8.7	-0.2	0.0

TABLE A.G.9 - CFB without CO_2 capture- Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	592.9	t/h
Net Power Output	791.8	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost
CO2 emissions	689.7	t/h

(*) 10.5 Euro/t = 1 \$/GJ (1 Euro= 1 \$)

Capital Expenditures	**MM Euro**
Installed Costs	698.6
Land purchase; surveys	34.9
Fees	14.0
Average Contingencies	48.9
Total Investment Cost	796.3

Operating Costs [MM Euro/year]	
at 85% load factor	
Fuel Cost	46.4
CO_2 cost	128.4
Maintenance	23.6
Waste Disposal	0.0
Chemicals + Consumable	11.0
Insurance and local taxes	14.0

Working Capital		**MM Euro**
30 days Chemical Storage		1.1
5 days Coal Storage		0.7
Total Working capital		1.8
Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.0496	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	5.00	%
Revenues / year	292.5	MM Euro/year
Carbon tax =	25	Euro/t
NPV	**0.00**	
IRR	**5.00%**	

CASH FLOW ANALYSYS Millions Euro	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				154.8	292.5	292.5	292.5	292.5	292.5	292.5	292.5	292.5	292.5	292.5	292.5
Operating Costs															
Fuel Cost				-24.5	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4
CO_2				-68.0	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4
Maintenance				-15.8	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2
Chemicals & Consumables				-5.8	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0
Working Capital Cost				-1.8											
Fixed Capital Expenditures	-159.3	-358.4	-278.7												
Total Cash flow (yearly)	-159.3	-358.4	-278.7	17.7	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9
Total Cash flow (cumulated)	-159.3	-517.6	-796.3	-778.6	-716.7	-654.9	-593.0	-531.1	-469.2	-407.3	-345.5	-283.6	-221.7	-159.8	-97.9
Discounted Cash Flow (Yearly)	-151.7	-325.0	-240.8	14.6	48.5	46.2	44.0	41.9	39.9	38.0	36.2	34.5	32.8	31.3	29.8
Discounted Cash Flow (Cumul.)	-151.7	-476.7	-717.5	-702.9	-654.4	-608.2	-564.3	-522.4	-482.5	-444.5	-408.3	-373.9	-341.1	-309.8	-280.0

CASH FLOW ANALYSYS Millions Euro	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	292.5	292.5	292.5	292.5	292.5	292.5	292.5	292.5	292.5	292.5	292.5	292.5	292.5	
Operating Costs														
Fuel Cost	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	
CO_2	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	-128.4	
Maintenance	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	
Labour	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	
Waste Disposal	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	
Insurance	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	
Working Capital Cost														1.8
Fixed Capital Expenditures														
Total Cash flow (yearly)	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	1.8
Total Cash flow (cumulated)	-36.1	25.8	87.7	149.6	211.5	273.3	335.2	397.1	459.0	520.9	582.7	644.6	706.5	708.3
Discounted Cash Flow (Yearly)	28.3	27.0	25.7	24.5	23.3	22.2	21.2	20.1	19.2	18.3	17.4	16.6	15.8	0.4
Discounted Cash Flow (Cumul.)	-251.7	-224.7	-199.0	-174.5	-151.2	-129.0	-107.8	-87.7	-68.5	-50.2	-32.8	-16.2	-0.4	0.0

TABLE A.G.10 - CFB without CO_2 capture- Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	592.9	t/h
Net Power Output	791.8	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost
CO2 emissions	689.7	t/h

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	MM Euro
Installed Costs	698.6
Land purchase; surveys	34.9
Fees	14.0
Average Contingencies	48.9
Total Investment Cost	796.3

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	46.4
CO_2 cost	256.8
Maintenance	23.6
Waste Disposal	0.0
Chemicals + Consumable	11.0
Insurance and local taxes	14.0

Working Capital		MM Euro
30 days Chemical Storage		1.1
5 days Coal Storage		0.7
Total Working capital		1.8
Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.0714	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	5.00	%
Revenues / year	420.8	MM Euro/year
Carbon tax =	50	Euro/t
NPV	0.00	
IRR	5.00%	

CASH FLOW ANALYSYS Millions Euro	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	000	00	0	1	2	3	4	5	6	7	8	9	10	11	12
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				222.8	420.8	420.8	420.8	420.8	420.8	420.8	420.8	420.8	420.8	420.8	420.8
Operating Costs															
Fuel Cost				-24.5	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4
CO_2				-135.9	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8
Maintenance				-15.8	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2
Chemicals & Consumables				-5.8	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0
Working Capital Cost				-1.8											
Fixed Capital Expenditures	-159.3	-358.4	-278.7												
Total Cash flow (yearly)	-159.3	-358.4	-278.7	17.7	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9
Total Cash flow (cumulated)	-159.3	-517.6	-796.3	-778.6	-716.7	-654.9	-593.0	-531.1	-469.2	-407.3	-345.5	-283.6	-221.7	-159.8	-97.9
Discounted Cash Flow (Yearly)	-151.7	-325.0	-240.8	14.6	48.5	46.2	44.0	41.9	39.9	38.0	36.2	34.5	32.8	31.3	29.8
Discounted Cash Flow (Cumul.)	-151.7	-476.7	-717.5	-702.9	-654.4	-608.2	-564.3	-522.4	-482.5	-444.5	-408.3	-373.9	-341.1	-309.8	-280.0

CASH FLOW ANALYSYS Millions Euro	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
	13	14	15	16	17	18	19	20	21	22	23	24	25	26
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	420.8	420.8	420.8	420.8	420.8	420.8	420.8	420.8	420.8	420.8	420.8	420.8	420.8	
Operating Costs														
Fuel Cost	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	
CO_2	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	-256.8	
Maintenance	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	-23.6	
Labour	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	-11.0	
Waste Disposal	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	
Insurance	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	-14.0	
Working Capital Cost														1.8
Fixed Capital Expenditures														
Total Cash flow (yearly)	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	61.9	1.8
Total Cash flow (cumulated)	-36.1	25.8	87.7	149.6	211.5	273.3	335.2	397.1	459.0	520.9	582.7	644.6	706.5	708.3
Discounted Cash Flow (Yearly)	28.3	27.0	25.7	24.5	23.3	22.2	21.2	20.1	19.2	18.3	17.4	16.6	15.8	0.4
Discounted Cash Flow (Cumul.)	-251.7	-224.7	-199.0	-174.5	-151.2	-129.0	-107.8	-87.7	-68.5	-50.2	-32.8	-16.2	-0.4	0.0

FOSTER WHEELER

TABLE A.G.11 - CFB with CO_2 capture- Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	592.9	t/h
Net Power Output	609.7	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost
CO2 emissions	103.5	t/h

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	838.5
Land purchase; surveys	41.9
Fees	16.8
Average Contingencies	57.9
Total Investment Cost	955.1

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	46.4
CO_2 cost	19.3
Maintenance	26.6
Waste Disposal	0.0
Chemicals + Consumable	25.7
Insurance and local taxes	16.8

Working Capital		**MM Euro**
30 days Chemical Storage		2.5
5 days Coal Storage		0.7
Total Working capital		3.2
Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.0476	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	5.00	%
Revenues / year	216.1	MM Euro/year
Carbon tax =	25	Euro/t
NPV	0.00	
IRR	**5.00%**	

CASH FLOW ANALYSYS
Millions Euro

	2005	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				114.4	216.1	216.1	216.1	216.1	216.1	216.1	216.1	216.1	216.1	216.1	216.1
Operating Costs															
Fuel Cost				-24.5	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4
CO_2				-10.2	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3
Maintenance				-17.8	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2
Chemicals & Consumables				-13.6	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8
Working Capital Cost				-3.2											
Fixed Capital Expenditures	-191.0	-429.8	-334.3												
Total Cash flow (yearly)	-191.0	-429.8	-334.3	21.1	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2
Total Cash flow (cumulated)	-191.0	-620.8	-955.1	-934.0	-859.8	-785.6	-711.4	-637.2	-563.0	-488.8	-414.6	-340.4	-266.2	-191.9	-117.7
Discounted Cash Flow (Yearly)	-181.9	-389.8	-288.8	17.4	58.1	55.4	52.7	50.2	47.8	45.6	43.4	41.3	39.4	37.5	35.7
Discounted Cash Flow (Cumul.)	-181.9	-571.8	-860.5	-843.2	-785.0	-729.6	-676.9	-626.7	-578.9	-533.3	-489.9	-448.6	-409.2	-371.8	-336.1

	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	216.1	216.1	216.1	216.1	216.1	216.1	216.1	216.1	216.1	216.1	216.1	216.1	216.1	
Operating Costs														
Fuel Cost	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	
CO_2	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	-19.3	
Maintenance	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	
Labour	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	
Waste Disposal	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	
Insurance	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	
Working Capital Cost														3.2
Fixed Capital Expenditures														
Total Cash flow (yearly)	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	3.2
Total Cash flow (cumulated)	-43.5	30.7	104.9	179.1	253.3	327.5	401.7	475.9	550.1	624.3	698.5	772.7	846.9	850.1
Discounted Cash Flow (Yearly)	34.0	32.4	30.8	29.4	28.0	26.6	25.4	24.2	23.0	21.9	20.9	19.9	18.9	0.8
Discounted Cash Flow (Cumul.)	-302.1	-269.7	-238.9	-209.5	-181.5	-154.9	-129.5	-105.4	-82.4	-60.5	-39.6	-19.7	-0.8	0.0

FOSTER WHEELER

TABLE A.G.12 - CFB with CO_2 capture- Cost Evaluation - Discount Rate = 10%

Production		
Coal Florate	592.9	t/h
Net Power Output	609.7	MW
Fuel Price	10.50	Euro/t (*)
Insurance and local taxes	2%	Installed cost
CO2 emissions	103.5	t/h

(*) 10.5 Euro/t = 1 $/GJ (1 Euro= 1 $)

Capital Expenditures	**MM Euro**
Installed Costs	838.5
Land purchase; surveys	41.9
Fees	16.8
Average Contingencies	57.9
Total Investment Cost	955.1

Operating Costs [MM Euro/year] at 85% load factor	
Fuel Cost	46.4
CO_2 cost	38.5
Maintenance	26.6
Waste Disposal	0.0
Chemicals + Consumable	25.7
Insurance and local taxes	16.8

Working Capital		**MM Euro**
30 days Chemical Storage		2.5
5 days Coal Storage		0.7
Total Working capital		3.2

Labour Cost		**MM Euro/year**
# operators		111
Salary		0.05
Direct Labour Cost		5.6
Administration	30% L.C.	1.7
Total Labour Cost		7.2

Electricity Production Cost	0.0519	Euro/kWh
Inflation	0.00	%
Taxes	0.00	%
Discount rate	5.00	%
Revenues / year	235.4	MM Euro/year
Carbon tax =	50	Euro/t

NPV	**0.00**
IRR	**5.00%**

CASH FLOW ANALYSYS Millions Euro	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
	000	**00**	**0**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
Load Factor				45%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
Equivalent yearly hours				3942	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446
Expediture Factor	20%	45%	35%												
Revenues															
Electric Energy				124.6	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4
Operating Costs															
Fuel Cost				-24.5	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4
CO_2				-20.4	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5
Maintenance				-17.8	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6
Labour				-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2
Chemicals & Consumables				-13.6	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7
Waste Disposal				0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Insurance				-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8
Working Capital Cost				-3.2											
Fixed Capital Expenditures	-191.0	-429.8	-334.3												
Total Cash flow (yearly)	-191.0	-429.8	-334.3	21.1	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2
Total Cash flow (cumulated)	-191.0	-620.8	-955.1	-934.0	-859.8	-785.6	-711.4	-637.2	-563.0	-488.8	-414.6	-340.4	-266.2	-191.9	-117.7
Discounted Cash Flow (Yearly)	-181.9	-389.8	-288.8	17.4	58.1	55.4	52.7	50.2	47.8	45.6	43.4	41.3	39.4	37.5	35.7
Discounted Cash Flow (Cumul.)	-181.9	-571.8	-860.5	-843.2	-785.0	-729.6	-676.9	-626.7	-578.9	-533.3	-489.9	-448.6	-409.2	-371.8	-336.1

CASH FLOW ANALYSYS Millions Euro	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
	13	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**
Load Factor	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	
Equivalent yearly hours	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	7446	
Expediture Factor														
Revenues														
Electric Energy	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	235.4	
Operating Costs														
Fuel Cost	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	-46.4	
CO_2	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	-38.5	
Maintenance	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	-26.6	
Labour	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	-7.2	
Chemicals & Consumables	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	-25.7	
Waste Disposal	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	
Insurance	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	-16.8	
Working Capital Cost														3.2
Fixed Capital Expenditures														
Total Cash flow (yearly)	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	74.2	3.2
Total Cash flow (cumulated)	-43.5	30.7	104.9	179.1	253.3	327.5	401.7	475.9	550.1	624.3	698.5	772.7	846.9	850.1
Discounted Cash Flow (Yearly)	34.0	32.4	30.8	29.4	28.0	26.6	25.4	24.2	23.0	21.9	20.9	19.9	18.9	0.8
Discounted Cash Flow (Cumul.)	-302.1	-269.7	-238.9	-209.5	-181.5	-154.9	-129.5	-105.4	-82.4	-60.5	-39.6	-19.7	-0.8	0.0

CLIENT : IEA GREENHOUSE GAS R&D PROGRAMME
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SECTION H

YEAR 2020 IMPROVEMENTS

I N D E X

SECTION H

SECTION H YEAR 2020 IMPROVEMENTS

1.0 General Background

The coal firing technology greatly improved in the past years. At the beginning of the 20^{th} century 1 kWh required for 4 to 6 kg of coal, depending on coal quality. Today the most modern power plants can produce 1 kWh with 300 g of coal, corresponding to a net efficiency of about 45%.

An increase of efficiency is generally coupled with an increase of investment, but the saving in fuel cost more than compensate the additional capital. So the efficiency increase has been a constant trend in the past years to increase the competitiveness of the technology. But an even more important advantage of the efficiency increase is the proportional reduction of the emissions and consequent increase of the level of acceptance.

However the increase of efficiency, albeit important, is not sufficient to reduce the emissions to the level imposed by the regulations and desired by the population. Consequently clean-up technologies have been developed to reduce emissions.

A today state of the art coal fired power plant operates with efficiency greater than 45% and can incorporate the following clean-up facilities:

- catalytic removal of NO_x;
- Electrostatic precipitation or bag filtration for the separation of particulates;
- Capture of SO_x with wet or dry scrubbing;
- Mercury and heavy metals removal.

The reduction of CO_2 emission is also under examination. Technologies are available to reduce CO_2 by 90%-95%.

All these options make coal the first positive answer to the great demand of power of the future years.

In the following paragraphs the coal firing technology improvements, expected in the next 15 years, are examined and evaluated.

Obviously these improvements are goals reflecting an educated guess of what may be the rate of success of the ongoing research and development programmes.

2.0 Pulverized Coal Combustion

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.
Operating examples of this state of the art technology are the following power plants:

- Aalborg (Denmark) : 285 bar/580°C/580°C/580°C
  net efficiency: 47%
- Avedöre (Denmark) : 285 bar/580°C/600°C
  net efficiency: 46%
- Matsuura (Japan) : 241 bar/593°C/593°C
  net efficiency: 45%

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, but a similar efficiency can be achieved if the water content of lignite is reduced below 20%.

Using low rank coals, the largest single module offered today is 1000 MW. An example is the Niederauβem plant, owned by RWE, with the following steam conditions:

- Pressure: 290 bar
- Temperature: 580/600 °C

The reduction of moisture of the lignite is a great area of interest in Europe and USA, because a lignite is expected to play a growing role in power production. As described in Section C, paragraph 2.0, research activities are going on to develop and demonstrate different process routes to effectively reduce lignite moisture. These efforts are expected to make available in the coming years drying technologies making competitive the use of lignite in the power industry.

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.
R&D programs are ongoing in Europe USA and Japan, sponsored respectively by the European Community (Thermie), the Department of Energy (DOE) and Japanese public

authorities. Various metallurgical options are under evaluation aiming to achieve in 2010-2015 steam cycle conditions equal to 350 bar/700°C/720°C and a corresponding net efficiency equal to 50%.
The most aggressive program is the one in USA, which has set a goal for the steam temperature equal to 750°C, with a net efficiency close to 52%.

3.0 Oxyfuel

This technology, although not yet used in commercial units, is attracting the attention of power producers in USA and Europe, in view of a future need to produce power from coal with close to zero emissions of greenhouse gases, including CO_2.
The technology is based on the use of a mixture of oxygen and recycled flue gas as oxidant, in lieu of air. The non recycled portion of the flue gas, mainly constituted of CO_2 and H_2O is treated cryogenically to separate CO_2 while the non condensables, N_2, O_2 and some CO_2, are purged to the atmosphere.
This technology is theoretically applicable to different power cycles: natural gas combined cycle, PC combustion, gasification (IGCC) and hybrid cycle (2nd generation PCFB).
The oxyfuel process permits to avoid the CO_2 enriching and separation processes, pre or postcombustion, and allows direct collection of CO_2 at the exit of the power cycle, resulting in a simpler power production process with sequestration of CO_2. The major penalty of the process is the cost of production of oxygen in quantity sufficient to fully oxidize the fuel feed.
So far the technology has been studied at the level of design to discover how much the existing technologies have to be stretched to operate in the oxyfuel mode.
Oxyfuel operation of natural gas combined cycles is a great technology challenge because this would require a complete redesign of the gas turbine, compressor and expander. In fact the working fluid characteristics are drastically different from those used in normal operation, with air combustion. The main component of the working fluid is CO_2 instead of N_2 and with CO_2 the temperature change, with a given pressure ratio across the turbine, is much lower. In order to maintain a high efficiency and therefore a high turbine inlet temperature (TIT) and, at the same time, a low turbine exhaust temperature (540°C or lower) it would be necessary to increase dramatically the turbine inlet pressure, which means to develop a completely new family of gas turbines.
Further a combined cycle, based on natural gas and without CO_2 capture, achieves a CO_2 emission rate equal to approximately 370 g of CO_2 per kWh, much lower than the typical emission of CO_2 of a PC boiler, based on coal and without CO_2 capture, which is approximately 750-800 g of CO_2 per kWh. So the incentive to reduce CO_2 emissions in a combined cycle are definitely lower.

The same problem of gas turbine availability for oxyfuel operation makes the oxyfuel application to IGCC or hybrid cycles difficult for the next 15 years, although in these two last cases the incentive to capture CO_2 is much greater than for the combined cycles, because the fuel used is coal.

Oxyfuel, on the contrary, is expected to have a realistic chance of success with the more traditional combustion processes, PC or CFB. In these cases, in fact, the currently used technologies can be easily adopted to oxyfuel operation. By year 2020 some commercial applications of oxyfuel for coal combustion are a distinct possibility in geographical areas, commanding a drastic drop of CO_2 emissions.

However the oxyfuel technology must be improved to increase its current degree of competitiveness (see Section F).
The main areas for Technological improvements are:

a. O_2 concentration in the furnace and related furnace peak temperature

So far the study efforts, developed for oxyfuel, have attempted to keep these parameters as close as possible to the values currently use in air fired boiler. However there is a great room for design improvements, because the average wall heat flux can be greatly increased compared to air fired boilers due to the higher CO_2 concentration (75% versus 14%) and higher flame temperature (2200° vs. 1850°C). This could easily achieve a reduction of the surface and, thus, size of the furnace possibly equal to 50% of what used in air fired boilers.
The impact of these changes on metallurgy, emissions and other aspect of the technology must however be evaluated.

b. Burner design

The design of the burners must be optimized to operate satisfactorily in the oxyfuel conditions.

c. Furnace design

The design of the furnace must reduce to a minimum the leakage of air into the furnace operating under slight vacuum. Air leaks, together with the N_2 present in the oxygen, must be purged from the recycle loop, does causing an increase of the loss of CO_2 to the atmosphere.

d. Air Separation Unit (ASU)

ASU is an important capital and operating item of cost in oxyfuel. New technologies for O_2 separation, able to reduce the cost of oxygen, such as membrane or pressure swing, will greatly improve the competitiveness of oxyfuel.

e. CO_2 separation from purge gas

The currently proposed technique is cryogenic, i.e., the purged flue gas is cooled to < 60°C to separate liquid CO_2. This requires capital (large heat exchangers) and energy. Improvements in this area would also be greatly beneficial.

4.0 Circulating Fluid Bed

The circulating fluid bed technology is expected to play, in the future years, an increasing role in the power industry and become the most serious competitor of the traditional PC combustion technology.
The most positive aspects of CFB are:

- Flexibility to process different fuels and in particular, difficult to burn, low cost, coals and lignite with high moisture content;
- coal need not to be pulverized but only reduced in size (5-8 mm), making the feed preparation and transportation less costly than what needed for PC combustion;
- in situ desulphurization using limestone/dolomite as bed material;
- possibility to use ultrasupercritical steam conditions similar to PC boilers;
- low NO_x emissions due to the lower combustion temperature (850-900°).

The main advantage, compared to PC boilers, is the flexibility to process different fuels like bituminous or brown coals. The main disadvantage is still the scale economy. Largest single module capacity in operation is 350 MW (260 MW using lignite), but it is likely that this limitation will be removed in the future years and CFB boilers of capacity similar to PC boilers, 800 MW or more, will become available. Actually, Foster Wheeler awarded a contract to build the world's first CFB boiler operating at supercritical steam conditions. This unit will be a 460 MW plant at the Lagisza station (Poland), operating at supercritical pressure (275 bar), with superheat and reheat steam temperatures of 560°C and 580°C.

5.0 Pressurized Fluid Bed

The pressurized fluid bed technology became a technology of interest in the early nineties. ABB offered two modules, P200 and P800, where 200 and 800 are the thermal MW liberated in the boiler. Units using the P200 module were constructed and operated in US (Tidd-Ohio), Spain (Escatron) and Sweden (Vartan). Other PFB plants have been installed in Germany (Cottbus) and other countries. In Japan a P800 modules was installed at Karita Power Station.

The operation of these PFB plants did not prove to be suitable on the whole. Investment and insufficient availability were the weak points of this technology. The gas turbine used in the process was a special equipment available only from one vendor (ABB) and its efficiency was penalized by the low turbine inlet temperature (TIT), about 850°C.

Alstom (formerly ABB), the world's leading developer, discounted few years later the marketing of the technology.

Case 4 of Section D of this study has evaluated PFB because of the potential advantages of CO_2 postcombustion capture from flue gas at 15 bar pressure. Nevertheless the results of this evaluation have confirmed the lack of competitiveness of this technology.

The future of PFB technology is however kept alive by a modification/improvement called 2nd Generation PFB or Hybrid Cycle. This is a drastic change of the PFB process formally proposed by ABB.

The process is described by the attached block flow diagram (Fig. 1).

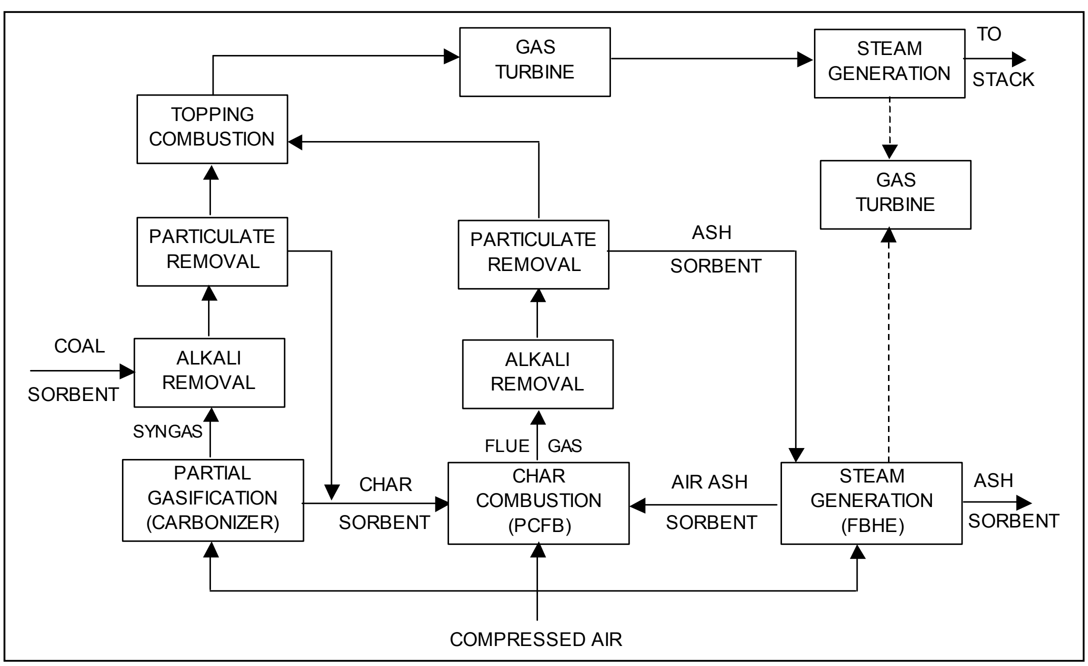

Figure 1 - Second Generation PFB Plant

Coal is processed in an air blown, pressurized (20 bar), fluid bed gasifier, called Carbonizer, which produces a low BTU syngas (1250 kcal/Nm^3) and a solid residue, char. The syngas pass through cyclones and ceramic filter for the removal of entrained particulates. Alkali vapours, detrimental for the gas turbine blades, are removed by injecting in the syngas pulverized emathelite. The hot (850-900°C) syngas is burnt in a specially designed gas turbine combustor, called topping combustor.
The char from the Carbonizer is fed to a PFB Combustor, which burns completely the char residue and generate HP steam.
Air compressed by the gas turbine compressor is fed to the Carbonizer and to the PFB Combustor. The O_2 rich flue gas from the PFB Combustor, flows to the Topping Combustor to burn the syngas and then drives the gas turbine. The exhaust flue gas from the gas turbine flows to a heat recovery steam generator (HRSG) and then to the stack.
Electric energy is generated by the gas turbine and by the steam turbine, driven by HP steam produced by the PFB Combustor and by the turbine HRSG.
Limestone or dolomite is the bed material of the Carbonizer and PFB Combustor. Sulphur is captured as calcium sulphide in the Carbonizer and later converted to sulphate in the oxidizing atmosphere of the PFB Combustor.
The 2nd Generation PFB is somewhat more complicated and costly but the great efficiency limit of the 1st Generation, i.e., the low turbine inlet temperature does not longer exists, thanks to the topping combustor. Net cycle efficiencies greater than 48% can be achieved.
The 2nd Generation PFB has been demonstrated at the level of large pilot plant scale by a group of companies: Foster Wheeler, Siemens-Westinghouse and Parsons. DOE provided financial support for these tests.
Carbonizer (10 inch diameter) and PFB Combustor (8 inch diameter) have been successfully tested, isolated and connected together.
An 18 inch diameter model of the Topping Combustor was also tested with simulated syngas.
The 2nd Generation PFB Technology has thus achieved a high level of development and is ready to enter commercial operation, based on Siemens-Westinghouse W501F gas turbine.
This technology is a serious candidate for the implementation of clean coal projects in USA in the next 10-15 years.

6.0 Integrated Gasification Combined Cycle

IGCC is the technology with the greatest potential of improvements. All the key components of the technology, are derived from previously demonstrated industrial applications and can be improved by optimizing their design for the specific IGCC type of operation.

a. Gas Turbine

Gas Turbines are continuously growing in capacity and performance. Several developments, tailored for IGCC, are being studied:

- air compressor power demand reduced by staging and intercooling;
- compressor and expander capacities better balanced to allow easier integration with ASU;
- fuel firing in two or more stages;
- TIT increase to allow, with the same pressure ratio across the turbine, the use of a supercritical or ultrasupercritical steam cycle.

b. Steam Cycle

To follow the current trend of increase of cycle efficiency the HRSGs of future IGCC are expected to operate in once-through and supercritical conditions. This development is, however, strictly related to the turbine exhaust temperature so the design of the two components, turbine and HRSG, must be jointly optimized having as target the maximum energy efficiency of the IGCC.

c. Gasifier

The priority for the design improvements of the gasifier are the reduction of the capital cost and the improvement of the reliability. A second priority is an increase of the cold gas efficiency.

Areas of improvements in gasification are:

- feed injector
- refractory
- quench design
- coal feeding system: pneumatic or slurry but avoiding the efficiency penalty associated with the use of water slurry
- slag and ash removal
- capability to handle low rank coals.

GE recently announced (at the Gasification Technologies 2005 Conference held in S. Francisco on October 9th –12th , 2005) a technology development program which includes modifications/ improvements to the following items:

- Feed system to enable low rank coal processing (presently GE gasifier is not suitable for the lignite composition selected for this study), increase gasifier efficiency and reduce oxygen consumption;

- Feed injection aimed at optimizing the gasifier flow distribution thus increasing availability and efficiency;

- Refractory aimed at increasing its life thus improving the availability and decreasing the maintenance costs.

- Synthesis Gas Cooler aimed at decreasing the size, increasing heat recovery and eliminating the deposition, with the benefits to increase availability and efficiency and decrease the investment cost.

At the same conference Shell declared to be implementing in the next and far future features and improvements aimed at reducing the investment cost (i.e. reactor/syngas cooler, steam system simplified), increasing the reactor syngas train capacity up to 5000 t/d , and increasing the plant availability (< 4% unplanned outages).

New gasification technologies are under development and will become available before year 2020. To mention two of them: Eagle gasifier in Japan and KBR Transport Gasifier in USA.

The KBR Transport Reactor is an advanced fluidized bed reactor which can operate as a pressurized boiler or as a gasifier, in two versions: air blown and oxygen blown.
A pilot plant has been operated, with the support of DOE, at the PSDF testing facility in Wilsonville, Alabama. It was operated for three years as a pressurized combustor until coal gasification testing began in September 1999. Through September 2005, the Transport Gasifier has achieved over 7,700 hours of coal gasification including 750 hours with North Dakota lignite.
The gasifier is a refractory lined vessel with 2 feed injections in the bottom section and one in the upper section; so it is classified as a two stage gasification (theoretically better cold gas efficiency). The coal feed is slurry type, while heat recovery is by WHB.

It seems to be particularly suitable for low-rank, high moisture/high ash coals due to the low temperature operation, and high circulating solid rates. The high reactivity of lignite results in a high carbon conversion with respect to the bituminous coals.
However the test campaign shows a maximum value equal to 97% for low sodium ash seam (1.7% Na_2O) and 96% for high sodium one (5.5% Na_2O).

In KBR's opinion the air blown made would be the adopted for power generation and oxygen made for chemical production.

The Transport Gasifier has been selected for an advanced 285 to 300 MW_e coal gasification demonstration project to be located in Orlando (Florida) partially funded by the DOE under the Clean Coal Power Initiative (CCPI).

There are other technologies that may be suitable for low rank coals, but have not been investigated in this study. Two of these are the HTW and HRL gasification technologies.

The High Temperature Winkler (HTW) gasifier is a development of the old Winkler atmospheric pressure gasifier used in the 1920s.
The high temperature feature of the HTW is accomplished by injecting a portion of the oxidant above the fluidized bed to obtain a much higher temperature over the original Winkler with the following advantages:

- increased carbon conversion (less char)
- reduced methane and heavier hydrocarbons formation.

Rheinbraun, a major producer of lignites, developed the HTW gasifier for lignite gasification.
A first demonstration unit was built in 1985 at Berrenrath (Germany) to gasify 700 t/d brown coal, at 10 bar pressure, with minimum content of methane to meet the requirements of a downstream methanol synthesis.
In 1989 a second demonstration unit, optimized for IGCC power generation, was started in Wesseling. This unit, having a capacity of 170 t/d coal, operates at 25 bar, and can be operated either as a bubbling or circulating bed, using either air or O_2. This unit was the demonstration step for a 350 MW IGCC project, called KoBRA, which was dropped later, for economical reasons. The KoBRA plant was expected to gasify 3600 t/d coal in an air blown gasifier.
Fuel is pressurized in a coal hopper and fed to the gasifier by a screw conveyor.

The gasifier vessel is refractory lined; the bottom is occupied by the fluid bed, fluidized by steam, O_2 or air. Generated gas is further heated in the upper zone by injection of oxidant. Entrained solids at the outlet of the gasifier are separated in a cyclone and recycled to the gasifier for further char conversion. The gasifier bottom temperature is kept at about 800-900°C to avoid ash melting, while the freeboard temperature can be 150-200°C higher.
Ash and residual char are removed from the base of the gasifier. Depending on the char content, the ash may be sent to an external fluid bed boiler for full combustion of char. When high rank, low reactive, coals are gasified additional combustion is necessary; whereas this may not be required with highly reactive lignites.

HRL is an Australian owned energy, technology and project development company. Its gasification technology was originally developed for low-rank coals, but is also applicable to high-reactivity bituminous coals.

HRL has worked with the air-blown pressurised fluidised bed gasification process since the late 1980s. The relatively moderate temperature of the process is suitable for high-reactivity coal and avoids the problems of handling molten ash associated with oxygen-blown entrained flow gasification systems.

HRL gasification technology for power generation IS called Integrated Drying Gasification Combined Cycle or "IDGCC".
This technology generates electricity at a higher efficiency and as a consequence, produces significantly less CO_2 when compared to current brown coal thermal technology.

The IDGCC technology has been developed over the last decade at an investment of over $120M. It is currently at the stage of commercialisation, having been proven at the 10 MW scale with electricity generated into the Grid.
HRL Developments has been granted an Exploration Licence in the Driffield coalfield in the Latrobe Valley for the development of a new commercial power station utilising IDGCC technology.

d. Syngas cooler

Design improvements of the syngas cooler are expected to achieve a reduction of the capital cost of this expensive equipment.

e. Acid Gas Removal

This technology has been studied and developed for the Chemical Industry for decades. So the technology is mature and important break-through are not expected in the next 15 years.

f. Air Separation Unit

This IGCC component, based on cryogenic technology, is also a mature process so major improvements are not expected.
New concepts are proposed for the separation of O_2 from N_2, based on use of selective membrane or pressure swing. Whether these technologies will become available before 2020 is still not known but, if successful, they could improve IGCC competitiveness substantially, since, even the most efficient cryogenic separation, absorbs 15% of the power produced by the IGCC.

If all these improvements will become available it is reasonable to expect that the IGCC in 2020 may achieve a net efficiency from coal to electric energy equal or superior to 50%, without CO_2 capture.

7.0 Environment Protection Technologies

All the power generation processes, examined in the previous paragraphs, have a common requirement to become acceptable to the population: a drastic reduction of the rate of emissions.
Great improvements have already been achieved in the abatement of the contaminants, as summarized herebelow.

a. Flue Gas Denitrification

The reduction of NO_x, a mixture of NO and NO_2, can be undertaken in the combustion stage, with the use of special burners or use of fuel re-burn, or after the combustion stage with alternative processes, SNCR, SCR, Low Tox as better described in Section C, paragraph 4.0.
NO_x reduction in the combustion stage is the first step undertaken because is the most economical way to achieve a NO_x reduction. However, if a high NO_x reduction is desired the answer can come only from processes located after the combustion stages.
SCR is the dominant technology that can achieve final NOx concentrations down to 100 and even 40 mg/Nm^3 (6%O_2-dry).
When the combustion takes place at low temperatures, for instance CFB boilers, the production of NO_x is reduced but when the temperature comes close to 800°C there is risk of formation of N_2O. N_2O and CH4 are the two greenhouse gases of greater concern for global warming. N_2O is 296 times more effective than CO_2 and CH_4 23 times.
The formation of N_2O can be contrasted by an increase of temperature (after burning in the cyclone). Limestone used as bed material has also demonstrated to reduce N_2O formation.
In conclusion the technology for reduction of NOx is mature, well developed and suitable to match present and future legislation standards, so no great break-through are expected for year 2020.

b. Flue Gas Desulphurization

The capture of S contained in the fuel is made with several different processes:

- capture of SO_2 with limestone in fluid bed combustion processes;
- capture of SO_2 in the flue gas with wet or dry FGD scrubbing processes, as described in Section C, paragraph 5;
- capture of H_2S in syngas generated during gasification, with the use of regenerative chemical of physical solvents.

All these processes can achieve a high rate of sulphur capture. Limestone and wet/dry FGD can reach sulphur removal efficiency equal or greater than 96-97%.

Chemical and physical solvents can easily achieve an efficiency of sulphur removal from syngas greater than 99%. This removal efficiency is generally sufficient to meet present and future environmental standards.
Also the S capture available technologies are mature and well developed so no major break-through is expected for year 2020.

c. Mercury and Heavy Metals removal

As explained in Section C, paragraph 6.0, the removal of Hg and heavy metals from the flue gas is a relatively recent requirement with a limited industrial experience so far accumulated. The technology available today, active carbon injection followed by a fabric filter, seems to work all right at reasonable costs. Improvements of the technology are possible but their impact on power production cost will be negligible.

d. CO_2 capture

CO_2 produced in the combustion of coal can be captured in different ways:

- Postcombustion: this process is generally applicable to all combustion processes: PC, CFB, PFB.
  The process proposed today is based on the use of a formulated amine regenerative solvent. A detailed description of this process is given Section C, paragraph 7.0.

- Precombustion: this process is applicable only to gasification processes and is based on the use of selective chemical and physical solvents, operating in a regenerative mode.
  A detailed description of these processes is given in Section C, paragraph 8.

Postcombustion processes are not proved on a large scale as required by the power industry. Several question marks still exist on the rate of solvent deterioration and plant corrosion. Capital and energy demands are very high. Consequently improvements of the technology are highly desirable and are expected to be implemented if the pressure for CO_2 removal will become greater. How much the technology can be improved and when these improvements will become available is not known. The only foreseeable step-forwards of the post-combustion processes, achievable in the coming years, will come from the operating experience of the first large plant(s), which hopefully will provide adequate solutions to the question marks indicated before.

Precombustion processes are better proved and do not present question marks as postcombustion processes. Their utilization in the power industry is only a problem of scale-up to the large capacities involved. However the available processes still require high capital and large consumption of energy, therefore improvements are desired but it is difficult to predict when these improvements will be available and the level of benefits involved. Considering of maturity achieved by these processes through the wide spread use in the chemical industry over the past 50-60 years, the probability of important new break troughs cannot ranked very high.

A third and interesting route to achieve the capture of CO_2 is the use of oxyfuel technology. As explained in paragraph 3 of this Section H, oxyfuel can be reasonably applied only to combustion processes, as PC or CFB.
The level of development of oxyfuel is today in the very first stages. A number of improvements are possible, as described in paragraph 3 and it is not unrealistic to predict for the year 2020 a successful development of oxyfuel as a competitive technology in areas requiring a drastic reduction of CO_2 emissions.

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ANALYSES OF LOW-RANK COALS

I N D E X

1.0 INTRODUCTION

Coal is one of the most important resources of fossil fuel in the world.

Today, coal is mined in 50 countries and current reserve/production ratios confirm over 200 years of resource availability. Actually, 38% of global electricity is generated from coal: Australia, Poland, South Africa and China all rely on coal to produce three quarters on their electricity, India over 60%, USA and Germany more than half.

Global hard (black) coal production has grown by almost 50% in the last 25 years to 3,639 millions of tons. Top five major producers include China (1171 million of tons), USA (899 millions of tons), India (310 million of tons), Australia (259 millions of tons) and South Africa (225 millions of tons.)
Brown coal/lignite production totaled 895 millions of tons in 2000 with Germany, Greece and North Korea among the leading producers and consumers.

Purpose of this report is to summarize the distribution of coal deposits, both high and low-rank coal type, performing the analyses of low rank coals from the major producing regions worldwide.

2.0 CLASSIFICATION OF COAL BY RANK

The rank of coal is a measure of its degree of metamorphism, or progressive alteration, in the natural series from lignite to anthracite.

The ASTM classification is shown in table 2.1 (D388, "Standard Specification for Classification of Coals by Rank", 1976 Annual Book of ASTM Standards, Part 26). Depending on the coal type, the following parameters are used for the classification:

- High-rank coals: dry, mineral-matter-free fixed carbon (or its complement, the volatile matter).
- Low-rank coals: gross calorific value on the basis of mineral-matter – free coal containing bed moisture, i.e., moisture just sufficient to fill the pores of the coal in its natural state in the ground.

Agglomerating character, as determined on the volatile-matter residue, is used as an additional criterion in two instances: agglomerating coal within the semianthracite fixed-carbon range is classified as low-volatile bituminous, whilst coal in the 10,500 to 11,500 Btu/lb range (moist, mineral-matter-free) is classified high-volatile C bituminous if agglomerating, or sub-bituminous A if non-agglomerating.

Table 2.1 – ASTM Classification of coal by rank.

Class	Group	Fixed Carbon Limits, % (Dry, Mineral-Matter-Free Basis) Equal or Greater Than	Fixed Carbon Limits, % (Dry, Mineral-Matter-Free Basis) Less Than	Volatile Matter Limits, % (Dry, Mineral-Matter-Free Basis) Greater Than	Volatile Matter Limits, % (Dry, Mineral-Matter-Free Basis) Equal or Less Than	Calorific Value Limits, Btu/lb (Moist,[b] Mineral-Matter-Free Basis) Equal or Greater Than	Calorific Value Limits, Btu/lb (Moist,[b] Mineral-Matter-Free Basis) Less Than	Agglomerating Character
I. Anthracitic	1. Meta-anthracite	98	—	—	2	—	—	Nonagglomerating
	2. Anthracite	92	98	2	8	—	—	
	3. Semianthracite[c]	86	92	8	14	—	—	
II. Bituminous	1. Low volatile bituminous coal	78	86	14	22	—	—	Commonly agglomerating[e]
	2. Medium volatile bituminous coal	69	78	22	31	—	—	
	3. High volatile A bituminous coal	—	69	31	—	14,000[d]	—	
	4. High volatile B bituminous coal	—	—	—	—	13,000[d]	14,000	
	5. High volatile C bituminous coal	—	—	—	—	11,500	13,000	
						10,500[e]	11,500	Agglomerating
III. Subbituminous	1. Subbituminous A coal	—	—	—	—	10,500	11,500	Nonagglomerating
	2. Subbituminous B coal	—	—	—	—	9,500	10,500	
	3. Subbituminous C coal	—	—	—	—	8,300	9,500	
IV. Lignitic	1. Lignite A	—	—	—	—	6,300	8,300	
	2. Lignite B	—	—	—	—	—	6,300	

[a] This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high volatile bituminous and subbituminous ranks. All of these coals either contain less than 48% dry, mineral-matter-free Btu/lb.

[b] Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[c] If agglomerating, classify in low volatile group of the bituminous class.

[d] Coals having 69% or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

[e] It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high volatile C bituminous group.

3.0 WORLD WIDE DISTRIBUTION OF COAL DEPOSITS

Many data are available in literature or in the web sites on the distribution of coal reserves, but the most important and reliable sources can be considered the following:

- **EIA**: Energy Information Administration, mainly operating in the United States.
- **WEC**: World Energy Council, with Member Committees in over 90 countries in the world.

The coal resource/reserve classification systems include several terms and criteria that have been jointly agreed upon by several authorities. The systems employ a concept by which coal beds are classified in terms of their degree of geologic identification (assurance of existence) and economic and technologic feasibility of recovery.

Following paragraph represents a summary of the most common terminology used in the coal classification systems.

3.1 Main terminology of coal classification systems

Resources:	Concentrations of coal in such forms that economic extraction is currently or may become feasible.
Identified Resources:	Specific bodies of coal whose location, rank, quality and quantity are known from geologic evidence supported by engineering measurements.
Undiscovered Resources:	Unspecified bodies of coal surmised to exist on the basis of broad geologic knowledge and theory.
Demonstrated Reserve Base (DRB) or Reserve Base:	The portion of identified coal resources from which reserves are calculated. These resources meet specified minimum physical and chemical criteria related to current mining and production practices.

Reserve:	That portion of the Identified Coal Resource that can be economically mined at the time of determination. Reserves include only recoverable coal.
Recoverable:	Coal that is, or can be, extracted from a coal-bed during mining.
Measured resources:	Refers to coal for which estimates of the rank and quantity have been computed to a high degree of geologic assurance, from sample analyses and measurements from closely spaced and geologically well known sample sites.
Indicated resources:	Refers to coal for which estimates of the rank, quality and quantity have been computed to a moderate degree of geologic assurance, partly from sample analyses and measurements from closely spaced and partly from reasonable geologic projections.
Proved Recoverable resources (World Energy Council):	Tonnage within the proved amount in place that can be recovered (extracted from the earth in raw form) under present and expected local economic conditions with existing available technology.

3.2 World Estimate Recoverable Coal

Data presented in this paragraph come from the Energy Information Administration (2004) and include both estimates from EIA for the United States and from the World Energy Council for all other countries.

Data from the World Energy Council represent the “Proved Recoverable Resources” (see paragraph 3.1), whilst data for the United States represent both the measured and indicated tonnage. However, the two terminologies can be considered equivalent.

Figures are dependent on the judgment of each reporting country to interpret local economic conditions and mineral assessment criteria. Consequently, the data may not all meet the same standards of reliability.

Further, data in this paragraph are referred to different base years: figures for the U.S. represent recoverable coal estimates as of December 31, 2002, and data for other countries are as of December 31, 1999.

Detailed data among each world country are presented in the Appendix A-1. Table 3.1 summarizes the total results of data shown in Appendix A-1 for the main world regions.

Table 3.1 – World Estimate Recoverable Sources (million short tons)

Region	Anthracite and Bituminous	Lignite and Sub-bituminous	Total Recoverable Coal
North America	130,629	149,836	280,465
Central & South America	8,530	15,448	23,978
Western Europe	27,650	73,693	101,343
Eastern Europe & Former U.S.S.R	132,046	158,138	290,184
Middle East	1,885	0	1,885
Africa	60,816	216	61,032
Asia & Oceania	208,719	113,675	322,394
WORLD TOTAL	570,274	511,006	1,081,280

Table 3.1 demonstrates the abundance of worldwide low-rank coal deposits: 47% of recoverable deposits is mainly composed of lignite and sub-bituminous coal (low-rank coals), the remaining 53% being of high-rank type.

The world concentration of low-rank coal deposits is mainly in the North America, Eastern Europe/Former U.S.S.R and Asia/Oceania (reference to be made to Appendix A-1 for further details on each country). Figure 3.1 summarizes the world distribution of the low-rank coals.

Similar data are available in the WEC web site and reported in the table of Appendix A-2. These data are dated 1999 also for the American countries (previous data for U.S. were date 2002), but allow knowing the recoverable reserves of both the sub bituminous and lignite coal in the world. Table 3.2 summarizes the total results for the main world regions.

Figure 3.1 – World distribution of low-rank coal deposits.

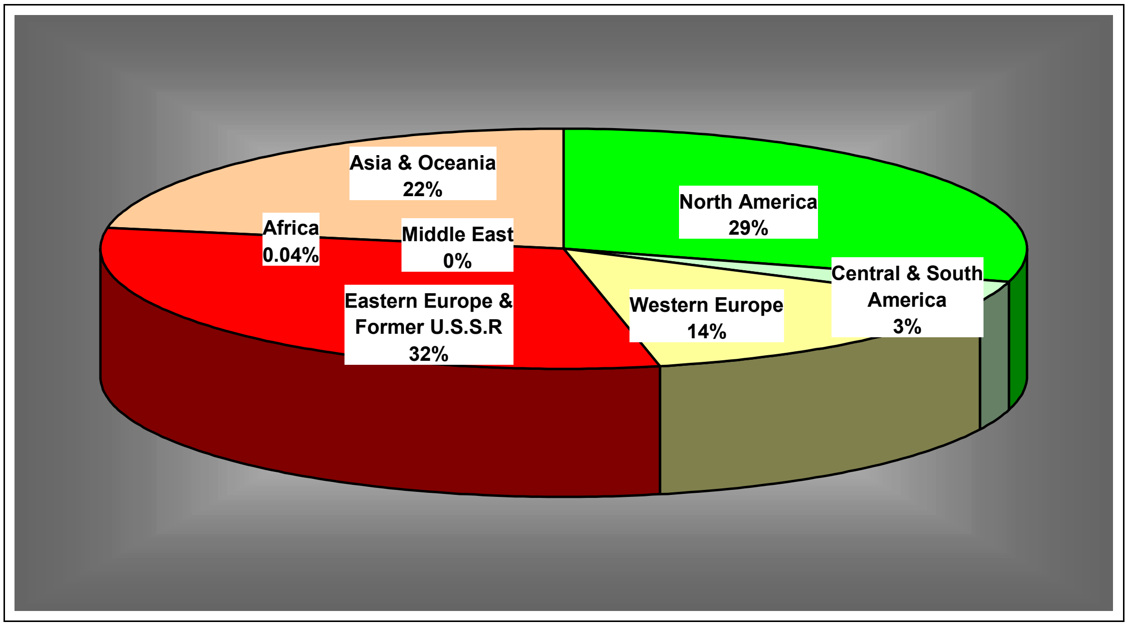


Table 3.2 – World Estimate Recoverable Sources of sub bituminous and lignite (million short tons)

Region	Sub bituminous	Lignite	Total Low-Rank Coal
Central & North America	112,849	38,987	151,836
South America	15,311	137	15,448
Total Europe	131,295	89,266	220,561
Middle East	-	-	-
Africa	213	3	216
Asia	42,646	38,118	80,764
Oceania	2,255	41,924	44,179
WORLD TOTAL	304,569	208,435	513,004

Table 3.2 shows that 59.4% of worldwide low-rank coal deposits is composed of sub-bituminous coal, being the remaining 40.6 % of lignite type.

Finally, figures 3.2 and 3.3 illustrate the distribution respectively of sub-bituminous and lignite in the world.

Figure 3.2 – World distribution of sub-bituminous coal deposits.

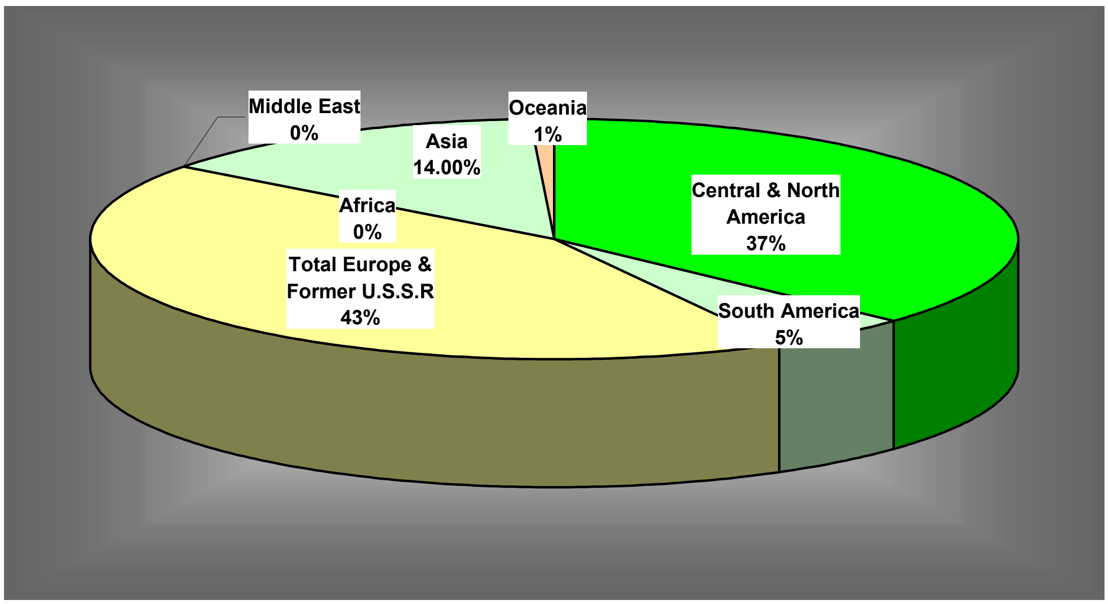
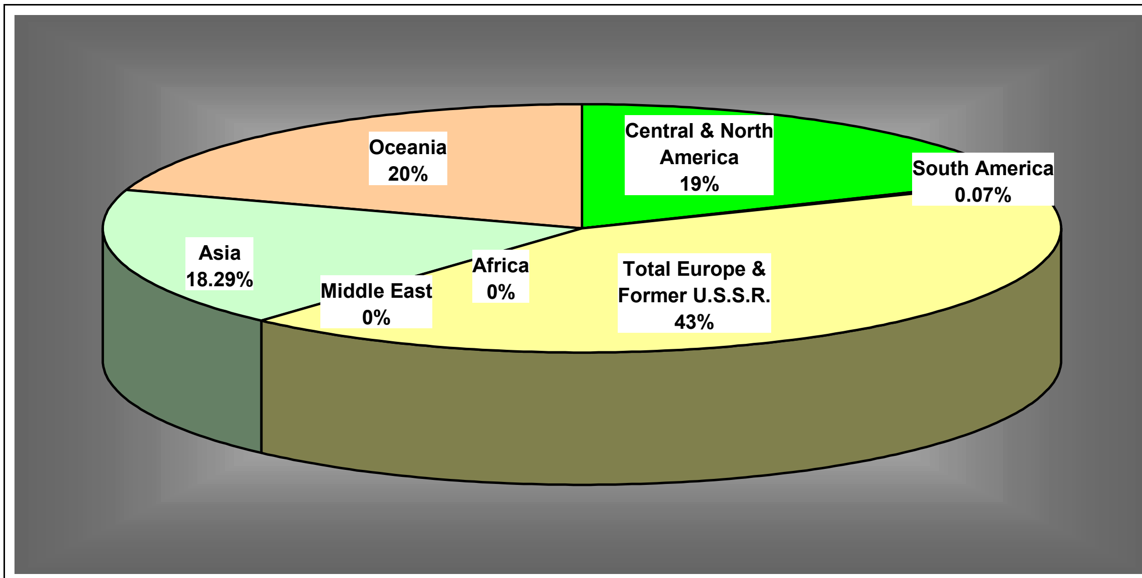


Figure 3.3 – World distribution of lignite coal deposits.



Figures 3.2 and 3.3 clearly demonstrate the importance of Europe & Former U.S.S.R. as recoverable reserve of low-rank coals, both for the sub-bituminous and lignite type. In particular, data shown in Appendix A-2, as well as papers listed in the references, demonstrate that Germany is the world's largest brown coal (lignite) producer and reserve, representing the 20% of global production in 2001.

4.0 PROPERTIES OF LOW-RANK COAL DEPOSITS

Investors and policymakers around the world require accurate information on coal properties and characteristics to make rational and informed decision on the investments.

Unfortunately, this comprehensive information is not yet available and an integrated source of reliable worldwide coal-quality does not exist. However, the U.S. Geological Survey (USGS), in conjunction with other partners, is developing an electronic database with geographic information system (GIS) coverage. The database is called the World Coal Quality Inventory (WoCQI) and will be available on the web (http://geode.usgs.gov). Actually, many data are available for the localization of the fossil fuels of several countries, but unfortunately at the moment only a few information are included on the coal-quality parameters.

Different data have been collected from several sources: literature, web sites, etc (see references). Many data for the U.S. deposits are available in the literature, from the Coal Research Station of Pennsylvania State University or from the U.S. CHEM computer file of the U.S. Geological Survey. Only figures relevant to the most important deposits of low-rank coal are reported.

All data collected from different sources are shown in table 4.1/2/3. Table 4.1 summarizes the main world regions production of low-rank coal, including also the typical production (reference to be made to Appendix A-3 for further details on each country). More detailed data relevant to the main U.S. low-rank coal deposits are reported in table 4.2, whilst table 4.3 summarizes detailed characteristics available for the other countries.

Table 4.1 – Production and characteristics of the world's lignites and brown coals (WEC, 2001; Couch, 1988) (1)

	Production, Mt/y (1999)	**Typical Characteristics**
USA	77	H_2O 16-36% Ash 5-24% LHV 21-30 MJ/kg
Germany	161	H_2O 30-60% Ash 7-25% LHV 7-16 MJ/kg
Turkey	65	H_2O 46% Ash 22% LHV 5 MJ/kg
Australia	66	H_2O 50-65% Ash 1-3% LHV 8-12 MJ/kg
Bulgaria	26	H_2O 40-50% Ash 20-30% LHV 5-8 MJ/kg
China	45	H_2O 35-50% Ash 15-40% LHV 9-12 MJ/kg
Czech Republic	45 (*)	H_2O 35-40% Ash 17-25% LHV 9-13 MJ/kg
Greece	62	H_2O 50-65% Ash 5-20% LHV 5-11 MJ/kg

Poland	61	H_2O 50-55% Ash 5-10% LHV 5-10 MJ/kg
Russia	83	H_2O 35-40% Ash 7-15% LHV 6-15 MJ/kg
Thailand	18	H_2O 20-35% Ash 10-35% LHV 5-10 MJ/kg

Notes (1): Source: The potential for coal use in Pakistan (IEA Clean Coal Centre).
(*) mainly classified as subbituminous in the WEC listing

Table 4.2 – Properties and composition of U.S. low-rank coal deposits (2).

Country	**Colorado**	**Illinois**	**Montana**	**Montana**	**North Dakota**	**Texas**	**Utah**	**Wyoming**	**West Virginia**
Rank (1)	Sub	Sub	Lig	Sub	Lig	Sub	Sub	Sub	Sub
Proximate, wt %:									
Moisture	19.69	17.69	35.92	19.84	31.70	24.52	16.66	24.12	18.21
Volatile matter, dry	38.04	38.46	54.95	39.02	41.60	42.28	40.56	52.57	39.12
Fixed Carbon, dry	56.56	51.39	35.58	51.82	46.91	47.44	51.31	23.39	38.39
Ash, dry	5.40	10.14	9.47	9.16	11.49	10.28	8.14	24.04	22.48
Ultimate, wt %:									
Carbon	72.00	70.78	64.78	68.39	63.63	66.68	70.25	53.07	56.27
Hydrogen	4.76	5.22	4.42	4.64	4.29	4.45	4.90	4.09	4.49
Nitrogen	1.63	1.39	0.75	0.99	0.72	0.33	0.07	0.55	1.09
Chlorine	0.02	0.00	0.00	0.02	0.00	0.03	0.00	0.00	0.02
Sulfur	0.39	2.59	0.45	0.79	1.22	0.68	1.32	0.72	1.01
Ash	5.40	10.14	9.47	9.16	11.49	10.28	8.14	24.04	22.48
Oxygen	15.80	9.87	20.13	16.01	18.65	17.55	15.32	17.53	14.62
Heating Value:									
Gross Dry, kJ/kg	28,863	29,481	25,146	27,177	25,149	26,672	28,307	21,671	23,148

Notes: (1) lig = lignite; sub = sub-bituminous. (2) Source: Coal Research Station of Pennsylvania State University.

Table 4.3 – Properties and composition of low-rank coal deposits for countries other than U.S.A..

Country	**Canada** (2)	**Canada** (2)	**Germany** (5)	**Germany** (5)	**Turkey** (6)	**India** (8)	**India** (8)	**Pakistan** (9)
Location	Alberta	Saskat-chewamn	Garantie	Mittel-punkt	TKI	Nevyeli	Kutch	Sindh
Rank (1)	Sub	Lig	Lig	Lig	Lig	Lig	Lig	Lig/Sub
Proximate, wt %:								
Moisture	20.00	33.54	50.70	55.50	46.56	47.00	36.00	9.7-38.1
Volatile matter, dry	NA	NA	54.00	54.00	1.84	NA	NA	18.3-38.6
Fixed Carbon, dry	NA	NA	38.90	29.15	36.54	NA	NA	9.8-38.2
Ash, dry	13.93	13.46	7.10	16.85	21.71	13.09	23.65	4.3-49
Ultimate, wt %:								
Carbon	73.93(4)	74.67(4)	63.54	56.54	52.99	48.78	44.66	NA
Hydrogen	4.26(4)	4.85(4)	4.65	4.16	4.02	4.36	4.78	NA
Nitrogen	0.91(4)	1.26(4)	0.74	0.67	19.89 (7)	0.45	1.39	NA
Sulfur	0.39(4)	0.92(4)	0.45	1.24	1.38	2.80	3.55	NA
Ash	NA	NA	7.10	16.85	21.72	13.09	23.65	NA
Oxygen	20.51(4)	18.30(4)	23.44	20.47	(7)	30.52	21.97	NA
Chlorine	NA	NA	0.05	0.06	NA	NA	NA	NA
Fluorite	NA	NA	0.03	0.01	NA	NA	NA	NA
Heating Value:								
LHV, kJ/kg	17,810(3)	13,560(3)	10,500	8,100	5,024	9,330	9,330	12,800-21,300

Notes: (1) lig = lignite; sub = sub-bituminous. (2) Source: Canadian Clean Power Coalition Studies on CO2 capture and storage (March 2004). (3) Calculated from the HHV using a conversion factor indicated in the 7th edition of "Technical Data on Fuel". (4) As received. (5) BoA 2 Projekt. (6) Mining Analysis and Tech. Department. (7) $O_2 + N_2$. (8) Ohio Super Computer Center (OSC) web site. (9) Geological Survey of Pakistan web site.

Table 4.3 – Properties and composition of Australian low-rank coal deposits.

Country	**Australia**	**Australia**	**Australia**	**Australia**	**Australia**	**Australia**	**Australia**	**Australia**
Location	Gippsland, Yallorun	Gippsland, Morwell	Gippsland, Latrobe	Lochiel	Kingston	Leigh Ck.	Esperance	Victoria, Morwell
Rank (1)	Lig	Lig	Lig	Lig	Lig	Lig	Lig	Lig
Proximate, wt %:								
Moisture	65.50	60.10	51.70	62.00	57.00	31.00	66.00	60.00
Volatile matter, dry	51.10	48.20	48.80	58.70	54.17	34.86	54.40	49.14
Fixed Carbon, dry	47.20	48.60	46.80	39.13	43.43	58.86	41.55	50.34
Ash, dry	1.70	3.20	4.40	2.17	2.40	6.28	4.05	0.52
Ultimate, wt %:								
Carbon	66.70	67.80	66.70	67.99	65.97	66.64	55.36	69.04
Hydrogen	4.70	4.80	4.70	5.48	4.98	3.84	5.09	4.87
Nitrogen	NA	NA	NA	0.68	0.59	1.69	30.22	0.60
Sulfur	0.30	0.40	0.50	3.13	3.22	0.84	5.28	0.30
Ash	NA	NA	NA	2.17	2.40	6.28	4.05	0.52
Oxygen	NA	NA	NA	23.48	22.84	20.71	NA	24.67
Chlorine	NA	NA	NA	NA	NA	NA	NA	NA
Fluorite	NA	NA	NA	NA	NA	NA	NA	NA
Heating Value:								
Gross Dry, kJ/kg	25,900	26,500	26,200	9,000 (3)	10,100 (3)	15,200 (3)	7,600 (3)	10,600 (3)

Notes: (1) lig = lignite; sub = sub-bituminous. (2) Calculated from the HHV using a conversion factor indicated in the 7th edition of "Technical Data on Fuel". (3) As-received basis.

4.1 Composition of Ash

Table 4.4 summarizes ash characteristics mainly for the U.S. low-rank-coal deposits. Only data from countries that have large coal deposits are shown. Main source for these data is U.S. Bureau of Mines; U.S. data were included in the Coal Conversion Systems Technical Data Book (Prepared for U.S. Department of Energy, March 1984).

Table 4.4 – Ash composition of low-rank coal deposits.

Country	**Arizona**	**Colorado**	**Montana**	**Montana**	**New Mexico**	**North Dakota**	**Texas**	**Wyoming**
Rank (1)	Sub	Sub	Lig	Sub	Sub	Lig	Lig	Sub
Source	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)
Ash Analysis, wt %:								
SiO_2	54.1	18.8	30.7	35.7	58.2	4.9	32.5	41.0
Al_2O_3	35.4	12.1	19.6	20.3	27.7	4.8	19.3	15.0
Fe_2O_3	5.4	10.6	18.9	5.3	4.2	14.0	5.3	2.5
TiO_2	-	0.5	1.1	0.6	-	-	1.6	-
P_2O_5	-	-	-	0.6	-	0.10	0.08	0.6
CaO	2.2	23.4	11.3	16.4	4.2	26.0	22.2	15.0
MgO	0.5	6.6	3.7	7.0	0.4	8.40	3.2	3.80
Na_2O	-	-	1.9	0.4	-	2.65	-	0.71
K_2O	-	-	0.5	0.9	-	<0.10	-	1.1
SO_3	1.6	26.5	12.2	12.8	3.9	39.0	14.3	10.0
Initial Deformation	N.A.	1221	1121	N.A.	N.A.	N.A.	N.A.	N.A.
Softening	N.A.	1243	1149	1227	N.A.	N.A.	N.A.	N.A.
Fluid	N.A.	1271	1178	N.A.	N.A.	N.A.	N.A.	N.A.

Notes: (1) lig = lignite; sub = sub-bituminous. (2) Coal Conversion Systems Technical Data Book.

Table 4.4 – Ash composition of low-rank coal deposits.

Country	**Germany** Garantie	**Germany** Mittelp.	**Australia** Gippsland, Yallorun	**Australia** Gippsland, Morwell	**Australia** Gippsland, Latrobe			
Rank (1)	Lig	Lig	Lig	Lig	Lig			
Source	(2)	(2)						
Ash Analysis, wt %:								
SiO_2	4.0/54.0	7.0/70.0	26.9	16.4	8.6			
Al_2O_3	1.7/22.0	1.0/22.0	8.6	3.4	5.0			
Fe_2O_3	5.0/26.0	4.0/30.0	20.0	9.3	19.8			
TiO_2	0.2/2.5	0.1/2.5	0.5	0.3	0.6			
P_2O_5	-	-	-	-	-			
CaO	7.0/34.0	7.0/45.0	6.0	24.7	25.1			
MgO	3.0/17.0	1.8/17.0	14.3	14.2	8.6			
Na_2O	1.0/9.4	0.1/9.4	6.5	4.9	3.5			
K_2O	0.4/1.5	0.1/1.5	0.3	0.3	0.2			
SO_3	11.0/24.0	10/75	17.1	26.6	28.6			
Initial Deformation	N.A.	N.A.	N.A.	N.A.	N.A.			
Softening	N.A.	N.A.	N.A.	N.A.	N.A.			
Fluid	N.A.	N.A.	N.A.	N.A.	N.A.			

Notes: (1) lig = lignite; sub = sub-bituminous. (2) BoA 2 Projekt.

4.2 Heavy metals in low-rank coals

Heavy metals can be present as trace elements in coals and their quantification can be very difficult. Generally these elements have relatively large ranges in concentrations and can be found in distinct phases in the coals.

Table 4.5 summarizes the typical range of elements determined for a large quantity of USA coals. These elements have been selected on the basis of the priority as potential pollutant of the EPA. Minimum and maximum values cannot be defined as absolute figures, but shall be considered as “minimum and maximum medium” data for the most common coals.

Table 4.5 – Trace elements in coal.

Trace elements	**Min Value** µg/g (1)	**Max Value** µg/g (1)
Antinomy	0.2	5
Arsenic	1	30
Beryllium	0.2	4
Cadmium	0.05	30
Chromium	0.5	30
Lead	2	20
Manganese	4	500
Mercury	0.01	0.8
Nickel	1.3	60
Selenium	0.1	8

Notes: (1) Whole coal basis.

5.0 SELECTION OF THE REFERENCE COAL FOR THE STUDY

Considerations made in the previous paragraphs lead the following main conclusions:

- Low-rank coal deposits are abundant all over the world, being 47% of the quantity recoverable deposits in the world mainly composed of lignite and sub-bituminous coal.
- The higher concentration of low-rank coal deposits is in the North America, Eastern Europe/Former U.S.S.R and Asia.
- 59.4 % of worldwide low-rank coal deposits is composed of sub-bituminous coal, the remaining 40.6 % being of lignite type.
- Germany is the world's largest brown coal producer/reserve, representing 20% of global production in 2001.
- Depending on the country, a wide range of coal-quality parameters is expected for the low-rank coals, both for the ultimate and proximate analyses.

Based on the above conclusions, the analysis of the different coal power plants alternatives will be made by assuming as a reference the "Garantie" German brown coal with the following variation ranges:

Moisture:	30%	to	60%
Ash (dry basis):	7%	to	25%
LHV:	7000	to	16000 kJ/kg

With reference to the ash composition, the "Garantie" German lignite shows a very wide variation of alkali (Na_2O, K_2O), SO_3 and Fe_2O_3 (reference to Table 4.4, paragraph 4.1).

Several literature studies demonstrated that:

- Fouling potential of ash is related to the alkali percentage;
- Slagging potential of ash is connected to the iron concentration;
- Fireside corrosion is related to the concentration in the ash of alkali iron and sulphur (corrosion results from the presence of molten sodium-potassium-iron sulfates).

The ash composition corresponding to the maximum percentage of the above components can represent a very severe operating condition for any coal power plant technology.

Metal temperature is an important corrosion-rate variable; this means that for the different boiler technologies is necessary to pay specific attention to this aspect, together with the material capability to operate under high stresses at ever increasing temperature. Corrosion problems are more and more important when increasing the firing temperature of the boiler, leading to possible severe constraints on both the material selection (high chromium content) and the equipment life.

Purpose of the study is to compare performances and costs of different Power Plant technologies that use low rank coal as primary fuel. The wide range of the ash composition, shown in Table 4.4 for the selected coal, leads to possible constraints in the design of some specific power plant technology.

Therefore, in order to develop a study on coal power plants which process low rank fuel with characteristics that are common to the majority of the coals, the range of the most critical components is reduced as follows:

- Fe_2O_3: 5.0/16.0 %
- Na_2O: 1.0/4.0 %
- SO_3: 11.0/15.0 %

In any case, it has to be taken into account that a power plant burning lignite coal with a wide variation of the characteristics requires a frequent monitoring of the composition. If the coal composition becomes severe, with respect to design parameter, the power plant will be generally capable to process the different coal by adjusting the combustion temperature of the boilers, thus affecting the performances of the plant.

REFERENCES

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- World Energy Council web site (http://www.worldenergy.org/wec-geis/).
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- World Coal Quality Inventory web site (http://geode.usgs.gov/).
- U.S. Department of Energy web site (http://www.doe.gov/engine/content.do).
- Coal Market Data and Statistics (http://power.about.com/od/coalindustry/).
- Canadian Clean Power Coalition Studies on CO_2 capture and storage (March, 2004).
- Ohio Super Computer Centre (OSC) web site: (http://www.osc.edu/research/pcrm/emissions/coal.shtml).
- Geological Survey of Pakistan (http://www.gsp.gov.pk/).
- World Coal Institute (WCI) web site (http://www.wci-coal.com/web/bl_content.php?menu_id=0.0).
- IEA Clean Coal Center: "The potential for coal use in Pakistan" (Gordon Couch, April 2004).

APPENDIX A-1

Summary of world estimate recoverable coal
(High rank and low rank coals)

Table A-1 World Estimated Recoverable Coal
(Million Short Tons)

Energy Information Administration			
International Energy Annual 2002			
Table Posted: May 21, 2004			
Next Update: March 2005			
A-1 World Estimated Recoverable Coal			
(Million Short Tons)			
Region/Country	**Recoverable Anthracite and Bituminous**	**Recoverable Lignite and Subbituminous**	**Total Recoverable Coal**
Bermuda			
Canada	3,826	3,425	7,251
Greenland	0	202	202
Mexico	948	387	1,335
Saint Pierre and Miquelon			
United States	125,855	145,822	271,677
North America	**130,629**	**149,836**	**280,464**
Antarctica			
Antigua and Barbuda			
Argentina	0	474	474
Aruba			
Bahamas, The			
Barbados			
Belize			
Bolivia	1	0	1
Brazil	0	13,149	13,149
Cayman Islands			
Chile	34	1,268	1,302
Colombia	6,908	420	7,328
Costa Rica			
Cuba			
Dominica			
Dominican Republic			
Ecuador	0	26	26
El Salvador			
Falkland Islands			
French Guiana			
Grenada			
Guadeloupe			
Guatemala			
Guyana			
Haiti			
Honduras			
Jamaica			
Martinique			
Montserrat			
Netherlands Antilles			
Nicaragua			
Panama			
Paraguay			

Table A-1 World Estimated Recoverable Coal
(Million Short Tons)

Region/Country	Recoverable Anthracite and Bituminous	Recoverable Lignite and Subbituminous	Total Recoverable Coal
Peru	1,058	110	1,168
Puerto Rico			
Saint Kitts and Nevis			
Saint Lucia			
Saint Vincent/Grenadines			
Suriname			
Trinidad and Tobago			
Turks and Caicos Islands			
Uruguay			
Venezuela	528	0	528
Virgin Islands, U.S.			
Virgin Islands, British			
Central & South America	**8,530**	**15,448**	**23,977**
Austria	0	28	28
Belgium			
Bosnia and Herzegovina			
Croatia	7	36	43
Denmark			
Faroe Islands			
Finland			
Former Yugoslavia			
France	24	15	40
Germany	25,353	47,399	72,753
Germany, East			
Germany, West			
Gibraltar			
Greece	0	3,168	3,168
Iceland			
Ireland	15	0	15
Italy	0	37	37
Luxembourg			
Macedonia, TFYR			
Malta			
Netherlands	548	0	548
Norway	0	1	1
Portugal	3	36	40
Slovenia	0	303	303
Spain	220	507	728
Sweden	0	1	1
Switzerland			
Turkey	306	3,760	4,066
United Kingdom	1,102	551	1,653
Yugoslavia	71	17,849	17,919
Western Europe	**27,650**	**73,693**	**101,343**
Albania			
Armenia			
Azerbaijan			
Belarus			

Table A-1 World Estimated Recoverable Coal
(Million Short Tons)

Region/Country	Recoverable Anthracite and Bituminous	Recoverable Lignite and Subbituminous	Total Recoverable Coal
Bulgaria	14	2,974	2,988
Czech Republic	2,330	3,929	6,259
Estonia			
Former Czechoslovakia			
Former U.S.S.R.			
Georgia			
Hungary	0	1,209	1,209
Kazakhstan	34,172	3,307	37,479
Kyrgyzstan	0	895	895
Latvia			
Lithuania			
Moldova			
Poland	22,377	2,050	24,427
Romania	1	1,605	1,606
Russia	54,110	118,964	173,074
Slovakia	0	190	190
Tajikistan			
Turkmenistan			
Ukraine	17,939	19,708	37,647
Uzbekistan	1,102	3,307	4,409
Eastern Europe & Former U.S.S.R.	**132,046**	**158,138**	**290,183**
Bahrain			
Cyprus			
Iran	1,885	0	1,885
Iraq			
Israel			
Jordan			
Kuwait			
Lebanon			
Oman			
Qatar			
Saudi Arabia			
Syria			
United Arab Emirates			
Yemen			
Middle East	**1,885**	**0**	**1,885**
Algeria	44	0	44
Angola			
Benin			
Botswana	4,740	0	4,740
Burkina Faso			
Burundi			
Cameroon			
Cape Verde			
Central African Republic	0	3	3
Chad			
Comoros			
Congo (Brazzaville)			

Table A-1 World Estimated Recoverable Coal
(Million Short Tons)

Region/Country	Recoverable Anthracite and Bituminous	Recoverable Lignite and Subbituminous	Total Recoverable Coal
Congo (Kinshasa)	97	0	97
Cote d'Ivoire (IvoryCoast)			
Djibouti			
Egypt	0	24	24
Equatorial Guinea			
Eritrea			
Ethiopia			
Gabon			
Gambia, The			
Ghana			
Guinea			
Guinea-Bissau			
Kenya			
Lesotho			
Liberia			
Libya			
Madagascar			
Malawi	0	2	2
Mali			
Mauritania			
Mauritius			
Morocco			
Mozambique	234	0	234
Namibia			
Niger	77	0	77
Nigeria	23	186	209
Reunion			
Rwanda			
Saint Helena			
Sao Tome and Principe			
Senegal			
Seychelles			
Sierra Leone			
Somalia			
South Africa	54,586	0	54,586
Sudan			
Swaziland	229	0	229
Tanzania	220	0	220
Togo			
Tunisia			
Uganda			
Western Sahara			
Zambia	11	0	11
Zimbabwe	553	0	553
Africa	**60,816**	**216**	**61,032**
Afghanistan	73	0	73
American Samoa			
Australia	46,903	43,585	90,489
Bangladesh			

Table A-1 World Estimated Recoverable Coal
(Million Short Tons)

Region/Country	Recoverable Anthracite and Bituminous	Recoverable Lignite and Subbituminous	Total Recoverable Coal
Bhutan			
Brunei			
Burma	2	0	2
Cambodia			
China	68,564	57,651	126,215
Cook Islands			
Fiji			
French Polynesia			
Guam			
Hawaiian Trade Zone			
Hong Kong			
India	90,826	2,205	93,031
Indonesia	871	5,049	5,919
Japan	852	0	852
Kiribati			
Korea, North	331	331	661
Korea, South	86	0	86
Laos			
Macau			
Malaysia	4	0	4
Maldives			
Mongolia			
Nauru			
Nepal	2	0	2
New Caledonia	2	0	2
New Zealand	36	594	631
Niue			
Pakistan	0	2,497	2,497
Papua New Guinea			
Philippines	0	366	366
Samoa			
Singapore			
Solomon Islands			
Sri Lanka			
Taiwan	1	0	1
Thailand	0	1,398	1,398
Tonga			
U.S. Pacific Islands			
Vanuatu			
Vietnam	165	0	165
Wake Island			
Asia & Oceania	**208,719**	**113,675**	**322,394**
World Total	**570,275**	**511,005**	**1,081,279**

APPENDIX A-2

Summary of world estimate recoverable coal
(Sub bituminous and lignite coals, 1999)

Table A.2 Coal: proved recoverable reserves at end-1999

	million tonnes			
	Bituminous including anthracite	**Sub-bituminous**	**Lignite**	**TOTAL**
Algeria	40			40
Botswana	4 300			4 300
Central African Republic			3	3
Congo (Democratic Rep.)	88			88
Egypt (Arab Rep.)		22		22
Malawi		2		2
Morocco	N			N
Mozambique	212			212
Niger	70			70
Nigeria	21	169		190
South Africa	49 520			49 520
Swaziland	208			208
Tanzania	200			200
Zambia	10			10
Zimbabwe	502			502
Total Africa	**55 171**	**193**	**3**	**55 367**
Canada	3 471	871	2 236	6 578
Greenland		183		183
Mexico	860	300	51	1 211
United States of America	115 891	101 021	33 082	249 994
Total North America	**120 222**	**102 375**	**35 369**	**257 966**
Argentina		430		430
Bolivia	1			1
Brazil		11 929		11 929
Chile	31	1 150		1 181
Colombia	6 267	381		6 648
Ecuador			24	24
Peru	960		100	1 060
Venezuela	479			479
Total South America	**7 738**	**13 890**	**124**	**21 752**
Afghanistan	66			66
China	62 200	33 700	18 600	114 500
India	82 396		2 000	84 396
Indonesia	790	1 430	3 150	5 370
Japan	773			773
Kazakhstan	31 000		3 000	34 000
Korea (Democratic People's Rep.)	300	300		600
Korea (Republic)	78			78
Kyrgyzstan			812	812
Malaysia	4			4
Mongolia				
Myanmar (Burma)	2			2
Nepal	2			2
Pakistan		2 265		2 265
Philippines		232	100	332
Taiwan, China	1			1
Thailand			1 268	1 268
Turkey	278	761	2 650	3 689
Uzbekistan	1 000		3 000	4 000
Vietnam	150			150
Total Asia	**179 040**	**38 688**	**34 580**	**252 308**

Table A.2 Coal: proved recoverable reserves at end-1999

	million tonnes			
	Bituminous including anthracite	**Sub-bituminous**	**Lignite**	**TOTAL**
Albania				
Austria			25	25
Bulgaria	13	233	2 465	2 711
Croatia	6		33	39
Czech Republic	2 114	3 414	150	5 678
France	22		14	36
Germany	23 000		43 000	66 000
Greece			2 874	2 874
Hungary		80	1 017	1 097
Ireland	14			14
Italy		27	7	34
Netherlands	497			497
Norway		1		1
Poland	20 300		1 860	22 160
Portugal	3		33	36
Romania	1	35	1 421	1 457
Russian Federation	49 088	97 472	10 450	157 010
Serbia, Montenegro	64	1 460	14 732	16 256
Slovakia			172	172
Slovenia		40	235	275
Spain	200	400	60	660
Sweden		1		1
Ukraine	16 274	15 946	1 933	34 153
United Kingdom	1 000		500	1 500
Total Europe	**112 596**	**119 109**	**80 981**	**312 686**
Iran (Islamic Rep.)	1 710			1 710
Total Middle East	**1 710**			**1 710**
Australia	42 550	1 840	37 700	82 090
New Caledonia	2			2
New Zealand	33	206	333	572
Total Oceania	**42 585**	**2 046**	**38 033**	**82 664**
TOTAL WORLD	**519 062**	**276 301**	**189 090**	**984 453**

Notes:

1. A quantification of proved recoverable reserves for Mongolia and Albania is not available
2. The data shown against Serbia, Montenegro include reserves in Bosnia-Herzogovina and the Former Yugoslav Republic of Macedonia
3. Sources: WEC Member Committees, 2000/2001; data reported for previous WEC Surveys of Energy Resources; national and international published sources

APPENDIX A-3

Summary of world estimate coal production
(Sub bituminous and lignite coals, 1999)

Table 1.3 Coal: 1999 production				
	thousand tonnes			
	Bituminous	Sub-bituminous	Lignite	Total
Algeria	25			25
Botswana	945			945
Congo (Democratic Rep.)	50			50
Egypt	200			200
Malawi		44		44
Morocco	129			129
Mozambique	18			18
Niger	168			168
Nigeria		20		20
South Africa	223 510			223 510
Swaziland	426			426
Tanzania	5			5
Zambia	128			128
Zimbabwe	4 977			4 977
Total Africa	**230 581**	**64**		**230 645**
Canada	36 538	24 300	11 659	72 497
Mexico	2 366	7 678		10 044
United States of America	568 260	352 260	76 570	997 090
Total North America	**607 164**	**384 238**	**88 229**	**1 079 631**
Argentina	337			337
Brazil	5 602			5 602
Chile	170	470		640
Colombia	32 754			32 754
Peru	20			20
Venezuela	6 500			6 500
Total South America	**45 383**	**470**		**45 853**
Afghanistan	2			2
Bhutan	50			50
China	985 000		45 000	1 030 000
Georgia	12			12
India	292 203		22 212	314 415
Indonesia	70 703			70 703
Japan	3 906			3 906
Kazakhstan	56 436		1 763	58 199
Korea (Democratic People's Rep.)	60 000	21 500		81 500
Korea (Republic)		4 197		4 197
Kyrgyzstan	135		280	415
Laos	202			202
Malaysia		309		309
Mongolia	1 423		3 529	4 952
Myanmar (Burma)	13		27	40
Nepal			9	9
Pakistan		3 307		3 307
Philippines		1 028		1 028
Taiwan, China	90			90
Tajikistan		19		19
Thailand			18 270	18 270
Turkey	1 990		65 050	67 040
Uzbekistan	89		2 864	2 953
Vietnam	8 830			8 830
Total Asia	**1 481 084**	**30 360**	**159 004**	**1 670 448**
Albania			33	33
Austria			1 137	1 137
Bosnia-Herzogovina			1 850	1 850
Bulgaria	90		25 940	26 030
Croatia	15			15
Czech Republic	14 419	44 278	512	59 209
FYR Macedonia			8 400	8 400
France	4 533		558	5 091
Germany	40 500		161 282	201 782

Table 1.3 Coal: 1999 production				
	thousand tonnes			
	Bituminous	**Sub-bituminous**	**Lignite**	**Total**
Greece			61 900	61 900
Hungary	700	6 500	7 700	14 900
Italy			19	19
Norway		400		400
Poland	110 200		60 800	171 000
Romania	N	2 751	20 131	22 882
Russian Federation	166 000		83 400	249 400
Serbia, Montenegro	49		30 451	30 500
Slovakia			3 748	3 748
Slovenia		758	3 804	4 562
Spain	13 200	3 700	8 500	25 400
Ukraine	34 871	46 176	1 182	82 229
United Kingdom	37 077			37 077
Total Europe	**421 654**	**104 563**	**481 347**	**1 007 564**
Iran (Islamic Rep.)	1 500			1 500
Total Middle East	**1 500**			**1 500**
Australia	222 000	16 200	65 800	304 000
New Zealand	1 630	1 670	210	3 510
Total Oceania	**223 630**	**17 870**	**66 010**	**307 510**
TOTAL WORLD	**3 010 996**	**537 565**	**794 590**	**4 343 151**

Notes:

1. Sources: WEC Member Committees, 2000/2001; BP Statistical Review of World Energy 2001; Energy - Monthly Statistics, Eurostat; World Mineral Statistics 1995-1999, British Geological Survey; national sources; estimates by the editors