CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS

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CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS

Key Messages

- This study provides an up-to-date assessment of the performance and costs of coal-based power and hydrogen plants with and without CO_2 capture.
- The thermal efficiencies of power plants with CCS based on pulverised coal firing with oxy-combustion or post combustion capture, and IGCC with pre-combustion capture are all around 35% (LHV basis), which is around 9 percentage points lower than a reference pulverised coal plant without capture.
- The levelised cost of electricity is about 92 €/MWh for plants with oxy-combustion or post combustion capture and 115 €/MWh for IGCC plants with pre-combustion capture. This is about 75-125% higher than the reference pulverised coal plant without CCS.
- Costs of CO_2 emission avoidance compared to the reference plant are 60-100 €/t.
- The rate of CO_2 capture in oxy-combustion and IGCC plants could be increased from 90% to 98%, while reducing the cost per tonne of CO_2 emissions avoided by 3%.
- Net CO_2 emissions of a plant with post combustion capture could be reduced to zero by co-firing 10% biomass (on a carbon basis), without increasing the cost per tonne of CO_2 avoided, depending on the price of biomass.
- The raw water requirements of the pulverised coal power plants with CCS could be reduced to near zero by using seawater or air cooling. For the ambient conditions considered in this study this would have little impact on the efficiency (<1 percentage point) and capital cost (<2%).
- The efficiency of producing hydrogen by coal gasification with CCS would be 58% LHV basis (65% HHV basis) and the levelised cost of production would be 16.1 €/GJ LHV basis (13.6 €/GJ HHV basis).

Background to the Study

In recent years IEAGHG has undertaken a series of studies on the performance and costs of plants incorporating the three leading CO_2 capture technologies: post combustion, oxy-combustion and pre-combustion capture. In the time since those studies were undertaken there have been significant technological advances and substantial increases in estimated plant costs. IEAGHG therefore decided to undertake a wholly new study on costs of capture at coal based plants producing the two leading low-carbon energy carriers, namely electricity and hydrogen. This study provides a baseline for possible future studies on plants in other countries, plants using other capture processes and capture in industries other than power and hydrogen generation. The study was carried out for IEAGHG by Foster Wheeler.

It should be noted that the focus of this study is to provide an up-to-date technical and economical assessment of coal-fired power and hydrogen plants with CCS. The study does not aim to provide a definitive comparison of different technologies or technology suppliers because such comparisons are strongly influenced by specific local constraints and by market factors, which can be subject to rapid changes.

Scope of Work

Study cases

The study assesses the design, performance and costs of the following coal based power generation plants.

- Supercritical pulverised coal power plant without CO_2 capture (reference plant)
- Supercritical pulverised coal power plant with post combustion capture based on CANSOLV solvent scrubbing
- Supercritical pulverised coal power plant using oxy-combustion
- IGCC plant based on GE slurry feed, oxygen blown gasification and pre-combustion capture using Selexol solvent scrubbing
- IGCC plant based on Shell dry feed, oxygen blown gasification and pre-combustion capture using Selexol solvent scrubbing
- IGCC plant based on MHI dry feed, air blown gasification and pre-combustion capture using Selexol solvent scrubbing

The study also assesses the following hydrogen production plants, all based on GE oxygen blown gasification and Selexol solvent scrubbing:

- Plant with high net electricity co-production, including two $130MW_e$ E class gas turbines
- Plant with intermediate net electricity co-production, including two $77MW_e$ F class gas turbines
- Plant with low electricity co-production, including a PSA off-gas fired boiler.

All of these baseline plants have 90% CO_2 capture. This is expected to be adequate for early CCS plants but some overall energy system models have shown that in the longer term, when national and global emission limits will be tighter, the emissions of the residual non-captured CO_2 may be a significant constraint on the amount CCS, particularly coal-based CCS, that can be accommodated in the overall energy system. If CCS plants emit significant amounts of CO_2 it will be necessary to apply even tighter emission controls to other areas of human activity, such as transport and agriculture, which could involve very high greenhouse gas abatement costs. This study assessed the technical feasibility and costs of achieving a higher level of CO_2 capture (around 98%) in oxy-combustion and IGCC plants. In the oxy-combustion case this was achieved by passing the vent gas from CO_2 purification through a membrane separation unit. For gasification based plants an additional MDEA solvent scrubbing stage was added after the Selexol scrubber.

An alternative way of achieving near-zero net emissions of CO_2 would be to co-fire some biomass, assuming that biomass that is produced in a sustainable way has near-zero net emissions of CO_2. Biomass could be used in post, pre and oxy-combustion capture plants. This study assesses a plant with 90% post combustion capture and sufficient co-firing of woody biomass to achieve zero net emissions.

Another possible constraint on the large scale application of CCS in some places may be water availability. To complement the base case plants which use natural draught cooling towers, sensitivity cases based on once-through sea water cooling and dry air cooling were assessed.

In addition to the sensitivities to percentage CO_2 avoidance and the type of cooling system, the study also assessed the sensitivities to various economic parameters, including the coal price, capacity factor, discount rate, plant life, CO_2 transport and storage cost and CO_2 emissions cost.

Technical and economic basis

The technical and economic basis for the study is described in detail in the main study report. The main base case assumptions are:

- Greenfield site, Netherlands coastal location
- 9C ambient temperature
- Natural draught cooling towers
- Eastern Australian internationally traded bituminous coal (0.86% sulphur a.r., 25.87 MJ/kg LHV)
- Coal price: €2.5/GJ LHV basis (equivalent to €2.39/GJ HHV basis)
- 2Q 2013 costs
- Discount rate: 8% (constant money values)
- Operating life: 25 years
- Construction time: Pulverised coal plants - 3 years, Gasification plants – 4 years
- Capacity factor: Pulverised coal plants – 90%, Gasification plants – 85%
- CO_2 transport and storage cost: €10/t stored

The pulverised coal plant without capture is based on a single boiler, a net output of around $1000MW_e$ and state-of-the-art steam conditions (27MPa, 600/620C) as used in new large coal fired power plants in Europe and Japan. The pulverised coal plants with post combustion and oxy-combustion capture have the same coal feed rate but lower net power outputs of 820-840 MW_e due to the energy consumption for capture. The coal feed rate of the IGCC plants is determined by the fuel feed rate of the two gas turbines, which are state of the art 50Hz F-class turbines suitable for high hydrogen content gas. The net power outputs of the IGCC plants are in the range of 800-880MW_e, i.e. similar to the pulverised coal plants with capture.

Cost definitions

Capital cost

The cost estimates were derived in general accordance with the White Paper "Toward a common method of cost estimation for CO_2 capture and storage at fossil fuel power plants", produced collaboratively by authors from IEAGHG, EPRI, USDOE/NETL, Carnegie Mellon University, IEA, the Global CCS Institute and Vattenfall[1].

The capital cost is presented as the Total Plant Cost (TPC) and the Total Capital Requirement (TCR).

TPC is defined as the installed cost of the plant, including project contingency. In the report TPC is broken down into:

- Direct materials
- Construction
- EPC services
- Other costs
- Contingency

TCR is defined as the sum of:

- Total plant cost (TPC)
- Interest during construction
- Owner's costs
- Spare parts cost
- Working capital
- Start-up costs

For each of the cases the TPC has been determined through a combination of licensor/vendor quotes, the use of Foster Wheeler's in-house database and the development of conceptual estimating models, based on the specific characteristics, materials and design conditions of each item of equipment in the plant. The other components of the TCR have been estimated mainly as percentages of other cost estimates in the plant. The overall estimate accuracy is in the range of +35/-15%.

[1] Toward a common method of cost estimation for CO_2 capture and storage at fossil fuel power plants, IEAGHG Technical Review 2013/TR2, March 2013.

Levelised cost of electricity

Levelised Cost of Electricity (LCOE) is widely recognised as a convenient tool for comparing the unit costs of different technologies over their economic lifetime. LCOE is defined as the price of electricity which enables the present value from all sales of electricity over the economic lifetime of the plant to equal the present value of all costs of building, maintaining and operating the plant over its lifetime. LCOE in this study was calculated assuming constant (in real terms) prices for fuel and other costs and constant operating capacity factors throughout the plant lifetime, apart from lower capacity factors in the first two years of operation.

The Levelised Cost of Hydrogen (LCOH) is calculated in the same way except that it is necessary to take into account the revenue from the sale of electricity co-product. It was assumed that the value of the electricity co-product is the cost of production in the IGCC plant that uses the same gasification and CO_2 capture technology as the hydrogen production plants, i.e. the GE gasification plant. If the lowest cost CCS power generation technology had been used to value the electricity output, the LCOH would have been higher.

Cost of CO_2 avoidance

Costs of CO_2 avoidance were calculated by comparing the CO_2 emissions per kWh and the levelised costs of electricity of plants with capture and a reference plant without capture.

$$CO_2 \text{ avoidance cost (CAC)} = \frac{LCOE_{ccs} - LCOE_{Reference}}{CO_2 \text{ Emission}_{Reference} - CO_2 \text{ Emission}_{ccs}}$$

Where:
CAC is expressed in Euro per tonne of CO_2
LCOE is expressed in Euro per MWh
CO_2 emission is expressed in tonnes of CO_2 per MWh

A pulverised coal plant without capture was used as the reference plant in all cases because the current power plant market indicates that this would in most cases be the preferred technology for coal fired plants without capture. The energy efficiency penalty for capture and the cost of CO_2 avoidance would be different if an alternative reference plant was used, for example an IGCC or a gas fired plant without capture.

Findings of the Study

Power generation plants

Plant performance

A summary of the performance of the baseline power plants with and without capture is given in Table 1.

Table 1 Power plant performance summary, pulverised coal plants

	Net power output	CO_2 captured	CO_2 emissions	Efficiency		Efficiency penalty for capture (LHV)
				HHV	LHV	
	MW	kg/MWh	kg/MWh	%	%	% points
Pulverised coal						
No capture (reference plant)	1030	-	746	42.2	44.1	
Post combustion capture	822	840	93	33.6	35.2	8.9
Oxy-combustion	833	823	92	34.1	35.7	8.4
IGCC						
Shell, oxygen-blown	804	837	93	33.9	35.5	8.6
GE, oxygen-blown	874	844	94	33.3	34.9	9.2
MHI, air-blown	863	842	104	33.2	34.8	9.3

The efficiencies and CO_2 emissions of the plants with capture are all broadly similar, the difference between the highest and lowest efficiency is less than 1 percentage point. Future technology improvements, such as development of improved solvents, air separation units and gas turbines, could change the relative efficiencies of the processes. For example, Cansolv reported that they have undertaken pilot plant tests with an improved solvent which is expected to achieve a 20% reduction in steam consumption compared to the figures they provided for use in this study and there would also be other cost improvements. They hope to commercialise this solvent in the near future.

The efficiency penalties for oxy-combustion and post combustion capture are towards the bottom of the range in published data[2], demonstrating the improvements in capture technologies and thermal integration. Most published studies compare the efficiencies of IGCC plants with capture against IGCC plants without capture, so the efficiency penalties in those studies are not comparable to those shown in table 1. However, the average efficiency of IGCCs with capture in this study is similar that of published studies[2].

CO_2 capture almost eliminates SOx emissions and also reduces NOx emissions, except for the post combustion capture case which has specific emissions about 25% higher than the reference plant, due to the lower thermal efficiency.

Capital cost

The capital costs of the plants are summarised in Table 2 and breakdowns of the total plant costs are given in Figures 1 and 2.

[2] Cost and performance of carbon dioxide capture from power generation. M. Finkenrath, IEA, 2011.

Table 2 Capital costs of electricity generation plants

	Total Plant Cost (TPC)	Total Capital Requirement (TCR)	TPC increase compared to the reference plant
	€/kW	€/kW	%
Pulverised coal plants			
No capture (reference plant)	1447	1887	
Post combustion capture	2771	3600	91
Oxy-combustion	2761	3583	91
IGCC plants			
Shell oxygen-blown	3157	4350	118
GE oxygen-blown	3074	4238	112
MHI air-blown	3046	4200	110

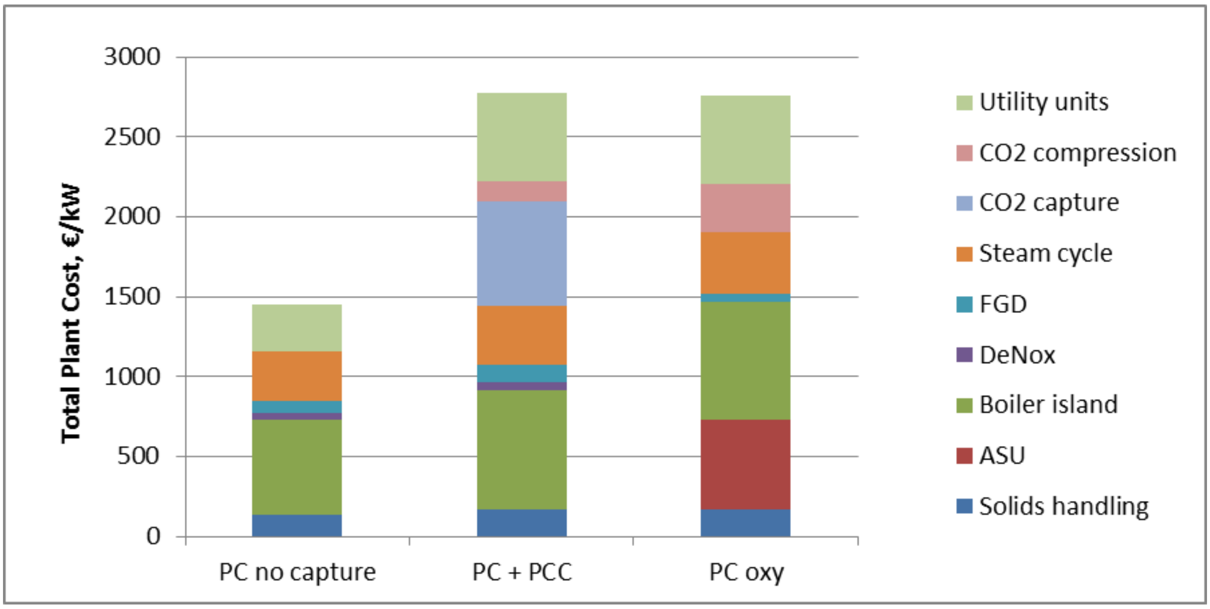

Figure 1 Specific Total Plant Cost of pulverised coal plants

Including capture increases the specific cost per kW_e of the pulverised coal cases by 91% compared to the pulverised coal reference plant. This cost increase is partly due to the cost of additional plant required for capture and partly due to the reduced net power output per unit of thermal capacity, e.g. boiler size. There is no significant difference between the specific capital costs of the post combustion capture (PCC) and oxy-combustion plants. The main cost of additional plant for oxy-combustion is the cost of the Air Separation Unit (ASU). The cost of the 'CO_2 compression' unit is higher in the oxy-combustion plant than in the post combustion plant because the volume of gas to be compressed is greater, due to the presence of impurities, and due to the cost of the CO_2 Processing Unit (CPU) which removes the impurities. The CPU is included in the 'CO_2 compression' unit cost in Figure 1, although it could also be considered to be a type of 'CO_2 capture' unit.

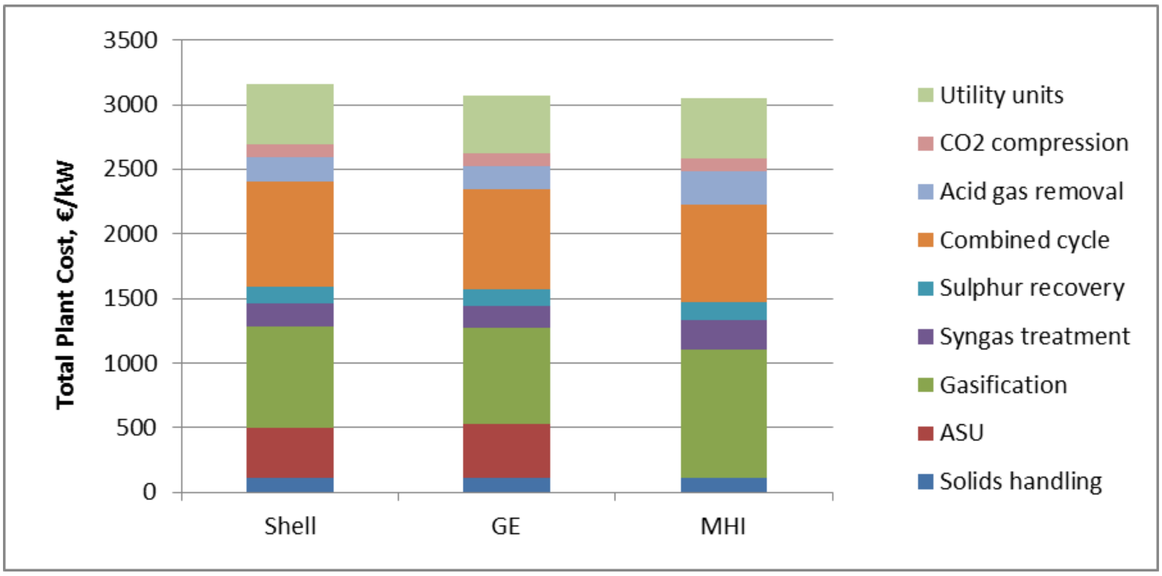

Figure 2 Specific Total Plant Cost of IGCC plants

The specific capital costs of the three IGCC plants with capture are similar and they are 110-118% higher than the cost of the pulverised coal reference plant, The MHI air blown gasifier plant has higher costs for gasification, syngas treating and acid gas removal (AGR), which is to be expected due to the higher volume of the fuel gas but it avoids the cost of a large ASU[3].

Levelised costs of electricity and CO_2 avoidance cost

Levelised costs of electricity (LCOE) and CO_2 avoidance cost (CAC) are shown in Table 3 and Figure 3. The costs of the IGCC plants are higher than those of the pulverised coal combustion plants, mainly because of higher capital costs and higher fixed operating and maintenance (O+M) costs, particularly maintenance costs.

[3] Note, the MHI gasifier plant includes a small ASU which provides nitrogen for coal feeding but the vendor included this in the cost of the gasification unit

Table 3 Levelised cost of electricity and CO_2 avoidance cost

	Levelised Cost of Electricity (LCOE)		CO_2 Avoidance Cost (CAC)
	€/MWh	% increase compared to the reference plant	€/tonne
Pulverised coal plants			
No capture (reference plant)	52.0		
Post combustion capture	94.7	82	65.4
Oxy-combustion	91.6	76	60.8
IGCC plants			
Shell oxygen-blown	116.5	124	98.9
GE oxygen-blown	114.4	120	95.8
MHI air-blown	114.5	120	97.4

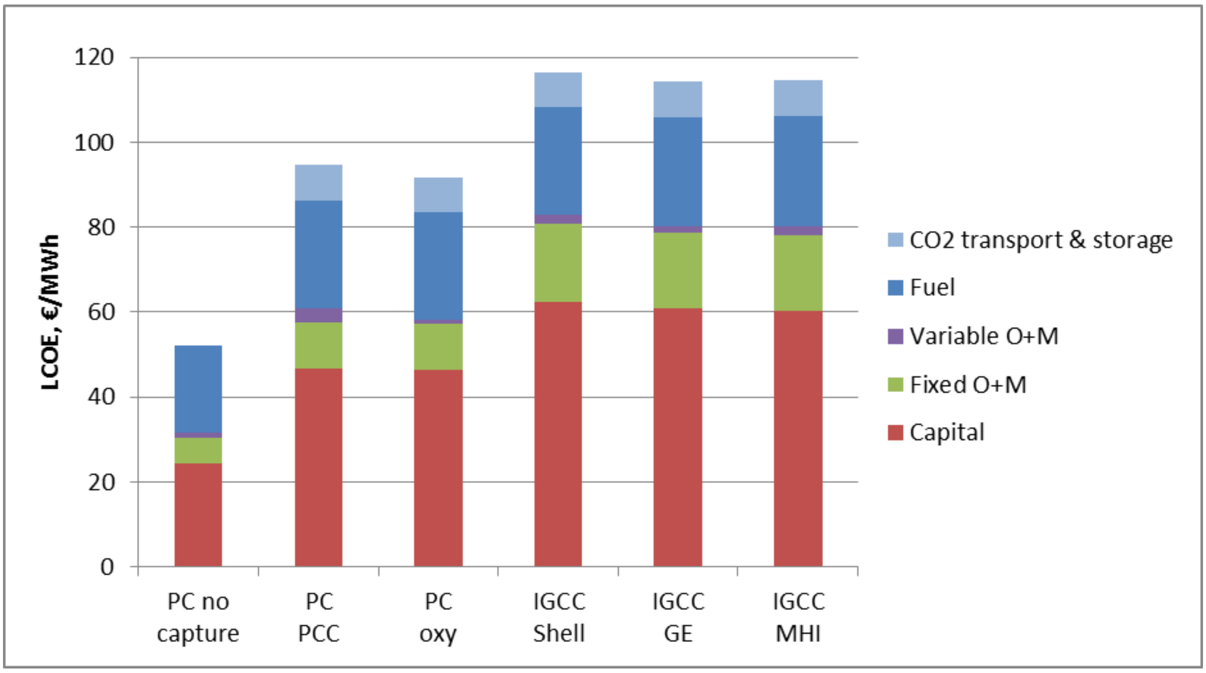

Figure 3 Levelised Costs of Electricity

Hydrogen plants

A summary of the performance of the baseline hydrogen plants with capture is given in Table 4. The plants co-produce electricity, to satisfy the plants' own consumption and they also provide some net output, as described earlier. The 'Net efficiency to hydrogen' in Table 4 is calculated by assuming that the net power output displaces electricity generated by a GE gasification IGCC plant with CO_2 capture. It should be noted that while the efficiencies of coal fired power plants are higher on an LHV basis than on an HHV basis, hydrogen plants have a higher efficiency on an HHV basis.

Table 4 Hydrogen plant performance summary

	Hydrogen output	Net power output	Efficiency to hydrogen	Efficiency to net power	Net efficiency to hydrogen	
			LHV	LHV	HHV	LHV
	MW	MW	%	%	%	%
High electricity	659	448	26.3	17.8	60.9	53.8
Medium electricity	969	289	38.6	11.5	65.3	57.7
Low electricity	1390	37	55.4	1.5	65.5	57.9

Capital costs of the hydrogen production plants are shown in Table 5 and the levelised costs of hydrogen (LCOH) are given in Table 6. For the calculation of LCOH, the electricity co-product is valued at 114.4 €/MWh, i.e. the production cost of the corresponding IGCC case (GE gasifier). Similarly, the capital cost associated with electricity production in the IGCC plant is subtracted from the capital cost of the co-production plants to give the specific capital cost of hydrogen production.

Table 5 Capital costs of hydrogen plants

	Total Plant Cost (TPC)	Total Plant Cost (TPC)	Total Capital Requirement (TCR)
	M€	€/kW_H net	€/kW_H net
High electricity co-production	2461	1646	2272
Medium electricity co-production	2390	1549	2137
Low electricity co-production	2101	1430	1974

Table 6 Levelised cost of hydrogen

	Levelised Cost of Hydrogen (LCOH), €/GJ	
	HHV basis	LHV basis
High electricity co-production	15.4	18.2
Medium electricity co-production	14.4	17.0
Low electricity co-production	13.6	16.1

The highest net efficiency to hydrogen and the lowest cost of hydrogen production are achieved by the plant with the lowest amount of electricity co-production, which is based on feeding the PSA off-gas to an on-site boiler.

Plant design sensitivity cases

Near-zero emission plants

The performance and costs of the plants with near-zero emissions are summarised in Table 7, which also shows the change in costs compared to plants with 90% capture. Increasing the percentage CO_2 abatement reduces the efficiency and increases the capital cost and LCOE. The largest increase in LCOE is for the biomass co-firing case and the lowest is for the oxy-combustion case. The CO_2 abatement costs per tonne are lower for the near-zero emission cases than for the 90% capture cases. In the case of oxy-combustion this is because capturing CO_2 from the vent gas from the CO_2 purification unit is relatively simple and low cost. In the case of IGCC, the reasons for the cost reduction are more complex. The cost of CO_2 abatement comprises the cost of cost of capture (shift conversion, CO_2 separation etc.) and the higher cost of the core IGCC process without capture compared to a pulverised coal plant without capture. Although the cost of capturing each extra tonne of CO_2 in an IGCC may be higher in the near-zero emissions case than in the 90% capture case, the extra costs for the core IGCC units compared to a pulverised coal plant remain the same. This cost is spread over a greater number of tonnes of CO_2 captured, resulting in a lower specific cost.

Table 7 Near-zero emission plants

	Efficiency		TPC		LCOE		CAC	
	%	% pt. change	€/kW	€/kW change	€/MWh	€/MWh change	€/t	€/t change
PCC+biomass (100% abatement)	34.6	-0.6	2887	+115	100.5	+5.8	65.1	-0.3
Oxy-combustion (97.6% capture)	35.3	-0.4	2823	+62	94.2	+2.6	58.3	-2.5
IGCC (98.6% capture)	34.1	-0.8	3203	+128	119.2	+4.8	92.5	-3.3

It should be noted that biomass could also be used in oxy-combustion and IGCC plants and greater proportions of biomass could be used, thereby achieving ‘negative emissions’. However, availability of biomass fuel may be limited due to competition with other land uses such as food production and natural habitats. Also, biomass may have a higher value for abatement of CO_2 emissions in other sectors where other low-CO_2 options are more limited, such as production of biofuels for transport. This study has shown that even if biomass availability is a constraint, it would be possible to build CCS plants with near-zero emissions, if required, without increasing the specific cost of CO_2 abatement.

A near-zero emission variant of the hydrogen plant with low electricity co-production was also assessed. The net efficiency to hydrogen (LHV basis) was 0.9% points lower than the 90% capture case and the TPC was 4.4% higher.

Cooling system sensitivity

The net raw water requirements of the power plants with CCS are 22-28% higher than that of the reference plant without capture. However, alternative cooling systems can be used to reduce the net water requirement of power plants with CCS to near zero in the case of oxy-combustion and post combustion capture and by around 70% in the case of IGCC. For the ambient conditions considered in this study, using once-though seawater cooling instead of natural draught cooling towers increases the thermal efficiency of plants with CCS by 0.5-0.7 percentage points and using air cooling reduces the efficiencies by 0.2-0.7 percentage points. This is mainly due to the effects on the turbine condenser pressure. Both of these cooling systems reduce the total plant cost by 1.5%. However, at higher ambient temperatures air cooling is expected to have a more negative impact.

Economic sensitivities

The costs of CCS depend on economic parameters which will vary over time and between different plant locations. It is important therefore to consider the sensitivity of costs to variations in parameters. The sensitivity to the coal price, economic discount rate, plant life, cost of CO_2 transport and storage, operating capacity factor and the cost penalty for non-captured CO_2 emissions were assessed. Sensitivities were assessed for all of the main study cases and the results for each parameter are presented in graphical format in the main report. As an example, sensitivities for the pulverised coal plant with post combustion capture are shown in Figure 4. The results would be similar for the oxy-combustion plant.

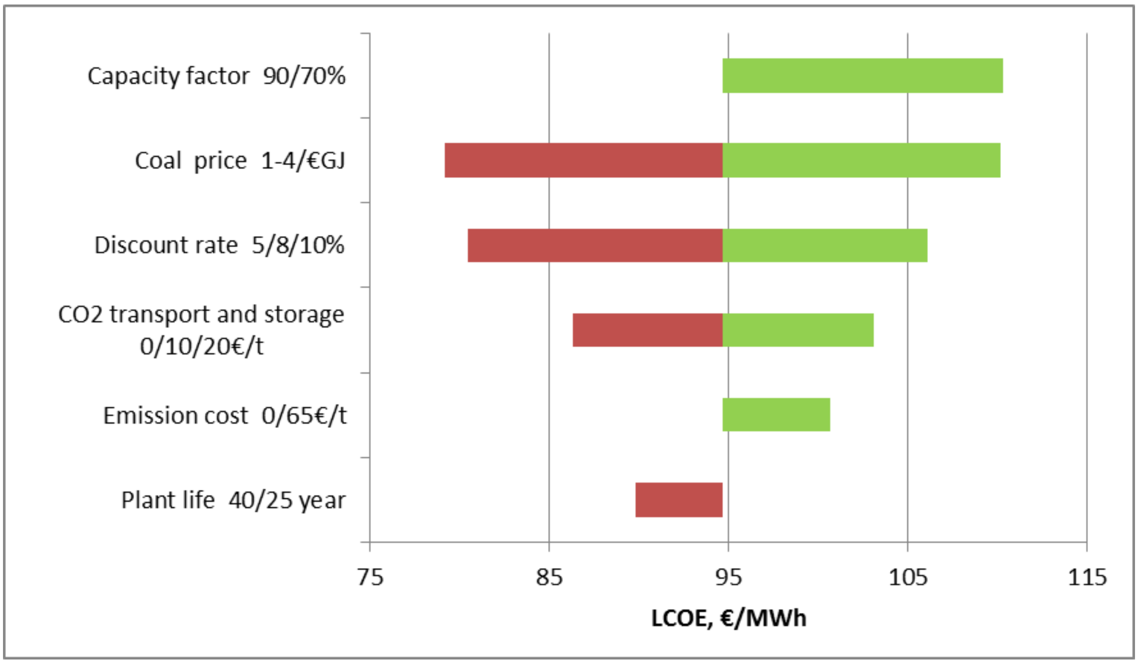

Figure 4 Sensitivities of Levelised Cost of Electricity (plant with post combustion capture)

Coal price can vary over a wide range due to local coal availability and mining costs and market variability. Varying the coal price by ±1.5 €/GJ from the base case of 2.5 €/GJ changes the LCOE by ±15.5 €/MWh.

The operating capacity factor of the plant may be lower than the 90% base case assumption in this study, either because of poor reliability and availability of the plant or because of electricity system constraints, i.e. other power generators with lower marginal operating costs being operated in preference to CCS plants at times of low power demand. Reducing the capacity factor can have a substantial effect of the LCOE. Figure 4 shows that reducing the capacity factor from 90% to 70% would increase the LCOE by 15.6 €/MWh. If the plant operates at a low capacity factor because of electricity system constraints the impacts on plant profitability and rate of return may be much less significant because the times when the plants are forced to not operate would by definition be times of low electricity prices. However, this is difficult to assess because electricity prices depend on the costs of the other generating plants in the overall electricity system.

Costs of CO_2 transport and storage are expected to vary considerably between different sites. At sites where CO_2 can be sold, for example for enhanced oil recovery, the net cost may be zero or even negative. If the CO_2 has to be transported a long distance in a relatively small pipeline for offshore storage the cost would be substantially greater than the 10 €/t base case scenario in this study. Sensitivities to costs in the range of zero to 20 €/t of CO_2 stored are shown in Figure 4 but the range of costs may be higher in some circumstances.

The main economic evaluation in this study does not include a cost for emitting non-captured CO_2 to the atmosphere. Including a cost that is equal to the cost of CO_2 abatement by CCS in this plant, i.e. 65 €/t CO_2, would increase the LCOE by 6 €/MWh.

The LCOE is relatively insensitive to increasing the plant life from 25 to 40 years, because of the effects of economic discounting.

The sensitivities of CO_2 avoidance cost (CAC) to variations in the economic parameters are shown in Figure 5.

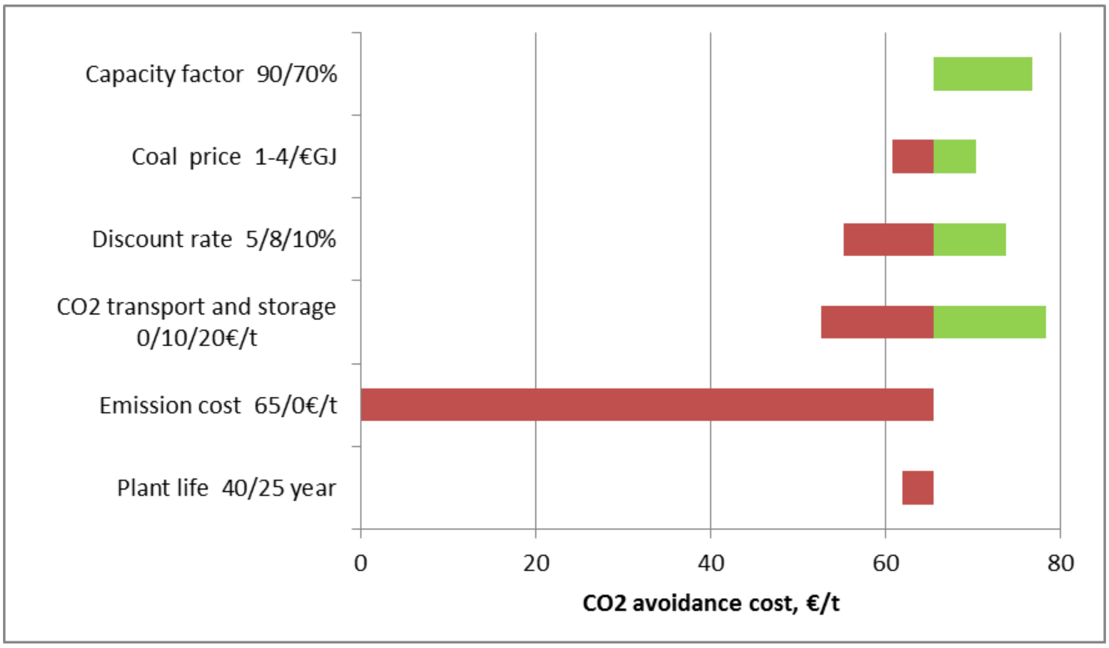

Figure 5 Sensitivities of CO_2 avoidance cost (plant with post combustion capture)

It can be seen that variations in the CO_2 emission cost, which has relatively little impact on the LCOE of the plant with capture, has by far the largest impact on the CO_2 avoidance cost, because it has a large impact on the LCOE of the reference plant. Conversely, the coal price, which has a relatively large impact on the LCOE of the plant with capture has a relatively small impact on the avoidance cost, because it has impacts on both plants, the only difference being due to the lower efficiency of the plant with capture. Apart from the emissions cost, the parameter which has the greatest impact on the avoidance cost, for the ranges considered in this study, is the CO_2 transport and storage cost, which obviously only affects the costs of the plant with capture.

Plot areas

Preliminary plot plans were produced for the baseline plants with and without capture. The area of the reference plant without capture is 20ha. The inclusion of CO_2 capture increases the area to 26ha for the boiler-based cases and 29ha for the IGCC cases.

Expert Review Comments

Comments on the draft report were received from reviewers at six organisations in the power industry, CCS project development and research. The contribution of the reviewers is gratefully acknowledged.

In general the reviewers thought the report was of a high standard. The contractor provided IEAGHG with responses to all of the comments and made appropriate modifications to the report.

The main critical comment was by a reviewer who said that if different gasifier designs had been selected for the IGCC and hydrogen cases, the results would have been more favourable. The choice of gasifiers for this study depended on the availability of licensors to support the study at the time it was carried out and the technology variants they wanted to offer. The CO_2 purity specification was also questioned but CO_2 purity is still a subject for debate. IEAGHG is currently undertaking a study to assess the effects of impurities on CO_2 transportation.

Conclusions

- The thermal efficiencies of power plants with CCS based on pulverised coal combustion with post combustion capture, oxy-combustion and IGCC with pre-combustion capture are 34.8 - 35.7% LHV basis, which is around 9 percentage points lower than a reference pulverised coal plant without capture.

- The levelised cost of base load electricity generation is about 92 €/MWh for boiler-based plants with oxy-combustion or post combustion capture and 115 €/MWh for IGCC plants with pre-combustion capture. This is about 75-125% higher than the reference pulverised coal plant without CCS.

- Costs of CO_2 emission avoidance compared to the reference plant are 60-65 €/t for boiler based plants with CCS and 95-100 €/t for IGCC plants.

- Increasing the rate of CO_2 capture to 98% in oxy-combustion and IGCC plants would increase the cost of electricity by 3-5% but reduce the cost per tonne of CO_2 emissions avoided by 3%.

- Co-firing biomass can be used to reduce net CO_2 emissions of plants with CCS to zero, assuming biomass is regarded as a 'zero net CO_2' fuel. In a plant with post combustion capture this increases the cost of electricity by 6% and has no impact on the cost of CO_2 avoidance, but the cost depends strongly on the cost of biomass, which depends on its availability.

- The net efficiency of producing hydrogen by coal gasification with CCS is 57.8% on an LHV basis (65.5% HHV basis) and the levelised cost of hydrogen is 16.1 €/GJ LHV basis (13.6 €/GJ HHV).

- Alternative cooling systems could be used to reduce the water requirements of pulverised coal power plants with CCS to close to zero and reduce the requirement for IGCC with CCS by around 70%. For the ambient conditions of this study, using sea-water cooling instead of cooling towers increases the thermal efficiency by a maximum of 0.7 percentage points and using air cooling reduces the efficiency by a maximum of 0.7 percentage points. Both cooling systems reduce the capital cost by 1.5%. It is expected that air cooling would have more negative impacts at higher ambient temperatures.

Recommendations

- The performance and costs of plants with without CCS will depend on local conditions, such as ambient conditions, fuel analyses and costs, and plant construction and operating costs. This study which is based on a site in the Netherlands could be extended to assess plants at other sites world-wide, particularly in developing countries which are expected in future to account for a large proportion of the global stock of coal fired power plants.

- Various new capture technologies are currently being developed, offering the prospect of lower energy consumptions and costs. When sufficient information becomes available further studies should be undertaken to assess such processes on a consistent basis to this study.

- This study assesses the relative costs of producing electricity and hydrogen with CCS, on a consistent basis. This information could be used as an input to further studies to assess the optimum low carbon energy carriers for different energy consuming sectors.

IEA
GREENHOUSE GAS R&D PROGRAMME

CO_2 CAPTURE
AT COAL BASED POWER AND HYDROGEN PLANTS

FINAL REPORT

January 2014

FWI Project # 1-BD-0681A

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CHAPTER F – ECONOMICS

ABBREVIATIONS

AGR	Acid Gas Removal
ASU	Air Separation Unit
BEDD	Basic Engineering Design Data
BFD	Block Flow Diagram
BFW	Boiler Feed Water
BL	Battery Limits
BOP	Balance Of Plant
CAC	CO_2 Avoidance Cost
CC	Combined Cycle
CCS	Carbon Capture and Storage
CPU	Cryogenic Purification Unit
CT	Cooling Tower
DC	Direct Current
DR	Discount Rate
ESP	Electro Static Precipitator
FD	Forced Draft
FGD	Flue Gas Desulphurisation
FW	Foster Wheeler
GEE	General Electric Energy
GOX	Gaseous Oxygen
GT	Gas Turbine
H&M	Heat and Mass
HP	High Pressure
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
IP	Intermediate Pressure
LCOE	Levelized Cost Of Electricity
LCOH	Levelized Cost Of Hydrogen
LHV	Low Heating Value
LIN	Liquid Nitrogen
LOX	Liquid Oxygen
LP	Low Pressure
MAC	Main Air Compressor
MEA	Mono-Ethanol-Amine
MHI	Mitsubishi Heavy Industries
MP	Medium Pressure
MWe	Mega Watt electrical
MWth	Mega Watt thermal
NEE	Net Electrical Efficiency
NPO	Net Power Output
O&M	Operating and Maintenance
PC	Pulverised Coal

PI	Power Island
PSA	Pressure Swing Adsorption
PU	Process Unit
RH	Re-Heated
S/D	Shutdown
SC PC	Super Critical Pulverised Coal
SCR	Selective Catalytic Reduction
SH	Super Heater
SRU	Sulphur Recovery Unit
ST	Steam Turbine
TCR	Total Capital Requirement
TGT	Tail Gas Treatment
TIC	Total Investment Cost
TPC	Total Plant Cost
U&O	Utilities & Offsite
VLP	Very Low Pressure
WWT	Waste Water Treatment

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1. Introduction

In the past years The International Energy Agency Greenhouse Gas R&D programme (IEAGHG) undertook a series of studies on the performance and costs of coal fired power and hydrogen plants with CO_2 capture, based on the three leading options, namely post-combustion capture and oxy-combustion for pulverised coal plants and pre-combustion capture in gasification plants.

Following the significant technological advances and the substantial increase of the plant costs, IEAGHG decided to undertake a wholly new study to provide an up-to-date assessment of the performance and costs of coal fired power and hydrogen plants, with and without capture of the generated CO_2.

With this premise, IEAGHG has contracted Foster Wheeler (FW) to perform a study that makes the technical and economical assessment of coal fired power and hydrogen plants with the leading CO_2 capture technologies.

This new study aims to provide a baseline for possible subsequent studies on other capture processes and capture in industries other than power and hydrogen generation from coal. It covers the following four plant types:

- Supercritical pulverised coal (SC-PC) power plant without CO_2 capture (reference plant for all the other cases);
- Supercritical pulverised coal power plant using oxy-combustion or with post combustion capture based on a high efficiency solvent washing process;
- Integrated Gasification Combined Cycle (IGCC) plant with pre-combustion capture using solvent scrubbing;
- Gasification for combined production of saleable hydrogen (99.5% purity, by means of PSA) and power (either by means of a combined cycle or using a conventional boiler-based unit), with pre-combustion capture via solvent scrubbing.

During the preparation of the study, FW has fruitfully cooperated with various technology suppliers and licensors, which provided an invaluable support for the success of the study. Therefore, FW and IEAGHG like to acknowledge the following companies, listed in alphabetical order:

- Air Products
- Alstom
- Cansolv
- Chiyoda Corporation
- Foster Wheeler Energie GmbH

- General Electric Energy
- IHI
- Johnson Matthey
- MHI
- Shell
- UOP.

It is noted that the comparison of either different technologies or technology suppliers was beyond the scope of the present study, which focused to provide an up-to-date technical and economical assessment of coal-fired power and hydrogen plants. In fact, the direct comparison of the technologies is always strongly influenced by specific local constraints and by unpredictable market logics, usually subject to rapid changes.

2. Study cases

The study investigates alternative designs of power and hydrogen generation plants, as listed in the following table. Technology suppliers that provided technical or cost data are also shown in the table. Other unit or equipment performance and costs (e.g. SC PC boiler for air- and oxy-fired cases, ASU for oxy-combustion and IGCC cases, SRU, etc.) are based on a generic design, not provided from a specific supplier.

Table 1. Study cases

Type	Case	Plant type	CO_2 capture target	Key technological features
Boiler-based	Case 1 (reference)	SC PC	-	• Alstom Wet limestone scrubbing FGD
Boiler-based	Case 2	SC PC w CCS	90%	• Alstom Wet limestone scrubbing FGD • CANSOLV solvent scrubbing (post-comb. capture)
Boiler-based	Case 3	Oxy-SC PC	90%	• FW Energie Circulating Fluid Bed Scrubber CFBS FGD technology • Air Products' Cryogenic Purification Unit
IGCC-based	Case 4.1	IGCC	90%	• Shell Coal Gasification Process, with Syngas Cooler • UOP Selexol solvent scrubbing • Two (2) F-class gas turbines (~275 MWe eq. NG)
IGCC-based	Case 4.2	IGCC	90%	• General Electric, Radiant Syngas Cooler • UOP Selexol solvent scrubbing • Two (2) F-class gas turbines (~275 MWe eq. NG)
IGCC-based	Case 4.3	IGCC	90%	• MHI, Air-Blown two-stage entrained-bed gasifier • UOP Selexol solvent scrubbing • Two (2) MHI 701 F4 gas turbines
H_2 & Power	Case 5.1	IGCC + H_2 (PSA)	90%	• General Electric, Radiant Syngas Cooler • UOP Selexol solvent scrubbing • Two (2) E-class gas turbines (~ 130 MWe eq. NG)
H_2 & Power	Case 5.2	IGCC + H_2 (PSA)	90%	• General Electric, Radiant Syngas Cooler • UOP Selexol solvent scrubbing • Two (2) frame 6 (~ 77 MWe eq. NG)
H_2 & Power	Case 5.3	Gasification + Boiler + H_2 (PSA)	90%	• General Electric, Radiant Syngas Cooler • UOP Selexol solvent scrubbing • Off-gas based Boiler to mostly cover auxiliary power demand of the plant

The study includes also *"sensitivity cases"* to:

- Assess performance and costs of a pulverised coal plant with post combustion capture in which sufficient woody biomass is co-fired to achieve zero net emissions of CO_2 (considering biomass as zero carbon fuel).
- Assess the performance and costs variants of the oxy-combustion, IGCC and Hydrogen production plants with near-zero emissions of CO_2 (e.g. 98-99% overall CO_2 capture). Near zero emissions in the post combustion capture is expected to be not technically feasible at reasonable cost, so this is achieved co-firing some biomass (refer to the above bullet).
- Make sensitivity of performance and costs to two alternative types of cooling system (once-through sea water cooling and dry air cooling) for the reference plant and the three main plants with CO_2 capture for power production only.

Table 2. - Sensitivity study cases

Case	**Plant type**	**CO_2 capture target**	**Key technological features**
Case 2.1	SC PC w CCS	100	As Case 2 + woody biomass co-firing (zero CO_2 emission)
Case 3.1	Oxy-SC PC	98-99%	As Case 3 + Air Products' PRISM membranes (near zero CO_2 emission)
Case 4.2.1	IGCC	98-99%	As Case 4.2 + additional MDEA solvent scrubbing (near zero CO_2 emission)
Case 5.3.1	IGCC + H_2 (PSA)	98-99%	As Case 5.2 + additional MDEA solvent scrubbing (near zero CO_2 emission)
Case 1(SW)	SC PC	-	As Case 1, with seawater cooling
Case 1(AC)	SC PC	-	As Case 1, with air cooling
Case 2(SW)	SC PC w CCS	90%	As Case 2, with seawater cooling
Case 2(AC)	SC PC w CCS	90%	As Case 2, with air cooling
Case 3(SW)	Oxy-SC PC	90%	As Case 3, with seawater cooling
Case 3(AC)	Oxy-SC PC	90%	As Case 3, with air cooling
Case 4.2 (SW)	IGCC	90%	As Case 4.2, with seawater cooling
Case 4.2 (AC)	IGCC	90%	As Case 4.2, with air cooling

The technical and economic assessment of the above listed study cases are mostly based on technology and equipment that suppliers would be capable to offer on a commercial basis today. In some cases, near term efficiency improvements have been considered, as already anticipated by specialized Vendors (e.g. ASU).

3. Main plant design bases

The main plant design bases, used as common bases for the design of the plant, are listed in the following:

- The site is a greenfield location on the North East coast of The Netherlands, at sea level and with an average reference ambient temperature of 9 °C.
- The reference coal is an Eastern Australian Bituminous internationally traded open-cast coal, delivered from a port to the plant site by unit trains. Its inherent moisture is 9.50% (AR), Sulphur content is 1.10% (DAF) and the heating value (AR) is 25.87 MJ/kg (LHV) / 27.06 MJ/kg (HHV).
- The pulverised coal plants are based on state-of-the-art steam conditions (27 MPa/600°C/620°C) as mostly used in recent large coal fired power plants in Europe and Japan.
- The IGCC plants of the main study cases use two (2) state-of-the-art F-class, 50 Hz gas turbines, commercially available for high hydrogen content gas.
- The net power output of the pulverised coal plant without capture is around 1,000 MWe. The pulverised coal plants with CO_2 capture are based on boilers with the same thermal capacity.
- CO_2 is delivered from the plant site to the pipeline at the following main conditions:

-	Pressure	11	MPa
-	Temperature	30	°C
-	Oxygen	100	ppm
-	H_2S	20	ppm
-	Water	50	ppm
-	Total non-condensable (max)	4	% (volume)

- The plant has access to sweet water, mainly used as make-up water for the cooling water system, this latter based on natural draft cooling tower.
- The overall gaseous emissions from the plant do not exceed the following limits:

	SC-PC based cases (1)	**IGCC based cases (2)**
NO_X (as NO_2)	≤ 150 mg/Nm^3	≤ 50 mg/Nm^3
SO_X (as SO_2)	≤ 150 mg/Nm^3	≤ 10 mg/Nm^3

Notes: (1) @ 6% O_2 volume dry. Not applicable for oxy-combustion plant. Regulatory approach for this plant type not yet defined. (2) @ 15% O_2 volume dry.

4. Performance summary

The main performance data of all study cases are shown in the following tables.

Table 3. – SC-PC-based cases: performance summary

		Case 1 SC-PC w/o CCS		Case 2 SC-PC with CCS		Case 3 Oxy SC-PC with CPU	
OVERALL PERFORMANCE							
Coal flowrate (A.R.)	**t/h**	325.0		325.0		325.0	
Thermal input (1)	**MWth**	2335		2335		2335	
Auxiliary power demand (2)	**MWe**	47.1		135.7		267.6	
Net Electric Power Output	**MWe**	1029.6		822.4		833.4	
Net Electrical Efficiency (1)	**%**	44.1		35.2		35.7	
CO_2 REMOVAL EFFICIENCY							
CO_2 capture rate	**%**	-		90.1		90.0	
CO_2 to atmosphere	**t/h**	767.4		76.5		76.8	
CO_2 to storage	**t/h**	-		690.9		685.9	
GASEOUS EMISSIONS (3)		kg/MWh	mg/Nm^3 (6% O_2)	kg/MWh	mg/Nm^3 (6% O_2)	kg/MWh	g/h
CO_2		745.8	-	93.0	-	92.2	-
NO_X		0.43	150	0.54	150	-	-
SO_X		0.43	150	0.01	<1ppm	-	-

Notes: (1): LHV basis.
(2): Including step-up transformer losses
(3): Emission expressed in mg/Nm^3 @6% O_2, dry basis, applicable to the air fired SC PC plants only; for the oxy-combustion based power plant this is not relevant, due to the very low flowrate of the inerts gas stream discharged to atmosphere.

Table 4. – IGCC study cases: performance summary

		Case 4.1 Shell with CCS	Case 4.2 GE with CCS	Case 4.3 MHI with CCS
OVERALL PERFORMANCE				
Coal flowrate (A.R.)	**t/h**	314.9	349.1	345.1
Thermal input(1)	**MWth**	2263	2509	2480
Thermal input to GT(1)	**MWth**	1600 (3)	1600 (3)	1667 (4)
Auxiliary power demand(2)	**MWe**	259.2	266.4	229.6
Net Electric Power Output	**MWe**	804.0	874.3	863.0
Net Electrical Efficiency(1)	**%**	35.5	34.9	34.8
CO_2 REMOVAL EFFICIENCY				
CO_2 capture rate	**%**	90.1	90.1	89.0
CO_2 to atmosphere	**t/h**	74.5	81.9	89.9
CO_2 to storage	**t/h**	673.2	737.9	726.8

		Case 4.1 Shell with CCS		Case 4.2 GE with CCS		Case 4.3 MHI with CCS	
GASEOUS EMISSIONS		kg/MWh	mg/Nm^3 (15% O_2)	kg/MWh	mg/Nm^3 (15% O_2)	kg/MWh	mg/Nm^3 (15% O_2)
CO_2		92.6	-	93.7	-	104.1	-
NO_X		0.33	<50	0.31	<50	0.31	<50
SO_X		0.01	<1	0.01	<1	0.01	<1

Notes: (1): LHV basis.
(2): Including step-up transformer losses.
(3): 2 x average F-class GT.
(4): 2 x MHI 701 F4 gas turbines

Table 5. – Power and hydrogen co-production cases: performance summary

		Case 5.1 GE, 2 E-Class GTs		Case 5.2 GE, Eq. Frame 6 GTs		Case 5.3 GE, Boiler (Off-gas)	
OVERALL PERFORMANCES							
Coal flowrate for H_2 (A.R.)	**t/h**	165.4		243.4		349.1	
Coal flowrate for power (A.R.)	**t/h**	183.7		105.7		-	
Thermal input(1)	**MWth**	2509		2509		2509	
Hydrogen production	**Nm^3/h**	220,600		324,700		465,700	
Hydrogen thermal capacity(1)	**MWth**	659		969		1390	
Auxiliary power demand(3)	**MWe**	237.7		230.4		222.1	
Net Electric Power Output	**Mwe**	447.6		289.3		37.0	
CO_2 REMOVAL EFFICIENCY							
CO_2 capture rate	**%**	90.1		90.1		90.1	
CO_2 to atmosphere	**t/h**	81.9		81.9		81.9	
CO_2 to storage	**t/h**	737.9		737.9		737.9	
GASEOUS EMISSIONS(2)		kg/MWh	mg/Nm^3 (15% O_2)	kg/MWh	mg/Nm^3 (15% O_2)	kg/MWh	mg/Nm^3 (15% O_2)
CO_2		93.7	-	93.7	-	93.7	-
NO_X		0.16	<50	0.11	<50	0.04	<50
SO_X		0.00	<1	0.00	<1	0.00	<1

Notes: (1): LHV basis.
(2): Referred to the net power production of Case 4.2.
(3): Including step-up transformer losses.

5. Cost summary

The Total Plant Cost (TPC) and the Total Capital Requirement (TCR) are defined in general accordance with the White Paper "*Toward a common method of cost estimation for CO_2 capture and storage at fossil fuel power plants*" (March 2013), produced collaboratively by authors from EPRI, IEAGHG, Carnegie Mellon University, MIT, IEA, GCCSI and Vattenfall [(1)].

The **Total Capital Requirement** (**TCR**) is defined as the sum of:

- Total Plant Cost (**TPC**)
- Interest during construction
- Spare parts cost
- Working capital
- Start-up costs
- Owner's costs.

The Total Plant Cost (TPC) is the installed cost of the plant, including project contingencies.

The TPC of the different study cases is presented in the overleaf pages, broken down into the main process units that compose the plant. Moreover, for each process unit, the TPC has been split into the following main items:

- Direct materials
- Construction
- EPC services
- Other costs
- Contingency.

For each case of the study, the total plant cost (TPC) has been determined through a combination of licensor/vendor quotes, the use of a Foster Wheeler (FW) in-house database and the development of conceptual estimating models, based on the specific characteristics, materials and design conditions of each equipment in the plant. The other components of the TCR have been mainly estimated as percentages of other cost estimates in the plant.

The estimate is in euro (€), based on 2Q2013 price level. Overall estimate accuracy is in the range of +35%/-15% (AACE Class 4).

For each plant type, the TPC of the different study cases is shown in the overleaf graphs. Total Plant Cost and Total Capital Requirement figures for the different cases are also reported in the below table for summary purpose.

[1] IEAGHG report 2013/TR2, http://www.ieaghg.org/publications/technical-reports

For the power production cases, the specific costs, defined as the ratio between either the TPC or the TCR and the net power output, are also reported in the same table.

Table 6. TPC and TCR of study cases (2Q2013)

Type	Case	Total Plant Cost (TPC) (M€)	Total Capital Requirement (TCR) (M€)	Specific cost [TPC/Net Power] (€/kW)	Specific cost [TCR/Net Power] (€/kW)
Boiler-based	Case 1	1,490	1,943	1,447	1,887
	Case 2	2,279	2,961	2,771	3,600
	Case 3	2,301	2,986	2,761	3,583
IGCC-based	Case 4.1	2,538	3,497	3,157	4,350
	Case 4.2	2,688	3,705	3,074	4,238
	Case 4.3	2,629	3,625	3,046	4,200
H_2 & Power	Case 5.1	2,461	3,394	N/A	N/A
	Case 5.2	2,390	3,297	N/A	N/A
	Case 5.3	2,101	2,901	N/A	N/A

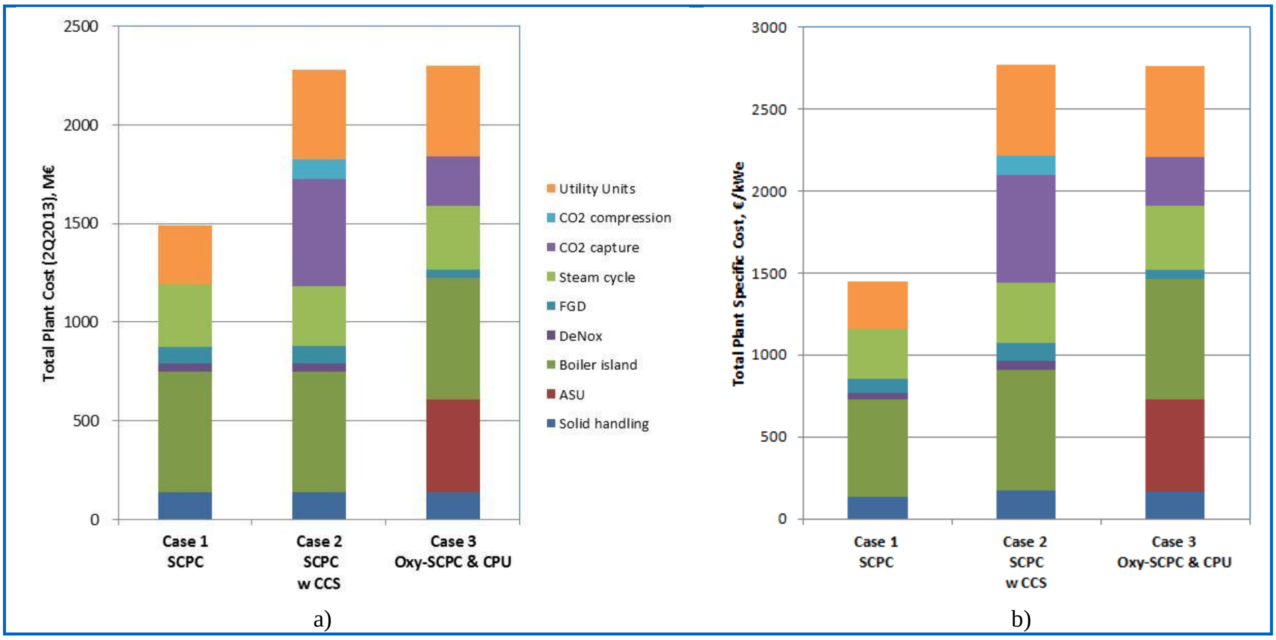

Figure 1: TPC (2Q2013) of Boiler-based cases: a) Total Plant cost, b) Specific Plant cost

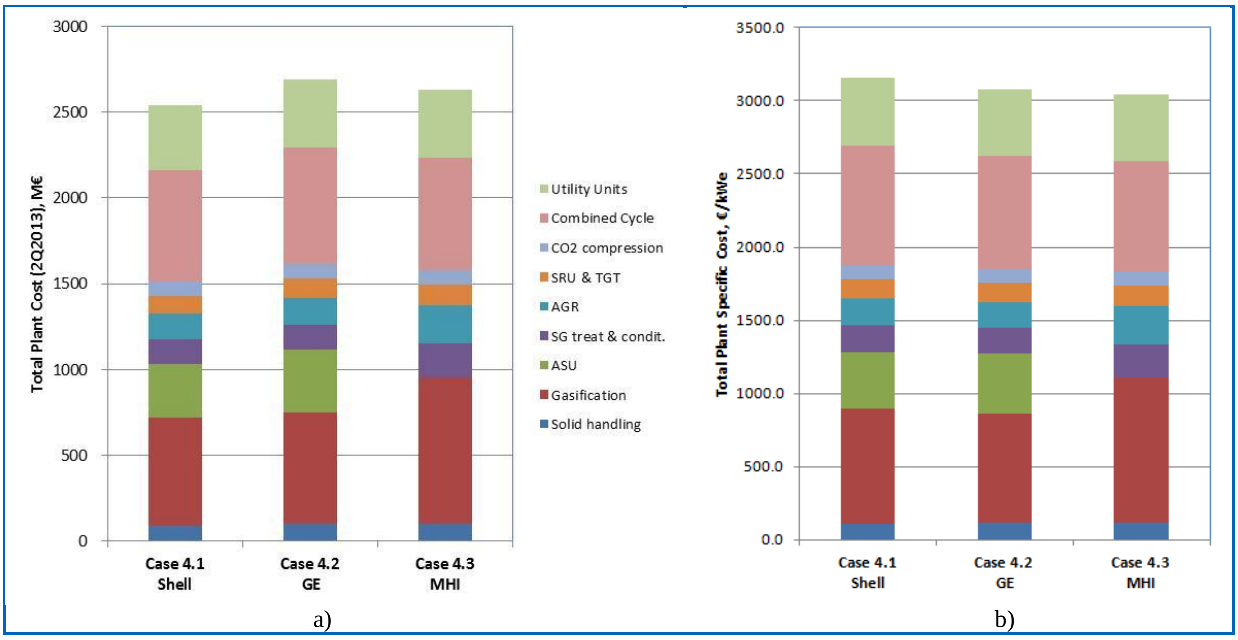

Figure 2: TPC (2Q2013) of IGCC-based cases: a) Total Plant cost, b) Specific Plant cost

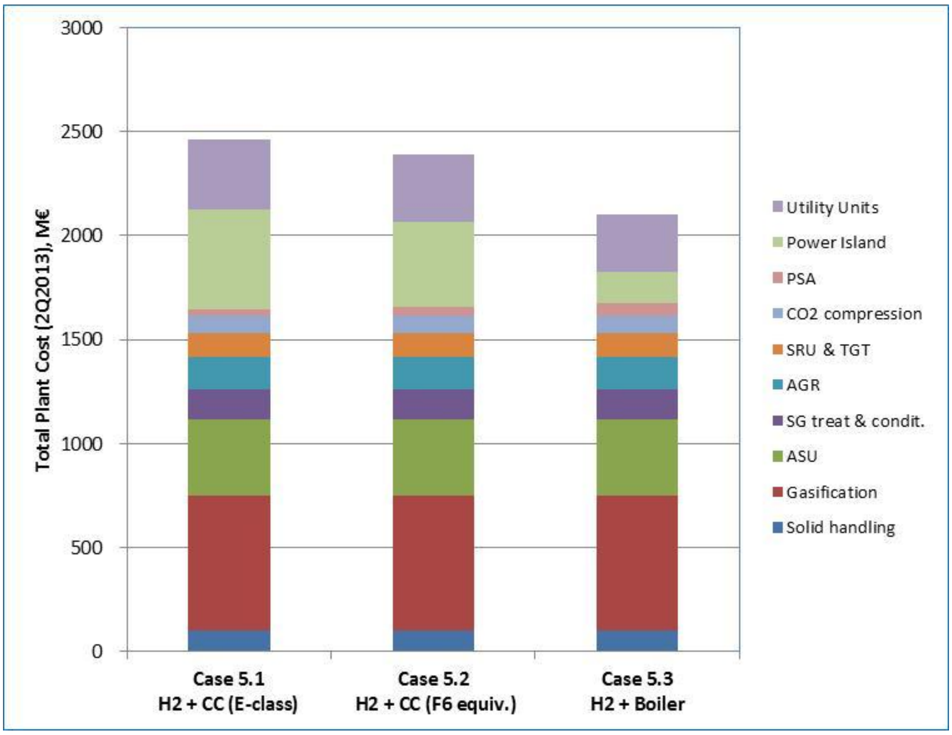

Figure 3: TPC (2Q2013) of Power and hydrogen co-production cases

6. Financial analysis

A simplified financial analysis has been performed to estimate, for each case, the Levelized Cost of Electricity (LCOE) and the CO_2 Avoidance Cost (CAC), based on a specific set of macroeconomic assumptions.
For the hydrogen and power co-production cases, the Levelized Cost of Hydrogen (LCOH) production has been also estimated.

The LCOE and the LCOH predictions are calculated under the assumption of obtaining a zero Net Present Value (NPV) for the project, corresponding to an Internal Rate of Return (IRR) equal to the Discount Rate (DR).
Therefore, the financial analysis is a high-level economical evaluation only, while the rigorous project profitability for the specific case is affected by project specific conditions and constraints.

6.1. LCOE and LCOH

The Cost of Electricity (COE) in power production plants is defined as the selling price at which electricity must be generated to reach the break even at the end of the plant lifetime for a targeted rate of return.

However, with the purpose of screening different technology alternatives, the levelized value of the cost of electricity (LCOE) is commonly preferred to the year-by-year data. The LCOE is defined as the uniform annual amount which returns the same net present value as the year-by-year amounts.

In this analysis, long-term inflation assumptions and price/cost variations throughout the project life-time were not considered and, therefore, the COE matches with the LCOE.

The same considerations apply to the hydrogen and power co-production cases, where the power selling price is valued at the cost of production of the base case with power production only (Case 4.2, GE-based IGCC).

6.2. CO_2 avoidance cost

For the power production cases, the CO_2 Avoidance Cost (CAC) is calculated by comparing the costs and specific emissions of a plant with CCS with those of the reference case without CCS. For a power generation plant, it is defined as follows:

$$CO_2 \text{ Avoidance Cost (CAC)} = \frac{LCOE_{CCS} - LCOE_{Reference}}{CO_2Emissions_{\ Reference} - CO_2Emissions_{\ CCS}}$$

where:

Cost of CO_2 avoidance is expressed in Euro per tonne of CO_2
LCOE is expressed in Euro per MWh
CO_2 emissions is expressed in tonnes of CO_2 per MWh.

The selected reference case for the evaluation of the CAC is Case 1, i.e. the conventional SC-PC power plant without capture of the generated carbon dioxide.

6.3. Macroeconomic bases

The main financial bases assumed to run the economic model are reported in the below table.

Table 7. Main financial bases

ITEM	DATA
Coal cost	2.5 €/GJ (LHV basis)
Discount Rate	8%
Financial leverage	100% debt
Maintenance cost (% of TPC)	1.5% (SC-PC based) 2.5% (IGCC-based)
Capacity factor (SC-PC/Gasification based)	90% / 85%
Plant life	25 years
CO_2 transport & storage cost	10 €/t $_{STORED}$
CO_2 emission cost	0 €/t $_{EMITTED}$
Inflation Rate	Constant Euro
Currency	Euro reported in 2Q2013

6.4. Results

Figure 4 and Figure 5 report respectively the LCOE for the power production only cases and the LCOH for the hydrogen and power co-production cases.

LCOE and LCOH figures also show the relative weight of:

- Capital investment,
- Fixed O&M (Operating Labor costs, Overhead Charges, Maintenance costs),
- Variable O&M (Raw water make-up, Solvents, Catalysts, Chemicals),
- Fuel,
- CO_2 transportation & storage.

A summary of the economical modeling results is also reported in the following Table 8 and Table 9.

Table 8. Financial results summary: LCOE and CO_2 avoidance cost

Type	Case	Description	LCOE (€/MWh)	CAC (€/t)
Boiler-based	Case 1	SC-PC w/o CCS	52.0	-
	Case 2	SC-PC w/CCS	94.7	65.4
	Case 3	OXY SC-PC	91.6	60.8
IGCC-based	Case 4.1	IGCC (Shell)	116.5	98.9
	Case 4.2	IGCC (GEE)	114.4	95.8
	Case 4.3	IGCC (MHI)	114.5	97.4

Table 9. Financial result summary: LCOH(1)

Type	Case	Description	LCOH(1) (c€/Nm^3)
Hydrogen & Power	Case 5.1	H_2&Power production: 2 x E-class GTs	19.5
	Case 5.2	H_2&Power production: 2 x F-class (77MWe) GTs	18.3
	Case 5.3	H_2&Power production: 2 x Boiler	17.3

(1) Assuming power selling price: 114.4 €/MWh, as per Case 4.2 (power production only)

Figure 6 shows the results of the sensitivity financial analyses performed to estimate the LCOE, CAC and LCOH of the different study cases versus the variation of the Coal Cost and the Plant Load Factor.

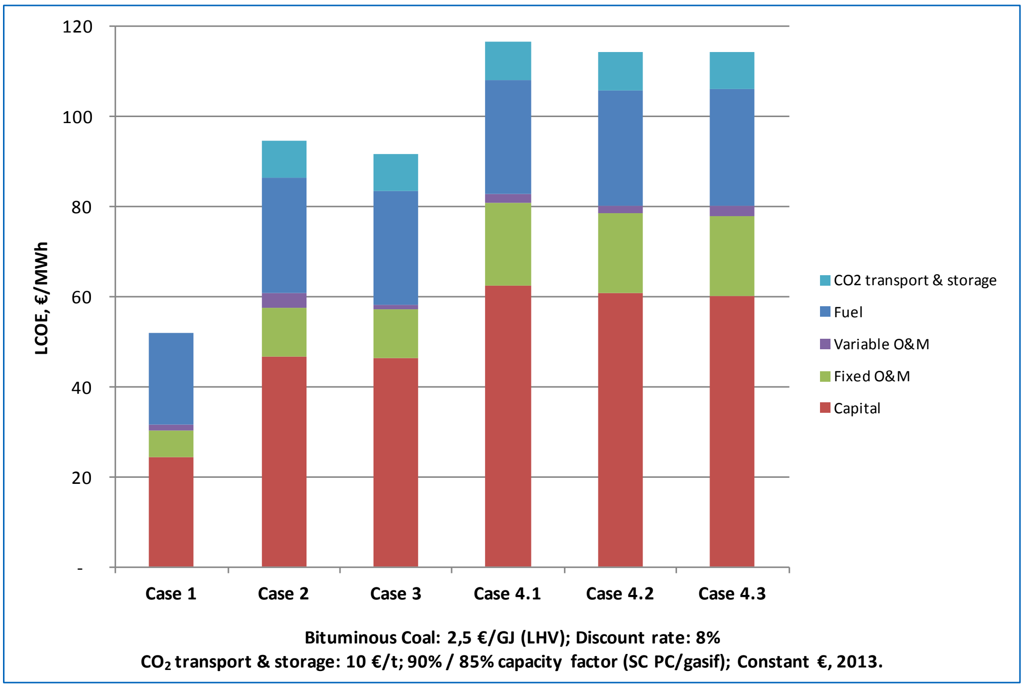

Figure 4. LCOE for all power production cases

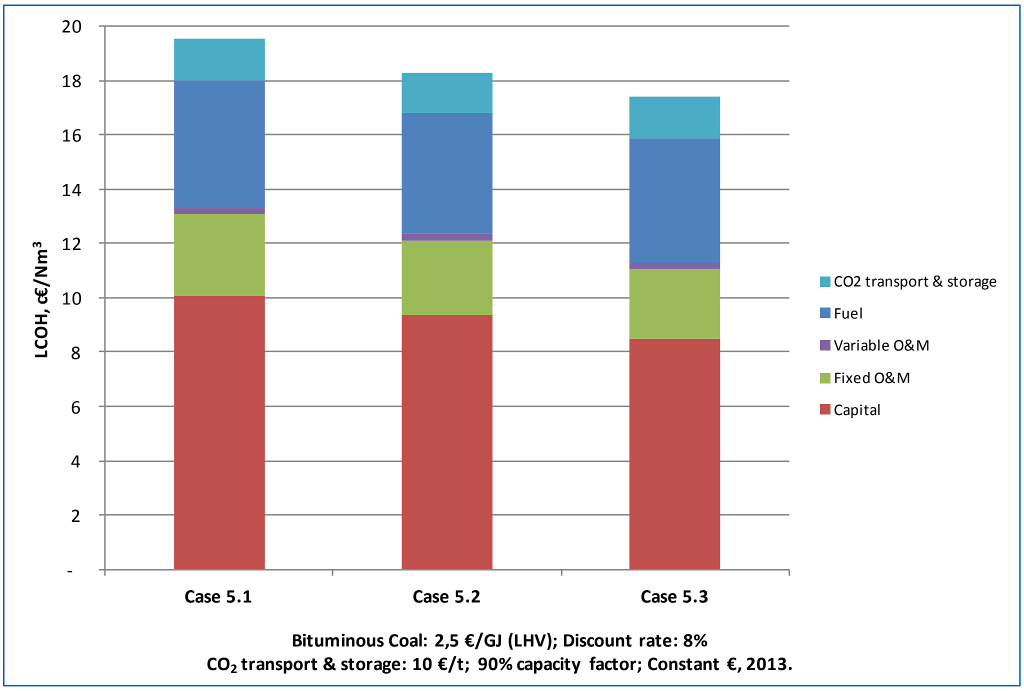

Figure 5. LCOH for all power and hydrogen co-production cases

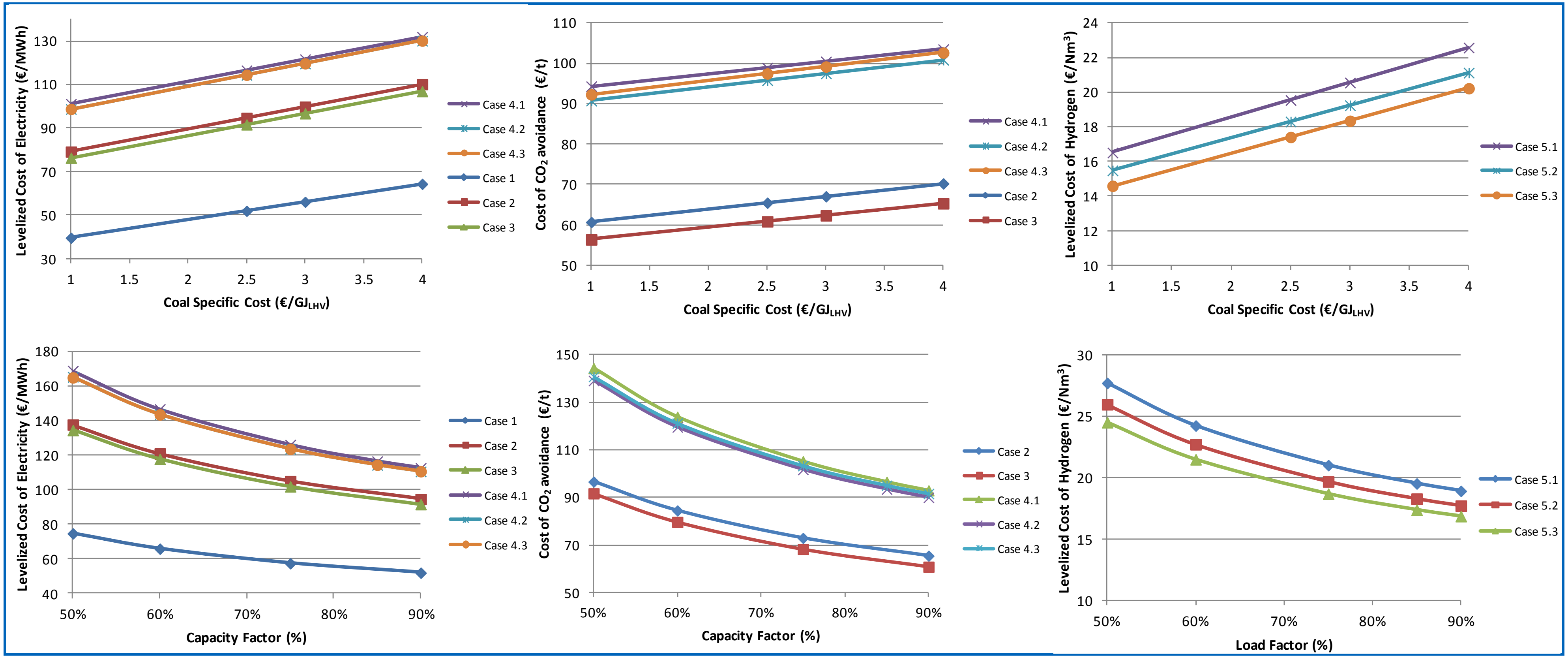

Figure 6. Sensitivity to Coal Cost and Capacity Factor

7. Sensitivity cases

The following graphs show the net electrical efficiency (NEE) and the Total Plant Cost (TPC) of the sensitivity cases, as follows:

- Figure 7 through Figure 10 show the sensitivity to two alternative types of cooling system (once-through sea water cooling and dry air cooling), for the reference plant (SC-PC) and the three main plants with CO_2 capture (pre-, post- and oxy-) for power production only. With respect to the 4.0 kPa of the reference case with cooling tower (CT), the once-through sea water (SW) cooling and dry air cooling (AC) systems allow to achieve a condensing pressure respectively of 3.0 kPa and 5.2 kPa, at the reference ambient temperature of the study.
- Figure 11 shows sensitivity of a pulverised coal plant with post combustion capture, in which sufficient woody biomass (7.5% LHV basis on thermal input) is co-fired to achieve zero net emissions of CO_2 (considering biomass as zero carbon fuel for accounting purpose).
- Figure 12 shows sensitivity of the oxy-combustion, IGCC and Hydrogen production plants with near-zero emissions of CO_2 (98% overall CO_2 capture). For these cases, also the results of the financial analysis are shown in Table 10 and Figure 13 and Figure 14.

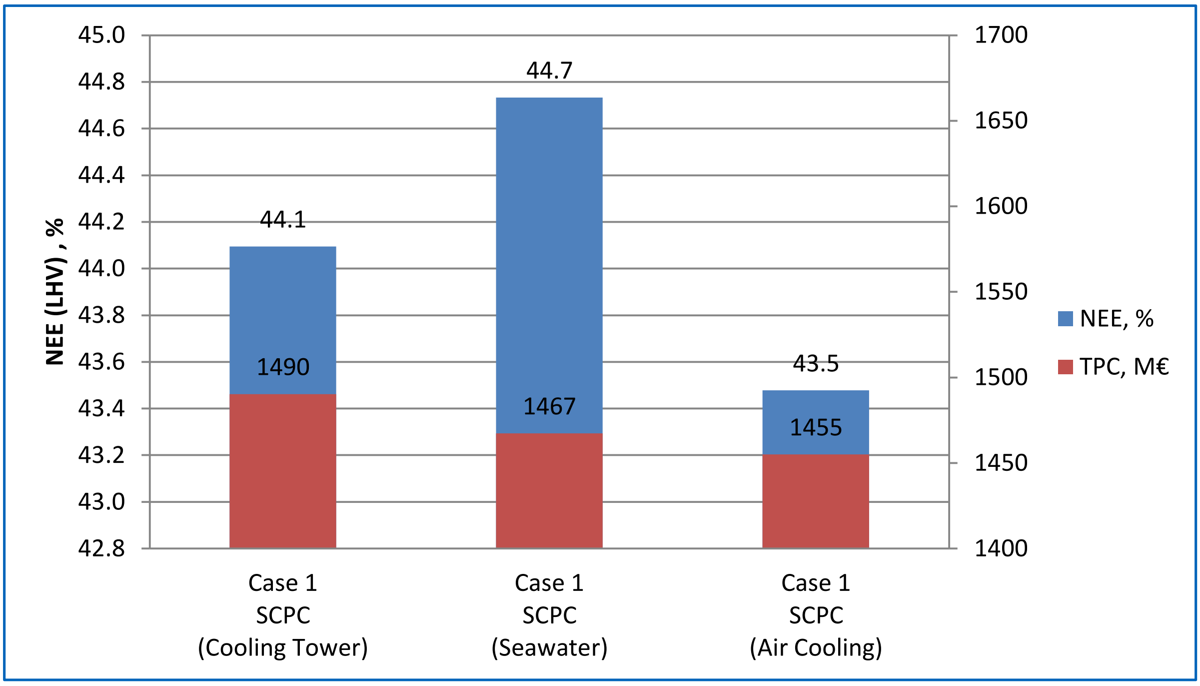

Figure 7. SCPC – sensitivity to cooling type

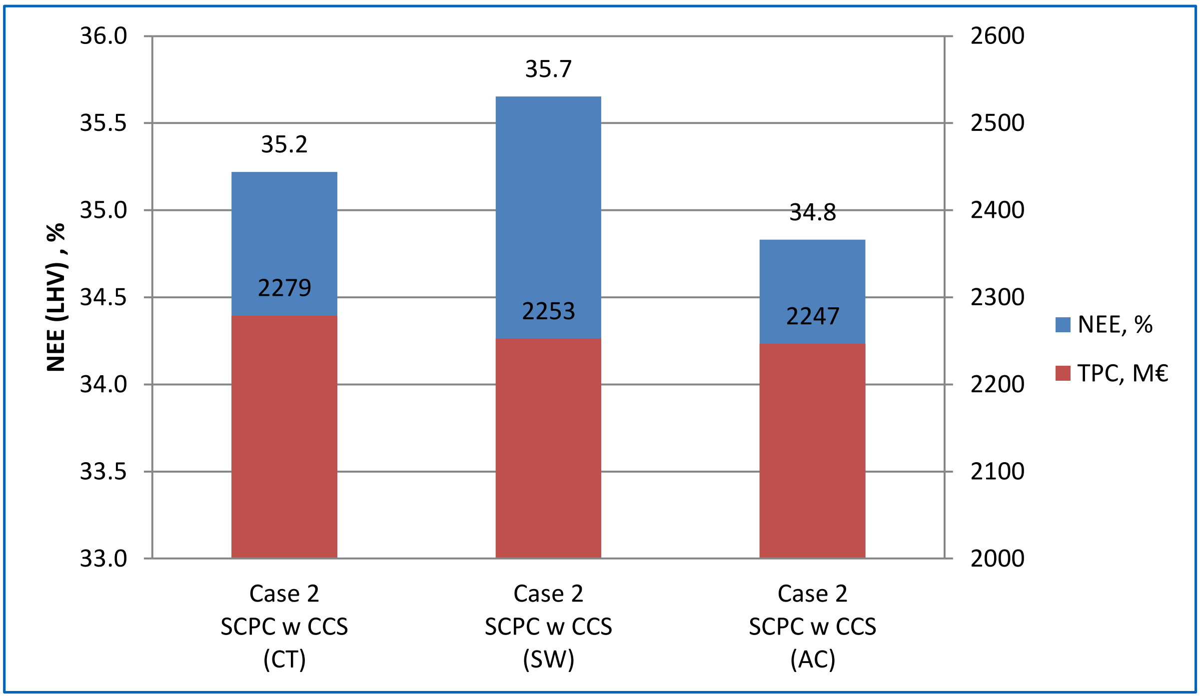

Figure 8. SCPC with CCS - sensitivity to cooling type

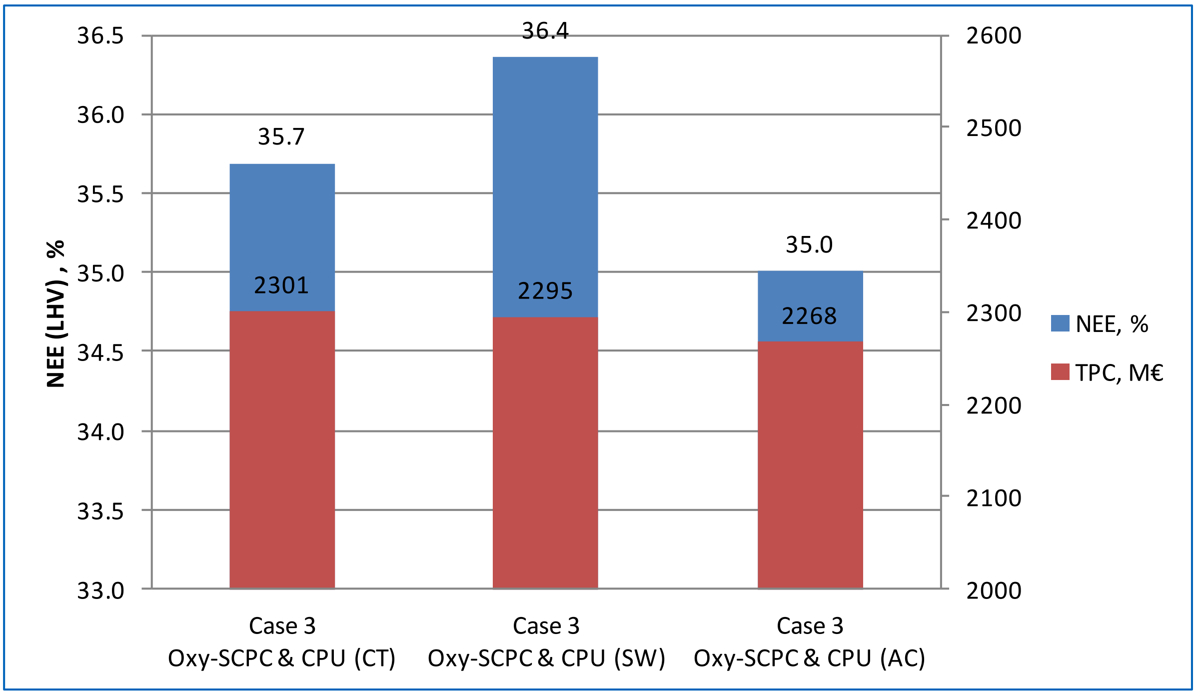

Figure 9. Oxy-SCPC with CPU - sensitivity to cooling type

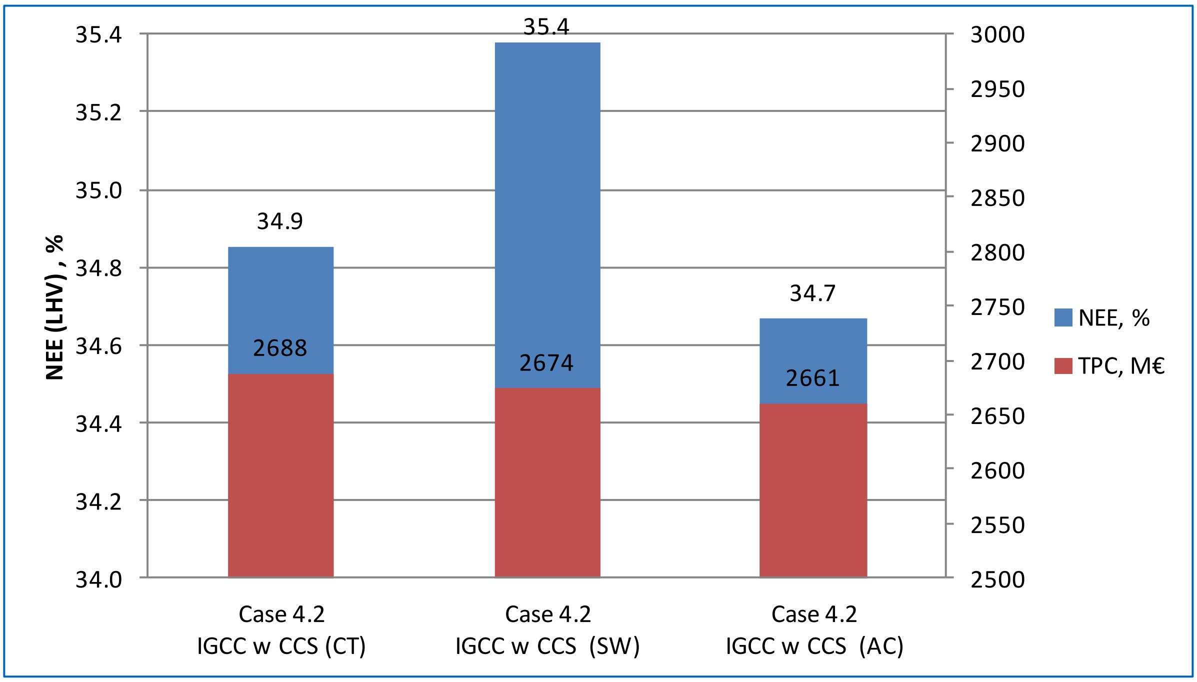

Figure 10. IGCC with CCS - sensitivity to cooling type

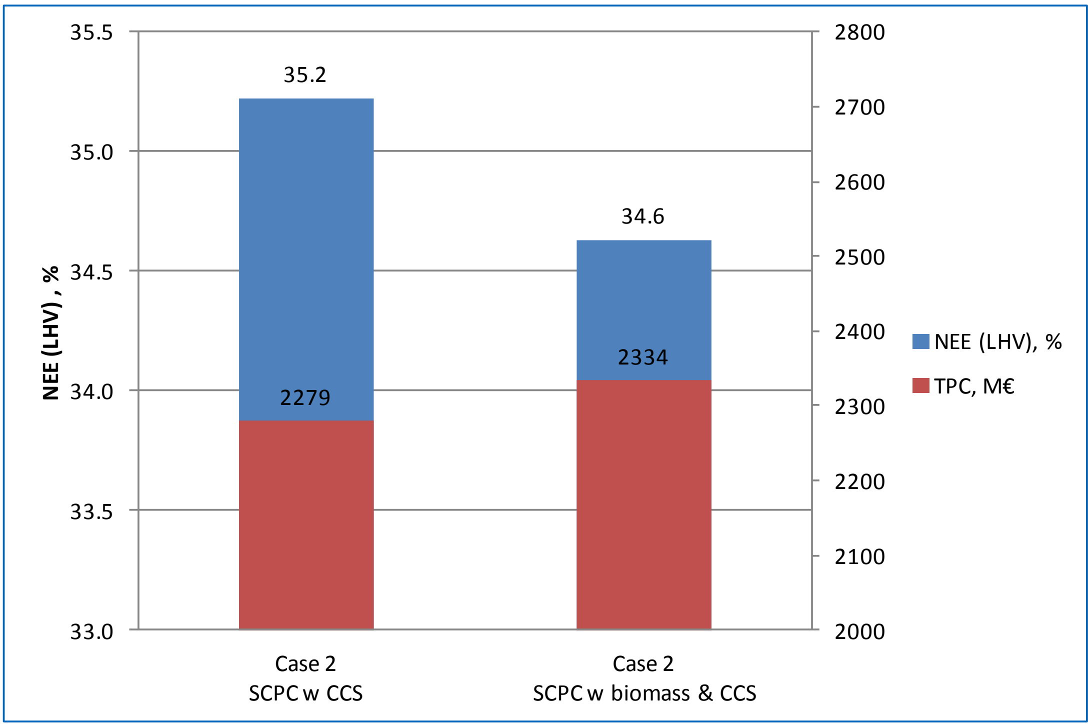

Figure 11. SCPC with CCS and biomass co-firing for zero net CO_2 emissions

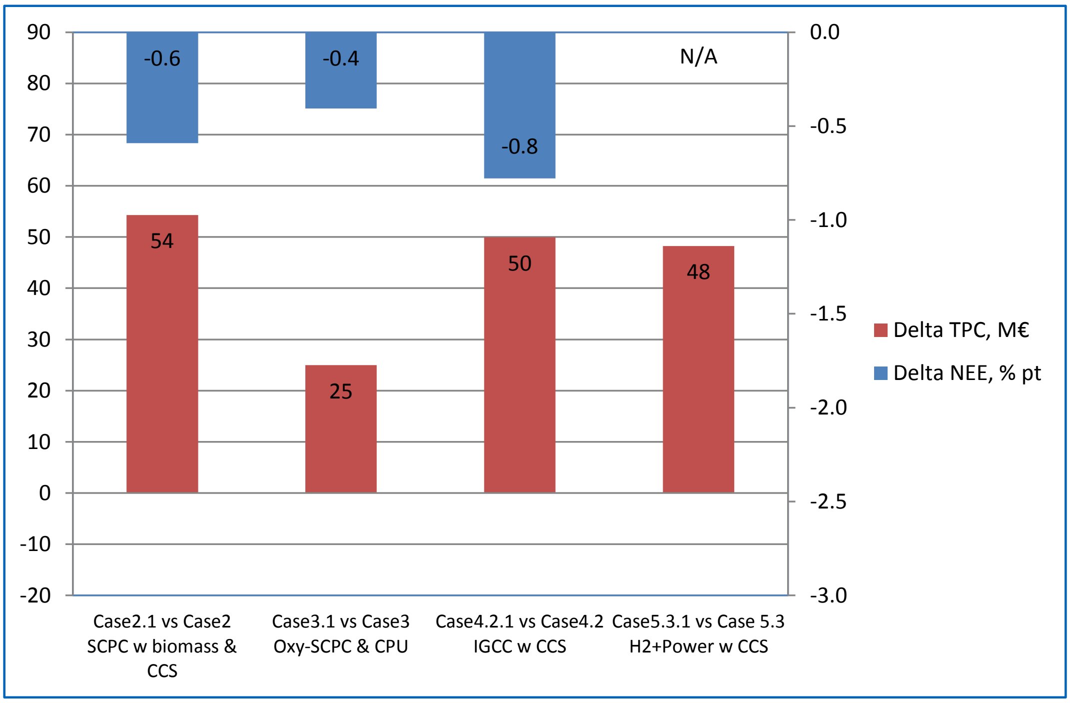

Figure 12. Oxy-SCPC, IGCC, H_2 & Power: near zero emission cases

Table 10. Financial analysis for near zero emission cases (reference's case data in gray)

Case	Description	LCOE (€/MWh)	CAC (€/t)
Case 2	SC-PC w/CCS	94.7	65.4
Case 2.1	SC-PC w/CCS near zero emission	100.5	65.1
Case 3	OXY SC-PC	91.6	60.8
Case 3.1	OXY SC-PC near zero emission	94.2	58.3
Case 4.2	IGCC (GEE)	114.4	95.8
Case 4.2.1	IGCC (GEE) near zero emission	119.2	92.5
Case	**Description**		**LCOH (c€/Nm³)**
Case 5.3	H_2&Power production: 2 x Boiler		17.3
Case 5.3.1	H_2&Power production: 2 x Boiler near zero emission		18.1(1)

(1) Assuming power selling price: 114.4 €/MWh, as per Case 4.2 (power production only)

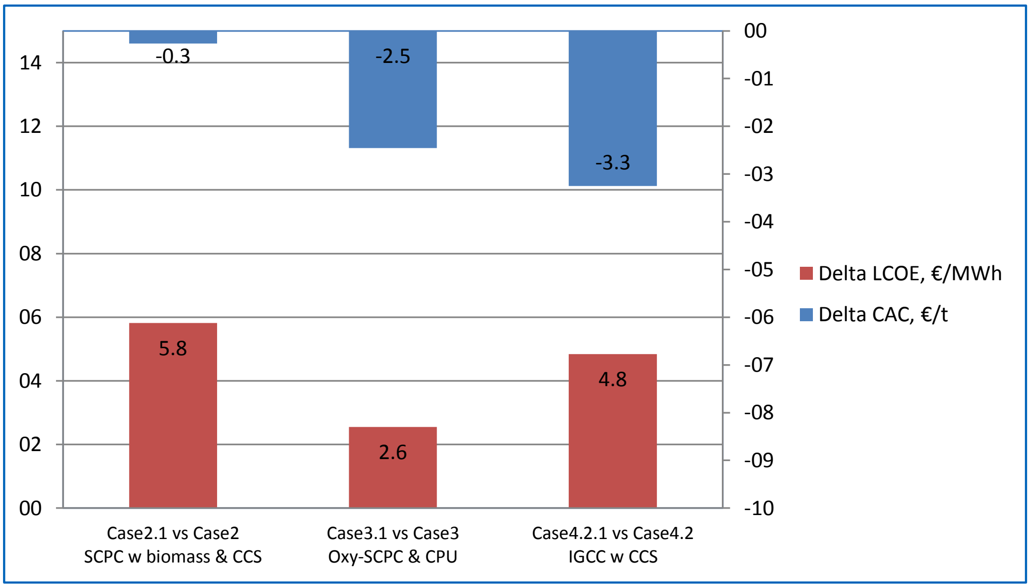

Figure 13. Biomass co-fired SCPC, Oxy-SCPC, IGCC: near zero emission cases

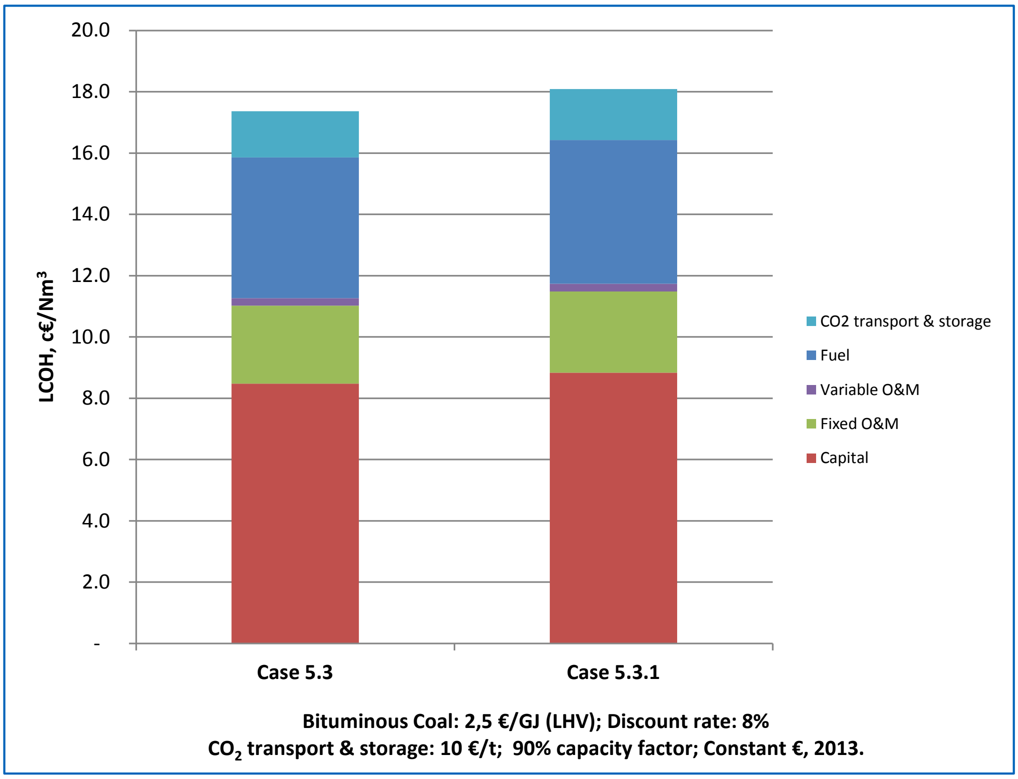

Figure 14. LCOH for near zero emission - power and hydrogen co-production case

8. Summary findings

The technical and economic assessments made in this study have generated a large amount of results for the coal fired power and hydrogen plants with the leading CO_2 capture technologies. The primary conclusions are given below.

SC-PC based cases (amine washing and oxy-combustion & CPU)

- For a Supercritical pulverized coal (SC-PC) power plant, using either oxy-combustion or post-combustion CO_2 capture, the net electrical efficiency loss is about 8.4-8.9% points compared to the case without capture (power production only), corresponding to approximately 20% reduction of the overall value. This is lower than the range (from 9 to 12 % points) of literature data([1],[2]), demonstrating the improvements made from the capture technology and the thermal integration design of the plant.
- The effect of introducing CO_2 capture in SC-PC power plants, either via post-combustion or oxy-combustion, leads to an increase of the Specific Total Plant Cost of about 91% in both capture technologies. This value appears to fall in the upper range of some literature studies([2]).
- The Levelized Cost of Electricity (LCOE) in boiler based plants with CO_2 capture is about 93 €/MWh (52 €/MWh is for the SC-PC power plant without CO_2 capture), while the CO_2 avoidance Cost (CAC) is about 63 €/t. Also these costs fall in the upper range of literature data([1,2]), mainly because the transportation and storage cost is included, but also as a result of the up-to-date capital cost assessment made in this work.
- The biomass co-firing in SC-PC boiler plants leads to a slightly worsening of both the performance and the costs of the plant, primarily due to the high biomass water content, resulting in an increased power requirement from the solid handling, milling and fan systems (higher flowrate).

IGCC based cases

- The net electrical efficiency loss is about 9% points and the Specific Total Plant Cost increase is more than twice (both referenced against the SC-PC boiler plant without capture). With respect to literature data([1,2]), the efficiency loss falls in the same range, while the specific TPC is higher. This latter data is mainly due to the up-to-date cost assessment of these plant types, which also

[1] EASAC policy report 20 (May 2013), collecting data from various sources: ZEP (2011), IEA (2005-2009), Global CCS Institute (2011), Alstom (2011).
[2] Cost and Performance of Carbon Dioxide Capture from Power Generation, IEA, Matthias Finkenrath, Working Paper (2011).

reflect the latest experience of the U.S. IGCCs (Kemper County and Edwardsport), though it is pointed out that these plants have been considered as Nth of a kind costs. Public available data from Edwardsport and Kemper experiences have shown that IGCC plants are more expensive than generally predicted in the past years in literature data; however, they are first of kind costs and cannot be considered as representative of technologies that, in the very near term, will achieve, or in some cases have already achieved, an advanced and well developed level of maturity.

- The LCOE and the CAC are respectively about 115 €/MWh and 97 €/t. Again, these costs are higher than those of literature studies([1,2]), due to the higher capital cost of the plant.

Hydrogen and power co-production cases

- Different hydrogen and power co-production cases have been assessed, based on various plant configurations designed to progressively reduce the net power production, while increasing the generation of high-purity hydrogen. In particular, with same coal thermal input, it has been possible to double the hydrogen production (from 220,600 Nm^3/h to 465,000 Nm^3/h), while reducing the net power export (from 440 MWe to 40 MWe).
- The higher the hydrogen production, the lower the Total Plant Cost, mainly due to the lower size of the power island (TPC of the boiler-based case is approximately 15% lower than the largest combined cycle case).
- With an electric energy selling price same as the IGCC-case for power production only (114 €/MWh), the Levelized Cost of Hydrogen (LCOH) is lowest for the highest hydrogen production case, i.e. the higher capital is not refunded by the higher power production. The LCOH of the lower hydrogen production cases only starts to become lower than that of the high hydrogen case when the electricity price is above €127/MWh.

Near-zero emission plants

- Near-zero emissions of CO_2 (about 98% overall CO_2 capture rate) is particularly favourable in oxy-combustion power plants, where the net electrical efficiency (NEE) reduction is 0.4% points and the Total Plant Cost increase is about 1%. On the other hand, both the NEE and the TPC penalties in IGCC plants are approximately twice. The same trend is also evident in the LCOE increase of the different near-zero emissions cases. This is mainly due to the use of the membrane technology in oxy-combustion plants, while a more energy demanding and more capital intensive solvent washing unit is required in gasification-based plants.

Other sensitivities

- The impact of cooling systems different from the natural draft cooling tower, namely once-through seawater cooling and dry air cooling, is respectively maximum +0.7% and - 0.7% points on the net electrical efficiency of the plant, at the reference ambient temperature of the study (9°C). On the other hand, a reduction of the Total Plant Cost is generally noted for both alternative cooling systems, in the range of -1.5%. It is pointed out that for higher reference ambient temperatures the delta performance between water cooled and air cooled based cases increases, negatively impacting the economics of the project.
- With a fuel cost variation from 1 to 4 €/GJ, all cases of the study show a linear increase of either the LCOE and CAC (power production) or the LCOH (power and hydrogen co-production). The trend increase follows the weight of the capital cost component of the different cases.
- If the Plant Capacity Factor changes, all cases of the study show a substantial variation of the main economical parameters: at 90% capacity factor the LCOE and LCOH are 30% lower than those at 50%, while in power plants with CO_2 capture the CAC at 90% capacity factor is about 30-35% lower than that at 50%.

This study has provided an up-to-date assessment of the performance and costs of various coal fired power and hydrogen plants, with and without capture of the generated CO_2. In general, the study has confirmed that any of the three leading capture technologies have made technological advances with respect to the past years, in particular the amine washing and the oxy-combustion in PC-based plants. On the other hand, the study has estimated that the CO_2 avoidance cost ranges from 60 to 100 €/t of CO_2, which corresponds to the incentive scheme needed for an economically viable investment.

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TABLE OF CONTENT

1. Background and objectives of the study

In the past years The International Energy Agency Greenhouse Gas R&D programme (IEAGHG) undertook a series of studies on the performance and costs of coal fired power and hydrogen plants with CO_2 capture, based on the three leading options, namely post-combustion capture and oxy-combustion for pulverised coal plants and pre-combustion capture in gasification plants.
Following the significant technological advances and the substantial increase of the plant costs, IEAGHG decided to undertake a wholly new study to provide an up-to-date assessment of the performance and costs of coal fired power and hydrogen plants, with and without capture of the generated CO_2.

With this premise, IEAGHG has contracted Foster Wheeler (FW) to perform a study that makes the technical and economical assessment of coal fired power and hydrogen plants with the leading CO_2 capture technologies.

This new study aims to provide a baseline for possible subsequent studies on other capture processes and capture in industries other than power and hydrogen generation from coal. It covers the following four plant types:

- Supercritical pulverised coal (SC-PC) power plant without CO_2 capture (reference plant for all the other cases);
- Supercritical pulverised coal power plant using oxy-combustion or with post combustion capture based on a high efficiency solvent washing process;
- Integrated Gasification Combined Cycle (IGCC) plant with pre-combustion capture using solvent scrubbing;
- Gasification for combined production of saleable hydrogen (99.5% purity, by means of PSA) and power (either by means of a combined cycle or using a conventional boiler-based unit), with pre-combustion capture via solvent scrubbing.

2. Study cases

The study investigates alternative designs of power and hydrogen generation plants, as shown in the following table. Technology suppliers that provided technical or cost data are also shown in the table. Other unit or equipment performance and costs (e.g. SC PC boiler for air- and oxy-fired cases, ASU for oxy-combustion and IGCC cases, SRU, etc.) are based on a generic design, not provided from a specific supplier.

Table 1. Study cases

Type	Case	Plant type	CO_2 capture target	Key technological features
Boiler-based	Case 1 (reference)	SC PC	-	• Alstom Wet limestone scrubbing FGD
	Case 2	SC PC w CCS	90%	• Alstom Wet limestone scrubbing FGD • CANSOLV solvent scrubbing (post-comb. capture)
	Case 3	Oxy-SC PC	90%	• FW Energie Circulating Fluid Bed Scrubber CFBS FGD technology • Air Products' Cryogenic Purification Unit
IGCC-based	Case 4.1	IGCC	90%	• Shell Coal Gasification Process, Radiant Syngas Cooler • UOP Selexol solvent scrubbing • Two (2) F-class gas turbines (~275 MWe eq. NG)
	Case 4.2	IGCC	90%	• General Electric, Radiant Syngas Cooler • UOP Selexol solvent scrubbing • Two (2) F-class gas turbines (~275 MWe eq. NG)
	Case 4.3	IGCC	90%	• MHI, Air-Blown two-stage entrained-bed gasifier • UOP Selexol solvent scrubbing • Two (2) MHI 701 F4 gas turbines
H_2 & Power	Case 5.1	IGCC + H_2 (PSA)	90%	• General Electric, Radiant Syngas Cooler • UOP Selexol solvent scrubbing • Two (2) E-class gas turbines (~ 130 MWe eq. NG)
	Case 5.2	IGCC + H_2 (PSA)	90%	• General Electric, Radiant Syngas Cooler • UOP Selexol solvent scrubbing • Two (2) frame 6 (~ 77 MWe eq. NG)
	Case 5.3	Gasification + Boiler + H_2 (PSA)	90%	• General Electric, Radiant Syngas Cooler • UOP Selexol solvent scrubbing • Off-gas based Boiler to mostly cover auxiliary power demand of the plant

The pulverised coal plants are based on state-of-the-art steam conditions (27 MPa/600°C/620°C) as used in new large coal fired power plants in Europe and Japan. The IGCC plants generally use two (2) state-of-the-art F-class 50Hz gas turbines, commercially available for firing high hydrogen content gas. The net output of the SCPC plant without capture is around 1,000 MW_e. The pulverised coal plants with capture are based on boilers with the same thermal capacity.

The technical and economic assessment of the above listed study cases are mostly based on technology and equipment that suppliers would be capable to offer on a commercial basis today. In some cases, near term efficiency improvements have been considered, as already anticipated by specialized Vendors (e.g. ASU).

The study includes also *"sensitivity cases"* to:

- Assess performance and costs of a pulverised coal plant with post combustion capture in which sufficient woody biomass is co-fired to achieve zero net emissions of CO_2 (considering biomass as zero carbon fuel).
- Assess the performance and costs variants of the oxy-combustion, IGCC and Hydrogen production plants with near-zero emissions of CO_2 (e.g. 98-99% overall CO_2 capture). Near zero emissions in the post combustion capture is expected to be not technically feasible at reasonable cost, so this is achieved co-firing some biomass (refer to the above bullet).
- Make sensitivity of performance and costs to two alternative types of cooling system (once-through sea water cooling and dry air cooling) for the reference plant and the three main plants with CO_2 capture for power production only.

Table 2. - Sensitivity study cases

Case	**Plant type**	**CO_2 capture target**	**Key technological features**
Case 2.1	SC PC w CCS	100	As Case 2 + woody biomass co-firing (zero CO_2 emission)
Case 3.1	Oxy-SC PC	98-99%	As Case 3 + Air Products' PRISM membranes (near zero CO_2 emission)
Case 4.2.1	IGCC	98-99%	As Case 4.2 + additional MDEA solvent scrubbing (near zero CO_2 emission)
Case 5.3.1	IGCC + H_2 (PSA)	98-99%	As Case 5.2 + additional MDEA solvent scrubbing (near zero CO_2 emission)
Case 1(SW)	SC PC	-	As Case 1, with seawater cooling
Case 1(AC)	SC PC	-	As Case 1, with air cooling
Case 2(SW)	SC PC w CCS	90%	As Case 2, with seawater cooling
Case 2(AC)	SC PC w CCS	90%	As Case 2, with air cooling
Case 3(SW)	Oxy-SC PC	90%	As Case 3, with seawater cooling
Case 3(AC)	Oxy-SC PC	90%	As Case 3, with air cooling
Case 4.2 (SW)	IGCC	90%	As Case 4.2, with seawater cooling
Case 4.2 (AC)	IGCC	90%	As Case 4.2, with air cooling

3. Project Design Bases (PDB)

This section describes the general plant design and cost estimating criteria, used as common basis for the design of the plant for the different study cases.

3.1. Location

The site is a Greenfield location on the North East coast of The Netherlands, with no major site preparation required. No restrictions on plant area and no special civil works or constraints on delivery of equipment are assumed. Rail lines, roads, fresh water supply and high voltage electricity transmission lines, high pressure natural gas pipeline are considered available at plant battery limits.

3.2. Climatic and meteorological data

Main climatic and meteorological data are listed in the following. Conditions marked (*) are considered reference conditions for plant performance evaluation.

• Atmospheric pressure	101.3	kPa	(*)
• Relative humidity			
average	80	%	(*)
maximum	95	%	
minimum	40	%	
• Ambient temperatures			
minimum air temperature	-10	°C	
maximum air temperature	30	°C	
average air temperature	9	°C	(*)

3.3. Feedstock specification

3.3.1. *Coal*

The main fuel of the different plants is bituminous coal type, with the characteristics and properties as shown in the following Table 3.

The reference coal is an Eastern Australian internationally traded open-cast coal, assumed delivered from a port to the plant site by unit trains.

Table 3. Bituminous Eastern Australian Coal characteristics

Proximate Analysis, wt% - As Received	
Inherent moisture	9.50
Ash	12.20
Coal (dry, ash free)	78.30
Total	**100.00**

Ultimate Analysis, wt% - Dry, ash free	
Carbon	82.50
Hydrogen	5.60
Oxygen	8.97
Nitrogen	1.80
Sulphur	1.10
Chlorine	0.03
Total	**100.00**

Ash analysis, wt%	
SiO_2	50.0
Al_2O_3	30.0
Fe_2O_3	9.7
CaO	3.9
TiO_2	2.0
MgO	0.4
Na_2O	0.1
K_2O	0.1
P_2O_5	1.7
SO_3	1.7

HHV (As Received), MJ/kg (*)	27.06
LHV (As Received), MJ/kg (*)	25.87
Grindability, Hardgrove Index	45
Ash Fusion Temperature at reduced atm., °C	1350

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

3.3.2. *Natural Gas*

Natural gas is used as start-up or plant back-up fuel and delivered to the plant battery limits from a high pressure pipeline.

The main characteristics of the natural gas are shown in the following Table 4.

Table 4. Natural Gas characteristics

Natural Gas analysis, vol%	
Methane	89.0
Ethane	7.0
Propane	1.0
Butane	0.1
Pentane	0.01
CO_2	2.0
Nitrogen	0.89
Total	**100.00**

HHV, MJ/kg	51.473
LHV, MJ/kg	46.502

Conditions at plant B.L.	
Pressure, MPa	7.0

3.3.3. *Biomass*

Wood chips biomass with the following characteristics is considered for Case 2.1, which makes co-firing of biomass and coal.

Table 5. Clean virgin wood, wood chips characteristics

Fuel As Received	
LHV, MJ/kg	7.3
Total moisture, %wt	50
Volatiles (Moisture and ash free basis), %wt	80
Bulk density, kg/m^3	250-350
Ash softening point (reducing conditions), °C	> 1100

Dry solid analysis, wt%	
Carbon	50.0
Hydrogen	5.4
Oxygen	42.2
Nitrogen	0.3
Sulphur	0.05
Ash	2.0
Chlorine	0.02
Total	**100.00**

Ash analysis, wt%	
SiO_2	15 – 50
TiO_2	0.1 – 0.4
Al_2O_3	4.0 – 10.0
Fe_2O_3	1.0 – 4.0
MgO	1.0 – 5.0
CaO	20 – 30
Na_2O	0.5 – 2.3
K_2O	1.0 – 6.5
P_2O_5	0.5 – 2.5
MnO	1.0 – 3.0
SO_3	0.5 – 2.0
Alkaline in ash (weak acid soluble)	
(Na + K)	$\leq$ 4.5

3.3.4. Limestone

A reactive, amorphous limestone, whose composition is shown in the below table, is assumed for the design of Flue Gas Desulphurization based on wet scrubbing technology.

	% by weight
$CaCO_3$	95.0
$MgCO_3$	1.5
Inerts	2.5
Moisture	1.0

3.4. Products and by-products

The main products and by-products of the study cases are listed here below, together with their main characteristics.

3.4.1. *Electric Power*

Grid Connection Voltage:	380	kV
Electricity Frequency:	50	Hz
Fault duty:	50	kA

3.4.2. *Carbon Dioxide*

Plants are generally designed for a capture rate not less than 90%.

CO_2 is delivered from the plant site to the pipeline at the following conditions and characteristics.

Table 6. CO_2 characteristics

CO_2 conditions at plant B.L.	
Pressure, MPa	11
Maximum Temperature, °C	30

CO_2 maximum impurities, vol. Basis [(0)]	
H_2	4% [(1,3)]
N_2 / Ar	4% [(2,3)]
CO	0.2% [(5)]
H_2O	50 ppm [(4)]
O_2	100 ppm [(6)]
H_2S	20 ppm [(7)]
SO_X	100 ppm [(5)]
NO_X	100 ppm [(5)]

(0) Based on information available in 2012 on the requirements for CO_2 transportation and storage in saline aquifers

(1) Hydrogen concentration to be normally lower to limit loss of energy and economic value. Further investigation is required to understand hydrogen impact on supercritical CO_2 behaviour.

(2) The limits on concentrations of inerts are to reduce the volume for compression, transport and storage and limit the increase in Minimum Miscibility Pressure (MMP) in Enhanced Oil Recovery (EOR).

(3) Total non-condensable content ($N_2 + O_2 + H_2 + CH_4$ + Ar): maximum 4% vol. Basis.

(4) Water specification is to ensure there is no free water and hydrate formation.

(5) H_2S, SO_2, NO_2 and CO limits are set from a health and safety perspective.

(6) O_2 limit is tentative in view of the lack of practical experience on effects of O_2 in underground reservoirs. EOR may require tighter specification.
(7) H_2S specification is for a corrosion and pipeline integrity perspective.

3.4.3. *Sulphur (Gasification-based cases)*

Sulphur characteristics at IGCC plant B.L. are the following:

Status:	solid/liquid
Colour:	bright yellow
Purity:	99.9 % wt. S (min)
H_2S content:	10 ppm (max)
Ash content:	0.05 % wt (max)
Carbonaceous material:	0.05 % wt (max)

3.4.4. *Hydrogen (Gasification for H_2 production cases)*

Hydrogen characteristics are the following:

H_2	99.5 % vol. (min)
$CO + CO_2$	10 ppm max
CO	10 ppm max
H_2S, HCl, COS, HCN, NH_3	free
N_2 + Ar	balance
Pressure at B.L.	about 50 barg
Temperature	40 °C

3.5. Environmental limits

The environmental limits set up for each case are outlined hereinafter.

3.5.1. *Gaseous emissions*

The overall gaseous emissions from the plant do not exceed the following limits, as per EU directives 2010/75/EU (Part 2 of Annex V):

	SC PC based cases (1)	**IGCC based cases (2)**
NO_X (as NO_2)	≤ 150 mg/Nm^3	≤ 50 mg/Nm^3
SO_X (as SO_2)	≤ 150 mg/Nm^3	≤ 10 mg/Nm^{3} (4)
CO	-	≤ 100 mg/Nm^3
Particulate	≤ 10 mg/Nm^3 (3)	≤ 10 mg/Nm^{3} (4)

Note: (1) Emission expressed in mg/Nm^3 @6% O_2, dry basis, applicable to the air fired SC PC plants only; for the oxy-combustion based power plant this is not relevant, due to the very

low flowrate of the inerts gas stream discharged to atmosphere. Regulatory approach for this plant type not yet defined.
(2) @ 15% O_2 volume dry
(3) 20 mg/Nm^3 for biomass
(4) Not included in the EU directive as assumed negligible in gas turbine plants

3.5.2. *Liquid effluent*

Characteristics of waste water discharged from the plant comply with the standard limits included in the EU directives currently in force.

The main continuous liquid effluent is the blow-down from the cooling towers (base option). Effluent from the Waste Water Treatment is generally recovered and recycled back to the plant as process water, where possible, or discharged to the final receiver.

3.5.3. *Solid wastes*

The solid wastes of the gasification-based cases are:

- Slag, which is potentially saleable to the building industry
- Filter cake, which contains some toxic compounds.

The solid wastes of the SC PC-based cases are:

- Bottom ash
- Fly Ash.

Other potential solid wastes are typical industrial plant waste (e.g. sludge from Waste Water Treatment etc.).

3.5.4. *Noise*

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

3.6. SC-PC-based cases: key features

3.6.1. *Capacity*

The nominal net power output of the reference SC PC plant (Case 1) without CO_2 capture is around 1,000 MWe, which is a typical size for new supercritical coal fired power plants.

The fuel thermal input of plant with CO_2 capture (Case 2) is same the reference case without capture.

3.6.2. *Unit arrangement*

Unit 1000 Feedstock and solid Storage and Handling

Unit 2000	Boiler Island
Unit 2050	DeNOx Plant
Unit 2100	FGD and Gypsum Handling Plant
Unit 3000	Steam Cycle
Unit 4000	CO_2 Amine Absorption (Case 2 only)
Unit 5000	CO_2 compression and dehydration (Case 2 only)
Unit 6000	Utility and offsite

3.6.3. *Minimum turndown*

The general minimum stable operating load of the boiler is 30% as far as duty is concerned.

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

The minimum stable operating load of the CO_2 capture plant is around 30% of the flue gases entering the unit.

Therefore, the expected overall plant minimum turndown is around 30%. No additional facilities or equipment are considered for further lowering this minimum turndown.

For further details on minimum plant turndown and plant capability to operate flexible and efficiently at part load reference shall be made to IEAGHG report 2012/06 '*Operating Flexibility of power Plant with CCS*'.

3.7. Oxy SC PC-based cases: key features

3.7.1. *Capacity*

Boiler capacity is set in order to maintain same thermal input as the reference SC PC plant without capture (Case 1).

3.7.2. *Unit Arrangement*

Unit 900	Air Separation Unit
Unit 1000	Feedstock and solid Storage and Handling
Unit 2000	Boiler Island
Unit 2100	FGD and solid by-product Handling Plant
Unit 3000	Steam Cycle
Unit 4000	Cryogenic Purification and Compression Unit
Unit 6000	Utility and offsite

3.7.3. *Minimum turndown*

The general minimum stable operating load of the boiler is 30% as far as duty is concerned.

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

The minimum stable operating load of the Cryogenic Purification Unit for CO_2 capture is expected to be around 30% on the basis of the flue gases inlet flowrate.

Therefore, the expected overall plant minimum turndown is around 30%. No additional facilities or equipment are considered for further lowering this minimum turndown.

For further details on minimum plant turndown and plant capability to operate flexible and efficiently at part load reference shall be made to IEAGHG report 2012/06 '*Operating Flexibility of power Plant with CCS*'.

3.8. Gasification-based cases: key features

3.8.1. *Capacity*

The gasification capacity, i.e. the coal flow rate of the IGCC Complex is fixed to match the thermal requirements of two commercially available gas turbines (F-Class equivalent) in the combined cycle, at the reference ambient temperature of the study.

For the hydrogen and power co-production cases, the gasification capacity is left unchanged, while the combined cycle or the boiler island require lower amount of syngas (lower power production). In this case, excess syngas is used to generate high-purity hydrogen.

Air Separation Unit (ASU) capacity is defined by oxygen requirements of the IGCC Complex (mainly the gasifiers requirement plus the marginal consumption of Sulphur Recovery Unit). ASU is also requested to produce nitrogen at different levels of pressure to be supplied to the IGCC Complex.

Sulphur Recovery Unit consists of two trains at 100% capacity. The Tail Gas Treatment consists of a Hydrogenation step plus gas scrubbing sections and a dedicated compressor to recycle the stream back to the AGR Unit. This Unit is designed for 100% of the max tail gas production of the SRU.

3.8.2. *Unit Arrangement*

Unit 900	Feedstock and solid Storage and Handling
Unit 1000	Gasification
Unit 2100	Air Separation Unit (ASU)

Unit 2200	Syngas Treatment and Conditioning Line
Unit 2300	Acid Gas Removal (AGR)
Unit 2400	Sulphur Recovery Unit (SRU) & Tail Gas Treatment (TGT)
Unit 2500	CO_2 Compression and Dehydration
Unit 2600	PSA (hydrogen production cases)
Unit 3000	Combined Cycle (or Steam Cycle)
Unit 4000	Utility & offsite

3.8.3. *Minimum turndown*

The Gasification Unit is composed of two gasifiers, allowing to operate at low loads with respect to the IGCC design capacity, the minimum turndown of the single gasifier being 50%.

Most other Units are based on twin trains (50% capacity each) thus limiting the events causing the shutdown of the entire IGCC Complex or of the entire Gasification Island.

The minimum stable operating load of each Gas Turbine on syngas is 20% as far as electrical generation is concerned, thus corresponding to 10% of the IGCC capacity. In practice, the minimum load at which the Gas Turbine is able to operate, still meeting the environmental limits, in particular NOx and CO emissions, is around 60%. i.e. 30% of the overall IGCC capacity.

Therefore, the expected overall plant minimum turndown is around 30%. No additional facilities or equipment are considered for further lowering this minimum turndown.

For further details on minimum plant turndown and plant capability to operate flexible and efficiently at part load reference shall be made to IEAGHG report 2012/06 '*Operating Flexibility of power Plant with CCS*'.

3.9. Availability

The table hereafter reports the expected maximum availability (average yearly load factor) assumed for each study case, along with the availability curve for the first years of operation.

Plant type	Year	Average Load factor
SC PC based	1st year of operation	65%
	2nd year of operation	85%
	3rd – 25th year of operation	90%
Gasification based	1st year of operation	60%
	2nd year of operation	80%
	3rd – 25th year of operation	85%

3.10. Cost estimating bases

The following sections describe the main cost estimating bases used to make the economic assessment of the various cases.

3.10.1. Total Capital Requirement

The Total Capital Requirement (TCR) includes:

- Total Plant Cost (TPC)
- Interest during construction
- Spare parts cost
- Working capital
- Start-up costs
- Owner's costs.

The estimate is in euro (€), based on 2Q2013 price level.

3.10.2. Total Plant Cost

The Total Plant Cost (TPC) is the installed cost of the plant including contingencies.

The TPC is broken down into the main process units and, for each unit, split into the following items:

- Direct materials
- Construction
- Other costs
- EPC services
- Contingency.

3.10.3. Estimate accuracy

Estimate accuracy is in the range of +35%/-15% (AACE Class 4).

3.10.4. Contingency

A project contingency is added to the capital cost to give a 50% probability of a cost over-run or under-run.

For the accuracy considered in this study, FW's view is that contingency should be in the range of 10-15% of the total plant cost. 10% is assumed for this study for all the different units of the plant, for consistency with the other IEAGHG studies.

3.10.5. Design and construction period

Plant design and construction period and curve of capital expenditure during construction depend on the plant type, as detailed in the following table.

	SC PC cases	Gasification cases
Construction period [(1)]	3 years	4 years
Curve of capital expenditure		
Year	Investment cost %	
1	20	15
2	45	40
3	35	30
4	-	15

Note: (1) Starting from issue of Notice to Proceed to the EPC contractor

3.10.6. *Financial leverage (debt / invested capital)*

All capital requirements are treated as debt, i.e. financial leverage equal to 100%.

3.10.7. *Discount rate*

Discount cash flow calculations are expressed at a discount rate of 8%.

3.10.8. *Interest during construction*

Interest during construction is calculated from the plant construction schedule and interest rate is assumed same as the discount rate. Expenditure is assumed to take place at the end of each year and interest during construction payable in a year is calculated based on money owed at the end of the previous year.

3.10.9. *Spare parts cost*

0.5% of the TPC is assumed to cover spare part costs. It is assumed that spare parts have no value at the end of the plant life due to obsolescence.

3.10.10. *Working capital*

Working capital includes inventories of fuel and chemicals (materials held in storage outside of the process plants). Storage for 30 days at full load is considered for coal, chemicals and consumables.

It is assumed that cost of these materials is recovered at the end of the plant life.

3.10.11. *Start-up cost*

Start-up costs consist of:

- 2 percent of TPC, to cover modifications to equipment that needed to bring the unit up to full capacity.
- 25% of the full capacity fuel cost for one month, to cover inefficient operation that occurs during the start-up period.
- Three months of operating and maintenance labour costs, to include training.

- One month of catalysts, chemicals and waste disposal and maintenance materials costs.

3.10.12. <u>Owner's cost</u>

7% of the TPC is assumed to cover the Owner's cost and fees.

Owner's costs cover the costs of feasibility studies, surveys, land purchase, construction or improvement to roads and railways, water supply etc. beyond the site boundary, owner's engineering staff costs, permitting and legal fees, arranging financing and other miscellaneous costs. Owner's costs are assumed to be all incurred in the first year of construction, allowing for the fact that some of the costs would be incurred before the start of construction.

3.10.13. <u>Insurance cost</u>

0.5% of the TPC is assumed to cover the insurance cost.

3.10.14. <u>Local taxes and fees</u>

0.5% of the TPC is assumed to cover the Local taxes and fees.

3.10.15. <u>Decommissioning cost</u>

For fossil fuel and CCS plants the salvage value of equipment and materials is normally assumed to be equal to the costs of dismantling and site restoration, resulting in a zero net cost of decommissioning.

3.11. Operating and Maintenance costs

Operating and Maintenance (O&M) costs include:

- Chemicals
- Catalysts
- Solvents
- Raw Water make-up
- Direct Operating labour
- Maintenance
- Overhead Charges.

O&M costs are generally allocated as variable and fixed costs.

<u>Variable costs</u> depend on the plant operating load. They can be expressed as €/kWh or €/h.

<u>Fixed operating costs</u> are essentially independent from the plant operating load. They can be expressed as €/y.

3.11.1. *Variable costs*

Consumables are the principal components of variable O&M costs. These include feedstock, water, catalysts, chemicals, solid waste disposal and other.

Costs are calculated on the basis of standard coal prices. Reference values for coal and main consumables prices are summarised in the table below.

Item	Cost
Coal, €/GJ (LHV)	2.5
Biomass, €/t dry	100
Limestone, €/t	20
Lime, €/t	45
Raw process water, €/m^3	0.2
Ash, slag, gypsum and sulphur net disposal cost	0
CO_2 transport and storage, €/t CO_2 stored (1)	10
CO_2 emission cost, €/t CO_2 emitted	0

(1) Transport and storage cost as specified by IEAGHG, in accordance with the range of costs information in the European Zero Emissions platform's report "The costs of CO_2 capture, transport and storage", published in 2009. Sensitivity to transport and storage costs are assessed to cover lower or negative cost for EOR, due to the revenue for sale of CO_2, or higher cost, in case of off shore storage with long transport distances.

3.11.2. *Fixed costs*

The fixed costs of the different plants include the following items:

Direct labour
The yearly cost of the direct labour is calculated assuming, for each individual, an average cost equal to 60,000 €/y. The number of personnel engaged is estimated for each plant type, considering a 5 shift working pattern.

Administrative and support labour
All other company services not directly involved in the operation of the plant 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.

Administrative and support labour is assumed to be 30% of the direct labour and maintenance labour cost (see below).

Maintenance

A precise evaluation of the cost of maintenance would require a breakdown of the costs amongst the numerous components and packages of the plant. 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 study level.

For this reason the annual maintenance cost of the plant is normally estimated as a percentage of the total plant cost of the facilities, as shown in the following:

SC PC based cases	1.5%
Gasification based cases	2.5%

Maintenance labour is assumed to be 40% of the overall maintenance cost.

4. Basic Engineering Design Data (BEDD)

Scope of the Basic Engineering Design Data is the definition of the common bases used for the design of the process and utility units of the different study cases, as listed in the following.

SC PC power plant with / without post-combustion capture

Process Units, including:

- Storage and Handling of solid materials, including:
  - Coal storage and handling
  - Ash and solid removal and handling
  - FGD sorbent storage and handling
  - FGD by-product storage and handling
- Boiler Island, including
  - Coal mills
  - ID fan
  - Particulate removal system (ESP)
  - Flue gas stack
- Flue Gas Desulphurisation, including gas-gas heat exchanger
- DeNOx plant
- CO_2 capture plant (only for case 2)
- CO_2 compression and drying (only for case 2)

Power Island, including:

- Steam Turbine and condenser;
- Preheating Line;
- Electrical Power Generation, including main power transformers.

Utility and Offsite Units, providing utility fluids to other units, including:

- Primary Cooling Water (cooling tower) and Machinery Cooling Water systems;
- Cooling Water/Machinery Cooling Water Systems;
- Demineralized, Condensate Recovery, Plant and Potable Water Systems;
- Back-up fuel system;
- Plant/Instrument Air Systems;
- Waste Water Treatment;
- Fire fighting System;
- Chemicals;
- Interconnecting (instrumentation, DCS, piping, electrical substations).

SC PC oxy-combustion power plant

Process Units, including:

- Storage and Handling of solid materials, including:
  - Coal storage and handling
  - Ash and solid removal and handling
  - FGD sorbent storage and handling
  - FGD by-product storage and handling
- Boiler Island
  - Coal mills
  - Flue gas fans
  - Particulate removal system (ESP)
  - Heat Recovery system
- Air Separation Unit
- Flue Gas Desulphurisation
- CO_2 purification and compression

Power Island, including:

- Steam Turbine and condenser;
- Preheating Line;
- Electrical Power Generation, including main power transformers.

Utility and Offsite Units, providing utility fluids to other units, including:

- Primary Cooling Water (cooling tower) and Machinery Cooling Water systems;
- Demineralised, Condensate Recovery, Plant and Potable Water Systems;
- Back-up fuel system;
- Plant/Instrument Air Systems;
- Waste Water Treatment;
- Fire fighting System;
- Chemicals;
- Interconnecting (instrumentation, DCS, piping, electrical substations).

Coal IGCC plant with pre-combustion capture (power only cases)

Process Units, including:

- Coal Handling and Storage;
- Gasification Island, including coal milling and drying (if applicable);
- Air Separation Unit;
- Syngas Treatment and Conditioning Line;
- Acid Gas Removal Unit;
- Sulphur Recovery and Tail Gas Treatment;
- CO_2 Compression and Drying.

Power Island, including:

- Gas Turbines;
- Heat Recovery Steam Generators;
- Steam Turbine;
- Electrical Power Generation, including main power transformers.

Utility and Offsite Units, providing utility fluids to other units, including:

- Primary Cooling Water (cooling tower) and Machinery Cooling Water systems;
- Demineralised, Condensate Recovery, Plant and Potable Water Systems;
- Back-up fuel system;
- Plant/Instrument Air Systems;
- Waste Water Treatment;
- Fire fighting System;
- Solid Handling;
- Sulphur Storage and Handling;
- Chemicals;
- Flare system
- Interconnecting (instrumentation, DCS, piping, electrical substations).

Coal gasification plant for power and hydrogen co-production

Process Units, including:

- Coal Handling and Storage;
- Gasification Island, including coal milling and drying (if applicable);
- Air Separation Unit;
- Syngas Treatment and Conditioning Line;
- Acid Gas Removal Unit;
- Pressure Swing Adsorption (PSA) unit
- Sulphur Recovery and Tail Gas Treatment;
- CO_2 Compression and Drying.

Power Island, including:

- Gas Turbines and Heat Recovery Steam Generators (combined cycle alternatives);
- PSA off-gas fired boilers (boiler alternative)
- Steam Turbine;
- Electrical Power Generation, including main power transformers.

Utility and Offsite Units, providing utility fluids to other units, including:

- Primary Cooling Water (cooling tower) and Machinery Cooling Water systems;
- Demineralised, Condensate Recovery, Plant and Potable Water Systems;
- Back-up fuel system;
- Plant/Instrument Air Systems;

- Waste Water Treatment;
- Fire fighting System;
- Solid Handling;
- Sulphur Storage and Handling;
- Chemicals;
- Flare system
- Interconnecting (instrumentation, DCS, piping, electrical substations).

4.1. Units of measurement

The units of measurement are in SI units.

4.2. Plant Battery Limits (main)

4.2.1. Electric Power

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

4.2.2. Process and utility streams

SC PC power plants with / without post-combustion capture

- Coal
- FGD sorbent/FGD by-product/ashes
- Natural gas
- Cooling tower make-up water
- Waste water streams, including cooling tower blow-down
- Plant/Raw/Potable water
- CO_2 rich stream (only in case 2).

SC PC oxy-combustion power plants

- Coal
- FGD sorbent/FGD by-product/ashes
- Natural gas
- Cooling tower make-up water
- Waste water streams, including cooling tower blow-down
- Plant/Raw/Potable water
- CO_2 rich stream.

Gasification plants with pre-combustion capture

- Coal
- Limestone (if applicable)
- Natural gas

- Cooling tower make-up water
- Waste Water streams, including cooling tower blow-down
- Gasification solid wastes
- Plant/Raw/Potable water
- Sulphur product
- CO_2 rich stream
- Hydrogen (hydrogen production cases).

4.3. Utility and service fluids characteristics/conditions

Following sections list main utilities and service fluids generated and distributed inside the plant.

4.3.1. Cooling Water

The cooling water system is based on natural draft cooling tower.
The cooling water system sensitivity analysis considers either once through seawater cooling system or dry air cooling system.

Main cases – Natural draft cooling tower

Cooling water approach to wet bulb temperature:	7 °C
Supply temperature	
- normal:	15 °C
- maximum:	36 °C

Primary system

Source : raw water in closed loop from Natural Draft Cooling towers.
Service : for steam turbine condenser.

Operating pressure at condenser inlet:	3.0 bar
Mechanical design pressure:	6.0 bar
Maximum allowable ΔP for condenser:	0.5 bar
Mechanical design temperature:	50°C
Maximum temperature difference at condenser:	11°C
Turbine condenser minimum ΔT:	3°C
Turbine condenser conditions	
Temperature	29°C
Pressure	4 kPa

Secondary system

Source : raw water in closed loop from Natural Draft Cooling tower (same as per condenser)
Service : for machinery cooling (different ΔP at users)

Operating pressure at User:	4.0 bar

Mechanical Design pressure:	7.0 bar
Max allowable ΔP for Users:	1.5 bar
Maximum temperature difference at users:	11°C
Mechanical design temperature:	50°C

Seawater cooling (sensitivity cases)

Primary system

Source : sea water in once through system
Service : for steam turbine condenser and CO_2 compression unit.
Type : clear filtered and chlorinated, without suspended solids and organic matter.
Salinity : 22 g/l

Supply temperature:	
- average supply temperature (on yearly basis):	12°C
- max supply temperature (average summer):	14°C
- min supply temperature (average winter):	9°C
- max allowed sea water temperature increase:	7°C
Return temperature:	
- average return temperature:	19°C
- max return temperature:	21°C
Design temperature:	50°C
Operating pressure at condenser inlet:	0.5 barg
Design pressure:	4.0 barg
Max allowable ΔP for Users:	0.5 bar
Turbine condenser minimum ΔT:	5°C
Turbine condenser conditions	
Temperature	28°C
Pressure	3.8 kPa

Secondary system

Source : demineralised water stabilized and conditioned – seawater cooled

Service : for machinery cooling and for all plant users other than steam turbine condenser and CO_2 compression exchangers

Supply temperature:	
- Average supply temperature	19°C
- max supply temperature:	21°C
- max allowed temperature increase:	11°C
Design temperature:	50 °C
Operating pressure at Users:	3.0 barg

Design pressure:	7.0 barg
Max allowable ΔP for Users:	1.5 bar

Air Cooling System (sensitivity cases)

Primary system

No primary cooling water is available at all. Air only is used as primary cooling medium.

The temperature difference considered between the inlet condensing steam and the ambient air in the steam condenser is 25 °C.

The temperature difference between hot fluid exit temperature and ambient air for service other than steam condenser is 10°C.

Secondary system

Source : demineralised water stabilized and conditioned – air cooled

Service : for machinery cooling and for all plant users where air cooling is not applicable

Supply temperature:

- max supply temperature:	38°C
- average supply temperature:	18°C
- max allowed temperature increase:	8°C
Design temperature:	50 °C

Operating pressure at Users:	3.0 barg
Design pressure:	7.0 barg
Max allowable ΔP for Users:	1.5 bar

4.3.2. Waters

Potable water

Source : from grid
Type : potable water

Operating pressure at grade (min):	0.8 barg
Design pressure:	5.0 barg
Operating temperature:	Ambient
Design temperature:	38°C

Raw water

Source : from grid
Type : raw water

Operating pressure at grade (min):	0.8 barg
Design pressure:	5.0 barg

Operating temperature:	Ambient
Design temperature:	38°C

Plant water

Source : from storage tank of raw water
Type : raw water

Operating pressure at grade:	3.5 barg
Design pressure:	9.0 barg
Operating temperature:	Ambient
Design temperature:	38°C

Demineralised water

Type : treated raw water

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

Characteristics:

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

4.3.3. *Steam, Steam Condensate and BFW*

SC PC-based cases

Steam

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

Table 7. SC PC cases: steam conditions

Main HP steam		
Pressure	bar	270
Temperature	°C	600
Cold reheat		
Temperature	°C	363
Hot reheat		
Pressure	bar	60
Temperature	°C	620

Boiler Feed Water

The Boiler Feed Water is available at Boiler B.L. at 290°C.

Gasification-based cases

Steam

Steam conditions are highly dependent on the gasification technology, in particular HP steam generation level. Steam conditions summarised below refer to the Process Units. Inside Power Island the steam levels are different even if interconnected to the Process.

Table 8. Process Units steam conditions

	Pressure, barg			Temperature, °C	
	Max	**Min**	**Design**	**Norm**	**Design**
High Pressure **(HP)** Nominal Pressure: 137 barg (GE)	138	137	150	336	343
High Pressure **(HP)** Nominal Pressure: 130 barg (Shell)	135	130	145	332	340
Medium Pressure **(MP)** Nominal Pressure: 40 barg	43	40	47	256	270
Low Pressure **(LP)** Nominal Pressure: 6.5 barg	8	6.5	12	175	250

In the table above:

- The maximum value indicates the steam generation pressure of 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.

Cold condensate

Type: condensate from Power Island (plus demineralised water make up)

Supply:

- Operating pressure at Users: 16 barg
- Design pressure: 22 barg
- Operating temperature: 21°C
- Design temperature: 50°C
- Fouling Factor: 0.0001 h °C m^2/kcal

Return:

- Operating pressure: 10 barg
- Design pressure: 22.8 barg

- Operating temperature: 95°C
- Design temperature: 130°C
- Fouling Factor: 0.0002 h °C m^2/kcal

Steam condensate from process, utility and off site units

Steam condensate is flashed within process units whenever possible to recover steam and piped back to the condensate collection header.

The condensate collection header has the following characteristics:

Operating pressure for other Units B.L.: 1 barg
Design pressure: 12 barg
Operating temperature: 94°C
Design temperature: 250°C

Boiler Feed Water

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

Table 9. Boiler Feed Water at units B.L.

	Pressure, barg Normal	Temperature, °C Normal
Boiler Feed Water, Low Pressure **(BWL)**	15	160
Boiler Feed Water, Medium Pressure **(BWM)**	60	160
Boiler Feed Water, High Pressure **(BWH)**	170	160

4.3.4. *Instrument and Plant Air*

Instrument air

Operating pressure
- normal: 7.0 barg
- minimum: 5.0 barg

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

Plant air

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

4.3.5. *Nitrogen (Gasification-based cases)*

Low Pressure Nitrogen

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

Medium Pressure Nitrogen (Syngas dilution)

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

Medium Pressure Nitrogen (GT injection)

Supply pressure:	26 barg
Design pressure:	35 barg
Supply temperature:	210°C
Design temperature:	240°C
Min Nitrogen content:	98 % vol

High Pressure Nitrogen (Gasifier Transport System)

Supply pressure:	88 barg (*)
Design pressure:	93 barg (*)
Supply temperature:	80°C (*)
Design temperature:	110°C (*)
Min Nitrogen content:	99.99 % vol

(*) Assumed by FWI

4.3.6. *Oxygen*

Oxygen for the oxy-combustion boiler (Case 3)

Supply pressure:	0.6 barg
Design pressure:	3.5 barg
Supply temperature:	16°C
Design temperature:	50°C
Purity:	97.0% mol. O_2 min 2.0% mol Ar 1.0% 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

Oxygen for the gasifier

Supply pressure:	46 barg (Shell)
	75-80 bar (GE) (*)
Design pressure:	55 barg (Shell) (*)
	99 barg (GE) (*)
Supply temperature:	25°C
Design temperature:	70°C
Purity:	95.0% mol. O_2 min
	3.5% mol Ar
	1.5% 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

(*) Assumed by FWI

Oxygen for Sulphur plant

Supply pressure at IGCC BL:	5.0 barg
Design pressure:	8.0 barg
Supply temperature (min):	15°C
Design temperature:	50°C
Purity:	95% mol. O_2 min

4.3.7. *Chemicals (main)*

Caustic Soda

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

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

Hydrochloric Acid

Two 20% by wt HCl storage vessels are foreseen and used to unload hydrochloric acid from trucks.
Concentrated HCl is pumped to users at following conditions:

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

Chemical for DeNOx

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

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

4.3.8. *Electrical System*

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

	Voltage level (V)	*Electric Wire*	*Frequency (Hz)*	*Fault current duty (kA)*
Primary distribution	33000 ± 5%	3	50 ± 0.2%	31.5 kA
MV distribution and utilization	10000 ± 5% 6000 ± 5%	3 3	50 ± 0.2% 50 ± 0.2%	31.5 kA 25 kA
LV distribution and utilization	400/230V±5%	3+N	50 ± 0.2%	50 kA
Uninterruptible 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	-	-

4.4. Plant Life

The Plant is designed for 25 years life.

4.5. Codes and standards

The design is of the process and utility units are in general accordance with the main International and EU Standard Codes.

4.6. Software codes

For the design of the plant for the different study cases, three software codes have been mainly used:

- PROMAX v3.2 (by Bryan Research & Engineering Inc.): flue gas amine sweetening process for CO_2 removal.
- Gate Cycle v6.1 (by General Electric): Simulator of Power Island used for Steam Turbine and Preheating Line simulation.
- Aspen HYSYS v7.3 (by AspenTech): Process Simulator used for CO_2 compression and drying.

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CHECKED BY : N. FERRARI
APPROVED BY : L. MANCUSO

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TABLE OF CONTENT

LIST OF ATTACHMENTS

1. Introduction

The supercritical pulverised coal (SC PC) plant is a combination of several process units, different for each case of the study. Main process blocks of the plant are the following:

- Feedstock and solids handling;
- Boiler island;
- Flue Gas Denitrification (DeNOx);
- Flue Gas Desulphurization (FGD);
- CO_2 capture unit;
- CO_2 compression and dehydration unit;
- Steam cycle.

Other ancillary utilities, such as cooling water, plant and instrument air, and demineralised water support the operation of these basic blocks.

The focus of this chapter C is to provide a general description of the major blocks of the SC PC power plant, which are generally common to the conventional air fired boiler-based cases of the study, while Chapters C.1 through C.5 of the report give basic engineering information for each alternative, with the support of specific heat and mass balances, utility consumption summaries, etc.

Table 1 lists the different air fired boiler-based cases, technically and economically assessed in this study. For some plant configurations, specific additional cases are developed to assess the performance and costs of biomass co-firing and near zero emission plants and to assess sensitivity to the cooling system; the list of these cases is shown in Table 2.

Table 1. SC PC air fired boiler-based main study cases

Case	Chapter	Description	Key features
Case 1 (reference)	C.1	SC PC boiler w/o CCS	• Generic state-of-art supercritical air-fired boiler • Alstom wet limestone scrubbing FGD • Primary cooling system: natural draft cooling tower
Case 2	C.2	SC PC boiler with CCS	• Generic state-of-art supercritical air-fired boiler • Alstom wet limestone scrubbing FGD • CANSOLV post-combustion capture • Primary cooling system: natural draft cooling tower

Table 2. SC PC air fired boiler-based additional study cases

Case	Chapter	Differences
Case 2 – Biomass co-firing		
2.1	C.3	• Biomass co-firing (7.5% of fuel thermal input)
Case 1 – Sensitivity to cooling water system		
1 - (SW)	C.4	• Primary cooling system: sea water
1 - (AC)		• Primary cooling system: air cooling
Case 2 – Sensitivity to cooling water system		
2 - (SW)	C.5	• Primary cooling system: sea water
2 - (AC)		• Primary cooling system: air cooling

2. Basic information of main process units

2.1. Feedstock and solids handling

2.1.1. *Coal storage and handling*

The scope of the feedstock receiving, handling and storage unit is to unload, convey, prepare, and store the coal delivered to the plant.

The coal is delivered from a port to the plant site by train. The unloading is done by a wagon tipper that unloads the coal to the receiving equipment. Coal from each hopper is fed directly into a vibratory feeder and subsequently discharged onto a belt extractor. A conveyor and transfer tower system finally delivers the coal to the open stockyard (as-received coal).

The storage pile is designed to hold an inventory of 30 days of design consumption to allow the facility to hedge against delivery disruptions.

From the storage piles, the coal is discharged onto enclosed belt conveyors to two elevated feed hoppers, each sized for a capacity equivalent to two hours. Coal is discharged from the feed hoppers, at a controlled rate, and transported by belt feeders to two parallel crushers, each sized for 100% of the full capacity. The crushers are designed to break down big lumps and deliver a coal with lump size not exceeding 35 mm. Coal from the crushers is then transferred by enclosed belt conveyors to the day silos close to the boiler island (as-fired coal).

Two magnetic plate separators for removal of tramp iron and two sampling systems are supplied for both the as-received coal and the as-fired coal. The recovered iron from the separators is delivered to a reclaim pile, while data from the analyses are used to support the reliable and efficient operation of the plant.

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

2.1.2. *Limestone storage and handling*

Limestone is delivered to the plant site by train and stored in a rectangular stockyard building, equipped with stacking and reclaiming machines. The storage capacity is made to ensure the plant is capable of feeding at maximum capacity for approximately 30 days.

The limestone feeding system, from the storage building to the FGD unit, is of the same type as that employed for coal, with conveyors that bring limestone to the mills for its pulverization and then to the FGD silos. The pulverization is useful to increase the surface area and consequently the sulphur removal efficiency of the FGD unit.

2.1.3. *Fly and bottom ash collection and storage*

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, fly ash is loaded by gravity to trucks for transportation. Cyclones and exhaust filter bags are used to prevent air contamination.

The bottom ash is collected and crushed by a grinder to reduce the lump size, thus making handling and transportation easier with conveyors that bring ash to the storage.

2.1.4. *Gypsum storage and handling*

The gypsum (in paste form) is discharged onto belt conveyors and sent to the storage building, where it is distributed by a tripper. The minimum storage capacity is approximately 30 days.
The gypsum is reclaimed by a portal type reclaimer, able to cover the full length of the building, transported by belt conveyors and loaded onto trucks or rails through a continuous loader.

2.2. Boiler Island

The boiler technology considered in this study is a market based design pulverized coal fired supercritical boiler and it is treated as a package supplied by specialised vendors. SC-PC coal fired boilers of the size proposed for this study are commercially available and have reached significant operational experience in the past years.

The boiler is a single pass tower type supercritical boiler, with coal burners located in the lower portion of the furnace. Each burner is a low NOx type, with staging of the coal combustion to minimize NOx formation. Additional over-fire air is also introduced to cool rising combustion products to inhibit NOx formation.

Air from the forced draft fans is preheated by contact with exhaust gases through regenerative pre-heaters. Pre-heated primary air, in the temperature range of 55-90°C, conveys part of the coal from the pulveriser mills directly to the burners at the rate set by the combustion control. A portion of the primary air supply is routed around the air pre-heaters and used as tempering air in the coal pulverisers. Preheated primary air and tempering air are mixed at each pulveriser to obtain the desired pulveriser fuel-air mixture and transport the pulverized fuel to the coal burners.

Most of the air from the forced draft fans, after pre-heating against flue gases, is distributed to the wind boxes enclosing the burners. The air supplied to the burners is mixed with the pulverised coal in the throat of the burner, where coal is ignited and burnt. The combustion process continues as the gases and unburned fuel move away from the burner up to the furnace shaft.

Hot combustion products exit the furnace and pass through to the radiant and convective heating surfaces for steam generation and superheating, then to the regenerative heaters for air pre-heating and finally to the flue gas clean-up system, including ESP and FGD.

Feed water enters the economizer, recovers heat from the combustion gases and then passes to the water wall circuits enclosing the furnace. The fluid then passes through heating surface banks to convective primary superheat, radiant secondary superheat and then to convective final superheat. The steam finally exits the steam generator to flow to the HP steam turbine module. Returning cold reheat steam passes through the reheater and is returned to the MP steam turbine module.

The furnace bottom comprises hoppers with a clinker grinding system situated below it. Ash passes through the clinker grinder to the ash handling system. Fly ash is collected from the discharge hoppers on the economisers and the ESP.

2.3. Flue Gas Denitrification (DeNOx)

The combustion of fossil fuels produces nitrogen oxide (NO) and dioxide (NO_2), collectively called as NOx. The monoxide (NO) is the predominant specie. SCR is today the dominant technology for the control of NOx in power generation industry.

A SCR system is considered to reduce NO_X produced by the combustion below the emission limit of 150 mg/Nm^3 for Case 1 and to minimize the NOx content (less than 20 ppmv) at the inlet to the carbon capture unit for Case 2.

The SCR system is based on the selective reduction of nitrogen oxides with ammonia in the presence of a catalyst. The reducing agent is injected into the flue-gas upstream of the catalyst.

NOx conversion takes place on the catalyst surface at a temperature usually between 170 and 510 °C, by the following main reactions.

$$4\,NO + 4\,NH_3 + O_2 \leftrightarrow 4\,N_2 + 6\,H_2O$$
$$6\,NO_2 + 8\,NH_3 \leftrightarrow 7\,N_2 + 12\,H_2O$$

The SCR system consists mainly of ammonia storage, evaporation and injection by means of a distribution grid and a SCR catalytic reactor, as schematically shown in Figure 1.

The honeycomb catalyst cells are contained in square catalytic baskets. The ceramic cells support the active catalyst components, V_2O_5, TiO_2 and WO_3. V_2O_5 is the most active but promotes also SO_2 oxidation to SO_3 and may be the cause of catalyst sintering at high temperature. Therefore, the catalyst formulation is different for different applications. As an alternative, plate-type catalysts can be used.

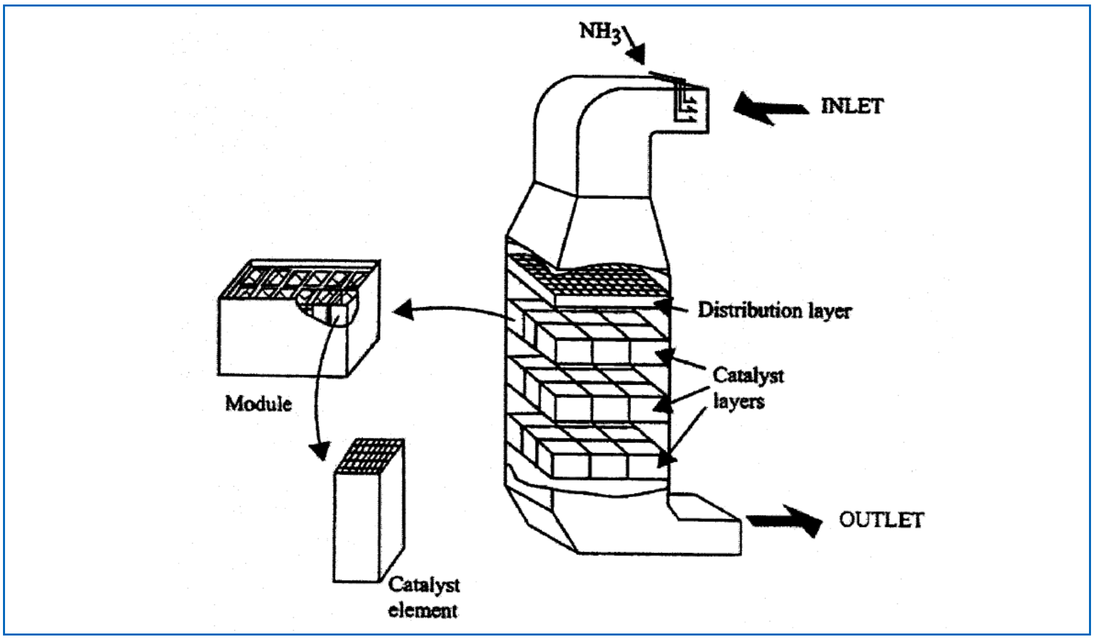


Figure 1 - SCR system

Cell size varies from 3 to 8 mm. Smaller cells are used in clean gas service; larger cells in dirty gas service. In the absence of SO_2, SCR can operate at low temperature, as low as 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 bisulphate. The first is powdery but the second is sticky and can plug catalyst and equipment. The lower the temperature the higher the probability of sulphate/bisulphate formation. For this reason SCR in the presence of SO_2/SO_3 must operate at high temperature: minimum 300-310°C if SO_3 is less than 5 ppm; higher temperatures, 310-330°C for higher SO_3 concentration. To obtain these temperatures the SCR is normally located between the economizer and the air pre-heater (Figure 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.

As shown in Figure 2, catalyst temperature is kept under control at reduced capacities by by-passing a portion of the flue gas around the last economizer bank.

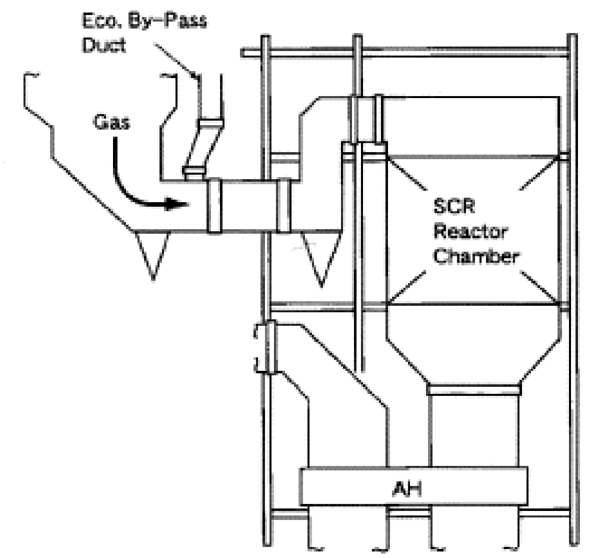


Figure 2. SCR in conventional boilers

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

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

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

2.4. Flue Gas Desulphurization (FGD) system

A flue gas desulphurisation system is required downstream of the boiler in order to meet the environmental SOx limits of 150 mg/Nm^3 (6% volume O_2, dry) for Case 1 and to reduce at the maximum extent the SO_X entering the carbon capture unit for Case 2, in order to minimize solvent degradation in the downstream absorber column.

Three different FGD systems were investigated during the course of the study, seeking the support of different specialized technology suppliers:

- Wet FGD, provided by Alstom;
- Wet bubbling FGD, provided by Chiyoda Corporation;
- Circulating fluid bed scrubbing FGD, provided by Foster Wheeler Energie GmbH (FWE).

Information received from each technology supplier is reported in the following sections 2.4.1, 2.4.2 and 2.4.3, limited to the information that suppliers have authorized for disclosure. A high level assessment of key features and the main advantages and disadvantages of each technology is also included in section 2.4.4.

It has to be noted that some differences may exist between figures in the vendors' information and those shown in the report of the specific study case. In fact, information in the attachments is based on preliminary stream properties and flowrates, as estimated during the early stages of the study; then, data have been slightly adjusted and optimised during study execution either by vendors or Foster Wheeler. Figures included in the report for each study case shall be considered as the final ones.

2.4.1. *Alstom's Wet Flue Gas Desulphurization (WFGD) system*

Wet limestone scrubbers are the most widely used of all the FGD systems, accounting for about 80% of all the installed capacity. As a matter of fact, since putting into service the first full-scale wet flue gas desulfurization (WFGD) system in the U.S. in 1968, Alstom has installed or is constructing WFGD systems on nearly 60,000 MW of fossil-fired power generation facilities (over 90 plants) with sulphur content in the flue gas ranging from 0.2 to 4.5%.

The following sections provide an overview of Alstom's technology. Alstom decided to support the study by providing a specific set of information for two boiler-based cases, namely Case 1 (SC-PC without CO_2 capture) and Case 2 (SC-PC with CO_2 capture).

Process description

The unit description makes reference to the simplified scheme reported in Figure 3 and the preliminary process flow diagram shown in Figure 4.

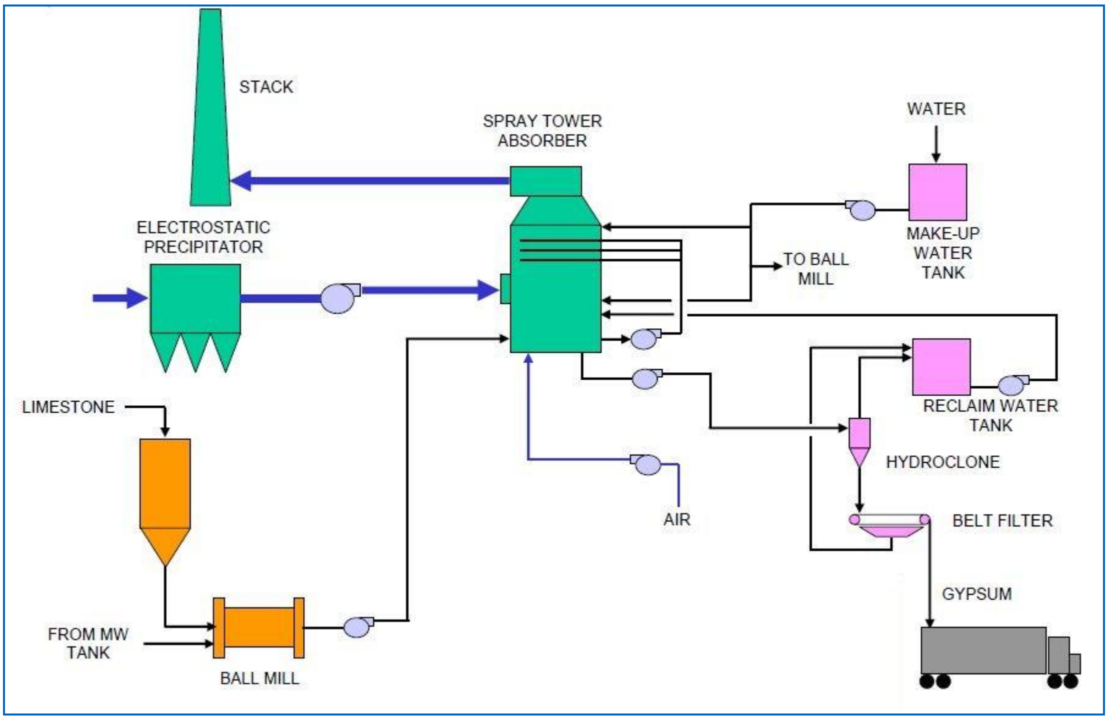


Figure 3. Wet FGD process diagram

Ground limestone reagent is used to react with SO_2 in the flue gas producing a gypsum (calcium sulphate dehydrate) by-product. Limestone is readily available in large quantities in most locations and can either be ground on site or provided pre-ground (as in this case). Gypsum is widely used in the construction industry in the form of gypsum board (wallboard) and in concrete mixtures. In the event that a market for gypsum does not exist in a particular location, the material can safely be land filled.

A spray tower absorber is used to accomplish the intimate gas/liquid contact necessary to achieve high removal efficiencies. Spray towers have high inherent reliability, low plugging potential and low pressure drop.

Flue gas enters the absorber where it passes upward through multiple levels of spray in a counter-current fashion. SO_2 and other acid gases (e.g. HCl, HF) are absorbed into the scrubbing slurry, which falls into the lower section of the vessel known as the reaction tank. Here finely ground limestone is added to neutralize and regenerate the scrubbing slurry. Oxygen in the form of compressed air is injected completing the scrubbing reaction and forming gypsum.

Gypsum slurry is discharged from the reaction tank to the primary and secondary dewatering equipment where the moisture content is reduced to levels required for land filling or commercial grade gypsum. The free flowing gypsum is then available for land filling or for shipment to end users.

In a wet limestone scrubbing system, a complex series of kinetic and equilibrium controlled reactions occur in the gas, liquid and solid phases. These reactions may be stated in an overall expression as:

$$CaCO_3 + SO_2 + 2\ H_2O + 1/2\ O_2 \rightarrow CaSO_4 \bullet 2H_2O + CO_2$$

(limestone) + (sulphur dioxide) + (water) + (oxygen) → (gypsum) + (carbon dioxide)

Absorption

The flue gas enters the spray tower near the bottom through an inlet zone of nickel alloy material that resists the corrosion that can take place at the wet/dry interface. Once in the absorber, the hot flue gas is immediately quenched as it travels upward counter-current to a continuous spray of process (recycle) slurry produced by multiple spray banks. The recycle slurry (a 15% concentration slurry of calcium sulphate, calcium sulphite, un-reacted alkali, inert materials, fly ash, and various dissolved materials) extracts the sulphur dioxide from the flue gas. Once in the liquid phase, the sulphur dioxide reacts with the dissolved alkali (calcium carbonate) to form dissolved calcium sulphite.

The quantity of recycle slurry needed to effectively remove the specified amount of SO_2 is determined by a parameter known as the liquid-to-gas ratio (L/G). The design L/G is provided by multiple spray levels, with each level being fed by a dedicated recycle pump, or one common pump, depending on the size of the absorber. The recycle pump feeds into a dedicated discharge pipe, from where the slurry is transported into the spray zone. Fixed speed pumps are used since in Alstom's configuration the flow-rate of each spray level is fixed. Each spray zone level consists of a spray header containing nitride-bonded silicon carbide spray nozzles designed to provide the proper sized droplets for optimum SO_2 absorption. The nozzles are arranged to ensure uniform and complete spray coverage for proper gas-to-liquid contact in the absorber. CFD modelling is used to optimize the nozzle positioning to ensure complete and uniform coverage. Two recycle levels for Case 1 and three recycle levels for Case 2 are foreseen in operation.

Reaction tank

The recycle slurry falls from the spray zone into the reaction tank that can be integral to the base of the absorber vessel, or it can be a separate tank below the absorber. This tank is sized to provide sufficient residence time (both liquid, for slurry de-saturation and solids, for crystal growth) for all of the FGD chemical reactions to occur. Fresh limestone slurry is added to the reaction tank where it reaches equilibrium with the bulk of the recycle slurry prior to being returned to the spray banks via the recycle pumps. The reaction tank is equipped with side entry agitators to keep the slurry suspended and homogeneously stirred; agitators are designed to keep solid suspended even with one of them is out of operation and with any combination of recycle pumps in operation. Water lances are provided to free agitator's blades in the unlikely event of a complete and prolonged power failure resulting in slurry sedimentation into the tank.

Mist Elimination

Two-stage high efficiency chevron type mist eliminators of the roof type design made of polypropylene are provided. The first and second stages are washed in segments on a continuous basis from the front and back sides. The mist eliminator wash rates and pressures have been designed to provide effective rinsing of solids and chemically reactive liquids while keeping the carry-over to the minimum. Two mist eliminator wash pumps (one operating and one stand-by) are used to supply mist eliminator wash water.

Forced oxidation

To produce the fully oxidized by-product (at least 99% sulphite oxidation), single stage centrifugal blowers supply air to a sparging system in the reaction tank. The oxygen in the air converts the dissolved calcium sulphite ($CaSO_3$) to calcium sulphate ($CaSO_4$), which then crystallizes as $CaSO_4 \cdot 2H_2O$, gypsum.

Alstom's oxidation air injection system utilizes lances located below the operating liquid level in the reaction tank. The oxidation air is quenched and saturated with a stream of water prior to discharge into the tank in order to prevent build-up in the lances. The oxidation lances are located in front of each agitator to ensure a complete and uniform air distribution into the slurry. The air header to the lances (after the water quench has been added) is FRP. Inside of the tank the lances are fabricated of duplex SS or FRP.

Limestone receiving, storage and slurry preparation

The limestone is stored in one cylindrical steel silo with a conical bottom. The silo discharges limestone to the reagent slurry preparation system via a rotary feeder and a weigh belt feeder through two separated hoppers (one discharging way is available as a spare).

The system prepares limestone slurry, about 30% solid, to be fed to the absorber. Limestone is fed to a limestone slurry preparation tank. Reclaim water and/or process water is added to produce the required density of the slurry.

Reagent slurry is transported from the storage tank to the absorber through the use of one dedicated pump (spared). Reagent slurry is added to the reaction tank, at the base of the absorber, in response to local measurement of the pH.

The flow of reagent slurry to the reaction tank is controlled by a feed forward flow control loop based on flue gas flow at the absorber inlet (or boiler operating load) that is trimmed by a feedback control loop based on the reaction tank pH. The flue gas flow is indicative of the incoming SO_2 load that has to be removed and provides the coarse adjustment of the reagent flow control valve.

This allows the system to respond to sudden load changes quickly and with limited fluctuations. The pH signal provides the fine-tuning of the reagent flow control valve to keep the pH at the desired level during steady state operation.

Dewatering and gypsum handling

Gypsum slurry is extracted from the reaction tank and pumped to a cluster of hydro cyclone classifiers. The slurry is split into a low-density stream of fines (the overflow) and a high-density stream of coarse crystals (the underflow). In so doing, the hydro cyclones also classify the slurry chemically. Un-reacted limestone is relatively fine and end up in the overflow.

The product gypsum is a coarse material and follows the underflow. The hydro cyclone underflow product flows by gravity to the vacuum belt filters. The overflow is partially sent to a reclaim water tank (collecting a mixture of this stream with the filtrate from the vacuum belt filters) and partially recycled back to the absorber. A portion of the reclaim water is blown down from the system to limit the chloride content in the recycle slurry to the required value and also to avoid fines accumulation in the system.

The hydro cyclone underflow product is routed to vacuum belt filters that further dewater the product slurry to approximately 90% solids. A liquid ring vacuum pump provides the suction needed at the filter cloth. Extracted filtrate is routed to the reclaim water tank. The produced gypsum is discharged by the filter to the battery limits. Two vacuum filter systems are provided (one operating and one in stand-by).

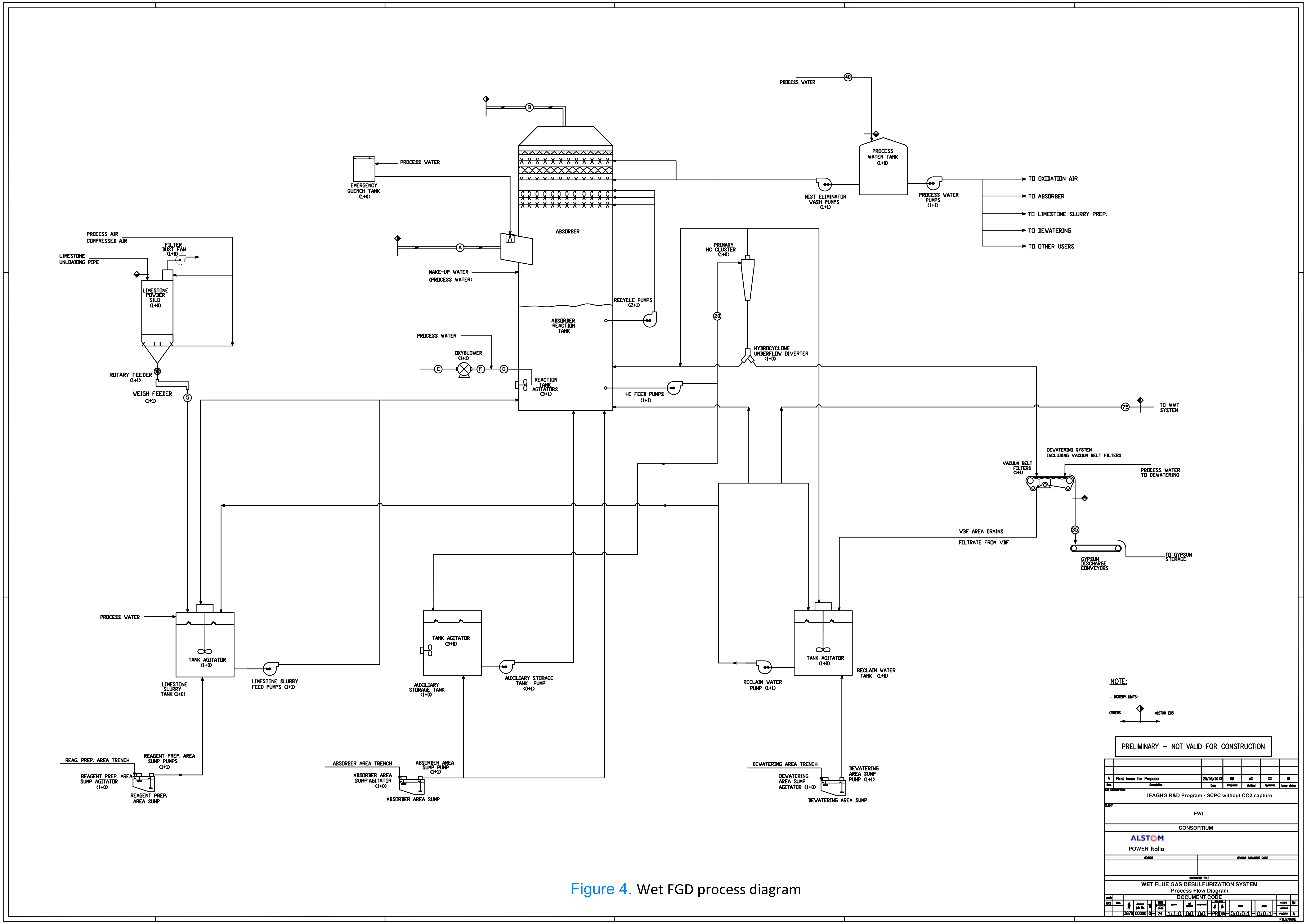


Figure 4. Wet FGD process diagram

Case 1 (SC-PC without CO_2 capture) data

Preliminary mass balance at WFGD battery limits

The following tables report the preliminary mass balance at WFGD battery limits for Case 1 (SC-PC without CO_2 capture), making reference to the process flow diagram shown in Figure 4.

		Stream A	Stream B	Stream E	Stream F	Stream G
		Raw Flue Gas To Absorbers	Clean Flue Gas From Absorbers	Air to Oxidation Blowers	Air from Oxidation Blowers	Quenched Oxidation Air to Absorber
Volum. Flow (wet)	[Nm^3/h]	2.703.445	2.794.135	6.870	6.870	7.177
Mass Flow	[kg/h]	3.585.000	3.658.945	8.460	8.460	8.460
Volum. Flow (wet)	[Am^3/h]	3.682.879	3.397.071	8.047	5.163	4.443
Temperature	[°C]	90	47	35	124	54
N2	[kg/h]	2.485.531	2.491.920	6.389	6.389	6.389
	[% vol.]	73,562	71,358	74,414	74,414	71,232
O2	[kg/h]	127.017	127.726	1.958	1.958	1.958
	[% vol.]	3,291	3,202	19,961	19,961	19,108
	[% vol.]dry	3,581	3,593	-	-	-
CO2	[kg/h]	748.990	752.512	4	4	4
	[% vol.]	14,110	13,716	0,031	0,031	0,030
Ar	[kg/h]	41.967	42.076	109	109	109
	[% vol.]	0,871	0,845	0,890	0,890	0,852
H2O	[kg/h]	175.896	244.249	260	260	506
	[% vol.]	8,095	10,876	4,703	4,703	8,777
SO2	[kg/h]	5.347	322	0	0	0
	[mg/Nm^3, dry, 6% O_2]	1.852	111	0	0	0
SO3	[kg/h]	174	139	0	0	0
	[mg/Nm^3, dry, 6% O_2]	60	48	0	0	0
SOx	[mg/Nm^3, dry, 6% O_2]	1.900	150	0	0	0
HCl	[kg/h]	77	1	0	0	0
	[mg/Nm^3, dry, 6% O_2]	27	0	0	0	0
HF	[kg/h]	0	0	0	0	0
	[mg/Nm^3, dry, 6% O_2]	0	0	0	0	0
Particulate	[kg/h]	29	17	0	0	0
	[mg/Nm^3, dry, 6% O_2]	10	6	0	0	0
Entrained Moisture (kg/h)	[kg/h]	0	145	0	0	0
	[mg/Nm^3, dry, 6% O_2]	0	50	0	0	0

		Stream 05	Stream 20	Stream 35	Stream 40	Stream 75
		Dry Reagent Feed	Absorber Bleed to Hydrocyclone	Filter Cake from Belt Filter	Process Water Supply	Reclaim Water to WWT
Mass Flow (kg/h)	[kg/h]	8.672	110.080	15.615	80.145	7.844
Mass Flow Liquid (kg/h)	[kg/h]	0	93.568	1.561	80.145	7.649
Mass Flow Solids (kg/h)	[kg/h]	8.672	16.512	14.053	0	195
Volumetric Flow (m^3/h)	[m^3/h]	-	100	-	80	8
$CaSO_4 \cdot 2H_2O$	[kg/h]	0	15.073	13.378	0	134
$CaSO_3 \cdot ½H_2O$	[kg/h]	0	57	50	0	1
$CaCO_3$ (kg/h)	[kg/h]	8.239	330	232	0	8
CaO (kg/h)	[kg/h]	0	0	0	0	0
$Ca(OH)_2$ (kg/h)	[kg/h]	0	0	0	0	0
CaF2 (kg/h)	[kg/h]	0	0	0	0	0
Alkali Inerts (kg/h)	[kg/h]	434	1.027	383	0	0
Flyash (kg/h)	[kg/h]	0	25	10	0	0
CaCl2 (kg/h, aq)	[kg/h]	0	1.757	2	25	139
H2O (kg/h)	[kg/h]	0	92.003	1.560	80.135	7.526
Suspended Solids Content	[%]	100	15	90	0	2
Cl- Concentr. (mg/kg aqueous)	[mg/kg]aqueous	0	12.000	900	200	11.608
Density	[kg/m^3]	-	1.100	-	997	1.016
Expected pH range		-	5 to 6	-	6 to 8.5	6 to 8.5
Expected temperature range	[°C]	-18 - 38	47	31 - 47	4 - 32	39 - 47

Expected emission

SO_2	111 mg/Nm^3 (dry, 6% O_2)
SO_X	150 mg/Nm^3 (dry, 6% O_2)

The WFGD plant is designed to achieve a SO_x removal efficiency of 92.1%, corresponding to approx. 94% SO_2 removal efficiency.

Expected consumption

Power consumption	2,800 kWh/h
Limestone consumption (100% purity)	8,300 kg/h
Make-up water consumption	85 m^3/h
Cooling water flowrate	NA (1)

(1) Air-cooled motor drives are assumed

Expected gypsum production and composition

Gypsum production (10% residual water)	15,650 kg/h
pH	5 – 9
Gypsum composition	
Moisture	10 %
$CaSO_4 \cdot 2\ H_2O$	95 %
$CaSO_3 \cdot ½\ H_2O$	0.5 %
Cl	100 ppm

Expected liquid effluent and composition

Chloride purge flowrate	10 m^3/h
Composition	
TSS	1 - 3 %
Cl	12,000 - 15,000 ppm
COD	100 – 150 ppm (2)

(2) Typical range

Case 2 (SC-PC with CO_2 capture) data

Preliminary mass balance at WFGD battery limits

The following tables report the preliminary mass balance at WFGD battery limits for Case 2 (SC-PC with CO_2 capture), making reference to the process flow diagram shown in Figure 4.

		Stream A	Stream B	Stream E	Stream F	Stream G
		Raw Flue Gas To Absorbers	Clean Flue Gas From Absorbers	Air to Oxidation Blowers	Air from Oxidation Blowers	Quenched Oxidation Air to Absorber
Volum. Flow (wet)	[Nm^3/h]	2.703.445	2.794.444	7.202	7.202	7.523
Mass Flow	[kg/h]	3.585.000	3.659.246	8.869	8.869	8.869
Volum. Flow (wet)	[Am^3/h]	3.682.879	3.397.449	8.436	5.413	4.657
Temperature	[°C]	90	47	35	124	54
N2	[kg/h]	2.485.531	2.492.229	6.698	6.698	6.698
	[% vol.]	73,562	71,359	74,414	74,414	71,232
O2	[kg/h]	127.017	127.760	2.052	2.052	2.052
	[% vol.]	3,291	3,202	19,961	19,961	19,108
	[% vol.]dry	3,581	3,593	-	-	-
CO2	[kg/h]	748.990	752.679	4	4	4
	[% vol.]	14,110	13,718	0,031	0,031	0,030
Ar	[kg/h]	41.967	42.082	114	114	114
	[% vol.]	0,871	0,845	0,890	0,890	0,852
H2O	[kg/h]	175.896	244.277	272	272	531
	[% vol.]	8,095	10,876	4,703	4,703	8,777
SO2	[kg/h]	5.347	79	0	0	0
	[mg/Nm^3, dry, 6% O_2]	1.852	27	0	0	0
SO3	[kg/h]	174	139	0	0	0
	[mg/Nm^3, dry, 6% O_2]	60	48	0	0	0
SOx	[mg/Nm^3, dry, 6% O_2]	1.900	66	0	0	0
HCl	[kg/h]	77	1	0	0	0
	[mg/Nm^3, dry, 6% O_2]	27	0	0	0	0
HF	[kg/h]	0	0	0	0	0
	[mg/Nm^3, dry, 6% O_2]	0	0	0	0	0
Particulate	[kg/h]	29	17	0	0	0
	[mg/Nm^3, dry, 6% O_2]	10	6	0	0	0
Entrained Moisture (kg/h)	[kg/h]	0	145	0	0	0
	[mg/Nm^3, dry, 6% O_2]	0	50	0	0	0

		Stream 05	Stream 20	Stream 35	Stream 40	Stream 75
		Dry Reagent Feed	Absorber Bleed to Hydrocyclone	Filter Cake from Belt Filter	Process Water Supply	Reclaim Water to WWT
Mass Flow (kg/h)	[kg/h]	9.083	115.432	16.374	80.373	7.844
Mass Flow Liquid (kg/h)	[kg/h]	0	98.117	1.637	80.373	7.649
Mass Flow Solids (kg/h)	[kg/h]	9.083	17.315	14.737	0	194
Volumetric Flow (m^3/h)	[m^3/h]	-	105	-	81	8
$CaSO_4 \cdot 2H_2O$	[kg/h]	0	15.802	14.027	0	134
$CaSO_3 \cdot ½H_2O$	[kg/h]	0	59	53	0	1
$CaCO_3$ (kg/h)	[kg/h]	8.629	347	244	0	8
CaO (kg/h)	[kg/h]	0	0	0	0	0
$Ca(OH)_2$ (kg/h)	[kg/h]	0	0	0	0	0
CaF2 (kg/h)	[kg/h]	0	0	0	0	0
Alkali Inerts (kg/h)	[kg/h]	454	1.082	403	0	0
Flyash (kg/h)	[kg/h]	0	25	11	0	0
CaCl2 (kg/h, aq)	[kg/h]	0	1.843	2	25	139
H2O (kg/h)	[kg/h]	0	96.477	1.635	80.363	7.526
Suspended Solids Content	[%]	100	15	90	0	2
Cl- Concentr. (mg/kg aqueous)	[mg/kg]aqueous	0	12.000	900	200	11.608
Density	[kg/m^3]	-	1.100	-	997	1.016
Expected pH range		-	5 to 6	-	6 to 8.5	6 to 8.5
Expected temperature range	[°C]	-18 - 38	47	31 - 47	4 - 32	39 - 47

Expected emission

SO_2	10 ppmv (dry, 6% O_2)
SO_3	13 ppmv (dry, 6% O_2)

The WFGD plant is designed to achieve a SO_2 removal efficiency of approximately 98.5%, resulting in 10 ppmv (dry, 6%O_2) of SO_2 emission and about 13 ppmv (dry, 6%O_2) of SO_3 due to the high content at WFGD inlet. To reduce the SO_3 content, the following options may be considered in combination with the WFGD plant:

- Installation of a condenser operated with NaOH at the absorber outlet,
- Installation of a WESP at the absorber outlet,
- Installation of a hydrated lime dry injection system downstream of the WFGD plant.

Expected consumption

Power consumption	3,900 kWh/h
Limestone consumption (100% purity)	9,100 kg/h
Make-up water consumption	85 m^3/h
Cooling water flowrate	NA (3)

(3) Air-cooled motor drives are assumed

Expected gypsum production and composition

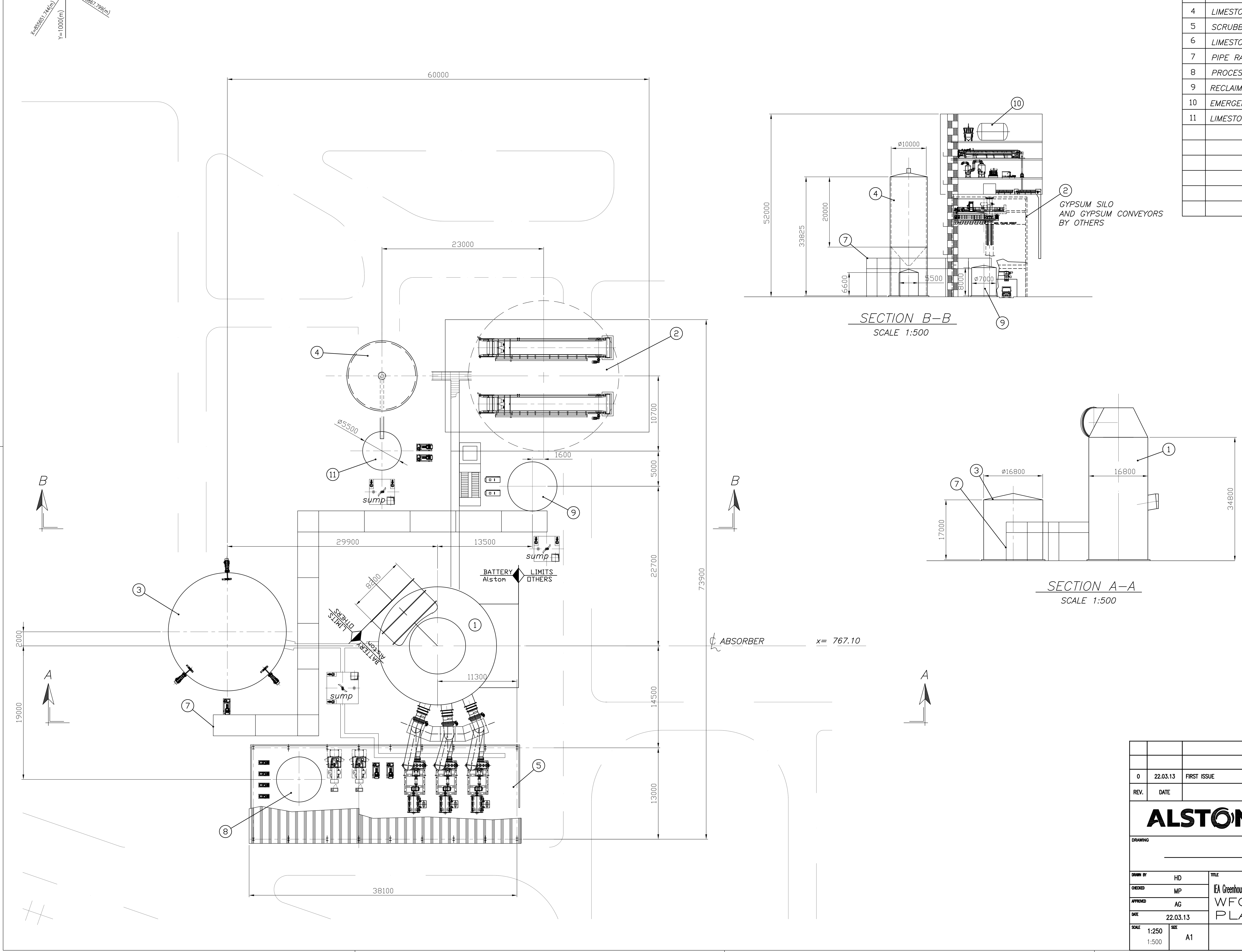
Gypsum production (10% residual water)	16,400 kg/h
pH	5 - 9
Gypsum composition	
Moisture	10 %
$CaSO_4 \cdot 2\ H_2O$	95 %
$CaSO_3 \cdot ½\ H_2O$	0.5 %
Cl	100 ppm

Expected liquid effluent and composition

Chloride purge flowrate	10 m^3/h
Composition	
TSS	1 - 3 %
Cl	12,000 - 15,000 ppm
COD	100 – 150 ppm (4)

(4) Typical range

Preliminary plot area



LEGEND	
1	ABSORBER
2	GYPSUM SILO (OUT OF SCOPE)
3	AUXILIARY STORAGE TANK
4	LIMESTONE SILO
5	SCRUBBER & COMPRESSOR PUMPING ROOM
6	LIMESTONE UNLOADING STATION/GYPSUM LOADING
7	PIPE RACK
8	PROCESS WATER TANK
9	RECLAIM WATER TANK
10	EMERGENCY QUENCHING TANK
11	LIMESTONE SLURRY TANK

REV.	DATE	DESCRIPTION	DRAWN BY	CHECKED	APPROVED
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TITLE: IEA Greenhouse Gas R&D Program: Study for Supercritical Pulverized Coal(SC_PC), without CO2 capture
WFGD EQUIPMENT LAYOUT PLAN AND ELEVATIONS

Capital investment costs

Indicative prices for the engineering, supply, delivery DDU (Incoterms 2000), erection/erection supervisions, testing, commissioning/commissioning supervisions and training for the project considered in this study are shown below for the two cases of the study.

Case	**Cost**, MM€
Case 1 - SC-PC without CO_2 capture	55.30
Case 2 - SC-PC with CO_2 capture	56.81

The indicative prices stated above are based on the scope of supply included within the battery limits identified in the WFGD system process flow diagram (Figure 4).

Following major items are excluded from mentioned quotation:

- foundations and civil works,
- electrical system supply and installation,
- DCS/PLC for WFGD plant control,
- control rooms and control room equipment,
- buildings,
- auxiliary sub-systems like waste water treatment plant, fire fighting and fire detection, HVAC, lighting, lightning protection.

2.4.2. *FWE Circulating Fluid Bed Scrubbing (CFBS) Technology*

FosterWheeler Energie GmbH (FWE) proposed for the IEAGHG study cases its Circulating Fluid Bed Scrubber (CFBS) system with hydrated lime injection and fabric filter, including product recirculation.

The following sections provide an overview of the CFBS technology, including the specific set of information for two boiler based cases, namely Case 1 (SC-PC without CO_2 capture) and Case 2 (SC-PC with CO_2 capture), as provided by FWE to support the study.

Process description

This flue gas desulphurization system is a Circulating Fluid Bed Scrubber (CFBS) system with water and absorbent injection, with a downstream fabric filter that includes recirculation of product from filter hoppers to CFBS. The typical design of the system is shown in Figure 5.

The flue gas cleaning concept consists mainly of:

- Flue gas ducts (for raw and clean gas) with dampers
- One Circulating Fluid Bed Scrubber (CFBS)
- Internal scrubber equipment
- One fabric filter with recirculating system
- ID-fan
- Air blowers and compressors
- Silo for absorbent
- Product silo for residue
- Water storage tank
- Water injection system for CFBS
- Electrical instrumentation & control (EIC).

The flue gas from the boiler fired by coal enters the Circulating Fluid Bed Scrubber (CFBS) and then passes to the bag house for final de-dusting, before the flue gas passes the ID-fan to the stack (or to the post-combustion plant).

Within the CFBS, pollutants such as SO_2, SO_3, HCl, HF and others will be removed by different chemical reactions as described. The following reactions typically take place in the dry desulphurization process in the temperature range 75 – 110 °C:

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 + H_2O$$

$$Ca(OH)_2 + SO_3 \rightarrow CaSO_4 + H_2O$$

$$CaSO_3 + ½\ O_2 \rightarrow CaSO_4$$

$$Ca(OH)_2 + 2\ HCl \rightarrow CaCl_2 + 2\ H_2O$$

$$Ca(OH)_2 + 2\ HF \rightarrow CaF_2 + 2\ H_2O$$

$$Ca(OH)_2 + CO_2 \rightarrow CaCO_3 + H_2O$$

The residue from the bag house is transported into the product silo by pneumatic equipment.

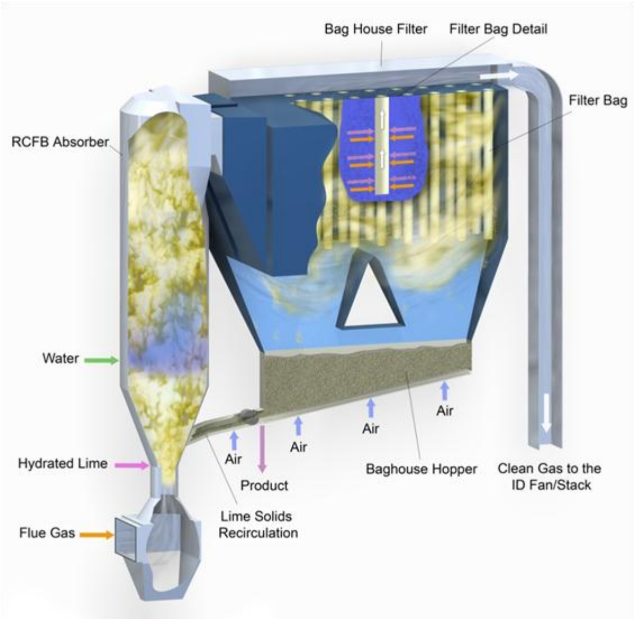


Figure 5. Typical Design FGD

Main components of the FGD

Scrubber design

The flue gas from the boiler enters the CFBS centrally from the bottom section of the absorber and move through venturi nozzles in turbulent flow with the hydrated lime feed and recirculated lime reaction products to the top section of the absorber. A turbulator wall surface ensures high mixing and capture efficiency of multiple pollutants. Water nozzles cool down the temperature to an efficient temperature for the removal process. The height of the scrubber assures a long gas and solid mixing time for high pollutant capture and maximum lime utilization.

Water route and water spraying installation

The flue gas is cooled by evaporation of finely sprayed water injection into the CFBS. The spraying rate is automatically adjusted according to the set process temperature. The water is sprayed through return-flow nozzles.

The water required for the desulphurization process is taken from the FGD water storage. High-pressure pumps are used for spraying the water evenly into the scrubber. The required water quantity, depending on the gas outlet temperature, is continuously controlled by electro-pneumatic valves in the back flow of the nozzles. The water system will be located on a floor below the water lances.

Fabric Filter

The bag house consists of separate compartments, each lockable on the flue gas sides for maintenance purposes. It is possible to shut down one compartment for maintenance while running the remaining compartment with reduced flue gas flow.

The bag house filter is a pulse-jet online cleaning type with differential pressure control. The dust containing gases enter the inlet hoods and are led into the lower area of the bag house. The dust is collected on the bags' outside surfaces. The bags are connected to the tube sheet, which fits securely into the tube sheet holes. To prevent collapse during filtering, each bag is equipped with a wire cage. Bags are cleaned by short pulses of dry compressed air, delivered at the top of the bags in the reverse direction of gas flow. These pulses cause bag motions that combine with the back-flushing action to dislodge the dust cake, which falls into the hoppers.

According to the emission values of the clean gas the dust cake which is collected in the filter hopper will be partly transferred back to the scrubber again. The transport takes place by means of a recirculation system until the absorption capacity of the absorbent is reached. This procedure reduces the amount of used absorbent and accumulated residue.

A large proportion of the material in the hoppers which act as temporary storage bins is fed into the solids recycling system by means of a control valve and flows via fluid slides back into the RCFB scrubber.

After a certain retention time in the recirculation system the by-product is discharged from the insulated filter hoppers by means of a control valve into an external product silo for further disposal.

Auxiliary equipment

Silos

The FGD unit needs a silo for the sorbent and a product silo for the residue. The size of the hydrated lime silo is based on the consumption of the hydrated lime for the dry desulphurization process and a selected storage time. The hydrated lime silo should be placed near to the scrubber and at a place where it is easy to fill in the hydrated lime via truck.

The design of residue silo includes that a truck can drive under it to be filled with product. The size of the product silo is based on the arising amount of product and a selected storage time.

Hydrated lime conveying system

For the FGD process the hydrated lime must be transported from the hydrated lime silo to the CFBS. For the hydrated lime transportation a speed controlled rotary valve with double flap, motor, feed ejector and blower are used. The rotary valve will be used for dosing the required amount of the absorbent.

The blower air transports the added absorbent via a piping system to the scrubber.

Product conveying system

The accruing product must be transported from the filter hoppers to the product silo. The equipment for product transport consists of the same components as for the hydrated lime conveying system: speed controlled rotary valve with double flap, motor, feed ejector and blower.

Recirculation

A part of the product is transported from the filter hoppers back to the CFBS. This solid transport consists for each compartment of one fluid slide including expansion joint, shut off gate and flow control gate. The fluidization air will be produced by blowers and the control valve regulates the solid flow into the scrubber.

Silo fluidization

For better transportation and handling conditions the cone of the hydrated lime silo and the cone of the product silo are fluidized with air. The needed fluidization air for silo cones is delivered from compressed air station or rotary piston blowers.

Compressed air

A compressed air station is necessary for pulsing air (cleaning of filter bags) and instrumentation air. The station mainly consists of the compressors and each compressor is equipped with one warm regenerated dryer.

ID-Fan

For the flue gas flow through the scrubber and the bag house the FGD is equipped with one variable speed regulated ID-Fan (typically shown in Figure 6). The speed regulation is done by a frequency converter.

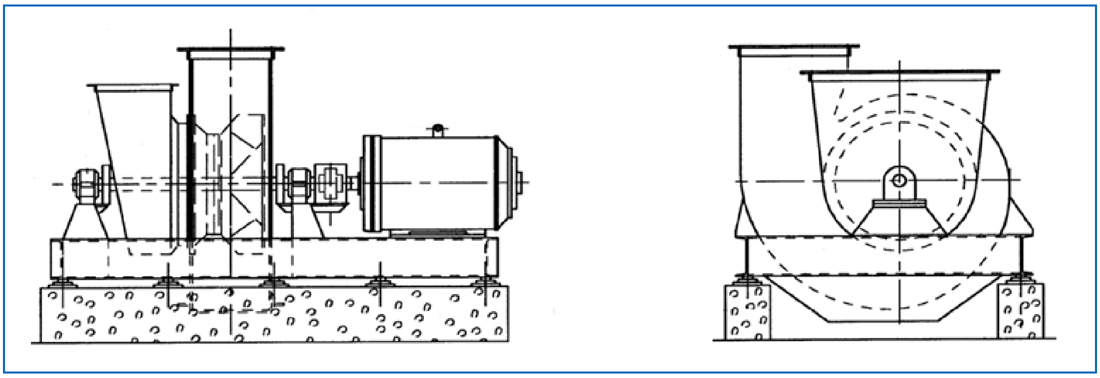


Figure 6. Drawing of an ID-Fan (Source: Rotamill)

FGD performance

The performance provided by FWE for Cases 1 and 2 refers to the following characteristics and conditions of the flue gas entering the FGD unit.

Flue gas condition	
Flue gas flow rate, t/h	3,585
Flue gas flow rate, Nm^3/h (1)	2,885,000
Temperature, °C	90-100 (2)
Flue gas composition	(%vol)
Ar	0.871
N_2	73.562
O_2	3.291
CO_2	14.110
H_2O	8.095
SO_2 / SO_3 (3)	0.071
HCl	27 mg/Nm^3 (1)
NOx	130 mg/Nm^3 (1)
Particulate	10,000 mg/Nm^3 (1) (4)

(1) 6% oxygen, dry

(2) Please consider the temperature required to exit at 80-85°C to avoid gas-gas heater installation or preheat the decarbonised flue gas. Please advise if temperature shall exceed the specified range.

(3) Assumed SO_2 to SO_3 conversion equal to 2.6%

(4) Corresponding to around 29-30 t/h of fly ash from coal combustion (12.2% of coal ash content).

		SCPC without CO_2 capture	**SCPC with CO_2 capture**
Gas Flow	Nm^3/h dry	2,888,702	2,888,702
Gas Flow	Nm^3/h dry, act. O_2	2,486,843	2,486,843
Gas Flow	Nm^3/h wet, act. O_2	2,703,090	2,703,090
H_2O	%	8.00	8.00
O_2	% wet	3.29	3.29
O_2	% dry	3.58	3.58
O_2	Oxygen reference	6.00	6.00
CO_2	% wet	14.10	14.10
CO_2	% dry	15.33	15.33
Emission limits			
SO_2	mg/Nm^3 dry	150	29
SO_3	mg/Nm^3 dry	< 5	< 5
Pollutants			
SO_2	mg/Nm^3 dry	2020	2020
SO_3	mg/Nm^3 dry	54	54

Main consumption data

		SCPC without CO_2 capture	SCPC with CO_2 capture
Clean gas temperature	°C	75-80	75-80
Water consumption FGD	m^3/h	30	30
Compressed Air consumption	m^3/h	1500	1500
ID-Fan (in case of 0mbar at battery limit and a foreseen pressure drop of FGD of 42mbar)	kW	6100	6100
Pump and Other	kW	4000	4000
Sum of electrical consumption	kW	10100	10100
Hydrated lime consumption (purity 100%)	kg/h	10000	11200
Lime consumption (purity 100%)	kg/h	7600	8500
Product	kg/h	16000	17600
Product composition according to design data			
$CaSO_3$	%	40 - 70	40 - 70
$CaSO_4$	%	10 - 30	10 - 30
$CaCO_3$	%	8 - 28	8 - 28
$Ca(OH)_2$	%	0 - 15	0 - 15

Requirements for FGD water quality

Max. content of solid matter	< 100	[ppm]
Max. content of abrasive components	< 10	[ppm]
Max. grain size of suspended matter	< 50	[microns]

Minimum required quality for soft burnt lime

Residue on mesh 0.09 mm	< 5	[%]
Particle size (d50**)	< 20	[µm]
Lime reactivity (T60*)	< 2	[min]
Purity (CaO content)	> 95	[%]
Moisture	≤ 1	[%]

Delivered hydrated lime minimum requirements

Particle size (d_{50}**)	≤ 5	[µm]
Hydrated Lime reactivity (BET) specific surface area	>18	[m^2/g]

*) T60 means temperature expansion from 20°C to 60°C at defined conditions.
**) d_{50} mean average particle size, the 50% weight fracture.

Plot area requirements

	SCPC without CO_2 capture	SCPC with CO_2 capture
Plot area	Approx. 65m x 30m	Approx. 65m x 30m

2.4.3. *Chiyoda Thoroughbred 121 (CT-201) Jet Bubbling Reactor process*

Chiyoda is the technology provider of the limestone forced oxidation flue gas desulfurization technology, named Chiyoda Thoroughbred 121 (CT-201) process, based on the simultaneous SO_2 absorption, oxidation, neutralization and crystallization in the Jet Bubbling Reactor (JBR).

An overview of the CT-201 process is attached to this section, including the specific set of information for two boiler based cases, namely Case 1 (SC-PC without CO_2 capture) and Case 2 (SC-PC with CO_2 capture) provided by Chiyoda to support the study.

2.4.4. *High level assessment of FGD technology*

The FGD technologies shown in the previous sections differ in the following main aspects:

- Flue gas treatment configuration
- FGD reagent and by-product
- Operating experience
- Water consumption
- Sulphur removal efficiency.

This section presents a high level assessment of these key features, for each technology. It is noted that this section is not aimed at making a detailed comparison of the different FGD technologies, which would require technical and economic information at a level of detail that is well beyond that of a feasibility study.

Flue gas treatment configuration

The selection of the optimum flue gas treatment configuration is highly dependent on the Flue Gas Desulphurisation (FGD) technology.

Figure 7 shows the typical flue gas treatment configuration of a wet FGD (i.e. Alstom wet scrubber technology or Chiyoda Jet Bubbling reactor) for Case 1 (no CCS) and Case 2 (CCS).

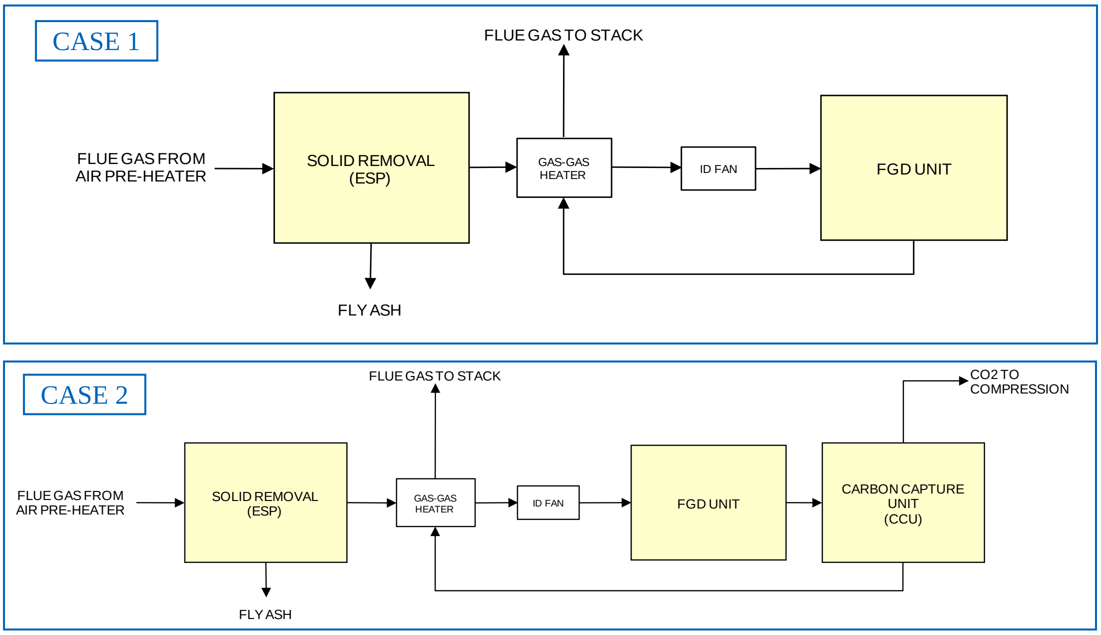


Figure 7. Flue gas treatment configuration with wet FGD for cases 1 and 2

Flue gases exit the air pre-heater and flow to the electrostatic precipitator (ESP) that lowers the solid content down to 10 mg/Nm^3. A gas-gas heater is considered to pre-heat the desulphurised flue gases, before discharge from the stack, against solid-free flue gases from the ESP. The gas-gas heater is designed to discharge the flue gas around 30°C above the saturation temperature, with the limit of a minimum inlet temperature to the FGD system of around 90-100°C. The flue gas ID fan is installed preferably upstream of the FGD system, as the cost increase due to the higher volume flowrate is lower than the higher cost related to the material required if it were downstream the FGD, due to the higher corrosion problem (flue gas conditions close to the water dew point). For Case 2, the flue gases from the FGD are sent to the capture unit and finally heated-up in the gas-gas heater.

Figure 8 shows the flue gas treatment configuration for the FWE Circulating Fluid Bed Scrubber (CFBS) technology.

The main difference is that, for Case 1, the installation of the CFBS would avoid the need for the gas-gas heater, as the flue gases from the FGD are not saturated with water, making also available duty for condensate preheating and potentially saving steam in the power island. In addition, the fabric filter included in the CFBS for product recirculation is able to remove also the fly ash from the boiler, still meeting 10 mg/Nm^3 for particulate emission; this avoids the installation of the ESP upstream of the unit. In this case, the preferred location for the ID fan is downstream of the FGD system, as flue gases are solid-free and above the water dew point. For Case 2 the gas-gas heater is required to heat-up the decarbonised flue gases exiting the carbon capture unit because they are saturated with water.

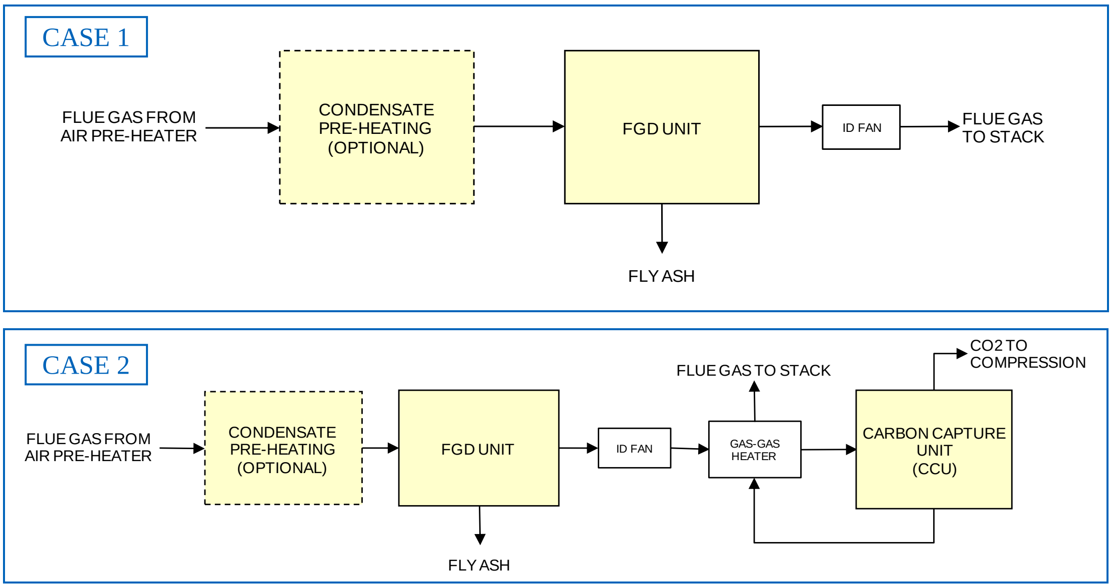


Figure 8. Flue gas treatment configuration with CFBS FGD for cases 1 and 2

FGD reagent and by-product

Wet Flue Gas Desulphurisation systems (i.e. Alstom wet scrubber technology or Chiyoda Jet Bubbling reactor) use limestone reagent as sorbent for SO_2 removal, as it is available in large amounts in many countries and is cheaper to process than other sorbents. By-products are either gypsum or a mixture of calcium sulphate/sulphite, depending on the oxidation mode. Saleable gypsum by-product is produced with both Alstom and Chiyoda technologies, potentially improving the economics of the project.

On the other hand, the CFBS uses higher cost lime as reactant with SOx and solid by-product is not sealable and must be disposed of, resulting in higher operating costs.

Operating experience

Wet scrubbers, especially the limestone-gypsum processes, are the leading FGD technologies. They have about 80 % of the market share and are used in large utility boilers. In particular, Alstom is a world leader in the flue gas desulphurisation technology, with more than 52,000 MWe of wet FGD delivered worldwide.

Since 1978, Chiyoda has designed more than 80 commercial CT-121 FGD plants, processing flue gas gases from coal boiler power stations, up to 950 MWe plants size.

On the other hand, since 1989, FWE have installed around 40 commercial FGD systems, processing flue gas from small industrial boilers to large coal power plants with capacities as high as 500 MWe.

Water consumption

Wet FGD technology requires a significant amount of make-up water, in particular for flue gas saturation and slurry preparation. On the other hand, in the CFBS technology, water is injected and evaporated in the absorber to reduce and control the flue gas temperature, resulting in a lower water demand.

Sulphur removal efficiency

The wet limestone FGD technology (i.e. Alstom wet scrubber or Chiyoda Jet Bubbling reactor) is able to achieve high SO_2 removal efficiency (around 99%), required for the post-combustion capture study case. The main limit of the wet limestone technology is that it is not generally able to remove more than 30% of SO_3. However, this does not represent a stringent limitation to the use of the wet FGD technology, in particular it does not affect the capability to meet the environmental emission limit of 150 mg/Nm^3 as required for Case 1.

On the contrary, it is not possible to meet the lower SOx specification of 10 ppm total SOx required by the post-combustion alternative (Case 2). As a caustic injection solution is anyhow required in the downstream CO_2 capture unit in order to reduce to the maximum extent possible solvent degradation, the more stringent SOx concentration upstream the absorber can be met, with a marginal higher operating cost.

On the other hand, the hydrated lime-based FWE Circulating Fluid Bed Scrubber technology is capable of removing nearly 99% of both SO_2 and SO_3 in the flue gases, meeting the strict specification of total SOx required by the downstream carbon capture unit.

2.4.5. *FGD technology for study cases development*

As shown in the previous sections, all FGD technologies meet the environmental requirements of the plant. Moreover, being at study level it is not possible to give a firm recommendation on the best technology for sulphur removal. Therefore, preliminary selection only is made in this study, on the basis of generic and high-level criteria, with the sole purpose of completing the technical and economical assessment of the cases.

More specifically, for the air fired boiler-based alternatives of the study it is proposed to utilize the Alstom wet scrubbing technology (WFGD), mainly because it is the most referenced technology supplier of FGD systems, accounting for about 80% of all the installed capacity. The same technology is considered for both cases without and with carbon capture for a better evaluation of the impact of capturing the CO_2 in these plant types.

2.5. Mercury removal systems

Nowadays, yet no emission limits have been defined for mercury emission from coal fired power plants in Europe.

Reduction of mercury emissions from coal-fired boilers is currently performed via existing controls used to remove particulate matter (PM), sulphur dioxide (SO_2) and nitrogen oxides (NOx). This includes capture of Hg_p in particulate matter control equipment (ESP or fabric filters) and soluble Hg^{2+} compounds in wet flue gas desulfurization (FGD) systems. Available data also reflect that use of selective catalytic reduction (SCR) for NOx control enhances oxidation of Hg^0 in flue gas and results in increased mercury removal in wet FGD.

In addition, in pulverised coal plant the fly ash has the capability to partially remove the mercury from the flue gas due to its residual carbon content. As for that, additional mercury removal facilities from the flue gas are not foreseen in the SC PC boiler based cases of this study.

A qualitative description of the effectiveness of flue gas treatment technologies in mercury removal and of the available technology dedicated to mercury removal is given in the below paragraph for possible future consideration in these power plants.

Hg formation in coal fired power plant

During combustion, the mercury in coal is volatilized and converted to elemental mercury (Hg^0) vapor in the high temperature regions of coal-fired boilers. As the flue gas is cooled, Hg^0 produces ionic mercury (Hg^{2+}) compounds and/or Hg compounds (Hg_p) that are in the solid-phase at the flue gas cleaning temperatures. The relative amount of the three species is highly dependent on coal type and has a considerable influence on selection and effectiveness of mercury control approaches. In general, the majority of gaseous mercury in bituminous coal-fired boilers is Hg^{2+}, while the majority of gaseous mercury in sub-bituminous/lignite-fired boilers is Hg^0.

Flue gas treatment technologies to reduce Hg emissions

Factors that enhance mercury control are the low temperature in the control device system (less than 150 ºC), the presence of effective mercury sorbent and the application of a method to collect the sorbent.

In general, high levels of carbon in the fly ash enhance mercury (Hg_p) adsorption onto particulate matter, which is subsequently removed by the **particulate matter control device**. Electrostatic precipitators and fabric filters are commonly used to remove particulate matter from flue-gases. Even if characterised by the same overall removal efficiency (>99.9), fabric filter shows better performance in controlling fine particulate matter, i.e. the size range in which particles enriched with metal elements might be found. In addition, the Hg removal efficiency depends strongly on the fuel properties (e.g. Cl). In fact, the presence of hydrogen chloride (HCl) can results in the formation of mercury chloride, which is readily adsorbed onto carbon-containing particulate matter.

Conversely, sulphur dioxide (SO_2) in flue-gas can act as a reducing agent to convert oxidised mercury to elemental mercury, which is more difficult to collect.

Gaseous compounds of Hg^{2+} are generally water-soluble and can absorb in the aqueous slurry of a **wet FGD system**. The Hg^{2+} adsorberd in the liquid slurry reacts with dissolved sulphites to form mercuric sulphide, which precipitates and it is removed as sludge. On the other hand, gaseous Hg^0 is insoluble in water and therefore does not absorb in such slurries. The capture of Hg in units equipped with wet FGD scrubbers is dependent on the relative amount of Hg^{2+}. The increase in mercury oxidation across **SCR systems** favoured Hg capture in the downstream FGD systems as increase the relative amount of more effective removable Hg^{2+} with respect to elemental Hg^0.

The Hg removal in **spray dry systems** is only dependent on the presence of a particulate removal system within the FGD system. Activated carbon technology has been applied in the US to increase Hg removal in spray dry scrubber/ESP systems.

Mercury removal rate up to 98% are achieved in bituminous coal fired boiler, due to the higher amount of removable Hg^{2+}, while maximum 70% is achieved in sub-bituminous fired boiler.

Hg reduction by systems designed for metal removal

Dedicated method for mercury removal consists in:

- Activated carbon injection (ACI) in the flue gas. ACI has the potential to achieve moderate to high levels of Hg control, depending on the activated carbon physical and chemical characteristics
- Activated carbon of coke filters
- Sulphur-impregnated adsorbent in packed bed
- Selenium impregnated filter. The filter relies on the strong affinity of Hg to Se, with which it combines to form mercury selenide (HgSe), a highly stable compound.

2.6. CO_2 capture unit (Case 2)

Whilst there is a large number of theoretical technology suppliers that could provide chemical-based solvents for CO_2 capture, there are in practice few that are capable to offer a technology that is reliable for large scale operation, since not many commercial applications processing large volumetric flows, as in boiler-based plants, have been fully developed yet.

The most quoted companies that could offer chemical solvents for CO_2 capture from flue gases are, in alphabetical order, the following:

- **AKER**: it offers, through its subsidiary Aker Clean Carbon, an amine-based solvent for CO_2 capture from various flue gases types.
- **ALSTOM**: it is the only referenced company that is developing an ammonia-based solvent process, using a solution containing ammonium carbonate (Chilled Ammonia Process, CAP).
- **CANSOLV**: it offers a combined SO_2/CO_2 scrubbing process, using 2 different amine-based solvents in a thermally integrated system. Cansolv is a subsidiary of Shell Global Solutions group.
- **CB&I**: ABB Lummus offered a MEA scrubbing technology on the original Kerr Mc Gee process. This technology, which was the first used on a coal flue gas, was then acquired by Chicago Bridge & Iron Co. (CB&I) in November 2007. CB&I and Lummus together now offer various processes for cleaning of hydrocarbon gases, including CO_2 capture.
- **FLUOR**: it offers the Econamine FG Plus (EFG+) process. This is a development of the MEA based ECONOAMINE process developed by Dow and acquired by Fluor.
- **HTC Energy**: it offers the Purenergy CCS Capture System™, which is a pre-engineered, pre-built and modularly constructed unit, using a technology developed in the University of Regina, based on an amine solvent.
- **MHI**: Mitsubishi Heavy Industries (MHI) offers the KS-1 process, based on a formulation of sterically hindered amines, which is a joint development between MHI and the Kansai Electric Power Company (KEPCO).
- **SIEMENS**: it is the only referenced company that is developing an aminoacid salt solution process for the chemical absorption of the carbon dioxide.

Some of the above-listed suppliers were asked to support the study; amongst them, Cansolv has provided specific data to develop Case 2 of the study, as reported in the following sections, only for the information that the supplier has authorized for disclosure.

An overview of the Cansolv post-combustion capture technology is attached to this chapter, including the specific set of performances provided by Cansolv to develop Case 2 (SC-PC with CO_2 capture) of the study. The technology overview of the Cansolv flue gas desulphurisation process is also attached to this chapter.

It has to be noted that some differences may exist between figures in the Cansolv's information and those shown in the report of the specific study case. In fact, information in the attachments is based on preliminary stream properties and flowrates, as estimated during the early stages of the study; then, data have been slightly adjusted and optimised during study execution either by either Cansolv or Foster Wheeler. Figures included in the report for each study case shall be considered as the final ones.

Data are covered by a secrecy agreement and the information included in this section and in the relevant attachment is limited to the information that Cansolv have authorized for disclosure.

2.7. CO_2 compression and dehydration (Case 2)

The compression and dehydration unit consists of two parallel trains, including compressor, separation drums, coolers, dehydration system and final pump.

Carbon dioxide from the stripper of the CO_2 capture unit is compressed to a pressure of 75 bar by means of a four stage integrally geared centrifugal compressor. The compression includes inter-stage cooling and knockout drums to remove and collect condensed water. At each stage outlet, part of the heat is recovered to pre-heat the condensate from the steam cycle. The CO_2 compression package consists of electrically driven multi-stage compression trains. The system includes anti-surge control, vent, inter-coolers, knockout drums and condensate draining facilities as appropriate.

The incoming stream from the AGR requires treatment for water removal down to a specific level. Therefore, CO_2 from the third compression stage is routed to the dehydration unit, where humidity water is removed and CO_2 is dried. The system is designed to produce CO_2 product with a final dew point temperature of –40°C. The dehydration is carried out via a solid desiccant, like Activated Alumina and Molecular Sieves. The dehydration unit is composed of two beds for each parallel train of the unit. In normal operation one bed is used for drying, while the water-saturated bed is regenerated using a small part (ca.10%) of the dry product gas.

Final compression stages downstream of the driers increase the CO_2 pressure above the critical point of the fluid. The presence of non-condensable gases affects the behaviour of CO_2 resulting in an increased pressure requirement for the condensation of CO_2. However, due to the almost negligible presence of non-condensable gases in the CO_2 leaving the top of the stripper, the final compression pressure is very close to the critical pressure of pure CO_2.

After being cooled, dried CO_2 in dense phase is finally pumped and delivered the to the battery limits of the plant at a pipeline pressure of 110 bar.

2.8. Steam Cycle

The steam cycle is mainly composed of the Steam Turbine Generator (STG) and the water pre-heating line. It consists basically of one supercritical steam turbine, equipped with one water cooled steam condenser, with multiple extractions for the pre-heating of the condensate and boiler feed water.

2.8.1. SC PC without CO_2 capture (Case 1)

The following description makes reference to the simplified process flow diagram of the steam cycle, attached to the end of this section.

The turbine consists of a HP, MP and LP sections all connected to the generator with a common shaft.

Supercritical steam from the boiler is sent to the steam turbine through the stop valves and control valves. 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 MP turbine. Boiler and turbine interface data are as follows:

HP turbine inlet:	270 bar; 600°C
MP turbine inlet:	60 bar; 620°C

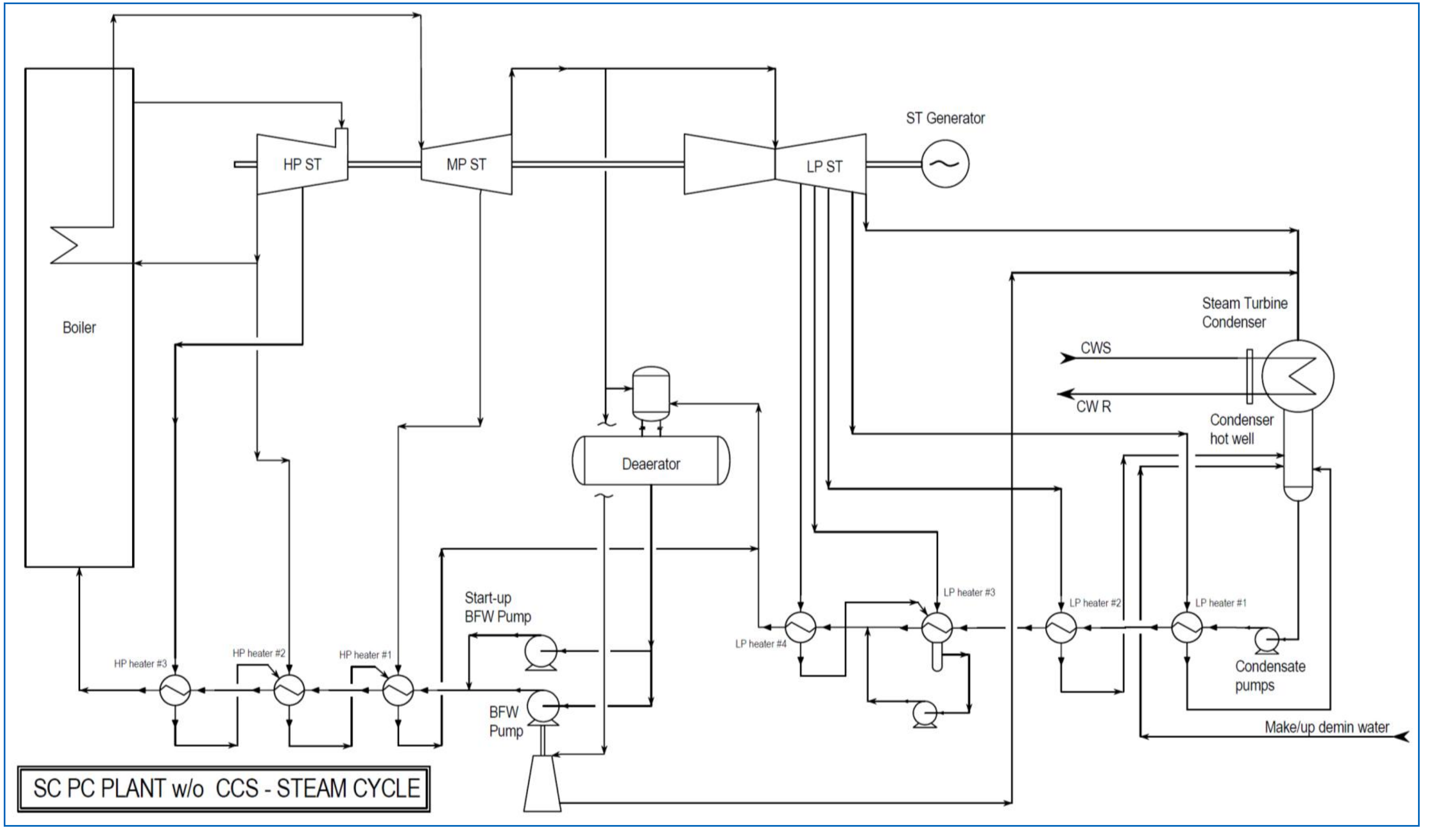
Exhaust steam from the MP turbines then flows into the double flow LP turbine system and finally downward into the water-cooled condenser at 4.0 kPa, corresponding to 29°C.

Recycled vacuum condensate from the condenser hot well is pumped by the condensate pumps and preheated in a bank of four condensate heaters, using extraction steam from the LP turbines. Steam condensate from the first two pre-heaters is recovered back to the condenser. Steam condensate from both the third and the fourth pre-heaters is mixed with the condensate downstream of the third exchanger.

The preheated condensate stream is then sent to the deaerator. Exhaust steam from the MP ST section is used to provide the steam necessary for the degassing of the condensate and the make-up demineralised water. Part of the MP ST exhaust steam is fed to a turbine to provide the power required by the HP boiler feed water pumps.

After the deaerator a further bank of pre-heaters preheats the feed water to 290°C prior to the boiler. These heaters are heated by MP turbine extraction steam and finally by an HP steam stream extracted from the turbine. Steam condensate recovered into the boiler feed water heaters is sent back to the deaerator.

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


ST Generator
HP ST
MP ST
LP ST
Boiler
Steam Turbine Condenser
CWS
CW R
Condenser hot well
Deaerator
Start-up BFW Pump
BFW Pump
HP heater #3
HP heater #2
HP heater #1
LP heater #4
LP heater #3
LP heater #2
LP heater #1
Condensate pumps
Make/up demin water
SC PC PLANT w/o CCS - STEAM CYCLE

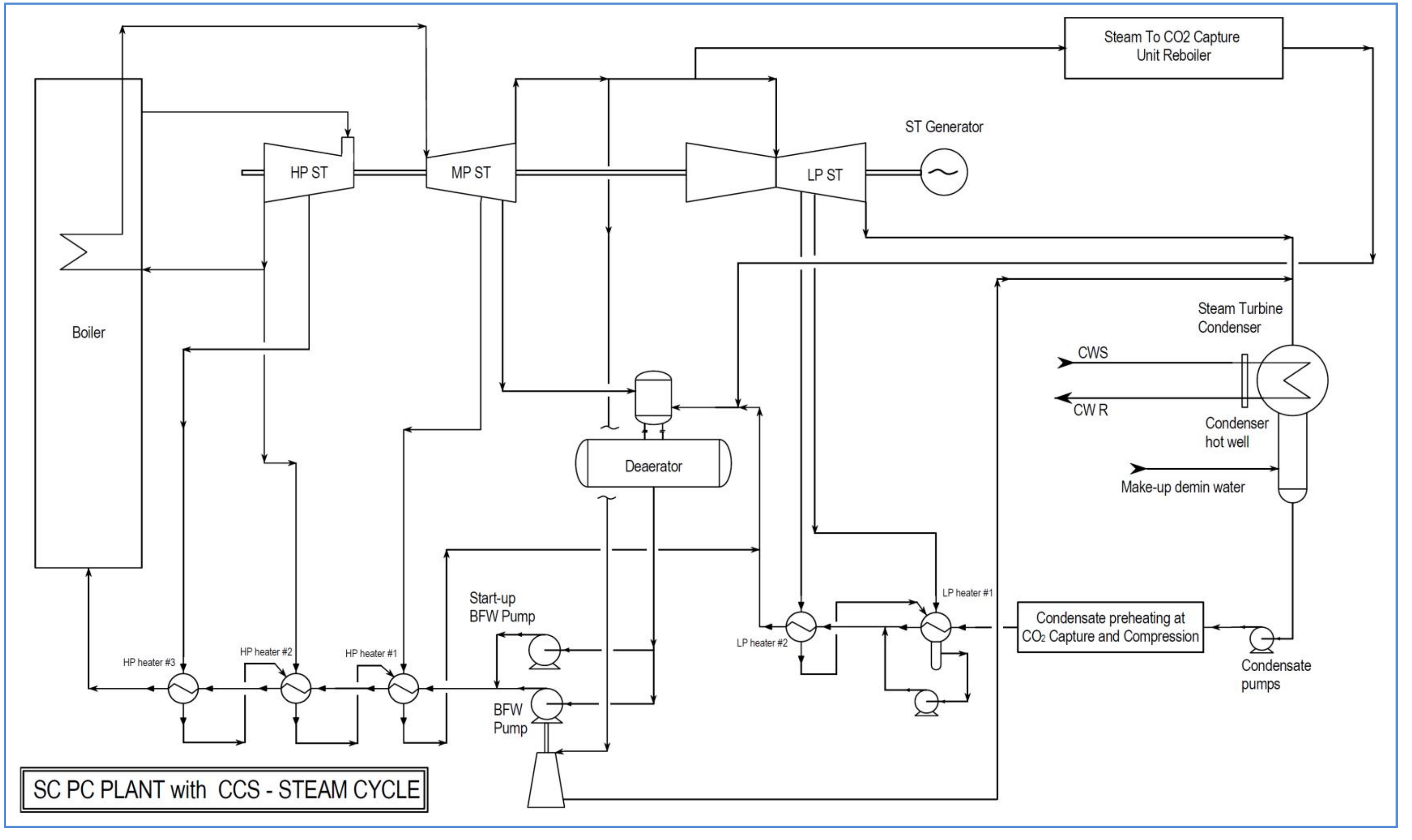
2.8.2. *SC PC with CO_2 capture (Case 2)*

The following description makes reference to the simplified process flow diagram of the steam cycle, attached to the end of this section.

Analogously to Case 1, the turbine consists of HP, MP and LP sections all connected to the generator with a common shaft. Also the HP and MP boiler and turbine interface data are the same as in Case 1, while the LP turbine conditions change to allow the extraction of steam from the MP turbine outlet at the required minimum pressure of the amine stripper reboiler. The extraction pressure is regulated via a dedicated pressure controller, acting on the admission valves of the steam turbine LP module.

Furthermore, recycled vacuum condensate from the condenser hot well is pumped by the condensate pumps to the carbon dioxide capture plant and preheated in the amine stripper overhead condenser and the carbon dioxide compressor intercoolers. Heat recovered in the carbon capture unit allows a reduction of the LP steam extraction in the preheat train. Only the two final pre-heaters upstream of the deaerator require steam from the steam turbine.

The preheated condensate stream is then sent to the deaerator. From this point on, the configuration of the steam cycle is same as in Case 1.


Steam To CO2 Capture Unit Reboiler
ST Generator
HP ST
MP ST
LP ST
Boiler
Steam Turbine Condenser
CWS
CW R
Condenser hot well
Make-up demin water
Deaerator
LP heater #1
LP heater #2
Condensate preheating at CO2 Capture and Compression
Condensate pumps
Start-up BFW Pump
BFW Pump
HP heater #3
HP heater #2
HP heater #1
SC PC PLANT with CCS - STEAM CYCLE

2.9. Utility and Offsite units

2.9.1. Cooling water

The cooling water system consists of raw water in a closed loop, with a natural draft evaporative cooling tower. There are two circulation systems, depending on the pressure profile through the circuit. The primary system is used for the steam turbine condenser, while the secondary system is used for machinery cooling and other users. Each circulation system is equipped with single-stage vertical water pumps.

The maximum allowed cooling water temperature increase is 11°C. The blow-down is used to prevent the concentration of dissolved solids increasing to the point where they may precipitate and scale-up heat exchangers and the cooling tower fill. The design concentrations cycles (CC) is 4.0.

Number and size of the cooling towers differs from the case with and without carbon capture. Case-specific details on the cooling tower design are included in the relevant chapter of the report. Each concrete tower will be equipped with two distribution systems, one primary distribution system supplying water from a concrete duct, and one secondary system from PVC pipes equipped with sprayers, connected to the concrete ducts. Tower filling, with vertical channels, increases the cooling and thermal efficiency, allowing pollutants to be easily washed through. Drift eliminators guarantee a low drift rate and low pressure drop. To avoid freezing in winter ambient conditions, the fill pack is divided into zones to allow step by step reduction of cooling capacity while maintaining an excellent water distribution and spray sprinklers are installed to create a warm water screen on the air inlets to preheat the ambient air when freezing ambient conditions occurs.

2.9.2. Raw and Demineralised water

Raw water is generally used as make-up water for the power plant, in particular as make-up of the cooling tower and of the FGD unit. Raw water is also used to produce demineralised water. Raw water from an adequate storage tank is pumped to the demineralised water package that supplies make-up water with adequate physical-chemical characteristics to the thermal cycle.

The treatment system includes the following:

- Filtering through a multimedia filter to remove solids.
- Removal of dissolved solids: filtered water passes through the Reverse Osmosis (RO) cartridge filter to remove dissolved CO_2 and then to a reverse osmosis system to remove dissolved solids.
- Demineralised water production: an electro de-ionization system is used for final polishing of the water to further remove trace ionic salts of the Reverse Osmosis (RO) permeate.

Adequate demineralised water storage is provided by means of a dedicated demineralised water tank.

The demineralised water make-up supplies the make-up water to the thermal cycle, whilst the demineralised water distribution pump supplies demineralised water to the other plant users or to the plant circuits for first filling.

2.9.3. *Fire fighting system*

This system consists of all the facilities able to locate possible fire and all the equipment necessary for its extinction. The fire detection and extinguishing system essentially includes the automatic and manual fire detection facilities, as well as the detection devices with relevant alarm system. An appropriate fire detection and suppression system is considered in each fire hazard area according to the applicable protection requirements. The fire fighting water is supplied by a water pumping station via a looping piping network consisting of a perimetrical circuit fed by water pumped from the cooling tower basin.

2.9.4. *Instrument and plant air system*

The air compression system supplies air to the different process and instrumentation users of the plant.

The system consists mainly of:

- Air compressors, one in operation, one in stand-by.
- Compressed air receiver drum.
- Compressed air dryer for the instrument air.

The ambient air compressed by means of the air compressor is stored in the air receiver in order to guarantee the hold-up required for emergency shutdown.

Plant air is directly taken from the air receiver, while air for instrumentation is sent to the air dryer where air is dried up to reach an adequate dew point, to ensure the proper operation of the instrumentation.

2.9.5. *Waste Water Treatment*

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

The following description gives an overview of the waste water treatment configuration, generally adopted in similarly designed power plants; it includes a preliminary identification of the operations necessary to treat the different waste water streams generated in the power plant.

The Waste Water Treatment unit is designed to treat the following main waste water streams:

- Blow-down from Wet Flue Gas Desulphurization Unit
- Potentially oil-contaminated rain water
- Potentially dust-contaminated rain water
- Clean rain water
- Sanitary waste water.

Mainly, the above streams are collected and routed to the waste water treatment in different systems according to their quality and final treatment destination.

The WWT system is equipped mainly with the following treatment sections:

- Treatment facilities for the FGD blow-down
- Treatment facilities for the potentially oily contaminated water
- Treatment facilities for the potentially dust contaminated water
- Treatment facilities for not contaminated water
- Treatment facilities for the sanitary wastewater.

FGD Blowdown

The blow-down from the flue gas desulphurization, with a high content of dissolved salts (TSS 1-3%wt, Cl^- = 12,000-15,000 ppm) is treated in a dedicated section consisting of a double Sludge settling (with the addition of polyelectrolyte) and a Sludge Treatment that separates the final sludge to disposal. Water from the Chemical Sludge settling (free from solids) is sent to a dedicated Reverse Osmosis (R.O.) in order to lower its high Cl^- content. The brine from the R.O. is evaporated and crystallized to separate clean water from salts. The liquid effluents from the RO and evaporation are recycled to the FGD unit, while the remaining sludge and solids are sent to disposal.

Potentially Dust Contaminated Water Treatment

Rain water and washing water from areas subject to potential dust contamination is treated in apposite water treatment systems prior to be sent to the “potentially oil contaminated” treatment system.

In particular, they are collected in a dedicated sewer, sent to a lamination tank and then to a chemical/physical treatment to remove the substances that are dissolved and suspended.

The system includes also a neutralization system to modify potential acidity and/or alkalinity of washing water used for the air pre-heaters.

Potentially Oil-Contaminated Water Treatment

Potentially oil-contaminated waters are:

- Washing water from areas where there is equipment containing oil.
- Rain water from areas where there is equipment containing oil.

After being mixed with treated water coming from “potentially dust contaminated” system, water is treated in a flotation and filtration system, where emulsified oil and suspended solids are respectively separated.

Treated effluent water will have the characteristics to respect the local regulations so that it can be consequently discharged.

Not Contaminated Water Treatment

Rainwater fallen on clean areas of the plant, such as roads, parking areas, building roofs, areas for warehouse/services/laboratory etc. where there is no risk of contamination, will be collected and disposed directly to the water discharge system.

A coarse solids trap is installed upstream the discharge point in order to retain coarse solids that may be carried together with the discharge water.

Sanitary Water Treatment

The sanitary waste water streams discharged from the different sanitary stations of the plant will be collected in a dedicated sewage and destined to the Sanitary Water Treatment system. This section generally involves the following main water treatment operations:

- Primary sedimentation for coarse solids removal.
- Biological treatment for BOD removal.
- Filtration for residual organic matter and suspended solids separation.
- Disinfection for bacteria inhibition.

ATTACHMENT A.1: Chiyoda Thoroughbred 121 (CT-201) process

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CT-121 FGD Study Results

for

IEAGHG CO2 Capture at Coal Fired Power Plants

June 25, 2013

CHIYODA CORPORATION

Chiyoda Corporation
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1. Introduction

This document has been prepared by Chiyoda Corporation ("Chiyoda") as the technology provider of the wet Limestone/ Gypsum CT-121 FGD process, based on the FDI's request by e-mail dated February 6th, 2013.

All numeric information, conclusions, volumes, prices and/or costs in this Study Results are for your reference purpose only. Nothing in this Study Results shall create proposal, offer and/or any commitments. This Study Results shall not be construed as granting a license under any intellectual property rights.

2. Process Design Basis

Process design basis for the following three different cases is shown in Attachment 1.1, 1.2 and 1.3, respectively.

Case 1: SC-PC without CO2 Capture

Case 2: SC-PC with CO2 Capture

Case-3: Oxy-Boiler

3. Process Description

The CT-121 FGD process is composed of three sections such as SO_2 Scrubbing Section, Limestone Grinding Section and Gypsum Dewatering Section.

<u>SO_2 Scrubbing Section</u>

Flue gas boosted up by FGD Booster Fan is introduced to Gas Cooler. In Gas Cooler, flue gas is quenched and saturated by contacting with continuously sprayed gypsum slurry which is pumped up. Quenched flue gas is introduced to the JBR and is injected into absorbent slurry through Sparger Tubes to remove SO_2. SO_2 absorbed from flue gas is oxidized with oxidation air, neutralized with limestone and is transformed to gypsum. A portion of gypsum slurry in the JBR is discharged to Gypsum Dewatering Section by Absorber Bleed Pump and the slurry concentration in the JBR is maintained around 20 wt %.

Treated flue gas leaving the JBR is introduced to Mist Eliminator to remove entrained mist from treated flue gas. The treated flue gas leaving the Mist Eliminator is directed to the chimney / CCS Section.

<u>Limestone Grinding Section</u>

Limestone pebbles with a size of <25 mm are stored in Limestone Silo. The limestone is transferred from Limestone Silo by Weigh Belt Feeder to Wet Ball Mill for grinding. Filtrate water is added at the feed chute in proportion to the feed rate of the limestone. The slurry discharged from Wet Ball Mill is sent to Ball Mill Classifier by Classifier Feed Pump. The overflow slurry with fine limestone is stored in Reagent Storage Tank and the underflow slurry with coarse limestone is returned to Wet Ball Mill for further grinding. The water balance is maintained to provide 30 wt% suspended limestone solids in the Reagent Storage Tank.

The limestone slurry is pumped from Reagent Storage Tank to the JBR to keep the absorbent slurry pH in the JBR.

Gypsum Dewatering Section

Gypsum slurry discharged from the JBR is directed to Gypsum Hydrocyclone and separated into solid rich underflow slurry and liquid rich overflow slurry.

The underflow slurry is sent to Vacuum Belt Filter and is dewatered to produce gypsum cake with free moisture of less than 10 wt%. The filter belt is washed with the collected Vacuum Pump seal water / makeup water to remove solids retained on the belt after the cake has been discharged. This water is collected in Filter Cloth Wash Water Tank and reused to wash the filter cake.

The gypsum cake from Vacuum Belt Filter is stored in Gypsum Storage Shed for shipping.

The overflow of Gypsum Hydrocyclone is collected in Hydrocyclone Overflow Tank and is bled from FGD system through Hydrocyclone Overflow Blowdown Pump to keep the concentration of chlorides and soluble salts at a proper level.

The filtrate from Belt Filter and a part of Hydrocyclone Overflow Tank liquid are collected in Reclaim Water Tank. A part of reclaim water is transferred to Wet Ball Mill for limestone slurry preparation. The rest of reclaim water is transferred from Reclaim Water Tank to the JBR.

4. Process Flow Diagram

Process flow diagram is shown in Attachment 2.

5. Overall Material and Heat Balance

Overall material and heat balance for the following three different cases is shown in Attachment 3.1, 3.2 and 3.3, respectively.

Case 1: SC-PC without CO2 Capture

Case 2: SC-PC with CO2 Capture

Case-3: Oxy-Boiler

6. Preliminary Plot Area Requirement

Preliminary plot area requirements for the following three different cases are shown below.

Case 1: SC-PC without CO_2 Capture

Total area requirement: 12,400 m2

Breakdown;

Area requirement for SO_2 removal section: 6,600 m2 (55 m x 120 m)

Area requirement for limestone preparation and gypsum dewatering sections: 5,800 m2

Case 2: SC-PC with CO_2 Capture

Total area requirement: 12,400 m2

Breakdown;

Area requirement for SO_2 removal section: 6,600 m2 (55 m x 120 m)

Area requirement for limestone preparation and gypsum dewatering sections: 5,800 m2

Case-3: Oxy-Boiler

Total area requirement: 7,200 m2

Breakdown;

Area requirement for SO_2 removal section: 4,050 m2 (45 m x 90 m)

Area requirement for limestone preparation and gypsum dewatering sections: 3,150 m2

7. Estimated Utility and Chemical Consumptions

Estimated utility and chemical consumptions for each case are estimated as follows;

Case 1: SC-PC without CO_2 Capture

Power Consumption	:	6,500 kW
Process Water Consumption	:	98 m3/h
Limestone Consumption	:	8.7 Ton/h (dry) as 95% purity limestone

Case 2: SC-PC with CO_2 Capture

Power Consumption	:	7,800 kW
Process Water Consumption	:	100 m3/h
Limestone Consumption	:	9.3 Ton/h (dry) as 95% purity limestone

Case 3: Oxy Boiler

Power Consumption	:	1,850 kW
Process Water Consumption	:	53 m3/h
Limestone Consumption	:	4.1 Ton/h (dry) as 95% purity limestone

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8. Waste Water Quality

Waste water bleed rate for each case and typical waste water quality are shown below.

Waste water bleed rate

Case 1: SC-PC without CO2 Capture

4.3 m3/h

Case 2: SC-PC with CO2 Capture

4.3 m3/h

Case 3: Oxy-Boiler

0.5 m3/h

Typical waste water quality

pH	: 5.5-7.5
Total suspended solids	: 3 wt%
Cl conc.	: 20,000 ppm

9. Budget Capital Cost

Budget capital cost for each case is estimated based on the following conditions:

- ✓ Engineering, procurement and construction are done in Japan
- ✓ Exchange rate is JPY125 / €

Case 1: SC-PC without CO2 Capture

€62,000,000

Case 2: SC-PC with CO2 Capture

€64,000,000

Case 3: Oxy-Boiler

€24,000,000

Including basic & detail design, procurement, erection and commissioning for the following facilities;

-SO2Scrubbing Section

-Limestone Slurry Preparation Section

-Gypsum Dewatering Section

but excluding flue gas by-pass ducts, dampers, chimney, civil and architectural works.

10. Attachments

Attachment - 1.1, 1.2 & 1.3	: Process Design Basis
Attachment - 2	: Process Flow Diagram
Attachment - 3.1, 3.2 & 3.3	: Overall Material and Heat Balance

====== End of the Document ======

CHIYODA CORPORATION

FOR FEASIBILITY STUDY

CASE 1: SC-PC without CO2 Capture

Design Conditions

Parameter	Design		Source/Note
(1) Generating Unit and Fuel Conditions			
Generating Unit			
Heat Output		MW	
Electric Output		MW	
Steam Flow		Ton/h	
Turn-down ratio		%/min	
Operating hour		hr/yr	
Fuel			
Type of Fuel	Coal		
Heating Value		KJ/Kg	
Composition			
C		wt%	
H		wt%	
N		wt%	
S (Maximum)		wt%	
S (Normal)		wt%	
S (Minimum)		wt%	
O		wt%	
Cl		wt%	
F		wt%	
H2O		wt%	
Ash		wt%	
(Ash Composition)			
SiO2		wt%	
Al2O3		wt%	
CaO		wt%	
MgO		wt%	
TiO2		wt%	
Fe2O3		wt%	
SO3		wt%	
Na2O		wt%	
K2O		wt%	
Ambient Conditions			
Atmospheric pressure	101.3	kPa	Email dated 02/6/2013
Relative humidity, Ave. / Max. / Min.	80 / 95 / 40	%	Email dated 02/6/2013
Ambient temperature, Ave. / Max. / Min.	9 / 30 / -10	deg. C	Email dated 02/6/2013

CHIYODA CORPORATION

FOR FEASIBILITY STUDY

CASE 1: SC-PC without CO2 Capture

Design Conditions

Parameter		Design		Source/Note
(2) FGD Inlet Flue Gas and Utility Conditions				
Inlet Flue Gas to FGD				
Flow rate	Volumetric Flow	3,170,000	Nm3/h (wet)	Calculated by Chiyoda
	Mass Flow	3,585	t/h	Email dated 02/6/2013
Temperature		100	deg. C	Email dated 02/12/2013
Pressure at FGD inlet		0	mmwg	Assumed by Chiyoda
Flue gas composition				
Ar		0.871	% Vol. (wet)	Email dated 02/6/2013
N_2		73.562	% Vol. (wet)	Email dated 02/6/2013
O_2		3.291	% Vol. (wet)	Email dated 02/6/2013
CO_2		14.110	% Vol. (wet)	Email dated 02/6/2013
H2O		8.095	% Vol. (wet)	Email dated 02/6/2013
SO_2 / SO_3 Note *1)		0.071	% Vol. (wet)	Email dated 02/6/2013
HCl		27	mg/Nm3 (dry, 6% O2)	Email dated 02/6/2013
NO_X		130	mg/Nm3 (dry, 6% O2)	Email dated 02/6/2013
Particulate		<10	mg/Nm3 (dry, 6% O2)	Email dated 02/6/2013
Limestone Reagent				
$CaCO_3$		95	wt%	Email dated 02/6/2013
$MgCO_3$		1.5	wt%	Email dated 02/6/2013
Inerts		2.5	wt%	Email dated 02/6/2013
Moisture		1.0	wt%	Email dated 02/6/2013
Grind size		4-25	mm	Email dated 02/6/2013
Make-up Water				
Cl		50	ppm	Assumed by Chiyoda
Alkalinity				
SS		30	mg/L	Assumed
Operating pressure at grade		3.5	barg	Email dated 02/6/2013
Design pressure		9.0	barg	Email dated 02/6/2013
Operating temperature at grade		9.0	deg. C (Ambient temp)	Email dated 02/6/2013
Design temperature		38	deg. C	Email dated 02/6/2013
Cooling Water				
Operating pressure		5.0	barg	Email dated 02/6/2013
Mechanical design pressure		8.0	barg	Email dated 02/6/2013
Maximum Users pressure drop		1.5	bar	Email dated 02/6/2013
Supply temperature		15	deg. C (Normal)	Email dated 02/6/2013
		36	deg. C (Maximum)	Email dated 02/6/2013
Mechanical design temperature		50	deg. C	Email dated 02/6/2013
Maximum temperature difference at Users		11	deg. C	Email dated 02/6/2013
Power				
LV distribution and utilization		40 / 230	V ± 5%-50Hz	Email dated 02/6/2013
MV distribution and utilization		6,000	V ± 5%-50Hz	Email dated 02/6/2013
(Motors rated 200kW or above)		10,000	V ± 5%-50Hz	Email dated 02/6/2013

CHIYODA CORPORATION

FOR FEASIBILITY STUDY

CASE 1: SC-PC without CO2 Capture

Design Conditions

Parameter	Design		Source/Note
(3) FGD Outlet Flue Gas Conditions and Byproduct Solids			
FGD Performance			
SO_x removal efficiency in JBR	92.1	%	Email dated 02/6/2013
Outlet SO_x	53	ppmv (dry, 6% O2)	Email dated 02/6/2013
Particulate emission		mg/Nm3-dry	
Limestone utilization			
Gas Temperature at FGD outlet		deg.C	
Gas Pressure at FGD outlet	0	mmwg	Assumed by Chiyoda
Byproduct Solids			
$CaSO_4 \cdot 2H_2O$		% dry weight	
Free Moisture	10	%	Assumed by Chiyoda
FGD Waste Water			
Cl	≤ 20,000	ppm	Assumed by Chiyoda
Total suspended solids	3	wt%	Assumed by Chiyoda

Note *1) Assumed SO2 to SO3 conversion equal to 5%

CHIYODA CORPORATION

FOR FEASIBILITY STUDY

CASE 2: SC-PC with CO2 Capture

Design Conditions

Parameter	Design		Source/Note
(1) Generating Unit and Fuel Conditions			
Generating Unit			
Heat Output		MW	
Electric Output		MW	
Steam Flow		Ton/h	
Turn-down ratio		%/min	
Operating hour		hr/yr	
Fuel			
Type of Fuel	Coal		
Heating Value		KJ/Kg	
Composition			
C		wt%	
H		wt%	
N		wt%	
S (Maximum)		wt%	
S (Normal)		wt%	
S (Minimum)		wt%	
O		wt%	
Cl		wt%	
F		wt%	
H_2O		wt%	
Ash		wt%	
(Ash Composition)			
SiO_2		wt%	
Al_2O_3		wt%	
CaO		wt%	
MgO		wt%	
TiO_2		wt%	
Fe_2O_3		wt%	
SO_3		wt%	
Na_2O		wt%	
K_2O		wt%	
Ambient Conditions			
Atmospheric pressure	101.3	kPa	Email dated 02/6/2013
Relative humidity, Ave. / Max. / Min.	80 / 95 / 40	%	Email dated 02/6/2013
Ambient temperature, Ave. / Max. / Min.	9 / 30 / -10	deg. C	Email dated 02/6/2013

CHIYODA CORPORATION

FOR FEASIBILITY STUDY

CASE 2: SC-PC with CO2 Capture

Design Conditions

Parameter		Design		Source/Note
(2) FGD Inlet Flue Gas and Utility Conditions				
Inlet Flue Gas to FGD				
Flow rate	Volumetric Flow	3,170,000	Nm3/h (wet)	Calculated by Chiyoda
	Mass Flow	3,585	t/h	Email dated 02/6/2013
Temperature		100	deg. C	Email dated 02/12/2013
Pressure at FGD inlet		0	mmwg	Assumed by Chiyoda
Flue gas composition				
Ar		0.871	% Vol. (wet)	Email dated 02/6/2013
N_2		73.562	% Vol. (wet)	Email dated 02/6/2013
O_2		3.291	% Vol. (wet)	Email dated 02/6/2013
CO_2		14.110	% Vol. (wet)	Email dated 02/6/2013
H2O		8.095	% Vol. (wet)	Email dated 02/6/2013
SO_2 / SO_3 Note *1)		0.071	% Vol. (wet)	Email dated 02/6/2013
HCl		27	mg/Nm3 (dry, 6% O2)	Email dated 02/6/2013
NO_X		130	mg/Nm3 (dry, 6% O2)	Email dated 02/6/2013
Particulate		<10	mg/Nm3 (dry, 6% O2)	Email dated 02/6/2013
Limestone Reagent				
$CaCO_3$		95	wt%	Email dated 02/6/2013
$MgCO_3$		1.5	wt%	Email dated 02/6/2013
Inerts		2.5	wt%	Email dated 02/6/2013
Moisture		1.0	wt%	Email dated 02/6/2013
Grind size		4-25	mm	Email dated 02/6/2013
Make-up Water				
Cl		50	ppm	Assumed by Chiyoda
Alkalinity				
SS		30	mg/L	Assumed by Chiyoda
Operating pressure at grade		3.5	barg	Email dated 02/6/2013
Design pressure		9.0	barg	Email dated 02/6/2013
Operating temperature at grade		9.0	deg. C (Ambient temp)	Email dated 02/6/2013
Design temperature		38	deg. C	Email dated 02/6/2013
Cooling Water				
Operating pressure		5.0	barg	Email dated 02/6/2013
Mechanical design pressure		8.0	barg	Email dated 02/6/2013
Maximum Users pressure drop		1.5	bar	Email dated 02/6/2013
Supply temperature		15	deg. C (Normal)	Email dated 02/6/2013
		36	deg. C (Maximum)	Email dated 02/6/2013
Mechanical design temperature		50	deg. C	Email dated 02/6/2013
Maximum temperature difference at Users		11	deg. C	Email dated 02/6/2013
Power				
LV distribution and utilization		40 / 230	V ± 5%-50Hz	Email dated 02/6/2013
MV distribution and utilization		6,000	V ± 5%-50Hz	Email dated 02/6/2013
(Motors rated 200kW or above)		10,000	V ± 5%-50Hz	Email dated 02/6/2013

CHIYODA CORPORATION

FOR FEASIBILITY STUDY

CASE 2: SC-PC with CO2 Capture

Design Conditions

Parameter	Design		Source/Note
(3) FGD Outlet Flue Gas Conditions and Byproduct Solids			
FGD Performance			
SO_x removal efficiency in JBR	98.5	%	Email dated 02/6/2013
Outlet SO_x	10	ppmv (dry, 6% O2)	Email dated 02/6/2013
Particulate emission		mg/Nm3-dry	
Limestone utilization			
Gas Temperature at FGD outlet		deg.C	
Gas Pressure at FGD outlet	0	mmwg	Assumed by Chiyoda
Byproduct Solids			
$CaSO_4 \cdot 2H_2O$		% dry weight	
Free Moisture	10	%	Assumed by Chiyoda
FGD Waste Water			
Cl	≤ 20,000	ppm	Assumed by Chiyoda
Total suspended solids	3	wt%	Assumed by Chiyoda

Note *1) Assumed SO2 to SO3 conversion equal to 5%

CHIYODA CORPORATION

FOR FEASIBILITY STUDY

CASE 3: Oxy-Boiler

Design Conditions

Parameter	Design		Source/Note
(1) Generating Unit and Fuel Conditions			
Generating Unit			
Heat Output		MW	
Electric Output		MW	
Steam Flow		Ton/h	
Turn-down ratio		%/min	
Operating hour		hr/yr	
Fuel			
Type of Fuel	Coal		
Heating Value		KJ/Kg	
Composition			
C		wt%	
H		wt%	
N		wt%	
S (Maximum)		wt%	
S (Normal)		wt%	
S (Minimum)		wt%	
O		wt%	
Cl		wt%	
F		wt%	
H2O		wt%	
Ash		wt%	
(Ash Composition)			
SiO2		wt%	
Al2O3		wt%	
CaO		wt%	
MgO		wt%	
TiO2		wt%	
Fe2O3		wt%	
SO3		wt%	
Na2O		wt%	
K2O		wt%	
Ambient Conditions			
Atmospheric pressure	101.3	kPa	Email dated 02/6/2013
Relative humidity, Ave. / Max. / Min.	80 / 95 / 40	%	Email dated 02/6/2013
Ambient temperature, Ave. / Max. / Min.	9 / 30 / -10	deg. C	Email dated 02/6/2013

CHIYODA CORPORATION

FOR FEASIBILITY STUDY

CASE 3: Oxy-Boiler

Design Conditions

Parameter		Design		Source/Note
(2) FGD Inlet Flue Gas and Utility Conditions				
Inlet Flue Gas to FGD				
Flow rate	Volumetric Flow	802,000	Nm3/h (wet)	Calculated by Chiyoda
	Mass Flow	1,300	t/h	Email dated 02/6/2013
Temperature		150	deg. C	Email dated 02/12/2013
Pressure at FGD inlet		0	mmwg	Assumed by Chiyoda
Flue gas composition				
Ar		1.553	% Vol. (wet)	Email dated 02/8/2013
N_2		11.809	% Vol. (wet)	Email dated 02/8/2013
O_2		5.374	% Vol. (wet)	Email dated 02/8/2013
CO_2		63.820	% Vol. (wet)	Email dated 02/8/2013
H2O		17.234	% Vol. (wet)	Email dated 02/8/2013
SO_2 / SO_3 Note *1)		0.170	% Vol. (wet)	Email dated 02/8/2013
HCl			mg/Nm3 (dry, 6% O2)	
NO_X		0.04	% Vol. (wet)	Email dated 02/8/2013
Particulate		<10	mg/Nm3 (dry, 6% O2)	Email dated 02/8/2013
Limestone Reagent				
$CaCO_3$		95	wt%	Email dated 02/6/2013
$MgCO_3$		1.5	wt%	Email dated 02/6/2013
Inerts		2.5	wt%	Email dated 02/6/2013
Moisture		1.0	wt%	Email dated 02/6/2013
Grind size		4-25	mm	Email dated 02/6/2013
Make-up Water				
Cl		50	ppm	Assumed by Chiyoda
Alkalinity				
SS		30	mg/L	Assumed by Chiyoda
Operating pressure at grade		3.5	barg	Email dated 02/6/2013
Design pressure		9.0	barg	Email dated 02/6/2013
Operating temperature at grade		9.0	degC (Ambient temp)	Email dated 02/6/2013
Design temperature		38	degC	Email dated 02/6/2013
Cooling Water				
Operating pressure		5.0	barg	Email dated 02/6/2013
Mechanical design pressure		8.0	barg	Email dated 02/6/2013
Maximum Users pressure drop		1.5	bar	Email dated 02/6/2013
Supply temperature		15	deg. C (Normal)	Email dated 02/6/2013
		36	deg. C (Maximum)	Email dated 02/6/2013
Mechanical design temperature		50	deg. C	Email dated 02/6/2013
Maximum temperature difference at Users		11	deg. C	Email dated 02/6/2013
Power				
LV distribution and utilization		40 / 230	V ± 5%-50Hz	Email dated 02/6/2013
MV distribution and utilization		6,000	V ± 5%-50Hz	Email dated 02/6/2013
(Motors rated 200kW or above)		10,000	V ± 5%-50Hz	Email dated 02/6/2013

CHIYODA CORPORATION

FOR FEASIBILITY STUDY

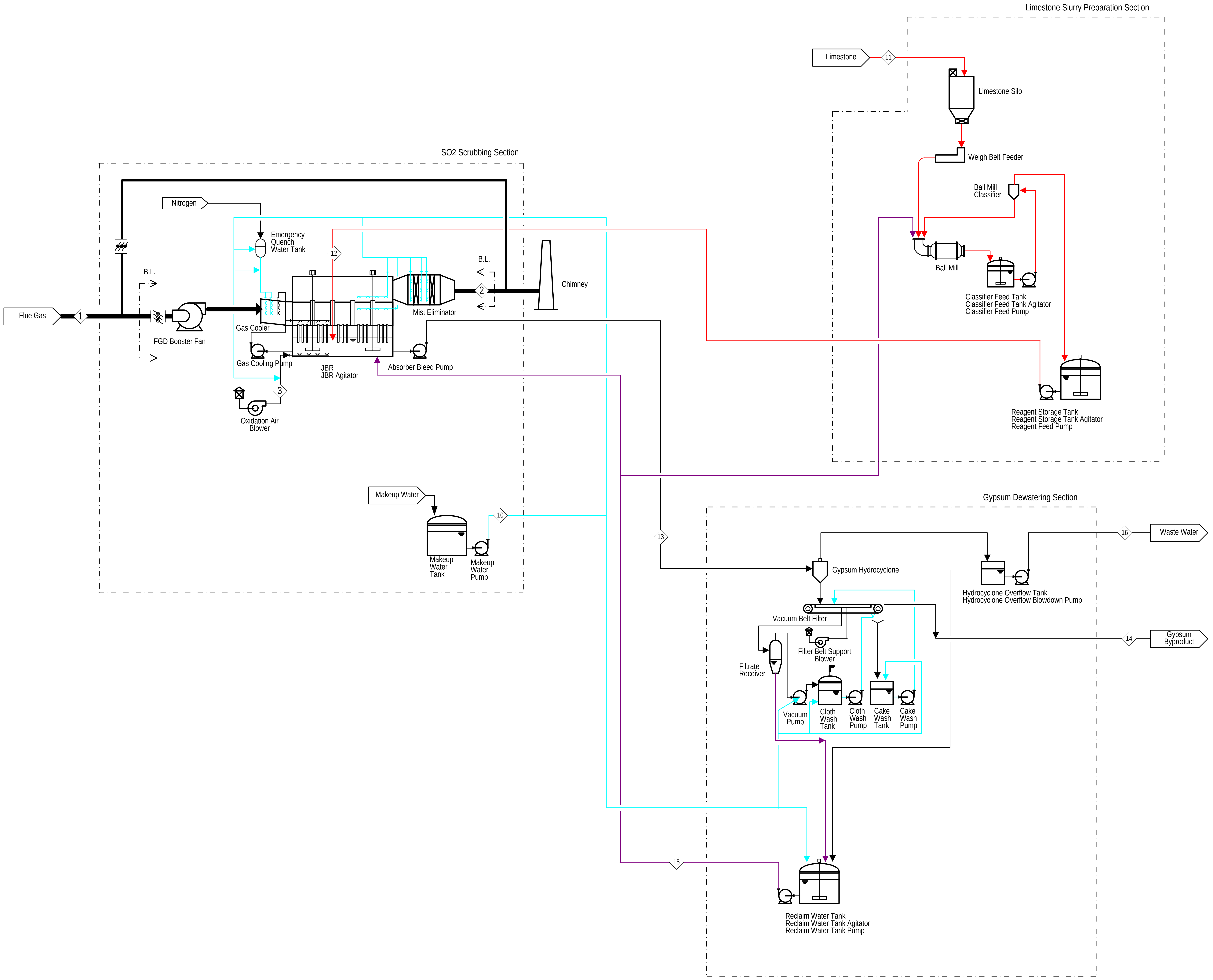
CASE 3: Oxy-Boiler

Design Conditions

Parameter	Design		Source/Note
(3) FGD Outlet Flue Gas Conditions and Byproduct Solids			
FGD Performance			
SO_x removal efficiency in JBR	60	%	Email dated 02/6/2013
Outlet SO_x	820	ppm (dry, 6% O2)	
Particulate emission		mg/Nm3-dry	
Limestone utilization			
Gas Temperature at FGD outlet		deg.C	
Gas Pressure at FGD outlet	0	mmwg	Assumed by Chiyoda
Byproduct Solids			
$CaSO_4 \cdot 2H_2O$		% dry weight	
Free Moisture	10	%	Assumed by Chiyoda
FGD Waste Water			
Cl	≤ 20,000	ppm	Assumed by Chiyoda
Total suspended solids	3	wt%	Assumed by Chiyoda

Note *1) Assumed SO2 to SO3 conversion equal to 5%

Attachment-2



FOR FEASIBILITY STUDY

NO	DESCRIPTION	BY	CHKD	APVD	DATE
1					

REVISION

DATE					
BY					
	DRAWN	DSGND	CHKD	APVD	APVD

FOR FOSTER WHEELER ITALIANA

CHIYODA CORPORATION

TITLE

PROCESS FLOW DIAGRAM
(PFD)

SCALE -   JOB NO.

PROJECT   DOC. NO.   REVISION A

CHIYODA CORPORATION

MATERIAL AND HEAT BALANCE

Case-1: SC-PC without CO2 capture

ISSUE DATE :	Feb 14, 2013
CUSTOMER :	FOSTER WHEELER ITALIANA
JOB NAME :	
JOB NO. :	
DOCUMENT :	
SHEET NO. :	1 OF 1

FOR FEASIBILITY STUDY

GAS STREAM

STREAM NO.		1			2			3		
STREAM NAME		FLUE GAS			FGD OUTLET GAS			OXIDATION AIR (at Blower Discharge)		
COMPONENT	MW	kg/h	Nm3/h	Vol.%	kg/h	Nm3/h	Vol.%	kg/h	Nm3/h	Vol.%
H_2O	18.02	177,958	221,000	8.1	267,000	332,000	11.7	124	155	0.9
SOx	64.06	5,548	1,941	710ppm	431	151	53ppm	-	-	-
O_2	32.00	128,506	90,014	3.3	132,393	92,738	3.3			
CO_2	44.01	757,770	385,929	14.1	761,342	387,749	13.7			
HCl	36.46	79	48	18ppm	0	0	0ppm	-	-	-
DRY GAS		3,407,042	2,514,000	91.9	3,426,000	2,507,000	88.3	22,180	17,230	99.1
TOTAL		3,585,000	2,735,000	100.0	3,693,000	2,838,000	100.0	22,310	17,380	100.0
DUST		29 kg/h			<29 kg/h			-		
(DUST-DRY BASE)		12 mg/Nm3, dry			<12 mg/Nm3, dry			-		
TEMPERATURE		100 deg C			49 deg C			56 deg C		
PRESSURE		0 mmH2O			0 mmH2O			4,800 mmH2O		
ACTUAL GAS FLOW RATE		3,737,000 m3/h			3,350,000 m3/h			14,300 m3/h		
REMARKS		SOx	1900	mg/Nm3, dry 6% O2	SOx	149	mg/Nm3, dry 6% O2			
			665	ppmv, dry 6% O2		52	ppmv, dry 6% O2			
		Particulate	10	mg/Nm3, dry 6% O2	Particulate	<10	mg/Nm3, dry 6% O2			

LIQUID & SOLID STREAM

STREAM NO.		10		11		12		13		14		15		16	
STREAM NAME		MAKE UP WATER		LIMESTONE		LIMESTONE SLURRY		GYPSUM SLURRY		BYPRODUCT GYPSUM		RECLAIM WATER		WASTE WATER	
COMPONENT	MW	kg/h	wt%	kg/h	wt%	kg/h	wt%	kg/h	wt%	kg/h	wt%	kg/h	wt%	kg/h	wt%
H_2O	18.02	96,710	100	90	1	20,480	66	60,610	76	1,560	10	56,640	92	3,940	92
Cl	35.45	5	50ppm	-	-	-	-	1,240	19,400ppm	0	0	1,160	19,400ppm	80	19,400ppm
$CaCO_3$	100.09	-	-	8,270	95	8,280	27	-	-	-	-	-	-	-	-
$MgCO_3$	84.32	-	-	290	2	290	0	-	-	-	-	-	-	-	-
$CaSO_4\ 2H_2O$	172.17	-	-	-	-	-	-	15,400	19	13,490	87	1,780	3	120	3
OTHERS	-	10	0	220	3	1,880	7	2,860	3	550	4	2,160	4	160	4
TOTAL		96,720	100	8,700	100	30,930	100	80,110	100	15,600	100	61,740	100.0	4,300	100.0
		98 m3/h				25 m3/h		72 m3/h				61 m3/h		4.3 m3/h	
TEMPERATURE		-		-		-		-		-		-		-	
pH				-		-		-		-		-		-	
REMARKS				Purity	96.0%	30%	Slurry	20%	Slurry	Purity	96.1%			TSS	3.0%

CHIYODA CORPORATION

MATERIAL AND HEAT BALANCE

Case-2: SC-PC with CO2 capture

ISSUE DATE : Feb 12, 2013
CUSTOMER : FOSTER WHEELER ITALIANA
JOB NAME :
JOB NO. :
DOCUMENT :
SHEET NO. : 1 OF 1

FOR FEASIBILITY STUDY

GAS STREAM

STREAM NO.		1			2			3		
STREAM NAME		FLUE GAS			FGD OUTLET GAS			OXIDATION AIR (at Blower Discharge)		
COMPONENT	MW	kg/h	Nm3/h	Vol.%	kg/h	Nm3/h	Vol.%	kg/h	Nm3/h	Vol.%
H2O	18.02	177,958	221,000	8.1	269,000	334,000	11.8	132	164	0.9
SOx	64.06	5,548	1,941	710ppm	72	25	9ppm	-	-	-
O2	32.00	128,506	90,014	3.3	132,610	92,889	3.3			
CO2	44.01	757,770	385,929	14.1	761,590	387,875	13.6			
HCl	36.46	79	48	18ppm	0	0	0ppm	-	-	-
DRY GAS		3,407,042	2,514,000	91.9	3,427,000	2,508,000	88.2	23,500	18,250	99.1
TOTAL		3,585,000	2,735,000	100.0	3,696,000	2,842,000	100.0	23,630	18,410	100.0
DUST		29 kg/h			<29 kg/h			-		
(DUST-DRY BASE)		12 mg/Nm3, dry			<12 mg/Nm3, dry			-		
TEMPERATURE		100 deg C			49 deg C			49 deg C		
PRESSURE		0 mmH2O			0 mmH2O			3,985 mmH2O		
ACTUAL GAS FLOW RATE		3,737,000 m3/h			3,356,000 m3/h			15,700 m3/h		
REMARKS		SOx	665	ppmv, dry 6% O2	SOx	9	ppmv, dry 6% O2			
		Particulate	10	mg/Nm3, dry 6% O2	Particulate	<10	mg/Nm3, dry 6% O2			

LIQUID & SOLID STREAM

STREAM NO.		10		11		12		13		14		15		16	
STREAM NAME		MAKE UP WATER		LIMESTONE		LIMESTONE SLURRY		GYPSUM SLURRY		BYPRODUCT GYPSUM		RECLAIM WATER		WASTE WATER	
COMPONENT	MW	kg/h	wt%	kg/h	wt%	kg/h	wt%	kg/h	wt%	kg/h	wt%	kg/h	wt%	kg/h	wt%
H2O	18.02	99,180	100	90	1	21,870	66	64,790	76	1,670	10	60,820	92	3,940	92
Cl	35.45	5	50ppm	-	-	-	-	1,330	19,400ppm	0	0	1,250	19,400ppm	80	19,400ppm
CaCO3	100.09	-	-	8,840	95	8,850	27	-	-	-	-	-	-	-	-
MgCO3	84.32	-	-	310	2	310	0	-	-	-	-	-	-	-	-
CaSO4 2H2O	172.17	-	-	-	-	-	-	16,490	19	14,450	87	1,910	3	120	3
OTHERS	-	10	0	230	3	2,050	7	3,170	3	590	4	2,430	4	160	4
TOTAL		99,190	100	9,300	100	33,080	100	85,780	100	16,710	100	66,410	100.0	4,300	100.0
		100 m3/h				27 m3/h		77 m3/h				66 m3/h		4.3 m3/h	
TEMPERATURE		-		-		-		-		-		-		-	
pH				-		-		-		-		-		-	
REMARKS				Purity	96.0%	30%	Slurry	20%	Slurry	Purity	96.1%			TSS	3.0%

CHIYODA CORPORATION

ISSUE DATE : Feb 12, 2013
CUSTOMER : FOSTER WHEELER ITALIANA
JOB NAME :
JOB NO. :
DOCUMENT :
SHEET NO. : 1 OF 1

MATERIAL AND HEAT BALANCE Case 3: Oxy-Boiler

FOR FEASIBILITY STUDY

GAS STREAM

STREAM NO.		1			2			3		
STREAM NAME		FLUE GAS			FGD OUTLET GAS			OXIDATION AIR (at Blower Discharge)		
COMPONENT	MW	kg/h	Nm3/h	Vol.%	kg/h	Nm3/h	Vol.%	kg/h	Nm3/h	Vol.%
H2O	18.02	111,066	138,000	17.2	160,000	199,000	23.2	58	73	0.9
SOx	64.06	3,898	1,364	1,701ppm	1,466	513	598ppm	-	-	-
O2	32.00	61,514	43,089	5.4	63,335	44,364	5.2			
CO2	44.01	1,004,749	511,714	63.8	1,006,424	512,568	59.7			
HCl	36.46	0	0	0ppm	0	0	0ppm	-	-	-
DRY GAS		1,188,934	664,000	82.8	1,198,000	659,000	76.8	10,430	8,100	99.1
TOTAL		1,300,000	802,000	100.0	1,358,000	858,000	100.0	10,490	8,170	100.0
DUST		0 kg/h			<0 kg/h			-		
(DUST-DRY BASE)		0 mg/Nm3, dry			<0 mg/Nm3, dry			-		
TEMPERATURE		150 deg C			64 deg C			42 deg C		
PRESSURE		0 mmH2O			0 mmH2O			3,205 mmH2O		
ACTUAL GAS FLOW RATE		1,242,000 m3/h			1,058,000 m3/h			7,200 m3/h		
REMARKS		SOx	2,125	ppmv, dry 6% O2	SOx	818	ppmv, dry 6% O2			

LIQUID & SOLID STREAM

STREAM NO.		10		11		12		13		14		15		16	
STREAM NAME		MAKE UP WATER		LIMESTONE		LIMESTONE SLURRY		GYPSUM SLURRY		BYPRODUCT GYPSUM		RECLAIM WATER		WASTE WATER	
COMPONENT	MW	kg/h	wt%	kg/h	wt%	kg/h	wt%	kg/h	wt%	kg/h	wt%	kg/h	wt%	kg/h	wt%
H2O	18.02	51,600	100	40	1	9,020	62	27,170	71	750	10	26,730	86	430	86
Cl	35.45	3	50ppm	-	-	-	-	160	5,100ppm	0	0	150	5,100ppm	0	5,100ppm
CaCO3	100.09	-	-	3,880	95	3,880	27	-	-	-	-	-	-	-	-
MgCO3	84.32	-	-	130	2	140	0	-	-	-	-	-	-	-	-
CaSO4 2H2O	172.17	-	-	-	-	-	-	7,370	19	6,460	87	900	3	10	3
OTHERS	-	0	0	100	3	1,470	11	3,570	9	240	3	3,260	11	60	11
TOTAL		51,600	100	4,080	100	14,510	100	38,270	100	7,450	100	31,040	100.0	500	100.0
		52 m3/h				12 m3/h		34 m3/h				31 m3/h		0.5 m3/h	
TEMPERATURE		-		-		-		-		-		-		-	
pH				-		-		-		-		-		-	
REMARKS				Purity	96.0%	30%	Slurry	20%	Slurry	Purity	96.3%			TSS	3.0%

ATTACHMENT A.2: Cansolv post-combustion capture technology

Cansolv CO_2 Capture System

Technical Study

Presented to:

Foster Wheeler

Submitted by:

Cansolv Technologies Inc.

February 22nd, 2013

Revision 0

REVISION PROCESS		
Prepared By	MG/MN	
Reviewed By	AS	
Verified By	KS	
Approved By	IS	

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1. INTRODUCTION

1.1 Project Scope

Cansolv Technologies Inc (CTI) is pleased to present to Foster Wheeler (FW) this technical study. FW is interested in evaluating the application of Cansolv CO_2 capture technology for the purposes of capturing CO_2 from a Coal Fired Power Plant.

The table to follow will guide you to the location of the specific deliverables as specified in the Request for Information (RfI):

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2. BUSINESS PROFILE

2.1 Cansolv Technologies

Cansolv Technologies Inc. (CTI) was formed in 1997 to commercialize the Cansolv SO_2 Scrubbing System. At this time nine commercial Cansolv Scrubbing Systems are in operation and several more are in the detailed engineering, construction or procurement phase. Driving from its expertise in regenerable amine technologies, Cansolv has developed an ingenious CO_2 Capture process. One Cansolv CO_2 Capture unit has recently successfully started and numerous Cansolv CO_2 Capture units are currently being engineered. Cansolv CO_2 Capture process is well positioned to serve the evolving Greenhouse Gas abatement market.

On November 30th of 2008, ***Shell Global Solutions International B.V. (SGSI)*** purchased 100% of the shares of CTI. The company now operates as a wholly owned subsidiary of SGSI.

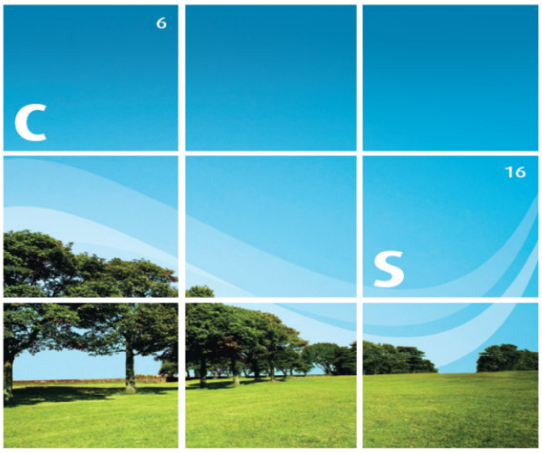
It is CTI's mission to be a leading global provider of high efficiency air pollution control and capture solutions. We want our patented technology to serve as the benchmark for stationary source air emission abatement around the world. Our commitment is to providing custom designed economic solutions to our clients' environmental problems.

Cansolv is an innovative, technology-centered company. The company continues to leverage its knowledge base to develop new and enhance existing applications for specific pollution abatement based on the Cansolv System platform. Through strategic partnerships and R&D, Cansolv strives to expand its product and service offering in the following areas:

- Multi-emission technology for control of SO_x and or CO_2.
- Valuable material recovery from emission control processes.

The benefits of the Cansolv Absorbent include:

- The elimination of the high cost of consumable absorbents and associated transportation costs;
- No environmental legacy obligations and costs;
- Reduced capital costs due to its high capacity and selectivity reduce; and minimal emission of effluents from the process.



Learn more at www.cansolv.com. At the website also literature papers are available describing the offered technological portfolio in more detail.

2.2 Royal Dutch Shell

Royal Dutch Shell, owner of Shell Global Solutions International and Cansolv Technologies Inc., is a global group of energy and petrochemical companies.

The aim of the Shell Group is to meet the energy needs of society in ways that are economically, socially and environmentally viable, now and in the future. We are active in more than 130 countries and territories and employ about 90,000 people worldwide. Royal Dutch Shell consists of the upstream businesses of Exploration & Production and Integrated Gas and the downstream businesses of Oil Products and Chemicals. We also have interests in other industry segments such as Renewables, Hydrogen, Bio-fuels and CO_2. Shell Global Solutions provides business and operational consultancy, technical services and research and development expertise to the energy and processing industries worldwide.

The scale of support can range from the provision of innovative - but field-tested - technologies including catalysts, through to assistance with the implementation of management practices and long-term strategic support in areas such as emissions management.

Within Shell Global Solutions International, more than 5000 staff across an extensive network of offices around the world are supported by primary commercial and world-class technical centres operating in the USA, Europe and Asia Pacific.

Shell has been audited and been awarded ISO 9001:2000 certification. Various internal quality procedures are in place covering solid project delivery and engineering.

3. SAMPLE COMMERCIAL EXPERIENCE

3.1 Cansolv CO_2 Scrubbing Commercial Experience

Location	Status	Application	Gas flow (Nm3/hr)	Feed Gas CO_2 Content	CO_2 Capture rate	Description
South Africa	Fabrication phase, and start-up in 2013	CO_2 capture	44,900	9%	170 tpd	This CANSOLV® unit will capture CO_2 for use at chrome chemicals production facility in Newcastle. Lanxess CISA is investing in a facility which will be burning Sasol's fuel gas to produce steam and generate a stream of flue gas from which CO_2 will be captured and used for the dichromate process.
Wales	Operating since Jan 2013	Coal Fired Power Plant	10,200	12%	50 tpd	This CANSOLV® unit will treat flue gas from a coal fired power plant station. The flue gas from the boiler is routed to a prescrubber, followed by a CANSOLV SO_2 Scrubbing System and then a CANSOLV CO_2 Capture System. The CO_2 Capture system targets a removal of 90% of the CO_2 in the feed gas.
Canada	Engineering phase. Start-up in 2013.	Coal Fired Power Plant Off-Gas	650,000	12%	2750 tpd	This CANSOLV® unit will treat flue gas from a 150 MW coal fired power plant boiler. The flue gas from the boiler is routed to a prescrubber, followed by a CANSOLV SO_2 Scrubbing System and then a CANSOLV CO_2 Capture System. The CO_2 Capture system targets a removal of 90% of the CO_2 in the feed gas. Recovered SO_2 is sent to a sulfuric acid plant and CO_2 is sent to a compressor and discharged to a product pipeline, where it travels to an offsite location where it is used for EOR.

3.2 Cansolv SO2 Scrubbing Commercial Experience

Location	Status	Application	Gas flow (Nm3/hr)	Feed Gas SO_2 Content	SO_2 Emission Specifications	Description
Belgium	Operating since 2002	Sulfur Recovery Unit Tail Gas	12,000	0.6 - 1.0 %	<50 ppmv	Located at a Belgian chemical facility. Tail gas from a sulfur recovery unit is burned with high sulfur content tars in an incinerator. The off-gas containing 0.6 - 1% SO_2 is quenched and cooled before entering the CANSOLV® unit which absorbs as much as 99.9% of the SO_2 leaving less than 50 ppmv residual SO_2 in the gas. Recovered SO_2 is recycled to the Claus unit.
Canada	Operating since 2002	Zinc Smelter Off-Gas	4,000	7 - 10 %	<100 ppmv	The process recovers SO_2 from a 7% to 10% SO_2 gas from a metallurgical roaster. The recovered SO_2 is absorbed to maximum loading in CANSOLV Absorbent DM™ (CANSOLV® SO_2SAFE™ process) and shipped by truck to a second site where the absorbent is regenerated and product SO_2 is used in a copper smelting process. The unit has a capacity of 33 tpd of SO_2 and emissions are maintained well below design values.
CA, USA	Operating since 2002	Sulfuric Acid Plant Tail Gas	40,000	0.35 - 0.50 %	<20 ppmv	Located at an oil refinery, this unit treats tail gas from a sulfuric acid plant. As the acid plant catalyst ages, the content of SO_2 in the acid plant tail gas increases. The Cansolv unit is designed to meet emissions of less than 20 ppmv to the atmosphere throughout the catalyst lifetime.
India	Operating since 2005	Lead Smelter Off-Gas	35,000	0.1 - 12 %	<150 ppmv	Located in Rajasthan, India, this unit captures off-gas from a batch lead smelter. Concentration of SO_2 varies one hundred fold during the process cycle (from 12% at peak down to 1,000 ppmv). The CANSOLV® unit is designed to dampen these

						surges in SO_2 feed rates through a load levelling solvent management protocol. The result is a steady flow of SO_2 product that allows the downstream acid plant to operate in exothermal mode through the entire range of operation of the batch smelter.
WA, USA	Operating since 2006	Sulfur Recovery Unit Tail Gas	20,000	4 %	<140 ppmv	The CANSOLV® unit is designed to treat tail gas from a 2-stage sulfur recovery unit at a US refinery. Part of the refinery acid gas bypasses the SRU and fuels an incinerator to oxidize the tail gas. After waste heat recovery, CANSOLV SO_2 Scrubbing System captures the SO_2 down to less than 60 ppmv by modulating heat input and circulation. Pure SO_2 is recycled to the thermal stage of the SRU, reducing both the duty of the thermal stage and the air input (and corresponding inter load). The SRU capacity increases by 12.5% with this strategy (without oxygen enrichment). Furthermore, zero COS and CS2 emissions are be achieved without any special catalysts.
DE, USA	Operating since 2006	Fluid Coker Off-Gas	430,000	2,000 ppmv	<25 ppmv	This unit removes SO_2 from refinery fluid coking unit (FCU) off-gas. Outlet concentration requirement is 25 ppmv, but emissions are maintained near zero by a caustic polishing section in the CANSOLV® absorber. Captured SO_2 is fed to the refinery sulfur unit and converted to sulfur. The unit run-length design basis is 3 years between shutdowns.
DE, USA	Operating since 2006	Fluid Cat Cracker Off-Gas	740,000	800 ppmv	<25 ppmv	This unit removes SO_2 from refinery catalytic cracking unit (FCCU) off-gas. Outlet concentration requirement is 25 ppmv, but emissions are maintained near zero by a caustic polishing section in the CANSOLV® absorber. Captured SO_2 is fed to the refinery sulfur unit and converted to sulfur. The unit is designed to run 5 years without interruption between scheduled shutdowns. This

						unit has the largest single CANSOLV SO_2 absorber in service to date, which is 11 meters in diameter.
Canada	Operated 2008-2009 (facility shutdown)	Spent Catalyst Roaster Off-Gas	50,000	9,000 ppmv	<150 ppmv	Located near Edmonton, Alberta, Canada. This roaster regenerates spent catalyst from oil and gas processing facilities. The CANSOLV® unit treats the SO_2 offgas from the roaster down to < 150 ppmv. The energy requirements of the CANSOLV® unit are supplied by pressurized hot water from a process gas heat recovery system. The product SO_2 is sold in the Edmonton area as dry liquid SO_2.
China	Operating since 2009	Coal Fired Boiler Off-Gas	960,000	4,000 ppmv	<140 ppmv	Located in the Guizhou province, China, these four CANSOLV® scrubbers treat a combined flow of 960,000 Nm3/hr (600,000 SCFM) containing up to 4,000 ppmv SO_2. The recovered SO_2 from the scrubbers will produce 130,000 tons per year of commercial grade (98%) sulfuric acid.
China	Operating since 2009	Sinter Machine Off-Gas	550,000	2,200 ppmv	<50 ppmv	Fumes from a 265 m^2 sinter machine are collected, pre-cleaned and fed to the CANSOLV SO_2 Scrubbing system for SO_2 removal. Captured SO_2 is directed to the onsite sulfuric acid facility.
China	Operating since 2010	Lead Smelter and Acid Plant Tail Gas	60,000	0.1 - 10 %	<140 ppmv	Located in Yunnan province, China, this unit captures SO_2 from the offgas of a batch lead smelter as well as from the tail gas of an acid plant. The gas flowrate and SO_2 concentration of the smelter offgas varies with the smelter cycle. A constant flowrate of the smelter offgas is sent directly to an acid plant. The CANSOLV® unit treats the remainder of the smelter offgas. In order to level the SO_2 concentration in the gas feed to the acid plant, the CANSOLV® unit varies the regeneration rate of SO_2 as a function of the SO_2 concentration in the smelter offgas. The advantage of this application is that the acid plant size is minimised and operates under steady conditions, whereas the CANSOLV®

						unit handles the varying SO_2 load while meeting emission requirements. Furthermore, heat integration by use of a double effect split flow regeneration configuration results in >25% steam savings compared to a conventional process line-up.
China	Operating since 2010	Ferric Ball Sinter Machine Off-Gas	300,000	2,400 ppmv	<140 ppmv	Off-gas from the sinter machine are collected, pre-treated, and fed to the CANSOLV SO_2 Scrubbing System for SO_2 removal. Captured SO_2 is directed to the onsite sulfuric acid facility.
LA, USA	Operating since 2011	Single Absorption Sulfuric Acid Plant Tail Gas	130,000	3,500 ppmv	<75 ppmv	This CANSOLV® unit was built and supplied as a modularized unit. The unit captures the SO_2 from the tail gas of a single absorption sulfuric acid plant. The unit is designed for outlet SO_2 concentration of 75 ppmv. The recovered SO_2 is routed to the front end of the acid plant.
CA, USA	Operating since 2011	Fluid Coker and Fluid Cat Cracking Unit Off-Gas	575,000	1,200 ppmv	<10 ppmv	This unit removes SO_2 from the combined off gas from a refinery's fluid coking unit (FCU) and fluid cat cracking unit (FCCU). The outlet SO_2 concentration requirement is 10 ppmv. Captured SO_2 is fed to the refinery sulfur unit and converted to sulfur. The unit run-length design basis is 6 years between shutdowns.
China	Engineering phase. Start-up in 2012.	Tin Smelter and Acid Plant Tail Gas	150,000	0.6 - 1.0 %	<140 ppmv	This unit will treat the combined flue gas from a tin smelter, 2 roasters, 2 furnaces, and an acid plant in a single train CANSOLV unit. The unit is designed for various turndown and turnup conditions, while targeting to meet at 140 ppmv SO_2 emission requirement. The product SO_2 will be converted to sulfuric acid.
China	Engineering phase. Start-up in 2012.	Coal Fired Power Plant Off-Gas	5,200,000	4,000 ppmv	<140 ppmv	This CANSOLV® unit will treat flue gas from two 660 MW coal fired power plant boilers. The flue gas is treated in two parallel trains processing 2,600,000 Nm3/hr each. The SO_2 produced is sent to a sulfuric acid plant for conversion.

India	Construction phase. Start-up in 2012.	Resid Fuel Fired Utility Boiler Off-Gas	1,550,000	3,000 ppmv	<150 ppmv	Flue gas from multiple refinery boilers are directed into two parallel trains of CANSOLV SO_2 Scrubbing Systems. Each CANSOLV® unit treats 775,000 Nm3/hr of flue gas. SO_2 is directed to the refinery SRU.
Canada	Engineering phase. Start-up in 2013.	Coal Fired Power Plant Off-Gas	650,000	900 ppmv	<5 ppmv	This CANSOLV® unit will treat flue gas from a 150 MW coal fired power plant boiler. The flue gas from the boiler is routed to a prescrubber, followed by a CANSOLV SO_2 Scrubbing System and then a CANSOLV CO_2 Capture System. The CO_2 Capture system targets a removal of 90% of the CO_2 in the feed gas. Recovered SO_2 is sent to a sulfuric acid plant and CO_2 is sent to a compressor and discharged to a product pipeline, where it travels to an offsite location where it is used for EOR.

4. PROCESS DESCRIPTION – Proposed Process Arrangement

The Cansolv CO_2 Capture System comprises the following major components: Direct Contact Cooler, CO_2 Absorber Tower, CO_2 Stripper Tower, CO_2 Lean Absorbent Flash MVR System and Absorbent Purification Unit (APU). The process description refers to the Preliminary Process Flow Diagram (PFD) presented in Appendix I. Note that the flue gas stream is split over two trains. The split and mixing points are indicated on the PFD. Gas pre-treating is required to minimize the SO_2 and NO_2 content of the feed gas and sub cool the flue gas before feed to the CO_2 Absorber Tower.

4.1 Direct Contact Cooler: Sub-cooler, SO_2/NO_2 removal and Booster Fan

The flue gas is sent to the Prescrubber (C-1901), which is operated as a Direct Contact Cooler (DCC) to sub-cool the flue gas before sending it to the CO_2 Absorber (C-1401). Sub-cooling the flue gas will improve CO_2 absorption capacity of the amine. The preliminary prescrubber design includes a Prescrubber Cooler (E-1901) to sub cool the flue gas down to 30°C, in order to reduce the required amine circulation rate and thus energy consumption of the Cansolv plant.

In order to decrease the impact of SO_2 on the absorbent, SO_2 removal is controlled by adding caustic on pH control in a caustic polishing section, inside the prescrubber column.

All post-combustion amine carbon capture plants are subject to some kind of an impact on the absorbent when it is exposed to nitrogen dioxide (NO_2) present in the flue gas. This is of special consideration when the NO_2 levels are relatively elevated.

After the Direct Contact Cooler, the gas is split over two equal sized trains. Note that equipment numbering provided below is for one train. In the equipment list, the equipment for both trains is given. After the split, a booster fan (K-1901) will be installed to drive the flue gas through the absorber and out the stack.

4.2 CO_2 Absorption

The flue gas exits the prescrubber (C-1901) and is ducted to the CO_2 Absorber (C-1401). CO_2 absorption from the flue gas occurs by counter-current contact with Cansolv Absorbent DC-103 in a vertical multi-level packed-bed tower, namely the CO_2 Absorber. The gas entering the absorption section of the tower will have sufficient pressure to overcome the pressure drop in the tower packing before being discharged at the top of the CO_2 Absorber stack.

The Lean Amine Pumps (P-1404) deliver CO_2 lean amine from the Lean Amine Flash Vessel (V-1401) through the Lean Amine Cooler (E-1403) then to the top of the CO_2 Absorber. The lean amine is cooled to prevent water loss from evaporation into the flue gas, to enhance the CO_2 removal performance of the absorbent and to maintain an overall water balance in the Cansolv absorbent DC inventory.

CO_2 absorption is an exothermic reaction. The heat generated by absorption must be removed to prevent temperature increase of the absorbent, which would reduce the amine absorption capacity. This would also increase water evaporation from the absorbent into the heated flue gas and cause a water imbalance in the process.

The treated flue gas leaving the top of the CO_2 absorption section will pass through a water wash section before being released through the stack. Before being released through the stack, the treated gas is combined with the treated gas from the other train.

4.3 CO_2 Amine Regeneration

The rich amine is collected in the bottom sump of the CO_2 Absorber and is pumped by the CO_2 Rich Amine Pumps (P-1403) and heated in the CO_2 Lean/Rich Exchangers (E-1406) to recover heat from the hot lean amine discharged from the Lean Amine Flash Vessel (V-1401). Rich amine is piped to the top of the CO_2 Stripper (C-1402) for amine regeneration and CO_2 recovery. The rich amine enters the column under the CO_2 reflux rectification packing section and flows onto a gallery tray that allows for disengagement of any vapor from the rich amine before it flows down to the two stripping packing sections under the gallery tray. The rich amine is depleted of CO_2 by water vapor generated in the CO_2 Amine Regenerator Reboilers (E-1404) which flows in an upward direction counter-current to the rich amine.

Water vapor in the stripper, carrying the stripped CO_2, flows up the stripper column into the rectification packing section at the top, where a portion of the vapor is condensed by recycled reflux to enrich the overhead CO_2 gas stream.

The CO_2 Stripper overhead gas is partially condensed in the CO_2 Amine Regenerator Condensers (E-1405). The partially condensed two phase mixture gravity flows to the CO_2 Reflux Accumulator (V-1402) where the two phases separate. The reflux water is collected and returned via the CO_2 Stripper Reflux Pumps (P-1405) to the CO_2 Stripper rectification section. The CO_2 product gas is piped to the CO_2 Compression System (OSBL). Reflux is pumped back on level control to the top of the CO_2 Stripper from the CO_2 Reflux Accumulator by the CO_2 Stripper Reflux Pumps. The pressure of the CO_2 Stripper is controlled by the product CO_2 discharge control valve.

The flow of steam to the reboiler is proportional to the rich amine flow sent to the CO_2 Stripper. The set-point of the low pressure steam flow controller feeding the CO_2 Amine Regenerator Reboilers (E-1404) is also dependent on the stripper top temperature controller. The steam to amine flow ratio set-point is adjusted by this temperature controller.

The temperature at the top of the column is set to maintain the required vapor traffic and stripping efficiency.

The steam flow rate can be controlled either by modulating a steam flow control valve or a condensate flow control valve. For large scale applications, it is recommended to control the flow of steam by modulating the flow of condensate since this method of control minimizes the pressure loss of the steam supplied to the reboiler and also reduces the size of the required control valve.

The CO_2 Lean Amine Pump (P-1404) delivers the lean amine from the Lean Flash Tank back to the CO_2 absorber after being cooled in the CO_2 Lean/Rich Exchangers and Lean Amine Cooler

4.4 Amine Purification Unit (APU)

As explained in the previous section, the amine quality needs to be maintained in the Amine Purification Unit (APU). Only one APU is installed which is operated batch wise: the treated absorbent is alternated between train 1 and 2.

Ion Exchange (U-0600)

The CO_2 Amine Purification Unit, APU (U-0600) is designed to remove Heat Stable Salts (HSS) from the Cansolv DC Absorbent. These salts are continuously formed within the absorbent, primarily due to residual amounts of NO_2 and SO_2 contained in the flue gas. Once absorbed, NO_2 forms nitric and nitrous acid while SO_2 forms sulfurous acid which oxidizes to sulfuric acid. These acids, and some organic acids formed by the oxidative degradation of the amine, neutralize a portion of the amine via an acid/base reaction. Therefore, a portion of the absorbent is inactivated for further CO_2 absorption. Although a certain level of HSS is desirable within the absorbent, any excess HSS must be removed. HSS removal is achieved by ion exchange (IX) using a resin bed contained inside a column.

The CO_2 APU process is a batch process which involves five main steps: 1. Salt Loading, 2. Amine Recovery Rinse, 3. Buffering Rinse, 4. Regeneration; 5. Excess Caustic Rinse. Together, these five steps constitute an IX cycle. Note that the sizing of the APU is standardized to minimize costs and schedule.

Thermal Reclaimer (U-0700)

The amine in the CO_2 Capture System accumulates ionic and non-ionic amine degradation products over time that must be removed from the solvent.

The purpose of the Thermal Reclaimer Unit (A-0700) is to remove the non-ionic degradation products from the active CO_2 amine. The thermal reclaimer unit distills the CO_2 amine under vacuum conditions to separate the water and amine, leaving the non-ionic degradation products in the bottom.

A slipstream is taken from the treated CO_2 lean amine exiting the CO_2 APU (A-0600) and fed to the Thermal Reclaimer Unit (A-0700). This stream will essentially consist of water, amine, degradation products, residual CO_2 and small amounts of sodium nitrate and sodium sulfate.

The design flow rate of CO_2 lean amine sent to the thermal reclaimer is based on the calculated amine degradation rate. To maintain the degradation products below design concentration, the thermal reclaimer must process a specific flowrate of CO_2 lean amine continuously.

The amine feed to the thermal reclaimer is heated up in a pre-heater using steam. The pre-heated feed is flashed over a control valve and fed into a vacuum distillation column. The overhead vapor of this column, which consists of amine and water, is condensed and separated while the remaining vapor is routed to a vacuum unit. A portion of the condensed amine and water is returned to the column as determined by minimum wetting rates of the rectifying packed bed. The rest of the condensed overhead is returned as lean, reclaimed amine to the Lean Amine Flash Vessel (V-1401).

The bottom of the thermal reclaimer distillation column is heated with medium pressure steam. Column pressure is typically kept at 55 mbar by a vacuum unit to operate with a bottom temperature of just under 200°C. The bottom residue, which mainly consists of degradation products, is continuously pumped to a storage tank, where it is diluted and cooled with process water. Diluted residues are periodically disposed of offsite, typically via incineration.

4.5 Amine Storage Facilities (U-0400)

One common solvent storage tank will be installed. The tank is designed such that the absorbent inventory of one train can be stored in the storage tank. During normal operation the tank is empty. The tank is used to provide amine make-up and during maintenance activities. The Amine Storage Facilities consists also an Amine Make-up Tank in order to sent the absorbent from the tank back into the process trains.

5. PROJECT DESIGN BASIS

5.1 Process Line-up and Battery Limits

Figure 1: Battery Limits CO_2 Carbon Capture Plant

Cansolv's process design is based on the available process design parameters, given in the "Post Combustion CO_2 Capture Unit Request For Information" document. The design basis as given by Foster Wheeler (FW) for this project is shown in Table 1.

Table 1: CO_2 Capture Plant Design Basis provided by FW

Flue Gas Specifications from FW		
Capture	wt-%	90
Flue gas	t/hr	3680
Pressure	bar(g)	0.01
Temperature	°C	50
CO_2	vol%	13.55
N_2	vol%	70.31
O_2	vol%	3.11
H_2O	vol%	12.19
Ar	vol%	0.83
Impurities (1)		
NO_x	mg/Nm^3	130
NO_2	ppmv	< 20
SO_x	ppmv	< 10
Particulates	mg/Nm^3	< 10

Notes: (1) based on 6% oxygen, dry.

The Carbon Capture System will be installed to treat flue gas. The Figure 1 shows the process line-up within the Carbon Capture System. The dotted block outlines the battery limits of the Cansolv scope of work for current study.

The treated flue gas from the absorption section will be released to atmosphere. The liquid effluent from the Prescrubber requires minimal treatment and can be reused as process water or for steam regeneration to reduce the energy demand. In addition to the liquid effluent, there is also a smaller caustic blowdown coming from the Prescrubber. This stream contains caustic components and is usually sent to a Waste Water Treatment System. The liquid effluent from the

Amine Purification Unit contains traces of amine and is usually sent to a Waste Water Treatment System. The waste from the Thermal Reclaimer Unit will require disposal by others.

5.2 List of Assumptions

For the purpose of this proposal, the following assumptions are taken to develop the design basis. All these assumptions needs to be validated in the next project phase.

1. Design capture rate: the CO_2 capture plant will be designed to capture 90 wt-% of the CO_2 in the feed gas by processing the entire flue gas flow.
2. NO_x content: the specified amount of NO_x is 130 mg/Nm^3.
3. The SO_x concentration in the feed gas is provided by FW to be 10 ppmv. In the absence of any specified SO_3 concentration in the feed gas, the provided SO_x concentration in the flue gas is assumed to be only SO_2.
4. Since there is no specified concentration of Benzene, Volatile Organic Compounds (VOC), Formaldehyde and Unburned Hydrocarbons (UHC) in the flue gas, concentration of these species are assumed to be negligible.
5. All contaminants levels are specified at a 6% oxygen and dry basis. For the purpose of the study, it is assumed that the levels are almost similar at actual operating conditions.
6. Filtration Requirement: The expected fly ash ingress rate into the absorbent is marginable. For this reason, only a multi cartridge filter type is expected to be required at this stage. During the next engineering stage, if the design dust load leads to an expected particulate matter ingress rate, a Candle Type Filtration System may be required, although highly unlikely.
7. Since no Unburned Hydrocarbons (UHC) are expected to be present in the Flue Gas sent to the CO_2 Absorber, an Activated Carbon Filter is not included in the process line-up at this stage.
8. None of the equipment has been spared, as no availability requirement is provided. With no sparing, expected availability is above 90% including planned maintenance activities. Exact sparing philosophy should be determined in the next project phase.
9. The current proposal maximizes the use of water cooling. An average cooling water temperature of 16°C has been assumed. The process fluids (flue gas, absorbent) are cooled to 30°C to optimize CO_2 removal performance.
10. No design features are foreseen for winterization.
11. The caustic polisher is designed for a standard packing height.
12. The temperature of the flue gas leaving the absorber is selected such that the required water make-up rate is minimised. Note that the water condensed in the pre-scrubber is not taken into account in setting the treated gas exit temperature. The temperature of the pure CO_2 product stream is equal to the flue gas inlet temperature, assuming the CO_2 product stream is further compressed hence temperature minimization might be beneficial.
13. The provided steam pressure (4.5 barg) and temperature (165 degC) are not in agreement with each other for saturated steam. It is assumed that the steam is superheated at the inlet of the reboiler. For the sizing of the reboiler, no credit is taken for this effect.
14. No industry margins on equipment have been applied. The equipment margins will be further agreed on in the project phase.

15. Equipment size limitations have been based on previous reference projects. These limitations are indicated in the Equipment List as given in the Appendix. Limitations need to be reconfirmed with vendors.

5.3 Inlet Gas Specification

The required flue gas flow rate to be treated was calculated based on the CO2 product yield of 12.68 t/h provided in the Basis of Design (section 4.3) of the China CCS Capacity Building Program Request for Information by FW. The Table 2 characterizes the flue gas to be treated at Cansolv Absorber:

Table 2: Characterizes the flue gas at the Cansolv Absorber

Design Feed Gas Characteristics	Unit	Value
Gas flow to Prescrubber	kg/h	3,486,481
Sub-cooled Temperature to Absorber	°C	30
CO2 Source	tpd	18,109
CO2 Removal	tpd	16,298
CO2 Capture rate	%	90
Inlet pressure	bar(g)	0.032
Flue Gas Composition		
O2	vol %	3.40
N2 (including Ar)	vol %	77.75
H2O	vol %	4.05
CO2	vol %	14.81
CO	vol %	0
SO3	ppmv	0
H2	vol %	0
Ar	vol %	0
Particulates	mg/Nm3	10
HCl	ppmv	0
HF	ppmv	0
Unburnt hydrocarbons	ppmv	0
Volatile organic compounds	ppbv	0
Formaldehyde	ppmv	0
Trace Metals	mg/Nm3	0
Trace Cations	ppmv	0

5.4 CO_2 Product Requirements

The required CO_2 Product Specifications have been provided by FW and summarized in table 3.

Table 3: CO2 Product Requirements

CO2 maximum impurities	Unit	
N_2/Ar (1)	Dry vol%	4
CO (1)	Dry vol%	0.2
O_2 (1)	ppm	100
SO_x	ppm	100
NO_x	ppm	100

Note: 1. Total non-condensable content (N_2 + O_2 + H_2 + CH_4 + Ar) shall be maximum 4% vol.basis

5.5 Available Utilities

The following utilities specifications are assumed to be available at battery limits. Electrical energy will also be required.

Table 4: Utilities Specifications

Utility	Unit	Specification
Low Pressure Steam	barg	4.5
Cooling Water Supply Temperature (Normal)	°C	15
Cooling Water Return Temperature (Normal)	°C	26
Caustic Soda Concentration*	wt %	50
Caustic temperature*	°C	30
Demineralised water Pressure*	kPag	750
Demineralised water Temperature*	°C	35
Raw water Pressure	kPag	800
High pressure steam*	barg	22

*These utilities have been assumed by Cansolv

6. CO_2 CAPTURE SYSTEM SPECIFICATIONS

6.1 Heat and Material Balances

The preliminary Heat and material balance outlining major streams is given in Appendix II. Note that some streams are provided for half of the flue gas stream, as the proposal is based on two equal sized trains. The flue gas inlet streams and product streams are provided for the total unit. The numbering in the Process Flow Scheme is also adjusted accordingly.

6.2 Process Equipment Design Considerations (and Capital Cost Advantages)

The Preliminary Process Equipment List is given in Appendix III.

Number of trains
Processing the flue gas in a single train is not considered to be feasible due to the quantity of flue gas which needs to be processed. For this proposal, it has been aimed to maximize economy of scale while still satisfying equipment size limitations. As also described above, the flue gas will be split after a common pre-scrubber. Two equal sized trains are proposed to process half of the pre-scrubbed flue gas (2 x 50%). The Amine Storage Facilities and Amine Purification Unit will be shared between both processing trains. Due to the installation of two trains, lower turndown rates can be achieved. Additionally, CO_2 capturing might still be feasible when the one of the two processing trains is not available. It is believed that by the installation of two processing trains, all required equipment fits within the current available sizing on the market. This needs to be confirmed with vendors in the next project phase.

CO_2 Absorber
The proposed CO_2 Absorber design, including selection of packing type, packing height and tower cross-sectional area, minimizes the CO_2 amine circulation rate, packing section pressure drop and installed equipment cost while providing the mass transfer surface area required to achieve the target CO_2 removal. Expected turndown of the plant is below 25% as packing is installed in the towers and all pumps can operate continuously in recycle mode.

The bottom of the CO_2 Absorber sump is designed with an elevated portion to minimize the CO_2 amine inventory, while providing enough positive suction head to the CO_2 Rich Amine Pumps.

CO_2 Stripper Reboilers
For designs involving large reboilers, most Cansolv Systems are using welded plate heat exchangers for the stripper reboilers.

The core of a welded plate heat exchanger is a stack of corrugated heat-transfer plates in stainless steel welded alternately to form channels. The frame of the welded plate heat exchanger consists of four corner beams, top and bottom heads and four side panels with nozzle connections. These components are bolted together and can be quickly taken apart for inspection, service or cleaning.

Welded plate heat exchangers are compact. All the heat transfer area is packed into a smaller footprint than that required for comparable heat exchangers. Welded plate heat exchangers provide many advantages over the typical shell and tube exchangers:

1. Alternately welded plates – permit access for inspection, service or cleaning.
2. No gaskets between plates – allows operating:
    a. with aggressive media.
    b. at higher temperatures and pressures.
3. Corrugated plates – promote high turbulence which, in turn:
    a. achieves three to five times greater overall heat transfer coefficients than a shell-and-tube heat exchanger.
    b. minimizes fouling, which makes longer operating periods possible.
4. Close temperature approach – can handle temperature approaches down to 3ºC.
5. Compactness – takes only a fraction of the floor space of a shell-and-tube heat exchanger.

Should fouling occur, it is easy to clean welded plate heat exchangers without removing it from the plant. Cleaning can be done on site by circulating cleaning solutions through the unit. Chemical cleaning is highly effective as a result of the unit’s high turbulence and low hold-up volume. Chemical cleaning can also be performed by removing the plate pack and immersing it in a chemical bath.

Other Process Heat Exchangers
For similar reasons, gasketed plate heat exchangers are recommended for all other process heat exchangers, including water coolers, CO_2 Stripper Condensers and Lean / Rich Exchangers. Plate heat exchangers minimize the temperature approach. Currently no sparing of heat exchangers is foreseen. It is likely that multiple heat exchangers are required to meet mechanical and construction contraints. The exact number of installed heat exchangers will be determined in the next project phase during detailled engineering.

Amine Storage Facilities
As two dedicated process trains will be installed, it has anticipated that the storage facilities only needs to be sized to store the amine inventory of one processing train. This will minimize the size of the required amine tank. During planned maintenance activities amine storage can also be take place in ISO-container. The installed storage facility is sufficient large to store the yearly make-up rate for both processing trains. There is no need to store possible contaminated amine, as an Amine Purification Unit is part of the process. This will ensure that the amine is continuously meeting the right specification.

6.3 Utilities, Chemical Consumption, Effluents

The preliminary utilities, chemicals and effluents summary defines the utilities required to operate the CO_2 Capture Plant. The summaries are given in appendix IV.

The figures reported for amine consumption are based on the assumptions stated in section 6.2. At this stage, a conservative approach was taken for these calculations. The expected amine consumption may be reduced at the next engineering stage, once the design basis for the inlet flue gas contaminants is fixed. Additionally, potential integration with other units on utilities can take place.

Solid wastes consist of the spent IX resin and filtered particulates, if any, from the CO_2 filter.

No Waste Water Treatment System is included in the current Proposal.

The waste stream from the Thermal Reclaimer Unit (A-0700) will need to be handled off-site, either via incineration or by certified disposal sites.

6.4 Treated Gas

The characteristics of the treated gas exiting the CO_2 Absorber section are shown in Table 5:

Table 5: Treated gas characteristics exiting the CO_2 Absorber water wash section

Parameter	Unit	
Treated gas temperature	°C	43.4
Treated gas pressure	kPag	0.2
Treated gas flow	Nm^3/h	2,347,654
Treated Gas Composition		
N_2 (including Ar)	vol %	85.98
O_2	vol %	3.76
CO_2	vol %	1.64
H_2O	vol %	8.62

6.5 CO_2 Product

The characteristics of the CO_2 product gas, on a wet basis, exiting the CO_2 Reflux Accumulator are shown in Table 6. The level of contaminants in the CO_2 product gas is expected to be very low..

Table 6: CO_2 product gas characteristics

Parameter	Unit	
Product gas temperature	°C	30
Product gas pressure	kPag	98

Product gas mass flow	kg/hr	686,919
Product Gas Composition		
CO_2	wt %	97.9
H_2O	wt %	2.1

The expected CO_2-composition is meeting the composition requirements as given in the BOD.

6.6 Cansolv CO_2 Absorbent Summary

Initial Fill

Cansolv CO_2 absorbent is procured through Cansolv, on an Incoterms 2010 FCA basis, usually at a concentration of ~50% so no further dilution is required before use.

Annual Make-Up

The Cansolv CO_2 absorbent make-up rate is defined by six main factors:

1. Absorbent degradation
2. Absorbent losses via the CO_2 Absorbent Filter (S-0500)
3. Absorbent losses via the CO_2 Absorbent Purification Unit (A-0600)
4. Absorbent Entrainment with the Flue Gas
5. Absorbent Entrainment via the Product Gas
6. Mechanical losses

#2 in this case is expected to be negligible

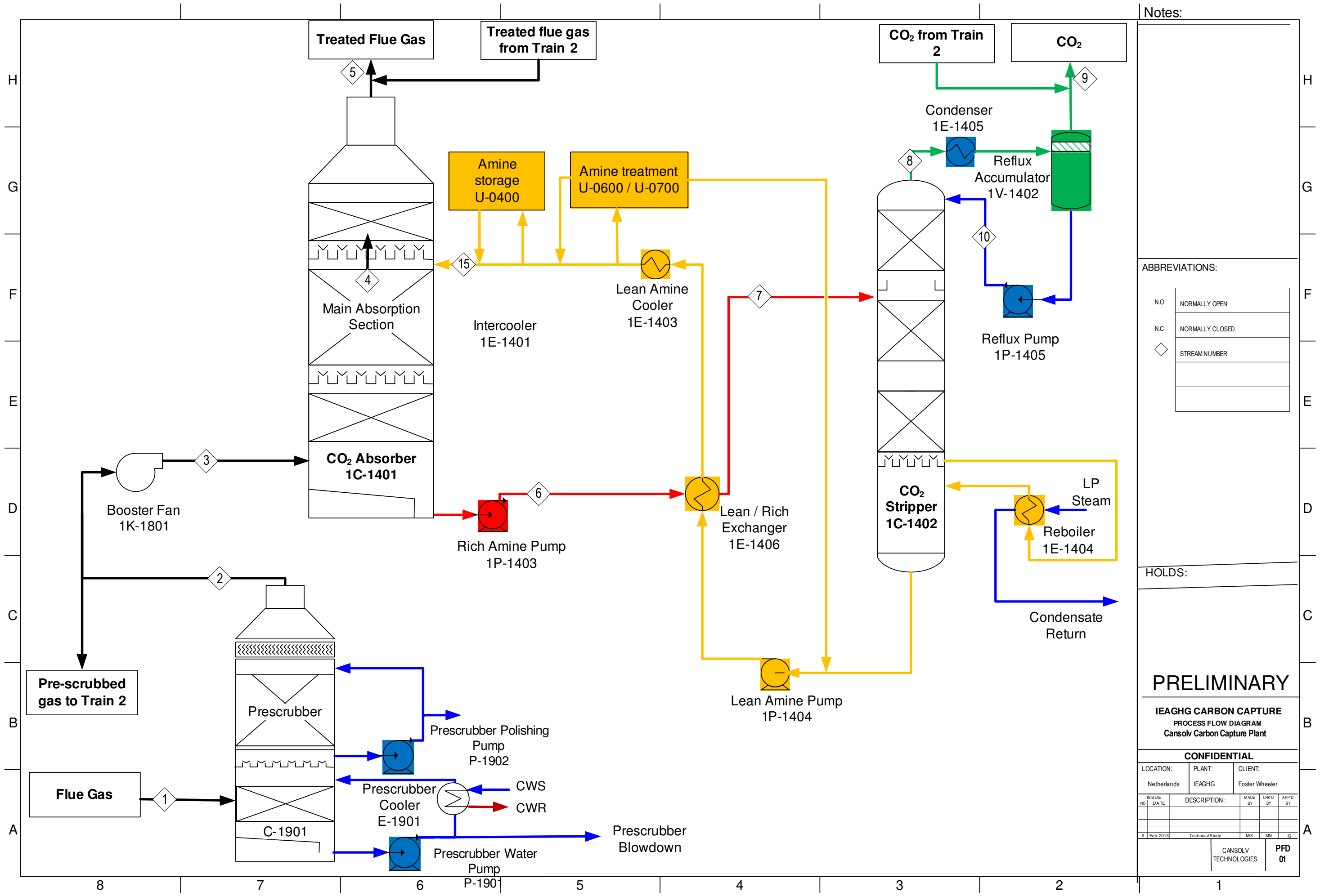
Absorbent degradation is the main cause of Cansolv CO_2 absorbent losses. Degradation products are removed in the APU. Absorbent entrainment into the flue gas and the product gas is minimal. The rectification section in the CO_2 Stripper captures absorbent vapour in the reflux water stream, returning the amine to the tower.

The expected make-up rate is ~18% of the total required inventory.

7. OPTIONS FOR INTERNAL HEAT RECOVERY

Cansolv uses different strategies in order to minimize energy consumption.

APPENDIX I: PROCESS FLOW DIAGRAM



APPENDIX II: PRELIMINARY HEAT & MATERIAL BALANCE

Please contact Cansolv Technologies Inc (CTI) for details.

APPENDIX III: SIZED EQUIPMENT LIST

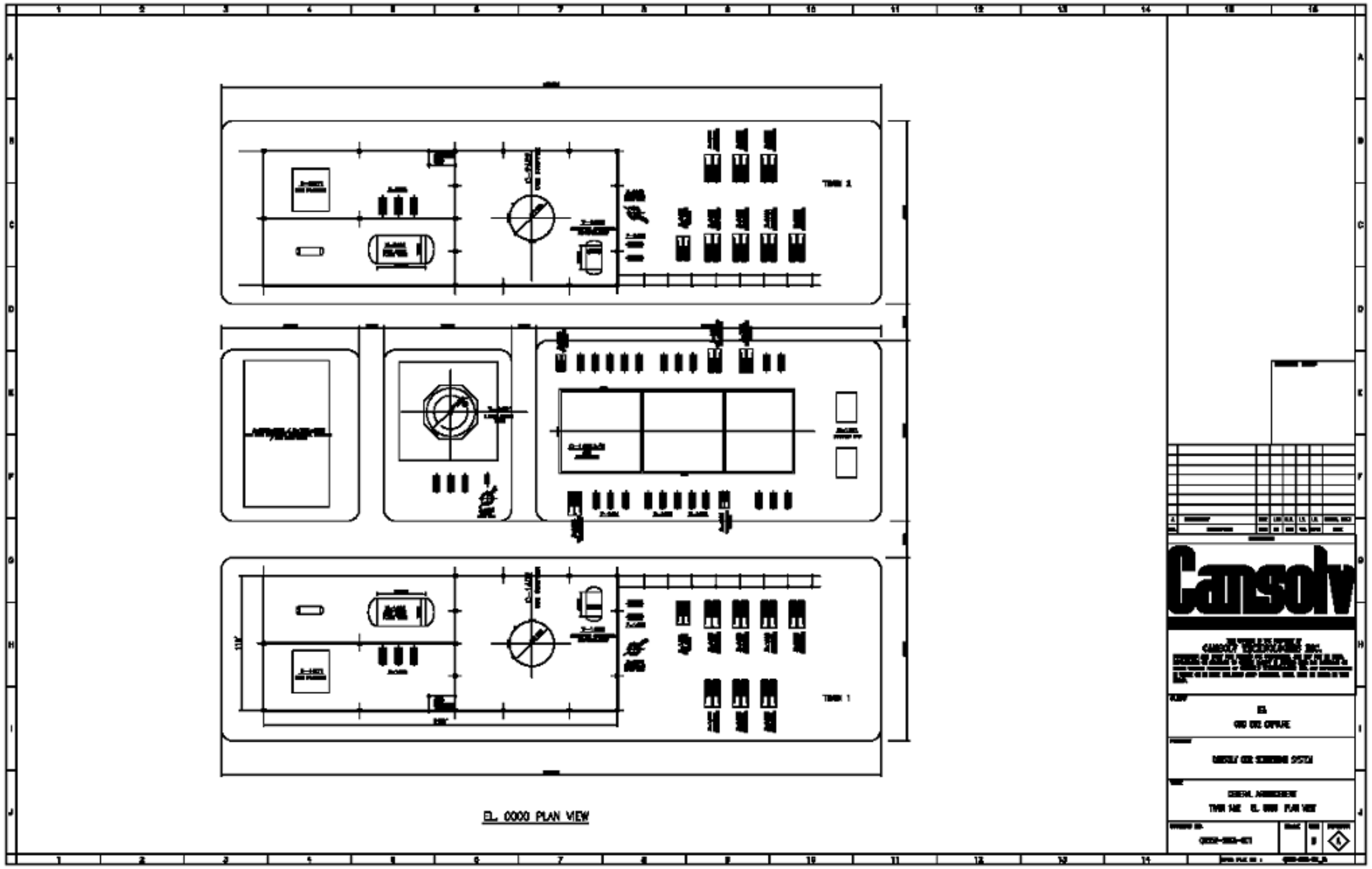
Please contact Cansolv Technologies Inc (CTI) for details.

APPENDIX IV: UTILITY CONSUMPTION TABLE

Please contact Cansolv Technologies Inc (CTI) for details.

APPENDIX V: ROUGH ESTIMATED LAYOUT / PLOT PLAN

A rough estimate of plot plan is presented. An estimation of overall plot space required is shown in table blew. The estimated plot space required includes Carbon Capture process area. The total estimated plot plant area is ~25000 m^2



APPENDIX VI: FUTURE INNOVATION AND DEVELOPMENT

INNOVATIVE FUTURE: Development of 2nd Generation Solvents for CO_2 Post Combustion Capture

Cansolv has established a comprehensive framework to steer development of 2nd generation solvents. Any new solvents are required to highlight the following improvements when compared to DC-103:

- Increased CO_2 loading capacity
- Lower regeneration energy requirement
- Increased stability

The table below presents the relationships between the technical objectives set for the new solvents and the resulting business value.

Table 7: Relationship between aimed technical objectives and expected business value

Technical Objectives (vs. DC-103)	Business Value
30% more CO_2 loading in the solvent	Reduction in solvent circulation leading to: • reduced CAPEX • reduced space requirements • less inventory
20% less steam requirement for steam regeneration	• reduced operating costs • lowered CO_2 footprint per ton CO_2 captured
25% more stability in oxidative environment	• reducing solvent loss and make-up rate

Development of new CANSOLV DC-201

The first development stage comprises of testing new candidates at the lab bench. During this "ranking exercise", the following solvent characteristics are studied:

- Loading-stripping capacity under different CO_2 partial pressures.
- Regeneration energy, using a lab bench unit mimicking the Cansolv CO_2 capture system, for screening and solvent comparison purposes
- Nuclear Magnetic Resonance for the carbamate/bicarbonate equilibrium and ease of regeneration

For one of the solvents that were tested in 2010, it was demonstrated that the technical and business objectives could potentially be met and thus warranted further consideration and testing. Upon further testing of this new solvent, CANSOLV DC-201, it was recognized that the loading capacity increased by more than 50% over DC-103. This in turn led to a reduction in liquid circulation rate, and hence to a lower contribution of the sensible heat and latent heat components in the regenerator. Furthermore, the optimization of the DC-201 formulation showed a 15% reduction in required regeneration energy over DC-103 on the Cansolv lab bench unit.

The second stage of the development consisted of testing DC-201 under real flue gas conditions at the 'pilot' size. Several piloting campaigns were performed, where some of the critical parameters studied were:

- Effect of gas temperature and inter-cooling on solvent loading;
- Effect of packing height and type on approach to equilibrium (gas and liquid sides);
- Effect of lean-rich temperature approach on stripper performance;
- Emission measurements (with or without the use of a water-wash section).

Currently pilot testing has been successfully concluded at four different test facilities. The first campaign was conducted at the SINTEF 1 ton/day Tiller pilot facility (Trondheim, Norway). The main purpose was to test the DC-201 under different conditions in the pilot plant.. Emission measurements were done; DC-201 volatility is really low. (7 times lower than MEA).CANSOLV DC201 was also tested in 2011 at a steel production site in Japan. Two gas conditions were studied: 22.5% CO_2 (flue gas from Blast Furnace) and 13.5% CO_2 (diluted gas).
In 2012, two pilot testing campaigns took place:

- Pilot testing (1 tpd) at an external facility, Energy and Environmental Research Center (North Dakota, US) sponsored by the United States Department Of Energy (US DOE).
- Large pilot testing (20 tpd) at an external facility, National Carbon Capture Center (Alabama, US), operated by Southern and sponsored by the US DOE. The test was conducted over a longer period of time (2 to 3 months) in order to evaluate the stability of the solvent

Expected performance for FW Design

We are currently working through the rigorous steps of making DC-201 a successful and commercial solvent. Based on the data and on the results gathered to date, it is possible to estimate the potential performance of the DC-201 solvent if it is to be used for the FW case compared to the DC-103 solvent.

Capex savings are anticipated since a reduction in solvent circulation, steam consumption and cooling requirements all of which is expected to lead to correspondingly smaller piping, regenerating equipment and exchangers & pumps.

Early indications are that the solvent will be commercially available from qualified suppliers and should be cheaper than the current DC-103 market price.

DC103 design performances and DC201 expected performances for FW case

Main parameters	DC201 vs. DC103 (% relative)
Solvent circulation	>36%
Steam consumption	>20%
Cooling water	>27%

Next validation steps

In order to further validate the above characteristics for solvent circulation and energy consumption; as well as to verify and quantify solvent stability (to validate solvent degradation under various fluegas conditions), the development of this 2nd generation solvent is ongoing and it is expected that DC-201 is commercial available in 2013: When the solvent is available at the market, it is proposed to update this proposal.

ATTACHMENT A.3: Cansolv SO_2 Scrubbing System

1. Business Profile

1.1 Cansolv Technologies

Cansolv Technologies Incorporated (CTI) mission is to be a leading global provider of high efficiency air pollution control and capture solutions. CTI's commitment is to providing custom designed economic solutions to our clients' environmental problems.

CTI is an innovative, technology-centered company that offers its clients high efficiency air pollution and capture solutions for the removal of SO_2 and CO_2 from gas streams in various industrial applications. Our commitment is to provide custom designed economic solutions to our clients' environmental problems.

CTI was formed in 1997 to commercialize the CANSOLV SO_2 Scrubbing System. On November 30th of 2008, Shell Global Solutions International B.V (SGSI) purchased 100% of the shares of CTI. The company now operates as a wholly owned subsidiary of SGSI.

CTI maintains an office and an R&D laboratory in Montreal, Canada and an office in Beijing, China. As a subsidiary of Shell Global Solutions, CTI can leverage large amounts of ancillary knowledge and incorporate its solutions into the largest of projects in many industries. A list of references is available in Appendix I.

1.2 Royal Dutch Shell

Royal Dutch Shell is a global group of energy and petrochemicals companies with around 90,000 employees in more than 80 countries and territories. Our innovative approach ensures we are ready to help tackle the challenges of the new energy future.

Shell Projects and Technology, formerly Shell Global Solutions, provides technical services and technology capability in upstream and downstream activities. It manages the delivery of major projects and helps to improve performance across the company.

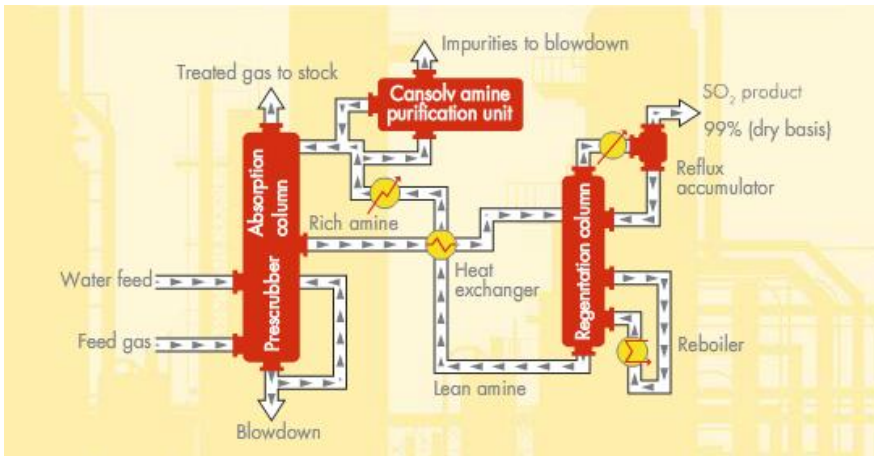
Shell Projects and Technology delivers differentiated technical information technology for Royal Dutch Shell and drive research and innovation to create tomorrow's technology solutions. Projects and Technology also houses Safety & Environment and Contracting & Procurement as these are integral to all our activities.

Safety is always our top priority. We aim to have zero fatalities and no incidents that harm people, or put our neighbors or facilities at risk.

Find more information at: www.cansolv.com and www.shell.com

2. Technology Overview

The CANSOLV SO_2 Scrubbing System uses regenerable amine-based solvents to selectively capture SO_2 from a gas stream. Low-pressure/saturated steam is used to strip the targeted chemical compounds from solution and the solvent is returned to the Scrubber for re-use. Pure water-saturated stream of SO_2 exits the System and can be used as feedstock for other industrial processes. The Amine Purification Unit, a proprietary equipment, regenerates the amine solvent to minimize the amount of make-up.



The CANSOLV SO2 Scrubbing System enables to:

- Decrease emissions of SO_2 to industry leading levels (levels as low as 10 ppm can be achieved);
- De-couple the emissions from the plant operations;
- Concentrate SO_2 to enable sulphuric acid production;
- Recycle back the SO_2 from the emissions to the process;
- Minimizing the size and complexity of the whole Tail Gas Treatment line-up;
- Minimize the risk associated with strengthening regulations.

The possibility of resetting the operational parameters of a CANSOLV-SO_2 to meet stricter regulations minimizes the risk of having to put in place additional scrubbing technologies in the future, thus securing the assets the entire lifespan of the plant.

The CANSOLV SO_2 Scrubbing System is fully automated and is a robust and forgiving process that does not require continuous monitoring to meet emission targets. It has a high turndown and turn-up capability.

If steam availability is limited, the system can be designed with steam optimization solutions such as Mechanical Vapour Recompression (MVR). Other options for reducing steam consumption are the Double Effect Split Flow (DESF), Hot Water Flash (HWF), Reflux Pre-Heater (RPH), Rich Amine Pre-Heater (RAPH) and Hot Water with Regenerator under Vacuum (HWRV).

Find more information at: www.cansolv.com/SO2/Cansolv_SO2_Scrubbing_Systems_Process.php

CLIENT	:	IEAGHG
PROJECT NAME	:	CO_2 CAPTURE AT COAL FIRED POWER PLANTS
DOCUMENT NAME	:	CASE 1: SC PC WITHOUT CCS
FWI CONTRACT	:	1-BD-0681 A

ISSUED BY	:	G. PERFUMO
CHECKED BY	:	N. FERRARI
APPROVED BY	:	L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

1. Introduction

This chapter of the report includes all technical information relevant to Case 1 of the study, which is a supercritical pulverised coal (SC PC) fired steam plant without carbon capture. The plant is designed to process coal, whose characteristic is shown in chapter B, and produce electric power for export to the external grid.

The configuration of the SC PC plant is based on one once through steam generator, with superheating and single steam reheating, and a steam turbine generator for around 1,000 MWe net power production.

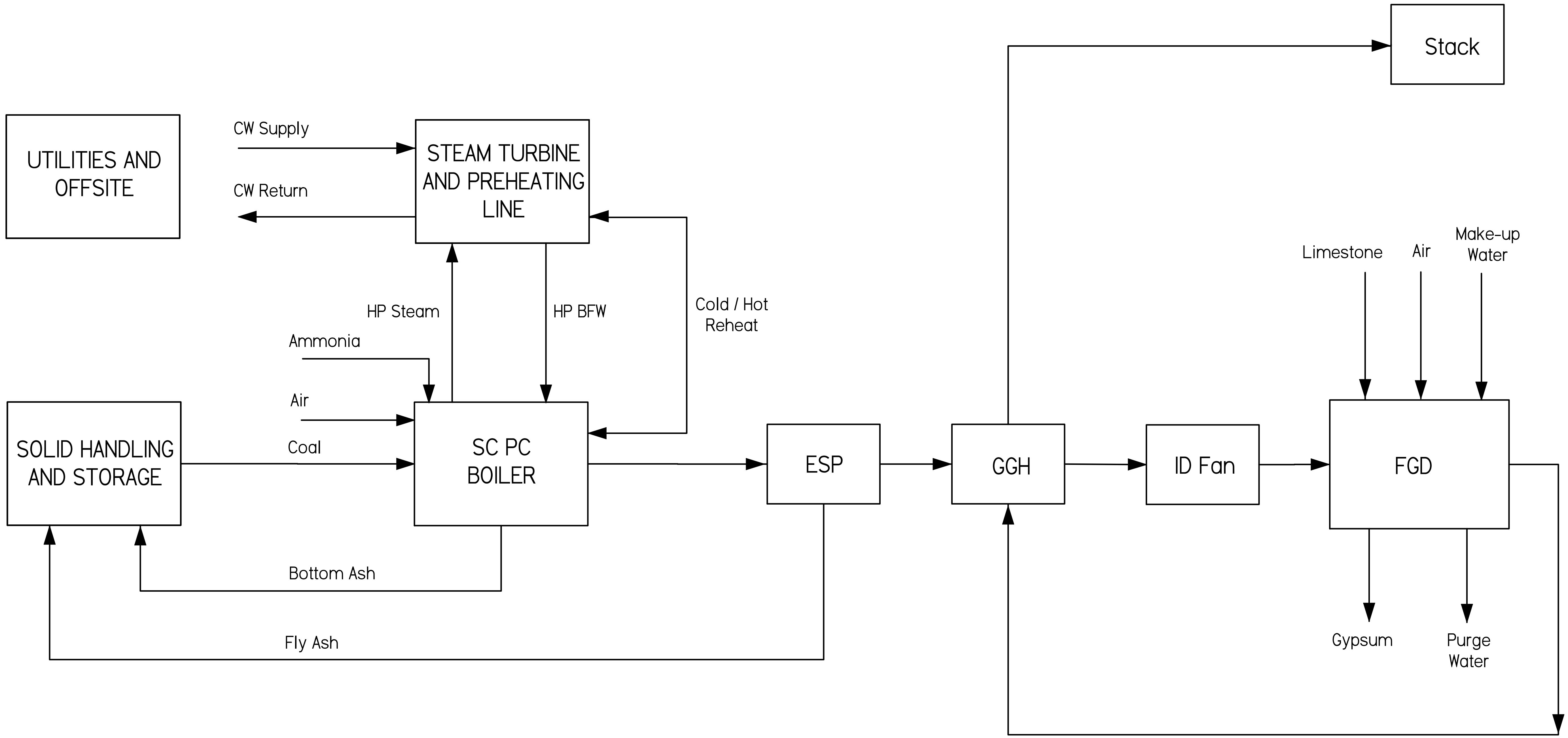
The description of the main process units is covered in chapter C of this report, so only features that are unique to this case are discussed in the following sections, together with the main modelling results.

1.1. Process unit arrangement

The arrangement of the main units is reported in the following Table 1. Reference is also made to the block flow diagram attached below.

Table 1. Case 1 – Unit arrangement

Unit	Description	Trains
1000	Storage and Handling of solid materials	N/A
2000	SC PC supercritical boilers	1 x 100%
	Electro Static precipitators	1 x 100%
2050	Flue Gas Denitrification (DeNOx) – SCR system	1 x 100%
2100	Flue Gas Desulphurisation (FGD)	1 x 100%
3000	Steam Cycle (SC)	
	Steam Turbine and Condenser	1 x 100%
	Deaerator	1 x 100%
	Water Preheating line	1 x 100%
6000	Utility and Offsite	N/A



0	June 13	Draft	GP	LM	**UNIT:** Block Flow Diagram	
Rev.	Date	Comment	By	Appr	**CASE:** 1	Sheet 01 of 01

2. Process description

2.1. Overview

The description reported in this section makes reference to the simplified Process Flow Diagrams (PFD) shown in section 3, while stream numbers refer to Section 4, which provides heat and mass balance details for the numbered streams in the PFD.

2.2. Unit 1000 – Feedstock and solid handling

The unit is composed of the following systems:

- Coal storage and handling
- Limestone storage and handling
- Ashes collection and storage
- Gypsum storage and handling

The general description relevant to this unit is reported in chapter C, section 2.1. Main process information of this case and the interconnections with the other units is shown in the relevant process flow diagram and the heat and mass balance table.

2.3. Unit 2000 – Boiler Island

This unit is mainly composed of the Boiler and the Selective Catalytic Reactor (SCR) system. Technical information relevant to these packages is reported in chapter C, sections 2.2 and 2.3 respectively. For this Case 1, SCR system is used to meet the environmental NO_X emission limits of 150 mg/Nm^3 (6% volume O_2, dry).

Main process information of this case and interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

2.4. Unit 2100 – Flue Gas Desulphurization

This unit is mainly composed of the FGD and the gypsum dehydration systems. For this Case 1, flue gas desulphurisation is required to meet the plant overall environmental SOx limit of 150 mg/Nm^3 (6% volume O_2, dry).

Alstom wet scrubbing technology was selected for the development of this study case. Technical information relevant to this system is reported in chapter C, section 2.4.1. The impact of a different FGD technology and supplier is also summarised in chapter C, section 2.4.4.

Main process information of this case and interconnections with the other units is shown in the relevant process flow diagram and the heat and mass balance table.

Gas-gas heat (GGH) exchanger

Saturated flue gases from top of the absorber in the FGD system are heated-up, before discharge from the stack, to ensure proper flue gas dispersion and avoid water condensation. Hot flue gases from the boiler air pre-heater are used as heating medium before entering the FGD absorber. The gas-gas heater is a very expensive equipment representing around 25-30% of the total FGD unit installed cost.

2.5. Unit 3000 – Steam Cycle

The steam cycle is mainly composed of one supercritical Steam Turbine Generator (STG), water-cooled condenser and the water pre-heating line. General description relevant to this unit is reported in chapter C, section 2.7.1.

Main process information of this case and interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

2.6. Unit 6000 - Utility Units

These units comprise all the systems necessary to allow the operation of the plant and the export of the produced power.

The main utility units include:

- Cooling Water system, based on one natural draft cooling tower, with the following characteristics:

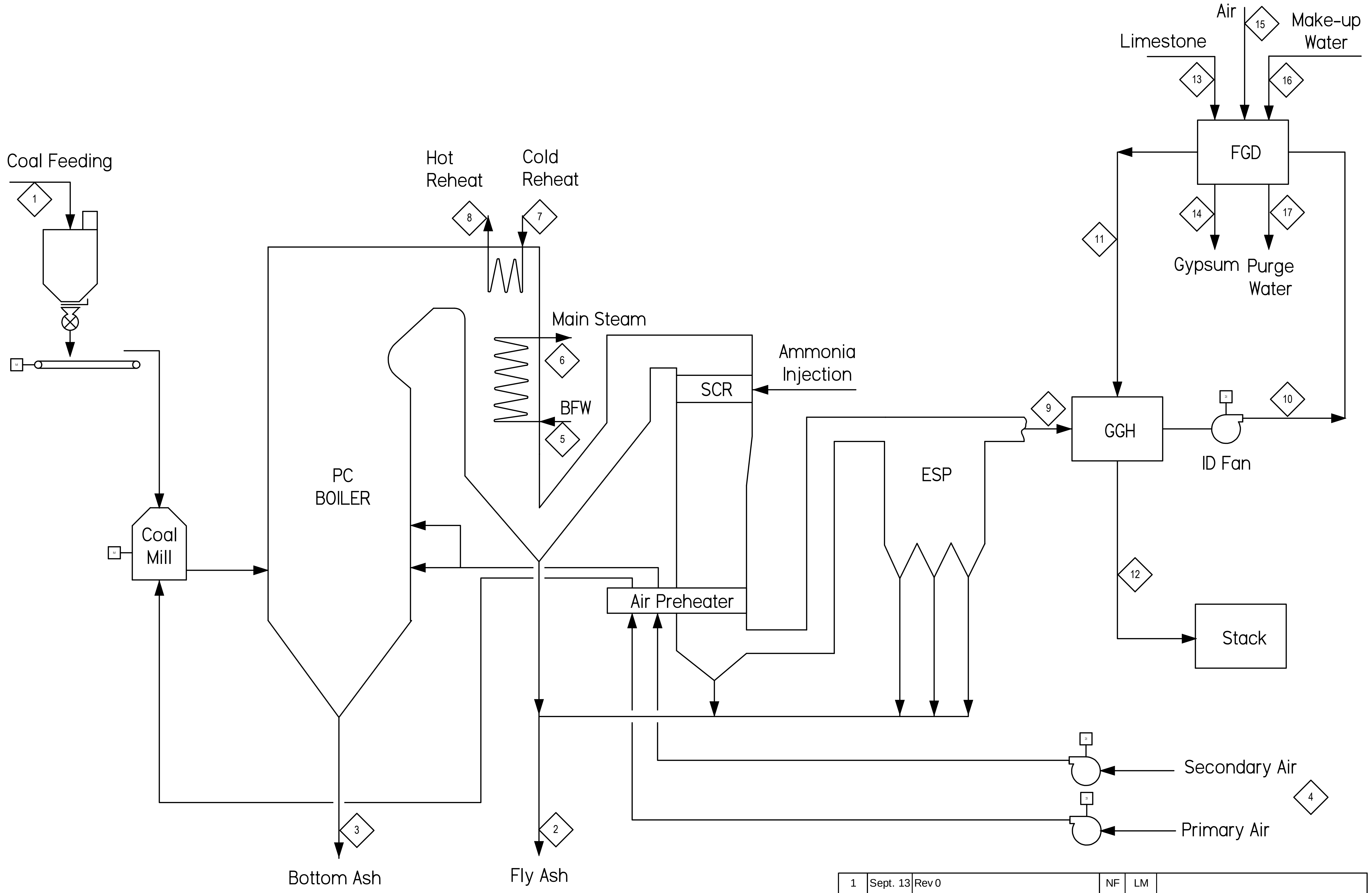
Basin diameter	150 m
Cooling tower height	210 m
Water inlet height	17 m

- Raw water system;
- Demineralised water plant;
- Fire fighting system;
- Instrument and Plant air.

Process descriptions of the above systems are enclosed in chapter C, section 2.8.

3. Process Flow Diagrams

Simplified Process Flow Diagrams of this case are attached to this section. Stream numbers refer to the heat and material balance shown in the next section.



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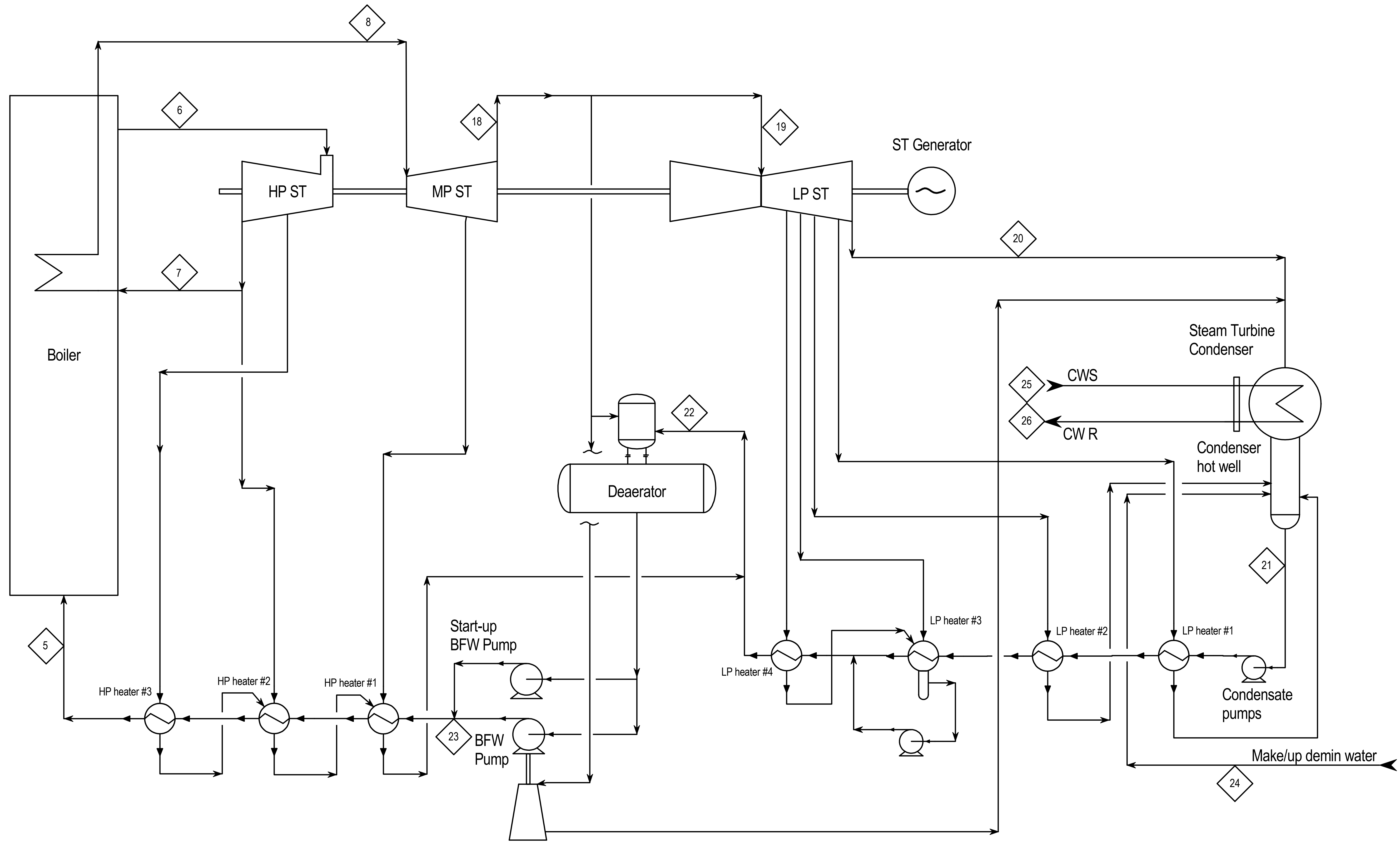
0	June 13	Draft	GP	LM	**UNIT:** Boiler Island	
Rev.	Date	Comment	By	Appr	**CASE:** 1	Sheet 01 of 02



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0	June 13	Draft	GP	LM	**UNIT:** Steam Cycle	
Rev.	Date	Comment	By	Appr	**CASE:** 1	Sheet 02 of 02

4. Heat and Material Balance

Heat & Material Balances here below reported make reference to the Process Flow Diagrams of section 3.

	Case 1 - SC PC w/o CCS - HEAT AND MATERIAL BALANCE						REVISION	draft	0	
FOSTER WHEELER	CLIENT :		IEAGHG				PREP.	GP	GP	
	PROJECT NAME:		CO2 capture at coal based power and hydrogen plants				CHECKED	NF	NF	
	PROJECT NO:		1-BD-0681 A				APPROVED	LM	LM	
	LOCATION:		The Netherlands				DATE	July 13	Sept. 13	

HEAT AND MATERIAL BALANCE
UNIT 2000 - BOILER ISLAND

STREAM	1	2	3	4	5	6	7	8		
	Coal to Boiler Island	Fly Ash	Bottom Ash	Air intake from Atmosphere	BFW from steam cycle	HP Steam to Steam Turbine	Cold Reheat from UNIT 3000	Hot Reheat to Steam Turbine		
Temperature (°C)	AMB	AMB	AMB	9	290	600	366	620		
Pressure (bar)	ATM	ATM	ATM	ATM	325	270	63	60		
TOTAL FLOW	Solid	Dry solid	Dry solid							
Mass flow (kg/h)	325,000	29,200	12,500	3,383,000	2,877,000	2,877,000	2,421,000	2,421,000		
Molar flow (kmol/h)				117,250	159,745	159,745	134,425	134,425		
LIQUID PHASE										
Mass flow (kg/h)					2,877,000					
GASEOUS PHASE										
Mass flow (kg/h)				3,383,000		2,877,000	2,421,000	2,421,000		
Molar flow (kmol/h)				117,250		159,745	134,425	134,425		
Molecular Weight				28.9		18.0	18.0	18.0		
Composition (vol %)	%wt									
H_2				0.00%	0.00%	0.00%	0.00%	0.00%		
CO	C: 64.6%			0.00%	0.00%	0.00%	0.00%	0.00%		
CO_2	H: 4.38%			0.03%	0.00%	0.00%	0.00%	0.00%		
N_2	O: 7.02%			77.27%	0.00%	0.00%	0.00%	0.00%		
O_2	S: 0.86%			20.73%	0.00%	0.00%	0.00%	0.00%		
CH_4	N: 1.41%			0.00%	0.00%	0.00%	0.00%	0.00%		
Ar	Cl: 0.03%			0.92%	0.00%	0.00%	0.00%	0.00%		
SO_2	Moisture: 9.5%			0.00%	0.00%	0.00%	0.00%	0.00%		
H_2O	Ash: 12.20%			1.05%	100%	100%	100%	100%		
Total				100%	100%	100%	100%	100%		
Emissions (mg/Nm^3, dry basis 6% vol O_2)										
SOx				-	-	-	-	-		
NOx				-	-	-	-	-		
Particulate				-	-	-	-	-		

	Case 1 - SC PC w/o CCS - HEAT AND MATERIAL BALANCE		REVISION	draft	0	
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	GP	GP	
	PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	CHECKED	NF	NF	
	PROJECT NO:	1-BD-0681 A	APPROVED	LM	LM	
	LOCATION:	The Netherlands	DATE	July 13	Sept. 13	

HEAT AND MATERIAL BALANCE
UNIT 2100 - FGD

STREAM	9	10	11	12	13	14	15	16	17	
	Flue Gas from ESP to GGH	Flue Gas to FGD	Treated Gas from FGD	Flue Gas to stack	Limestone to FGD	Product Gypsum	Oxidation Air	Make up Water	Waste water from FGD	
Temperature (°C)	132	90	47	90	AMB	AMB	AMB	15	AMB	
Pressure (bar)	-	-	-	-	ATM	ATM	ATM	ATM	ATM	
TOTAL FLOW					Solid	Solid				
Mass flow (kg/h)	3,667,000	3,667,000	3,740,700	3,740,700	8,850	16,165	8,655	85,000	7,790	
Molar flow (kmol/h)	123,410	123,410	127,460	127,460			300	4,720	433	
LIQUID PHASE										
Mass flow (kg/h)								85,000	7,790	
GASEOUS PHASE										
Mass flow (kg/h)	3,667,000	3,667,000	3,740,700	3,740,700			8,655			
Molar flow (kmol/h)	123,410	123,410	127,460	127,460			300			
Molecular Weight	29.7	29.7	29.3	29.3			28.85			
Composition (vol %)										
H_2	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%	
CO_2	14.06%	14.06%	13.68%	13.68%			0.03%	0.00%	0.00%	
N_2	73.56%	73.56%	71.40%	71.40%			77.27%	0.00%	0.00%	
O_2	3.28%	3.28%	3.20%	3.20%			20.73%	0.00%	0.00%	
CH_4	0.00%	0.00%	0.00%	0.00%			0.00%	0.00%	0.00%	
Ar	0.87%	0.87%	0.85%	0.85%			0.92%	0.00%	0.00%	
SO_2	0.07%	0.07%	0.00%	0.00%			0.00%	0.00%	0.00%	
H_2O	8.16%	8.16%	10.88%	10.88%			1.05%	100%	100%	
Total	100%	100%	100%	100%			100%	100%	100%	
Emissions (mg/Nm^3, dry basis 6% vol O_2)										
SOx	1897	1897	150	150	-	-	-	-	-	
NOx	150	150	150	150	-	-	-	-	-	
particulate	10	10	10	10	-	-	-	-	-	

NOTE
1. Air in-leakage are included in the flue gas streams

	Case 1 - SC PC w/o CCS - H&M BALANCE		REVISION	draft	0
	CLIENT:	IEAGHG	PREP.	GP	GP
	PROJECT NAME:	CO2 capture at coal based power and H2 plants	CHECKED	NF	NF
	PROJECT NO:	1-BD-0681 A	APPROVED	LM	LM
	LOCATION:	The Netherlands	DATE	July 13	Sept. 13

HEAT AND MATERIAL BALANCE
UNIT 3000 - STEAM CYCLE

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
5	HP Water to Boiler Island	2,877	290	323	1278
6	HP Steam from Boiler to HP Steam Turbine	2,877	600	270.0	3475
7	Cold Reheat to Boiler	2,421	366	63.0	3081
8	Hot Reheat to MP Steam Turbine	2,421	620	60.0	3706
18	MP Steam Turbine exhaust	2,150	285	6.0	3031
19	Steam to LP Steam Turbine	1,967	285	5.9	3031
20	Exhaust from LP Steam Turbine	1,585	29	0.04	2292
21	Condensate	1,947	29	0.04	121
22	LP Preheated Condensate	2,826	142	9.5	597
23	BFW to pre-heating	2,877	156	325	678
24	Make up Water	5	9	0.04	38
25	Cooling Water Inlet	82,588	15	4.0	63
26	Cooling Water Outlet	82,588	26	3.5	109

5. Utility and chemicals consumption

Main utility consumption of the process and utility units is reported in the following tables. More specifically:

- Water consumption summary is reported in Table 2,
- Electrical consumption summary is shown in Table 3,
- Sorbent and chemicals consumption is shown in Table 4.

Table 2. Case 1 – Water consumption summary

CLIENT:	IEAGHG	REVISION	0
PROJECT NAME:	CO2 capture at coal fired power plants	DATE	Jun-13
PROJECT No. :	1-BD-0681 A	MADE BY	GP
LOCATION :	The Netherlands	APPROVED BY	LM

Case 1 - Water consumption

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water 1° syst. [DT = 11°C] [t/h]	Cooling Water 2° syst. [DT = 11°C] [t/h]
1000	FEEDSTOCK AND SOLID HANDLING				
	Solid Receiving, Handling and storage				
2000	BOILER ISALND and FLUE GAS TREATMENT				
	Boiler island				
	Flue Gas Desulphurization (Wet FGD)	85			
500	POWER ISLAND (Steam Turbine)				
	Condenser			82590	
	Turbine and generator auxiliaries		5		4960
BoP	UTILITY and OFFSITE UNITS				
	Cooling Water System	1575			
	Demineralized/Condensate Recovery/Plant and Potable Water Systems	8	-5		
	Waste Water Treatment	-10			
	Miscellanea				100
	BALANCE	1658	0.0	82590	5060

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

Table 3. Case 1 – Electrical consumption summary

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	**DATE**	Jun-13
PROJECT No. :	1-BD-0681 A	**MADE BY**	GP
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 1 - Electrical consumption

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
1000	**FEEDSTOCK AND SOLID HANDLING**	
	Solids Handling	3330
2000	**BOILER ISLAND and FLUE GAS TREATMENT**	
	Boiler island (including ID fan)	21920
	Flue Gas Desulphurization (FGD)	2890
3000	**POWER ISLAND (Steam Turbine)**	
	Steam Turbine Auxiliaries and condenser	2600
	Condensate and feedwater system	1250
	Miscellanea	600
BoP	**UTILITY and OFFSITE UNITS**	
	Cooling Water System	9990
	Other Units	1440
	BALANCE	**44,020**

Table 4. Case 1 – Sorbent and chemicals consumption

	Consumption
Limestone injection to the FGD	8.85 t/h
Ammonia solution to SCR [1]	4.5 t/h

(1) 25%wt ammonia solution

6. Overall Performance

The following table shows the overall performance of Case 1.

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	**DATE**	Jun-13
PROJECT No. :	1-BD-0681 A	**MADE BY**	GP
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 1 - SC PC Plant Performance Summary

OVERALL PERFORMANCES		
Fuel flow rate (A.R.)	t/h	325.0
Fuel HHV (A.R.)	kJ/kg	27060
Fuel LHV (A.R.)	kJ/kg	25870
THERMAL ENERGY OF FEEDSTOCK (based on LHV) (A)	**MWth**	**2335**
THERMAL ENERGY OF FEEDSTOCK (based on HHV) (A')	**MWth**	**2443**
Steam turbine power output (@ gen terminals)	MWe	1076.7
GROSS ELECTRIC POWER OUTPUT (C) (1)	**MWe**	**1076.7**
Boiler Island and FGD	MWe	24.8
Utility & Offsite Units consumption	MWe	11.4
Power Islands consumption	MWe	4.5
Feedstock and solids handling	MWe	3.3
ELECTRIC POWER CONSUMPTION	**MWe**	**44.0**
NET ELECTRIC POWER OUTPUT	**MWe**	**1032.7**
(Step Up transformer efficiency = 0.997%) (B)	MWe	1029.6
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**46.1%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**44.1%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**44.1%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**42.1%**
Fuel Consumption per net power production	**MWth/MWe**	**2.27**
CO_2 emission per net power production	**kg/MWh**	**745.3**

(1) Steam driven BFW pumps are included

7. Environmental impact

The SC PC steam plant design is based on advanced technologies that allow to reach high electrical generation efficiency, while minimizing impact to the environment. Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

7.1. Gaseous emissions

During normal operation at full load, main continuous emissions are the flue gases from the boiler. Table 5 summarizes the expected flue gases flowrate and composition.

Minor and fugitive emissions are related to the milling, storage and handling of solids (e.g. solid transfer, leakage). As summarised in Table 6, these emission mainly consists of air containing particulate.

Table 5. Case 1 – Plant emission during normal operation

Flue gas to stack	
Emission type	Continuous
Conditions	
Wet gas flowrate, kg/h	3,740,000
Flow, Nm^3/h (1)	2,857,000
Temperature, °C	90
Composition	(% vol)
Ar	0.85
N_2	71.40
O_2	3.20
CO_2	13.68
H_2O	10.88
Emission	mg/Nm^3 (1)
NOx	< 150
SOx	< 150
Particulate	< 10

(1) Dry gas, O_2 content 6% vol.

Table 6. Case 1 – Plant minor emission

Emission source	**Emission type**	**Temperature**	
Coal milling and feed system	Continuous	ambient	Air: 10 mg/Nm^3 particulate
Limestone milling and preparation	Intermittent	ambient	Air: 10 mg/Nm^3 particulate
Gypsum handling and de-hydration	Intermittent	ambient	Air: 10 mg/Nm^3 particulate
Ash storage and transfer	Intermittent	ambient	Air: 10 mg/Nm^3 particulate

7.2. Liquid effluents

The plant does not produce significant liquid waste. FGD unit blow-down is treated in a dedicated R.O. system to recover water, so main liquid effluent is the cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids.

Cooling Tower blow-down

Flowrate : 376.5 m^3/h

FGD blow-down

Flowrate : 10 m^3/h

7.3. Solid effluents

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

Fly ash from boiler

Flowrate : 29.2 t/h

Bottom ash from boiler

Flowrate : 12.5 t/h

Fly and bottom ash might be sold to cement industries, if local market exist, or sent to disposal.

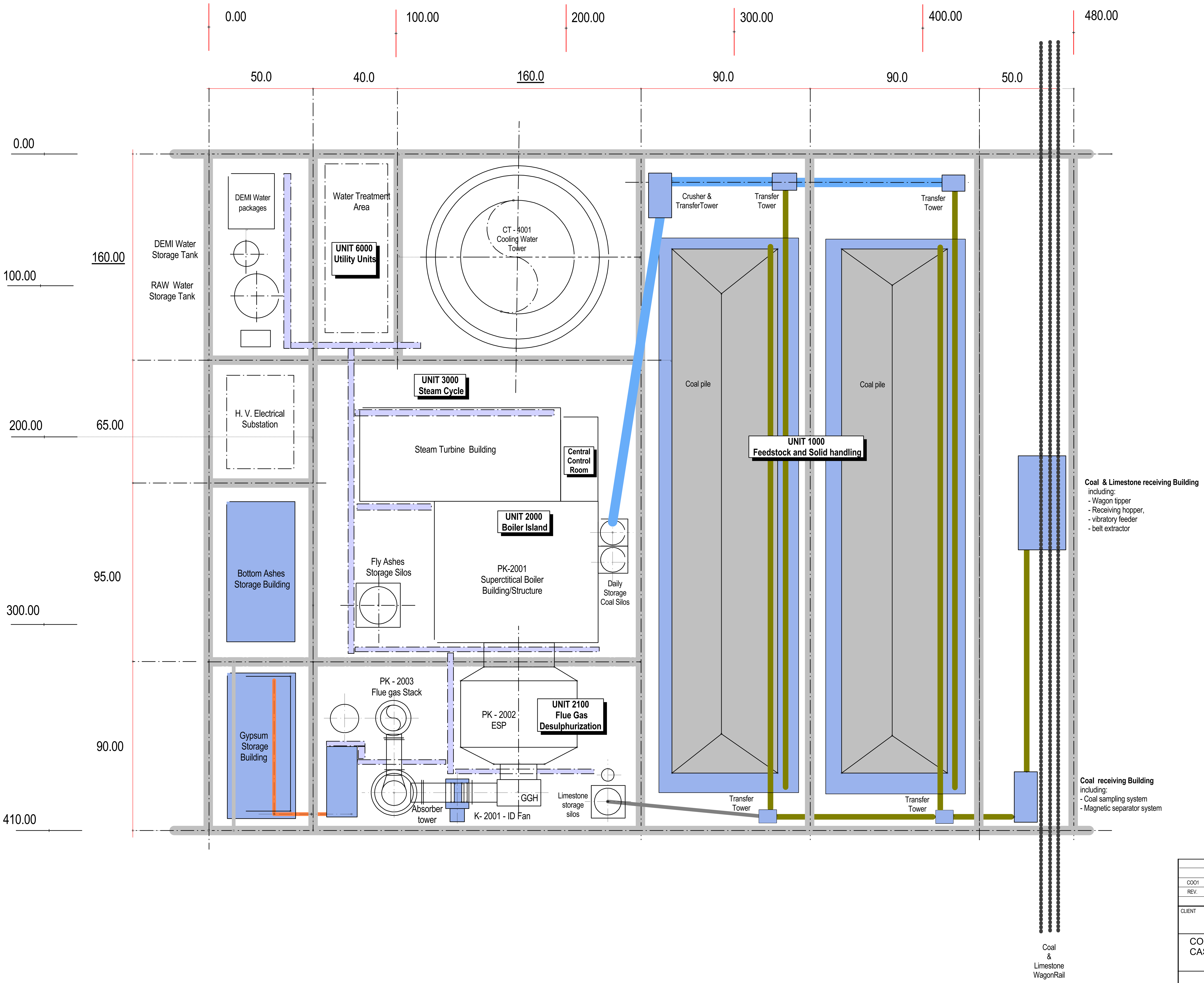
Solid gypsum from FGD

Solid gypsum, produced in de-hydrated form in the FGD system, can be sold in the market.

Flowrate : 16.2 t/h
Moisture content : 10%wt

8. Preliminary plot plan

Plot plan at block level of Case 1 is attached to this section, showing the area occupied by the main units and equipment of the plant.



REV.	DATE	DESCRIPTION	DRAW	BY	CHD.	APP.
COO1	AUG. 2013	Preliminary issue for comments	APeccati			

DESCRIPTION

CLIENT IEA GHG

SITE The Netherlands

CO2 Capture and coal fired Power Plants
CASE: 1 - SC PC without carbon capture
PRELIMINARY PLOT PLAN

APPROVED FOR CONSTRUCTION
DWG. REV. DATE
SIGNATURE
ORDER N°
SUPPLIER
CONTRACT N°
FRAME N°
CLIENT DWG N°
SHEET SHEET
SCALE N. A.
FWI DWG N° 1BD0681A - 01 - 001
SHEET OF
REV. COO1

CAD FILE NAME

Form. A3

9. Equipment list

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

	CLIENT: IEA GHG	REVISION	Rev. Draft	Rev. 0	Rev. 1	Rev. 2
FOSTER WHEELER	LOCATION: The Netherlands	DATE	June 13	Sept. 2013	January 2014	
	PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	GP	GP	GP	
	CONTRACT N. 1-BD-0681 A	CHECKED BY	NF	NF	NF	
	CASE: 1 - SC PC without carbon capture	APPROVED BY	LM	LM	LM	

EQUIPMENT LIST
Unit 1000 - Feedstock and Solid handling

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	COAL HANDLING SYSTEM							
	Including:		Coal flowrate to boiler: 325 t/h					*30 days storage*
	- Wagon tipper							*Storage piles: 2 x 128,000 t each*
	- Receiving Hopper, vibratory feeder and belt extractor							
	- Conveyors	Belt						
	- Transfer Towers	enclosed						
	- As-Received Coal Sampling System	Two - Stage						
	- As-Received Magnetic separator System	Magnetic Plates						
	- Conveyors	Belt						
	- Transfer Towers	enclosed						
	- Cruscher Tower	Impactor reduction						
	- As-Fired Coal Sampling System	Swing hammer						
	- As-Fired Magnetic separator System	Magnetic Plates						
	- Coal Silo		2 x 4900 m3					*For daily storage*
	- Filters							
	- Fans							
	LIMESTONE HANDLING SYSTEM							
	Including:		Limestone flowrate to FGD: 9.0 t/h					
	- Wagon tipper		Limestone Storage volume: 5700 m3					*30 days storage capacity*
	- Receiving Hopper, vibratory feeder and belt extractor							
	- Conveyor	Belt						
	- Transfer Tower	enclosed						
	- Conveyor	Belt						
	- Limestone Sampling System	Swing Hammer						
	- Separator System	Magnetc Plates						
	- Transfer Tower	enclosed						
	- Conveyor	Belt with tipper						
	- Limestone Mills							
	- Limestone Silo		1 x 200 m3					*For daily storage*
	- Filters							
	- Fan							

	CLIENT:	IEA GHG	REVISION	Rev. Draft	Rev. 0	Rev. 1	Rev. 2
FOSTER WHEELER	LOCATION:	The Netherlands	DATE	June 13	Sept. 2013	January 2014	
	PROJ. NAME:	CO2 capture at coal based power and hydrogen plants	ISSUED BY	GP	GP	GP	
	CONTRACT N.	1-BD-0681 A	CHECKED BY	NF	NF	NF	
	CASE:	1 - SC PC without carbon capture	APPROVED BY	LM	LM	LM	

EQUIPMENT LIST
Unit 1000 - Feedstock and Solid handling

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	ASH SYSTEM							
	Including: - Ash storage silos - Ash conveyors - Bottom ash crusher - Pneumatic conveying system - Filters - Fans		Bottom Ash Capacity: 12.5 t/h Bottom Ash Storage volume: 6000 m3 Fly Ash Capacity: 29.2 t/h Fly Ash Storage volume: 14000 m3					*14 days storage capacity* *14 days storage capacity*
	GYPSUM SYSTEM							
	Including: - Storage unit - Conveyors		Capacity: 16.165 t/h Storage volume: 9000 m3					*30 days storage capacity* *1 operating, 1 spare*

	CLIENT:	IEA GHG	REVISION	Rev. Draft	Rev. 0	Rev. 1	Rev. 2
FOSTER WHEELER	LOCATION:	The Netherlands	DATE	June 13	Sept. 2013	January 2014	
	PROJ. NAME:	CO2 capture at coal based power and hydrogen plants	ISSUED BY	GP	GP	GP	
	CONTRACT N.	1-BD-0681 A	CHECKED BY	NF	NF	NF	
	CASE:	1 - SC PC without carbon capture	APPROVED BY	LM	LM	LM	

EQUIPMENT LIST
Unit 2000 - Boiler Island

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	BOILER							
PK - 2001	**Super Critical Boiler, including:**		Capacity: 2877t/h main steam production Thermal input: 2443 MWth (HHV) / 2335 MWth (LHV) Main steam condition: 270 bar(a)/600 °C Reheat steam condition: 60 bar(a)/620 °C				(1)	Boiler package including: - Coal mill - Fuel Feeding system - One Fired Boiler Furnace -Low NOx burners system including main burners and pilots - Economizers/super heater coils, water wall circuit - Reheating coils - Air pre-heater - Ash collection hoppers - Combustion air fans with electric motor (2 x 60% primary air, 2 x 60% secondary - Ash collection hoppers - Start-up system - Flue gas ducts - Bottom Ash cooling devices
K - 2001 A/B	**ID fan**	Axial	Flowrate: 2 x 1660 x 10^3 Nm3/h Vol. Flow: 2 x 652 x 10^3 m3/h Power consumption: 2 x 5045 kW	2 x 6660 kWe				
PK - 2002	**Flue gas cleaning system**	ESP						
PK - 2003	**Flue gas stack**	cement stack						
PK - 2004	**Continuous emission monitoring system**							

	CLIENT: IEA GHG	REVISION	Rev. Draft	Rev. 0	Rev. 1	Rev. 2
FOSTER WHEELER	LOCATION: The Netherlands	DATE	June 13	Sept. 2013	January 2014	
	PROJ. NAME: CO_2 capture at coal based power and hydrogen plants	ISSUED BY	GP	GP	GP	
	CONTRACT N. 1-BD-0681 A	CHECKED BY	NF	NF	NF	
	CASE: 1 - SC PC without carbon capture	APPROVED BY	LM	LM	LM	

EQUIPMENT LIST
Unit 2000 - Boiler Island

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	SCR SYSTEM - UNIT 2050							
	SCR system Including: - Reactor casing - Catalyst - Bypass system - Ammonia injection equipment - Handling equipment - Control System							

Notes:
(1) Reference for boiler material selection:
A. Robertson, H. Agarwal, M. Gagliano, A. Seltzer, Oxy-combustion boiler material development, 35th International Technical Conference on Clean Coal & Fuel System, Clearwater, Florida (USA)

	CLIENT: IEA GHG	REVISION	Rev. Draft	Rev. 0	Rev. 1	Rev. 2
	LOCATION: The Netherlands	DATE	June 13	Sept. 2013	January 2014	
	PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	GP	GP	GP	
	CONTRACT N. 1-BD-0681 A	CHECKED BY	NF	NF	NF	
	CASE: 1 - SC PC without carbon capture	APPROVED BY	LM	LM	LM	

EQUIPMENT LIST

Unit 2100 - Flue Gas Desulphurization

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	FGD SYSTEM							
	Wet FGD system Including: - Limestone feeder - Absorber tower - Oxydation air blower - Make up water system - Limestone slurry preparation system - Reagent feed pump - Gypsum dewatering system - Miscellaneous equipment		Flue gas inlet flowrate:2766 x10^3 Nm3/h Removal efficiency: 92.1 %					
	GAS-GAS HEATER							
	Gas-gas heat exchanger		Hot side flowrate: 2766 x 10^3 Nm3/h Cold side flowrate: 2856 x 10^3 Nm3/h Duty: 42.9 MWth					

FOSTER WHEELER	CLIENT: IEA GHG	REVISION	Rev. Draft	Rev. 0	Rev. 1	Rev. 2
	LOCATION: The Netherlands	DATE	June 13	Sept. 2013	January 2014	
	PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	GP	GP	GP	
	CONTRACT N. 1-BD-0681 A	CHECKED BY	NF	NF	NF	
	CASE: 1 - SC PC without carbon capture	APPROVED BY	LM	LM	LM	

EQUIPMENT LIST

Unit 3000 - Steam Cycle

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	PACKAGES							
PK- 3001	**Steam Turbine and Generator Package**							
ST- 3001	Steam Turbine		1076 MWe *HP admission:* *2877 t/h @ 270 bar* *Hot reheat admission:* *2420 t/h @ 60 bar* *LP admission:* *2118 t/h @ 5.9 bar*					*Including:* *Lube oil system* *Cooling system* *Idraulic control system* *Drainage system* *Seals system* *Drainage system* *Electrical generator and relevant auxiliaries*
E- 3001 A/B	Inter/After Condenser							
E- 3002	Gland Condenser							
PK- 3002	**Steam Condenser Package**							*Including:*
E- 3001	Steam condenser	water cooled	1055 MWth					*Hot well* *Vacuum pump (or ejectors)* *Start up ejector (if required)*
PK- 3003	**Steam Turbine Bypass System**							*Including:* *MP dump tube* *LP dump tube* *HP/MP Letdown station* *MP Letdown station* *LP Letdown station*
PK- 3004	**Phosphate injection package**							
PK- 3005	**Oxygen scavanger injection package**							
PK- 3006	**Amines injection package**							

	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: 1 - SC PC without carbon capture	REVISION	Rev. Draft	Rev. 0	Rev. 1	Rev. 2
		DATE	June 13	Sept. 2013	January 2014	
		ISSUED BY	GP	GP	GP	
		CHECKED BY	NF	NF	NF	
		APPROVED BY	LM	LM	LM	

EQUIPMENT LIST
Unit 3000 - Steam Cycle

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	HEAT EXCHANGERS		**Duty (kW)**		Shell/tube	Shell/tube		
E- 3002	BFW Economiser #1		240080					
E- 3003	BFW Economiser #2		191335					
E- 3003	BFW Economiser #3		47180					
E- 3004	Condensate heater #1		73630					
E- 3005	Condensate heater #2		43915					
E- 3006	Condensate heater #3		91775					
E- 3006	Condensate heater #4		42050					
	PUMPS		**Q [m^3/h] x H [m]**					
P- 3001	BFW pumps	Centrifugal Steam driven	2877 m3/h x 3566 m	33000 kWe equivalent				*One operating*
P- 3002	BFW pump	Centrifugal	40% MCR					*For start-up, electric motor*
P- 3003 A/B	Condensate pump	Centrifugal	2540 m3/h x 170 m	1600				*One operating one spare, electric motor*
	VESSEL							
D- 3001	Dearator	Horizontal						

	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: 1 - SC PC without carbon capture	REVISION	Rev. Draft	Rev. 0	Rev. 1	Rev. 2
		DATE	June 13	Sept. 2013	January 2014	
		ISSUED BY	GP	GP	GP	
		CHECKED BY	NF	NF	NF	
		APPROVED BY	LM	LM	LM	

EQUIPMENT LIST
Unit 6000 - Utility units

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	COOLING SYSTEM		**Duty**					
CT - 6001	**Cooling Tower** including: Cooling water basin	Natural draft	1120 MWth Diameter: 150 m, Height: 210 m, Water inlet: 17 m				concrete	
	PUMPS		**Q [m3/h] x H [m]**					
P- 6001 A/.. /F	Cooling Water Pumps (primary system)	Centrifugal	15000 m3/h x 35 m	1600				*Six in operation*
P- 6002 A/B	Cooling Water Pumps (secondary system)	Centrifugal	5070 m3/h x 45 m	800				*One in operation, one spare*
P- 6003 A/B	Cooling tower make-up pumps	centrifugal	1700 m3/h x 30 m	220				*One in operation, one spare*
	PACKAGES **Cooling Water Filtration Package** Cooling Water Sidestream Filters		Capacity: 9500 m3/h					
	Sodium Hypochlorite Dosing Package Sodium Hypochlorite storage tank Sodium Hypochlorite dosage pumps							
	Antiscalant Package Dispersant storage tank Dispersant dosage pumps							
	RAW WATER SYSTEM		**Q [m3/h] x H [m]**					
T- 6001	Raw Water storage tank		2520 m3					*24 hour storage*
P- 6004 A/B	Raw water pumps to RO	centrifugal	10 m3/h x 50 m	50				*One in operation, one spare*
P- 6005A/B	Raw water pump to FGD (make-up)	centrifugal	95 m3/h x 40 m	18.5				*One in operation, one spare*

	CLIENT: IEA GHG	REVISION	Rev. Draft	Rev. 0	Rev. 1	Rev. 2
FOSTER WHEELER	LOCATION: The Netherlands	DATE	June 13	Sept. 2013	January 2014	
	PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	GP	GP	GP	
	CONTRACT N. 1-BD-0681 A	CHECKED BY	NF	NF	NF	
	CASE: 1 - SC PC without carbon capture	APPROVED BY	LM	LM	LM	

EQUIPMENT LIST
Unit 6000 - Utility units

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	DEMINERALIZED WATER SYSTEM		**Q [m3/h] x H [m]**					
PK- 6001	**Demin Water Package, including:**							
	- Multimedia filter							
	- Reverse Osmosis (RO) Cartidge filter							
	- Electro de-ionization system							
T- 6002	Demin Water storage tank		120 m3					*24 hour storage*
P- 6005A/B	Demin water pump to Power Island (make-up)	centrifugal	5 m3/h x 40 m	3.5				*One in operation, one spare*
	FIRE FIGHTING SYSTEM							
T- 6003	Fire water storage tank							
	Fire pumps (diesel)							
	Fire pumps (electric)							
	FW jockey pump							
	OTHER UTILITIES							
	Plant air compression skid							
	Emergency diesel generator system							
	Waste water treatment							
	Electrical equipment							
	Buildings							
	Auxiliary boiler							
	Condensate polishing system							

CLIENT	:	IEAGHG
PROJECT NAME	:	CO_2 CAPTURE AT COAL FIRED POWER PLANTS
DOCUMENT NAME	:	CASE 2: SC PC WITH CCS
FWI CONTRACT	:	1-BD-0681 A

ISSUED BY	:	G. PERFUMO
CHECKED BY	:	N. FERRARI
APPROVED BY	:	L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

1. Introduction

This chapter of the report includes all technical information relevant to Case 2 of the study, which is a supercritical pulverised coal (SC PC) fired steam plant with amine-based solvent washing for carbon capture. The plant is designed to process coal, whose characteristic is shown in chapter B, and produce electric power for export to the external grid.

The configuration of the SC PC plant is based on one once-through steam generator, with superheating and single steam reheating, and a steam turbine generator. Plant is designed with the same thermal capacity of the reference case without carbon capture (refer to chapter C.1 of this report).

The description of the main process units is covered in chapter C of this report, so only features that are unique to this case are discussed in the following sections, together with the main modelling results.

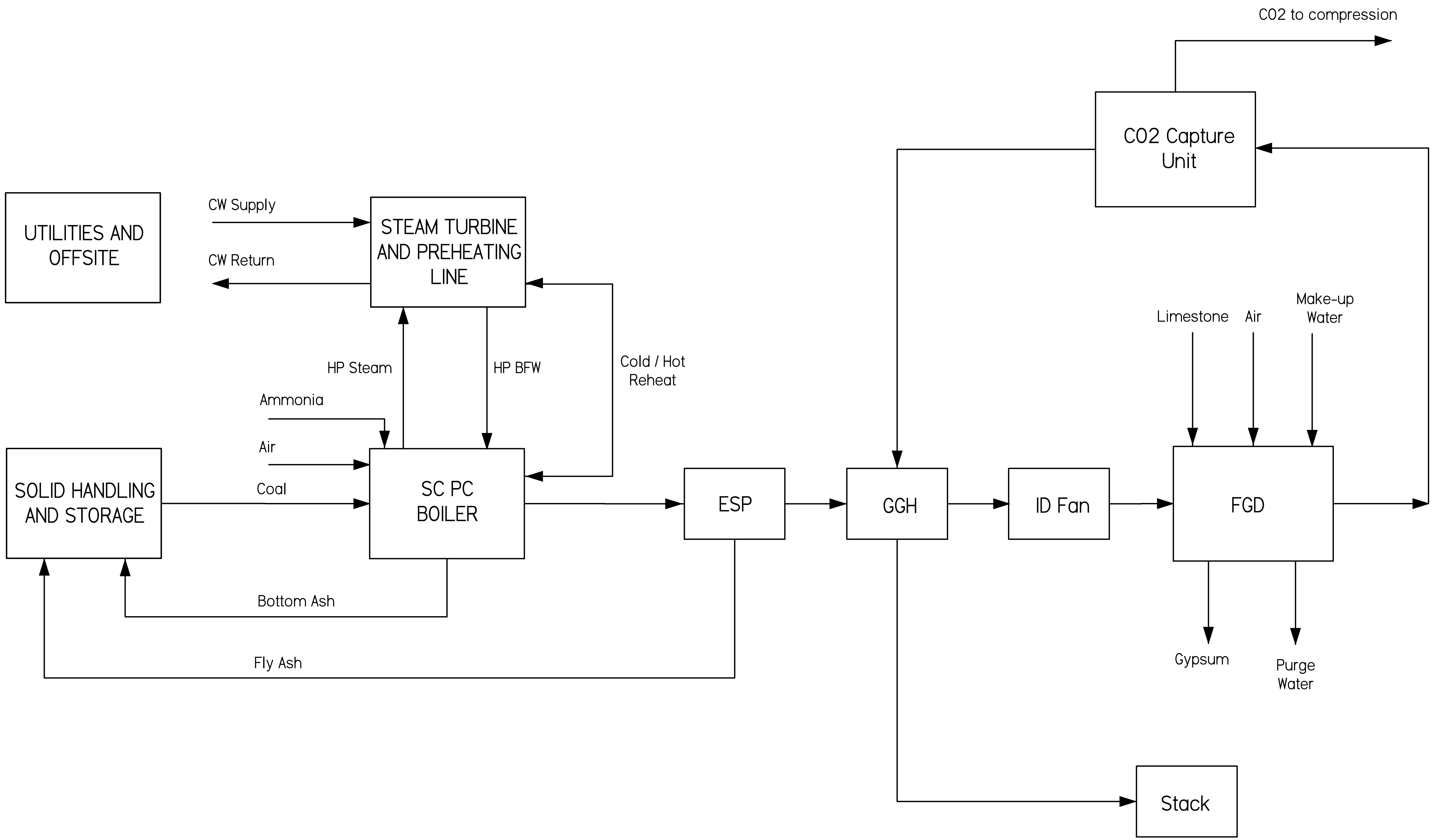
1.1. Process unit arrangement

The arrangement of the main units is reported in the following Table 1. Reference is also made to the block flow diagram attached below.

Table 1. Case 2 – Unit arrangement

Unit	Description	Trains
1000	Storage and Handling of solid materials	N/A
2000	SC PC supercritical boilers	1 x 100%
	Electro Static precipitators	1 x 100%
2050	Flue Gas Denitrification (DeNOx) – SCR system	1 x 100%
2100	Flue Gas Desulphurisation (FGD)	1 x 100%
4000	Steam Cycle (SC)	
	Steam Turbine and Condenser	1 x 100%
	Deaerator	1 x 100%
	Water Preheating line	1 x 100%
4000	CO_2 Amine Absorption Unit	
	Flue gas quencher	2 x 50%
	Absorber	2 x 50%
	Regenerator	2 x 50%

Unit	Description	Trains
5000	CO_2 compression	2 x 50%
6000	Utility and Offsite	N/A



0	July 13	Draft	GP	LM	**UNIT:** Block Flow Diagram	
Rev.	Date	Comment	By	Appr	**CASE:** 2	Sheet 01 of 01

2. Process description

2.1. Overview

The description reported in this section makes reference to the simplified Process Flow Diagrams (PFD) shown in Section 3, while stream numbers refer to Section 4, which provides heat and mass balance details for the numbered streams in the PFD.

2.2. Unit 1000 – Feedstock and Solid Handling

The unit is composed of the following systems:

- Coal storage and handling
- Limestone storage and handling
- Ashes collection and storage
- Gypsum storage and handling

The general description relevant to this unit is reported in chapter C, section 2.1. Main process information of this case and the interconnections with the other units is shown in the relevant process flow diagram and the heat and mass balance table.

2.3. Unit 2000 – Boiler Island

This unit is mainly composed of the Boiler and the Selective Catalytic Reactor (SCR) system. Technical information relevant to these packages is reported in Chapter C, sections 2.2 and 2.3 respectively.

Main process information of this case and interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

2.4. Unit 2100 – Flue Gas Desulphurization

This unit is mainly composed of the FGD and the gypsum dehydration systems. For this Case 2 with carbon capture, higher desulphurisation efficiency is required from the FGD system of the plant, so to limit solvent degradation in the downstream absorber washing column to the maximum extent. The FGD plant is designed to meet a SO_2 concentration in the flue gas of 10 ppmv (dry, 6%O_2), corresponding to a SO_2 removal efficiency of approximately 98.5%. The SO_3 emissions are reduced to the minimum with respect to the Wet FGD capability, thus corresponding to 13 ppmv (dry, 6%O_2) at the FGD outlet.

Alstom wet scrubbing technology was selected for the development of this study case. Technical information relevant to this system is reported in chapter C, section 2.4.1. The impact of a different FGD technology and supplier is also summarised in chapter C, section 2.4.4.

Main process information of this case and interconnections with the other units is shown in the relevant process flow diagram and the heat and mass balance table.

Gas-gas heat exchanger

Saturated flue gases from top of the absorber in the post-combustion unit are heated-up, before discharge from the stack to ensure proper flue gas dispersion and avoid water condensation. Hot flue gases from the boiler air pre-heater are used as heating medium before entering the FGD absorber. The gas-gas heater is a very expensive equipment representing around 25-30% of the total FGD unit installed cost.

2.5. Unit 3000 – Steam Cycle

The steam cycle is mainly composed of one supercritical Steam Turbine Generator (STG), water-cooled condenser and the water pre-heating line. General description relevant to this unit is reported in chapter C, section 2.7.2.

Main process information of this case and interconnections with the other units are shown in the block flow diagram and in the heat and mass balance tables.

2.6. Unit 4000 – CO_2 Amine Absorption

This unit is mainly composed of flue gas quencher, CO_2 absorption column and amine regenerator. Cansolv technology was considered for the development of this study case. Technical information relevant to this system is reported in chapter C, section 2.5.1.

Main process information of this case and interconnections with the other units are shown in the block flow diagram and in the heat and mass balance tables.

2.7. Unit 5000 – CO_2 Compression and drying

The process description of CO_2 Compression and drying package is reported in chapter C, section 2.6. Main process information of this case and interconnections with the other units are shown in the block flow diagram and in the heat and mass balance tables.

2.8. Unit 6000 - Utility Units

These units comprise all the systems necessary to allow the operation of the plant and the export of the produced power.

The main utility units include:

- Cooling Water system, based on two natural draft cooling tower, with the following characteristics:

Basin diameter	120 m
Cooling tower height	210 m
Water inlet height	17 m

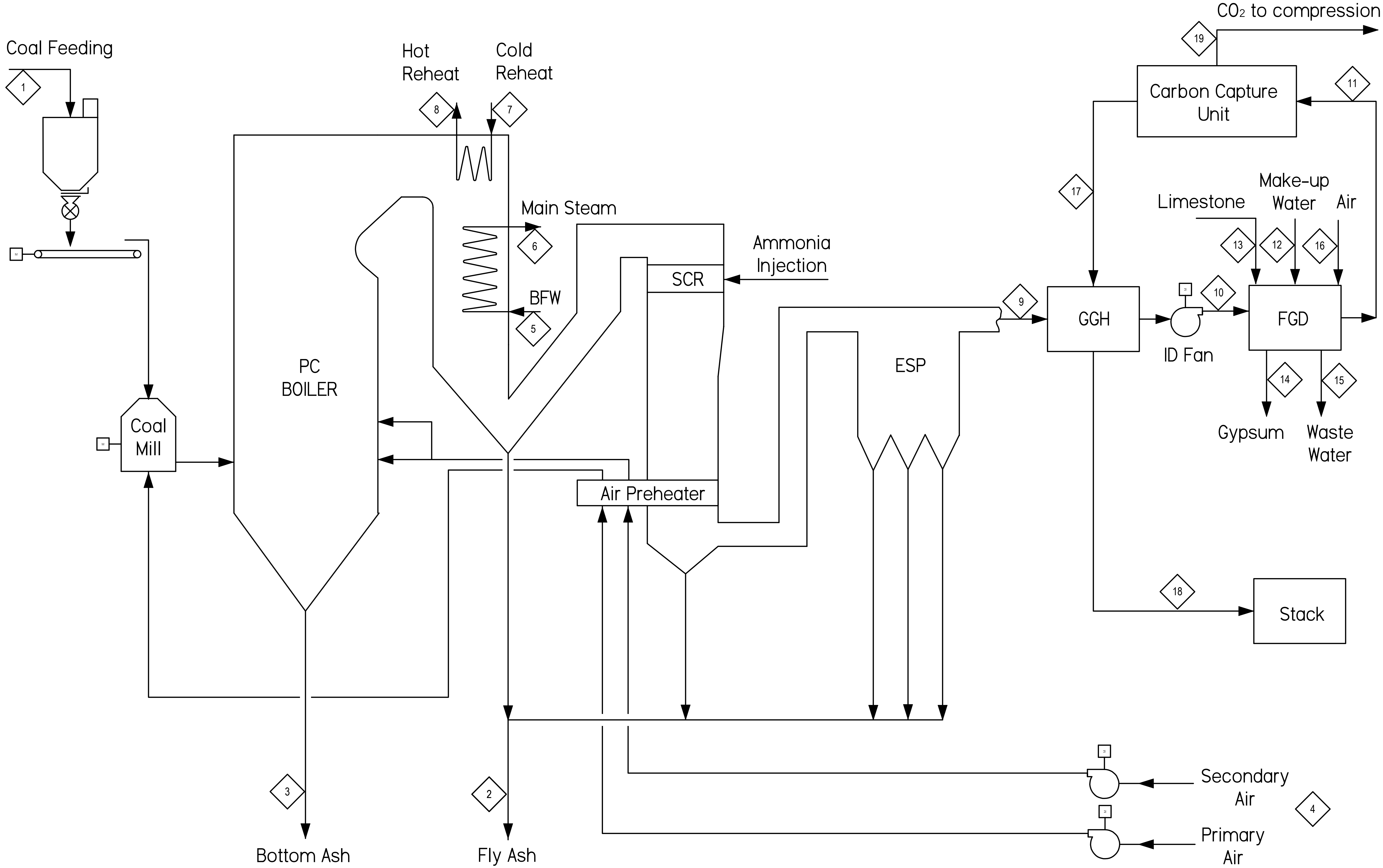
- Raw water system;

- Demineralised water plant;
- Fire fighting system;
- Instrument and Plant air.

Process descriptions of the above systems are enclosed in chapter C, section 2.8.

3. Process Flow Diagrams

Simplified Process Flow Diagrams of this case are attached to this section. Stream numbers refer to the heat and material balance shown in the next section.



1	Sept. 13	Rev 0	NF	LM	
0	July 13	Draft	GP	LM	**UNIT:** Boiler Island
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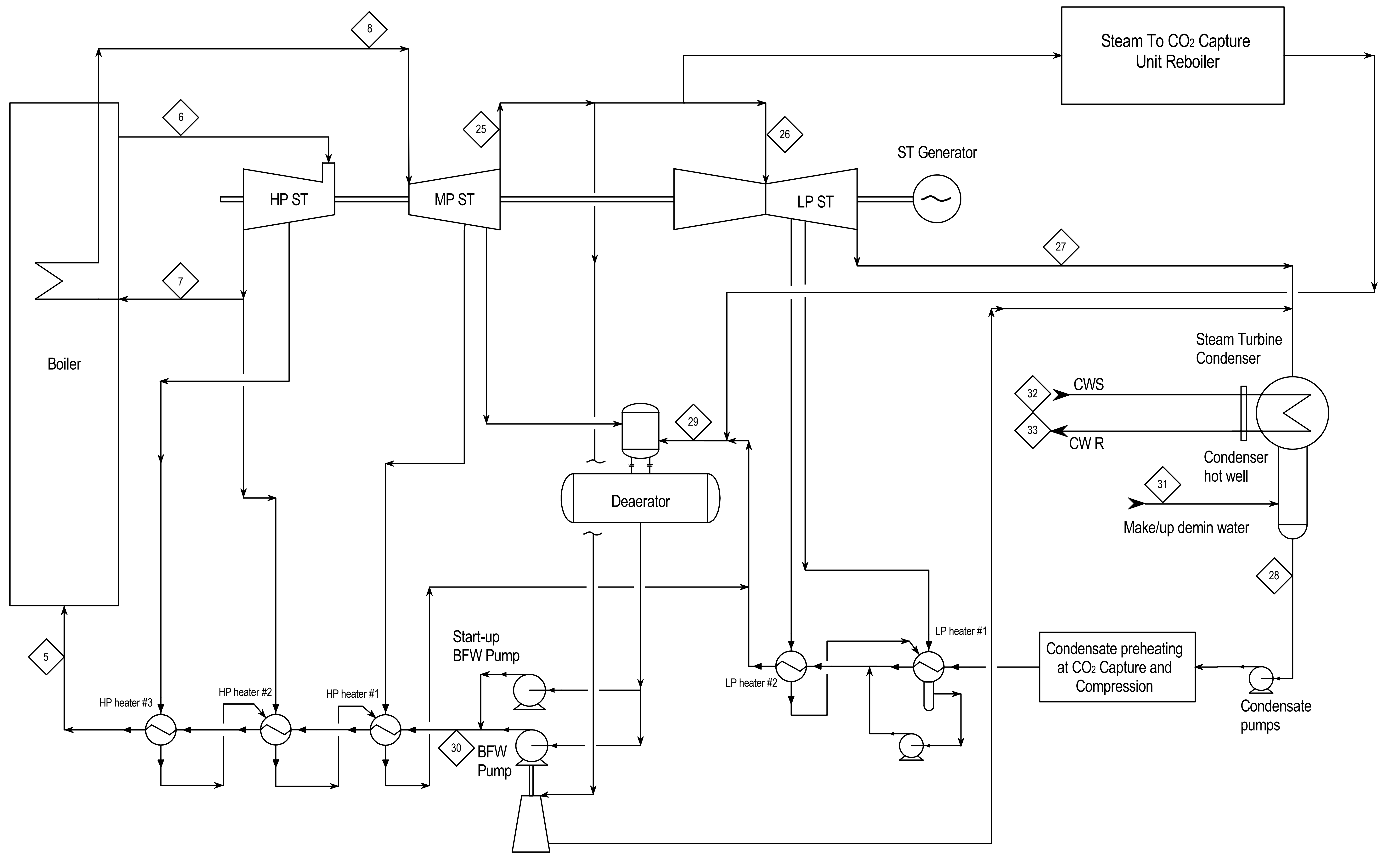
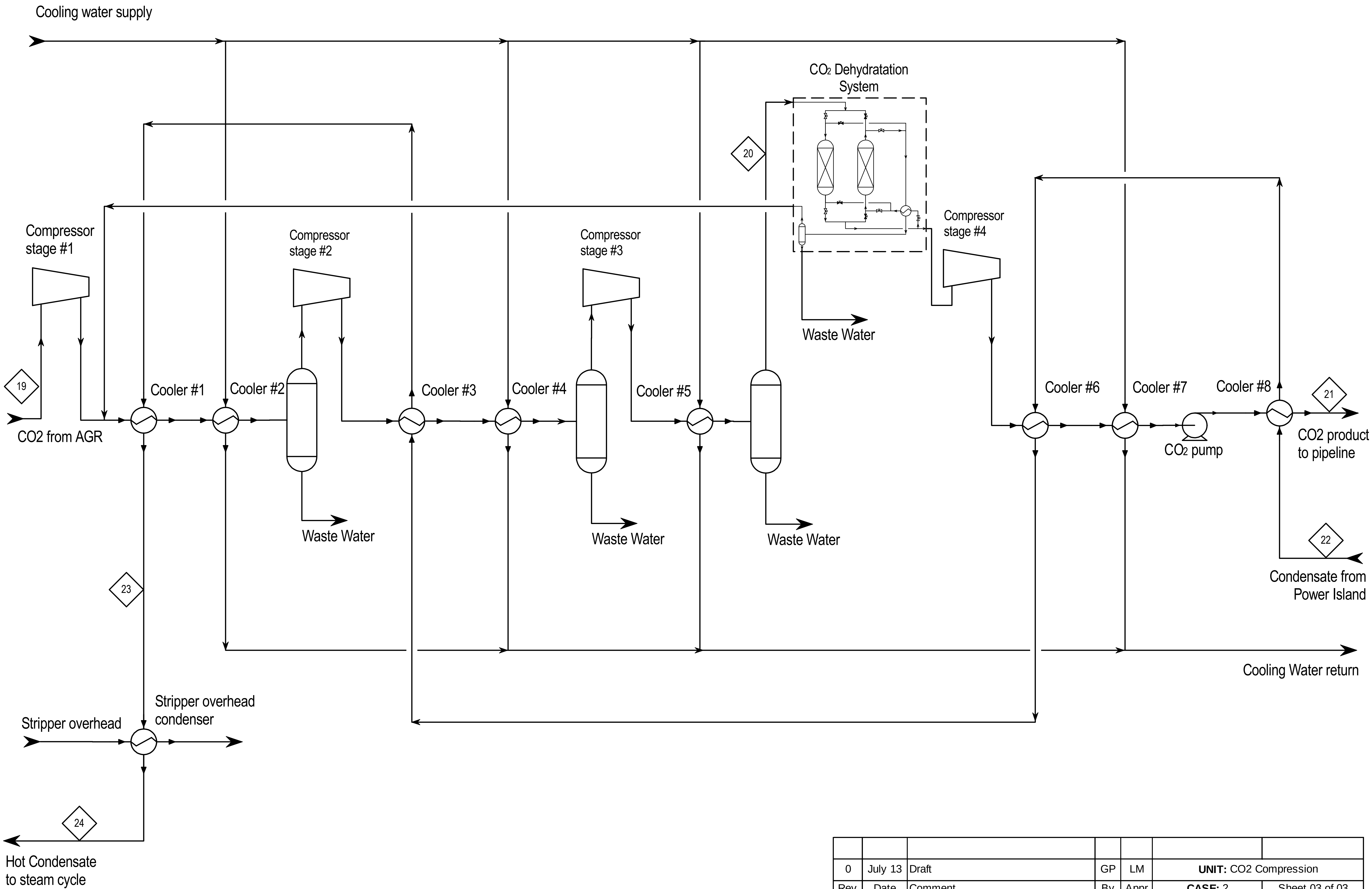


1	Sept. 13	Rev 0	NF	LM		
0	July 13	Draft	GP	LM	**UNIT:** Steam Cycle	
Rev.	Date	Comment	By	Appr	**CASE:** 2	Sheet 02 of 03



0	July 13	Draft	GP	LM	**UNIT:** CO2 Compression	
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4. Heat and Material Balance

Heat & Material Balances here below reported make reference to the Process Flow Diagrams of section 3.

	Case 2 - SC PC with CCS - HEAT AND MATERIAL BALANCE		REVISION	draft	0	
	CLIENT :	IEA GHG	PREP.	GP	GP	
	PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	CHECKED	NF	NF	
	PROJECT NO:	1-BD-0681 A	APPROVED	LM	LM	
	LOCATION:	The Netherlands	DATE	July 13	Sept. 13	

HEAT AND MATERIAL BALANCE
UNIT 2000 - BOILER ISLAND

STREAM	1	2	3	4	5	6	7	8		
	Coal to Boiler Island	Fly Ash	Bottom Ash	Air intake from Atmosphere	BFW from steam cycle	HP Steam to Steam Turbine	Cold Reheat from UNIT 3000	Hot Reheat to Steam Turbine		
Temperature (°C)	AMB	AMB	AMB	9	290	600	366	620		
Pressure (bar)	AMB	ATM	ATM	1.013	324	270	63	60		
TOTAL FLOW	Solid									
Mass flow (kg/h)	325,000	29,200	12,500	3,383,000	2,868,000	2,868,000	2,456,000	2,456,000		
Molar flow (kmol/h)				117,250	159,245	159,245	136,369	136,369		
LIQUID PHASE										
Mass flow (kg/h)					2,868,000					
GASEOUS PHASE										
Mass flow (kg/h)				3,383,000		2,868,000	2,456,000	2,456,000		
Molar flow (kmol/h)				117,250		159,245	136,369	136,369		
Molecular Weight				28.85		18.01	18.01	18.01		
Composition (vol %)	%wt									
H_2				0.00%	0.00%	0.00%	0.00%	0.00%		
CO	C: 64.6%			0.00%	0.00%	0.00%	0.00%	0.00%		
CO_2	H: 4.38%			0.03%	0.00%	0.00%	0.00%	0.00%		
N_2	O: 7.02%			77.27%	0.00%	0.00%	0.00%	0.00%		
O_2	S: 0.86%			20.73%	0.00%	0.00%	0.00%	0.00%		
CH_4	N: 1.41%			0.00%	0.00%	0.00%	0.00%	0.00%		
Ar	Cl: 0.03%			0.92%	0.00%	0.00%	0.00%	0.00%		
SO_2	Moisture: 9.5%			0.00%	0.00%	0.00%	0.00%	0.00%		
H_2O	Ash: 12.20%			1.05%	100.00%	100.00%	100.00%	100.00%		
Total				100.00%	100.00%	100.00%	100.00%	100.00%		
Emissions (mg/Nm^3, dry basis 6% vol O_2)										
SOx				-	-	-	-	-		
NOx				-	-	-	-	-		
particulate				-	-	-	-	-		

FOSTER WHEELER	Case 2 - SC PC with CCS - HEAT AND MATERIAL BALANCE		REVISION	draft	0	
	CLIENT :	IEA GHG	PREP.	GP	GP	
	PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	CHECKED	NF	NF	
	PROJECT NO:	1-BD-0681 A	APPROVED	LM	LM	
	LOCATION:	The Netherlands	DATE	July 13	Sept. 13	

HEAT AND MATERIAL BALANCE
UNIT 2100 - FGD

STREAM	9	10	11	12	13	14	15	16		
	Flue Gas from ESP to GGH	Flue Gas to FGD	Treated gas from FGD	Make up Water	Limestone to FGD	Product Gypsum	Waste water from FGD	Oxidation Air		
Temperature (°C)	132	90	47	15	AMB	AMB	AMB	AMB		
Pressure (bar)	-	-	-	ATM	ATM	ATM	ATM	ATM		
TOTAL FLOW					Solid	Solid				
Mass flow (kg/h)	3,667,000	3,667,000	3,741,000	85,000	9,200	16,900	7,800	9,100		
Molar flow (kmol/h)	123,412	123,412	127,470	4,720			433	315		
LIQUID PHASE										
Mass flow (kg/h)				85,000			7,800			
GASEOUS PHASE										
Mass flow (kg/h)	3,667,000	3,667,000	3,741,000					9,100		
Molar flow (kmol/h)	123,412	123,412	127,470					315		
Molecular Weight	29.71	29.71	29.3					28.85		
Composition (vol %)										
H_2	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%		
CO_2	14.06%	14.06%	13.68%	0.00%			0.00%	0.03%		
N_2	73.56%	73.56%	71.40%	0.00%			0.00%	77.27%		
O_2	3.28%	3.28%	3.20%	0.00%			0.00%	20.73%		
CH_4	0.00%	0.00%	0.00%	0.00%			0.00%	0.00%		
Ar	0.87%	0.87%	0.84%	0.00%			0.00%	0.92%		
SO_2	0.07%	0.07%	0.00%	0.00%			0.00%	0.00%		
H_2O	8.16%	8.16%	10.88%	100.00%			100.00%	1.05%		
Total	100.00%	100.00%	100.00%	100.00%			100.00%	100.00%		
Emissions (mg/Nm^3, dry basis 6% vol O_2)										
SOx	1897	1897	SO_2: 10 ppm SO_3: 13 ppm	-	-	-	-	-		
NOx	130	130	130	-	-	-	-	-		
particulate	10	10	10	-	-	-	-	-		

NOTE
1. Air in-leakage are included in the flue gas streams

Case 2 - SC PC with CCS - HEAT AND MATERIAL BALANCE		**REVISION**	draft	0
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PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	**CHECKED**	NF	NF
PROJECT NO:	1-BD-0681 A	**APPROVED**	LM	LM
LOCATION:	The Netherlands	**DATE**	July 13	Sept. 13

HEAT AND MATERIAL BALANCE
UNIT 4000 and 5000 - CO2 CAPTURE AND COMPRESSION

STREAM	**11**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
	Feed Gas to CCU	**Treated Gas to GGH**	**Flue Gas to Stack**	**Carbon Dioxide to Compression**	**CO2 to drying package**	**CO2 to long term Storage**	**Condensate from Power Island**	**Preheated Condensate to Stripper Condenser**	**Preheated Condensate to Power Island**
Temperature (°C)	47	43	95	30	26	30	29	60	74
Pressure (bar)	-	-	-	2.0	30.3	110.0	14.5	14.0	13.5
TOTAL FLOW									
Mass flow (kg/h)	3,741,000	2,924,000	2,924,000	701,000	770,205	690,900	1,310,000	1,310,000	1,310,000
Molar flow (kmol/h)	127,470	107,502	107,502	16,075	17,520	15,700	72,713	72,713	72,713
LIQUID PHASE						supercritical state			
Mass flow (kg/h)						692,000	1,310,000	1,310,000	1,310,000
GASEOUS PHASE									
Mass flow (kg/h)	3,741,000	2,924,000	2,924,000	701,000	770,205				
Molar flow (kmol/h)	127,470	107,502	107,502	16,075	17,520				
Molecular Weight	29	27.2	27.2	43.6	44.0				
Composition (vol %)									
H_2	0.00%	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%	0.00%
CO_2	13.68%	1.58%	1.58%	97.90%	99.82%	100.00%	0.00%	0.00%	0.00%
N_2	71.40%	84.66%	84.66%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
O_2	3.20%	4.13%	4.13%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CH_4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ar	0.84%	1.00%	1.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
SO_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
H_2O	10.88%	8.62%	8.62%	2.10%	0.18%	0.00%	100.00%	100.00%	100.00%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Emissions (mg/Nm^3, dry basis 6% vol O_2)									
SOx	SO2: 10 ppm SO3: 13 ppm	< 1 ppm	< 1 ppm	-	-	-			
NOx	130	150	150	-	-	-			
particulate	10	10	10	-	-	-			

FOSTER WHEELER

Case 2 - SC PC with CCS - H&M BALANCE	**Revision**	draft	0
CLIENT: IEA GHG	**Prepared**	GP	GP
PROJECT NAME: CO2 capture at coal based power and H2 plants	**Checked**	NF	NF
PROJECT NO: 1-BD-0681 A	**Approved**	LM	LM
LOCATION: The Netherlands	**Date**	July 13	Sept. 13

HEAT AND MATERIAL BALANCE

UNIT 3000 - STEAM CYCLE

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
6	HP Water to Boiler Island	2,868	290	323	1278
7	HP Steam from Boiler	2,868	600	270	3475
8	Cold Reheat to Boiler	2,456	366	63.0	3081
9	Hot Reheat to MP Steam Turbine	2,456	620	60.0	3706
25	MP Steam Turbine exhaust	2,105	275	5.5	3011
26	Steam to LP Steam Turbine	1,252	275	5.4	3012
27	Exhaust from LP Steam Turbine	1,130	29	0.04	2292
28	Condensate	1,310	29	0.04	121
29	LP Preheated Condensate	2,910	143	9.5	602
30	BFW to preheating	2,957	156	325	678
31	Make up Water	5	9	0.04	38
32	Cooling Water Inlet	60,752	15	4.0	63
33	Cooling Water Outlet	60,752	26	3.5	109

5. Utility and chemicals consumption

Main utility consumption of the process and utility units is reported in the following tables. More specifically:

- Water consumption summary is reported in Table 2,
- Electrical consumption summary is shown in Table 3,
- Sorbent and chemicals consumption, shown in Table 4.

Table 2. Case 2 – Water consumption summary

CLIENT:	IEAGHG	REVISION	0
PROJECT NAME:	CO2 capture at coal based power and H2 plants	DATE	Jul-13
PROJECT No. :	1-BD-0681 A	MADE BY	GP
LOCATION :	The Netherlands	APPROVED BY	LM

Case 2 - Water consumption

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water 1° syst. [DT = 11°C] [t/h]	Cooling Water 2° syst. [DT = 11°C] [t/h]
1000	FEEDSTOCK AND SOLID HANDLING				
	Solid Receiving, Handling and storage				
2000	BOILER ISALND and FLUE GAS TREATMENT				
	Boiler island				
	Flue Gas Desulphurization (Wet FGD)	85			
500	POWER ISLAND (Steam Turbine)				
	Condenser			60800	
	Miscellanea		5		4420
BoP	UTILITY and OFFSITE UNITS				
	Cooling Water System	2170			
	Demineralized/Condensate Recovery/Plant and Potable Water Systems	10	-7		
	Waste Water Treatment	-170.0			
	Miscellanea				100
	CO2 CAPTURE UNIT				
4000	CO2 capture unit		2		53070
5000	CO2 compression				
	BALANCE	2095	0.0	60800	57590

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

Table 3. Case 2 – Electrical consumption summary

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	**DATE**	Jul-13
PROJECT No. :	1-BD-0681 A	**MADE BY**	GP
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 2 - Electrical consumption

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
1000	**FEEDSTOCK AND SOLID HANDLING**	
	Solids Handling	3350
2000	**BOILER ISLAND and FLUE GAS TREATMENT**	
	Boiler island (including ID fan)	22370
	Flue Gas Desulphurization (FGD)	4000
3000	**POWER ISLAND (Steam Turbine)**	
	Steam Turbine Auxiliaries and condenser	3300
	Condensate pump and feedwater system	920
	Miscellanea	600
	CO2 CAPTURE UNIT	
4000	CO2 capture unit	82230
5000	CO2 Compression	
BoP	**UTILITY and OFFSITE UNITS**	
	Cooling Water System	15020
	Other Units	1440
	BALANCE	**133,230**

Table 4. Case 2 – Sorbent and chemicals consumption

	Consumption
Limestone injection to the FGD	9.21 t/h
Ammonia solution to SCR (1)	4.72 t/h
NaOH to CO_2 capture unit (2)	200 kg/h

(1) 25%wt ammonia solution

(2) 50%wt. FWI estimate

6. Overall Performance

The following table shows the overall performance of Case 2.

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	**DATE**	Jul-13
PROJECT No. :	1-BD-0681 A	**MADE BY**	GP
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 2 - SC PC Plant with carbon capture Performance Summary

OVERALL PERFORMANCES		
Fuel flow rate (A.R.)	t/h	325.0
Fuel HHV (A.R.)	kJ/kg	27060
Fuel LHV (A.R.)	kJ/kg	25870
THERMAL ENERGY OF FEEDSTOCK (based on LHV) (A)	**MWth**	**2335**
THERMAL ENERGY OF FEEDSTOCK (based on HHV) (A')	**MWth**	**2443**
Steam turbine power output (@ gen terminals)	MWe	958.1
GROSS ELECTRIC POWER OUTPUT (C) (1)	**MWe**	**958.1**
Boiler Island	MWe	26.4
Utility & Offsite Units consumption	MWe	16.5
Power Islands consumption (note 1)	MWe	4.8
CO2 Capture and compression unit	MWe	82.2
Feedstock and solids handling	MWe	3.3
ELECTRIC POWER CONSUMPTION	**MWe**	**133.2**
NET ELECTRIC POWER OUTPUT	**MWe**	**824.9**
(Step Up transformer efficiency = 0.997%) (B)	MWe	822.4
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**41.0%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**35.2%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**39.2%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**33.7%**
Fuel Consumption per net power production	**MWth/MWe**	**2.84**
CO_2 emission per net power production	**kg/MWh**	**93.0**

(1) Steam driven BFW pumps are included

The following Table shows the overall CO_2 balance and removal efficiency of Case 2.

CO_2 removal efficiency	**Equivalent flow of CO_2** kmol/h
INPUT	
FUEL CARBON CONTENT (A)	17495
FROM the DeSOX reaction + CO_2 in air (B)	109
OUTPUT	
Carbon losses (D)	166
CO_2 flue gas content	17438
Total to storage (C)	15700
Emission	1738
TOTAL	17604
Overall Carbon Capture, % ((C+D)/(A+B))	90.1

7. Environmental impact

The SC PC steam plant design is based on advanced technologies that allow to reach high electrical generation efficiency, while minimizing impact to the environment. Main gaseous emissions, liquid effluents and solid wastes from the plant are summarized in the following sections.

7.1. Gaseous emissions

During normal operation at full load, the main continuous emissions are the flue gases from the top of the absorber. Table 5 summarizes the expected flue gas flow rate and composition.

Minor and fugitive emissions are related to the milling, storage and handling of solids (e.g. solid transfer, leakage). As summarised in Table 6 these emission mainly consists of air containing particulate.

Table 5. Case 2 – Plant emission during normal operation

Flue gas to stack	
Emission type	Continuous
Conditions	
Wet gas flowrate, kg/h	2,977,000
Flow, Nm^3/h (1)	2,410,000
Temperature, °C	95
Composition	(% vol)
Ar	1.00
N_2	84.66
O_2	4.13
CO_2	1.58
H_2O	8.62
Emission	
NOx	< 150 mg/Nm^3 (1)
SOx	< 1 ppmv (1)
Particulate	< 10 mg/Nm^3 (1)

(1) Dry gas, O_2 content 6% vol.

Table 6. Case 2 – Plant minor emission

Emission source	**Emission type**	**Temperature**	
Coal milling and feed system	Continuous	ambient	Air: 10 mg/Nm^3 particulate
Limestone milling and preparation	Intermittent	ambient	Air: 10 mg/Nm^3 particulate
Gypsum handling and de-hydration	Intermittent	ambient	Air: 10 mg/Nm^3 particulate
Ash storage and transfer	Intermittent	ambient	Air: 10 mg/Nm^3 particulate

7.2. Liquid effluents

The plant does not produce significant liquid waste. Plant blow-downs (e.g. FGD, CO_2 capture unit) are treated to recover water, so main liquid effluent is cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids.

Cooling Tower blow-down

Flowrate : 518.5 m^3/h

FGD blow-down

Flowrate : 10 m^3/h

7.3. Solid effluent

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

Fly ash from boiler

Flowrate : 29.2 t/h

Bottom ash from boiler

Flowrate : 12.5 t/h

Fly and bottom ash might be sold to cement industries, if local market exist, or sent to disposal.

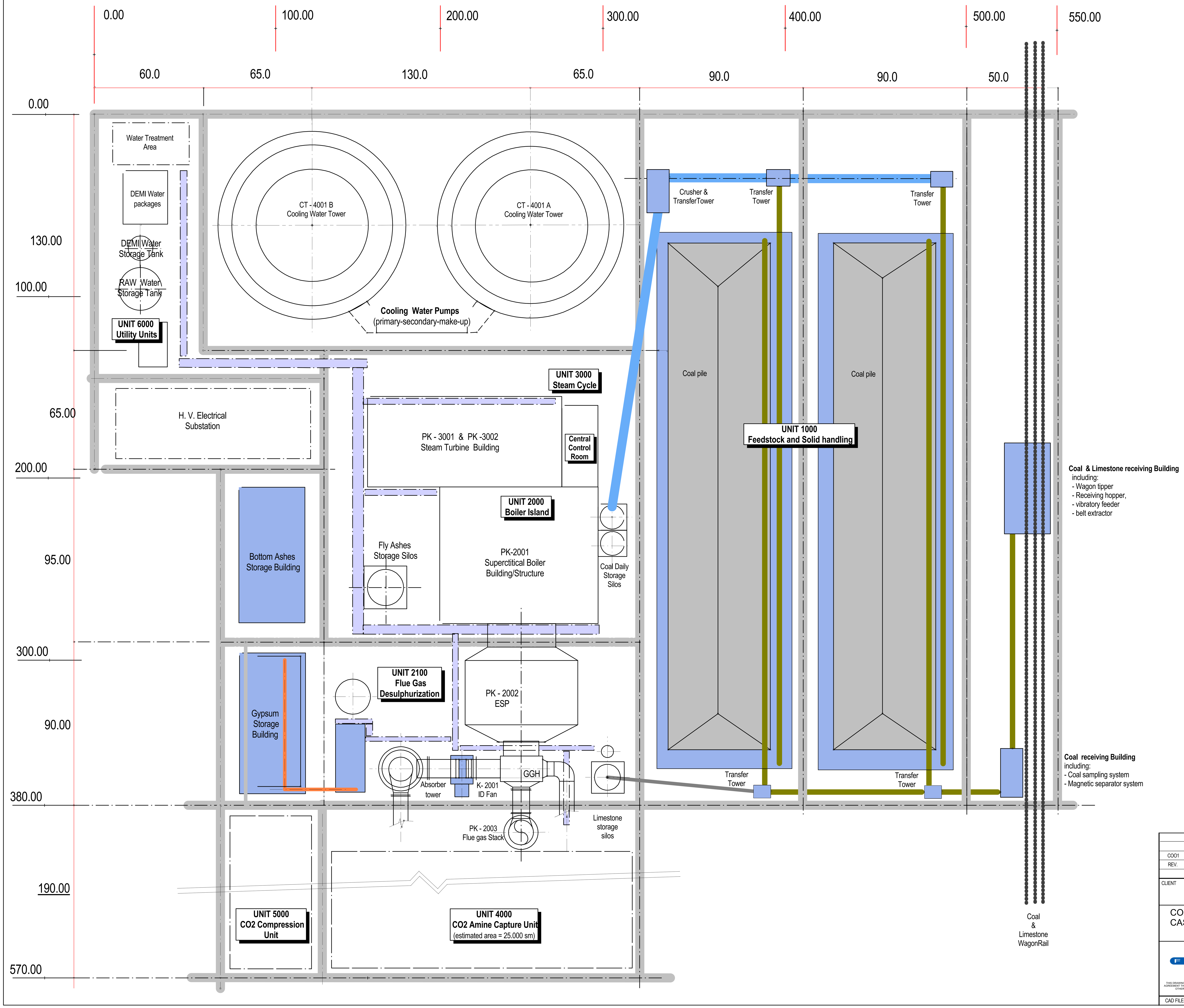
Solid gypsum from FGD

Solid gypsum, produced in de-hydrated form in the FGD system, can be sold in the market.

Flowrate : 16.9 t/h
Moisture content : 10%wt

8. Preliminary plot plan

Plot plan at block level of Case 2 is attached to this section, showing the area occupied by the main units and equipment of the plant.



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COO1	AUG. 2013	Preliminary issue for comments	APeccati			

DESCRIPTION

CLIENT IEA GHG

SITE The Netherlands

CO2 Capture and coal fired Power Plants
CASE: 2 - SC PC with carbon capture
PRELIMINARY PLOT PLAN

FOSTER WHEELER

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ORDER N°
SUPPLIER
CONTRACT N°
FRAME N°
CLIENT DWG N°
SHEET SHEET
SCALE N. A.
FWI DWG N° 1BD0681A - 01 - 002
REV. COO1
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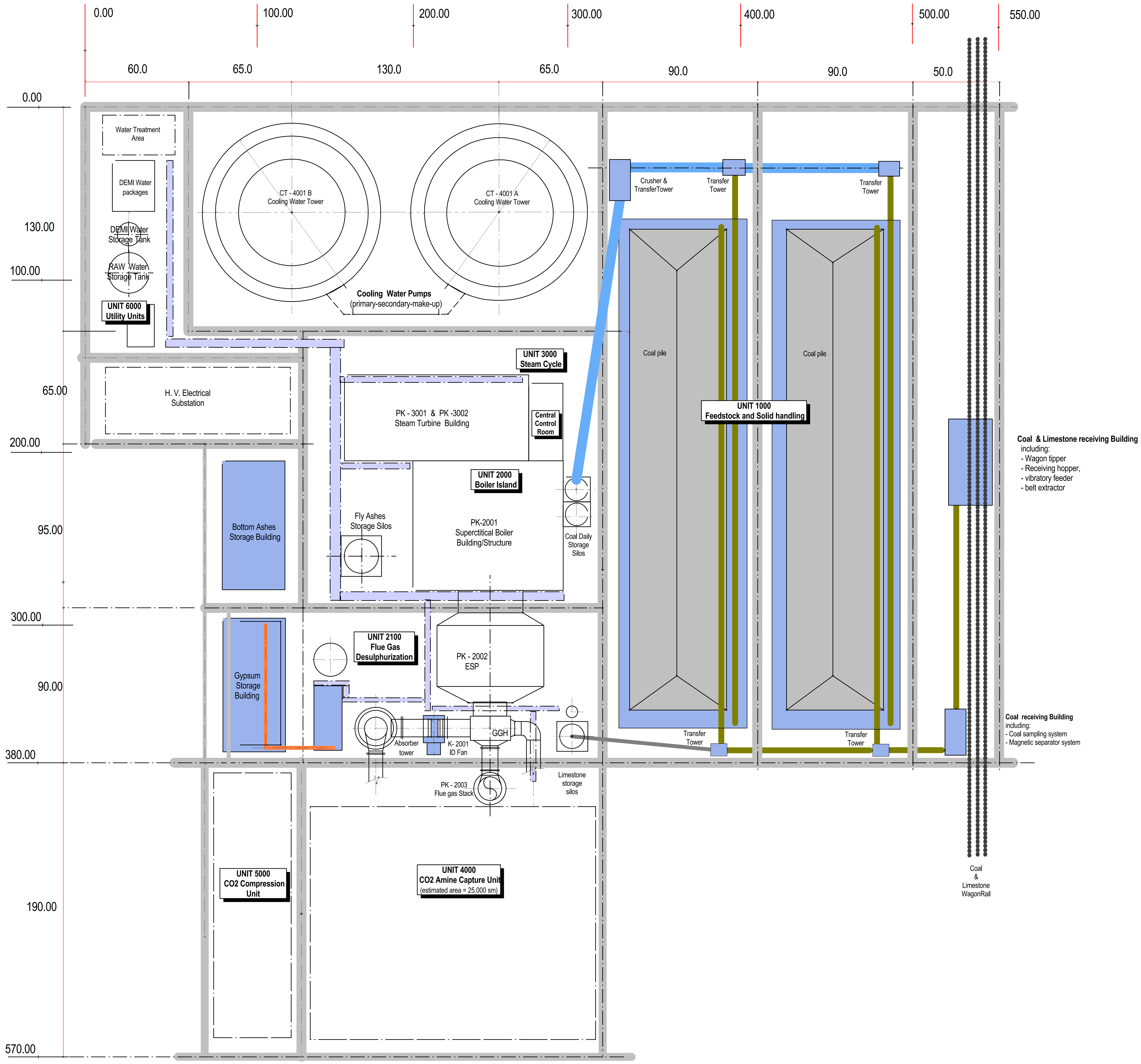

REV.	DATE	DESCRIPTION	DRAW	BY	CHD.	APP.
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DESCRIPTION

CLIENT IEA GHG

SITE The Netherlands

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CASE: 2 - SC PC with carbon capture
PRELIMINARY PLOT PLAN

ORDER N°
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FRAME N°

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SHEET SHEET
SCALE N. A.

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9. Equipment list

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

CLIENT:	IEA GHG	REVISION	Rev.: Draft	Rev. 0	Rev. 1	Rev. 2
LOCATION:	The Netherlands	DATE	Jun-13	January 2014		
PROJ. NAME:	CO2 capture at coal based power and hydrogen plants	ISSUED BY	GP	GP		
CONTRACT N.	1-BD-0681 A	CHECKED BY	NF	NF		
CASE:	2 - SC PC with carbon capture	APPROVED BY	LM	LM		

EQUIPMENT LIST

Unit 1000 - Feedstock and Solid handling

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	COAL HANDLING SYSTEM							
	Including:		Coal flowrate to boiler: 325 t/h					*30 days storage*
	- Wagon tipper							*Storage piles: 2 x 128,000 t each*
	- Receiving Hopper, vibratory feeder and belt extractor							
	- Conveyors	Belt						
	- Transfer Towers	enclosed						
	- As-Received Coal Sampling System	Two - Stage						
	- As-Received Magnetic separator System	Magnetic Plates						
	- Conveyors	Belt						
	- Transfer Towers	enclosed						
	- Cruscher Tower	Impactor reduction						
	- As-Fired Coal Sampling System	Swing hammer						
	- As-Fired Magnetic separator System	Magnetic Plates						
	- Coal Silos		2 x 4900 m3					*For daily storage*
	- Filters							
	- Fan							
	LIMESTONE HANDLING SYSTEM							
	Including:		Limestone flowrate to FGD: 9.2 t/h					
	- Wagon tipper		Limestone Storage volume: 6000 m3					*30 days storage*
	- Receiving Hopper, vibratory feeder and belt extractor							
	- Conveyor	Belt						
	- Transfer Tower	enclosed						
	- Conveyor	Belt						
	- Limestone Sampling System	Swing Hammer						
	- Separator System	Magnetc Plates						
	- Transfer Tower	enclosed						
	- Conveyor	Belt with tipper						
	- Limestone Mills							
	- Limestone Silos		1 x 200 m3					*For daily storage*
	- Filters							
	- Fan							

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	PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	GP	GP		
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	CASE: 2 - SC PC with carbon capture	APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 1000 - Feedstock and Solid handling

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	ASH SYSTEM							
	Including: - Ash storage silos - Ash conveyors - Bottom ash crusher - Pneumatic conveying system - Compressors - Filters - Fans		Bottom Ash Capacity: 12.5t/h Bottom Ash Storage volume: 6000 m3 Fly Ash Capacity: 29.2 t/h Fly Ash Storage volume: 14000 m3					 *14 days storage capacity* *14 days storage capacity*
	GYPSUM SYSTEM							
	Including: - Storage unit - Conveyors		Capacity: 16.9 t/h Storage volume: 9360 m3					 *30 days storage capacity* *1 operating, 1 spare*

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						APPROVED BY	LM	LM	

EQUIPMENT LIST
Unit 2000 - Boiler Island

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	BOILER							
PK - 2001	**Super Critical Boiler, including:**		Capacity: 2868 t/h main steam production Thermal input: 2435 MWth (HHV) / 2335 MWth (LHV) Main steam condition: 270 bar(a)/600 °C Reheat steam condition: 60 bar(a)/620 °C				(1)	Boiler package including: - Coal mill - Fuel Feeding system - One Fired Boiler Furnace - Low NOx burners system including main burners and pilots - Economizers/super heater coils, water wall circuit - Reheating coils - Air pre-heater - Ash collection hoppers - Combustion air fans with electric motor (2 x 60% primary air, 2 x 60% secondary - Ash collection hoppers - Start-up system - Flue gas ducts - Bottom Ash cooling devices
K - 2001 A/B	**ID fan**	Axial	Flowrate: 2 x 1660 x 10^3 Nm3/h Vol. Flow: 2 x 652 x 10^3 m3/h Power consumption: 2 x 5265 kW	2 x 6950 kWe				
PK - 2002	**Flue gas cleaning system**	ESP						
PK - 2003	**Flue gas stack**	cement stack						
PK - 2004	**Continuous emission monitoring system**							

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EQUIPMENT LIST
Unit 2000 - Boiler Island

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	SCR SYSTEM - UNIT 2050							
	SCR system Including: - Reactor casing - Catalyst - Bypass system - Ammonia injection equipment - Handling equipment - Control System							

Notes:
(1) Reference for boiler material selection:
A. Robertson, H. Agarwal, M. Gagliano, A. Seltzer, Oxy-combustion boiler material development, 35th International Technical Conference on Clean Coal & Fuel System, Clearwater, Florida (USA)

EQUIPMENT LIST
Unit 2100 - Flue Gas Desulphurization

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	FGD SYSTEM							
	Wet FGD system Including: - Limestone feeder - Absorber tower - Oxydation air blower - Make up water system - Limestone slurry preparation - Reagent feed pump - Gypsum dewatering - Miscellaneous equipment		Flue gas inlet flowrate: 2766 x 10^3 Nm3/h Removal efficiency: 98.5 %					
	GAS-GAS HEATER							
	Gas-gas heat exchanger		Hot side flowrate: 2766 x10^3 Nm3/h Cold side flowrate: 2410 x10^3 Nm3/h Duty: 42.9 MWth					

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		APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 3000 - Steam Cycle

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	PACKAGES							
PK- 3001	**Steam Turbine and Generator Package**							
ST- 3001	Steam Turbine		958 MWe *HP admission:* *2868 t/h @ 270 bar* *Hot reheat admission:* *2456 t/h @ 60 bar* *LP admission:* *1252 t/h @ 5.4 bar*					*Including:* *Lube oil system* *Cooling system* *Idraulic control system* *Drainage system* *Seals system* *Drainage system* *Electrical generator and relevant auxiliaries*
E- 3001 A/B	Inter/After Condenser							
E- 3002	Gland Condenser							
PK- 3002	**Steam Condenser Package**							*Including:*
E- 3001	Steam condenser		776 MWth					*Hot well* *Vacuum pump (or ejectors)* *Start up ejector (if required)*
PK- 3003	**Steam Turbine Bypass System**							*Including:* *MP dump tube* *LP dump tube* *HP/MP Letdown station* *MP Letdown station* *LP Letdown station*
PK- 3004	**Phosphate injection package**							
PK- 3005	**Oxygen scavanger injection package**							
PK- 3006	**Amines injection package**							

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		APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 3000 - Steam Cycle

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	HEAT EXCHANGERS		**Duty (kW)**		Shell/tube	Shell/tube		
E- 3002	BFW Economiser #1		267630					
E- 3003	BFW Economiser #2		162430					
E- 3003	BFW Economiser #3		47030					
E- 3004	Condensate heater #3		69000					
E- 3005	Condensate heater #4		16140					
	PUMPS		**Q [m^3/h] x H [m]**					
P- 3001	BFW pumps	Centrifugal Steam driven	2956 m3/h x 3565 m	34000 kWe equivalent				*One operating*
P- 3002	BFW pump	Centrifugal	40% MCR					*For start-up, electric motor*
P- 3003 A/B	Condensate pump	Centrifugal	1710 x 170	1120				*One operating one spare, electric motor*
	VESSEL							
D- 3001	Dearator	Horizontal						

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EQUIPMENT LIST
Unit 4000 - CO2 Capture Unit (2 x 50%)

	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	PACKAGES							
	CO_2 capture Unit		For each train: Feed gas flowrate: 1428560 Nm3/h CO2 product: 180150 Nm3/h; 97.9% purity Treated gas florate: 1204770 Nm3/h CO2 capture rate: 90 %					2 x 50%
	PUMPS		**Q [m3/h] x H [m]**					
	For each train:							
K001	Flue gas Blower							
P001-A/B	Flue gas cooling water pumps							
P002-A/B	wash water circulation pumps							
P003-A/B	Risch solution pumps							
P004-A/B	Regenerator reflux pumps							
P005-A/B	Lean solution pumps							
P006	Solution sump pump							
P007-A/B	Steam condensate return pumps							
P008-A/B	Flue gas wash water pumps							
P009-A/B	Caustic soda make-up pumps							
P010	Reclaimed waste pump							
P011	Reclaimed waste transfer pump							
P012	Reclaimer caustic soda feed pump							

FOSTER WHEELER	CLIENT: IEA GHG	REVISION	Rev.: Draft	Rev. 0	Rev. 1	Rev. 2
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EQUIPMENT LIST
Unit 4000 - CO2 Capture Unit (2 x 50%)

	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	DRUMS / COLUMNS / TANKS							
	For each train:							
D-001	Flue gas quencher							
D-002	CO2 absorber							
D-003	Regenerator							
V-001	Regenerator reflux drum							
V-002	Steam condensatte drum							
T-001	Solution storage tank							
T-002	Solution sump tank							
T-003	Reclaimed waste tank							
T-004	Caustic soda storage tank							
	HEAT EXCHANGERS							
	For each train:							
E-001	Flue gas cooling water cooler							
E-002	Wash water cooler							
E-003	Solution heat exchanger							
E-004	Regenerator condenser							
E-005	Regenerator reboiler							
E-006	Lean solution cooler							
E-007	Reclaimer							
	MISCELLANEA							
	For each train:							
F-001	Up Stream guard filter							
F-002	Carbon filter							
F-003	Down stream guard filter							
F-004	Solution sump filter							

	CLIENT: IEA GHG	REVISION	Rev.: Draft	Rev. 0	Rev. 1	Rev. 2
	LOCATION: The Netherlands	DATE	Jun-13	January 2014		
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	CASE: 2 - SC PC with carbon capture	APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 5000 - CO2 compression Unit (2 x 50%)

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	COMPRESSORS							
K - 5001	CO_2 Compressor	Centrifugal, integrally geared, Electrical Driven 4 Stages	180200 Nm3/h p in: 1,6 bar a p out:75 bar a	36000 kW				Intercooling: Condensate from Power island Cooling Water
	PUMPS		**Q,m3/h x H,m**					
P - 5001	CO_2 Pump	centrifugal	500 x 530	675 kW				Liquid CO2 product, per each train: Flowrate: 346 t/h; 110 bar a; 30°C
	PACKAGE							
PK - 5001	CO_2 drying package							

Note 1: Equipment shown are for one train only

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: 2 - SC PC with carbon capture	REVISION	Rev.: Draft	Rev. 0	Rev. 1	Rev. 2
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EQUIPMENT LIST
Unit 6000 - Utility units

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	COOLING SYSTEM		**Duty**					
CT- 6001 A/B	**Cooling Tower** including: Cooling water basin	Natural draft	2 x 758 MWth Diameter: 120 m each, Height: 210 m, Water inlet: 17 m				concrete	
	PUMPS		**Q [m^3/h] x H [m]**					
P- 6001 A/B/C/D	Cooling Water Pumps (primary system)	Centrifugal	15200 x 35	1700				*Four in operation*
P- 6002 A/B/C/D	Cooling Water Pumps (secondary system)	Centrifugal	14400 x 45	2100				*Four in operation, one spare*
P- 6003 A/B	Cooling tower make-up pumps	centrifugal	2400 x 30	300				*One in operation, one spare*
	PACKAGES							
	Cooling Water Filtration Package Cooling Water Sidestream Filters		Capacity: 12000 m3/h					
	Sodium Hypochlorite Dosing Package Sodium Hypochlorite storage tank Sodium Hypochlorite dosage pumps							
	Antiscalant Package Dispersant storage tank Dispersant dosage pumps							
	RAW WATER SYSTEM							
T- 6001	Raw Water storage tank		2640 m3					*24 hour storage*
P- 6004 A/B	Raw water pumps to RO	centrifugal	15 x 50	7.5				*One in operation, one spare*
P- 6005 A/B	Raw water pump to FGD (make-up)	centrifugal	50 x 7.5	360				*One in operation, one spare*

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		CHECKED BY	NF	NF		
		APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 6000 - Utility units

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	DEMINERALIZED WATER SYSTEM							
PK- 6001	**Demin Water Package, including:**							
	- Multimedia filter							
	- Reverse Osmosis (RO) Cartidge filter							
	- Electro de-ionization system							
T- 6002	Demin Water storage tank		240 m3					*24 hour storage*
P- 6005 A/B	Demin water pump to FGD (make-up)	centrifugal	95 x 40	18.5				*One in operation, one spare*
P- 6006 A/B	Demin water pump to Power Island (make-up)	centrifugal	10 x 40	4				*One in operation, one spare*
	FIRE FIGHTING SYSTEM							
T- 6003	Fire water storage tank							
	Fire pumps (diesel)							
	Fire pumps (electric)							
	FW jockey pump							
	MISCELLANEA							
	Plant air compression skid							
	Emergency diesel generator system							
	Waste water treatment system							
	Electrical equipment							
	Buildings							
	Auxiliary boiler							
	Condensate Polishing system							

CLIENT : IEAGHG

PROJECT NAME : CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS

DOCUMENT NAME : CASE 2.1: SC PC WITH CCS – BIOMASS CO-FIRING

FWI CONTRACT : 1-BD-0681 A

ISSUED BY : G. PERFUMO

CHECKED BY : N. FERRARI

APPROVED BY : L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

1. Introduction

This chapter of the report includes all technical information relevant to Case 2.1 of the study, which is a supercritical PC boiler steam plant, co-firing coal and biomass (wood chips), with amine-based solvent washing for carbon capture.

Plant configuration is basically same as Case 2, though plant of Case 2.1 is designed to co-fire biomass in the amount required to meet zero net emission of carbon dioxide, considering biomass as zero carbon fuel. The resulting biomass feed corresponds to 7.5% of the total thermal input (based on LHV), while the plant has same thermal capacity and same carbon removal efficiency of the reference case (Case 2).

The description of the main process units and the reference Case 2 performance are covered respectively in chapter C and C.2 of this report; only plant design changes required to co-fire coal and biomass are discussed in the following sections, together with the main plant performance results.

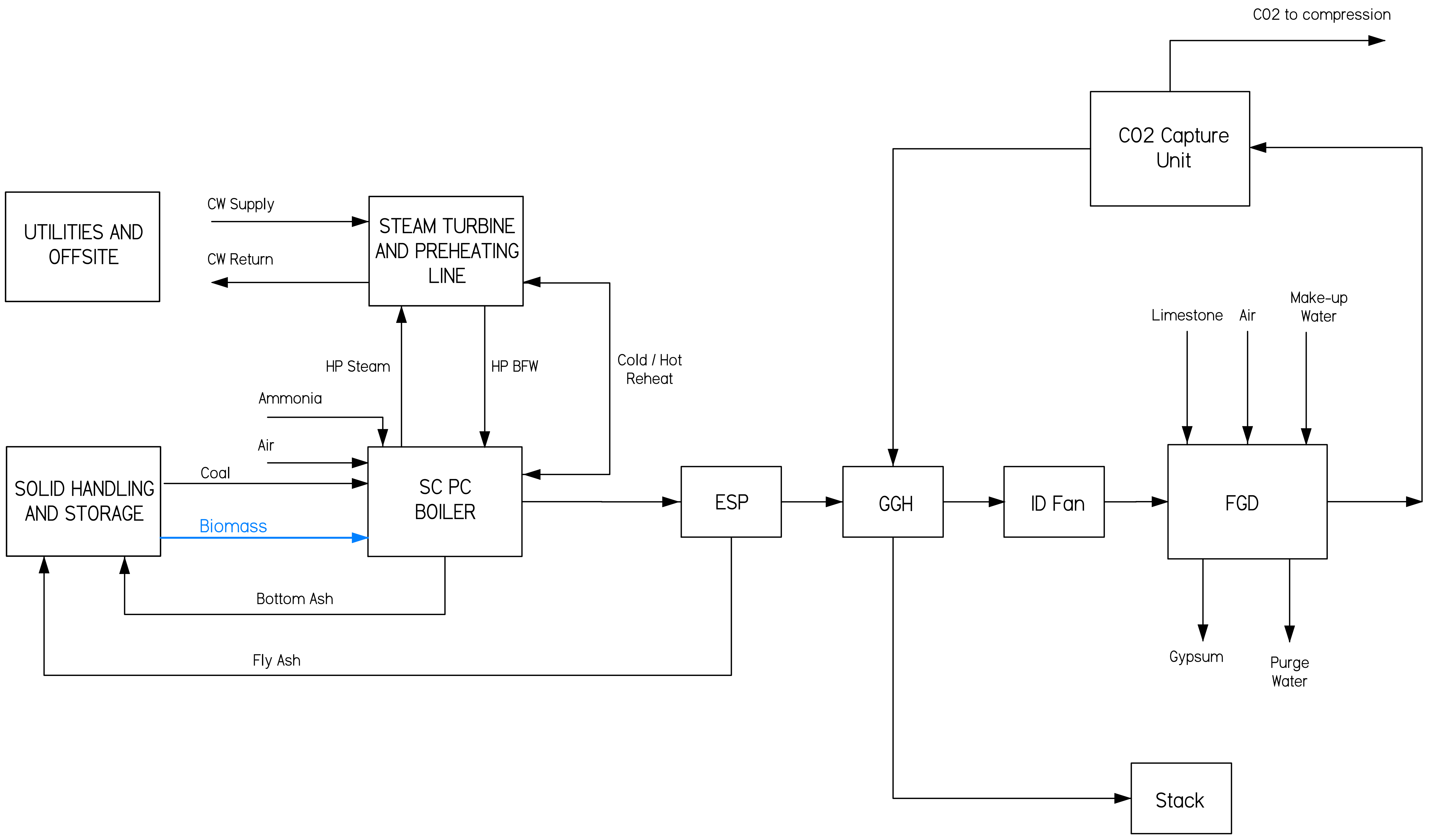
1.1. Process unit arrangement

The arrangement of the main units is reported in Table 1, together with the main differences with respect to the base case, as further discussed in the following sections. Reference is also made to the block flow diagram attached below.

Table 1. Case 2.1 – Unit arrangement

Unit	Description	Trains	Difference
1000	Storage and Handling of solid materials	N/A	Biomass storage to be added No significant design changes for coal and other solid handling: slightly lower consumptions
2000	SC PC supercritical boiler Electro Static precipitator SCR system	1 x 100%	No significant design changes: same thermal capacity, slightly higher volumetric flowrate due to the lower LHV of biomass fuel
2100	Flue Gas Desulphurisation (FGD)	1 x 100%	No significant design changes: slightly higher flue gas flowrate; lower limestone circulation and consumption due to lower biomass sulphur content
4000	Steam Cycle (SC) Steam Turbine and Condenser Deaerator Water Preheating line		-

Unit	Description	Trains	Difference
4000	CO_2 Amine Absorption Unit Flue gas quencher Absorber Regenerator		No significant design changes: Same carbon removal efficiency, slightly higher design capacity: higher carbon flowrate due to the increased fuel consumption (%wt)
5000	CO_2 compression	2 x 50%	No significant design changes: slightly higher design capacity: higher carbon flowrate due to the increased fuel consumption (%wt)
6000	Utility and Offsite	N/A	-



0	July13	Draft	GP	LM	**UNIT:** Block Flow Diagram	
Rev.	Date	Comment	By	Appr	**CASE:** 2.1	Sheet 01 of 01

2. Process Description

2.1. Overview

The description reported in this section focuses only on those units with a design different from that of the reference case, necessary to co-fire the amount of biomass required to meet zero carbon emission. Design changes are also reflected in the simplified Process Flow Diagrams (PFD) shown in section 3.

For all the other units, reference shall be made to the base case description, included in chapter C.2, section 2.

2.2. Unit 1000 – Feedstock and Solid Handling

In addition to the coal, ashes, limestone and gypsum storage and handling system, biomass storage and handling system is included for the present case.

Biomass will be delivered to the site by rails and stored in a rectangular stockyard building, equipped with stacking and reclaiming machines. The storage capacity is made to ensure the plant feeding at maximum capacity for approximately 30 days.

Biomass feeding system, from the storage building to the boiler, is of the same type of that employed for coal, with conveyors that bring biomass to the crushers and then to the biomass silos.

No difference are expected for the coal and other solid system, apart a slightly lower capacity due to the reduced coal consumption.

2.3. Unit 2000 – Boiler Island

The boiler is a single pass tower type supercritical boiler, with low NOx type burners located in the lower portion of the furnace and staging of the combustion to minimize NOx formation. Hot combustion products exit the furnace and pass through the radiant and convective heating surfaces for steam generation and superheating, then to the regenerative heaters for air pre-heating and finally to the flue gas clean-up system, including ESP and FGD, as for Case 2.

The main difference consists on the type of burners; coal burners have to be modified in order to allow a biomass injection lance down the centre axis of the burner. With this type of burner, the biomass is fired separately, but concentrically with the coal, in the same burner.

It has to be noted that for this particular case no additional biomass drying pre-treatment is required, as the moisture content of the resulting fuel mixture with 7.5% biomass fired (LHV basis) is low enough to be handled if the boiler furnace. However, the higher moisture content of the biomass leads to a higher feed flowrate to meet the same thermal capacity of the reference case, corresponding to a higher design capacity of both the fuel system (approximately +20%) and the flue gas ducts (approximately +4%).

2.4. Flue Gas Treatment (FGD and CO_2 capture unit)

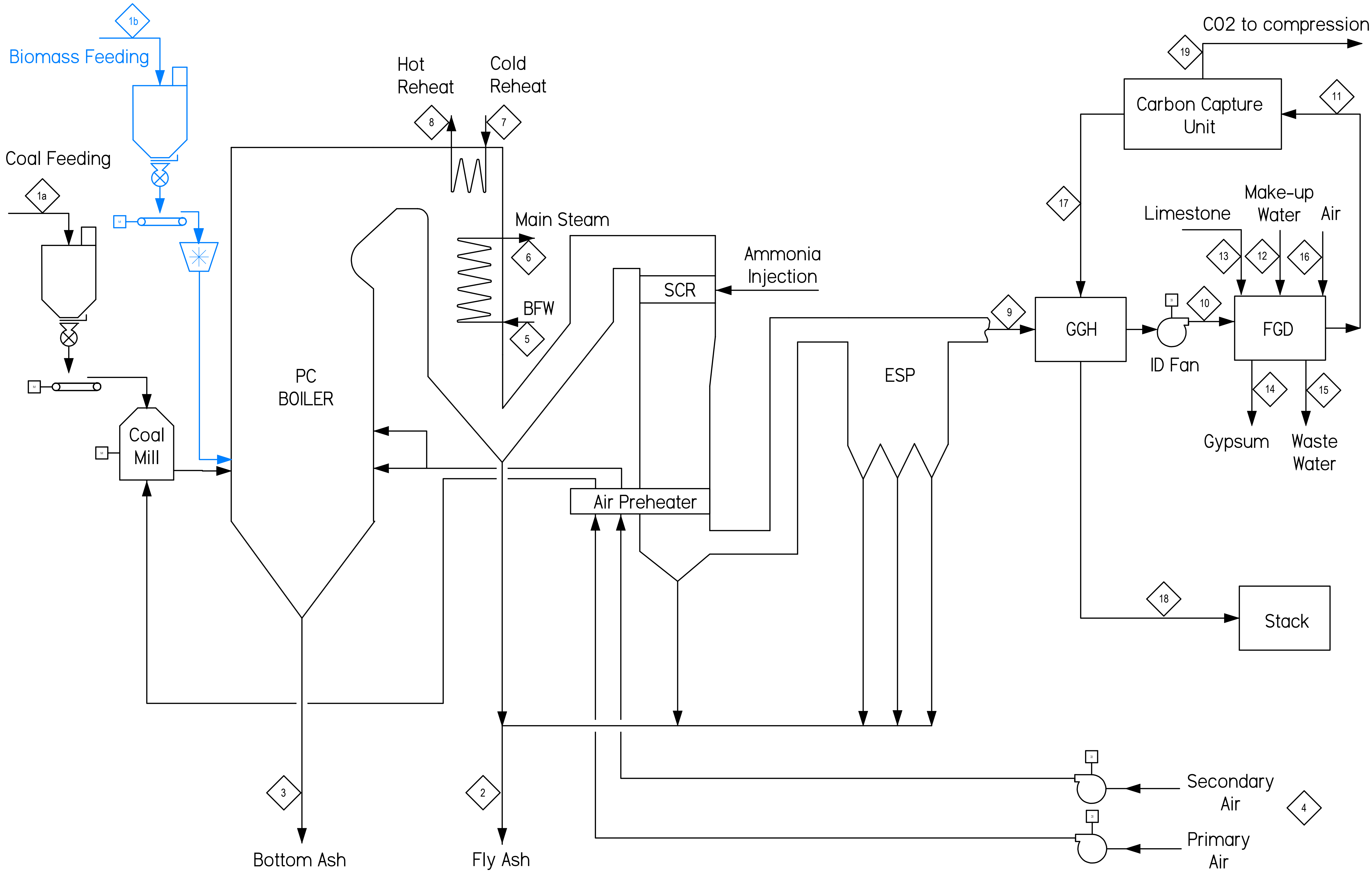
The co-firing of biomass and coal in the boiler does not have significant impact on the downstream flue gas treatment unit. The design is almost the same as Case 2, with the exception of slight difference in the capacity due to the different flowrate and composition of the flue gas resulting from the combustion of a higher moisture content fuel.

Main differences are the following:

- Flue gas flowrate is higher with respect to the reference case due to the higher feed flowrate. The difference is particularly significant upstream the FGD (+4%), due to the higher water content. As the flue gases exit at their water dew point from the FGD absorber, the difference in the downstream unit is lower, as well as the water make-up required to the desulphurisation unit.
- Carbon dioxide flowrate is slightly higher than the reference case, thus resulting in a higher design capacity of the CO_2 capture and compression unit. The higher carbon flowrate is related to the increased fuel feed mass flowrate required to meet the same thermal capacity of the reference case boiler.

3. Process Flow Diagrams

Simplified Process Flow Diagrams of this case, showing process modifications with respect to the reference case, are attached to this section. Stream numbers refer to the heat and material balance shown in the next section.



0	Sept. 13	Draft	GP	LM	**UNIT:** Boiler Island	
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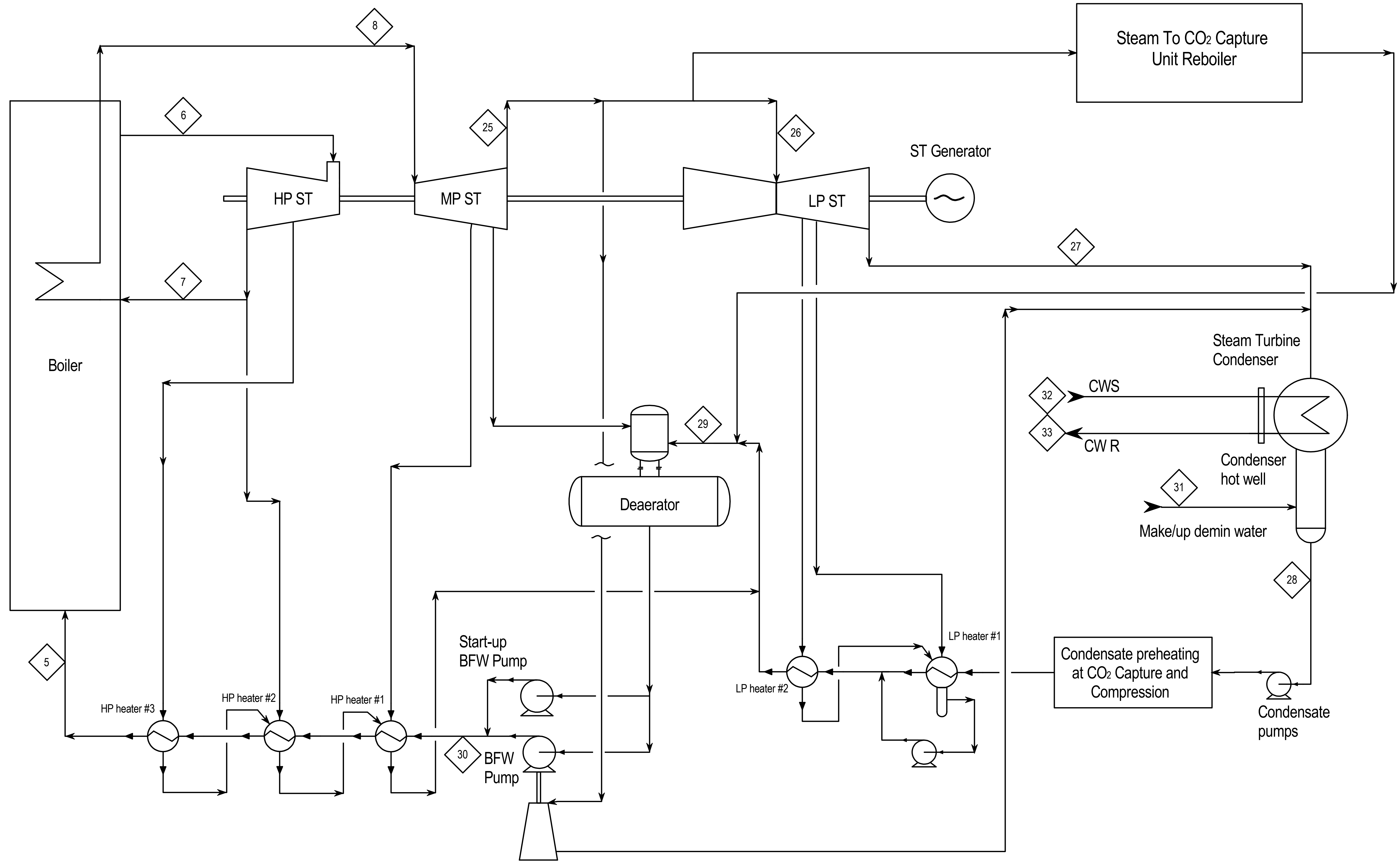

0	Sept. 13	Draft	GP	LM	**UNIT:** Steam Cycle	
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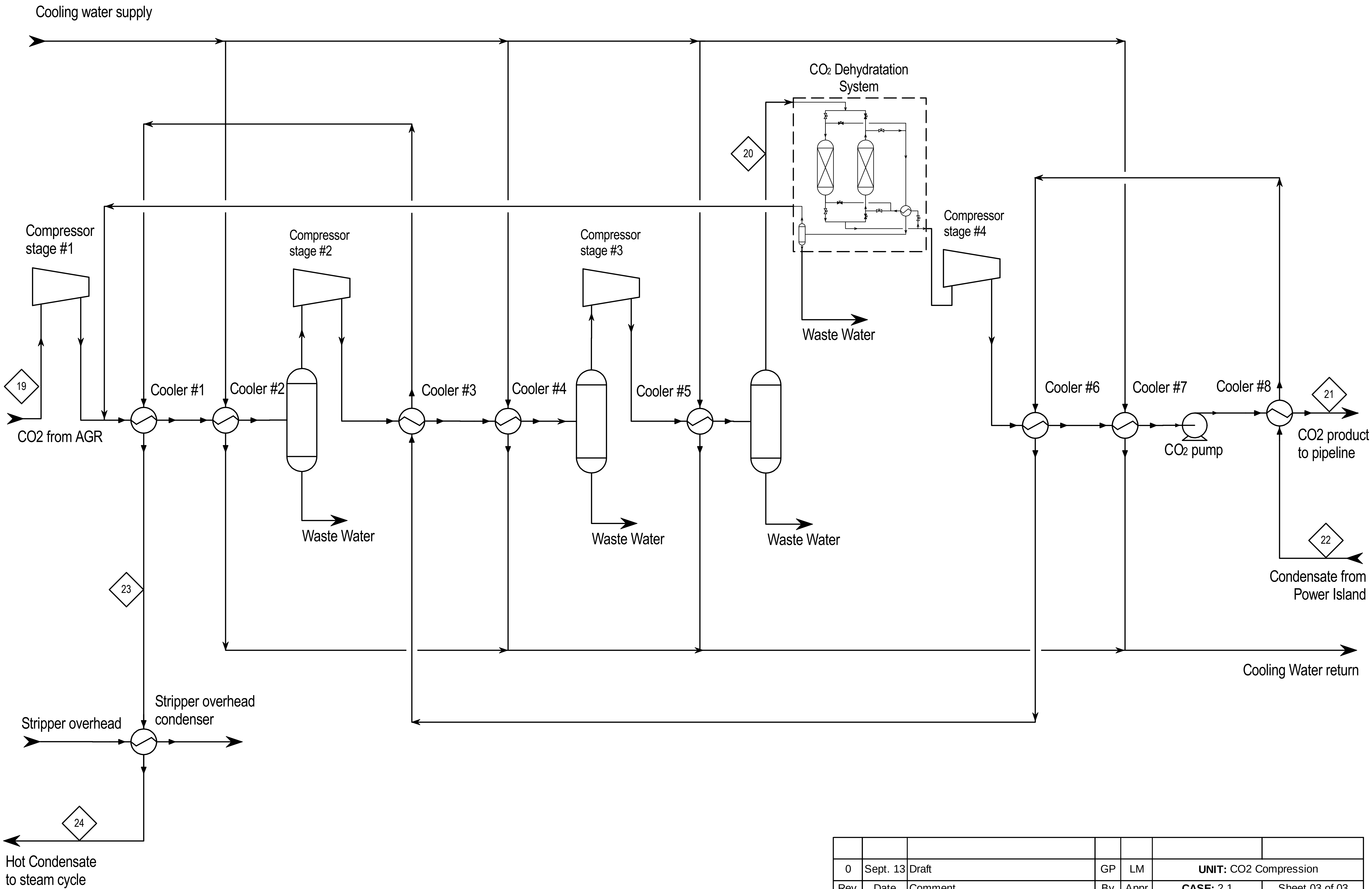

0	Sept. 13	Draft	GP	LM	**UNIT:** CO2 Compression	
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4. Heat and Material Balance

Heat & Material Balances here below reported make reference to the Process Flow Diagrams of section 3.

	Case 2.1 - SC PC with CCS - Biomass co-firing - HEAT AND MATERIAL BALANCE		REVISION	draft		
FOSTER WHEELER	CLIENT :	IEA GHG	PREP.	GP		
	PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	Sept. 13		

HEAT AND MATERIAL BALANCE
UNIT 2000 - BOILER ISLAND

STREAM	1a	1b	2	3	4	5	6	7	8	
	Coal to Boiler Island	Biomass to boiler island	Fly Ash	Bottom Ash	Air intake from Atmosphere	BFW from steam cycle	HP Steam to Steam Turbine	Cold Reheat from UNIT 3000	Hot Reheat to Steam Turbine	
Temperature (°C)	AMB	AMB	AMB	AMB	9	290	600	366	620	
Pressure (bar)	AMB	AMB	ATM	ATM	1.013	324	270	63	60	
TOTAL FLOW	Solid	Solid								
Mass flow (kg/h)	300,600	86,400	27,800	11,900	3,428,800	2,852,000	2,852,000	2,442,000	2,442,000	
Molar flow (kmol/h)					118,840	158,356	158,356	135,591	135,591	
LIQUID PHASE										
Mass flow (kg/h)						2,852,000				
GASEOUS PHASE										
Mass flow (kg/h)					3,428,800		2,852,000	2,442,000	2,442,000	
Molar flow (kmol/h)					118,840		158,356	135,591	135,591	
Molecular Weight					28.85		18.01	18.01	18.01	
Composition (vol %)	%wt	%wt								
H_2					0.00%	0.00%	0.00%	0.00%	0.00%	
CO	C: 64.6%	C: 25.0%			0.00%	0.00%	0.00%	0.00%	0.00%	
CO_2	H: 4.38%	H: 2.70%			0.03%	0.00%	0.00%	0.00%	0.00%	
N_2	O: 7.02%	O: 21.1%			77.27%	0.00%	0.00%	0.00%	0.00%	
O_2	S: 0.86%	S: 0.03%			20.73%	0.00%	0.00%	0.00%	0.00%	
CH_4	N: 1.41%	N: 0.15%			0.00%	0.00%	0.00%	0.00%	0.00%	
Ar	Cl: 0.03%	Cl: 0.01%			0.92%	0.00%	0.00%	0.00%	0.00%	
SO_2	Moisture: 9.5%	Moisture: 50.0%			0.00%	0.00%	0.00%	0.00%	0.00%	
H_2O	Ash: 12.20%	Ash: 1.0%			1.05%	100.00%	100.00%	100.00%	100.00%	
Total					100.00%	100.00%	100.00%	100.00%	100.00%	
Emissions (mg/Nm^3, dry basis 6% vol O_2)										
SOx					-	-	-	-	-	
NOx					-	-	-	-	-	
particulate					-	-	-	-	-	

	Case 2.1 - SC PC with CCS - Biomass co-firing - HEAT AND MATERIAL BALANCE		REVISION	draft		
	CLIENT :	IEA GHG	PREP.	GP		
	PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	Sept. 13		

HEAT AND MATERIAL BALANCE
UNIT 2100 - FGD

STREAM	9	10	11	12	13	14	15	16		
	Flue Gas from ESP to GGH	Flue Gas to FGD	Treated gas from FGD	Make up Water	Limestone to FGD	Product Gypsum	Waste water from FGD	Oxidation Air		
Temperature (°C)	134	90	47	15	AMB	AMB	AMB	AMB		
Pressure (bar)	-	-	-	ATM	ATM	ATM	ATM	ATM		
TOTAL FLOW					Solid	Solid				
Mass flow (kg/h)	3,776,000	3,776,000	3,801,400	40,000	8,580	15,780	7,250	8,475		
Molar flow (kmol/h)	128,080	128,080	129,420	2,220			403	294		
LIQUID PHASE										
Mass flow (kg/h)				40,000			7,250			
GASEOUS PHASE										
Mass flow (kg/h)	3,776,000	3,776,000	3,801,400					8,475		
Molar flow (kmol/h)	128,080	128,080	129,420					294		
Molecular Weight	29.48	29.48	29.37					28.85		
Composition (vol %)										
H_2	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%		
CO_2	13.92%	13.92%	13.84%	0.00%			0.00%	0.03%		
N_2	71.82%	71.82%	71.25%	0.00%			0.00%	77.27%		
O_2	3.21%	3.21%	3.19%	0.00%			0.00%	20.73%		
CH_4	0.00%	0.00%	0.00%	0.00%			0.00%	0.00%		
Ar	0.85%	0.85%	0.84%	0.00%			0.00%	0.92%		
SO_2	0.06%	0.06%	0.00%	0.00%			0.00%	0.00%		
H_2O	10.14%	10.14%	10.88%	100.00%			100.00%	1.05%		
Total	100.00%	100.00%	100.00%	100.00%			100.00%	100.00%		
Emissions (mg/Nm^3, dry basis 6% vol O_2)										
SOx	1897	1897	SO_2: 10 ppm SO_3: 13 ppm	-	-	-	-	-		
NOx	130	130	130	-	-	-	-	-		
particulate	10	10	10	-	-	-	-	-		

NOTE
1. Air in-leakage are included in the flue gas streams

	Case 2.1 - SC PC with CCS - Biomass co-firing - HEAT AND MATERIAL BALANCE		REVISION	draft		
FOSTER WHEELER	CLIENT :	IEA GHG	PREP.	GP		
	PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	Sept. 13		

HEAT AND MATERIAL BALANCE
UNIT 4000 and 5000 - CO2 CAPTURE AND COMPRESSION

STREAM	11	17	18	19	20	21	22	23	24	
	Feed Gas to CCU	Treated Gas to GGH	Flue Gas to Stack	Carbon Dioxide to Compression	CO2 to drying package	CO2 to long term Storage	Condensate from Power Island	Preheated Condensate to Stripper Condenser	Preheated Condensate to Power Island	
Temperature (°C)	47	43	95	30	26	30	29	60	74	
Pressure (bar)	-	-	-	2.0	30.3	110.0	14.5	14.0	13.5	
TOTAL FLOW										
Mass flow (kg/h)	3,801,400	2,449,340	2,449,340	717,650	791,045	710,000	1,284,860	1,284,860	1,284,860	
Molar flow (kmol/h)	129,420	109,280	109,280	16,510	17,990	16,114	71,341	71,341	71,341	
LIQUID PHASE						supercritical state				
Mass flow (kg/h)						710,000	1,284,860	1,284,860	1,284,860	
GASEOUS PHASE										
Mass flow (kg/h)	3,801,400	2,449,340	2,449,340	717,650	791,045					
Molar flow (kmol/h)	129,420	109,280	109,280	16,510	17,990					
Molecular Weight	29	22.4	22.4	43.5	44.0					
Composition (vol %)										
H_2	0.00%	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%	0.00%	
CO_2	13.84%	1.60%	1.60%	97.90%	99.82%	100.00%	0.00%	0.00%	0.00%	
N_2	71.25%	84.38%	84.38%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
O_2	3.19%	4.11%	4.11%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
CH_4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
Ar	0.84%	1.00%	1.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
SO_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
H_2O	10.88%	8.62%	8.62%	2.10%	0.18%	0.00%	100.00%	100.00%	100.00%	
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
Emissions (mg/Nm^3, dry basis 6% vol O_2)										
SOx	SO2: 10 ppm SO3: 13 ppm	< 1 ppm	< 1 ppm	-	-	-				
NOx	130	150	150	-	-	-				
particulate	10	10	10	-	-	-				

Case 2.1 - SC PC with CCS - Biomass co-firing **H&M BALANCE**		**Revision**	draft	
CLIENT:	IEA GHG	**Prepared**	GP	
PROJECT NAME:	CO_2 capture at coal based power and H_2 plants	**Checked**	NF	
PROJECT NO:	1-BD-0681 A	**Approved**	LM	
LOCATION:	The Netherlands	**Date**	Sept. 13	

HEAT AND MATERIAL BALANCE
UNIT 3000 - STEAM CYCLE

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
6	HP Water to Boiler Island	2,852	290	323	1278
7	HP Steam from Boiler	2,852	600	270	3475
8	Cold Reheat to Boiler	2,442	366	63.0	3081
9	Hot Reheat to MP Steam Turbine	2,442	620	60.0	3706
25	MP Steam Turbine exhaust	2,096	275	5.5	3011
26	Steam to LP Steam Turbine	1,382	275	5.4	3012
27	Exhaust from LP Steam Turbine	1,095	29	0.04	2292
28	Condensate	1,285	29	0.04	121
29	LP Preheated Condensate	2,899	143	9.5	602
30	BFW to preheating	2,943	156	325	678
31	Make up Water	5	9	0.04	38
32	Cooling Water Inlet	59,600	15	4.0	63
33	Cooling Water Outlet	59,600	26	3.5	109

5. Utility and chemicals Consumption

Main utility and chemical consumption of the plant is reported in the following tables, compared with the reference case figures (in brackets). More specifically:

- Water consumption summary is reported in Table 2,
- Electrical consumption summary is shown in Table 3,
- Sorbent and chemicals consumption, shown in Table 4.

With respect to the reference case, the following considerations can be made:

- The solid handling consumption is slightly lower than the reference case. In fact, the increased consumption of the feedstock handling system (coal and biomass), due to the increased flowrate required to meet the same thermal duty, is more than offset by the reduced consumption of the ashes handling system. In fact the consumptions of pneumatic transport required for the ashes have a greater impact on plant consumption than the feedstock conveyor consumption.
- The increased flue gas flowrate results in a higher power demand within the boiler island, in particular for the ID fan, while the reduced limestone recirculation related to the lower sulphur content in the fuel mixture leads to a lower power demand within the FGD unit.
- Utilities and offsite consumption increases, mainly due to the higher cooling water requirements within the CO_2 capture and compression unit.

Table 2. Case 2.1 – Water consumption summary

CLIENT:	IEAGHG	REVISION	0
PROJECT NAME:	CO2 capture at coal based power and H2 plants	DATE	Jul-13
PROJECT No. :	1-BD-0681 A	MADE BY	GP
LOCATION :	The Netherlands	APPROVED BY	LM

Case 2.1 - Biomass co-firing - Water consumption

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water 1° syst. [DT = 11°C] [t/h]	Cooling Water 2° syst. [DT = 11°C] [t/h]
1000	FEEDSTOCK AND SOLID HANDLING				
	Solid Receiving, Handling and storage				
2000	BOILER ISALND and FLUE GAS TREATMENT				
	Boiler island				
	Flue Gas Desulphurization (Wet FGD)	40 *(85)*			
500	POWER ISLAND (Steam Turbine)				
	Condenser			59600 *(60800)*	
	Steam Turbine generator and auxiliaries		5		4370 *(4420)*
BoP	UTILITY and OFFSITE UNITS				
	Cooling Water System	2170			
	Demineralized/Condensate Recovery/Plant and Potable Water Systems	10	-7		
	Waste Water Treatment	-170.0			
	Miscellanea				100
	CO2 CAPTURE UNIT				
4000	CO2 capture unit		2		54260 *(53070)*
5000	CO2 compression				
	BALANCE	2050 *(2095)*	0.0	59600 (60800)	58730 *(57590)*

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

Table 3. Case 2.1 – Electrical consumption summary

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	**DATE**	Jul-13
PROJECT No. :	1-BD-0681 A	**MADE BY**	GP
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 2.1 - Biomass co-firing - Electrical consumption

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
1000	**FEEDSTOCK AND SOLID HANDLING**	
	Solids Handling	3270 *(3350)*
2000	**BOILER ISLAND and FLUE GAS TREATMENT**	
	Boiler island (including ID fan)	24220 *(22370)*
	Flue Gas Desulphurization (FGD)	3720 *(4000)*
3000	**POWER ISLAND (Steam Turbine)**	
	Steam Turbine Auxiliiaries and condenser	3350 *(3300)*
	Condensate pump and feedwater system	910 *(920)*
	Miscellanea	600
	CO2 CAPTURE UNIT	
4000	CO2 capture unit	84340 *(82230)*
5000	CO2 Compression	
BoP	**UTILITY and OFFSITE UNITS**	
	Cooling Water System	16080 *(15020)*
	Other Units	1440
	BALANCE	**137,930** ***(133,230)***

Table 4. Case 2.1 – Sorbent and chemicals consumption

	Consumption
Limestone injection to the FGD	8.58 t/h
Ammonia solution to SCR (1)	4.8 t/h
NaOH to flue gas quencher (2)	200 kg/h

(1) 25%wt ammonia solution

(2) 50%wt. FWI estimate

6. Overall Performance

The following Table shows the overall performance of Case 2.1, compared with the reference case performance.

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	**DATE**	Jul-13
PROJECT No. :	1-BD-0681 A	**MADE BY**	GP
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 2.1 - Biomass co-firing - SC PC Plant with carbon capture performance summary

OVERALL PERFORMANCES COMPARISON			
		CASE 2.1	CASE 2 (reference)
Coal flow rate (A.R.)	t/h	300.6	325.0
Coal LHV (A.R.)	kJ/kg	25870	25870
Biomass flowrate (A.R.)	t/h	86.4	-
Biomass LHV (A.R.)	kJ/kg	7300	-
Fuel flowrate	t/h	386.9	325.0
Fuel HHV	kJ/kg	23289	27060
Fuel LHV	kJ/kg	21725	25870
THERMAL ENERGY OF FEEDSTOCK (based on LHV) (A)	**MWth**	**2335**	**2335**
Thermal energy of coal (based on LHV)	**MWth**	**2160**	**2335**
Thermal energy of biomass (based on LHV)	**MWth**	**175**	**-**
THERMAL ENERGY OF FEEDSTOCK (based on HHV) (A')	**MWth**	**2503**	**2443**
Steam turbine power output (@ gen terminals)	MWe	948.8	958.1
GROSS ELECTRIC POWER OUTPUT (C) (1)	**MWe**	**948.8**	**958.1**
Boiler Island	MWe	27.9	26.4
Utility & Offsite Units consumption	MWe	17.5	16.5
Power Islands consumption (note 1)	MWe	4.9	4.8
CO2 Capture and compression unit	MWe	84.3	82.2
Feedstock and solids handling	MWe	3.3	3.3
ELECTRIC POWER CONSUMPTION	**MWe**	**137.9**	**133.2**
NET ELECTRIC POWER OUTPUT	**MWe**	**810.9**	**824.9**
(Step Up transformer efficiency = 0.997%) (B)	MWe	808.5	822.4
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**40.6%**	**41.0%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**34.6%**	**35.2%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**37.9%**	**39.2%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**32.3%**	**33.7%**
Fuel Consumption per net power production	**MWth/MWe**	**3.10**	**2.84**
CO_2 emission per net power production	**kg/MWh**	**0.0**	**93.0**

(1) Steam driven BFW pumps are included

With respect to the reference case, the following considerations can be made:

- Gross power production is reduced because of the lower boiler efficiency, related to the increased moisture content, and the increased steam consumption in the regenerator reboiler, due to the higher carbon flowrate.
- Net electrical efficiency decreases of about 0.6 percentage points, due to the above consideration and to the increased plant auxiliary demand.

The following Table shows the overall CO_2 balance and removal efficiency of Case 2.1. Carbon emission corresponds to the carbon content in the biomass feed.

CO_2 removal efficiency	**Equivalent flow of CO_2** kmol/h
INPUT	
FUEL CARBON CONTENT (A)	17978
Carbon content from coal	16180
Carbon content from biomass	1798
FROM the DeSOX reaction + CO_2 in air (B)	104
OUTPUT	
Carbon losses (D)	170
CO_2 flue gas content	17912
Total to storage (C)	16114
Emission	1798
TOTAL	18082
Overall Carbon Capture, % ((C+D)/(A+B))	90.1

7. Environmental Impact

Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

7.1. Gaseous Emission

During normal operation at full load, the main continuous emissions are the flue gases from the boiler. Table 5 summarizes the expected flue gas flow rate and composition. Differences with respect to reference case are related to the changes in the feed composition and flow.

The same minor and fugitive emissions related to the milling, storage and handling of solid materials and listed for the base case, also including biomass handling system, are applied also for this alternative.

Table 5. Case 2.1 – Plant emission during normal operation

Flue gas to stack	
Emission type	Continuous
Conditions	
Wet gas flowrate, kg/h	3,030,000
Flow, Nm^3/h (1)	2,445,000
Temperature, °C	95
Composition	(% vol)
Ar	1.00
N_2	84.38
O_2	4.11
CO_2	1.60
H_2O	8.62
Emission	
NOx	< 50 mg/Nm^3 (1)
SOx	< 1 ppmv (1)
Particulate	< 10 mg/Nm^3 (1)

(1) Dry gas, O_2 content 6% vol.

7.2. Liquid effluents

The plant does not produce significant liquid waste. FGD unit blow-down is treated in a dedicated R.O. system to recover water, so main liquid effluent is cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids.

Cooling Tower blowdown

Flowrate : 518 m^3/h

FGD blow-down

Flowrate : 10 m^3/h

7.3. Solid effluents

As for the base case, the power plant is expected to produce the following solid effluents:

Fly ash from boiler

Flowrate	:	27.8 t/h

Bottom ash from boiler

Flowrate	:	11.9 t/h

Fly and bottom ash might be sold to cement industries, if local market exists, or sent to disposal.

Solid gypsum from FGD

As for the base case, solid gypsum produced in hydrated form in the FGD system, can be sold in the market.

Flowrate	:	15.8 t/h
Moisture content	:	10%wt

8. Main equipment design changes

The overleaf equipment summary table shows the major design differences between the present Case 2.1 and the reference Case 2.

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: 2.1 - SC PC with carbon capture - co-firing with biomass	REVISION DATE ISSUED BY CHECKED BY APPROVED BY	Rev.: Draft July 13 GP NF LM	Rev.: 1 Jan-14 GP NF LM	Rev.2	Rev.3	

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	Difference with respect to reference case
	UNIT 1000 - FEEDSTOCK AND SOLID HANDLING					
	Coal handling		300.6 t/h (Storage pile: 2 x 116,000)			**Size changed (- 7.5%)**
	Biomass handling		86.4 t/h (Storage pile: 1 x 35,000)			**To be added**
	Limestone handling		8.5 t/h (Storage volume 3300 m3)			**Size changed (- 7.6%)**
	Ash handling		39.7 t/h			**Size changed (- 5.0%)**
	Gypsum handling		15.8 t/h			**Size changed (- 6.5%)**
	UNIT 2000 - BOILER ISLAND					
PK - 2001	**Super Critical Boiler, including:**		Capacity: 2852 t/h main steam production Thermal input: 2500 MWth (HHV) / 2335 MWth (LHV) Main steam condition: 270 bar(a)/ 600°C Reheat steam condition: 60 bar(a)/ 620°C			**Size changes** - Feed system: + 20% - Flue gas system: + 4%
K - 2001 A/B	ID fan	Axial	Flowrate: 2 x 1720 x 10^3 Nm3/h Vol. Flow: 2 x 660 x 10^3 m3/h Power consumption: 2 x 5418 kW	2 x 7150 kWe		**Size changed (+ 3.6%)**
PK - 2002	**Flue gas cleaning system**	ESP				**Size changed (+ 3.6%)**
PK - 2003	**Flue gas stack**	cement stack				
	SCR System					
	UNIT 2100 - Flue Gas Desulphurization					
	Wet FGD system		Flue gas inlet flowrate: 2870 x 10^3 Nm3/h gypsum production: 15.8 t/h			**Size changed:** feed flowrate: +3.6% sorbent recirculation: -6.5%
	Gas-gas heat exchanger		Hot side flowrate: 2870 x 10^3 Nm3/h Cold side flowrate: 2450 x 10^3 Nm3/h			**Size changed**
	Unit 4000 - CO_2 Amine Absorption Unit (2x50%)					
	CO_2 capture Unit (2 x 50%)		For each train: Feed gas flowrate: 1450 x 10^3 Nm3/h			**Size changed (+ 1.5%)**
	Unit 5000 - CO_2 compression Unit (2 x 50%)					
	CO_2 compression Unit (2 x 50%)		Feed gas flowrate: 185,000 Nm3/h each train			**Size changed (+ 2.6%)**

CLIENT : IEAGHG
PROJECT NAME : CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
DOCUMENT NAME : CASE 1: SC PC WITHOUT CCS
COOLING SYSTEM SENSITIVITY
FWI CONTRACT : 1-BD-0681 A

ISSUED BY : G. PERFUMO
CHECKED BY : N. FERRARI
APPROVED BY : L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

1. Introduction

This chapter presents the main impacts on plant design and performance of alternative types of cooling system, taking as reference the supercritical pulverised coal (SC PC) fired steam plant without carbon capture described in chapter C.1 (Case 1). With respect to this case, based on natural draft cooling water tower system, two different systems are analysed hereafter:

- SW: once-through seawater cooling;
- AC: dry air cooling.

The description of the main process units and the reference Case 1 performance are covered respectively in chapter C and C.1 of this report; only plant design changes related to the alternative cooling systems are discussed in the following sections, together with the main plant performance results.

2. Process Description

2.1. Overview

The description of the following sections makes reference to the simplified Process Flow Diagrams (PFD) of section 3, which show only the design changes related to the alternative cooling systems. For all the other units, reference shall be made to the base case description, included in chapter C.1, section 2.

2.2. Impact on process units

The adoption of a cooling system different from the reference case does not lead to significant modification within the process units.

2.3. Unit 3000 – Steam Cycle

The main consequence of a cooling system alternative to that of the reference case is a different steam condenser type.

2.3.1. Seawater system

A seawater cooled steam condenser is considered in this case. The lower sea water inlet temperature, as well as the lower permitted temperature increase (see data below) allows to achieve a condensing pressure lower than the reference case (3.0 kPa vs. 4.0 kPa respectively), with consequent higher steam turbine power generation.

In fact, being the sea water supplied to the steam condenser at 12°C and considering a maximum allowed temperature increase of 7°C, the condensation temperature is 24°C.

2.3.2. Air cooling system

The exhaust steam from the LP turbine is piped directly to the air-cooled, finned tube, condenser. The finned tubes are usually arranged in an “A” form or delta over a forced draught fan in order to reduce the plot area requirements.

A temperature difference of 25°C is considered between ambient air and the condensing steam, resulting in a higher steam condensing pressure with respect to the reference case (5.2 kPa vs. 4.0 kPa respectively) with consequent lower steam turbine power generation.

2.4. Unit 6000 - Utility Units

Apart from the cooling water system, alternative to the cooling tower type of the reference case, no significant impact is foreseen in the other utility units of the SC PC power plant.

2.4.1. *Seawater system*

In the once-through system, seawater is pumped from the sea, directly used in the heat exchangers of the plant and then discharged back to sea.

This system has the advantage of using a “free” coolant medium, without generating a real stream of waste water, since seawater is returned to the sea without any significant change in composition, apart from its higher temperature. However, the maximum allowable seawater temperature increase is 7°C, in order to minimize environmental impact of the sea, thus resulting in a higher circulating cooling water flowrate.

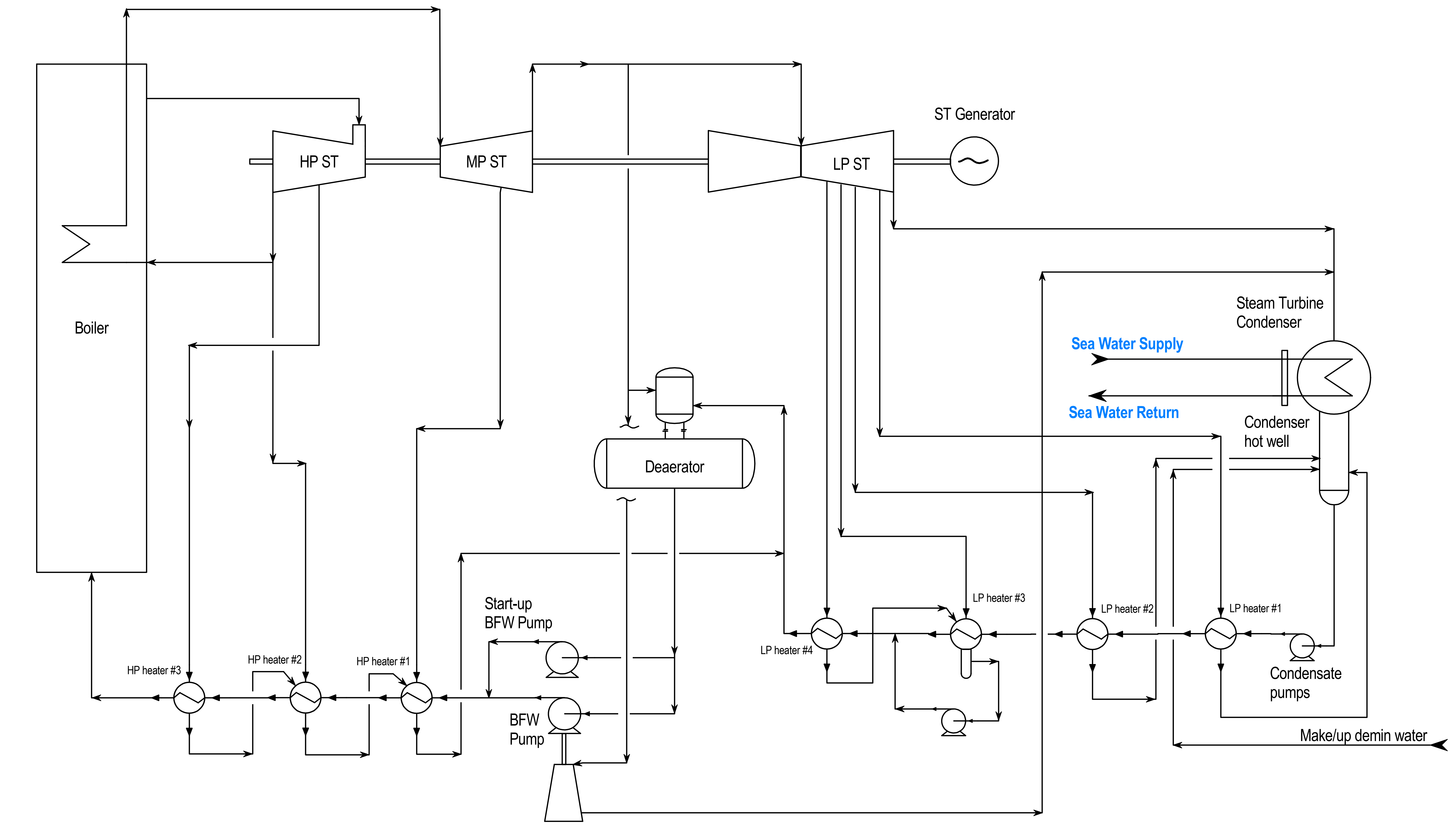
In addition to the once-trough system, a seawater-cooled closed circuit of demineralised water is considered (secondary system) for machinery and steam turbine generator cooling and for all plant users where seawater is not applicable.

2.4.2. *Air cooling system*

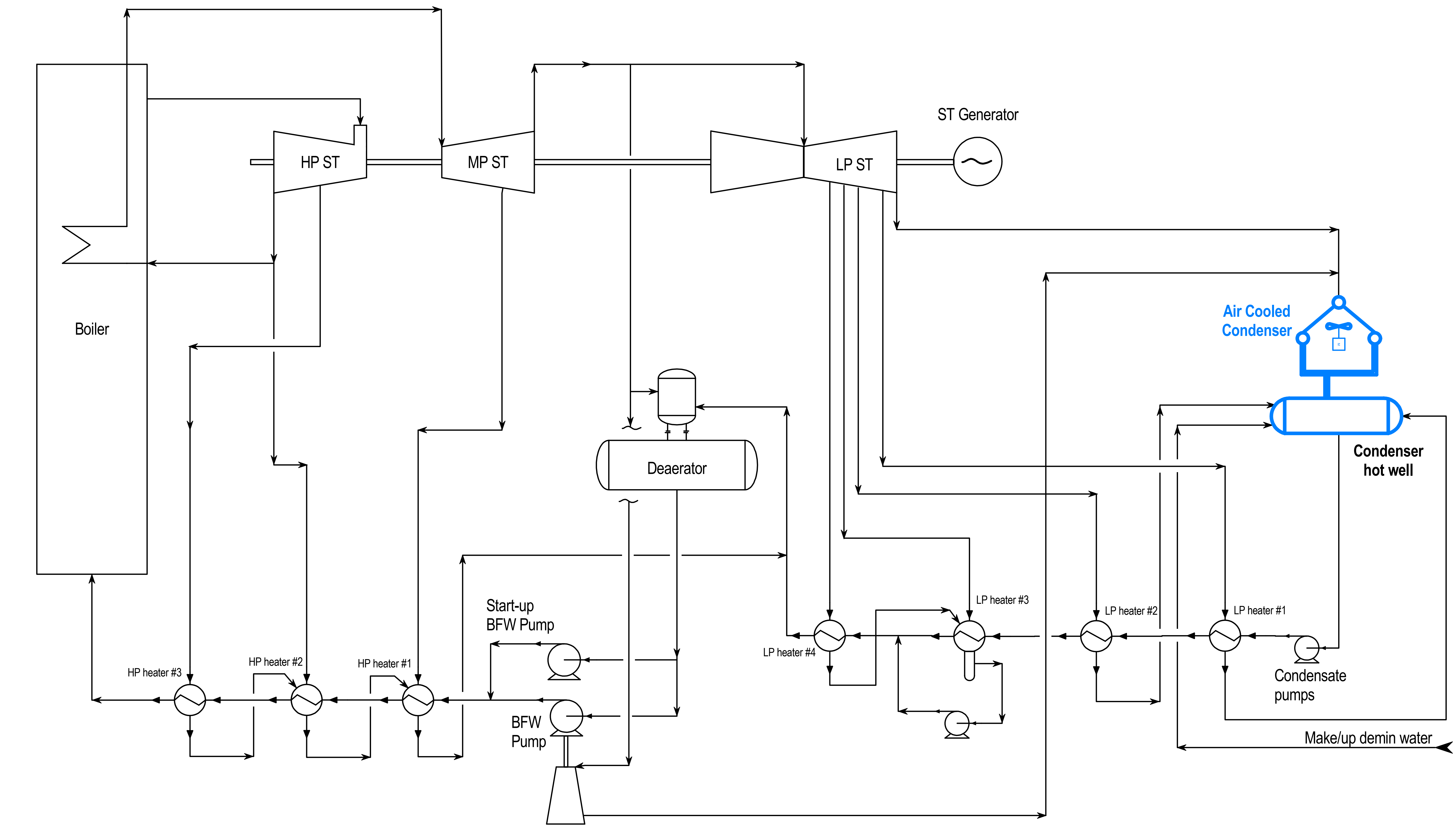
Ambient air is generally used as cooling medium. Similarly to the previous case, a secondary system consisting of an air-cooled closed circuit of demineralised water, conditioned and stabilised, is used for machinery and steam turbine generator cooling.

3. Process Flow Diagrams

Simplified Process Flow Diagrams of this case, showing process modifications with respect to the reference case, are attached to this section.



0	July 13	Draft	GP	LM	**UNIT:** Steam Cycle	
Rev.	Date	Comment	By	Appr	**CASE:** 1 - Sea Water	Sheet 01 of 01



0	July 13	Draft	GP	LM	**UNIT:** Steam Cycle	
Rev.	Date	Comment	By	Appr	**CASE:** 1 - Air Cooling	Sheet 01 of 01

4. Utility and chemicals consumption

Main utility consumption of the process and utility units is reported in the following tables, including data of the reference case. More specifically:

- Water consumption summary is reported in Table 1 and Table 2, respectively for the seawater cooling and air cooling systems (reference case consumptions shown in brackets).
- Electrical consumption summary is shown in Table 3 for both the seawater cooling and the air cooling systems.

With respect to the reference case, the following considerations can be made:

- For both the alternative systems, raw water requirement is significantly lower than the reference case, mainly because there is no cooling tower make-up.
- The overall electrical consumption of the seawater system is slightly lower than the reference case with cooling tower. In fact, the cooling water system shows almost the same consumption as the higher cooling water flowrate, due to the lower ΔT allowed for the seawater, is offset by the lower cooling water pump head required for pumping the cooling water to the users.
- The overall electrical consumption of the air cooling system is slightly lower than the reference case with cooling tower. The absence of cooling water pumps, with the exception of those of the closed circuit, partially offsets the additional consumption of the air coolers fans, i.e. the air condenser in the steam cycle.

Table 1. Case 1 (Sea Water Cooling) – Water consumption summary

CLIENT:	IEAGHG	REVISION	0
PROJECT NAME:	CO2 capture at coal based power and H2 plants	DATE	Jun-13
PROJECT No. :	1-BD-0681 A	MADE BY	NF
LOCATION :	The Netherlands	APPROVED BY	LM

Case 1 (SW) - Water consumption

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Sea Cooling Water DT = 7°C [t/h]	Machinery CW DT = 11°C [t/h]
1000	FEEDSTOCK AND SOLID HANDLING				
	Solid Receiving, Handling and storage				
2000	BOILER ISALND and FLUE GAS TREATMENT				
	Boiler island				
	Flue Gas Desulphurization (Wet FGD)	85			
500	POWER ISLAND (Steam Turbine)				
	Condenser			131640	
	Turbine and generator auxiliaries		5		5030
BoP	UTILITY and OFFSITE UNITS				
	Cooling Water System			8320	
	Demineralized/Condensate Recovery/Plant and Potable Water Systems	8	-5		
	Waste Water Treatment	-10			
	Miscellanea				100
	BALANCE	83 *(1658)*	0.0	139,960 *(82,590)*	5,130 *(5,060)*

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

Table 2. Case 1 (Air Cooling) – Water consumption summary

CLIENT: IEAGHG	REVISION 0
PROJECT NAME: CO2 capture at coal based power and H2 plants	DATE Jun-13
PROJECT No. : 1-BD-0681 A	MADE BY NF
LOCATION : The Netherlands	APPROVED BY LM

Case 1 (AC) - Water consumption

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery CW DT = 8°C [t/h]	Primary cooling medium
1000	FEEDSTOCK AND SOLID HANDLING				NO PRIMARY COOLING WATER IS AVAILABLE. AIR IS USED AS PRIMARY COOLING MEDIUM
	Solid Receiving, Handling and storage				
2000	BOILER ISALND and FLUE GAS TREATMENT				
	Boiler island				
	Flue Gas Desulphurization (Wet FGD)	85			
500	POWER ISLAND (Steam Turbine)				
	Condenser				
	Turbine and generator auxiliaries		5	6730	
BoP	UTILITY and OFFSITE UNITS				
	Cooling Water System				
	Demineralized/Condensate Recovery/Plant and Potable Water Systems	8	-5		
	Waste Water Treatment	-10			
	Miscellanea			140	
	BALANCE	83 *(1658)*	0.0	6,870 *(5,060)*	0 *(82,590)*

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

Table 3. Case 1 (Cooling medium sensitivity) – Electrical consumption summary

CLIENT:	IEAGHG		REVISION	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants		DATE	Jun-13
PROJECT No. :	1-BD-0681 A		MADE BY	GP
LOCATION :	The Netherlands		APPROVED BY	LM

Case 1 - Electrical consumption
Sensitivity to cooling system

UNIT	DESCRIPTION UNIT	Absorbed Electric Power CASE 1 (Cooling tower) [kW]	CASE 1 (Sea Water) [kW]	CASE 1 (Dry air) [kW]
1000	**FEEDSTOCK AND SOLID HANDLING**			
	Solids Handling	3330	3330	3330
2000	**BOILER ISLAND and FLUE GAS TREATMENT**			
	Boiler island (including ID fan)	21920	21920	21920
	Flue Gas Desulphurization (FGD)	2890	2890	2890
3000	**POWER ISLAND (Steam Turbine)**			
	Steam Turbine Auxiliaries	2600	2600	2600
	Condenser	-	-	7500
	Condensate and feedwater system	1250	1250	1250
	Miscellanea	600	600	600
BoP	**UTILITY and OFFSITE UNITS**			
	Cooling Water System	9990	9290	2220
	Other Units	1440	1440	1440
	BALANCE	44,020	43,320	43,750

5. Overall Performance

The following Table shows the overall performance of the plant with the three different cooling systems assessed in the study.

FOSTER WHEELER

CLIENT:	IEAGHG	REVISION	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	DATE	Jul-13
PROJECT No. :	1-BD-0681 A	MADE BY	NF
LOCATION :	The Netherlands	APPROVED BY	LM

Case 1 - SC PC Plant Performance Summary

OVERALL PERFORMANCES				
		CASE 1 (Cooling tower)	CASE 1 (Sea Water)	CASE 1 (Dry air)
Fuel flow rate (A.R.)	t/h	325.0	325.0	325.0
Fuel HHV (A.R.)	kJ/kg	27060	27060	27060
Fuel LHV (A.R.)	kJ/kg	25870	25870	25870
THERMAL ENERGY OF FEEDSTOCK (based on LHV) (A)	**MWth**	**2335**	**2335**	**2335**
THERMAL ENERGY OF FEEDSTOCK (based on HHV) (A')	**MWth**	**2443**	**2443**	**2443**
Steam turbine power output (@ gen terminals)	MWe	1076.7	1091.0	1062.0
GROSS ELECTRIC POWER OUTPUT (C) (1)	**MWe**	**1076.7**	**1091.0**	**1062.0**
Boiler Island and FGD	MWe	24.8	24.8	24.8
Utility & Offsite Units consumption	MWe	11.4	10.7	3.7
Power Islands consumption	MWe	4.5	4.5	12.0
Feedstock and solids handling	MWe	3.3	3.3	3.3
ELECTRIC POWER CONSUMPTION	**MWe**	**44.0**	**43.3**	**43.7**
NET ELECTRIC POWER OUTPUT	**MWe**	**1032.7**	**1047.7**	**1018.3**
(Step Up transformer efficiency = 0.997%) (B)	MWe	1029.6	1044.5	1015.2
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**46.1%**	**46.7%**	**45.5%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**44.1%**	**44.7%**	**43.5%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**44.1%**	**44.7%**	**43.5%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**42.1%**	**42.8%**	**41.6%**
Fuel Consumption per net power production	**MWth/MWe**	**2.27**	**2.24**	**2.30**
CO_2 emission per net power production	**kg/MWh**	**745.3**	**734.6**	**755.8**

(1) Steam driven BFW pumps are included

By comparing the results of the reference case with those of the alternative cooling system type, the following consideration can be made:

- *Sea water system*: Net electrical efficiency increases of about 0.6 percentage points, due to the higher gross power production, related to the lower condensation pressure, and the lower plant auxiliary power demand.
- *Air cooling system*. Net electrical efficiency decreases of about 0.6, due to the lower gross power production, related to the higher condensation pressure.

6. Environmental Impact

Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

6.1. Gaseous emissions

As for the reference case, main continuous emissions during normal operation are the flue gases from the boiler. No difference is expected in the flowrate and composition of this stream. The same minor and fugitive emissions, related to leakages within the handling of solid materials, are valid for these alternative systems.

6.2. Liquid effluents

Waste water treatment

As per the reference case, the plant does not produce significant liquid waste. FGD unit blow-down is treated in a dedicated R.O. system to recover water.

6.2.1. Seawater system

For the seawater case, seawater is returned to the sea basin after exchanging heat in the plant, with a maximum temperature increase of 7°C. The main characteristics of the discharged seawater are listed below:

Maximum flow rate :	140,000	m^3/h
Temperature:	19	°C

6.3. Solid effluents

No difference is expected in the production of solid by-products with respect to the reference case.

7. Equipment list

The following equipment summary tables show the major impact on equipment design for the alternative cooling system types.

FOSTER WHEELER	CLIENT: IEA GHG	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
	LOCATION: The Netherlands	DATE	20-Jun-13			
	PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	NF			
	CONTRACT N. 1-BD-0681 A	CHECKED BY	LM			
	CASE: 1 - SC PC without carbon capture - Sea Water sensitivity case	APPROVED BY	LM			

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	Difference with respect to reference case
	UNIT 3000 - STEAM CYCLE					
PK- 3001	**Steam Turbine and Generator Package**					
ST- 3001	Steam Turbine		1091 MWe			**Size changed**
PK- 3002	**Steam Condenser Package**					
~~E- 3001~~	~~Steam condenser~~	~~Water cooled~~	~~1055 MWth~~			**To be deleted (*)**
E- 3001	Steam condenser	Sea Water cooled	1040 MWth			**To be added (*)**
	COOLING SYSTEM					
E- 6001	Closed cooling water cooler		65 MWth			**To be added**
P- 6001 A /.. / H	Sea Cooling Water Pumps	Centrifugal	17000 m3/h x 20 m	1600	*Eight in operation*	**To be added (*)**
P- 6002 A / B	Machinery Cooling Water Pumps	Centrifugal	5150 m3/h x 35 m	800	*One in operation, one spare*	**Size changed**
~~CT - 6001~~	~~**Cooling Tower**~~ ~~includind:~~ ~~Cooling water basin~~	~~Natural draft~~	~~1120 MWth~~ ~~Diameter: 150 m,~~ ~~Height: 210 m,~~ ~~Water inlet: 17 m~~			**To be deleted**
~~P- 6001 A/.. /F~~	~~Cooling Water Pumps (primary system)~~	~~Centrifugal~~	~~15000 m3/h x 35 m~~	~~1600~~	~~*Six in operation*~~	**To be deleted (*)**
~~P- 6003 A / B~~	~~Cooling tower make-up pumps~~	~~centrifugal~~	~~1700 m3/h x 30 m~~	~~220~~		
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 9500 m3/h~~			
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					**To be deleted**
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					

(*) Different material selection (titanium) is considered for the steam condenser and cooling water pumps design to address corrosion issues related to the use of SW as cooling medium.

CLIENT:	IEA GHG
LOCATION:	The Netherlands
PROJ. NAME:	CO2 capture at coal based power and hydrogen plants
CONTRACT N.	1-BD-0681 A
CASE:	1 - SC PC without carbon capture - Air Cooled sensitivity case

REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
DATE	03-Jun-13			
ISSUED BY	NF			
CHECKED BY	LM			
APPROVED BY	LM			

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	Difference with respect to reference case
	UNIT 3000 - STEAM CYCLE					
PK- 3001	**Steam Turbine and Generator Package**					
ST- 3001	Steam Turbine		1062 MWe			**Size changed**
PK- 3002	**Steam Condenser Package**					
~~E- 3001~~	~~Steam condenser~~		~~1055 MWth~~			**To be deleted**
AC- 3001	Air cooled Steam condenser		1070 MWth	100 x 90 kW		**To be added**
	COOLING SYSTEM					
AC- 6001	Closed loop air cooler		64 MWth	1700 kWe		**To be added**
P- 6002 A / B	Cooling Water Pumps (secondary system)	Centrifugal	6880 m3/h x 35 m	950	*One in operation, one spare*	**Size changed**
~~CT- 6001~~	~~**Cooling Tower**~~ ~~includind:~~ ~~Cooling water basin~~	~~Natural draft~~	~~1120 MWth~~ ~~Diameter: 150 m,~~ ~~Height: 210 m,~~ ~~Water inlet: 17 m~~			**To be deleted**
~~P- 6001 A/.. /F~~	~~Cooling Water Pumps (primary system)~~	~~Centrifugal~~	~~15000 m3/h x 35 m~~	~~1600~~	~~*Six in operation*~~	**To be deleted**
~~P- 6003 A / B~~	~~Cooling tower make-up pumps~~	~~centrifugal~~	~~1700 m3/h x 30 m~~	~~220~~		
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 9500 m3/h~~			
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					**To be deleted**
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					

CLIENT	:	IEAGHG
PROJECT NAME	:	CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
DOCUMENT NAME	:	CASE 2: SC PC WITH CCS COOLING SYSTEM SENSITIVITY
FWI CONTRACT	:	1-BD-0681 A

ISSUED BY	:	G. PERFUMO
CHECKED BY	:	N. FERRARI
APPROVED BY	:	L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

1. Introduction

This chapter presents the main impacts on plant design and performance of alternative types of cooling system, taking as reference the supercritical pulverised coal (SC PC) fired steam plant with carbon capture described in chapter C.2 (Case 2). With respect to this case, based on natural draft cooling water tower system, two different systems are analysed hereafter:

- SW: once-through seawater cooling;
- AC: dry air cooling.

The description of the main process units and the reference Case 2 performance are covered respectively in chapter C and C.2 of this report; only plant design changes related to the alternative cooling systems are discussed in the following sections, together with the main plant performance results.

2. Process Description

2.1. Overview

The description of the following sections makes reference to the simplified Process Flow Diagrams (PFD) of section 3, which show only the design changes related to the alternative cooling systems. For all the other units, reference shall be made to the base case description, included in chapter C.2, section 2.

2.2. Impact on process units

The adoption of a cooling system different from the reference case leads to the following modification within the process units.

2.2.1. Seawater system

- CO_2 capture unit: Sweet cooling water from the closed water circuit exchanging with seawater is used as cooling medium in the capture unit. This is because seawater is not generally used for the direct cooling of process streams with relative small duty.
- CO_2 compression: Seawater coolers are considered for the after-coolers of the CO_2 compressor trains. This allows to achieve a cooling level of the CO_2 stream greater than the reference case, corresponding also to a lower compressor power demand.

2.2.2. Air cooling system

- CO_2 capture unit: Air coolers are considered for each cooling service in the capture unit.
- CO_2 compression: Air coolers are considered for the after-coolers of the CO_2 compressor trains. During operation at normal ambient conditions, , this allows to achieve a cooling level of the CO_2 stream greater than the reference case, corresponding to a lower compressor power demand, offset by the additional power requirement of the air cooler fans.

Details on the temperature that can be achieved with both cooling system are reported in the following section 2.4.

2.3. Unit 3000 – Steam Cycle

The main consequence of a cooling system alternative to that of the reference case is a different steam condenser type.

2.3.1. Seawater system

A seawater cooled steam condenser is considered in this case. The lower sea water inlet temperature, as well as the lower permitted temperature increase (see data below) allows to achieve a condensing pressure lower than the reference case (3.0 kPa vs. 4.0 kPa respectively), with consequent higher steam turbine power generation.

In fact, being the sea water supplied to the steam condenser at 12°C and considering a maximum allowed temperature increase of 7°C, the condensation temperature is 24°C.

2.3.2. *Air cooling system*

The exhaust steam from the LP turbine is piped directly to the air-cooled, finned tube, condenser. The finned tubes are usually arranged in an "A" form or delta over a forced draught fan in order to reduce the plot area requirements.

A temperature difference of 25°C is considered between ambient air and the condensing steam, resulting in a higher steam condensing pressure with respect to the reference case (5.2 kPa vs. 4.0 kPa respectively) with consequent lower steam turbine power generation.

2.4. Unit 6000 - Utility Units

Apart from the cooling water system, alternative to the cooling tower type of the reference case, no significant impact is foreseen in the other utility units of the SC PC power plant.

2.4.1. *Seawater system*

In the once-through system, seawater is pumped from the sea, directly used in the heat exchangers of the plant and then discharged back to sea.

This system has the advantage of using a "free" coolant medium, without generating a real stream of waste water, since seawater is returned to the sea without any significant change in composition, apart from its higher temperature. However, the maximum allowable seawater temperature increase is 7°C, in order to minimize environmental impact of the sea, thus resulting in a higher circulating cooling water flowrate.

In addition to the steam turbine condenser, seawater is used for the CO_2 compressors intercoolers. During normal operation conditions, this allows achieving a temperature of the hot stream of 19°C, which is lower than the temperature achieved in the reference case (i.e. 26°C).

In addition to the once-trough system, a seawater-cooled closed circuit of demineralised water is considered (secondary system) for machinery and steam turbine generator cooling and for all plant users where seawater is not applicable, e.g. for cooling of process streams within the capture unit.

2.4.2. *Air cooling system*

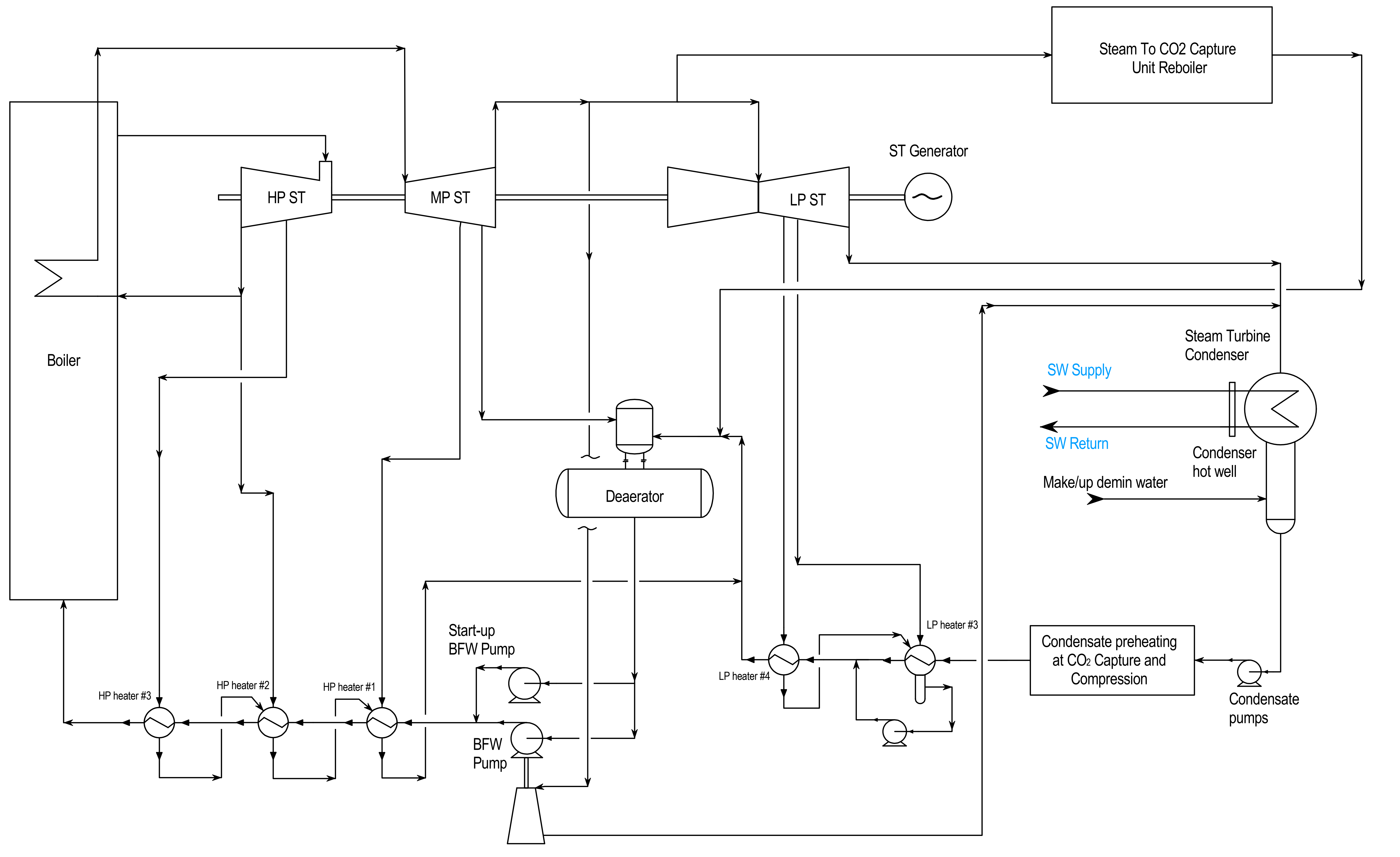
The use of ambient air as cooling medium is maximised. The secondary system, consisting of an air-cooled closed circuit of demineralised water, conditioned and stabilised, is used only for machinery and steam turbine generator cooling.

As above stated, the installation of an air cooled steam turbine condenser has a negative impact on the performance, due to the higher condensation pressure resulting from the 25°C approach normally considered for this application.

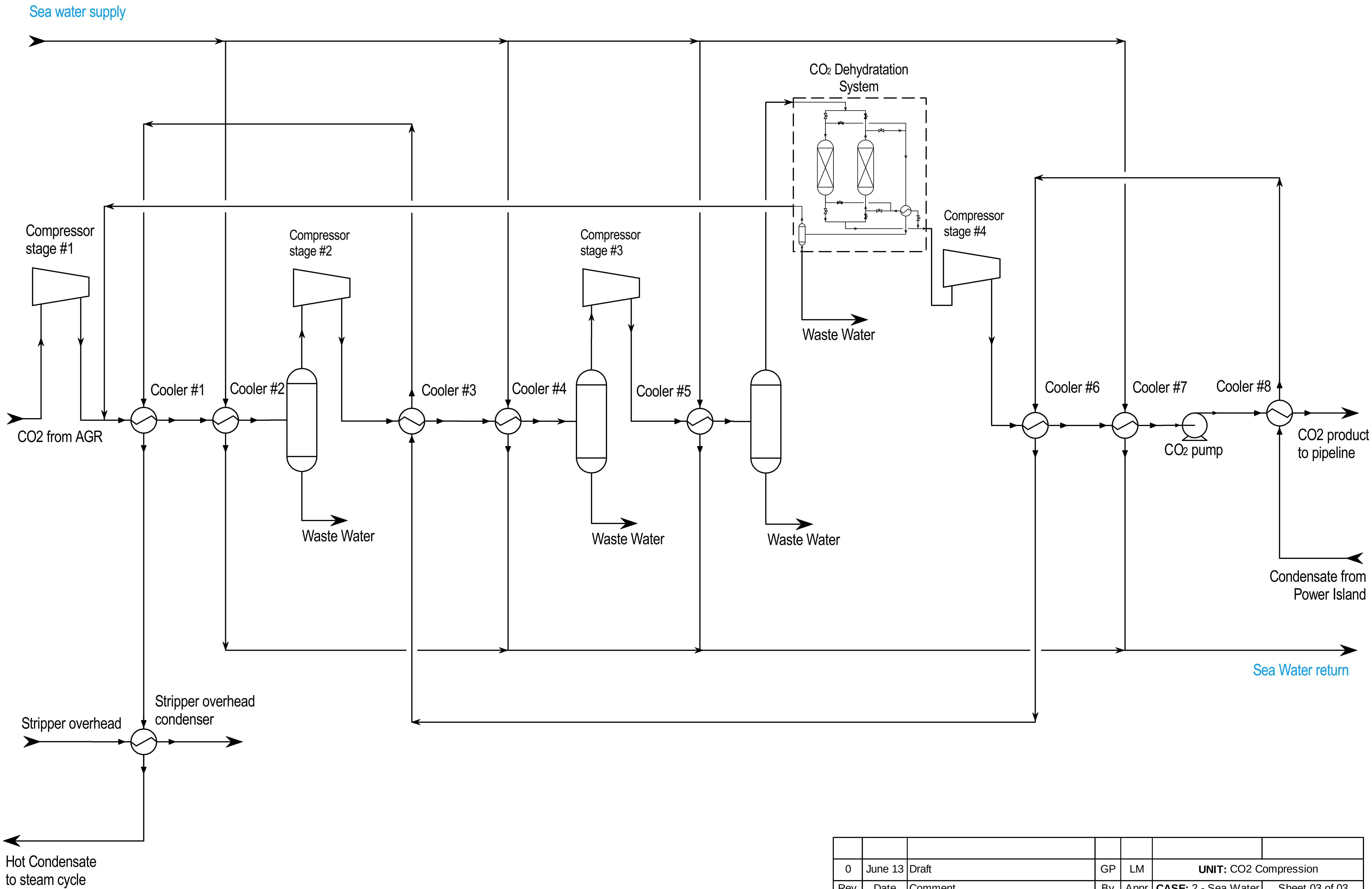
For services other than steam condenser, e.g. water air coolers or compressor intercoolers, the temperature difference between hot fluid exit temperature and ambient air is generally lower, around 10°C, corresponding to a final hot fluid temperature of 19°C, which is lower than the temperature achieved in the reference case (i.e. 26°C).

3. Process Flow Diagrams

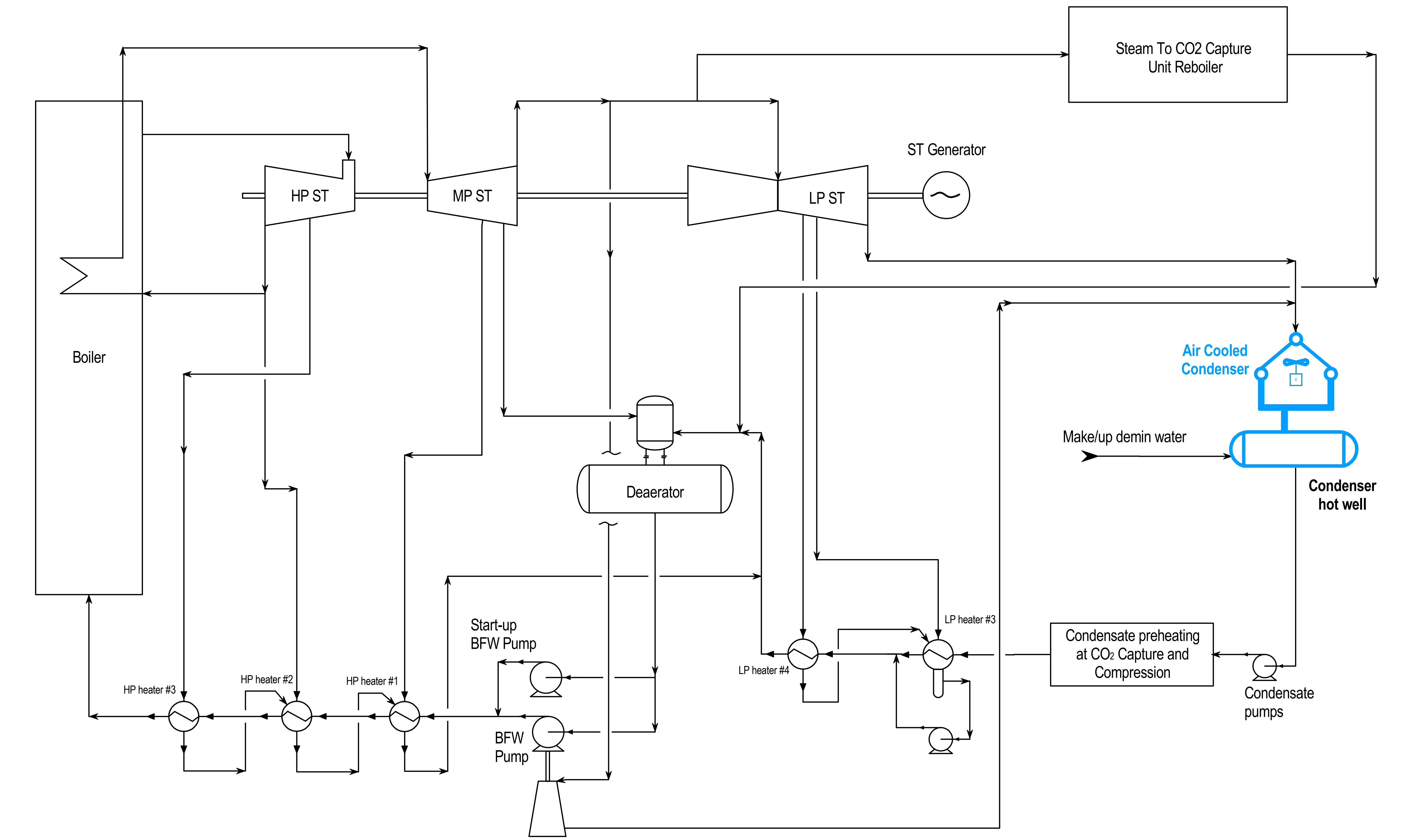
Simplified Process Flow Diagrams of this case, showing process modifications with respect to the reference case, are attached to this section.



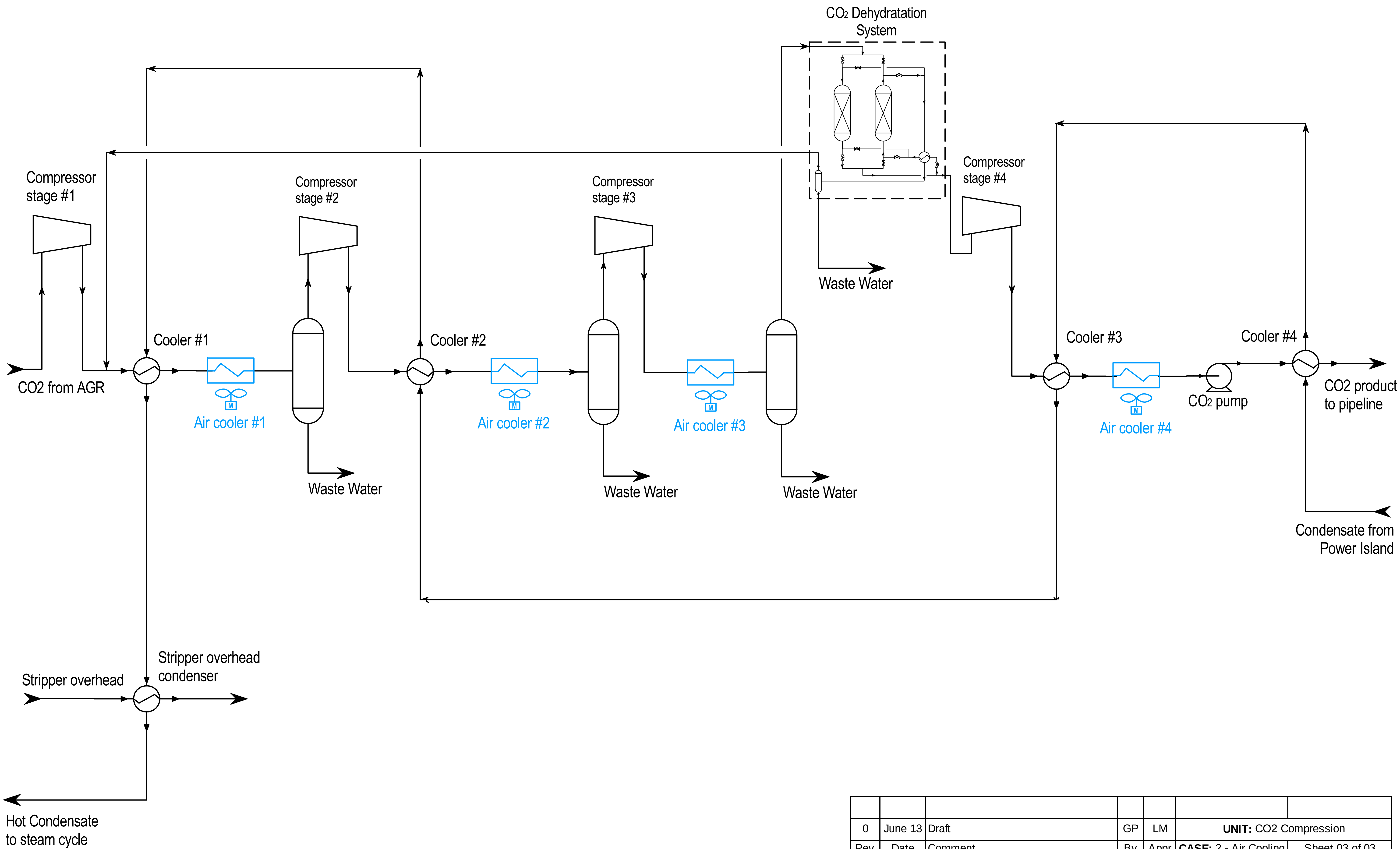
0	June 13	Draft	GP	LM	**UNIT:** Steam Cycle	
Rev.	Date	Comment	By	Appr	**CASE:** 2 - Sea Water	Sheet 02 of 03



0	June 13	Draft	GP	LM	**UNIT:** CO2 Compression	
Rev.	Date	Comment	By	Appr	**CASE:** 2 - Sea Water	Sheet 03 of 03



0	June 13	Draft	GP	LM	**UNIT:** Steam Cycle	
Rev.	Date	Comment	By	Appr	**CASE:** 2 - Air Cooling	Sheet 02 of 03



0	June 13	Draft	GP	LM	**UNIT:** CO2 Compression	
Rev.	Date	Comment	By	Appr	**CASE:** 2 - Air Cooling	Sheet 03 of 03

4. Utility and chemicals consumption

Main utility consumption of the process and utility units is reported in the following tables, including data of the reference case. More specifically:

- Water consumption summary is reported in Table 1 and Table 2, respectively for the seawater cooling and air cooling systems (reference case consumptions shown in brackets).
- Electrical consumption summary is shown in Table 3 for both the seawater cooling and the air cooling systems.

With respect to the reference case, the following considerations can be made:

- For both the alternative systems, raw water requirement is significantly lower than the reference case, mainly because there is no cooling tower make-up. The raw water required by the demineralised water plant and the FGD is totally recovered in the Waste Water Treatment, resulting in a zero raw water demand.
- The overall electrical consumption of the seawater system is slightly higher than the reference case with cooling tower. In fact, the cooling water system consumption increases due to the higher amount of sea water required for the closed water circuit providing the cooling medium to the CO_2 capture unit, while consumption related to the seawater for the condenser is almost the same as the reference case, as the higher cooling water flowrate, due to the lower ΔT allowed for the seawater, is compensated by the lower cooling water pump head required for pumping the cooling water to the users. This increased consumption offsets the lower compressor consumption in the CO_2 compression unit because of the increased cooling capacity.
- The overall electrical consumption of the air cooling system is slightly lower than the reference case with cooling tower. The absence of cooling water pumps, with the exception of those of the closed circuit, partially offsets the additional consumption of the air coolers fans, i.e. the air condenser in the steam cycle.

Table 1. Case 2 (Sea Water Cooling) – Water consumption summary

CLIENT: IEAGHG	REVISION 0
PROJECT NAME: CO2 capture at coal based power and H2 plants	DATE Jul-13
PROJECT No. : 1-BD-0681 A	MADE BY NF
LOCATION : The Netherlands	APPROVED BY LM

Case 2 (SW) - Water consumption

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Sea Cooling Water DT = 7°C [t/h]	Machinery CW DT = 11°C [t/h]
1000	FEEDSTOCK AND SOLID HANDLING				
	Solid Receiving, Handling and storage				
2000	BOILER ISALND and FLUE GAS TREATMENT				
	Boiler island				
	Flue Gas Desulphurization (Wet FGD)	85			
500	POWER ISLAND (Steam Turbine)				
	Condenser			97900	
	Turbine and generator auxiliaries		5		4470
BoP	UTILITY and OFFSITE UNITS				
	Cooling Water System			84880	
	Demineralized/Condensate Recovery/Plant and Potable Water Systems	10	-7		
	Waste Water Treatment	-95			100
	Miscellanea				
	CO2 CAPTURE UNIT				
4000	CO2 capture unit		2	8220	47840
5000	CO2 compression				
	BALANCE	0 *(2095)*	0.0	191,000 *(60,800)*	52,410 *(57,590)*

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

Table 2. Case 2 (Air Cooling) – Water consumption summary

CLIENT: IEAGHG	REVISION: 0
PROJECT NAME: CO2 capture at coal based power and H2 plants	DATE: Jul-13
PROJECT No. : 1-BD-0681 A	MADE BY: NF
LOCATION : The Netherlands	APPROVED BY: LM

Case 2 (AC) - Water consumption

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery CW DT = 8°C [t/h]	Primary cooling medium
1000	FEEDSTOCK AND SOLID HANDLING				NO PRIMARY COOLING WATER IS AVAILABLE. AIR IS USED AS PRIMARY COOLING MEDIUM
	Solid Receiving, Handling and storage				
2000	BOILER ISALND and FLUE GAS TREATMENT				
	Boiler island				
	Flue Gas Desulphurization (Wet FGD)	85			
500	POWER ISLAND (Steam Turbine)				
	Condenser				
	Turbine and generator auxiliaries		5	6000	
BoP	UTILITY and OFFSITE UNITS				
	Cooling Water System				
	Demineralized/Condensate Recovery/Plant and Potable Water Systems	10	-7		
	Waste Water Treatment	-95.0			
	Miscellanea			140	
	CO2 CAPTURE UNIT				
4000	CO2 capture unit		2		
5000	CO2 compression				
	BALANCE	0 *(2095)*	0.0	6,140 *(57,590)*	- *(60,800)*

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

Table 3. Case 2 (Cooling medium sensitivity) – Electrical consumption summary

CLIENT:	IEAGHG		REVISION	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants		DATE	Jul-13
PROJECT No. :	1-BD-0681 A		MADE BY	NF
LOCATION :	The Netherlands		APPROVED BY	LM

Case 2 - Electrical consumption

Sensitivity to cooling system

UNIT	DESCRIPTION UNIT	Absorbed Electric Power CASE 2 (Cooling tower) [kW]	CASE 2 (Sea Water) [kW]	CASE 2 (Dry air) [kW]
1000	**FEEDSTOCK AND SOLID HANDLING**			
	Solids Handling	3350	3350	3350
2000	**BOILER ISLAND and FLUE GAS TREATMENT**			
	Boiler island (including ID fan)	22370	22370	22370
	Flue Gas Desulphurization (FGD)	4000	4000	4000
3000	**POWER ISLAND (Steam Turbine)**			
	Steam Turbine Auxiliaries	3300	3300	3300
	Steam turbine air condenser	-	-	5250
	Condensate and feedwater system	920	920	920
	Miscellanea	600	600	600
	CO2 CAPTURE UNIT			
4000	CO2 capture unit	82230	80630	88180
5000	CO2 Compression			
BoP	**UTILITY and OFFSITE UNITS**			
	Cooling Water System	15020	17600	2000
	Other Units	1440	1440	1460
	BALANCE	**133,230**	**134,210**	**131,430**

5. Overall Performance

The following Table shows the overall performance of the plant with the three different cooling systems assessed in the study.

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	**DATE**	Jul-13
PROJECT No. :	1-BD-0681 A	**MADE BY**	NF
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 2 - SC PC Plant Performance Summary

OVERALL PERFORMANCES				
		CASE 2 (Cooling tower)	**CASE 2 (Sea Water)**	**CASE 2 (Dry air)**
Fuel flow rate (A.R.)	t/h	325.0	325.0	325.0
Fuel HHV (A.R.)	kJ/kg	27060	27060	27060
Fuel LHV (A.R.)	kJ/kg	25870	25870	25870
THERMAL ENERGY OF FEEDSTOCK (based on LHV) (A)	**MWth**	**2335**	**2335**	**2335**
THERMAL ENERGY OF FEEDSTOCK (based on HHV) (A')	**MWth**	**2443**	**2443**	**2443**
Steam turbine power output (@ gen terminals)	MWe	958.1	969.3	947.2
GROSS ELECTRIC POWER OUTPUT (C) (1)	**MWe**	**958.1**	**969.3**	**947.2**
Boiler Island and FGD	MWe	26.4	26.4	26.4
Utility & Offsite Units consumption	MWe	16.5	19.0	3.5
Power Islands consumption	MWe	4.8	4.8	10.1
CO2 Capture and compression unit	MWe	82.2	80.6	88.2
Feedstock and solids handling	MWe	3.3	3.3	3.3
ELECTRIC POWER CONSUMPTION	**MWe**	**133.2**	**134.2**	**131.4**
NET ELECTRIC POWER OUTPUT	**MWe**	**824.9**	**835.0**	**815.8**
(Step Up transformer efficiency = 0.997%) (B)	MWe	822.4	832.5	813.3
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**41.0%**	**41.5%**	**40.6%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**35.2%**	**35.6%**	**34.8%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**39.2%**	**39.7%**	**38.8%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**33.7%**	**34.1%**	**33.3%**
Fuel Consumption per net power production	**MWth/MWe**	**2.84**	**2.81**	**2.87**
CO_2 emission per net power production	**kg/MWh**	**93.0**	**91.9**	**94.1**

(1) Steam driven BFW pumps are included

By comparing the results of the reference case with those of the alternative cooling system type, the following consideration can be made:

- *Sea water system*: Net electrical efficiency increases of about 0.4 percentage points, as the higher gross power production, related to the lower condensation pressure, and the lower plant auxiliary power demand more than offset the plant power auxiliary demand.
- *Air cooling system*. Net electrical efficiency decreases of about 0.4, as the lower gross power production, related to the higher condensation pressure, more than offsets the lower plant power auxiliary demand.

The overall CO_2 balance and removal efficiency is unchanged with respect to Case 3, as shown in the following.

CO_2 removal efficiency	**Equivalent flow of CO_2** kmol/h
INPUT	
FUEL CARBON CONTENT (A)	17495
FROM the DeSOX reaction (B)	109
OUTPUT	
Carbon losses (D)	166
CO_2 flue gas content	17438
Total to storage (C)	15700
Emission	1738
TOTAL	17604
Overall Carbon Capture, % ((C+D)/(A+B))	90.1

6. Environmental Impact

Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

6.1. Gaseous emissions

As for the reference case, main continuous emissions during normal operation are the flue gases from the boiler. No difference is expected in the flowrate and composition of this stream. The same minor and fugitive emissions, related to leakages within the handling of solid materials, are valid for these alternative systems.

6.2. Liquid effluents

Waste water treatment

As per the reference case, the plant does not produce significant liquid waste. FGD and CO_2 capture units blow-down is treated in a dedicated R.O. system to recover water.

6.2.1. Seawater system

For the seawater case, seawater is returned to the sea basin after exchanging heat in the plant, with a maximum temperature increase of 7°C. The main characteristics of the discharged seawater are listed below:

Maximum flow rate :	191,000	m^3/h
Temperature:	19	°C

6.3. Solid effluents

No difference is expected in the production of solid by-products with respect to the reference case.

7. Equipment list

The following equipment summary tables show the major impact on equipment design for the alternative cooling system types.

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: 2 - SC PC with carbon capture - Sea Water sensitivity case	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
		DATE	03-Jul-13			
		ISSUED BY	NF			
		CHECKED BY	LM			
		APPROVED BY	LM			

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	Difference with respect to reference case
	UNIT 3000 - STEAM CYCLE					
PK- 3001	**Steam Turbine and Generator Package**					
ST- 3001	Steam Turbine		970 MWe			**Size changed**
PK- 3002	**Steam Condenser Package**					
~~E- 3001~~	~~Steam condenser~~	~~Water cooled~~	~~776 MWth~~			**To be deleted (*)**
E- 3001	Steam condenser	Sea Water cooled	772 MWth			**To be added (*)**
	UNIT 5000 - CO2 COMPRESSION					
K - 5001 / 2	CO2 compression trains	Centrifugal, integrally geared, Electrical Driven 4 Stages	180200 Nm3/h p in : 1,6 bar a p out : 75 bar a	35000	*Intercooling:* *Condensate from Power island* *Sea Water ~~Cooling Water~~*	**Size changed** **Intercooling medium changed**
	COOLING SYSTEM					
E- 6001	Closed cooling water cooler		670 MWth			**To be added**
P- 6001 A /.. / H	Sea Cooling Water Pumps (primary system)	Centrifugal	16500 m3/h x 20 m	1100	*Twelve in operation*	**To be added (*)**
P- 6002 A/B/C/D/E	Cooling Water Pumps (secondary system)	Centrifugal	13500 m3/h x 35 m	1500	*Four in operation, one spare*	**Size changed**
~~CT - 6001 A/B~~	~~**Cooling Tower**~~ ~~includind:~~ ~~Cooling water basin~~	~~Natural draft~~	~~2 x 758 MWth~~ ~~Diameter: 120 m each,~~ ~~Height: 210 m,~~ ~~Water inlet: 17 m~~			**To be deleted**
~~P- 6001 A/.. /F~~	~~Cooling Water Pumps (primary system)~~	~~Centrifugal~~	~~15200 m3/h x 35 m~~	~~1700~~	*~~Four in operation~~*	**To be deleted (*)**
~~P- 6003 A / B~~	~~Cooling tower make-up pumps~~	~~centrifugal~~	~~2400 m3/h x 30 m~~	~~300~~		
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 12000 m3/h~~			
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					**To be deleted**
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					

(*) Different material selection (titanium) is considered for the steam condenser and cooling water pumps design to address corrosion issues related to the use of SW as cooling medium.

FOSTER WHEELER						
	CLIENT: IEA GHG	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
	LOCATION: The Netherlands	DATE	03-Jul-13			
	PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	NF			
	CONTRACT N. 1-BD-0681 A	CHECKED BY	LM			
	CASE: 2 - SC PC with carbon capture - Air cooled sensitivity case	APPROVED BY	LM			

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	Difference with respect to reference case
	UNIT 3000 - STEAM CYCLE					
PK- 3001	**Steam Turbine and Generator Package**					
ST- 3001	Steam Turbine		947 MWe			**Size changed**
PK- 3002	**Steam Condenser Package**					
~~E- 3001~~	~~Steam condenser~~	~~Water cooled~~	~~776 MWth~~			**To be deleted**
AC- 3001	Air cooled Steam condenser		780 MWth	70 x 90 kWe		**To be added**
	UNIT 4000 - CO2 CAPTURE					
~~E-~~ AC-001	Flue gas cooling water air cooler		Duty: 610 MWth (both train)			**Changed from CW cooler to air cooler**
~~E-~~ AC-002	Wash water air cooler					
~~E-~~ AC-004	Regenerator condenser					
~~E-~~ AC-006	Lean solution cooler					
	UNIT 5000 - CO2 COMPRESSION					
K - 5001 / 2	CO2 compression trains	Centrifugal, integrally geared, Electrical Driven 4 Stages	180200 Nm3/h p in : 1,6 bar a p out : 75 bar a	35000	*Intercooling:* *Condensate from Power island*	**Size changed** **Intercooling medium changed**
AC - 5001 / 2 / 3 / 4	Intercooler	Air cooler	35 MWth per train	510 kWe	*Air cooled ~~Cooling Water~~*	
	COOLING SYSTEM					
AC- 6001	Closed loop air cooler		60 MWth	1600 kWe		**To be added**
P- 6002	Cooling Water Pumps (secondary system)	Centrifugal	6150 m3/h x 35 m	800	*~~Four~~ One in operation, one spare*	**Size and number changed**
~~CT - 6001 A/B~~	~~**Cooling Tower**~~ ~~includind:~~ ~~Cooling water basin~~	~~Natural draft~~	~~2 x 758 MWth~~ ~~Diameter: 120 m each,~~ ~~Height: 210 m,~~ ~~Water inlet: 17 m~~			**To be deleted**
~~P- 6001 A/.. /F~~	~~Cooling Water Pumps (primary system)~~	~~Centrifugal~~	~~15200 m3/h x 35 m~~	~~1700~~	*~~Four in operation~~*	**To be deleted**
~~P- 6003 A / B~~	~~Cooling tower make-up pumps~~	~~centrifugal~~	~~2400 m3/h x 30 m~~	~~300~~		
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 12000 m3/h~~			
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					**To be deleted**
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					

CLIENT	:	IEAGHG
PROJECT NAME	:	CO_2 CAPTURE AT COAL FIRED POWER PLANTS
DOCUMENT NAME	:	BASIC INFORMATION ON OXY-COMBUSTION SC PC PLANT
FWI CONTRACT	:	1-BD-0681 A

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APPROVED BY	:	L. MANCUSO

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TABLE OF CONTENT

1. Introduction

The oxy-combustion supercritical pulverised coal (SC PC) plant is a combination of several process units. The main process blocks of the plant are the following:

- Air separation unit;
- Feedstock and solids handling;
- Oxy-combustion boiler island;
- Flue Gas Desulphurization (FGD);
- Steam cycle;
- CO_2 purification and compression.

Other ancillary utilities, such as cooling water, plant and instrument air, demineralised water support the operation of these basic blocks.

The focus of this Chapter D is to provide a general description of the major blocks of the oxy-combustion SC PC power plant, which are included in the oxy-combustion coal fired boiler-based case of the study, while Chapter D.1 through D.3 of the report gives basic engineering information for each alternative, with the support of specific heat and mass balances, utility consumption summaries, etc.

Table 1 provides key features of the oxy fired boiler-based case, technically and economically assessed in this study. In addition, some specific additional cases are developed to assess performance and costs of near zero emission plants (around 98% CO_2 capture) and to assess sensitivity to the cooling system; the list of these cases is shown in Table 2.

Table 1. SC PC oxy-fired boiler-based main study case

Case	Chapter	Description	Key features
Case 3	D.1	Oxy-combustion SC PC boiler with cryogenic CO_2 purification	• Generic state-of-art supercritical oxygen-fired boiler • Generic low pressure air separation unit • CFBS FGD technology • Air Products' CPU • Primary cooling system: natural draft cooling tower

Table 2. SC PC oxy-fired boiler-based additional study cases

Case	Chapter	Differences
Case 3 – Near zero emissions		
3.1	D.2	• Around 98% CO_2 capture through Air Products' PRISM® membrane technology
Case 3 – Sensitivity to cooling water system		
3 - (SW)	D.3	• Primary cooling system: sea water
3 - (AC)		• Primary cooling system: air cooling

2. Basic information of main process units

2.1. Feedstock and solids handling

2.1.1. Coal storage and handling

This unit is the same as the one described in chapter C for the air-fired boiler cases. Anyhow, the description of the unit is here below reported for clarity of the reader.

The scope of the feedstock receiving, handling and storage unit is to unload, convey, prepare, and store the coal delivered to the plant.

The coal is delivered from a port to the plant by train. The unloading is done by a wagon tipper that unloads the coal to the receiving equipment. Coal from each hopper is fed directly into a vibratory feeder and subsequently discharged onto a belt extractor. A conveyor and transfer tower system finally delivers the coal to the open stockyard (as-received coal).

The storage pile is designed to hold an inventory of 30 days of design consumption to allow the facility to hedge against delivery disruptions.

From the storage piles, the coal is discharged onto enclosed belt conveyors to two elevated feed hoppers, each sized for a capacity equivalent to two hours. Coal is discharged from the feed hoppers, at a controlled rate, and transported by belt feeders to parallel crushers, each sized for 100% of the full capacity. The crushers are designed to break down big lumps and deliver a coal with lump size not exceeding 35 mm. Coal from the crushers is then transferred by enclosed belt conveyors to the day silos close to the boiler island (as-fired coal).

Two magnetic plate separators for removal of tramp iron and two sampling systems are supplied for both the as-received coal and the as-fired coal. The recovered iron from the separators is delivered to a reclaim pile, while data from the analyses are used to support the reliable and efficient operation of the plant.

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

2.1.2. Lime storage and handling

Lime is delivered to the plant site by trains and is stored in dedicated silos, equipped with stacking and reclaiming machines. The storage capacity is made to ensure the plant is capable of feeding at maximum capacity for approximately 30 days.

Hydrated lime is prepared at site. A hydrated lime silo is provided to cover the requirement of the hydrated lime for the desulphurization process in case of malfunction of the hydration system; the hydrated lime silo is located close to the scrubber.

For the FGD process the hydrated lime must be transported from the hydrated lime silo to the CFBS. For the hydrated lime transportation a speed controlled rotary valve with double flap, motor, feed ejector and blower are used. The rotary valve is used to dose the required amount of absorbent. The blower air transports the added absorbent via a piping system to the scrubber.

2.1.3. *Fly and bottom ash collection and storage*

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, fly ash is loaded by gravity to trucks for transportation. Cyclones and exhaust filter bags are used to prevent air contamination.

The bottom ash is collected and crushed by a grinder to reduce the lump size, thus making handling and transportation easier with conveyors that bring ash to the storage.

2.1.4. *FGD by-product storage and handling*

The FGD by-product is discharged from the insulated filter hoppers by means of a control valve into the dedicated product silo, within the storage and handling unit battery limits. The equipment for product transport consists of the same components as for the hydrated lime conveying system: speed controlled rotary valve with double flap, motor, feed ejector and blower.

The design of residue silo foresees enough space to allow discharging to either truck or train wagon. Minimum storage capacity is approximately 30 days.

2.2. Boiler Island

The boiler 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 yet. However, based on literatures studies, it is expected that the behaviour and design features of the boiler would not be different from those of air fired plants [1, 2].

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[1] A. Seltzer, Z. Fan, H. Hack, *Design of a flexi-Burn™ Pulverised Coal Power Plant for Carbon Dioxide Sequestration* , 34th International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, Florida (USA)

[2] A. Robertson, H. Agarwal, M. Gagliano, A. Seltzer, *Oxy-combustion boiler material development*, 35th International Technical Conference on Clean Coal & Fuel System, Clearwater, Florida (USA)

The following description refers to the simplified scheme shown in Figure 1.

The boiler is a single pass tower-type super critical boiler. For reduction of NOx emission level, the firing system is provided with staging in the furnace, incorporating multi-stage supply of combustion oxygen and flue gas. Oxygen at 97%vol purity from the Air Separation Unit is supplied to the burners.

Hot combustion products exit the furnace and pass through the radiant and convective heating surfaces for steam generation and superheating. Then, flue gases exiting the convective section at 340°C are used to heat the primary and secondary recycle flue gas streams via a regenerative gas/gas heater. Furthermore, flue gases are de-dusted via the ESP and split into two, with one stream forming the secondary recycle and returning back through the gas/gas heater (exit temp 330°C) to the burners. The remaining stream is cooled, dried and split again to form primary recycle and net flue gases (CO_2 product stream). The primary recycle passes through the FGD and then through the gas/gas heater (exit temperature 250°C) and it is finally delivered to the coal mills. For additional details on the selection of the FGD technology and its positioning (i.e. primary recycle, secondary recycle or whole flue gas flow) reference has to be made to section 2.3. The pulverized fuel is dried in the mill using this flow and transported to the burners. The net flue gases are sent to the downstream CO_2 purification and compression unit.

Feed water enters the economizer, recovers heat from the combustion gases and then passes to the water wall circuits enclosing the furnace. The fluid then passes through heating surface banks to convective primary superheat, radiant secondary superheat and then to convective final superheat. The steam finally exits the steam generator to flow to the HP steam turbine module. Returning cold reheat steam passes through the reheater and is returned to the IP steam turbine module.

The furnace bottom comprises hoppers with a clinker grinding system situated below it. Ash passes through the clinker grinder to the ash handling system. Fly ash is collected from the discharge hoppers on the economisers and the ESP.

2.2.1. *Key features of Oxy-combustion boiler*

As almost pure oxygen is used for combustion, there is a deficient mass flow rate in the boiler due to absence of inert nitrogen present in standard air fired plants, which leads to the following:

- Overall balance of heat absorbed throughout the furnace chamber changes substantially, as the same heat quantity is introduced to a reduced mass of combustion products. This would result in greatly increased temperatures, and consequently increased radiant heat pick-up, greater slagging and higher NOx emissions. Furthermore, the reduced volumetric flow (and hence gas velocity) in the convective passes of the boiler would lead to lower heat transfer coefficients and reduced heat absorption.

- Properties of the flue gases and design of the furnace would be considerably different due to the high content of CO_2 in the gases.

To compensate for this loss in mass flowrates and to reach flue gases characteristics similar to those of the air fired cases, a proper portion of the flue gases is recycled back to the furnace, so as to maintain the mass/volume flow at an acceptable level and to achieve a similar heat transfer in the radiant and convection sections as compared to conventional boilers. In addition, the oxygen flowrate is selected in order to maintain the oxygen concentration in the furnace (before combustion) at around 20%-30%, close to conventional air-fired boilers conditions.

Flue gas recycles

Two streams of recycle flue gas are required for the oxy-combustion system.

The Primary recycle stream, which passes through the coal mills, is used for drying and transportation of the pulverised fuel to the burners.

The primary recycle stream is characterised by low water content, so to be able to remove coal moisture at relatively low temperature level, and low SOx content in order to avoid the risk of acid corrosion in the mill machinery.

Because of the above, primary recycle is taken downstream of the final contact cooler, where the water content is reduced down to the dew point at 28°C, and it is sent firstly to the FGD unit and then heated up in the regenerative gas-gas heater, to increase the temperature above the dew point before being fed to the coal mills.

The secondary recycle stream provides the additional gas heat capacity to the burners to maintain temperatures within the furnace similar to those of air firing boilers. The wet solid-free secondary flue gas recycle is taken downstream of the electrostatic precipitator (ESP), to avoid excessive ash concentrations into the boiler flue gas passes and erosion of the related fan. A secondary air fan blows the flue gas recycle through the regenerative gas-gas heater to be heated up before being recycled into the boiler.

The combined primary and secondary gas recycle is approximately 68% of the original flue gas leaving the economiser.

Oxygen supply

O_2 purity supplied by the Air Separation Unit (ASU) is set to 97%mol. Several literature studies indicate this purity as the optimum point that minimises ASU + CPU total costs (operating and capital) [1, 2].

Most of the oxygen is mixed with the secondary recycle downstream of the gas-gas heater to avoid oxygen leakage to the flue gas. However, the oxygen content of the secondary recycle should not exceed 40% to avoid the need to specify pure oxygen construction materials standards for the ducting. The remaining portion of the oxygen is injected to the primary recycle, downstream of the coal pulverisers to minimize risk of fires and explosions in the mills, in the event of lower or no recycle flow.

Air leakage into the boiler

As the conventional boilers, also oxy-combustion boilers are operated at a slight vacuum to prevent leakage of hot flue gases at any level out of the system, for safety reasons. This leads to unavoidable ambient air leakage into the boiler, affecting the purity of the flue gases generated in the boiler. Air leakage represents the biggest source of nitrogen in the product gases, which is to be removed from the final CO_2 product.

Considering a good and adequate sealing for the boiler, the minimum air leakage obtainable on a new pulverized coal boiler could be about 1% of the flue gas flow [1, 3]. Other sources of air infiltration are the electrostatic precipitators and the FGD filters. For this study an overall air-in leakage of 3% of the flue gas has been considered.

Flue gas fans

A flue gas fan is installed on the secondary recycle downstream of the ESP to force the flue gas through the gas-gas heater back to the boiler. The ID fan is installed downstream of the final contact cooler, providing the primary flue gas recycle the required pressure to get back to the boiler through the FGD and the coal mills. Net flue gases (CO_2 product stream) are sent to the CO_2 purification and compression section at the same pressure of the primary flue gas recycle.

[1] A. Seltzer, Z. Fan, H. Hack, *Design of a flexi-Burn™ Pulverised Coal Power Plant for Carbon Dioxide Sequestration* , 34th International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, Florida (USA)

[2] IHI Corporation entrusted by New Energy and Industrial technology Development Organisation, *Feasibility Study for Carbon Dioxide Capture based on Oxyfuel Combustion Technology for Coal Fired Power Plant*, FY2010 Clean Coal Technology Promotion Project, March 2011

[3] IEAGHG Report 2005/9, *Oxy Combustion Processes for CO_2 Capture from Power Plant*

Heat Recovery

In an oxy-combustion boiler, the overall heat exchanged in the gas-gas heater is lower than in the air pre-heater in a conventional air fired boiler, as flue gas are recycled at high temperature. Available heat is recovered from the flue gases upstream of the ESP to preheat feed water. Condensate preheating can also be foreseen upstream of the final flue gas cooling in the contact cooler.

Indirect contact cooler

The CO_2-rich flue gas downstream of the heat recovery section, after the secondary recycle, is sent to a conventional contact cooler. The flue gases at around 110°C are sent to a venturi scrubber for first quench with water from the bottom of the contact column. In the column, the flue gases are cooled down to 28°C by contact with condensate that has been cooled against cooling water. Most of the SO_3 and HCl impurities in the flue gases are removed in the contacting column, while very little SO_2 or NOx is removed due to the low system pressure.

Around half of the flue gases from the top of the contact column are recycled back to the boiler as primary recycle. The remaining stream is sent to the downstream CO_2 purification and compression unit.

Air firing during start-up and up-set conditions

The oxy-combustion power plant is not designed for the continuous operation in air-firing mode. However, during start-up sequence and up-set conditions, e.g. trip of the ASU, the boiler can be switched to air firing for the time required for safe shutdown. In these conditions, the flue gases are released to atmosphere through the dedicated stack.

NOx emission

Because of the peculiarity of the Air Products' CO_2 purification unit (CPU), no secondary measures are foreseen for the NOx reduction (e.g. SNCR). In fact, nitrogen oxide formation is lower in oxy-fired conditions with respect to air-firing mode and almost all the NOx content is removed as nitric acid in the CPU.

Should the CPU not foresee the NOx removal section, the requirement of a secondary reduction system for NOx abatement would depend on both the emission limits and the CO_2 specification, because most of the NOx remain in the vent stream, while some is trapped in the condensed CO_2. As CO_2 specification requirements and emission limits for oxy-fuel applications are still not defined, some literature studies have considered the installation of the SNCR [(1)], others have not [(2)].

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[1] A. Seltzer, Z. Fan, H. Hack, *Design of a flexi-Burn™ Pulverised Coal Power Plant for Carbon Dioxide Sequestration* , 34th International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, Florida (USA)

[2] IEAGHG Report 2005/9, *Oxy Combustion Processes for CO_2 Capture from Power Plant*

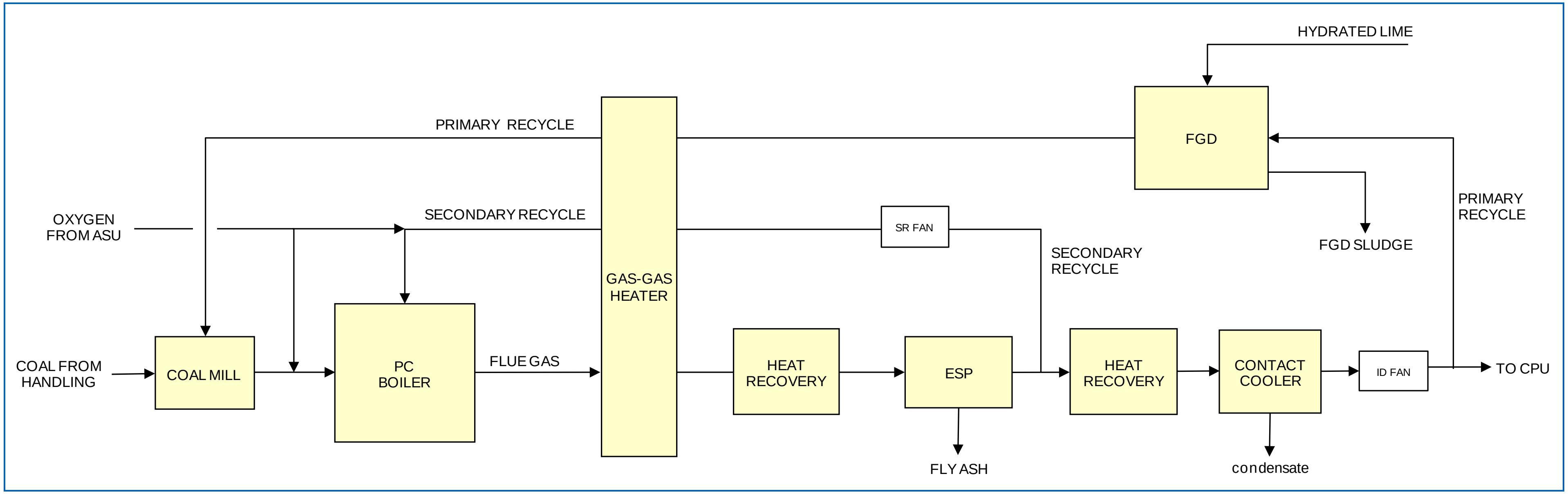


Figure 1. Oxy-fired boiler and flue gas recirculation block scheme

2.3. Flue Gas Desulphurization (FGD) system

A flue gas desulphurisation system is included to reduce the SO_X concentration in the furnace and in the flue gas recycle loop below the limit at which excessive gas-side tube corrosion occurs. Furthermore, the installation of the FGD allows controlling the SOx/NOx ratio to the optimum value for the downstream CO_2 purification and compression unit (CPU).

Two different FGD systems were investigated during the course of the study, seeking the support of different specialized technology suppliers:

- Wet bubbling FGD, provided by Chiyoda Corporation.
- Circulating fluid bed scrubbing FGD provided by Foster Wheeler Energie GmbH (FWE).

However, it is pointed out that conventional wet scrubbing FGD technologies could also be taken into for oxy-fuel applications.

Information received from each technology supplier is reported in the following sections 2.3.1 and 2.3.2, limited to the information that suppliers have authorized for disclosure. A high level assessment on key features and main advantages and disadvantages of each technology is also included in section 2.3.3.

It has to be noted that some differences may exist between figures in the vendors' information and those shown in the report of the specific study case. In fact, information in the attachments is based on preliminary stream properties and flowrates, as estimated during the early stages of the study; then, data have been slightly adjusted and optimised during study execution either by vendors or Foster Wheeler. Figures included in the report for each study case shall be considered as the final ones.

2.3.1. *FWE Circulating Fluid Bed Scrubbing (CFBS) Technology*

Foster Wheeler Energie GmbH (FWE) proposed for the IEAGHG study cases its Circulating Fluid Bed Scrubber (CFBS) system with hydrated lime injection and fabric filter, including product recirculation.

The general technical information on the CFBS technology is summarised in chapter C, section 2.4.2. The following sections include the specific set of information for the oxy-combustion boiler alternative, namely Case 3, provided by FWE to support the study.

FGD performance

The performance provided by FWE for Case 3 refers to the following characteristics and conditions of the flue gas entering the FGD unit.

Flue gas condition		
Flue flow rate	t/h	820
Gas Flow	Nm^3/h wet, act. O_2	459,520
Gas Flow	Nm^3/h dry, act. O_2	442,380
Gas Flow	Nm^3/h dry [(1)]	427,865
Temperature	°C	38 [(1)]
Flue gas composition (wet)		
H_2O	%	3,73
Ar	%	1.81
N_2	%	13.75
CO_2	%	74,24
O_2	%	6,25
Flue gas composition (dry)		
O_2	% dry	6,49
CO_2	% dry	77,12
Pollutants		
SO_2	mg/Nm^3 dry	5539
SO_3	mg/Nm^3 dry	108
Emission requirements		
SO_2	mg/Nm^3 dry	275
SO_3	mg/Nm^3 dry	< 5

(1) 38°C=28°C+10°C from ID fan.

Main consumption data

Clean gas temperature	°C	38
Flue gas inlet temperature	°C	38
Water consumption FGD	m^3/h	0
Compressed Air consumption	m^3/h	1000
ID-Fan (in case of 0mbar at battery limit and a	kW	900

foreseen pressure drop of FGD of 42 mbar)		
Pump and Other	kW	1050
Sum of electrical consumption	kW	1950
Hydrated lime consumption (purity 100%)	kg/h	8725
Product	kg/h	13000
Product composition according to design data		
$CaSO_3$	%	15 - 25
$CaSO_4$	%	15 - 25
$CaCO_3$	%	50
$Ca(OH)_2$	%	5 - 15

Requirements for FGD water quality

Max. content of solid matter	< 100	[ppm]
Max. content of abrasive components	< 10	[ppm]
Max. grain size of suspended matter	< 50	[microns]

Minimum required quality for soft burnt lime

Residue on mesh 0.09 mm	< 5	[%]
Particle size (d50**)	< 20	[µm]
Lime reactivity (T60*)	< 2	[min]
Purity (CaO content)	> 95	[%]
Moisture	≤ 1	[%]

Delivered hydrated lime minimum requirements

Particle size (d_{50}**)	≤ 5	[µm]
Hydrated Lime reactivity (BET) specific surface area	>18	[m^2/g]

*) T60 means temperature expansion from 20°C to 60°C at defined conditions.
**) d_{50} mean average particle size, the 50% weight fracture.

Plot area requirements

	OXY SCPC
Plot area	Approx. 35m x 10m

2.3.2. *Chiyoda Thoroughbred 121 (CT-201) Jet Bubbling Reactor process*

Chiyoda is the technology provider of the limestone forced oxidation flue gas desulfurization technology, named Chiyoda Thoroughbred 121 (CT-201) process, based on the simultaneous SO_2 absorption, oxidation, neutralization and crystallization in the Jet Bubbling Reactor (JBR).

An overview of the CT-201 process is attached to chapter C, section 2.4.3, including the specific set of information for Case 3, provided by Chiyoda to support the study.

2.3.3. *High level assessment of FGD technology*

Key features of the various FGD technologies were analysed in chapter C, section 2.4.4, in particular considering the following main aspects:

- FGD reagent and by-product,
- Operating experience,
- Water consumption,
- Sulphur removal efficiency.

The purpose of this section is to make a high-level discussion of specific aspects related to the preliminary selection of the FGD technology for the oxy-combustion alternative. More general considerations on the positioning of the FGD in the flue gas recirculation loop within oxy-combustion boiler are also discussed. However it has to be noted that optimisation of the sulphur oxide removal in oxy-fuel application (technology options, positioning, CAPEX/OPEX, heat recovery, integration with CPU, etc.) is strictly case-specific (e.g. coal sulphur content, CPU technology, CO_2 specification) and it would require a detailed analysis that is beyond the scope of the current study

Due to the SOx removal rate required in the oxy-combustion alternative and because of the low sulphur content in the coal feed, a full sized FGD installed to treat the entire flue gas flowrate is not deemed necessary, as it would lead to an unjustified high investment cost.

Depending on the technology, two different possibilities have been identified with each vendor, in order to reduce the SO_X content to a level that does not leads to corrosion issues in the boiler furnace and the flue gas recirculation duct (< 2000-3000 ppm).

With reference to the Chiyoda technology, the optimum flue gas inlet temperature is around 150°C, to avoid reduction of oxidation reactivity of absorbed SO_2 and crystallization of gypsum by-product. Therefore, the best suited configuration for this process is the installation of the FGD on the secondary recycle stream to the boiler island. In this configuration, around 60% sulphur removal efficiency is required to meet the above target, also providing a great flexibility in controlling the SOx content in the flue gas recirculation and in the flue gas to the CPU. On the other hand, the secondary flue gas recycle exits the FGD at around 65°C, and consequently more heat is required in the gas-gas heater to reach the proper boiler inlet temperature, resulting in less heat available for feed water heating in the boiler flue gas path.

FWE technology leads to the possibility of installing a smaller FGD on the primary recycle stream downstream of the flue gas fan, provided that the temperature increase through the fan is enough to provide the increase of the inlet temperature above the dew point, as required by CFBS technology. In this configuration, around 96% sulphur capture is required, maximising the capability of the FGD technology, though leading to a lower flexibility in the SOx control. In addition, the lower investment cost related to the smaller size is partially offset by the installation of the fabric filter, which is mandatory for the CFBS technology.

The following Figure 2 and Figure 3 show the two different flue gas schemes, depending on the FGD technology. The main differences described above are highlighted in the schemes.

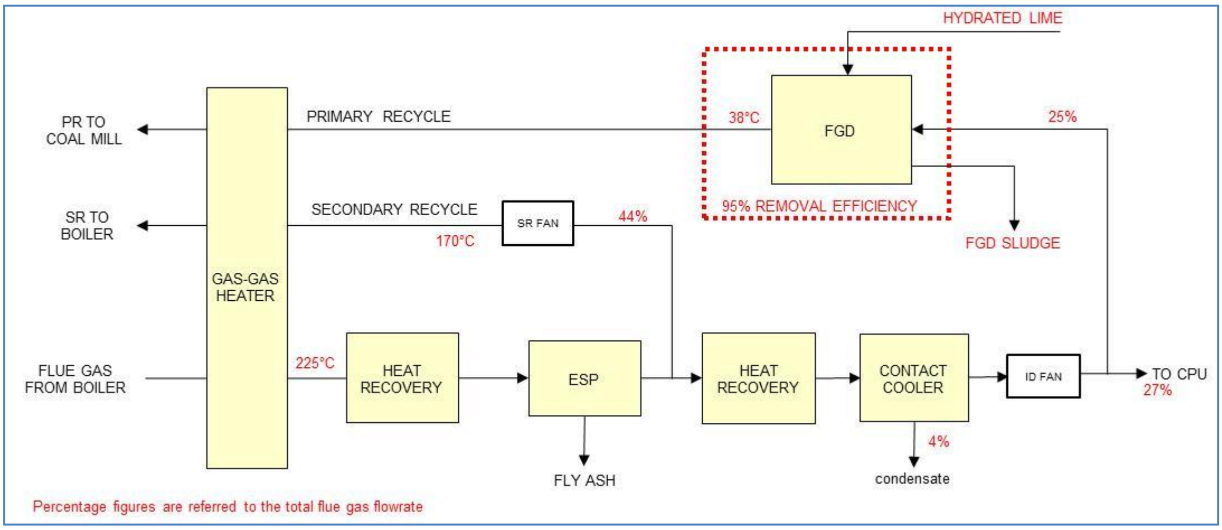


Figure 2. Flue gas configuration with dry FGD installed on primary recycle

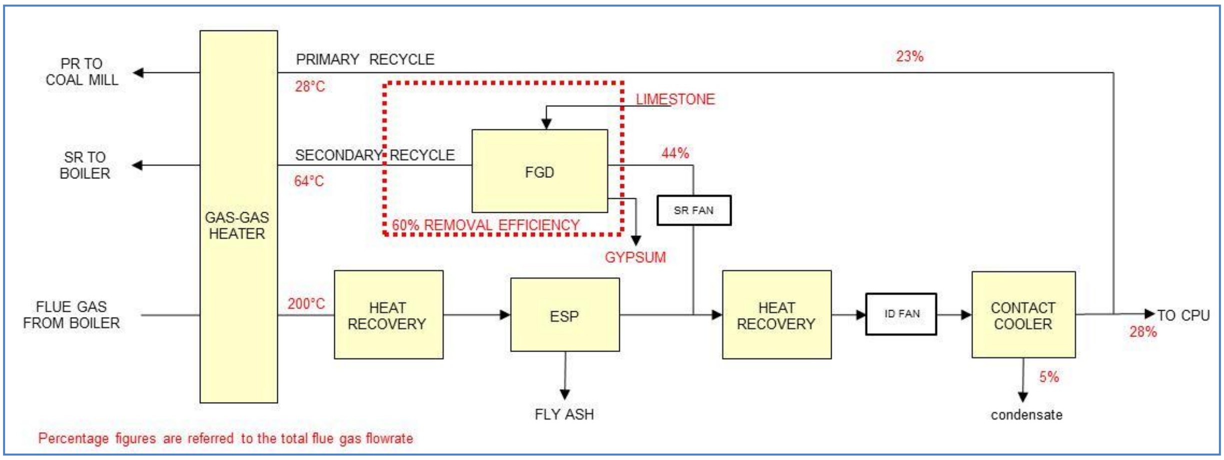


Figure 3. Flue gas configuration with wet FGD installed on secondary recycle

Extending the above consideration out of the design conditions of the specific study case, the following point should be considered for the FGD technology and its positioning in the plant configuration.

Coal sulphur content is of primary importance for the evaluation of FGD requirement, type and positioning as it fixes the desulphurisation efficiency required to lower the sulphur concentration in the furnace. In case of low coal sulphur content (< 0.5%wt) no FGD is required, as sulphur oxide concentration in the furnace and the recirculation loop remains below the threshold level to control corrosion without secondary reduction measure. If coal had a sulphur content in the range of 0.5-2%wt, the FGD can be installed either on the primary recycle, with high removal rate efficiency due to the lower flowrate, or on the secondary recycle, with low removal rate. These are the conditions of the specific study case. On the other hand, for a coal sulphur content higher than 2%wt FGD should be installed on the secondary recycle or even on the total flue gas flowrate. In this case, the primary recycle flowrate is too small to achieve the required sulphur removal, even maximising the removal efficiency.

Should the sulphur oxide not be removed in the CPU, the FGD requirement depends also on the maximum SOx concentration allowed in the CO_2 product. In fact, most of the SOx entering the CO_2 purification unit remains in the captured CO_2 and not in the inert gas stream discharged to the atmosphere.

2.3.4. *FGD technology for study cases development*

As shown in the previous sections, all FGD technologies meet the desulphurisation efficiency required for the proper operation of the plant. Moreover, being at study level it is not possible to give a firm recommendation on the best technology for sulphur removal. Therefore, preliminary selection only is made in this work, on the basis of generic and high-level criteria, with the solely purpose of completing the technical and economical assessment of the cases.

More specifically for the oxygen fired boiler-based cases of the study, it was decided to utilize the circulating fluid bed scrubbing FGD provided by FWE, mainly because the dry FGD technology is typically considered for the oxy-combustion boiler, preferring a solution with smaller size FGD and high removal rate, with respect to a bigger system with removal rate far below the capability of a high removal efficiency system as wet scrubbing or bubbling reactor FGD.

2.4. Carbon dioxide compression and purification

The purpose of this section is to cool, dry, compress and purify to the required level the product CO_2 stream from the indirect contact cooler before sending it to the pipeline, outside plant battery limits.

Nowadays several Companies (e.g. Air Liquide, Air Products, Linde and Praxair) have developed and tested at pilot plant scale the technology for the cryogenic purification process of oxy-fired boiler flue gases. Further development and demonstration is required at commercial scale to fully validate the processes.

For this study case, the CO_2 purification and compression section is based on Air Products' (AP) process, as described in the Air Products' patent N° EP 1 953 486 B1.

The CO_2 purification and compression unit consists of the following main sections:

- Sour compression for the combined removal of SOx and NOx.
- TSA unit.
- Auto-refrigerated Inerts Removal, including distillation column to meet the required oxygen specification in the CO_2 product.
- Final compression up to 110 bar.

Sour compression

The acidic impurities, such as SO_3, SO_2, HCl and NO_X as produced during combustion, need to be removed from the CO_2 stream to prevent corrosion of the export pipeline and comply with possible regulations. As written before, SO_3 and HCl are removed in the contacting column, so SO_2 and NO_X need to be treated at this stage of the process.

The Air Products' sour compression scheme is based on the reactions of the sulphur oxide and nitrogen oxide to form respectively sulphuric acid and nitric acid. These reactions occur at elevated pressure and in the presence of molecular oxygen and water, if enough contact time is provided. The latter acids are removed from the system as aqueous solution, producing a SO_2-free, NO_x-lean carbon dioxide stream.

Process chemistry

To remove NO from the CO_2, NO is first converted to NO_2 [1].

$$NO + ½\, O_2 \rightarrow NO_2 \qquad [1]$$

The kinetics of this reaction increases at low temperature and high pressure; at 15 bar only a few seconds are required to reach equilibrium and convert most of the NO to NO_2 especially since there is plenty of oxygen in the raw CO_2 stream, due to the excess oxygen required for combustion.

The second reaction of significance at this point is the reaction of NO_2 with SO_2 to form sulphuric acid:

$$NO_2 + SO_2 + H_2O \rightarrow NO + H_2SO_4 \qquad [2]$$

Once all of the SO_2 has been removed by equations 1 and 2, NO_2 is converted to nitric acid by the well understood process nitric acid process, with the NO formed in Equations 2 and 4 being reconverted to NO_2 by Equation 1:

$$2\, NO_2 + H_2O \rightarrow HNO_2 + HNO_3 \qquad [3]$$

$$3\, HNO_2 \rightarrow HNO_3 + 2\, NO + H_2O \qquad [4]$$

These reactions give a path-way for SO_2 to be removed as H_2SO_4 and NO and NO_2 to be removed as HNO_3. Any elemental mercury or mercury compounds present in the gaseous carbon dioxide are also removed as mercury is converted to mercuric nitrate since mercury compounds react readily with nitric acid. Typical nitric acid concentrations in the process are sufficient to remove all mercury from the carbon dioxide stream, either by reaction or dissolution.

Process description

The following description refers to the simplified scheme shown in Figure 4.

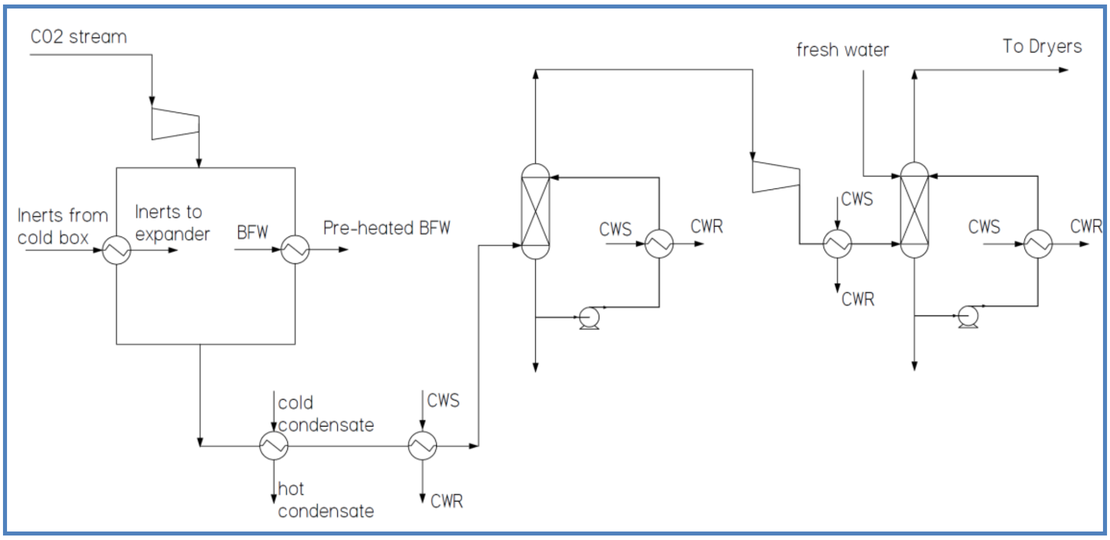


Figure 4. Sour compression scheme to 30 bar

The CO_2 stream entering Air Products' package is compressed adiabatically to 15 bar, producing a stream of compressed impure carbon dioxide at about 300°C. Such stream is used to preheat boiler feed water and the vent stream from the downstream inerts purification section, in two exchangers arranged in parallel configuration, and then condensate. Final cooling is made against a stream of cooling water to produce a stream of CO_2 at about 26°C. The conversion of sulphur oxide to sulphuric acid starts as the CO_2 rich stream is cooled down in these exchangers.

The CO_2 stream is fed to the bottom of the first contacting column, where it ascends and contacts counter-currently a stream of descending acid water. The column is designed to provide sufficient contact time between the ascending gas and the descending liquid to completely convert the remaining SO_2 to sulphuric acid and also to convert part of NO_x to nitric acid. Thus, a stream of SO_2-free carbon dioxide is removed from the top of the column and a stream of aqueous sulphuric acid that also contains some nitric acid is removed from the column bottom. The liquid is then pumped and split into two: part of the liquid is cooled down and recycled to the same contacting column as reflux, whereas the excess of liquid is sent to the Waste Water

Treatment unit. Due to the high acid content of the discharged stream (around 5%v sulphuric and nitric acid), specific treatment is required in the WWT (refer to section 2.7.5 for further details). However it has to be noted that further development is still needed to fully understand the most suitable treatment option and related cost.

The stream of SO_2-free carbon dioxide from the top of the first contacting column is compressed to about 30 bar by an integrally geared centrifugal compressor. Heat of compression generated in the compression stage is removed by means of a cooling water exchanger in order to produce a stream of cooled, compressed SO_2-free carbon dioxide, which is fed to the bottom of the second contacting column.

The gas stream ascends the column and contacts counter-currently a stream of aqueous nitric acid solution. The column is designed to provide sufficient contact time between the ascending gas and the descending liquid to almost completely convert the remaining NO_x contaminant to produce nitric acid. The SO_2-free and NO_x-lean carbon dioxide stream is removed from the top of the column and a stream of aqueous nitric acid is removed from the column bottom. The liquid is then pumped and divided into two: part of the liquid is cooled down and recycled to the same contacting column as reflux, whereas the excess of liquid is sent to the Waste Water Treatment unit. A stream of fresh water is injected into the top of the column to increase NO_x conversion and to ensure that no acid droplets are entrained in the gas stream leaving the column top.

All the SO_2 and about 90% the NO_x contained in the flue gas are removed in the sour compression and a stream of SO_2-free and NO_x-lean carbon dioxide is obtained. Such stream is then sent to the following sections of CO_2 inerts removal and compression.

TSA system

The raw CO_2 gas passes through a thermally regenerated dual bed desiccant dryer to lower the dew point below -55°C before entering the auto-refrigerated inerts removal section. This desiccant dryer system prevents ice formation which could cause a blockage in the cold box as well as causing corrosion in the pipeline.

Auto-refrigerated inerts removal

The inerts removal process is based on the principle of phase separation between condensed liquid CO_2 and insoluble inerts gas at a temperature of –55°C, which is very close to the triple point, or freezing temperature, of CO_2.

The actual CO_2 pressure levels and the configuration selected for the separation are fixed by the CO_2 purity and recovery specification requirements. The inerts removal process configuration is mainly affected by the oxygen specification in the CO_2 product of 100 ppm, which implies the installation of a distillation column operating at around -37°C and a flash separator at around -55°C.

The following description refers to the simplified scheme shown in Figure 5. Numbers in brackets refer to the stream tag in the figure.

The CO_2 feed gas pressure is 30 bar. The necessary refrigeration for plant operation is obtained by evaporating liquid CO_2 at a pressure around 16-17 bar and 5.6 bar and compressing these two low pressure gas streams in the main CO_2 product compressor to the final pipeline delivery pressure of 110 bar.

The dry gas from the TSA unit (102) is fed to the cold box and is cooled to -5°C (104) with the returning stream evaporating and superheating CO_2 streams and the waste streams in the main exchanger, then it is used as heating medium in the distillation column reboiler (E106), exiting at about -20°C. The main heat exchangers are multi-stream plate-fin aluminium blocks.

The stream from the reboiler (105) is cooled further to –54°C where it partially condenses (106) and is passed to the flash drum. The pressure at this point is critical in controlling the process since cooling the vapour below –56.2°C would lead to the formation of solid carbon dioxide. The vapour from the separator (107), containing the separated inerts together with some CO_2, is sent back through the heat exchangers for a first pre-heating. This stream of inerts (108), which is at a pressure of 30 bara, is then heated against hot CO_2 compressed at 15 bar in the sour compression section and is expanded in a power recovery turbo-expander (K103) before being vented (110).

The liquid stream from the separator (111), at 30 bara, is heated in the second main heat exchanger and is then expanded through a valve to 16-17 bara (V103), corresponding to around -37°C before entering the distillation column. The vapour stream exiting the distillation column (114), which still contains a large portion of CO_2, is heated through both the main heat exchangers, re-compressed to 30 bara, cooled against cooling water and finally recycled to the dry gas feeding the cold box (117).

The liquid stream exiting the bottom of the distillation column (118) is split into two streams which are both expanded through a valve to two different pressure levels and heated up in the main heat exchangers, providing the necessary refrigeration.

Final compression stage

The CO_2 vapour stream leaving the first main heat exchanger at 5.6 bara (121) is then compressed in an integrally geared compressor to the same pressure as the second CO_2 stream (126) (around 16-17 bara). The two streams are combined and compressed in two intercooled stages (K101) to the required pressure of 110 bara.

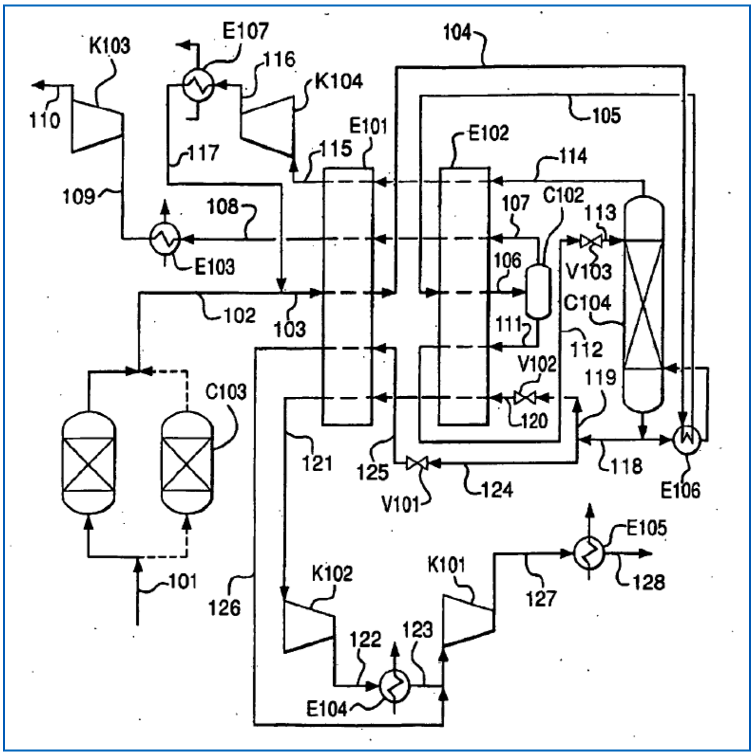


Figure 5. Auto-refrigerated inerts removal process (from EP 1 953 486 B1)

High level assessment on CO_2 purification and compression unit configuration

For this study, different options have been evaluated in order to identify the best solution from a technical and electrical efficiency point of view. As described above, the following key features characterised the final selected option:

- Axial compressor followed by an inline radial compressor, for the 1-15 bar compression.
- Vent gas heating to the maximum possible temperature using the hot CO_2 stream leaving the 1-15 bar compression stage as heating medium.
- BFW and condensate pre-heating against the hot stream leaving the 1-15 bar compression stage.
- Integrally geared intercooled machines for the 15-30 bar compression and the final compression of the purified CO_2 product stream.

The following alternative configurations have been analysed with the help of Air Products, in addition to the selected option described above:

- *Installation of an intercooled integrally geared machine for the 1-15 bar compression*. In this case, the overall consumption of the compression train is lower, but no thermal integration is possible with the steam cycle. In particular, the vent gas stream should be heated-up completely with high pressure steam or recycled back to the boiler for heating before being expanded in the CPU, adding more complexity to the plant. Cooling water requirements also increase.

- *BFW and condensate pre-heating only downstream of 1-15 bar compression.* In this case a higher thermal duty is available for BFW preheating, but no heat is available to heat-up the vent stream before expansion. As for the previous option the vent gas stream would need to be heated-up completely with high pressure steam or recycled back to the boiler for heating with flue gas before being expanded in the CPU. In this latter option, the difference in efficiency with respect to the selected configuration is negligible, but the recycle of the flue gas to the boiler would increase plant layout complexity.
- *Sensitivity to inert vent stream temperature.* The temperature of the vent stream before being expanded offers an additional degree of freedom in the optimisation of the CPU configuration. The minimum temperature is set by the minimum temperature downstream of the expander to avoid condensation, while the maximum is limited by the temperature of the hot CO_2 stream used as heating medium. Within this range, the higher the vent stream temperature, the lower the heat available for BFW pre-heating against hot CO_2, but the higher the expander power production. In addition, as part of the vent stream is sent to the TSA drying for bed regeneration, a lower vent stream temperature implies a higher duty required to the regenerator heater, thus increasing the HP steam consumption. For this study case, the vent stream is heated-up to the maximum possible temperature, in order to reduce steam extraction from the steam cycle, reducing movement between the two units.

High CO_2 capture rate: the PRISM® membrane configuration

The above described CO_2 purification and compression process achieves a CO_2 recovery of around 90%, as required for the main study case. An alternative with near zero CO_2 emissions was also investigated, consisting of processing the inert vent stream from the auto-refrigerated process through dedicated membranes, in order to maximise CO_2 recovery from this stream that would otherwise be vented to the atmosphere.

For this purpose, Air Products' process foresees a series of PRISM® membrane modules that recovers CO_2 from the vent stream, recycling it to the boiler, as schematically shown in Figure 6 [(1)].

[1] The same concept of including vent gas permeation in membrane system is under development by Air Liquide within their Cryocap™ process. *M.Leclerc, R. Dubettier, F. Lockwood, High recovery Near-Zero CPU*, OCC3, Ponferrada, Sept. 2013

An additional bonus is that whilst the membrane is recovering CO_2 it is also recovering oxygen that is also recycled to the boiler with the co-recovered CO_2. This reduces the amount of oxygen required from the air separation unit, corresponding to a lower ASU power demand.

The dry oxygen and carbon dioxide-rich stream is returned back to the boiler and mixed with the secondary recycle. In fact, though it is a dry stream as required to be used for coal drying and transportation from the mill to the burners, the high oxygen content (around 25%) leads to possible risk of explosion, in particular in case of no primary recycle flow.

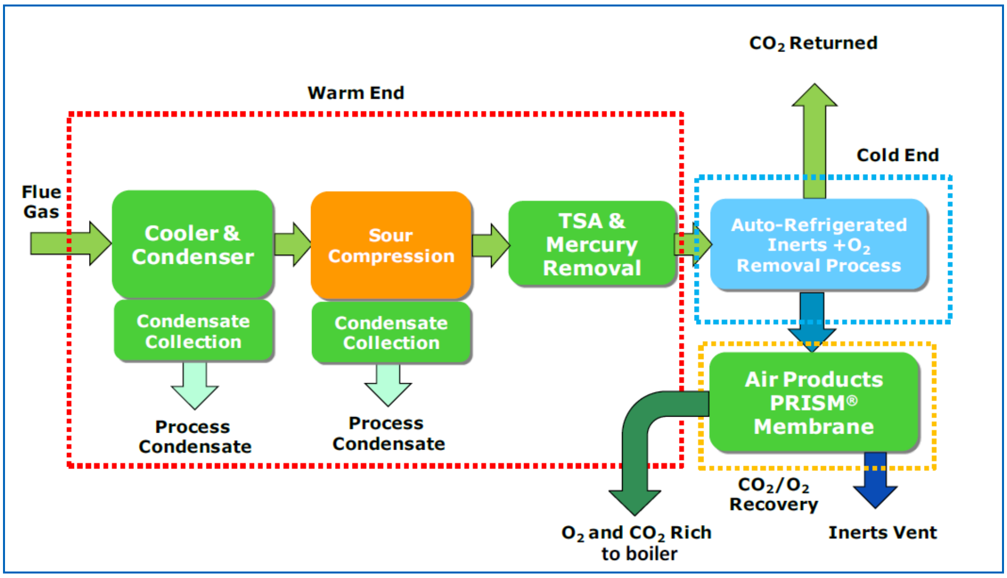


Figure 6. Air Products' process including PRISM® membrane

2.5. Air Separation Unit

The ASU is based on the cryogenic distillation of atmospheric air at low pressure and is designed to produce oxygen at 97 %mol O_2 purity. For this study case a generic ASU has been simulated with no reference to a specific supplier.

The power consumptions related to the ASU for oxy-combustion application is in the range of 190-210 kWh/ton O_2. A figure on the lower side of this range has been considered for this study as all of the ASU suppliers are currently improving their technology and they expect to be ready in the next few years.

The amount of oxygen required for the oxy-combustion boiler is 16,650 tonne/day. The configuration proposed for this study case is based on three (3 x 33%) cryogenic ASUs of 5,550 tonnes/day each. This is within the range of ASU currently being commercially offered. Single train axial flow air compressors required for this duty are also commercially available. Due to the high reliability of the air compressor machine, no sparing equipment is foreseen.

The cycle chosen is one in which gaseous oxygen (GOX) is produced by boiling liquid oxygen (LOX) which is ideally suited to this application as the delivery pressure required is low.

The ASU configuration typically proposed for oxy-combustion application is based on three-pressure levels distillation columns:

- The conventional double column includes the low pressure column with its reboiler integrated with the condenser of the high pressure column. The column pressures are set to give a temperature driving force in the reboiler/condenser.
- An extra column is added operating at intermediate pressure. The condenser for this column also integrates with a reboiler in the low pressure column but at a lower temperature, boiling a liquid stream higher up within the low pressure column.

This arrangement minimises the amount of feed air that must be compressed to the higher pressure of high pressure column condenser, leading to the low power requirement of the whole unit.

With reference to the simplified block flow diagram shown in Figure 7, the plant includes the following main sections.

Compression system

Process air is cleaned from dust and particulate matter through an intake air filter before being fed to the main air compressor (MAC), where it is compressed to 3.5 bar. An axial compressor without inter-cooling is used to compress the feed air, so as to provide a higher temperature air stream which can be used as a source of heat for preheating condensate from the steam cycle. The compressed air is further cooled by cooling water and the condensed water is then separated in a dedicated separator.

Adsorption front end air purification system

Before air is cooled to cryogenic temperatures in the main heat exchanger, water vapour, carbon dioxide and other trace impurities are removed in order to avoid the cryogenic equipment blockage.

The selected configuration includes two purification systems based on dual bed adsorbers: one system after the first air compression stage for feed to the intermediate pressure column and the other after the last compression stage to the high pressure column pressure.

The adsorber operates on a staggered cycle, i.e one vessel adsorbing and the other being reactivated. The adsorbents generally used consist of layers of alumina or silica gel plus layers of zeolite. The adsorber vessels are vertical cylindrical units having annular adsorbent beds.

Cold box

Both the intermediate and high pressure air streams exiting the two adsorbent systems are split in two. These four streams are fed directly to the main heat exchanger, consisting of several parallel aluminium plate-fin heat exchanger blocks manifolded together.

The first intermediate pressure stream is cooled close to its dew point and fed to the bottom of the intermediate pressure column. Downstream of the main heat exchanger the second intermediate pressure stream is expanded in a centrifugal expansion turbine providing the power for the centrifugal compressor, providing the air feed to the high pressure column. The expanded air is fed to the middle of the low pressure column in order to provide refrigeration for the operation of the ASU.

The first high pressure stream is cooled close to its dew point and fed to the bottom of the high pressure column while the second high pressure air stream is cooled and condensed in the main heat exchanger against boiling oxygen. The resulting liquid air from the main exchanger is fed to the middle of both the high pressure and intermediate pressure columns.

In the high and intermediate pressure columns, the gaseous air feed is separated into an overhead nitrogen vapour and an oxygen-enriched bottom liquid. The nitrogen vapour from the high pressure column is condensed against boiling oxygen in the low pressure column sump, providing the liquid reflux for both the high and the low pressure columns. Boiling oxygen in an upper stage of the low pressure column provides the condensing medium also for the nitrogen from the intermediate pressure column is condensed. The resulting liquid nitrogen stream provides the reflux stream for both the low pressure and the intermediate pressure columns.

Liquid oxygen from the bottom of the high and intermediate pressure columns is cooled in the subcooler against waste nitrogen and is flashed to the low pressure column as intermediate feeds. The feeds to the low pressure column are separated into a waste nitrogen overhead vapour and a liquid oxygen bottom product, which reaches the required purity of 97% by volume.

The waste nitrogen is withdrawn from the top of the low pressure column and warmed in the subcooler and the main heat exchanger. A portion of the nitrogen stream from the main exchanger is used for adsorber reactivation. The remaining dry nitrogen is vented through a Chilled Water Tower to produce chilled water by evaporative cooling.

Pure liquid oxygen is withdrawn from the bottom of the low pressure column and returned to the main heat exchanger where it is vaporised and warmed up to ambient conditions against boosted air feed to the columns. The gaseous O_2 is then regulated and supplied to the power plant.

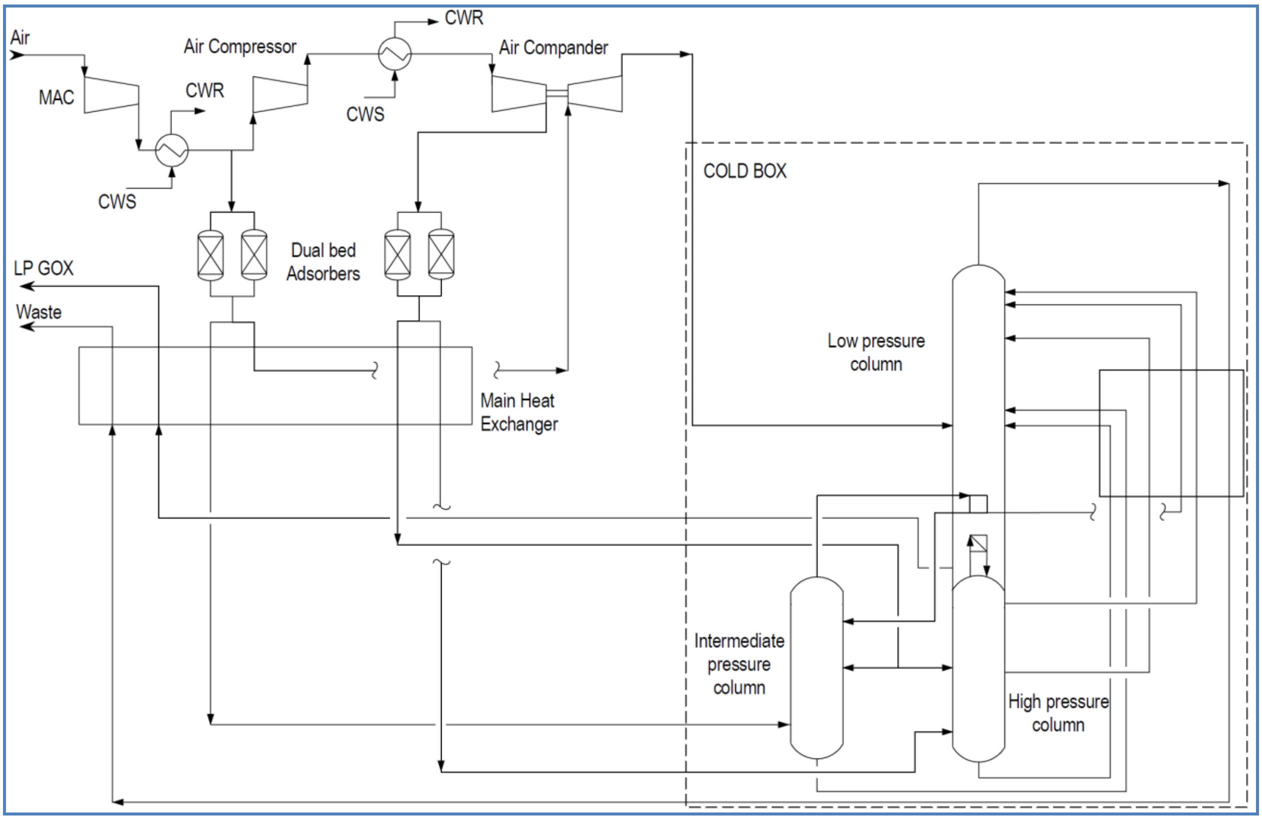


Figure 7. ASU simplified scheme

Oxygen back-up

The oxy-combustion PC boiler is designed in such a way as to allow air firing as a fallback position in the event of ASU trip. Therefore, enough oxygen back-up storage is provided in order to allow a controlled changeover to air-firing.

Backup is in the form of liquid oxygen (LOX) at a pressure of 2.5 bar in a vacuum insulated storage tank, common to all trains, filled by gravity from the ASU.

2.5.1. *Impact on ASU design for high operational flexibility*

The ASU significantly impacts the overall net electricity production of the plant, mainly due to its high auxiliary power demand. Therefore, if the plant were called to operate flexibly with respect to the electricity daily demand, a possibility could be to operate the ASU at partial load during peak hours, while the rest of the plant runs at full load, thus reducing the auxiliary consumption and increasing the overall net electricity production. Vice versa, during low-electricity demand period, the ASU could be operated at load higher than that of the process unit, producing the extra oxygen required during peak demand period.

On this respect, LOX (and associated liquid air) storages become of primary importance because they allow decoupling the ASU from the rest of the power plant, providing the buffer capacity required for balancing the cycling operation of the plant. Design changes and related costs mainly depend on the load demand cycle the plant is required to respect. The following Table 3 summarises the expected impact on performance and costs of the additional LOX and liquid air storages required to follow two commonly requested power demand cycles, the first to cover daily peak demand and the second to follow a weekly cycle. For further details on the provision of LOX and liquid air storage for enhancing plant operating flexibility and for plant capabilities to operate efficiently at part load reference shall be made to IEAGHG report 2012/06 '*Operating Flexibility of power Plant with CCS*'.

Table 3. LOX storage option for Oxy-combustion plant flexible operation

Case description	Delta performance	Delta capital costs
LOX / liquid air covering daily peak	+6% NPO (2 hours per day)	+1%
LOX/ liquid air covering weekly peak	+5% NPO (60 hours per week)	+2-3%

2.6. Steam Cycle

The following description makes reference to the simplified process flow diagram of the steam cycle, attached to the end of this section.

The steam cycle is mainly composed of the Steam Turbine Generator (STG) and the water pre-heating line. It consists basically of one supercritical steam turbine, equipped with one steam condenser water cooled type, with multiple extractions for the pre-heating of the condensate and boiler feed water. In addition, the condensate and the boiler feed water are heated as far as possible utilising the available heat from the ASU, CO_2 compression and purification and flue gas sources in order to maximise the overall efficiency of the plant.

The turbine consists of HP, MP and LP sections all connected to the generator with a common shaft. Supercritical steam from the boiler is sent to the steam turbine through the stop valves and control valves. 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 MP turbine. A small steam stream is sent to the CPU for inert gas heating upstream the expander.

Boiler and turbine interface data are as follows:

HP turbine inlet:	270 bar; 600°C
MP turbine inlet:	60 bar; 620°C

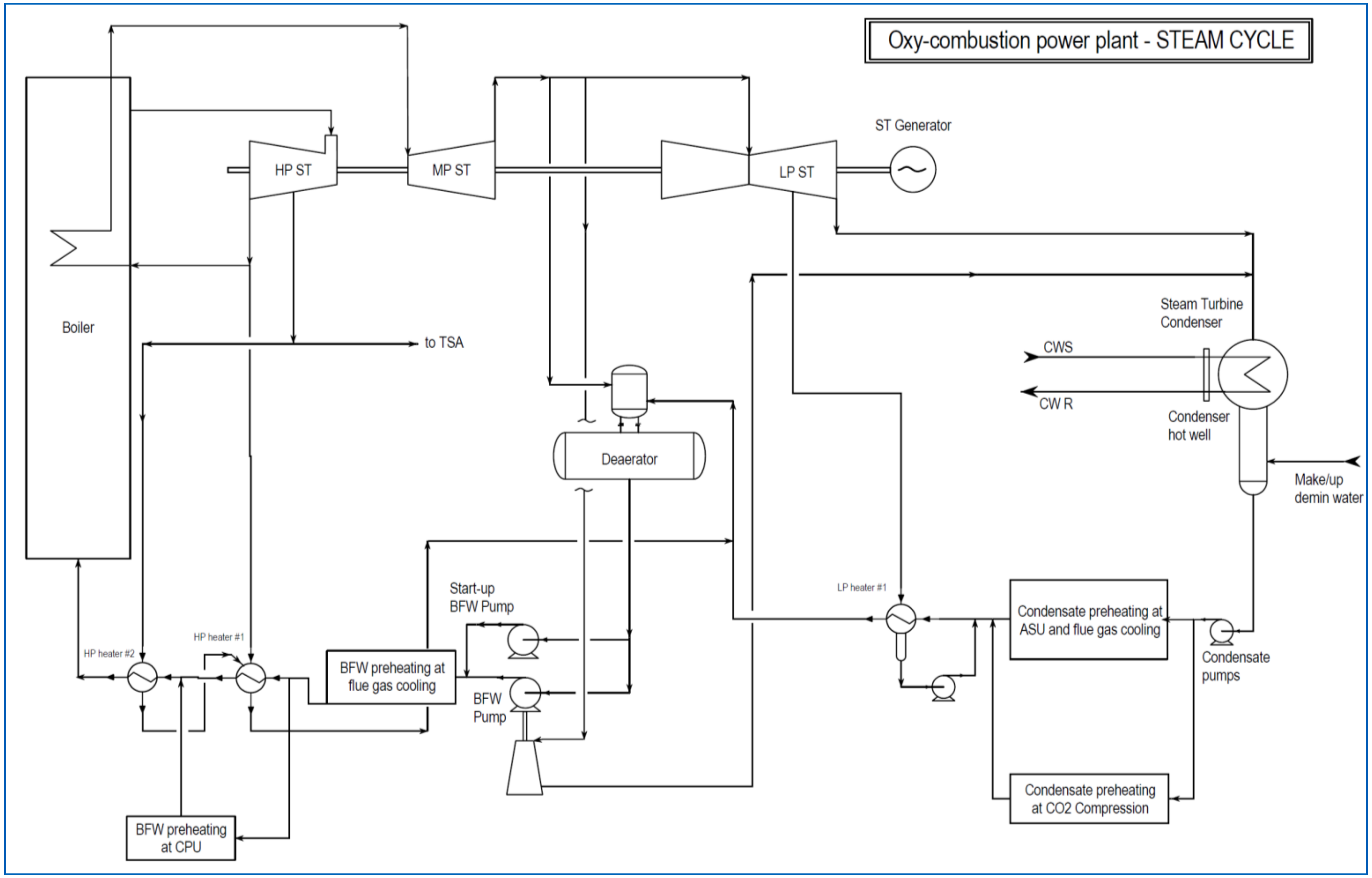
Exhaust steam from the MP turbines then flows into the double flow LP turbine system and downward into the water-cooled condenser at 4.0 kPa, corresponding to 29°C.

Recycled vacuum condensate from the condenser hot well is pumped by the condensate pumps to the process unit for heat recovery from the flue gases and in the compressor intercoolers of CPU and ASU. This allows reducing the LP steam extraction in the preheat train. Only the final pre-heater upstream of the deaerator requires steam from the steam turbine.

The preheated condensate stream is then sent to the deaerator. Exhaust steam from the MP section of the turbine is used to provide the steam necessary for the degassing of the condensate and make-up demineralised water. Part of the exhaust steam is fed to a turbine to provide the power required by the HP boiler feed water pumps.

After the deaerator a further bank of pre-heaters preheats the feed water to 290°C prior to the boiler. These heaters are heated by MP turbine exhaust steam and finally by HP steam stream extracted from the turbine. Heat recovered in the CPU and in the boiler island allows avoiding the extraction from the MP section. Steam condensate recovered into the boiler feed water heaters is sent back to the deaerator.

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


Oxy-combustion power plant - STEAM CYCLE
Boiler
HP ST
MP ST
LP ST
ST Generator
to TSA
Steam Turbine Condenser
CWS
CW R
Condenser hot well
Make/up demin water
Deaerator
Start-up BFW Pump
BFW Pump
BFW preheating at flue gas cooling
HP heater #2
HP heater #1
BFW preheating at CPU
LP heater #1
Condensate preheating at ASU and flue gas cooling
Condensate pumps
Condensate preheating at CO2 Compression

2.7. Utility and Offsite units

These units are the same as the ones described in Chapter C for the air-fired boiler cases. Anyhow, the description of the units is here below reported for clarity of the reader.

2.7.1. Cooling water

The cooling water system consists of raw water in a closed loop, with a natural draft, evaporative cooling tower. There are two circulation systems, depending on the pressure profile through the circuit. The primary system is used for the steam turbine condenser while the secondary one is used for machinery cooling and other users. Each circulation system is equipped with single-stage vertical water pumps.

The maximum allowed cooling water temperature increase is 11°C. The blow-down is used to prevent the concentration of dissolved solids from increasing to the point where they may precipitate and scale-up heat exchangers and the cooling tower fill. The design concentrations cycles (CC) is 4.0.

Two concrete towers are considered, with a basin diameter around 120 m and 210 meters high. Each tower is equipped with two distribution systems, one primary distribution system supplying water from a concrete duct and one secondary system from PVC pipes equipped with sprayers, connected to the concrete ducts. Tower filling, with vertical channels, increases the cooling and thermal efficiency, allowing pollutants to be easily washed through. Drift eliminators guarantee a low drift rate and low pressure drop. To avoid freezing in winter ambient conditions, the fill pack is divided into zones to allow step by step reduction of cooling capacity while maintaining an excellent water distribution and spray sprinklers are installed to create a warm water screen on the air inlets to preheat the ambient air when freezing ambient conditions occurs.

2.7.2. Raw and Demineralised water

Raw water is generally used as make-up water for the power plant, in particular as make-up of the cooling tower. Raw water is also used to produce demineralised water. Raw water from an adequate storage tank is pumped to the demineralised water package that supplies make-up water with adequate physical-chemical characteristics to the thermal cycle and to the hydrated lime preparation unit.

The treatment system includes the following:

- Filtering through a multimedia filter to remove solids.
- Removal of dissolved solids: filtered water passes through the Reverse Osmosis (RO) cartridge filter to remove dissolved CO_2 and then to a reverse osmosis system to remove dissolved solids.

- Demineralised water production: an electro de-ionization system is used for final polishing of the water to further remove trace ionic salts of the Reverse Osmosis (RO) permeate.

Adequate demineralised water storage is provided by means of a dedicated demineralised water tank.

The demineralised water make-up supplies the make-up water to the thermal cycle, whilst the demineralised water distribution pump supplies demineralised water to the other plant users or to the plant circuits for first filling.

2.7.3. *Fire fighting system*

This system consists of all the facilities able to locate possible fire and all the equipment necessary for its extinction. The fire detection and extinguishing system essentially includes the automatic and manual fire detection facilities, as well as the detection devices with relevant alarm system. An appropriate fire detection and suppression system is considered in each fire hazard area according to the applicable protection requirements. The fire fighting water is supplied by a water pumping station via a looping piping network consisting in a perimetrical circuit fed by water pumped from the cooling tower basin.

2.7.4. *Instrument and plant air system*

The air compression system supplies air to the different process and instrumentation users of the plant.

The system consists mainly of:

- Air compressors, one in operation, one in stand-by.
- Compressed air receiver drum.
- Compressed air dryer for the instrument air.

The ambient air compressed by means of the air compressor is stored in the air receiver in order to guarantee the hold-up required for emergency shutdown.

Plant air is directly taken from the air receiver, while air for instrumentation is sent to the air dryer where air is dried up to reach an adequate dew point, to ensure proper operation of the instrumentation.

2.7.5. *Waste Water Treatment*

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

The following description gives an overview of the waste water treatment configuration, generally adopted in similarly designed power plants; it includes a preliminary identification of the operations necessary to treat the different waste water streams generated in the power plant.

The Waste Water Treatment unit is designed to treat the following main waste water streams:

- Sour condensate from the boiler warm end and the sour compression section of the CPU
- Potentially oil-contaminated rain water
- Potentially dust-contaminated rain water
- Clean rain water
- Sanitary waste water.

Mainly, the above streams are collected and routed to the waste water treatment in different systems according to their quality and final treatment destination.

The WWT system is equipped mainly with the following treatment sections:

- Treatment facilities for the sour condensate
- Treatment facilities for the potentially oily contaminated water
- Treatment facilities for the potentially dust contaminated water
- Treatment facilities for not contaminated water
- Treatment facilities for the sanitary wastewater.

Sour condensate

Sour condensate from the boiler warm end and the sour compression section of the CPU are treated in dedicated section of the Waste Water Treatment to remove acidic component and maximise water recovery. The following alternative treatment can be considered:

- Neutralisation
- Resins
- Reverse osmosis

At this study level, it is not possible to identify the optimum solution for the study case. Main parameter affecting the selection and the severity of the treatment are the recovered water utilisation and destination of the blow-down stream to be discharged (i.e. river or sea).

Potentially Dust Contaminated Water Treatment

Rain water and washing water from areas subject to potential dust contamination is treated in apposite water treatment systems prior to be sent to the “potentially oil contaminated” treatment system.

In particular, they are collected in a dedicated sewer, sent to a lamination tank and then to a chemical/physical treatment to remove the substances that are dissolved and suspended.

The system includes also a neutralization system to modify potential acidity and/or alkalinity of washing water used for the air pre-heaters.

Potentially Oil-Contaminated Water Treatment

Potentially oil-contaminated waters are:

- Washing water from areas where there is equipment containing oil.
- Rain water from areas where there is equipment containing oil.

After being mixed with treated water coming from "potentially dust contaminated" system, water is treated in a flotation and filtration system, where emulsified oil and suspended solids are respectively separated.

Treated effluent water will have the characteristics to respect the local regulations so that it can be consequently discharged.

Not Contaminated Water Treatment

Rainwater fallen on clean areas of the plant, such as roads, parking areas, building roofs, areas for warehouse/services/laboratory etc. where there is no risk of contamination, will be collected and disposed directly to the water discharge system.

A coarse solids trap is installed upstream the discharge point in order to retain coarse solids that may be carried together with the discharge water.

Sanitary Water Treatment

The sanitary waste water streams discharged from the different sanitary stations of the plant will be collected in a dedicated sewage and destined to the Sanitary Water Treatment system. This section generally involves the following main water treatment operations:

- Primary sedimentation for coarse solids removal.
- Biological treatment for BOD removal.
- Filtration for residual organic matter and suspended solids separation.
- Disinfection for bacteria inhibition.

CLIENT : IEAGHG
PROJECT NAME : CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
DOCUMENT NAME : CASE 3: OXY-COMBUSTION SC PC WITH CCS
FWI CONTRACT : 1-BD-0681 A

ISSUED BY : G. PERFUMO
CHECKED BY : N. FERRARI
APPROVED BY : L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

1. Introduction

This chapter of the report includes all technical information relevant to Case 3 of the study, which is an oxy-combustion supercritical pulverised coal (SC PC) fired steam plant, with cryogenic purification and separation of the carbon dioxide. The plant is designed to process coal, whose characteristic is shown in chapter B, and produce electric power for export to the external grid.

The configuration of the oxy-combustion SC PC plant is based on one once-through steam generator, with superheating and single steam reheating, and a steam turbine generator. Plant is sized by considering same input thermal capacity as the reference case without carbon capture (refer to chapter C.1 of the report).

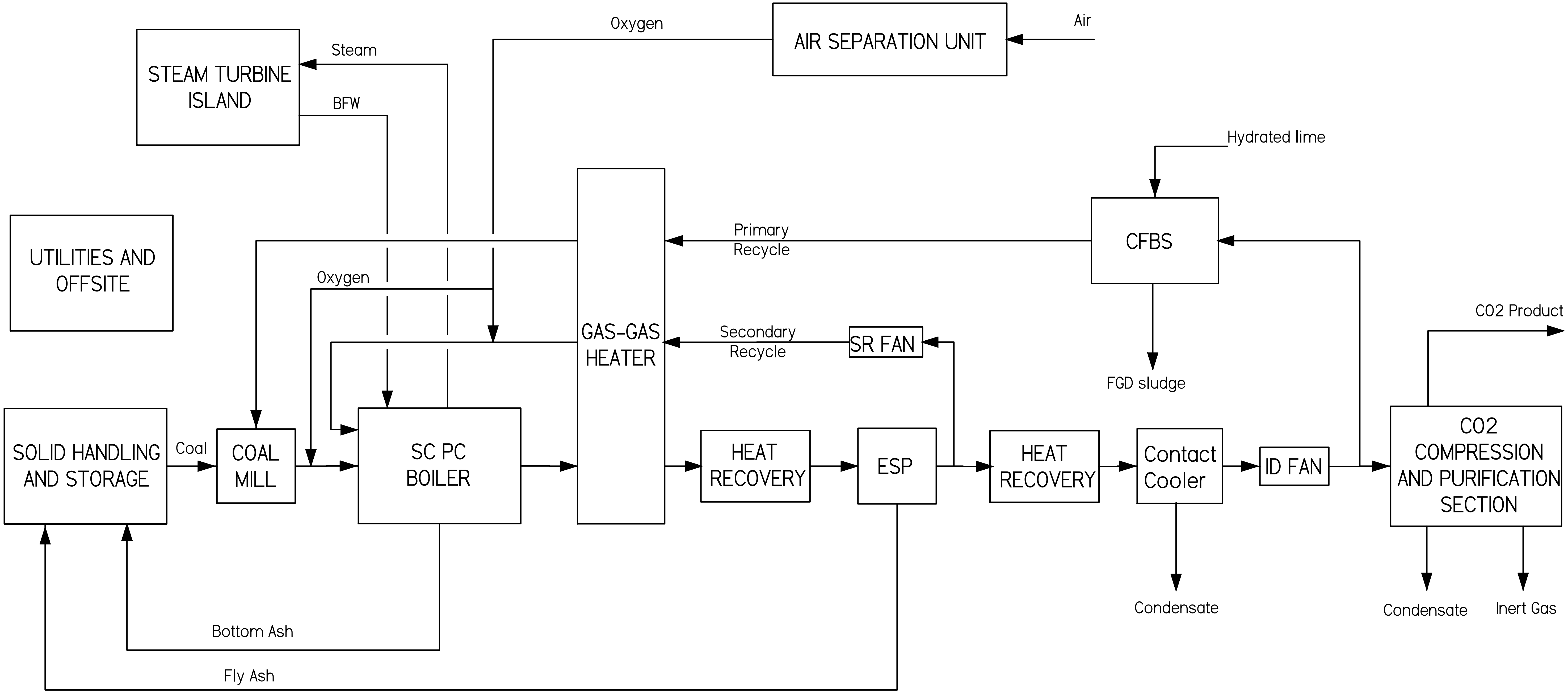
The description of the main process units is covered in chapter D of this report and only features that are unique to this case are discussed in the following sections, together with the main modelling results.

1.1. Process unit arrangement

The arrangement of the main units is reported in the following Table 1. Reference is also made to the block flow diagram attached below.

Table 1. Case 3 – Unit arrangement

Unit	Description	Trains
900	Air Separation Unit	3 x 33%
1000	Storage and Handling of solid materials	N/A
2000	Oxy combustion SC PC supercritical boiler	1 x 100%
	Electro Static precipitators	1 x 100%
2100	Flue Gas Desulphurisation (FGD)	1 x 100%
3000	Steam Cycle (SC)	
	Steam Turbine and Condenser	1 x 100%
	Deaerator	1 x 100%
	Water Preheating line	1 x 100%
4000	CO_2 purification and compression	
	Sour compression	1 x 100%
	Auto-refrigerated inert removal section	1 x 100%
	CO_2 compressors	2 x 50%
6000	Utility and Offsite	N/A



0	July 13	Draft	GP	LM	**UNIT:** Block Flow Diagram	
Rev.	Date	Comment	By	Appr	**CASE:** 3	Sheet 01 of 01

2. Process description

2.1. Overview

The description reported in this section makes reference to the simplified Process Flow Diagrams (PFD) shown in section 3, while stream numbers refer to section 4, which provides heat and mass balance details for the numbered streams in the PFD.

2.2. Unit 900 – Air Separation Unit

The ASU is based on the cryogenic distillation of atmospheric air at low pressure and it is designed to produce oxygen at 97 % mol O_2 purity.

Technical information relevant to this unit is reported in chapter D, section 2.5, while main process information of this case and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

2.3. Unit 1000 – Feedstock and solid handling

The unit is composed of the following systems:

- Coal storage and handling
- Lime storage and handling
- Ashes collection and storage
- FGD sludge storage and handling.

The general description relevant to this unit is reported in chapter D, section 2.1.

Main process information of this case and the interconnections with the other units is shown in the relevant process flow diagram and the heat and mass balance table.

2.4. Unit 2000 – Boiler Island

This unit includes single pass tower-type super critical boiler, with multistage combustion of oxygen and flue gas for NOx control, the primary and secondary recycle ducts, the heat recovery section and the contact column for final flue gas cooling. Oxygen at 97% vol. purity from the Air Separation Unit is fed as oxidiser to the burners.

Technical information relevant to this unit is reported in chapter D, section 2.2, while main process information of this case and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

2.5. Unit 2100 – Flue Gas Desulphurization

Foster Wheeler Energie GmbH Circulating Fluid Bed Scrubber (CFBS) system with hydrated lime injection and fabric filter was selected for the development of this study case.

The FGD is installed on the primary recycle to reduce the SO_2 concentration in the furnace and in the flue gas recycle loop below the limit at which excessive gas-side tube corrosion occurs. Furthermore, the installation of the FGD allows controlling the SOx/NOx ratio to the optimum value for the downstream CO_2 purification and compression unit (CPU). For this study case, the FGD is sized to reduce the sulphur concentration in the furnace below 1700 ppmv.

Technical information relevant to this technology is reported in chapter D, section 2.3.1. The impact of a different FGD technology and supplier is also summarised in chapter D, section 2.3.4.

Main process information of this case and interconnections with the other units is shown in the relevant process flow diagram and the heat and mass balance table.

2.6. Unit 3000 – Steam Cycle

The steam cycle is mainly composed of one supercritical Steam Turbine Generator (STG), one water-cooled condenser and the water pre-heating line. General description relevant to this unit is reported in chapter D, section 2.6.

Main process information of this case and interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

2.7. Unit 4000 – CO_2 compression and purification

This unit is mainly composed of the following systems:

- Sour compression for the combined removal of SOx and NOx;
- TSA unit;
- Auto-refrigerated inerts removal, including distillation column for meeting the required oxygen specification in the CO_2 product;
- The remaining part of the compression system up to 110 bar.

Air Products’ process is considered for the development of this study case. Technical information relevant to this system is reported in chapter D, section 2.4.

Main process information of this case and interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

2.8. Unit 6000 - Utility Units

These units comprise all the systems necessary to allow the operation of the plant and the export of the produced power.

The main utility units include:

- Cooling Water system, based on two natural draft cooling towers, with the following characteristics:

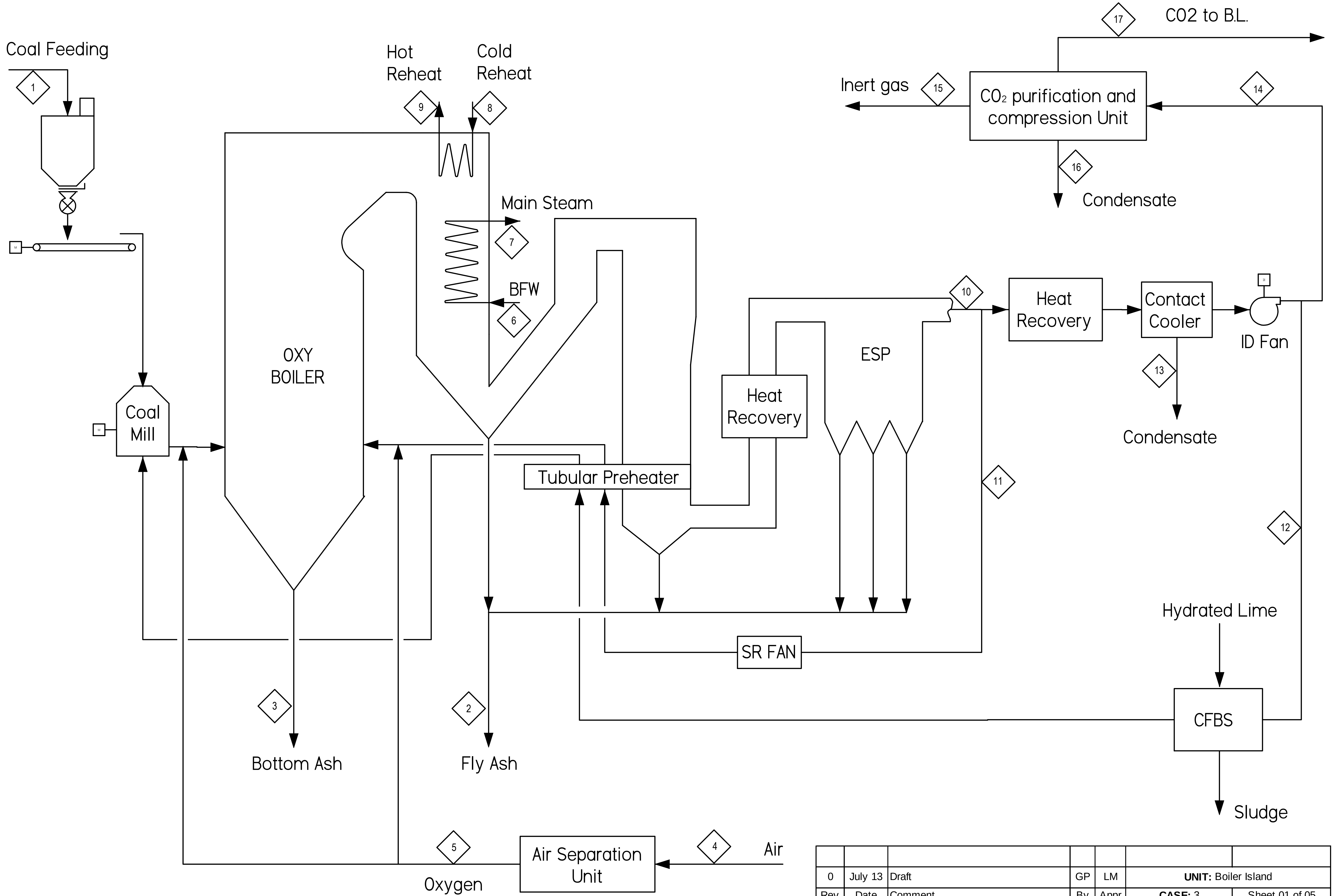
Basin diameter	120 m
Cooling tower height	210 m
Water inlet height	17 m

- Raw water system;
- Demineralised water plant;
- Fire fighting system;
- Instrument and Plant air.

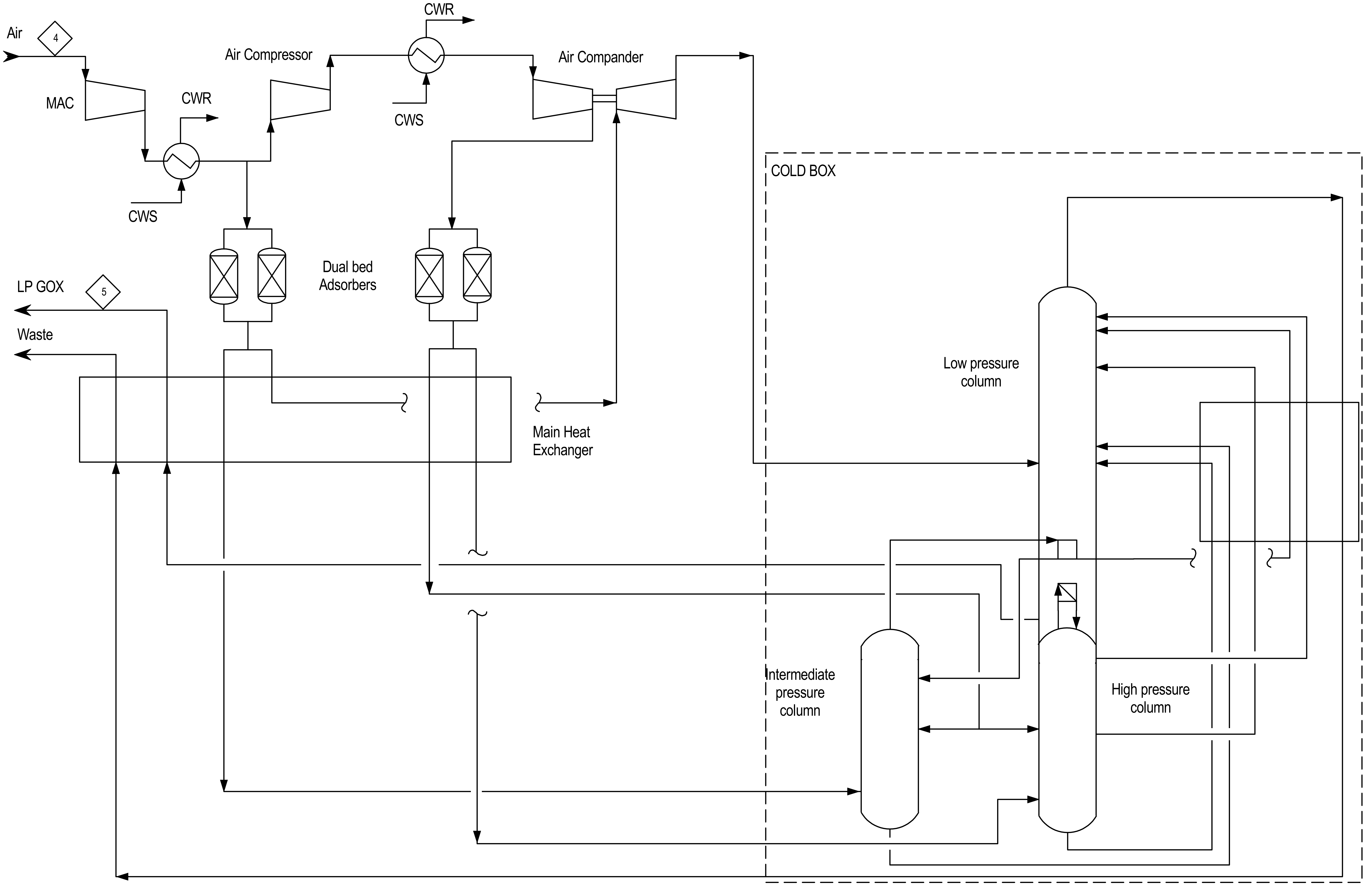
Process descriptions of the above systems are enclosed in chapter D, section 2.7.

3. Process Flow Diagrams

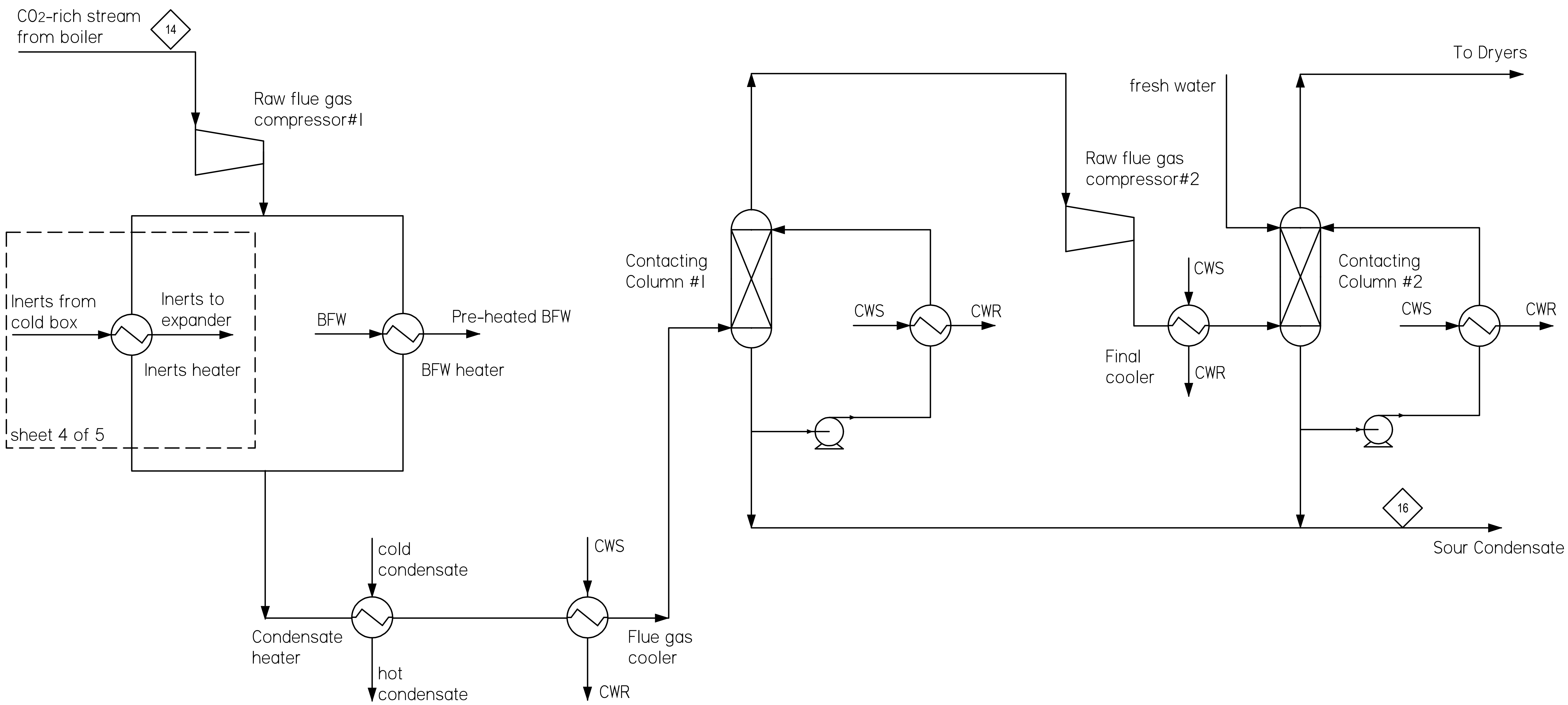
Simplified Process Flow Diagrams of this case are attached to this section. Stream numbers refer to the heat and material balance shown in the next section.



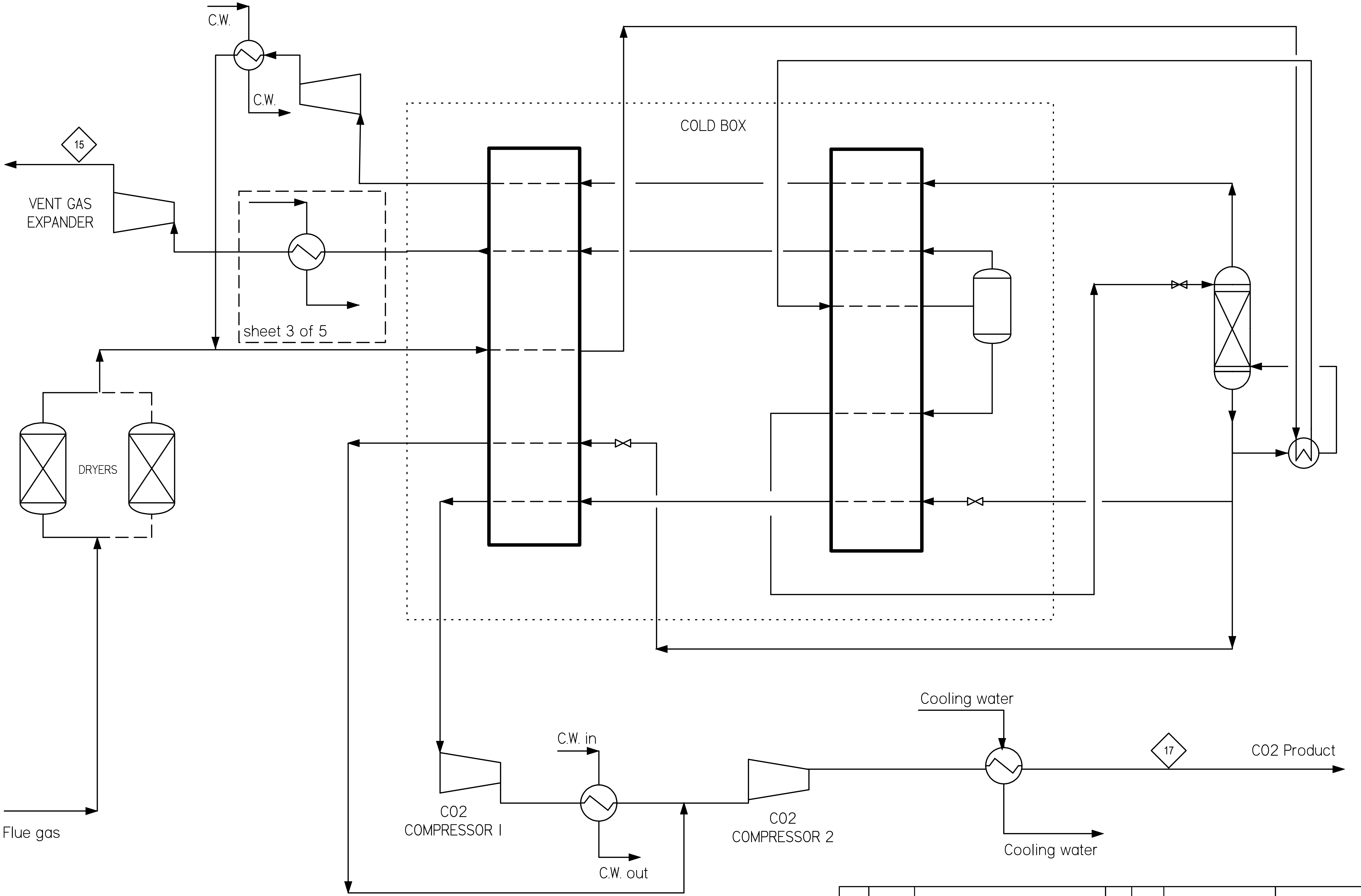
0	July 13	Draft	GP	LM	**UNIT:** Boiler Island	
Rev.	Date	Comment	By	Appr	**CASE:** 3	Sheet 01 of 05



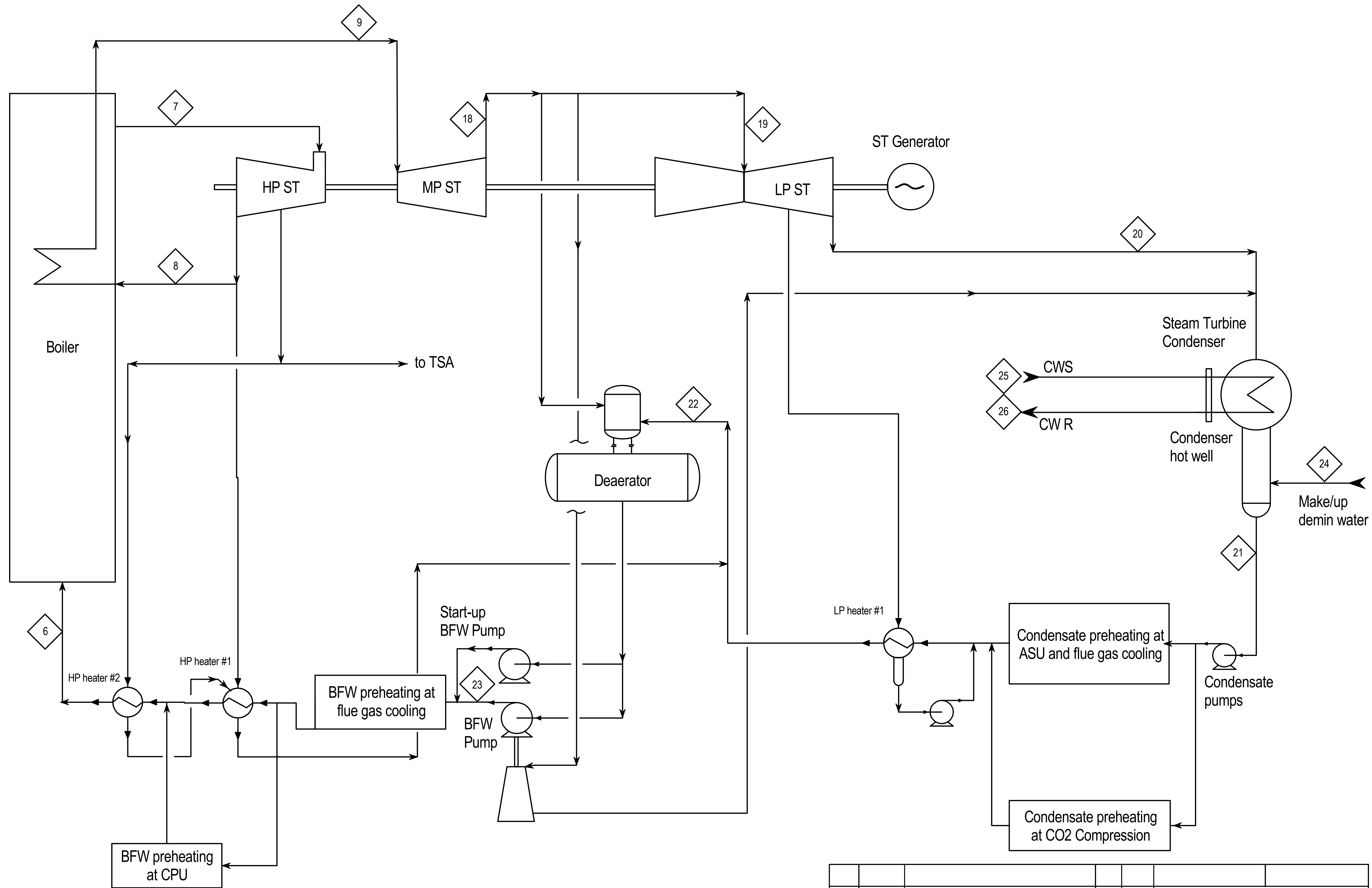
0	July 13	Draft	GP	LM	**UNIT:** Air Separation Unit	
Rev.	Date	Comment	By	Appr	**CASE:** 3	Sheet 02 of 05



0	July13	Draft	GP	LM	**UNIT:** Sour compression	
Rev.	Date	Comment	By	Appr	**CASE:** 3	Sheet 03 of 05



0	July13	Draft	GP	LM	**UNIT:** CO_2 Purification and compression	
Rev.	Date	Comment	By	Appr	**CASE:** 3	Sheet 04 of 05



0	July 13	Draft	GP	LM	**UNIT:** Steam Cycle	
Rev.	Date	Comment	By	Appr	**CASE:** 3	Sheet 05 of 05

4. Heat and Material Balance

Heat & Material Balances reported make reference to the simplified Process Flow Diagrams reported in section 3.

	Case 3 - Oxycombustion SC PC - HEAT AND MATERIAL BALANCE		REVISION	0		
FOSTER WHEELER	CLIENT :	IEA GHG	PREP.	NF		
	PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	CHECKED	LM		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 13		

HEAT AND MATERIAL BALANCE

UNIT 2000 - BOILER ISLAND

STREAM	1	2	3	4	5	6	7	8	9	10
	Coal to Boiler Island	Fly Ash	Bottom Ash	Air intake from Atmosphere	Oxygen to boiler	BFW from steam cycle	HP Steam to Steam Turbine	Cold Reheat from Steam Turbine	Hot Reheat to Steam Turbine	Flue gas from ESP
Temperature (°C)	AMB	AMB	AMB	9	AMB	290	600	366	620	160
Pressure (bar)	ATM	ATM	ATM	ATM	ATM	325	270	63	60	-
TOTAL FLOW	Solid	Dry solid	Dry solid							
Mass flow (kg/h)	325,000	29,200	12,500	2,920,000	694,000	2,900,000	2,900,000	2,195,000	2,195,000	3,400,000
Molar flow (kmol/h)				101,200	21,635	161,020	161,020	121,880	121,880	92,700
LIQUID PHASE										
Mass flow (kg/h)						2,900,000				
GASEOUS PHASE										
Mass flow (kg/h)				2,920,000	694,000		2,900,000	2,195,000	2,195,000	3,400,000
Molar flow (kmol/h)				101,200	21,635		161,020	121,880	121,880	92,700
Molecular Weight				28.9	32.1		18.0	18.0	18.0	36.7
Composition (vol %)	%wt									
H_2				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CO	C: 64.6%			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CO_2	H: 4.38%			0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	62.93%
N_2	O: 7.02%			77.27%	1.20%	0.00%	0.00%	0.00%	0.00%	11.44%
O_2	S: 0.86%			20.73%	97.00%	0.00%	0.00%	0.00%	0.00%	5.29%
CH_4	N: 1.41%			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ar	Cl: 0.03%			0.92%	1.80%	0.00%	0.00%	0.00%	0.00%	1.53%
H_2O	Moisture: 9.5%			1.05%	0.00%	100%	100%	100%	100%	18.60%
SO_2	Ash: 12.20%			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.17%
NO / NO_2				-	-	-	-	-	-	0.04%
HNO_3				-	-	-	-	-	-	-
H_2SO_4				-	-	-	-	-	-	-
Total				100%	100%	100%	100%	100%	100%	100%

NOTE

1. Air in-leakage are included in the flue gas streams

FOSTER WHEELER	**Case 3 - Oxycombustion SC PC - HEAT AND MATERIAL BALANCE**		**REVISION**	0		
	CLIENT :	IEA GHG	**PREP.**	NF		
	PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	**CHECKED**	LM		
	PROJECT NO:	1-BD-0681 A	**APPROVED**	LM		
	LOCATION:	The Netherlands	**DATE**	July 13		

HEAT AND MATERIAL BALANCE
UNIT 2000 - BOILER ISLAND

STREAM	**11**	**12**	**13**	**14**	**15**	**16**	**17**			
	Secondary recycle to boiler	**Primary recycle to FGD**	**Condensate from Contact Cooler**	**Flue gas to CPU**	**Inert gas vent**	**Condensate from CPU**	**CO_2 product**			
Temperature (°C)	170	38	28	38	210	25	30			
Pressure (bar)	-	-	-	-	1.6	2.0	110			
TOTAL FLOW										
Mass flow (kg/h)	1,490,000	850,000	146,600	932,880	222,000	20,470	685,985			
Molar flow (kmol/h)	40,630	21,210	8,140	23,290	6,630	930	15,587			
LIQUID PHASE										
Mass flow (kg/h)			146,600			20,470				
GASEOUS PHASE										
Mass flow (kg/h)	1,490,000	850,000		932,880	222,000		685,985			
Molar flow (kmol/h)	40,630	21210		23290	6,630		15,587			
Molecular Weight	36.7	40.1		40.1	33.5		44.0			
Composition (vol %)										
H_2	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%			
CO_2	62.93%	74.41%	0.00%	74.41%	24.50%	0.03%	99.98%			
N_2	11.44%	13.54%	0.00%	13.54%	47.24%	0.00%	46 ppmv			
O_2	5.29%	6.25%	0.00%	6.25%	21.41%	0.00%	100 ppmv			
CH_4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-			
Ar	1.53%	1.82%	0.00%	1.82%	6.33%	0.00%	27 ppmv			
H_2O	18.60%	3.76%	99.99%	3.76%	0.52%	94.55%	-			
SO_2	0.17%	0.18%	0.00%	0.18%	0.00%	240 ppmv	-			
NO / NO_2	0.04%	0.04%	0.00%	0.04%	0.00%	0.23 ppmv	-	-	-	
HNO_3	-	-	0.00%	-	-	0.99%	-	-	-	
H_2SO_4	-	-	0.01%			4.41%	-			
Total	100%	100%	100%	100%		100%	100%			

NOTE
1. Air in-leakage are included in the flue gas streams

	Case 3 - Oxycombustion SC PC - H&M BALANCE		Revision	0	
	CLIENT:	IEA GHG	**Prepared**	NF	
	PROJECT NAME:	CO2 capture at coal based power and H2 plants	**Checked**	LM	
	PROJECT NO:	1-BD-0681 A	**Approved**	LM	
	LOCATION:	The Netherlands	**Date**	July 13	

HEAT AND MATERIAL BALANCE
UNIT 3000 - STEAM CYCLE

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
6	HP Water to Boiler Island	2,900	290	323.5	1278
7	HP Steam from Boiler to HP Steam Turbine	2,900	600	270.0	3475
8	Cold Reheat to Boiler	2,195	367	63.0	3084
9	Hot Reheat to MP Steam Turbine	2,195	620	60.0	3706
18	MP Steam Turbine exhaust	2,195	285	6.0	3031
19	Steam to LP Steam Turbine	2,010	285	5.9	3031
20	Exhaust from LP steam turbine	1,864	29	0.04	2284
21	Condensate from condenser	2,040	29	0.04	121
22	Condensate to deaerator	2,850	138	9.5	581
23	BFW to pre-heating train	2,900	148	325	644
24	Make up Water	5	9	ATM	38
25	Cooling Water Inlet	94,745	15	4.0	63
26	Cooling Water Outlet	94,745	26	3.5	109

5. Utility and chemicals Consumption

Main utility consumption of the process and utility units is reported in the following tables. More specifically:

- Water consumption summary, reported in Table 2,
- Electrical consumption summary, shown in Table 3,
- Sorbent and chemicals consumption, shown in Table 4.

Table 2. Case 3 – Water consumption summary

CLIENT:	IEAGHG	REVISION	0
PROJECT NAME:	CO2 capture at coal based power and H2 plants	DATE	Apr-13
PROJECT No. :	1-BD-0681 A	MADE BY	NF
LOCATION :	The Netherlands	APPROVED BY	LM

Case 3 - Water consumption

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water 1° syst. [DT = 11°C] [t/h]	Cooling Water 2° syst. [DT = 11°C] [t/h]
1000	FEEDSTOCK AND SOLID HANDLING				
	Solid Receiving, Handling and storage	5			
2000	Air Separation Unit				
	Air Separation unit				1250
2000	BOILER ISALND and FLUE GAS TREATMENT				
	Boiler island				11080
	Flue Gas Desulphurization (CFBS)				
	CO2 compression and purification				9015
500	POWER ISLAND (Steam Turbine)				
	Condenser			94745	
	Turbine and generator auxiliaries		5.0		5080
BoP	UTILITY and OFFSITE UNITS				
	Cooling Water System	2180			
	Demineralized/Condensate Recovery/Plant and Potable Water Systems	8.0	-5.0		
	Waste Water Treatment	-160			
	Miscellanea				100
	BALANCE	2033	0.0	94745	26525

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

Table 3. Case 3 – Electrical consumption summary

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	**DATE**	Apr-13
PROJECT No. :	1-BD-0681 A	**MADE BY**	NF
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 3 - Electrical consumption

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
900	AIR SEPARATION UNIT	
	Main air compressors	111060
	Booster air compressors + pumps	18280
1000	FEEDSTOCK AND SOLID HANDLING	
	Solid Handling	3255
2000	BOILER ISLAND and FLUE GAS TREATMENT	
	Boiler island (including FGD)	14370
3000	STEAM CYCLE	
	Steam Turbine Auxiliaries and condenser	4700
	Condensate and feedwater system	1250
	Miscellanea	600
4000	CO2 PURIFICATION AND COMPRESSION	
	Flue gas compression (up to 35 bar)	83390
	CO2 compression (up to 110 bar)	26790
	Overhead recycle	790
	Expander	-15110
BoP	UTILITY and OFFSITE UNITS	
	Cooling Water System	14290
	Other Units	1430
	BALANCE	**265,095**

Table 4. Case 3 – Sorbent and chemicals consumption

	Consumption
Lime injection to the FGD	7.0 t/h

6. Overall Performance

The following table shows the overall performance of Case 3.

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	**DATE**	Jun-13
PROJECT No. :	1-BD-0681 A	**MADE BY**	NF
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 3 - Oxy SC PC Plant Performance Summary

OVERALL PERFORMANCES		
Fuel flow rate (A.R.)	t/h	325.0
Fuel HHV (A.R.)	kJ/kg	27060
Fuel LHV (A.R.)	kJ/kg	25870
THERMAL ENERGY OF FEEDSTOCK (based on LHV) (A)	**MWth**	**2335**
THERMAL ENERGY OF FEEDSTOCK (based on HHV) (A')	**MWth**	**2443**
Steam turbine power output (@ gen terminals)	MWe	1101.0
GROSS ELECTRIC POWER OUTPUT (C) (1)	**MWe**	**1101.0**
Boiler Island (including FGD)	MWe	14.4
Utility & Offsite Units consumption	MWe	15.7
Power Islands consumption	MWe	6.6
Air Separation Unit consumptions	MWe	129.3
CO2 purification and compression	MWe	95.9
Feedstock and solids handling	MWe	3.3
ELECTRIC POWER CONSUMPTION	**MWe**	**265.1**
NET ELECTRIC POWER OUTPUT	**MWe**	**835.9**
(Step Up transformer efficiency = 0.997%) (B)	MWe	833.4
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**47.1%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**35.7%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**45.1%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**34.1%**
Fuel Consumption per net power production	**MWth/MWe**	**2.80**
CO_2 emission per net power production	**kg/MWh**	**92.2**

(1) Steam driven BFW pumps are included

The following table shows the overall CO_2 balance and removal efficiency of Case 3.

CO_2 removal efficiency	**Equivalent flow of CO_2** kmol/h
INPUT	
FUEL CARBON CONTENT (A)	17495
OUTPUT	
Carbon losses (B)	166
CO_2 flue gas content	17329
Total to storage (C)	15584
Emission (inert + losses)	1745
TOTAL	17495
Overall Carbon Capture, % ((B+C)/A)	90.0

7. Environmental impact

The oxy-combustion SC PC steam plant design is based on advanced technologies that allow to reach high electrical generation efficiency, while minimizing impact to the environment. Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

7.1. Gaseous emissions

During normal operation at full load, main continuous emissions are the inerts vent stream from the CO_2 purification unit. Table 5 summarizes the expected flow rate and composition of the inerts vent.

Minor and fugitive emissions are related to seal losses in the CO_2 purification unit and to the milling, storage and handling of solids (e.g. solid transfer, leakage). As summarised in Table 6, these emission mainly consists of air containing particulate.

Table 5. Case 3 – Plant emission during normal operation

Flue gas to stack	
Emission type	Continuous
Conditions	
Wet gas flowrate, kg/h	222,000
Flow, Nm^3/h	149,000
Composition	(% vol)
Ar	6.33
N_2	47.24
O_2	21.41
CO_2	24.50
H_2O	0.52
NOx	< 1 ppmv
SOx	< 1 pmmv

Table 6. Case 3 – Plant minor emission

Emission source	**Emission type**	**Temperature**	
Coal milling and feed system	Continuous	ambient	Air: 10 mg/Nm^3 particulate
Lime milling and preparation	Intermittent	ambient	Air: 10 mg/Nm^3 particulate
Ash storage and transfer	Intermittent	ambient	Air: 10 mg/Nm^3 particulate
CO_2 purification unit	Continuous	N/A	CO_2, O_2, N_2, Ar

7.2. Liquid effluent

The plant does not produce significant liquid waste. Plant blow-downs (e.g. flue gas final contact cooler, CO_2 purification unit) are treated to recover water, so main liquid effluent is cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids.

Cooling Tower blowdown

Flowrate : 520 m^3/h

7.3. Solid effluents

The power plant is expected to produce the following solid effluents:

Fly ash from boiler

Flowrate : 29.2 t/h

Bottom ash from boiler

Flowrate : 12.5 t/h

Sludge from FGD

Flowrate : 13.3 t/h

Fly and bottom ash might be sold to cement industries, if local market exist, or sent to disposal, outside plant battery limits. Sludge from FGD shall also be sent to outside disposal.

8. Preliminary plot plan

Plot plan at block level of Case 3 is attached to this section, showing the area occupied by the main units and equipment of the plant.

450.00
400.00
300.00
200.00
100.00
0.00
40.0
90.0
90.0
140.0
35.0
55.0
Coal Railways
Coal receiving Building
including:
- Wagon tipper, Receiving hopper,
vibratory feeder, belt extractor
Coal receiving Building
including:
- Coal sampling system
- Magnetic separator system
Transfer Tower
Transfer Tower
Transfer Tower
Transfer Tower
Crusher & Transfer Tower
Coal pile
(128.000 t. -> about 16 days storage)
UNIT 1000
Feedstock and Solid handling
Coal pile
(128.000 t. -> about 16 days storage)
ASU Compressors Building
ASU Compressors Building
UNIT 900
Air Separation Units
(n° 3 x 33%)
ASU Compressors Building
CT - 6001 B
Cooling Water
Tower
CT - 6001 A
Cooling Water
Tower
Cooling Water Pumps
(primary/secondary/make-up)
Coal Daily
Storage Silos
Central
Control
Room
PK - 3001
&
PK -3002
Steam Turbine
Building
(110 x 50 m.)
UNIT 3000
Steam Cycle
UNIT 2000
Boiler Island
PK-2001
Super Critical
Oxycombustion Boiler
Building/Structure
PK - 2003
ID Fan
PK - 2002
ESP
SR Fan
CFBS
PK-4001
Sour Compression
section
CO2 Compressors
Building
UNIT 4000
CO2 Compression
&
Purification
CO2 Compressors
Building
Fly Ashes
Storage Silos
UNIT 2100
Flue Gas
Desulphurization
PK-4002 & PK - 4003
Dual Bed essicant system
Cold box for inert removal
Water Treatment
Area
UNIT 6000
Utility Units
PK - 6001
DEMI Water
packages
H. V. Electrical
Substation
Bottom Ashes
Storage Building
FGD Sludge
Storage Building
Workshops &
Warehouse
Storage Building
Administrative
Building
T - 6002
DEMI Water
Storage Tank
T-6001
RAW Water
Storage Tank
500.00
535.00
135.0
135.0
65.0
105.0
135.0
120.0
-135.00
0.00
100.00
200.00
300.00
400.00
CO01
AUG. 2013
Preliminary issue for comments
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DATE
DESCRIPTION
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BY
CHD.
APP.
CLIENT
IEA GHG
SITE The Netherlands
CO2 Capture and coal fired Power Plants
CASE: 3 - Oxycombustion SC PC
PRELIMINARY PLOT PLAN
FOSTER WHEELER
SCALE
N. A.
1BD0681A - 01 - 003
CO01
CAD FILE NAME
Form. A3

9. Equipment list

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

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		DATE	Jun-13	Jan-14		
		ISSUED BY	NF	NF		
		CHECKED BY	LM	LM		
		APPROVED BY	LM	LM		

EQUIPMENT LIST

Unit 900 - Air Separation Unit (3 x 33%)

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	AIR SEPARATION UNIT							
PK - 901 A/B/C	**Air Separation unit**		3 x 5555 t/d					
	Including							
	- Main Air Compressors	Axial		2 x 21,000 kWe				
	- Booster air compressor			6,400 kWe				
	- Compander							
	- Air purification system							
	- Main heat exchanger							
	- ASU compander							
	- ASU Column System							
	- Pumps	Centrifugal						
	- ASU chiller							
TK - 901	LOX storage tank		200 t					*Common to all trains. Required for safe switch of the boiler to air operation*

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EQUIPMENT LIST

Unit 1000 - Feedstock and Solid handling

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	COAL HANDLING SYSTEM							
	Including:		Coal flowrate to boiler: 325 t/h					*30 days storage*
	- Wagon tipper							*Storage piles: 2 x 128,000 t each*
	- Receiving Hopper, vibratory feeder and belt extractor							
	- Conveyors	Belt						
	- Transfer Towers	enclosed						
	- As-Received Coal Sampling System	Two - Stage						
	- As-Received Magnetic separator System	Magnetic Plates						
	- Conveyors	Belt						
	- Transfer Towers	enclosed						
	- Cruscher Tower	Impactor reduction						
	- As-Fired Coal Sampling System	Swing hammer						
	- As-Fired Magnetic separator System	Magnetic Plates						
	- Coal Silo		2 x 4900 m3					*For daily storage*
	- Filters							
	- Fans							
	LIME HANDLING SYSTEM							
	Including:		Lime flowrate to FGD: 7.0 t/h					
	- Wagon tipper		*Lime storage volume: 4600 m3*					*30 days storage*
	- Receiving Hopper, vibratory feeder and belt extractor							
	- Conveyor	Belt						
	- Transfer Tower	enclosed						
	- Lime Sampling System	Swing Hammer						
	- Separator System	Magnetc Plates						
	- Transfer Tower	enclosed						
	- Conveyor	Belt with tipper						
	- Lime Silo		2 x 155 m3					*For daily storage*
	- Filters and fans							

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	CASE: 3 - Oxycombustion SC PC					

EQUIPMENT LIST
Unit 1000 - Feedstock and Solid handling

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	ASH SYSTEM							
	Including:		Bottom Ash Capacity: 12.5t/h					
	- Ash storage silos		*Bottom Ash Storage volume: 6000 m3*					*14 days storage capacity*
	- Ash conveyors							
	- Bottom ash crusher		Fly Ash Capacity: 29.2t/h					*14 days storage capacity*
	- Pneumatic conveying system		*Fly Ash Storage volume: 14000 m3*					
	- Compressors							
	- Filters							
	- Fans							
	FGD BY-PRODUCT SYSTEM							
	Including:		Capacity: 13.3t/h					
	- Storage unit		Storage volume: 7367 m3					*30 days storage capacity*
	- Conveyors							*1 operating, 1 spare*

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CASE: 3 - Oxycombustion SC PC		APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 2000 - Boiler Island

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	BOILER							
PK - 2001	**Super Critical Oxycombustion Boiler**		Capacity: 2900 t/h main steam production Thermal input: 2443 MWth (HHV) / 2335 MWth (LHV) Main steam condition: 270 bar(a)/600 °C Reheat steam condition: 60 bar(a)/620 °C				(1)	Boiler package including: - Fuel Feeding system - Coal mill - One Fired Boiler Furnace - Low NOx burners system including main burners and pilots - Economizers/super heater coils, water wall circuit - Reheating coils - Tubular gas/gas heater - Secondary Flue Gas Recycle fans with electric motor (2 x 60%) - Flue gas ducts - Start-up system - Ash collection hoppers - Bottom Ash cooling devices - All exchangers, drums, and miscellaneous equipment required for the heat recovery of the flue gases
K - 2001 A/B	**ID fan**	Axial	Flowrate: 2 x 500 x 10^3 Nm3/h Vol. Flow: 2 x 575 x 10^3 m3/h Power consumption: 2 x 2880 kW	2 x 3200 kWe				
PK - 2002	**Flue gas cleaning system**	ESP	Removal efficiency: 99.9%					
PK - 2003	**Indirect Contact Cooler**							
PK - 2004	**Stack**							For start-up and up-set conditions

Notes:
(1) Reference for boiler material selection:
A. Robertson, H. Agarwal, M. Gagliano, A. Seltzer, Oxy-combustion boiler material development, 35th International Technical Conference on Clean Coal & Fuel System, Clearwater, Florida (USA)

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: 3 - Oxycombustion SC PC	REVISION	Rev.: Draft	Rev.: 0	Rev.1	Rev.2
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EQUIPMENT LIST
Unit 2100 - FGD

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	FGD SYSTEM							
	FGD system Including: - Flue gas ducts with dampers - One Circulating Fluid Bed Scrubber (CFBS) - Internal scrubber equipment - One Fabric filter with recirculating system - Air blowers - Silo for absorbent - Product Silo for residue - Water storage tank - Water injection system for CFBS - Lime hydration system		Flue gas inlet flowrate: 476000 Nm3/h Removal efficiency: 95 %					

EQUIPMENT LIST

Unit 3000 - Steam Cycle

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	PACKAGES							
PK- 3001	**Steam Turbine and Generator Package**							
ST- 3001	Steam Turbine		1100 MWe *HP admission:* *2900 t/h @ 270 bar* *Hot reheat admission:* *2200 t/h @ 60 bar* *LP admission:* *2020 t/h @ 5.9 bar*					*Including:* *Lube oil system* *Cooling system* *Idraulic control system* *Drainage system* *Seals system* *Drainage system* *Electrical generator and relevant auxiliaries*
E- 3001 A/B	Inter/After Condenser							
E- 3002	Gland Condenser							
PK- 3002	**Steam Condenser Package**							*Including:*
E- 3001	Steam condenser		1210 MWth					*Hot well* *Vacuum pump (or ejectors)* *Start up ejector (if required)*
PK- 3003	**Steam Turbine Bypass System**							*Including:* *MP dump tube* *LP dump tube* *HP/MP Letdown station* *MP Letdown station* *LP Letdown station*
PK- 3004	**Phosphate injection package**							
PK- 3005	**Oxygen scavanger injection package**							
PK- 3006	**Amines injection package**							

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		ISSUED BY	NF	NF		
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EQUIPMENT LIST

Unit 3000 - Steam Cycle

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	HEAT EXCHANGERS		**Duty (kW)**		Shell/tube	Shell/tube		
E- 3003	BFW Economiser #1		66500					
E- 3004	BFW Economiser #2		360000					
E- 3005	Condensate heater #1		101000					
	PUMPS		**Q [m^3/h] x H [m]**					
P- 3001 A/B	BFW pumps	Centrifugal Steam driven	3200 x 3560	35000				*Two operating*
P- 3002	BFW pump	Centrifugal						*For start-up, electric motor*
P- 3003 A/B	Condensate pump	Centrifugal	2500 x 160	1120				*One operating one spare, electric motor*
	VESSEL							
D- 3001	Dearator	Horizontal						

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EQUIPMENT LIST
Unit 4000 - CO2 compression and purification

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	PACKAGES							
PK - 4001	**Sour compression section**		Dry flue gas: 22,415 kmol/h 3.8% vol H_2O					
	Including:							
	- Raw flue gas compressors (two stages)			*2 x 48 MWe*				
	- Contacting column with liquid pump around for sulphuric and nitric acid removal							
	- Flue gas cooler downstream compressor							
	BFW heater		*14 MWth*					
	Condensate heater		*26 MWth*					
PK - 4002	**Dual Bed essicant system**							
PK - 4003	**Cold box for inerts removal**							
	Including:							
	- Main heat exchangers							
	- CO2 liquid separator							
	- CO2 distillation column							
	- CO2 compressors and coolers			*2 x 15 MWe*				
	- Inerts heater							
	- Inerts expander			*16.6 MWe*				
	- Overhead recycle compressors			*1.0 MWe*				

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		ISSUED BY	NF	NF		
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		APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 6000 - Utility units

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	COOLING SYSTEM		**Duty**					
CT- 6001 A/B	**Cooling Tower** including: Cooling water basin	Natural draft	2 x 775 MWth Diameter: 120 m each, Height: 210 m, Water inlet: 17 m				concrete	
	PUMPS		**Q [m3/h] x H [m]**					
P- 6001 A/…/F	**Cooling Water Pumps (primary system)**	Centrifugal	16000 x 35	1900				*Six in operation*
P- 6002 A/B/C	**Cooling Water Pumps (secondary system)**	Centrifugal	13500 x 45	2200				*Two in operation, one spare*
P- 6003 A/B	**Cooling tower make up pumps**	Centrifugal	2400 x 30	300				
	PACKAGES							
	Cooling Water Filtration Package Cooling Water Sidestream Filters		Capacity: 12300 m3/h					
	Sodium Hypochlorite Dosing Package Sodium Hypochlorite storage tank Sodium Hypochlorite dosage pumps							
	Antiscalant Package Dispersant storage tank Dispersant dosage pumps							
	RAW WATER SYSTEM		**Q [m3/h] x H [m]**					
T- 6001	Raw Water storage tank		120 m3					*12 hour storage*
P- 6004 A/B	Raw water pumps	centrifugal	10 x 50	5.5				*One operating, one spare*
	DEMINERALIZED WATER SYSTEM		**Q [m3/h] x H [m]**					
PK- 6001	**Demin Water Package, including:** - Multimedia filter - Reverse Osmosis (RO) Cartidge filter - Electro de-ionization system							
T- 6002	Demin Water storage tank		60 m3					*12 hour storage*
P- 6005 A/B	Demin water pumps	centrifugal	5 x 65	3.5				*One operating, one spare*

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EQUIPMENT LIST
Unit 6000 - Utility units

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	FIRE FIGHTING SYSTEM							
T- 6003	Fire water storage tank							
	Fire pumps (diesel)							
	Fire pumps (electric)							
	FW jockey pump							
	OTHER UTILITIES							
	Plant air compression skid							
	Emergency diesel generator system							
	Waste water treatment							
	Electrical equipment							
	Buildings							
	Auxiliary boiler							
	Condensate polishing system							

CLIENT	:	IEA GHG
PROJECT NAME	:	CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
DOCUMENT NAME	:	CASE 3.1: OXY-COMBUSTION SC PC WITH CCS NEAR-ZERO EMISSION CASE
FWI CONTRACT	:	1-BD-0681 A

ISSUED BY	:	G. PERFUMO
CHECKED BY	:	N. FERRARI
APPROVED BY	:	L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

1. Introduction

This chapter of the report includes all technical information relevant to Case 3.1 of the study, which is an oxy-combustion supercritical pulverised coal (SC PC) fired steam plant, with cryogenic purification of the flue gases and capture of the carbon dioxide.

Plant configuration is basically same as Case 3, though plant of Case 3.1 is designed to meet near-zero CO_2 emission target (around 98% carbon capture rate).

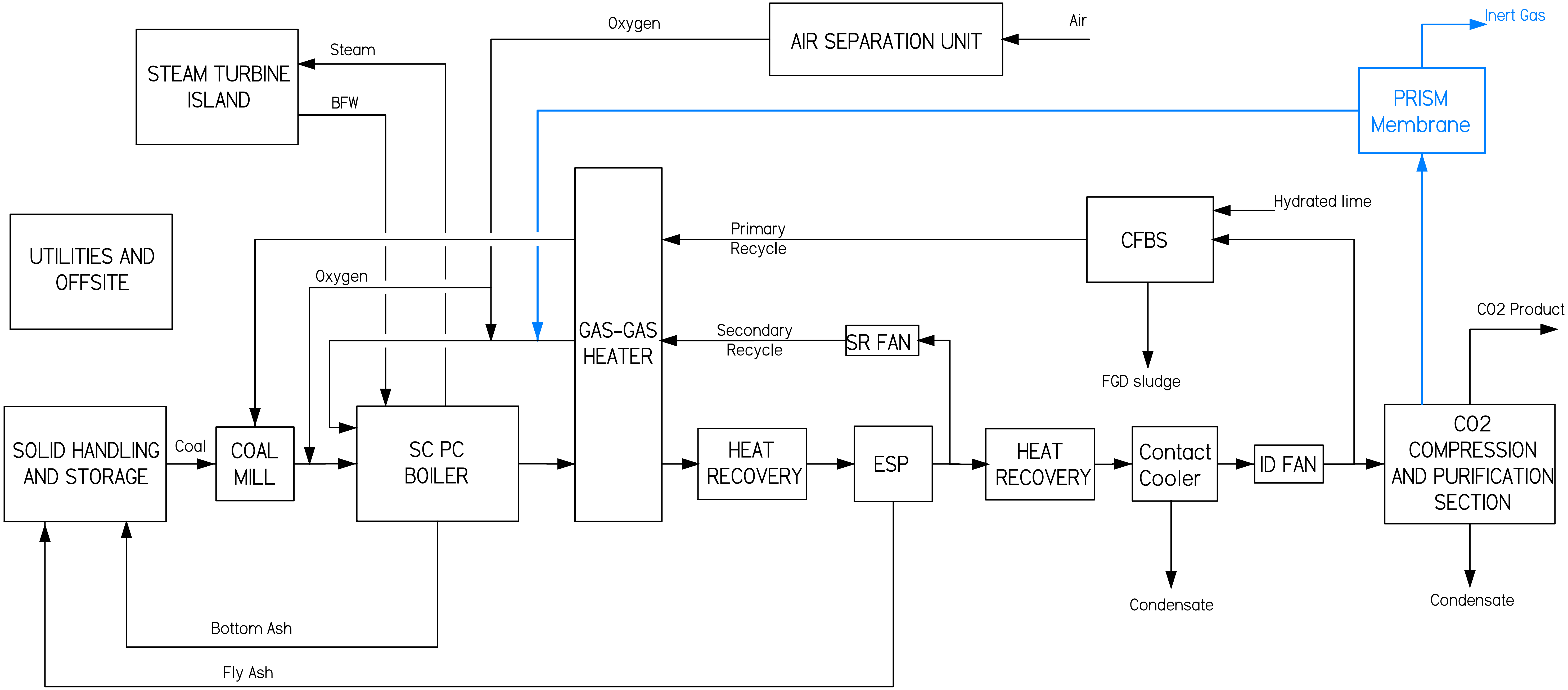
The description of the main process units and the reference Case 3 performance are covered respectively in chapter D and D.1 of this report; only plant design changes required to meet near-zero emission target are discussed in the following sections, together with the main plant performance results.

1.1. Process unit arrangement

The arrangement of the main units is reported in Table 1, together with the main differences with respect to the base case, as further discussed in the following sections. Reference is also made to the block flow diagram attached below.

Table 1. Case 3.1 – Unit arrangement

Unit	Description	Trains	Differences
900	Air Separation Unit	3 x 33%	No significant design change: slightly lower oxygen requirement
1000	Storage and Handling of solid materials	N/A	-
2000	Oxy combustion SC PC boiler Electro Static precipitators	1 x 100%	No significant design changes: higher flue gas flowrate and minor composition changes
2100	Flue Gas Desulphurisation (FGD)	1 x 100%	No significant design changes: minor composition changes
3000	Steam Cycle (SC) Steam Turbine and Condenser Deaerator Water Preheating line	1 x 100%	No significant design changes: minor changes in heat integration with process unit
4000	CO_2 compression and purification Sour compression Auto-refrigerated inert removal section CO_2 compressors	 1 x 100% 1 x 100% 2 x 50%	Increased design capacity (+10%) Additional PRISM® membrane unit
6000	Utility and Offsite	N/A	Minor changes in cooling water system capacity



0	July 13	Draft	NF	LM	**UNIT:** Block Flow Diagram
Rev.	Date	Comment	By	Appr	**CASE:** 3.1 — Sheet 01 of 01

2. Process description

2.1. Overview

The description reported in this section focuses only on those units with a design different from that of the reference case, necessary to meet near-zero carbon emission target. Design changes are also reflected in the simplified Process Flow Diagrams (PFD) shown in section 3.

For all the other units, reference shall be made to the base case description, included in chapter D.1, section 2.

2.2. Unit 2000 – Boiler Island

This unit is based on single pass tower-type super critical boiler, with multistage combustion of oxygen and flue gas for NOx control, the primary and secondary recycle ducts, the heat recovery section and the contact column for final flue gas cooling, as for Case 3. The main design change is the additional duct from the membrane section of the CO_2 purification unit for recycling the CO_2 and oxygen-rich stream back to the furnace, after mixing with the secondary recycle.

The additional recirculation in the furnace results in an increased flue gas flowrate to the CO_2 purification unit and, as a consequence, of the flue gas recirculation in the warm end section of the boiler.

2.3. Unit 4000 – CO_2 compression and purification

This unit differs from the Air Products' process of the reference case for the following features:

- Inerts gas from the auto-refrigerated section is processed through dedicated PRISM® membrane, in order to recover enough CO_2 to meet around 98% carbon capture rate. Further information relevant to this system is reported in chapter D, section 2.4.
- The recirculation back to the furnace of the CO_2 and oxygen-rich stream recovered from the membrane results in an increased flue gas flowrate entering the CO_2 purification unit. As for that, the design capacity of the unit, as well as the compression consumption and the heat recovery, is increased with respected to the base case. On the contrary, the inert gas expander is smaller, reducing the internal electrical production of the unit.

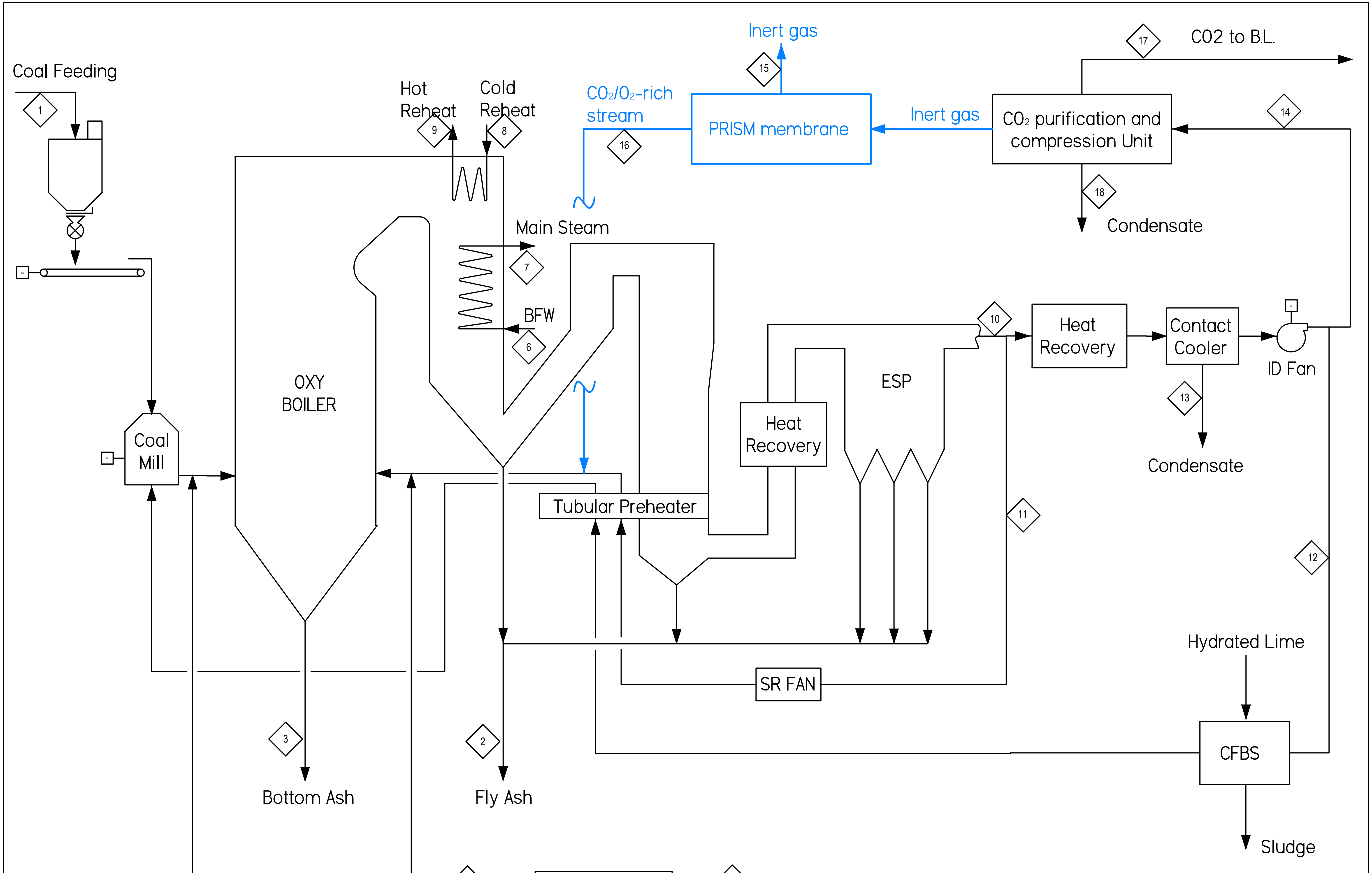
Following Table 2 summarises key stream data of this case, while main interconnections with the other units are shown in the process flow diagram.

Table 2. Case 3.1 – Key stream data

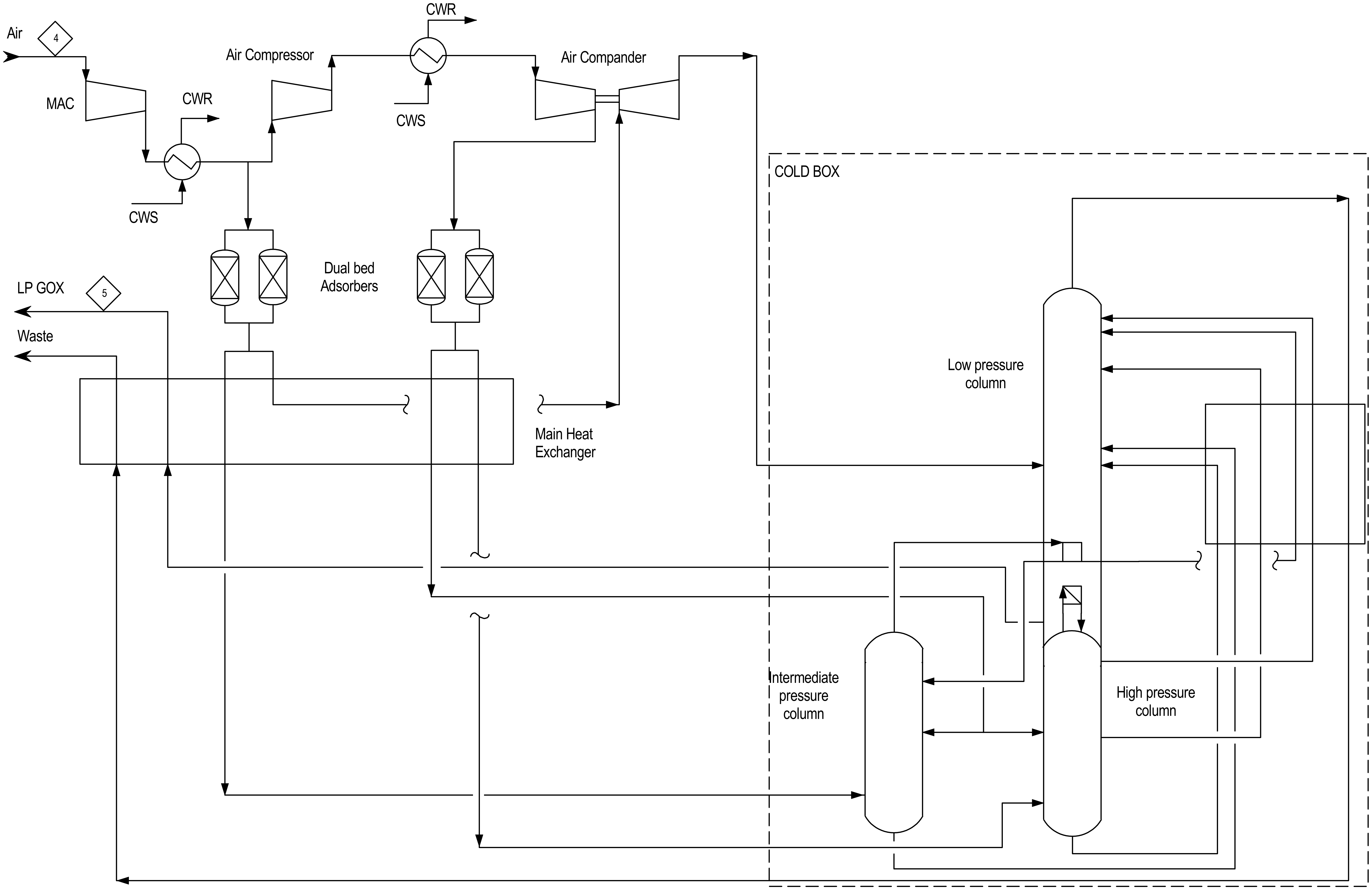
Stream	Flue gas to CPU	Inert gas vent	Inert gas recycle	CO_2 product
Mass flowrate, kg/h	1,018,650	140,000	108,360	744,400
Molar flowrate, kmol/h	25,465	4,570	2,845	16,915
Composition (% vol)				
Ar	2.13	8.6	4.6	34 ppmv
N_2	14.21	69.1	16.7	53 ppmv
O_2	5.70	15.1	25.4	100 ppmv
CO_2	73.99	6.4	53.2	99.98%
H_2O	3.76	0.8	-	-
NOx	0.04	< 1 ppmv	-	-
SOx	0.17	< 1 pmmv	-	-

3. Process Flow Diagrams

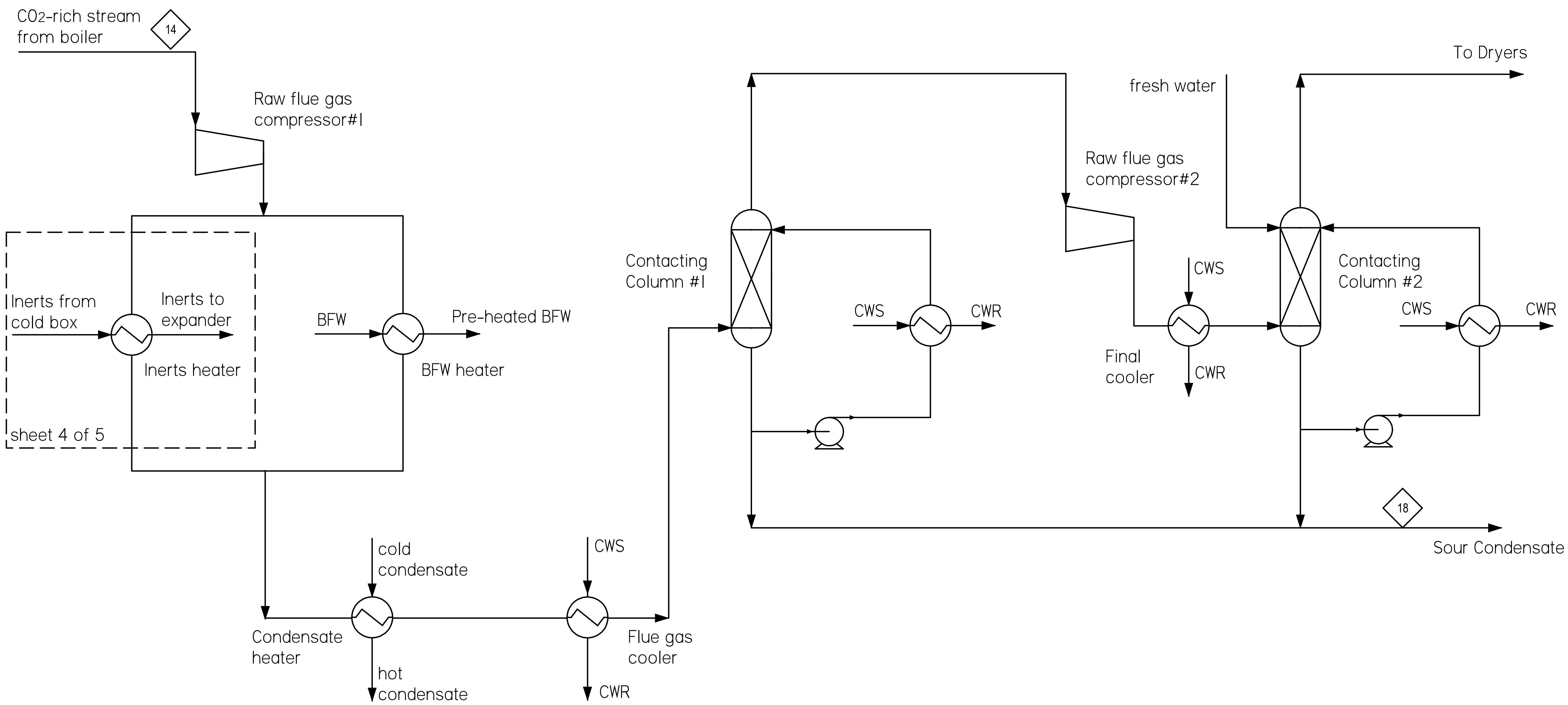
Simplified Process Flow Diagrams of this case are attached to this section. Stream numbers refer to the heat and material balance shown in the next section.



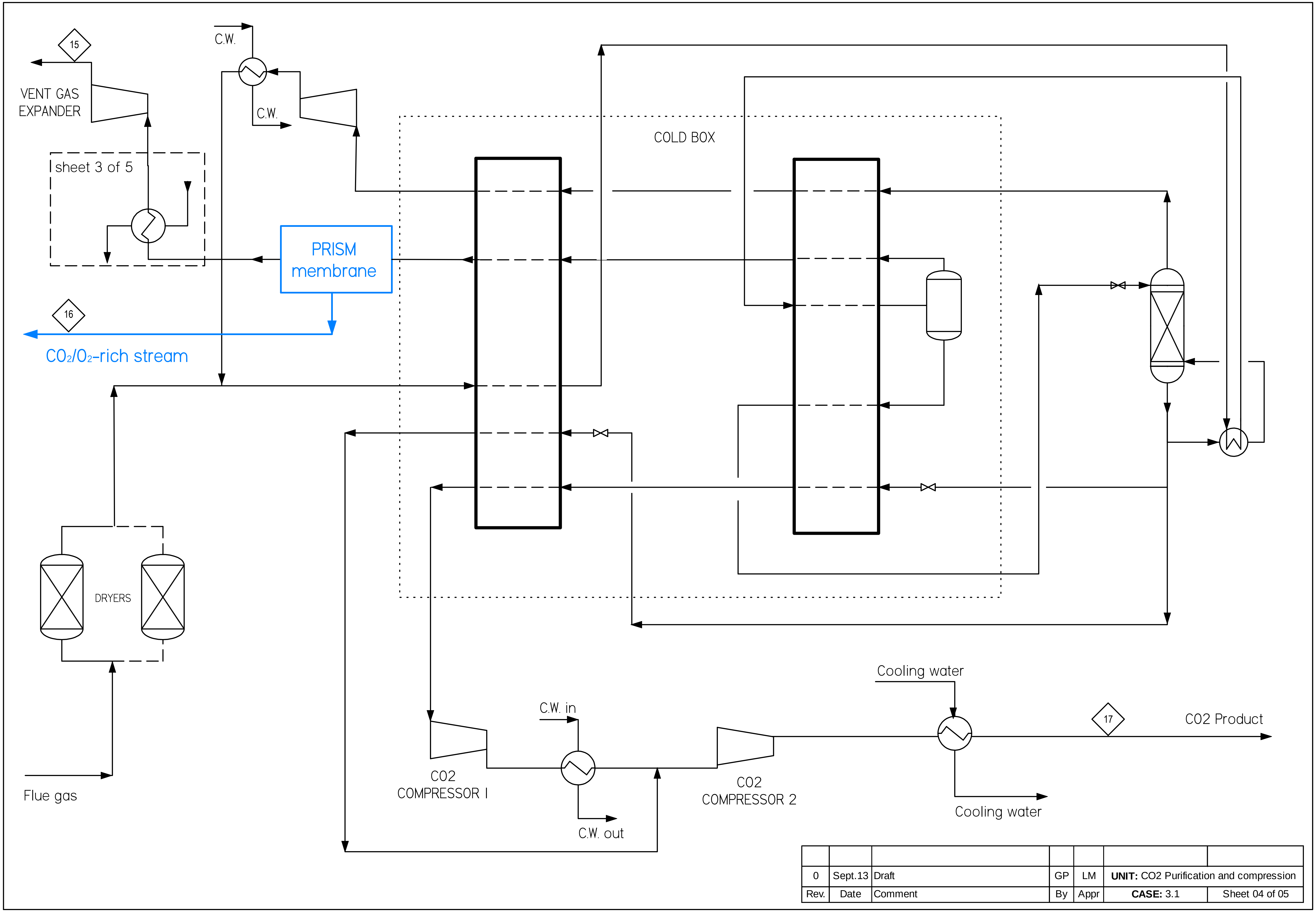
0	Sept. 13	Draft	NF	LM	**UNIT:** Boiler Island	
Rev.	Date	Comment	By	Appr	**CASE:** 3.1	Sheet 01 of 01



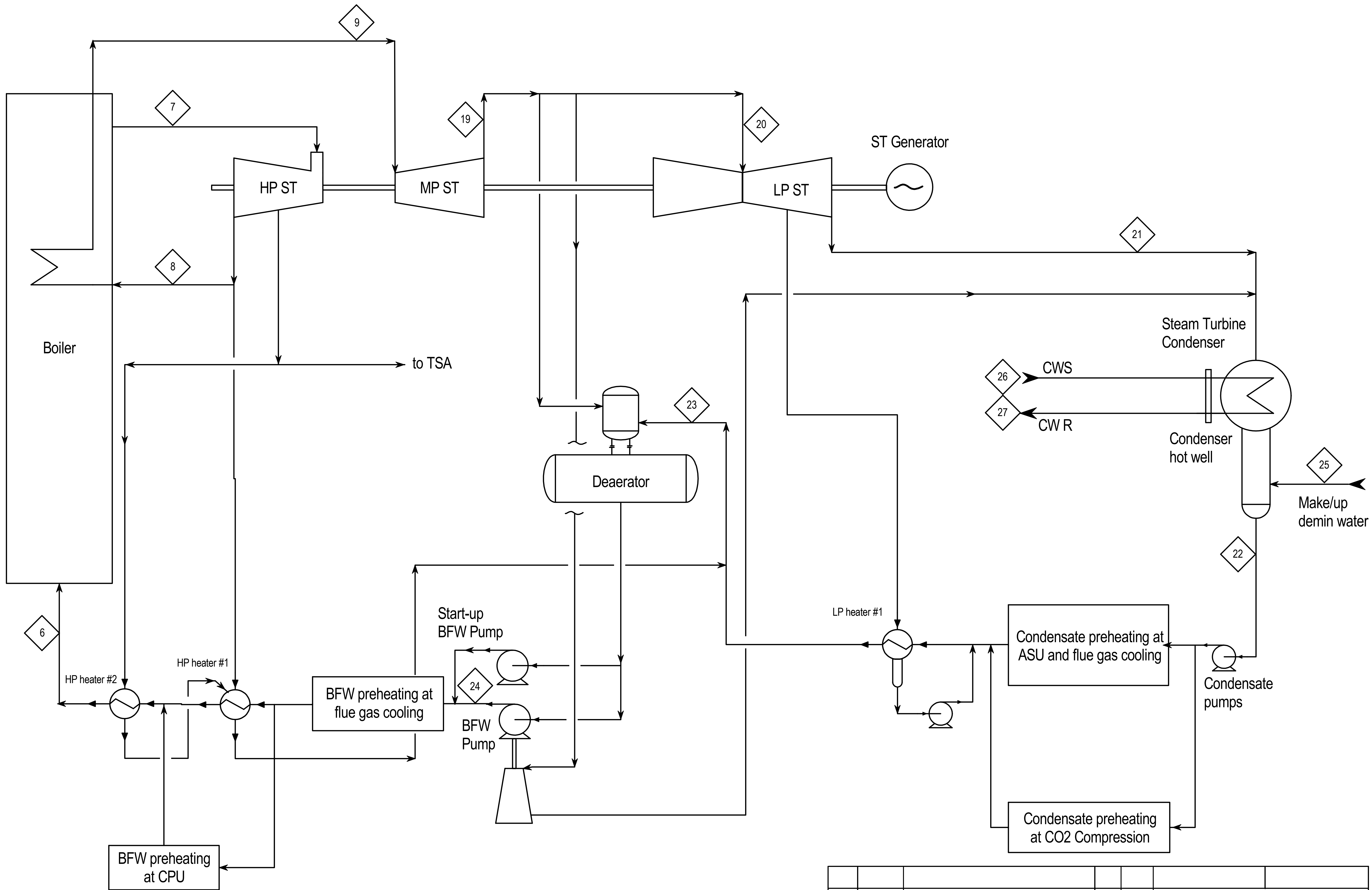
0	Sept.13	Draft	GP	LM	**UNIT:** Air Separation Unit	
Rev.	Date	Comment	By	Appr	**CASE:** 3.1	Sheet 02 of 05



0	Sept.13	Draft	GP	LM	**UNIT:** Sour compression	
Rev.	Date	Comment	By	Appr	**CASE:** 3.1	Sheet 03 of 05



0	Sept.13	Draft	GP	LM	**UNIT:** CO2 Purification and compression	
Rev.	Date	Comment	By	Appr	**CASE:** 3.1	Sheet 04 of 05



0	Sept. 13	Draft	GP	LM	**UNIT:** Steam Cycle	
Rev.	Date	Comment	By	Appr	**CASE:** 3.1	Sheet 05 of 05

4. Heat and Material Balance

Heat & Material Balances reported make reference to the simplified Process Flow Diagrams reported in section 3.

FOSTER WHEELER	Case 3 - Oxycombustion SC PC - HEAT AND MATERIAL BALANCE		REVISION	0		
	CLIENT :	IEA GHG	PREP.	NF		
	PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	CHECKED	LM		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	September 13		

HEAT AND MATERIAL BALANCE
UNIT 2000 - BOILER ISLAND

STREAM	1	2	3	4	5	6	7	8	9	10
	Coal to Boiler Island	Fly Ash	Bottom Ash	Air intake from Atmosphere	Oxygen to boiler	BFW from steam cycle	HP Steam to Steam Turbine	Cold Reheat from Steam Turbine	Hot Reheat to Steam Turbine	Flue gas from ESP
Temperature (°C)	AMB	AMB	AMB	9	AMB	290	600	366	620	160
Pressure (bar)	ATM	ATM	ATM	ATM	ATM	325	270	63	60	-
TOTAL FLOW	Solid	Dry solid	Dry solid							
Mass flow (kg/h)	325,000	29,200	12,500	2,820,000	670,260	2,895,000	2,895,000	2,208,000	2,208,000	3,400,000
Molar flow (kmol/h)				97,740	20,885	160,740	160,740	122,600	122,600	92,400
LIQUID PHASE										
Mass flow (kg/h)						2,895,000				
GASEOUS PHASE										
Mass flow (kg/h)				2,820,000	670,260		2,895,000	2,208,000	2,208,000	3,400,000
Molar flow (kmol/h)				97,740	20,885		160,740	122,600	122,600	92,400
Molecular Weight				28.9	32.1		18.0	18.0	18.0	36.8
Composition (vol %)	%wt									
H_2				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CO	C: 64.6%			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CO_2	H: 4.38%			0.03%	0.00%	0.00%	0.00%	0.00%	0.00%	63.14%
N_2	O: 7.02%			77.27%	1.20%	0.00%	0.00%	0.00%	0.00%	12.12%
O_2	S: 0.86%			20.73%	97.00%	0.00%	0.00%	0.00%	0.00%	4.86%
CH_4	N: 1.41%			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Ar	Cl: 0.03%			0.92%	1.80%	0.00%	0.00%	0.00%	0.00%	1.81%
H_2O	Moisture: 9.5%			1.05%	0.00%	100%	100%	100%	100%	17.87%
SO_2	Ash: 12.20%			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.16%
NO / NO_2				-	-	-	-	-	-	0.04%
HNO_3				-	-	-	-	-	-	-
H_2SO_4				-	-	-	-	-	-	-
Total				100%	100%	100%	100%	100%	100%	100%

NOTE
1. Air in-leakage are included in the flue gas streams

	Case 3 - Oxycombustion SC PC - HEAT AND MATERIAL BALANCE		REVISION	0		
	CLIENT :	IEA GHG	PREP.	NF		
	PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	CHECKED	LM		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	September 13		

HEAT AND MATERIAL BALANCE
UNIT 2000 - BOILER ISLAND

STREAM	11	12	13	14	15	16	17	18		
	Secondary recycle to boiler	Primary recycle to FGD	Condensate from Contact Cooler	Flue gas to CPU	Inert gas vent	Inert gas recycle	CO_2 product	Condensate from CPU		
Temperature (°C)	170	38	28	38	210	20	30	25		
Pressure (bar)	-	-	-	-	1.6	1.2	110	2.0		
TOTAL FLOW										
Mass flow (kg/h)	1,380,000	850,000	146,600	1,018,650	140,000	108,360	744,400	20,360		
Molar flow (kmol/h)	37,500	21,240	8,140	25,465	4,570	2,845	16,915	924		
LIQUID PHASE										
Mass flow (kg/h)			146,600					20,360		
GASEOUS PHASE										
Mass flow (kg/h)	1,380,000	850,000		1,018,650	140,000	108,360	744,400			
Molar flow (kmol/h)	37,500	21,240		25,465	4,570	2,845	16,915			
Molecular Weight	36.8	40.0		40.0	30.6	38.1	44.0			
Composition (vol %)										
H_2	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%		
CO_2	63.14%	73.99%	0.00%	73.99%	6.40%	53.20%	99.98%	0.03%		
N_2	12.12%	14.21%	0.00%	14.21%	69.10%	16.70%	53 ppmv	0.00%		
O_2	4.86%	5.70%	0.00%	5.70%	15.10%	25.40%	100 ppmv	0.00%		
CH_4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-	0.00%		
Ar	1.81%	2.13%	0.00%	2.13%	8.60%	4.60%	34 ppmv	0.00%		
H_2O	17.87%	3.76%	99.99%	3.76%	0.80%	0.00%	-	94.55%		
SO_2	0.16%	0.17%	0.00%	0.17%	0.00%	0.00%	-	240 ppmv		
NO / NO_2	0.04%	0.04%	0.00%	0.04%	0.00%	0.00%	-	0.23 ppmv	-	
HNO_3	-	-	0.00%	-	-	-	-	0.99%	-	
H_2SO_4	-	-	0.01%	-	-	-	-	4.41%		
Total	100%	100%	100%	100%			100%	100%		

NOTE
1. Air in-leakage are included in the flue gas streams

	Case 3 - Oxycombustion SC PC - H&M BALANCE		Revision	0	
	CLIENT:	IEA GHG	Prepared	NF	
	PROJECT NAME:	CO2 capture at coal based power and H2 plants	Checked	LM	
	PROJECT NO:	1-BD-0681 A	Approved	LM	
	LOCATION:	The Netherlands	Date	September 13	

HEAT AND MATERIAL BALANCE
UNIT 3000 - STEAM CYCLE

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
6	HP Water to Boiler Island	2,895	290	323.5	1278
7	HP Steam from Boiler to HP Steam Turbine	2,895	600	270.0	3475
8	Cold Reheat to Boiler	2,208	367	63.0	3084
9	Hot Reheat to MP Steam Turbine	2,208	620	60.0	3706
19	MP Steam Turbine exhaust	2,208	285	6.0	3031
20	Steam to LP Steam Turbine	2,023	285	5.9	3031
21	Exhaust from LP steam turbine	1,874	29	0.04	2284
22	Condensate from condenser	2,047	29	0.04	121
23	Condensate to deaerator	2,842	138	9.5	581
24	BFW to pre-heating train	2,895	148	325	644
25	Make up Water	5	9	ATM	38
26	Cooling Water Inlet	95,200	15	4.0	63
27	Cooling Water Outlet	95,200	26	3.5	109

5. Utility and chemical consumption

Main utility and chemical consumption of the plant is reported in the following tables, compared with the reference case figures (in brackets). More specifically:

- Water consumption summary is reported in Table 3,
- Electrical consumption summary is shown in Table 4,
- Sorbent and chemicals consumption, shown in Table 5.

With respect to the reference case, the following considerations can be made:

- Both water and electrical demand of the boiler island are slightly greater, due to the higher flue gas recirculation in the furnace.
- The Air Separation Unit, even though the design capacity is fixed to meet the oxygen demand considering no recirculation from the membrane, is operated at marginal lower load, with consequently marginal lower power demand, as part of the oxygen is provided by the recycle stream from the CO_2 purification unit.
- As detailed in previous section, consumption of the CO_2 purification unit increases as more CO_2 is processed and compressed up to the final pressure and a small inert gas flowrate is expanded to generate power.
- Utilities and offsite consumption increases, mainly due to the higher cooling water requirements.

Table 3. Case 3.1 – Water consumption summary

CLIENT: IEAGHG		REVISION	0
PROJECT NAME: CO2 capture at coal based power and H2 plants		DATE	Jun-13
PROJECT No. : 1-BD-0681 A		MADE BY	NF
LOCATION : The Netherlands		APPROVED BY	LM

Case 3.1 - Near zero emission - Water consumption

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water 1° syst. [DT = 11°C] [t/h]	Cooling Water 2° syst. [DT = 11°C] [t/h]
1000	**FEEDSTOCK AND SOLID HANDLING**				
	Solid Receiving, Handling and storage	5			
2000	**Air Separation Unit**				
	Air Separation unit				1210 *(1250)*
2000	**BOILER ISALND and FLUE GAS TREATMENT**				
	Boiler island				11170 *(11080)*
	Flue Gas Desulphurization (CFBS)				
	CO2 compression and purification				9655 *(9015)*
500	**POWER ISLAND (Steam Turbine)**				
	Condenser			95200 *(94745)*	
	Turbine and generator auxiliaries		5		5100 *(5080)*
BoP	**UTILITY and OFFSITE UNITS**				
	Cooling Water System	2200 *(2180)*			
	Demineralized/Condensate Recovery/Plant and Potable Water Systems	8	-5		
	Miscellanea	-160			100
	BALANCE	**2053** ***(2033)***	**0.0**	**95200** *(94745)*	**27235** *(26525)*

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

Table 4. Case 3.1 – Electrical consumption summary

CLIENT:	IEAGHG	REVISION	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	DATE	Jun-13
PROJECT No. :	1-BD-0681 A	MADE BY	NF
LOCATION :	The Netherlands	APPROVED BY	LM

Case 3.1 - Near zero emission - Electrical consumption

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
900	AIR SEPARATION UNIT	
	Main air compressors	101190 (111060)
	Booster air compressors + pumps	17680 (18280)
1000	FEEDSTOCK AND SOLID HANDLING	
	Solid Handling	3255
2000	BOILER ISLAND and FLUE GAS TREATMENT	
	Boiler island (including FGD)	14650 (14370)
3000	STEAM CYCLE	
	Steam Turbine Auxiliaries and condenser	4900 (4700)
	Condensate and feedwater system	1250
	Miscellanea	600
4000	CO2 PURIFICATION AND COMPRESSION	
	Flue gas compression (up to 35 bar)	93080 (83390)
	CO2 compression (up to 110 bar)	29230 (26790)
	Overhead recycle	850 (790)
	Expander	-10220 (15110)
BoP	UTILITY and OFFSITE UNITS	
	Cooling Water System	14740 (14290)
	Other Units	1430
	BALANCE	278,635 (265,095)

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

Table 5. Case 3.1 – Sorbent and chemicals consumption

	Consumption
Lime injection to the FGD	6.6 t/h

6. Overall performance

The following Table shows the overall performance of Case 3.1, compared with the reference case performance.

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	**DATE**	Jun-13
PROJECT No. :	1-BD-0681 A	**MADE BY**	NF
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 3.1 - Near zero emission - Oxy SC PC Plant Performance Summary

OVERALL PERFORMANCES COMPARISON			
		CASE 3.1	**CASE 3 (reference)**
Fuel flow rate (A.R.)	t/h	325.0	325.0
Fuel HHV (A.R.)	kJ/kg	27060	27060
Fuel LHV (A.R.)	kJ/kg	25870	25870
THERMAL ENERGY OF FEEDSTOCK (based on LHV) (A)	**MWth**	**2335**	**2335**
THERMAL ENERGY OF FEEDSTOCK (based on HHV) (A')	**MWth**	**2443**	**2443**
Steam turbine power output (@ gen terminals)	MWe	1105.0	1101.0
GROSS ELECTRIC POWER OUTPUT (C) (1)	**MWe**	**1105.0**	**1101.0**
Boiler Island (including FGD)	MWe	14.7	14.4
Utility & Offsite Units consumption	MWe	16.2	15.7
Power Islands consumption	MWe	6.8	6.6
Air Separation Unit consumptions	MWe	124.9	129.3
CO2 purification and compression	MWe	112.9	95.9
Feedstock and solids handling	MWe	3.3	3.3
ELECTRIC POWER CONSUMPTION	**MWe**	**278.6**	**265.1**
NET ELECTRIC POWER OUTPUT	**MWe**	**826.4**	**835.9**
(Step Up transformer efficiency = 0.997%) (B)	MWe	823.9	833.4
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**47.3%**	**47.1%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**35.3%**	**35.7%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**45.2%**	**45.1%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**33.7%**	**34.1%**
Fuel Consumption per net power production	**MWth/MWe**	**2.83**	**2.80**
CO_2 emission per net power production	**kg/MWh**	**22.3**	**92.2**

(1) Steam driven BFW pumps are included

With respect to the reference case, the following considerations can be made:

- Gross power production is slightly increased as more heat recovery is possible within the CO_2 purification unit and the boiler island, due to the higher flue gas flowrate through the units.
- Net electrical efficiency decreases of about 0.4 percentage points, due to increased power demand related to the required higher capture rate.

The following Table shows the overall CO_2 balance and removal efficiency of Case 3.1, compared with the reference case.

	CASE 3.1	CASE 3 (reference)
CO_2 removal efficiency	**Equivalent flow of CO_2** kmol/h	**Equivalent flow of CO_2** kmol/h
INPUT		
FUEL CARBON CONTENT (A)	17495	17495
OUTPUT		
Carbon losses (B)	166	166
CO_2 flue gas content (to CPU)	18842	17329
Recovered through membrane	1513	0
Total to storage (C)	16912	15584
Emission (inert + losses)	417	1745
TOTAL	17495	17495
Overall Carbon Capture, % ((B+C)/A)	97.6	90.0

7. Environmental impact

The oxy-combustion SC PC steam plant design is based on advanced technologies that allow to reach high electrical generation efficiency, while minimizing impact to the environment. Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

7.1. Gaseous emissions

During normal operation at full load, main continuous emissions are the inerts vent stream from the PRISM® membrane within the CO_2 purification unit. Table 6 summarizes the expected flow rate and composition of the inerts vent.

The same minor and fugitive emissions, related to seal losses and handling of solid materials and listed for the base case, are applied also for this alternative.

Table 6. Case 3.1 – Plant emission during normal operation

Flue gas to stack	
Emission type	Continuous
Conditions	
Wet gas flowrate, kg/h	140,000
Flow, Nm^3/h	102,000
Composition	(% vol)
Ar	8.6
N_2	69.1
O_2	15.1
CO_2	6.4
H_2O	0.8
NOx	< 1 ppmv
SOx	< 1 pmmv

7.2. Liquid effluent

As for the reference case, main liquid effluent is the following cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids.

Cooling Tower blowdown

Flowrate : 526 m^3/h

7.3. Solid effluent

As for the base case, the power plant is expected to produce the following solid effluents:

Fly ash from boiler

Flowrate : 29.2 t/h

Bottom ash from boiler

Flowrate : 12.5 t/h

Sludge from FGD

Flowrate : 12.6 t/h

Fly and bottom ash might be sold to cement industries, if local market exist, or sent to disposal, outside plant battery limits. Sludge from FGD shall also be sent to outside disposal.

8. Main equipment design changes

The overleaf equipment summary table shows the major design differences between the present Case 3.1 and the reference Case 3.

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: 3.1 - Oxycombustion SC PC - Near Zero Emission					

REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
DATE	Jul-13			
ISSUED BY	NF			
CHECKED BY	LM			
APPROVED BY	LM			

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor Rating [kW]	Remarks	Difference with respect to reference case
	AIR SEPARATION UNIT					
PK - 901 A/B/C	**Air Separation unit**		3 x 5555 t/d		*Oxygen feed: -4% with respect to base case*	**No changes in ASU size**
	CO2 COMPRESSION AND PURIFICATION					
PK - 4001	**Sour compression section**		Dry flue gas: 24,510 kmol/h 3.8% vol H_2O			**Size changed**
	Including:					
	- Raw flue gas compressors (two stages)			*2 x 50 MWe*		**Size changed**
	- Contacting column with liquid pump around for sulphuric and nitric acid removal					
	- Flue gas cooler downstream compressor					
	BFW heater		*26 MWth*			**Size changed**
	Condensate heater		*27 MWth*			**Size changed**
PK - 4002	**Dual Bed essicant system**					**Size changed**
PK - 4003	**Cold box for inerts removal**					
	Including:					
	- Main heat exchangers					
	- CO2 liquid separator					
	- CO2 distillation column					
	- CO2 compressors and coolers			*2 x 16 MWe*		**Size changed**
	- Inerts heater					
	- Inerts expander			*11.5 MWe*		**Size changed**
	- Overhead recycle compressors			*1.0 MWe*		
	COOLING SYSTEM					
CT- 6001 A/B	**Cooling Tower** **including:** **Cooling water basin**	Natural draft	2 x 780 MWth Diameter: 120 m each, Height: 210 m, Water inlet: 17 m			
P- 6002 A/B/C	**Cooling Water Pumps (secondary system)**	Centrifugal	14000 m3/h x 45 m	2250 kW	*Two operating, one spare*	**Size changed**

CLIENT : IEAGHG
PROJECT NAME : CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
DOCUMENT NAME : CASE 3: OXY-COMBUSTION SC PC WITH CCS
COOLING SYSTEM SENSITIVITY
FWI CONTRACT : 1-BD-0681 A

ISSUED BY : G. PERFUMO
CHECKED BY : N. FERRARI
APPROVED BY : L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

1. Introduction

This chapter presents the main impacts on plant design and performance of alternative types of cooling system, taking as reference the oxy-supercritical pulverised coal (oxy-SC PC) power plant with carbon dioxide capture described in chapter D.1 (Case 3). With respect to this case, based on natural draft cooling water tower system, two different systems are analysed hereafter:

- SW: once-through seawater cooling;
- AC: dry air cooling.

The description of the main process units and the reference Case 3 performance are covered respectively in chapter D and D.1 of this report; only plant design changes related to the alternative cooling systems are discussed in the following sections, together with the main plant performance results.

2. Process description

2.1. Overview

The description of the following sections makes reference to the simplified Process Flow Diagrams (PFD) of section 3, which show only the design changes related to the alternative cooling systems. For all the other units, reference shall be made to the base case description, included in chapter D.1, section 2.

2.2. Impact on process units

The adoption of a cooling system different from the reference case leads to the following modifications within the process units.

2.2.1. *Seawater system*

- ASU: Seawater coolers are considered for the after-coolers of the main air compressor. This allows to achieve a cooling level of the process air greater than the reference case, corresponding also to a lower compressor power demand.
- Boiler Island: Seawater is used as cooling medium in the Indirect Contact Cooler, allowing higher flue gas cooling and water condensation compared to the reference case, with consequent lower water content and flowrate of the CO_2-rich stream flowing to the CO_2 purification and compression section.
- CO_2 purification unit: As written above, a lower flue gas flowrate is entering this unit due to its lower water content, leading to a reduced compressor size and relevant power demand. In addition, seawater is used as cooling medium in the compressor after-coolers, allowing further cooling of the CO_2-rich stream with respect to the reference case, with associated lower compressor power demand. On the other hand, heat recovery for condensate and boiler feed water pre-heating is lower than the reference case.

2.2.2. *Air cooling system*

- ASU: Air coolers are considered for the after-coolers of the main air compressor. During operation at normal ambient conditions, this allows to achieve a cooling level of the process air greater than the reference case, corresponding to a lower compressor power demand, offset by the additional power requirement of the air cooler fans.
- Boiler Island: Air cooling is used as cooling medium in the Indirect Contact Cooler, again allowing higher flue gas cooling and water condensation with respect to the reference case at normal ambient conditions, with consequent

lower water content and flowrate of the CO_2-rich stream flowing to the CO_2 purification and compression section.

- CO_2 purification unit: As written above, a lower flue gas flowrate is entering this unit due to its lower water content, leading to a reduced compressor size and relevant power demand. In addition, air coolers are considered as compressor after-coolers, allowing further cooling of the CO_2-rich stream with respect to the reference case, with associated lower compressor power demand. On the other hand, heat recovery for condensate and boiler feed water pre-heating is lower and the air coolers fans lead to higher electric power demand.

Details on the temperature that can be achieved with both cooling system are reported in the following section 2.4.

2.3. Unit 3000 – Steam Cycle

The main consequence of a cooling system alternative to that of the reference case is a different steam condenser type.

2.3.1. *Seawater system*

A seawater cooled steam condenser is considered in this case. The lower sea water inlet temperature, as well as the lower permitted temperature increase (see data below) allows to achieve a condensing pressure lower than the reference case (3.0 kPa vs. 4.0 kPa respectively), with consequent higher steam turbine power generation.

In fact, being the sea water supplied to the steam condenser at 12°C and considering a maximum allowed temperature increase of 7°C, the condensation temperature is 24°C.

2.3.2. *Air cooling system*

The exhaust steam from the LP turbine is piped directly to the air-cooled, finned tube, condenser. The finned tubes are usually arranged in an “A” form or delta over a forced draught fan in order to reduce the plot area requirements.

A temperature difference of 25°C is considered between ambient air and the condensing steam, resulting in a higher steam condensing pressure with respect to the reference case (5.2 kPa vs. 4.0 kPa respectively) with consequent lower steam turbine power generation.

2.4. Unit 6000 - Utility Units

Apart from the cooling water system, alternative to the cooling tower type of the reference case, no significant impact is foreseen in the other utility units of the oxy-combustion power plant.

2.4.1. <u>Seawater system</u>

In the once-through system, seawater is pumped from the sea, directly used in the heat exchangers of the plant and then discharged back to sea.

This system has the advantage of using a “free” coolant medium, without generating a real stream of waste water, since seawater is returned to the sea without any significant change in composition, apart from its higher temperature. However, the maximum allowable seawater temperature increase is 7°C, in order to minimize environmental impact of the sea, thus resulting in a higher circulating cooling water flowrate.

In addition to the steam turbine condenser, seawater is used for the CO_2 compressors intercoolers and the main air compressor aftercoolers. During normal operation conditions, this allows achieving a temperature of the hot stream of 19°C, which is lower than the temperature achieved in the reference case (i.e. 26°C).

In addition to the once-trough system, a seawater-cooled closed circuit of demineralised water is considered (secondary system) for machinery and steam turbine generator cooling and for all plant users where seawater is not applicable.

2.4.2. <u>Air cooling system</u>

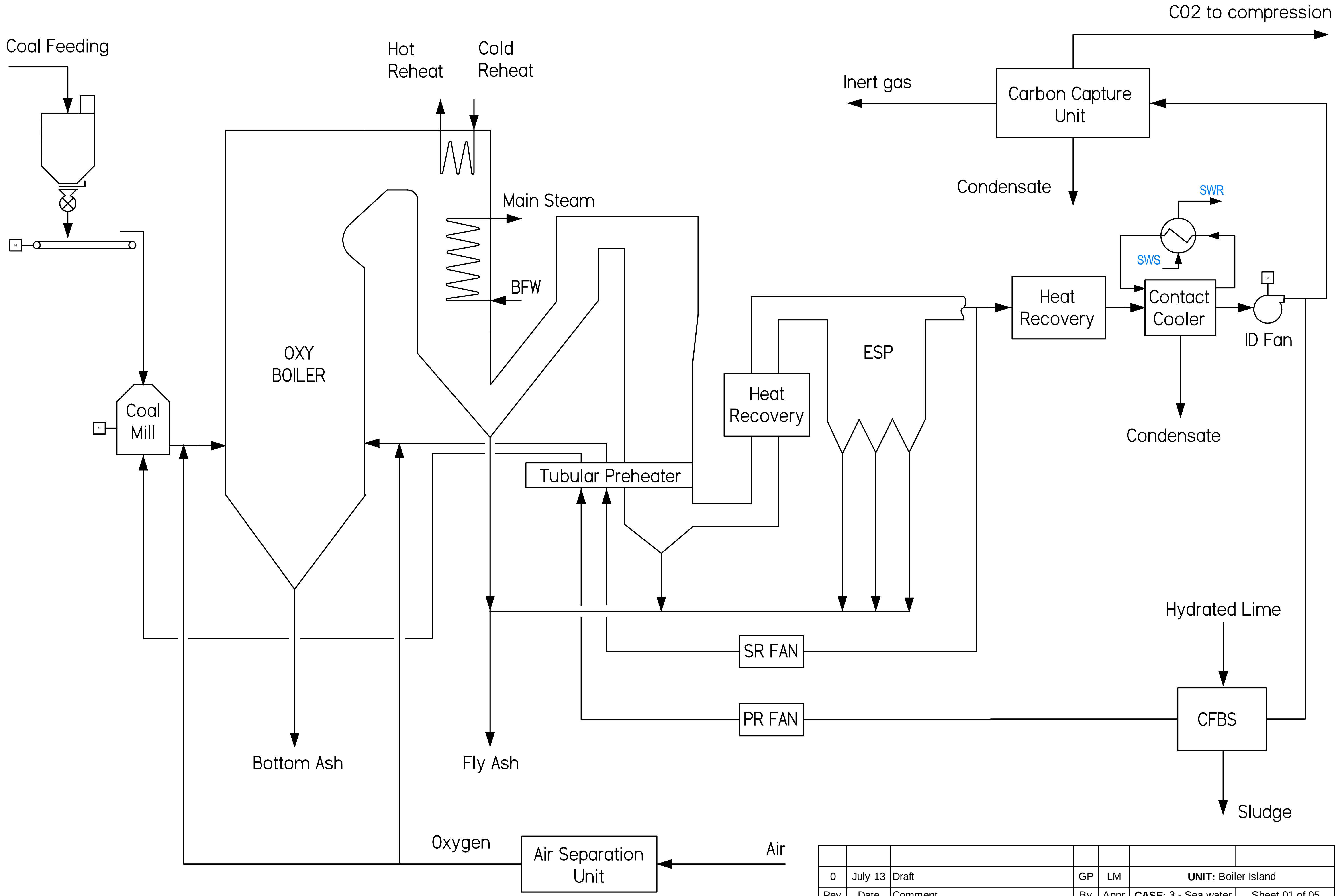
The use of ambient air as cooling medium is maximised. A secondary system consisting of an air-cooled closed circuit of demineralised water, conditioned and stabilised, is only used for machinery and steam turbine generator cooling.

As above stated, the installation of an air cooled steam turbine condenser has a negative impact on the performance, due to the higher condensation pressure resulting from the 25°C approach normally considered for this application.

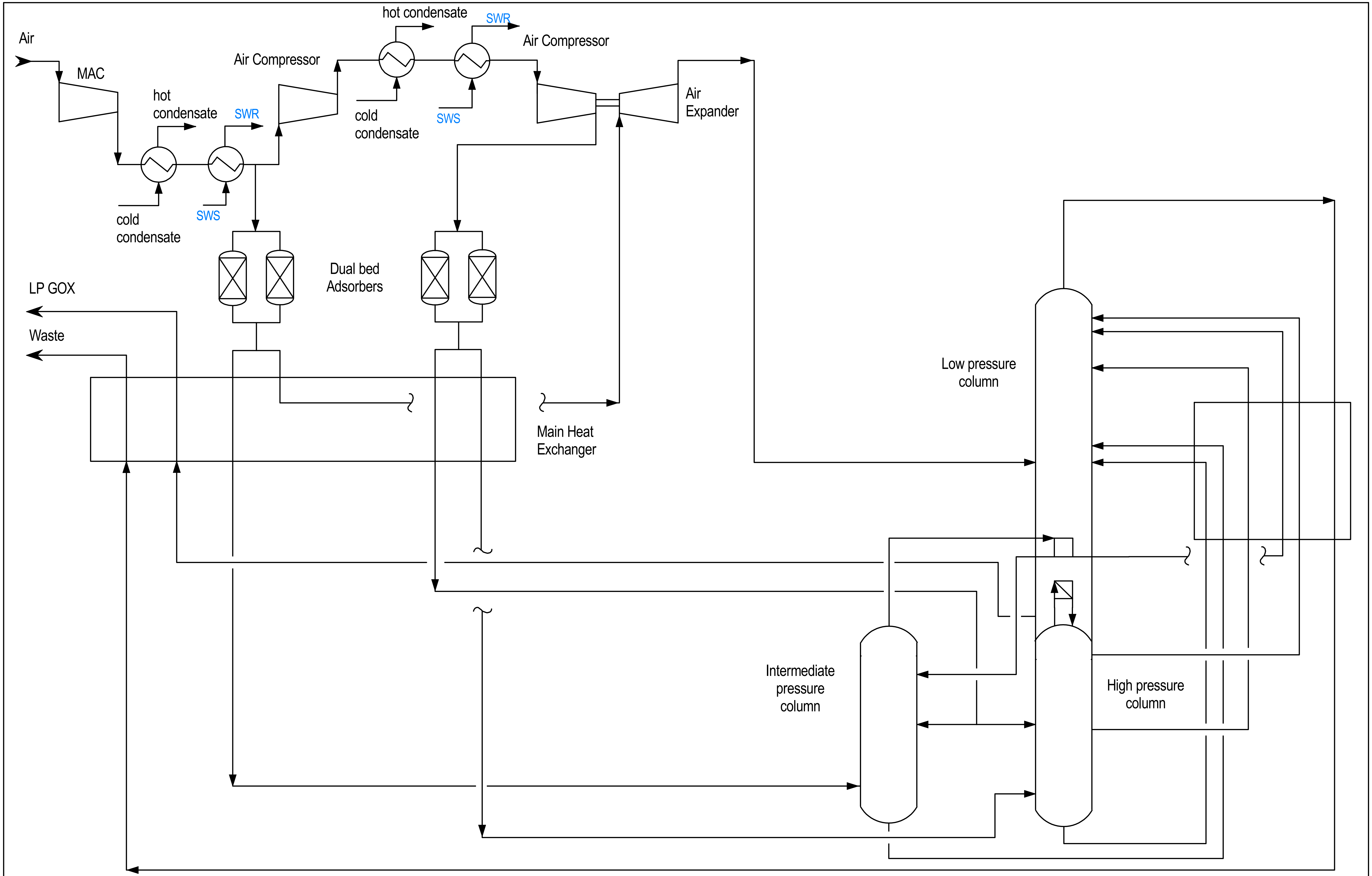
For services other than steam condenser, e.g. water air coolers or compressor intercoolers, the temperature difference between hot fluid exit temperature and ambient air is generally lower, around 10°C, corresponding to a final hot fluid temperature of 19°C, which is lower than the temperature achieved in the reference case (i.e. 26°C).

3. Process Flow Diagrams

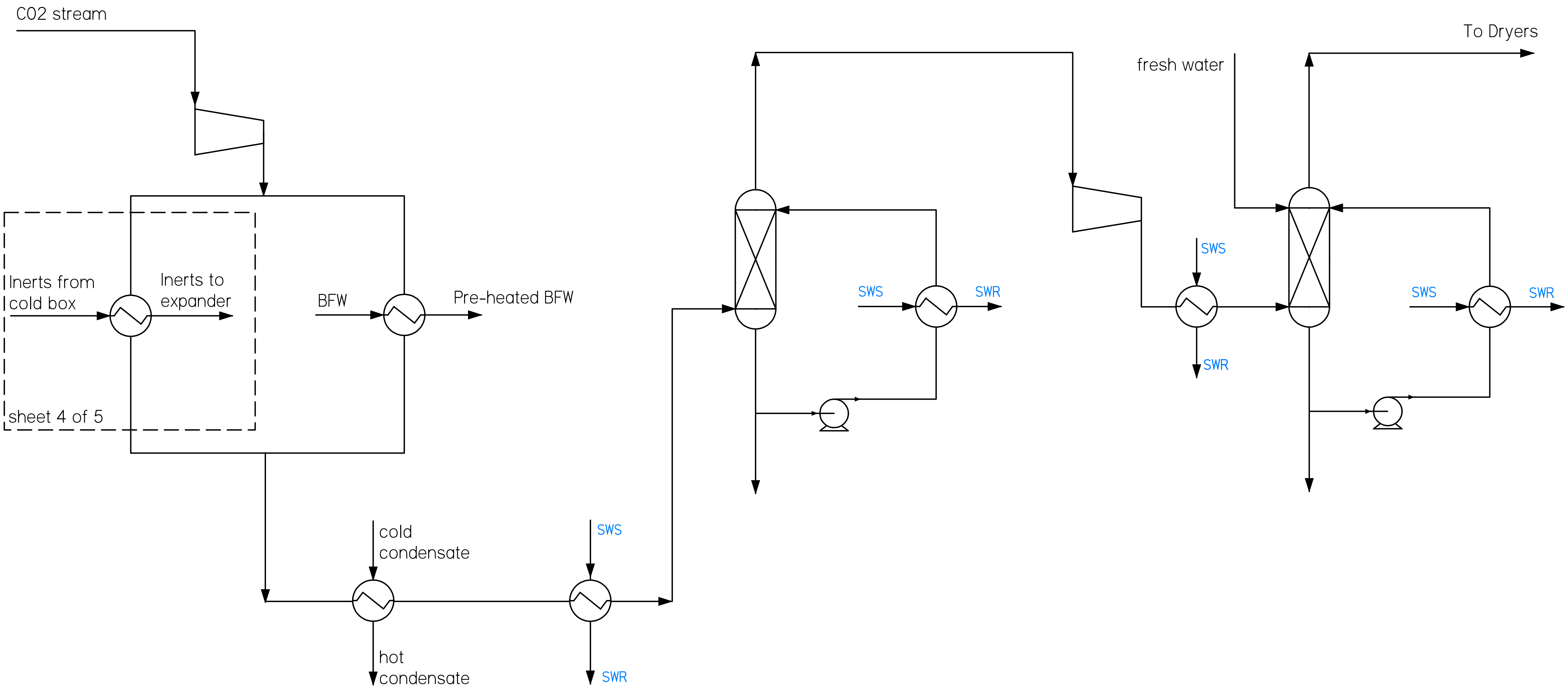
Simplified Process Flow Diagrams of this case, showing process modifications with respect to the reference case, are attached to this section.



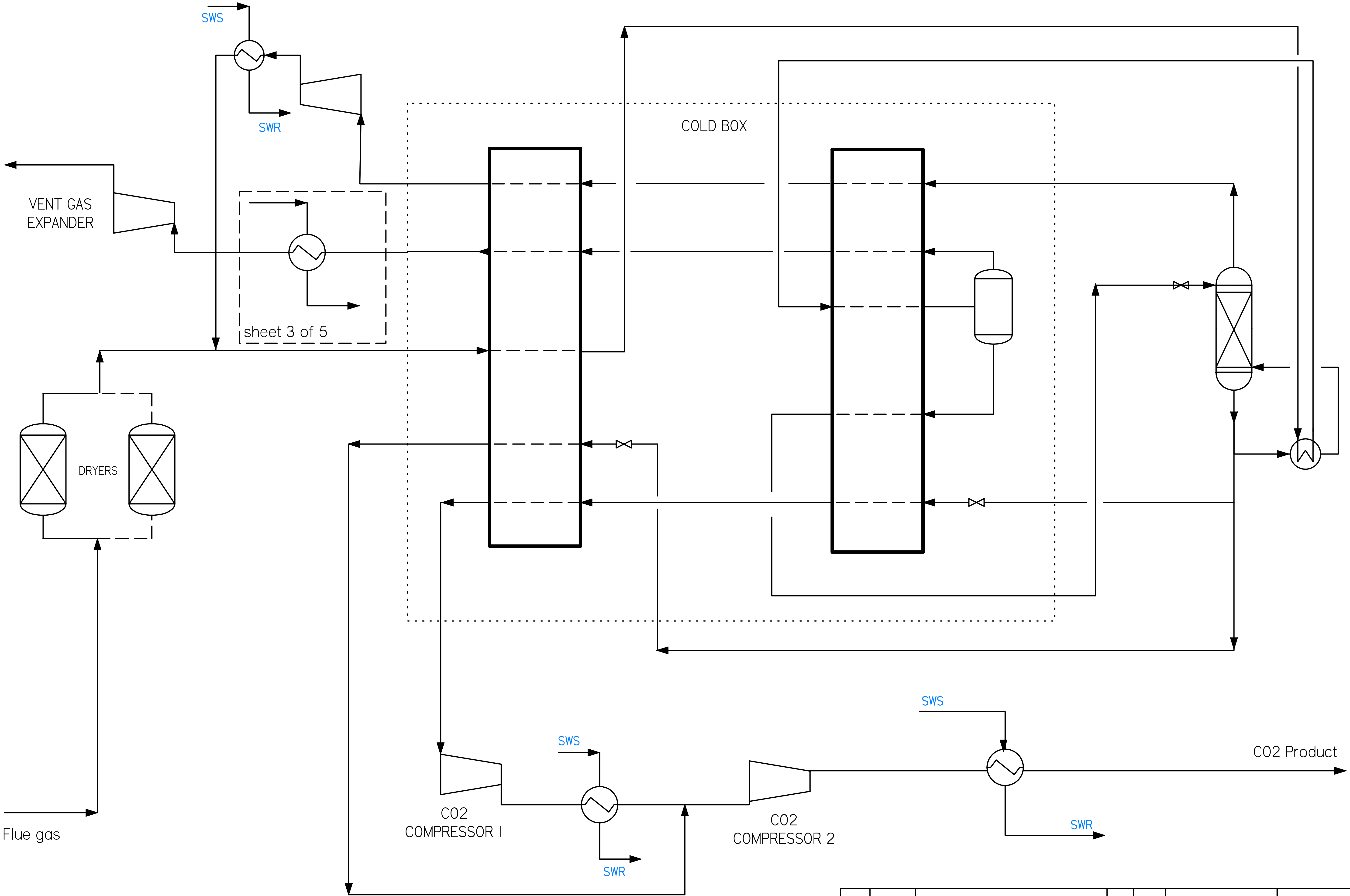
0	July 13	Draft	GP	LM	**UNIT:** Boiler Island	
Rev.	Date	Comment	By	Appr	**CASE:** 3 - Sea water	Sheet 01 of 05



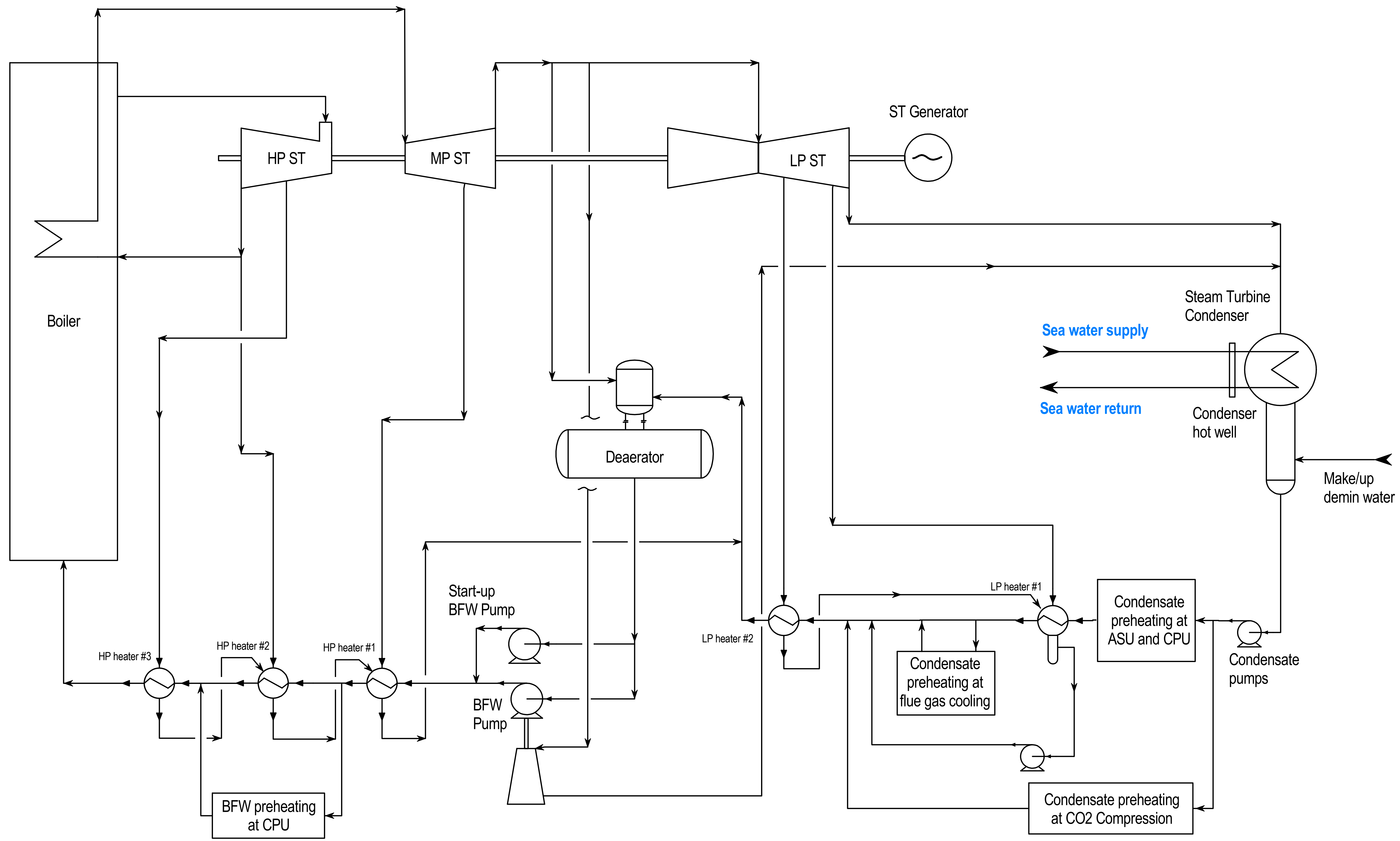
0	July 13	Draft	GP	LM	**UNIT:** Air Separation Unit	
Rev.	Date	Comment	By	Appr	**CASE:** 3 - Sea water	Sheet 02 of 05



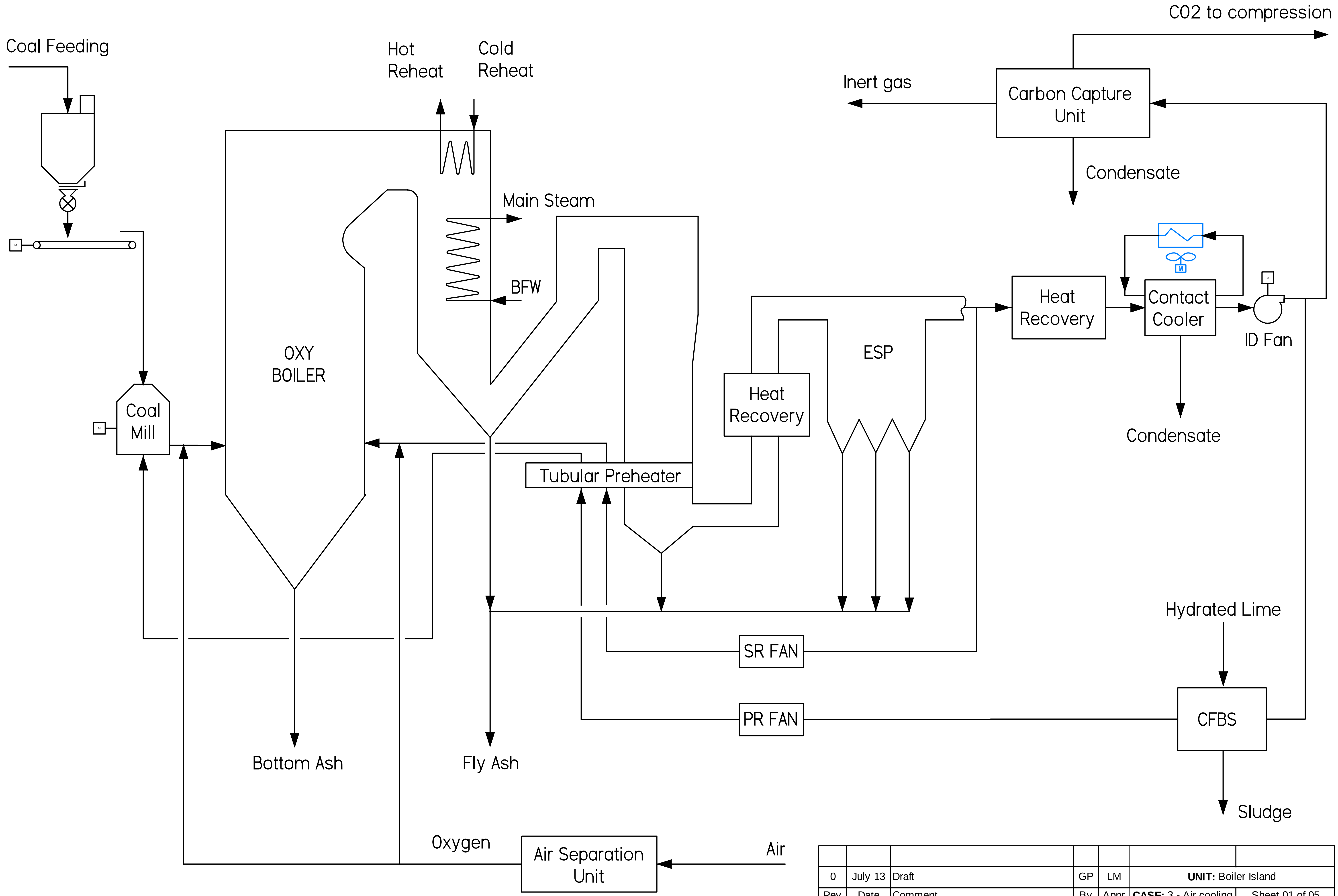
0	July13	Draft	GP	LM	**UNIT:** Sour compression	
Rev.	Date	Comment	By	Appr	**CASE:** 3 - Sea water	Sheet 03 of 05



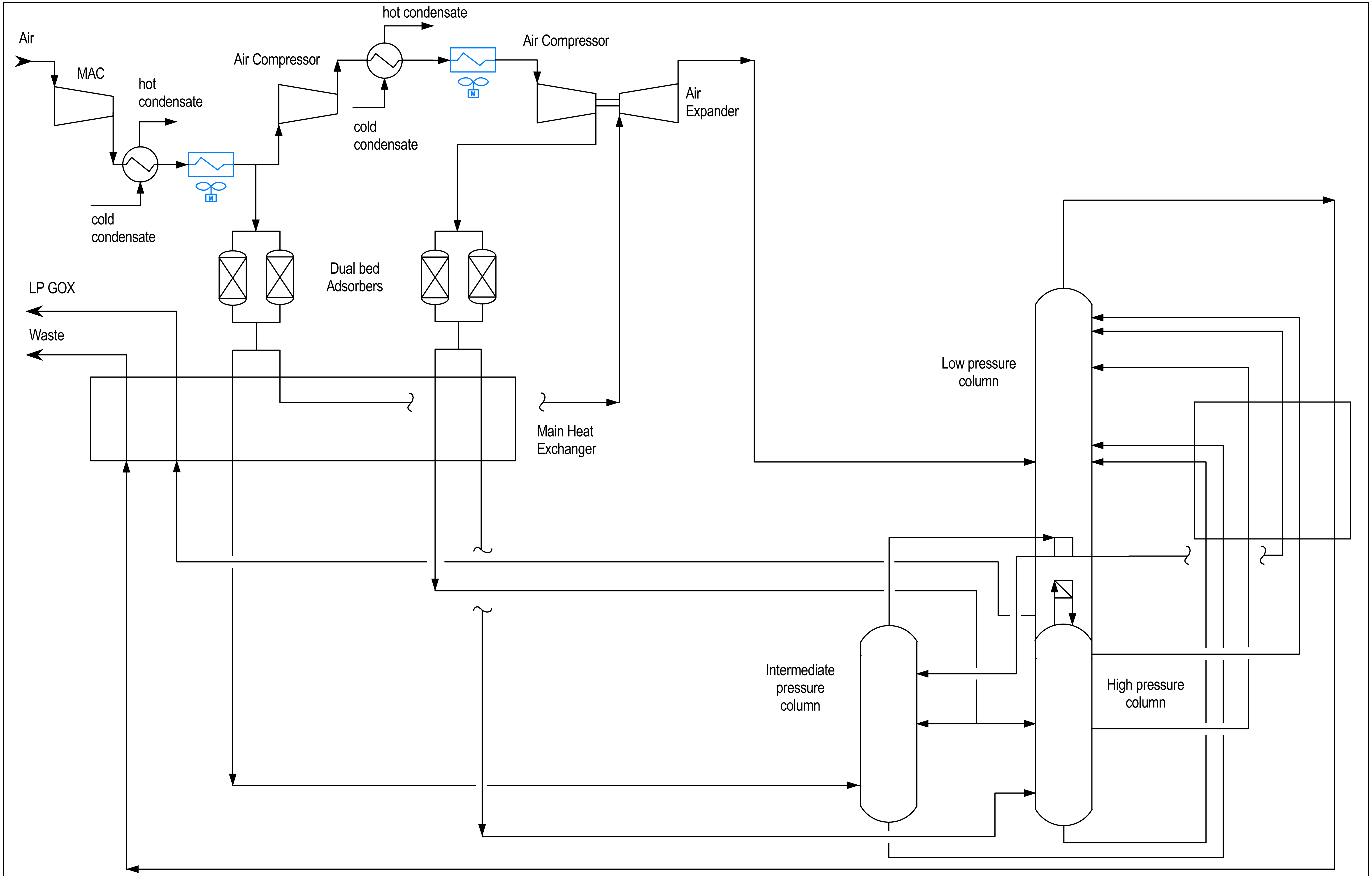
0	July13	Draft	GP	LM	**UNIT:** CO2 Purification and compression	
Rev.	Date	Comment	By	Appr	**CASE:** 3 - Sea water	Sheet 04 of 05



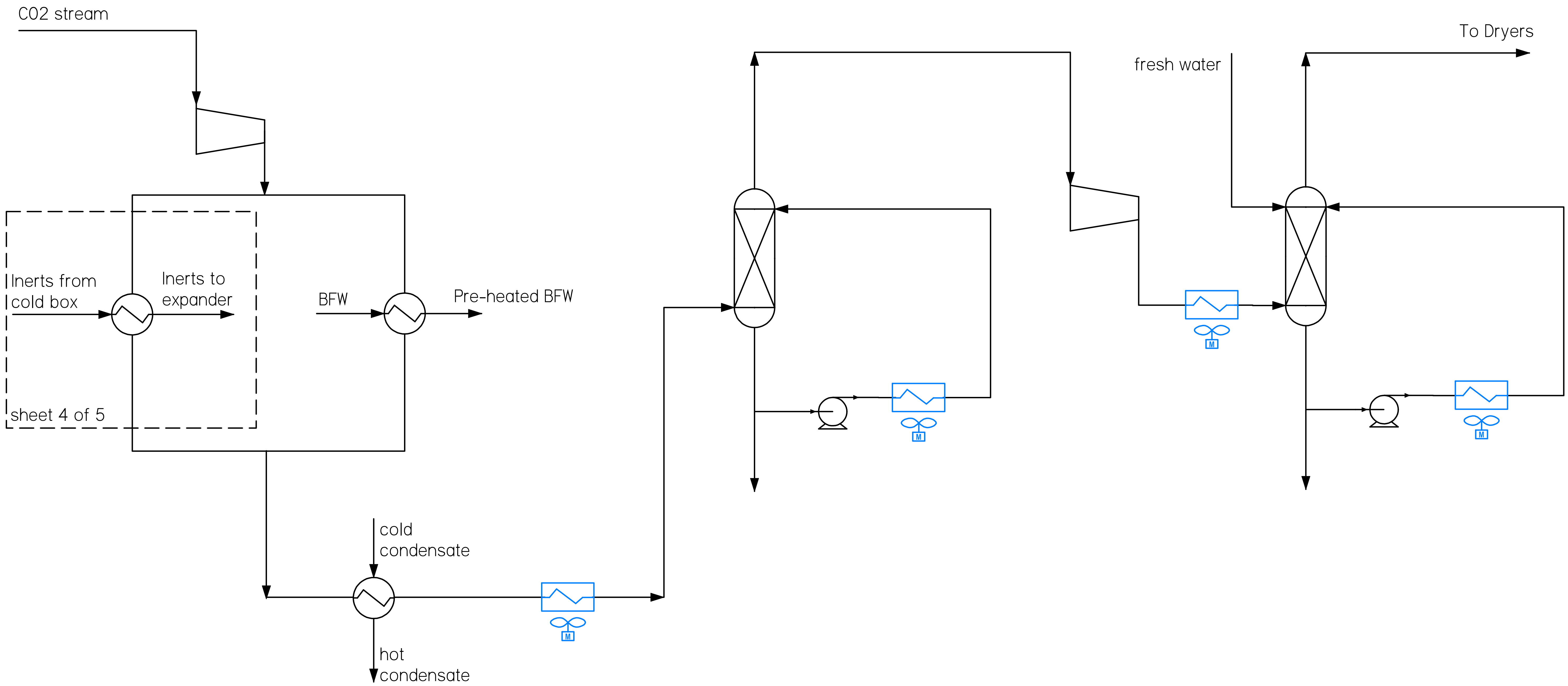
0	July 13	Draft	GP	LM	**UNIT:** Steam Cycle	
Rev.	Date	Comment	By	Appr	**CASE:** 3 - Sea water	Sheet 05 of 05



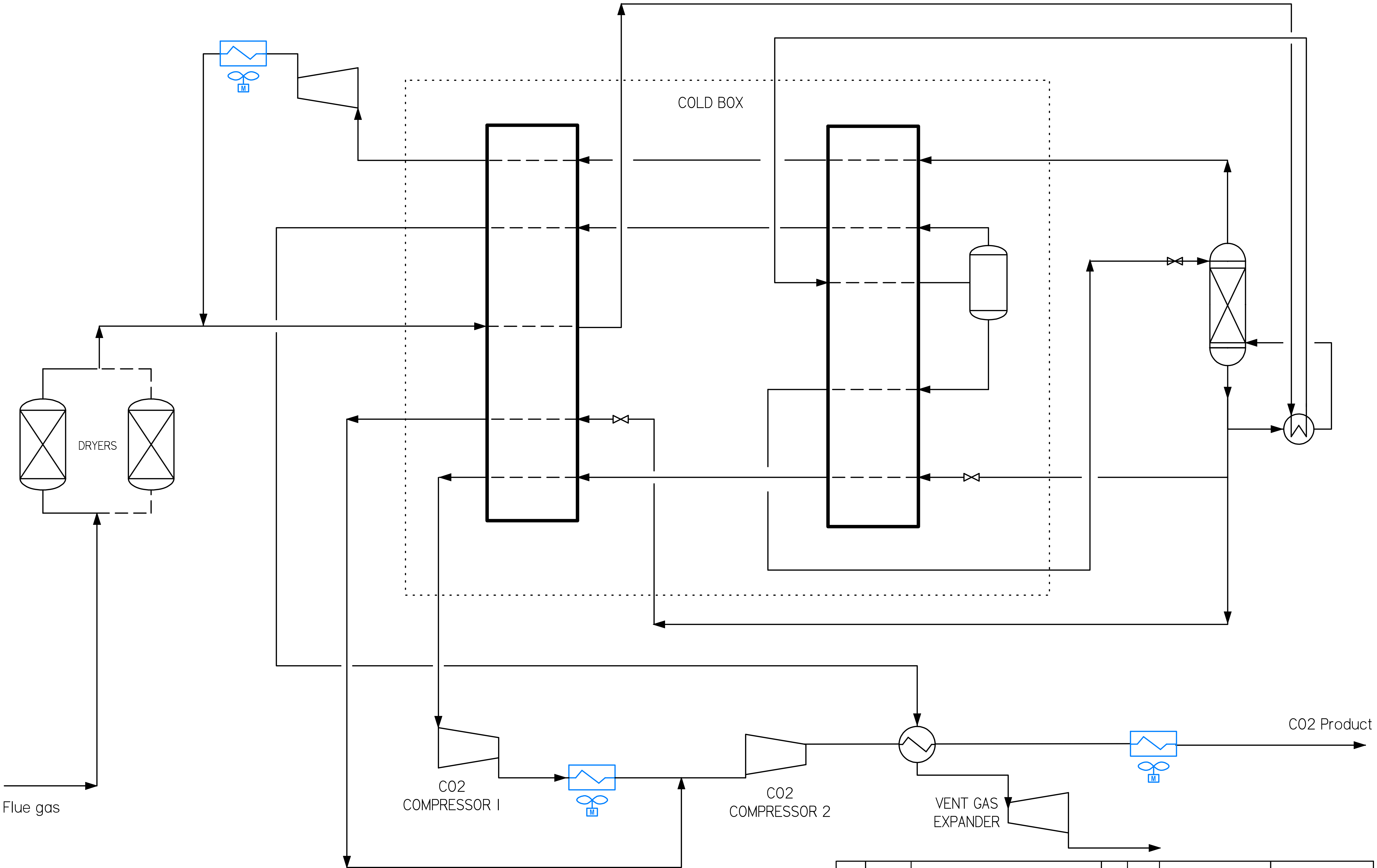
0	July 13	Draft	GP	LM	**UNIT:** Boiler Island	
Rev.	Date	Comment	By	Appr	**CASE:** 3 - Air cooling	Sheet 01 of 05



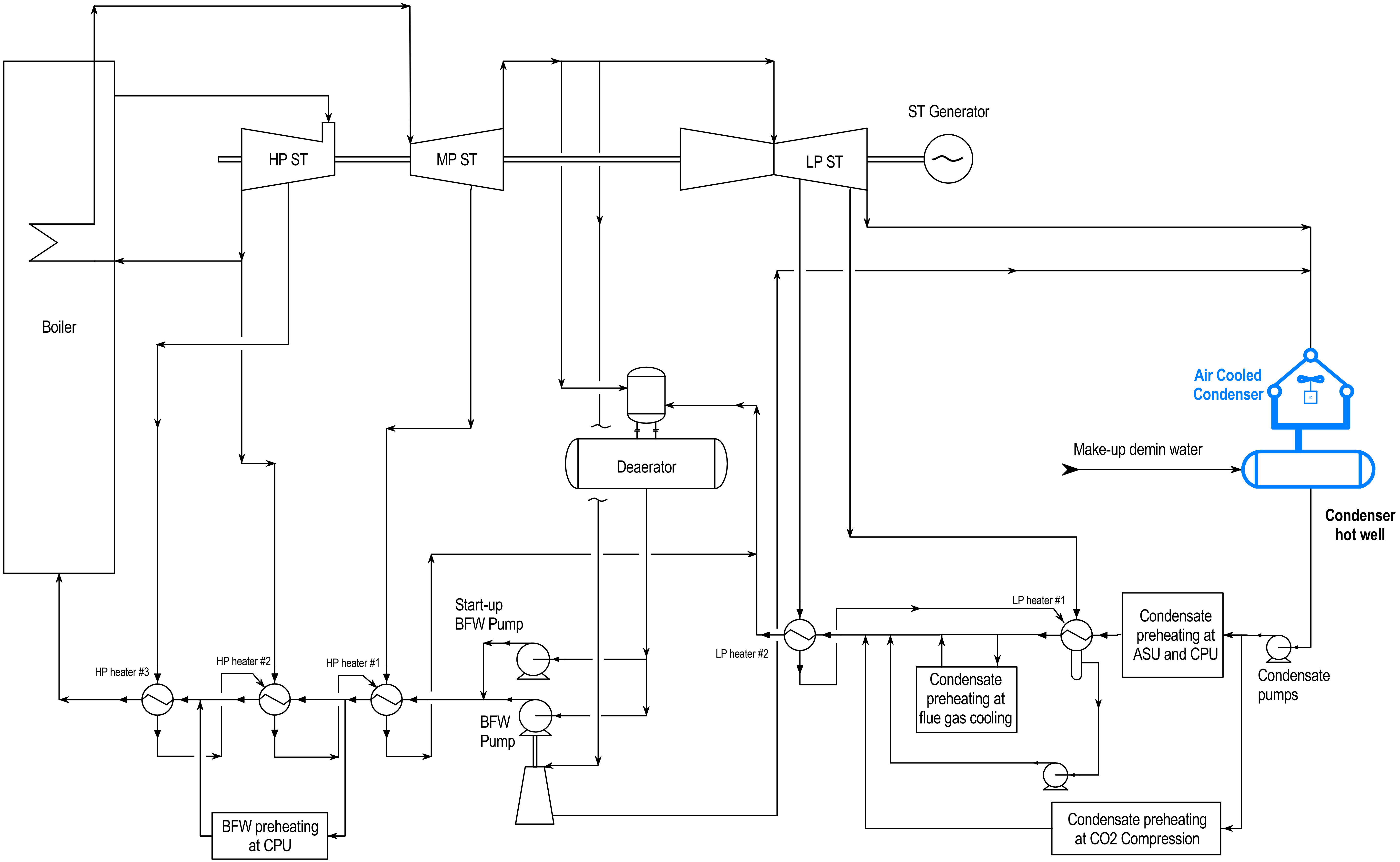
0	July 13	Draft	GP	LM	**UNIT:** Air Separation Unit	
Rev.	Date	Comment	By	Appr	**CASE:** 3	Sheet 02 of 05



0	July13	Draft	GP	LM	**UNIT:** Sour compression	
Rev.	Date	Comment	By	Appr	**CASE:** 3 - Air cooling	Sheet 03 of 05



0	July 13	Draft	GP	LM	**UNIT:** CO2 Purification and compression	
Rev.	Date	Comment	By	Appr	**CASE:** 3 - Air cooling	Sheet 04 of 05



0	July 13	Draft	GP	LM	**UNIT:** Steam Cycle	
Rev.	Date	Comment	By	Appr	**CASE:** 3 - Air cooling	Sheet 05 of 05

4. Utility and chemicals consumption

Main utility consumption of the process and utility units is reported in the following tables, including data of the reference case. More specifically:

- Water consumption summary is reported in Table 1 and Table 2, respectively for the seawater cooling and air cooling systems (reference case consumptions shown in brackets).
- Electrical consumption summary is shown in Table 3 for both the seawater cooling and the air cooling systems.

With respect to the reference case, the following considerations can be made:

- For both the alternative systems, raw water requirement is significantly lower than the reference case, mainly because there is no cooling tower make-up. The raw water required by the demineralised water plant is totally recovered in the Waste Water Treatment, resulting in a zero raw water demand.
- The overall electrical consumption of the seawater system is slightly lower than the reference case with cooling tower. This is mainly related to the reduced compressor consumption in the CO_2 purification unit, due to the reduced flowrate and temperature of the CO_2 rich feed. Minor contributions are related to the reduced compressor consumption in the Air Separation Unit because of the increased cooling capacity. The cooling water system shows almost the same consumption as the higher cooling water flowrate, due to the lower ΔT allowed for the seawater, is compensated by the lower cooling water pump head required for pumping the cooling water to the users.
- The overall electrical consumption of the air cooling system is slightly lower than the reference case with cooling tower. The lower compressors consumption in both the CO_2 purification unit and the ASU, coupled with the absence of cooling water pumps, apart those of the closed circuit, more than offset the additional consumptions of the air coolers fans, mainly the air condenser in the steam cycle.

Table 1. Case 3 (Seawater Cooling) – Water consumption summary

CLIENT:	IEAGHG	REVISION	0
PROJECT NAME:	CO2 capture at coal based power and H2 plants	DATE	Jul-13
PROJECT No. :	1-BD-0681 A	MADE BY	NF
LOCATION :	The Netherlands	APPROVED BY	LM

Case 3 (SW) - Water consumption

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Sea Cooling Water DT = 7°C [t/h]	Machinery CW DT = 11°C [t/h]
1000	FEEDSTOCK AND SOLID HANDLING				
	Solid Receiving, Handling and storage	5			
2000	Air Separation Unit				
	Air Separation unit			2025	
2000	BOILER ISALND and FLUE GAS TREATMENT				
	Boiler island			19530	
	Flue Gas Desulphurization (CFBS)				
	CO2 compression and purification			14570	
500	POWER ISLAND (Steam Turbine)				
	Condenser			150770	
	Turbine and generator auxiliaries		5		5130
BoP	UTILITY and OFFSITE UNITS				
	Cooling Water System			8480	
	Demineralized/Condensate Recovery/Plant and Potable Water Systems	8	-5		
	Miscellanea	-13			100
	BALANCE	0 *(2033)*	0.0	195,375 *(94,745)*	5230 *(26525)*

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

Table 2. Case 3 (Air Cooling) – Water consumption summary

FOSTER WHEELER	CLIENT: IEAGHG	REVISION	0
	PROJECT NAME: CO2 capture at coal based power and H2 plants	DATE	Jul-13
	PROJECT No. : 1-BD-0681 A	MADE BY	NF
	LOCATION : The Netherlands	APPROVED BY	LM

Case 3 (AC) - Water consumption

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery CW DT = 8°C [t/h]	Primary cooling medium [t/h]
1000	**FEEDSTOCK AND SOLID HANDLING**				
	Solid Receiving, Handling and storage	5			
2000	**Air Separation Unit**				
	Air Separation unit				
2000	**BOILER ISALND and FLUE GAS TREATMENT**				
	Boiler island				
	Flue Gas Desulphurization (CFBS)				
	CO2 compression and purification				
500	**POWER ISLAND (Steam Turbine)**				
	Condenser				
	Turbine and generator auxiliaries		5	6870	
BoP	**UTILITY and OFFSITE UNITS**				
	Cooling Water System				
	Demineralized/Condensate Recovery/Plant and Potable Water Systems	8	-5		
	Waste Water Treatment	-13			
	Miscellanea			140	
	BALANCE	0 (2,033)	0.0	7,010 (26,525)	*(94,745)*

NO PRIMARY COOLING WATER IS AVAILABLE. AIR IS USED AS PRIMARY COOLING MEDIUM

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

Table 3. Case 3 (Cooling medium sensitivity) – Electrical consumption summary

FOSTER WHEELER

CLIENT:	IEAGHG	REVISION	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	DATE	Jul-13
PROJECT No. :	1-BD-0681 A	MADE BY	NF
LOCATION :	The Netherlands	APPROVED BY	LM

Case 3 - Electrical consumption

Sensitivity to cooling system

UNIT	DESCRIPTION UNIT	Absorbed Electric Power CASE 3 (Cooling tower) [kW]	CASE 3 (Sea Water) [kW]	CASE 3 (Dry air) [kW]
900	AIR SEPARATION UNIT			
	Main air compressors	111060	111060	111060
	Booster air compressors + pumps + air coolers	18280	17890	18060
1000	FEEDSTOCK AND SOLID HANDLING			
	Solid handling	3255	3255	3255
2000	BOILER ISLAND and FLUE GAS TREATMENT			
	Boiler island (including FGD)	14370	14300	15850
3000	STEAM CYCLE			
	Steam Turbine Auxiliaries and condenser	4700	4700	4700
	Steam turbine air condenser	-	-	8250
	Condensate and feedwater system	1250	1250	1250
	Miscellanea	600	600	600
4000	CO2 PURIFICATION AND COMPRESSION			
	Flue gas compression (up to 35 bar)	83390	80660	80660
	CO2 compression (up to 110 bar)	26790	26750	29000
	Overhead recycle	790	850	850
	Expander	-15110	-15110	-15110
BoP	UTILITY and OFFSITE UNITS			
	Cooling Water System	14290	13640	3010
	Other Units	1430	1430	1420
	BALANCE	265,095	261,275	262,855

5. Overall performance

The following Table shows the overall performance of the plant with the three different cooling systems assessed in the study.

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	**DATE**	Jul-13
PROJECT No. :	1-BD-0681 A	**MADE BY**	NF
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 3 - Oxy SC PC Plant Performance

Sensitivity to cooling system

OVERALL PERFORMANCES		CASE 3 (Cooling tower)	CASE 3 (Sea Water)	CASE 3 (Dry Air)
Fuel flow rate (A.R.)	t/h	325	325.0	325.0
Fuel HHV (A.R.)	kJ/kg	27060	27060	27060
Fuel LHV (A.R.)	kJ/kg	25870	25870	25870
THERMAL ENERGY OF FEEDSTOCK (based on LHV) (A)	**MWth**	**2335**	**2335**	**2335**
THERMAL ENERGY OF FEEDSTOCK (based on HHV) (A')	**MWth**	**2443**	**2443**	**2443**
Steam turbine power output (@ gen terminals)	MWe	1101	1112.8	1082.8
GROSS ELECTRIC POWER OUTPUT (C) (1)	**MWe**	**1101**	**1112.8**	**1082.8**
Boiler Island (including FGD)	MWe	14.4	14.3	15.9
Utility & Offsite Units consumption	MWe	15.7	15.1	4.4
Power Islands consumption	MWe	6.6	6.6	14.8
Air Separation Unit consumptions	MWe	129.3	129.0	129.1
CO2 purification and compression	MWe	95.9	93.2	95.4
Feedstock and solids handling	MWe	3.3	3.3	3.3
ELECTRIC POWER CONSUMPTION	**MWe**	**265.1**	**261.3**	**262.9**
NET ELECTRIC POWER OUTPUT	**MWe**	**835.9**	**851.5**	**819.9**
(Step Up transformer efficiency = 0.997%) (B)	MWe	833.4	849.0	817.5
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**47.1%**	**47.6%**	**46.4%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**35.7%**	**36.4%**	**35.0%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**45.1%**	**45.6%**	**44.3%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**34.1%**	**34.8%**	**33.5%**
Fuel Consumption per net power production	**MWth/MWe**	**2.80**	**2.75**	**2.86**
CO2 emission per net power production	**kg/MWh**	**92.2**	**90.5**	**93.9**

(1) Steam driven BFW pumps are included

By comparing the results of the reference case with those of the alternative cooling system type, the following considerations can be made:

- *Seawater system*: Net electrical efficiency increases of about 0.7 percentage points, due to the higher gross power production, related to the lower condensation pressure, and to the lower plant auxiliary power demand.
- *Air cooling system*. Net electrical efficiency decreases of about 0.7, due to the lower gross power production, related to the higher condensation pressure, and the lower heat recovery within the CO_2 purification and compression.

The overall CO_2 balance and removal efficiency is unchanged with respect to Case 3, as shown in the following.

CO_2 removal efficiency	**Equivalent flow of CO_2** kmol/h
INPUT	
FUEL CARBON CONTENT (A)	17495
OUTPUT	
Carbon losses (B)	166
CO_2 flue gas content	17329
Total to storage (C)	15584
Emission (inert + losses)	1745
TOTAL	17495
Overall Carbon Capture, % ((B+C)/A)	90.0

6. Environmental impact

Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

6.1. Gaseous emissions

As for the reference case, main continuous emissions during normal operation are the inert vent streams from the CO_2 purification unit. No difference is expected in the flowrate and composition of this stream. The same minor and fugitive emissions, related to seal losses and handling of solid materials, are valid for these alternative systems.

6.2. Liquid effluents

As per the reference case, the plant does not produce significant liquid waste. Plant blow-downs (e.g. flue gas final contact cooler, CO_2 purification unit) are treated to maximise water recovery. As the amount of water that can be potentially recovered as raw water is higher than the plant requirements, the excess water is discharged.

Waste Water Treatment blow-down

Flowrate : 150 m^3/h

6.2.1. Seawater system

For the seawater case, seawater is returned to the sea basin after exchanging heat in the plant, with a maximum temperature increase of 7°C. The main characteristics of the discharged seawater are listed below:

Maximum flow rate :	196,000	m^3/h
Temperature:	19	°C

6.3. Solid effluents

No difference is expected in the production of solid by-products with respect to the reference case.

7. Main equipment design changes

The following equipment summary tables show the major impact on equipment design for the alternative cooling system types.

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE Case 3 - Oxycombustion boiler - Sea Water Sensitivity case	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
		DATE	18-Jun-13			
		ISSUED BY	NF			
		CHECKED BY	LM			
		APPROVED BY	LM			

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	Difference with respect to reference case
	UNIT 900 - AIR SEPARATION UNIT					
PK - 901 A/B/C	**Air Separation unit**					
	Main Air Compressor				*Intercooling:* *Sea Water Cooled* ~~*Cooling Water*~~	**Intercooling medium changed (*)**
	UNIT 2000 - BOILER					
PK - 2003	**Indirect Contact Cooler**					
	Contact cooler exchanger	Sea Water Cooled ~~Water cooled~~	146 MWth			**Size changed** **Intercooling medium changed (*)**
	UNIT 3000 - STEAM CYCLE					
PK- 3001	**Steam Turbine and Generator Package**					
ST- 3001	Steam Turbine		1115 MWe		Condensate pressure: 3.0 kPa	**Size changed**
PK- 3002	**Steam Condenser Package**					
~~E- 3001~~	~~Steam condenser~~	~~Water cooled~~	~~1210 MWth~~			**To be deleted (*)**
E- 3001	Steam condenser	Sea Water cooled	1190 MWth			**To be added (*)**
	UNIT 4000 - CO_2 PURIFICATION AND COMPRESSION					
PK - 4001	**Sour compression section**		Dry flue gas: 22,415 kmol/h 2.6% vol H_2O			**Lower wet flue gas flowrate**
	Including:					
	- Raw flue gas compressors (two stages)			*2 x 46 MWe*		**Size changed**
	- Flue gas cooler downstream compressor					
	BFW heater		*10.6 MWth*			**Size changed**
	Condensate heater		*22.4 MWth*			**Size changed**
PK - 4003	**Cold box for inerts removal**					
	CO_2 compressors aftercoolers	Sea Water Cooled ~~Water cooled~~	*110 MWth*			**Intercooling medium changed**

	CLIENT: IEA GHG	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
	LOCATION: The Netherlands	DATE	18-Jun-13			
FOSTER WHEELER	PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	NF			
	CONTRACT N. 1-BD-0681 A	CHECKED BY	LM			
	CASE Case 3 - Oxycombustion boiler - Sea Water Sensitivity case	APPROVED BY	LM			

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	Difference with respect to reference case
	COOLING SYSTEM					
E - 6001	Closed Cooling Water cooler		*67 MWth*			**To be added**
P- 6001 A/…/H	Sea Cooling Water Pumps (primary system)	Centrifugal	16500 m3/h x 20 m	1100	*Twelve in operation*	**To be added (*)**
P- 6002 A/B	Cooling Water Pumps (secondary system)	Centrifugal	5500 m3/h x 35 m	1250	*One in operation, one spare*	**Size changed**
~~CT- 6001 A/B~~	~~**Cooling Tower**~~ ~~including:~~ ~~Cooling water basin~~	~~Natural draft~~	~~2 x 775 MWth~~ ~~Diameter: 120 m each,~~ ~~Height: 210 m,~~ ~~Water inlet: 17 m~~			**To be deleted**
~~P- 6001 A/…/F~~	~~**Cooling Water Pumps (primary system)**~~	~~Centrifugal~~	~~16000 m3/h x 35 m~~	~~1900~~	~~*Six in operation*~~	**To be deleted (*)**
~~P- 6003 A/B~~	~~**Cooling tower make up pumps**~~	~~Centrifugal~~	~~2400 m3/h x 30 m~~	~~300~~		**To be deleted**
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 12300 m3/h~~			
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					**To be deleted**
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					

(*) Different material selection (titanium) is considered for the exchangers and pumps design (e.g. steam condenser, cooling water pumps, compressors intercoolers) to address corrosion issues related to the use of SW as cooling medium.

CLIENT: IEA GHG
LOCATION: The Netherlands
PROJ. NAME: CO2 capture at coal based power and hydrogen plants
CONTRACT N. 1-BD-0681 A
CASE Case 3 - Oxycombustion boiler - Air cooled Sensitivity case

REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
DATE	Jun-13			
ISSUED BY	NF			
CHECKED BY	LM			
APPROVED BY	LM			

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	Difference with respect to reference case
	UNIT 900 - AIR SEPARATION UNIT					
PK - 901 A/B/C	**Air Separation unit** Main Air Compressor				*Intercooling:* *Air Cooled ~~Cooling Water~~*	**Intercooling medium changed**
	UNIT 2000 - BOILER					
PK - 2003	**Indirect Contact Cooler** Contact cooler exchanger	Air Cooler ~~Water cooled~~	146 MWth	1860 kWe		**Size changed** **Intercooling medium changed**
	UNIT 3000 - STEAM CYCLE					
PK- 3001 ST- 3001	**Steam Turbine and Generator Package** Steam Turbine		1085 MWe		Condensate pressure: 5.2 kPa	**Size changed**
PK- 3002 ~~E- 3001~~ AC- 3001	**Steam Condenser Package** ~~Steam condenser~~ Steam condenser	~~Water cooled~~ Air cooler	~~1210 MWth~~ 1220 MWth	110 x 90 kWe		**To be deleted** **To be added**
	UNIT 4000 - CO_2 PURIFICATION AND COMPRESSION					
PK - 4001	**Sour compression section** Including: - Raw flue gas compressors (two stages) - Flue gas cooler downstream compressor *BFW heater* *Condensate heater*		Dry flue gas: 22,415 kmol/h 2.6% vol H_2O *10.6 MWth* *22.4 MWth*	2 x 46 MWe		**Lower wet flue gas flowrate** **Size changed** **Size changed** **Size changed**
PK - 4003	**Cold box for inerts removal** CO_2 compressors aftercoolers	Air coolers ~~Water cooled~~	*110 MWth*	2700 kWe		**Intercooling medium changed**

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE Case 3 - Oxycombustion boiler - Air cooled Sensitivity case	

REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
DATE	Jun-13			
ISSUED BY	NF			
CHECKED BY	LM			
APPROVED BY	LM			

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	Difference with respect to reference case
	COOLING SYSTEM					
AC - 6001	Closed loop air cooler		*65 MWth*	1770 kWe		**To be added**
P- 6002 A/B	Cooling Water Pumps (secondary system)	Centrifugal	7500 m3/h x 35 m	1700	*One in operation, one spare*	**Size changed**
~~CT- 6001 A/B~~	~~**Cooling Tower**~~ ~~including:~~ ~~Cooling water basin~~	~~Natural draft~~	~~2 x 775 MWth~~ ~~Diameter: 120 m each,~~ ~~Height: 210 m,~~ ~~Water inlet: 17 m~~			**To be deleted**
~~P- 6001 A/…/F~~	~~**Cooling Water Pumps (primary system)**~~	~~Centrifugal~~	~~16000 m3/h x 35 m~~	~~1900~~	~~*Six in operation*~~	**To be deleted**
~~P- 6003 A/B~~	~~**Cooling tower make up pumps**~~	~~Centrifugal~~	~~2400 m3/h x 30 m~~	~~300~~		**To be deleted**
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 12300 m3/h~~			
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					**To be deleted**
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					

CLIENT : IEAGHG

PROJECT NAME : CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS

DOCUMENT NAME : BASIC INFORMATION OF IGCC PLANT

FWI CONTRACT : 1-BD-0681 A

ISSUED BY : G. PERFUMO / L. CASTRONUOVO

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Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

1. Introduction

The Integrated Gasification Combined Cycle (IGCC) Complex is a large production facility, converting coal to syngas in order to generate electric energy, with a low impact to the environment.

The key and initial process step of the plant is the gasification of coal. Gasification is the partial oxidation of any fossil fuel to a gas, often identified as synthesis gas (syngas), in which the major components are hydrogen and carbon monoxide. Syngas generated by gasification is cleaned from acid gas components and then used in a combined cycle, which is today the most efficient thermal cycle for power generation. Therefore, gasification acts as a bridge between low quality fossil fuels and the gas turbines, with the target of high-energy efficiency and minimum emissions to the environment.

The IGCC Complex is a combination of several process units, different for each alternative of the study. The main process blocks are the following:

- Feedstock and solids handling;
- Gasification Island (GI);
- Air Separation Unit (ASU);
- Syngas treatment and conditioning line;
- Acid Gas Removal (AGR);
- Sulphur Recovery Unit and Tail Gas Treatment (SRU & TGT);
- Pressure Swing Adsorption (PSA, hydrogen cases only);
- CO_2 compression and dehydration;
- Combined Cycle (CC).

Other ancillary utilities, such as cooling water, flare, plant and instrument air, demineralised water and auxiliary fuels support the operation of these basic blocks.

The focus of this chapter E is to provide a general description of the major blocks of the IGCC Complex, common to the gasification-based cases of the study, and to summarize the information received from various gasification licensors on their technology, limited to those information that licensors have authorized for disclosure.

Chapters E.1 through E.9 of the report give basic engineering information for each alternative, with the support of specific heat and mass balances, utility consumption summaries, etc.

Table 1 and Table 2 provide key features of the gasification-based cases, technically and economically assessed in this study, respectively for the power production and the hydrogen and power co-production alternatives. In addition, some specific additional cases are developed to assess the performance and costs of near zero emission plants (around 98% CO_2 capture) and to assess the sensitivity to the cooling system type; the list of these cases is shown in Table 3.

Table 1. IGCC main study cases – power production

Case	Chapter	Description	Key features
Case 4.1	E.1	Shell-based IGCC	• Shell Coal Gasification process (Waste Heat Recovery, WHR) • Hybrid CO shift scheme • Two generic F-class Gas Turbines • UOP Acid Gas Removal (Selexol) • Cooling system: natural draft cooling tower
Case 4.2	E.2	GE-based IGCC	• GE Gasification process (Radiant Syngas Cooler, RSC) • Sour CO shift scheme • Two generic F-class Gas Turbines • UOP Acid Gas Removal (Selexol) • Cooling system: natural draft cooling tower
Case 4.3	E.3	MHI-based IGCC	• MHI air-blown gasification process • Sour CO shift scheme • Two MHI F-class Gas Turbines • UOP Acid Gas Removal (Selexol) • Cooling system: natural draft cooling tower

Table 2. Hydrogen and power co-production main study cases

Case	Chapter	Description	Key features
Case 5.1	E.4	IGCC + H_2 production (PSA)	• GE Gasification process (same as case 4.2) • PSA • Two E-class Gas Turbines
Case 5.2	E.5	IGCC + H_2 production (PSA)	• GE Gasification process (same as case 4.2) • PSA • Two equivalent Frame 6 Gas Turbines
Case 5.3	E.6	H_2 production (Gasification + PSA) + boiler	• GE Gasification process (same as case 4.2) • PSA • PSA off-gas fired boiler to meet plant auxiliary demand

Table 3. Gasification-based additional study cases

Case	Chapter	Differences
Case 3 – Sensitivity to cooling water system		
4.2 - (SW)	E.7	• Cooling system: sea water
4.2 - (AC)		• Cooling system: air cooling
Case 3 – Near zero emissions		
4.2.1	E.8	• Around 98% CO_2 capture
5.3.1	E.9	• Hydrogen production with 98% CO_2 capture

2. Basic information of main process units

2.1. Feedstock and solids handling

2.1.1. *Coal storage and handling*

This unit is the same as the one described in chapter C for the air-fired boiler cases. Anyhow, the description of the unit is here below reported for clarity of the reader.

The scope of the feedstock receiving, handling and storage unit is to unload, convey, prepare, and store the coal delivered to the plant.

The coal is delivered from a port to the plant by train. The unloading is done by a wagon tipper that unloads the coal to the receiving equipment. Coal from each hopper is fed directly into a vibratory feeder and subsequently discharged onto a belt extractor. A conveyor and transfer tower system finally delivers the coal to the open stockyard (as-received coal).

The storage pile is designed to hold an inventory of 30 days of design consumption to allow the facility to hedge against delivery disruptions.

From the storage piles, the coal is discharged onto enclosed belt conveyors to two elevated feed hoppers, each sized for a capacity equivalent to two hours. Coal is discharged from the feed hoppers, at a controlled rate, and transported by belt feeders to parallel crushers, each sized for 100% of the full capacity. The crushers are designed to break down big lumps and deliver a coal with lump size not exceeding 35 mm. Coal from the crushers is then transferred by enclosed belt conveyors to the day silos close to the boiler island (as-fired coal).

Two magnetic plate separators for removal of tramp iron and two sampling systems are supplied for both the as-received coal and the as-fired coal. The recovered iron from the separators is delivered to a reclaim pile, while data from the analyses are used to support the reliable and efficient operation of the plant.

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

The downstream coal handling and feed preparation system is different for each gasification technology; case-specific descriptions are reported in the relevant section of each technology licensor.

2.1.2. *Limestone handling*

Depending on the gasification technology, limestone fluxant is used as an additive to the coal feed. Limestone is used as a moderator, affecting the ash fusion temperature of the feed to the gasifier, in order to ensure proper characteristics of the slag flow from the gasifier. Limestone is added to the coal feed before being fed to the mills for pulverization.

Limestone is delivered to the plant site by train and stored in a rectangular stockyard building, equipped with stacking and reclaiming machines. The storage capacity is made to ensure the plant is capable of feeding at maximum capacity for approximately 30 days.

The limestone feeding system, from the storage building to the gasification unit, is the same type as that employed for coal, with conveyors transporting limestone firstly to the dedicated silo before being fed to the coal milling and drying.

2.2. Gasification Island

Reference is made to section 3, which summarizes information received from the different Gasification Island Licensors.

As listed in Table 1, three different gasification technologies have been assessed in the study, namely the Shell Coal Gasification Process (SCGP) with syngas cooler line-up, the GE's gasification process with the Radiant Syngas Cooler (RSC) and the MHI air blown gasification.

The general reasons for taking into considerations the above listed technologies are the following:

- Willingness of the Licensors to support the study effort at the time of the request, providing the most updated information on performance and costs for their proprietary technology.
- Assessment of the most referenced and well-proven gasification technologies.
- Investigation of CO_2 capture within an IGCC based on an air-blown gasification technology, as presently few techno-economic assessments of air blown IGCC/CCS plants are available in the public domain, while the interest in the technology is growing, like for the Kemper plant. The purpose is directly assessing the advantages of a lower size ASU with the disadvantages of higher gas volume and lower CO_2 partial pressure.

It is also noted that each gasification Licensor has provided information relevant to the technology option (e.g. quench, syngas cooler etc) that, at its judgement, was best suited for the specific requirements of the study case. As an example, Shell decided to propose their Syngas Cooler gasifier technology, coupled with the proprietary shift catalyst to partially overcome the penalty due to the low syngas water content, while GE proposed the Radiant Syngas Cooler to enhance overall plant net electrical efficiency.

On the other hand, with reference to the hydrogen and power co-production cases, the GE gasification technology was considered mainly because the high gasification pressure allows the production of high pressure hydrogen, without need for final compression.

2.3. Air Separation Unit

The technology currently used for large oxygen (and nitrogen) production in gasification plants is based on the distillation of atmospheric air at cryogenic temperatures. This technology has been known for over 100 years and at present it is the most cost-effective one, with a number of international companies able not only to offer lump sum turnkey plants, but also often willing to build, own and operate the plant by themselves.

The Air Separation Unit (ASU) of this study is based on the high-pressure cryogenic distillation of ambient air; it is designed to produce high pressure oxygen at 95%mol O_2 purity for the gasification and a small quantity of low-pressure oxygen for the Sulphur Recovery Unit (SRU). Nitrogen is also produced at different pressure and purity levels, depending on its final use and the gasification technology:

- In the GE-based IGCC, medium pressure nitrogen is mixed with the syngas and injected in the combustion chamber of the gas turbine of the combined cycle for dilution and NOx control purpose.
- In the Shell-based IGCC, very high pressure nitrogen is also used as carrier gas for pneumatic transport of dried and pulverized coal from the feeding system to the gasifier.
- MHI technology considered in the study is the air-blown type; however, a small ASU is included in the gasification island battery limits, with the main purpose of producing nitrogen for coal transportation. In this case, oxygen is a by-product of the distillation, which is also used as oxidant for the partial oxidation reactions in the gasifier.

Table 4 lists the main process streams produced in the ASU, accordingly to the requirements of each gasification technology.

Table 4. ASU product stream

Product type	Use [1]	Gasification technology	Purity (%)
Oxygen			
HP gaseous oxygen for gasification (HP GOX)	C	GE / Shell / MHI	> 95
LP gaseous oxygen for sulphur recovery unit (LP GOX)	C	GE / Shell / MHI	> 95
Nitrogen			
MP nitrogen for gas turbine injection	C	GE / Shell	> 98
MP nitrogen for syngas dilution	C	GE / Shell	> 98
High purity HP nitrogen for dried coal transport	C	Shell / MHI	> 99.99
High purity LP nitrogen for dried coal transport	C	Shell / MHI	> 99.99
LP nitrogen for syngas dilution to CMD	C	Shell / MHI	> 98
High purity LP nitrogen for blanketing and equipment purging	C	GE / Shell / MHI	> 99.99
High purity HP/LP nitrogen for purging during gasifier and gas turbine shutdown	I	GE / Shell / MHI	> 99.99

[1] C = Continuous; I = Intermittent

The following description refers to the Shell and GE based gasification technologies. For MHI, reference shall be made to the relevant section of the technology.

The ASU is arranged on the dual train configuration (2 x 50% trains) with a nominal capacity defined by the oxygen requirement of the gasification island and the sulphur plant. The unit is also marginally oversized to provide additional oxygen and nitrogen production capacity and maintain desired inventories of storage systems of liquid and gaseous products. These systems are common to both trains.

With reference to the simplified block flow diagram shown in Figure 1, the plant includes the main sections described hereinafter.

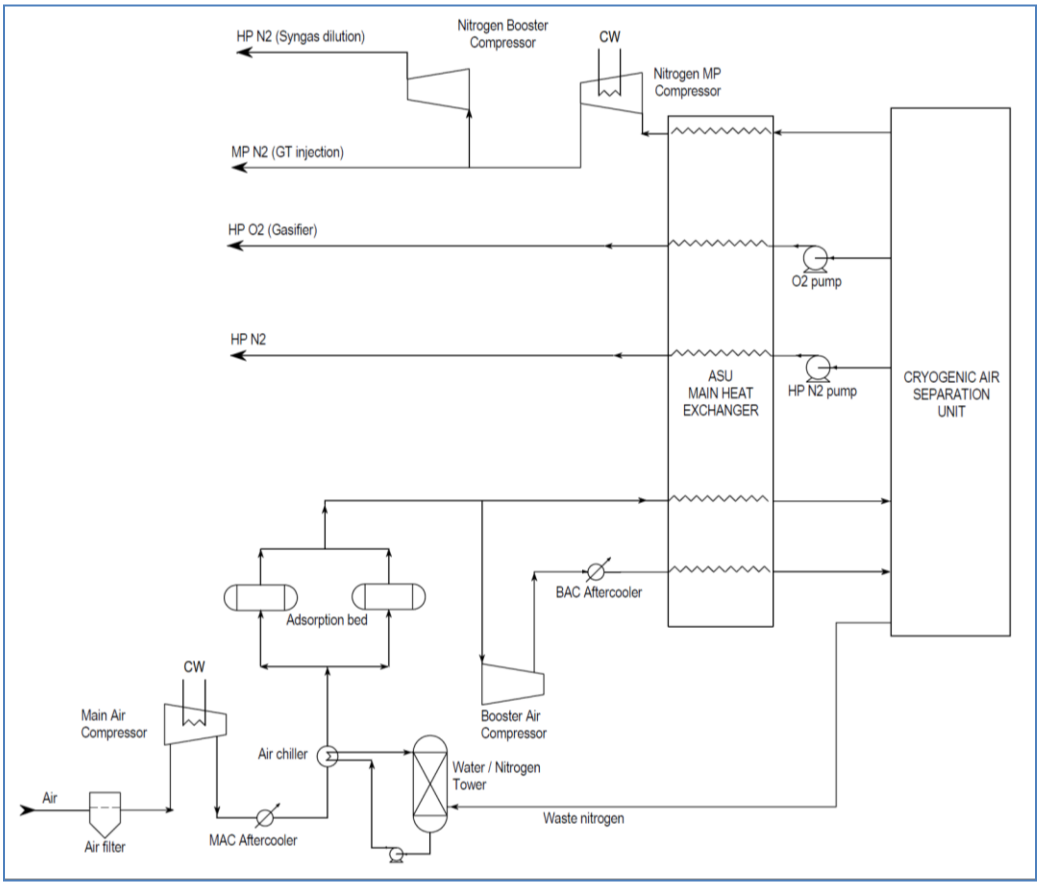


Figure 1. ASU simplified scheme

Air Compression and pre-cooling section

Ambient air is cleaned from dust and other particles by an intake air filter system and then compressed to the required process pressure of around 10 barg by multistage inter-cooled air compressors (Main Air Compressor, MAC) without direct oil contact.

The compressed air is cooled down by cooling water and chilled water from the nitrogen/water tower. In the nitrogen/water tower, water enters at the top whilst dry nitrogen is sent to the bottom. In the tower the water is cooled by vaporization which is taken up by the dry nitrogen gas. The water is recovered at the bottom of the nitrogen/water tower.

Adsorption front end air purification section

The air feed to the ASU needs monitoring for the air-borne contaminants.

An adsorption-type purification system is provided for removal of water, carbon dioxide and other impurities from the air feed before entering the cryogenic section.

The system is made up of two vessels containing alumina and molecular sieve adsorbents. By means of a set of automatically controlled switching valves, the compressed air passes alternately through one adsorber or the other.

Moisture, carbon dioxide, and most of the other impurities are removed by adsorption. At the end of each period, air is switched to the other bed and the adsorbed impurities are removed by a heated waste nitrogen stream flowing through the bed counter-current to the normal airflow. The regeneration gas is purged to the atmosphere. Once the regeneration is completed, the bed is cooled down to be ready for the next adsorption cycle.

Booster and cold production section (cold box)

Air from the pre-purifier is then split into two streams and fed to the cold box. The main stream of purified air enters the cold box, where it is cooled in the main heat exchanger against the product and waste gas streams leaving the cold box. Downstream of the heat exchanger the main air stream is fed to the distillation column.

The remaining part of the air is compressed up to around 20 barg by a booster air compressor (BAC) and cooled and liquefied in the heat exchanger where it serves as heating medium to vaporize and warm up the internally compressed products, i.e. the liquid oxygen (LOX) and the liquid nitrogen (LIN) that are withdrawn from the distillation column and pumped to the required product pressure by internal pumps.

Downstream of the heat exchanger the stream from the BAC is sent to the distillation column. Part of the air stream from the BAC is also fed to an expansion turbine to provide the required cold production.

Air separation

In the cold box, the air is separated into oxygen and nitrogen. Oxygen is withdrawn from the distillation column as a liquid and pressurized by a cryogenic pump; pressurized liquid oxygen (LOX) is then vaporized and fed to the process units. Nitrogen is produced from the cold box at different purities and used in the plant as shown in the previous Figure 1.

For the GE-based alternative, all nitrogen products are withdrawn as gaseous product from the columns, heated up in the main heat exchanger, and are directly available as low pressure nitrogen. Part of this stream is further compressed to the level required for syngas dilution or injection in the gas turbine.

For the Shell-based alternative, part of the liquid nitrogen is also withdrawn from the distillation column and pumped to the pressure required by the final dried coal transportation system. Pressurised liquid nitrogen is then vaporised and warmed up in the main heat exchanger against the boosted air stream; finally it leaves the cold box as high pressure nitrogen.

In both alternatives, liquid nitrogen and oxygen are produced in the distillation column at a pressure adequate to feed the respective liquid storage tanks.

2.3.1. *Back-up oxygen and nitrogen systems*

The continuity of supply of oxygen and nitrogen to the IGCC Complex is extremely critical. Therefore, a back-up oxygen and nitrogen system is included to avoid gasifier shutdown for ASU outages of short duration. A back-up nitrogen system is also considered to allow the gas turbines to switch from nitrogen to steam for NOx emission control.

The ASU is also marginally oversized with respect to the oxygen requirement at 100% plant operational load and at the reference ambient temperature of the plant, in order to have additional spare capacity to refill the stores during normal operation.

Back-up oxygen system

The back-up oxygen system is mainly based on liquid oxygen (LOX) storage and a vaporization system. The system is sized to provide eight (8) hours at the design oxygen flow of one ASU train. At storage outlet, liquid oxygen is vaporised at the required pressure by a steam heated vaporiser.

The ASU also includes a high pressure gaseous oxygen (GOX) tank and system, sized to provide oxygen from two ASU trains during the time required to get the LOX vaporization system on-stream and this is capable of maintaining oxygen supply pressure at the unit battery limits within the required limits.

Back-up nitrogen system

The back-up nitrogen system is mainly based on liquid nitrogen (LIN) storage and a steam heated vaporization system. The system is sized to provide the following streams:

- Four (4) minutes at the design nitrogen flow for syngas dilution or turbine injection.
- Eight (8) hours at design nitrogen flow for one gasifier feed system and continuous blanketing/purging of the process units.

The ASU also includes a high pressure gaseous nitrogen (GAN) tank and system, sized to provide nitrogen from two ASU trains during the time required to get the LIN vaporization system on-stream and capable of maintaining nitrogen supply pressure at the unit battery limits within the required limits.

2.3.2. *Impact on ASU design for high operational flexibility*

The ASU significantly impacts the overall net electricity production of the plant, mainly due to its high auxiliary power demand. Therefore, if the plant were called to operate flexibly with respect to the daily demand for electricity, a possibility could be to operate the ASU at partial load during peak hours, while the rest of the plant runs at full load, thus reducing the auxiliary consumption and increasing the overall net electricity production. Vice versa, during low-electricity demand periods, the ASU could be operated at load higher than that of the process unit, producing the extra oxygen and nitrogen required during peak demand period.

In this respect, LOX and LIN storages become of primary importance because they allow decoupling the ASU from the rest of the IGCC plant, providing the buffer capacity required for balancing the cycling operation of the plant. Design changes and related costs mainly depend on the load demand cycle the plant is required to respect. The following Table 5 summarises the expected impact on performance and costs of the additional LOX and LIN storages required to follow two commonly requested power demand cycles, the first to cover daily peak demand and the second to follow a weekly cycle. For further details on the provision of LOX and LIN storage for enhancing plant operating flexibility, reference shall be made to IEAGHG report 2012/06 '*Operating Flexibility of power Plant with CCS*'.

Table 5. LOX/LIN storage option for IGCC flexible operation

Case description	Delta performance	Delta costs
LOX / LIN covering daily peak	+6-10% NPO (2 hours per day)	+1-2%
LOX / LIN covering weekly peak	+5-8% NPO (60 hours per week)	+2-3%

Another aspect that should be considered in case the plants were required to operate flexibly is the possible air integration between the ASU and the gas turbine. In principle, there are several possible degrees of integration between the ASU and the gas turbines:

- In the case of total integration, 100% of the air required by the air separation is supplied by bleeding some of the air from the discharge of the gas turbine compressor.
- Alternatively, the air separation plant can be *stand-alone*, not integrated. In this case, the air separation plant includes its own full-size air compressor delivering air to the cryogenic process.
- The intermediate design between these two cases is the partially integrated air separation. Air is partly supplied by the gas turbine and partly by a separate air compressor. The percentage of air required by the air separation unit that is supplied by the gas turbine defines the degree of integration.

The integration between the ASU and the gas turbine may potentially limit the capability of the IGCC to operate flexibly, especially in those operating modes where the ASU and the other units shall be maintained at different loads to meet variable power production. In particular, if the full-size main air compressor is not foreseen in the air-integrated alternatives, then the ASU cannot be operated at full load, when the power plant is operated at lower loads, as the air extracted from the gas turbine is not enough to meet the amount required by the air separation unit. That means that the main air compressor shall be adequately sized, by considering all the different operating scenarios of the plant. As written before, further details can be found in the IEAGHG report 2012/06 '*Operating Flexibility of power Plant with CCS*'.

2.4. Syngas treatment and conditioning unit

Raw syngas leaving the gasification island is routed to the syngas treatment and conditioning unit. Syngas is hot, generally humid, and contaminated with acid gases (e.g. CO_2 and H_2S) and other species like carbonyl sulphide (COS), hydrogen cyanide (HCN) and ammonia (NH_3).

Before being fed to the gas turbines as fuel or to the PSA for hydrogen production, most of the acid gases and contaminants must be removed for several reasons, like: to meet the required carbon capture rate, respect project environmental targets, meet product purity requirements and have stable operation of the combustion process in the gas turbines.

Depending on the case of the study, the preparation of the syngas at the proper temperature and pressure conditions and composition may include the following processing steps:

- Catalytic conversion of CO and water to H_2 and CO_2, assisted by a sulphur tolerant catalyst (sour shift reaction);
- Syngas cooling in waste heat boilers, recovering heat while generating steam at different levels of pressure or pre-heating circulating water for the nitrogen/syngas saturator;
- Preheating of the cold process condensate from the steam condenser of the combined cycle;
- Mercury removal;
- Removal of the acid gases in the Acid Gas Removal Unit, as separately described in section 2.5;
- Conditioning of the fuel before combustion in the gas turbines. Depending on the alternative, final treatment of the fuel may consist of pre-heating, humidification, or nitrogen dilution.

Each of the cases examined in the study have a different combination and sequence of the above listed processing steps. For all cases, a specific description of the syngas treatment and conditioning unit is provided in the case-specific reports, with the support of dedicated process flow diagrams. For all cases, the unit is composed of two parallel lines, each receiving the raw syngas from two equally-sized gasifiers.

2.4.1. CO shift

CO shift unit is considered in order to convert carbon monoxide and water to hydrogen and carbon dioxide, in accordance to the following reaction:

$$CO + H_2O \rightarrow CO_2 + H_2$$

The reaction is performed over a catalyst in a fixed bed suitable to process syngas containing sulphur (sour shift).

The equilibrium constant for the water-gas shift is a function of the temperature, with greater shift occurring at lower temperature. As the shift reaction is exothermic and heats the gas as CO shifts to CO_2, it tends to inhibit the conversion. While the shift reaction is favoured at low temperatures, the reaction rates and the catalyst reactivity at low temperature are low, so commercial water gas shift reactors generally operate at a practical compromise temperature, where the catalyst proves most effective.

The following process description makes reference to the conventional sour shift simplified process flow diagram shown in Figure 2. For the Shell-based alternative a different configuration including a hybrid shift reactor upstream of the two-stages of conventional shift has been considered to reduce the amount of steam to be injected in the raw syngas. Reference shall be made to chapter E.1 for further details on this configuration.

The conventional shift reaction takes place into two consecutive stages, with intermediate cooling for syngas pre-heating and steam generation between them. A two-stage process is generally required to reach an overall CO conversion higher than 85-90%. Hot syngas from the first reaction stage preheats the saturated syngas from the scrubber up to the minimum temperature required for the operation of the CO shift catalyst.

In order to maximize the conversion of the CO, the injection of steam might become necessary, in particular for non-water quenched gasification technology, to maintain the water content in the syngas higher than the minimum level required for proper catalyst operation.

Downstream of the CO shift reactors, syngas is cooled in a series of heat exchangers, whose configuration varies depending on the case, as explained in the case-specific chapters of the report.

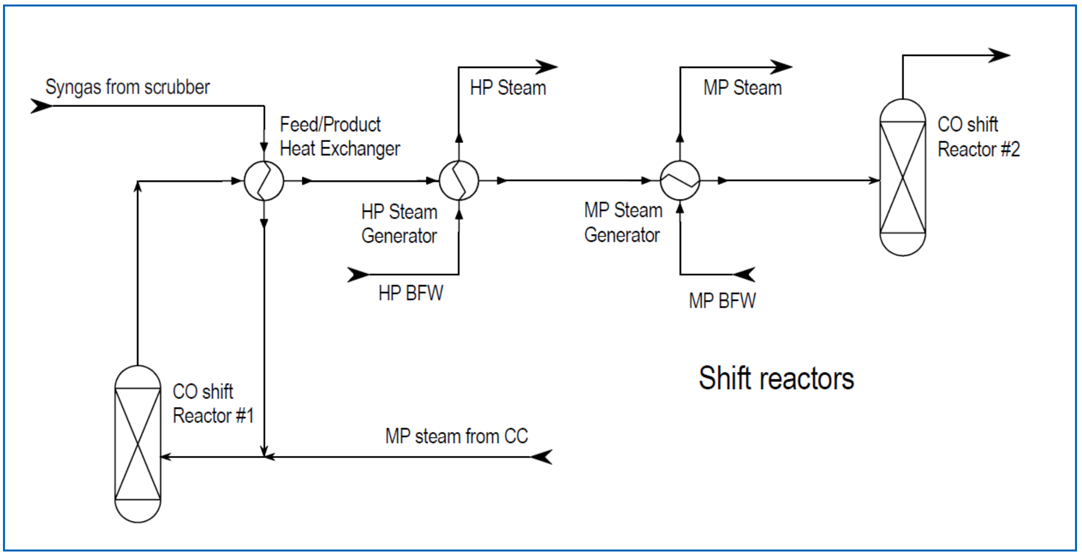


Figure 2. CO shift diagram (typical).

2.4.2. *Mercury removal*

The IGCC Complex includes a mercury removal system employed to eliminate mercury from the syngas before combustion in the gas turbine. This system uses sulphur-impregnated activated carbon beds capable of removing almost all the mercury in the syngas stream, thus meeting the environmental requirements.

The mercury removal package is located immediately upstream of the Acid Gas Removal unit, allowing operation of the system in its optimum conditions and enhancing the downstream AGR system performance and solvent life due to mercury and other contaminants removal.

Before entering the package, fuel gas is cooled to a temperature of about 34°C and the resulting process condensate is removed. Fuel gas is passed through one bed (one for each train) of sulphur-impregnated activated carbon.

2.5. Acid Gas Removal

The primary purpose of the Acid Gas Removal (AGR) unit is the removal of acid gases, H_2S and CO_2, to a level compatible with the plant environmental limits. Besides being a key unit for meeting the environmental performance of the plant, the AGR section is also a capital intensive unit and a large consumer of energy.

H_2S shall be removed to meet the environmental requirements of the project, while CO_2 shall be partially removed to reach the target of 90% carbon capture.

The accurate selection of the process and solvent type for making the capture of the acid gases is important for the performance of the entire gasification plant.

Several different technologies are commercially available for the acid gas removal. They can be grouped into the following main categories:

- **Physical solvents**, capturing the acid gases in accordance with Henry's law, which states that "at a constant temperature, the amount of a given gas dissolved in a given type and volume of liquid is directly proportional to the partial pressure of that gas in equilibrium with that liquid". *Selexol* and *Rectisol* are typical examples of physical solvents.
- **Chemical solvents**, including many amines, which capture the acid gases through a chemical reaction. The amines are classified as either primary (MEA), secondary (DEA) or tertiary (MDEA). MEA can effectively remove virtually all hydrogen sulfide and carbon dioxide, but requires a large quantity of heat for regeneration. Secondary amines are suited for gas steams with less stringent product specifications. Tertiary amines are used selectively on gas streams with pressure higher than approximately 20 barg for deep hydrogen sulfide removal and only moderate carbon dioxide removal. MDEA is generally preferred for IGCC applications on account of its selectivity.
- **Physical-chemical or hybrids solvents,** which combine the high treated-gas purity offered by chemical solvents with the flash regeneration and lower energy requirements of physical solvents. *Sulfinol*, as an example, is a mixture of sulfolane (a physical solvent), diisopropanolamine (DIPA) or MDEA (chemical solvent), and water: *DIPA* is used when total acid gas removal is specified, while MDEA provides for selective removal of H_2S.
- **Oxidative washes**, in which the H_2S is oxidized to elemental sulfur in the solution. This type of washing has high operational costs and is limited to application with low sulfur production (about 15 t/d). Typical examples of this washing are *Crystasulf* and *Sulferox*.

Figure 3 shows equilibrium solubility data - expressed as standard cubic feet of gas per gallon liquid per atmosphere gas partial pressure - for H_2S and CO_2 in various representative solvents and the effects of temperature. More importantly, it shows how H_2S has solubility an order of magnitude higher than that of CO_2 at a given temperature, which increases the selective absorption of H_2S in physical solvents. It also illustrates that the acid gas solubility in physical solvents increases with lower solvent temperatures.

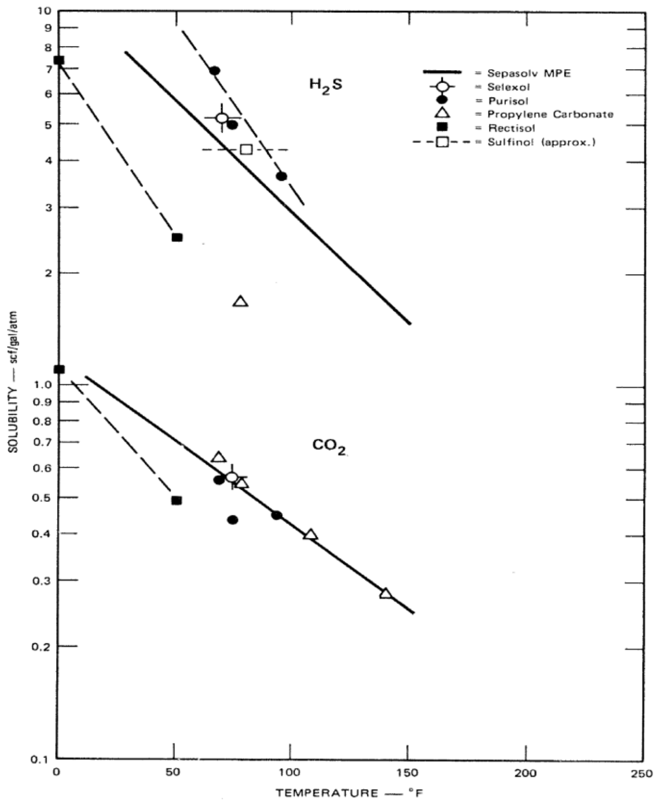


Figure 3. Equilibrium solubility data on H_2S and CO_2 in various solvents [DOE/NETL-2007/1281, Exhibit 3-8].

For the IGCC cases of the study, a physical solvent is deemed as the most adequate solution for separately removing H_2S and CO_2 from the syngas.

The most quoted, commercially available, physical solvents are *Selexol* (UOP) and *Rectisol* (Linde, Lurgi). For this study, Selexol solvent has been preliminary selected as the solvent of the AGR unit. The information received from UOP is covered by secrecy agreements. The part included in the following section and in the specific section of each case is limited to the information that UOP has authorized for disclosure.

The following section gives a general description of the process scheme used for the separation and removal of H_2S and CO_2. Case-specific data are shown in the technical descriptions of each case.

2.5.1. Selexol acid gas removal process

The following process description makes reference to the simplified process flow diagram shown in Figure 4.

Feed gas enters the unit battery limits, it is combined with recycle streams from the H_2S Flash Gas loop and Tail Gas Recovery Unit, cooled through a Feed/Product gas exchanger, and sent to the Feed Gas Knockout Drum. The gas stream is then routed to the bottom of the H_2S Absorber and flows upward through packed beds where it contacts chilled, loaded solvent entering at the top of the tower via three parallel Loaded Solvent Pumps. The loaded solvent is laden with CO_2 from three parallel CO_2 Absorbers, which improves the selectivity of the solvent for H_2S absorption. The contact between the gas phase and liquid phase is enhanced as they each pass through the packed beds, where primarily H_2S, CO_2, and other gases such as hydrogen, are transferred from the gas phase to the liquid phase. The treated gas passes through de-entrainment devices at the top of the packed bed and exits the tower.

The treated gas leaves the top of the H_2S Absorber and is sent to three parallel CO_2 Absorbers where the gas flows upward through packed beds and contacts chilled lean solvent entering at the top of the tower via the Lean Solvent Chiller and flash regenerated semi-lean solvent entering near the top of the tower via the Semi-Lean Solvent Pump. The contact between the gas phase and liquid phase is enhanced as they pass through the packed beds, where CO_2 plus some H_2S, hydrogen, and other gases are transferred from the gas phase to the liquid phase. The treated gas then passes through de-entrainment devices at the top of the towers, exits the top of the CO_2 Absorbers, is sent to the Feed/Product exchanger, and finally reaches the Selexol unit battery limits.

The solvent from the CO_2 Absorbers is collected at the bottom of the towers and becomes termed loaded solvent, as it is loaded with CO_2. The loaded solvent is then split, with a portion routed to the H_2S Absorber for H_2S removal and the remaining portion sent to four successive flash drums to partially regenerate the solvent by removal of CO_2.

The first flash drum is the CO_2 Recycle Flash Drum where H_2, CO_2 and some dissolved and entrained gas are transferred to the gas phase by reduction of pressure. The separated gas is compressed and cooled before reintroduction into the CO_2 Absorbers.

The solvent from the CO_2 Recycle Flash Drum is sent to three consecutive Flash Drums characterized by decreasing pressure levels in order to maximize the CO_2 flashing process. The separated gas streams from the HP, MP, and LP CO_2 Flash Drums are sent to the Selexol battery limits as a HP, MP, and LP CO_2 product respectively. Possibility to recycle a portion or the whole HP CO_2 stream flowrate to minimise hydrogen losses in the captured CO_2 is also an option that could be evaluated in more detail, in particular for the cases with high hydrogen content in this stream (e.g. MHI gasification based case).

The flashed solvent from the HP and MP CO_2 Flash Drum is routed to the LP CO_2 Flash Drum which provides a deeper flash of CO_2 from the solvent. The flash regenerated semi-lean solvent is returned to the CO_2 Absorbers via the Semi-Lean Solvent Pump.

The rich solvent from the H_2S Absorber is sent to the Lean/Rich Exchanger via the H_2S Rich Solvent Pump in order to increase its temperature by heat exchange with the hot lean solvent from the Regenerator. The hot lean (regenerated) solvent is cooled in the Lean/Rich Exchanger before flowing to the Lean Solvent Cooler. By cross-exchanging these streams, the Lean/Rich Exchanger significantly reduces the duties of the Lean Solvent Cooler and the Regenerator Reboiler. The heated solvent stream is sent to the Concentrator followed by a series of flash drums to remove CO_2 and other dissolved components from the rich solvent before reaching the Regenerator for complete thermal regeneration.

The rich solvent and desorbed vapours from the Lean/Rich Exchanger are routed to the Concentrator, where some CO_2 and dissolved and entrained gas are stripped using a slipstream of treated gas. In the Concentrator, compounds such as CO_2, H_2, and CO with lower solubility in Selexol than H_2S are transferred from the liquid phase to the gas phase. Hydrogen sulphide has a high solubility in Selexol, and as such, has more of a tendency than most other gases to stay in the liquid phase. The gas exiting the Concentrator is primarily composed of CO_2, N_2, CO, and some H_2S. The gas stream joins the other flashed stream from the acid gas enrichment section for routing to the Stripped Gas Cooler and then recycled to the inlet of the H_2S Absorber tower.

The partially regenerated Selexol solvent from the Concentrator is sent to the H_2S Rich Flash Drum where additional non-H_2S components are flashed from the solvent, thereby increasing the H_2S concentration of the Acid Gas stream from the Regenerator. The flashed stream from the H_2S Rich Flash Drum is compressed and combined with the Concentrator off gas stream. The combined flash stream is recycled back to the H_2S Absorbers.

The arrangement of the Concentrator and recycle flash drums in series optimizes power consumption while maximizing the recovery of non-H_2S components and the H_2S content of the acid gas stream. The rich solvent from the Rich Solvent Flash Drum is sent to the Regenerator for complete thermal regeneration. Liquid from the H_2S Flash Gas knockout drums is combined with this rich solvent stream to the Regenerator.

Solvent regeneration is accomplished in the Regenerator, where the remaining H_2S, CO_2 and other compounds are transferred from the liquid phase to the gas phase by contact with the steam generated in the Regenerator Reboiler. The Regenerator is composed of a lower section containing packed beds of Raschig Super Rings, and an upper section containing several reflux trays, in order to contact the overhead vapour with the reflux water.

The partially regenerated SELEXOL™ solvent enters the Regenerator above the upper packed bed. After flashing, the solvent passes through a liquid distributor, and then flows down the packed bed in the stripping section releasing H_2S, CO_2 and other components after contact with the steam generated in the Regenerator Reboiler.

The steam and liberated gases exit the upper section of the Regenerator, and then flow upward to the trayed section of the column. The gas first passes through a demister and then into the trayed section, where the rising gas is contacted with counter-current flowing reflux water to cool and condense the hot overhead vapour and reduce solvent entrainment. The overhead stream passes through a de-entrainment device and exits the top of the column. The overhead gas then passes through the Reflux Condenser in order to recover the overhead steam. The liquid and vapor phases are separated in the Reflux Drum. The liquid is returned to the trayed section of the Regenerator via the Reflux Pump. The Acid Gas stream is typically sent to the Sulfur Recovery Unit outside the battery limits.

The Regenerator Reboiler generates vapour from the solvent. Solvent for the reboiler is collected in a trap-out tray located below the bottom packed section in the Regenerator. The resulting vapour generated in the reboiler re-enters the bottom of the Regenerator below the trap-out tray and travels up the column, stripping the acid gas from the down-flowing solvent.

The hot regenerated solvent from the Regenerator Reboiler is cooled through the Lean/Rich Exchanger and the Lean Solvent Chiller prior to being returned to the top of the CO_2 Absorbers via the LP Lean Solvent Pump and HP Lean Solvent Pump, thereby completing the thermal regeneration portion of the Selexol circuit.

After passing through the Lean / Rich Exchanger, a slipstream of the lean solvent is filtered prior to being sent to the CO_2 absorbers. The Solvent Filters (not shown on flow diagram) use automated back-flushed filters to remove solids from the Selexol Unit. Specifically, if any metal carbonyls are generated in the upstream gasification section, they are captured by the SELEXOL™ solvent and converted to insoluble metal sulphides. The filters capture the metal sulphides which are collected and sent back upstream to the gasification section for separation from the water.

The following Table 6 shows the main AGR performance data for a reference case of the study.

Table 6. Selexol AGR consumption summary

Case	%H_2S removed	%CO_2 removed	Steam Consumption	Electrical Consumption
	%	%	t/h	kW
Case 4.1	99.97%	91.1%	81.5	21,400

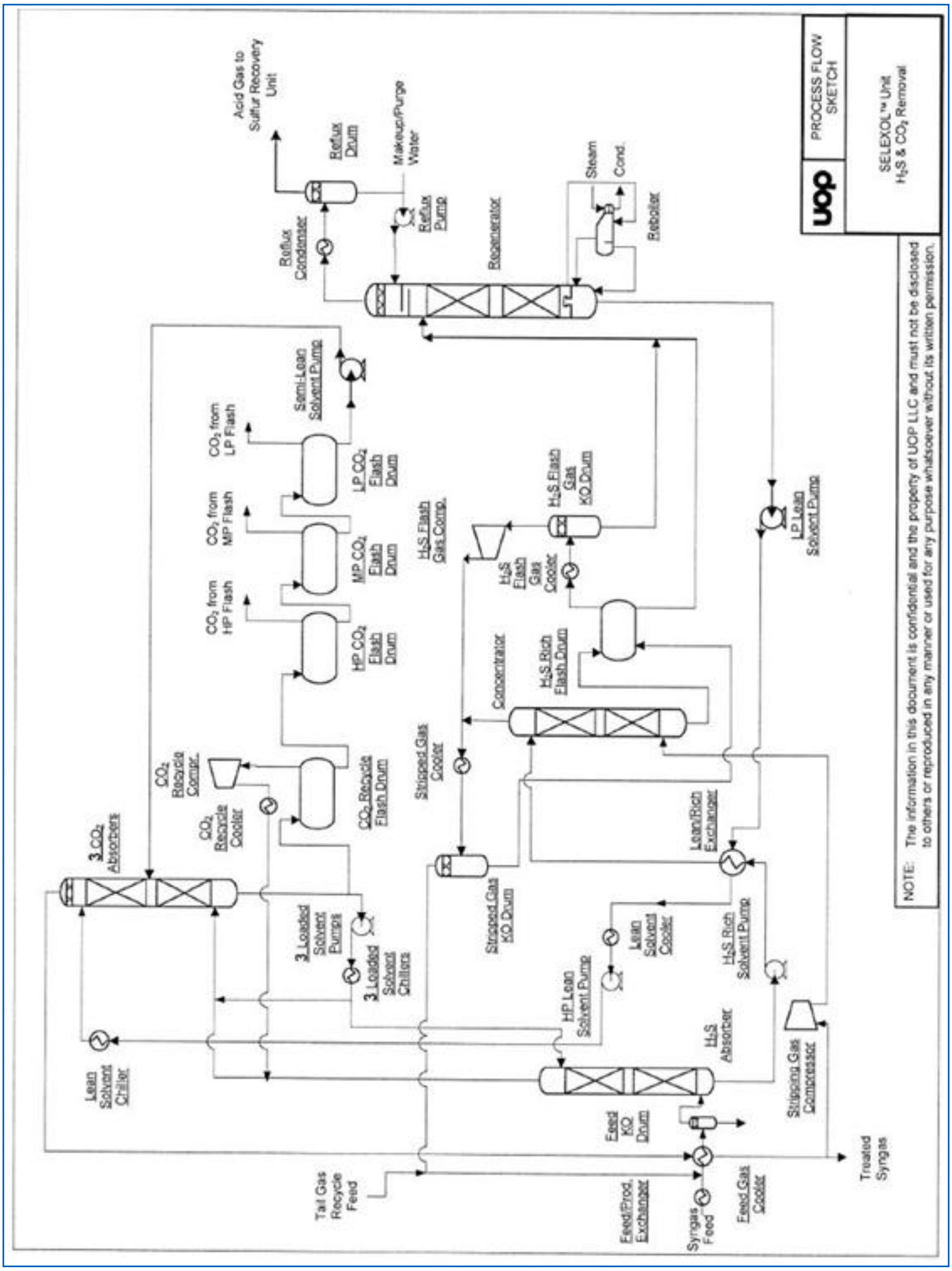


Figure 4. H_2S removal and CO_2 capture: Selexol process flow diagram

2.6. Sour Water Stripper

The Sour Water Stripper (SWS) unit treats part of the contaminated condensate from the syngas treatment section and the blow-down from the AGR and the SRU, in order to avoid accumulation of ammonia and H_2S and other dissolved gases (e.g. CO_2, CO) in the water recycled to the gasification section. These dissolved gases, in particular the bulk of CO_2, H_2S and NH_3 contained in the sour water are removed by means of LP stripping steam supplied to the re-boiler.

Around 15% of the condensate from the syngas cooling is sent to the sour water stripper. All condensate from the last syngas separator, upstream the AGR, plus a portion of the condensate from the upstream separator, is sent to the stripper as solubility of NH_3 and H_2S increases at low temperature.

Before entering the stripper, sour condensate is heated against treated column bottoms, in order to enhance removal of gases from water. The warm stream enters via a distributor at the top of the stripper column.

The vapour stream from the top of the stripper is sent to an overhead system where vapour is condensed and the sour gases are separated from the condensate in the gas/liquid separator. The condensed water is routed back to the column as reflux, above the rectifying bed. The sour gases are routed to the SRU. The bottom from the column is pumped to the condensate collection vessel within the syngas treatment section, before being used as heating medium to pre-heat the stripper feed.

2.7. Sulphur Recovery Unit and Tail Gas Treatment

The Sulphur Recovery Unit (SRU) processes the main acid gas from the Acid Gas Removal unit, together with other small flash gas and ammonia containing off-gas streams coming from other units. The SRU consists of two Claus Units for each line, each sized for approximately 100% of the maximum sulphur production in order to assure a satisfactory service factor. Low-pressure oxygen is used as oxidant of the Claus reaction.

A typical diagram of the Claus process is shown in Figure 5. The Claus plant consists of a Claus furnace and two catalytic conversion stages. The high operating temperature of the Claus furnace (approx 1100-1200°C) allows the destruction of the residual ammonia in the gas fed to the unit.

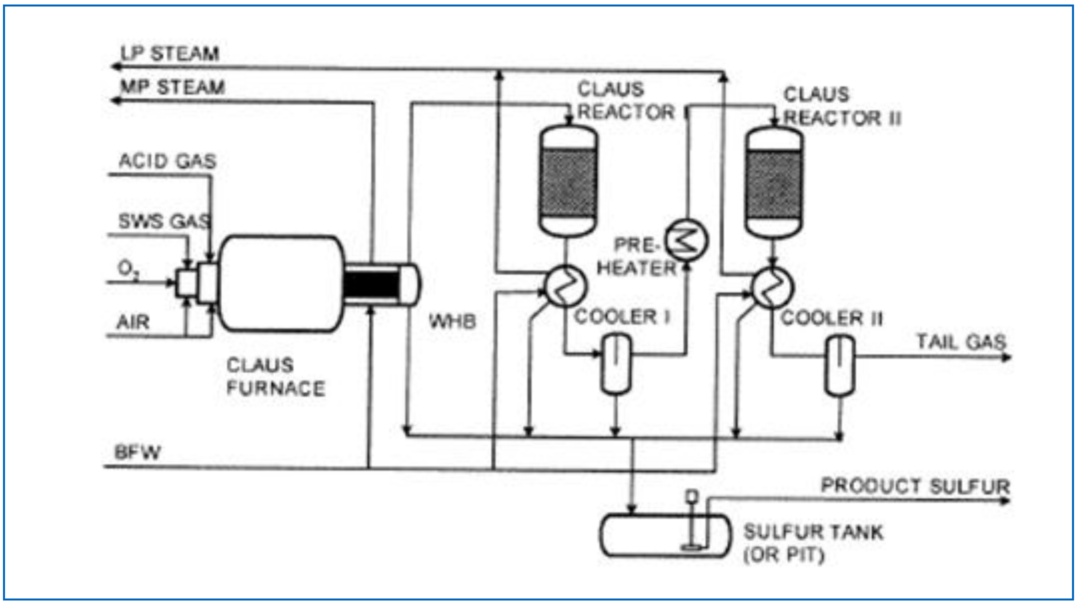


Figure 5. Claus unit diagram

The Claus process technology itself is limited by chemical equilibrium to approximately 98%, using multiple stages. To further enhance the sulphur recovery, it is therefore necessary to make provision for treating the tail gas, which contains the residual sulphur, in the Tail Gas Treatment Unit (TGT). This unit is designed as a single train, capable of processing 100% of the tail gas resulting from the possible SRU operating modes. The resulting overall sulphur recovery exceeds 98-99%.

The unit mainly includes a reduction reaction section, where the complete hydrogenation of SO_2, residual COS, CS_2, and elemental sulphur is achieved. The high hydrogen content in the shifted syngas results in a hydrogen content in the tail gas sufficient for complete hydrogenation of the tail gas stream itself. After quenching, tail gas is recycled back to the AGR by means of a tail gas recycle compressor.

2.8. Carbon dioxide compression and dehydration

The compression and dehydration unit consists of two parallel trains, including compressor, separation drums, coolers, dehydration system and final pump.

Carbon dioxide from the stripper of the CO_2 capture unit is compressed to a pressure of 80 bar by means of a two parallel eight-stage centrifugal compressor trains. Each CO_2 compressor is an integrally geared, electrically driven machine. The compression system includes anti-surge control, vent, inter-stage coolers, knockout drums and condensate draining facilities as appropriate.

The incoming streams to the CO_2 compression and dehydration unit are the combination of three streams at different pressures. The LP stream from the AGR is firstly compressed in two stages to the pressure level of the MP stream, before being mixed with the MP stream itself. The resulting stream is compressed in a two-stage compressor up to the pressure level of the HP stream, and mixed with it. This stream requires treatment for water removal to the specified level.

At the discharge of each compressor stage, CO_2 is cooled against cooling water in a separate cooler, with free condensate being drained from the compressed gas. A further two-stage compression is foreseen before feeding the CO_2 stream to the dehydration unit, where humidity water is removed and the gas is dried. The driers are designed to produce CO_2 product with a final dew point temperature of –40°C. The dehydration is carried out via a solid desiccant, like Activated Alumina and Molecular Sieves. The dehydration unit is composed of two beds for each parallel train of the unit. In normal operation one bed is used for drying, while the water-saturated bed is regenerated using a small part (ca.10%) of the dry product gas.

Final compression stages downstream of the driers increase the CO_2 pressure above the critical point of the fluid. The presence of non-condensable gases affects the behaviour of CO_2 resulting in an increased pressure requirement for the condensation of CO_2. In particular the hydrogen in CO_2 has the largest effect on the phase equilibrium, increasing the final compression pressure from the critical point of the CO_2 (74 bar) up to 80 bar.

After being cooled, dried CO_2 in dense phase is finally pumped and delivered the to the battery limits of the plant at pipeline pressure of 110 bar.

2.9. PSA unit (Hydrogen production cases)

The hydrogen separation unit included in the hydrogen co-production cases is based on a Pressure Swing Adsorption (PSA) system for hydrogen purification, fed by hydrogen rich gas from the AGR unit.

The PSA system is based on the property of specific adsorbent materials to preferentially adsorb gaseous components different from hydrogen. The impurities retained by the adsorbents (PSA off-gas) are routed to the HRSG supplementary firing system in the combined cycle (Cases 5.1 and 5.3) or are fired as primary fuel in the gas-fired boilers in case 5.3.

The unit consists of multiple adsorber beds in cyclic operation. Each adsorber operates on a repeated cycle, consisting of adsorption and regeneration phases at constant temperature, with the exception of the variation due to the heat of adsorption and desorption. During the adsorption phase, a hydrogen rich stream is passed through static beds of selective adsorbents in a high pressure environment (molecular sieves, activated carbons). The impurities are retained on the available surfaces, while hydrogen is produced at the required purity. Before the impurities saturate the adsorbent material, the hydrogen rich stream is directed to a clean adsorber vessel. Meanwhile, the loaded adsorber is taken off line for a series of depressurization cycle and counter current purging in order to clean the adsorption material. The impurities (PSA tail gas) are sent through the tail gas surge drum, before being routed to the supplementary firing system or to the boilers' burners in the power plant.

The PSA product gas is high purity hydrogen (> 99.5%) and is exported to battery limits at approximately 50 barg.

2.10. Combined Cycle

The combined cycle configuration selected for the power only alternatives is based on two parallel trains, each composed of one generic F-Class equivalent gas turbine and one Heat Recovery Steam Generator (HRSG) that generates steam at 3 levels of pressure, plus a LP integrated deaerator. The generated steam feeds one steam turbine (ST), common to the two parallel trains. A similar configuration with small size gas turbine (either 80 or 160 equivalent MWe) or a boiler is considered for the alternatives with hydrogen and power co-production.

The following description makes reference to the simplified process flow diagrams of the combined cycle of the power-only alternatives, attached to the end of this section. The main differences of the hydrogen and power co-production cases are also described, while case-specific characteristics are shown in the technical descriptions of the relevant case.

The combined cycle is thermally integrated with the other process units in order to maximize the net electrical efficiency of the plant. The following interfaces generally exist, though the combined cycle schemes may present some case-related differences:

- Air extraction from gas turbine compressor (MHI case);
- HP steam generated in the process units is superheated in the HRSG and processed in the steam turbine (ST);
- MP and LP steam are balanced between the steam cycle and the process unit;
- BFW for steam generation is supplied to the process units from the combined cycle;
- Steam condensate from the condenser in pumped to the syngas treatment line to be preheated against hot syngas;
- Process condensate, recovered from the process units, is recycled to the combined cycle, after polishing.

2.10.1. *Gas Turbine*

Commercially available combustion turbines have been developed for the use of natural gas, i.e. a fuel with high calorific value (LHV). With the development of the gasification plants, these turbines have been adapted to the use of syngas, characterized by lower LHV (on volumetric basis), which leads to some significant design changes.

The main change is that, while with natural gas premix burners have become common practice for NOx control, they are not used with fuels having high content of H_2 (flash back risk), both in case of syngas and hydrogen rich fuel. For these fuel types diffusion burners are used and control of NOx is achieved by diluting the fuel with nitrogen, steam or carbon dioxide, thus reducing the flame peak temperature and consequently the rate of formation of NOx.

The use of diluent for NOx control increases substantially the overall mass flow (air + fuel + diluent) through the turbine expander, thus increasing the backpressure at the air compressor discharge, which may bring the air compressor operation close to pressure ratio limits and sometimes overload the turbine blades up to their mechanical limit. To better suit the gas turbine design to syngas or hydrogen rich fired operation, some turbine frames are designed with an expander oversized with respect to the air compressor, so that the extra mass flow of fuel and diluent can be easily accommodated without pressure ratio limits or mechanical problems. When this overcapacity is not provided, only a limited amount of diluents can be accepted, thus limiting the reduction of NOx to acceptable values, so that an SCR system shall be foreseen in the HRSG.

The normal operation of the gas turbine is with de-carbonized fuel, whilst the start-up or back-up fuel can be either natural gas or a liquid fuel. The normal gas turbine firing temperature is generally de-rated on hydrogen rich fuel compared to natural gas, due to the combustion characteristics of the hydrogen, as explained in the following sections.

Main features of hydrogen combustion

The main characteristics of hydrogen combustion are:

- Low ignition energy;
- Low density;
- High flame speed;
- High flame temperature;
- Wide flammability range.

Table 7 summarizes the main properties of the hydrogen combustion with respect to the methane.

Table 7. Comparison of methane and hydrogen combustion

Property	Methane	Hydrogen
Mass basis Low Heating Value (LHV) (kJ/kg)	50,030	119,910
Volume basis Low Heating Value (LHV) (kJ/Nm^3)	33,950	10,230
Flame speed (burning in air) (m/s) [(1)]	0.43	3.5
Minimum ignition energy (mJ)	0.33	0.18
Auto-ignition delay time (s) (17 atm 1000°K) [(2)]	0.0456	0.0062
Stoichiometric combustion temperature (°K)	2227	2370
Density (g/l)	0.71	0.09

(1) Velocity at which un-burnt gas mixture flows into a stable flame

(2) Time from the instant of mixing hot streams of fuel and oxidant to the instant at which flame appears

The main considerations that can be drawn from the above table are the following:

- The flame speed is much faster and the auto-ignition delay time is much shorter for hydrogen, by an order of magnitude in both cases.
  As for that, hydrogen rich gas cannot be burnt in pre-mix combustion systems, but diffusion systems are needed to avoid potential flashback.
- On a mass basis, hydrogen has a high LHV, but not on a volume basis, and therefore a higher volumetric flowrate is required to satisfy the thermal requirement of the gas turbine. This effect is increased by the diluents required for NOx control.
  This low volumetric heat content leads to the need for large fuel supply headers and fuel admission valves.
- The high flame temperature leads to extremely high NOx emissions and very expensive materials of construction. Therefore, diluents need to be added to the fuel to reduce the combustion temperature and limit the NOx emission (refer also to next section). Materials of construction must be suitable for hydrogen exposure.
- The extremely low flammability limit of hydrogen requires additional time and volume of purge gas to ensure that the lines are fuel free after shutdown.

In summary, hydrogen combustion properties are well known and, taking into account these characteristics in the design of the gas turbine, no particular technological barriers are foreseen for hydrogen combustion in the machine.

Gas turbine for study cases

The following combustion turbines, suited for operation with hydrogen-rich gas, are considered in this study.

F-class gas turbine (O_2-blown IGCC alternatives)

The F-class machine (approximately 280 MWe ISO condition firing natural gas) is the most reasonable choice for an IGCC power plant of the capacity set for the project (around 1,000 MWe).

Though E-class gas turbines are probably the most referenced ones for operation with these fuel types, their low efficiency and power production capability (approximately 160 MWe) would lead to need for a high number of gas turbines, thus resulting in a non-economic or non-attractive IGCC plant. On the other hand, G or H-class gas turbines are the newest generation machines, which have recently found application on natural gas, so their possible use on either syngas or hydrogen rich fuel could be deemed premature at the moment, in particular for the H-class turbine.

The following F-class gas turbine vendors and machinery types are currently available in the European market (50 Hz) for operation with either syngas or hydrogen-rich fuel:

- General Electric (GE) Energy: 9F and 6F gas turbine type;
- Mitsubishi Heavy Industries (MHI): M701F;
- Siemens: SGT5-4000F.

Among the above-listed suppliers, MHI provided the information on their F-class machine, but only for use in the case based on their gasification technology. Instead, other suppliers decided to not support the study effort.

Because of the above, it was decided to base the oxygen blown IGCC cases on a generic F-class machine, whose performance represents an average of the gas turbines available in the market, evaluated on the basis of data coming from the public domain or simulation tools.

Hydrogen and power co-production cases: E-class or Frame 6 equivalent

The study cases with power and hydrogen co-production use gas turbines with a power production lower than the F-class described above. With the same number and size of gasifiers, this makes available part of the generated syngas for the hydrogen production, while the remaining part is used for power generation, at least meeting the plant auxiliary consumptions and also ensuring adequate plant operating flexibility.

Two alternative gas turbine sizes, generating different amount of power, have been identified and assessed in the study cases:

- 160 MWe, i.e. E-class equivalent machine.
- 90 MWe, i.e. Frame 6 equivalent machine.

The following gas turbine vendors and machinery types are currently available in the European market (50 Hz) for operation with either syngas or hydrogen-rich fuel in the above range:

- General Electric (GE) Energy: 9E and 6F gas turbine types;
- Siemens: SGT5-2000E.

As for the F-class, gas turbine suppliers have not provided data to support the study, so reference to generic gas turbine performance was made for the assessments, evaluated on the basis of simulation tools or data available from the public domain.

NOx reduction systems

As stated in the above sections, the combustion of hydrogen rich fuel leads to a high flame temperature and consequent high NOx formation. Fuel dilution is therefore necessary to meet the desired emission limits. The increased diluted fuel mass flow results in power augmentation of the machine with respect to the natural gas standard performance.

The fuel can be diluted either with nitrogen, carbon dioxide (only for plant w/o CCS) or water (either fuel/diluent saturation or steam injection) or a simultaneous combination of the different streams. Depending on the gas turbine frame, the diluent shall be injected into the fuel combustion chamber, or added to either the fuel or the nitrogen in a saturation tower.

Figure 6 provides a representation of the above-mentioned alternatives for diluent addition.

For these study cases, the following have been assumed:

- Generic F-class gas turbine (IGCC cases 4.1 and 4.2): nitrogen is used for hydrogen dilution down to a molar concentration around 65%, before being fed to the combustion chamber. In addition, saturated nitrogen is injected directly into the gas turbine combustion chamber for final dilution.
- MHI F-class gas turbine (IGCC case 4.3): nitrogen already present in the hydrogen rich gas, as air is used as oxidant for the gasification reaction, provides sufficient diluent effect.
- Generic E-class Frame 6 gas equivalent turbine (Hydrogen cogeneration cases): moisturised nitrogen is used as fuel diluent, before injection in the gas turbine combustion chamber.

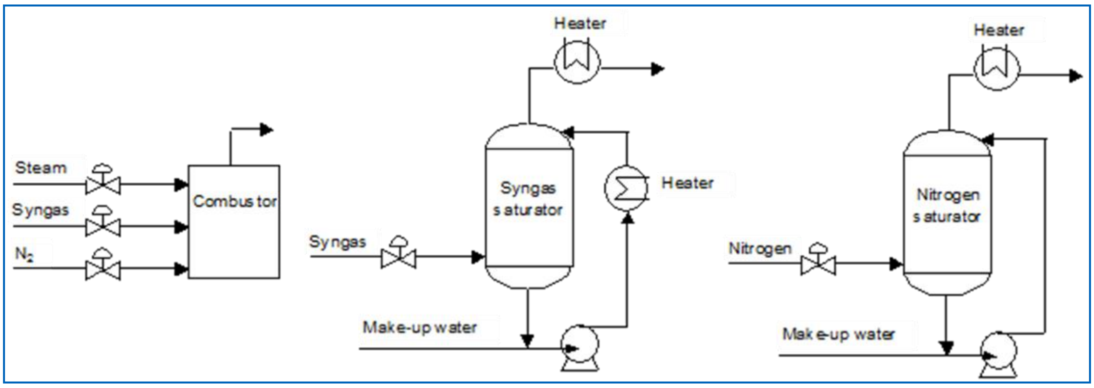


Figure 6. Alternative for hydrogen-rich gas dilution

2.10.2. *Heat Recovery Steam Generator*

The exhaust gases from the gas turbine are conveyed to the Heat Recovery Steam Generators, located downstream of the machine and connected by means of an exhaust duct.

The simplified process flow diagram of the HRSG is shown in Figure 7.

The HRSG is a natural circulation type, with horizontal flue gas flow arrangement and vertical tubes generating steam at three pressure level, plus integral deaerator for BFW production. Further details on steam generation conditions are listed in chapter B, section 4.3.3.

Exhaust gases coming from the Gas Turbine enter the HRSG casing through the inlet duct, flow counter-current to steam/water and meet in sequence the following coils, before being discharged to the atmosphere through the stack:

- HP super-heater (2nd section) / MP re-heater (2nd section) (in parallel arrangement);
- HP super-heater (1st section) / MP re-heater (1st section) (in parallel arrangement);
- HP evaporator;
- HP economizer (3rd section);
- MP super-heater;
- MP evaporator;
- LP super-heater;
- HP economizer (2nd section) / MP economizer (2nd section) (in parallel arrangement);
- LP evaporator;
- HP economizer (1st section) / MP economizer (1st section) / LP economizer (in parallel arrangement);

- VLP Evaporator, with integral deaerator.

The above sequence of steam/water coils is typical for the combined cycle of IGCC plants. The same configuration is applicable also for the alternatives with co-production of power and hydrogen. However, as the combined cycle is undersized with respect to the whole gasification capacity, the steam drum, in particular the HP steam drum generates a lower amount of steam, allowing to accommodate the significant amount of steam generated in the process units that has to be superheated before flowing to the steam turbine. In addition, part of the BFW pre-heating before being sent to the steam generation in the process unit is done in the syngas treatment against condensing syngas.

The pre-heated condensate coming back from the syngas treatment line is mixed with the polished hot condensate from the steam heaters in the IGCC process units and then fed to the VLP steam drum, equipped with a degassing tower to generate the Boiler Feed Water (BFW). The VLP steam drum is the last coil before the exhaust gases are released to atmosphere through the stack. The drum is designed to the minimum pressure that keeps the flue gas temperature and the temperature of the water in the bundles at least 10-15°C above the acid dew point of the flue gas.

For each case of the study, the acid dew point temperature is calculated using the following Müller-Totman equation [“Get acid dew point of flue gases” – A.G. Okkes, Badger B.V. – Hydrocarbon Processing – July 1987]:

$$T = 203.25 + 27.6 \cdot Log(pH_2O) + 10.83 \cdot Log(pSO_3) + 1.06 \cdot (Log(pSO_3) + 8\ )^{2.19}$$

where pressure is shown as [atm] and T as [°C].

The above equation determines the dew point temperature as a function of the partial pressure of water and SO_3 in the flue gas. The study assumes 6% conversion SO_2 to SO_3.

Degassed BFW for HP, MP, LP and VLP services is directly taken from the deaerator and delivered to the relevant sections by means of dedicated BFW pumps.

HP BFW from the deaerator is delivered to the HP economizer coils by means of the HP BFW pumps (one in operation and one in hot stand-by); flows through the HP economizer coils and then feeds the HP Steam Drum. From the outlet of the 1st section of the HP economizer coils a portion of hot water is exported at a temperature level of about 160 °C to the process units as HP BFW for steam generation.

The generated steam, together with the HP steam imported from the process units, is finally superheated to the maximum possible temperature level in two sections of HP super-heating coils and then sent to the HP module of the steam turbine. To control the maximum value of the HP superheated steam final temperature, a de-superheating station, located between the two HP super-heater coils, is provided. The cooling medium is HP BFW taken from the HP BFW pumps discharge and adjusted through a dedicated temperature control valve.

MP BFW from the deaerator is delivered to the MP economizer coils of the HRSG by means of the MP BFW pumps (one operating and one in stand-by); it flows through the MP economizer coils and feeds the MP steam drum. From the outlet of the 1st section of the MP economizer coils a portion of hot water is exported at a temperature level of about 160 °C to the process units as MP BFW.

The generated MP steam together, superheated in the dedicated coils and mixed with the exhaust steam coming from the HP module of the steam turbine, is reheated in the two sections of MP re-heating coils and then enters the MP module of the steam turbine. To control the reheated steam final temperature, a de-superheating station, located between the re-heater coils, is provided. The cooling medium is MP BFW, taken out from the MP BFW pumps discharge and adjusted through a dedicated temperature control valve. Depending on the IGCC case, MP steam imported from the process unit is mixed with the steam from the MP generator before the re-heating section or MP steam is to be exported from the combined cycle to the process unit.

For each design case of the study, the HP superheated steam and MP reheated steam temperature is selected in order to respect the most severe of the following design criteria:

- Minimum approach temperature between steam and exhaust gas temperature of 25°C to have an adequate heat transfer coefficient and limit the requirement of the surface.
- Maximum steam temperature of 565°C, to use material ASME A 335, 9Cr-1Mo-V, Grade P91 and avoid the use of more exotic materials.

LP BFW from the deaerator is delivered to the LP economizer coil by means of two LP BFW pumps (one operating and one in stand-by); it flows through the LP economizer coil and feeds the LP steam drum. Before entering the LP steam drum, a portion of hot water is exported at a temperature level of about 160°C to the process units as LP BFW. The excess superheated LP steam is mixed with the exhaust of the MP module and then flows to the steam turbine LP module.

Continuous HP and MP and LP blow-down flowrates from the HRSG are manually adjusted by means of dedicated angle valves; they are sent to the dedicated blow-down drum to flash and recover VLP steam, which is fed to the deaerator. The remaining flashed liquid is cooled down against cooling water by means of a dedicated blow-down cooler and delivered to the atmospheric blow-down drum, which also collects the possible overflows coming from HRSG’s steam drums and the intermittent HP, MP and LP blow-down flowrates, which are manually adjusted by means of dedicated angle valves.

Figure 8 shows a typical Heat Transfer vs. Temperature of the HRSG (T-Q diagram). The red line (the upper curve) represents the exhaust gases from the GT (high temperature) to the stack. The blue lines represent the water path in the economizers (at lower temperature), the steam generators (horizontal lines) and the super-heater/re-heater (at higher temperature).

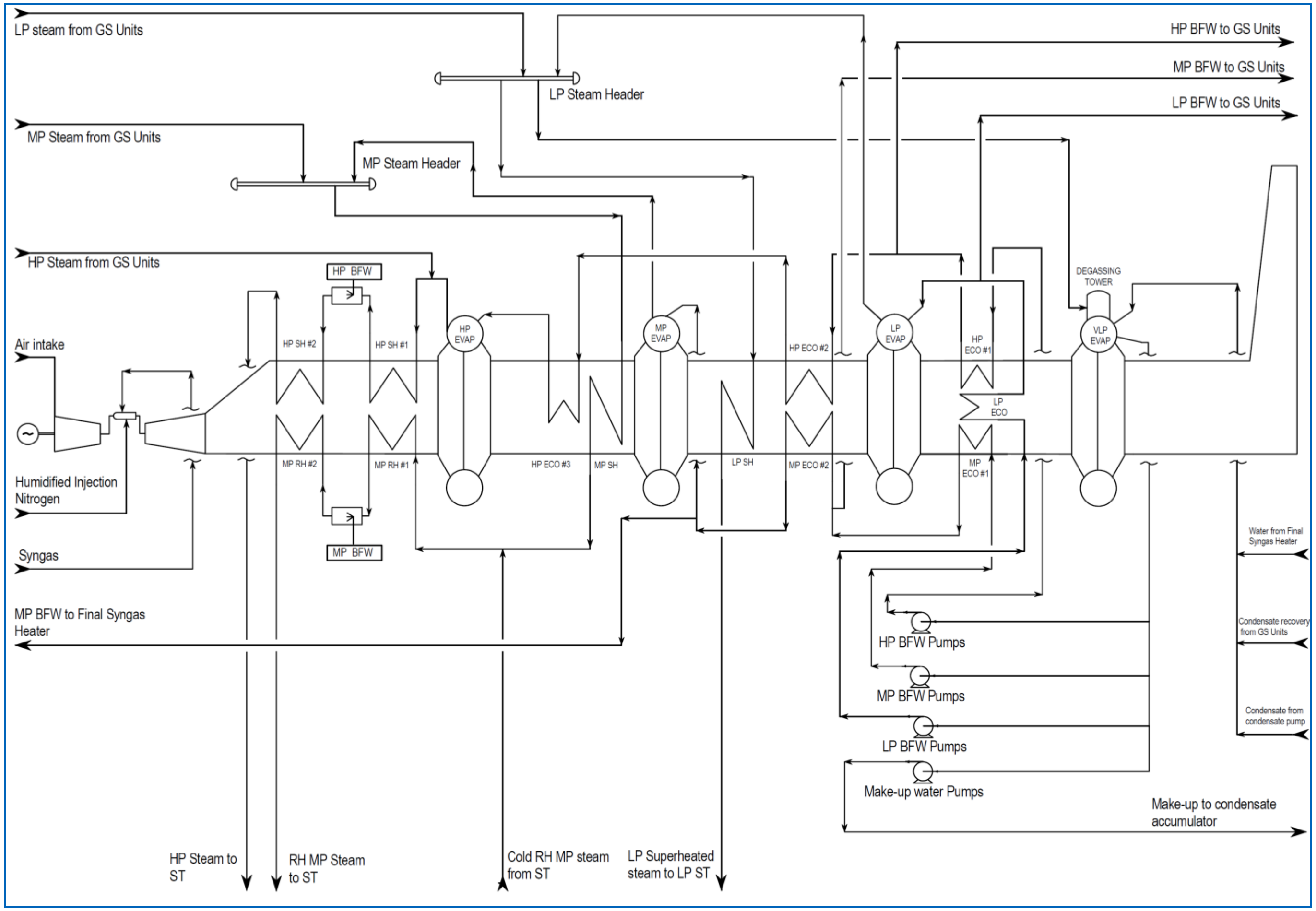


Figure 7. HRSG simplified process flow diagram

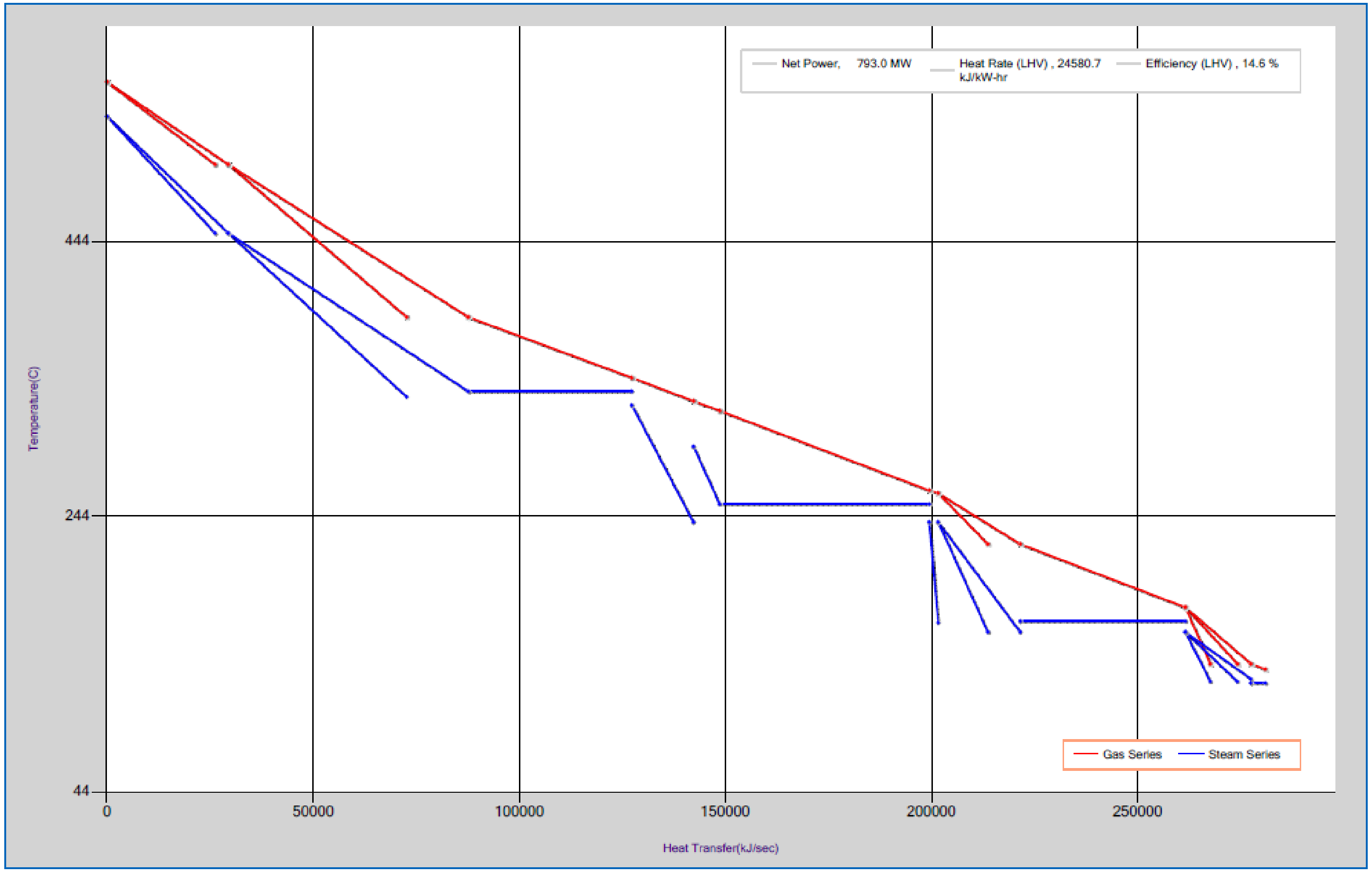


Figure 8. HRSG Heat Transfer vs. Temperature diagram

2.10.3. *Steam turbine and condenser*

The following process description makes reference to the simplified process flow diagram shown in Figure 9.

The Steam Turbine consists of an HP section, MP section and a double-flow LP section, all connected to the generator by a common shaft. Depending on the alternative, the last stage bucket length of the LP section is selected to have an exhaust annulus velocity in the range of 220-300 m/s.

The superheated HP steam from each HRSG is combined in a header and then enters the HP section of the steam turbine. The exhaust steam from the HP module of the steam turbine is split between the HRSG's, mixed with the MP saturated steam coming from the relevant HRSG section, and reheated. The reheated steam from the HRSGs is combined in a header and then enters the MP section of the steam turbine. The exhaust steam from the MP module of the steam turbine is mixed with the superheated LP steam and delivered to the LP module.

The wet steam at the outlet of the LP module is routed to the steam condenser at 4.0 kPa, corresponding to 29°C. The cooling medium in the tube side of the surface condenser is cooling water from the cooling tower.

The condensate stream, extracted from the steam condenser by means of two, motor-driven and vertical condensate pumps (one operating and one in stand-by), is mixed with demineralised water makeup and sent to the IGCC process units, recovering the low temperature heat available from the syngas cooling.

In case of steam turbine trip, live HP steam is bypassed to the MP manifold by means of a dedicated letdown station, while MP steam and excess of LP steam are also let down and then sent directly into the condenser neck.

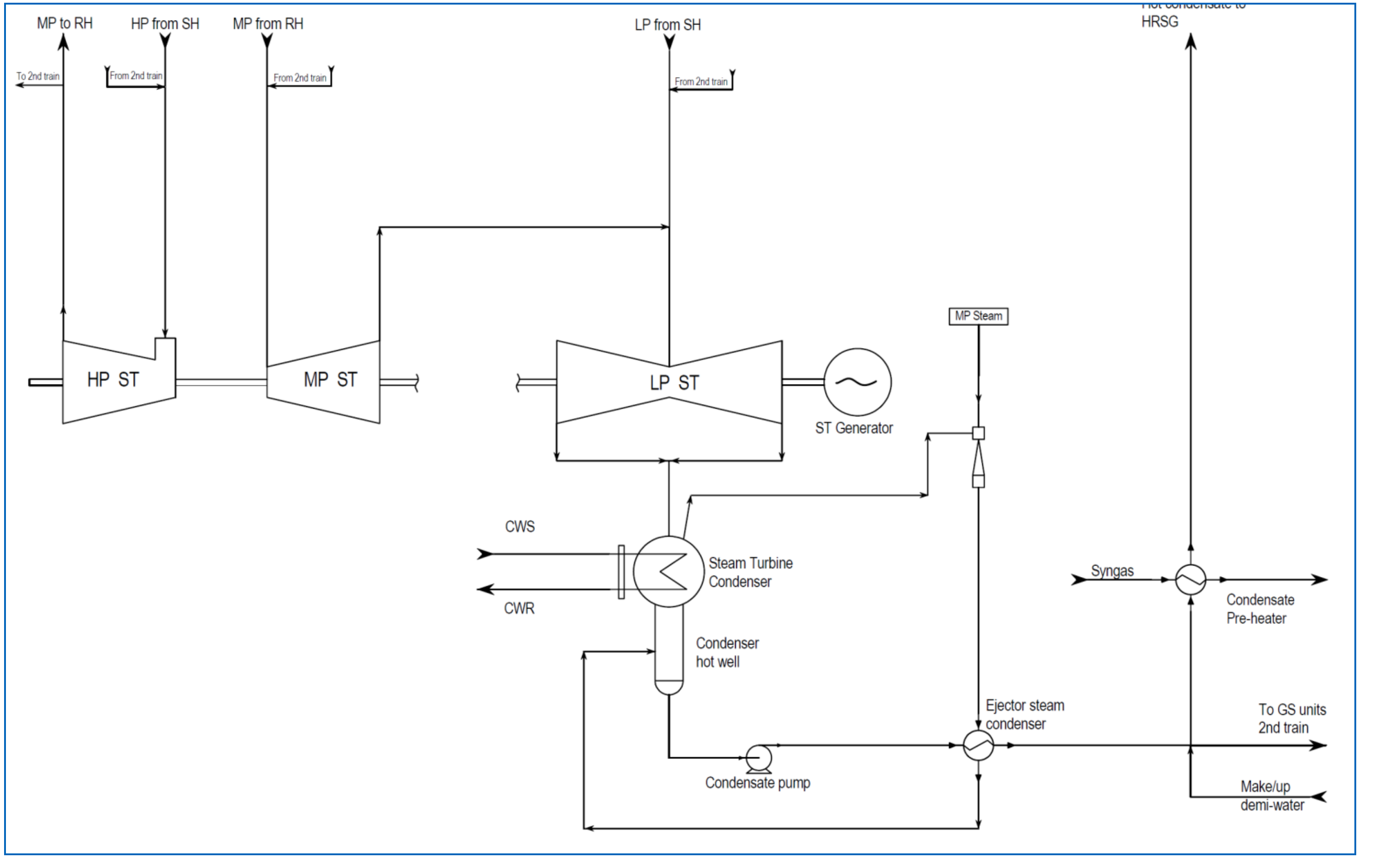


Figure 9. Steam Turbine simplified process flow diagram

2.11. Utility and Offsite units

These units are the same as the ones described in Chapter C for the air-fired boiler cases. Anyhow, the description of the units is here below reported for clarity of the reader.

2.11.1. Cooling water

The cooling water system consists of raw water in a closed loop, with a natural draft, evaporative cooling tower. There are two circulation systems, depending on the pressure profile through the circuit. The primary system is used for the steam turbine condenser while the secondary system is used for the process units of the plant, machinery cooling and other users. Each circulation system is equipped with single-stage and vertical water pumps.

The maximum allowed cooling water temperature increase is 11°C. The blow-down is used to prevent the concentration of dissolved solids from increasing to the point where they may precipitate and scale-up heat exchangers and the cooling tower fill. The design concentrations cycles (CC) is 4.0.

A single concrete tower is considered, having different size depending on the alternative. The main cooling tower design details are summarised in the case-specific chapter of each gasification-based alternative.. The tower will be equipped with two distribution systems, one primary distribution system supplying water from a concrete duct, and one secondary system from PVC pipes equipped with sprayers, connected to the concrete ducts. Tower filling, with vertical channels, increases the cooling and thermal efficiency, allowing pollutants to be easily washed through. Drift eliminators guarantee a low drift rate and low pressure drop. To avoid freezing in winter ambient conditions, the fill pack is divided into zones to allow step by step reduction of cooling capacity while maintaining an excellent water distribution and spray sprinklers are installed to create a warm water screen on the air inlets to preheat the ambient air when freezing ambient conditions occurs.

2.11.2. Raw and Demineralised water

Raw water is generally used as make-up water for the power plant, in particular as make-up of the cooling tower. Raw water is also used to produce demineralised water. Raw water from an adequate storage tank is pumped to the demineralised water package that supplies make-up water with adequate physical-chemical characteristics to the combined cycle.

The treatment system includes the following:

- Filtering through a multimedia filter to remove solids.

- Removal of dissolved solids: filtered water passes through the Reverse Osmosis (RO) cartridge filter to remove dissolved CO_2 and then to a reverse osmosis system to remove dissolved solids.
- Demineralised water production: an electro de-ionization system is used for final polishing of the water to further remove trace ionic salts of the Reverse Osmosis (RO) permeate.

Adequate demineralised water storage is provided by means of a dedicated demineralised water tank.

The demineralised water make-up supplies the make-up water to the combined cycle, whilst the demineralised water distribution pump supplies demineralised water to the other plant users or to the plant circuits for first filling.

2.11.3. *Fire fighting system*

This system consists of all the facilities able to locate possible fire and all the equipments necessary for its extinction. The fire detection and extinguishing system essentially includes the automatic and manual fire detection facilities, as well as the detection devices with relevant alarm system. An appropriate fire detection and suppression system is considered in each fire hazard area according to the applicable protection requirements. The fire fighting water is supplied by a water pumping station via a looping piping network consisting of a perimetrical circuit fed by water pumped from the cooling tower basin.

2.11.4. *Instrument and plant air system*

The air compression system supplies air to the different process and instrumentation users of the plant.

The system consists mainly of:

- Air compressors, one in operation, one in stand-by.
- Compressed air receiver drum.
- Compressed air dryer for the instrument air.

The ambient air compressed by means of the air compressor is stored in the air receiver in order to guarantee the hold-up required for emergency shutdown.

Plant air is directly taken from the air receiver, while air for instrumentation is sent to the air dryer where air is dried up to reach an adequate dew point, to ensure the proper operation of the instrumentation.

2.11.5. *Waste Water Treatment*

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

The following description gives an overview of the waste water treatment configuration, generally adopted in similarly designed power plants; it includes a preliminary identification of the operations necessary to treat the different waste water streams generated in the power plant.

The Waste Water Treatment unit is designed to treat the following main waste water streams:

- Waste water from process unit, e.g. from gasification island
- Potentially oil-contaminated rain water
- Potentially dust-contaminated rain water
- Clean rain water
- Sanitary waste water.

Mainly, the above streams are collected and routed to the waste water treatment in different systems according to their quality and final treatment destination.

The WWT system is equipped mainly with the following treatment sections:

- Treatment facilities for the waste water from process unit, e.g. from gasification island
- Treatment facilities for the potentially oily contaminated water
- Treatment facilities for the potentially dust contaminated water
- Treatment facilities for not contaminated water
- Treatment facilities for the sanitary wastewater.

Waste water from process unit

The different contaminated streams from the process units of the IGCC plant are sent to an equalization section in order to make uniform the wastewater physical characteristic and optimize the following treatment units (e.g. pollutants concentration, temperature, etc.).

The equalization section consists of one or more ponds or tanks, generally at the front end of the treatment plant, where inlet streams are collected and mixed. Equalization basin is normally designed in order to guarantee a hydraulic retention time of 8-10 hours to smooth the peaks of pollution and maintain constant the treatments efficiency.

A physical-chemical treatment section consisting of two basins in series is foreseen, where chemicals are added for chemical coagulation, flocculation and for specific pollutants removal. The purpose of wastewater clariflocculation is to form aggregates or flocs from finely divided particles and from chemical destabilized particles in order to remove them in the following sedimentation step.

In the first basin, coagulation basin, a coagulant as Ferric Chloride is added and a flash-mixing is performed. Simultaneously with ferric chloride, Ferrous Sulphate is added in order to remove H_2S. As the present reaction gives an acid contribution, NaOH is added in order to neutralize the sulphuric acid produced.

In the second basin, flocculation basin, polyelectrolyte is added and slow-mixing is performed. In the flocculation basin H_2S oxidation and H_2SO_4 neutralization are also completed.

Effluent water from coagulation/flocculation section flows into a clarification basin where solids separation is performed and all setteable compounds are removed. The produced sludge, constituted by settled solids, is removed from the bottom of each clarifier by a scraper.

Chemical sludge from chemical sludge settler is subjected to a chemical conditioning in order to favour the sludge dewatering. Ferric Chloride and polyelectrolyte are added in order to favour solids aggregation and to improve the subsequent dewatering treatment. The conditioned sludge is so sent to a dewatering system (i.e. centrifugal system) in order to achieve a dry solids content of minimum 20%. The separated supernatant, sludge is sent to final disposal.

The clarified water from chemical sludge settler is sent to an aerated lagoon in order to remove the organic load, expressed as COD and BOD, still present in the polluted water. An aerated lagoon is an underground basin, equipped with mechanical aerators in order to provide oxygen for biological degradation and to permit to keep solids in suspension. Despite of the requirement of big areas, aerated lagoons guarantee management simplicity and a low maintenance.

The clarified water from aerated lagoon is delivered to the top of the sand filter bed in order to remove the remaining unsetteable solids. As the water passes through the filter bed, the suspended matter in the wastewater is intercepted. With the passage of time, as material accumulates within the interstices of the granular medium, the headloss through the filter start to build up beyond the initial value. When the operating headloss through the filter reaches a predetermined headloss value, the filter must be cleaned.

Potentially Dust Contaminated Water Treatment

Rain water and washing water from areas subject to potential dust contamination is treated in apposite water treatment systems prior to be sent to the “potentially oil contaminated” treatment system.

In particular, they are collected in a dedicated sewer, sent to a lamination tank and then to a chemical/physical treatment to remove the substances that are dissolved and suspended.

The system includes also a neutralization system to modify potential acidity and/or alkalinity of washing water used for the air pre-heaters.

Potentially Oil-Contaminated Water Treatment

Potentially oil-contaminated waters are:

- Washing water from areas where there is equipment containing oil.
- Rain water from areas where there is equipment containing oil.

After being mixed with treated water coming from "potentially dust contaminated" system, water is treated in a flotation and filtration system, where emulsified oil and suspended solids are respectively separated.

Treated effluent water will have the characteristics to respect the local regulations so that it can be consequently discharged.

Not Contaminated Water Treatment

Rainwater fallen on clean areas of the plant, such as roads, parking areas, building roofs, areas for warehouse/services/laboratory etc. where there is no risk of contamination, will be collected and disposed directly to the water discharge system.

A coarse solids trap is installed upstream the discharge point in order to retain coarse solids that may be carried together with the discharge water.

Sanitary Water Treatment

The sanitary waste water streams discharged from the different sanitary stations of the plant will be collected in a dedicated sewage and destined to the Sanitary Water Treatment system. This section generally involves the following main water treatment operations:

- Primary sedimentation for coarse solids removal.
- Biological treatment for BOD removal.
- Filtration for residual organic matter and suspended solids separation.
- Disinfection for bacteria inhibition.

3. Gasification

This section summarizes information received from the different Gasification Island Licensors. Data are covered by a secrecy agreement and the information included in this section and in the specific section of each case is limited to the information that Licensors have authorized for disclosure.

It has to be noted that some differences may exist between figures in the vendors' information and those shown in the report of the specific study case. In fact, information in the attachments is based on preliminary stream properties and flowrates, as estimated during the early stages of the study; then, data have been slightly adjusted and optimised during study execution either by vendors or Foster Wheeler. Figures included in the report for each study case shall be considered as the final ones.

3.1. Shell gasification

3.1.1. *Introduction*

The purpose of this section is to summarize the information received from Shell on the Gasification Island (GI), representing the basic information on which the technical and economical analysis of the Shell gasification based IGCC alternative of the study (Case 4.1) has been performed.

The Shell Coal Gasification Process (SCGP) information provided here is a first estimation of SCGP performance and should not be used as final design information. Shell has to be consulted for any project specific application confirming data selected for SCGP application.

SCGP scope includes coal feeding up to and including syngas wet scrubbing. Shell has selected the syngas cooler option for this project based on experience on previous similar projects.

Additionally, Shell has recommended the use of a hybrid Water Gas Shift (WGS) scheme, followed by a sour tolerant 2-stage WGS in order to minimize the steam consumption of the unit.

3.1.2. *Process Description*

The study case is based on the proven Synthesis Gas Cooler concept option. Two SGCP units will be required to deliver the thermal power requested by two F-class gas turbines.

The key features of the Shell Coal Gasification Process (SCGP) are the following:

- Pressurized: compact equipment;
- Entrained flow: compact gasifier;

- Oxygen blown: compact equipment, high gasification efficiency;
- Membrane wall, slagging gasifier: robustness, high temperature, insulation by slag layer;
- Multiple burner design: good mixing, high conversion, scale-up possibility;
- Dry feed of pulverized coal: high gasification efficiency, high feed flexibility.

The SCGP process can handle and has been proven on a wide variety of solid fuels, ranging from bituminous to lignite, as well as petroleum coke in a coal mix. The SCGP also showed capability to handle coal feed with biomass/sewage sludge.

Figure 10 shows the block flow scheme for the coal gasification process with syngas cooler line-up. The general process description is given below.

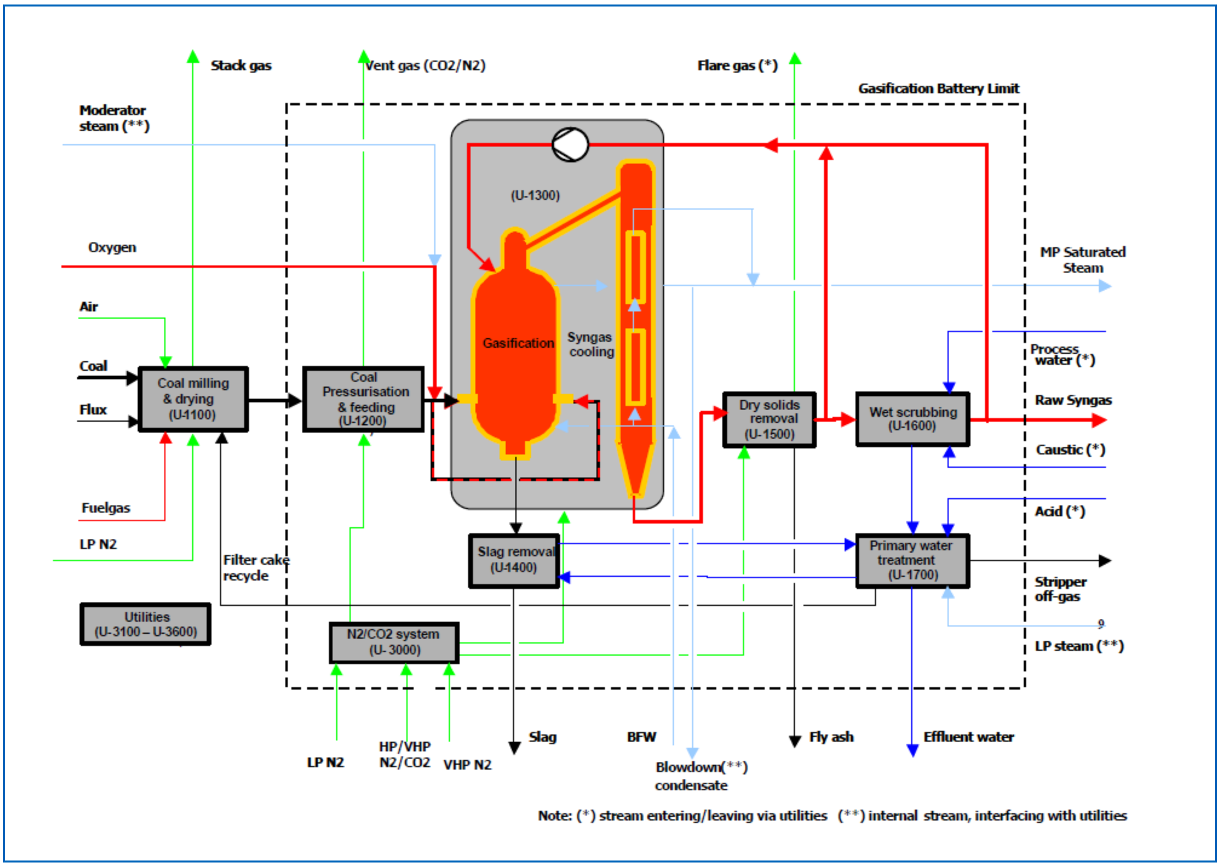


Figure 10. SCGP - Preliminary Block Flow Diagram

Coal is received from the coal yard by belt conveyor, milled and dried in the "Coal Milling and Drying" system (out of Shell's scope of work) and then fed, under pressure, to the burners of the gasifier via the "Coal Pressurization and Feeding" (lock hopper) system.

The coal reacts in the gasifier with the blast (steam diluted oxygen) to form syngas and (fly) slag. The syngas leaving the gasifier at the top is quenched with "cold" recycled syngas to solidify entrained fly ash particles. The gas is further cooled in the syngas cooler vessel to typically 340°C.

The gasifier itself is a membrane wall reactor installed inside a pressure vessel. The membrane wall is made out of tubes leading to a very robust thermal design. Within tubes a forced water circulation is maintained, the absorbed heat being used to produce steam.

The majority of ash in the feedstock leaves the gasifier membrane wall via the bottom as molten inert slag which is then quenched with cooled water and subsequently scattered to small (on average approximately 5-10 mm) glassy granulates in the slag (water) bath. The slag collected in the slagbath is discharged via a lock-hopper system.

Coal Milling and Drying (out of Shell's scope of work)

In order to meet Shell SCGP specification for particle size distribution and moisture content, coal needs to be milled. The moisture content in combination with the particle size ensures proper flow properties of the pulverised coal in downstream equipment.

Shell recommends to let the entire coal milling and drying system be designed, installed and started up by, or under responsibility of, an experienced coal mill manufacturer to avoid interface problems between the various pieces of equipment. In view of the importance to ensure the proper flow properties of the coal and to give input for the design requirements of the coal milling and drying section, a fluidisation test of a coal test sample is generally required.

Multiple units have to be installed in order to ensure high process reliability, allowing maintenance work on one unit while the other unit is still in operation. During normal operation the units are fired with "clean" syngas drying the raw coal supplied from the coal yard.

Coal Pressurization and Feeding

Milled and dried coal from the coal milling and drying area is pneumatically transported to the coal pressurization and feeding system. This system consists of lock-hoppers and feed-hoppers. Once a lock-hopper has been charged with coal, it is pressurized with nitrogen and its content discharged into a feed vessel.

Pressurized coal is drawn from the feed hoppers and pneumatically conveyed with nitrogen to the gasifier's coal burners.

Lock-hoppers are widely used in materials handling application. 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.

Gasification and Syngas Cooler

The coal feed is gasified with a blast consisting of a mixture of oxygen and (superheated) process steam. Fluxing components, which reduce the slag viscosity at a given temperature through the reaction with the slag, are typically added to the coal before the mills to ensure good mixing and conveying. Because of the entrained flow, high temperature, and ash slagging condition, an almost complete carbon conversion (>99%) is achieved. Moreover, the high temperature ensures essentially no organic components heavier than "C1" are present in the raw syngas.

Insulation of the gasifier membrane wall provided by the partially solidified slag layer in the gasifier minimizes heat losses such that cold gas efficiencies are high and CO_2 levels in the syngas are very low. This slag layer also protects the gasifier wall against high heat load variations during upsets since the solidified slag layer will react by melting or solidifying.

The pressurized coal, oxygen, and steam enter the gasifier through two pairs of opposed burners. During normal operation load-following operation should be done with all four burners balanced. The capacity of the gasifier and syngas cooler is mainly determined by the amount of ($CO + H_2$) in the syngas to be produced, which depends on the coal type.

The operating syngas pressure of the gasifier is about 2.3-4.3 MPag. The gasifier membrane wall steam pressure is, for safety reasons, always, at least, some 1.5 MPag above the maximum operating syngas pressure.

The syngas cooler is of the water pipe type, typically containing both evaporating and superheating surfaces. The syngas cooler is designed according to Licensee's steam pressure and temperature requirements.

The water quench vessel is of the dip leg type where the ash laden syngas from the gasifier is quenched with water to cool the syngas close to saturation temperature and also to capture the fly ash in water bath.

Slag Removal

Depending on the ash content in the feedstock, and the fresh ash addition, about 70-80% of the mineral content of the coal/fresh ash leaves the gasification zone in the form of molten slag. The high gasification temperature above the ash melting point ensures that the slag flows freely down the membrane wall. The heat from the molten slag is removed in the slag bath and transferred to the water via a slagbath-water circulation loop with an external water-cooled cooler.

Finally, slag is separated from water via a drag chain, or a de-watering screw, and is transported offsite via a conveyor belt. Fines are removed via the clarifier/thickener system, and the clarified water is recycled in the Primary Water Treatment System.

Slag is depressurized in a lock-hopper system, which is controlled with a sequence program (on the basis of hourly slag make). The slag is non-leachable and classified as non-hazardous (Dutch and US regulations).

Dry Solids Removal

The target for overall solids removal from the syngas has a maximum value of 1 mg/Nm³ of solids in the syngas after the Wet Scrubber. This target is reached by means of a commercially demonstrated high pressure, high temperature (HPHT) filter system that will remove 99.9% of the entrained solids in the syngas stream.

The lock-hopper operation is controlled with a sequential program as a part of the DCS of the plant. Proper tracing is required to avoid dew-point corrosion and to avoid sluicing problems. Properties of the dry fly ash are dependent on ash composition. Nevertheless, the carbon content of the dry fly ash is low allowing selling the ash to cement or ceramic industry.

Wet Scrubbing

The gas leaving the dry solids removal in the SGC configuration is further processed by passing through a wet scrubbing system which consists of a venturi scrubber and a packed bed wash column. The only specific design aspects are material of construction and selection/design of packing, water (circulation) lines, water distributor and circulation pump, such that they can handle solids containing water streams during upsets. Caustic is injected into the scrubber to keep the pH in the circulation loops close to neutral.

Residual solids, as well as halide contents are reduced to <<1 ppmv. Other acidic compounds, like formic acid, are removed to a large extent, while ammonia removal is minimal. The design capacity is based on the maximum syngas flow.

Primary Waste Water Treatment

The primary waste water treatment system contains one slurry stripper and a solid/liquid separation step. The design capacity is set, in principle, by the maximum bleed from slag bath and wet scrubbing systems.

The only specific design aspect for this system is the selection/design of packing, water (circulation) lines, water distributor, and circulation pumps such that they can handle slurries. Acid is injected to prevent scale formation in these systems.

Recommendation on Water Gas Shift

The water gas shift, also called CO shift, $CO + H_2O \rightarrow CO_2 + H_2$, is well known as a common industrial process. In IGCC with carbon capture, its main function is to convert CO in the syngas to CO_2 so that CO_2 can be captured via the gas treating unit. The steam consumption in the WGS unit leads to a considerable energy efficiency penalty of IGCC with carbon capture.

Shell proposes a hybrid WGS scheme for the application of SCGP IGCC with carbon capture. The first WGS reactor is low steam shift reactor, converting about 35% of CO to CO_2; the catalyst is designed to completely suppress unwanted methanation under these relatively dry conditions. This is followed by a conventional sour tolerant 2-stage WGS to convert the rest CO. Such a scheme is designed to minimize the steam consumption of the WGS unit, and amount of condensate to Sour Water Stripper.

With the proposed scheme, the overall CO conversion ratio is above 98% and water content at the third shift reactor outlet is about 19.30 %mol.

3.1.3. *Process Data*

This section contains the feed and product information for the normal operating conditions (NOC) case.

Syngas composition and conditions at wet scrubber outlet, dry basis (gasifier B.L.)

Syngas at wet scrubber outlet	
	% mol, dry basis
H_2O	0.00
H_2	29.63
CO	58.03
CO_2	3.03
N_2	8.09
Ar	0.84
H_2S	0.27
	ppm
COS	<310
NH_3	<310
HCN	<310
CH_4	<125
Pressure, barg	40

Syngas at wet scrubber outlet	
Syngas to B.L., kmol/s	3.96
Syngas to B.L., kg/s	82.70
$CO + H_2$ to B.L., kNm^3/h	279.6
Syngas LHV, MWth	940.8

Notes:
1) Syngas exit of wet scrubber is saturated by water. Moisture content will be determined by syngas pressure and temperature.
2) All process condensate available downstream the gas treating section should be sent back to the gasification unit after ammonia (NH_3<200 ppm wt) stripping and without cooling. This ensures that the syngas can be saturated with water vapour at the estimated temperature and pressure.

Main Input and output streams to CMD unit (per gasifier)

	T (°C)	P (MPa)	Flow (t/d)	Note
Input				
Raw Coal AR basis	ambient	ambient	3,867	
Fluxant	ambient	ambient	112	2
Output				
Coal from CMD to Coal Pressurization and Feeding	105	5.3	3,757	3

Notes:
1) Slag fines from Gasification Island is recycled to CMD, dry basis
2) Limestone will be used as fluxing agent with assumed composition of CaCO3 100%
3) Coal will be dried to 1.3 % moisture content at exit of the dryer.

Main Input and output streams to SCGP unit (per gasifier)

	T (°C)	P (MPa)	Flow (t/d)	Note
Input				
Coal from CMD to Coal Pressurization and Feeding	105	5.3	3,757	
Oxygen	25	4.7	3,074	2
Moderator Steam	300	5.2	221	
Condensate to scrubber	95	5.0	1,814	1
Gasification and CMD power consumption	13 MW			
Output				
Crude Syngas, at gasification island outlet	167	4.0	8,628	
Slag	<80	ambient	337	

Fly ash (dry)	<100	ambient	197	
Effluent water	<50	0.5	340	1

Notes:
1) Preliminary figure.
2) O_2 purity: 95%

Main Input and output BFW / steam / condensate streams (per gasifier)

	T (°C)	P (MPa)	Flow (t/d)	Note
Input				
HP BFW	160	14.9	5,800	
MP BFW	160	5.9	1,332	
Output				
HP Saturated Steam (at B.L.)	332	13.0	5,703	
MP Saturated Steam (at B.L.)	265	5.2	1,051	

Main Input and output utilities streams to gasification island (per gasifier)

	T (°C)	P (MPa)	Flow (t/d)	Note
Input				
Fresh Water	Ambient	0.4	52	1
Cooling Water supply	32	0.4	36,667	1
LP Steam	148	0.35	164	1
Caustic, 20% wt	Ambient	5.0	7	1
Acid, 15% wt HCl	Ambient	0.35	3	1
Output				
Cooling Water return	42	0.25	36,667	1

Notes:
1) Preliminary figure.

3.1.4. *Plot Plan*

Reference plot areas for the main process blocks (single train) are indicated in the following table.

Reference project	Plot dimensions L X W (m x m)	Capacity Feedstock (t/d)	Scope
Buggenum, the Netherlands	300 x 250	2000	Power block, Gasification (including CMD), ASU, Gas treating, Water treating
Dongting, China	200 x 200	2000	ASU, Gasification (including CMD), Slag yard

3.1.5. *Capital Investment Costs*

The capital cost estimate reported in the following table, with an accuracy range of -35% / +35%, is based on the investment cost of other Shell gasification projects in China (2012).

It is assumed that the currency exchange rate of Euro/RMB is 8, and the cost factor of the Rest of the world vs. China is 2.0.

	Direct Investment, Million Euro (2012)	
Syngas capacity	Single gasifier train 940 MWth	Total two trains 1880 MWth
Total direct cost, MM€	**237.5**	**475**

Direct costs of the plant include Coal Milling and Drying, Coal pressurization and feeding, Gasification and SC, Slag and dry solids removal, Wet scrubbing, Primary water treatment, gasification utilities, coal yard, handling / conveying facilities and gasification facilities.

3.1.6. *Availability Data*

Based on the track record of SCGP, Shell expects the following availability data:

1st year 60 %

2nd year 80 %

3rd year 90 %

The above mentioned values include scheduled maintenance.

3.1.7. *Technology Experience (References)*

The following table details the SCGP reference list on various applications; such as power, hydrogen, ammonia and methanol plants.

Plants in operation:

Owner	Location	Feedstock (t/d)	Syngas x10^6 Nm^3/d	Final Product	Start-up date
Shell/Koppers	Harburg, Germany	150	0.2	Syngas	1980°
Shell	Houston, USA	200	0.3	Syngas	1985°
NUON Power	Buggenum,The Netherlands	2000	3.4	Power	1994
Shuanghuan Chem.	Yingcheng, Hubei, PRC	900	1.3	Ammonia	Q2 2006
Sinopec/Shell	Dongting, Hunan, PRC	2000	3.4	Ammonia	Q4 2006
Sinopec Hubei	Zhijiang, Hubei, PRC	2000	3.4	Ammonia	Q4 2006
Sinopec	Anqing, Anhui, PRC	2000	3.4	Ammonia	Q4 2006

Anqing					
Liuhua Chem.	Liuzhou, Guanxi, PRC	1200	1.7	Ammonia	Q1 2007
Yuntianhua	Anning, Yunnan, PRC	2700	3.4	Ammonia	Q2 2008
Yunzhanhua	Huashan, Yunnan, PRC	2700	3.4	Ammonia	Q2 2008
Shenhua DCL	Majiata, Inner Mongolia, PRC	2x2250	7.3	Hydrogen	Q2 2008
Yongcheng Chem	Yongcheng, Henan, PRC	2150	3.1	Methanol	Q2 2008
Zhongyuan Dahua	Puyang, Henan, PRC	2100	3.1	Methanol	Q2 2008
Kaixiang	Yima, Henan, PRC	1100	1.7	Methanol	Q3 2008
Dahua Chem.	Dalian, Liaoning, PRC	1100	1.7	Methanol	Q4 2009
Datang	InnerMongolia, PRC	3x4000	11.3	Methanol	Q4 2010
Tianjin Soda	Tianjin, PRC	2x2050	6.4	Methanol	Q4 2010
Tianfu	GuiZhou, PRC	2050	3.1	Ammonia/ DME	Q4 2010
Vinachem	Ninh Puc, Vietnam	1350	2.2	Ammonia	Q2 2012
Shuifu	Shuifu, Yunnan, PRC	1100	1.7	Methanol	Q2 2012
Hebi	Hebi City, Henan, PRC	2750	4.0	Methanol	2013

° Plant now scrapped

Plants under start-up / construction / design:

Owner	Location	Feedstock (t/d)	Syngas x10^6 Nm^3/d	Final Product	Start-up date
Datong	Datong, Shanxi, PRC	2750	4.0	Methanol	2013
Wison	Nanjing, PRC	900	Not disclosed	Chemicals	2013
Habac fertilizer	Ha Bac, Vietnam	1350	2.0	Ammonia	2014
KOWEPO	Teaen-Eub, Korea	2650	4.2	IGCC	2015
Not disclosed	Shanxi Province, PRC	4x3000	19.8	Liquids	2015
Kaixiang Phase II	Yima, Henan, PRC	1100	1.7	Methanol	2015
2Co Energy	Hatfield, UK	Not disclosed	Not disclosed	Power	t.b.a
Perdaman	Australia	2x4000	9.4	Ammonia	t.b.a

3.2. GE Energy gasification

3.2.1. *Introduction*

The purpose of this section is to summarize the information received from GE Energy on the Gasification Island (GI), constituting the basic information on which the technical and economical analysis of the GE Energy IGCC cases of the study have been performed.

3.2.2. *Process Description*

The Gasification Island employs the GE's gasification process to convert coal into syngas. In the study, the Radiant Syngas Cooler (RSC) is analyzed.

The Gasification Island includes the following units, briefly described in the following sections making reference to the block flow diagram in Figure 11.

- Coal Grinding & Slurry Preparation;
- Gasification (RSC) & Scrubbing;
- Black Water Flash & Coarse Slag Handling;
- Grey Water & Fines Handling.

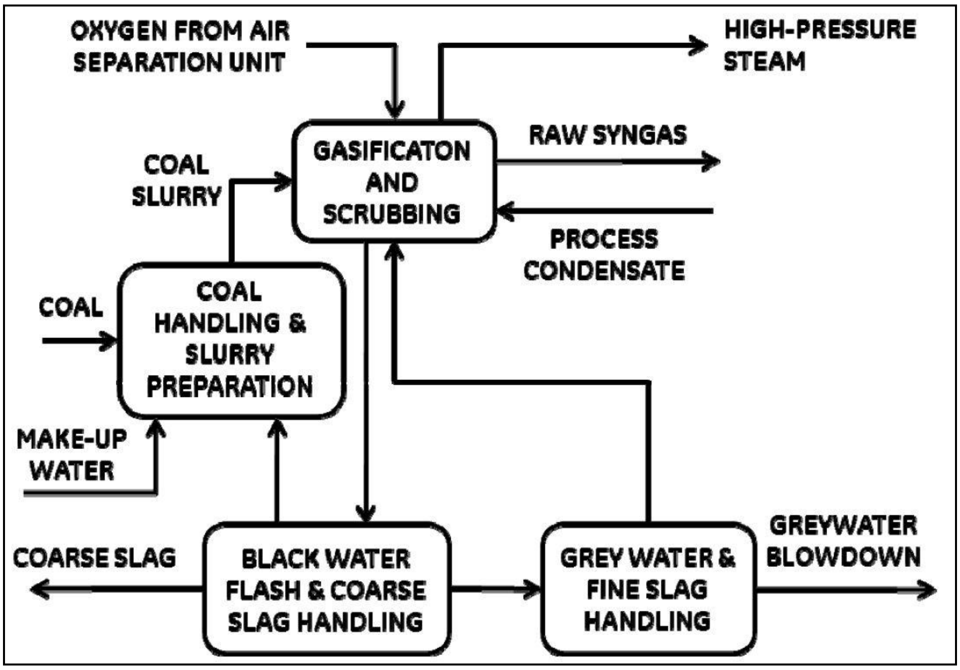


Figure 11. GE RSC - Preliminary Block Flow Diagram

Coal Grinding & Slurry Preparation

The coal grinding and slurry preparation system is dedicated to the preparation of the coal slurry feed for the gasifier.

Solid feedstock from offsite is continuously conveyed to a weigh feeder system that regulates the solid feed rate to the grinding mill. Fine slag may also be recycled into the grinding mill, which provides a means to prepare the solid as slurry feed for the gasifier. Grey water and/or fresh water are then used to slurry the grinding mill feed.

A fluxant system may be required based upon feedstock properties or if desired for future feedstock flexibility.

The slurry is transferred to a gasifier train by the slurry charge pump which provides a controlled flow of slurry to the gasifier feed injector.

Gasification & Scrubbing

A Gasification and Scrubbing train includes a Radiant-only Gasifier with high-pressure steam production, followed by a direct water quench cooling system.

The radiant-only gasifier is a refractory lined vessel capable of withstanding high temperatures and pressures. The coal slurry from the slurry run tank and oxygen from the air separation unit are fed and mixed through a gasifier feed injector and react at very high temperatures (approximately 1400°C). The pursuing partial oxidation reaction generates slag and syngas with a high hydrogen and carbon monoxide content, lesser content of water vapor, carbon dioxide, hydrogen sulfide, methane, nitrogen, and traces of carbonyl sulfide (COS) and ammonia. The ash content of the coal feed melts in the gasifier and transforms into slag.

The tip of the Feed Injector is protected from the high temperatures in the Gasifier by a water jacket and cooling coils through which cooling water is continuously circulated.

From the gasifier vessel, the hot syngas and slag from the reaction chamber flow down into the Radiant Syngas Cooler (RSC) chamber. The RSC is a high-pressure steam generator equipped with a circulating boiler feed water wall to protect the vessel shell. Heat is transferred primarily by radiation from the hot syngas to the circulating BFW. The high-pressure steam flows to a liquid disengagement system and then to the high-pressure steam header for Power Generation and/or export to other applications. In the RSC chamber, the raw syngas from the radiant section is first cooled by direct contact with water, and then sent to the Syngas Scrubber for cooling, condensation of water vapor, and removal of particulates by scrubbing with water.

The syngas from the overhead of the Syngas Scrubber is routed to the Low Temperature Gas Cooling section (out of the GE's scope). The bottom of the RSC vessel receives a portion of the syngas scrubber bottoms for cooling of the raw syngas and solidification of the molten slag. The water also wets the slag solids and assists its removal to the Lock Hopper.

Black Water & Coarse Slag Handling

The purpose of the black water flash system is to recover heat from the black water and to remove dissolved syngas, possibly requiring a deaerator (or sour water stripper) to provide deaerated return water to the syngas scrubber.

Black water from the RSC chamber and from the syngas scrubber is letdown and partially flashed through a series of flash stages the last of which is a vacuum flash stage. The flash stages serve to remove dissolved gases from the black water and to lower the black water temperature. The removed dissolved gases are routed to either a sour water stripper or offsite for treatment. Following the flashes, the black water is pumped to the gravity settler, which is part of the grey water handling system.

Black water from the vacuum flash vessel flows to the gravity settler where the solids are concentrated. A small amount of flocculent may be added upstream of the gravity settler to improve the settling efficiency. The gravity settler contains a slow moving rake that keeps the concentrated fine slag solids moving towards the bottom outlet. The concentrated gravity settler bottoms is either recycled to the grinding mill or pumped to filter feed tank in the fines filtration system.

The overflow water from the gravity settler (grey water) flows to the grey water tank. A slag crusher at the bottom of the radiant syngas cooler crushes the coarse slag which then gravity flows into the lockhopper, where an automated batch process is used for the collection of the solids. Once a solids collection cycle is complete, the lockhopper is isolated from the radiant gasifier, depressurized, flushed into a slag sump, re-pressurized, and opened to the radiant syngas cooler.

In the slag sump, slag settles onto a submerged slag drag conveyor, which separates the slag from the water. The coarse slag is dumped into trucks for removal offsite while the water removed from the slag is pumped to the black water flash system.

Grey Water & Fines Handling

The purpose of the grey water handling system is to concentrate solids in black water and to provide surge capacity for the grey water.

Black water from the vacuum flash vessel flows to the gravity settler where solids are concentrated. A small amount of flocculant may be added upstream of the gravity settler to improve settling efficiency.

The gravity settler contains a slow moving rake that keeps the concentrated fine slag solids moving towards the bottom outlet. The concentrated gravity settler bottoms is either sent to the filter (to be discharged as soot) and/or recycled to the grinding mill (to reduce soot disposal cost). The overflow water from the gravity settler (grey water) flows to the grey water tank, essentially free of particulates.

A low pressure grey water pump returns part of grey water to the lockhopper flash drum and the remaining water is blown down as grey water blowdown.

The high pressure grey water pump re-circulates grey water to the syngas scrubber through the deaerator.

3.2.3. *Process Data*

This section contains the feed and product information for the normal operating conditions (NOC) case.

Configuration and Charge to Gasifiers

Total Number of Gasifier Trains	2 operating + 0 spare
Feed charge rate	7728 t/d (dry basis)
Fluxant rate (100% ash)	114 t/d
Oxygen feed (pure basis)	220893 Nm^3/h
Gasifier operating pressure	65.5 barg

Syngas Product at Scrubber Overhead

Raw syngas composition	% mol
CO	22.6
H_2	18.9
CO_2	9.4
H_2O	47.2
Ar + N_2	1.7
H_2S + COS	0.2
Total	100.0
H_2 + CO flowrate	$13.4 \cdot 10^6$ Nm^3/d
Temperature	229°C
Pressure	63.6 barg

High-pressure Steam produced

HP Steam flowrate	19330 t/d
Temperature	336°C
Pressure	138 barg

Other major by-products

Coarse Slag Slag Water	1086 t/d (dry basis) 45200 kg/h 45200 kg/h
Grey Water Blow-down	1630 l/d

Preliminary Utility summary

Boiler Feed Water	810 t/h
Cooling Water	4400 t/h
Process Make-up Water	150 t/h
Electricity	9100 kWe

3.2.4. *Preliminary Plot Area*

The following scheme represents a preliminary plot area for the gasification island.

3.2.5. *Plant Cost Estimate*

The Capital Cost Estimate for the GE's Radiant gasification technology is reported in the following table, reflective of two (2) gasification trains and limited to GE Energy's gasification package as described in Section 3.2.2.

In addition to the process units listed above, the estimates include a Balance of Plant (BOP) category to account for utilities, interconnecting piping, pipe rack, roads, and buildings for GE's estimate scope. In these estimates, BOP is calculated based on a ratio of the direct cost estimates.

DESCRIPTION	1Q2013 Million US Dollars (USGC basis)
Gasification Process Blocks	640
Balance of Plant (BOP)	210
Subtotal Direct Costs	**850**
Indirect Construction Costs, Engineering & Home Office Services, Contingency, EPC Fee	630
Sales/Use/Local Taxes/Owner's Cost	Excluded
Total Estimated Cost	**1480**

The capital cost estimates are factored estimates within an accuracy range of and have been developed by GE Energy by comparing these configurations to other GE Energy projects of similar feed, capacity, trains, and scope.

Indirect construction costs reflect such things as construction equipment, temporary facilities, craft payroll taxes & social security, contractor home office and field staff, small tools, etc.

3.2.6. *O&M Costs*

The solid-fed Gasification Operating & Maintenance (O&M) budget consists of fixed and variable costs which generally correspond to 3-5% of all-in plant cost for the facility.

3.2.7. *Technology Experience (references)*

The total number of facilities licensed by GE Energy is 90, which includes 21 licensed facilities in engineering, design, and construction phase.

The following table details the licensed facilities based on solid feedstock.

	Location	Feedstock	End Product	Startup	Mode[1]
1	USA	Coal	Methanol/Acetic Acid	1983	A
2	Japan	Pet. Coke	Ammonia	1984	A
3	China	Coal	Ammonia	1993	A
4	China	Coal	Town Gas/Chemicals	1995	A
5	China	Coal	Ammonia	1996/2010	A
6	USA	Coal/Pet. Coke[2]	Power	1996	B
7	China	Coal	Ammonia	2000	A
8	USA	Petroleum Coke	Ammonia	2000	A
9	China	Coal	Ammonia/Urea	2004	A
10	China	Coal	Ammonia/Hydrogen	2005	A
11	China	Coal	Methanol	2005/2008	A
12	China	Coal	Ammonia/Urea	2006	A
13	China	Coal	Methanol	2007/2009	A
14	China	Coal	Methanol	2007	A
15	China	Coal/Pet. Coke	Methanol	2008	A
16	China	Coal	Methanol	2008	A
17	China	Coal	Methanol	2009	A
18	China	Coal	Ammonia	2009	A
19	China	Coal	Methanol	2010	A
20	China	Coal	Oxochemicals	2010	A
21	China	Coal	Methanol	2010	A
Engineering, Design & Construction					
22	Russia	Petroleum Coke	Power & Steam	2015*	A
23	China	Coal	Methanol/Ammonia	2011*	A
24	China	Coal	Ammonia/Urea	2011*	A
25	China	Coal	Methanol	2011*	A
26	China	Coal	Oxochemicals/Methanol	2011*	A
27	USA	Petroleum Coke	Methanol/Hydrogen	2014*	A
28	USA	Coal	Power & SNG	2012*	B
29	USA	Coal	Substitute Natural Gas	2012*	A
30	USA	Coal	Power	2012*	B
31	USA	Coal	Gasoline	2013*	A
32	USA	Petroleum Coke	Ammonia	2013*	A
33	USA	Petroleum Coke	Substitute Natural Gas	2013*	A
34	China	Coal	Methanol	2012*	A
35	China	Coal	Methanol	2013*	A
36	China	Coal	Ammonia	2012*	A
37	USA	Coal/Pet. Coke	Power/Hydrogen/CO2	2015*	A
38	China	Coal	Methanol	2012*	A
39	China	Coal	Methanol	2013*	A
40	China	Coal	Ammonia/Urea	2014*	A
41	China	Petroleum Coke / Coal	Hydrogen	2014*	A

Notes:
[1] Syngas cooling mode: A – direct water quench; B – syngas cooler; C – combination of A & B
[2] Originally configured for coal; then converted to pet coke

* Expected start-up date

3.3. Mitsubishi gasification

3.3.1. *Introduction*

The purpose of this section is to summarize the information received from Mitsubishi on the MHI gasification technology, representing the basic information on which the technical and economical analysis of the MHI gasification based IGCC alternative of the study (Case 4.3) have been performed.

3.3.2. *Process Description*

The Gasification Unit includes the following main sub-units, which are described briefly in the next sections:

- Coal Handling and Preparation.
- Gasifier.
- Syngas Cooler and Char Removal.
- Air Separation Unit.
- Gasification Air Booster Compressor.

Coal Handling and Preparation

The milling of the coal is part of the MHI scope and aimed at reducing the size of the raw coal to the requirement of the gasifier.

For each gasifier, coal is stored in three coalbunkers which feed associated 43% capacity pulverizers. After pulverizing process, the pulverized coal flows to lockhoppers. From the distribution hoppers, the coal is transported into the gasifier by nitrogen from the Air Separation Unit (ASU).

Gasifier

The MHI gasifier uses a dry feed design that avoids the need for mixing the pulverized coal feedstock with water as would otherwise be required by slurry transport designs. The MHI air-blown system also reduces the auxiliary power that would otherwise be consumed by a full-sized ASU required for oxygen-blown gasifiers and the high investment cost that goes with those larger ASU-based configurations. Since the nitrogen in the air (gasification agent) lowers the syngas temperature in the gasifier, special attention is required to ensure both the proper discharge of molten ash and maintaining a sufficiently high heat content in the syngas for stable burner operation in the gas turbine. MHI has adopted a two-stage gasification process as a solution to these issues.

MHI's gasifier design features an up-flow two-stage configuration that consists of two chambers: a lower combustor chamber and an upper reductor chamber. A description of the major features of this configuration is provided below, and illustrated in the Figure 12. The MHI gasifier configuration enables continuous molten slag discharge from the bottom of the gasifier, and overall higher carbon conversion to syngas, both within the same pressure vessel.

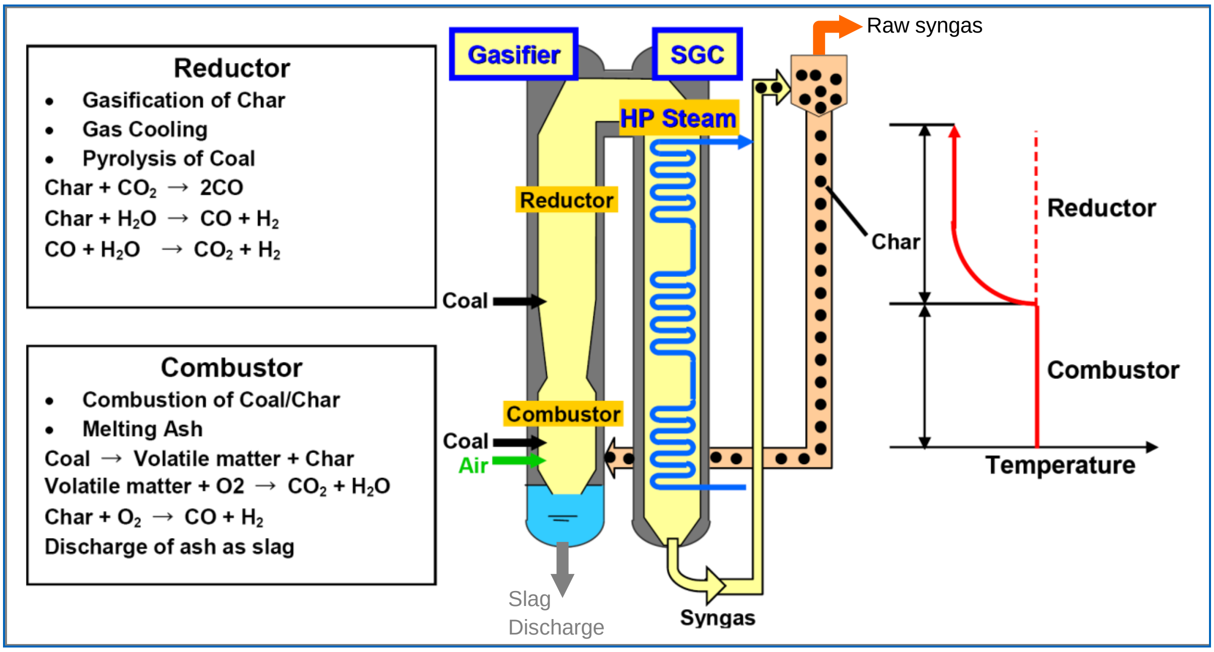


Figure 12. Operating principle of MHI Air-Blown two-stage entrained-bed gasifier

Gasifier – Stage one: Combustor

In the first stage, coal and recycled char are fed to the combustor chamber, along with the oxygen-enriched air at a relatively high air/fuel ratio. Both full and partial oxidation reactions take place to generate a mixture of gases, primarily CO and CO_2. Water vapour needed for "water shift" gasification reactions in the second stage is also generated here.

Water vapour is formed as a product of combustion involving the hydrocarbons contained in the coal volatile matter that are liberated from the coal by the intense heating in this stage. High temperatures enable the coal ash to separate from the gas stream in the form of molten slag.

The molten slag flows down to the bottom of the chamber, where it is quenched in water. The slag is recovered in the form of a glassy bead-like by-product with less than 0.1 percent unburned carbon. The slag is removed from the slag hopper and transported by conveyor to an outdoor storage pile. The slag is in a glassy form and contains virtually no leachable trace elements. The slag has a relatively high density, so the volume of slag is only about half that of the fly ash from a conventional pulverized coal plant. This slag has possible commercial applications as road paving materials or as a fine aggregate for concrete.

The air feed to the combustor section is enriched with oxygen to enhance this part of the process. Oxygen enrichment adds to the operating flexibility of the gasifier, and also increases the heating value of the syngas ultimately delivered to the gas turbine combustor. The gasifier has a "membrane water wall" configuration that eliminates the need for a refractory lining. An initial startup refractory lining is applied only for the inner surface of the combustor for protection until it is gradually replaced by the formation of a solid-state slag layer.

Gasifier – Stage two: Reductor

In the second stage, more coal is fed to the hot gas stream flowing upwards into the reductor, but no additional air is supplied. In this fuel-rich, low-oxygen environment, the key reactions take place such as gasification of char to CO, reduction of CO_2 to CO, reduction of H_2O to H_2, additional pyrolysis of coal, and subsequent gasification of products. These reactions are generally endothermic in nature, resulting in a drop in gas mixture temperature before the gas stream exits at the top the gasifier.

At this reduced temperature, solid particles containing char or ash carryover are hardened so that sticking and fouling of downstream heat exchanger surfaces is minimal.

Syngas Cooler and Char Removal

From the gasifier, the syngas flows to the syngas cooler where the gas is cooled and high-pressure (HP) steam is generated for further superheating and use in the power steam cycle. The cooler includes an economizer section, an evaporator section with steam drum, and two superheater sections. From the syngas cooler, the gas flows to the char recovery and feed system. This system removes the ash and char in the syngas and recycles it back into the gasifier. The system consists of a cyclone, a set of porous filters, storage bin and distribution lockhoppers.

Air Separation Unit

For MHI's air-blown gasifier, the majority of the gasification agent is supplied as air extracted from the gas turbine compressor. Nitrogen is also required for pneumatic coal feed to the gasifier from the distribution hoppers. Basically, the amount of oxygen that is generated as a by-product of ASU when required amount of nitrogen is withdrawn is fed to the combustor stage of the gasifier.

One full capacity air separation unit is provided to supply oxygen and nitrogen for both gasifier trains. Ambient air is compressed, cooled and dried by molecular sieves. By expansion and cooling, the temperature is lowered and the air is partially liquefied. The air is then distilled in a distillation column. This process produces oxygen at 95 percent purity and high purity nitrogen (<1 percent O_2). The oxygen is fed to the gasification unit to supplement the air. For each train, the nitrogen and oxygen are fed to the gasifier from the ASU by one full capacity compressor for each stream. A liquid nitrogen system is provided as a backup to the ASU for coal feeding.

Gasification Air Booster Compressor

Air is provided to the gasifier for the combustion/reduction processes by a motor drive booster air compressor. The air is supplied to the compressor from an extraction from the compressor of the gas turbine. One compressor is provided for each train.

3.3.3. *Process Flow Diagrams*

The simplified process flow diagram including details of each unit of the MHI Gasification Island is shown in Figure 13.

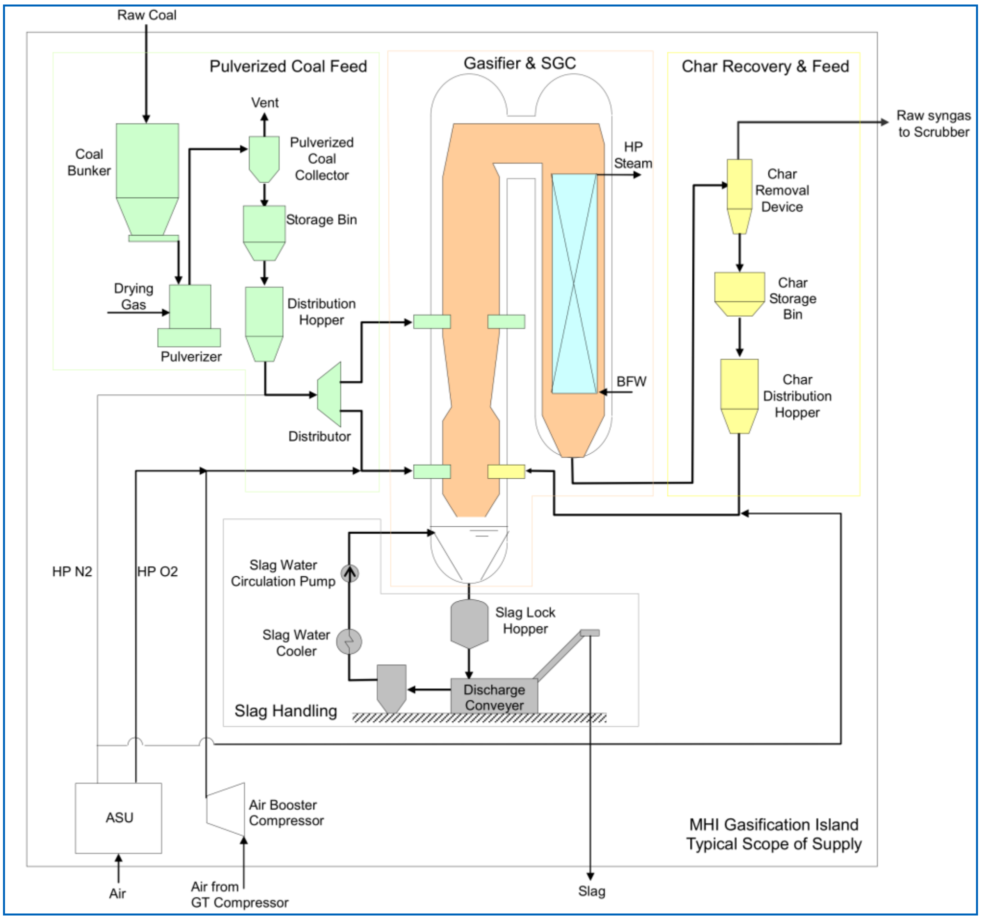


Figure 13. Typical Gasification Plant Process Flow Diagram

3.3.4. References

The operation experience of MHI air-blown gasifier is shown in following table.

Owner	Plant Name	Country	Site	Yr Start	Coal input t/day
CRIEPI	2t/d PDU	Japan	Yokosuka	1984	2.4
IGC Association	200t/d Pilot Plant	Japan	Nakoso	1993	200
MHI (R&D center)	24t/d pilot test plant	Japan	Nagasaki	1999	24
Clean Coal Power	IGCC Demo. Plant	Japan	Nakoso	2007	1,700

The IGCC Demo. Plant, evaluated as 'very successful' by the owner and the Japanese government, finished its demonstration operation, and was shifted to the first commercial plant in Japan in April of 2013. Its new owner and the plant name are 'Joban Joint Company, Ltd.' and 'Nakoso Unit No. 10 IGCC Plant'.

Here below the performance details of the IGCC Demo plant of Nakoso based on MHI's two-stage entrained-bed, pressurized, air-blown gasifiers. The experience of the MHI gasifier with different types of coal is shown in the Figure 14 and includes the tests done in the Nakoso plant.

		Targets	Achievements	Note
Performance	Output	250MW	250MW	
	Efficiency (Net, LHV)	> 42.0%	42.9%	
	Carbon Conversion	> 99.9%	> 99.9%	
Emission (@dry, 16%O2)	SOx NOx Dust	< 8 ppm < 5 ppm < 4 mg/m³N	1.0 ppm 3.4 ppm < 0.1 mg/m³N	
Operational Flexibility	Coal Kinds	Bituminous Sub-bituminous	Chinese, Canadian 2 US (includ. PRB) 3 Indonesian Subs Colombian, Russian	Continuously expanding
	Start-up Time	< 18 hr	15 hr	
	Minimum Load	50%	36%	
	Ramping Rate	3%/min	3%/min	
Reliability	Long-term Continuous Operation	2,000 hr	2,238 hr	
	Long-Term Reliability Run	5,000 hr	5,013 hr	Accumulated operating hours exceeded 20,000 hrs.
	Availability (Feb.2011-Jan.2012)	–	84 %	Except Tsunami and scheduled shutdown

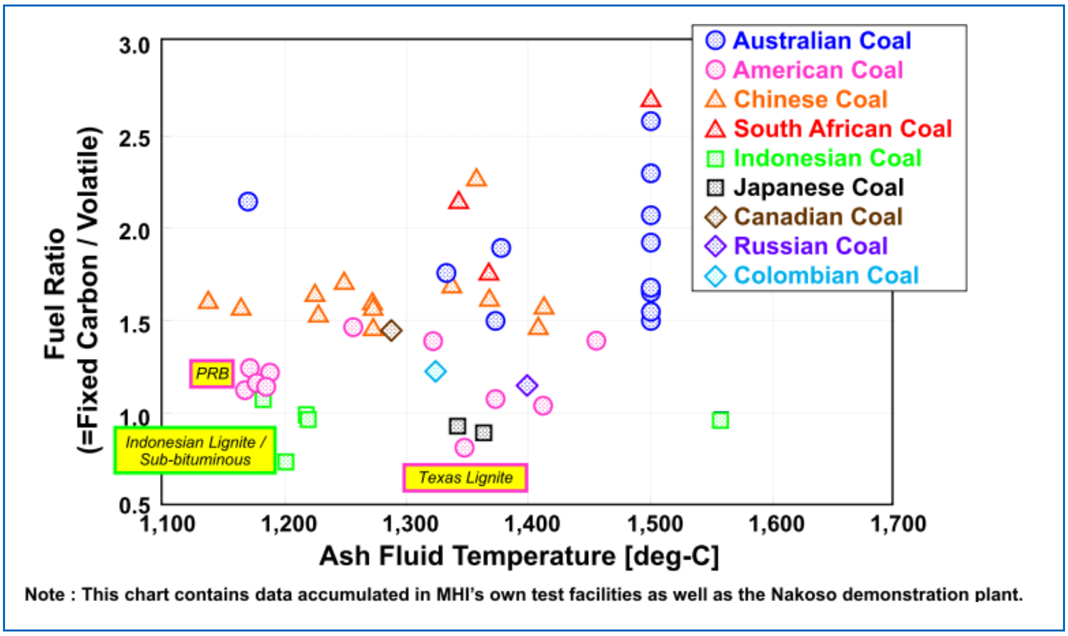


Figure 14. Coal types tested in the MHI Air-Blown Gasifier

CLIENT : IEAGHG
PROJECT NAME : CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
DOCUMENT NAME : CASE 4.1: IGCC WITH CCS – SHELL GASIFICATION TECHNOLOGY
FWI CONTRACT : 1-BD-0681 A

ISSUED BY : L. CASTRONUOVO
CHECKED BY : N. FERRARI
APPROVED BY : L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

1. Introduction

This Chapter of the report includes all technical information relevant to Case 4.1 of the study, which is an IGCC plant based on the Shell gasification technology. The plant is designed to process coal, whose characteristic is shown in chapter B, and produce electric power for export to the external grid, with capture of the generated carbon dioxide.

The configuration of the plant is based on the following main features:

- Medium-pressure (40 barg) Shell Coal Gasification Process (SCGP), with dry-feed system and Synthesis Gas Cooler;
- Hybrid CO shift stage, as recommended by Shell, followed by 2-stages sour shift;
- Removal of acid gases (H_2S and CO_2), based on Selexol physical solvent process;
- Oxygen-blown Claus unit, with tail gas catalytic treatment and recycle of the treated tail gas to the AGR;
- CO_2 compression and dehydration unit;
- Combined cycle based on two F-class gas turbines.

The description of the main process units is covered in chapter E of this report, so only features that are unique to this case are discussed in the following sections, together with the main modelling results.

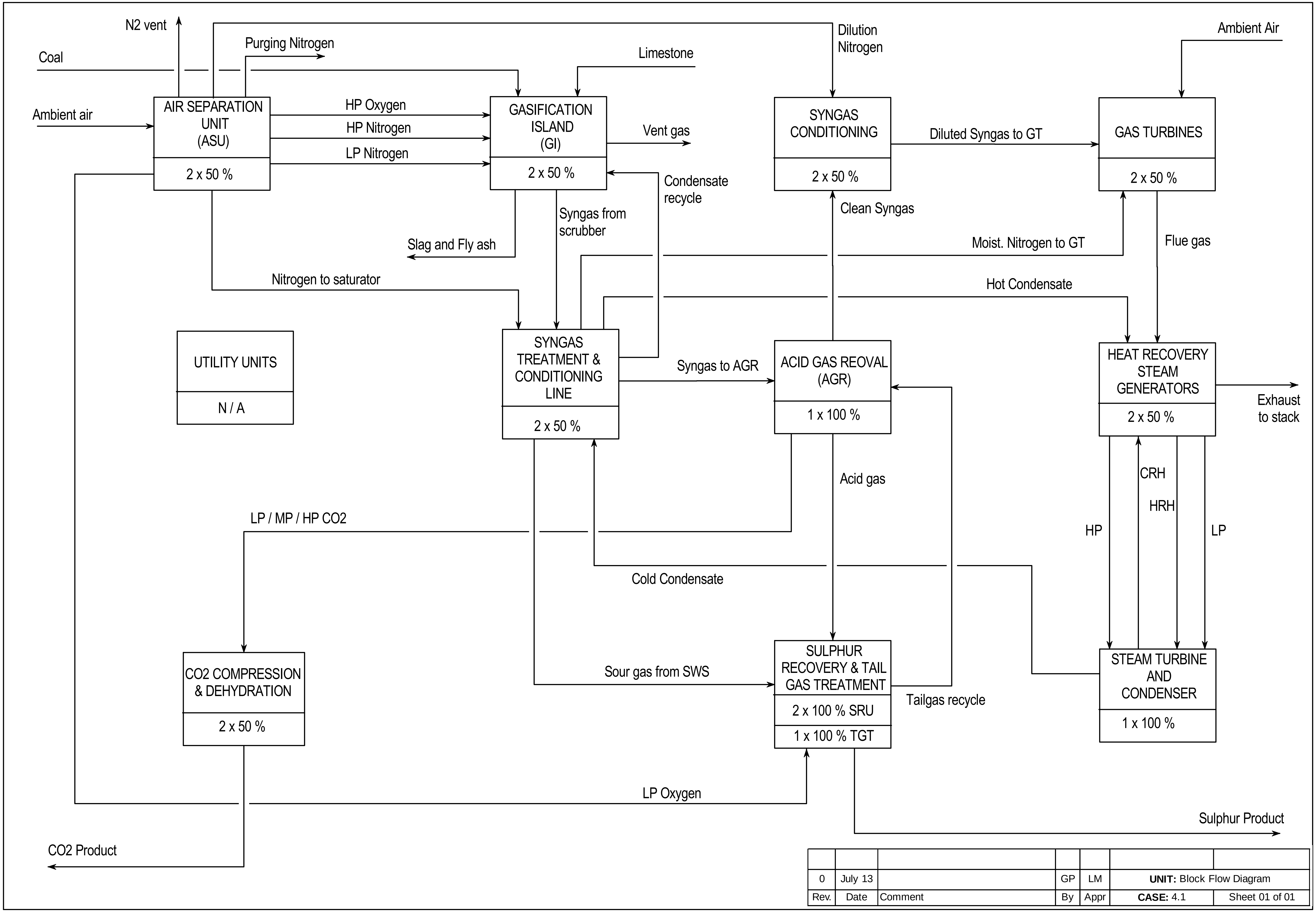
1.1. Process unit arrangement

The arrangement of the main units is reported in the following Table 1. Reference is also made to the block flow diagram attached below.

Table 1. Case 4.1 – Unit arrangement

Unit	Description	Trains
900	Solid Handling & Storage	N/A
1000	Coal Milling and Drying	4 x 33%
	Gasification	2 x 50%
	Coal Pressurization and Feeding	
	Gasification and Syngas Cooler	
	Slag Removal	
	Dry solids removal	

Unit	Description	Trains
	Wet Scrubbing	
	Primary Waste Water Treatment	
2100	Air Separation Unit	2 x 50%
2200	Syngas Treatment and Conditioning Line	2 x 50%
2250	Sour Water Stripper (SWS)	1 x 100%
2300	Acid Gas Removal	1 x 100%
2400	Sulphur Recovery Unit	2 x 100%
	Tail Gas Treatment	1 x 100%
2500	CO_2 Compression & Drying	2 x 50%
3000	Combined Cycle	
	Gas Turbine	2 x 50%
	HRSG	2 x 50%
	Steam Turbine	1 x 100%
4000	Utility and Offsite	N/A


N2 vent
Purging Nitrogen
Coal
Limestone
Dilution Nitrogen
Ambient Air
Ambient air
AIR SEPARATION UNIT (ASU)
2 x 50 %
HP Oxygen
HP Nitrogen
LP Nitrogen
GASIFICATION ISLAND (GI)
2 x 50 %
Vent gas
SYNGAS CONDITIONING
2 x 50 %
Diluted Syngas to GT
GAS TURBINES
2 x 50 %
Condensate recycle
Syngas from scrubber
Slag and Fly ash
Clean Syngas
Moist. Nitrogen to GT
Flue gas
Nitrogen to saturator
Hot Condensate
UTILITY UNITS
N / A
SYNGAS TREATMENT & CONDITIONING LINE
2 x 50 %
Syngas to AGR
ACID GAS REOVAL (AGR)
1 x 100 %
HEAT RECOVERY STEAM GENERATORS
2 x 50 %
Exhaust to stack
CRH
HRH
HP
LP
Acid gas
LP / MP / HP CO2
Cold Condensate
CO2 COMPRESSION & DEHYDRATION
2 x 50 %
Sour gas from SWS
SULPHUR RECOVERY & TAIL GAS TREATMENT
2 x 100 % SRU
1 x 100 % TGT
Tailgas recycle
STEAM TURBINE AND CONDENSER
1 x 100 %
LP Oxygen
Sulphur Product
CO2 Product
0
July 13
GP
LM
UNIT: Block Flow Diagram
Rev.
Date
Comment
By
Appr
CASE: 4.1
Sheet 01 of 01

2. Process description

2.1. Overview

The description reported in this section makes reference to the simplified Process Flow Diagrams (PFD) of section 3, while stream numbers refer to section 4, which provides heat and mass balance details for the numbered streams in the PFD.

2.2. Unit 900 – Solid Handling & Storage

The unit is composed of the following systems:

- Coal storage and handling
- Limestone storage and handling
- Fly ash collection and storage
- Slag storage

The general description relevant to this unit is reported in chapter E, section 2.1. Main process information of this case and the interconnections with the other units is shown in the relevant process flow diagram and the heat and mass balance table.

2.3. Unit 1000 – Gasification Island

This unit is mainly composed of the Coal Milling and Drying unit and the Shell Gasification Island (including Coal pressurization and feeding, Gasification and syngas cooling, syngas scrubber, slag removal, dry solids removal, primary waste water system, etc.). Technical information relevant to these packages is reported in chapter E, section 3.1.

The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

2.4. Unit 2100 – Air Separation Unit

Technical information relevant to this packaged unit is reported in chapter E, section 2.3. The main process information of the unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The sizing capacity of the Air Separation Unit is determined by the oxygen requirement of the gasification island and the SRU. The total required oxygen flowrate for the case is approximately 250 t/h.

The Air Separation unit supplies very high pressure nitrogen, used as carrier gas for the feed pneumatic transport system of the gasifier, and medium pressure nitrogen, used as diluent for the syngas or injected in the gas turbine for NOx suppression and power production augmentation.

2.5. Unit 2200 – Syngas Treatment and Conditioning line

The general description of this unit is shown in chapter E, section 2.4, while case-specific features are reported hereinafter. The main process information and the interconnections with the other units are shown in the relevant process flow diagram and the heat and mass balance tables.

Saturated raw syngas from the gasification scrubber, at approximately 40 barg, is heated-up in the Feed/Product Heat Exchanger, before entering the first shift reactor, in order to increase the temperature up to the level required for the proper operation of the shift catalyst.

In the shift unit, CO is shifted to H_2 and CO_2 and COS is converted to H_2S. Shell proposes a hybrid water gas shift (WGS) scheme for this case of the study. The first WGS reactor is low steam shift reactor, converting about 35% of CO to CO_2; the catalyst is designed to completely suppress unwanted methanation under these relatively dry conditions. This is followed by a conventional sour tolerant 2-stage WGS to convert the remaining CO. Such a scheme is designed to minimize the steam consumption of the WGS unit and amount of condensate to Sour Water Stripper, achieving an overall CO conversion greater than 98%.

Downstream the first shift reactor, after the feed/product heat exchanger, syngas is mixed with MP steam and BFW in order to ensure that the minimum water content in the syngas at third shift reactor outlet is around 20% mol, corresponding to a steam to dry gas ratio of about 0.25. Water injection has also the effect of reducing syngas temperature down to the level required for feeding the second shift reactor.

The partially-shifted syngas temperature is increased by the exothermic shift reaction, allowing for further thermal recovery. The syngas is cooled down in a series of heat exchangers, before being fed to the third reactor stage:

- HP Steam Generator,
- MP Steam Generator,
- LP Steam Generator #1.

After being cooled, the syngas is directed to the third and last shift reactor. The hot shifted syngas outlet from the last stage is again cooled in the following series of heat exchangers, to thermally recover heat and increase the power generation of the plant:

- LP Steam Generator #2,
- Nitrogen Saturator Circulating Water Heater,
- Condensate Pre-heater.

Final cooling of the syngas is made against clean syngas coming from the AGR, in a gas–gas exchanger, and against cooling water, before passing through a sulphur-impregnated activated carbon bed to remove approximately 95% of the mercury. Cool, mercury-depleted syngas then enters the AGR unit.

During the cooling of the syngas, the process condensate is separated and collected in the process condensate accumulator. Before being sent to the accumulator, the condensate from the last syngas separator, upstream the AGR, plus a portion of the condensate from the upstream separator, is sent to the Sour Water Stripper in order to avoid accumulation of ammonia and H_2S and other dissolved gases in the water recycle to the gasification section. Part of the condensate from the accumulator is sent to the Gasification Island, while the remainder condensate is sent to Waste Water Treatment Unit.

From the AGR unit, cool hydrogen rich gas returns to the syngas treatment and conditioning line as de-carbonized fuel gas after H_2S and CO_2 removal. The de-carbonized fuel gas is preheated in the syngas/syngas exchanger and against LP steam after being mixed with nitrogen, coming from the ASU, up to maximum hydrogen content of 65% molar. Finally, the diluted syngas is sent to the combined cycle at 155°C, for final heating against boiler feed water and combustion in the gas turbine.

The unit includes nitrogen saturator, generating moisturised nitrogen to be injected in the gas turbine. Nitrogen humidification is achieved by means of hot water heated in the syngas cooling line. The humidified nitrogen is finally heated using MP steam and then injected in the gas turbine combustion chamber.

2.6. Unit 2300 – Acid Gas Removal (AGR)

The AGR unit is intended to selectively remove H_2S and CO_2 in sequent steps by employing Selexol as physical solvent. Technical information relevant to this package is reported in chapter E, section 2.5. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The AGR is designed to meet the following process specifications of the treated gas and of the CO_2 product exiting the unit:

- The H_2S+COS concentration of the treated gas exiting the unit is around 1 ppmv. This is due to the integration of CO_2 removal with the H_2S removal, which makes available a large circulation of solvent that is cooled down by a refrigerant package before flowing to the CO_2 absorber.
- The CO_2 product is characterised by a content of incondensable around 2%, while simultaneously meeting the specification of H_2S content lower than 20 ppmv and CO content lower than 0.2% mol (actual 0.06% mol).
- The acid gas H_2S concentration is about 35% dry basis, suitable to feed the oxygen blown Claus process.

The CO_2 removal rate is 91.8% of the carbon dioxide entering the unit, allowing reaching an overall carbon capture of approximately 90% with respect to the carbon

in the syngas. These excellent performances on both the H_2S removal and CO_2 capture are achieved with significant power consumption and steam demand.

2.7. Unit 2400 – SRU and TGT

Technical information relevant to this package is reported in chapter E, section 2.5. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The SRU is designed to process the acid gas from the AGR and other minor acid streams, like the acid off-gas from the primary water treatment within the gasification island and the sour gases from the SWS, using low pressure oxygen from the ASU. In the furnace, H_2S is catalytically oxidized to SO_2 which is further reacted with H_2S to form H_2O and elemental sulphur. Following the thermal stage, sulphur is condensed, while the tail gas is hydrogenated and recycled back to the AGR unit at approximately 35 barg by means of a dedicated compressor.

The overall sulphur production is approximately 65 tons per day.

2.8. Unit 2500 – CO_2 compression and drying

This unit is mainly composed of a compression and dehydration package, followed by last stage CO_2 pumps, supplied by specialized vendors. Technical information relevant to this package is reported in chapter E, section 2.6. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

Three different streams of CO_2 from the Acid Gas Removal unit are routed to the CO_2 compression unit, delivered at approximately 9 barg, 2 barg, and 0.1 barg respectively.

The stream at lower pressure is initially compressed up to the pressure of the medium pressure stream and then combined with it. The resulting stream is compressed to allow the mixing with the last stream without any pressure loss. The combined stream is then compressed up to approximately 30 barg and sent to the dehydration system, which is a standard solid desiccant package that dehydrates the CO_2 stream to a dew point of -40°C. After dehydration, the CO_2 stream is finally compressed to a supercritical condition at 80 barg.

The resulting stream of CO_2 is pumped to the required pressure of 110 barg. The CO_2 product (approximately 97.9 % mol purity) is transported to the plant battery limits for final sequestration.

2.9. Unit 3000 – Combined cycle

Technical information relevant to these packages is reported in chapter E, section 2.10. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The diluted syngas exiting the syngas treatment and conditioning line is finally heated in the combined cycle using MP boiler feed water before entering the burners of the gas turbine at 210°C.

The gas turbine compressors provide combustion air to the burner only, i.e. no air integration with the ASU is foreseen. The exhaust gases from the gas turbine enter the HRSG at 560°C. The HRSG recovers heat available from the exhaust gas producing steam at three different pressure levels for the steam turbine, plus an additional steam generator with integral deaerator. The final exhaust gas temperature to the stack of the HRSG is 133°C. The calculated acid gas dew point temperature of the exhaust flue gas is around 90°C.

The Heat Transfer vs. Temperature of the HRSG (T-Q diagram) of case 4.1 is shown in Figure 1. The red line (the upper curve) represents the exhaust gases from the GT to the stack. The blue lines represent the water path in the economizers (at lower temperature), the steam generators (horizontal lines) and the super-heater/re-heater (at higher temperature).

The combined cycle is thermally integrated with the process unit, in order to maximize the net electrical efficiency of the plant. The main steam and water interfaces with the process units are given in Table 2.

2.10. Utility Units

These units comprise all the systems necessary to allow the operation of the plant and the export of the produced power.

The main utility units include:

- Cooling Water system, based on one natural draft cooling tower, with the following characteristics:

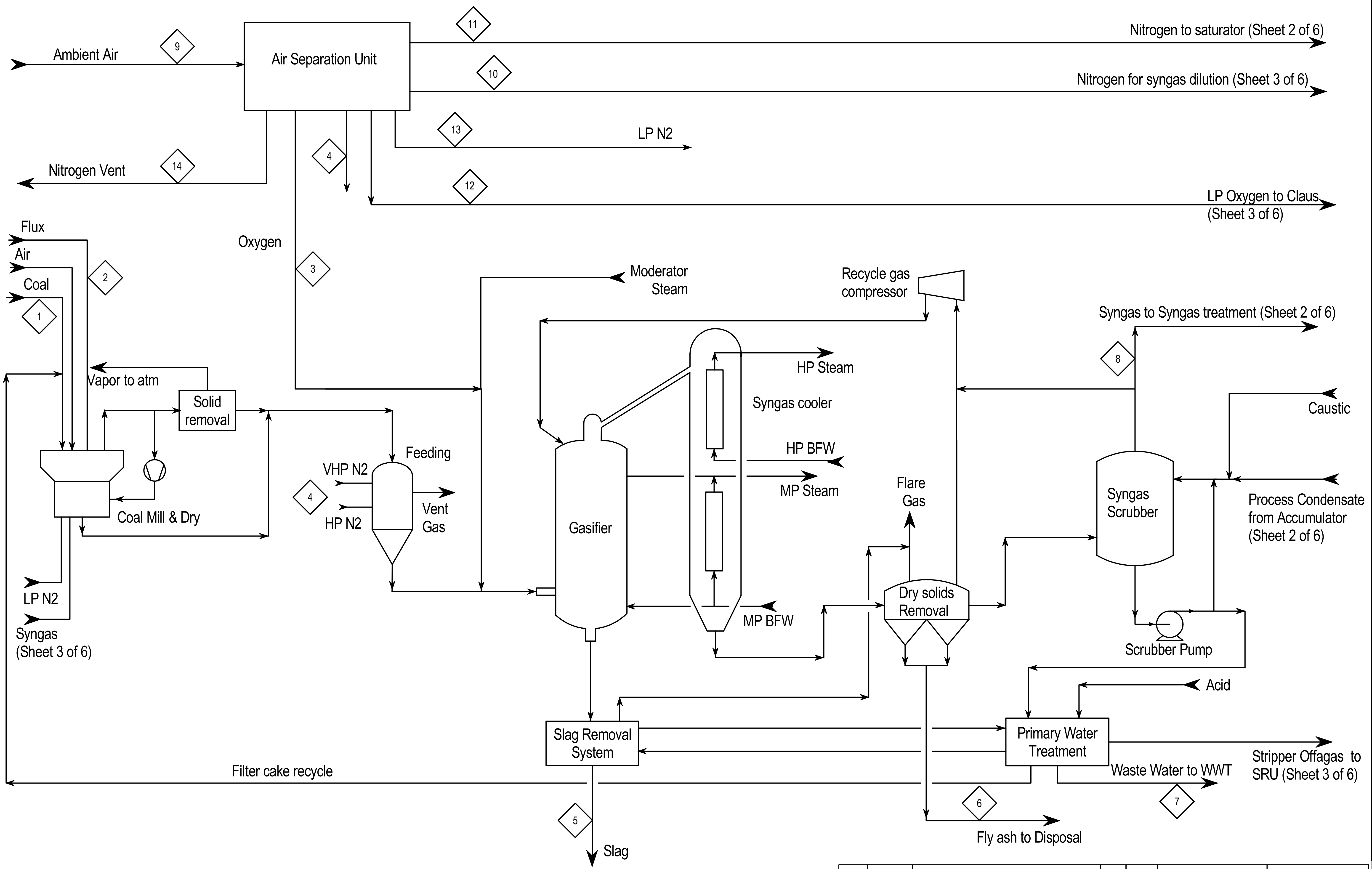
Basin diameter	145 m
Cooling tower height	210 m
Water inlet height	17 m

- Raw water system;
- Demineralised water plant;
- Fire fighting system;
- Instrument and Plant air.

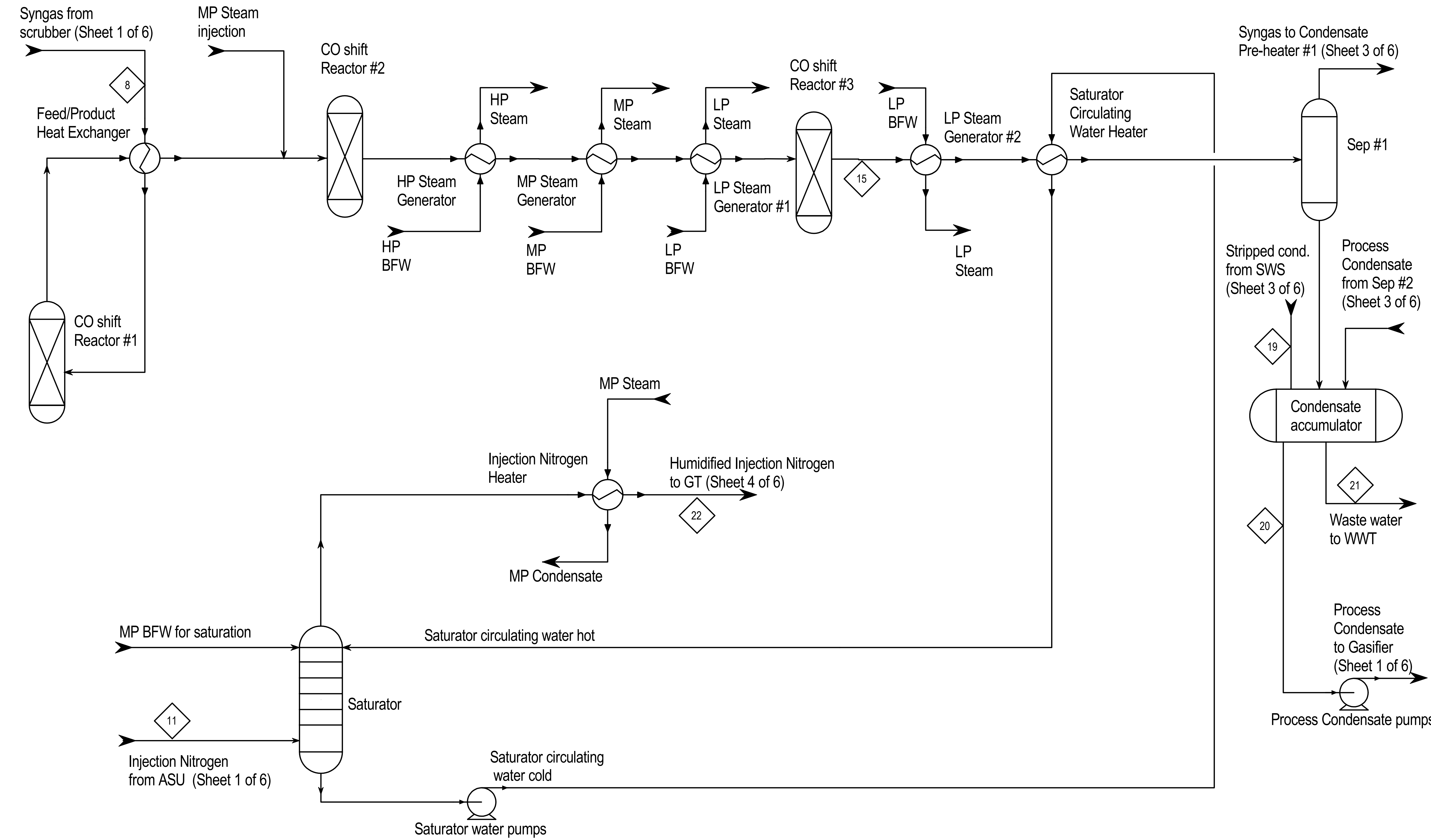
Process descriptions of the above systems are enclosed in chapter E, section 2.11.

3. Process Flow Diagrams

Simplified Process Flow Diagrams of this case are attached to this section. Stream numbers refer to the heat and material balance shown in the next section.

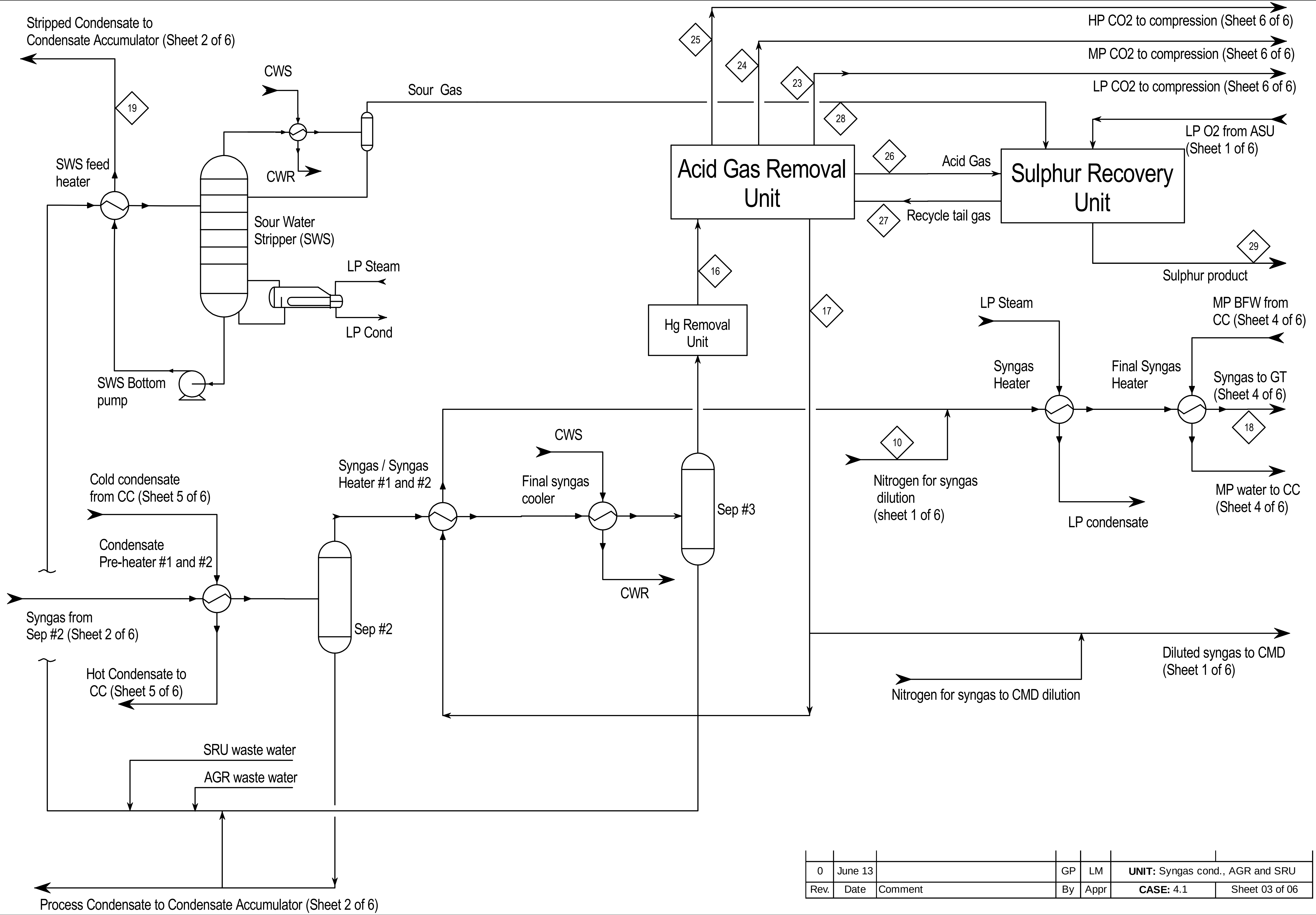


0	June 13		GP	LM	**UNIT:** Gasification and ASU	
Rev.	Date	Comment	By	Appr	**CASE:** 4.1	Sheet 01 of 06

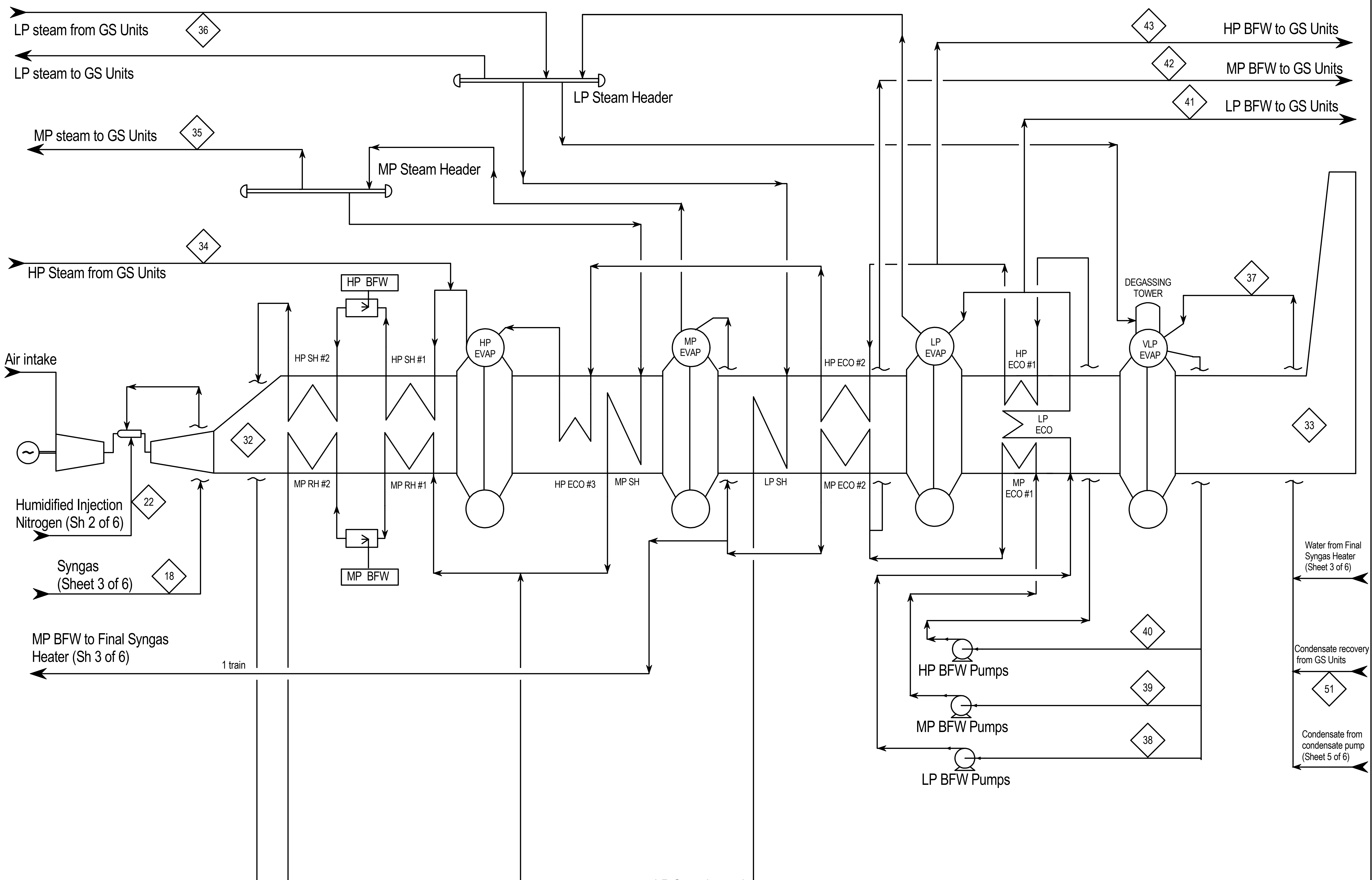


Note: Mass flowrates refer to both GS trains

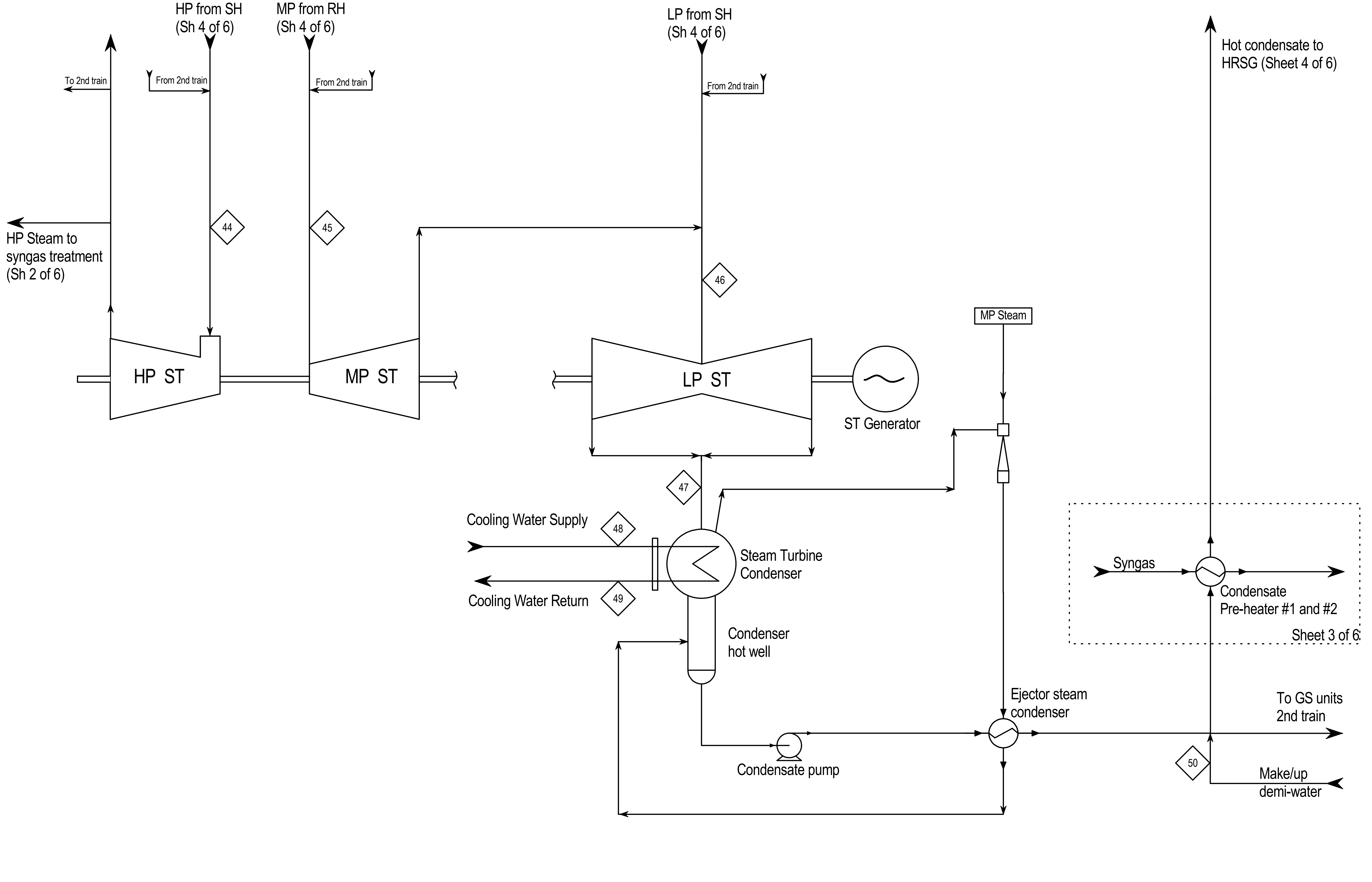
0	June 13		GP	LM	**UNIT:** Syngas treatment	
Rev.	Date	Comment	By	Appr	**CASE:** 4.1	Sheet 02 of 06



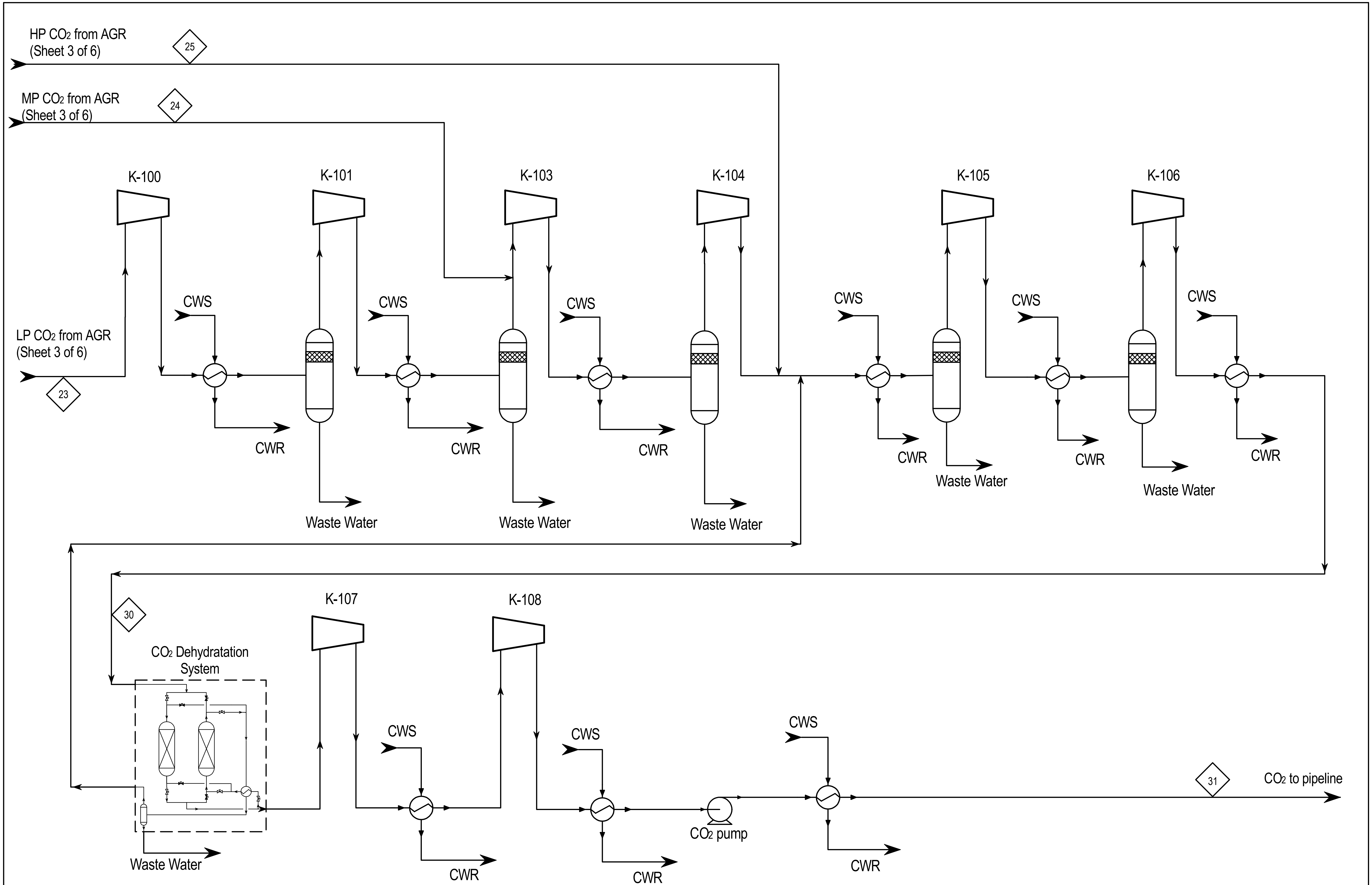
0	June 13		GP	LM	**UNIT:** Syngas cond., AGR and SRU	
Rev.	Date	Comment	By	Appr	**CASE:** 4.1	Sheet 03 of 06



0	June 13		GP	LM	**UNIT:** Gas Turbines and HRSG	
Rev.	Date	Comment	By	Appr	**CASE:** 4.1	Sheet 04 of 06



0	June 13		GP	LM	**UNIT:** Steam Turbine and Condenser	
Rev.	Date	Comment	By	Appr	**CASE:** 4.1	Sheet 05 of 06



0	June 13		GP	LM	**UNIT:** CO2 compression	
Rev.	Date	Comment	By	Appr	**CASE:** 4.1	Sheet 06 of 06

4. Heat and Material Balance

Heat & Material Balances here below reported make reference to the simplified Process Flow Diagrams of section 3.

FOSTER WHEELER	Case 4.1 - SHELL-BASED IGCC - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
	CLIENT :	IEA GHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 1000 - Gasification Island

STREAM	1	2	3	4	5	6	7	8		
	Coal to Gasification Island	Fluxant	HP Oxygen to Gasification	Nitrogen to Gasification	Slag from Gasification	Fly Ash from Gasification	Effluent Water from Gasification	Syngas at Scrubber Outlet to Shift Reactor		
Temperature (°C)	AMB	AMB	25	N/D	80	100	50	N/D		
Pressure (bar)	ATM	ATM	48	N/D (1)	ATM	ATM	ATM	41		
TOTAL FLOW	Solid				Dry solid	Dry solid				
Mass flow (kg/h)	314,900	9.1	250,285	N/D	27,400	16,000	27,700	581,973		
Molar flow (kmol/h)			7,768	N/D				27,832		
LIQUID PHASE										
Mass flow (kg/h)	-		-	-			27,700	-		
GASEOUS PHASE										
Mass flow (kg/h)			250,285	N/D				581,973		
Molar flow (kmol/h)			7,768	N/D				27,832		
Molecular Weight			32.2	28.0				20.9		
Composition (vol %)	%wt	100% $CaCO_3$						(dry basis)		
H_2	C: 64.6%		-	-				29.64		
CO	H: 4.38%		-	-				58.05		
CO_2	O: 7.02%		-	-				3.03		
N_2	S: 0.86%		1.50	99.999				8.09		
O_2	N: 1.41%		95.00	0.001				0.00		
CH_4	Cl: 0.03%		-	-				0.01		
H_2S + COS	Moisture: 9.5%		-	-				0.30		
Ar	Ash: 12.20%		3.50	-				0.84		
HCN			-	-				0.03		
NH_3			-	-				0.03		
H_2O			-	-				-		

Notes (1) LP, HP and VHP N_2

	Case 4.1 - SHELL-BASED IGCC - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEA GHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 2100 - Air Separation Unit

STREAM	9	3	4	10	11	12	13	14		
	Air Intake from Atmosphere	HP Oxygen to Gasification	Nitrogen to Gasification	MP Nitrogen for Syngas Dilution	MP Nitrogen to saturator for NOx Control	Oxygen to SRU	LP N_2	N_2 vent		
Temperature (°C)	AMB	25	N/D	122	122	AMB	N/D	AMB		
Pressure (bar)	ATM	48	N/D (1)	32	28	6	N/D	ATM		
TOTAL FLOW										
Mass flow (kg/h)	1,076,775	250,285	N/D	238,402	308,864	1,611	33,344	11,490		
Molar flow (kmol/h)	37,304	7,768	N/D	8,506	11,020	50	1,190	410		
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-	-	-	-		
GASEOUS PHASE										
Mass flow (kg/h)	1,076,775	250,285	N/D	238,402	308,864	1,611	33,344	11,490		
Molar flow (kmol/h)	37,304	7,768	N/D	8,506	11,020	50	1,190	410		
Molecular Weight	28.9	32.2	28.0	28.0	28.0	32.2	28.0	28.0		
Composition (vol %)										
H_2	-	-	-	-	-	-	-	-		
CO	-	-	-	-	-	-	-	-		
CO_2	0.04	-	-	0.05	0.05	-	-	0.05		
N_2	77.32	1.50	99.999	98.00	98.00	1.50	99.999	98.00		
O_2	20.75	95.00	0.001	1.00	1.00	95.00	0.001	1.00		
CH_4	-	-	-	-	-	-	-	-		
H_2S + COS	-	-	-	-	-	-	-	-		
Ar	0.92	3.50	-	0.25	0.25	3.50	-	0.25		
HCN	-	-	-	-	-	-	-	-		
NH_3	-	-	-	-	-	-	-	-		
H_2O	0.97	-	-	0.70	0.70	-	-	0.70		

Notes (1) LP, HP and VHP N_2

	Case 4.1 - SHELL-BASED IGCC - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEA GHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 2200 - Syngas cooling & Conditioning line

STREAM	8	15	16	17	18	19	20	21	11	22
	Syngas at Scrubber Outlet to Shift Reactor	Syngas from CO shift	Raw Syngas to Acid Gas Removal	Purified Syngas from Acid Gas Removal	Diluted Syngas to Combined Cycle	Condensate from SWS	Return Condensate to Gasification	Waste water to WWt	MP Nitrogen to saturator	Moist. N_2 to Combined Cycle
Temperature (°C)	N/D	231	34	15	210	115	95	78	122	210
Pressure (bar)	41	37.6	35	33.5	31.0	7	50	36	28.0	27.0
TOTAL FLOW										
Mass flow (kg/h)	581,973	1,063,296	868,184	188,947	425,147	30,700	147,700	50,460	308,864	387,047
Molar flow (kmol/h)	27,832	54,520	43,741	27,920	36,055	1,707	8,188		11,020	15,360
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-	30,700	147,700	50,460	-	-
GASEOUS PHASE										
Mass flow (kg/h)	581,973	1,063,296	868,184	188,947	425,147	-	-		308,864	387,047
Molar flow (kmol/h)	27,832	54,520	43,741	27,920	36,055	-	-		11,020	15,360
Molecular Weight	20.9	19.5	19.8	6.8	11.8	-	-		28.0	25.2
Composition (vol %)	(dry basis)									
H_2	29.64	44.16	55.02	85.08	65.00	-	-		-	0.00
CO	58.05	0.61	0.76	1.14	0.88	-	-		-	0.00
CO_2	3.03	30.59	38.08	4.91	3.77	-	-		0.05	0.04
N_2	8.09	4.13	5.14	8.00	29.22	-	-		98.00	70.29
O_2	0.00	0.00	-	-	0.24	-	-		1.00	0.72
CH_4	0.01	0.01	0.01	0.01	0.01	-	-		-	0.00
H_2S + COS	0.30	0.16	0.19	0.00	0.00	-	-		-	0.00
Ar	0.84	0.43	0.54	0.81	0.69	-	-		0.25	0.18
HCN	0.03	0.02	0.00	0.00	0.00	-	-		-	-
NH_3	0.03	0.02	0.01	0.01	0.01	-	-		-	-
H_2O	-	19.90	0.24	0.02	0.18	-	-		0.70	28.77

FOSTER WHEELER	Case 4.1 - SHELL-BASED IGCC - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
	CLIENT :	IEA GHG	**PREP.**	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**CHECKED**	NF		
	PROJECT NO:	1-BD-0681 A	**APPROVED**	LM		
	LOCATION:	The Netherlands	**DATE**	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 2300 - Acid Gas Removal

STREAM	16	17	23	24	25	26	27			
	Raw SYNGAS from Syngas Cooling	**Purified Syngas to Syngas Cooling**	**LP CO_2 to Compression**	**MP CO_2 to Compression**	**HP CO_2 to Compression**	**Acid Gas to SRU & TGT**	**Recycle Tail Gas from SRU**			
Temperature (°C)	34	15	-1	3	10	20	20			
Pressure (bar)	35.0	33.5	1.0	3.0	10.0	2.0	35.0			
TOTAL FLOW										
Mass flow (kg/h)	868,184	188,947	149,211	372,190	153,330	8,317	5,310			
Molar flow (kmol/h)	43,741	27,920	3,395	8,482	3,757	254	150			
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-	-	-			
GASEOUS PHASE										
Mass flow (kg/h)	868,184	188,947	149,211	372,190	153,330	8,317	5,310			
Molar flow (kmol/h)	43,741	27,920	3,395	8,482	3,757	254	150			
Molecular Weight	19.8	6.8	44.0	43.9	40.8	32.8	35.4			
Composition (vol %)										
H_2	55.02	85.08	0.00	0.22	7.29	17.17	19.14			
CO	0.76	1.14	0.00	0.00	0.22	0.36	0.00			
CO_2	38.08	4.91	99.77	99.63	91.80	45.09	76.20			
N_2	5.14	8.00	0.00	0.01	0.47	1.01	1.70			
O_2	-	-	0.00	0.00	0.00	-	0.00			
CH_4	0.01	0.01	0.00	0.00	0.00	0.00	0.00			
H_2S + COS	0.19	0.00	0.00	0.00	0.00	34.96	2.95			
Ar	0.54	0.81	0.00	0.01	0.14	0.23	0.00			
HCN	-	-	-	-	-	-	-			
NH_3	0.01	0.01	-	-	-	-	-			
H_2O	0.24	0.02	0.23	0.12	0.08	1.19	0.00			

	Case 4.1 - SHELL-BASED IGCC - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
	CLIENT :	IEA GHG	**PREP.**	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**CHECKED**	NF		
	PROJECT NO:	1-BD-0681 A	**APPROVED**	LM		
	LOCATION:	The Netherlands	**DATE**	July 2013		

HEAT AND MATERIAL BALANCE

UNIT 2400 - Sulfur Recovery Unit (SRU) & Tail Gas Treatment (TGT)

STREAM	26	28	27	29	12					
	Acid Gas from AGR Unit	**Sour Gas from SWS**	**Claus Tail Gas to AGR Unit**	**Product Sulphur**	**Oxygen to SRU**					
Temperature (°C)	20	80	20	-	AMB					
Pressure (bar)	2.0	3.8	35.0	-	6					
TOTAL FLOW										
Mass flow (kg/h)	8,317	59	5,310	2,700	1,611					
Molar flow (kmol/h)	254	3	150	-	50					
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-					
GASEOUS PHASE										
Mass flow (kg/h)	8,317	59	5,310	-	1,611					
Molar flow (kmol/h)	254	3	150	-	50					
Molecular Weight	32.8	20.4	35.4	-	32.2					
Composition (vol %)										
H_2	17.17	0.28	19.14	-	-					
CO	0.36	0.19	0.00	-	-					
CO_2	45.09	40.38	76.20	-	-					
N_2	1.01	0.26	1.70	-	1.50					
O_2	-	-	0.00	-	95.00					
CH_4	0.00	0.00	0.00	-	-					
H_2S + COS	34.96	0.86	2.95	-	-					
Ar	0.23	0.00	0.00	-	3.50					
HCN	-	-	-	-	-					
NH_3	-	45.73	-	-	-					
H_2O	1.19	12.45	0.00		-					

	Case 4.1 - SHELL-BASED IGCC - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEA GHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
Unit 2500 - CO2 Compression and Drying

STREAM	23	24	25	30	31					
	LP CO2 to Compression	MP CO2 to Compression	HP CO2 to Compression	CO_2 to drying package	CO_2 to storage					
Temperature (°C)	-1	3	10	26	30					
Pressure (bar)	1.0	3.0	10.0	30.0	110.0					
TOTAL FLOW										
Mass flow (kg/h)	149,211	372,190	153,330	374,818	673,921					
Molar flow (kmol/h)	3,395	8,482	3,757	8,689	15,602					
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	374,818	673,921					
GASEOUS PHASE										
Mass flow (kg/h)	149,211	372,190	153,330	374,818	673,921					
Molar flow (kmol/h)	3,395	8,482	3,757	8,689	15,602					
Molecular Weight	44.0	43.9	40.8	43.1	43.2					
Composition (vol %)										
H_2	0.00	0.22	7.29	1.87	1.88					
CO	0.00	0.00	0.22	0.06	0.06					
CO_2	99.77	99.63	91.80	97.69	97.91					
N_2	0.00	0.01	0.47	0.12	0.12					
O_2	0.00	0.00	0.00	0.00	0.00					
CH_4	0.00	0.00	0.00	0.00	0.00					
H_2S + COS	0.00	0.00	0.00	0.00	0.00					
Ar	0.00	0.01	0.14	0.04	0.04					
HCN	-	-	-	-	-					
NH_3	-	-	-	-	-					
H_2O	0.23	0.12	0.08	0.22	<50ppm					

Case 4.1 - SHELL-BASED IGCC - H&M BALANCE - Case 4.1		REVISION	0	1
CLIENT :	IEA GHG	PREP.	GP	
PROJECT NAME:	CO_2 capture at coal based power and H2 plants	CHECKED	NF	
PROJECT NO:	1-BD-0681 A	APPROVED	LM	
LOCATION:	The Netherlands	DATE	July 2013	

HEAT AND MATERIAL BALANCE
Unit 3000 - Power Island

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
18	Treated Syngas from Syngas Cooling (*)	212.4	210	30.8	-
22	Moisturized Nitrogen for NOx control (*)	193.6	210	26.90	-
32	Flue gas from GT (*)	2780	560	1.02	-
33	Flue gas at stack (*) (1)	2780	133	atm	-
34	HP Steam from Process Units (*)	241.3	332	130.0	2663
35	MP Steam to Process Units (*)	43.1	260	46.5	2797
36	LP Steam from Process Units (*)	40.2	168	7.5	2766
37	Condensate to Deaerator (*)	903.4	113	4.2	474
38	BFW to LP BFW Pumps (*)	123.9	123	2.2	518
39	BFW to MP BFW Pumps (*)	363.8	123	2.2	518
40	BFW to HP BFW Pumps (*)	429.8	123	2.2	518
41	LP BFW to Process Units (*)	54.1	160	19.2	676
42	MP BFW to Process Units (*)	187.8	160	50.7	678
43	HP BFW to Process Units (*)	246.4	160	184.0	686
44	HP Steam to Steam Turbine	847.7	532	125.5	3428
45	Hot RH Steam to Steam Turbine	894.8	532	34.8	3524
46	LP Steam to Steam Turbine	947.0	260	5.7	2980
47	Steam to Condenser	947.0	29	0.04	2299
48	Water Supply to Steam Condenser	44180	15	4.0	63
49	Water Return from Steam Condenser	44180	26	3.5	109
50	Make-up water	506.1	15	6.0	64
51	Condensate return from Process Units	176.7	94	4.2	394

(*) Flowrate figure refers to one train (50% capacity)
(1) Flue gas molar composition: N_2: 72.9%; H_2O: 14.5%; O_2: 10.9%; CO_2: 0.9%; Ar: 0.9%.

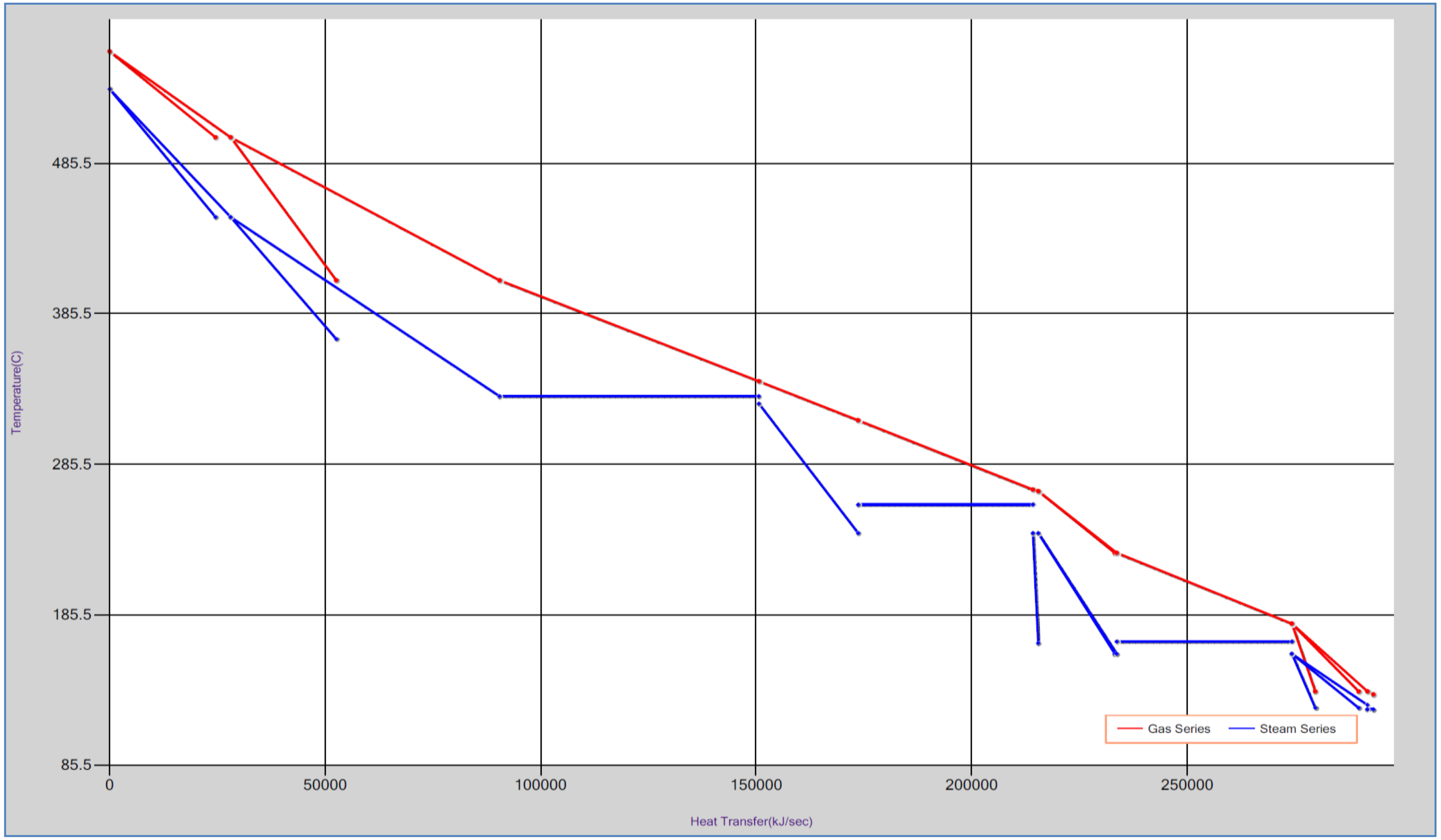


Figure 1 – Case 4.1 – HRSG T-Q diagram

5. Utility consumption

Main utility consumption of the process and utility units is reported in the following tables. More specifically:

- Steam / BFW / condensate interface summary is reported in Table 2.
- Water consumption summary is shown in Table 3.
- Electrical consumption summary is included in Table 4.

Table 2. Case 4.1 – Steam/BFW/condensate interface summary

FOSTER WHEELER

CLIENT: IEAGHG
PROJECT: CO2 capture at coal based power and H2 plants
LOCATION: 1-BD-0681 A
FWI Nº: The Netherlands

REVISION	Rev.0		
DATE	April 2013		
ISSUED BY	GP		
CHECKED BY	NF		
APPROVED BY	LM		

Case 4.1 - Shell based IGCC - Steam and water balance

UNIT	DESCRIPTION UNIT	HP Steam barg 130	MP Steam barg 47.0	LP Steam barg 8.0	HP BFW	MP BFW	LP BFW	condensate recovery	Losses
		[t/h]	[t/h]	[t/h]	[t/h]	[t/h]	[t/h]	[t/h]	[t/h]
	PROCESS UNITS								
900	**Air Separation Unit (ASU)**								
1100	**Gasification Section**	**-463.7**	**-67.6**	**13.4**	**473.6**	**108.5**		**-2.0**	**-62.1**
2000	**Syngas Treating and Conditioning Line**	**-18.9**	**191.3**	**-40.2**	**19.1**	**260.7**	**108.2**	**-79.9**	**-440.3**
2100	**Acid Gas Removal**			**79.8**				**-79.8**	**0.00**
2200	**Sulphur Recovery (SRU)**		**-6.3**			**6.4**		**0.00**	**-0.06**
3000	**POWER ISLANDS UNITS**	**482.6**	**-117.4**	**-67.9**	**-492.7**	**-375.6**	**-108.2**	**176.7**	
	UTILITY and OFFSITE UNITS			**15.0**				**-15.0**	**0.00**
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-502.5**

Note: (1) Negative figures represent generation

Table 3. Case 4.1 – Water consumption summary

CLIENT:	IEAGHG	Rev.0
PROJECT:	CO2 capture at coal based power and hydrogen plants	Date: April 2013
LOCATION:	1-BD-0681 A	ISSUED BY: GP
FWI Nº:	The Netherlands	CHECKED BY: NF
		APPR. BY: LM

Case 4.1 - Shell based IGCC - Water consumption summary

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water 1° syst. [DT = 11°C] [t/h]	Cooling Water 2° syst. [DT = 11°C] [t/h]
	AIR SEPARATION UNIT (ASU)				
900	**Air Separation Unit**				**10150**
	GASIFICATION SECTION (GS)				
1100	**Gasification**				**2720**
2000	**Syngas treatment and conditioning line**				**840**
2100	**Acid Gas Removal**		**0.6**		**6910**
2200	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**				**120**
	CO_2 COMPRESSION				
2300	**CO_2 Compression**				**6300**
	COMBINED CYCLE (CC)				
3100	**Gas Turbines and Generator auxiliaries**			**44180**	**780**
3200	**Heat Recovery Steam Generator**				
3300	**Steam Turbine and Generator auxiliaries**		**506**		**1730**
	Miscellanea				
	UTILITY UNITS (UU)				
	Cooling Water System	**1340**			
	Demineralized/Condensate Recovery/Plant and Potable Water Systems	**760**	**-507**		
	Waste Water Treatment	**-80**			
	Balance of Plant (BOP)				**440**
	TOTAL CONSUMPTION	**2020**	**0**		**29990**

Note: Negative figures represent generation

Table 4. Case 4.1 – Electrical consumption summary

CLIENT:	IEAGHG	Rev.0
PROJECT:	CO2 capture at coal based power and hydrogen plants	Date: April 2013
LOCATION:	1-BD-0681 A	ISSUED BY: GP
FWI Nº:	The Netherlands	CHECKED BY: NF
		APPR. BY: LM

Case 4.1 - Shell based IGCC - Electrical consumption summary

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
2100	**AIR SEPARATION UNIT (ASU)**	
	MAC consumptions	**96510**
	BAC consumptions	**9930**
	Nitrogen compressor and miscellanea	**33240**
	GASIFICATION SECTION (GS)	
900	**Coal Receiving Handling and Storage**	**370**
1000	**Gasification**	**25400**
2200	**Syngas treatment and conditioning line**	**430**
2300	**Acid Gas Removal**	**20970**
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**	**580**
2500	**CO_2 Compression**	**45280**
	COMBINED CYCLE (CC)	
3100	**Gas Turbines auxiliaries**	**2000**
3200	**Steam Cycle**	**7160**
3300	**Steam Turbine auxiliaries and excitation system**	**710**
3300	**Miscellanea**	**3210**
	UTILITY UNITS (UU)	
	Cooling Water System	**9200**
	Demineralized/Condensate Recovery/Plant and Potable Water Systems	**730**
	Balance of Plant (BOP)	**1110**
	TOTAL CONSUMPTION	**256830**

6. Overall performance

The following table shows the overall performance of Case 4.1.

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**DATE**	May 2013
PROJECT No. :	1-BD-0681 A	**MADE BY**	GP
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 4.1 - IGCC Plant Performance Summary

OVERALL PERFORMANCES		
Coal Flowrate (as received)	t/h	314.9
Coal LHV (as received)	kJ/kg	25870
Coal HHV (as received)	kJ/kg	27060
THERMAL ENERGY OF FEEDSTOCK(A)	**MWth (LHV)**	**2263**
THERMAL ENERGY OF FEEDSTOCK(A')	**MWth (HHV)**	**2367**
Thermal Power of Raw Syngas exit Scrubber	MWth (LHV)	1838
Thermal power of syngas to AGR	MWth (LHV)	1657
Thermal Power of Clean Syngas to Gas Turbines	MWth (LHV)	1600
Syngas treatment efficiency	% (LHV)	88.3
Gas turbines total electric power output	MWe	688.0
Steam turbine electric power output	MWe	375.2
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (C)	**MWe**	**1063.2**
Gasification Section units consumption	MWe	47.8
ASU consumption	MWe	139.7
Combined Cycle units consumption	MWe	13.1
CO_2 Compression and Dehydration unit consumption	MWe	45.3
Utility Units consumption	MWe	11.0
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**256.8**
NET ELECTRIC POWER OUTPUT OF IGCC	**MWe**	**806.4**
(Step-up transformer Eff. = 0.997) (B)	**MWe**	**804.0**
Gross electrical efficiency (C/A x 100)	% (LHV)	47.0
Net electrical efficiency (B/A x 100)	**% (LHV)**	**35.5**
Gross electrical efficiency (C/A' x 100)	% (HHV)	44.9
Net electrical efficiency (B/A' x 100)	**% (HHV)**	**34.0**
Fuel Consumption per net power production	**MWth/Mwe**	**2.81**
CO_2 emission per net power production	**kg/MWh**	**92.6**

The following table shows the overall CO_2 balance and CO_2 removal efficiency of Case 4.1.

CO_2 removal efficiency	**Equivalent flow of CO_2** kmol/h
INPUT	
Fuel Mix (Carbon AR)	16936
Flux ($CaCO_3$)	91
TOTAL (A)	17027
OUTPUT	
Slag (B)	38
CO_2 product pipeline	
CO	9
CO_2	15288
CH_4	0.0
COS	0.0
Total to storage (C)	15297
Emission	
CO_2 + CO (Combined Cycle)	1668
CO2 + CO (fuel drying)	24
TOTAL	17027
Overall Carbon Capture, % ((B+C)/A)	90.1

7. Environmental impact

The IGCC plant design is based on advanced technologies that allow to reach high electrical generation efficiency, while minimizing impact to the environment. Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

7.1. Gaseous emissions

During normal operation at full load, main continuous emissions are the combustion flue gases of the two trains of the combined cycle, from the combustion of the syngas in the two gas turbines. Table 5 summarises expected flow rate and concentration of the combustion flue gas from one train of the combined cycle.

Minor gaseous emissions are created by 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 related to the milling, storage and handling of solids (e.g. solid transfer, leakage). As summarised in Table 6, these emission mainly consists of air or nitrogen containing particulate.

Table 5. Case 4.1 – Plant emission during normal operation

Flue gas to HRSG stack	
Emission type	Continuous
Conditions	
Wet gas flowrate, kg/h	2,780,000
Flow, Nm^3/h (1)	2,681,100
Temperature, °C	133
Composition	(% vol)
Ar	0.88
N_2	72.87
O_2	10.92
CO_2	0.86
H_2O	14.47
Emission	mg/Nm^3 (1)
NOx	< 50
SOx	< 1
CO	< 100
Particulate	< 10

(1) Dry gas, O_2 content 15% vol.

Table 6. Case 4.1 – Plant minor emission

Emission source	Emission type	Temperature	
Coal milling and drying system	Continuous	ambient	Air: 10 mg/Nm^3 particulate
Coal feeding system	Intermittent	ambient	Nitrogen: 10 mg/Nm^3 particulate
Limestone milling and preparation	Intermittent	ambient	Air: 10 mg/Nm^3 particulate

7.2. Liquid effluents

Main liquid effluents are the cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids, and the effluent from the Waste Water Treatment, which flows to an outside plant battery limits recipient.

Cooling Tower blow-down

Flowrate : 295 m^3/h

Waste Water Treatment effluent

Flowrate : 255 m^3/h

7.3. Solid effluents

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

Fly ash from gasifier

Flowrate : 16 t/h (dry)

Fly ash can be dispatched to the cement industries, if local market exists, or sent to disposal.

Slag from gasifier

Flowrate : 28 t/h

Slag product has a potential use as major components in concrete mixtures to make road, pads, storage bins.

8. Preliminary plot plan

Plot plan at block level of Case 4.1 is attached to this section, showing the area occupied by the main units and equipment of the plant.

REV.	DATE	DESCRIPTION	DRAW	BY	CHD.	APP.
C001	AUG. 2013	Preliminary issue for comments	APeccati			

CLIENT IEA GHG

SITE The Netherlands

CO2 Capture and coal fired Power Plants
CASE: 4.1 - IGCC (Shell)
PRELIMINARY PLOT PLAN

FOSTER WHEELER

SCALE N. A.

FWI DWG N° 1BD0681A - 01 - 004 REV. C001

Form. A3

9. Equipment list

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

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 4.1 - IGCC (Shell)	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
		DATE	may 13	January 2014		
		ISSUED BY	GP	GP		
		CHECKED BY	NF	NF		
		APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 900 - Coal handling and storage

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	COAL HANDLING SYSTEM							
	Including		Coal flowrate: 315 t/h					*30 days storage*
	Wagon tipper							*Storage piles: 2 x 124,000 t each*
	Receiving Hopper, vibratory feeder and belt extractor							
	Conveyors	Belt						
	Transfer Towers	Enclosed						
	As-Received Coal Sampling System	Two-Stage						
	As-Received Magnetic Separator System	Magnetic Plates						
	Conveyors	Belt						
	Transfer Towers	Enclosed						
	Crushers Towers	Impactor reduction						
	As-Fired Coal Sampling System	Swing hammer						
	As-Fired Magnetic Separator System	Magnetic Plates						
	Coal Silo		2 x 4800 m3					for daily storage
	LIMESTONE HANDLING SYSTEM							
	Including		Limestone flowrate: 9.0 t/h					
	Wagon tipper		Limestone Storage volume: 5700 m3					*30 days storage capacity*
	Receiving Hopper, vibratory feeder and belt extractor							
	Conveyors	Belt						
	Transfer Towers	Enclosed						
	Limestone storage	Silos						
	Conveyors	Belt						
	Limestone Sampling System	Swing hammer						
	Separator System	Magnetic Plates						
	Transfer Towers	Enclosed						
	Conveyors	Belt with tipper						
	Limestone Silo		1 x 200 m3					For daily storage

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		APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 1000 - Gasification (2 x 50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-1001	**Coal milling and drying**		4 x 2270 t/d raw coal, AR basis Water content at dryer outlet: 1.3%					3 Operating, one spare
Z-1002	**SHELL Coal gasification package**							
	Coal pressurization and feeding							Included in Z-1002
	Gasifiers		2 x 3780 t/d coal to burners, as received 2 x 920 MWth (LHV basis) syngas at scrubber outlet					Included in Z-1002 2x50% design capacity
	Syngas Cooler							Included in Z-1002
	Slag Removal System							Included in Z-1002
	Dry Fly Ash Removal System							Included in Z-1002
	Wet Scrubbing							Included in Z-1002
	Primary Water Treatment							Included in Z-1002
	Nitrogen + Blowback Systems							Included in Z-1002
	Flare headers and fuel distribution systems							Included in Z-1002
	LP cooling water system							Included in Z-1002
	Process water systems							Included in Z-1002
	Steam/Condensate systems							Included in Z-1002
	Plant/Instrument Air Systems							Included in Z-1002
	NaOH/HCl Distribution Systems							Included in Z-1002

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 4.1 -IGCC (Shell)			REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
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				APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 2100 - Air Separation Unit (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	ASU PACKAGE							
Z-2101	**ASU Package** including:							
	Cold Box	Cryogenic	125 t/h of 95% purity O2, each					
	Main Air compressors	Electric motor driven, centrifugal, with intercooling	Flowrate: 2 x 231200 Nm3/h	2 x 26750 kW				Included in Z-2101
	Booster air compressors	Electric motor driven, centrifugal, with intercooling	Flowrate: 185000 Nm3/h	5500 kW				Included in Z-2101
	MP N2 compressors	Electric motor driven, centrifugal, with intercooling	Flowrate: 2 x 120350 Nm3/h	2 x 8750 kW				Included in Z-2101
	MP N2 compressors - booster	Electric motor driven, centrifugal, with intercooling	Flowrate: 104900 Nm3/h	850 kW				Included in Z-2101
	O2 pumps	centrifugal						Included in Z-2101
	HP N2 pumps	centrifugal						Included in Z-2101
	VHP N2 pumps	centrifugal						Included in Z-2101
	Back-up oxygen vaporiser	Shell and tube						Included in Z-2101
Common units to both trains:								
	LOX (liquid oxygen) storage	Fixed roof storage tank						8 hour storage for 1 gasification train Normal operating p: 5 bar a Normal operating T: -165 °C
	LIN (liquid nitrogen) storage	Fixed roof storage tank						8 hour storage for 1 Gasifier & 4 min storage for Syngas dilution and NOX control Normal operating p: 5 bar a Normal operating T: -180 °C
	Gaseous oxygen storage							2 min storage for 2 Gasifiers
	Gaseous nitrogen storage							2 min storage for 2 Gasifiers & for Syngas dilution and NOX control

Note: Equipment list refers to one train only

FOSTER WHEELER	CLIENT: IEA GHG	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
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	CASE: Case 4.1 -IGCC (Shell)	APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 2200 - Syngas Treatment and Conditioning Line (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	HEAT EXCHANGERS							
E-2201	**Feed/Product Heat Exchanger**	Shell & Tube						
E-2202	**HP steam generator**	Kettle						
E-2203	**MP steam generator**	Kettle						
E-2204	**LP steam generator**	Kettle						
E-2205	**LP steam generator**	Kettle						
E-2206 A/B	**Circulating Water Heater**	Shell & Tube						
E-2207 A/B	**Condensate preheater**	Shell & Tube						
E-2208	**Raw Syngas / Treated Syngas Heat Exchanger**	Shell & Tube						
E-2209	**Final sygas cooler**	Shell & Tube						
E-2210	**Final Syngas heater**	Shell & Tube						
E-2211	**Saturated Nitrogen heater**	Shell & Tube						
	DRUMS							
D-2201	**Condensate Separator**	Vertical						
D-2202	**Condensate Separator**	Vertical						
D-2203	**Condensate Separator**	Vertical						
D-2204	**Condensate accumulator**	Horizontal						Common for both syngas tratment and conditiong line trains

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 4.1 -IGCC (Shell)	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
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EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning Line (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	COLUMN							
C-2201	**Nitrogen saturator**	Vertical						
	REACTOR							
R-2201	**1st Shift Catalyst Reactor**	vertical low steam shift reactor						Overall CO conversion: 98%
R-2202	**2nd Shift Catalyst Reactor**	vertical conventional WGS						
R-2203	**3rd Shift Catalyst Reactor**	vertical conventional WGS						
	PUMPS							
P-2201	**Saturator Circulating Water Pump**							
	MISCELLANEA							
X-2201	**Mercury Adsorber**	Sulfur-impregnated activated carbon beds						

Note: Equipment list refers to one train only

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 4.1 -IGCC (Shell)	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
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EQUIPMENT LIST

Unit 2250 - Sour Water System (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-2251	**SWS PACKAGE**							
C-2251	Sour Water Stripper	Vertical						
	SWS Reboiler							
	SWS Condenser							
E-2251	Sour water heat exchanger (SWS feed / purified)							
P-2251	SWS Pump							

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EQUIPMENT LIST
Unit 2300 - Acid Gas Removal Unit (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2301	**Acid Gas Removal Unit - Absorption section** (Acid Gas Removal Unit, sized for 50% of the capacity)	Solvent Selexol	Feed gas: 980420 Nm3/h; 34 barg; 34 °C					One H2S removal column, 3 CO2 removal columns, CO2 removal: 91.78% Separated removal of CO2 and H2S Total carbon capture: 90 %
Z-2302	**Acid Gas Removal Unit - Solvent regeneration** (One Acid Gas Removal Unit, sized for 100% of the capacity)							Total CO2 removal= 16150 t/d; 10 ppm H2S (dry) in combined CO2
Z-2303	**Chiller Unit**	electrical driven						T= -10 °C

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	PROJ. NAME:	CO2 capture at coal based power and hydrogen plants	ISSUED BY	GP	GP		
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	CASE:	Case 4.1 -IGCC (Shell)	APPROVED BY	LM	LM		

EQUIPMENT LIST

Unit 2400 - Sulphur Recovery Unit (2x100%) & Tail Gas Treatment (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2401	**Sulphur Recovery Unit and Tail Gas Treatment Package** - two Sulphur Recovery Unit, each sized for 100% of the capacity - one Tail Gas Treatment Unit sized for 100% of capacity (including Reduction Reactor and Tail Gas Compressor)		*Sulphur Prod.= 65 t/d* Acid Gas from AGR: 5760 Nm3/h; Sulphur content: 35 % mol (wet basis) Expected Treated Tail Gas =3025 Nm3/h					Sulphur content > 99,9 % mol min (dry basis)

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 4.1 -IGCC (Shell)	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2		
		DATE	may 13	January 2014				
		ISSUED BY	GP	GP				
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		APPROVED BY	LM	LM				

EQUIPMENT LIST
Unit 2500 - CO2 Compression and Drying (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [MW]	P design [barg]	T design [°C]	Materials	Remarks
	COMPRESSORS							
C-2501	CO_2 Compressor	Centrifugal, Electrical Driven, 8 intercooled Stages	175210 Nm3/h p in: 1 bar a p out: 80 bar a	21930 kW				water cooled
	PUMPS		**Q,m3/h x H,m**					
P-2501	CO_2 Pump	centrifugal	600 x 560	800 kW				liquid CO2 product, per each train: flowrate: 343.2 t/h; 110 bar a; 30°C
	PACKAGE							
PK-2501	CO_2 drying package							

Note: Equipment list refers to one train only

	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 4.1 -IGCC (Shell)	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
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		ISSUED BY	GP	GP		
		CHECKED BY	NF	NF		
		APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 3100 - Gas Turbine (2x 50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-3101	**Gas Turbine & Generator Package**							
GT-3101	Gas turbine	F Class GT	344 MW					Included in Z-3101
G-3101	Gas turbine Generator		450 MVA					Included in Z-3101

Note: Equipment list refers to one train only

FOSTER WHEELER	CLIENT: IEA GHG			REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
	LOCATION: The Netherlands			DATE	may 13	January 2014		
	PROJ. NAME: CO2 capture at coal based power and hydrogen plants			ISSUED BY	GP	GP		
	CONTRACT N. 1-BD-0681 A			CHECKED BY	NF	NF		
	CASE: Case 4.1 -IGCC (Shell)			APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 3200 - Heat Recovery Steam Generator (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	HEAT RECOVERY STEAM GENERATOR							
HRSG-3201	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels. Simple Recovery, Reheated.						
Each HRSG including:								
D-3201	**HP steam Drum**							
D-3202	**MP steam Drum**							
D-3203	**LP steam Drum**							
D-3204	**VLP steam Drum with degassing section**							
E-3201	**HP Superheater 2nd section**							Included in HRSG-3201
E-3202	**HP Superheater 1st section**							Included in HRSG-3201
E-3203	**HP Evaporator**							Included in HRSG-3201
E-3204	**HP Economizer 3rd section**							Included in HRSG-3201
E-3205	**HP Economizer 2nd section**							Included in HRSG-3201
E-3206	**HP Economizer 1st section**							Included in HRSG-3201
E-3207	**MP Reheater 2nd section**							Included in HRSG-3201
E-3208	**MP Reheater 1st section**							Included in HRSG-3201
E-3209	**MP Superheater**							Included in HRSG-3201
E-3210	**MP Evaporator**							Included in HRSG-3201
E-3211	**MP Economizer 2nd section**							Included in HRSG-3201
E-3212	**MP Economizer 1st section**							Included in HRSG-3201
E-3213	**LP Superheater**							Included in HRSG-3201
E-3214	**LP Evaporator**							Included in HRSG-3201
E-3215	**LP Economizer**							Included in HRSG-3201
E-3216	**VLP Evaporator**							Included in HRSG-3201

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	CASE:	Case 4.1 -IGCC (Shell)	APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 3200 - Heat Recovery Steam Generator (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PUMPS		**Q,m^3/h x H,m**					
P-3201 A/B	**HP BFW Pumps**	centrifugal	503 x 1695	2700				One operating, one spare
P-3203 A/B	**MP BFW Pumps**	centrifugal	425 x 620	900				One operating, one spare
P-3205 A/B	**LP BFW Pumps**	centrifugal	145 x 130	75				One operating, one spare
	MISCELLANEA		**D,mm x H,mm**					
X-3201	**Flue Gas Monitoring System**							NOx, CO, SO_2, particulate, H_2O,
STK-3201	**CCU Stack**							
SL-3201	**Stack Silencer**							
DS-3201	**HP Steam Desuperheater**							Included in HRSG-3201
DS-3202	**MP Steam Desuperheater**							Included in HRSG-3201
	PACKAGES							
Z-3201	**Fluid Sampling Package**							
Z-3202	**Phosphate Injection Package**							
D-3204	Phosphate storage tank							Included in Z - 3202
P-3205 A/B	Phosphate dosage pumps							Included in Z - 3202 One operating , one spare
Z-3203	**Oxygen Scavanger Injection Package**							
D-3205	Oxygen scavanger storage tank							Included in Z - 3203
P-3206 A/B	Oxygen scavanger dosage pumps							Included in Z - 3203 One operating , one spare
Z-3204	**Amines Injection Package**							
D-3206	Amines Storage tank							Included in Z - 3204
P-3207 A/B	Amines Dosage pumps							Included in Z - 3204 One operating , one spare

Note: Equipment list refers to one train only

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	CONTRACT N. 1-BD-0681 A		CHECKED BY	NF	NF		
	CASE: Case 4.1 -IGCC (Shell)		APPROVED BY	LM	LM		

EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-3301	**Steam Turbine and Generator Package**							
ST-3301	Steam Turbine		375 MWe					*Including:* *Lube oil system* *Cooling system* *Idraulic control system* *Drainage system* *Seals system* *Drainage system*
G-3402	Steam Turbine Generator		493 MVA					*Including relevant auxiliaries*
E-3301A/B	Inter/After condenser							
E-3302	Gland Condenser							
Z-3302	**Steam Condenser Package**							
E-3303	Steam Condenser	Water cooled	565 MWt					*Including:* *Hot well* *Vacuum pump (or ejectors)* *Start up ejector (if required)*
Z-3303	**Steam Turbine by-pass system**							
	PUMPS		**$Q,m^3/h$ x H,m**					
P-3301A/B	**Condensate Pumps**	Centrifugal, vertical	1895 x 90	630				One operating, one spare
	HEAT EXCHANGERS		**S, m2**					
E-3304	**Blow-Down Cooler**	Shell & Tube						
	DRUMS		**D,mm x TT,mm**					
D-3301	**Continuous Blow-down Drum**	vertical						
D-3302	**Discontinuous Blow-down Drum**	vertical						

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	CASE: Case 4.1 -IGCC (Shell)	APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 4000 -Utility & Offsite

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-4001	**COOLING WATER SYSTEM**							
CT-4001	Cooling Tower Including: Cooling water basin	Evaporative, Natural draft	Total heat duty 942 MWth Diameter: 145 m, Height: 210 m, Water inlet: 17 m				concrete	Included in Z-4001
	Pumps							
P-4001A/B/C/D	Cooling Water pumps (primary system)	Vertical	14725 m3/h x 35 m	1600 kW				Included in Z-4001 3 operating
P-4002A/B/C	Cooling Water pumps (secondary system)	Vertical	14770 m3/h x 45 m	2250 kW				Included in Z-4001 2 operating, one spare
P-4003A/B	Cooling tower make-up pumps	centrifugal	1465 m3/h x 30 m	185 kW				Included in Z-4001 1 operating, one spare
	Packages							
	Cooling Water Filtration Package Cooling Water Sidestream Filters		Capacity: 7380 m3/h					
	Sodium Hypochlorite Dosing Package Sodium Hypochlorite storage tank Sodium Hypochlorite dosage pumps							
	Antiscalant Package Dispersant storage tank Dispersant dosage pumps							
Z-4002	**RAW WATER SYSTEM**							
T-4001	Raw Water storage tank		13320 m3					Included in Z-4002 24 hour storage
P-4004A/B	Raw Water Pumps	centrifugal	555 m3/h x 50 m	110 kW				Included in Z-4002 One operating, one spare
Z-4003	**DEMI WATER SYSTEM**							
PK-4001	**Demin Water Package, including:**							
	- Multimedia filter - Reverse Osmosis (RO) Cartidge filter - Electro de-ionization system							
T-4002	Demi Water storage tank		13370 m3					Included in Z-4002 24 hour storage

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	CONTRACT N. 1-BD-0681 A	CHECKED BY	NF	NF		
	CASE: Case 4.1 -IGCC (Shell)	APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 4000 -Utility & Offsite

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
P-4005A/B	Demi Water Pumps	centrifugal	557 m3/h x 36 m	90 kW				Included in Z-4002 One operating, one spare
Z-4004	**FIRE FIGHTING SYSTEM**							
	Fire water storage tank							
	Fire pumps (diesel)							
	Fire pumps (electric)							
	FW jockey pump							
	MISCELLANEA							
	Natural Gas (Back-up fuel)							
	Waste Water Treatment							
	Sulphur Storage/Handling		65 t/d S prod.					30 days storage
	Flare system							
	Interconnecting							
	Instrumentation							
	DCS							
	Piping							
	Electrical							
	Plant Air							
	Buildings							

CLIENT	:	IEAGHG
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FWI CONTRACT	:	1-BD-0681 A

ISSUED BY	:	L. CASTRONUOVO
CHECKED BY	:	N. FERRARI
APPROVED BY	:	L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

1. Introduction

This chapter of the report includes all technical information relevant to Case 4.2 of the study, which is an IGCC plant based on the GE gasification technology. The plant is designed to process coal, whose characteristic is shown in chapter B, and produce electric power for export to the external grid, with capture of the generated carbon dioxide.

The configuration of the plant is based on the following main features:

- High-pressure (65 barg) GE Energy Gasification process, with slurry-feed system and Radiant Syngas Cooler (RSC);
- 2-stages sour shift;
- Removal of acid gases (H_2S and CO_2) based on Selexol physical solvent process;
- Oxygen-blown Claus unit, with tail gas catalytic treatment and recycle of the treated tail gas to the AGR;
- CO_2 compression and dehydration unit;
- Combined cycle based on two F-class gas turbines.

The description of the main process units is covered in chapter E of this report, so only features that are unique to this case are discussed in the following sections, together with the main modelling results.

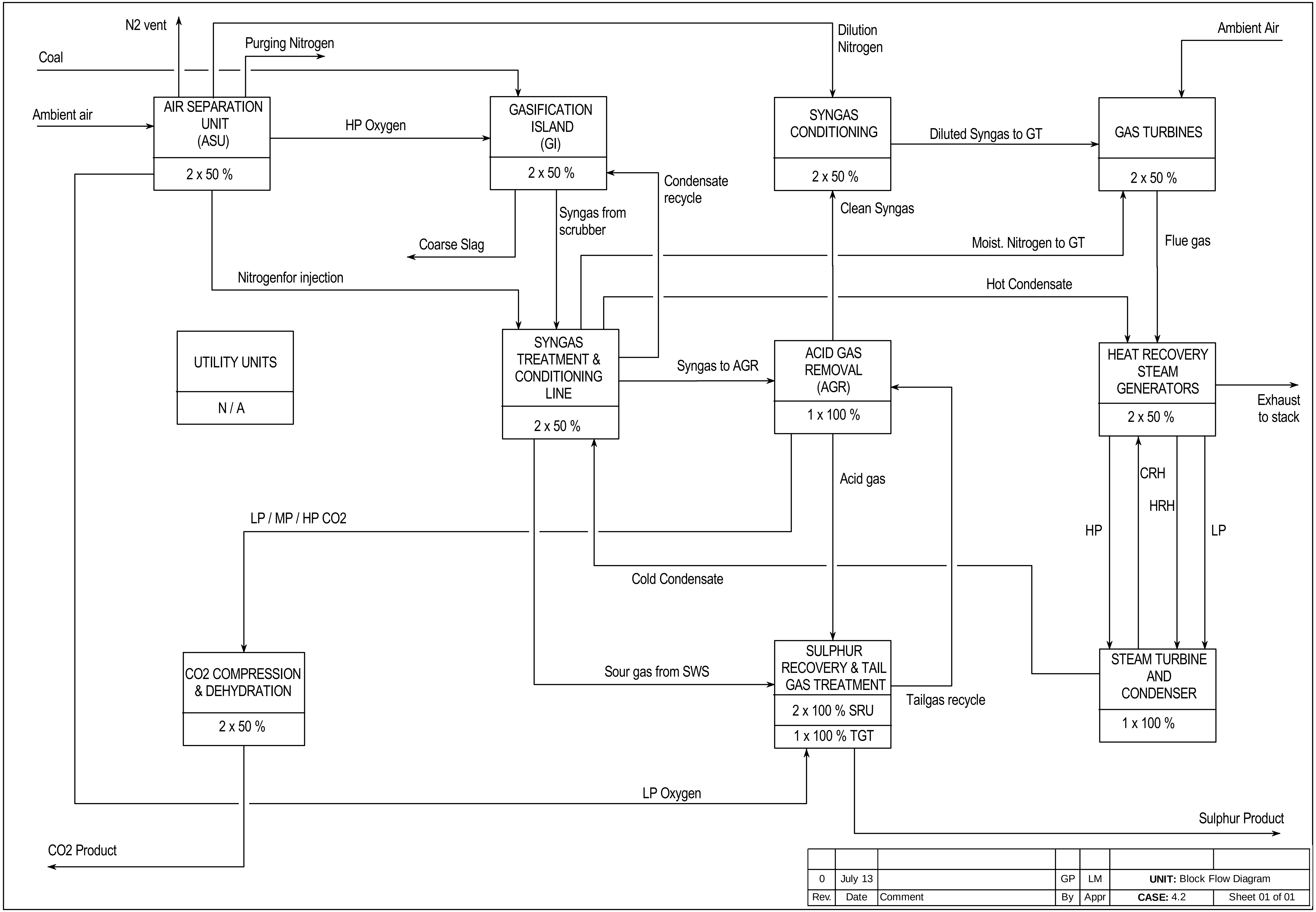
1.1. Process unit arrangement

The arrangement of the main units is reported in the following Table 1. Reference is also made to the block flow diagram attached below.

Table 1. Case 4.2 – Unit arrangement

Unit	Description	Trains
900	Coal Handling & Storage	N/A
1000	Gasification	2 x 50%
	Coal Grinding & Slurry Preparation	
	Gasification (Radiant Syngas Cooler) and scrubber	
	Black Water Flash & Coarse Slag Handling	
	Grey Water & Fines Handling	
2100	Air Separation Unit	2 x 50%
2200	Syngas Treatment and Conditioning Line	2 x 50%

Unit	Description	Trains
2250	Sour Water Stripper (SWS)	1 x 100%
2300	Acid Gas Removal	1 x 100%
2400	Sulphur Recovery Unit	2 x 100%
	Tail Gas Treatment	1 x 100%
2500	CO_2 Compression & Drying	2 x 50%
3000	Combined Cycle	
	Gas Turbine	2 x 50%
	HRSG	2 x 50%
	Steam Turbine	1 x 100%
4000	Utility and Offsite	N/A



N2 vent
Purging Nitrogen
Coal
Dilution Nitrogen
Ambient Air
Ambient air
AIR SEPARATION UNIT (ASU)
2 x 50 %
HP Oxygen
GASIFICATION ISLAND (GI)
2 x 50 %
SYNGAS CONDITIONING
2 x 50 %
Diluted Syngas to GT
GAS TURBINES
2 x 50 %
Condensate recycle
Syngas from scrubber
Coarse Slag
Clean Syngas
Moist. Nitrogen to GT
Flue gas
Nitrogenfor injection
Hot Condensate
UTILITY UNITS
N / A
SYNGAS TREATMENT & CONDITIONING LINE
2 x 50 %
Syngas to AGR
ACID GAS REMOVAL (AGR)
1 x 100 %
HEAT RECOVERY STEAM GENERATORS
2 x 50 %
Exhaust to stack
CRH
Acid gas
HRH
HP
LP
LP / MP / HP CO2
Cold Condensate
CO2 COMPRESSION & DEHYDRATION
2 x 50 %
Sour gas from SWS
SULPHUR RECOVERY & TAIL GAS TREATMENT
2 x 100 % SRU
1 x 100 % TGT
Tailgas recycle
STEAM TURBINE AND CONDENSER
1 x 100 %
LP Oxygen
Sulphur Product
CO2 Product
0
July 13
GP
LM
UNIT: Block Flow Diagram
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CASE: 4.2
Sheet 01 of 01

2. Process description

2.1. Overview

The description reported in this section makes reference to the simplified Process Flow Diagrams (PFD) of section 3, while stream numbers refer to section 4, which provides heat and mass balance details for the numbered streams in the PFD.

2.2. Unit 900 – Coal Handling & Storage

The unit mainly consists of the coal storage and handling.

The general description relevant to this unit is reported in chapter E, section 2.1. Main process information of this case and the interconnections with the other units is shown in the relevant process flow diagram and the heat and mass balance table.

2.3. Unit 1000 – Gasification Island

The gasification island based on GE gasification mainly includes the coal grinding and slurry preparation section, the gasification (RSC) and the scrubber, the Black Water Flash and Coarse Slag Handling, and Grey Water & Fines Handling. Technical information relevant to these packages is reported in chapter E, section 3.2.

The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

2.4. Unit 2100 – Air Separation Unit

Technical information relevant to this packaged unit is reported in chapter E, section 2.3. The main process information of the unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The sizing capacity of the Air Separation Unit is determined by the oxygen requirement of the gasification island and the SRU. The total required oxygen flowrate for the case is approximately 325 t/h.

The Air Separation unit supplies medium pressure nitrogen, used as diluent for the syngas or injected in the gas turbine for NOx suppression and power production augmentation.

2.5. Unit 2200 – Syngas Treatment and Conditioning line

The general description of this unit is shown in chapter E, section 2.4, while case-specific features are reported hereinafter. The main process information and the interconnections with the other units are shown in the relevant process flow diagram and the heat and mass balance tables.

Saturated raw syngas from the gasification scrubber, at approximately 64 barg, is heated-up in the Feed/Product Heat Exchanger, before entering the first shift reactor, in order to increase the temperature up to the level required for the proper operation of the shift catalyst.

In the shift unit, CO is shifted to H_2 and CO_2 and COS is converted to H_2S. A double stage shift, containing sulphur tolerant shift catalyst (sour shift) is selected in order to increase the H_2 content in the fuel and maximize the degree of CO_2 removal. The overall CO conversion is approximately 98%. The water content in the syngas is adequate for the shift reaction to take place with no additional steam injection.

The partially-shifted syngas temperature is increased by the exothermic shift reaction, allowing for thermal recovery. The syngas is cooled down in a series of heat exchangers, before being fed to the second reactor stage:

- Feed/Product Heat Exchanger,
- HP Steam Generator,
- MP Steam Generator #1.

After being cooled, the syngas is directed to the second and last shift reactor. The hot shifted syngas outlet from the second stage is cooled in the following series of heat exchangers, to thermally recover heat and increase the overall power generation:

- MP Steam Generator #2,
- LP Steam Generator,
- Saturator Circulating Water Heater #1 and #2,
- Condensate Pre-heater #1 and #2.

Final cooling of the syngas is made cooling water, before passing through a sulphur-impregnated activated carbon bed to remove approximately 95% of the mercury. Cool, mercury-depleted syngas is then directed to the AGR.

During the cooling of the syngas, the process condensate is separated and collected in the process condensate accumulator. Before being sent to the accumulator, the condensate from the last syngas separator, upstream the AGR, plus a portion of the condensate from the upstream separator, is sent to the Sour Water Stripper in order to avoid accumulation of ammonia and H_2S and other dissolved gases in the water recycle to the gasification section. The condensate from the accumulator is sent to the gasification scrubber for syngas saturation. Boiler Feed Water from the deaerator of the combined cycle provides the make-up water to substitute the steam reacted in the shift unit.

From the AGR unit, cool hydrogen-rich gas returns to the syngas treatment and conditioning line as de-carbonized fuel gas after H_2S and CO_2 removal. The de-carbonized fuel gas is preheated against circulating water coming from the nitrogen saturator and then expanded down to the pressure required from the gas turbine, thus producing additional electric power.

Downstream the expander, the syngas is diluted with nitrogen from the ASU in order to reduce the H_2 content of the fuel gas to maximum 65% (molar basis).

Finally, the diluted syngas is preheated against LP steam and sent to the combined cycle at around 155°C, for final heating against boiler feed water and combustion in the gas turbine.

The unit includes nitrogen saturator, providing moisturised nitrogen to be injected in the gas turbine. Nitrogen humidification is achieved by means of hot water heated in the syngas cooling line. The humidified nitrogen is finally heated using MP steam and then injected in the gas turbine combustion chamber.

2.6. Unit 2300 – Acid Gas Removal (AGR)

The AGR unit is intended to selectively remove H_2S and CO_2 in sequent steps by employing Selexol as physical solvent. Technical information relevant to this package is reported in chapter E, section 2.5. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The AGR is designed to meet the following process specifications of the treated gas and of the CO_2 product exiting the unit:

- The H_2S+COS concentration of the treated gas exiting the unit is around 1 ppmv. This is due to the integration of CO_2 removal with the H_2S removal, which makes available a large circulation of solvent that is cooled down by a refrigerant package before flowing to the CO_2 absorber.
- The CO_2 product is characterised by a content of incondensable around 2%, while simultaneously meeting the specification of H_2S content lower than 20 ppmv and CO content lower than 0.2% mol (actual 0.06% mol).
- The acid gas H_2S concentration is about 41% dry basis, suitable to feed the oxygen blown Claus process.

The CO_2 removal rate is 91.7% of the carbon dioxide entering the unit, allowing reaching an overall carbon capture of approximately 90% with respect to the carbon in the syngas. These excellent performances on both the H_2S removal and CO_2 capture are achieved with significant power consumption and steam demand.

2.7. Unit 2400 – SRU and TGT

Technical information relevant to this package is reported in chapter E, section 2.5. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The SRU is designed to process the acid gas from the AGR and other minor acid streams like the acid off-gas from the black water flash within the gasification island and the sour gases from the SWS, using low pressure oxygen from the ASU. In the furnace, H_2S is catalytically oxidized to SO_2 which is further reacted with H_2S to form H_2O and elemental sulphur. Following the thermal stage, sulphur is condensed, while the tail gas is hydrogenated and recycled back to the AGR unit at approximately 60 barg by means of a dedicated compressor.

The overall sulphur production is approximately 72 tons per day.

2.8. Unit 2500 – CO_2 compression and drying

This unit is mainly composed of a compression and dehydration package, followed by last stage CO_2 pumps, supplied by specialized vendors. Technical information relevant to this package is reported in chapter E, section 2.6. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

Three different streams of CO_2 from the Acid Gas Removal unit are routed to the CO_2 compression unit, delivered at approximately 19 barg, 6 barg, and 1.5 barg respectively.

The stream at lower pressure is initially compressed up to the pressure of the medium pressure stream and then combined with it. The resulting stream is compressed to allow the mixing with the last stream without any pressure loss. The combined stream is then compressed up to approximately 40 barg and sent to the dehydration system, which is a standard solid desiccant package that dehydrates the CO_2 stream to a dew point of -40°C. After dehydration, the CO_2 stream is finally compressed to a supercritical condition at 80 barg.

The resulting stream of CO_2 is pumped to the required pressure of 110 barg. The CO_2 product (approximately 97.9 % wt purity) is transported to the plant battery limits for final sequestration.

2.9. Unit 3000 – Combined cycle

Technical information relevant to these packages is reported in chapter E, section 2.10. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The diluted syngas exiting the syngas treatment and conditioning line is finally heated in the combined cycle using MP boiler feed water before entering the burners of the gas turbine at 210°C.

The gas turbine compressors provide combustion air to the burner only, i.e. no air integration with the ASU is foreseen. The exhaust gases from the gas turbine enter the HRSG at 560°C. The HRSG recovers heat available from the exhaust gas producing steam at three different pressure levels for the steam turbine, plus an additional steam generator with integral deaerator. The final exhaust gas temperature to the stack of the HRSG is 133°C. The calculated acid gas dew point temperature of the exhaust flue gas is around 90°C.

The Heat Transfer vs. Temperature of the HRSG (T-Q diagram) of case 4.2 is shown in Figure 1. The red line (the upper curve) represents the exhaust gases from the GT to the stack. The blue lines represent the water path in the economizers (at lower temperature), the steam generators (horizontal lines) and the super-heater/re-heater (at higher temperature).

The combined cycle is thermally integrated with the process unit, in order to maximize the net electrical efficiency of the plant. The main steam and water interfaces with the process units are given in Table 2.

2.10. Utility Units

These units comprise all the systems necessary to allow the operation of the plant and the export of the produced power.

The main utility units include:

- Cooling Water system, based on one natural draft cooling tower, with the following characteristics:

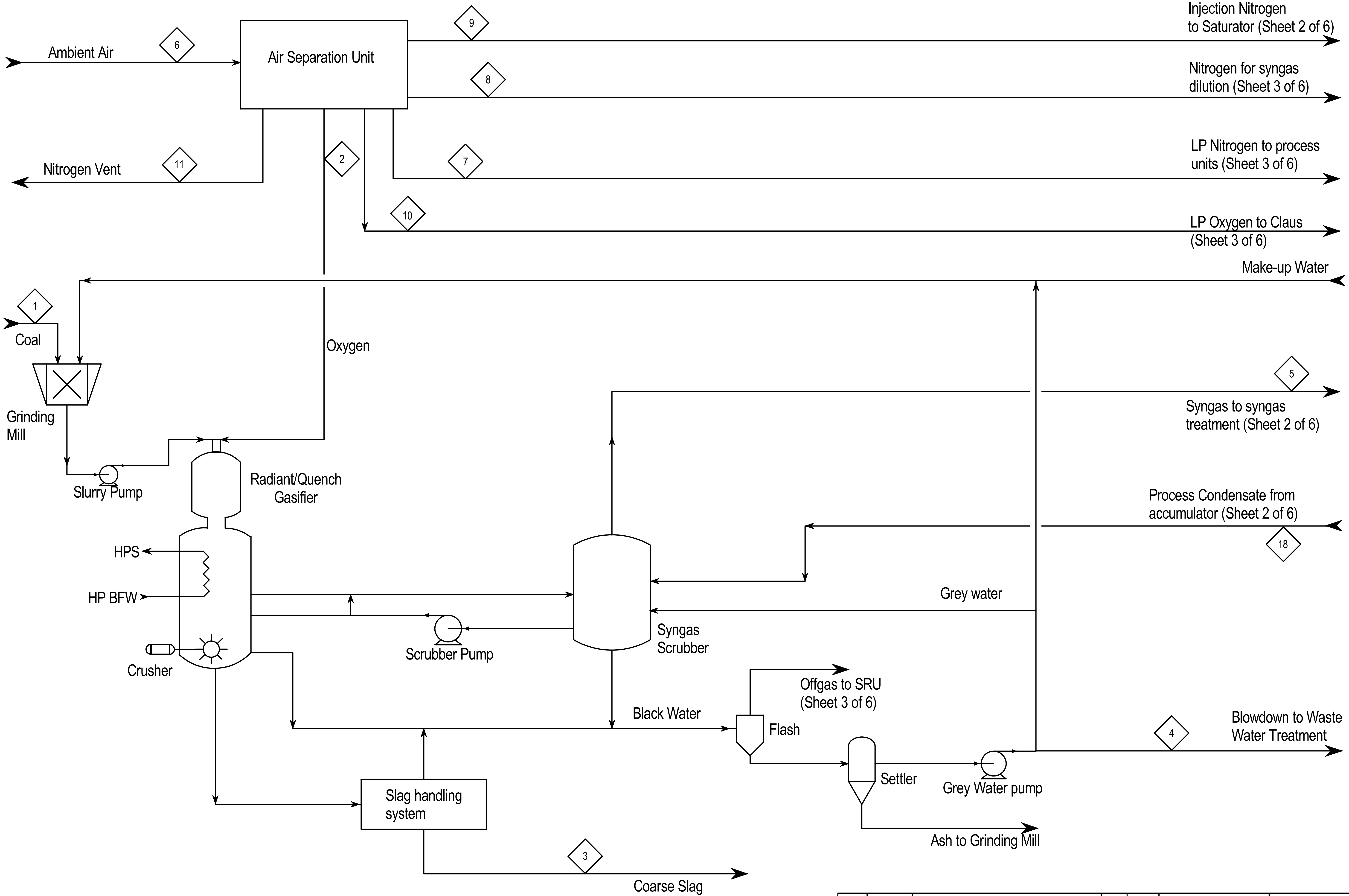
Basin diameter	150 m
Cooling tower height	210 m
Water inlet height	17 m

- Raw water system;
- Demineralised water plant;
- Fire fighting system;
- Instrument and Plant air.

Process descriptions of the above systems are enclosed in chapter E, section 2.11.

3. Process Flow Diagrams

Simplified Process Flow Diagrams of this case are attached to this section. Stream numbers refer to the heat and material balance shown in the next section.



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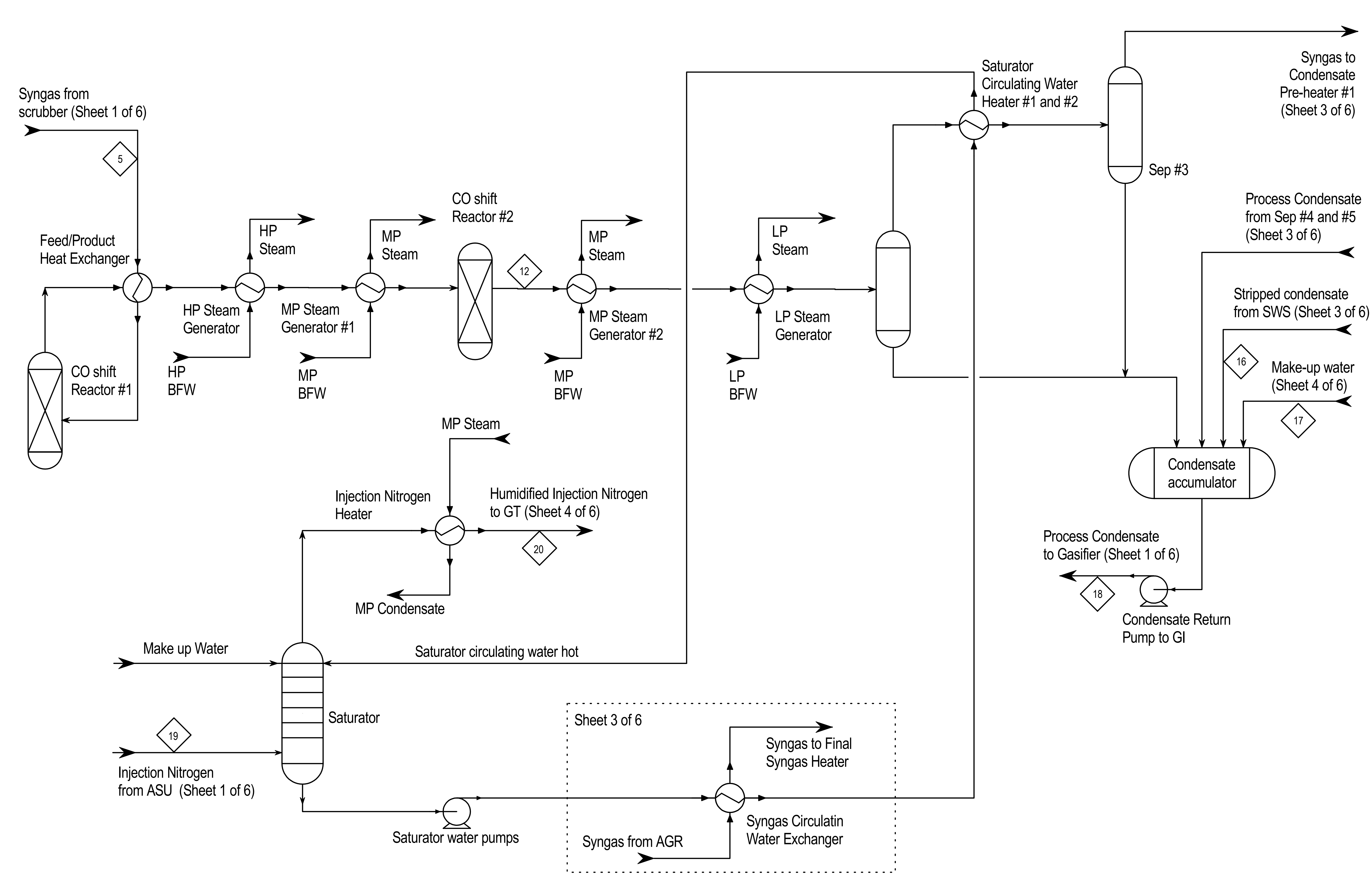
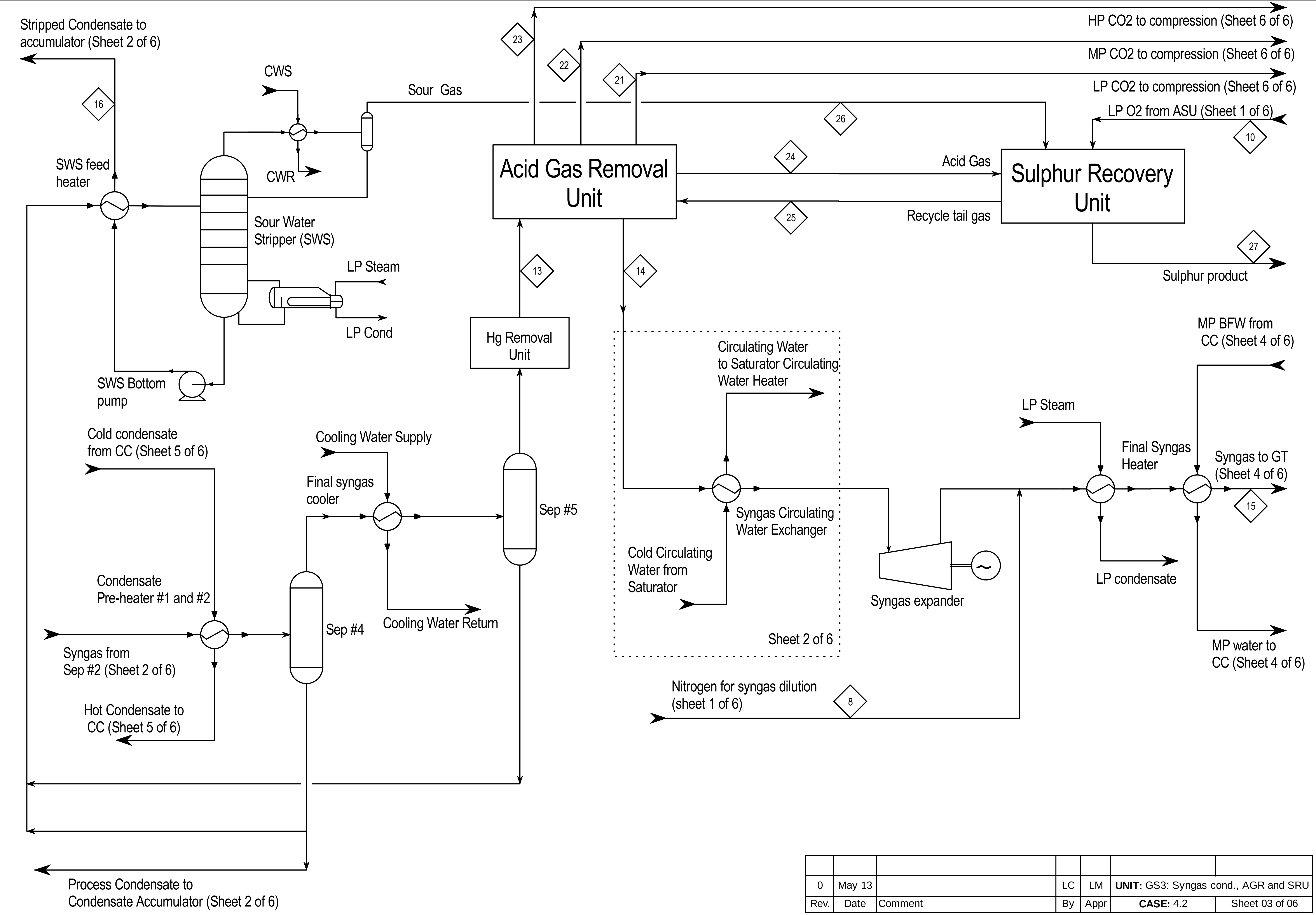
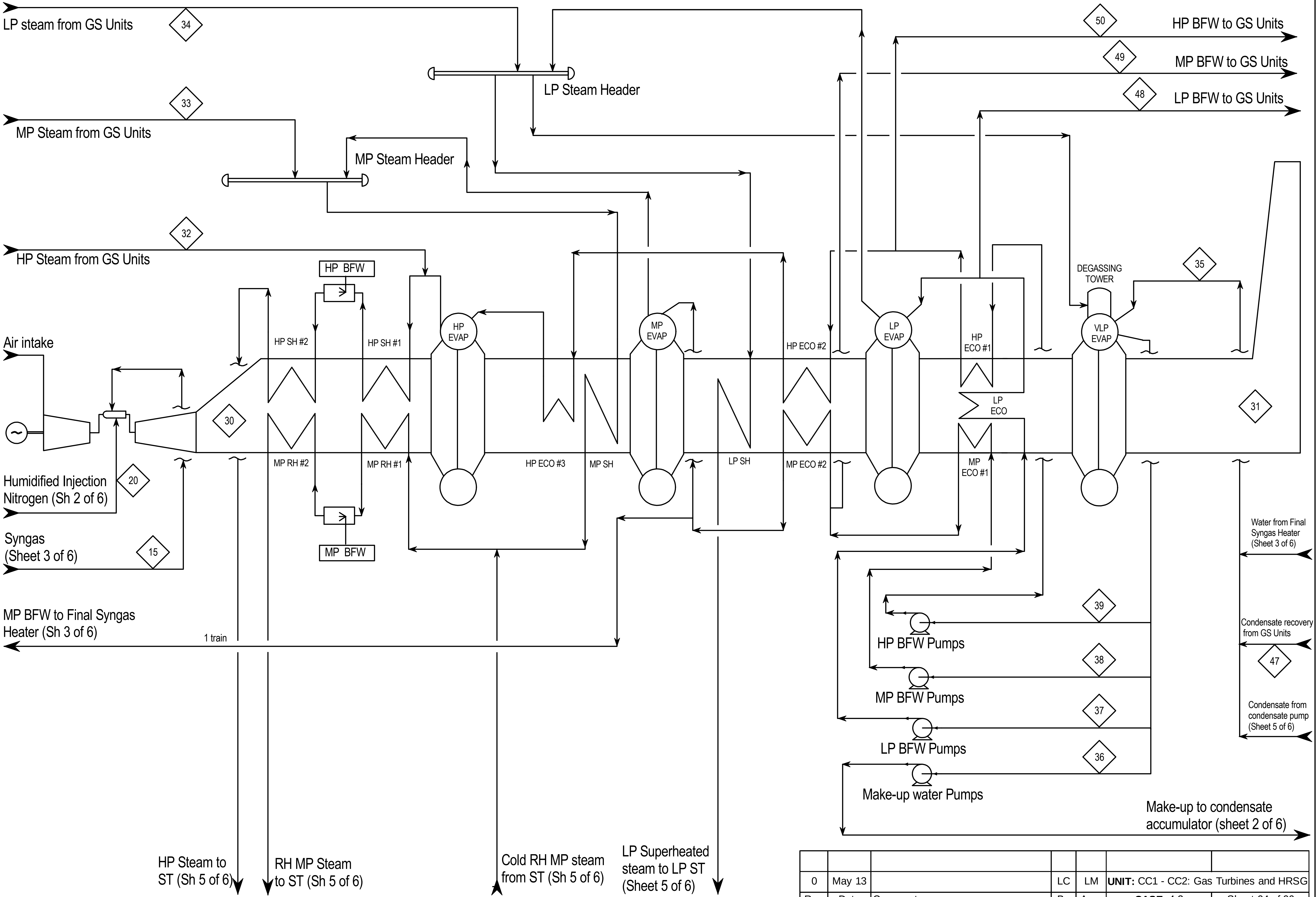
Rev.	Date	Comment	By	Appr	**CASE:** 4.2	Sheet 01 of 06



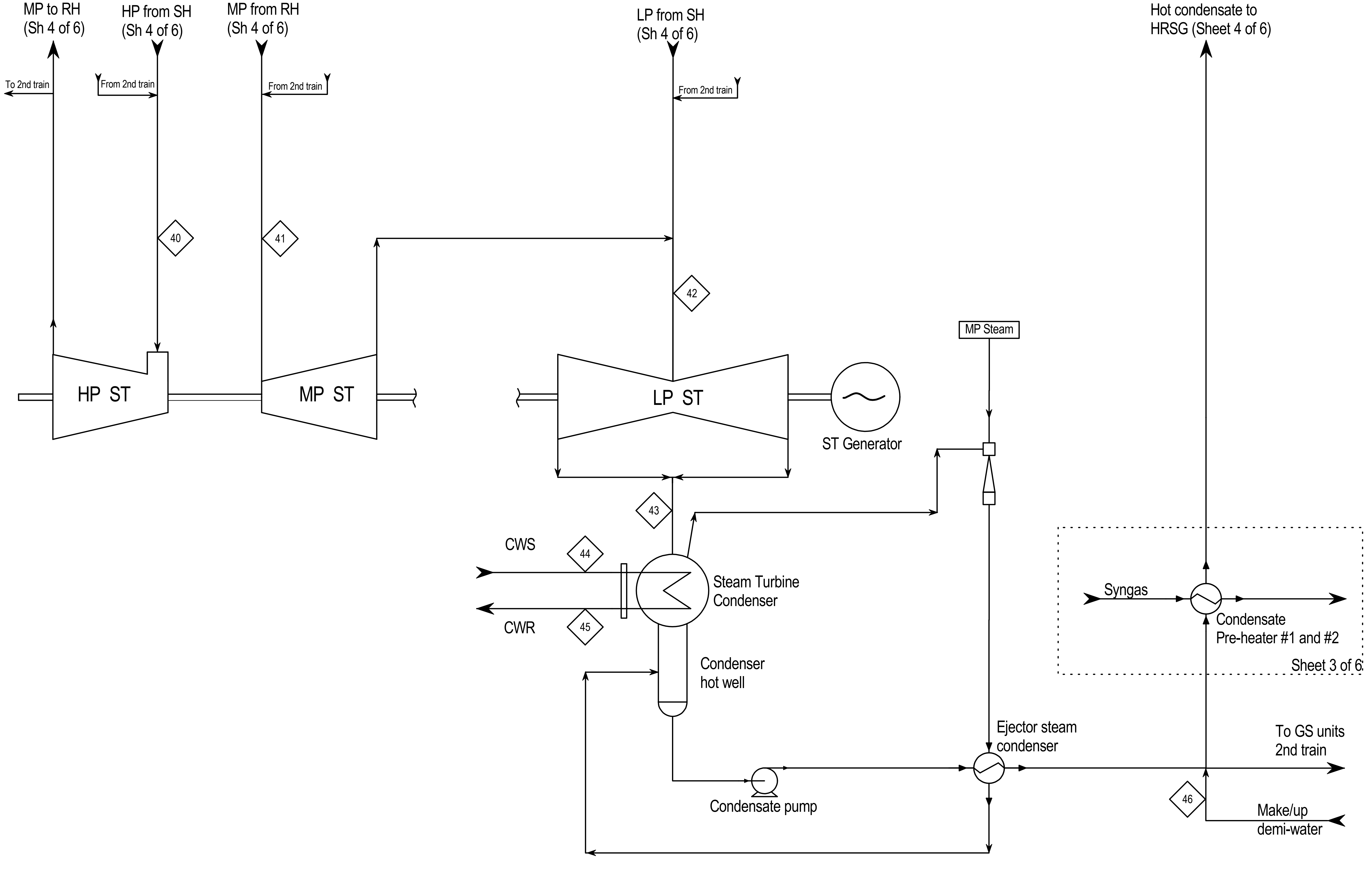
0	May 13		LC	LM	**UNIT:** GS3: Syngas treatment	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2	Sheet 02 of 06



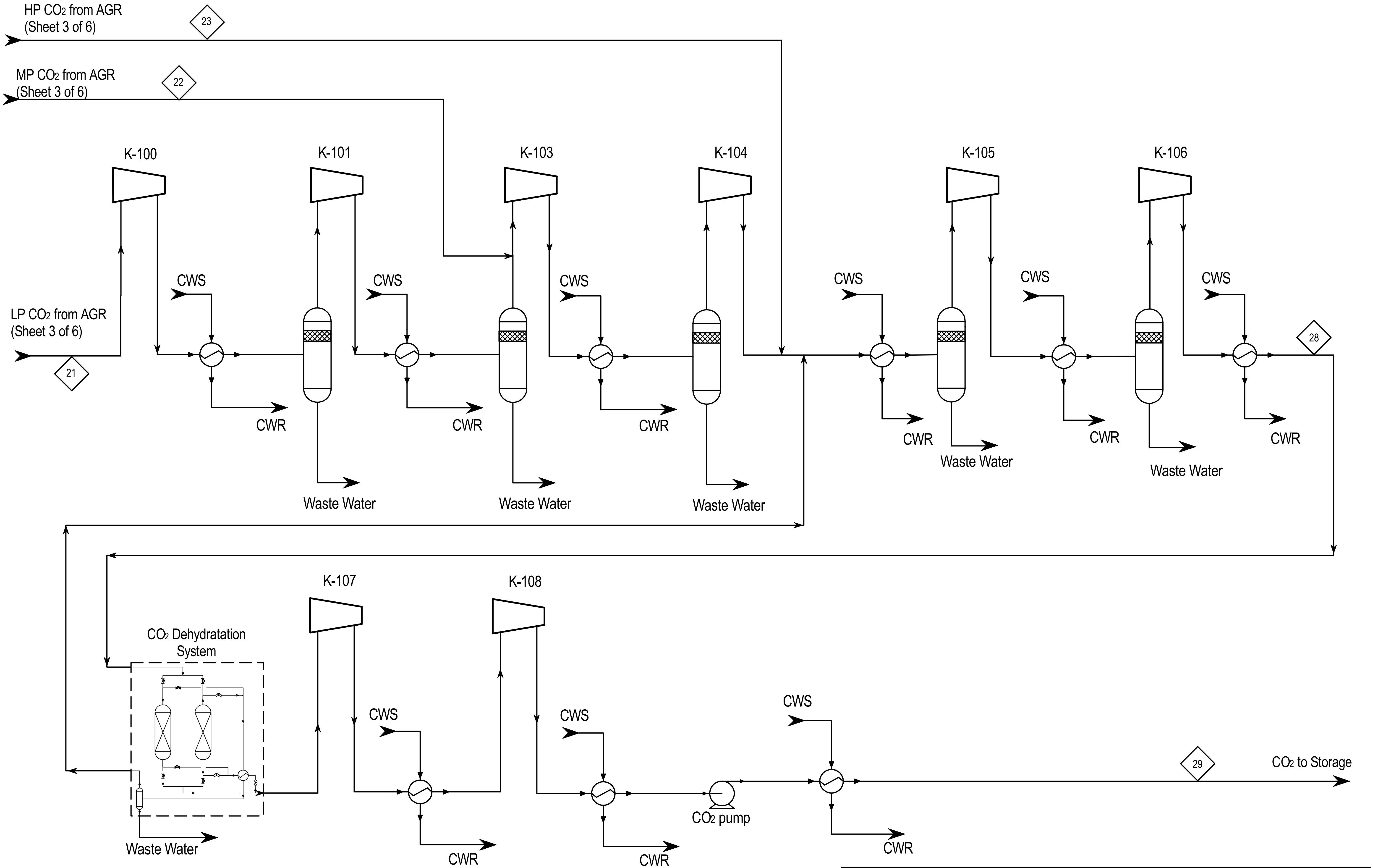
0	May 13		LC	LM	**UNIT:** GS3: Syngas cond., AGR and SRU	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2	Sheet 03 of 06



Rev.	Date	Comment	By	Appr		
0	May 13		LC	LM	**UNIT:** CC1 - CC2: Gas Turbines and HRSG	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2	Sheet 04 of 06



0	May 13		LC	LM	**UNIT:** CC3: Steam Turbine and Condenser	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2	Sheet 05 of 06



0	May 13		LC	LM	**UNIT:** CO2 compression	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2	Sheet 06 of 06

4. Heat and Material Balance

Heat & Material Balances here below reported make reference to the simplified Process Flow Diagrams of section 3.

FOSTER WHEELER	Case 4.2 - GE-BASED IGCC - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
	CLIENT :	IEAGHG	PREP.	LC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 1000 - Gasification Island

STREAM	1	2	3	4	5	18				
	Coal to Gasification Island	HP Oxygen to Gasification	Slag from Gasification	Effluent Water from Gasification	Syngas at Scrubber Outlet to Shift Reactor	Return condensate to gasification				
Temperature (°C)	AMB	10	80	AMB	N/D	144				
Pressure (bar)	ATM	75-80 (1)	ATM	ATM	64.6	70				
TOTAL FLOW	Solid		Solid + water							
Mass flow (kg/h)	349,100	323,000	87,400	94,500	1,154,000	493,200				
Molar flow (kmol/h)		10,025		5,250	58,004	27,385				
LIQUID PHASE										
Mass flow (kg/h)			43,700	94,500	-	493,200				
GASEOUS PHASE										
Mass flow (kg/h)		323,000			1,154,000					
Molar flow (kmol/h)		10,025			58,004					
Molecular Weight		32.22			-					
Composition (vol %)	%wt		50% moisture		dry basis					
H_2	C: 64.6%	-			35.80					
CO	H: 4.38%	-			42.80					
CO_2	O: 7.02%	-			17.80					
N_2	S: 0.86%	1.50			3.22					
O_2	N: 1.41%	95.00			0.00					
CH_4	Cl: 0.03%	-			0.00					
H_2S + COS	Moisture: 9.5%	-			0.38					
Ar	Ash: 12.20%	3.50			0.00					
HCN		-			0.00					
NH_3		-			0.00					
H_2O		-			-					

Notes 1. FW assumption

	Case 4.2 - GE-BASED IGCC - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	LC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE

UNIT 2100 - Air Separation Unit

STREAM	6	2	7	8	9	10	11			
	Air Intake from Atmosphere	HP Oxygen to Gasification	LP Nitrogen to process unit	MP Nitrogen forSyngas Dilution	MP Nitrogen for NOx Control	Oxygen to SRU	Nitrogen vent			
Temperature (°C)	Ambient	10	Ambient (°)	135	122	Ambient	Ambient			
Pressure (bar)	Ambient	75-80 (°)	7,5 (°)	32	28	6	Atmospheric			
TOTAL FLOW										
Mass flow (kg/h)	1,394,750	323,000	25,220	277,810	306,450	1,933	445,990			
Molar flow (kmol/h)	48,320	10,025	900	9,912	10,934	60	15,912			
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-		-	-			
GASEOUS PHASE										
Mass flow (kg/h)	1,394,750	323,000	25,220	277,810	306,450	1,933	445,990			
Molar flow (kmol/h)	48,320	10,025	900	9,912	10,934	60	15,912			
Molecular Weight	28.86	32.22	28.02	28.03	28.03	32.22	28.03			
Composition (vol %)										
H_2	-	-	-	-	-	-	-			
CO	-	-	-	-	-	-	-			
CO_2	0.04	-	-	0.05	0.05	-	0.05			
N_2	77.32	1.50	99.999	98.00	98.00	1.50	98.00			
O_2	20.75	95.00	0.001	1.00	1.00	95.00	1.00			
CH_4	-	-	-	-	-	-	-			
H_2S + COS	-	-	-	-	-	-	-			
Ar	0.92	3.50	-	0.25	0.25	3.50	0.25			
H_2O	0.97	-	-	0.70	0.70	-	0.70			

Notes 1. FW assumption

	Case 4.2 - GE-BASED IGCC - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	LC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE

UNIT 2200 - Syngas cooling & Conditioning line

STREAM	5	12	13	14	15	16	17	18	19	20
	Syngas at Scrubber Outlet to Shift Reactor	Syngas at Shift Reactor Outlet	Raw Syngas to Acid Gas Removal	HP Purified Syngas from Acid Gas Removal	Diluted Syngas to Power Island	Stripped condensate from SWS	BFW make-up to condensate accumulator	Return condensate to gasification	Nitrogen to saturator	Moist. Nitrogen to combined cycle
Temperature (°C)	N/D	323	34	15	210	132	123	144	122	210
Pressure (bar)	64.6	61.6	57	53	31.0	70.0	2.2	70.0	28.0	27.0
TOTAL FLOW										
Mass flow (kg/h)	1,154,000	1,154,000	891,750	148,235	425,861	43,225	227,000	492,600	306,481	384,099
Molar flow (kmol/h)	58,004	58,004	43,496	26,243	36,150	2,400	12,600	27,350	10,935	15,243
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-	43,225	227,000	492,600	-	
GASEOUS PHASE										
Mass flow (kg/h)	1,154,000	1,154,000	891,750	148,235	425,861	-	-	-	306,481	384,099
Molar flow (kmol/h)	58,004	58,004	43,496	26,243	36,150	-	-	-	10,935	15,243
Molecular Weight	-	19.90	20.50	5.65	11.78	-	-	-	28.03	25.20
Composition (vol %)	dry basis									
H_2	35.80	41.04	54.74	89.55	65.00	-	-	-	0.00	0.00
CO	42.80	0.46	0.61	0.98	0.71	-	-	-	0.00	0.00
CO_2	17.80	31.54	41.98	5.73	4.17	-	-	-	0.05	0.04
N_2	3.22	3.22	2.27	3.73	29.57	-	-	-	98.00	70.29
O_2	0.00	0.00	-	-	0.27	-	-	-	1.00	0.72
CH_4	0.00	0.00	-	-	0.00	-	-	-	0.00	0.00
H_2S + COS	0.38	0.38	0.26	0.00	0.00	-	-	-	0.00	0.00
	0.00	0.00	0.00	0.00	0.00	-	-	-	-	-
	0.00	0.00	0.00	0.00	0.00	-	-	-	-	-
Ar	0.00	0.00	-	-	0.07	-	-	-	0.25	0.18
H_2O	-	25.06	0.14	0.01	0.20	-	-	-	0.70	28.77

	Case 4.2 - GE-BASED IGCC - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	LC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 2300 - Acid Gas Removal

STREAM	13	14	21	22	23	24	25			
	Raw Syngas from Syngas Cooling	HP Purified Syngas to Syngas Cooling	LP CO2 to Compression	MP CO2 to Compression	HP CO2 to Compression	Acid Gas to SRU & TGT	Recycle Tail Gas from SRU			
Temperature (°C)	34	15	-9	-1	8	20	35			
Pressure (bar)	57	53	2.5	6.6	20.3	1.6	56.5			
TOTAL FLOW										
Mass flow (kg/h)	891,750	148,235	163,504	407,928	167,385	9,831	5,804			
Molar flow (kmol/h)	43,496	26,243	3,718	9,290	4,068	293	161			
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-	-	-			
GASEOUS PHASE										
Mass flow (kg/h)	891,750	148,235	163,504	407,928	167,385	9,831	5,804			
Molar flow (kmol/h)	43,496	26,243	3,718	9,290	4,068	293	161			
Molecular Weight	20.5	5.6	44.0	43.9	41.1	33.6	36.1			
Composition (vol %)										
H_2	54.74	89.55	0.00	0.20	6.66	14.47	17.65			
CO	0.61	0.98	0.00	0.00	0.16	0.25	0.00			
CO_2	41.98	5.73	99.87	99.74	92.95	43.29	77.90			
N_2	2.27	3.73	0.00	0.00	0.19	0.38	0.69			
O_2	-	-	0.00	0.00	0.00	-	0.00			
CH_4	-	-	0.00	0.00	0.00	0.00	0.00			
H_2S + COS	0.26	0.00	0.00	0.00	0.00	40.70	3.76			
Ar	-	-	0.00	0.00	0.00	0.00	0.00			
HCN										
NH_3	-	-	-	-	-	0.11	-			
H_2O	0.14	0.01	0.13	0.06	0.04	0.80	0.00			

FOSTER WHEELER	Case 4.2 - GE-BASED IGCC - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
	CLIENT :	IEAGHG	**PREP.**	LC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**CHECKED**	NF		
	PROJECT NO:	1-BD-0681 A	**APPROVED**	LM		
	LOCATION:	The Netherlands	**DATE**	July 2013		

HEAT AND MATERIAL BALANCE

UNIT 2400 - Sulfur Recovery Unit (SRU) & Tail Gas Treatment (TGT)

STREAM	8	24	25	26	27					
	Oxygen to SRU	Acid Gas from AGR Unit	Claus Tail Gas to AGR Unit	Sour Gas from Sour water stripper	Product Sulphur					
Temperature (°C)	Amb	20	35	80	-					
Pressure (bar)	6	1.6	56.5	4	-					
TOTAL FLOW										
Mass flow (kg/h)	1,933	9,831	5,804	170	3,000					
Molar flow (kmol/h)	60	293	161	4.5	-					
LIQUID PHASE										
Mass flow (kg/h)		-	-	-	-					
GASEOUS PHASE										
Mass flow (kg/h)	1,933	9,831	5,804	170	-					
Molar flow (kmol/h)	60	293	161	4.5	-					
Molecular Weight	32.2	33.6	36.1	37.7	-					
Composition (vol %)										
H_2	-	14.47	17.65	0.49	-					
CO	-	0.25	0.00	0.03	-					
CO_2	-	43.29	77.90	74.16	-					
N_2	1.50	0.38	0.69	0.19	-					
O_2	95.00	-	0.00	-	-					
CH_4	-	0.00	0.00	-	-					
H_2S + COS	-	40.70	3.76	3.57	-					
Ar	3.50	0.00	0.00	-	-					
HCN										
NH_3	-	0.11	-	9.14	-					
H_2O	-	0.80	0.00	12.42	-					

	Case 4.2 - GE-BASED IGCC - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	LC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
Unit 2500 - CO2 Compression and Drying

STREAM	21	22	23	28	29					
	LP CO2 to Compression	**MP CO2 to Compression**	**HP CO2 to Compression**	**CO_2 to drying package**	**CO_2 to storage**					
Temperature (°C)	-9	-1	8	26	30					
Pressure (bar)	2.5	6.6	20.3	39.8	110.0					
TOTAL FLOW										
Mass flow (kg/h)	163,504	407,928	167,385	806,058	725,168					
Molar flow (kmol/h)	3,718	9,290	4,068	18,630	16,740					
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-					
GASEOUS PHASE										
Mass flow (kg/h)	163,504	407,928	167,385	806,058	725,168					
Molar flow (kmol/h)	3,718	9,290	4,068	18,630	16,740					
Molecular Weight	44	43.9	41.1	43.3	43.3					
Composition (vol %)										
H_2	0.0	0.20	6.66	1.61	1.61					
CO	0.0	0.00	0.16	0.04	0.04					
CO_2	99.9	99.74	92.95	98.18	98.30					
N_2	0.0	0.00	0.19	0.05	0.05					
O_2	0.0	0.00	0.00	0.00	0.00					
CH_4	0.0	0.00	0.00	0.00	0.00					
H_2S + COS	0.0	0.00	0.00	0.00	0.00					
Ar	0.0	0.00	0.00	0.00	0.00					
HCN	0.0	0.00	0.00	0.00	0.00					
NH3	0.0	0.00	0.00	0.00	0.00					
H_2O	0.1	0.06	0.04	0.12	0.00					

Case 4.2 - GE-BASED IGCC - HEAT AND MATERIAL BALANCE		REVISION	0	1
CLIENT :	IEAGHG	**PREP.**	LC	
PROJECT NAME:	CO_2 capture at coal based power and H2 plants	**CHECKED**	NF	
PROJECT NO:	1-BD-0681 A	**APPROVED**	LM	
LOCATION:	The Netherlands	**DATE**	July 2013	

Unit 3000 - Power Island

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
15	Treated Syngas from Syngas Cooling (*)	201.0	210	30.8	-
20	Moisturized Nitrogen for NOx control (*)	192.0	210	26.9	-
30	Flue gas from GT (*)	2780	560	1.05	-
31	Flue gas at stack (*) (1)	2780	133	atm	-
32	HP Steam from Process Units (*)	267.7	335	137.0	2646
33	MP Steam from Process Units (*)	52.5	253	41.0	2801
34	LP Steam from Process Units (*)	23.1	168	7.5	2766
35	Condensate to Deaerator (*)	896.1	94	2.2	394
36	BFW to Make-up Water Pumps (*)	113.5	123	2.2	518
37	BFW to LP BFW Pumps (*)	138.8	123	2.2	518
38	BFW to MP BFW Pumps (*)	296.4	123	2.2	518
39	BFW to HP BFW Pumps (*)	390.9	123	2.2	518
40	HP Steam to Steam Turbine	772.2	532	132.0	3421
41	Hot RH Steam to Steam Turbine	1088.3	532	34.8	3524
42	LP Steam to Steam Turbine	1179.1	283	5.7	3027
43	Steam to Condenser	1179.1	29	0.04	2299
44	Water Supply to Steam Condenser	55731	15	4.0	63
45	Water Return from Steam Condenser	55731	26	3.5	109
46	Make-up water	313.2	15	6.0	64
47	Condensate return from Process Units	129.2	94	4.2	394
48	LP BFW to Process Units	140.0	160	19	676
49	MP BFW to Process Units	197.6	160	56	678
50	HP BFW to Process Units	538.7	160	180	686

(*) Flowrate figure refers to one train (50% capacity)
(1) Flue gas molar composition: N_2: 73.8%; H_2O: 13.7%; O_2: 10.9%; CO_2: 0.8%; Ar: 0.8%.

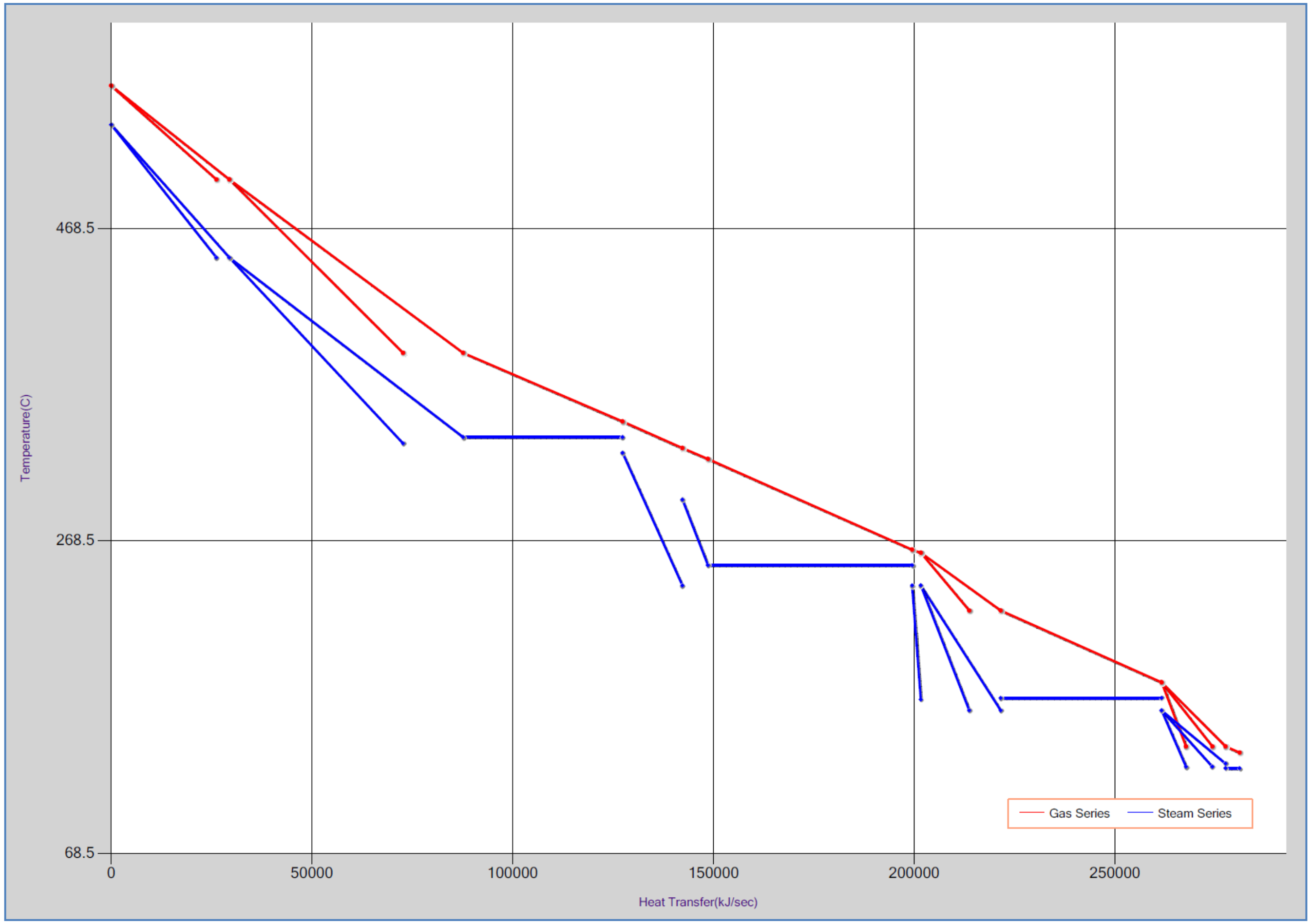


Figure 1 – Case 4.2 – HRSG T-Q diagram

5. Utility consumption

Main utility consumption of the process and utility units is reported in the following tables. More specifically:

- Steam / BFW / condensate interface summary is reported in Table 2.
- Water consumption summary is shown in Table 3.
- Electrical consumption summary is included in Table 4.

Table 2. Case 4.2 – Steam/BFW/condensate interface summary

CLIENT:	IEAGHG
PROJECT:	CO2 capture at coal based power and hydrogen plants
LOCATION:	The Netherlands
FWI Nº:	1-BD-0681 A

REVISION	Rev.0		
DATE	May 2013		
ISSUED BY	LC		
CHECKED BY	NF		
APPROVED BY	LM		

Case 4.2 - GE based IGCC - Steam and water balance

UNIT	DESCRIPTION UNIT	HP Steam barg 137 [t/h]	MP Steam barg 40 [t/h]	LP Steam barg 6.5 [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									
2100	**Air Separation Unit (ASU)**									
1000	**Gasification Section**	**-444.1**			**446.7**					**-2.5**
2200	**Syngas Treating and Conditioning Line**	**-91.2**	**-97.2**	**-102.2**	**92.1**	**188.9**	**140.1**	**227.0**	**-49.5**	**-308.0**
2300	**Acid Gas Removal**			**64.0**					**-64.0**	**0.00**
2400	**Sulphur Recovery (SRU)**		**-7.9**			**8.7**			**-0.75**	**-0.08**
3000	**POWER ISLANDS UNITS**	**535.3**	**105.1**	**23.2**	**-538.7**	**-197.6**	**-140.1**	**-227.0**	**129.2**	
4000	**UTILITY and OFFSITE UNITS**			**15.0**					**-15.0**	**0.00**
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-310.6**

Notes: (1) Negative figures represent generation

Table 3. Case 4.2 – Water consumption summary

CLIENT:	IEAGHG
PROJECT:	CO2 capture at coal based power and H2 plants
LOCATION:	The Netherlands
FWI Nº:	1-BD-0681 A

Revision	0
Date	May 2013
ISSUED BY	LC
CHECKED BY	NF
APPR. BY	LM

Case 4.2 - GE based IGCC - Water consumption summary

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water Primary system [t/h]	Cooling Water Secondary System [t/h]
	AIR SEPARATION UNIT (ASU)				
2100	**Air Separation Unit**				**11220**
	GASIFICATION SECTION (GS)				
1000	**Gasification**	**145**			**3870**
2200	**Syngas treatment and conditioning line**				**490**
2300	**Acid Gas Removal**		**0.6**		**6870**
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**				**160**
	CO_2 COMPRESSION				
2500	**CO_2 Compression**				**5850**
	COMBINED CYCLE (CC)				
3100	**Gas Turbines and Generator auxiliaries**			**55510**	**780**
3200	**Heat Recovery Steam Generator**				
3300	**Steam Turbine and Generator auxiliaries**		**313.3**		**2050**
	Miscellanea				
	UTILITY UNITS (UU)				
4000	**Cooling Water System**	**1598**			
4000	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**471**	**-314**		
4000	**Waste Water Treatment**	**-91.7**			
4000	**Balance of Plant (BOP)**				**410**
	TOTAL CONSUMPTION	**2122**	**0**	**55510**	**31700**

Note: Negative figures represent generation

Table 4. Case 4.2 – Electrical consumption summary

CLIENT: IEAGHG
PROJECT: CO2 capture at coal based power and hydrogen plants
LOCATION: The Netherlands
FWI Nº: 1-BD-0681 A

Rev.0
Date: May 2013
ISSUED BY: LC
CHECKED BY: NF
APPR. BY: LM

Case 4.2 - GE based IGCC - Electrical consumption summary

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	AIR SEPARATION UNIT (ASU)	
2100	**MAC consumptions**	**124220**
	BAC consumptions	**12270**
	Nitrogen compressor and miscellanea	**35530**
	GASIFICATION SECTION (GS)	
900	**Coal Receiving Handling and Storage**	**410**
1000	**Gasification**	**8790**
2200	**Syngas treatment and conditioning line**	**1250**
2300	**Acid Gas Removal**	**20850**
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**	**700**
2500	**CO_2 Compression**	**33970**
	COMBINED CYCLE (CC)	
3100	**Gas Turbines auxiliaries**	**2000**
3200	**Heat Recovery Steam Generator**	**7530**
3300	**Steam Turbine auxiliaries and excitation system**	**850**
3300	**Miscellanea**	**3120**
	UTILITY UNITS (UU)	
4000	**Cooling Water System**	**10490**
4000	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**730**
4000	**Balance of Plant (BOP)**	**1090**
	TOTAL CONSUMPTION	**263800**

6. Overall Performance

The following table shows the overall performance of Case 4.2.

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**DATE**	May 2013
PROJECT No. :	1-BD-0681 A	**MADE BY**	LC
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 4.2 - IGCC Plant Performance Summary

OVERALL PERFORMANCES		
Coal Flowrate (as received)	t/h	349.1
Coal LHV (as received)	kJ/kg	25870
Coal HHV (as received)	kJ/kg	27060
THERMAL ENERGY OF FEEDSTOCK (A)	**MWth (LHV)**	**2509**
THERMAL ENERGY OF FEEDSTOCK (A')	**MWth (HHV)**	**2624**
Thermal Power of Raw Syngas exit Scrubber (D)	MWth (LHV)	1785
Thermal power of syngas to AGR	MWth (LHV)	1638
Thermal Power of Clean Syngas to Gas Turbines (E)	MWth (LHV)	1600
Syngas treatment efficiency (E/D x 100)	% (LHV)	89.6
Gas turbines total electric power output	MWe	688.0
Steam turbine electric power output	MWe	443.8
Syngas expader	MWe	9.0
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (C)	**MWe**	**1140.8**
Gasification Section units consumption	MWe	32.0
ASU consumption	MWe	172.0
Combined Cycle units consumption	MWe	13.5
CO_2 Compression and Dehydration unit consumption	MWe	34.0
Utility Units consumption	MWe	12.3
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**263.8**
NET ELECTRIC POWER OUTPUT OF IGCC	**MWe**	**877.0**
(Step Up transformer efficiency = 0.997%) (B)	**MWe**	**874.3**
Gross electrical efficiency (C/A x 100)	% (LHV)	45.5
Net electrical efficiency (B/A x 100)	**% (LHV)**	**34.9**
Gross electrical efficiency (C/A' x 100)	% (HHV)	43.5
Net electrical efficiency (B/A' x 100)	**% (HHV)**	**33.3**
Fuel Consumption per net power production	**MWth/MWe**	**2.87**
CO_2 emission per net power production	**kg/MWh**	**93.7**

The following table shows the overall CO_2 balance and CO_2 removal efficiency of Case 4.2.

CO_2 removal efficiency	Equivalent flow of CO_2 kmol/h
INPUT	
Fuel Mix (Carbon AR)	18730
TOTAL (A)	18730
OUTPUT	
Slag + Waste water (B)	101
CO_2 product pipeline	
CO	7
CO_2	16759
CH_4	0
COS	0
Total to storage (C)	16766
Emission	
CO_2 + CO (Combined Cycle)	1862
TOTAL	18730
Overall Carbon Capture, % ((B+C)/A)	90.1

7. Environmental impact

The IGCC plant design is based on advanced technologies that allow to reach high electrical generation efficiency, while minimizing impact to the environment. Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

7.1. Gaseous emissions

During normal operation at full load, main continuous emissions are the combustion flue gases of the two trains of the combined cycle, from the combustion of the syngas in the two gas turbines. Table 5 summarises expected flow rate and concentration of the combustion flue gas from one train of the combined cycle.

Minor gaseous emissions are created by 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 related to the milling, storage and handling of solids (e.g. solid transfer, leakage). As summarised in Table 6, these emission mainly consists of air or nitrogen containing particulate.

Table 5. Case 4.2 – Plant emission during normal operation

Flue gas to HRSG stack	
Emission type	Continuous
Conditions	
Wet gas flowrate, kg/h	2,780,000
Flow, Nm^3/h (1)	2,679,300
Temperature, °C	133
Composition	(% vol)
Ar	0.77
N_2	72.92
O_2	10.92
CO_2	0.90
H_2O	14.49
Emission	mg/Nm^3 (1)
NOx	< 50
SOx	< 1
CO	< 100
Particulate	< 10

(1) Dry gas, O_2 content 15% vol.

Table 6. Case 4.2 – Plant minor emission

Emission source	Emission type	Temperature	
Coal handling and storage	Continuous	ambient	Air: 10 mg/Nm^3 particulate

7.2. Liquid effluents

Main liquid effluents are the cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids, and the effluent from the Waste Water Treatment, which flows to an outside plant battery limits recipient.

Cooling Tower blow-down

Flowrate : 380 m^3/h

Waste Water Treatment effluent

Flowrate : 160 m^3/h

7.3. Solid effluents

The IGCC plant is expected to produce the following solid by-product:

Slag from gasifier

Flowrate : 45 t/h (dry basis)

Moisture content : 50%

Slag product has a potential use as major components in concrete mixtures to make road, pads, storage bins.

8. Preliminary plot plan

Plot plan at block level of Case 4.2 is attached to this section, showing the area occupied by the main units and equipment of the plant.

REV.	DATE	DESCRIPTION	DRAW	BY	CHD.	APP.
COO1	AUG 2013	Preliminary issue for comments	APeccati			

DESCRIPTION

CLIENT IEA GHG

SITE The Netherlands

CO2 Capture and coal fired Power Plants

CASE: 4.2 - IGCC (GE Energy)

PRELIMINARY PLOT PLAN

FOSTER WHEELER

SCALE N. A.

FWI DWG N° 1BD0681A - 01 - 005

REV. COO1

CAD FILE NAME

Form. A3

9. Equipment list

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

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	LOCATION:	The Netherlands	DATE	May 2013	January 2014		
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EQUIPMENT LIST

Unit 900 - Coal Handling & Storage (NA)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-901	**Coal Handling**		Coal flowrate: 349 t/h					30 days storage
	Wagon tipper							Storage piles: 2 x 137,000 t each
	Receiving Hopper, vibratory feeder and belt extractor							
	Conveyors	Belt						
	Transfer Towers	Enclosed						
	As-Received Coal Sampling System	Two-Stage						
	As-Received Magnetic Separator System	Magnetic Plates						
	Conveyors	Belt						
	Transfer Towers	Enclosed						
	Crushers Towers	Impactor reduction						
	As-Fired Coal Sampling System	Swing hammer						
	As-Fired Magnetic Separator System	Magnetic Plates						
	Coal Silo		2 x 5300 m3					for daily storage

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EQUIPMENT LIST
Unit 1000 - Gasification Island (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-1002	**GE Energy Coal gasification package**							
	Coal grinding and slurry preparation							Included in Z-1002
	Gasifiers (RSC)		2 x 4200 t/d coal (as received) to burners 2 x 900 MWth (LHV basis) syngas at scrubber outlet					Included in Z-1002
	Scrubber							Included in Z-1002
	Black Water flash							Included in Z-1002
	Coarse slag handling							Included in Z-1002
	Grey water systeam and fines handling							Included in Z-1002

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EQUIPMENT LIST
Unit 2100 - Air Separation Unit (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2101	**ASU Package** including:							
	Cold Box	Cryogenic	162 t/h of 95% purity O2 each train					Included in Z-2101
	Main Air compressors (MAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 2 x 297800 Nm3/h	2 x 35250 kW				Included in Z-2101
	Booster air compressors (BAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 238200 Nm3/h	7500 kW				Included in Z-2101
	MP N2 compressors (GAN)	Electric motor driven, centrifugal, with intercooling	Flowrate: 2 x 128500 Nm3/h	2 x 9500 kW				Included in Z-2101
	MP N2 compressors - booster (GAN)	Electric motor driven, centrifugal	Flowrate: 122200 Nm3/h	1120 kW				Included in Z-2101
	O2 pumps	Centrifugal						Included in Z-2101
	Back-up oxygen vaporiser	Shell and tube						Included in Z-2101
Common units to both trains:								
	LOX (liquid oxygen) storage	Fixed roof storage tank						8 hour storage for 1 gasification train Normal operating p: 5 bar a Normal operating T: -165 °C Included in Z-2101
	LIN (liquid nitrogen) storage	Fixed roof storage tank						8 hour storage for 1 Gasifier & 4 min storage for Syngas dilution and NOX control Normal operating p: 5 bar a Normal operating T: -180 °C Included in Z-2101
	Gaseous oxygen storage							
	Gaseous nitrogen storage							

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EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning Line (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	HEAT EXCHANGERS				Shell/tube	Shell/tube		
E-2201	**Feed/Product Heat Exchanger**	Shell & Tube						
E-2202	**HP steam generator**	Kettle						
E-2203	**MP steam generator #1**	Kettle						
E-2204	**MP steam generator #2**	Kettle						
E-2205	**LP steam generator**	Kettle						
E-2206 A/B	**Circulating Water Heater**	Shell & Tube						
E-2207 A/B	**Condensate preheater**	Shell & Tube						
E-2208	**Syngas heater / Circulating water cooler**	Shell & Tube						
E-2209	**Final sygas cooler**	Shell & Tube						
E-2210	**Syngas final heater**	Shell & Tube						
E-2211	**Saturated Nitrogen heater**	Shell & Tube						
	DRUMS							
D-2201	**Condensate Separator**	Vertical						
D-2202	**Condensate Separator**	Vertical						
D-2203	**Condensate Separator**	Vertical						
D-2204	**Condensate Separator**	Vertical						
D-2205	**Condensate Separator**	Vertical						
D-2206	**Condensate accumulator**	Horizontal						Common for both syngas tratment and conditiong line trains

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EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning Line (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	COLUMN							
C-2201	**Nitrogen saturator**	Vertical						
	REACTOR							
R-2201	**1st Shift Catalyst Reactor**	vertical						Overall CO conversion = 98%
R-2202	**2nd Shift Catalyst Reactor**	vertical						
	PUMPS							
P-2201	**Saturator Circulating Water Pump**							
P-2202	**Condensate Pump (to Gasifiers)**							
	EXPANDER							
EX-2201	**Syngas Expander**		Flowrate = 590000 Nm^3/h	10000 kW				
	MISCELLANEA							
X-2201	**Mercury Adsorber**	Sulfur-impregnated activated carbon beds						

Note: equipment list referred to one train only

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EQUIPMENT LIST

Unit 2250 - Sour Water System (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-2251	**SWS PACKAGE**							
C-2251	Sour Water Stripper	Vertical						
	SWS Reboiler							
	SWS Condenser							
E-2251	Sour water heat exchanger (SWS feed / purified)							
P-2251	SWS Pump							

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EQUIPMENT LIST

Unit 2300 - Acid Gas Removal Unit (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2301	**Acid Gas Removal Unit - Absorption section**	Solvent: Selexol	Feed gas: 974900 Nm3/h; 56 barg; 34 °C					One H2S removal column, 3 CO2 removal columns, CO2 removal =91.78% Total Carbon Capture =90.5% Separated removal of CO2 and H2S
Z-2303	**Acid Gas Removal Unit - Solvent regeneration**							Total CO2 removal= 17700 t/d; 10 ppm H2S (dry) in combined CO2
Z-2304	**Chiller Unit**	Electrical driven						T= -10 °C

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EQUIPMENT LIST

Unit 2400 - Sulphur Recovery Unit (2x100%) & Tail Gas Treatment (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2401	**Sulphur Recovery Unit and Tail Gas Treatment Package** - two Sulphur Recovery Unit, each sized for 100% of the capacity - one Tail Gas Treatment Unit sized for 100% of capacity (including Reduction Reactor and Tail Gas Compressor)		Sulphur Prod.= 72 t/d Acid Gas from AGR = 6680 Nm3/h Expected Treated Tail Gas =3602 Nm3/h					Sulphur content > 99,9 % mol min (dry basis)

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EQUIPMENT LIST

Unit 2500 - CO_2 Compression Package (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [MW]	P design [barg]	T design [°C]	Materials	Remarks
	COMPRESSORS							
C-2501	CO_2 Compressors	Centrifugal, Electrical Driven, 8 intercooled Stages	190000 Nm3/h p in: 2,45 bar a p out: 80 bar a	18000 kW				Water cooled
	PUMPS		**Q,m3/h x H,m**					
P-2501	CO_2 Pump	Centrifugal	640 x 530	800 kW				Liquid CO_2 product, per each train: Flowrate: 370 t/h; 110 bar a; 30°C
	PACKAGE							
PK-2501	CO_2 drying package							

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EQUIPMENT LIST
Unit 3100 - Gas Turbine (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-3101	**Gas Turbine & Generator Package**							
GT-3101	Gas turbine	F-Class Gas Turbine	344 MW					Included in Z-3101
G-3101	Gas turbine Generator		450 MVA					Included in Z-3101

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	HEAT RECOVERY STEAM GENERATOR							
HRSG-3201	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels. Simple Recovery, Reheated.						
Each HRSG including:								
D-3201	**HP steam Drum**							
D-3202	**MP steam Drum**							
D-3203	**LP steam Drum**							
D-3204	**VLP steam Drum with degassing section**							
E-3201	**HP Superheater 2nd section**							Included in HRSG-3201 / 2
E-3202	**HP Superheater 1st section**							Included in HRSG-3201 / 2
E-3203	**HP Evaporator**							Included in HRSG-3201 / 2
E-3204	**HP Economizer 3rd section**							Included in HRSG-3201 / 2
E-3205	**HP Economizer 2nd section**							Included in HRSG-3201 / 2
E-3206	**HP Economizer 1st section**							Included in HRSG-3201 / 2
E-3207	**MP Reheater 2nd section**							Included in HRSG-3201 / 2
E-3208	**MP Reheater 1st section**							Included in HRSG-3201 / 2
E-3209	**MP Superheater**							Included in HRSG-3201 / 2
E-3210	**MP Evaporator**							Included in HRSG-3201 / 2
E-3211	**MP Economizer 2nd section**							Included in HRSG-3201 / 2
E-3212	**MP Economizer 1st section**							Included in HRSG-3201 / 2
E-3213	**LP Superheater**							Included in HRSG-3201 / 2
E-3214	**LP Evaporator**							Included in HRSG-3201 / 2
E-3215	**LP Economizer**							Included in HRSG-3201 / 2
E-3216	**VLP Evaporator**							Included in HRSG-3201 / 2

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PUMPS		$Q, m^3/h \times H, m$					
P-3201 A/B	**HP BFW Pumps**	centrifugal	440 x 1800	2800				One operating, one spare
P-3203 A/B	**MP BFW Pumps**	centrifugal	350 x 600	750				One operating, one spare
P-3205 A/B	**LP BFW Pumps**	centrifugal	160 x 130	75				One operating, one spare
P-3207 A/B	**VLP BFW Pumps**	centrifugal	140 x 815	400				One operating, one spare
	MISCELLANEA							
X-3201	**Flue Gas Monitoring System**							NOx, CO, SO_2, particulate, H_2O, O_2
STK-3201	**CCU Stack**							
SL-3201	**Stack Silencer**							
DS-3201	**HP Steam Desuperheater**							Included in HRSG-3201
DS-3202	**MP Steam Desuperheater**							Included in HRSG-3201
	PACKAGES							
Z-3201	**Fluid Sampling Package**							
Z-3202	**Phosphate Injection Package**							
D-3204	Phosphate storage tank							Included in Z - 3202
P-3205 A/B	Phosphate dosage pumps							Included in Z - 3202 One operating , one spare
Z-3203	**Oxygen Scavanger Injection Package**							
D-3205	Oxygen scavanger storage tank							Included in Z - 3203
P-3206 A/B	Oxygen scavanger dosage pumps							Included in Z - 3203 One operating , one spare
Z-3204	**Amines Injection Package**							
D-3206	Amines Storage tank							Included in Z - 3204
P-3207 A/B	Amines Dosage pumps							Included in Z - 3204 One operating , one spare

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EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-3301	**Steam Turbine and Generator Package**							
ST-3301	Steam Turbine		444 MWe					*Including:* *Lube oil system* *Cooling system* *Idraulic control system* *Drainage system* *Seals system* *Drainage system*
G-3402	Steam Turbine Generator		580 MVA					*Including relevant auxiliaries*
E-3301A/B	Inter/After condenser							
E-3302	Gland Condenser							
Z-3302	**Steam Condenser Package**							
E-3303	Steam Condenser	Water cooled	710 MWt					*Including:* *Hot well* *Vacuum pump (or ejectors)* *Start up ejector (if required)*
Z-3303	**Steam Turbine by-pass system**							
	PUMPS		**Q,m^3/h x H,m**					
P-3301A/B	Condensate Pumps	Centrifugal, vertica	1940 x 110	800				One operating, one spare
	HEAT EXCHANGERS							
E-3304	Blow-Down Cooler	Shell & Tube						
	DRUMS							
D-3301	Continuous Blow-down Drum	vertical						
D-3302	Discontinuous Blow-down Drum	vertical						

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EQUIPMENT LIST
Unit 4000 - Utility and Offsite

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-4001	**COOLING WATER SYSTEM**							
CT-4001	Cooling Tower Including Cooling water basin	Evaporative, Natural draft	Total heat duty 1070 MWth Diameter: 150 m, Height: 210 m, Water inlet: 17 m				concrete	Included in Z-4001
	Pumps							
P-4001A/B/C/D	Cooling Water pumps (primary system)	Vertical	13880 m3/h x 35 m	1600 kW				Included in Z-4001 4 operating
P-4002A/B/C	Cooling Water pumps (secondary system)	Vertical	14710 m3/h x 45 m	2200 kW				Included in Z-4001 2 operating, one spare
P-4003A/B	Raw water pumps (make-up)	centrifugal	1690 m3/h x 35 m	200 kW				Included in Z-4001 1 operating, one spare
	Packages							
	Cooling Water Filtration Package Cooling Water Sidestream Filters		Capacity: 8500 m3/h					
	Sodium Hypochlorite Dosing Package Sodium Hypochlorite storage tank Sodium Hypochlorite dosage pumps							
	Antiscalant Package Dispersant storage tank Dispersant dosage pumps							
Z-4002	**RAW WATER SYSTEM**							
T-4001	Raw Water storage tank		12720 m3					Included in Z-4002 24 hour storage
P-4004A/B	Raw Water Pumps to gasification island	centrifugal	150 m3/h x 50 m	30 kW				Included in Z-4002 One operating, one spare
P-4005A/B	Raw Water Pumps to demi plant	centrifugal	380 m3/h x 50 m	75 kW				Included in Z-4002 One operating, one spare

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EQUIPMENT LIST

Unit 4000 - Utility and Offsite

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-4003	**DEMI WATER SYSTEM**							
PK-4001	**Demin Water Package, including:**							
	- Multimedia filter - Reverse Osmosis (RO) Cartidge filter - Electro de-ionization system							
T-4002	Demi Water storage tank		8400 m3					Included in Z-4003 24 hour storage
P-4006A/B	Demi Water Pumps	centrifugal	350 m3/h x 35 m	55 kW				Included in Z-4003 One operating, one spare
Z-4004	**FIRE FIGHTING SYSTEM**							
	Fire water storage tank							
	Fire pumps (diesel)							
	Fire pumps (electric)							
	FW jockey pump							
	MISCELLANEA							
	Natural Gas system							
	Waste Water Treatment							
	Sulphur Storage/Handling		72 t/d S prod.					30 days storage
	Flare system							
	Interconnecting							
	Instrumentation							
	DCS							
	Piping							
	Electrical							
	Plant Air							
	Buildings							

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PROJECT NAME	:	CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
DOCUMENT NAME	:	CASE 4.3: IGCC WITH CCS – MHI GASIFICATION TECHNOLOGY
FWI CONTRACT	:	1-BD-0681 A

ISSUED BY	:	M. CARLONI
CHECKED BY	:	N. FERRARI
APPROVED BY	:	L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

1. Introduction

This chapter of the report includes all technical information relevant to Case 4.3 of the study, which is an IGCC plant based on the MHI gasification technology. The plant is designed to process coal, whose characteristic is shown in Chapter B, and produce electric power, exported to the external grid, with capture of the generated carbon dioxide.

The configuration of the plant is based on the following main features:

- MHI Air-Blown Gasification process, with dry feed system;
- Coal Nitrogen Dry Feed;
- Double stage sour CO shift;
- Removal of acid gases (H_2S and CO_2) based on Selexol physical solvent process;
- Oxygen-blown Claus unit, with tail gas catalytic treatment and recycle of the treated tail gas to the AGR;
- CO_2 compression and drying.
- Combined cycle based on two MHI M701F4 gas turbines.

The description of the main process units is covered in chapter E of this report, so only features that are unique to this case are discussed in the following sections, together with the main modelling results.

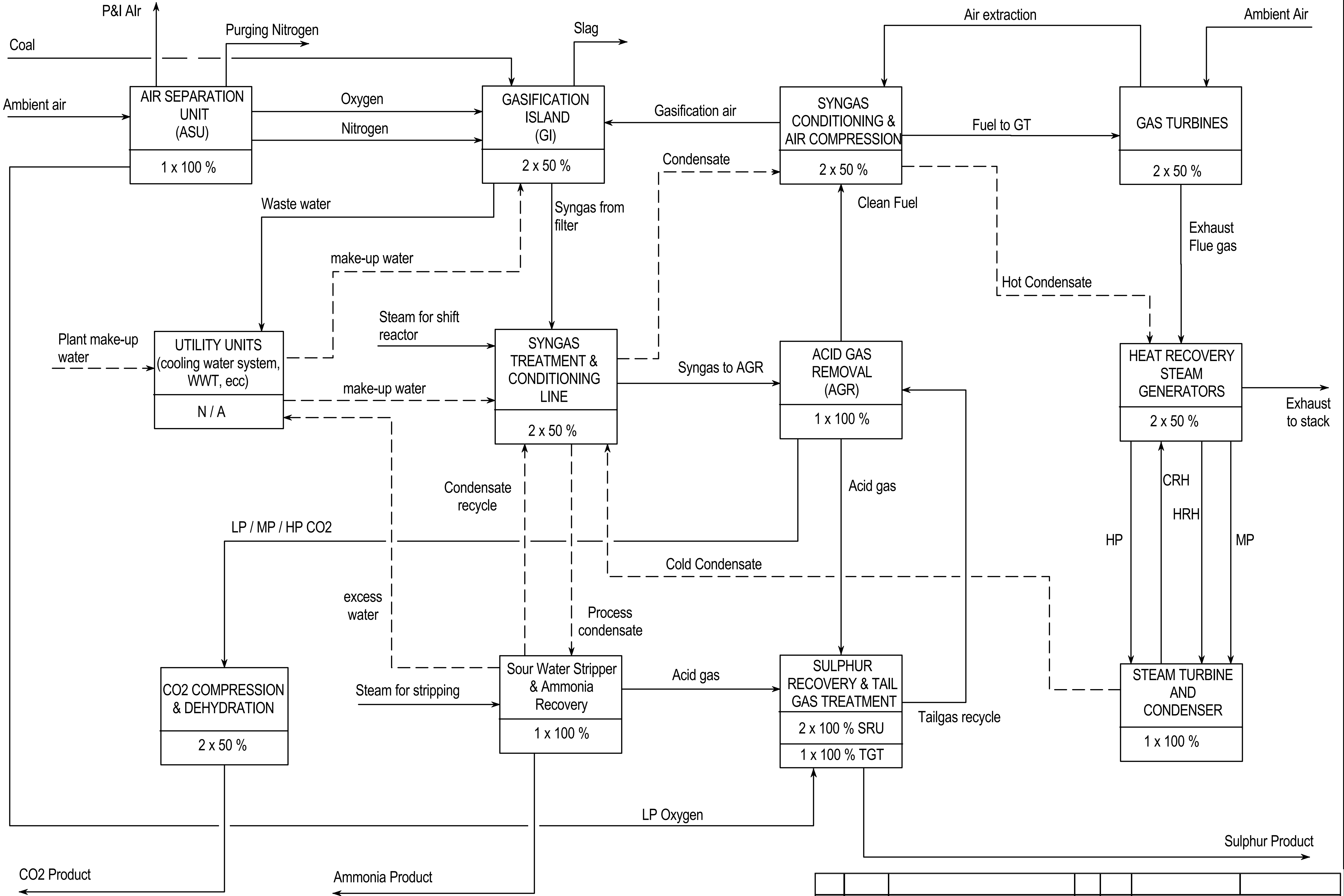
1.1. Process unit arrangement

The arrangement of the main units is reported in the following Table 1. Reference is also made to the block flow diagram attached below.

Table 1. Case 4.3 – Unit arrangement

Unit	Description	Trains
900	Coal Handling & Storage	N/A
1000	Gasification	
	Coal Milling	3 x 43%
	Pulverised Coal Feeding system	3 x 43%
	Gasifiers	2 x 50%
	Syngas Cooler and Char Removal	2 x 50%
	Slag Discharge	2 x 50%
	Air Separation unit	1 x 100%

Unit	Description	Trains
2200	Syngas Treatment and Conditioning Line	2 x 50%
	Air Booster Compressor	2 x 50%
	Ammonia scrubber	2 x 50%
2250	Ammonia Recovery unit	1 x 100%
2300	Acid Gas Removal	1 x 100%
2400	Sulphur Recovery Unit	2 x 100%
	Tail Gas Treatment	1 x 100%
2500	CO_2 Compression & Drying	2 x 50%
3000	Combined Cycle	
	Gas Turbine	2 x 50%
	HRSG	2 x 50%
	Steam Turbine	1 x 100%
4000	Utility and Offsite	N/A



0	July 13		MC	LM	**UNIT:** Block Flow Diagram
Rev.	Date	Comment	By	Appr	**CASE:** 4.3 — Sheet 01 of 01

2. Process Description

2.1. Overview

The description reported in this section makes reference to the simplified Process Flow Diagrams (PFD) of section 3, while stream numbers refer to section 4, which provides heat and mass balance details for the numbered streams in the PFD.

2.2. Unit 900 – Coal Handling & Storage

The unit mainly consists of the coal storage and handling.

The general description relevant to this unit is reported in chapter E, section 2.1. Main process information of this case and the interconnections with the other units is shown in the relevant process flow diagram and the heat and mass balance table.

2.3. Unit 1000 – Gasification Unit

The gasification island based on MHI gasification mainly includes the coal preparation section, the gasification and syngas cooler and char removal section and the slag discharge from the gasifier. This Air Separation unit is also included as a packaged unit supplied by MHI, sized to produce the nitrogen required by the feed transportation system of the gasifier. Technical information relevant to these packages is reported in chapter E, section 3.3.

The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

2.4. Unit 2200 – Syngas Treatment and Conditioning line

The general description of this unit is shown in chapter E, section 2.4, while case-specific features are reported hereinafter. The main process information and the interconnections with the other units are shown in the relevant process flow diagram and the heat and mass balance tables.

Filtered raw syngas from gasification is first cooled in the HP Steam Generator for HP Steam production and then enters the saturator to increase its water content. The partially humidified syngas is heated-up in the Feed/Product Heat Exchanger, before entering the first shift reactor, in order to increase the temperature up to the level required for the proper operation of the shift catalyst.

In the shift unit, CO is shifted to H_2 and CO_2 and COS is converted to H_2S. A double stage shift, containing sulphur tolerant shift catalyst (sour shift) is selected in order to increase the H_2 content in the fuel and maximize the degree of CO_2 removal. The overall CO conversion is approximately 98%. The required dry syngas/H_2O molar ratio for the shift reaction is achieved by means of MP steam injection after syngas heating in the Feed/Product Heat Exchanger, upstream the first stage reactor.

The partially-shifted syngas temperature is increased at approximately 420°C by the exothermic shift reaction, allowing for thermal recovery. The syngas is cooled down in a series of heat exchangers, before being fed to the second reactor stage:

- Feed/Product Heat Exchanger
- HP Steam Generator #2
- MP Steam Generator

After being cooled, the syngas is directed to the second and last shift reactor. The hot shifted syngas exiting from the second stage at approximately 285°C is first cooled in two dedicated heat exchangers to heat the circulating water coming from the de-saturator and then further cooled and condensed in a de-saturator column that reduces the number of exchangers and drums. The process condensate and make-up demineralised water recovered in the de-saturator are mixed to the circulating water.

Final cooling of the syngas is made against cooling water before passing through the Ammonia Scrubber. After the scrubber, syngas passes through a sulphur-impregnated activated carbon bed to remove approximately 95% of the mercury. Cool, mercury-depleted syngas then enters the AGR unit.

The blowdown of the circulating water and the process condensate from the ammonia scrubber are collected in a condensate accumulator. This process condensate is sent to the Ammonia Recovery and Waste Water Treatment which recover water at different purity level for re-use in the plant.

From the AGR unit, cool hydrogen rich gas returns to the syngas treatment and conditioning line as de-carbonized fuel gas after H_2S and CO_2 removal. The de-carbonized fuel gas is preheated in the Syngas Circulating Water Exchanger and then in the Syngas Final Heater with LP steam before entering the Combined Cycle for final heating and combustion.

This unit includes also compression of the air required by Gasifiers. The air extracted from gas turbines is cooled in the following exchangers before entering the air booster compressor:

- Gasification Air Exchanger
- LP Steam Generator
- Condensate Preheater
- Final Air Cooler.

2.5. Unit 2300 – Acid Gas Removal (AGR)

The AGR unit is intended to selectively remove H_2S and CO_2 in sequent steps by employing Selexol as physical solvent. Technical information relevant to this package is reported in chapter E, section 2.5. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The AGR is designed to meet the following process specifications of the treated gas and of the CO_2 product exiting the unit.

- The H_2S+COS concentration of the treated gas exiting the unit is lower than 1 ppmv. This is due to the integration of CO_2 removal with the H_2S removal, which makes available a large circulation of solvent that is cooled down by a refrigerant package before flowing to the CO_2 absorber.
- The CO_2 product is characterised by a content of incondensable around 4%, while simultaneously meeting the specification of H_2S content lower than 20 ppmv and CO content lower than 0.2% mol (actual 0.08% mol).
- The acid gas H_2S concentration is about 35% dry basis, suitable to feed the oxygen blown Claus process.

The CO_2 removal rate is 92% of the carbon dioxide entering the unit, allowing reaching an overall carbon capture of approximately 89% with respect to the carbon in the syngas. These excellent performances on both the H_2S removal and CO_2 capture are achieved with significant power consumption and steam demand.

2.6. Unit 2400 – SRU and TGT

Technical information relevant to this package is reported in chapter E, section 2.5. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The SRU is designed to process the acid gas from the AGR, and minor acid stream as the sour gases from the stripper, using low pressure oxygen from the ASU. In the furnace, H_2S is catalytically oxidized to SO_2 which is further reacted with H_2S to form H_2O and elemental sulphur. Following the thermal stage, sulphur is condensed, while the tail gas is hydrogenated and recycled back to the AGR unit at approximately 35 barg by means of a dedicated compressor.

The overall sulphur production is approximately 70 tons per day.

2.7. Unit 2500 – CO_2 compression and drying

This unit is mainly composed of a compression and dehydration package, supplied by specialized vendors. Technical information relevant to this package is reported in chapter E, section 2.6. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

Three different streams of CO_2 from the Acid Gas Removal unit are routed to the CO_2 compression unit, delivered at approximately 9 barg, 2 barg, and 0.1 barg respectively.

The stream at lower pressure is initially compressed up to the pressure of the medium pressure stream and then combined with it. The resulting stream is compressed to allow the mixing with the last stream without any pressure loss. The combined stream is then compressed up to approximately 30 bar and sent to the dehydration system, which is a standard solid desiccant package that dehydrates the CO_2 stream to a dew point of -40°C. After dehydration, the CO_2 stream is finally compressed to a supercritical condition at 110 barg. Due to the higher nitrogen content, the CO_2 stream is compressed up to the pressure level required at plant battery limits.

The CO_2 product is transported to the plant battery limits for final sequestration.

2.8. Unit 3000 – Combined cycle

Technical information relevant to these packages is reported in chapter E, section 2.10. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

Hydrogen rich syngas exiting the syngas treatment and conditioning line is finally heated in the combined cycle using MP boiler feed water before entering the burner of the MHI gas turbine M701F.

The gas turbine compressors provide combustion air to the burner and also to the combustion/reduction sections of the gasifiers.

The exhaust gases from the gas turbine enter the HRSG, where the heat available is recovered producing steam at three different pressure levels for the steam turbine, plus an additional steam generator with integral deaerator. The HRSG also provides HP BFW for cooling of the combustion air (Turbine Cooling Air, TCA). Hot BFW is then recycled back to the HRSG for steam generation. The final exhaust gas temperature to the stack of the HRSG is 140°C. The calculated acid gas dew point temperature of the exhaust flue gas is 93°C.

The Heat Transfer vs. Temperature of the HRSG (T-Q diagram) of case 4.3 is shown in Figure 1. The red line (the upper curve) represents the exhaust gases from the GT to the stack. The blue lines represent the water path in the economizers (at lower temperature), the steam generators (horizontal lines) and the super-heater/re-heater (at higher temperature).

The combined cycle is thermally integrated with the process unit, in order to maximize the net electrical efficiency of the plant. The main steam and water interfaces with the process units are given in Table 2.

2.9. Utility Units

These units comprise all the systems necessary to allow the operation of the plant and the export of the produced power.

The main utility units include:

- Cooling Water system, based on one natural draft cooling tower, with the following characteristics:

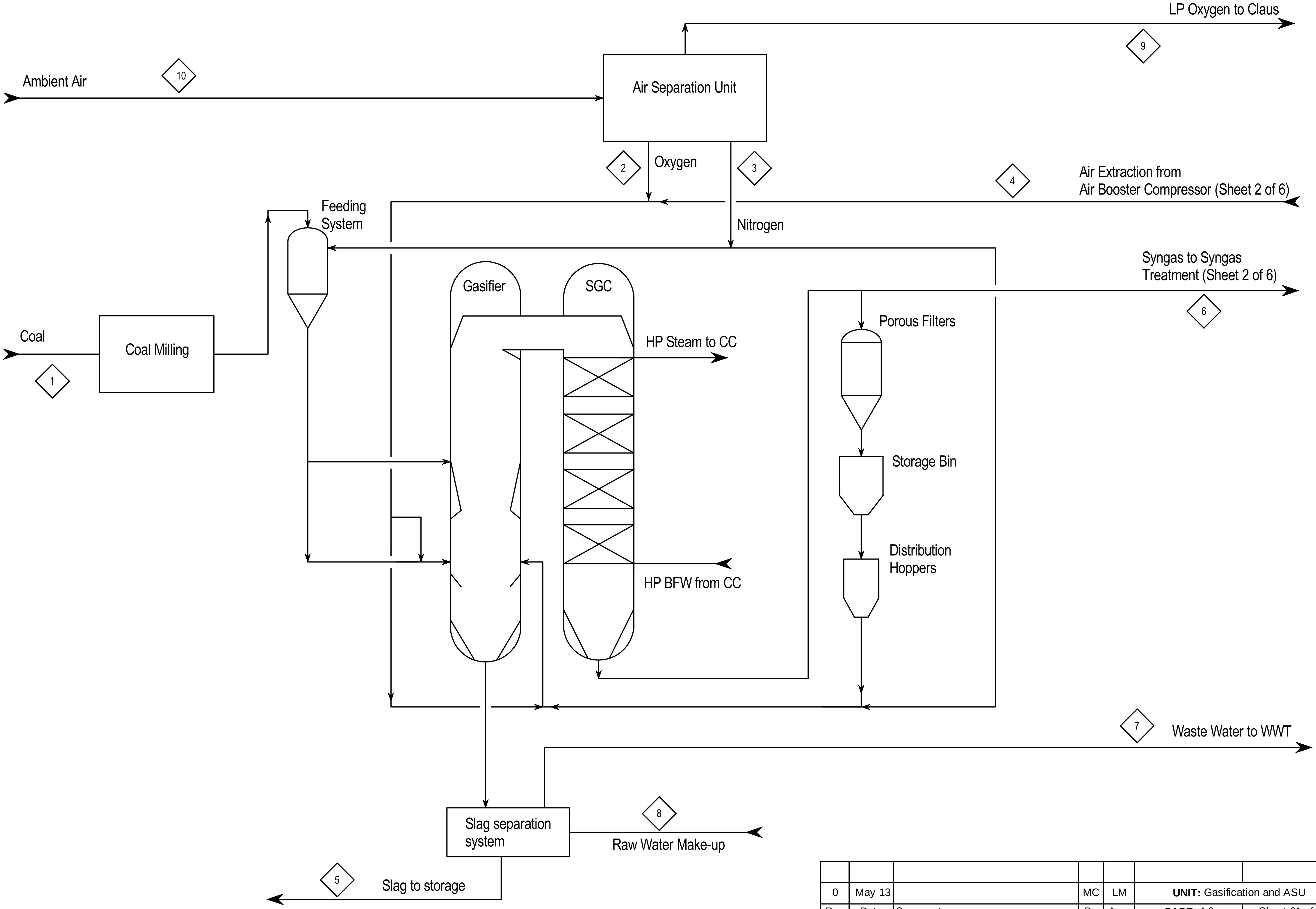
Basin diameter	160 m
Cooling tower height	210 m
Water inlet height	17 m

- Raw water system;
- Demineralised water plant,
- Fire fighting system,
- Instrument and Plant air.

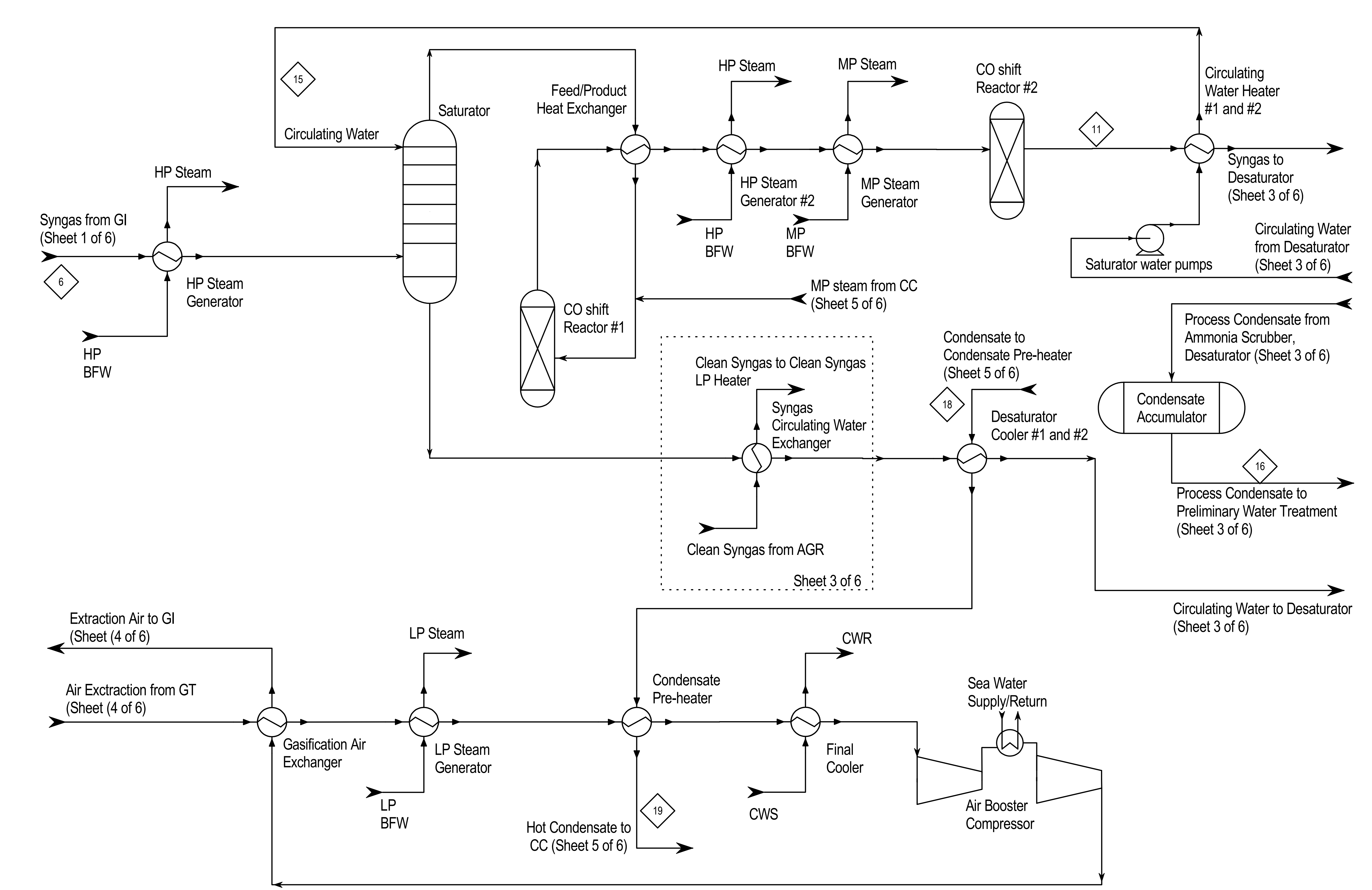
Process descriptions of the above systems are enclosed in chapter E, section 2.11.

3. Process Flow Diagram

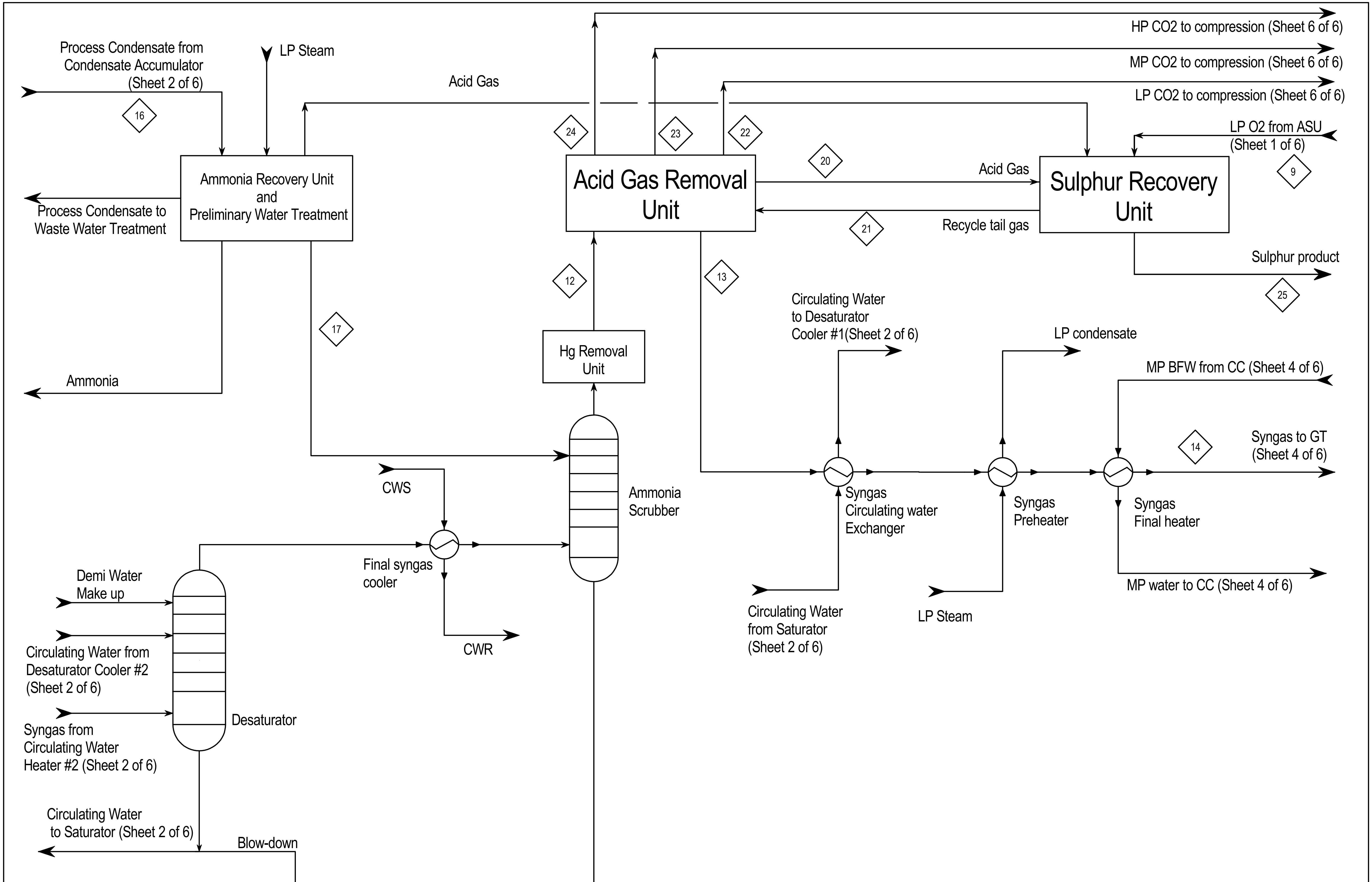
Simplified Process Flow Diagrams of this case are attached to this section. Stream numbers refer to the heat and material balance shown in the next section.



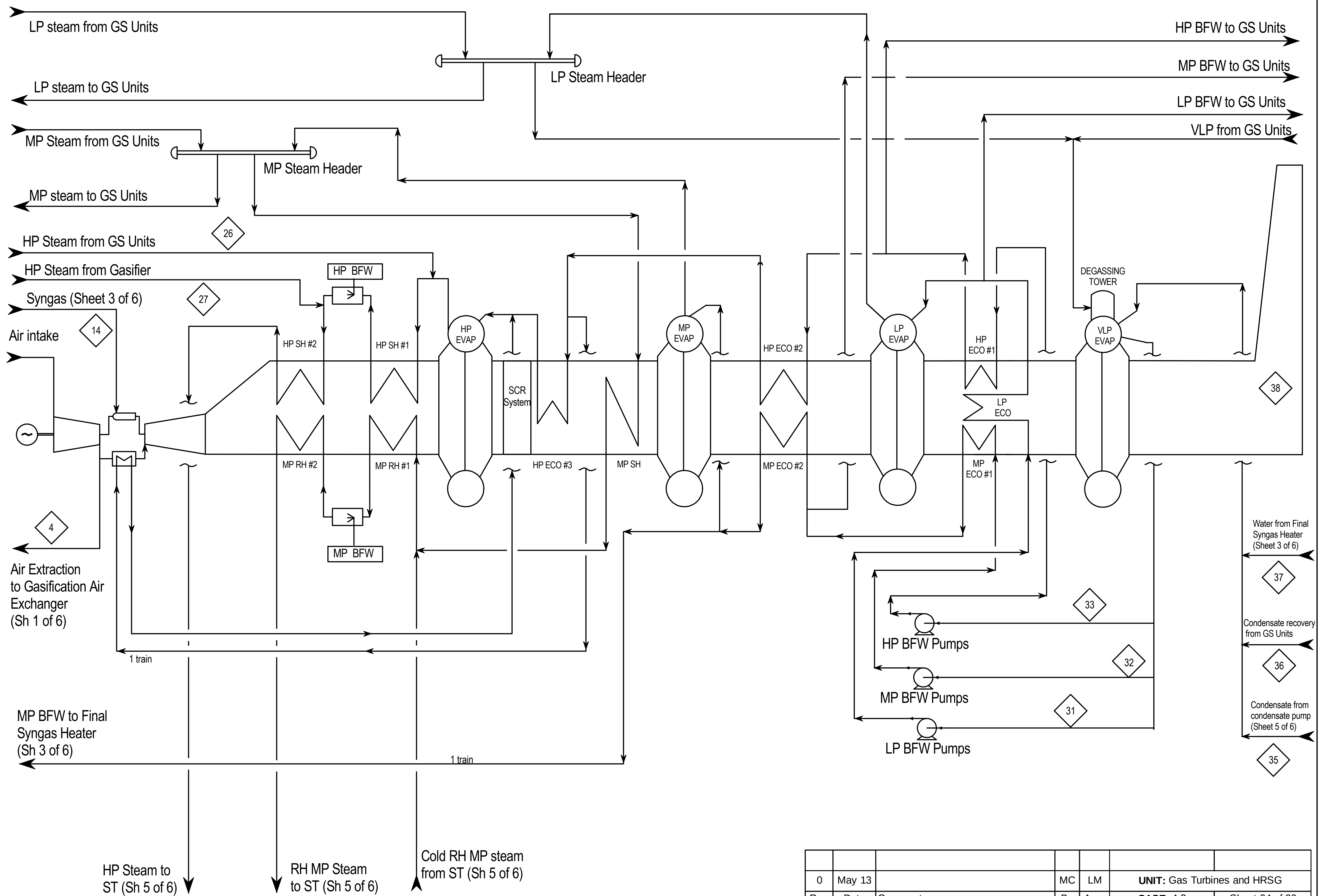
0	May 13		MC	LM	**UNIT:** Gasification and ASU	
Rev.	Date	Comment	By	Appr	**CASE:** 4.3	Sheet 01 of 06



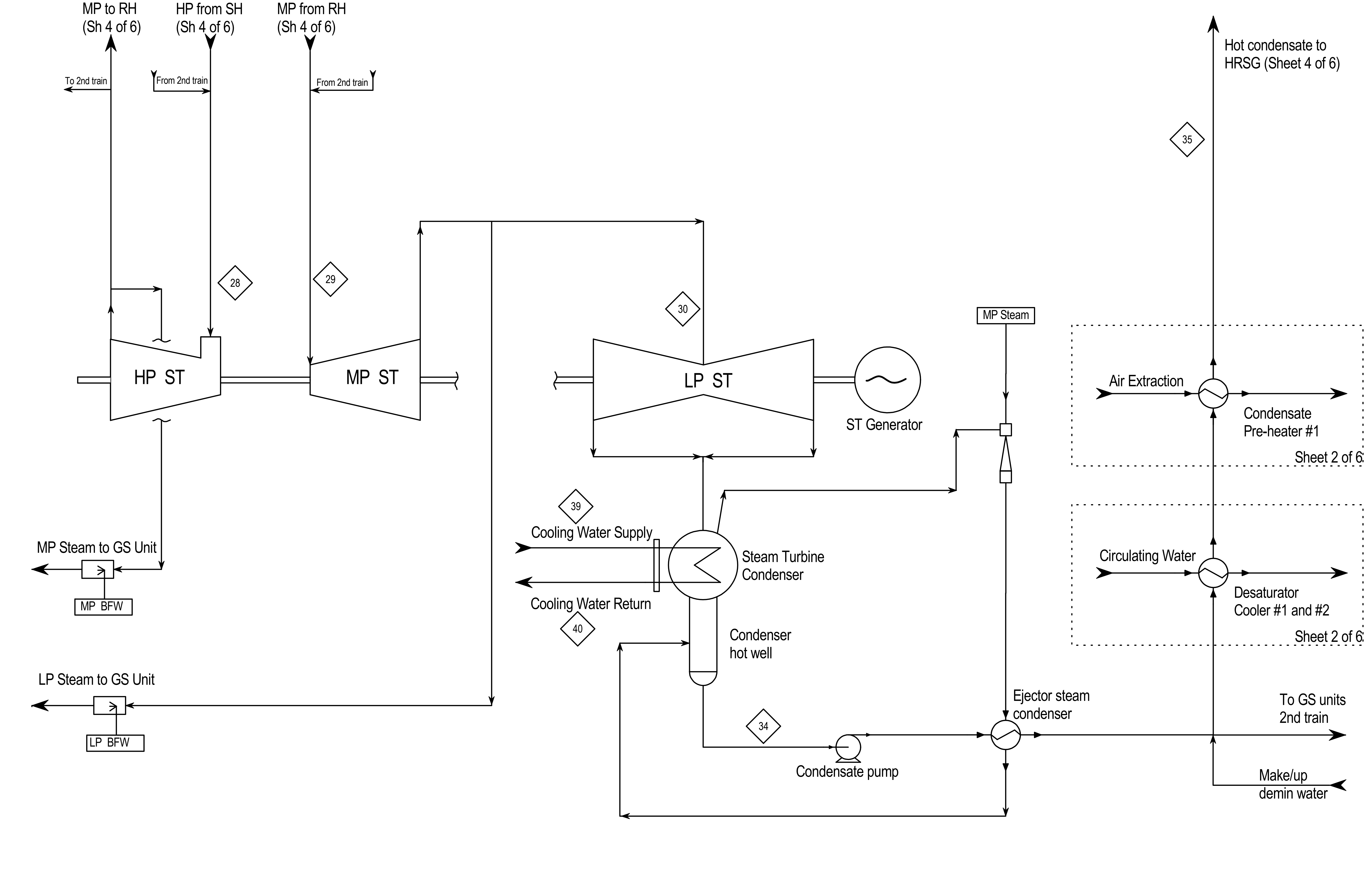
0	May 13		MC	LM	**UNIT:** Syngas treatment	
Rev.	Date	Comment	By	Appr	**CASE:** 4.3	Sheet 02 of 06



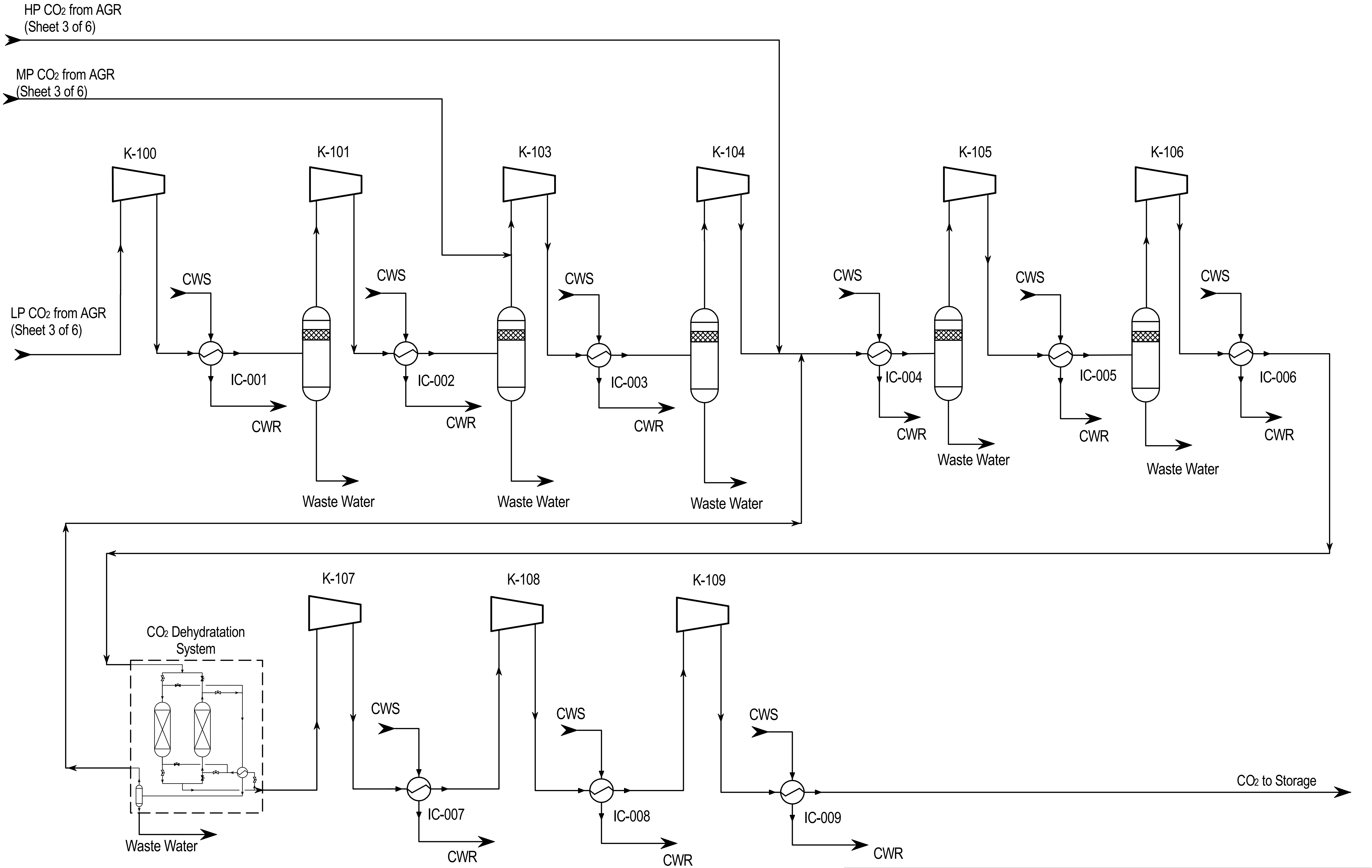
0	May 13		MC	LM	**UNIT:** Syngas cond., AGR and SRU	
Rev.	Date	Comment	By	Appr	**CASE:** 4.3	Sheet 03 of 06



0	May 13		MC	LM	**UNIT:** Gas Turbines and HRSG	
Rev.	Date	Comment	By	Appr	**CASE:** 4.3	Sheet 04 of 06



0	May 13		MC	LM	**UNIT:** Steam Turbine and Condenser	
Rev.	Date	Comment	By	Appr	**CASE:** 4.3	Sheet 05 of 06



0	May 13		MC	LM	**UNIT:** CO2 compression	
Rev.	Date	Comment	By	Appr	**CASE:** 4.3	Sheet 06 of 06

4. Heat and Material Balance

Heat & Material Balances here below reported make reference to the simplified Process Flow Diagrams of section 3.

	IGCC HEAT AND MATERIAL BALANCE - Case 4.3		**REVISION**	0	1	2
	CLIENT :	IEAGHG	**PREP.**	MC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**CHECKED**	NF		
	PROJECT NO:	1-BD-0681 A	**APPROVED**	LM		
	LOCATION:	The Netherlands	**DATE**	May 2013		

UNIT 1000 - Gasification Island

STREAM	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**		
	Coal to Gasification Island (Total)	**HP OXYGEN from ASU**	**HP NITROGEN from ASU**	**Air extraction from Compressors**	**Slag (Total)**	**SYNGAS at Gasifier Outlet to Shift Reactor (Total)**	**Waste Water**	**Makeup Water**		
Temperature (°C)		N/D	N/D	N/D	N/D	N/D	N/D	N/D		
Pressure (bar)		N/D	N/D	N/D	N/D	N/D	N/D	N/D		
TOTAL FLOW										
Mass flow (kg/h)	345100	N/D	N/D	N/D	42102	1365540	N/D	N/D		
Molar flow (kgmole/h)		N/ D	N/D	N/D		55240				
LIQUID PHASE										
Mass flow (kg/h)							N/D	N/D		
GASEOUS PHASE										
Mass flow (kg/h)		N/D	N/D	N/D		1365540				
Molar flow (kgmole/h)		N/D	N/D	N/D		55240				
Molecular Weight		N/D	N/D	N/D		N/D				
Composition (vol %)										
H_2						N/D				
CO						N/D				
CO_2				0.04		N/D				
N_2		1.50	N/D	1.50		N/D				
O_2		95.00	N/D	20.71		N/D				
CH_4						N/D				
H_2S + COS						N/D				
Ar		3.50	N/D	0.92		N/D				
H_2O				1.17		N/D				
NH_3						N/D				

Note: (1) N/D: Not Displayable.

	IGCC HEAT AND MATERIAL BALANCE - Case 4.3		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	MC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	May 2013		

UNIT 2100 - Air Separation Unit (ASU)

STREAM	2	3	9	10						
	HP OXYGEN to Gasification	HP NITROGEN to Gasific.	LP OXYGEN to SRU	Air Intake from Atmosphere						
Temperature (°C)	N/D	N/D	15	AMB.						
Pressure (bar)	N/D	N/D	7.5	AMB.						
TOTAL FLOW										
Mass flow (kg/h)	N/D	N/D	1535	N/D						
Molar flow (kgmole/h)	N/ D	N/D	48	N/D						
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	N/D	N/D	1535	N/D						
Molar flow (kgmole/h)	N/D	N/D	48	N/D						
Molecular Weight	N/D	N/D	32.22	N/D						
Composition (vol %)										
H_2										
CO										
CO_2				0.04						
N_2	1.50	N/D	1.50	1.50						
O_2	95.00	N/D	95.00	20.71						
CH_4										
H_2S + COS										
Ar	3.50	N/D	3.50	0.92						
H_2O				1.17						
NH_3										

Note: (1) N/D: Not Displayable.

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE - Case 4.3		REVISION	0	1	2
	CLIENT :	IEAGHG	PREP.	MC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	May 2013		

UNIT 2200 - Syngas cooling & Conditioning line

STREAM	6	11	12	13	14	15	16	17	18	19
	SYNGAS at Gasifier Outlet to Shift Reactor (2 Trains)	SYNGAS at Shift Reactor Outlet (2 Trains)	RAW SYNGAS to Acid Gas Removal (2 Trains)	HP Purified SYNGAS from Acid Gas Removal (Total)	Treated SYNGAS to Power Island (Total)	Circulating Water to Saturator (2 Trains)	Contaminated Condensate to Stripping (2 Trains)	Condensate Recovered from Stripping (2 Trains)	Cold Condensate from Unit 4200 (2 Trains)	Hot Condensate to Unit 4200 (2 Trains)
Temperature (°C)	N/D	258	38	14	165	193	104	35	25	123
Pressure (bar)	N/D	38.3	35	33.1	34.6	45.0	36.3	37.0	14.5	10.1
TOTAL FLOW										
Mass flow (kg/h)	1365540	2043696	1642315	N/D	N/D	2587906	277112	101806	1493767	1493767
Molar flow (kgmole/h)	55240	92771	70664	N/D	N/D					
LIQUID PHASE										
Mass flow (kg/h)						2587906	277112	101806	1493767	1493767
GASEOUS PHASE										
Mass flow (kg/h)	1365540	2043696	1642315	N/D	N/D					
Molar flow (kgmole/h)	55240	92771	70664	N/D	N/D					
Molecular Weight	N/D	22.0	23.2	N/D	N/D					
Composition (vol %)										
H_2	N/D	25.84	33.92	N/D	43.99					
CO	N/D	0.36	0.46	N/D	0.57					
CO_2	N/D	31.50	25.33	N/D	2.68					
N_2	N/D	29.63	38.90	N/D	51.47					
O_2	N/D	0.00	0.00	N/D	0.00					
CH_4	N/D	0.36	0.47	N/D	0.57					
H_2S + COS	N/D	0.09	0.12	N/D	0.00					
Ar	N/D	0.42	0.55	N/D	0.69					
H_2O	N/D	23.71	0.25	N/D	0.02					
NH_3	N/D	0.16	0.00	N/D	0.00					

Note: (1) N/D: Not Displayable.

FOSTER WHEELER	IGCC HEAT AND MATERIAL BALANCE - Case 4.3		REVISION	0	1	2
	CLIENT :	IEAGHG	PREP.	MC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	May 2013		

UNIT 2300 - Acid Gas Removal (AGR)

STREAM	12	13	20	21	22	23	24			
	Raw SYNGAS from Syngas Cooling	HP Purified Syngas to Syngas Cooling	Acid Gas to SRU & TGT	Recycle Tail Gas from SRU	LP CO2 to Compression	MP CO2 to Compression	HP CO2 to Compression			
Temperature (°C)	38	14	20	20	6.1	8.8	11.6			
Pressure (bar)	35.3	33.1	1.6	35.7	1.1	3.2	10.2			
TOTAL FLOW										
Mass flow (kg/h)	1642315	N/D	8942	5807	320421	363816	46569			
Molar flow (kgmole/h)	70664	N/D	261	158	7303	8435	1456			
LIQUID PHASE										
Mass flow (kg/h)										
GASEOUS PHASE										
Mass flow (kg/h)	1642315	N/D	8942	5807	320421	363816	46569			
Molar flow (kgmole/h)	70664	N/D	261	158	7303	8435	1456			
Molecular Weight	23.2	N/D	34.3	36.8	43.9	43.1	32.0			
Composition (vol %)										
H_2	33.92	N/D	11.00	12.01	0.03	1.49	27.61			
CO	0.46	N/D	0.24	0.00	0.00	0.07	0.64			
CO_2	25.33	N/D	44.46	73.50	99.49	97.10	69.88			
N_2	38.90	N/D	7.00	11.58	0.02	0.94	0.19			
O_2	0.00	N/D	0.00	0.00	0.00	0.00	0.00			
CH_4	0.47	N/D	0.52	0.00	0.01	0.14	0.86			
H_2S + COS	0.12	N/D	35.24	2.90	0.00	0.00	0.00			
Ar	0.55	N/D	0.26	0.00	0.00	0.07	0.71			
H_2O	0.25	N/D	1.27	0.00	0.44	0.19	0.10			
NH_3	0.00	N/D	0.00	0.00	0.00	0.00	0.00			

Note: (1) - CO2 stream is the combination of three different streams at following pressue levels: 10.2 bara; 3.2 bara; 1.1 bara;

IGCC HEAT AND MATERIAL BALANCE - Case 4.3	
CLIENT :	IEAGHG
PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants
PROJECT NO:	1-BD-0681 A
LOCATION:	The Netherlands

REVISION	0	1	2
PREP.	MC		
CHECKED	NF		
APPROVED	LM		
DATE	May 2013		

UNIT 2400 - Sulfur Recovery Unit (SRU) & Tail Gas Treatment (TGT)

STREAM	20	21	9	25
	Acid Gas from AGR Unit	Claus Tail Gas to AGR Unit	LP OXYGEN from ASU	Product Sulphur
Temperature (°C)	20	20	15	
Pressure (bar)	1.6	35.7	7.5	
TOTAL FLOW				
Mass flow (kg/h)	8942	5807	1535	2763
Molar flow (kgmole/h)	261	158	48	
LIQUID PHASE				
Mass flow (kg/h)				
GASEOUS PHASE				
Mass flow (kg/h)	8942	5807	1535	
Molar flow (kgmole/h)	261	158	48	
Molecular Weight	34.3	36.8	32.22	
Composition (vol %)				
H_2	11.00	12.01		
CO	0.24	0.00		
CO_2	44.46	73.50		
N_2	7.00	11.58	1.50	
O_2	0.00	0.00	95.00	
CH_4	0.52	0.00		
H_2S + COS	35.24	2.90		
Ar	0.26	0.00	3.50	
H_2O	1.27	0.00		
NH_3	0.00	0.00		

IGCC HEAT AND MATERIAL BALANCE - Case 4.3		REVISION	0	1
CLIENT :	IEAGHG	PREP.	MC	
PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF	
PROJECT NO:	1-BD-0681 A	APPROVED	LM	
LOCATION:	The Netherlands	DATE	May 2013	

Unit 3000 - Power Island

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Enthalpy kJ/kg
14	Treated SYNGAS from Syngas Cooling (*) (1)	N/D	165	34.6	66.7
4	Extraction Air to Gasifier (*)	N/D	N/D	N/D	-
26	Saturated HP Steam from Process Units (*)	59.3	331	131.0	2660
27	Superheated HP Steam from Gasifier (*)	N/D	N/D	N/D	N/D
28	HP Steam to Steam Turbine	1099.1	558	126.0	3495
29	Hot RH Steam to Steam Turbine	1130.0	558	41.3	3576
30	LP Steam to Steam Turbine	1057.2	340	9.0	3138
31	BFW to LP BFW Pumps (*)	83.8	132	2.9	554
32	BFW to MP BFW Pumps (*)	209.9	132	2.9	554
33	BFW to HP BFW Pumps (*)	547.1	132	2.9	554
34	LP Steam Turbine exhaust	1057.2	29.0	0.040	2303
35	Hot Condensate to HRSG (*)	1493.8	123	10.1	517
36	Recovered Condensate from process units(*)	157.8	111	5.5	466
37	Condensate from Final Syngas Heater (*)	30.4	168	45.5	711
38	Flue Gas at stack (*) (2)	N/D	140	AMB.	135
39	Cooling Water Supply to Steam Condenser	50198.4	15	4.0	63.3
40	Cooling Water Return from Steam Condenser	50198.4	26	3.5	109.3

(*) flowrate for one train
(1) Syngas composition as per stream 14 of Material Balance for Unit 2200.
(2) Flues gas molar composition: N2:74.8%, H2O: 13%; O2: 9.6%; CO2: 1.6%; Ar: 1%.

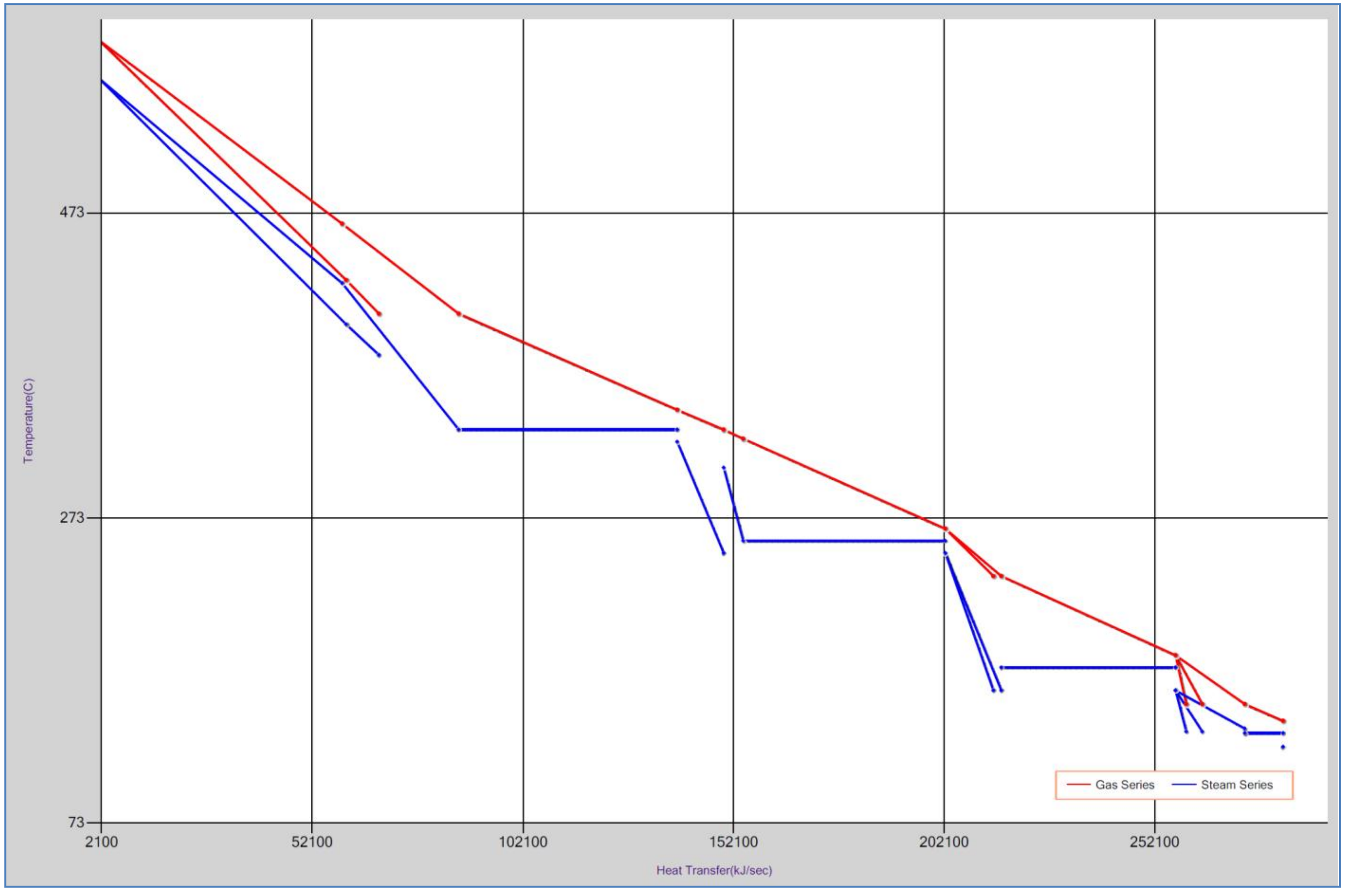


Figure 1 – Case 4.3 – HRSG T-Q diagram

5. Utility consumption

Main utility consumption of the process and utility units is reported in the following tables. More specifically:

- Steam / BFW / condensate interface summary is reported in Table 2
- Water consumption summary is shown in Table 3.
- Electrical consumption summary is included in Table 4.

Table 2. Case 4.3 – Steam/BFW/condensate interface summary

FOSTER WHEELER	CLIENT: IEAGHG					REVISION	Rev.0	Rev.1	
	PROJECT: CO2 capture at coal based power and hydrogen plants					DATE	May 2013		
	LOCATION: The Netherlands					ISSUED BY	MC		
	FWI Nº: 1-BD-0681A					CHECKED BY	NF		
						APPROVED BY	LM		

Case 4.3 - Steam and water balance

UNIT	DESCRIPTION UNIT	HP Steam 130 barg [t/h]	MP Steam 44.5 barg [t/h]	LP Steam 8 barg [t/h]	HP BFW [t/h]	MP BFW [t/h]	LP BFW [t/h]	condensate recovery [t/h]	Losses [t/h]
	PROCESS UNITS								
1000/2100	**Gasification Section/ Air Separation Unit**	**N/D**	**N/D**	**N/D**	**N/D**			**N/D**	**N/D**
2200	**Syngas Treating and Conditioning Line**	**-118.6**	**199.8**	**88.2**	**119.7**	**151.9**	**14.9**	**-15.1**	**-440.9**
2300	**Acid Gas Removal**			**119.5**				**-119.5**	
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**		**-6.0**			**6.0**		**-0.1**	**0.0**
3000	**POWER ISLANDS UNITS**	**N/D**	**N/D**	**N/D**	**N/D**	**-158.0**	**-14.9**	**N/D**	
4000	**UTILITY and OFFSITE UNITS**			**12.8**				**-12.8**	
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-444.3**

Note: (1) Minus prior to figure means figure is generated
(2) N/D: Not Displaylable.

Table 3. Case 4.3 – Water consumption summary

CLIENT:	IEA GHG	Rev.0
PROJECT:	CO2 capture at coal based power and hydrogen plants	Date: May - 13
LOCATION:	1-BD-0681 A	ISSUED BY: MC
FWI Nº:	The Netherlands	CHECKED BY: NF
		APPR. BY: LM

WATER CONSUMPTION SUMMARY

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water 1 system [t/h]	Cooling Water 2 system [t/h]
	PROCESS UNITS				
1000	**Gasification Section**	**N/D**			**N/D**
2100	**Air Separation Unit**				**N/D**
2200	**Syngas treatment and conditioning line**		**103**		**11447**
2300	**Acid Gas Removal**				**11864**
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**				**163**
2500	**CO2 Compression and drying**				**7335**
	POWER ISLANDS UNITS				
3100/3400	**Gas Turbines and Generator auxiliaries**			**50198**	**1409**
3200	**Heat Recovery Steam Generator**				
3300/3400	**Steam Turbine and Generator auxiliaries**		**444**		**2348**
3500	**Miscellanea**				
	UTILITY and OFFSITE UNITS 4000/5200				
4000	**Cooling Water System**	**1785**			
4000	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**821**	**-547.5**		
4000	**Waste Water Treatment**	**-282**			
4000	**Balance of Plant (BOP)**				**428**
	BALANCE including CO2 compression	**N/D**	**0**	**50198**	**N/D**

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

Table 4. Case 4.3 – Electrical consumption summary

CLIENT:	IEAGHG	Rev.0
PROJECT:	CO2 capture at coal based power and H2 plants	May-13
LOCATION:	The Netherlands	ISSUED BY: MC
FWI Nº:	1-BD-0681A	CHECKED BY: NF
		APPR. BY: LM

ELECTRICAL CONSUMPTION SUMMARY - MHI IGCC - CASE 4.3

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	PROCESS UNITS	
900	**Coal Handling and Storage**	**837**
1000	**Gasification Section**	**N/D**
2100	**Air Separation Unit**	**N/D**
2200	**Syngas treatment and conditioning line**	**32628**
2300	**Acid Gas Removal**	**44013**
2400	**Sulphur Recovery (SRU)- Tail gas treatment (TGT)**	**639**
2500	**CO2 Compression and Drying**	**54300**
	POWER ISLANDS UNITS	
3100/3400	**Gas Turbines, Generator auxiliaries and Step-up transformer losses**	**N/D**
3200	**Heat Recovery Steam Generator**	**8902**
3300/3400	**Steam Turbines, Generator auxiliaries and Step-up transformer losses**	**864**
3500	**Miscellanea**	**2757**
	UTILITY and OFFSITE UNITS 4000/5200	
4100	**Cooling Water (Sea Water / Machinery Water)**	**12687**
4200	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**494**
	Other Units	**1467**
	TOTAL CONSUMPTION	**226983**

Notes: (1) Minus prior to figure means figure is generated
(2) N/D: Not displaylable.

6. Overall performance

The following Table shows the overall performance of Case 4.3.

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**DATE**	May 2013
PROJECT No. :	1-BD-0681 A	**MADE BY**	MC
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 4.3 - IGCC Plant Performance Summary

OVERALL PERFORMANCES		
Coal Flowrate (as received)	t/h	345.1
Coal LHV (as received)	kJ/kg	25870
Coal HHV (as received)	kJ/kg	27060
THERMAL ENERGY OF FEEDSTOCK(A)	**MWth (LHV)**	**2480**
THERMAL ENERGY OF FEEDSTOCK(A')	**MWth (HHV)**	**2594**
Thermal Power of Raw Syngas exit Gasification Island (D)	MWth (LHV)	1914
Thermal power of syngas to AGR	MWth (LHV)	1723
Thermal Power of Clean Syngas to Gas Turbines (E)	MWth (LHV)	1667
Syngas treatment efficiency (F/E*100)	% (LHV)	87.1
Gas turbines total electric power output	MWe	630.0
Steam turbine electric power output	MWe	462.7
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (C)	**MWe**	**1093**
Gasification Section units & ASU consumption	MWe	144.5
Combined Cycle units consumption	MWe	13.6
CO_2 Compression and Dehydration unit consumption	MWe	54.3
Utility Units consumption	MWe	14.6
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**227**
NET ELECTRIC POWER OUTPUT OF IGCC	**MWe**	**865.6**
(Step Up transformer efficiency = 0.997%) (B)	**MWe**	**863.0**
Gross electrical efficiency (C/A x 100)	% (LHV)	44.1
Net electrical efficiency (B/A x 100)	**% (LHV)**	**34.8**
Gross electrical efficiency (C/A' x 100)	% (HHV)	42.1
Net electrical efficiency (B/A' x 100)	**% (HHV)**	**33.3**
Fuel Consumption per net power production	**MWth/MWe**	**2.87**
CO_2 emission per net power production	**kg/MWh**	**104.1**

The following Table shows the overall CO_2 balance and CO_2 removal efficiency of Case 4.3.

CO_2 removal efficiency	**Equivalent flow of CO_2 kmol/h**
INPUT	
Fuel Mix (Carbon AR)	18577
TOTAL (A)	18577
OUTPUT	
Slag (B)	21
CO_2 product pipeline	
CO	15
CO_2	16473
CH_4	25
COS	0
Total to storage (C)	16514
Emission	
CO_2 + CO (Combined Cycle)	2042
TOTAL	18577
Overall Carbon Capture, % ((B+C)/A)	89.0

7. Environmental impact

The IGCC plant design is based on advanced technologies that allow to reach high electrical generation efficiency, while minimizing impact to the environment. Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

7.1. Gaseous emissions

During normal operation at full load, main continuous emissions are the combustion flue gases of the two trains of the combined cycle, from the combustion of the syngas in the two gas turbines. Table 5 summarises expected flow rate and concentration of the combustion flue gas from one train of the combined cycle. A continuous emissions monitoring system will be provided on the stack to monitor flowrate and concentration of main components.

Minor gaseous emissions are created by 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 related to the milling, storage and handling of solids (e.g. solid transfer, leakage). As summarised in Table 6 these emission mainly consists of air or nitrogen containing particulate.

Table 5. Case 4.3 – Plant emission during normal operation

Flue gas to HRSG stack	
Emission type	Continuous
Conditions	
Wet gas flowrate, kg/h	N/D (2)
Flow, Nm^3/h (1)	N/D (2)
Temperature, °C	140
Composition	(% vol)
Ar	N/D (2)
N_2	N/D (2)
O_2	N/D (2)
CO_2	N/D (2)
H_2O	N/D (2)
Emission	mg/Nm^3 (1)
NOx	< 50
SOx	< 1
CO	< 31
Particulate	< 4

(1) Dry gas, O_2 content 15% vol. (2) Not displayable

Table 6. Case 4.3 – Plant minor emission

Emission source	Emission type	Temperature	
Coal milling and drying system	Continuous	ambient	Air: 10 mg/Nm^3 particulate
Coal feeding system	Intermittent	ambient	Nitrogen: 10 mg/Nm^3 particulate

7.2. Liquid effluents

Main liquid effluents are the cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids, and the effluent from the Waste Water Treatment, which flows to an outside plant battery limits recipient.

Cooling Tower blow-down

Flowrate : 425 m^3/h

Waste Water Treatment effluent

Flowrate : 275 m^3/h

7.3. Solid effluents

The IGCC plant is expected to produce the following solid by-product:

Slag from gasifier

Flowrate : 42 t/h

Slag product has a potential use as major components in concrete mixtures to make road, pads, storage bins.

8. Preliminary plot plan

Plot plan at block level of Case 4.3 is attached to this section, showing the area occupied by the main units and equipment of the plant.

REV.	DATE	DESCRIPTION	DRAW	BY	CHD.	APP.
COO1	SEPT. 2013	Preliminary issue for comments	APeccati			

DESCRIPTION

CLIENT IEA GHG

SITE The Netherlands

CO2 Capture and coal fired Power Plants

CASE: 4.3 - MHI Gasification

PRELIMINARY PLOT PLAN

FOSTER WHEELER

APPROVED FOR CONSTRUCTION
DWG. REV. DATE
SIGNATURE
ORDER N°
SUPPLIER
CONTRACT N°
FRAME N°
CLIENT DWG N°
SHEET SHEET
SCALE N. A.
FW DWG N° 1BD0681A - 01 - 006
REV. COO1
SHEET OF

CAD FILE NAME

Form. A3

9. Equipment list

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

FOSTER WHEELER	CLIENT: IEAGHG	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
	LOCATION: The Netherlands	DATE	May 2013			
	PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	MC			
	CONTRACT N. 1-BD-0681 A	CHECKED BY	NF			
	CASE: Case 4.3 - MHI Gasification	APPROVED BY	LM			

EQUIPMENT LIST
Unit 900 - Coal handling and storage

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-901	**Coal Handling**							*30 days storage*
	Wagon tipper		Coal flowrate: 345 t/h					*Storage piles: 2 x 135,000 t each*
	Receiving Hopper, vibratory feeder and belt extractor							
	Conveyor	Belt						
	Transfer Tower	Enclosed						
	As-Received Coal Sampling System	Two-Stage						
	As-Received Magnetic Separator System	Magnetic Plates						
	Conveyor	Belt						
	Transfer Tower	Enclosed						
	Crushers Tower	Impactor reduction						
	As-Fired Coal Sampling System	Swing hammer						
	As-Fired Magnetic Separator System	Magnetic Plates						
	Coal Silo		2 x 5200 m3					for daily storage

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		CHECKED BY	NF			
		APPROVED BY	LM			

EQUIPMENT LIST
Unit 1000 - Gasification

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-1001	**MHI Coal gasification package**		2 x 4140 t/d coal as received.					
	Coal Milling							Included in Z-1001
	Pulverized Coal Feeding System							Included in Z-1001
	Gasification Reactor		2 x 960 MWth (LHV basis) syngas at filters outlet of gasifier reactor					Included in Z-1001
	Syngas Cooler and Char Removal							Included in Z-1001
	Slag Discharge							Included in Z-1001
	Black Water Treatment Plant							Included in Z-1001
	Air Booster Compressor							Included in Z-1001
	ASU							Included in Z-1001

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		CHECKED BY	NF			
		APPROVED BY	LM			

EQUIPMENT LIST
Unit 2100 - Air Separation Unit

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2101	**ASU**		N/D					Included in Z-1001

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EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning Line (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	HEAT EXCHANGERS							
E-2201	**Feed/Product Heat Exchanger**	Shell & Tube						
E-2202	**HP steam generator #1**	Kettle						
E-2203	**HP steam generator #2**	Kettle						
E-2204	**MP steam generator**	Kettle						
E-2205	**Circulating Water Heater #1**	Shell & Tube						
E-2206	**Circulating Water Heater #2**	Shell & Tube						
E-2207	**Desaturator Cooler #1**	Shell & Tube						
E-2208	**Desaturator Cooler #2**	Shell & Tube						
E-2209	**Final Syngas Cooler**	Shell & Tube						
E-2210	**Syngas Circulating Water Exchanger**	Shell & Tube						
E-2211	**Syngas Preheater**	Shell & Tube						
E-2212	**Syngas Final Heater**	Shell & Tube						
E-2213	**Gasification Air Exchanger**	Shell & Tube						
E-2214	**LP Steam Generator**	Kettle						
E-2215	**Condensate Pre-heater**	Shell & Tube						
E-2216	**Final Cooler**	Shell & Tube						

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EQUIPMENT LIST
Unit 2200 - Syngas Treatment and Conditioning Line (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	DRUMS							
D-2201	**Condensate accumulator**	Horizontal						
	COLUMN							
C-2201	**Syngas saturator**	Vertical						
C-2202	**Syngas desaturator**	Vertical						
C-2203	**Ammonia Scrubber**	Vertical						
	REACTOR							
R-2201	**1st Shift Catalyst Reactor**	vertical						
R-2202	**2nd Shift Catalyst Reactor**	vertical						
	PUMPS							
P-2201 A/B	**Saturator Circulating Water Pump**	centrifugal						
	MISCELLANEA							
X-2201	**Mercury Adsorber**	Sulfur-impregnated activated carbon beds						

Note: Equipment list refers to one train only

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FOSTER WHEELER	LOCATION:	The Netherlands	DATE	May 2013			
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	CONTRACT N.	1-BD-0681 A	CHECKED BY	NF			
	CASE:	Case 4.3 - MHI Gasification	APPROVED BY	LM			

EQUIPMENT LIST
Unit 2300 - Acid Gas Removal Unit (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2301	**Acid Gas Removal Unit - Absorption Section** (Acid Gas Removal Unit, sized for 100% of the capacity)	Solvent Selexol	1 x 100%, Multiple absorbers Feed gas: 1583900 Nm3/h; 35 barg; 38 °C					CO2 removal =92% Separated removal of CO2 and H2S Total carbon capture: 0%"
Z-2302	**Acid Gas Removal Unit - Regeneration Section** (Acid Gas Removal Unit, sized for 100% of the capacity)		1x100 %					Total CO2 removal= 731 t/d; 8 ppm H2S (dry) in combined CO2
Z-2303	**Chiller Unit**	electrical driven						T= -10 °C

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	CASE:	Case 4.3 - MHI Gasification	APPROVED BY	LM			

EQUIPMENT LIST
Unit 2400 - Sulphur Recovery Unit (2x100%) & Tail Gas Treatment (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2401	**Sulphur Recovery Unit and Tail Gas Treatment Package** - two Sulphur Recovery Unit, each sized for 100% of the capacity - one Tail Gas Treatment Unit sized for 100% of capacity (including Reduction Reactor and Tail Gas Compressor)		Sulphur Prod.= 72 t/d Acid Gas from AGR = 5900 Nm3/h Expected Treated Tail Gas =3600 Nm3/h					Sulphur content > 99.9 % mol min (dry basis) Sulphur content = 35.1% mol (wet basis)

FOSTER WHEELER	CLIENT: IEAGHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and H2 plants CONTRACT N. 1-BD-0681 A CASE: Case 4.3 - MHI Gasification	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2

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ISSUED BY	MC			
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EQUIPMENT LIST
Unit 2500 - CO2 Compression and Drying (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [MW]	P design [barg]	T design [°C]	Materials	Remarks
	COMPRESSORS							
C-2501	**CO_2 compression package**	Centrifugal, Electrical Driven, 9 intercooled Stages	192140 Nm3/h p in: 1 bar a p out: 110 bar a	29900 MWe				Water Cooled
	PACKAGE							
PK-2501	**CO_2 drying package**							

FOSTER WHEELER		CLIENT: IEAGHG			REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
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		PROJ. NAME: CO2 capture at coal based power and H2 plant			ISSUED BY	MC			
		CONTRACT N. 1-BD-0681 A			CHECKED BY	NF			
		CASE: Case 4.3 - MHI Gasification			APPROVED BY	LM			

EQUIPMENT LIST
Unit 3100 - Gas Turbine (2x 50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-3101	**Gas Turbine & Generator Package**							
GT-3101	Gas turbine	MHI 701 F	315 MW					Included in Z-3101
G-3101	Gas turbine Generator		413 MVA					Included in Z-3101

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PROJ. NAME:	CO2 capture at coal based power and H2 plants	CHECKED BY	NF			
CONTRACT N.	1-BD-0681 A	APPROVED BY	LM			
CASE:	Case 4.3 - MHI Gasification					

EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	HEAT RECOVERY STEAM GENERATOR							
HRSG-3201	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels. Simple Recovery, Reheated.						
Each HRSG including:								
D-3202	**HP steam Drum**							
D-3203	**MP steam Drum**							
D-3204	**LP steam Drum**							
D-3205	**VLP steam Drum with degassing section**							
E-3201	**HP Superheater 2nd section**							Included in HRSG-3201
E-3202	**HP Superheater 1st section**							Included in HRSG-3201
E-3203	**HP Evaporator**							Included in HRSG-3201
E-3204	**HP Economizer 3rd section**							Included in HRSG-3201
E-3205	**HP Economizer 2nd section**							Included in HRSG-3201
E-3206	**HP Economizer 1st section**							Included in HRSG-3201
E-3207	**MP Reheater 2nd section**							Included in HRSG-3201
E-3208	**MP Reheater 1st section**							Included in HRSG-3201
E-3209	**MP Superheater**							Included in HRSG-3201
E-3210	**MP Evaporator**							Included in HRSG-3201
E-3211	**MP Economizer 2nd section**							Included in HRSG-3201
E-3212	**MP Economizer 1st section**							
E-3213	**LP Evaporator**							Included in HRSG-3201
E-3214	**LP Economizer**							Included in HRSG-3201
E-3215	**VLP Evaporator**							Included in HRSG-3201

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		ISSUED BY	MC			
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EQUIPMENT LIST
Unit 3200 - Heat Recovery Steam Generator (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PUMPS		**Q,m^3/h x H,m**					
P-3201 A/B/C	**HP BFW Pumps**	centrifugal	292 x 1590	2000				Two operating & one spare
P-3202 A/B	**MP BFW Pumps**	centrifugal	224 x 670	600				One operating & one spare
P-3203 A/B	**LP BFW Pumps**	centrifugal	89 x 110	45				One operating & one spare
	MISCELLANEA							
X-3201	**Flue Gas Monitoring System**							NOx, CO, SO_2, particulate, H_2O, O_2
STK-3201	**CCU Stack**							
SL-3201	**Stack Silencer**							
DS-3201	**HP Steam Desuperheater**							Included in HRSG-3201
DS-3202	**MP Steam Desuperheater**							Included in HRSG-3201
DS-3203	**LP Steam Desuperheater**							Included in HRSG-3201
X-3202	**SCR System**	Ammonia Injection						
	PACKAGES							
Z-3201	**Fluid Sampling Package**							
Z-3202	**Phosphate Injection Package**							
D-3202	Phosphate storage tank							Included in Z - 3202
P-3204 A/B	Phosphate dosage pumps							Included in Z - 3202
								One operating , one spare
Z-3203	**Oxygen Scavanger Injection Package**							
D-3203	Oxygen scavanger storage tank							Included in Z - 3203
P-3205 A/B	Oxygen scavanger dosage pumps							Included in Z - 3203
								One operating , one spare
Z-3204	**Amines Injection Package**							
D-3204	Amines Storage tank							Included in Z - 3204
P-3206 A/B	Amines Dosage pumps							Included in Z - 3204
								One operating , one spare

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		DATE	May 2013			
		ISSUED BY	MC			
		CHECKED BY	NF			
		APPROVED BY	LM			

EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-3301	**Steam Turbine & Condenser Package**							
ST-3301	Steam Turbine		470 MW					*Including:* *Lube oil system* *Cooling system* *Idraulic control system* *Drainage system* *Seals system* *Drainage system*
G-3402	Steam Turbine Generator		610 MVA					*Including relevant auxiliaries*
E-3301A/B	Inter/After condenser							
E-3302	Gland Condenser							
Z-3302	**Steam Condenser Package**							
E-3303	Steam Condenser	Water cooled	737 MWt					*Including:* *Hot well* *Vacuum pump (or ejectors)* *Start up ejector (if required)*
Z-3303	**Steam Turbine by-pass system**							
	PUMPS		**Q,m^3/h x H,m**					
P-3301A/B	**Condensate Pumps**	Centrifugal, vertical	1500 x 220	1260				One operating, one spare
	HEAT EXCHANGERS							
E-3301	**Blow-Down Cooler**	Shell & Tube						
	DRUMS							
D-3301	**Continuous Blow-down Drum**	vertical						
D-3302	**Discontinuous Blow-down Drum**	vertical						

EQUIPMENT LIST
Unit 4000 -Utility & Offsite

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-4001	**COOLING WATER SYSTEM**							
PK-4001	**Cooling Water System**							
CT-4001	Cooling Tower Including: Cooling water basin	Evaporative, Natural draft	Total heat duty 1270 MWth Diameter: 160 m, Height: 210 m, Water inlet: 17 m				concrete	Included in Z-4001
	Pumps							
P-4001A/B/C/D/E	Circulating pump to condensers	Vertical	12600 m3/h x 35 m	1600				Included in Z-4001 4 operating
P-4002A/B/C/D/E	Circulating pump to other users	Vertical	N/D	2200				Included in Z-4001 4 operating, one spare
P-4003A/B	Cooling tower make-up pumps	centrifugal	1785 m3/h x 30 m	kW				Included in Z-4001 1 operating, one spare
	Packages							
	Cooling Water Filtration Package Cooling Water Sidestream Filters		N/D					
	Sodium Hypochlorite Dosing Package Sodium Hypochlorite storage tank Sodium Hypochlorite dosage pumps							
	Antiscalant Package Dispersant storage tank Dispersant dosage pumps							
Z-4002	**RAW WATER SYSTEM**							
T-4001	Raw Water storage tank		27400 m3					Included in Z-4002 24 hour storage
P-4004A/B	Raw Water Pumps		N/D	100				Included in Z-4002 One operating, one spare

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EQUIPMENT LIST
Unit 4000 -Utility & Offsite

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-4003	**DEMI WATER SYSTEM**							
PK-4001	Demin Water Package, including: - Multimedia filter - Reverse Osmosis (RO) Cartidge filter - Electro de-ionization system							
T-4002	Demi Water storage tank		13200 m3					Included in Z-4003 24 hour storage
P-4005A/B	Demi Water Pumps to C.C.	centrifugal	444 m3/h x 61 m	110 kW				Included in Z-4003 "One operating, one spare
P-4006A/B	Demi Water Pumps to Syngas Cooling	centrifugal	52 m3/h x 428 m	90 kW				Included in Z-4003 "Two operating, two spare
Z-4004	**FIRE FIGHTING SYSTEM**							
	Fire water storage tank							
	Fire pumps (diesel)							
	Fire pumps (electric)							
	FW jockey pump							
	MISCELLANEA							
	Ammonia Recovery system		277 t/h of treated water					
	Natural Gas (Back-up fuel)							
	Waste Water Treatment							
	Sulphur Storage/Handling		72 t/d S prod.					30 days storage
	Flare system							
	Interconnecting							
	Instrumentation							
	DCS							
	Piping							
	Electrical							
	Plant Air							
	Buildings							

CLIENT	:	IEA GHG
PROJECT NAME	:	CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
DOCUMENT NAME	:	CASE 5.1 – HYDROGEN AND POWER CO-PRODUCTION POWER ISLAND: 2 X E-CLASS GAS TURBINE
FWI CONTRACT	:	1-BD-0681 A

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CHECKED BY	:	L. MANCUSO
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TABLE OF CONTENT

1. Introduction

This chapter of the report includes all technical information relevant to Case 5.1 of the study, which is a gasification plant based on the GE technology, designed for the co-production of hydrogen and power from coal, whose characteristic is shown in chapter B, and with capture of the generated carbon dioxide. Both power and hydrogen are exported outside plant battery limits respectively to the external electrical grid and to a hydrogen distribution network.

Plant capacity is the same of the GE technology based IGCC case, for power production only (refer to Case 4.2 in chapter E.2 of this report).

The configuration of the plant is based on the following main features:

- High-pressure (65 barg) GE Energy Gasification process, with slurry-feed system and Radiant Syngas Cooler (RSC);
- 2-stages sour shift;
- Removal of acid gases (H_2S and CO_2) based on Selexol physical solvent process;
- Oxygen-blown Claus unit, with tail gas catalytic treatment and recycle of the treated tail gas to the AGR;
- CO_2 compression and dehydration unit;
- Hydrogen production unit based on Pressure Swing Adsorption (PSA);
- Combined cycle based on two E-class gas turbines.

The description of the main process units is covered in chapter E of this report, so only features that are unique to this case are discussed in the following sections, together with the main modelling results.

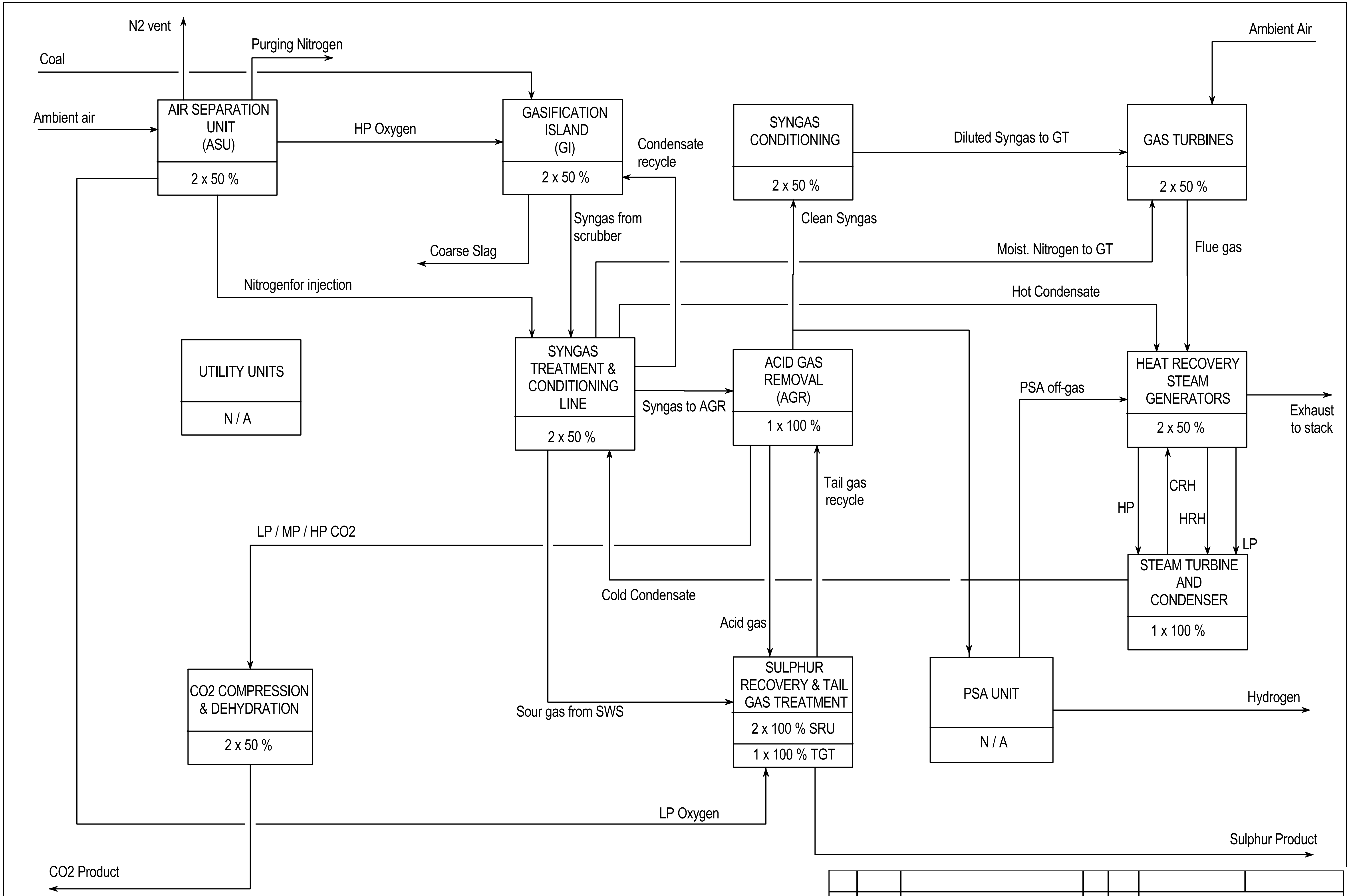
1.1. Process unit arrangement

The arrangement of the main units is reported in the following Table 1. Reference is also made to the block flow diagram attached below.

Table 1. Case 5.1 – Unit arrangement

Unit	Description	Trains
900	Coal Handling & Storage	N/A
1000	Gasification	2 x 50%
	Coal Grinding & Slurry Preparation	
	Gasification (Radiant Syngas Cooler) and scrubber	

Unit	Description	Trains
	Black Water Flash & Coarse Slag Handling	
	Grey Water & Fines Handling	
2100	Air Separation Unit	2 x 50%
2200	Syngas Treatment and Conditioning Line	2 x 50%
2250	Sour Water Stripper (SWS)	1 x 100%
2300	Acid Gas Removal	1 x 100%
2400	Sulphur Recovery Unit	2 x 100%
	Tail Gas Treatment	1 x 100%
2500	CO_2 Compression & Drying	2 x 50%
2600	Hydrogen production unit (PSA)	N/A
3000	Combined Cycle	
	Gas Turbine (E-class equivalent)	2 x 50%
	HRSG	2 x 50%
	Steam Turbine	1 x 100%
4000	Utility and Offsite	N/A



0	July 13		GP	LM	**UNIT:** Block Flow Diagram	
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2. Process description

2.1. Overview

The description reported in this section makes reference to the simplified Process Flow Diagrams (PFD) of section 3, while stream numbers refer to section 4, which provides heat and mass balance details for the numbered streams in the PFD.

2.2. Unit 900 – Coal Handling & Storage

The unit mainly consists of the coal storage and handling.

The general description relevant to this unit is reported in chapter E, section 2.1. Main process information of this case and the interconnections with the other units is shown in the relevant process flow diagram and the heat and mass balance table.

2.3. Unit 1000 – Gasification Island

The gasification island based on GE gasification mainly includes the coal grinding and slurry preparation section, the gasification (RSC) and the scrubber, the Black Water Flash and Coarse Slag Handling, and Grey Water & Fines Handling. Technical information relevant to these packages is reported in chapter E, section 3.2.

The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

2.4. Unit 2100 – Air Separation Unit

Technical information relevant to this packaged unit is reported in chapter E, section 2.3. The main process information of the unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The sizing capacity of the Air Separation Unit is determined by the oxygen requirement of the gasification island and the SRU. The total required oxygen flowrate for the case is approximately 325 t/h.

The Air Separation unit supplies medium pressure nitrogen, injected in the gas turbine, after being moisturised, for NOx suppression and power production augmentation.

2.5. Unit 2200 – Syngas Treatment and Conditioning line

The general description of this unit is shown in chapter E, section 2.4, while case-specific features are reported hereinafter. It has to be noted that syngas treatment line from the gasification scrubber to the AGR exit is almost the same of case 4.2. The main process information and the interconnections with the other units are shown in the relevant process flow diagram and the heat and mass balance tables.

Saturated raw syngas from the gasification scrubber, at approximately 64 barg, is heated-up in the Feed/Product Heat Exchanger, before entering the first shift reactor, in order to increase the temperature up to the level required for the proper operation of the shift catalyst.

In the shift unit, CO is shifted to H_2 and CO_2 and COS is converted to H_2S. A double stage shift, containing sulphur tolerant shift catalyst (sour shift) is selected in order to increase the H_2 content in the fuel and maximize the degree of CO_2 removal. The overall CO conversion is approximately 98%. The water content in the syngas is adequate for the shift reaction to take place with no additional steam injection.

The partially-shifted syngas temperature is increased by the exothermic shift reaction, allowing for thermal recovery. The syngas is cooled down in a series of heat exchangers, before being fed to the second reactor stage:

- Feed/Product Heat Exchanger,
- HP Steam Generator,
- MP Steam Generator #1.

After being cooled, the syngas is directed to the second and last shift reactor. The hot shifted syngas outlet from the second stage is cooled in the following series of heat exchangers, to thermally recover heat and increase the overall power generation:

- MP Steam Generator #2,
- LP Steam Generator,
- Saturator Circulating Water Heater #1 and #2,
- Condensate Pre-heater #1 and #2.

Final cooling of the syngas is made against cooling water, before passing through a sulphur-impregnated activated carbon bed to remove approximately 95% of the mercury. Cool, mercury-depleted syngas is then directed to the AGR.

During the cooling of the syngas, the process condensate is separated and collected in the process condensate accumulator. Before being sent to the accumulator, the condensate from the last syngas separator, upstream the AGR, plus a portion of the condensate from the upstream separator, is sent to the Sour Water Stripper in order to avoid accumulation of ammonia and H_2S and other dissolved gases in the water recycle to the gasification section. The condensate from the accumulator is sent to the gasification scrubber for syngas saturation. Boiler Feed Water from the deaerator of the combined cycle provides the make-up water to substitute for the steam reacted in the shift unit.

From the AGR unit, part of the cool hydrogen-rich gas returns to the syngas treatment and conditioning line as de-carbonized fuel gas after H_2S and CO_2 removal for final treatment before being fed to the combined cycle. This syngas flow is preheated against circulating water coming from the nitrogen saturator and then expanded down to the pressure required from the gas turbine, thus producing additional electric power.

Then, the hydrogen-rich syngas necessary to saturate the thermal demand of the gas turbines at the reference ambient temperature of the project, which corresponds to about 52% of the total syngas flowrate coming from the AGR, is preheated against LP and MP steam and sent to the combined cycle at around 230°C, for combustion in the gas turbine.

The balancing syngas from the AGR is sent to the PSA unit for high-purity hydrogen production.

The unit includes nitrogen saturator, providing moisturised nitrogen to be injected in the gas turbine. Nitrogen humidification is achieved by means of hot water heated in the syngas cooling line. The humidified nitrogen is finally heated using MP steam and then injected in the gas turbine combustion chamber.

2.6. Unit 2300 – Acid Gas Removal (AGR)

The AGR unit is intended to selectively remove H_2S and CO_2 in sequent steps by employing Selexol as physical solvent. Technical information relevant to this package is reported in chapter E, section 2.5. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The AGR is designed to meet the following process specifications of the treated gas and of the CO_2 product exiting the unit:

- The H_2S+COS concentration of the treated gas exiting the unit is around 1 ppmv. This is due to the integration of CO_2 removal with the H_2S removal, which makes available a large circulation of solvent that is cooled down by a refrigerant package before flowing to the CO_2 absorber.
- The CO_2 product is characterised by a content of incondensable around 2%, while simultaneously meeting the specification of H_2S content lower than 20 ppmv and CO content lower than 0.2% mol (actual 0.06% mol).
- The acid gas H_2S concentration is about 41% dry basis, suitable to feed the oxygen blown Claus process.

The CO_2 removal rate is 91.7% of the carbon dioxide entering the unit, allowing reaching an overall carbon capture of approximately 90% with respect to the carbon

in the syngas. These excellent performances on both the H_2S removal and CO_2 capture are achieved with significant power consumption and steam demand.

2.7. Unit 2400 – SRU and TGT

Technical information relevant to this package is reported in chapter E, section 2.5. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The SRU is designed to process the acid gas from the AGR and other minor acid streams like the acid off-gas from the black water flash within the gasification island and the sour gases from the SWS, using low pressure oxygen from the ASU. In the furnace, H_2S is catalytically oxidized to SO_2 which is further reacted with H_2S to form H_2O and elemental sulphur. Following the thermal stage, sulphur is condensed, while the tail gas is hydrogenated and recycled back to the AGR unit at approximately 60 barg by means of a dedicated compressor.

The overall sulphur production is approximately 72 tons per day.

2.8. Unit 2500 – CO_2 Compression and Drying

This unit is mainly composed of a compression and dehydration package, followed by last stage CO_2 pumps, supplied by specialized vendors. Technical information relevant to this package is reported in chapter E, section 2.6. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

Three different streams of CO_2 from the Acid Gas Removal unit are routed to the CO_2 compression unit, delivered at approximately 19 barg, 6 barg, and 1.5 barg respectively.

The stream at lower pressure is initially compressed up to the pressure of the medium pressure stream and then combined with it. The resulting stream is compressed to allow the mixing with the last stream without any pressure loss. The combined stream is then compressed up to approximately 40 barg and sent to the dehydration system, which is a standard solid desiccant package that dehydrates the CO_2 stream to a dew point of -40°C. After dehydration, the CO_2 stream is finally compressed to a supercritical condition at 80 barg.

The resulting stream of CO_2 is pumped to the required pressure of 110 barg. The CO_2 product (approximately 97.9 % wt purity) is transported to the plant battery limits for final sequestration.

2.9. Unit 2600 – Hydrogen Production Unit

Technical information relevant to this package is reported in chapter E, section 2.9. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.
The PSA unit is designed to produce 220,000 Nm^3/h of high-purity hydrogen at around 51 barg, to be sent to the plant battery limits. The PSA off-gases are sent to the supplementary firing system of the combined cycle.

2.10. Unit 3000 – Combined Cycle

Technical information relevant to these packages is reported in chapter E, section 2.10. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The hydrogen-rich syngas heated up to around 230°C in the syngas treatment and conditioning line enters the burners of the gas turbine.

The gas turbine compressors provide combustion air to the burner only, i.e. no air integration with the ASU is foreseen. The exhaust gases from the gas turbine enter the HRSG at 560°C. Off-gas from the PSA unit are burn in the supplementary firing system of the HRSG, increasing the flue gas temperature up to 598°C. The HRSG recovers heat available from the exhaust gas producing steam at three different pressure levels for the steam turbine, plus an additional steam generator with integral deaerator. The final exhaust gas temperature to the stack of the HRSG is 133°C. The calculated acid gas dew point temperature of the exhaust flue gas is around 90°C.

The Heat Transfer vs. Temperature of the HRSG (T-Q diagram) of case 5.1 is shown in Figure 1. The red line (the upper curve) represents the exhaust gases from the GT to the stack. The blue lines represent the water path in the economizers (at lower temperature), the steam generators (horizontal lines) and the super-heater/re-heater (at higher temperature).

The combined cycle is thermally integrated with the process unit, in order to maximize the net electrical efficiency of the plant. The main steam and water interfaces with the process units are given in Table 2.

2.11. Utility Units

These units comprise all the systems necessary to allow the operation of the plant and the export of the produced power.

The main utility units include:

- Cooling Water system, based on one natural draft cooling tower, with the following characteristics:

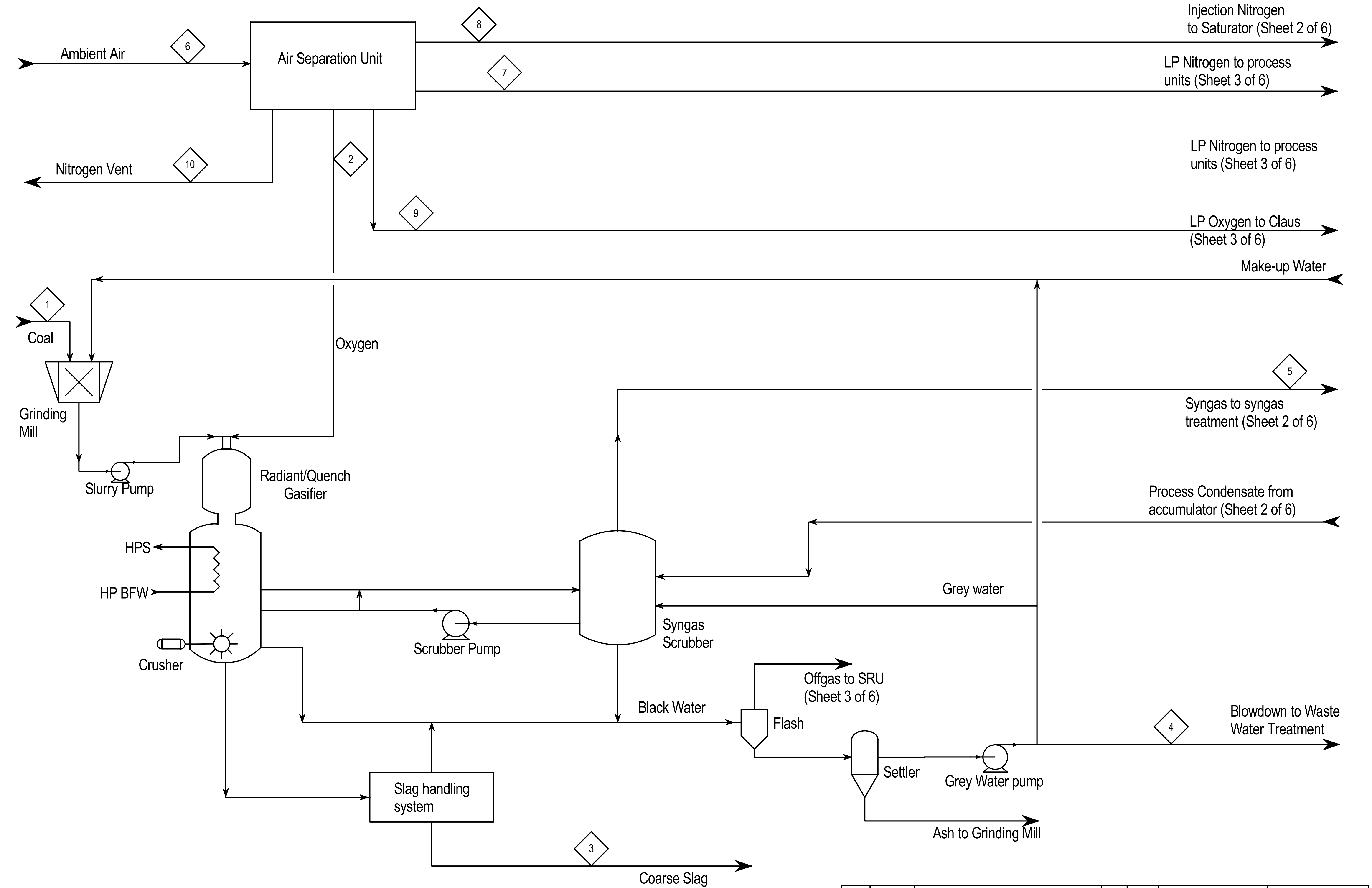
Basin diameter	140 m
Cooling tower height	210 m
Water inlet height	17 m

- Raw water system;
- Demineralised water plant;
- Fire fighting system;
- Instrument and Plant air.

Process descriptions of the above systems are enclosed in chapter E, section 2.11.

3. Process Flow Diagrams

Simplified Process Flow Diagrams of this case are attached to this section. Stream numbers refer to the heat and material balance shown in the next section.



0	May 13		LC	LM	**UNIT:** GS2 - AS1: Gasification and ASU	
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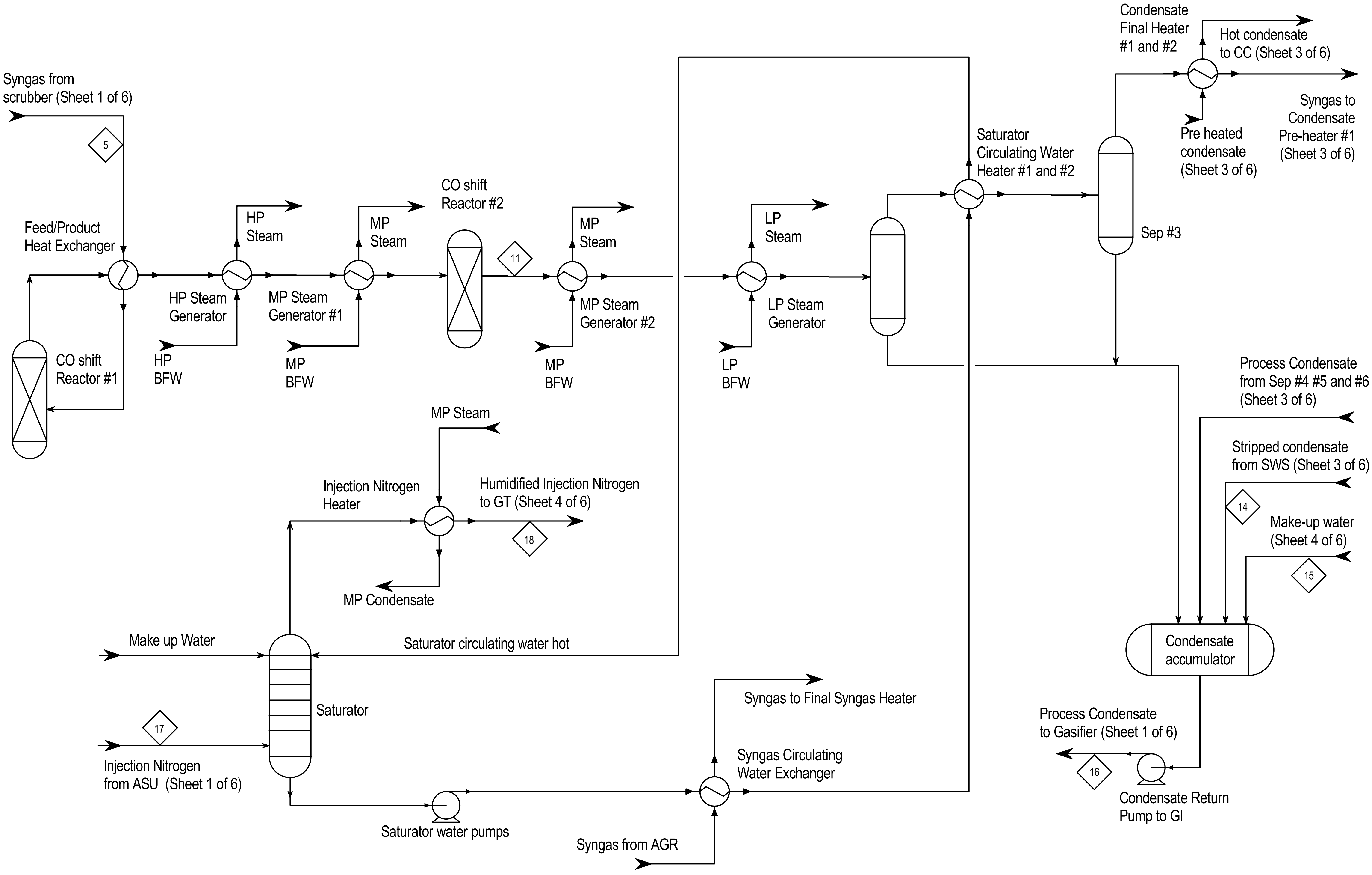
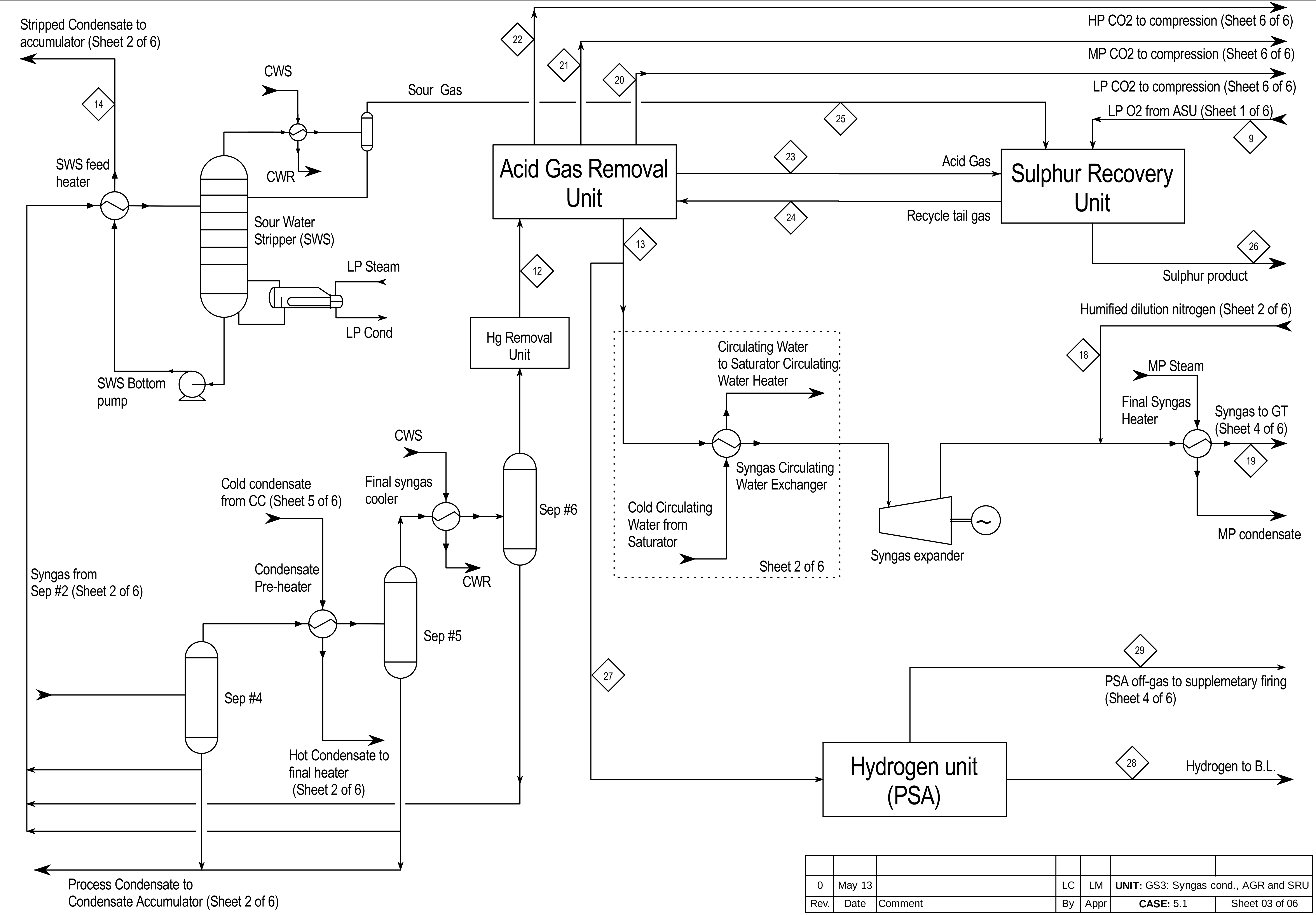


0	May 13		LC	LM	**UNIT:** GS3: Syngas treatment	
Rev.	Date	Comment	By	Appr	**CASE:** 5.1	Sheet 02 of 06



0	May 13		LC	LM	**UNIT:** GS3: Syngas cond., AGR and SRU	
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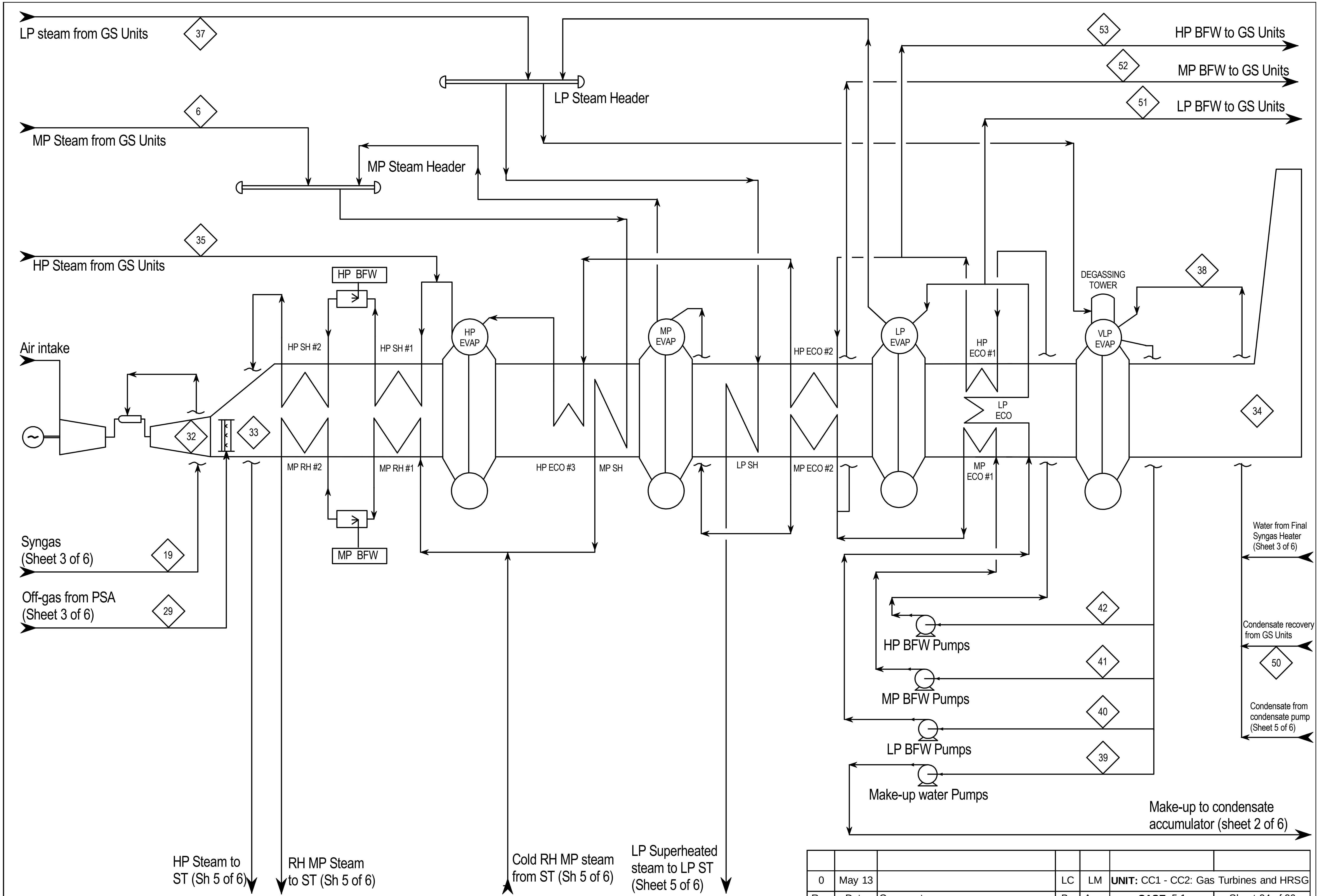

0	May 13		LC	LM	**UNIT:** CC1 - CC2: Gas Turbines and HRSG	
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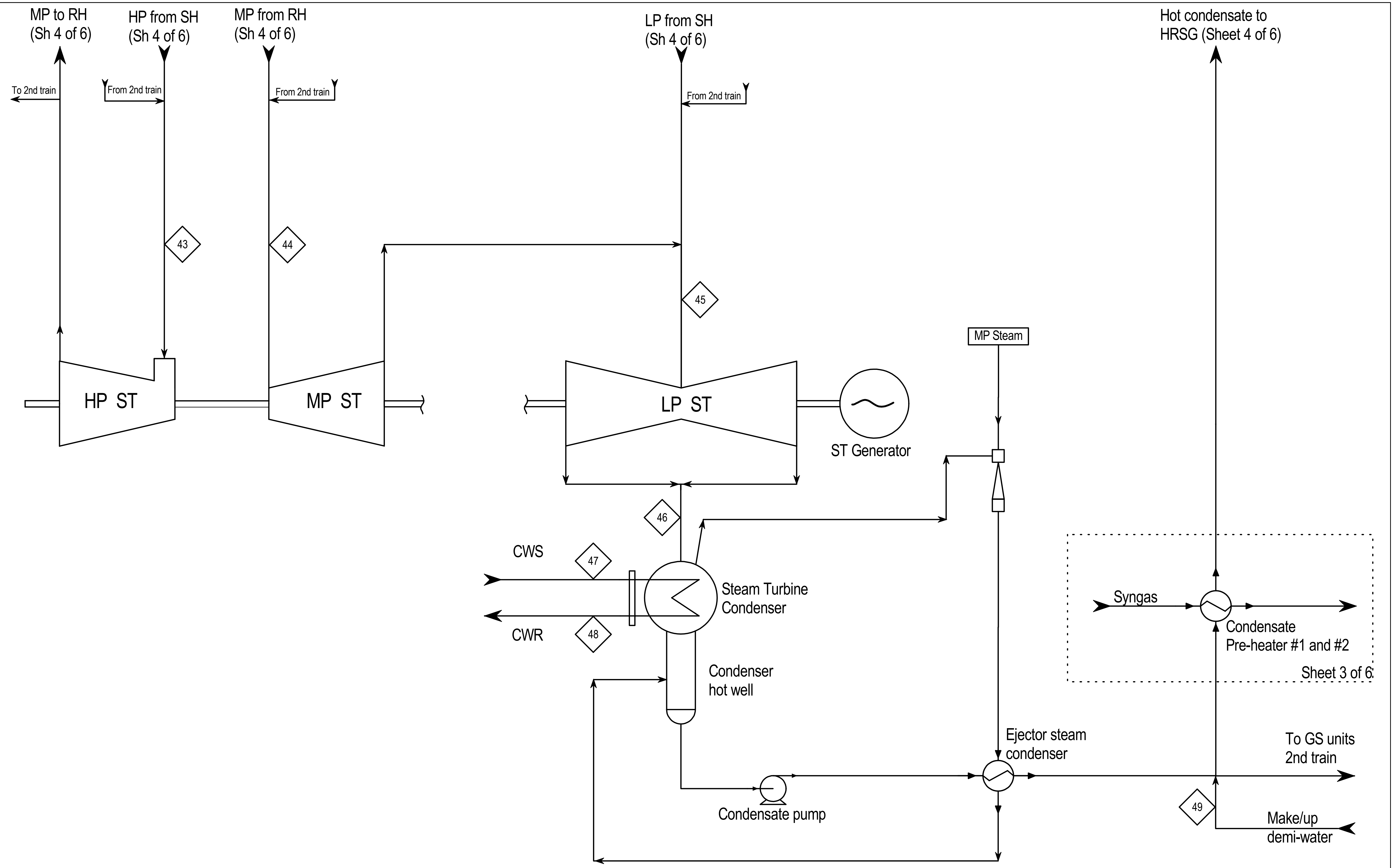

0	May 13		LC	LM	**UNIT:** CC3: Steam Turbine and Condenser	
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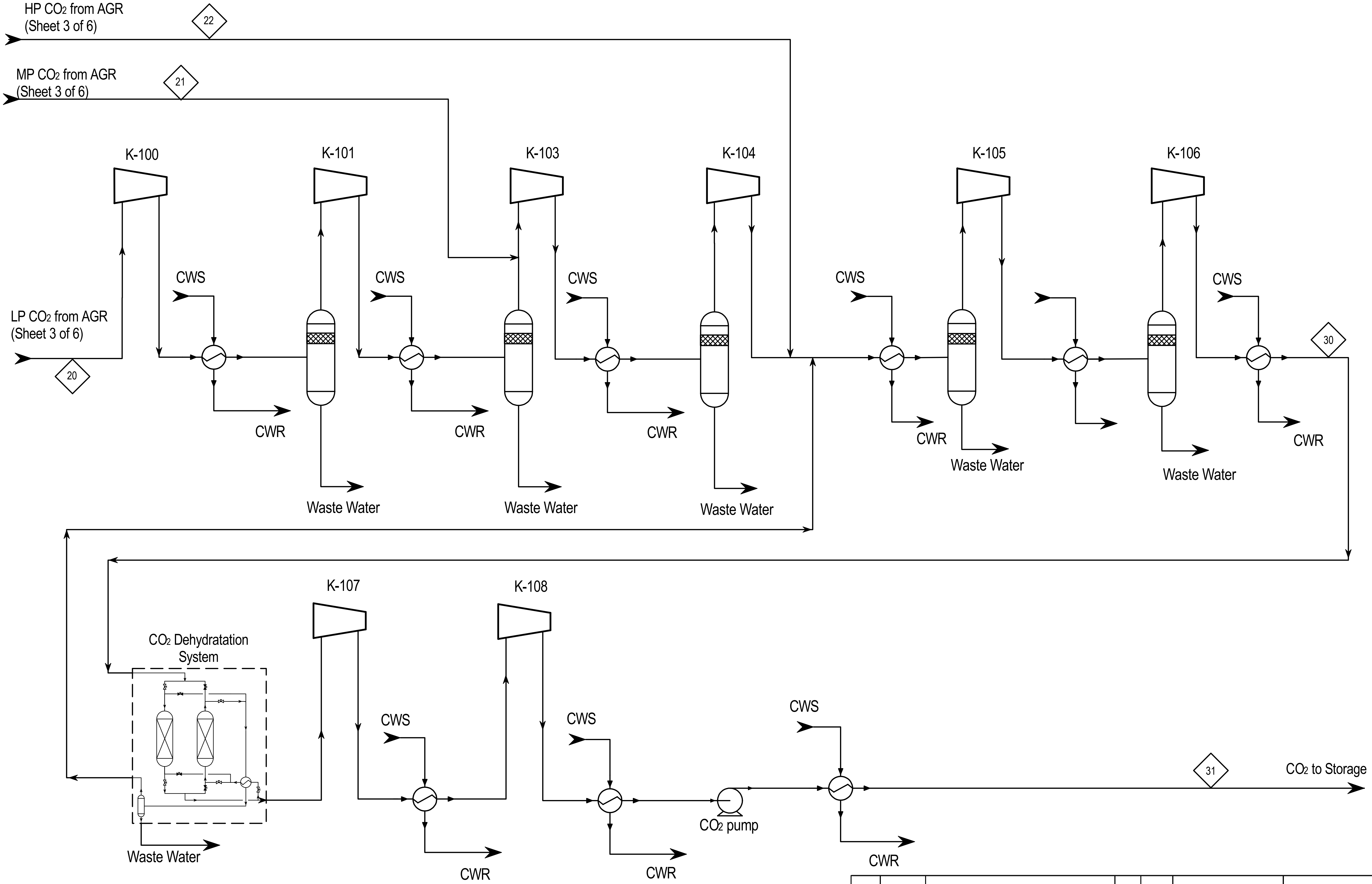

0	May 13		LC	LM	**UNIT:** CO2 compression	
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4. Heat and Material Balance

Heat & Material Balances here below reported make reference to the simplified Process Flow Diagrams of section 3.

	HYDROGEN AND POWER COPRODUCTION - Case 5.1 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 1000 - Gasification Island

STREAM	1	2	3	4	5	16				
	Coal to Gasification Island	HP Oxygen to Gasification	Slag from Gasification	Effluent Water from Gasification	Syngas at Scrubber Outlet to Shift Reactor	Return condensate to gasification				
Temperature (°C)	AMB	10	80	AMB	N/D	136				
Pressure (bar)	ATM	75-80 (1)	ATM	ATM	64.6	70				
TOTAL FLOW	Solid		Solid + water		Dry basis					
Mass flow (kg/h)	349,100	323,000	87,400	94,500	1,154,000	493,200				
Molar flow (kmol/h)		10,025		5,250	58,004	27,385				
LIQUID PHASE										
Mass flow (kg/h)			43,700	94,500	-	493,200				
GASEOUS PHASE										
Mass flow (kg/h)		323,000			1,154,000					
Molar flow (kmol/h)		10,025			58,004					
Molecular Weight		32.22			-					
Composition (vol %)	%wt		50% moisture		(dry basis)					
H_2	C: 64.6%	-			35.80					
CO	H: 4.38%	-			42.80					
CO_2	O: 7.02%	-			17.80					
N_2	S: 0.86%	1.50			3.22					
O_2	N: 1.41%	95.00			0.00					
CH_4	Cl: 0.03%	-			0.00					
H_2S + COS	Moisture: 9.5%	-			0.38					
Ar	Ash: 12.20%	3.50			0.00					
HCN		-			0.00					
NH_3		-			0.00					
H_2O					-					

Notes 1) FWI assumption

	HYDROGEN AND POWER COPRODUCTION - Case 5.1 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 2100 - Air Separation Unit (ASU)

STREAM	6	2	7	8	9	10				
	Air Intake from Atmosphere	HP Oxygen to Gasification	LP Nitrogen to process unit	MP Nitrogen for Syngas dilution	Oxygen to SRU	Nitrogen vent				
Temperature (°C)	Ambient	10	Ambient (1)	122	Ambient	Ambient				
Pressure (bar)	Ambient	75-80 (1)	7.5 (1)	28	6	Atmospheric				
TOTAL FLOW										
Mass flow (kg/h)	1,394,750	323,000	25,220	206,000	1,933	824,290				
Molar flow (kmol/h)	48,320	10,025	900	7,350	60	29,410				
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-	-				
GASEOUS PHASE										
Mass flow (kg/h)	1,394,750	323,000	25,220	206,000	1,933	824,290				
Molar flow (kmol/h)	48,320	10,025	900	7,350	60.0	29,410				
Molecular Weight	28.86	32.22	28.02	28.03	32.22	28.03				
Composition (vol %)										
H_2	-	-	-	-	-	-				
CO	-	-	-	-	-	-				
CO_2	0.04	-	-	0.05	-	0.05				
N_2	77.32	1.50	99.999	98.00	1.50	98.00				
O_2	20.75	95.00	0.001	1.00	95.00	1.00				
CH_4	-	-	-	-	-	-				
H_2S + COS	-	-	-	-	-	-				
Ar	0.92	3.50	-	0.25	3.50	0.25				
H_2O	0.97	-	-	0.70	-	0.70				

Notes 1) FWI assumption

HYDROGEN AND POWER COPRODUCTION - Case 5.1 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
CLIENT :	IEAGHG	PREP.	GP		
PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
PROJECT NO:	1-BD-0681 A	APPROVED	LM		
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HEAT AND MATERIAL BALANCE
UNIT 2200 - Syngas cooling & Conditioning line

STREAM	5	11	12	13	14	15	16	17	18	19
	Syngas at Scrubber Outlet to Shift Reactor	Syngas at Shift Reactor Outlet	Raw Syngas to Acid Gas Removal	HP Purified Syngas from Acid Gas Removal	Stripped condensate from SWS	BFW make-up to condensate accumulator	Return Condensate to Gasification	Nitrogen to saturator	Moist. Nitrogen for syngas dilution	Diluted Syngas to Power Island
Temperature (°C)	N/D	323	34	15	110	123	136	122	168	230
Pressure (bar)	64.5	61.5	57	53	70.0	2.2	70.0	28.0	27.0	27.0
TOTAL FLOW										
Mass flow (kg/h)	1,154,000	1,154,000	891,750	148,235	43,225	227,000	492,600	205,765	262,995	340,980
Molar flow (kmol/h)	58,004	58,004	43,496	26,243	2,400	12,600	27,350	7,350	10,513	24,322
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	43,225	227,000	492,600	-	-	-
GASEOUS PHASE										
Mass flow (kg/h)	1,154,000	1,154,000	891,750	148,235	-	-	-	205,765	262,995	340,980
Molar flow (kmol/h)	58,004	58,004	43,496	26,243	-	-	-	7,350	10,513	24,322
Molecular Weight	-	19.90	20.50	5.65	-	-	-	28.00	25.02	14.02
Composition (vol %)	(dry basis)									
H_2	35.80	41.04	54.73	89.55	-	-	-	0.00	0.00	50.58
CO	42.80	0.46	0.61	0.98	-	-	-	0.00	0.00	0.56
CO_2	17.80	31.54	41.98	5.73	-	-	-	0.05	0.03	3.25
N_2	3.22	1.70	2.27	3.73	-	-	-	98.00	68.54	31.93
O_2	0.00	0.00	-	-	-	-	-	1.00	0.70	0.30
CH_4	0.00	0.00	-	-	-	-	-	0.00	0.00	0.00
H_2S + COS	0.38	0.20	0.26	0.00	-	-	-	0.00	0.00	0.00
Ar	0.00	0.00	-	-	-	-	-	0.25	0.17	0.08
HCN	0.00	0.00	-	-	-	-	-	0.00	0.00	0.00
NH_3	0.00	0.00	-	-	-	-	-	0.00	0.00	0.00
H_2O	-	25.06	0.15	0.01	-	-	-	0.70	30.55	13.30

	HYDROGEN AND POWER COPRODUCTION - Case 5.1 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 2300 - Acid Gas Removal (AGR)

STREAM	12	13	20	21	22	23	24			
	Raw Syngas from Syngas Cooling	HP Purified Syngas to Syngas Cooling	LP CO2 to Compression	MP CO2 to Compression	HP CO2 to Compression	Acid Gas to SRU & TGT	Recycle Tail Gas from SRU			
Temperature (°C)	34	15	-9	-1	8	20	35			
Pressure (bar)	57.0	53.0	2.5	6.6	20.3	1.6	56.5			
TOTAL FLOW										
Mass flow (kg/h)	891,750	148,235	163,504	407,928	167,385	9,831	5,804			
Molar flow (kmol/h)	43,496	26,243	3,718	9,290	4,068	293	161			
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-	-	-			
GASEOUS PHASE										
Mass flow (kg/h)	891,750	148,235	163,504	407,928	167,385	9,831	5,804			
Molar flow (kmol/h)	43,496	26,243	3,718	9,290	4,068	293	161			
Molecular Weight	20.5	5.6	44.0	43.9	41.1	33.6	36.1			
Composition (vol %)										
H_2	54.73	89.55	-	0.20	6.66	14.47	17.65			
CO	0.61	0.98	-	-	0.16	0.25	-			
CO_2	41.98	5.73	99.87	99.74	92.95	43.29	77.90			
N_2	2.27	3.73	-	-	0.19	0.38	0.69			
O_2	-	-	-	-	-	-	-			
CH_4	-	-	-	-	-	-	-			
H_2S + COS	0.26	0.00	-	-	-	40.70	3.76			
Ar	-	-	-	-	-	-	-			
HCN										
NH_3	-	-	-	-	-	0.11	-			
H_2O	0.15	0.01	0.13	0.06	0.04	0.80	-			

	HYDROGEN AND POWER COPRODUCTION - Case 5.1 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 2400 - Sulfur Recovery Unit (SRU) & Tail Gas Treatment (TGT)

STREAM	9	23	24	25	26					
	Oxygen to SRU	Acid Gas from AGR Unit	Claus Tail Gas to AGR Unit	Sour Gas from Sour water stripper	Product Sulphur					
Temperature (°C)	Ambient	20	35	80	-					
Pressure (bar)	6.0	1.6	56.5	4	-					
TOTAL FLOW										
Mass flow (kg/h)	1,933	9,831	5,804	170	3,000					
Molar flow (kmol/h)	60	293	161	4.5	-					
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-					
GASEOUS PHASE										
Mass flow (kg/h)	1,933	9,831	5,804	170	-					
Molar flow (kmol/h)	60	293	161	4.5	-					
Molecular Weight	32.2	33.6	36.1	37.7	-					
Composition (vol %)										
H_2	-	14.47	17.65	0.49	-					
CO	-	0.25	-	0.03	-					
CO_2	-	43.29	77.90	74.16	-					
N_2	1.50	0.38	0.69	0.19	-					
O_2	95.00	-	-	-	-					
CH_4	-	-	-	-	-					
H_2S + COS	-	40.70	3.76	3.57	-					
Ar	3.50	-	-	-	-					
HCN										
NH_3		0.11	-	9.14	-					
H_2O	-	0.80	-	12.42						

	HYDROGEN AND POWER COPRODUCTION - Case 5.1 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
Unit 2500 - CO2 Compression and Drying

STREAM	20	21	22	30	31					
	LP CO2 to Compression	MP CO2 to Compression	HP CO2 to Compression	CO_2 to drying package	CO_2 to storage					
Temperature (°C)	-9	-1	8	26	30					
Pressure (bar)	2.5	6.6	20.3	39.8	110.0					
TOTAL FLOW										
Mass flow (kg/h)	163,504	407,928	167,385	806,058	725,168					
Molar flow (kmol/h)	3,718	9,290	4,068	18,630	16,740					
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-					
GASEOUS PHASE										
Mass flow (kg/h)	163,504	407,928	167,385	806,058	725,168					
Molar flow (kmol/h)	3,718	9,290	4,068	18,630	16,740					
Molecular Weight	44	43.9	41.1	43.3	43.3					
Composition (vol %)										
H_2	-	0.20	6.66	1.61	1.61					
CO	-	-	0.16	0.04	0.04					
CO_2	99.87	99.74	92.95	98.18	98.30					
N_2	-	-	0.19	0.05	0.05					
O_2	-	-	-	0.00	0.00					
CH_4	-	-	-	0.00	0.00					
H_2S + COS	-	-	-	0.00	0.00					
Ar	-	-	-	0.00	0.00					
HCN	-	-	-	0.00	0.00					
NH_3	-	-	-	0.00	0.00					
H_2O	0.13	0.06	0.04	0.12	0.00					

	HYDROGEN AND POWER COPRODUCTION - Case 5.1 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 2600 - Hydrogen Production Unit

STREAM	27	28	29							
	Syngas to PSA	High-purity Hydrogen	PSA off-gas							
Temperature (°C)	15	20	10							
Pressure (bar)	53	52	5							
TOTAL FLOW										
Mass flow (kg/h)	70,210	21,050	49,160							
Molar flow (kmol/h)	12,430	9,844	2,586							
LIQUID PHASE										
Mass flow (kg/h)	-	-	-							
GASEOUS PHASE										
Mass flow (kg/h)	70,210	21,050	49,160							
Molar flow (kmol/h)	12,430	9,844	2,586							
Molecular Weight	5.6	2.1	19.0							
Composition (vol %)										
H_2	89.55	99.53	51.61							
CO	0.98	-	4.72							
CO_2	5.73	-	27.50							
N_2	3.73	0.47	16.11							
O_2	-	-	-							
CH_4	-	-	-							
H_2S + COS	0.00	-	0.00							
Ar	-	-	-							
HCN	-	-	-							
NH_3	-	-	-							
H_2O	0.01	-	0.06							

H2 AND POWER CO-PRODUCTION - Case 5.1 - H&M BALANCE		REVISION	0	
CLIENT :	IEAGHG	PREP.	GP	
PROJECT NAME:	CO_2 capture at coal based power and H2 plants	CHECKED	NF	
PROJECT NO:	1-BD-0681 A	APPROVED	LM	
LOCATION:	The Netherlands	DATE	July 2013	

HEAT AND MATERIAL BALANCE
Unit 3000 - Power Island

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
29	PSA off-gas to post-firing (*)	24.6	10	5.0	-
19	Treated Syngas from Syngas Cooling (*)	170.5	230	27.0	-
32	Flue gas from GT (*) (1)	1679.8	521	1.05	-
33	Flue gas after post-firing (*) (2)	1704.4	597	1.05	-
34	Flue gas at stack (*) (2)	1704.4	133	atm	-
35	HP Steam from Process Units (*)	267.6	335	137.0	2646
36	MP Steam from Process Units (*)	35.5	252	41.0	2801
37	LP Steam from Process Units (*)	53.0	168	7.5	2766
38	Condensate to Deaerator (*)	705.0	113	2.2	474
39	BFW to VLP Pumps (*)	113.5	123	2.2	518
40	BFW to LP BFW Pumps (*)	127.7	123	2.2	518
41	BFW to MP BFW Pumps (*)	144.0	123	2.2	518
42	BFW to HP BFW Pumps (*)	331.8	123	2.2	518
43	HP Steam to Steam Turbine	659.5	517	132.0	3381
44	Hot RH Steam to Steam Turbine	841.1	517	34.8	3490
45	LP Steam to Steam Turbine	982.8	270	5.7	3000
46	Steam to Condenser	982.8	29	0.04	2299
47	Water Supply to Steam Condenser	46105	15	4.0	63
48	Water Return from Steam Condenser	46105	26	3.5	109
49	Make-up water	292.5	15	6.0	64
50	Condensate return from Process Units	134.7	94	4.2	394
51	LP BFW to Process Units	142.0	160	19.0	676
52	MP BFW to Process Units	176.9	160	56.0	678
53	HP BFW to Process Units	538.7	130	180.0	558

(*) Flowrate figure refers to one train (50% capacity)
(1) Flue gas molar composition: N_2: 72.3%; H_2O: 13.5%; O_2: 12.6%; CO_2: 0.8%; Ar: 0.8%.
(2) Flue gas molar composition: N_2: 71.5%; H_2O: 14.4%; O_2: 11.8%; CO_2: 1.5%; Ar: 0.8%.

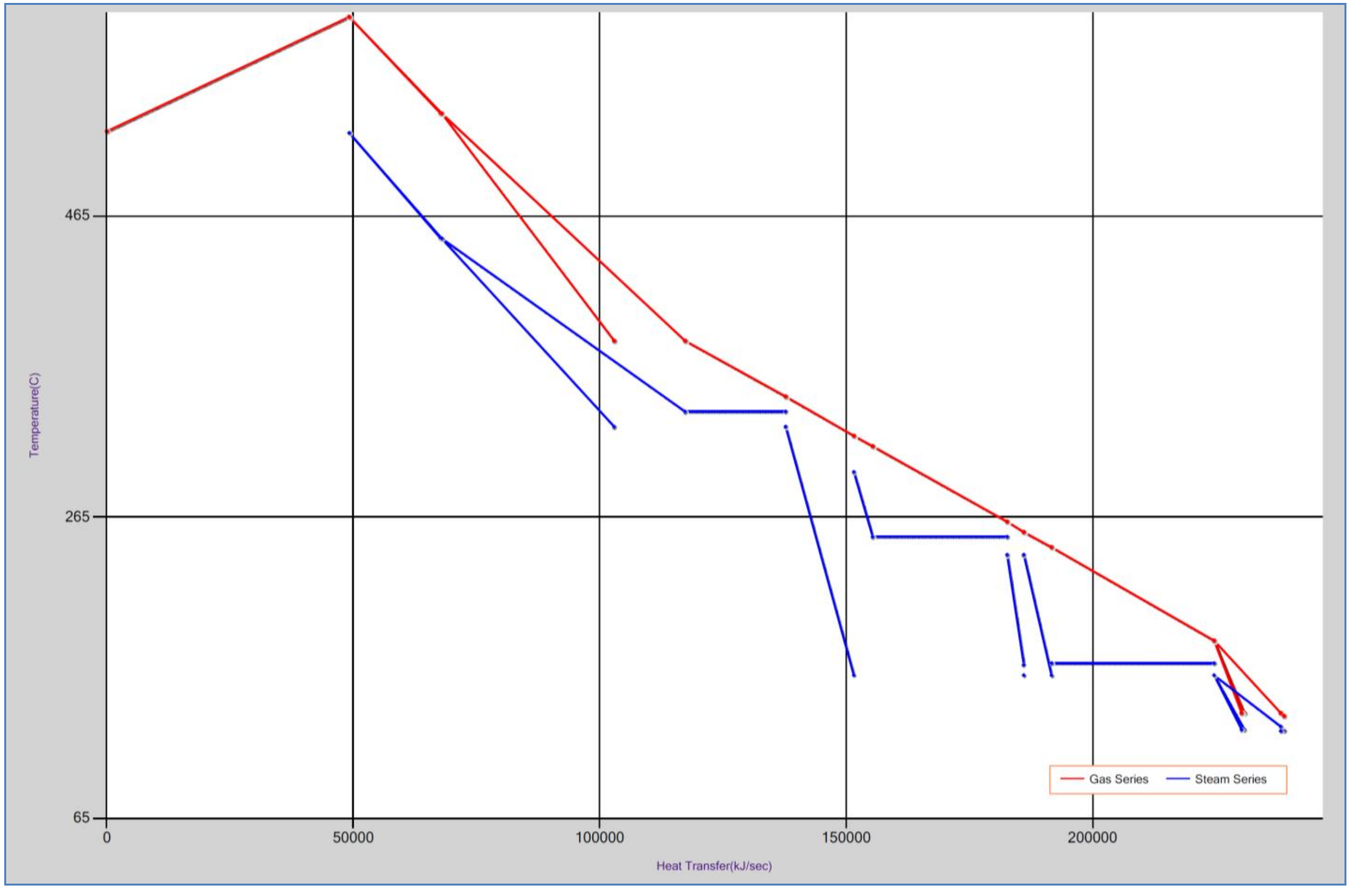

Figure 1 – Case 5.1 – HRSG T-Q diagram

5. Utility consumption

Main utility consumption of the process and utility units is reported in the following tables. More specifically:

- Steam / BFW / condensate interface summary is reported in Table 2.
- Water consumption summary is shown in Table 3.
- Electrical consumption summary is included in Table 4.

Table 2. Case 5.1 – Steam/BFW/condensate interface summary

CLIENT:	IEAGHG						REVISION	Rev.0		
PROJECT:	CO2 capture at coal based power and hydrogen plants						DATE	August 2013		
LOCATION:	The Netherlands						ISSUED BY	LC		
FWI Nº:	1-BD-0681 A						CHECKED BY	NF		
							APPROVED BY	LM		

Hydrogen and power co-production - Case 5.1 (Power Island: 2 x E-class Gas Turbine) - Steam and water balance

UNIT	DESCRIPTION UNIT	HP Steam barg 137.0	MP Steam barg 40.0	LP Steam barg 6.5	HP BFW	MP BFW	LP BFW	VLP BFW	condensate recovery	Losses
		[t/h]	[t/h]	[t/h]	[t/h]	[t/h]	[t/h]	[t/h]	[t/h]	[t/h]
	PROCESS UNITS									
2100	**Air Separation Unit (ASU)**								**0.0**	
1000	**Gasification Section**	**-444.1**			**446.7**				**0.0**	**-2.5**
2200	**Syngas Treating and Conditioning Line**	**-91.2**	**-63.1**	**-132.1**	**92.1**	**168.2**	**142.0**	**227.0**	**-55.6**	**-287.3**
2300	**Acid Gas Removal**			**64.0**					**-64.0**	**0.00**
2400	**Sulphur Recovery (SRU)**		**-7.9**			**8.7**				**-0.83**
3000	**POWER ISLANDS UNITS**	**535.3**	**70.9**	**53.0**	**-538.7**	**-176.9**	**-142.0**	**-227.0**	**134.6**	
4000	**UTILITY and OFFSITE UNITS**			**15.0**					**-15.0**	**0.00**
5000	**Hydrogen Unit (PSA)**									
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-290.7**

Note: (1) Negative figures represent generation

Table 3. Case 5.1 – Water consumption summary

FOSTER WHEELER

CLIENT: IEAGHG
PROJECT: CO2 capture at coal based power and H2 plants
LOCATION: The Netherlands
FWI Nº: 1-BD-0681 A

Revision	0
Date	August 2013
ISSUED BY	LC
CHECKED BY	NF
APPR. BY	LM

Hydrogen and power co-production - Case 5.1 (Power Island: 2 x E-class Gas Turbine)

Water Consumption Summary

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water Primary system [t/h]	Cooling Water Secondary System [t/h]
	AIR SEPARATION UNIT (ASU)				
2100	**Air Separation Unit**				**10550**
	GASIFICATION SECTION (GS)				
1000	**Gasification**	**145**			**3870**
2200	**Syngas treatment and conditioning line**				**720**
2300	**Acid Gas Removal**		**0.6**		**6870**
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**				**160**
	CO_2 COMPRESSION				
2500	**CO_2 Compression**				**5850**
	COMBINED CYCLE (CC)				
3100	**Gas Turbines and Generator auxiliaries**			**46110**	**470**
3200	**Heat Recovery Steam Generator**				
3300	**Steam Turbine and Generator auxiliaries**		**292.5**		**1830**
	Miscellanea				
	UTILITY UNITS (UU)				
4000	**Cooling Water System**	**1378**			
4000	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**440**	**-293**		
4000	**Waste Water Treatment**	**-91.0**			
4000	**Balance of Plant (BOP)**				**240**
	TOTAL CONSUMPTION	**1872**	**0**	**46110**	**30560**

Note: Negative figures represent generation

Table 4. Case 5.1 – Electrical consumption summary

FOSTER WHEELER	CLIENT: IEAGHG PROJECT: CO2 capture at coal based power and H2 plants LOCATION: The Netherlands FWI Nº: 1-BD-0681 A	Rev.0 Date: August 2013 ISSUED BY: LC CHECKED BY: NF APPR. BY: LM

Hydrogen and power co-production - Case 5.1 (Power Island: 2 x E-class Gas Turbine)
Electrical Consumption Summary

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	AIR SEPARATION UNIT (ASU)	
2100	**MAC consumptions**	**124220**
	BAC consumptions	**12270**
	Nitrogen compressor and miscellanea	**12550**
	GASIFICATION SECTION (GS)	
900	**Coal Receiving Handling and Storage**	**410**
1000	**Gasification**	**8790**
2200	**Syngas treatment and conditioning line**	**1240**
2300	**Acid Gas Removal**	**20850**
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**	**700**
2500	**CO_2 Compression**	**33970**
	COMBINED CYCLE (CC)	
3100	**Gas Turbines auxiliaries**	**1000**
3200	**Heat Recovery Steam Generator**	**5670**
3300	**Steam Turbine auxiliaries and excitation system**	**700**
3300	**Miscellanea**	**2850**
	UTILITY UNITS (UU)	
4000	**Cooling Water System**	**9310**
4000	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**730**
4000	**Balance of Plant (BOP)**	**1080**
	TOTAL CONSUMPTION	**236340**

6. Overall performance

The following table shows the overall performance of Case 5.1.

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**DATE**	August 2013
PROJECT No. :	1-BD-0681 A	**MADE BY**	LC
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 5.1 - H2 and power co-production Plant Performance Summary
(Power island: 2 E-class GTs)

OVERALL PERFORMANCES		
Coal Flowrate (as received)	t/h	349.1
Coal LHV (as received)	kJ/kg	25870
Coal HHV (as received)	kJ/kg	27060
THERMAL ENERGY OF FEEDSTOCK	**MWth (LHV)**	**2509**
THERMAL ENERGY OF FEEDSTOCK	**MWth (HHV)**	**2624**
Thermal Power of Raw Syngas exit Scrubber	MWth (LHV)	1785
Thermal power of syngas to AGR	MWth (LHV)	1638
Thermal Power of Clean Syngas to Gas Turbines	MWth (LHV)	842
Thermal Power of Off-gas to post-firing	MWth (LHV)	99
Thermal Power of Clean Syngas to Hydrogen PSA	MWth (LHV)	758
HYDROGEN PRODUCTION	**Nm^3/h**	**220600**
Thermal Power of Hydrogen	**MWth (LHV)**	**659**
Gas turbines total electric power output	MWe	319.8
Steam turbine electric power output	MWe	359.6
Syngas expander	MWe	5.9
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX	**MWe**	**685.3**
Gasification Section units consumption	MWe	32.0
ASU consumption	MWe	149.0
Combined Cycle units consumption	MWe	10.2
CO_2 Compression and Dehydration unit consumption	MWe	34.0
Utility Units consumption	MWe	11.1
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**236.3**
NET ELECTRIC POWER OUTPUT OF IGCC (Step-up transformer Eff. = 0.997)	**MWe**	**447.6**
CO_2 emission per net power production (*)	**kg/MWh**	**93.7**

(*) Referred to the net power production fo case 4.2

The following table shows the overall CO_2 balance and CO_2 removal efficiency of Case 5.1.

CO_2 removal efficiency	**Equivalent flow of CO_2** kmol/h
INPUT	
Fuel Mix (Carbon AR)	18730
TOTAL (A)	18730
OUTPUT	
Slag + Waste water (B)	101.0
CO_2 product pipeline	
CO	7
CO_2	16759
CH_4	0.0
COS	0.0
Total to storage (C)	16766.5
Emission	
CO_2 + CO (Combined Cycle)	979
CO2 + CO (to PF)	884
TOTAL	18730
Overall Carbon Capture, % ((B+C)/A)	90.1

7. Environmental impact

The gasification plant design is based on advanced technologies that allow to reach high electrical generation efficiency, while minimizing impact to the environment. Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

7.1. Gaseous emissions

During normal operation at full load, main continuous emissions are the combustion flue gases of the two trains of the combined cycle, from the combustion of the syngas in the two gas turbines. Table 5 summarises expected flow rate and concentration of the combustion flue gas from one train of the combined cycle.

Minor gaseous emissions are created by 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 related to the milling, storage and handling of solids (e.g. solid transfer, leakage). As summarised in Table 6, these emission mainly consists of air or nitrogen containing particulate.

Table 5. Case 5.1 – Plant emission during normal operation

Flue gas to HRSG stack	
Emission type	Continuous
Conditions	
Wet gas flowrate, kg/h	1,704,000
Flow, Nm^3/h (1)	1,428,800
Temperature, °C	133
Composition	(% vol)
Ar	0.79
N_2	71.53
O_2	11.83
CO_2	1.45
H_2O	14.40
Emission	mg/Nm^3 (1)
NOx	< 50
SOx	< 1
CO	< 100
Particulate	< 10

(1) Dry gas, O_2 content 15% vol.

Table 6. Case 5.1 – Plant minor emission

Emission source	Emission type	Temperature	
Coal handling and storage system	Continuous	ambient	Air: 10 mg/Nm^3 particulate

7.2. Liquid effluents

Main liquid effluents are the cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids, and the effluent from the Waste Water Treatment, which flows to an outside plant battery limits recipient.

Cooling Tower blow-down

Flowrate : 330 m^3/h

Waste Water Treatment effluent

Flowrate : 150 m^3/h

7.3. Solid effluents

The IGCC plant is expected to produce the following solid by-product:

Slag from gasifier

Flowrate : 45 t/h (dry basis)

Moisture content : 50%

Slag product has a potential use as major components in concrete mixtures to make road, pads, storage bins.

8. Preliminary plot plan

Plot plan at block level of Case 5.1 is attached to this section, showing the area occupied by the main units and equipment of the plant.

REV.	DATE	DESCRIPTION	DRAW	BY	CHD.	APP.
C001	SEPT. 2013	Preliminary issue for comments	APeccati			

CLIENT IEA GHG

SITE The Netherlands

CO2 Capture and coal fired Power Plants

CASE: 5.1- H2 & Power co-production (E-Class GT)

PRELIMINARY PLOT PLAN

FOSTER WHEELER

SCALE N. A.

1BD0681A - 01 - 007

REV. C001

CAD FILE NAME

Form. A3

9. Equipment list

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

FOSTER WHEELER	CLIENT: IEA GHG		REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2	
	LOCATION: The Netherlands		DATE	May 2013	January 2014			
	PROJ. NAME: CO2 capture at coal based power and hydrogen plants		ISSUED BY	LC	GP			
	CONTRACT N. 1-BD-0681 A		CHECKED BY	NF	NF			
	CASE: Case 5.1 - H2 and power co-production (E-class GT)		APPROVED BY	LM	LM			

EQUIPMENT LIST

Unit 900 - Coal Handling & Storage (N/A)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-901	**Coal Handling**		Coal flowrate: 349 t/h					30 days storage
	Wagon tipper							Storage piles: 2 x 137,000 t each
	Receiving Hopper, vibratory feeder and belt extractor							
	Conveyors	Belt						
	Transfer Towers	Enclosed						
	As-Received Coal Sampling System	Two-Stage						
	As-Received Magnetic Separator System	Magnetic Plates						
	Conveyors	Belt						
	Transfer Towers	Enclosed						
	Crushers Towers	Impactor reduction						
	As-Fired Coal Sampling System	Swing hammer						
	As-Fired Magnetic Separator System	Magnetic Plates						
	Coal Silo		2 x 5300m3					for daily storage

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	CASE:	Case 5.1 - H2 and power co-production (E-class GT)	APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 1000 - Gasification Island (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-1002	**GE Energy Coal gasification package**							
	Coal grinding and slurry preparation							Included in Z-1002
	Gasifiers (RSC)		2 x 4200 t/d coal (as received) to burners 2 x 900 MWth (LHV basis) syngas at scrubber outlet					Included in Z-1002
	Scrubber							Included in Z-1002
	Black Water flash							Included in Z-1002
	Coarse slag handling							Included in Z-1002
	Grey water systeam and fines handling							Included in Z-1002

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EQUIPMENT LIST
Unit 2100 - Air Separation Unit (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2101	**ASU Package** including:							
	Cold Box	Cryogenic	162 t/h of 95% purity O2 each train					Included in Z-2101
	Main Air compressors (MAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 2 x 297800 Nm3/h	2 x 35250 kW				Included in Z-2101
	Booster air compressors (BAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 238200 Nm3/h	7500 kW				Included in Z-2101
	MP N2 compressors (GAN)	Electric motor driven, centrifugal, with intercooling	Flowrate: 90600 Nm3/h	7500 kW				Included in Z-2101
	O2 pumps	Centrifugal						Included in Z-2101
	Back-up oxygen vaporiser	Shell and tube						Included in Z-2101
Common units to both trains:								
	LOX (liquid oxygen) storage	Fixed roof storage tank						8 hour storage for 1 gasification train Normal operating p: 5 bar a Normal operating T: -165 °C Included in Z-2101
	LIN (liquid nitrogen) storage	Fixed roof storage tank						8 hour storage for 1 Gasifier & 4 min storage for Syngas dilution and NOX control Normal operating p: 5 bar a Normal operating T: -180 °C Included in Z-2101
	Gaseous oxygen storage							
	Gaseous nitrogen storage							

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EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning Line (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	HEAT EXCHANGERS				Shell/tube	Shell/tube		
E-2201	**Feed/Product Heat Exchanger**	Shell & Tube						
E-2202	**HP steam generator**	Kettle						
E-2203	**MP steam generator #1**	Kettle						
E-2204	**MP steam generator #2**	Kettle						
E-2205	**LP steam generator**	Kettle						
E-2206 A/B	**Circulating Water Heater**	Shell & Tube						
E-2207 A/B	**Condensate preheater**	Shell & Tube						
E-2208	**Syngas heater / Circulating water cooler**	Shell & Tube						
E-2209	**Final sygas cooler**	Shell & Tube						
E-2210	**Syngas final heater**	Shell & Tube						
	DRUMS							
D-2201	**Condensate Separator**	Vertical						
D-2202	**Condensate Separator**	Vertical						
D-2203	**Condensate Separator**	Vertical						
D-2204	**Condensate Separator**	Vertical						
D-2205	**Condensate Separator**	Vertical						
D-2205	**Condensate accumulator**	Horizontal						Common for both syngas tratment and conditiong line trains

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EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning Line (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	COLUMN							
C-2201	**Nitrogen saturator**	Vertical						
	REACTOR							
R-2201	**1st Shift Catalyst Reactor**	vertical						Overall CO conversion = 98%
R-2202	**2nd Shift Catalyst Reactor**	vertical						
	PUMPS							
P-2201	**Saturator Circulating Water Pump**			355 kW				
P-2202	**Condensate Pump (to Gasifiers)**			630 kW				
	EXPANDER							
EX-2201	**Syngas Expander**		Flowrate = 310000 Nm^3/h	6500 kW				
	MISCELLANEA							
X-2201	**Mercury Adsorber**	Sulfur-impregnated activated carbon beds						

Note: equipment list referred to one train only

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EQUIPMENT LIST

Unit 2250 - Sour Water System (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-2251	**SWS PACKAGE**							
C-2251	Sour Water Stripper	Vertical						
	SWS Reboiler							
	SWS Condenser							
E-2251	Sour water heat exchanger (SWS feed / purified)							
P-2251	SWS Pump							

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EQUIPMENT LIST

Unit 2300 - Acid Gas Removal Unit (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2301	**Acid Gas Removal Unit - Absorption section**	Solvent: Selexol	Feed gas: 974900 Nm3/h; 56 barg; 34 °C					One H2S removal column, 3 CO2 removal columns, CO2 removal =91.78% Total Carbon Capture =90.5% Separated removal of CO2 and H2S
Z-2303	**Acid Gas Removal Unit - Solvent regeneration**							Total CO2 removal= 17700 t/d; 10 ppm H2S (dry) in combined CO2
Z-2304	**Chiller Unit**	Electrical driven						T= -10 °C

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EQUIPMENT LIST

Unit 2400 - Sulphur Recovery Unit (2x100%) & Tail Gas Treatment (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2401	**Sulphur Recovery Unit and Tail Gas Treatment Package** - two Sulphur Recovery Unit, each sized for 100% of the capacity - one Tail Gas Treatment Unit sized for 100% of capacity (including Reduction Reactor and Tail Gas Compressor)		Sulphur Prod.= 72 t/d Acid Gas from AGR = 6680 Nm3/h Expected Treated Tail Gas = 3602 Nm3/h					Sulphur content > 99,9 % mol min (dry basis)

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EQUIPMENT LIST

Unit 2500 - CO_2 Compression Package (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [MW]	P design [barg]	T design [°C]	Materials	Remarks
	COMPRESSORS							
C-2501	CO_2 Compressors	Centrifugal, Electrical Driven, 8 intercooled Stages	190000 Nm3/h p in: 2,45 bar a p out: 80 bar a	18000 kW				Water cooled
	PUMPS		**Q,m3/h x H,m**					
P-2501	CO_2 Pump	Centrifugal	640 x 530	800 kW				Liquid CO_2 product, per each train: Flowrate: 370 t/h; 110 bar a; 30°C
	PACKAGE							
PK-2501	CO_2 drying package							

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EQUIPMENT LIST

Unit 2600 - Hydrogen Production

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [MW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
	Hydrogen Production package	PSA	220000 Nm3/h P out = 51 barg T out =20 °C					Hydrogen purity =99.5 %

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EQUIPMENT LIST

Unit 3100 - Gas Turbine (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-3101	**Gas Turbine & Generator Package**							
GT-3101	Gas turbine	E-Class Gas Turbine	160 MW					Included in Z-3101
G-3101	Gas turbine Generator		210 MVA					Included in Z-3101

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	HEAT RECOVERY STEAM GENERATOR							
HRSG-3201	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels. Simple Recovery, Reheated.						
Each HRSG including:								
D-3201	**HP steam Drum**							
D-3202	**MP steam Drum**							
D-3203	**LP steam Drum**							
D-3204	**VLP steam Drum with degassing section**							
E-3201	**HP Superheater 2nd section**							Included in HRSG-3201 / 2
E-3202	**HP Superheater 1st section**							Included in HRSG-3201 / 2
E-3203	**HP Evaporator**							Included in HRSG-3201 / 2
E-3204	**HP Economizer 3rd section**							Included in HRSG-3201 / 2
E-3205	**HP Economizer 2nd section**							Included in HRSG-3201 / 2
E-3206	**HP Economizer 1st section**							Included in HRSG-3201 / 2
E-3207	**MP Reheater 2nd section**							Included in HRSG-3201 / 2
E-3208	**MP Reheater 1st section**							Included in HRSG-3201 / 2
E-3209	**MP Superheater**							Included in HRSG-3201 / 2
E-3210	**MP Evaporator**							Included in HRSG-3201 / 2
E-3211	**MP Economizer 2nd section**							Included in HRSG-3201 / 2
E-3212	**MP Economizer 1st section**							Included in HRSG-3201 / 2
E-3213	**LP Superheater**							Included in HRSG-3201 / 2
E-3214	**LP Evaporator**							Included in HRSG-3201 / 2
E-3215	**LP Economizer**							Included in HRSG-3201 / 2
E-3216	**VLP Evaporator**							Included in HRSG-3201 / 2

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PUMPS		**Q,m^3/h x H,m**					
P-3201 A/B	**HP BFW Pumps**	centrifugal	390 x 1800	2500				One operating, one spare
P-3203 A/B	**MP BFW Pumps**	centrifugal	170 x 570	335				One operating, one spare
P-3205 A/B	**LP BFW Pumps**	centrifugal	150 x 130	75				One operating, one spare
P-3207 A/B	**VLP BFW Pumps**	centrifugal	140 x 100	55				One operating, one spare
	MISCELLANEA							
X-3201	**Flue Gas Monitoring System**							NOx, CO, SO_2, particulate, H_2O, O_2
STK-3201	**CCU Stack**							
SL-3201	**Stack Silencer**							
DS-3201	**HP Steam Desuperheater**							Included in HRSG-3201
DS-3202	**MP Steam Desuperheater**							Included in HRSG-3201
	PACKAGES							
Z-3201	**Fluid Sampling Package**							
Z-3202	**Phosphate Injection Package**							
D-3204	Phosphate storage tank							Included in Z - 3202
P-3205 A/B	Phosphate dosage pumps							Included in Z - 3202 One operating , one spare
Z-3203	**Oxygen Scavanger Injection Package**							
D-3205	Oxygen scavanger storage tank							Included in Z - 3203
P-3206 A/B	Oxygen scavanger dosage pumps							Included in Z - 3203 One operating , one spare
Z-3204	**Amines Injection Package**							
D-3206	Amines Storage tank							Included in Z - 3204
P-3207 A/B	Amines Dosage pumps							Included in Z - 3204 One operating , one spare

FOSTER WHEELER

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EQUIPMENT LIST
Unit 3300 - Steam Turbine and Blow Down System (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-3301	**Steam Turbine and Generator Package**							
ST-3301	Steam Turbine		354 MWe					*Including:* *Lube oil system* *Cooling system* *Idraulic control system* *Drainage system* *Seals system* *Drainage system*
G-3402	Steam Turbine Generator		460 MVA					*Including relevant auxiliaries*
E-3301A/B	Inter/After condenser							
E-3302	Gland Condenser							
Z-3302	**Steam Condenser Package**							
E-3303	Steam Condenser	Water cooled	590 MWt					*Including:* *Hot well* *Vacuum pump (or ejectors)* *Start up ejector (if required)*
Z-3303	**Steam Turbine by-pass system**							
	PUMPS		**$Q,m^3/h$ x H,m**					
P-3301A/B	Condensate Pumps	Centrifugal, vertical	1656 x 110	670				One operating, one spare
	HEAT EXCHANGERS							
E-3304	Blow-Down Cooler	Shell & Tube						
	DRUMS							
D-3301	Continuous Blow-down Drum	vertical						
D-3302	Discontinuous Blow-down Drum	vertical						

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EQUIPMENT LIST
Unit 4000 - Utility and Offsite

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-4001	**COOLING WATER SYSTEM**							
CT-4001	Cooling Tower Including Cooling water basin	Evaporative, Natural draft	Total heat duty 930 MWth Diameter: 140 m, Height: 210 m, Water inlet: 17 m					Included in Z-4001
	Pumps							
P-4001A/B/C/D	Cooling Water pumps (primary system)	Vertical	15300 m3/h x 35 m	1400 kW				Included in Z-4001 3 operating
P-4002A/B/C	Cooling Water pumps (secondary system)	Vertical	13400 m3/h x 45 m	2000 kW				Included in Z-4001 2 operating, one spare
P-4003A/B	Raw water pumps (make-up)	centrifugal	1440 m3/h x 35 m	185 kW				Included in Z-4001 1 operating, one spare
	Packages							
	Cooling Water Filtration Package Cooling Water Sidestream Filters		Capacity: 7270 m3/h					
	Sodium Hypochlorite Dosing Package Sodium Hypochlorite storage tank Sodium Hypochlorite dosage pumps							
	Antiscalant Package Dispersant storage tank Dispersant dosage pumps							
Z-4002	**RAW WATER SYSTEM**							
T-4001	Raw Water storage tank		12480 m3					Included in Z-4002 24 hour storage
P-4004A/B	Raw Water Pumps to gasification island	centrifugal	160 m3/h x 50 m	30 kW				Included in Z-4002 One operating, one spare
P-4005A/B	Raw Water Pumps to demi plant	centrifugal	360 m3/h x 50 m	75 kW				Included in Z-4002 One operating, one spare
Z-4003	**DEMI WATER SYSTEM**							
PK-4001	**Demin Water Package, including:**							
	- Multimedia filter - Reverse Osmosis (RO) Cartidge filter - Electro de-ionization system							
T-4002	Demi Water storage tank		7920 m3					Included in Z-4003 24 hour storage
P-4006A/B	Demi Water Pumps	centrifugal	330 m3/h x 35 m	45 kW				Included in Z-4003 One operating, one spare

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EQUIPMENT LIST
Unit 4000 - Utility and Offsite

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-4004	**FIRE FIGHTING SYSTEM**							
	Fire water storage tank							
	Fire pumps (diesel)							
	Fire pumps (electric)							
	FW jockey pump							
	MISCELLANEA							
	Natural Gas system							
	Waste Water Treatment							
	Sulphur Storage/Handling		72 t/d S prod.					30 days storage
	Flare system							
	Interconnecting							
	Instrumentation							
	DCS							
	Piping							
	Electrical							
	Plant Air							
	Buildings							

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DOCUMENT NAME : CASE 5.2 – HYDROGEN AND POWER CO-PRODUCTION
POWER ISLAND: 2 X FRAME 6 EQUIVALENT GAS TURBINE
FWI CONTRACT : 1-BD-0681 A

ISSUED BY : N. FERRARI
CHECKED BY : L. MANCUSO
APPROVED BY : L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

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1. Introduction

This chapter of the report includes all technical information relevant to Case 5.2 of the study, which is a gasification plant based on the GE technology, designed for the co-production of hydrogen and power from coal, whose characteristic is shown in chapter B, and with capture of the generated carbon dioxide. Both power and hydrogen are exported outside plant battery limits respectively to the external electrical grid and to a hydrogen distribution network.

Plant capacity is the same of the GE technology based IGCC case, for power production only (refer to Case 4.2 in chapter E.2 of this report).

The configuration of the plant is based on the following main features:

- High-pressure (65 barg) GE Energy Gasification process, with slurry-feed system and Radiant Syngas Cooler (RSC);
- 2-stages sour shift;
- Removal of acid gases (H_2S and CO_2) based on Selexol physical solvent process;
- Oxygen-blown Claus unit, with tail gas catalytic treatment and recycle of the treated tail gas to the AGR;
- CO_2 compression and dehydration unit;
- Hydrogen production unit based in Pressure Swing Adsorption package
- Combined cycle based on two frame 6 equivalent gas turbines for power production

The description of the main process units is covered in chapter E of this report, so only features that are unique to this case are discussed in the following sections, together with the main modelling results.

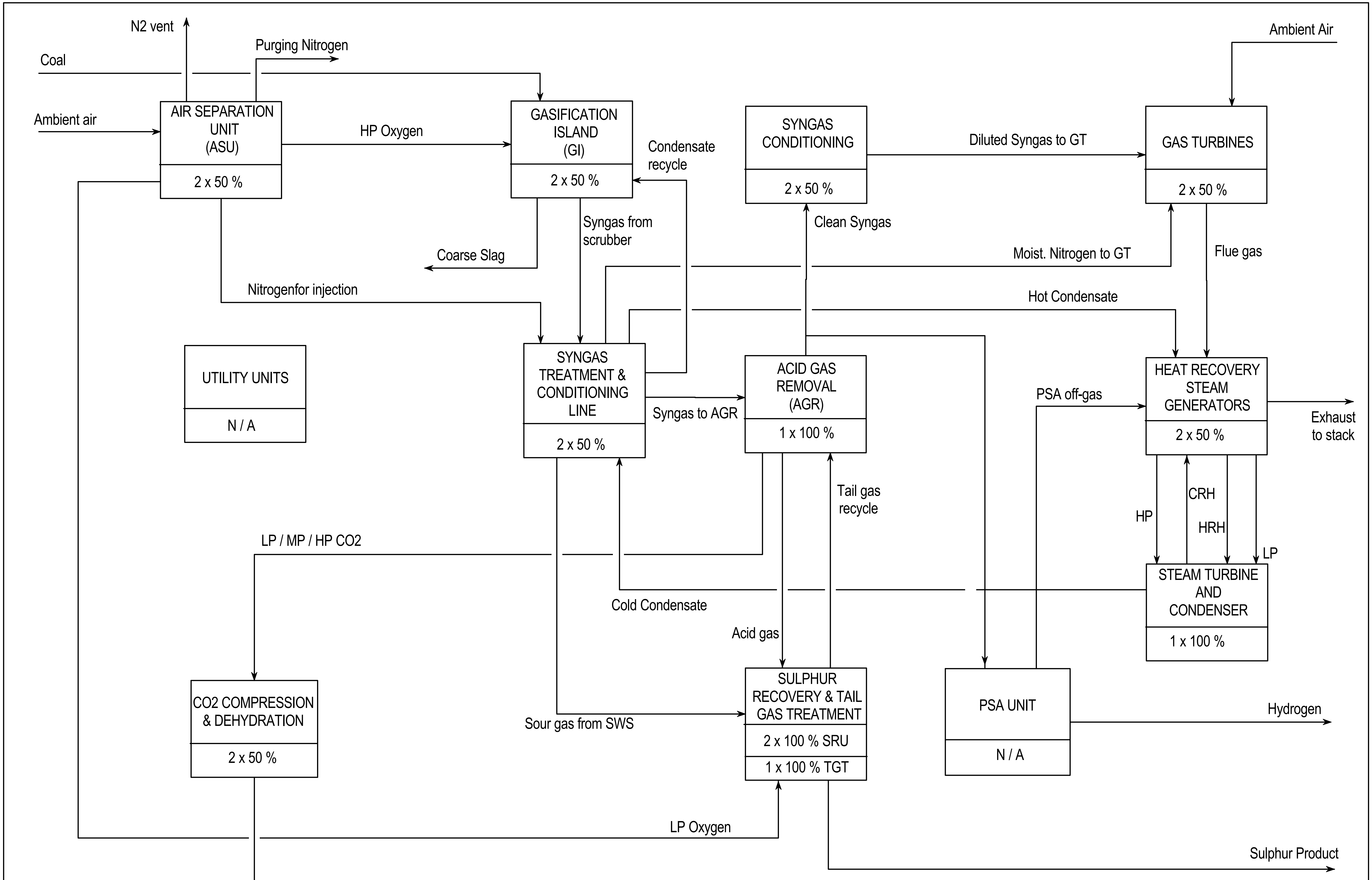
1.1. Process unit arrangement

The arrangement of the main units is reported in the following Table 1. Reference is also made to the block flow diagram attached below.

Table 1. Case 5.2 – Unit arrangement

Unit	Description	Trains
900	Coal Handling & Storage	N/A
1000	Gasification	2 x 50%
	Coal Grinding & Slurry Preparation	

Unit	Description	Trains
	Gasification (Radiant Syngas Cooler) and scrubber	
	Black Water Flash & Coarse Slag Handling	
	Grey Water & Fines Handling	
2100	Air Separation Unit	2 x 50%
2200	Syngas Treatment and Conditioning Line	2 x 50%
2250	Sour Water Stripper (SWS)	1 x 100%
2300	Acid Gas Removal	1 x 100%
2400	Sulphur Recovery Unit	2 x 100%
	Tail Gas Treatment	1 x 100%
2500	CO_2 Compression & Drying	2 x 50%
2600	Hydrogen production unit (PSA)	N/A
3000	Combined Cycle	
	Gas Turbine (frame 6 equivalent)	2 x 50%
	HRSG	2 x 50%
	Steam Turbine	1 x 100%
4000	Utility and Offsite	N/A



0	July 13		GP	LM	**UNIT:** Block Flow Diagram	
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2. Process description

2.1. Overview

The description reported in this section makes reference to the simplified Process Flow Diagrams (PFD) of section 3, while stream numbers refer to section 4, which provides heat and mass balance details for the numbered streams in the PFD.

2.2. Unit 900 – Coal Handling & Storage

The unit mainly consists of the coal storage and handling.

The general description relevant to this unit is reported in chapter E, section 2.1. Main process information of this case and the interconnections with the other units is shown in the relevant process flow diagram and the heat and mass balance table.

2.3. Unit 1000 – Gasification Island

The gasification island based on GE gasification mainly includes the coal grinding and slurry preparation section, the gasification (RSC) and the scrubber, the Black Water Flash and Coarse Slag Handling, and Grey Water & Fines Handling. Technical information relevant to these packages is reported in chapter E, section 3.2.

The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

2.4. Unit 2100 – Air Separation Unit

Technical information relevant to this packaged unit is reported in chapter E, section 2.3. The main process information of the unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The sizing capacity of the Air Separation Unit is determined by the oxygen requirement of the gasification island and the SRU. The total required oxygen flowrate for the case is approximately 325 t/h.

The Air Separation unit supplies medium pressure nitrogen, injected in the gas turbine, after being moisturised, for NOx suppression and power production augmentation.

2.5. Unit 2200 – Syngas Treatment and Conditioning line

The general description of this unit is shown in chapter E, section 2.4, while case-specific features are reported hereinafter. It has to be noted that syngas treatment line from the gasification scrubber to the AGR exit is almost the same of case 4.2. The main process information and the interconnections with the other units are shown in the relevant process flow diagram and the heat and mass balance tables.

Saturated raw syngas from the gasification scrubber, at approximately 64 barg, is heated-up in the Feed/Product Heat Exchanger, before entering the first shift reactor, in order to increase the temperature up to the level required for the proper operation of the shift catalyst.

In the shift unit, CO is shifted to H_2 and CO_2 and COS is converted to H_2S. A double stage shift, containing sulphur tolerant shift catalyst (sour shift) is selected in order to increase the H_2 content in the fuel and maximize the degree of CO_2 removal. The overall CO conversion is approximately 98%.The water content in the syngas is adequate for the shift reaction to take place with no additional steam injection.

The partially-shifted syngas temperature is increased by the exothermic shift reaction, allowing for thermal recovery. The syngas is cooled down in a series of heat exchangers, before being fed to the second reactor stage:

- Feed/Product Heat Exchanger,
- HP Steam Generator,
- MP Steam Generator #1.

After being cooled, the syngas is directed to the second and last shift reactor. The hot shifted syngas outlet from the second stage is cooled in the following series of heat exchangers, to thermally recover heat and increase the overall power generation:

- MP Steam Generator #2,
- LP Steam Generator,
- Saturator Circulating Water Heater #1 and #2,
- Condensate Pre-heater #1 and #2.
- BFW pre-heater

Final cooling of the syngas is made against cooling water, before passing through a sulphur-impregnated activated carbon bed to remove approximately 95% of the mercury. Cool, mercury-depleted syngas is then directed to the AGR.

During the cooling of the syngas, the process condensate is separated and collected in the process condensate accumulator. Before being sent to the accumulator, the condensate from the last syngas separator, upstream the AGR, plus a portion of the condensate from the upstream separator, is sent to the Sour Water Stripper in order to avoid accumulation of ammonia and H_2S and other dissolved gases in the water recycle to the gasification section. The condensate from the accumulator is sent to the gasification scrubber for syngas saturation. Boiler Feed Water from the deaerator of the combined cycle provides the make-up water to substitute for the steam reacted in the shift unit.

From the AGR unit, part of the cool hydrogen-rich gas returns to the syngas treatment and conditioning line as de-carbonized fuel gas after H_2S and CO_2 removal for final treatment before being fed to the combined cycle. This syngas flow is preheated against circulating water coming from the nitrogen saturator and then expanded down to the pressure required from the gas turbine, thus producing additional electric power.

Then, the hydrogen-rich syngas necessary to saturate the thermal demand of the gas turbines at the reference ambient temperature of the project, which corresponds to about 30% of the total syngas flowrate coming from the AGR, is sent to the combined cycle for final heating against boiler feed water and combustion in the gas turbine.

The balancing syngas from the AGR is sent to the PSA unit for high purity hydrogen production.

The unit includes nitrogen saturator, providing moisturised nitrogen to be injected in the gas turbine. Nitrogen humidification is achieved by means of hot water heated in the syngas cooling line. The humidified nitrogen is finally heated using MP steam and then injected in the gas turbine combustion chamber.

2.6. Unit 2300 – Acid Gas Removal (AGR)

The AGR unit is intended to selectively remove H_2S and CO_2 in sequent steps by employing Selexol as physical solvent. Technical information relevant to this package is reported in chapter E, section 2.5. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The AGR is designed to meet the following process specifications of the treated gas and of the CO_2 product exiting the unit:

- The H_2S+COS concentration of the treated gas exiting the unit is around 1 ppmv. This is due to the integration of CO_2 removal with the H_2S removal, which makes available a large circulation of solvent that is cooled down by a refrigerant package before flowing to the CO_2 absorber.
- The CO_2 product is characterised by a content of incondensable around 2%, while simultaneously meeting the specification of H_2S content lower than 20 ppmv and CO content lower than 0.2% mol (actual 0.06% mol).
- The acid gas H_2S concentration is about 41% dry basis, suitable to feed the oxygen blown Claus process.

The CO_2 removal rate is 91.7% of the carbon dioxide entering the unit, allowing reaching an overall carbon capture of approximately 90% with respect to the carbon

in the syngas. These excellent performances on both the H_2S removal and CO_2 capture are achieved with significant power consumption and steam demand.

2.7. Unit 2400 – SRU and TGT

Technical information relevant to this package is reported in chapter E, section 2.5. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The SRU is designed to process the acid gas from the AGR and other minor acid streams like the acid off-gas from the black water flash within the gasification island and the sour gases from the SWS, using low pressure oxygen from the ASU. In the furnace, H_2S is catalytically oxidized to SO_2 which is further reacted with H_2S to form H_2O and elemental sulphur. Following the thermal stage, sulphur is condensed, while the tail gas is hydrogenated and recycled back to the AGR unit at approximately 60 barg by means of a dedicated compressor.

The overall sulphur production is approximately 72 tons per day.

2.8. Unit 2500 – CO_2 Compression and Drying

This unit is mainly composed of a compression and dehydration package, followed by last stage CO_2 pumps, supplied by specialized vendors. Technical information relevant to this package is reported in chapter E, section 2.6. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

Three different streams of CO_2 from the Acid Gas Removal unit are routed to the CO_2 compression unit, delivered at approximately 19 barg, 6 barg, and 1.5 barg respectively.

The stream at lower pressure is initially compressed up to the pressure of the medium pressure stream and then combined with it. The resulting stream is compressed to allow the mixing with the last stream without any pressure loss. The combined stream is then compressed up to approximately 40 barg and sent to the dehydration system, which is a standard solid desiccant package that dehydrates the CO_2 stream to a dew point of -40°C. After dehydration, the CO_2 stream is finally compressed to a supercritical condition at 80 barg.

The resulting stream of CO_2 is pumped to the required pressure of 110 barg. The CO_2 product (approximately 97.9 % wt purity) is transported to the plant battery limits for final sequestration.

2.9. Unit 2600 – Hydrogen Production Unit

Technical information relevant to this package is reported in chapter E, section 2.9. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.
The PSA unit is designed to produce 325,000 Nm^3/h of high-purity hydrogen at around 51 barg, to be sent to the plant battery limits. The PSA off-gases are sent to the supplementary firing system of the combined cycle.

2.10. Unit 3000 – Combined Cycle

Technical information relevant to these packages is reported in chapter E, section 2.10. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The hydrogen-rich syngas heated up to around 220°C in the syngas treatment and conditioning line enters the burners of the gas turbine.

The gas turbine compressors provide combustion air to the burner only, i.e. no air integration with the ASU is foreseen. The exhaust gases from the gas turbine enter the HRSG at 585°C. Off-gas from the PSA unit are burned in the supplementary firing system of the HRSG, increasing the flue gas temperature up to 790°C. The HRSG recovers heat available from the exhaust gas producing steam at three different pressure levels for the steam turbine, plus an additional steam generator with integral deaerator. The final exhaust gas temperature to the stack of the HRSG is 133°C. The calculated acid gas dew point temperature of the exhaust flue gas is around 90°C.

The Heat Transfer vs. Temperature of the HRSG (T-Q diagram) of case 5.2 is shown in Figure 1. The red line (the upper curve) represents the exhaust gases from the GT to the stack. The blue lines represent the water path in the economizers (at lower temperature), the steam generators (horizontal lines) and the super-heater/re-heater (at higher temperature).

The combined cycle is thermally integrated with the process unit, in order to maximize the net electrical efficiency of the plant. The main steam and water interfaces with the process units are given in Table 2.

2.11. Utility Units

These units comprise all the systems necessary to allow the operation of the plant and the export of the produced power.

The main utility units include:

- Cooling Water system, based on one natural draft cooling tower, with the following characteristics:

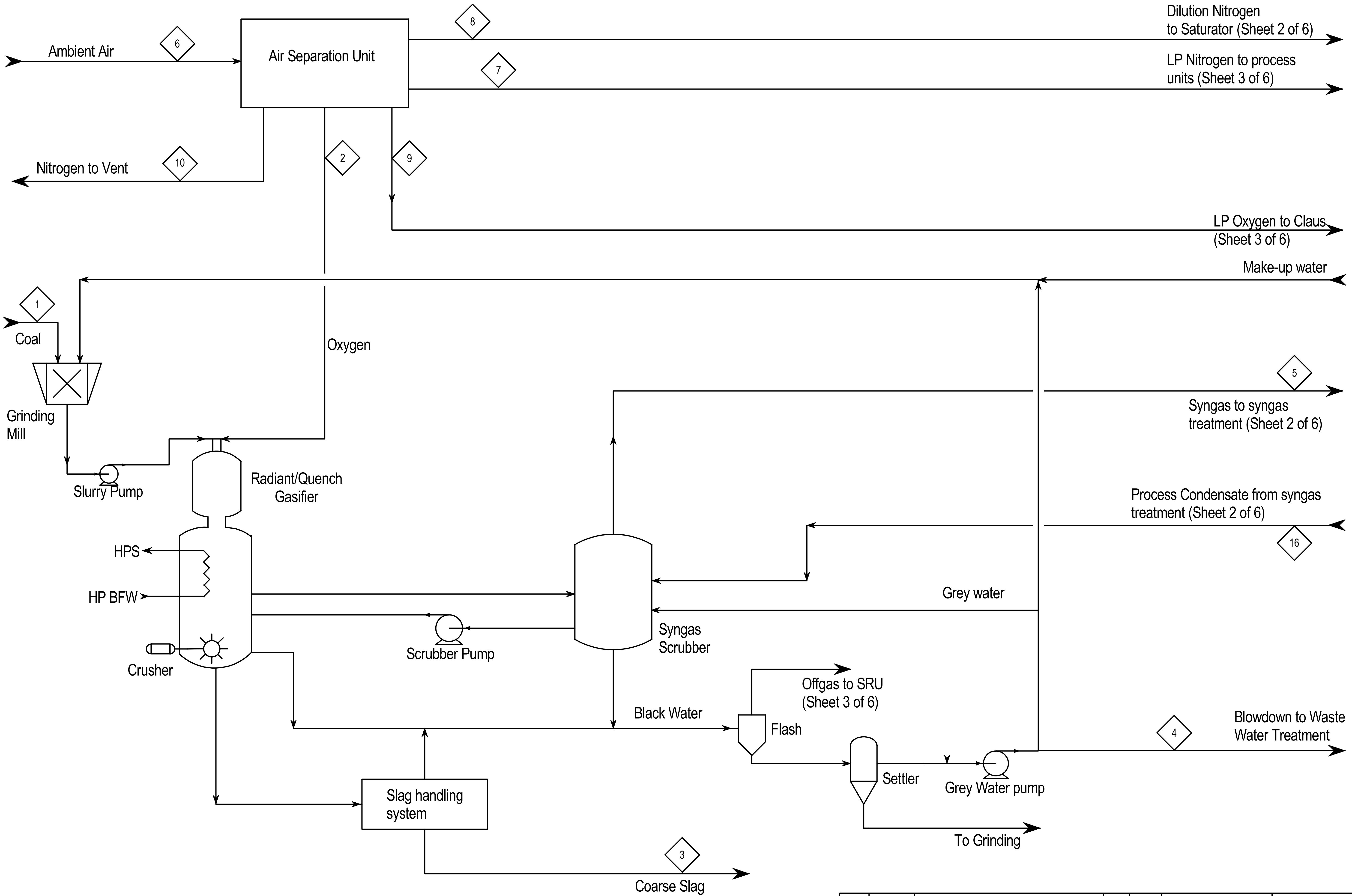
Basin diameter	140 m
Cooling tower height	210 m
Water inlet height	17 m

- Raw water system;
- Demineralised water plant;
- Fire fighting system;
- Instrument and Plant air.

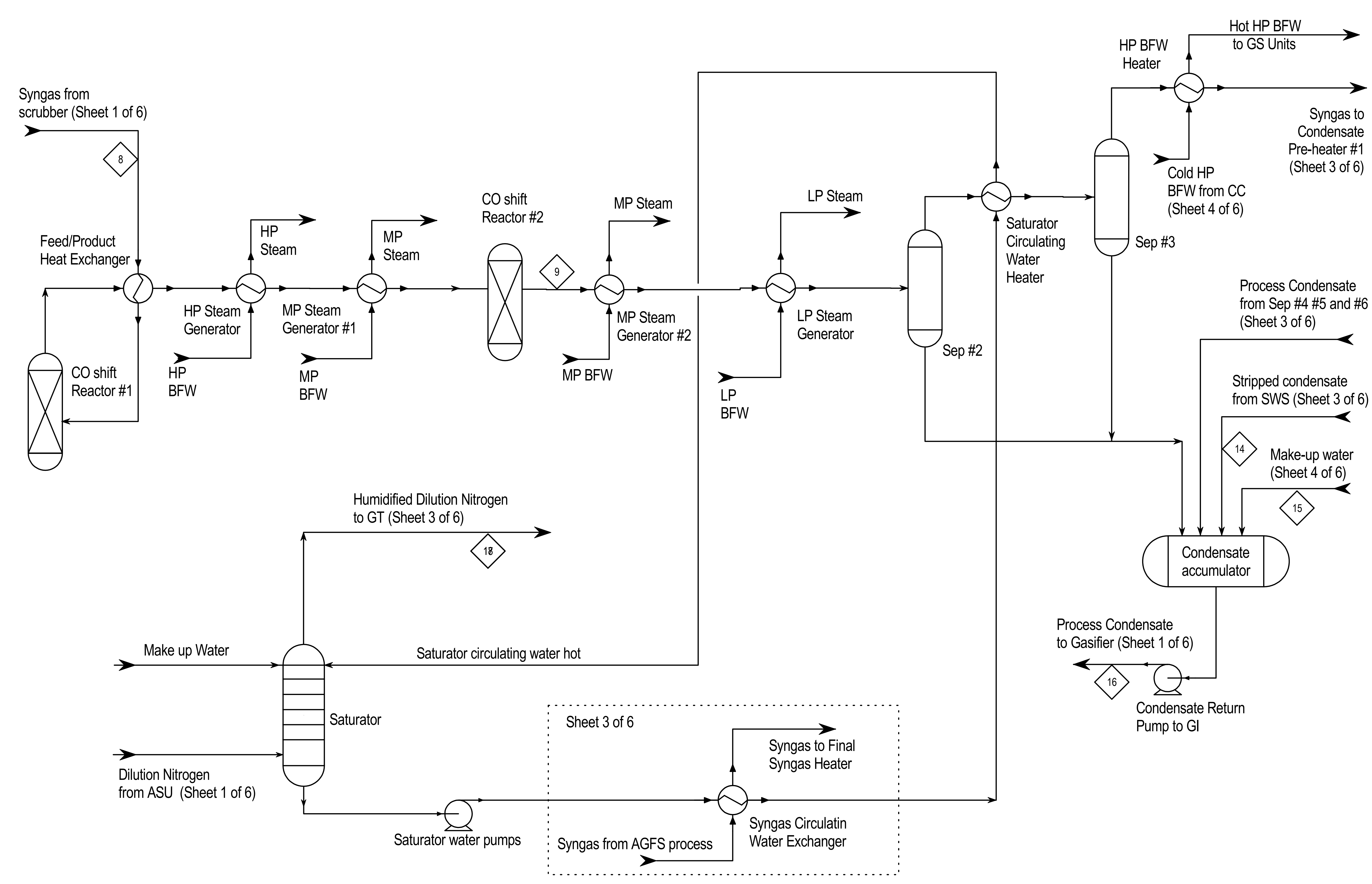
Process descriptions of the above systems are enclosed in chapter E, section 2.11.

3. Process Flow Diagrams

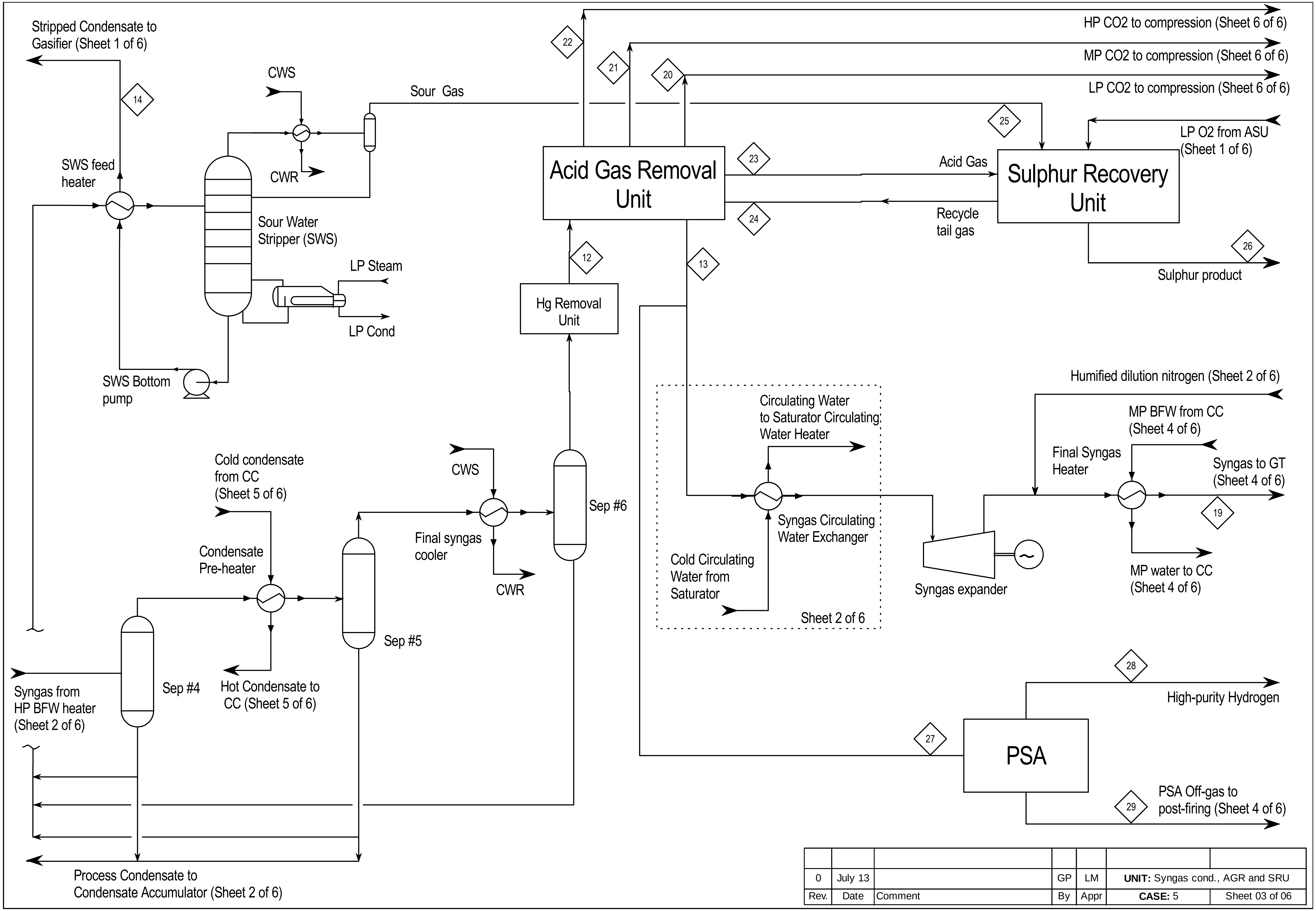
Simplified Process Flow Diagrams of this case are attached to this section. Stream numbers refer to the heat and material balance shown in the next section.

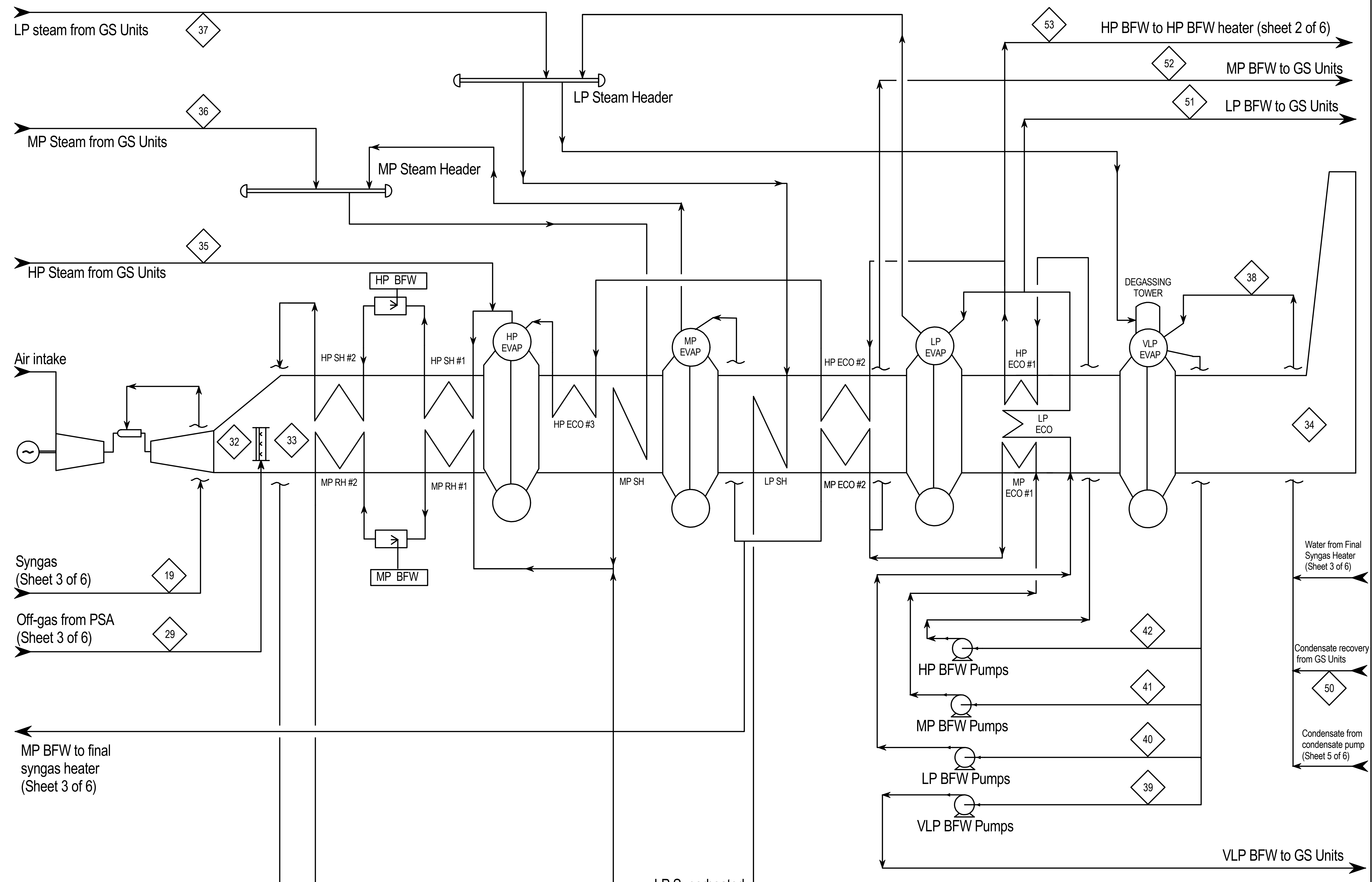


0	July 13		GP	LM	**UNIT:** Gasification and ASU	
Rev.	Date	Comment	By	Appr	**CASE:** 5.2	Sheet 01 of 06

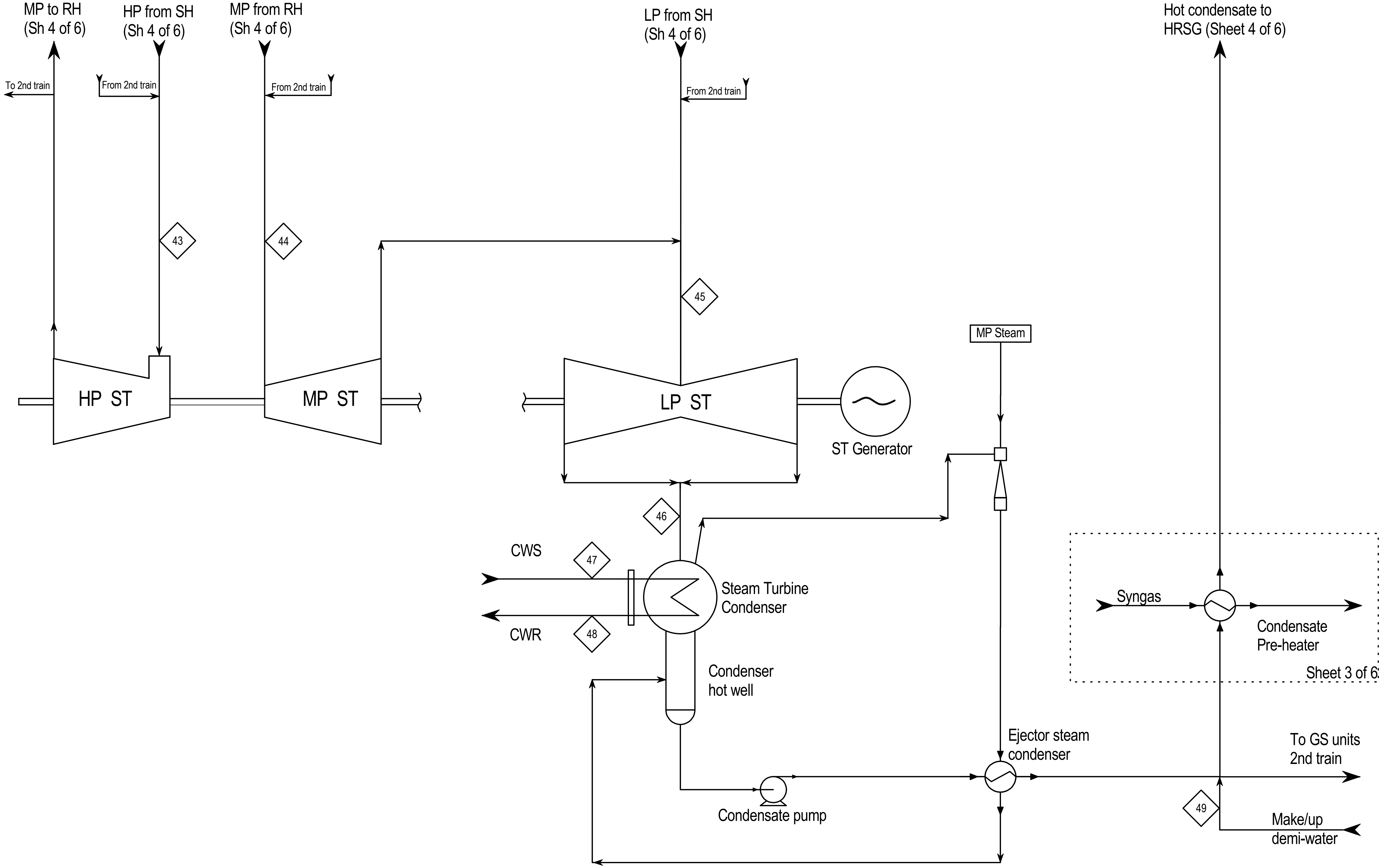


0	July 13		GP	LM	**UNIT:** Syngas treatment	
Rev.	Date	Comment	By	Appr	**CASE:** 5.2	Sheet 02 of 06

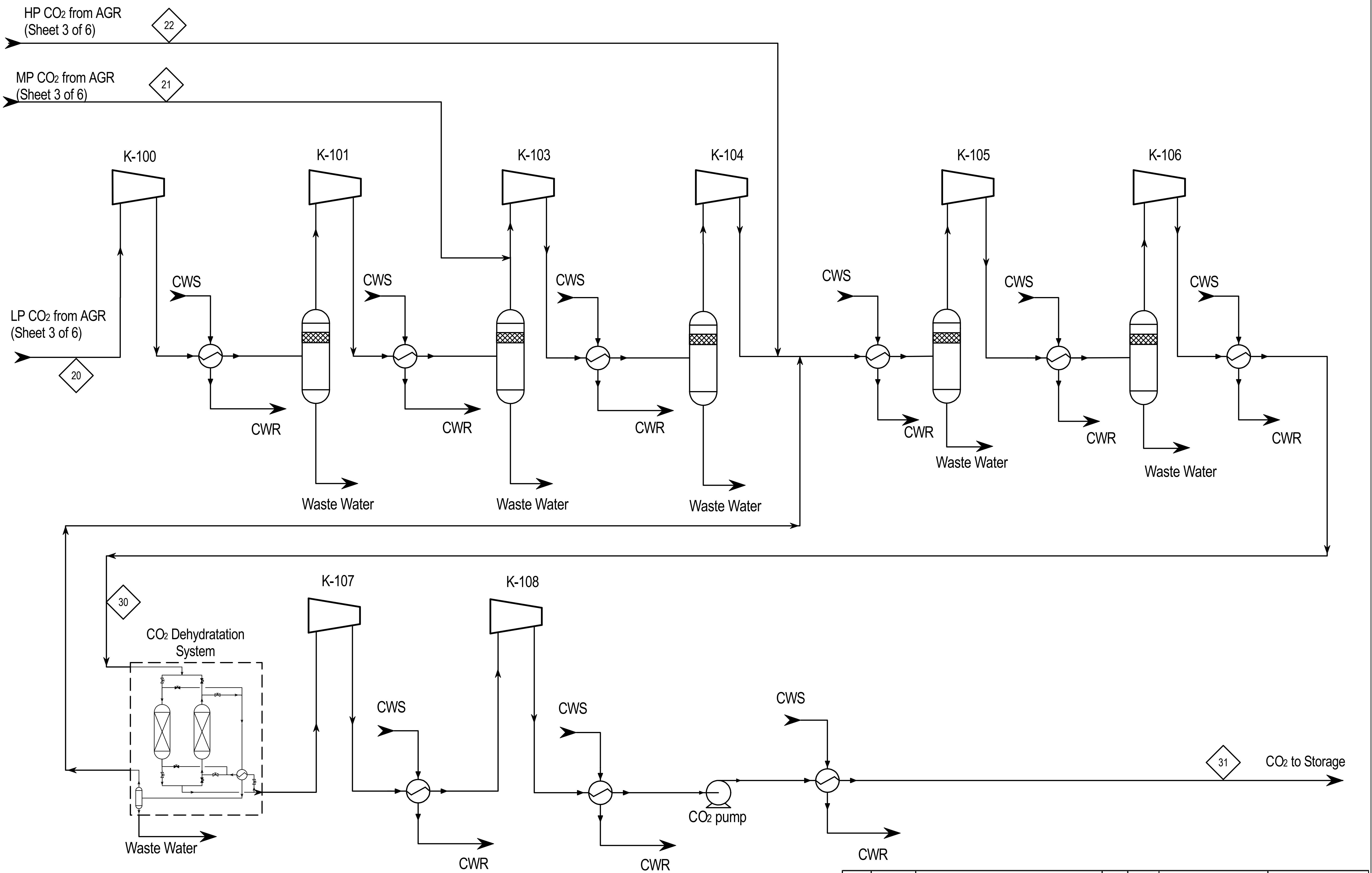

Stripped Condensate to
Gasifier (Sheet 1 of 6)
14
CWS
Sour Gas
22
HP CO2 to compression (Sheet 6 of 6)
21
MP CO2 to compression (Sheet 6 of 6)
20
LP CO2 to compression (Sheet 6 of 6)
25
LP O2 from ASU
(Sheet 1 of 6)
SWS feed
heater
CWR
Acid Gas Removal
Unit
23
Acid Gas
Sulphur Recovery
Unit
24
Recycle
tail gas
Sour Water
Stripper (SWS)
12
13
26
Sulphur product
LP Steam
LP Cond
Hg Removal
Unit
SWS Bottom
pump
Humified dilution nitrogen (Sheet 2 of 6)
Circulating Water
to Saturator Circulating
Water Heater
MP BFW from CC
(Sheet 4 of 6)
Final Syngas
Heater
Syngas to GT
(Sheet 4 of 6)
Cold condensate
from CC
(Sheet 5 of 6)
CWS
Sep #6
19
Syngas Circulating
Water Exchanger
Condensate
Pre-heater
Final syngas
cooler
Cold Circulating
Water from
Saturator
MP water to CC
(Sheet 4 of 6)
CWR
Syngas expander
Sheet 2 of 6
Sep #5
28
High-purity Hydrogen
Syngas from
HP BFW heater
(Sheet 2 of 6)
Sep #4
Hot Condensate to
CC (Sheet 5 of 6)
27
PSA
PSA Off-gas to
post-firing (Sheet 4 of 6)
29
Process Condensate to
Condensate Accumulator (Sheet 2 of 6)
0 | July 13 | | GP | LM | UNIT: Syngas cond., AGR and SRU
Rev. | Date | Comment | By | Appr | CASE: 5 | Sheet 03 of 06



0	July 13		GP	LM	**UNIT:** Gas Turbines and HRSG	
Rev.	Date	Comment	By	Appr	**CASE:** 5.2	Sheet 04 of 06



0	July 13		GP	LM	**UNIT:** Steam Turbine and Condenser	
Rev.	Date	Comment	By	Appr	**CASE:** 5.2	Sheet 05 of 06



0	July 13		GP	LM	**UNIT:** CO2 compression	
Rev.	Date	Comment	By	Appr	**CASE:** 5.2	Sheet 06 of 06

4. Heat and Material Balance

Heat & Material Balances here below reported make reference to the simplified Process Flow Diagrams of section 3.

FOSTER WHEELER	HYDROGEN AND POWER COPRODUCTION - Case 5.2 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
	CLIENT :	IEAGHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 1000 - Gasification Island

STREAM	1	2	3	4	5	16				
	Coal to Gasification Island	HP Oxygen to Gasification	Slag from Gasification	Effluent Water from Gasification	Syngas at Scrubber Outlet to Shift Reactor	Return condensate to gasification				
Temperature (°C)	AMB	10	80	AMB	N/D	144				
Pressure (bar)	ATM	75-80 (1)	ATM	ATM	64.6	70				
TOTAL FLOW	Solid		Solid + water		Dry basis					
Mass flow (kg/h)	349,100	323,000	87,400	94,500	1,154,000	493,200				
Molar flow (kmol/h)		10,025		5,250	58,004	27,385				
LIQUID PHASE										
Mass flow (kg/h)			43,700	94,500	-	493,200				
GASEOUS PHASE										
Mass flow (kg/h)		323,000			1,154,000					
Molar flow (kmol/h)		10,025			58,004					
Molecular Weight		32.22			21.58					
Composition (vol %)	%wt		50% moisture							
H_2	C: 64.6%	-			35.80					
CO	H: 4.38%	-			42.80					
CO_2	O: 7.02%	-			17.80					
N_2	S: 0.86%	1.50			3.22					
O_2	N: 1.41%	95.00			0.00					
CH_4	Cl: 0.03%	-			0.00					
H_2S + COS	Moisture: 9.5%	-			0.38					
Ar	Ash: 12.20%	3.50			0.00					
HCN		-			0.00					
NH_3		-			0.00					
H2O		-			0.00					
Notes	1) FWI assumption									

	HYDROGEN AND POWER COPRODUCTION - Case 5.2 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 2100 - Air Separation Unit (ASU)

STREAM	6	2	7	8	9	10				
	Air Intake from Atmosphere	HP Oxygen to Gasification	LP Nitrogen to process unit	MP Nitrogen for Syngas dilution	Oxygen to SRU	Nitrogen vent				
Temperature (°C)	Ambient	10	Ambient (1)	122	Ambient	Ambient				
Pressure (bar)	Ambient	75-80 (1)	7.5 (1)	28	6	Atmospheric				
TOTAL FLOW										
Mass flow (kg/h)	1,394,750	323,000	25,220	119,990	1,933	910,308				
Molar flow (kmol/h)	48,320	10,025	900	4,281	60	32,478				
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-	-				
GASEOUS PHASE										
Mass flow (kg/h)	1,394,750	323,000	25,220	119,990	1,933	910,308				
Molar flow (kmol/h)	48,320	10,025	900	4,281	60	32,478				
Molecular Weight	28.86	32.22	28.02	28.03	32.22	28.03				
Composition (vol %)										
H_2	-	-	-	-	-	-				
CO	-	-	-	-	-	-				
CO_2	0.04	-	-	0.05	-	0.05				
N_2	77.32	1.50	99.999	98.00	1.50	98.00				
O_2	20.75	95.00	0.001	1.00	95.00	1.00				
CH_4	-	-	-	-	-	-				
H_2S + COS	-	-	-	-	-	-				
Ar	0.92	3.50	-	0.25	3.50	0.25				
HCN	-	-	-	-	-	-				
NH_3	-	-	-	-	-	-				
H_2O	0.97	-	-	0.70	-	0.70				
Notes	1) FWI assumption									

FOSTER WHEELER	HYDROGEN AND POWER COPRODUCTION - Case 5.2 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
	CLIENT :	IEAGHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 2200 - Syngas cooling & Conditioning line

STREAM	5	11	12	13	14	15	16	17	18	19
	Syngas at Scrubber Outlet to Shift Reactor	Syngas at Shift Reactor Outlet	Raw Syngas to Acid Gas Removal	HP Purified Syngas from Acid Gas Removal	Stripped condensate from SWS	BFW make-up to condensate accumulator	Return Condensate to Gasification	Nitrogen to saturator	Moist. Nitrogen for syngas dilution	Diluted Syngas to Power Island
Temperature (°C)	N/D	323	34	15	130	123	144	122	168	170
Pressure (bar)	64.5	61.5	57.0	53.0	70.0	2.2	70.0	28.0	27.0	27.0
TOTAL FLOW										
Mass flow (kg/h)	1,154,000	1,154,000	891,750	148,235	43,225	227,000	492,600	119,986	153,110	198,017
Molar flow (kmol/h)	58,004	58,004	43,496	26,243	2,400	12,600	27,350	4,281	6,121	14,066
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	43,225	227,000	492,600	-	-	-
GASEOUS PHASE										
Mass flow (kg/h)	1,154,000	1,154,000	891,750	148,235	-	-	-	119,986	153,110	198,017
Molar flow (kmol/h)	58,004	58,004	43,496	26,243	-	-	-	4,281	6,121	14,066
Molecular Weight	19.90	19.90	20.50	5.65	-	-	-	28.03	25.01	14.08
Composition (vol %)										
H_2	35.80	41.04	54.73	89.55	-	-	-	0.00	0.00	50.58
CO	42.80	0.46	0.61	0.98	-	-	-	0.00	0.00	0.56
CO_2	17.80	31.54	41.98	5.73	-	-	-	0.05	0.03	3.25
N_2	3.22	3.22	2.27	3.73	-	-	-	98.00	68.54	31.93
O_2	0.00	0.00	-	-	-	-	-	1.00	0.70	0.30
CH_4	0.00	0.00	-	-	-	-	-	0.00	0.00	0.00
H_2S + COS	0.38	0.38	0.26	0.00	-	-	-	0.00	0.00	0.00
Ar	0.00	0.00	-	-	-	-	-	0.25	0.17	0.08
HCN	0.00	0.00	-	-	-	-	-	0.00	0.00	0.00
NH_3	0.00	0.00	-	-	-	-	-	0.00	0.00	0.00
H_2O	0.00	25.06	0.15	0.01	-	-	-	0.70	30.55	13.30

	HYDROGEN AND POWER COPRODUCTION - Case 5.2 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 2300 - Acid Gas Removal (AGR)

STREAM	12	13	20	21	22	23	24			
	Raw Syngas from Syngas Cooling	HP Purified Syngas to Syngas Cooling	LP CO2 to Compression	MP CO2 to Compression	HP CO2 to Compression	Acid Gas to SRU & TGT	Recycle Tail Gas from SRU			
Temperature (°C)	34	15	-9	-1	8	20	35			
Pressure (bar)	57.0	53.0	2.5	6.6	20.3	1.6	56.5			
TOTAL FLOW										
Mass flow (kg/h)	891,750	148,235	163,504	407,928	167,385	9,826	5,804			
Molar flow (kmol/h)	43,496	26,243	3,718	9,290	4,068	293	161			
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-	-	-			
GASEOUS PHASE										
Mass flow (kg/h)	891,750	148,235	163,504	407,928	167,385	9,826	5,804			
Molar flow (kmol/h)	43,496	26,243	3,718	9,290	4,068	293	161			
Molecular Weight	20.5	5.6	44.0	43.9	41.1	33.5	36.1			
Composition (vol %)										
H_2	54.73	89.55	-	0.20	6.66	14.47	17.65			
CO	0.61	0.98	-	-	0.16	0.25	-			
CO_2	41.98	5.73	99.87	99.74	92.95	43.29	77.90			
N_2	2.27	3.73	-	-	0.19	0.38	0.69			
O_2	-	-	-	-	-	-	-			
CH_4	-	-	-	-	-	-	-			
H_2S + COS	0.26	0.00	-	-	-	40.70	3.76			
Ar	-	-	-	-	-	-	-			
HCN	-	-	-	-	-	-	-			
NH_3	-	-	-	-	-	0.11	-			
H_2O	0.15	0.01	0.13	0.06	0.04	0.80	-			

	HYDROGEN AND POWER COPRODUCTION - Case 5.2 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 2400 - Sulfur Recovery Unit (SRU) & Tail Gas Treatment (TGT)

STREAM	9	23	24	25	26					
	Oxygen to SRU	Acid Gas from AGR Unit	Claus Tail Gas to AGR Unit	Sour Gas from Sour water stripper	Product Sulphur					
Temperature (°C)	Ambient	20	35	80	-					
Pressure (bar)	6	1.6	56.5	4	-					
TOTAL FLOW										
Mass flow (kg/h)	1,933	9,826	5,804	170	3,000					
Molar flow (kmol/h)	60.0	293	161	4.5	-					
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-					
GASEOUS PHASE										
Mass flow (kg/h)	1933	9,826	5,804	170	-					
Molar flow (kmol/h)	60	293	161	4.5	-					
Molecular Weight	32.2182	33.5	36.1	38.0	-					
Composition (vol %)										
H_2	-	14.69	17.65	0.67	-					
CO	-	0.25	-	0.03	-					
CO_2	-	42.76	77.90	75.60	-					
N_2	1.50	0.38	0.69	0.24	-					
O_2	95.00	-	-	-	-					
CH_4	-	-	-	-	-					
H_2S + COS	-	41.31	3.76	3.26	-					
Ar	3.50	-	-	-	-					
HCN										
NH_3	-	0.00	-	7.70	-					
H_2O	-	0.61	-	12.50						
	-									

	HYDROGEN AND POWER COPRODUCTION - Case 5.2 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE

Unit 2500 - CO2 Compression and Drying

STREAM	20	21	22	30	31					
	LP CO2 to Compression	MP CO2 to Compression	HP CO2 to Compression	CO_2 to drying package	CO_2 to storage					
Temperature (°C)	-9	-1	8	26	30					
Pressure (bar)	2.5	6.6	20.3	39.8	110.0					
TOTAL FLOW										
Mass flow (kg/h)	163,504	407,928	167,385	806,058	725,168					
Molar flow (kmol/h)	3,718	9,290	4,068	18,630	16,740					
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-					
GASEOUS PHASE										
Mass flow (kg/h)	163,504	407,928	167,385	806,058	725,168					
Molar flow (kmol/h)	3,718	9,290	4,068	18,630	16,740					
Molecular Weight	44	43.9	41.1	43.3	43.3					
Composition (vol %)										
H_2	-	0.20	6.66	1.61	1.61					
CO	-	-	0.16	0.04	0.04					
CO_2	99.87	99.74	92.95	98.18	98.30					
N_2	-	-	0.19	0.05	0.05					
O_2	-	-	-	0.00	0.00					
CH_4	-	-	-	0.00	0.00					
H_2S + COS	-	-	-	0.00	0.00					
Ar	-	-	-	0.00	0.00					
HCN	-	-	-	0.00	0.00					
NH_3	-	-	-	0.00	0.00					
H_2O	0.13	0.06	0.04	0.12	0.00					

	HYDROGEN AND POWER COPRODUCTION - Case 5.2 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	GP		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	July 2013		

HEAT AND MATERIAL BALANCE
UNIT 2600 - Hydrogen Production Unit

STREAM	27	28	29							
	Syngas to PSA	High-purity Hydrogen	PSA off-gas							
Temperature (°C)	15	20	10							
Pressure (bar)	53	52	5							
TOTAL FLOW										
Mass flow (kg/h)	103,340	30,970	72,370							
Molar flow (kmol/h)	18,295	14,485	3,810							
LIQUID PHASE										
Mass flow (kg/h)	-	-	-							
GASEOUS PHASE										
Mass flow (kg/h)	103,340	30,970	72,370							
Molar flow (kmol/h)	18,295	14,485	3,810							
Molecular Weight	5.65	2.1	19.0							
Composition (vol %)										
H_2	89.55	99.53	51.61							
CO	0.98	-	4.72							
CO_2	5.73	-	27.50							
N_2	3.73	0.47	16.11							
O_2	-	-	-							
CH_4	-	-	-							
H_2S + COS	0.00	-	0.00							
Ar	-	-	-							
HCN										
NH_3										
H_2O	0.01	-	0.06							

H2 AND POWER CO-PRODUCTION - Case 5.2 - H&M BALANCE		REVISION	0	1
CLIENT :	IEAGHG	PREP.	GP	
PROJECT NAME:	CO_2 capture at coal based power and H_2 plants	CHECKED	NF	
PROJECT NO:	1-BD-0681 A	APPROVED	LM	
LOCATION:	The Netherlands	DATE	July 2013	

HEAT AND MATERIAL BALANCE
Unit 3000 - Power Island

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
29	PSA off-gas to post-firing (*)	36.2	10	5.0	-
19	Treated Syngas from Syngas Cooling (*)	99.0	170	27.00	-
32	Flue gas from GT (*) (1)	839.5	585	1.05	-
33	Flue gas after post-firing (*) (2)	875.2	790	1.05	-
34	Flue gas at stack (*) (2)	875.2	133	atm	-
35	HP Steam from Process Units (*)	267.6	335	137.0	2646
36	MP Steam from Process Units (*)	59.0	252	41.0	2801
37	LP Steam from Process Units (*)	53.0	168	7.5	2766
38	Condensate to Deaerator (*)	658.4	115	2.2	483
39	BFW to VLP Pumps (*)	113.5	123	2.2	518
40	BFW to LP BFW Pumps (*)	88.7	123	2.2	518
41	BFW to MP BFW Pumps (*)	158.4	123	2.2	518
42	BFW to HP BFW Pumps (*)	304.3	123	2.2	518
43	HP Steam to Steam Turbine	604.8	557	132.0	3488
44	Hot RH Steam to Steam Turbine	767.9	557	34.8	3581
45	LP Steam to Steam Turbine	854.8	300	5.7	3063
46	Steam to Condenser	854.8	29	0.04	2299
47	Water Supply to Steam Condenser	40765	15	4.0	63
48	Water Return from Steam Condenser	40765	26	3.5	109
49	Make-up water	268.0	15	6.0	64
50	Condensate return from Process Units	87.5	94	4.2	394
51	LP BFW to Process Units	142.0	160	19.0	676
52	MP BFW to Process Units	153.1	160	56.0	678
53	HP BFW to Process Units	538.7	130	180.0	558

(*) Flowrate figure refers to one train (50% capacity)

(1) Flue gas molar composition: N_2: 71.5%; H_2O: 15.35%; O_2: 11.4%; CO_2: 0.9%; Ar: 0.8%.

(2) Flue gas molar composition: N_2: 69.5%; H_2O: 17.8%; O_2: 9.3%; CO_2: 2.8%; Ar: 0.8%.

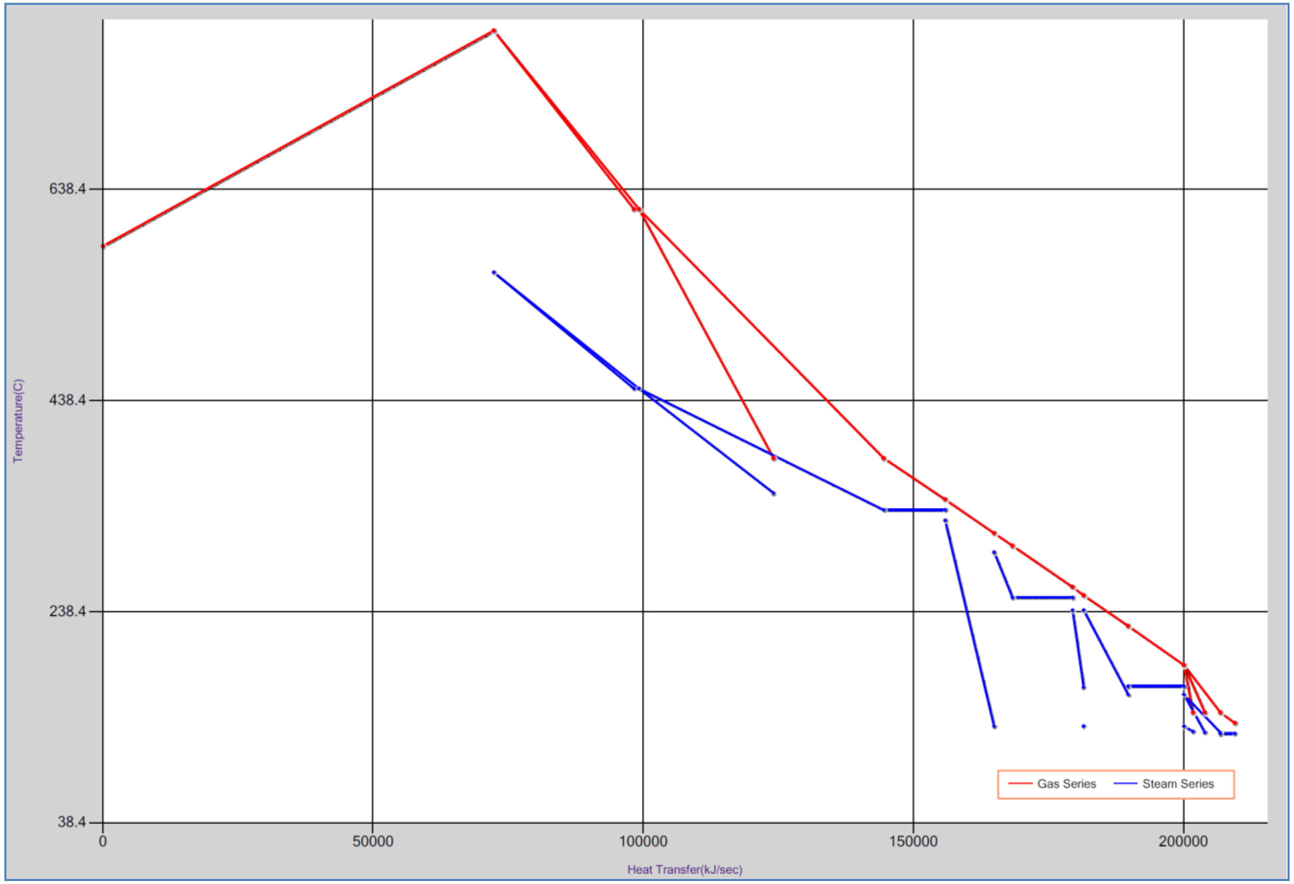


Figure 1 – Case 5.2 – HRSG T-Q diagram

5. Utility consumption

Main utility consumption of the process and utility units is reported in the following tables. More specifically:

- Steam / BFW / condensate interface summary is reported in Table 2.
- Water consumption summary is shown in Table 3.
- Electrical consumption summary is included in Table 4.

Table 2. Case 5.2 – Steam/BFW/condensate interface summary

CLIENT:	IEAGHG	REVISION	Rev.0		
PROJECT:	CO2 capture at coal based power and hydrogen plants	DATE	August 2013		
LOCATION:	The Netherlands	ISSUED BY	GP		
FWI Nº:	1-BD-0681 A	CHECKED BY	NF		
		APPROVED BY	LM		

Hydrogen and power co-production - Case 5.2 (Power Island: 2 x frame 6 equivalent Gas Turbine) - Steam and water balance

UNIT	DESCRIPTION UNIT	HP Steam barg 137 [t/h]	MP Steam barg 40 [t/h]	LP Steam barg 6.5 [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									
2100	**Air Separation Unit (ASU)**								**0.0**	
1000	**Gasification Section**	**-444.1**			**446.7**				**0.0**	**-2.5**
2200	**Syngas Treating and Conditioning Line**	**-91.2**	**-110.1**	**-132.1**	**92.1**	**144.4**	**142.0**	**227.1**	**-8.5**	**-263.6**
2300	**Acid Gas Removal**			**64.0**					**-64.0**	**0.00**
2400	**Sulphur Recovery (SRU)**		**-7.9**			**8.7**				**-0.83**
3000	**POWER ISLANDS UNITS**	**535.3**	**118.0**	**53.0**	**-538.7**	**-153.1**	**-142.0**	**-227.1**	**87.6**	
2600	**Hydrogen Unit (PSA)**									
4000	**UTILITY and OFFSITE UNITS**			**15.0**					**-15.0**	**0.00**
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-267.0**

Note: (1) Negative figures represent generation

Table 3. Case 5.2 – Water consumption summary

CLIENT:	IEAGHG	Revision	0
PROJECT:	CO2 capture at coal based power and H2 plants	Date	August 2013
LOCATION:	The Netherlands	ISSUED BY	GP
FWI Nº:	1-BD-0681 A	CHECKED BY	NF
		APPR. BY	LM

Hydrogen and power co-production - Case 5.2 (Power Island: 2 x frame 6 equivalent Gas Turbine)

Water Consumption Summary

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water Primary system [t/h]	Cooling Water Secondary System [t/h]
	AIR SEPARATION UNIT (ASU)				
2100	**Air Separation Unit**				**10400**
	GASIFICATION SECTION (GS)				
1000	**Gasification**	**145**			**3870**
2200	**Syngas treatment and conditioning line**				**2390**
2300	**Acid Gas Removal**		**0.6**		**6870**
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**				**160**
	CO_2 COMPRESSION				
2500	**CO_2 Compression**				**5850**
	COMBINED CYCLE (CC)				
3100	**Gas Turbines and Generator auxiliaries**				**300**
3200	**Heat Recovery Steam Generator**				
				40760	
3300	**Steam Turbine and Generator auxiliaries**		**268.1**		**1700**
	Miscellanea				
	UTILITY UNITS (UU)				
4000	**Cooling Water System**	**1303**			
4000	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**403**	**-269**		
4000	**Waste Water Treatment**	**-90.3**			
4000	**Balance of Plant (BOP)**				**190**
	TOTAL CONSUMPTION	**1761**	**0**	**40760**	**31730**

Note: Negative figures represent generation

Table 4. Case 5.2 – Electrical consumption summary

CLIENT:	IEAGHG	Rev.0
PROJECT:	CO2 capture at coal based power and hydrogen plants	Date: August 2013
LOCATION:	The Netherlands	ISSUED BY: GP
FWI Nº:	1-BD-0681 A	CHECKED BY: NF
		APPR. BY: LM

Hydrogen and power co-production - Case 5.2 (Power Island: 2 x frame 6 equivalent Gas Turbine)

Electrical Consumption Summary

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	AIR SEPARATION UNIT (ASU)	
2100	**MAC consumptions**	**124240**
	BAC consumptions	**12270**
	Nitrogen compressor and miscellanea	**7710**
	GASIFICATION SECTION (GS)	
900	**Coal Receiving Handling and Storage**	**410**
1000	**Gasification**	**8790**
2200	**Syngas treatment and conditioning line**	**1090**
2300	**Acid Gas Removal**	**20850**
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**	**700**
2500	**CO_2 Compression**	**33970**
	COMBINED CYCLE (CC)	
3100	**Gas Turbines auxiliaries**	**500**
3200	**Heat Recovery Steam Generator**	**4860**
3300	**Steam Turbine auxiliaries and excitation system**	**650**
3300	**Miscellanea**	**2790**
	UTILITY UNITS (UU)	
4000	**Cooling Water System**	**8880**
4000	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**730**
4000	**Balance of Plant (BOP)**	**1070**
	TOTAL CONSUMPTION	**229510**

6. Overall performance

The following table shows the overall performance of Case 5.2.

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**DATE**	August 2013
PROJECT No. :	1-BD-0681 A	**MADE BY**	GP
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 5.2 - H2 and power co-production Plant Performance Summary
(2 frame 6 equivalent GTs)

OVERALL PERFORMANCES		
Coal Flowrate (as received)	t/h	349.1
Coal LHV (as received)	kJ/kg	25870
Coal HHV (as received)	kJ/kg	27060
THERMAL ENERGY OF FEEDSTOCK	**MWth (LHV)**	**2509**
THERMAL ENERGY OF FEEDSTOCK	**MWth (HHV)**	**2624**
Thermal Power of Raw Syngas exit Scrubber	MWth (LHV)	1785
Thermal power of syngas to AGR	MWth (LHV)	1638
Thermal Power of Clean Syngas to Gas Turbines	MWth (LHV)	484
Thermal Power of Off-gas to post-firing	MWth (LHV)	146
Thermal Power of Clean Syngas to Hydrogen PSA	MWth (LHV)	1116
HYDROGEN PRODUCTION	**Nm^3/h**	**324700**
Thermal Power of Hydrogen	**MWth (LHV)**	**969**
Gas turbines total electric power output	MWe	181.2
Steam turbine electric power output	MWe	335.1
Syngas expander	MWe	3.4
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX	**MWe**	**519.7**
Gasification Section units consumption	MWe	31.8
ASU consumption	MWe	144.2
Combined Cycle units consumption	MWe	8.8
CO_2 Compression and Dehydration unit consumption	MWe	34.0
Utility Units consumption	MWe	10.7
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**229.5**
NET ELECTRIC POWER OUTPUT OF IGCC (Step-up transformer Eff. = 0.997)	**MWe**	**289.3**
CO_2 emission per net power production (*)	**kg/MWh**	**93.8**

(*) Referred to the net power production fo case 4.2

The following Table shows the overall CO_2 balance and CO_2 removal efficiency of Case 5.2.

CO_2 removal efficiency	**Equivalent flow of CO_2** kmol/h
INPUT	
Fuel Mix (Carbon AR)	18730
TOTAL (A)	18730
OUTPUT	
Slag (B)	101.0
CO_2 product pipeline	
CO	7
CO_2	16759
CH_4	0.0
COS	0.0
Total to storage (C)	16766
Emission	
CO_2 + CO (Combined Cycle)	560
CO2 + CO (to PF)	1303
TOTAL	18730
Overall Carbon Capture, % ((B+C)/A)	90.1

7. Environmental impact

The gasification plant design is based on advanced technologies that allow to reach high electrical generation efficiency, while minimizing impact to the environment. Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

7.1. Gaseous emissions

During normal operation at full load, main continuous emissions are the combustion flue gases of the two trains of the combined cycle, from the combustion of the syngas in the two gas turbines. Table 5 summarises expected flow rate and concentration of the combustion flue gas from one train of the combined cycle.

Minor gaseous emissions are created by 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 related to the milling, storage and handling of solids (e.g. solid transfer, leakage). As summarised in Table 6, these emission mainly consists of air or nitrogen containing particulate.

Table 5. Case 5.2 – Plant emission during normal operation

Flue gas to HRSG stack	
Emission type	Continuous
Conditions	
Wet gas flowrate, kg/h	876,175
Flow, Nm^3/h (1)	963,650
Temperature, °C	133
Composition	(% vol)
Ar	0.75
N_2	69.46
O_2	9.27
CO_2	2.76
H_2O	17.76
Emission	mg/Nm^3 (1)
NOx	< 50
SOx	< 1
CO	< 100
Particulate	< 10

(1) Dry gas, O_2 content 15% vol.

Table 6. Case 5.2 – Plant minor emission

Emission source	Emission type	Temperature	
Coal handling and storage system	Continuous	ambient	Air: 10 mg/Nm^3 particulate

7.2. Liquid effluents

Main liquid effluents are the cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids, and the effluent from the Waste Water Treatment, which flows to an outside plant battery limits recipient.

Cooling Tower blow-down

Flowrate : 310 m^3/h

Waste Water Treatment effluent

Flowrate : 160 m^3/h

7.3. Solid effluents

The IGCC plant is expected to produce the following solid by-product:

Slag from gasifier

Flowrate : 45 t/h (dry basis)

Moisture content : 50%

Slag product has a potential use as major components in concrete mixtures to make road, pads, storage bins.

8. Preliminary plot plan

Plot plan at block level of Case 5.2 is attached to this section, showing the area occupied by the main units and equipment of the plant.

REV.	DATE	DESCRIPTION	DRAW	BY	CHD.	APP.
CO01	SEPT. 2013	Preliminary issue for comments	APeccati			

DESCRIPTION

CLIENT IEA GHG

SITE The Netherlands

CO2 Capture and coal fired Power Plants

CASE: 5.1- Hydrogen Production (Frame 6 GTs)

PRELIMINARY PLOT PLAN

FOSTER WHEELER

APPROVED FOR CONSTRUCTION
DWG. REV.
DATE
SIGNATURE
ORDER N°
SUPPLIER
CONTRACT N°
FRAME N°
CLIENT DWG N°
SHEET
SHEET
SCALE N. A.
FWI DWG N° 1BD0681A - 01 - 008
REV. CO01
SHEET OF

CAD FILE NAME

Form. A3

9. Equipment list

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

CLIENT:	IEA GHG	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
LOCATION:	The Netherlands	DATE	July 2013	January 2014		
PROJ. NAME:	CO2 capture at coal based power and hydrogen plants	ISSUED BY	GP	GP		
CONTRACT N.	1-BD-0681 A	CHECKED BY	NF	NF		
CASE:	Case 5.2 -Hydrogen Production (Frame 6 GTs)	APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 900 - Coal Handling & Storage (NA)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-901	**Coal Handling**		Coal flowrate: 349 t/h					30 days storage
	Wagon tipper							Storage piles: 2 x 137,000 t each
	Receiving Hopper, vibratory feeder and belt extractor							
	Conveyors	Belt						
	Transfer Towers	Enclosed						
	As-Received Coal Sampling System	Two-Stage						
	As-Received Magnetic Separator System	Magnetic Plates						
	Conveyors	Belt						
	Transfer Towers	Enclosed						
	Crushers Towers	Impactor reduction						
	As-Fired Coal Sampling System	Swing hammer						
	As-Fired Magnetic Separator System	Magnetic Plates						
	Coal Silo		2 x 5300m3					for daily storage

	CLIENT:	IEA GHG	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2	
	LOCATION:	The Netherlands	DATE	July 2013	January 2014			
FOSTER WHEELER	PROJ. NAME:	CO2 capture at coal based power and H2 plants	ISSUED BY	GP	GP			
	CONTRACT N.	1-BD-0681 A	CHECKED BY	NF	NF			
	CASE:	Case 5.2 -Hydrogen Production (Frame 6 GTs)	APPROVED BY	LM	LM			

EQUIPMENT LIST
Unit 1000 - Gasification Island (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-1002	**GE Energy Coal gasification package**							
	Coal grinding and slurry preparation							Included in Z-1002
	Gasifiers (RSC)		2 x 4200 t/d coal (as received) to burners 2 x 900 MWth (LHV basis) syngas at scrubber outlet					Included in Z-1002
	Scrubber							Included in Z-1002
	Black Water flash							Included in Z-1002
	Coarse slag handling							Included in Z-1002
	Grey water systeam and fines handling							Included in Z-1002

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 5.2 -Hydrogen Production (Frame 6 GTs)			REVISION DATE ISSUED BY CHECKED BY APPROVED BY	Rev. Draft July 2013 GP NF LM	Rev.0 January 2014 GP NF LM	Rev.1	Rev.2

EQUIPMENT LIST
Unit 2100 - Air Separation Unit (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2101	**ASU Package** including:							
	Cold Box	Cryogenic	162 t/h of 95% purity O2 each train					Included in Z-2101
	Main Air compressors (MAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 2 x 297800 Nm3/h	2 x 35250 kW				Included in Z-2101
	Booster air compressors (BAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 238200 Nm3/h	7500 kW				Included in Z-2101
	MP N2 compressors (GAN)	Electric motor driven, centrifugal, with intercooling	Flowrate: 51500 Nm3/h	3750 kW				Included in Z-2101
	O2 pumps	Centrifugal						Included in Z-2101
	Back-up oxygen vaporiser	Shell and tube						Included in Z-2101
Common units to both trains:								
	LOX (liquid oxygen) storage	Fixed roof storage tank						8 hour storage for 1 gasification train Normal operating p: 5 bar a Normal operating T: -165 °C Included in Z-2101
	LIN (liquid nitrogen) storage	Fixed roof storage tank						8 hour storage for 1 Gasifier & 4 min storage for Syngas dilution and NOX control Normal operating p: 5 bar a Normal operating T: -180 °C Included in Z-2101
	Gaseous oxygen storage							
	Gaseous nitrogen storage							

	CLIENT:	IEA GHG	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
FOSTER WHEELER	LOCATION:	The Netherlands	DATE	July 2013	January 2014		
	PROJ. NAME:	CO2 capture at coal based power and hydrogen plants	ISSUED BY	GP	GP		
	CONTRACT N.	1-BD-0681 A	CHECKED BY	NF	NF		
	CASE:	Case 5.2 -Hydrogen Production (Frame 6 GTs)	APPROVED BY	LM	LM		

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning Line (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	HEAT EXCHANGERS				Shell/tube	Shell/tube		
E-2201	**Feed/Product Heat Exchanger**	Shell & Tube						
E-2202	**HP steam generator**	Kettle						
E-2203	**MP steam generator #1**	Kettle						
E-2204	**MP steam generator #2**	Kettle						
E-2205	**LP steam generator**	Kettle						
E-2206	**Circulating Water Heater**	Shell & Tube						
E-2207	**HP BFW heater**	Shell & Tube						
E-2208	**Condensate preheater**	Shell & Tube						
E-2209	**Syngas heater / Circulating water cooler**	Shell & Tube						
E-2210	**Final sygas cooler**	Shell & Tube						
E-2211	**Syngas final heater**	Shell & Tube						
	DRUMS							
D-2201	**Condensate Separator**	Vertical						
D-2202	**Condensate Separator**	Vertical						
D-2203	**Condensate Separator**	Vertical						
D-2204	**Condensate Separator**	Vertical						
D-2205	**Condensate Separator**	Vertical						
D-2204	**Condensate accumulator**	Horizontal						Common for both syngas tratment and conditiong line trains
	COLUMN							
C-2201	**Nitrogen saturator**	Vertical						

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 5.2 -Hydrogen Production (Frame 6 GTs)	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
		DATE	July 2013	January 2014		
		ISSUED BY	GP	GP		
		CHECKED BY	NF	NF		
		APPROVED BY	LM	LM		

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning Line (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	REACTOR							
R-2201	**1st Shift Catalyst Reactor**	vertical						Overall CO conversion = 98%
R-2202	**2nd Shift Catalyst Reactor**	vertical						
	PUMPS							
P-2201	**Saturator Circulating Water Pump**							
P-2202	**Condensate Pump (to Gasifiers)**							
	EXPANDER							
EX-2201	**Syngas Expander**		Flowrate = 178000 Nm^3/h	3465 kW				
	MISCELLANEA							
X-2201	**Mercury Adsorber**	Sulfur-impregnated activated carbon beds						

Note: equipment list referred to one train only

	CLIENT: IEA GHG	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
FOSTER WHEELER	LOCATION: The Netherlands	DATE	July 2013	January 2014		
	PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	GP	GP		
	CONTRACT N. 1-BD-0681 A	CHECKED BY	NF	NF		
	CASE: Case 5.2 -Hydrogen Production (Frame 6 GTs)	APPROVED BY	LM	LM		

EQUIPMENT LIST

Unit 2250 - Sour Water System (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-2251	**SWS PACKAGE**							
C-2251	Sour Water Stripper	Vertical						
	SWS Reboiler							
	SWS Condenser							
E-2251	Sour water heat exchanger (SWS feed / purified)							
P-2251	SWS Pump							

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EQUIPMENT LIST

Unit 2300 - Acid Gas Removal Unit (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2301	**Acid Gas Removal Unit - Absorption section**	Solvent: Selexol	Feed gas: 974900 Nm3/h; 56 barg; 34 °C					One H2S removal column, 3 CO2 removal columns, CO2 removal =91.78% Total Carbon Capture =90% Separated removal of CO2 and H2S
Z-2303	**Acid Gas Removal Unit - Solvent regeneration**							Total CO2 removal= 17700 t/d; 10 ppm H2S (dry) in combined CO2
Z-2304	**Chiller Unit**	Electrical driven						T= -10 °C

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EQUIPMENT LIST

Unit 2400 - Sulphur Recovery Unit (2x100%) & Tail Gas Treatment (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2401	**Sulphur Recovery Unit and Tail Gas Treatment Package** - two Sulphur Recovery Unit, each sized for 100% of the capacity - one Tail Gas Treatment Unit sized for 100% of capacity (including Reduction Reactor and Tail Gas Compressor)		Sulphur Prod.= 72 t/d Acid Gas from AGR = 6680 Nm3/h Expected Treated Tail Gas = 3602 Nm3/h					Sulphur content > 99,9 % mol min (dry basis)

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EQUIPMENT LIST

Unit 2500 - CO_2 Compression Package (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [MW]	P design [barg]	T design [°C]	Materials	Remarks
	COMPRESSORS							
C-2501	CO_2 Compressors	Centrifugal, Electrical Driven, 8 intercooled Stages	190000 Nm3/h p in: 2.45 bar a p out: 80 bar a	18000 kW				Water cooled
	PUMPS		**Q,m3/h x H,m**					
P-2501	CO_2 Pump	Centrifugal	640 x 530	800 kW				Liquid CO2 product, per each train: Flowrate: 370 t/h; 110 bar a; 30°C
	PACKAGE							
PK-2501	CO_2 drying package							

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EQUIPMENT LIST
Unit 2600 - Hydrogen Production

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [MW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
	Hydrogen Production package	PSA	325000 Nm3/h P out = 51 barg T out =20 °C					Hydrogen purity =99.5 %

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EQUIPMENT LIST
Unit 3100 - Gas Turbine (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-3101	**Gas Turbine & Generator Package**							
GT-3101	Gas turbine	Frame 6 Gas Turbine	90.3 MW					Included in Z-3101
G-3101	Gas turbine Generator		120 MVA					Included in Z-3101

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	HEAT RECOVERY STEAM GENERATOR							
HRSG-3201	**Heat Recovery Steam Generator**	Horizontal, Natural Circulated, 4 Pressure Levels. Simple Recovery, Reheated.						
Each HRSG including:								
D-3201	**HP steam Drum**							
D-3202	**MP steam Drum**							
D-3203	**LP steam Drum**							
D-3204	**VLP steam Drum with degassing section**							
E-3201	**HP Superheater 2nd section**							Included in HRSG-3201 / 2
E-3202	**HP Superheater 1st section**							Included in HRSG-3201 / 2
E-3203	**HP Evaporator**							Included in HRSG-3201 / 2
E-3204	**HP Economizer 3rd section**							Included in HRSG-3201 / 2
E-3205	**HP Economizer 2nd section**							Included in HRSG-3201 / 2
E-3206	**HP Economizer 1st section**							Included in HRSG-3201 / 2
E-3207	**MP Reheater 2nd section**							Included in HRSG-3201 / 2
E-3208	**MP Reheater 1st section**							Included in HRSG-3201 / 2
E-3209	**MP Superheater**							Included in HRSG-3201 / 2
E-3210	**MP Evaporator**							Included in HRSG-3201 / 2
E-3211	**MP Economizer 2nd section**							Included in HRSG-3201 / 2
E-3212	**MP Economizer 1st section**							Included in HRSG-3201 / 2
E-3213	**LP Superheater**							Included in HRSG-3201 / 2
E-3214	**LP Evaporator**							Included in HRSG-3201 / 2
E-3215	**LP Economizer**							Included in HRSG-3201 / 2
E-3216	**VLP Evaporator**							Included in HRSG-3201 / 2

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EQUIPMENT LIST

Unit 3200 - Heat Recovery Steam Generator (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PUMPS		$Q, m^3/h$ x H,m	kW				
P-3201 A/B	**HP BFW Pumps**	centrifugal	360 x 1800	2150				One operating, one spare
P-3203 A/B	**MP BFW Pumps**	centrifugal	185 x 570	375				One operating, one spare
P-3205 A/B	**LP BFW Pumps**	centrifugal	105 x 130	55				One operating, one spare
P-3207 A/B	**VLP BFW Pumps**	centrifugal	140 x 70	37				One operating, one spare
	MISCELLANEA							
X-3201	**Flue Gas Monitoring System**							NOx, CO, SO_2, particulate, H_2O, O_2
STK-3201	**CCU Stack**							
SL-3201	**Stack Silencer**							
DS-3201	**HP Steam Desuperheater**							Included in HRSG-3201
DS-3202	**MP Steam Desuperheater**							Included in HRSG-3201
	PACKAGES							
Z-3201	**Fluid Sampling Package**							
Z-3202	**Phosphate Injection Package**							
D-3204	Phosphate storage tank							Included in Z - 3202
P-3205 A/B	Phosphate dosage pumps							Included in Z - 3202 One operating , one spare
Z-3203	**Oxygen Scavanger Injection Package**							
D-3205	Oxygen scavanger storage tank							Included in Z - 3203
P-3206 A/B	Oxygen scavanger dosage pumps							Included in Z - 3203 One operating , one spare
Z-3204	**Amines Injection Package**							
D-3206	Amines Storage tank							Included in Z - 3204
P-3207 A/B	Amines Dosage pumps							Included in Z - 3204 One operating , one spare

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EQUIPMENT LIST

Unit 3300 - Steam Turbine and Blow Down System (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-3301	**Steam Turbine and Generator Package**							
ST-3301	Steam Turbine		331 MWe					*Including:* *Lube oil system* *Cooling system* *Idraulic control system* *Drainage system* *Seals system* *Drainage system*
G-3402	Steam Turbine Generator		430 MVA					*Including relevant auxiliaries*
E-3301A/B	Inter/After condenser							
E-3302	Gland Condenser							
Z-3302	**Steam Condenser Package**							
E-3303	Steam Condenser	Water cooled	510 MWt					*Including:* *Hot well* *Vacuum pump (or ejectors)* *Start up ejector (if required)*
Z-3303	**Steam Turbine by-pass system**							
	PUMPS		**Q,m^3/h x H,m**	**kW**				
P-3301A/B	Condensate Pumps	Centrifugal, vertical	1445 x 96	500				One operating, one spare
	HEAT EXCHANGERS							
E-3304	Blow-Down Cooler	Shell & Tube						
	DRUMS							
D-3301	Continuous Blow-down Drum	vertical						
D-3302	Discontinuous Blow-down Drum	vertical						

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EQUIPMENT LIST
Unit 4000 - Utility and Offsite

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-4001	**COOLING WATER SYSTEM**							
CT-4001	Cooling Tower Including Cooling water basin	Evaporative, Natural draft	Total heat duty 930 MWth Diameter: 140 m, Height: 210 m, Water inlet: 17 m				concrete	Included in Z-4001
	Pumps							
P-4001A/B/C	Cooling Water pumps (primary system)	Vertical	13600 m3/h x 35 m	1600 kW				Included in Z-4001 3 operating
P-4002A/B/C	Cooling Water pumps (secondary system)	Vertical	10600 m3/h x 45 m	2400 kW				Included in Z-4001 3 operating, one spare
P-4003A/B	Raw water pumps (make-up)	centrifugal	1435 m3/h x 30 m	185 kW				Included in Z-4001 1 operating, one spare
	Packages							
	Cooling Water Filtration Package Cooling Water Sidestream Filters		Capacity: 7260 m3/h					
	Sodium Hypochlorite Dosing Package Sodium Hypochlorite storage tank Sodium Hypochlorite dosage pumps							
	Antiscalant Package Dispersant storage tank Dispersant dosage pumps							
Z-4002	**RAW WATER SYSTEM**							
T-4001	Raw Water storage tank		11720 m3					Included in Z-4002 24 hour storage
P-4004A/B	Raw Water Pumps to gasification island	centrifugal	160 m3/h x 50 m	30 kW				Included in Z-4002 One operating, one spare
P-4005A/B	Raw Water Pumps to demi plant	centrifugal	328 m3/h x 50 m	75 kW				Included in Z-4002 One operating, one spare
Z-4003	**DEMI WATER SYSTEM**							
PK-4001	**Demin Water Package, including:**							
	- Multimedia filter - Reverse Osmosis (RO) Cartidge filter - Electro de-ionization system							
T-4002	Demi Water storage tank		7200 m3					Included in Z-4003 24 hour storage
P-4006A/B	Demi Water Pumps	centrifugal	300 m3/h x 35 m	45 kW				Included in Z-4003 One operating, one spare

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EQUIPMENT LIST

Unit 4000 - Utility and Offsite

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-4004	**FIRE FIGHTING SYSTEM**							
	Fire water storage tank							
	Fire pumps (diesel)							
	Fire pumps (electric)							
	FW jockey pump							
	MISCELLANEA							
	Natural Gas system							
	Waste Water Treatment							
	Sulphur Storage/Handling		72 t/d S prod.					30 days storage
	Flare system							
	Interconnecting							
	Instrumentation							
	DCS							
	Piping							
	Electrical							
	Plant Air							
	Buildings							

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TABLE OF CONTENT

1. Introduction

This chapter of the report includes all technical information relevant to Case 5.3 of the study, which is a gasification plant based on the GE technology. The plant is designed to process coal, whose characteristic is shown in chapter B, and produce hydrogen to be distributed to a hydrogen network, with capture of the generated carbon dioxide. The electrical demand of the hydrogen plant is covered by the power produced in a boiler-based steam cycle, fired with the off-gases from the Pressure Swing Adsorption (PSA) unit.

Plant capacity is the same of the GE technology based IGCC case, for power production only (refer to Case 4.2 in chapter E.2 of this report).

The configuration of the plant is based on the following main features:

- High-pressure (65 barg) GE Energy Gasification process, with slurry-feed system and Radiant Syngas Cooler (RSC);
- 2-stages sour shift;
- Removal of acid gases (H_2S and CO_2) based on Selexol physical solvent process;
- Oxygen-blown Claus unit, with tail gas catalytic treatment and recycle of the treated tail gas to the AGR;
- CO_2 compression and dehydration unit;
- Hydrogen production unit based on Pressure Swing Adsorption;
- PSA off-gases fired in two conventional subcritical boilers, without reheating, to generate steam that is sent to two related steam turbine generators.

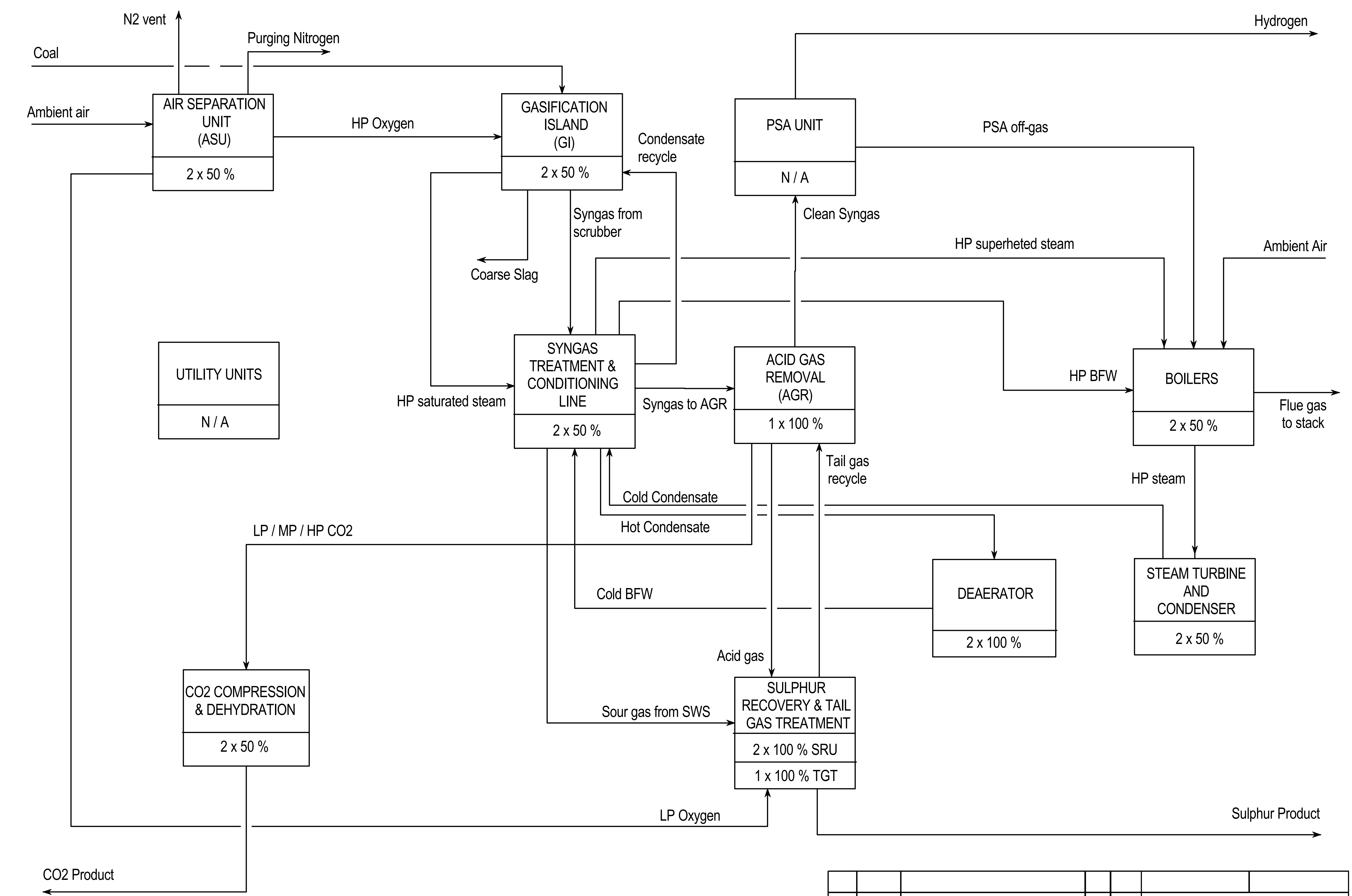
The description of the main process units is covered in chapter E of this report, so only features that are unique to this case are discussed in the following sections, together with the main modelling results.

1.1. Process unit arrangement

The arrangement of the main units is reported in the following Table 1. Reference is also made to the block flow diagram attached below.

Table 1. Case 5.3 – Unit arrangement

Unit	Description	Trains
900	Coal Handling & Storage	N/A
1000	Gasification	2 x 50%
	Coal Grinding & Slurry Preparation	
	Gasification (Radiant Syngas Cooler) and scrubber	
	Black Water Flash & Coarse Slag Handling	
	Grey Water & Fines Handling	
2100	Air Separation Unit	2 x 50%
2200	Syngas Treatment and Conditioning Line	2 x 50%
2250	Sour Water Stripper (SWS)	1 x 100%
2300	Acid Gas Removal	1 x 100%
2400	Sulphur Recovery Unit	2 x 100%
	Tail Gas Treatment	1 x 100%
2500	CO_2 Compression & Drying	2 x 50%
2600	Hydrogen production unit (PSA)	N/A
3000	Power island	
	PSA off-gas fired subcritical boiler	2 x 50%
	Steam Turbine	2 x 50%
4000	Utility and Offsite	N/A



0	Aug. 13		NF	LM	**UNIT:** Block Flow Diagram	
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2. Process description

2.1. Overview

The description reported in this section makes reference to the simplified Process Flow Diagrams (PFD) of section 3, while stream numbers refer to section 4, which provides heat and mass balance details for the numbered streams in the PFD.

2.2. Unit 900 – Coal Handling & Storage

The unit mainly consists of the coal storage and handling.

The general description relevant to this unit is reported in chapter E, section 2.1. Main process information of this case and the interconnections with the other units is shown in the relevant process flow diagram and the heat and mass balance table.

2.3. Unit 1000 – Gasification Island

The gasification island based on GE gasification mainly includes the coal grinding and slurry preparation section, the gasification (RSC) and the scrubber, the Black Water Flash and Coarse Slag Handling, and Grey Water & Fines Handling. Technical information relevant to these packages is reported in chapter E, section 3.2.

The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

2.4. Unit 2100 – Air Separation Unit

Technical information relevant to this packaged unit is reported in chapter E, section 2.3. The main process information of the unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The sizing capacity of the Air Separation Unit is determined by the oxygen requirement of the gasification island and the SRU. The total required oxygen flowrate for the case is approximately 325 t/h.

The Air Separation unit supplies medium pressure nitrogen, injected in the gas turbine, after being moisturised, for NOx suppression and power production augmentation.

2.5. Unit 2200 – Syngas Treatment and Conditioning line

The general description of this unit is shown in chapter E, section 2.4, while case-specific features are reported hereinafter. The main process information and the interconnections with the other units are shown in the relevant process flow diagram and the heat and mass balance tables.

The heat recovered from the syngas is used to generate all the steam required in the gasification plant, mainly the steam for the AGR reboiler and the deaerator of the steam cycle and to heat-up the condensate, the BFW for steam generation and the water make-up of the gasification scrubber.

Saturated raw syngas from the gasification scrubber, at approximately 64 barg, is heated-up in the Feed/Product Heat Exchanger, before entering the first shift reactor, in order to increase the temperature up to the level required for the proper operation of the shift catalyst.

In the shift unit, CO is shifted to H_2 and CO_2 and COS is converted to H_2S. A double stage shift, containing sulphur tolerant shift catalyst (sour shift) is selected in order to increase the H_2 content in the fuel and maximize the degree of CO_2 removal. The overall CO conversion is approximately 98%.The water content in the syngas is adequate for the shift reaction to take place with no additional steam injection.

The partially-shifted syngas temperature is increased by the exothermic shift reaction, allowing for thermal recovery. The syngas is cooled down in a series of heat exchangers, before being fed to the second reactor stage:

- Feed/Product Heat Exchanger,
- HP Steam super-heater #1

After being cooled, the syngas is directed to the second and last shift reactor. The hot shifted syngas outlet from the second stage is cooled in the following series of heat exchangers, to thermally recover heat and increase the overall power generation:

- HP Steam super-heater #2,
- HP BFW pre-heater #1, #2 and #3,
- LP Steam Generator,
- Condensate Pre-heater #1, #2 and #3.

Final cooling of the syngas is made against cooling water, before passing through a sulphur-impregnated activated carbon bed to remove approximately 95% of the mercury. Cool, mercury-depleted syngas is then directed to the AGR.

During the cooling of the syngas, the process condensate is separated and collected in the process condensate accumulator. Before being sent to the accumulator, the condensate from the last syngas separator, upstream the AGR, plus a portion of the condensate from the upstream separator, is sent to the Sour Water Stripper in order to avoid accumulation of ammonia and H_2S and other dissolved gases in the water recycle to the gasification section. The condensate from the accumulator is sent to the gasification scrubber for syngas saturation. Boiler Feed Water from the deaerator of the combined cycle provides the make-up water to substitute for the steam reacted in the shift unit.

From the AGR unit, the hydrogen rich syngas is sent to the PSA unit for high-purity hydrogen production.

2.6. Unit 2300 – Acid Gas Removal (AGR)

The AGR unit is intended to selectively remove H_2S and CO_2 in sequent steps by employing Selexol as physical solvent. Technical information relevant to this package is reported in chapter E, section 2.5. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The AGR is designed to meet the following process specifications of the treated gas and of the CO_2 product exiting the unit:

- The H_2S+COS concentration of the treated gas exiting the unit is around 1 ppmv. This is due to the integration of CO_2 removal with the H_2S removal, which makes available a large circulation of solvent that is cooled down by a refrigerant package before flowing to the CO_2 absorber.
- The CO_2 product is characterised by a content of incondensable around 2%, while simultaneously meeting the specification of H_2S content lower than 20 ppmv and CO content lower than 0.2% mol (actual 0.06% mol).
- The acid gas H_2S concentration is about 41% dry basis, suitable to feed the oxygen blown Claus process.

The CO_2 removal rate is 91.7% of the carbon dioxide entering the unit, allowing reaching an overall carbon capture of approximately 90% with respect to the carbon in the syngas. These excellent performances on both the H_2S removal and CO_2 capture are achieved with significant power consumption and steam demand.

2.7. Unit 2400 – SRU and TGT

Technical information relevant to this package is reported in chapter E, section 2.5. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The SRU is designed to process the acid gas from the AGR and other minor acid streams like the acid off-gas from the black water flash within the gasification island and the sour gases from the SWS, using low pressure oxygen from the ASU. In the furnace, H_2S is catalytically oxidized to SO_2 which is further reacted with H_2S to form H_2O and elemental sulphur. Following the thermal stage, sulphur is condensed, while the tail gas is hydrogenated and recycled back to the AGR unit at approximately 60 barg by means of a dedicated compressor.

The overall sulphur production is approximately 72 tons per day.

2.8. Unit 2500 – CO_2 Compression and Drying

This unit is mainly composed of a compression and dehydration package, followed by last stage CO_2 pumps, supplied by specialized vendors. Technical information relevant to this package is reported in chapter E, section 2.6. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

Three different streams of CO_2 from the Acid Gas Removal unit are routed to the CO_2 compression unit, delivered at approximately 19 barg, 6 barg, and 1.5 barg respectively.

The stream at lower pressure is initially compressed up to the pressure of the medium pressure stream and then combined with it. The resulting stream is compressed to allow the mixing with the last stream without any pressure loss. The combined stream is then compressed up to approximately 40 barg and sent to the dehydration system, which is a standard solid desiccant package that dehydrates the CO_2 stream to a dew point of -40°C. After dehydration, the CO_2 stream is finally compressed to a supercritical condition at 80 barg.

The resulting stream of CO_2 is pumped to the required pressure of 110 barg. The CO_2 product (approximately 97.9 % wt purity) is transported to the plant battery limits for final sequestration.

2.9. Unit 2600 – Hydrogen Production Unit

Technical information relevant to this package is reported in chapter E, section 2.9. The main process information of this unit and the interconnections with the other units are shown in the process flow diagram and in the heat and mass balance tables.

The PSA unit is designed to produce 465,000 Nm^3/h of high-purity hydrogen at around 51 barg, to be sent to the plant battery limits.

The PSA off-gases are sent to the power island for firing in subcritical boilers.

2.10. Unit 3000 – Power Island

2.10.1. <u>Boiler Island</u>

The boiler technology considered in this case is a gas fired subcritical boiler, treated as a package supplied by specialised vendors. The boiler is a single pass tower type subcritical boiler, with the burners located in the lower portion of the furnace. Each burner is low NOx type, with staging of the coal combustion to minimize NOx formation. Air from the forced draft fans is preheated by contact with exhaust gases through regenerative pre-heaters. Hot combustion products exit the furnace and pass through to the radiant and convective heating surfaces for steam generation and superheating, then to the regenerative heaters for air pre-heating. ID fan provides the required delta pressure to draw flue gases to the boiler stack.

The high pressure preheated BFW enters the economizer in second back-pass where is further preheated against the flue gases and sent to the steam drum.

Saturated water from the drum is delivered via down comers to the supply pipes, which feed the furnace lower headers via natural circulation, eliminating the need for circulation pumps and reducing mechanical complexity and auxiliary power consumption. The steam/water mixture from the furnace wall tubes is collected in the upper furnace headers and returned to the steam drum via riser pipes. Steam/water separation takes place in the drum.

The primary super-heater is a convective super-heater section located in the lower portion of the first back-pass. The final super-heaters are located in the upper portion of the furnace and consist of membrane wing wall or pendant in-furnace panels. In addition to the steam generated in the boiler, the superheating sections also provides the heat for superheating the steam generated in the gasification island and partially superheated in the syngas treatment, up to the temperature level required for admission in the steam turbine. The superheated steam finally exits the boiler to flow to the HP steam turbine module.

2.10.2. Steam Turbine

The steam cycle is mainly composed of two subcritical steam turbine generators (STG), equipped with steam condensers and water pre-heating lines.

Main steam from the boiler is sent to the steam turbine through the stop valves and control valves. Boiler and turbine interface data are as follows:

HP turbine inlet: 110 bar; 550°C

The steam turbine have no steam extraction as all the heat required for water pre-heating is recovered from the syngas. Exhaust steam from the turbines downward into the condenser. Recycled vacuum condensate from the condenser hot well is pumped by the condensate pumps and preheated in a bank of three condensate heaters against syngas. Condensate from the steam heaters in the gasification island is mixed with the condensate from the condenser.

The preheated condensate stream is then sent to the deaerator. LP steam generated in the syngas treatment line is used to provide the steam necessary for the degassing of the condensate and also deaerated make-up demineralised water.

From the deaerator boiler feed water is pumped through dedicated pumps to the following users:

- Part of the BFW is sent the condensate accumulator in the syngas treatment providing the required make-up water to the gasification scrubber;
- Part of the BFW is pumped to the gasification island for steam generation after being pre-heated against syngas;
- The remaining part of the BFW is pre-heated against syngas to around 245°C prior to being fed to the boiler.

The main steam and water interfaces with the process units are given in Table 2.

2.11. Utility Units

These units comprise all the systems necessary to allow the operation of the plant and the export of the produced power.

The main utility units include:

- Cooling Water system, based on one natural draft cooling tower, with the following characteristics:

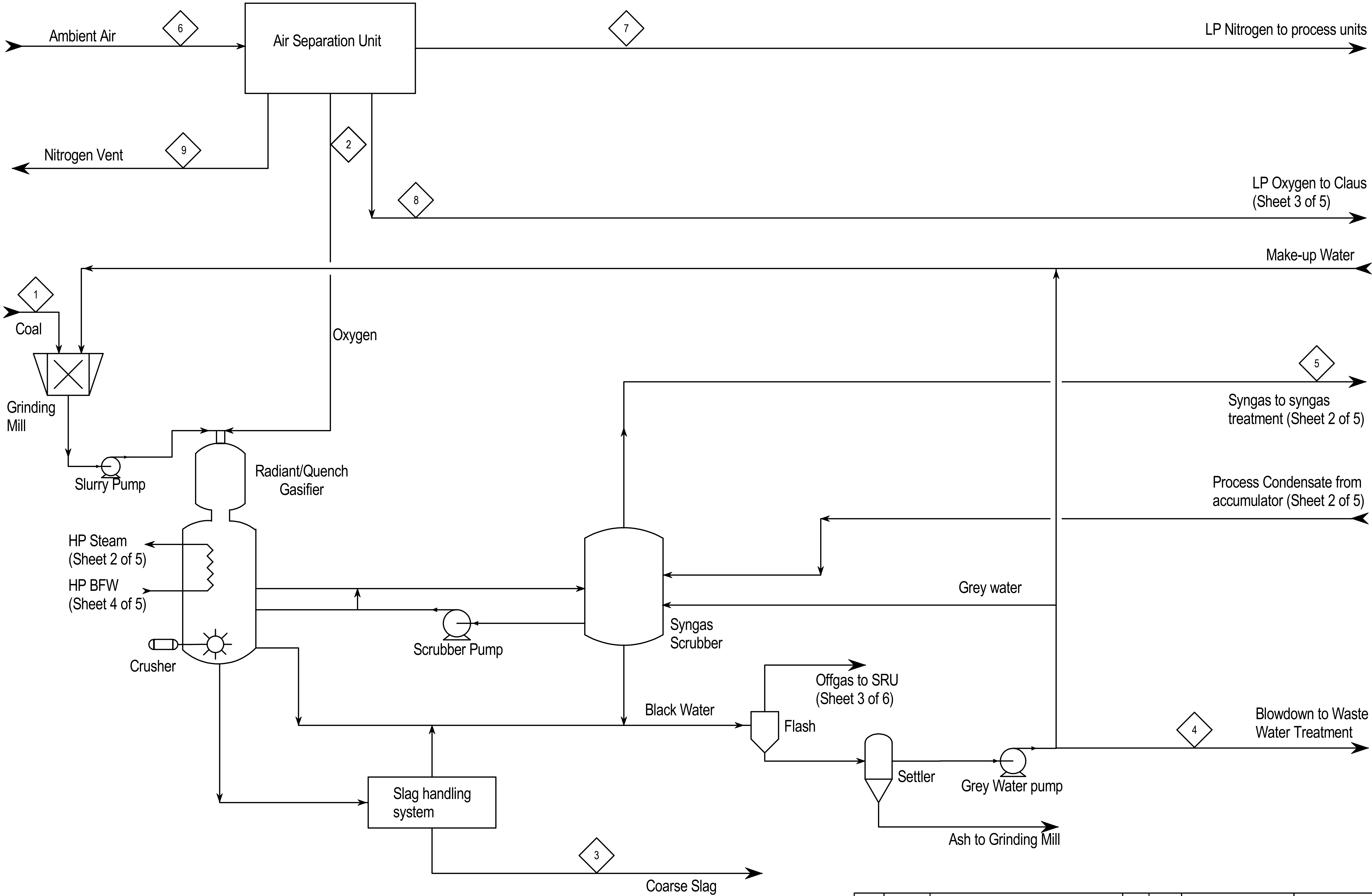
Basin diameter	130 m
Cooling tower height	210 m
Water inlet height	17 m

- Raw water system;
- Demineralised water plant;
- Fire fighting system;
- Instrument and Plant air.

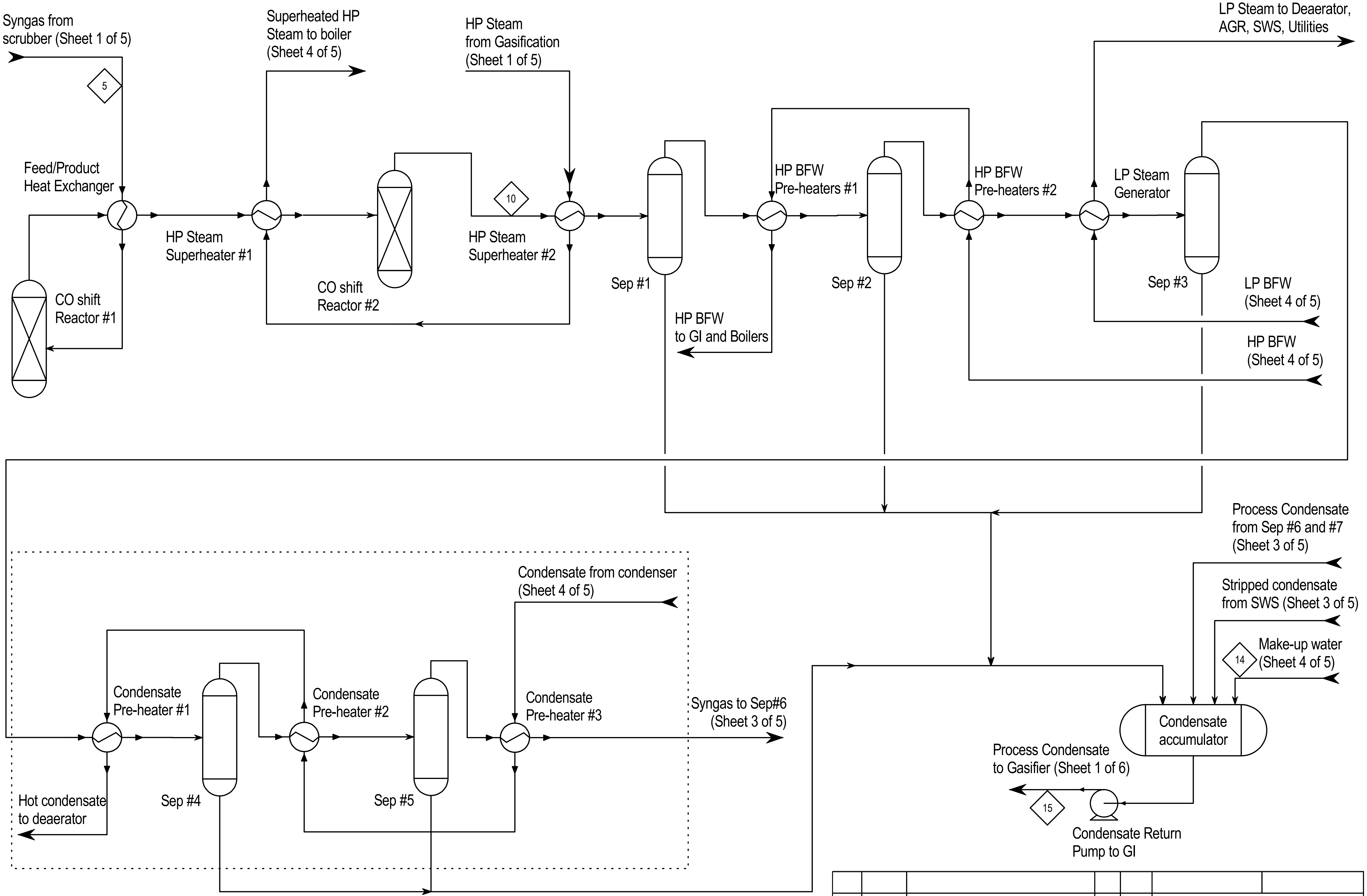
Process descriptions of the above systems are enclosed in chapter E, section 2.11.

3. Process Flow Diagrams

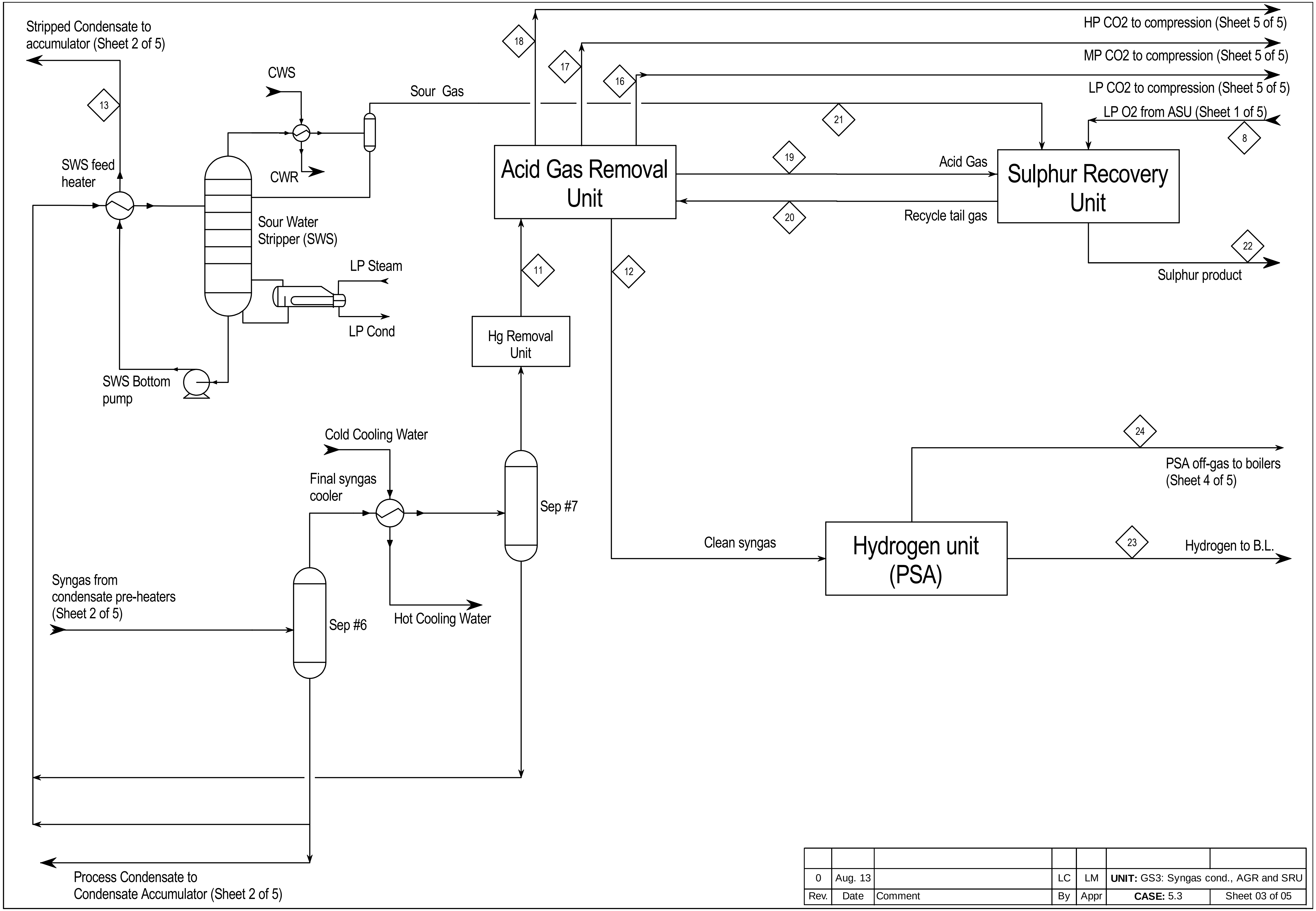
Simplified Process Flow Diagrams of this case are attached to this section. Stream numbers refer to the heat and material balance shown in the next section.



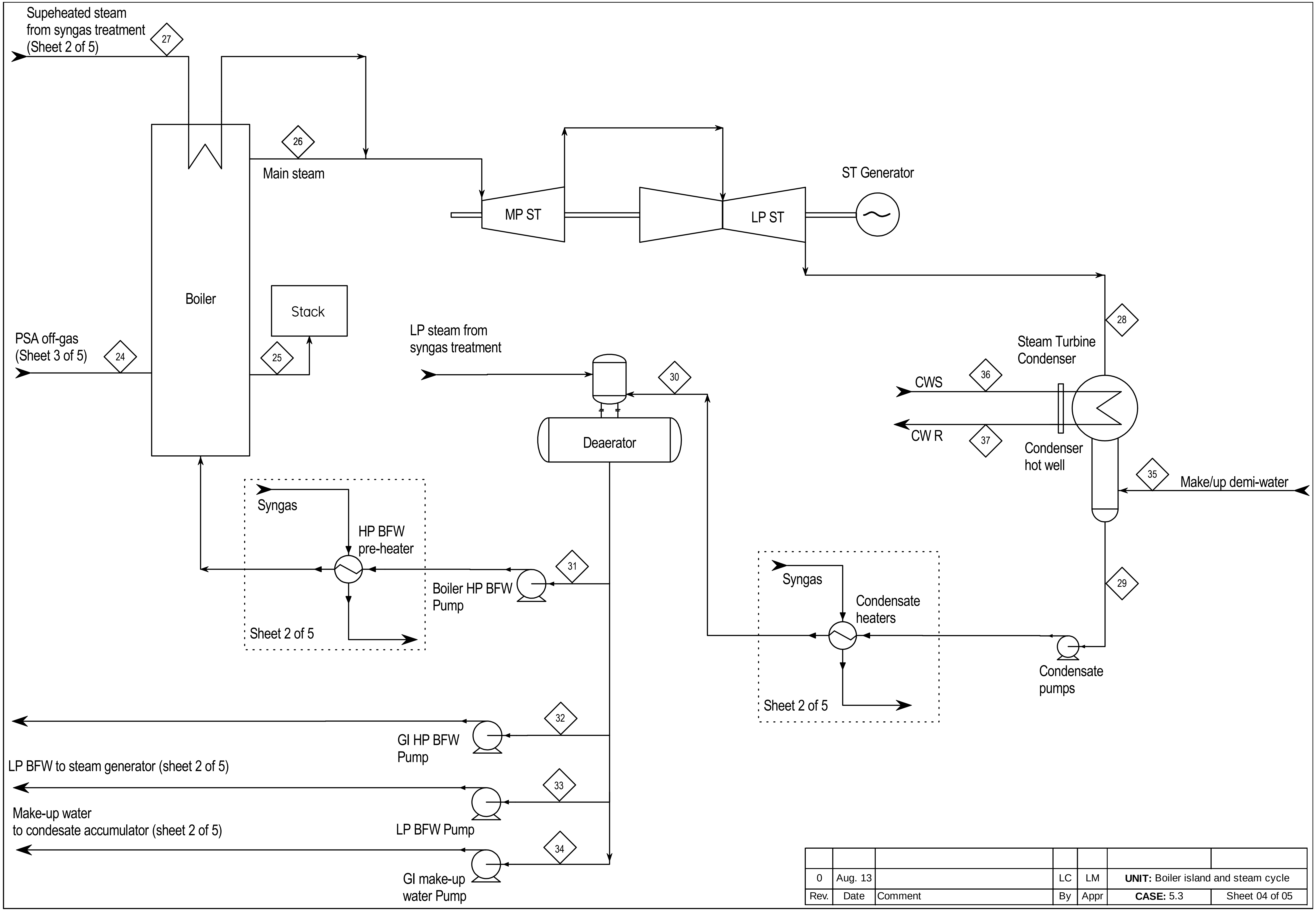
0	Aug. 13		LC	LM	**UNIT:** GS2 - AS1: Gasification and ASU	
Rev.	Date	Comment	By	Appr	**CASE:** 5.3	Sheet 01 of 05

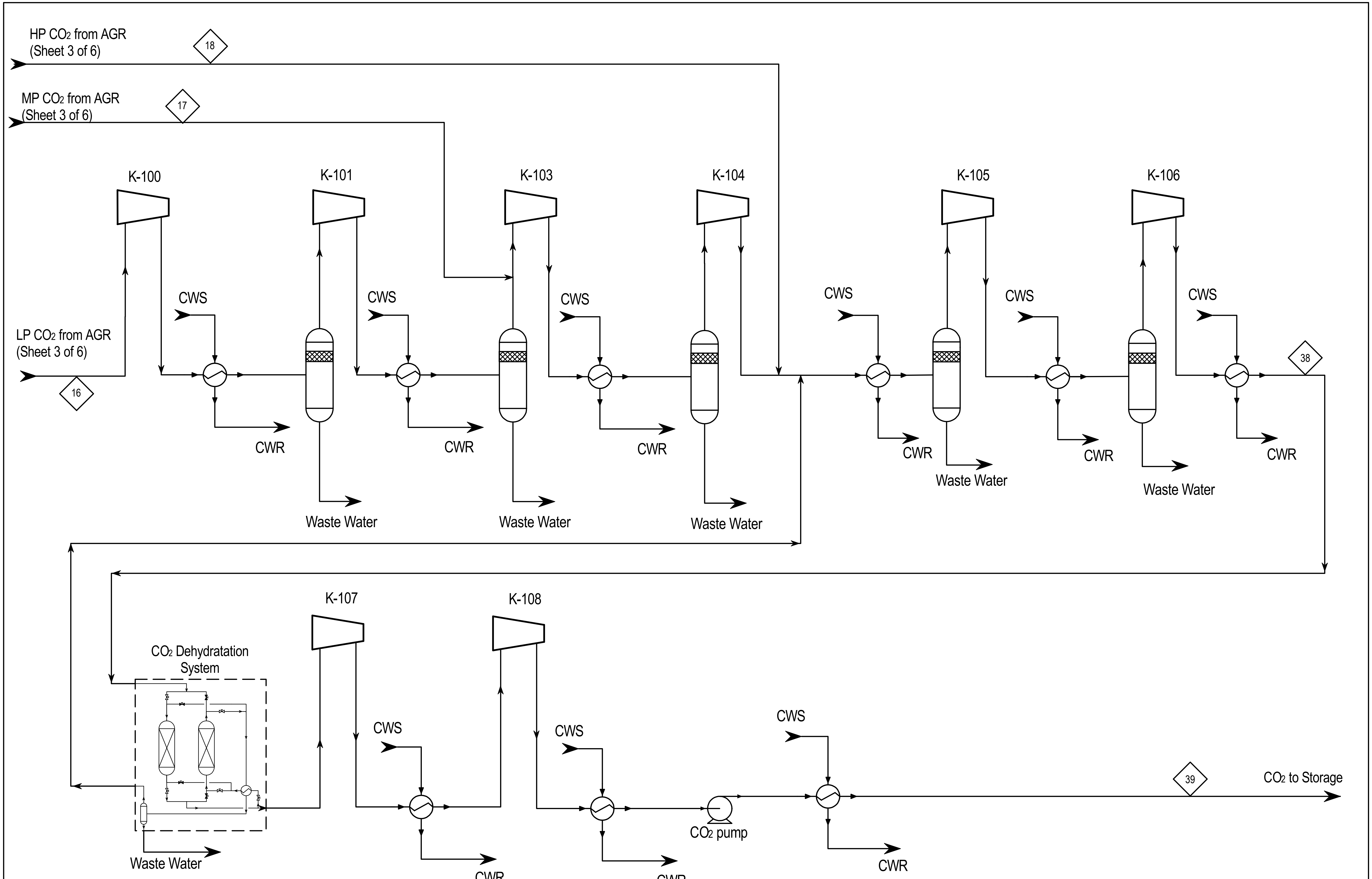


0	Aug. 13		LC	LM	**UNIT:** GS3: Syngas treatment	
Rev.	Date	Comment	By	Appr	**CASE:** 5.3	Sheet 02 of 05



0	Aug. 13		LC	LM	**UNIT:** GS3: Syngas cond., AGR and SRU	
Rev.	Date	Comment	By	Appr	**CASE:** 5.3	Sheet 03 of 05


Supeheated steam
from syngas treatment
(Sheet 2 of 5)
27
26
Main steam
Boiler
Stack
MP ST
LP ST
ST Generator
PSA off-gas
(Sheet 3 of 5)
24
25
LP steam from
syngas treatment
30
Deaerator
28
Steam Turbine
Condenser
CWS
36
CW R
37
Condenser
hot well
35
Make/up demi-water
Syngas
HP BFW
pre-heater
Boiler HP BFW
Pump
31
Sheet 2 of 5
29
Syngas
Condensate
heaters
Condensate
pumps
Sheet 2 of 5
32
GI HP BFW
Pump
LP BFW to steam generator (sheet 2 of 5)
33
LP BFW Pump
Make-up water
to condesate accumulator (sheet 2 of 5)
34
GI make-up
water Pump
0
Aug. 13
LC
LM
UNIT: Boiler island and steam cycle
Rev.
Date
Comment
By
Appr
CASE: 5.3
Sheet 04 of 05



0	Aug. 13		LC	LM	**UNIT:** CO2 compression	
Rev.	Date	Comment	By	Appr	**CASE:** 5.3	Sheet 05 of 05

4. Heat and Material Balance

Heat & Material Balances here below reported make reference to the simplified Process Flow Diagrams of section 3.

	HYDROGEN PRODUCTION CASE - Case 5.3 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
	CLIENT :	IEA GHG	**PREP.**	LC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**CHECKED**	NF		
	PROJECT NO:	1-BD-0681 A	**APPROVED**	LM		
	LOCATION:	The Netherlands	**DATE**	August 2013		

HEAT AND MATERIAL BALANCE
UNIT 1000 - Gasification Island

STREAM	1	2	3	4	5	15				
	Coal to Gasification Island	**HP Oxygen to Gasification**	**Slag from Gasification**	**Effluent Water from Gasification**	**Syngas at Scrubber Outlet to Shift Reactor**	**Return condensate to gasification**				
Temperature (°C)	AMB	10	80	AMB	N/D	157				
Pressure (bar)	ATM	75-80 (1)	ATM	ATM	64.6	70				
TOTAL FLOW	Solid		Solid + water							
Mass flow (kg/h)	349,100	323,000	87,400	94,500	1,154,000	493,200				
Molar flow (kmol/h)		10,025		5,250	58,004	27,385				
LIQUID PHASE										
Mass flow (kg/h)			43,700	94,500	-	493,200				
GASEOUS PHASE										
Mass flow (kg/h)		323,000			1,154,000					
Molar flow (kmol/h)		10,025			58,004					
Molecular Weight		32.22			-					
Composition (vol %)	%wt		50% moisture		dry basis					
H_2	C: 64.6%	-			35.80					
CO	H: 4.38%	-			42.80					
CO_2	O: 7.02%	-			17.80					
N_2	S: 0.86%	1.50			3.22					
O_2	N: 1.41%	95.00			0.00					
CH_4	Cl: 0.03%	-			0.00					
H_2S + COS	Moisture: 9.5%	-			0.38					
Ar	Ash: 12.20%	3.50			0.00					
HCN		-			0.00					
NH_3		-			0.00					
H_2O		-			-					

Notes: 1. FW Assumption

FOSTER WHEELER	HYDROGEN PRODUCTION CASE - Case 5.3 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
	CLIENT :	IEA GHG	**PREP.**	LC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**CHECKED**	NF		
	PROJECT NO:	1-BD-0681 A	**APPROVED**	LM		
	LOCATION:	The Netherlands	**DATE**	August 2013		

HEAT AND MATERIAL BALANCE

UNIT 2100 - Air Separation Unit (ASU)

STREAM	6	2	7	8	9					
	Air Intake from Atmosphere	**HP Oxygen to Gasification**	**LP Nitrogen to process unit**	**Oxygen to SRU**	**Nitrogen vent**					
Temperature (°C)	Ambient	10	Ambient (°)	Ambient	Ambient					
Pressure (bar)	Ambient	75-80 (°)	7.5 (°)	6.0	Atmospheric					
TOTAL FLOW										
Mass flow (kg/h)	1,394,750	323,000	25,220	1,933	1,030,045					
Molar flow (kmol/h)	48,320	10,025	900	60	36,750					
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-					
GASEOUS PHASE										
Mass flow (kg/h)	1,394,750	323,000	25,220	1,933	1,030,045					
Molar flow (kmol/h)	48,320	10,025	900	60.0	36,750					
Molecular Weight	28.86	32.22	28.02	32.22	28.03					
Composition (vol %)										
H_2	-	-	-	-	-					
CO	-	-	-	-	-					
CO_2	0.04	-	-	-	0.05					
N_2	77.32	1.50	99.999	1.50	98.00					
O_2	20.75	95.00	0.001	95.00	1.00					
CH_4	-	-	-	-	-					
H_2S + COS	-	-	-	-	-					
Ar	0.92	3.50	-	3.50	0.25					
H_2O	0.97	-	-	-	0.70					

(°) FWI assumption

FOSTER WHEELER	HYDROGEN PRODUCTION CASE - Case 5.3 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
	CLIENT :	IEAGHG	PREP.	LC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	August 2013		

HEAT AND MATERIAL BALANCE

UNIT 2200 - Syngas cooling & Conditioning line

STREAM	5	10	11	12	13	14	15			
	Syngas at Scrubber Outlet to Shift Reactor	Syngas at Shift Reactor Outlet	Raw Syngas to Acid Gas Removal	HP Purified Syngas from Acid Gas Removal to PSA	Stripped condensate from SWS	BFW make-up to condensate accumulator	Return Condensate to Gasification			
Temperature (°C)	N/D	413	34	15	133	165	157			
Pressure (bar)	64.5	62.1	57	53	70.0	9.0	70.0			
TOTAL FLOW										
Mass flow (kg/h)	1,154,000	1,154,000	891,750	148,235	43,225	227,000	492,600			
Molar flow (kmol/h)	58,004	58,004	43,496	26,243	2,400	12,600	27,350			
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	43,225	227,000	492,600			
GASEOUS PHASE										
Mass flow (kg/h)	1,154,000	1,154,000	891,750	148,235	-	-	-			
Molar flow (kmol/h)	58,004	58,004	43,496	26,243	-	-	-			
Molecular Weight	-	19.90	20.50	5.65	-	-	-			
Composition (vol %)	(dry basis)									
H_2	35.80	41.04	54.73	89.55	-	-	-			
CO	42.80	0.46	0.61	0.98	-	-	-			
CO_2	17.80	31.54	41.98	5.73	-	-	-			
N_2	3.22	3.22	2.27	3.73	-	-	-			
O_2	0.00	0.00	-	-	-	-	-			
CH_4	0.00	0.00	-	-	-	-	-			
H_2S + COS	0.38	0.38	0.26	0.00	-	-	-			
Ar	0.00	0.00	-	-	-	-	-			
HCN	0.00	0.00	-	-	-	-	-			
NH_3	0.00	0.00	-	-	-	-	-			
H_2O	-	25.06	0.15	0.01	-	-	-			

FOSTER WHEELER	HYDROGEN PRODUCTION CASE - Case 5.3 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
	CLIENT :	IEAGHG	PREP.	LC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	August 2013		

HEAT AND MATERIAL BALANCE

UNIT 2300 - Acid Gas Removal (AGR)

STREAM	11	12	16	17	18	19	20			
	Raw Syngas from Syngas Cooling	HP Purified Syngas to PSA	LP CO2 to Compression	MP CO2 to Compression	HP CO2 to Compression	Acid Gas to SRU & TGT	Recycle Tail Gas from SRU			
Temperature (°C)	34	15	-9	-1	8	21	35			
Pressure (bar)	57	53	2.5	6.6	20.3	1.6	56.5			
TOTAL FLOW										
Mass flow (kg/h)	891,750	148,235	163,504	407,913	167,385	9,831	5,804			
Molar flow (kmol/h)	43,496	26,243	3,718	9,290	4,068	293	161			
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-	-	-			
GASEOUS PHASE										
Mass flow (kg/h)	891,750	148,235	163,504	407,913	167,385	9,831	5,804			
Molar flow (kmol/h)	43,496	26,243	3,718	9,290	4,068	293	161			
Molecular Weight	20.5	5.65	44.0	43.9	41.1	33.6	36.1			
Composition (vol %)										
H_2	54.73	89.55	-	0.20	6.66	14.69	17.65			
CO	0.61	0.98	-	0.01	0.16	0.25	-			
CO_2	41.98	5.73	99.87	99.73	92.95	42.76	77.90			
N_2	2.27	3.73	-	-	0.19	0.38	0.69			
O_2	-	-	-	-	-	-	-			
CH_4	-	-	-	-	-	-	-			
H_2S + COS	0.26	0.00	-	-	-	41.30	3.76			
Ar	-	-	-	-	-	-	-			
HCN	-	-	-	-	-	-	-			
NH_3	-	-	-	-	-	-	-			
H_2O	0.15	0.01	0.13	0.06	0.04	0.61	-			

HYDROGEN PRODUCTION CASE - Case 5.3 - HEAT AND MATERIAL BALANCE		**REVISION**	0	1	2
CLIENT :	IEAGHG	**PREP.**	LC		
PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**CHECKED**	NF		
PROJECT NO:	1-BD-0681 A	**APPROVED**	LM		
LOCATION:	The Netherlands	**DATE**	August 2013		

HEAT AND MATERIAL BALANCE
UNIT 2400 - Sulfur Recovery Unit (SRU) & Tail Gas Treatment (TGT)

STREAM	19	21	20	22
	Acid Gas from AGR Unit	**Sour Gas from Sour water stripper**	**Claus Tail Gas to AGR Unit**	**Product Sulphur**
Temperature (°C)	21	80	35	-
Pressure (bar)	1.6	4	56.5	-
TOTAL FLOW				
Mass flow (kg/h)	9,831	170	5,804	3,000
Molar flow (kmol/h)	293	4.5	161	-
LIQUID PHASE				
Mass flow (kg/h)	-	-	-	-
GASEOUS PHASE				
Mass flow (kg/h)	9,831	170	5,804	-
Molar flow (kmol/h)	293	4.5	161	-
Molecular Weight	33.6	38.0	36.1	-
Composition (vol %)				
H_2	14.69	0.84	17.65	-
CO	0.25	0.03	-	-
CO_2	42.76	75.60	77.90	-
N_2	0.38	0.24	0.69	-
O_2	-	-	-	-
CH_4	-	-	-	-
H_2S + COS	41.31	2.95	3.76	-
Ar	-	-	-	-
HCN				
NH_3	0.00	7.85	-	-
H_2O	0.61	12.49	-	

FOSTER WHEELER	HYDROGEN PRODUCTION CASE - Case 5.3 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
	CLIENT :	IEAGHG	PREP.	LC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	August 2013		

HEAT AND MATERIAL BALANCE
Unit 2500 - CO2 Compression and Drying

STREAM	16	17	18	38	39
	LP CO2 to Compression	MP CO2 to Compression	HP CO2 to Compression	CO_2 to drying package	CO_2 to storage
Temperature (°C)	-9	-1	8	26	30
Pressure (bar)	2.5	6.6	20.3	39.8	110.0
TOTAL FLOW					
Mass flow (kg/h)	163,504	407,913	167,385	806,461	725,168
Molar flow (kmol/h)	3,718	9,290	4,068	18,630	16,740
LIQUID PHASE					
Mass flow (kg/h)	-	-	-	-	-
GASEOUS PHASE					
Mass flow (kg/h)	163,504	407,913	167,385	806,461	725,168
Molar flow (kmol/h)	3,718	9,290	4,068	18,630	16,740
Molecular Weight	44.0	43.9	41.1	43.3	43.3
Composition (vol %)					
H_2	0.0	0.20	6.66	1.61	1.61
CO	0.0	0.00	0.16	0.04	0.04
CO_2	99.87	99.74	92.95	98.18	98.30
N_2	0.0	0.00	0.19	0.05	0.05
O_2	0.0	0.00	0.00	0.00	0.00
CH_4	0.0	0.00	0.00	0.00	0.00
H_2S + COS	0.0	0.00	0.00	0.00	0.00
Ar	0.0	0.00	0.00	0.00	0.00
HCN	0.0	0.00	0.00	0.00	0.00
NH_3	0.0	0.00	0.00	0.00	0.00
H_2O	0.13	0.06	0.04	0.12	0.00

	HYDROGEN PRODUCTION CASE - Case 5.3 - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	LC		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	NF		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	August 2013		

HEAT AND MATERIAL BALANCE
UNIT 2600 - Hydrogen Production Unit

STREAM	12	23	24							
	Syngas to PSA	High-purity Hydrogen	PSA off-gas to Boiler							
Temperature (°C)	15	20	10							
Pressure (bar)	53	52	5							
TOTAL FLOW										
Mass flow (kg/h)	148,235	44,430	103,805							
Molar flow (kmol/h)	26,243	20,780	5,463							
LIQUID PHASE										
Mass flow (kg/h)	-	-	-							
GASEOUS PHASE										
Mass flow (kg/h)	148,235	44,430	103,805							
Molar flow (kmol/h)	26,243	20,780	5,463							
Molecular Weight	5.65	2.14	19.0							
Composition (vol %)										
H_2	89.55	99.53	51.61							
CO	0.98	-	4.72							
CO_2	5.73	-	27.50							
N_2	3.73	0.47	16.11							
O_2	-	-	-							
CH_4	-	-	-							
H_2S + COS	0.00	-	0.00							
Ar	-	-	-							
HCN										
NH_3	-	-	-							
H_2O	0.01	-	0.06							

HYDROGEN PRODUCTION CASE - Case 5.3 - H&M BALANCE		REVISION	0	1
CLIENT :	IEAGHG	PREP.	LC	
PROJECT NAME:	CO_2 capture at coal based power and H2 plants	CHECKED	NF	
PROJECT NO:	1-BD-0681 A	APPROVED	LM	
LOCATION:	The Netherlands	DATE	August 2013	

HEAT AND MATERIAL BALANCE
Unit 3000 - Power Island (*)

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
24	PSA off-gas to Boiler	51.9	10	5.0	-
25	Flue gas from boiler (1)	161	140-150	AMB	-
26	Boiler Main Steam	100.5	550	110.0	3492
27	HP Steam from process unit	265.5	408	115.0	3090
28	Steam to Condenser	366.5	29	0.04	2197
29	Condensate to Process Units	484.9	28	0.04	117
30	Condensate to Deaerator	530.0	155	7.2	654
31	HP BFW to Pumps (Boiler)	101.5	166	7.2	702
32	HP BFW to Pumps (G.I.)	268.6	166	7.2	702
33	LP BFW to steam generator	58.5	166	7.2	702
34	BFW make-up to gasification	113.5	166	7.2	702
35	Make-up water	118.4	15	6.0	64
36	Water Supply to Steam Condenser	16537	15	4.0	63
37	Water Return from Steam Condenser	16537	26	3.5	109

(*) Flowrate figure refers to one train (50% capacity)
(1) Flue gas molar composition at stack: N_2: 58.6%; H_2O: 25.2%; O_2: 0.3%; CO_2: 2.6%; Ar: 0.6%.

5. Utility consumption

Main utility consumption of the process and utility units is reported in the following tables. More specifically:

- Steam / BFW / condensate interface summary is reported in Table 2.
- Water consumption summary is shown in Table 3.
- Electrical consumption summary is included in Table 4

Table 2. Case 5.3 – Steam/BFW/condensate interface summary

CLIENT:	IEAGHG	REVISION	Rev.0
PROJECT:	CO2 capture at coal based power and hydrogen plants	DATE	Sept 2013
LOCATION:	The Netherlands	ISSUED BY	LC
FWI Nº:	1-BD-0681 A	CHECKED BY	NF
		APPROVED BY	LM

Hydrogen production - Case 5.3 (Power island: PSA off-gases fired boiler) - Steam and water balance

UNIT	DESCRIPTION UNIT	HP Steam barg 120	MP Steam barg 40	LP Steam barg 6.5	HP BFW	MP BFW	LP BFW	condensate recovery	Losses
		[t/h]	[t/h]	[t/h]	[t/h]	[t/h]	[t/h]	[t/h]	[t/h]
	PROCESS UNITS								
2100	**Air Separation Unit (ASU)**								
1000	**Gasification Section**	**-531.9**			**537.2**				**-5.3**
2200	**Syngas Treating and Conditioning Line**			**-96.1**			**335.3**	**-11.1**	**-228.1**
2300	**Acid Gas Removal**			**64.0**				**-64.0**	**0.00**
2400	**Sulphur Recovery (SRU)**			**-8.0**			**8.8**		**-0.85**
3000	**POWER ISLAND**	**531.9**		**25.1**	**-537.2**		**-344.2**	**90.1**	**-2.0**
2600	**Hydrogen Unit (PSA)**								
4000	**UTILITY and OFFSITE UNITS**			**15.0**				**-15.0**	**0.00**
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-236.3**

Note: (1) Negative figures represent generation

Table 3. Case 5.3 – Water consumption summary

	CLIENT: IEAGHG		Revision	0	
	PROJECT: CO2 capture at coal based power and H2 plants		Date	July 2013	
	LOCATION: The Netherlands		ISSUED BY	LC	
	FWI Nº: 1-BD-0681 A		CHECKED BY	NF	
			APPR. BY	LM	

Hydrogen production - Case 5.3 (Power island: PSA off-gases fired boiler)
Water Consumption Summary

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water Primary system [t/h]	Cooling Water Secondary System [t/h]
	AIR SEPARATION UNIT (ASU)				
2100	**Air Separation Unit**				**9810**
	GASIFICATION SECTION (GS)				
1000	**Gasification**	**145**			**3870**
2200	**Syngas treatment and conditioning line**				**3370**
2300	**Acid Gas Removal**		**0.6**		**6870**
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**				**160**
	CO_2 COMPRESSION				
2500	**CO_2 Compression**				**5850**
	POWER ISLAND (CC)				
3300	**Steam Turbine and Generator auxiliaries**		**236.3**		**1320**
	Condenser			**33080**	
	UTILITY UNITS (UU)				
4000	**Cooling Water System**	**1164**			
4000	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**355**	**-237**		
4000	**Waste Water Treatment**	**-96.6**			
4000	**Balance of Plant (BOP)**				**400**
	TOTAL CONSUMPTION	**1567**	**0**	**33080**	**31650**

Note: Negative figures represent generation

Table 4. Case 5.3 – Electrical consumption summary

CLIENT:	IEAGHG	Rev.0
PROJECT:	CO2 capture at coal based power and hydrogen plants	Date: July 2013
LOCATION:	The Netherlands	ISSUED BY: LC
FWI Nº:	1-BD-0681 A	CHECKED BY: NF
		APPR. BY: LM

Hydrogen production - Case 5.3 (Power island: PSA off-gases fired boiler)
Electrical Consumption Summary

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	AIR SEPARATION UNIT (ASU)	
2100	**MAC consumptions**	**124220**
	BAC consumptions	**12270**
	Miscellanea	**1000**
	GASIFICATION SECTION (GS)	
900	**Coal Receiving Handling and Storage**	**410**
1000	**Gasification**	**8790**
2200	**Syngas treatment and conditioning line**	**910**
2300	**Acid Gas Removal**	**20850**
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**	**700**
2500	**CO_2 Compression**	**33970**
3000	**STEAM CYCLE**	
	Condensate and BFW pumps	**4890**
	Boiler	**1120**
	Steam Turbine auxiliaries and excitation system	**400**
	Miscellanea	**2660**
	UTILITY UNITS (UU)	
4000	**Cooling Water System**	**8040**
4000	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**730**
4000	**Balance of Plant (BOP)**	**1060**
	TOTAL CONSUMPTION	**222020**

6. Overall performance

The following table shows the overall performance of Case 5.3.

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**DATE**	Sept 2013
PROJECT No. :	1-BD-0681 A	**MADE BY**	LC
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 5.3 - H2 Plant Performance Summary
(Boiler Island)

OVERALL PERFORMANCES		
Coal Flowrate (as received)	t/h	349.1
Coal LHV (as received)	kJ/kg	25870
Coal HHV (as received)	kJ/kg	27060
THERMAL ENERGY OF FEEDSTOCK	**MWth (LHV)**	**2509**
THERMAL ENERGY OF FEEDSTOCK	**MWth (HHV)**	**2624**
Thermal Power of Raw Syngas exit Scrubber	MWth (LHV)	1785
Thermal power of syngas to AGR	MWth (LHV)	1638
Thermal Power of Clean Syngas to Hydrogen PSA	MWth (LHV)	1600
Thermal Power of offgas to boiler island	MWth (LHV)	210
HYDROGEN PRODUCTION	**Nm^3/h**	**465700**
Thermal Power of Hydrogen	**MWth (LHV)**	**1390**
Steam turbine electric power output	MWe	259.1
GROSS ELECTRIC POWER OUTPUT OF STEAM CYCLE	**MWe**	**259.1**
Gasification Section units consumption	MWe	31.7
ASU consumption	MWe	137.5
Steam Cycle auxiliaries consumption	MWe	9.1
CO_2 Compression and Dehydration unit consumption	MWe	34.0
Utility Units consumption	MWe	9.8
ELECTRIC POWER CONSUMPTION OF GASIFICATION COMPLEX	**MWe**	**222.0**
NET ELECTRIC POWER OUTPUT OF IGCC (Step-up transformer Eff. = 0.997)	**MWe**	**37.0**
CO_2 emission per net power production (*)	**kg/MWh**	**93.7**

(*) Referred to the net power production fo case 4.2

The following table shows the overall CO_2 balance and CO_2 removal efficiency of Case 5.3.

CO_2 removal efficiency	**Equivalent flow of CO_2** kmol/h
INPUT	
Fuel Mix (Carbon AR)	18730
TOTAL (A)	18730
OUTPUT	
Slag (B)	101
CO_2 product pipeline	
CO	7
CO_2	16759
CH_4	0
COS	0
Total to storage (C)	16766
CO2 emission from boiler	1862
TOTAL	18730
Overall Carbon Capture, % ((B+C)/A)	90.1

7. Environmental impact

The gasification plant design is based on advanced technologies that allow to reach high electrical generation efficiency, while minimizing impact to the environment. Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

7.1. Gaseous emissions

During normal operation at full load, main continuous emissions are the flue gases from the boilers' stack. Table 5 summarises expected flow rate and concentration of the combustion flue gas from both the boilers included in the power island.

Minor gaseous emissions are created by 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 related to the milling, storage and handling of solids (e.g. solid transfer, leakage). As summarised in Table 6, these emission mainly consists of air containing particulate.

Table 5. Case 5.3 – Plant emission during normal operation

Flue gas to HRSG stack	
Emission type	Continuous
Conditions	
Wet gas flowrate, kg/h	322,050
Flow, Nm^3/h (1)	265,100
Temperature, °C	140-150
Composition	(% vol)
Ar	0.61
N_2	58.57
O_2	0.27
CO_2	15.35
H_2O	25.21
Emission	mg/Nm^3 (1)
NOx	< 150
SOx	< 10
Particulate	< 10

(1) Dry gas, O_2 content 6% vol.

Table 6. Case 5.3 – Plant minor emission

Emission source	Emission type	Temperature	
Coal storage and handling system	Continuous	ambient	Air: 10 mg/Nm^3 particulate

7.2. Liquid effluents

Main liquid effluents are the cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids, and the effluent from the Waste Water Treatment, which flows to an outside plant battery limits recipient.

Cooling Tower blow-down

Flowrate : 280 m^3/h

Waste Water Treatment effluent

Flowrate : 125 m^3/h

7.3. Solid effluents

The IGCC plant is expected to produce the following solid by-product:

Slag from gasifier

Flowrate : 45 t/h (dry basis)

Moisture content : 50%

Slag product has a potential use as major components in concrete mixtures to make road, pads, storage bins.

8. Preliminary plot plan

Plot plan at block level of Case 5.3 is attached to this section, showing the area occupied by the main units and equipment of the plant.

COO1	SEPT. 2013	Preliminary issue for comments	APeccati			
REV.	DATE	DESCRIPTION	DRAW	BY	CHD.	APP.

DESCRIPTION

CLIENT IEA GHG

SITE The Netherlands

CO2 Capture and coal fired Power Plants

CASE: 5.1- Hydrogen Production (Boilers)

PRELIMINARY PLOT PLAN

APPROVED FOR CONSTRUCTION
DWG. REV. DATE
SIGNATURE
ORDER N°
SUPPLIER
CONTRACT N°
FRAME N°
CLIENT DWG N°
SHEET SHEET
SCALE N. A.
FWI DWG N° 1BD0681A - 01 - 009
SHEET OF
REV. COO1

FOSTER WHEELER

CAD FILE NAME

Form. A3

9. Equipment list

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

FOSTER WHEELER	CLIENT: IEAGHG LOCATION: The Netherlands PROJ. NAME: CO_2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 5.3 -Hydrogen Production (Boiler)	

REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
DATE	August 2013	January 2014		
ISSUED BY	LC	GP		
CHECKED BY	NF	NF		
APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 900 - Coal handling and storage (N/A)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-901	**Coal Handling**		Coal flowrate: 349 t/h					30 days storage
	Wagon tipper							Storage piles: 2 x 137,000 t each
	Receiving Hopper, vibratory feeder and belt extractor							
	Conveyors	Belt						
	Transfer Towers	Enclosed						
	As-Received Coal Sampling System	Two-Stage						
	As-Received Magnetic Separator System	Magnetic Plates						
	Conveyors	Belt						
	Transfer Towers	Enclosed						
	Crushers Towers	Impactor reduction						
	As-Fired Coal Sampling System	Swing hammer						
	As-Fired Magnetic Separator System	Magnetic Plates						
	Coal Silo		2 x 5300 m3					for daily storage

FOSTER WHEELER	CLIENT: IEAGHG LOCATION: The Netherlands PROJ. NAME: CO_2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 5.3 -Hydrogen Production (Boiler)		

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EQUIPMENT LIST
Unit 1000 - Gasification Island (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-1002	**GE Energy Coal gasification package**							
	Coal grinding and slurry preparation							Included in Z-1002
	Gasifiers (RSC)		2 x 4200 t/d coal (as received) to burners 2 x 900 MWth (LHV basis) syngas at scrubber outlet					Included in Z-1002
	Scrubber							Included in Z-1002
	Black Water flash							Included in Z-1002
	Coarse slag handling							Included in Z-1002
	Grey water systeam and fines handling							Included in Z-1002

FOSTER WHEELER	CLIENT: IEAGHG LOCATION: The Netherlands PROJ. NAME: CO_2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 5.3 -Hydrogen Production (Boiler)		REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2	
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			APPROVED BY	LM	LM			

EQUIPMENT LIST
Unit 2100 - Air Separation Unit (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2101	**ASU Package** including:							
	Cold Box	Cryogenic	162 t/h of 95% purity O_2 each train					Included in Z-2101
	Main Air compressors (MAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 2 x 297800 Nm3/h	2 x 35250 kW				Included in Z-2101
	Booster air compressors (BAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 238200 Nm3/h	7500 kW				Included in Z-2101
	O_2 pumps	Centrifugal						Included in Z-2101
	Back-up oxygen vaporiser	Shell and tube						Included in Z-2101
Common units to both trains:								
	LOX (liquid oxygen) storage	Fixed roof storage tank						8 hour storage for 1 gasification train Normal operating p: 5 bar a Normal operating T: -165 °C Included in Z-2101
	LIN (liquid nitrogen) storage	Fixed roof storage tank						8 hour storage for 1 Gasifier Normal operating p: 5 bar a Normal operating T: -180 °C Included in Z-2101
	Gaseous oxygen storage							
	Gaseous nitrogen storage							

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	CASE: Case 5.3 -Hydrogen Production (Boiler)	APPROVED BY	LM	LM		

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning Line (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	HEAT EXCHANGERS				Shell/tube	Shell/tube		
E-2201	**Feed/Product Heat Exchanger**	Shell & Tube						
E-2202	**HP steam superheater #1**	Shell & Tube						
E-2203	**HP steam superheater #2**	Shell & Tube						
E-2204 A/B	**HP BFW preheater #1 and #2**	Shell & Tube						
E-2205	**HP BFW preheater #3**	Shell & Tube						
E-2206	**LP steam generator**	Shell & Tube						
E-2207	**Condensate preheater #1**	Shell & Tube						
E-2208	**Condensate preheater #2**	Shell & Tube						
E-2209	**Condensate preheater #3**	Shell & Tube						
E-2210	**Final sygas cooler**	Shell & Tube						
	DRUMS							
D-2201	**Condensate Separator**	Vertical						
D-2202	**Condensate Separator**	Vertical						
D-2203	**Condensate Separator**	Vertical						
D-2204	**Condensate Separator**	Vertical						
D-2205	**Condensate Separator**	Vertical						
D-2206	**Condensate Separator**	Vertical						
D-2207	**Condensate Separator**	Vertical						
D-2208	**Condensate accumulator**	Horizontal						Common for both syngas tratment and conditiong line trains

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	CASE: Case 5.3 -Hydrogen Production (Boiler)	APPROVED BY	LM	LM		

EQUIPMENT LIST

Unit 2200 - Syngas Treatment and Conditioning Line (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	REACTOR							
R-2201	**1st Shift Catalyst Reactor**	vertical						Overall CO conversion = 98%
R-2202	**2nd Shift Catalyst Reactor**	vertical						
	PUMPS							
P-2201	**Condensate Pump (to Gasifiers)**							
	MISCELLANEA							
X-2201	**Mercury Adsorber**	Sulfur-impregnated activated carbon beds						

Note: equipment list referred to one train only

	CLIENT: IEAGHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 5.3 -Hydrogen Production (Boiler)	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
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		APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 2250 - Sour Water System (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-2251	**SWS PACKAGE**							
C-2251	Sour Water Stripper	Vertical						
	SWS Reboiler							
	SWS Condenser							
E-2251	Sour water heat exchanger (SWS feed / purified)							
P-2251	SWS Pump							

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	CASE: Case 5.3 -Hydrogen Production (Boiler)	APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 2300 - Acid Gas Removal Unit (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2301	**Acid Gas Removal Unit - Absorption section**	Solvent: Selexol	Feed gas: 974900 Nm3/h; 56 barg; 34 °C					One H2S removal column, 3 CO2 removal columns, CO2 removal =91.78% Total Carbon Capture =90% Separated removal of CO2 and H2S
Z-2303	**Acid Gas Removal Unit - Solvent regeneration**							Total CO2 removal= 17700 t/d; 10 ppm H2S (dry) in combined CO2
Z-2304	**Chiller Unit**	Electrical driven						T= -10 °C

FOSTER WHEELER	CLIENT: IEAGHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 5.3 -Hydrogen Production (Boiler)	

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EQUIPMENT LIST

Unit 2400 - Sulphur Recovery Unit (2x100%) & Tail Gas Treatment (1x100%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-2401	**Sulphur Recovery Unit and Tail Gas Treatment Package** - two Sulphur Recovery Unit, each sized for 100% of the capacity - one Tail Gas Treatment Unit sized for 100% of capacity (including Reduction Reactor and Tail Gas Compressor)		Sulphur Prod.= 72 t/d Acid Gas from AGR = 6680 Nm3/h Expected Treated Tail Gas = 3602 Nm3/h					Sulphur content > 99,9 % mol min (dry basis)

FOSTER WHEELER	CLIENT: IEAGHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 5.3 -Hydrogen Production (Boiler)			REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
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				ISSUED BY	LC	GP		
				CHECKED BY	NF	NF		
				APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 2500 - CO_2 Compression Package (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [MW]	P design [barg]	T design [°C]	Materials	Remarks
	COMPRESSORS							
C-2501	CO_2 Compressors	Centrifugal, Electrical Driven, 8 intercooled Stages	190000 Nm3/h p in: 2.45 bar a p out: 80 bar a	18000 kW				Water cooled
	PUMPS		**Q,m3/h x H,m**					
P-2501	CO_2 Pump	Centrifugal	640 x 530	800 kW				Liquid CO2 product, per each train: Flowrate: 370 t/h; 110 bar a; 30°C
	PACKAGE							
PK-2501	CO_2 drying package							

	CLIENT:	IEAGHG	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
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	PROJ. NAME:	CO2 capture at coal based power and hydrogen plants	ISSUED BY	LC	GP		
	CONTRACT N.	1-BD-0681 A	CHECKED BY	NF	NF		
	CASE:	Case 5.3 -Hydrogen Production (Boiler)	APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 2600 - Hydrogen Production

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [MW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
	Hydrogen Production package	PSA	465000 Nm3/h P out = 51 barg T out = 20 °C					Hydrogen purity =99.5 %

	CLIENT:	IEAGHG	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
	LOCATION:	The Netherlands	DATE	August 2013	January 2014		
	PROJ. NAME:	CO2 capture at coal based power and hydrogen plants	ISSUED BY	LC	GP		
	CONTRACT N.	1-BD-0681 A	CHECKED BY	NF	NF		
	CASE:	Case 5.3 -Hydrogen Production (Boiler)	APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 3000 - Boiler Island (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	BOILER (2 x 50%)							
PK - 3501	**Boiler Package**	Gas fired Boiler	Capacity: 100 t/h main steam each boiler Thermal input (PSA off-gas from Unit 2600): 105 MWth (LHV) each boiler Main steam condition: 550 °C / 110 bar (a)					***Boiler package including:*** - One Fired Boiler Furnace - Low NOx burners system including main burners and pilots - Economizers/super heater coils, steam drum - Air pre-heater - Combustion air fans with electric motor - Start-up system - Flue gas ducts
K - 3501	**ID fan**	Axial	Flowrate: 130x10^3 Nm3/h Vol. Flow: 205 x 10^3 m3/h Power consumption: 405 kW					
Common to both boilers								
PK - 3502	Flue gas stack	Cement Stack						Equipped with two flues
PK - 3503	Continuous emission monitoring system							NOx, CO, SO_2, particulate, H_2O, O_2

	CLIENT: IEAGHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 5.3 -Hydrogen Production (Boiler)	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
FOSTER WHEELER		DATE	August 2013	January 2014		
		ISSUED BY	LC	GP		
		CHECKED BY	NF	NF		
		APPROVED BY	LM	LM		

EQUIPMENT LIST

Unit 3000 - Steam Cycle (2x50%)

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
	PACKAGES							
Z-3001 A/B	**Steam Turbine and Generator Package**							
ST-3001	Steam Turbine		2 x 130 MWe HP steam admission: 110 bar, 550°C					*Including:* *Lube oil system* *Cooling system* *Idraulic control system* *Drainage system* *Seals system* *Drainage system*
G-3002	Steam Turbine Generator		2 x 170 MVA					*Including relevant auxiliaries*
E-3001A/B	Inter/After condenser							
E-3002	Gland Condenser							
Z-3002 A/B	**Steam Condenser Package**							
E-3003	Steam Condenser	Water cooled	2 x 220 MWth					*Including:* *Hot well* *Vacuum pump (or ejectors)* *Start up ejector (if required)*
Z-3003 A/B	**Steam Turbine by-pass system**							
Z-3004	**Phosphate injection package**							
Z-3005	**Oxygen scavanger injection package**							
Z-3006	**Amines injection package**							
	PUMPS		**Q,m^3/h x H,m**	**kW**				
P-3001 A/B	**HP BFW Pumps (to Unit 1000)**	centrifugal	328 x 1550	1800				One operating, one spare, per each train.
P-3002 A/B	**HP BFW Pumps (to Unit 3500)**	centrifugal	124 x 1500	630				One operating, one spare, per each train.
P-3003 A/B	**LP BFW Pumps**	centrifugal	71.5 x 50	15				One operating, one spare, per each train.
P-3004 A/B	**Condensate Pumps**	Centrifugal, vertical	1360 x 150	800				One operating, one spare
	DRUMS							
D-3001	**Continuous Blow-down Drum**	vertical						
D-3002	**Discontinuous Blow-down Drum**	vertical						

FOSTER WHEELER	CLIENT: IEAGHG LOCATION: The Netherlands PROJ. NAME: CO_2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 5.3 -Hydrogen Production (Boiler)			REVISION DATE ISSUED BY CHECKED BY APPROVED BY	Rev. Draft August 2013 LC NF LM	Rev.0 January 2014 GP NF LM	Rev.1	Rev.2

EQUIPMENT LIST
Unit 4000 - Utility and Offsite

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-4001	**COOLING WATER SYSTEM**							
CT-4001	Cooling Tower Including Cooling water basin	Evaporative, Natural draft	Total heat duty 825 MWth Diameter: 130 m, Height: 210 m, Water inlet: 17 m				concrete	Included in Z-4001
	Pumps							
P-4001A/B/C/D	Cooling Water pumps (primary system)	Vertical	11025 m3/h x 35 m	1200 kW				Included in Z-4001 3 operating, one spare
P-4002A/B/C	Cooling Water pumps (secondary system)	Vertical	15670 m3/h x 45 m	2200 kW				Included in Z-4001 2 operating, one spare
P-4003A/B	Raw water pumps (make-up)	centrifugal	1275 m3/h x 30 m	160 kW				Included in Z-4001 1 operating, one spare
	Packages							
	Cooling Water Filtration Package Cooling Water Sidestream Filters		Capacity: 6450 m3/h					
	Sodium Hypochlorite Dosing Package Sodium Hypochlorite storage tank Sodium Hypochlorite dosage pumps							
	Antiscalant Package Dispersant storage tank Dispersant dosage pumps							
Z-4002	**RAW WATER SYSTEM**							
T-4001	Raw Water storage tank		10680 m3					Included in Z-4002 24 hour storage
P-4004A/B	Raw Water Pumps to gasification island	centrifugal	160 m3/h x 50 m	30 kW				Included in Z-4002 One operating, one spare
P-4005A/B	Raw Water Pumps to demi plant	centrifugal	285 m3/h x 50 m	55 kW				Included in Z-4002 One operating, one spare
Z-4003	**DEMI WATER SYSTEM**							
PK-4001	**Demin Water Package, including:**							
	- Multimedia filter - Reverse Osmosis (RO) Cartidge filter - Electro de-ionization system							
T-4002	Demi Water storage tank		6240 m3					Included in Z-4003 24 hour storage
P-4006A/B	Demi Water Pumps	centrifugal	260 m3/h x 35 m	37 kW				Included in Z-4003 One operating, one spare

FOSTER WHEELER	CLIENT: IEAGHG	REVISION	Rev. Draft	Rev.0	Rev.1	Rev.2
	LOCATION: The Netherlands	DATE	August 2013	January 2014		
	PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	LC	GP		
	CONTRACT N. 1-BD-0681 A	CHECKED BY	NF	NF		
	CASE: Case 5.3 -Hydrogen Production (Boiler)	APPROVED BY	LM	LM		

EQUIPMENT LIST
Unit 4000 - Utility and Offsite

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	P design [barg]	T design [°C]	Materials	Remarks
Z-4004	**FIRE FIGHTING SYSTEM**							
	Fire water storage tank							
	Fire pumps (diesel)							
	Fire pumps (electric)							
	FW jockey pump							
	MISCELLANEA							
	Natural Gas system							
	Waste Water Treatment							
	Sulphur Storage/Handling		72 t/d S prod.					30 days storage
	Flare system							
	Interconnecting							
	Instrumentation							
	DCS							
	Piping							
	Electrical							
	Plant Air							
	Buildings							

CLIENT	:	IEAGHG
PROJECT NAME	:	CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
DOCUMENT NAME	:	CASE 4.2: IGCC WITH CCS – GE GASIFICATION TECHNOLOGY COOLING SYSTEM SENSITIVITY
FWI CONTRACT	:	1-BD-0681 A

ISSUED BY	:	G. PERFUMO
CHECKED BY	:	N. FERRARI
APPROVED BY	:	L. MANCUSO

Date	**Revised Pages**	**Issued by**	**Checked by**	**Approved by**

TABLE OF CONTENT

1. Introduction

This chapter presents the main impacts on plant design and performance of alternative types of cooling system, taking as reference the IGCC plant based on the GE gasification technology described in chapter E.2 (Case 4.2). With respect to this case, based on natural draft cooling water tower system, two different systems are analysed hereafter:

- SW: once-through seawater cooling;
- AC: dry air cooling.

The description of the main process units and the reference Case 4.2 performance are covered respectively in chapter E and E.2 of this report; only plant design changes related to the alternative cooling systems are discussed in the following sections, together with the main plant performance results.

2. Process description

2.1. Overview

The description of the following sections makes reference to the simplified Process Flow Diagrams (PFD) of section 3, which show only the design changes related to the alternative cooling systems. For all the other units, reference shall be made to the base case description, included in chapter E.2, section 2.

2.2. Impact on process units

The adoption of a cooling system different from the reference case leads to the following modification within the process units.

2.2.1. Seawater system

- ASU: Seawater coolers are considered for the after-coolers of the main air and nitrogen compressor. This allows to achieve a cooling level of the process air greater than the reference case, corresponding also to a lower compressor power demand.
- CO_2 compression: Seawater coolers are considered for the after-coolers of the CO_2 compressor trains. This allows to achieve a cooling level of the process air greater than the reference case, corresponding also to a lower compressor power demand.
- The machinery closed cooling water circuit provides the cooling medium to the final syngas cooler and the heat exchangers within the AGR.

2.2.2. Air cooling system

- ASU: Air coolers are considered for the after-coolers of the main air and nitrogen compressor. During operation at normal ambient conditions, this allows to achieve a cooling level of the process air greater than the reference case, corresponding to a lower compressor power demand, offset by the additional power requirement of the air cooler fans.
- CO_2 compression: Air coolers are considered for the after-coolers of the CO_2 compressor trains. During operation at normal ambient conditions, this allows to achieve a cooling level of the process air greater than the reference case, corresponding to a lower compressor power demand, offset by the additional power requirement of the air cooler fans.
- An air cooler is considered for syngas cooling upstream the AGR.
- Air coolers are considered for each cooling service within the AGR unit.

Details on the temperature that can be achieved with both cooling system are reported in the following section 2.4.

2.3. Unit 3000 – Steam Cycle

The main consequence of a cooling system alternative to that of the reference case is a different steam condenser type.

2.3.1. Seawater system

A seawater cooled steam condenser is considered in this case. The lower sea water inlet temperature, as well as the lower permitted temperature increase (see data below) allows to achieve a condensing pressure lower than the reference case (3.0 kPa vs. 4.0 kPa respectively), with consequent higher steam turbine power generation.

In fact, being the sea water supplied to the steam condenser at 12°C and considering a maximum allowed temperature increase of 7°C, the condensation temperature is 24°C.

2.3.2. Air cooling system

The exhaust steam from the LP turbine is piped directly to the air-cooled, finned tube, condenser. The finned tubes are usually arranged in an "A" form or delta over a forced draught fan in order to reduce the plot area requirements.

A temperature difference of 25°C is considered between ambient air and the condensing steam, resulting in a higher steam condensing pressure with respect to the reference case (5.2 kPa vs. 4.0 kPa respectively) with consequent lower steam turbine power generation.

2.4. Unit 6000 - Utility Units

Apart from the cooling water system, alternative to the cooling tower type of the reference case, no significant impact is foreseen in the other utility units of the oxy-combustion power plant.

2.4.1. Seawater system

In the once-through system, seawater is pumped from the sea, directly used in the heat exchangers of the plant and then discharged back to sea.

This system has the advantage of using a "free" coolant medium, without generating a real stream of waste water, since seawater is returned to the sea without any significant change in composition, apart from its higher temperature. However, the maximum allowable seawater temperature increase is 7°C, in order to minimize environmental impact of the sea, thus resulting in a higher circulating cooling water flowrate.

In addition to the steam turbine condenser, seawater is used for the CO_2 compressors intercoolers and the main air compressor aftercoolers. During normal operation conditions, this allows achieving a temperature of the hot stream of 19°C, which is lower than the temperature achieved in the reference case (i.e. 26°C).

In addition to the once-trough system, a seawater-cooled closed circuit of demineralised water is considered (secondary system) for machinery and steam turbine generator cooling and for all plant users where seawater is not applicable, e.g. for cooling of process streams within syngas treatment of the gasification unit.

2.4.2. *Air cooling system*

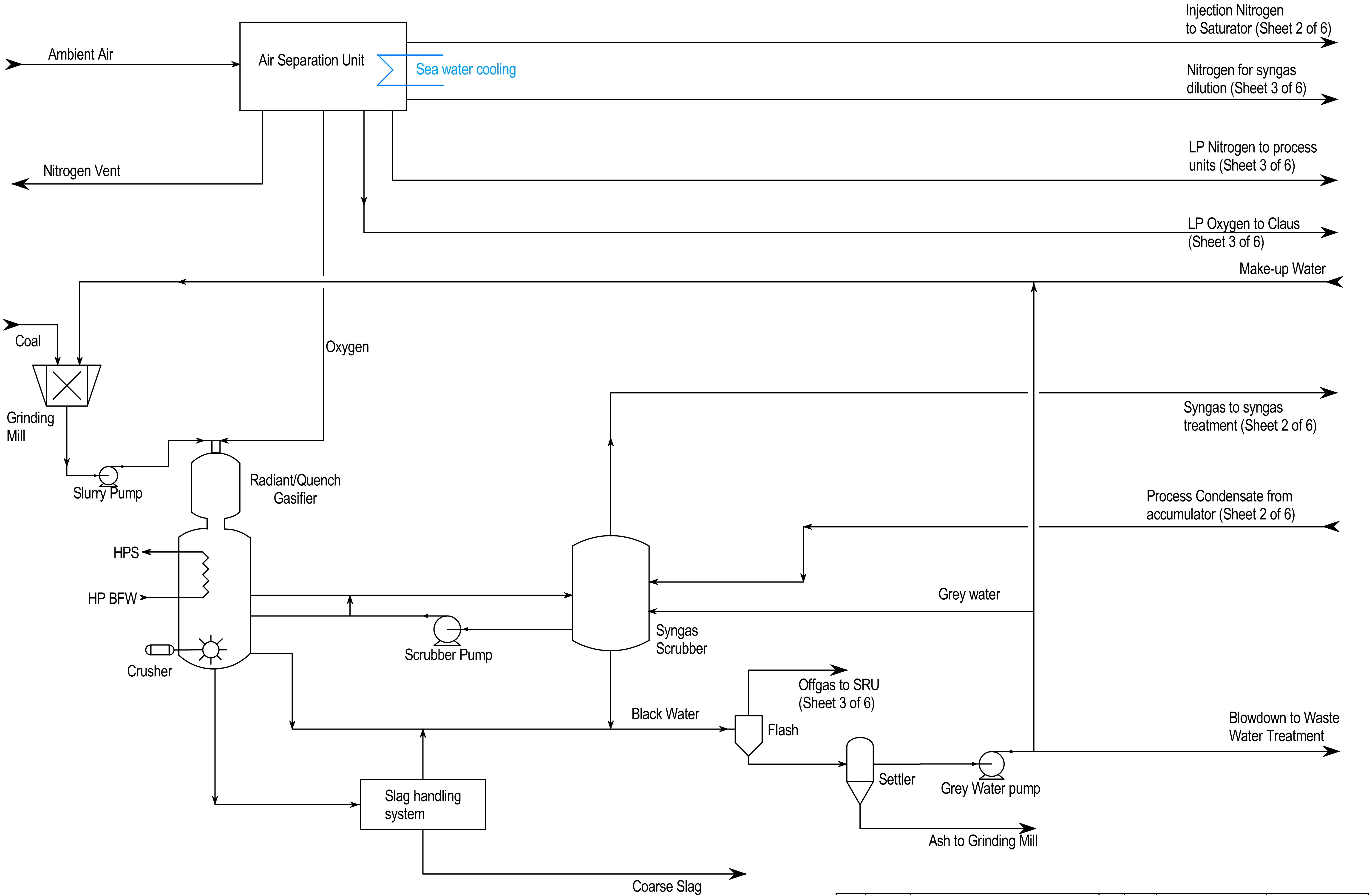
The use of ambient air as cooling medium is maximised. A secondary system consisting of an air-cooled closed circuit of demineralised water, conditioned and stabilised, is only used for machinery and steam turbine generator cooling.

As above stated, the installation of an air cooled steam turbine condenser has a negative impact on the performance, due to the higher condensation pressure resulting from the 25°C approach normally considered for this application.

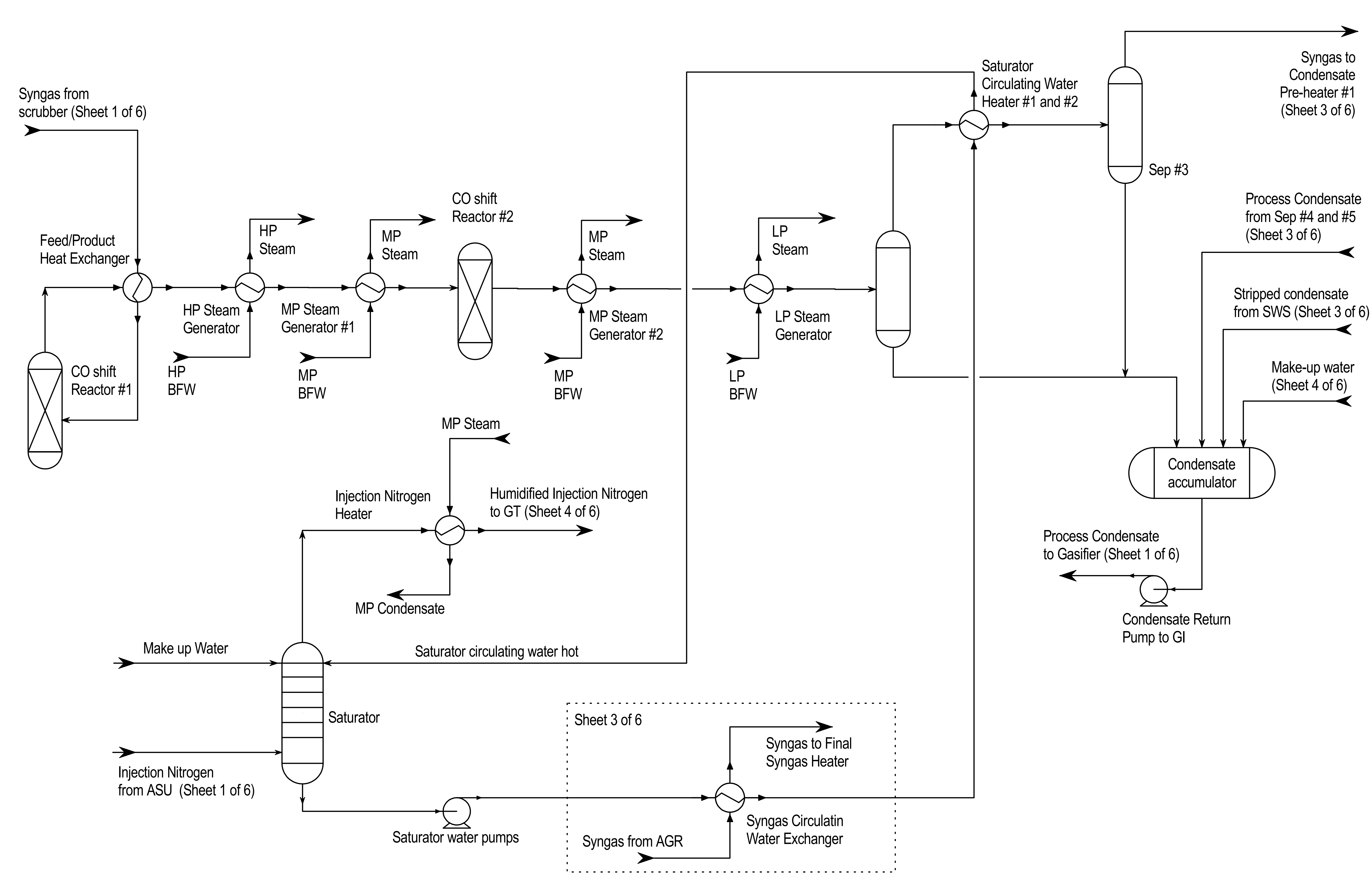
For services other than steam condenser, e.g. water air coolers or compressor intercoolers, the temperature difference between hot fluid exit temperature and ambient air is generally lower, around 10°C, corresponding to a final hot fluid temperature of 19°C, which is lower than the temperature achieved in the reference case (i.e. 26°C).

3. Process Flow Diagrams

Simplified Process Flow Diagrams of this case, showing process modifications with respect to the reference case, are attached to this section.



0	July 13		LC	LM	**UNIT:** GS2 - AS1: Gasification and ASU	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2 sea water	Sheet 01 of 06



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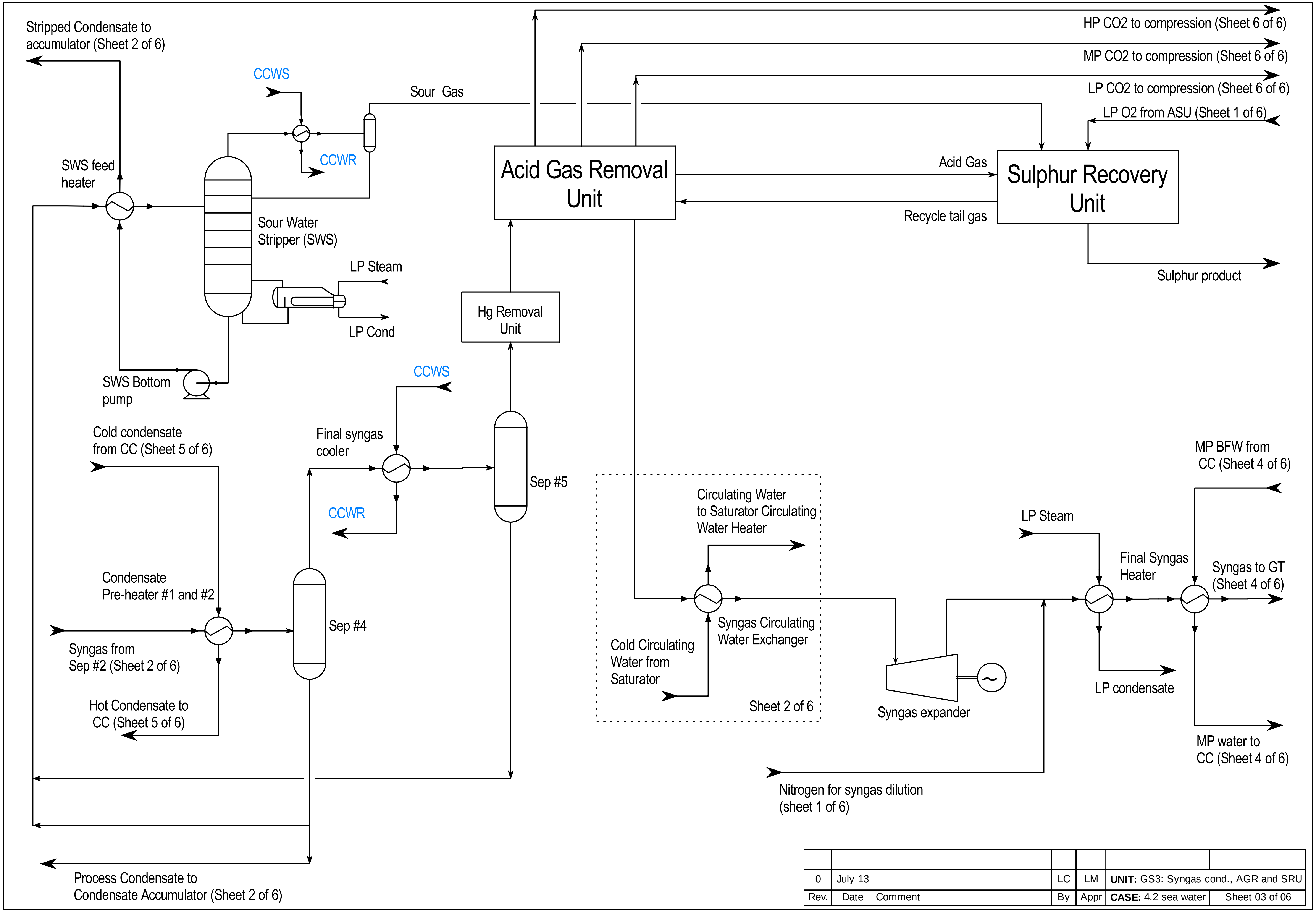
Rev.	Date	Comment	By	Appr	**CASE:** 4.2 sea water	Sheet 02 of 06



Stripped Condensate to accumulator (Sheet 2 of 6)
CCWS
CCWR
Sour Gas
HP CO2 to compression (Sheet 6 of 6)
MP CO2 to compression (Sheet 6 of 6)
LP CO2 to compression (Sheet 6 of 6)
LP O2 from ASU (Sheet 1 of 6)
SWS feed heater
Acid Gas Removal Unit
Acid Gas
Sulphur Recovery Unit
Recycle tail gas
Sour Water Stripper (SWS)
LP Steam
LP Cond
Sulphur product
Hg Removal Unit
SWS Bottom pump
CCWS
Final syngas cooler
Cold condensate from CC (Sheet 5 of 6)
CCWR
Sep #5
MP BFW from CC (Sheet 4 of 6)
Circulating Water to Saturator Circulating Water Heater
LP Steam
Final Syngas Heater
Syngas to GT (Sheet 4 of 6)
Condensate Pre-heater #1 and #2
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Cold Circulating Water from Saturator
Syngas Circulating Water Exchanger
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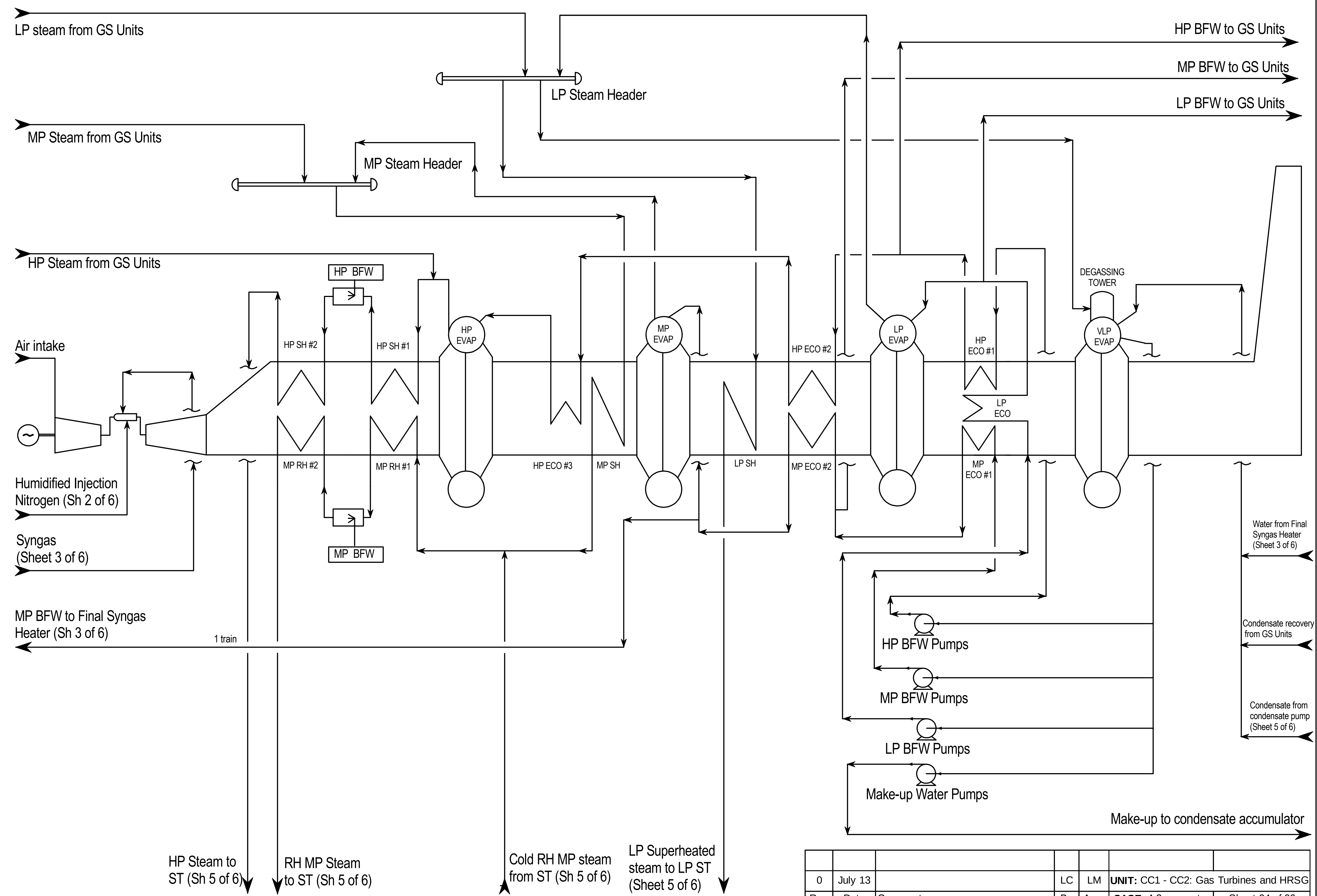
Syngas expander
LP condensate
Hot Condensate to CC (Sheet 5 of 6)
MP water to CC (Sheet 4 of 6)
Nitrogen for syngas dilution (sheet 1 of 6)
Process Condensate to Condensate Accumulator (Sheet 2 of 6)
0
July 13
LC
LM
UNIT: GS3: Syngas cond., AGR and SRU
Rev.
Date
Comment
By
Appr
CASE: 4.2 sea water
Sheet 03 of 06



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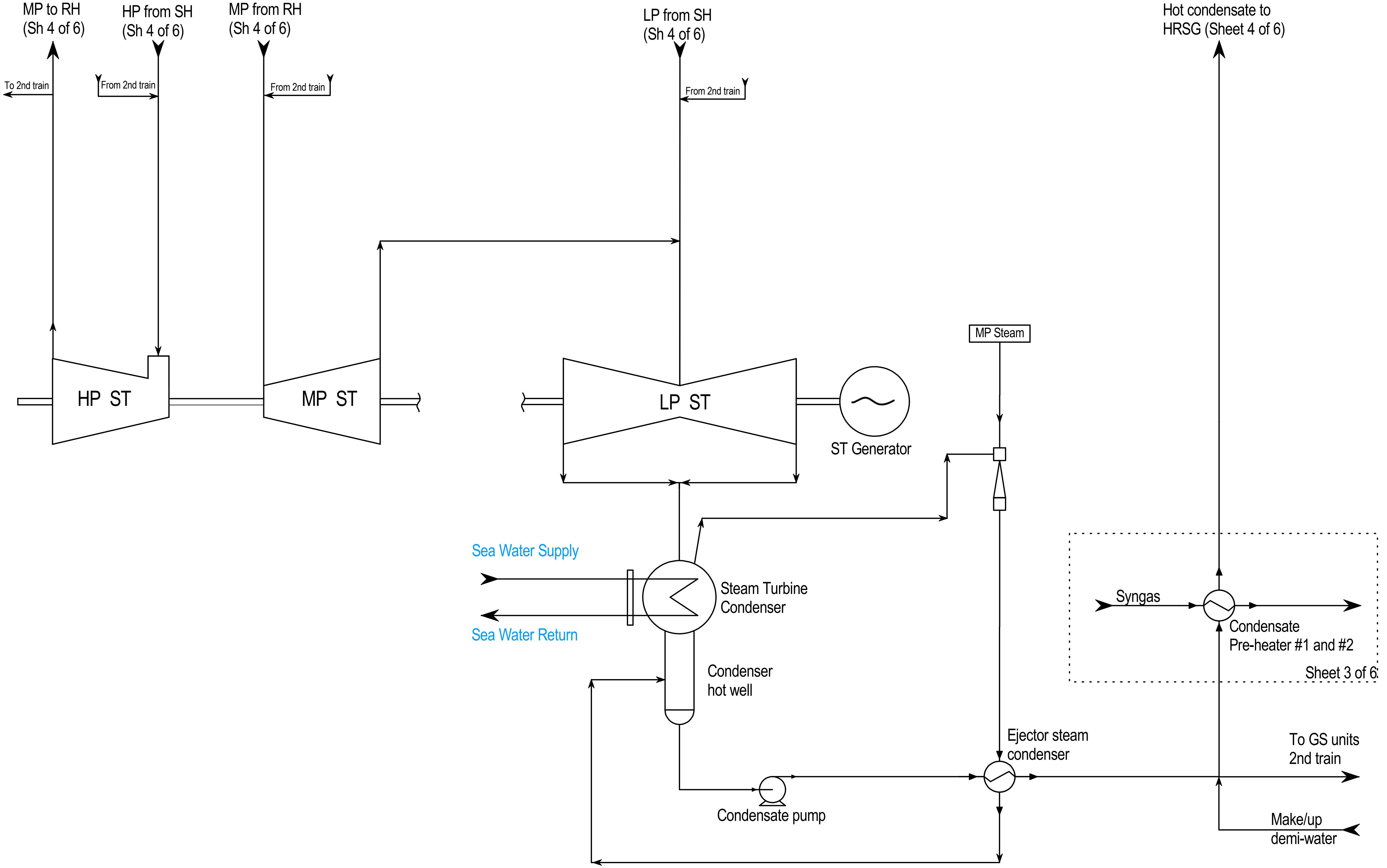
Rev.	Date	Comment	By	Appr	**CASE:** 4.2 sea water	Sheet 04 of 06



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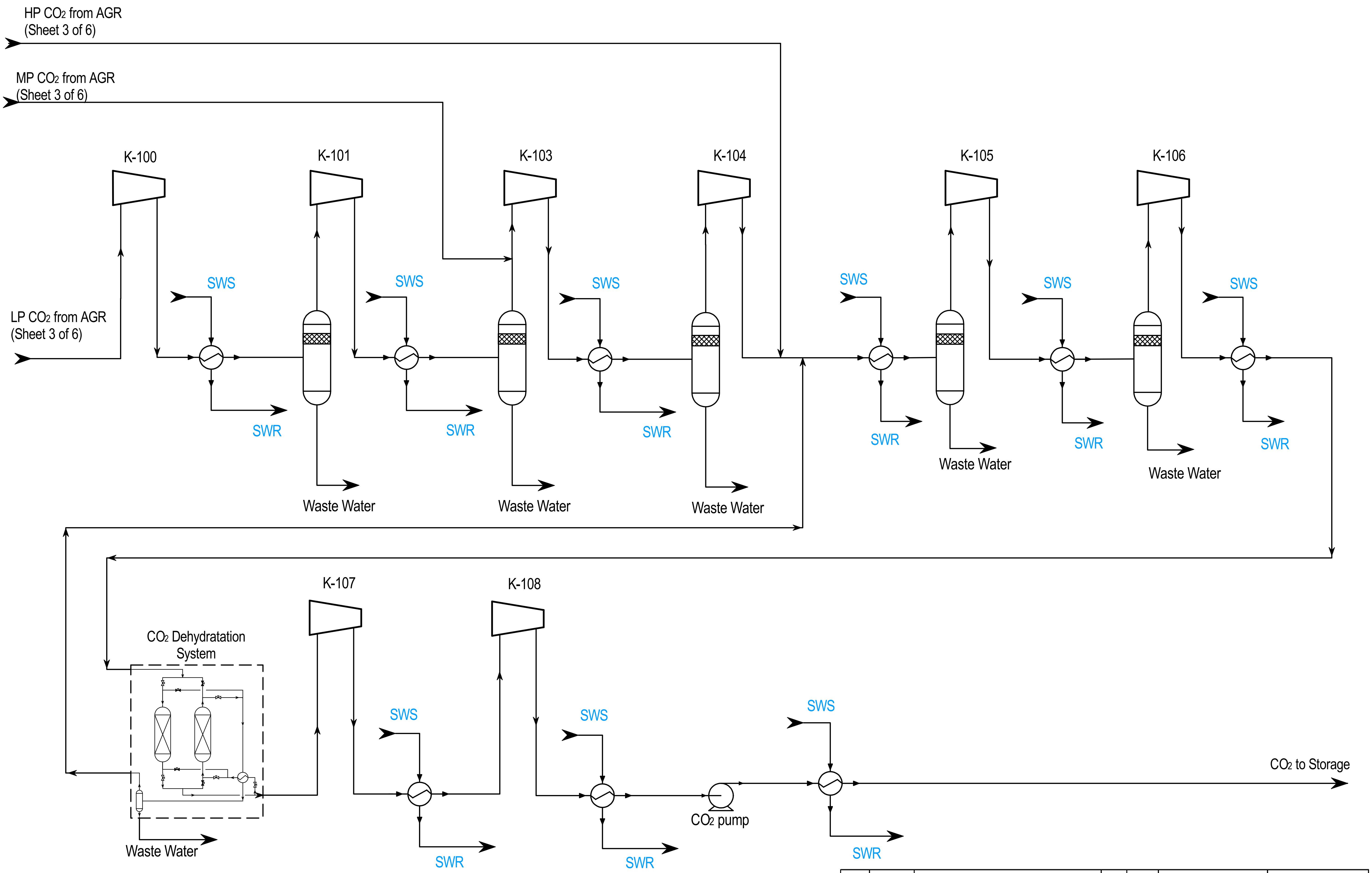
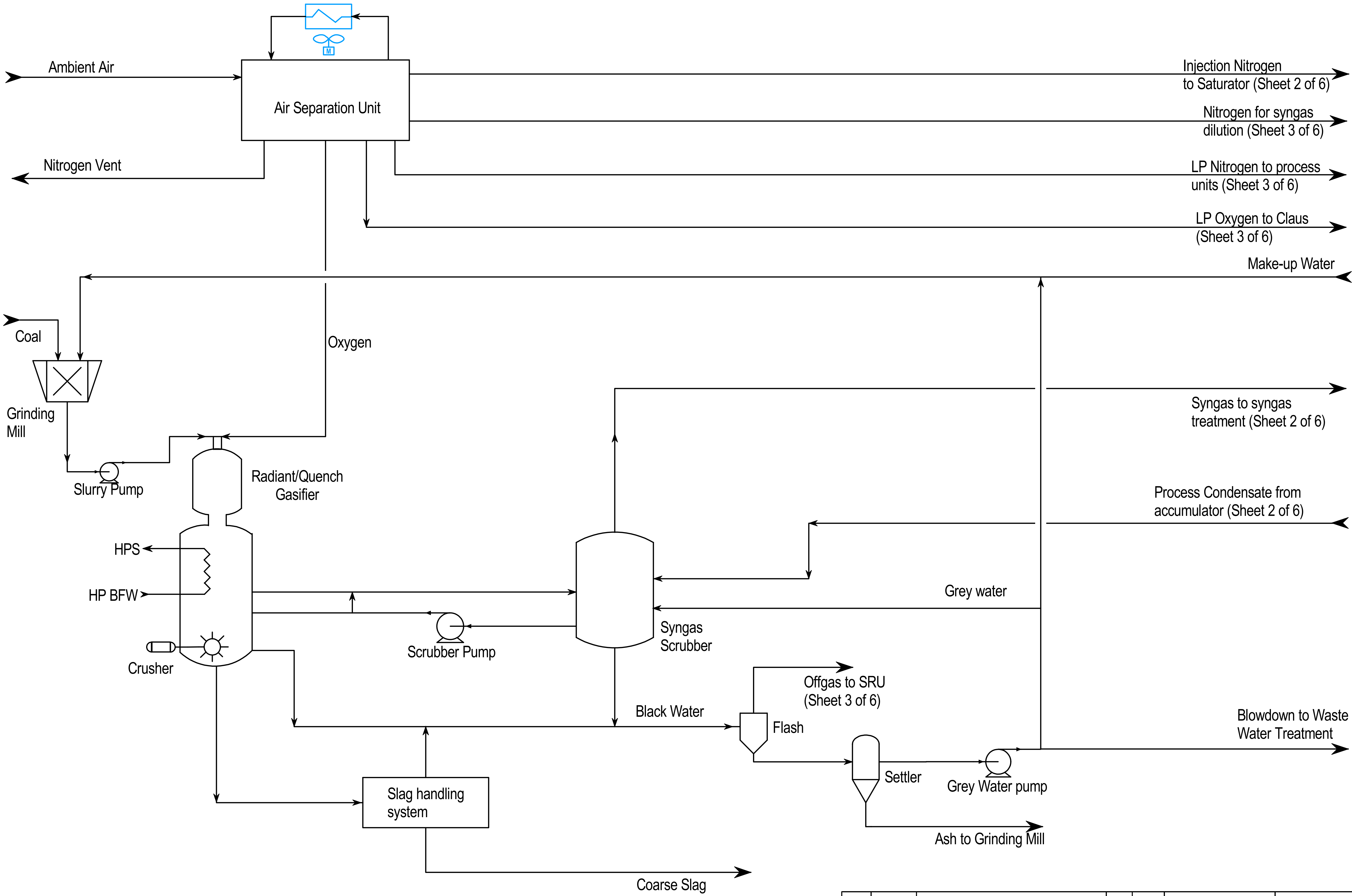
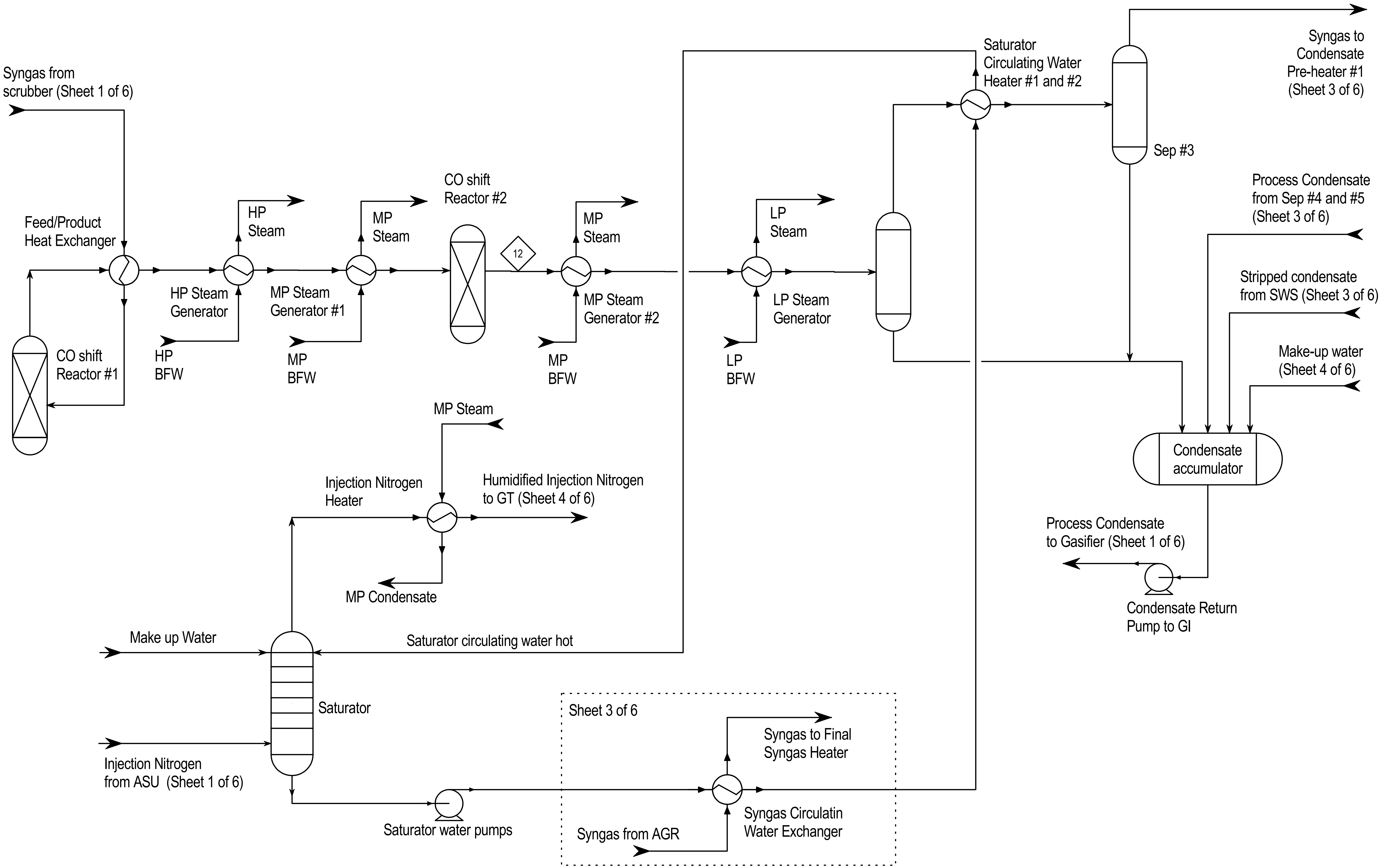
Rev.	Date	Comment	By	Appr	**CASE:** 4.2 sea water	Sheet 05 of 06



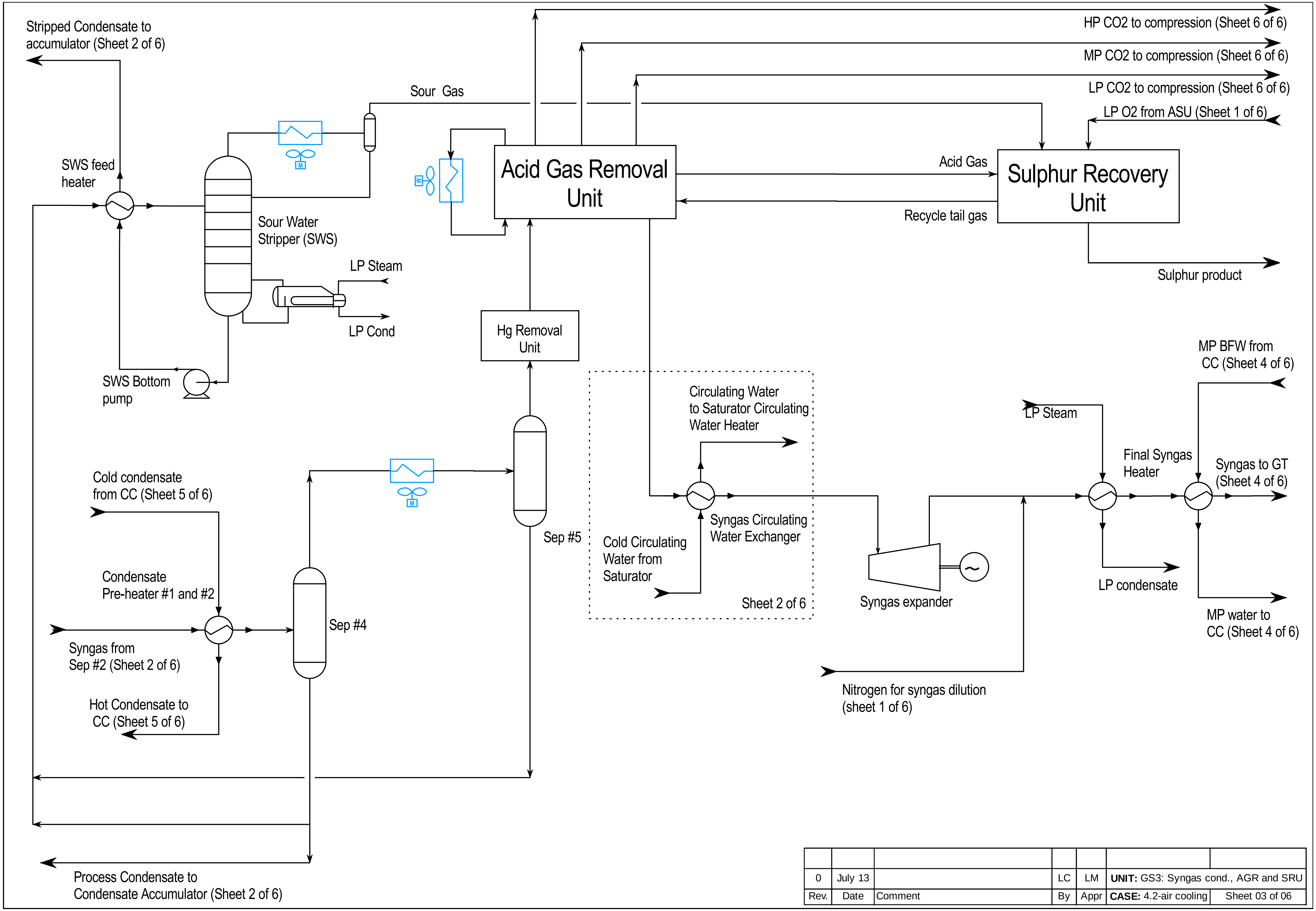
0	July 13		LC	LM	**UNIT:** CO2 compression	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2 sea water	Sheet 06 of 06

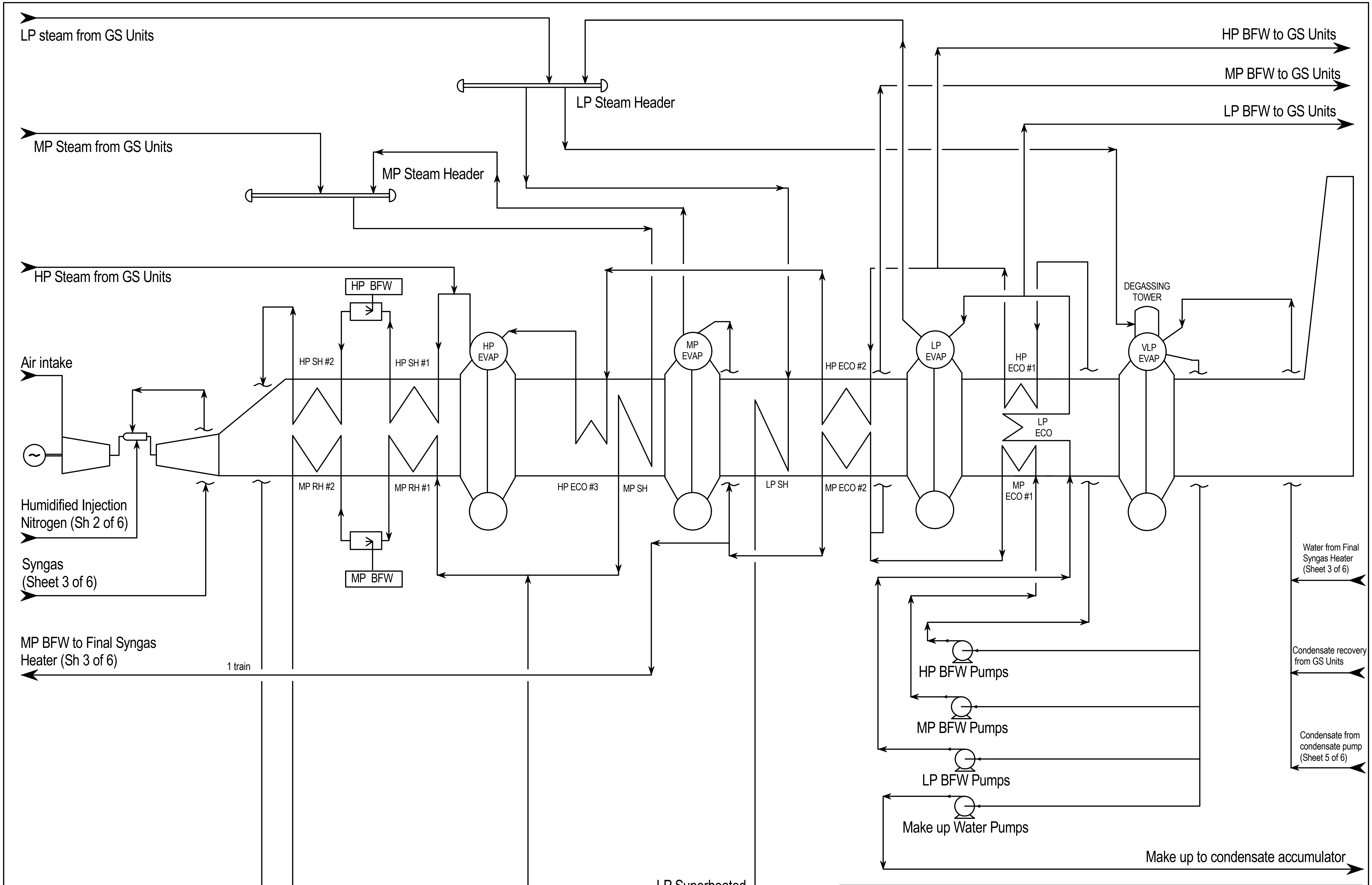


0	July 13		LC	LM	**UNIT:** GS2 - AS1: Gasification and ASU	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2-air cooling	Sheet 01 of 06

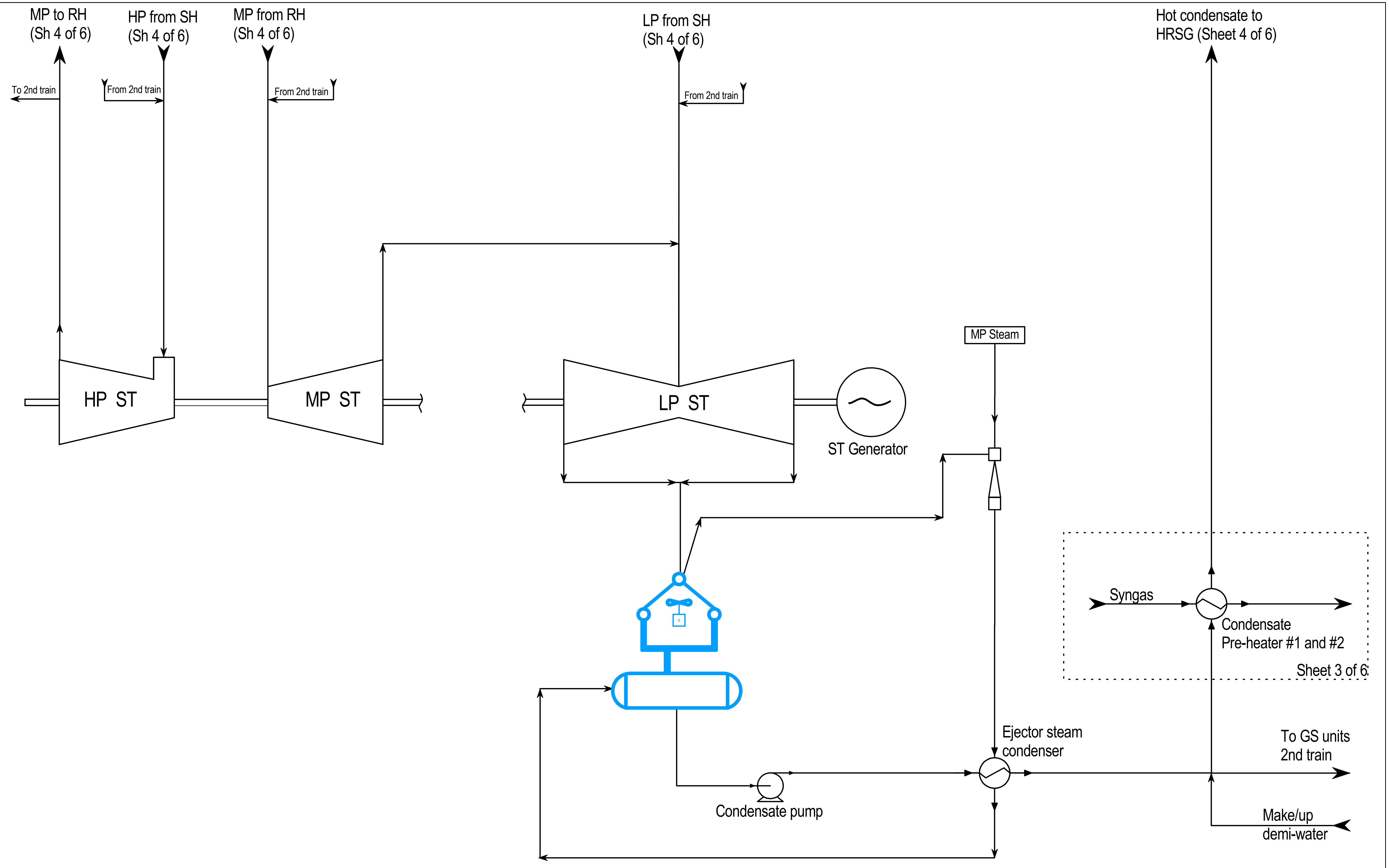


0	July 13		LC	LM	**UNIT:** GS3: Syngas treatment	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2-air cooling	Sheet 02 of 06

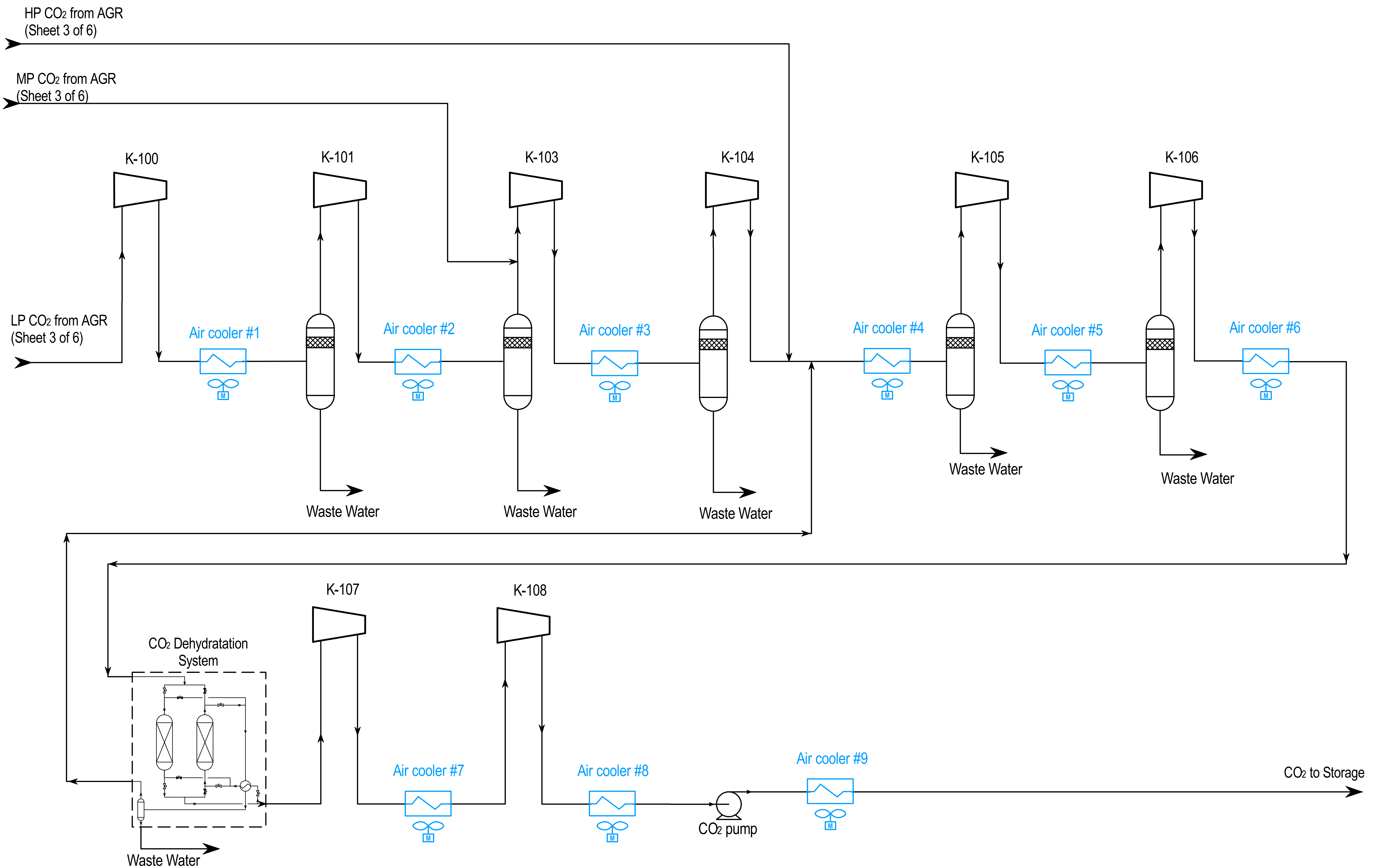

Stripped Condensate to accumulator (Sheet 2 of 6)
HP CO2 to compression (Sheet 6 of 6)
MP CO2 to compression (Sheet 6 of 6)
LP CO2 to compression (Sheet 6 of 6)
LP O2 from ASU (Sheet 1 of 6)
Sour Gas
SWS feed heater
Acid Gas Removal Unit
Acid Gas
Sulphur Recovery Unit
Recycle tail gas
Sour Water Stripper (SWS)
LP Steam
LP Cond
Sulphur product
Hg Removal Unit
SWS Bottom pump
MP BFW from CC (Sheet 4 of 6)
Circulating Water to Saturator Circulating Water Heater
LP Steam
Final Syngas Heater
Syngas to GT (Sheet 4 of 6)
Cold condensate from CC (Sheet 5 of 6)
Syngas Circulating Water Exchanger
Sep #5
Cold Circulating Water from Saturator
LP condensate
Condensate Pre-heater #1 and #2
Sheet 2 of 6
Syngas expander
Sep #4
MP water to CC (Sheet 4 of 6)
Syngas from Sep #2 (Sheet 2 of 6)
Hot Condensate to CC (Sheet 5 of 6)
Nitrogen for syngas dilution (sheet 1 of 6)
Process Condensate to Condensate Accumulator (Sheet 2 of 6)
0 | July 13 | LC | LM | UNIT: GS3: Syngas cond., AGR and SRU
Rev. | Date | Comment | By | Appr | CASE: 4.2-air cooling | Sheet 03 of 06



0	July 13		LC	LM	UNIT: CC1 - CC2: Gas Turbines and HRSG	
Rev.	Date	Comment	By	Appr	CASE: 4.2 air cooling	Sheet 04 of 06



0	July 13		LC	LM	**UNIT:** CC3: Steam Turbine and Condenser	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2 air cooling	Sheet 05 of 06



0	July 13		LC	LM	**UNIT:** CO2 compression	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2 air cooling	Sheet 06 of 06

4. Utility consumption

Main utility consumption of the process and utility units is reported in the following tables, including data of the reference case. More specifically:

- Water consumption summary is reported in Table 1 and Table 2, respectively for the seawater cooling and air cooling systems (reference case consumptions shown in brackets).
- Electrical consumption summary is shown in Table 3 for both the seawater cooling and the air cooling systems.
- The cooling system does not have any impact on the steam / BFW / condensate streams within the process unit and the combined cycle, so reference can be made to chapter E.2, section 5.

With respect to the reference case, the following considerations can be made:

- For both the alternative systems, raw water requirement is significantly lower than the reference case, mainly because there is no cooling tower make-up.
- The overall electrical consumption of the seawater system is slightly lower than the reference case with cooling tower. This is related to the reduced compressor consumption in the Air Separation Unit and in the CO_2 compression unit because of the increased cooling capacity. The cooling water system shows almost the same consumption as the higher cooling water flowrate, due to the lower ΔT allowed for the seawater, is compensated by the lower cooling water pump head required for pumping the cooling water to the users.
- The overall electrical consumption of the air cooling system is slightly lower than the reference case with cooling tower. The lower compressor consumption of both the Air Separation Unit and the CO_2 compression unit, coupled with absence of cooling water pumps, with the exception of those of the closed circuit, partially offsets the additional consumptions of the air coolers fans, mainly the air condenser in the steam cycle.

Table 1. Case 4 (Seawater Cooling) – Water consumption summary

FOSTER WHEELER	CLIENT: IEAGHG PROJECT: CO2 capture at coal based power and H2 plants LOCATION: The Netherlands FWI Nº: 1-BD-0681 A			Revision: 0 Date: June 2013 ISSUED BY: NF CHECKED BY: LM APPR. BY: LM	
	CASE 4.2 (SW) - WATER CONSUMPTION SUMMARY				
UNIT	**DESCRIPTION UNIT**	**Raw Water** [t/h]	**Demi Water** [t/h]	**Sea Cooling Water DT = 7°C** [t/h]	**Machinery CW DT = 11°C** [t/h]
	AIR SEPARATION UNIT (ASU)				
2100	**Air Separation Unit**			**18390**	
	GASIFICATION SECTION (GS)				
1000	**Gasification**	**145**			**3870**
2200	**Syngas treatment and conditioning line**				**350**
2300	**Acid Gas Removal**		**0.6**		**6870**
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**				**160**
	CO_2 COMPRESSION				
2500	**CO_2 Compression**			**9010**	
	COMBINED CYCLE (CC)				
3100	**Gas Turbines and Generator auxiliaries**			**89440**	**780**
3200	**Heat Recovery Steam Generator**				
3300	**Steam Turbine and Generator auxiliaries**		**313.3**		**2090**
	Miscellanea				
	UTILITY UNITS (UU)				
4000	**Cooling Water System**			**18325**	
4000	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**470**	**-314**		
4000	**Waste Water Treatment**	**-92**			
4000	**Balance of Plant (BOP)**				**410**
	TOTAL CONSUMPTION	**524** ***(2122)***	**0**	**135165** ***(55510)***	**14530** ***(31700)***

Note: Negative figures represent generation

Table 2. Case 4 (Air Cooling) – Water consumption summary

CLIENT:	IEAGHG	Revision	0
PROJECT:	CO2 capture at coal based power and H2 plants	Date	June 2013
LOCATION:	The Netherlands	ISSUED BY	NF
FWI Nº:	1-BD-0681 A	CHECKED BY	LM
		APPR. BY	LM

CASE 4.2 (AC) - WATER CONSUMPTION SUMMARY

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Machinery CW DT = 8°C [t/h]	Primary cooling medium [t/h]
					NO PRIMARY COOLING WATER IS AVAILABLE. AIR IS USED AS PRIMARY COOLING MEDIUM
	AIR SEPARATION UNIT (ASU)				
2100	**Air Separation Unit**				
	GASIFICATION SECTION (GS)				
1000	**Gasification**	**145**		**5310**	
2200	**Syngas treatment and conditioning line**				
2300	**Acid Gas Removal**		**0.6**		
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**				
	CO_2 COMPRESSION				
2500	**CO_2 Compression**				
	COMBINED CYCLE (CC)				
3100	**Gas Turbines and Generator auxiliaries**			**1080**	
3200	**Heat Recovery Steam Generator**				
3300	**Steam Turbine and Generator auxiliaries**		**313.3**		
	Miscellanea				
	UTILITY UNITS (UU)				
4000	**Cooling Water System**				
4000	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**470**	**-314**		
4000	**Waste Water Treatment**	**-92**			
4000	**Balance of Plant (BOP)**			**600**	
	TOTAL CONSUMPTION	**524** *(2122)*	**0**	**9750** *(31700)*	**0** *(55,510)*

Note: Negative figures represent generation

Table 3. Case 4 (Cooling medium sensitivity) – Electrical consumption summary

CLIENT:	IEAGHG			Rev.0
PROJECT:	CO2 capture at coal based power and hydrogen plants			Date: June 2013
LOCATION:	The Netherlands			ISSUED BY: NF
FWI Nº:	1-BD-0681 A			CHECKED BY: LM
				APPR. BY: LM

Case 4.2 - Cooling system sensitivity - ELECTRICAL CONSUMPTION SUMMARY

UNIT	DESCRIPTION UNIT	Absorbed Electric Power		
		CASE 4.2 (Cooling tower) [kW]	CASE 4.2 (Sea Water) [kW]	CASE 4.2 (Dry air) [kW]
	AIR SEPARATION UNIT (ASU)			
2100	**MAC consumptions**	**124220**	**122000**	**122770**
	BAC consumptions	**12270**	**11970**	**12050**
	Nitrogen compressor and miscellanea	**35530**	**34940**	**35030**
	GASIFICATION SECTION (GS)			
900	**Coal Receiving Handling and Storage**	**410**	**410**	**410**
1000	**Gasification**	**8790**	**8790**	**8790**
2200	**Syngas treatment and conditioning line**	**1250**	**1250**	**1340**
2300	**Acid Gas Removal**	**20850**	**20850**	**21290**
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**	**700**	**700**	**720**
2500	**CO_2 Compression**	**33970**	**32890**	**33890**
	COMBINED CYCLE (CC)			
3100	**Gas Turbines auxiliaries**	**2000**	**2000**	**2000**
3200	**Heat Recovery Steam Generator**	**7530**	**7530**	**7530**
3300	**Steam Turbine auxiliaries and excitation system**	**850**	**850**	**850**
3300	**Miscellanea**	**-**	**-**	**4875**
3300	**Miscellanea**	**3120**	**3080**	**3020**
	UTILITY UNITS (UU)			
4000	**Cooling Water System**	**10490**	**10200**	**3180**
4000	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**730**	**730**	**730**
4000	**Balance of Plant (BOP)**	**1090**	**1090**	**1090**
	TOTAL CONSUMPTION	**263800**	**259280**	**259565**

5. Overall performance

The following table shows the overall performance of the plant with the three different cooling systems assessed in the study.

CLIENT:	IEAGHG	REVISION	0
PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	DATE	July 2013
PROJECT No. :	1-BD-0681 A	MADE BY	NF
LOCATION :	The Netherlands	APPROVED BY	LM

Case 4.2 - IGCC Plant Performance Summary

OVERALL PERFORMANCES		CASE 4.2 (Cooling tower)	CASE 4.2 (Sea Water)	CASE 4.2 (Dry air)
Coal Flowrate (as received)	t/h	349.1	349.1	349.1
Coal LHV (as received)	kJ/kg	25870	25870	25870
Coal HHV (as received)	kJ/kg	27060	27060	27060
THERMAL ENERGY OF FEEDSTOCK (A)	**MWth (LHV)**	**2509**	**2509**	**2509**
THERMAL ENERGY OF FEEDSTOCK (A')	**MWth (HHV)**	**2624**	**2624**	**2624**
Thermal Power of Raw Syngas exit Scrubber (D)	MWth (LHV)	1785	1785	1785
Thermal power of syngas to AGR	MWth (LHV)	1638	1638	1638
Thermal Power of Clean Syngas to Gas Turbines (E)	MWth (LHV)	1600	1600	1600
Syngas treatment efficiency (E/D x 100)	% (LHV)	89.6	89.6	89.6
Gas turbines total electric power output	MWe	688.0	688.0	688.0
Steam turbine electric power output	MWe	443.8	452.6	435.0
Syngas expader	MWe	9.0	9.0	9.0
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (C)	**MWe**	**1141**	**1150**	**1132**
Gasification Section units consumption	MWe	32.0	32.0	32.6
ASU consumption	MWe	172.0	168.9	169.9
Combined Cycle units consumption	MWe	13.5	13.5	18.3
CO_2 Compression and Dehydration unit consumption	MWe	34.0	32.9	33.9
Utility Units consumption	MWe	12.3	12.0	5.0
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**264**	**259**	**260**
NET ELECTRIC POWER OUTPUT OF IGCC	**MWe**	**877.0**	**890.3**	**872.4**
(Step Up transformer efficiency = 0.997%) (B)	**MWe**	**874.3**	**887.6**	**869.8**
Gross electrical efficiency (C/A x 100)	% (LHV)	45.5	45.8	45.1
Net electrical efficiency (B/A x 100)	**% (LHV)**	**34.9**	**35.4**	**34.7**
Gross electrical efficiency (C/A' x 100)	% (HHV)	43.5	43.8	43.1
Net electrical efficiency (B/A' x 100)	**% (HHV)**	**33.3**	**33.8**	**33.1**
Fuel Consumption per net power production	**MWth/MWe**	**2.87**	**2.83**	**2.88**
CO_2 emission per net power production	**kg/MWh**	**93.7**	**87.0**	**89.1**

By comparing the results of the reference case with those of the alternative cooling system type, the following consideration can be made:

- *Sea water system*: Net electrical efficiency increases of about 0.5 percentage points, due to the higher gross power production, related to the lower condensation pressure, and to the lower plant auxiliary power demand.
- *Air cooling system*. Net electrical efficiency decreases of about 0.2, as the lower power consumption partly compensate the lower gross power production, related to the higher condensation pressure

The overall CO_2 balance and removal efficiency is unchanged with respect to Case 4.2, as shown in the following.

CO_2 removal efficiency	**Equivalent flow of CO_2** kmol/h
INPUT	
Fuel Mix (Carbon AR)	18730
TOTAL (A)	18730
OUTPUT	
Slag + Waste water (B)	101
CO_2 product pipeline	
CO	7
CO_2	16759
CH_4	0
COS	0
Total to storage (C)	16766
Emission	
CO_2 + CO (Combined Cycle)	1862
TOTAL	18730
Overall Carbon Capture, % ((B+C)/A)	90.1

6. Environmental impact

Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

6.1. Gaseous emissions

As for the reference case, main continuous emissions during normal operation are the combustion flue gases of the two trains of the combined cycle, from the combustion of the syngas in the two gas turbines. No difference is expected in the flowrate and composition of this stream. The same minor and fugitive emissions, related to leakages within the handling of solid materials, are valid for these alternative systems.

6.2. Liquid effluents

As per the reference case, plant liquid effluents mainly consist of the discharge from the Waste Water Treatment, which flows to an outside plant battery limits recipient.

Waste Water Treatment blow-down

Flowrate : 160 m^3/h

6.2.1. *Seawater system*

For the seawater case, seawater is returned to the sea basin after exchanging heat in the plant, with a maximum temperature increase of 7°C. The main characteristics of the discharged seawater are listed below:

Maximum flow rate :	135,000	m^3/h
Temperature:	19	°C

6.3. Solid effluents

No difference is expected in the production of solid by-products with respect to the reference case.

7. Main equipment design changes

The following equipment summary tables show the major impact on equipment design for the alternative cooling system types.

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 4.2 - GE based IGCC - Cooling water sensitivity (SW)	REVISION	Rev 0	Rev.1	Rev.2	Rev.3
		DATE	May 2013			
		ISSUED BY	NF			
		CHECKED BY	LM			
		APPROVED BY	LM			

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	Remarks	Difference with respect to reference case
	UNIT 2100 - AIR SEPARATION UNIT (2 x 50%)					
	Main Air compressors (MAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 2 x 297,800 Nm3/h	2 x 34750 kW	*Intercooling:* *Sea Water ~~Cooling Water~~*	**Size changed** **Intercooling medium changed (*)**
	Booster air compressors (BAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 238200 Nm3/h	7500 kW	*Intercooling:* *Sea Water ~~Cooling Water~~*	**Intercooling medium changed (*)**
	MP N2 compressors (GAN)	Electric motor driven, centrifugal, with intercooling	Flowrate: 2 x 128,500 Nm3/h	2 x 9500 kW	*Intercooling:* *Sea Water ~~Cooling Water~~*	**Intercooling medium changed (*)**
	UNIT 2500 - CO2 COMPRESSION (2 x 50%)					
C-2501	CO_2 Compressors	Centrifugal, Electrical Driven, 8 intercooled Stages	190000 Nm3/h p in: 2,45 bar a p out: 80 bar a	17000 kW	*Intercooling:* *Sea Water ~~Cooling Water~~*	**Size changed** **Intercooling medium changed (*)**
	UNIT 3300 - STEAM TURBINE					
Z-3301	**Steam Turbine & Condenser Package**					
ST-3301	Steam Turbine		455 MWe			**Size changed**
~~E-3303~~	~~Steam Condenser~~		~~710 MWth~~		~~Water cooled~~	**To be deleted (*)**
E-3303	Steam Condenser		730 MWth		Sea Water cooled Inlet water temperature 12°C Water temperature rise 7°C	**To be added (*)**
G-3402	Steam Turbine Generator		600 MVA			**Size changed**
	COOLING SYSTEM					
E-4001	Closed cooling loop exchanger		145 MWth			**To be added**
P-4001A/B/C/D	Sea Cooling Water pumps (primary system)	Vertical	18000 m3/h x 20 m	1250 kW	*Eight in operation*	**To be added (*)**
P-4002A/B/C	Cooling Water pumps (secondary system)	Vertical	14000 m3/h x 35 m	1600 kW		**Size changed**
~~CT-4001~~	~~Cooling Tower~~ ~~Including Cooling water basin~~	~~Evaporative,~~ ~~Natural draft~~	~~Total heat duty~~ ~~1070 MWth~~ ~~Diameter: 150 m,~~ ~~Height: 210 m,~~ ~~Water inlet: 17 m~~			**To be deleted**
~~P-4001A/B/C/D~~	~~Cooling Water pumps (primary system)~~	~~Vertical~~	~~13880 m3/h x 35 m~~	~~1600 kW~~		**To be deleted (*)**
~~P-4003A/B~~	~~Raw water pumps (make-up)~~	~~centrifugal~~	~~1690 m3/h x 35 m~~	~~200 kW~~		**To be deleted**
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 8500 m3/h~~			**To be deleted**
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					

(*) Different material selection (titanium) is considered for the exchangers and pumps design (e.g. steam condenser, cooling water pumps, compressors intercoolers) to address corrosion issues related to the use of SW as cooling medium.

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 4.2 - GE based IGCC - Cooling water sensitivity (AC)		

REVISION	Rev 0	Rev.1	Rev.2	Rev.3
DATE	May 2013			
ISSUED BY	NF			
CHECKED BY	LM			
APPROVED BY	LM			

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	Remarks	Difference with respect to reference case
	UNIT 2100 - AIR SEPARATION UNIT (2 x 50%)					
	Main Air compressors (MAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 2 x 297,800 Nm3/h	2 x 34750 kW	*Intercooling:* *Air cooling ~~Cooling Water~~*	**Size changed** **Intercooling medium changed**
	Booster air compressors (BAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 238200 Nm3/h	7500 kW	*Intercooling:* *Air cooling ~~Cooling Water~~*	**Intercooling medium changed**
	MP N2 compressors (GAN)	Electric motor driven, centrifugal, with intercooling	Flowrate: 2 x 128,500 Nm3/h	2 x 9500 kW	*Intercooling:* *Air cooling ~~Cooling Water~~*	**Intercooling medium changed**
	UNIT 2200 - SYNGAS TREATMENT (2x50%)					
~~**E-2209**~~	~~Final syngas cooler~~	~~Shell & Tube~~				**To be deleted**
AC-2201	Final syngas cooler	Air cooler	4 MWth	45 kWe	*each train*	**To be added**
	UNIT 2250 - SWS					
	~~Sour water stripper condenser~~	~~Shell & Tube~~				**To be deleted**
AC-2251	Sour water stripper condenser	Air cooler				**To be added**
	UNIT 2300 - AGR					
	Water cooled heat exchangers and refrigerator condenser in AGR will be replaced with air cooling. Total installed rated capcity: 550 MWe					
	UNIT 2500 - CO2 COMPRESSION (2 x 50%)					
C-2501	CO_2 Compressors	Centrifugal, Electrical Driven, 8 intercooled Stages	190000 Nm3/h p in: 2,45 bar a p out: 80 bar a	17000 kW	*Intercooling:* *Air cooling ~~Cooling Water~~*	**Size changed** **Intercooling medium changed**
	UNIT 3300 - STEAM TURBINE					
Z-3301	**Steam Turbine & Condenser Package**					
ST-3301	Steam Turbine		435 MWe			**Size changed**
~~E-3303~~	~~Steam Condenser~~		~~710 MWth~~		~~Water cooled~~	**To be deleted**
AC-3301	Steam Condenser	air cooled	715 MWth	65 x 90 kWe		**To be added**
G-3402	Steam Turbine Generator		570 MVA			**Size changed**

CLIENT:	IEA GHG	REVISION	Rev 0	Rev.1	Rev.2	Rev.3
LOCATION:	The Netherlands	DATE	May 2013			
PROJ. NAME:	CO2 capture at coal based power and hydrogen plants	ISSUED BY	NF			
CONTRACT N.	1-BD-0681 A	CHECKED BY	LM			
CASE:	Case 4.2 - GE based IGCC - Cooling water sensitivity (AC)	APPROVED BY	LM			

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	Remarks	Difference with respect to reference case
	COOLING SYSTEM					
AC-4001	Closed loop air cooler		90 MWth	2500 kWe		**To be added**
P-4002A/B/C	Cooling Water pumps (secondary system)	Vertical	14000 m3/h x 35 m	1600 kW		**Size changed**
~~CT-4001~~	~~Cooling Tower~~ ~~Including Cooling water basin~~	~~Evaporative,~~ ~~Natural draft~~	~~Total heat duty~~ ~~1070 MWth~~ ~~Diameter: 150 m,~~ ~~Height: 210 m,~~ ~~Water inlet: 17 m~~			**To be deleted**
~~P-4001A/B/C/D~~	~~Cooling Water pumps (primary system)~~	~~Vertical~~	~~13880 m3/h x 35 m~~	~~1600 kW~~		**To be deleted**
~~P-4003A/B~~	~~Raw water pumps (make-up)~~	~~centrifugal~~	~~1690 m3/h x 35 m~~	~~200 kW~~		**To be deleted**
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 8500 m3/h~~			
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					**To be deleted**
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					

CLIENT	:	IEAGHG
PROJECT NAME	:	CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
DOCUMENT NAME	:	CASE 4.2.1: IGCC WITH CCS – GE GASIFICATION TECHNOLOGY NEAR-ZERO EMISSION CASE
FWI CONTRACT	:	1-BD-0681 A

ISSUED BY	:	G. PERFUMO
CHECKED BY	:	N. FERRARI
APPROVED BY	:	L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

1. Introduction

This chapter of the report includes all technical information relevant to Case 4.2.1 of the study, which is an IGCC plant based on the GE gasification technology.

Plant configuration is basically same as Case 4.2, though plant of Case 4.2.1 is designed to meet near-zero CO_2 emission target (around 98% carbon capture rate).

The description of the main process units and the reference Case 4.2 performance are covered respectively in chapter E and E.2 of this report; only plant design changes required to meet near-zero emission target are discussed in the following sections, together with the main plant performance results.

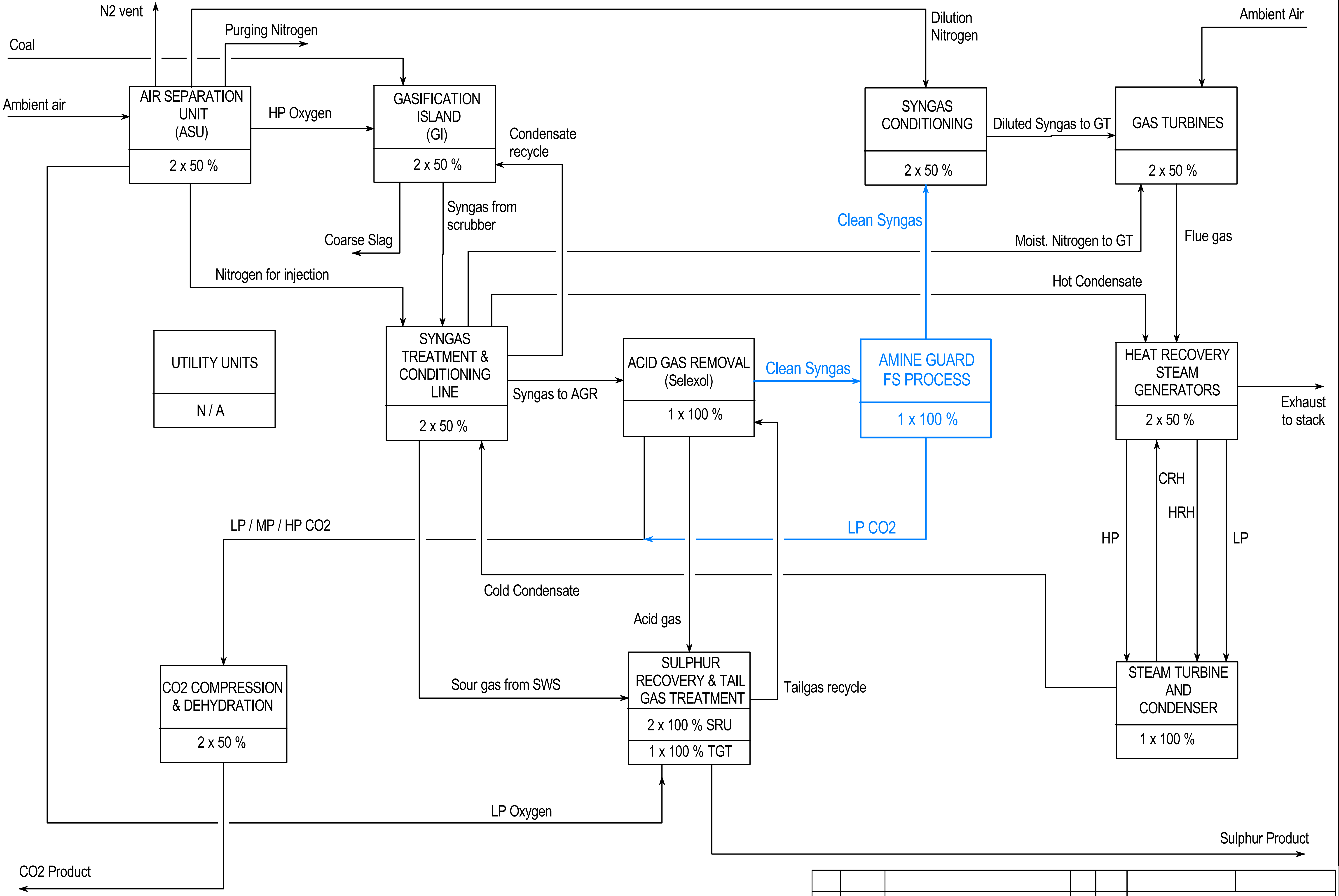
1.1. Process unit arrangement

The arrangement of the main units is reported in Table 1, together with the main differences with respect to the base case, as further discussed in the following sections. Reference is also made to the block flow diagram attached below.

Table 1. Case 4.2.1 – Unit arrangement

Unit	Description	Trains	Differences
900	Coal Handling & Storage	N/A	-
1000	Gasification Coal Grinding & Slurry Preparation Gasification and scrubber Black Water Flash Coarse Slag Handling Grey Water & Fines Handling	2 x 50%	-
2100	Air Separation Unit	2 x 50%	-
2200	Syngas Treatment and Conditioning Line	2 x 50%	Minor design changes: different syngas composition from AGR affects nitrogen saturator and syngas pre-heating line
2250	Sour Water Stripper (SWS)	1 x 100%	-
2300	Acid Gas Removal Selexol Amine Guard FS Process	 1 x 100% 1 x 100%	 Additional unit to meet near-zero emission target
2400	Sulphur Recovery Unit	2 x 100%	-

Unit	Description	Trains	Differences
	Tail Gas Treatment	1 x 100%	
2500	CO_2 Compression & Drying	2 x 50%	Increase design capacity: additional CO_2-rich flow from amine unit
3000	Combined Cycle Gas Turbine HRSG Steam Turbine	 2 x 50% 2 x 50% 1 x 100%	No significant design changes: additional LP steam export to amine unit
4000	Utility and Offsite	N/A	Minor changes in cooling water system capacity



0	July 13		GP	LM	**UNIT:** Block Flow Diagram	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2.1	Sheet 01 of 01

2. Process description

2.1. Overview

The description reported in this section focuses only on those units with a design different from that of the reference case, necessary to meet near-zero carbon emission target. Design changes are also reflected in the simplified Process Flow Diagrams (PFD) shown in section 3.

For all the other units, reference shall be made to the base case description, included in chapter E.2, section 2.

2.2. Unit 2300 – Acid Gas Removal (AGR)

In the reference case, the AGR unit uses the Selexol physical solvent washing for the selective removal of H_2S and CO_2. Reference is made to Section E for the general information about the technology and detailed process description.

For the present near-zero CO_2 emission plant, an additional Amine Guard FS Process is included, processing the pre-treated (de-sulphurised and de-carbonized) syngas from the Selexol unit, in order to meet the desired overall 98% CO_2 removal efficiency.

2.2.1. Amine Guard FS Process

The following process description makes reference to the simplified process flow diagram shown in Figure 1.

Treated gas from AGR enters the unit battery limits, is routed to the bottom of the CO_2 Absorber and flows upward through packed beds where it contacts cooled lean solvent entering at the top of the tower via the Lean Solution Pump. The contact between the gas phase and liquid phase is enhanced as they pass through the packed beds, where CO_2 is transferred from the gas phase to the liquid phase. The treated gas then passes through de-entrainment devices at the top of the towers, exits the top of the CO_2 Absorber and finally reaches the Amine Guard FS unit battery limits.

The rich solvent from the CO_2 Absorber is sent to the Lean/Rich in order to increase its temperature by heat exchange with the hot lean solvent from the Regenerator. The hot lean (regenerated) solvent is cooled in the Lean/Rich Exchanger before flowing to the Lean Solution Cooler. By cross-exchanging these streams, the Lean/Rich Exchanger significantly reduces the duties of the Lean Solvent Cooler and the Regenerator Reboiler. The heated solvent stream is sent to the Regenerator for complete thermal regeneration.

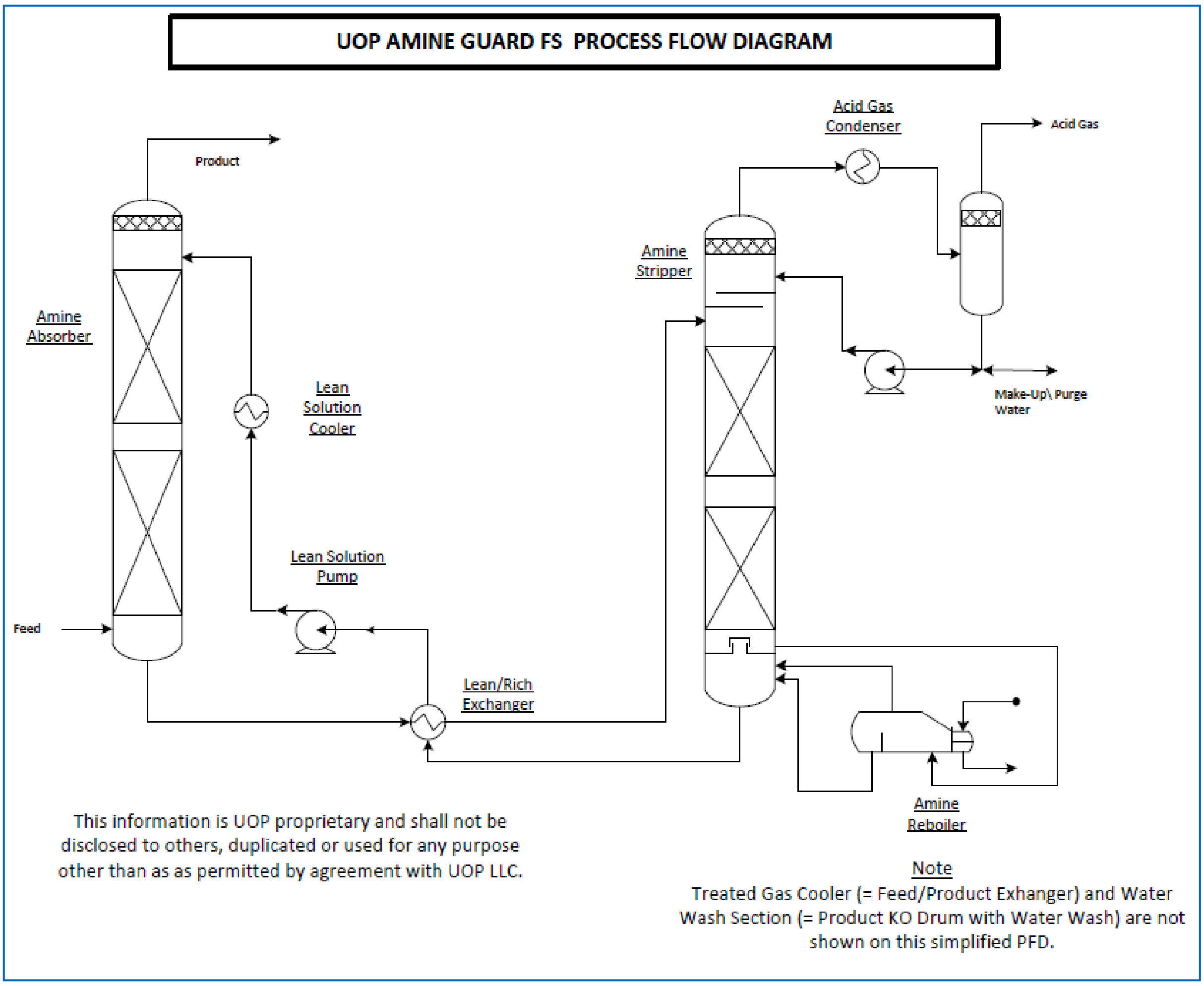


Figure 1. Amine guard unit simplified process scheme

Solvent regeneration is accomplished in the Regenerator, where the remaining CO_2 is transferred from the liquid phase to the gas phase by contact with the steam generated in the Regenerator Reboiler. The Regenerator is composed of a lower section containing packed beds and an upper section containing several reflux trays, in order to contact the overhead vapour with the reflux water.

The rich solvent enters the Regenerator above the upper packed bed. After flashing, the solvent passes through a liquid distributor, and then flows down the packed bed in the stripping section releasing CO_2 after contact with the steam generated in the Regenerator Reboiler.

The steam and liberated gases exit the upper section of the Regenerator, and then flow upward to the trayed section of the column. The gas first passes through a demister and then into the trayed section, where the rising gas is contacted with counter-current flowing reflux water to cool and condense the hot overhead vapour and reduce solvent entrainment. The overhead stream passes through a de-entrainment device and exits the top of the column. The overhead gas then passes through the Reflux Condenser in order to recover the overhead steam. The liquid and vapour phases are separated in the Reflux Drum. The liquid is returned to the trayed section of the Regenerator via the Reflux Pump. The Acid Gas CO_2 rich stream (97.33% mol of $CO_{2)}$ is then sent to the CO_2 compression and drying unit, outside the battery limits, where it will be mixed to the LP CO_2 stream coming from AGR unit.

2.3. Unit 2500 – CO_2 compression and drying

As for the reference case, the unit is mainly composed of two eight inter-cooled compressors and dehydration packages, supplied by specialized Vendors. With respect to the reference case, the additional CO_2-rich stream at low pressure exiting the Amine Guard FS Process is mixed with the LP CO_2 stream coming from the Selexol unit, before being sent to the first compression stage.

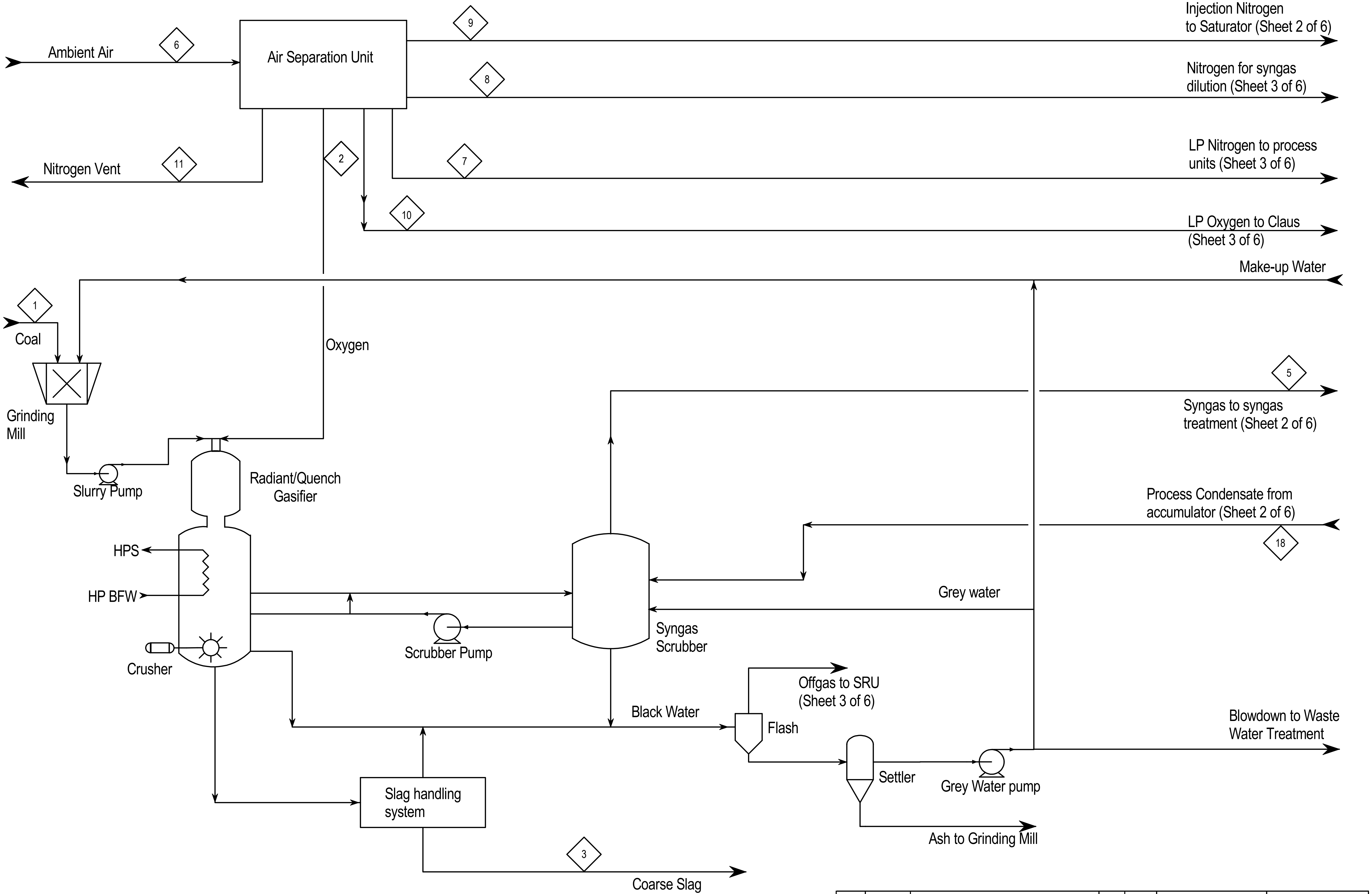
Following Table 2 summarises key stream data of this case, while main interconnections with the other units are shown in the process flow diagram.

Table 2. Case 4.2.1 – Key stream data

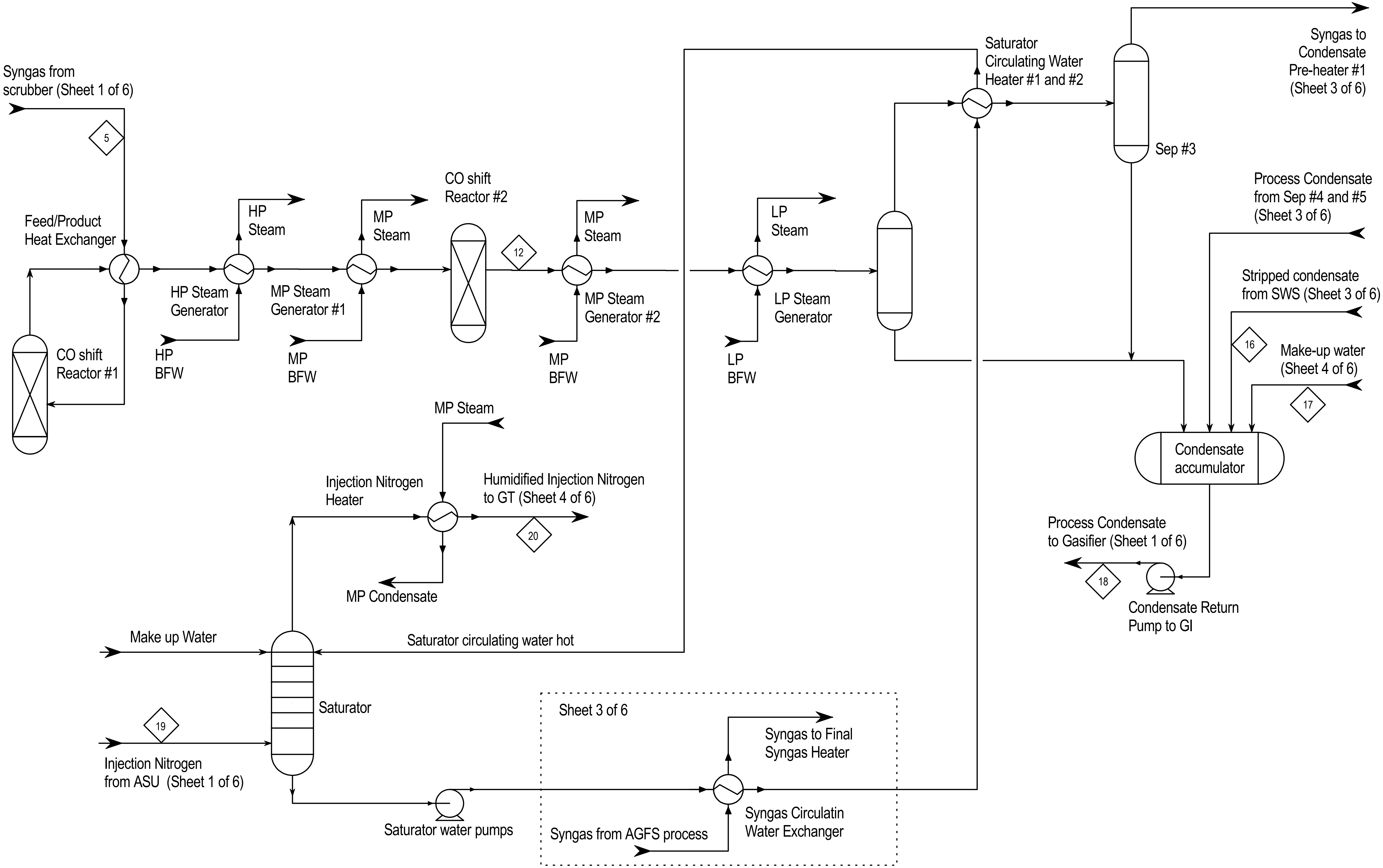
Stream	Flue gas to AGR	Flue gas to AGFS	Treated gas	Acid gas – CO_2 rich from AGFS
Mass flowrate, kg/h	891,980	148,230	82,372	66,769
Molar flowrate, kmol/h	43,506	26,248	24,753	1,543
Composition (% vol)				
CO	0.61	0.98	1.04	-
N_2	2.27	3.73	3.95	0.01
H_2	54.73	89.55	94.94	0.38
CO_2	41.98	5.73	0.01	97.33
H_2O	0.14	0.01	0.06	2.27
H_2S	0.26	0	0	-

3. Process Flow Diagrams

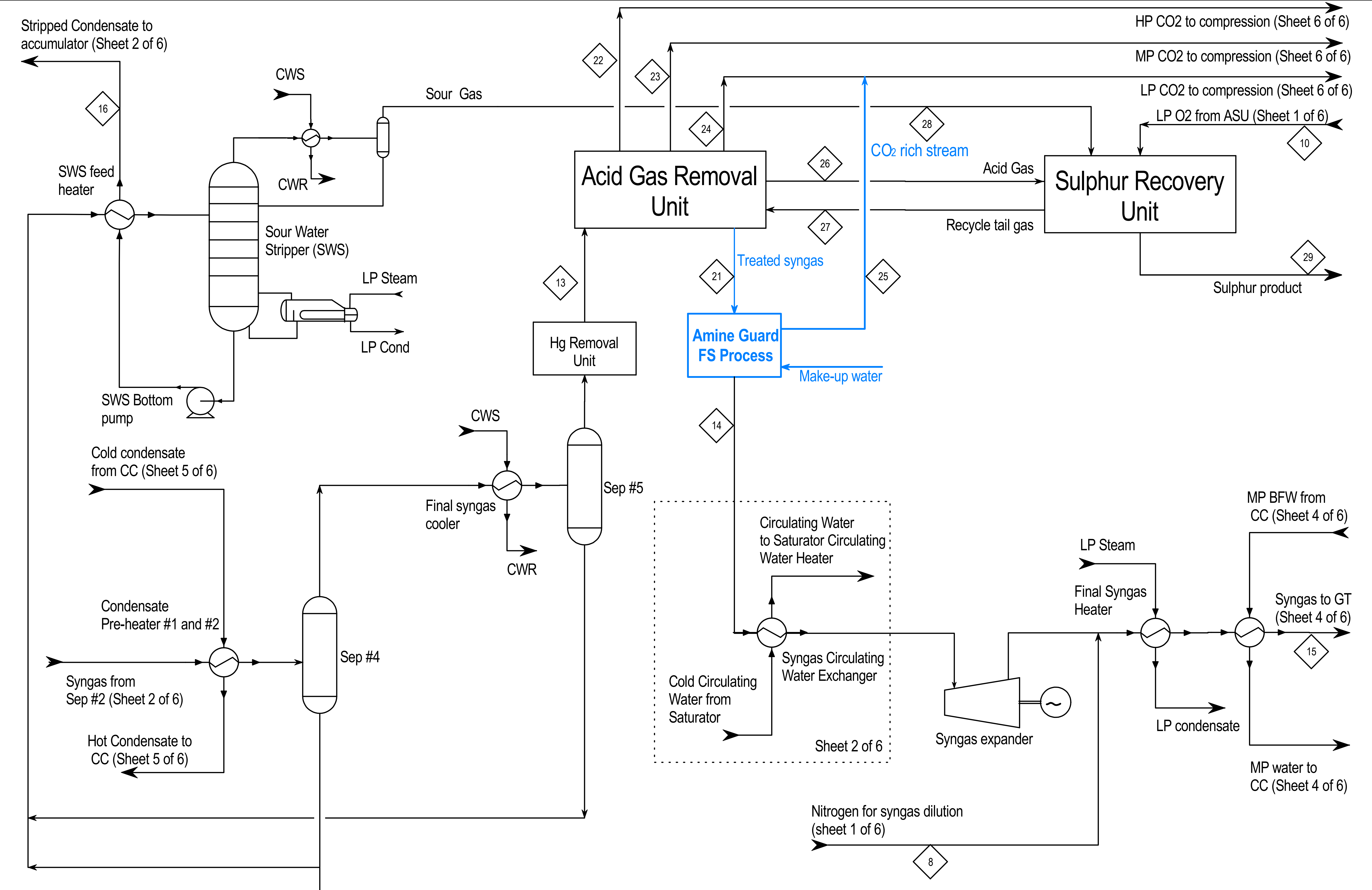
Simplified Process Flow Diagrams of this case are attached to this section. Stream numbers refer to the heat and material balance shown in the next section.



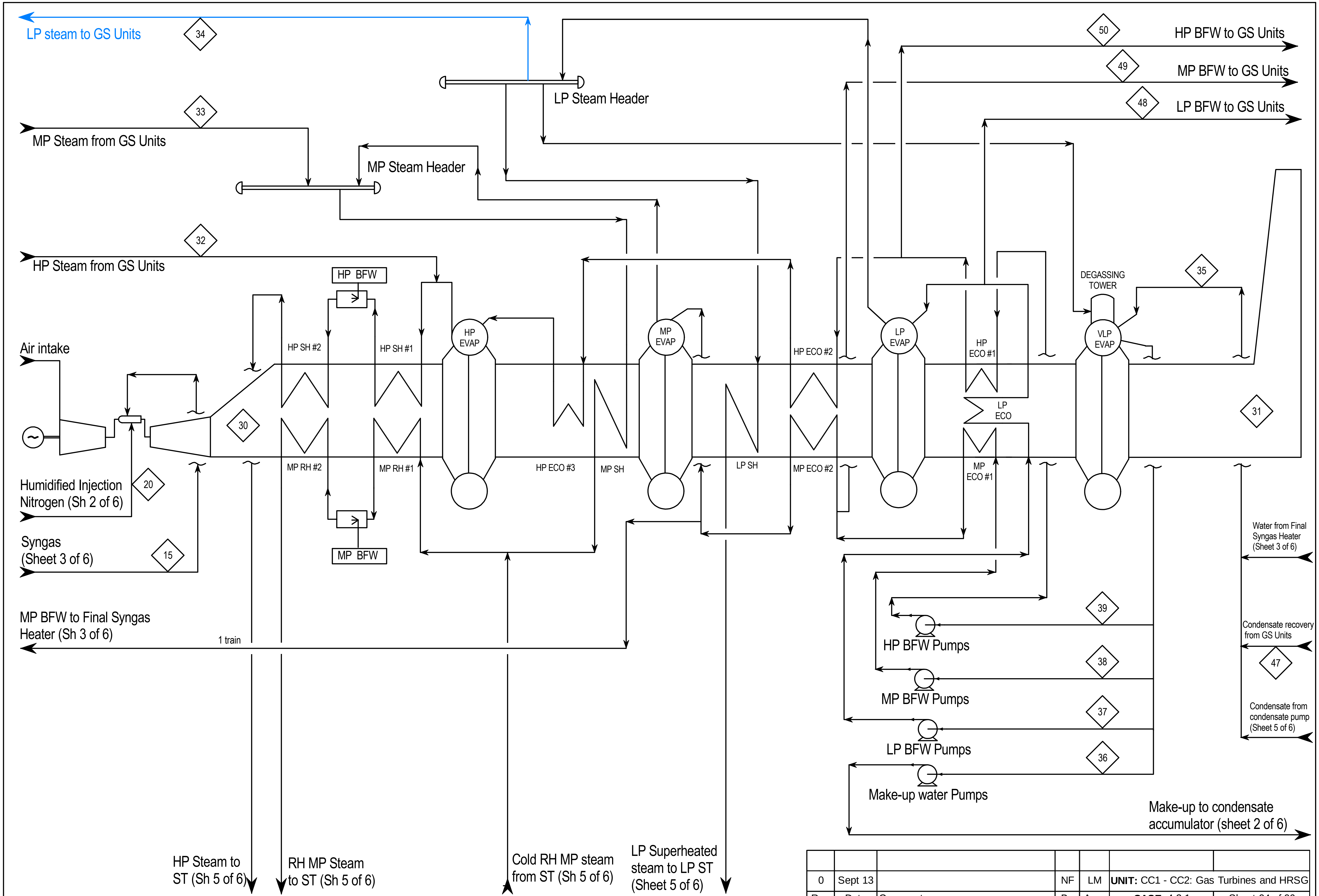
0	Sept 13		NF	LM	**UNIT:** GS2 - AS1: Gasification and ASU	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2.1	Sheet 01 of 06



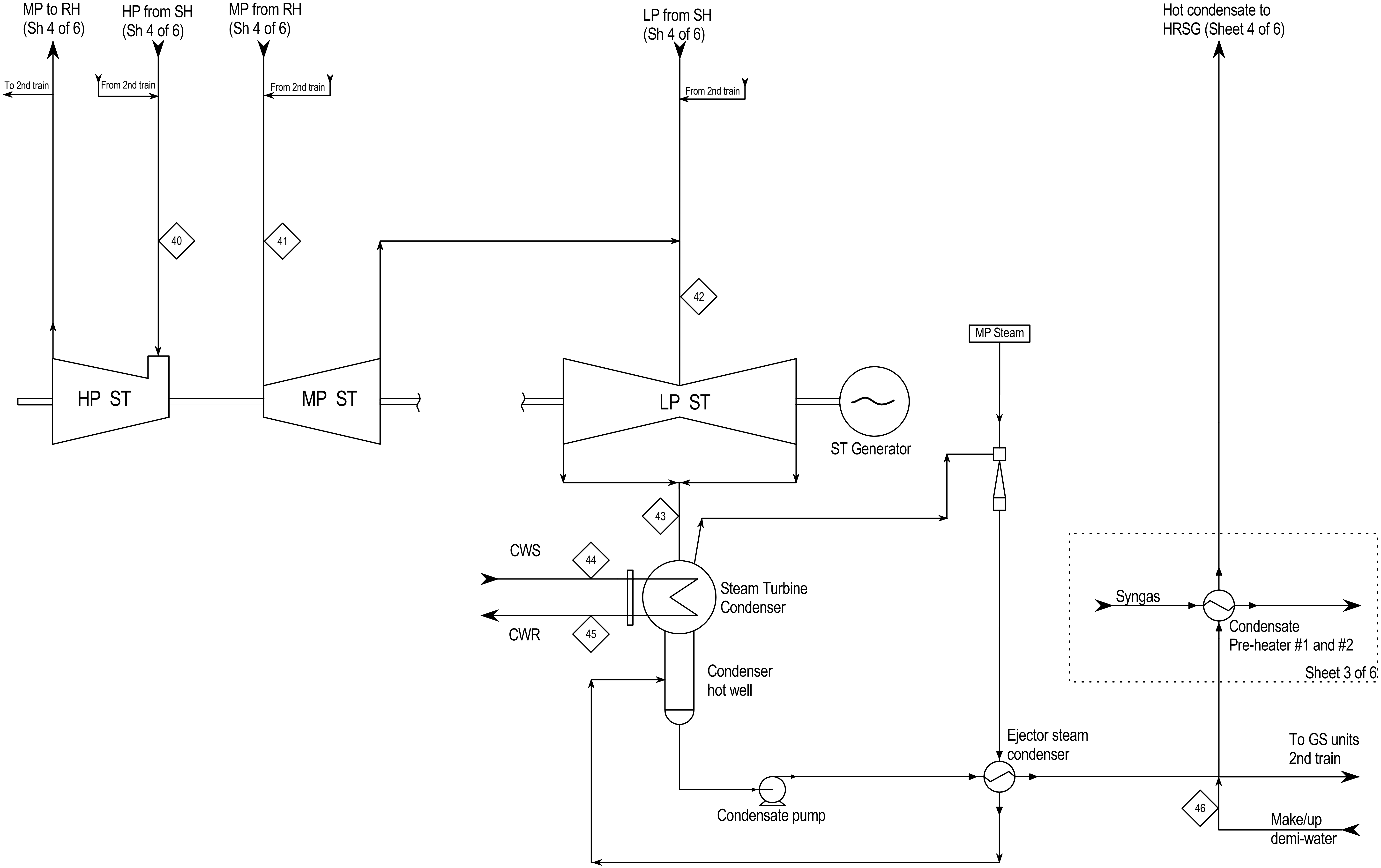
0	Sept 13		NF	LM	**UNIT:** GS3: Syngas treatment	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2.1	Sheet 02 of 06



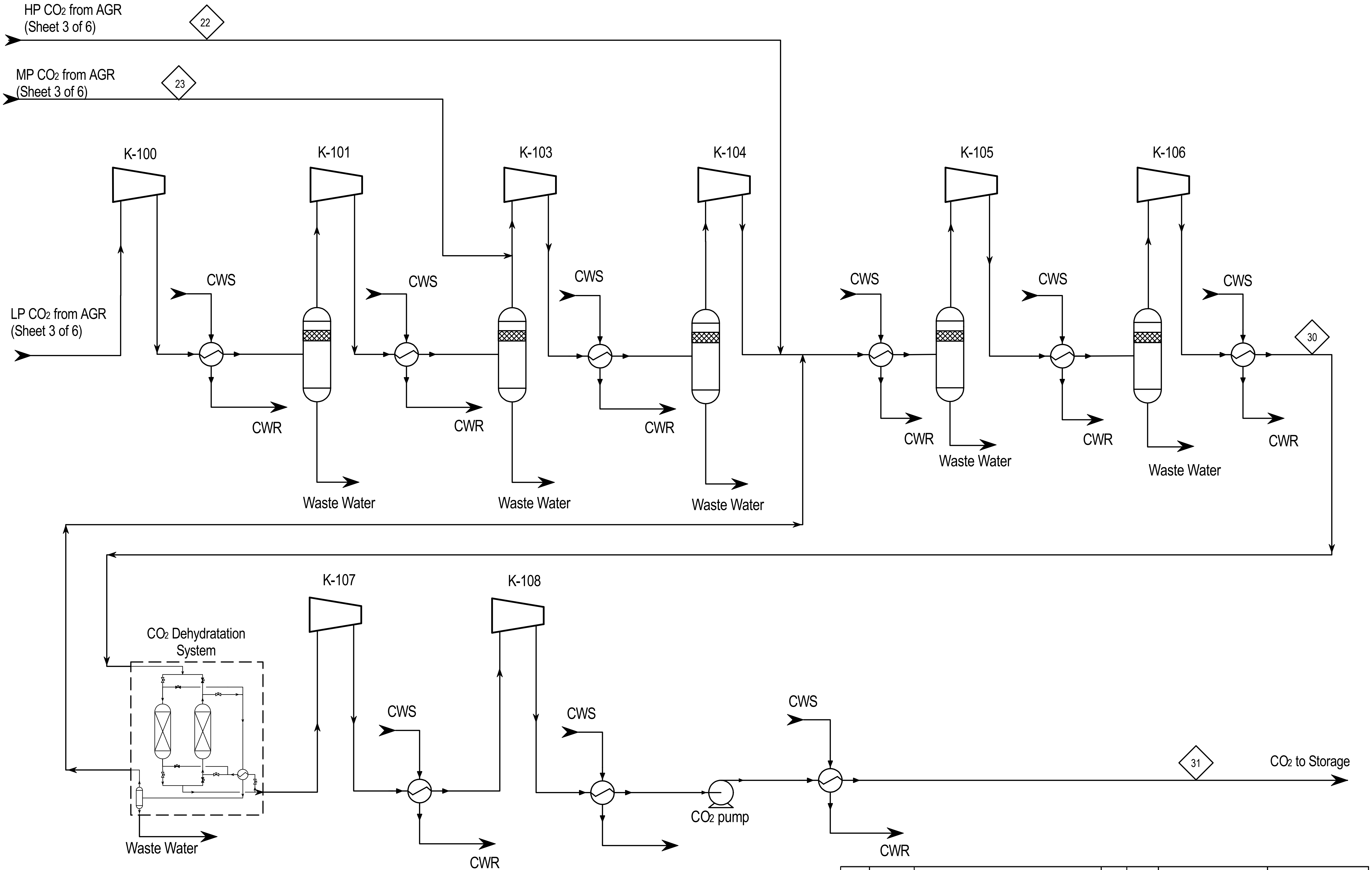
0	Sept 13		NF	LM	**UNIT:** GS3: Syngas cond., AGR and SRU	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2.1	Sheet 03 of 06



0	Sept 13		NF	LM	**UNIT:** CC1 - CC2: Gas Turbines and HRSG	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2.1	Sheet 04 of 06



0	Sept 13		NF	LM	**UNIT:** CC3: Steam Turbine and Condenser	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2.1	Sheet 05 of 06



0	Sept 13		NF	LM	**UNIT:** CO2 compression	
Rev.	Date	Comment	By	Appr	**CASE:** 4.2.1	Sheet 06 of 06

4. Heat and Material Balance

Heat & Material Balances reported make reference to the simplified Process Flow Diagrams reported in section 3.

	Case 4.2.1 - GE-BASED IGCC - NEAR ZERO EMISSION CASE - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
	CLIENT :	IEAGHG	PREP.	NF		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	LM		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	September 2013		

HEAT AND MATERIAL BALANCE
UNIT 1000 - Gasification Island

STREAM	1	2	3	4	5	18				
	Coal to Gasification Island	HP Oxygen to Gasification	Slag from Gasification	Effluent Water from Gasification	Syngas at Scrubber Outlet to Shift Reactor	Return condensate to gasification				
Temperature (°C)	AMB	10	80	AMB	N/D	144				
Pressure (bar)	ATM	75-80 (1)	ATM	ATM	64.6	70				
TOTAL FLOW	Solid		Solid + water							
Mass flow (kg/h)	349,200	323,000	87,420	94,520	1,154,260	493,640				
Molar flow (kmol/h)		10,025		5,251	58,017	27,400				
LIQUID PHASE										
Mass flow (kg/h)			43,710	94,520	-	493,640				
GASEOUS PHASE										
Mass flow (kg/h)		323,000			1,154,260					
Molar flow (kmol/h)		10,025			58,017					
Molecular Weight		32.22			-					
Composition (vol %)	%wt		50% moisture		dry basis					
H_2	C: 64.6%	-			35.80					
CO	H: 4.38%	-			42.80					
CO_2	O: 7.02%	-			17.80					
N_2	S: 0.86%	1.50			3.22					
O_2	N: 1.41%	95.00			0.00					
CH_4	Cl: 0.03%	-			0.00					
H_2S + COS	Moisture: 9.5%	-			0.38					
Ar	Ash: 12.20%	3.50			0.00					
HCN		-			0.00					
NH_3		-			0.00					
H_2O		-			-					

Notes 1. FW assumption

	Case 4.2.1 - GE-BASED IGCC - NEAR ZERO EMISSION CASE - HEAT AND MATERIAL BALANCE		**REVISION**	0	1	2
	CLIENT :	IEAGHG	**PREP.**	NF		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**CHECKED**	LM		
	PROJECT NO:	1-BD-0681 A	**APPROVED**	LM		
	LOCATION:	The Netherlands	**DATE**	September 2013		

HEAT AND MATERIAL BALANCE

UNIT 2100 - Air Separation Unit

STREAM	**6**	**2**	**7**	**8**	**9**	**10**	**11**			
	Air Intake from Atmosphere	**HP Oxygen to Gasification**	**LP Nitrogen to process unit**	**MP Nitrogen forSyngas Dilution**	**MP Nitrogen for NOx Control**	**Oxygen to SRU**	**Nitrogen vent**			
Temperature (°C)	Ambient	10	Ambient (°)	135	122	Ambient	Ambient			
Pressure (bar)	Ambient	75-80 (°)	7,5 (°)	32	28	6	Atmospheric			
TOTAL FLOW										
Mass flow (kg/h)	1,394,750	323,000	25,220	319,040	306,820	1,934	404,700			
Molar flow (kmol/h)	48,320	10,025	900	11,383	10,947	60	14,439			
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-		-	-			
GASEOUS PHASE										
Mass flow (kg/h)	1,394,750	323,000	25,220	319,040	306,820	1,934	404,700			
Molar flow (kmol/h)	48,320	10,025	900	11,383	10,947	60	14,439			
Molecular Weight	28.86	32.22	28.02	28.03	28.03	32.22	28.03			
Composition (vol %)										
H_2	-	-	-	-	-	-	-			
CO	-	-	-	-	-	-	-			
CO_2	0.04	-	-	0.05	0.05	-	0.05			
N_2	77.32	1.50	99.999	98.00	98.00	1.50	98.00			
O_2	20.75	95.00	0.001	1.00	1.00	95.00	1.00			
CH_4	-	-	-	-	-	-	-			
H_2S + COS	-	-	-	-	-	-	-			
Ar	0.92	3.50	-	0.25	0.25	3.50	0.25			
H_2O	0.97	-	-	0.70	0.70	-	0.70			

Notes 1. FW assumption

FOSTER WHEELER	Case 4.2.1 - GE-BASED IGCC - NEAR ZERO EMISSION CASE - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
	CLIENT :	IEAGHG	PREP.	NF		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	LM		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	September 2013		

HEAT AND MATERIAL BALANCE
UNIT 2200 - Syngas cooling & Conditioning line

STREAM	5	12	13	14	15	16	17	18	19	20
	Syngas at Scrubber Outlet to Shift Reactor	Syngas at Shift Reactor Outlet	Raw Syngas to Acid Gas Removal	HP Purified Syngas from AGR (amine unit)	Diluted Syngas to Power Island	Stripped condensate from SWS	BFW make-up to condensate accumulator	Return condensate to gasification	Nitrogen to saturator	Moist. Nitrogen to combined cycle
Temperature (°C)	N/D	323	34	25	210	132	123	144	122	210
Pressure (bar)	64.6	61.6	57	51	31.0	70.0	2.2	70.0	28.0	27.0
TOTAL FLOW										
Mass flow (kg/h)	1,154,260	1,154,260	891,980	82,372	401,400	43,250	227,050	493,640	306,818	384,494
Molar flow (kmol/h)	58,017	58,017	43,506	24,753	36,140	2,401	12,603	27,400	10,947	15,259
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-	43,250	227,050	493,640	-	
GASEOUS PHASE										
Mass flow (kg/h)	1,154,260	1,154,260	891,980	82,372	401,400	-	-	-	306,818	384,494
Molar flow (kmol/h)	58,017	58,017	43,506	24,753	36,140	-	-	-	10,947	15,259
Molecular Weight	-	19.90	20.50	3.33	11.11	-	-	-	28.03	25.20
Composition (vol %)	dry basis									
H_2	35.80	41.04	54.74	94.94	65.03	-	-	-	0.00	0.00
CO	42.80	0.46	0.61	1.04	0.72	-	-	-	0.00	0.00
CO_2	17.80	31.54	41.98	0.01	0.02	-	-	-	0.05	0.04
N_2	3.22	3.22	2.27	3.95	33.58	-	-	-	98.00	70.29
O_2	0.00	0.00	-	-	0.31	-	-	-	1.00	0.72
CH_4	0.00	0.00	-	-	0.00	-	-	-	0.00	0.00
H_2S + COS	0.38	0.38	0.26	0.00	0.00	-	-	-	0.00	0.00
Ar	0.00	0.00	-	-	0.08	-	-	-	0.25	0.18
HCN	0.00	0.00	0.00	0.00	0.00	-	-	-	-	-
NH_3	0.00	0.00	0.00	0.00	0.00	-	-	-	-	-
H_2O	-	25.06	0.14	0.06	0.26	-	-	-	0.70	28.77

FOSTER WHEELER	Case 4.2.1 - GE-BASED IGCC - NEAR ZERO EMISSION CASE - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
	CLIENT :	IEAGHG	PREP.	NF		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	LM		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	September 2013		

HEAT AND MATERIAL BALANCE
UNIT 2300 - Acid Gas Removal

STREAM	13	14	21	22	23	24	25	26	27	
	Raw Syngas from Syngas Cooling	HP Purified Syngas to Syngas Cooling	Treated syngas from AGR (Selexol)	HP CO2 to Compression	MP CO2 to Compression	LP CO2 to Compression	Acid gas to compression from amine unit	Acid Gas to SRU & TGT	Recycle Tail Gas from SRU	
Temperature (°C)	34	25	15	8	-1	-9	40	20	35	
Pressure (bar)	57	51	53	20.3	6.6	2.0	2.0	1.6	56.5	
TOTAL FLOW										
Mass flow (kg/h)	891,980	82,372	148,230	167,423	408,019	163,540	66,769	9,833	5,805	
Molar flow (kmol/h)	43,506	24,753	26,248	4,069	9,292	3,719	1,543	293	161	
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-	-	-	-	-	
GASEOUS PHASE										
Mass flow (kg/h)	891,980	82,372	148,230	167,423	408,019	163,540	66,769	9,833	5,805	
Molar flow (kmol/h)	43,506	24,753	26,248	4,069	9,292	3,719	1,543	293	161	
Molecular Weight	20.5	3.3	5.6	41.1	43.9	44.0	43.3	33.6	36.1	
Composition (vol %)										
H_2	54.74	94.94	89.55	6.66	0.20	0.00	0.38	14.47	17.65	
CO	0.61	1.04	0.98	0.16	0.00	0.00	0.00	0.25	0.00	
CO_2	41.98	0.01	5.73	92.95	99.74	99.87	97.34	43.29	77.90	
N_2	2.27	3.95	3.73	0.19	0.00	0.00	0.01	0.38	0.69	
O_2	-	-	-	0.00	0.00	0.00	0.00	-	0.00	
CH_4	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00	
H_2S + COS	0.26	0.00	0.00	0.00	0.00	0.00	0.00	40.70	3.76	
Ar	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00	
HCN										
NH_3	-	-	-	-	-	-	0.00	0.11	-	
H_2O	0.14	0.06	0.01	0.04	0.06	0.13	2.27	0.80	0.00	

	Case 4.2.1 - GE-BASED IGCC - NEAR ZERO EMISSION CASE - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	NF		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	LM		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	September 2013		

HEAT AND MATERIAL BALANCE
UNIT 2400 - Sulfur Recovery Unit (SRU) & Tail Gas Treatment (TGT)

STREAM	8	26	27	28	29					
	Oxygen to SRU	Acid Gas from AGR Unit	Claus Tail Gas to AGR Unit	Sour Gas from Sour water stripper	Product Sulphur					
Temperature (°C)	Amb	20	35	80	-					
Pressure (bar)	6	1.6	56.5	4	-					
TOTAL FLOW										
Mass flow (kg/h)	1,934	9,833	5,805	170	3,000					
Molar flow (kmol/h)	60	293	161	4.5	-					
LIQUID PHASE										
Mass flow (kg/h)		-	-	-	-					
GASEOUS PHASE										
Mass flow (kg/h)	1,934	9,833	5,805	170	-					
Molar flow (kmol/h)	60	293	161	4.5	-					
Molecular Weight	32.2	33.6	36.1	37.7	-					
Composition (vol %)										
H_2	-	14.47	17.65	0.49	-					
CO	-	0.25	0.00	0.03	-					
CO_2	-	43.29	77.90	74.16	-					
N_2	1.50	0.38	0.69	0.19	-					
O_2	95.00	-	0.00	-	-					
CH_4	-	0.00	0.00	-	-					
H_2S + COS	-	40.70	3.76	3.57	-					
Ar	3.50	0.00	0.00	-	-					
HCN										
NH_3	-	0.11	-	9.14	-					
H_2O	-	0.80	0.00	12.42	-					

	Case 4.2.1 - GE-BASED IGCC - NEAR ZERO EMISSION CASE - HEAT AND MATERIAL BALANCE		REVISION	0	1	2
FOSTER WHEELER	**CLIENT :**	IEAGHG	**PREP.**	NF		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**CHECKED**	LM		
	PROJECT NO:	1-BD-0681 A	**APPROVED**	LM		
	LOCATION:	The Netherlands	**DATE**	September 2013		

HEAT AND MATERIAL BALANCE
Unit 2500 - CO2 Compression and Drying

STREAM	22	23	24	25	30	31				
	HP CO2 to Compression	MP CO2 to Compression	LP CO2 to Compression	Acid gas to compression from amine unit	CO_2 to drying package	CO_2 to storage				
Temperature (°C)	8	-1	-9	40	26	30				
Pressure (bar)	20.3	6.6	2.0	2.0	39.8	110.0				
TOTAL FLOW										
Mass flow (kg/h)	167,423	408,019	163,540	66,769	894,320	804,720				
Molar flow (kmol/h)	4,069	9,292	3,719	1,543	20,690	18,572				
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-	-				
GASEOUS PHASE										
Mass flow (kg/h)	167,423	408,019	163,540	66,769	894,320	804,720				
Molar flow (kmol/h)	4,069	9,292	3,719	1,543	20,690	18,572				
Molecular Weight	41.1	43.9	44	43	43.2	43.3				
Composition (vol %)										
H_2	6.66	0.20	0.0	0.0	1.59	1.59				
CO	0.16	0.00	0.0	0.0	0.04	0.04				
CO_2	92.95	99.74	99.9	99.9	98.09	98.33				
N_2	0.19	0.00	0.0	0.0	0.04	0.04				
O_2	0.00	0.00	0.0	0.0	0.00	0.00				
CH_4	0.00	0.00	0.0	0.0	0.00	0.00				
H_2S + COS	0.00	0.00	0.0	0.0	0.00	0.00				
Ar	0.00	0.00	0.0	0.0	0.00	0.00				
HCN	0.00	0.00	0.0	0.0	0.00	0.00				
NH3	0.00	0.00	0.0	0.0	0.00	0.00				
H_2O	0.04	0.06	0.1	0.1	0.24	0.00				

Case 4.2.1 - GE-BASED IGCC - NEAR ZERO EMISSION CASE HEAT AND MATERIAL BALANCE		**REVISION**	0
CLIENT :	IEAGHG	**PREP.**	NF
PROJECT NAME:	CO_2 capture at coal based power and H2 plants	**CHECKED**	LM
PROJECT NO:	1-BD-0681 A	**APPROVED**	LM
LOCATION:	The Netherlands	**DATE**	September 2013

Unit 3000 - Power Island

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
15	Treated Syngas from Syngas Cooling (*)	200.7	210	30.8	-
20	Moisturized Nitrogen for NOx control (*)	192.2	210	26.90	-
32	HP Steam from Process Units (*)	267.7	335	137.0	2646
33	MP Steam from Process Units (*)	52.5	253	41.0	2801
34	LP Steam to Process Units (*)	35.3	168	7.5	2766
35	Condensate to Deaerator (*)	897.1	94	2.2	394
36	BFW to Make-up Water Pumps (*)	113.5	123	2.2	518
37	BFW to LP BFW Pumps (*)	140.9	123	2.2	518
38	BFW to MP BFW Pumps (*)	294.1	123	2.2	518
39	BFW to HP BFW Pumps (*)	392.9	123	2.2	518
40	HP Steam to Steam Turbine	781.2	532	132.0	3421
41	Hot RH Steam to Steam Turbine	1091.6	532	34.8	3524
42	LP Steam to Steam Turbine	1122.8	283	5.7	3027
43	Steam to Condenser	1122.8	29	0.04	2299
44	Water Supply to Steam Condenser	53150	15	4.0	63
45	Water Return from Steam Condenser	53150	26	3.5	109
46	Make-up water	313.5	15	6.0	64
47	Condensate return from Process Units	190.9	94	4.2	394
48	LP BFW to Process Units	143.4	160	19.0	676
49	MP BFW to Process Units	197.7	160	56.0	678
50	HP BFW to Process Units	538.7	160	180.0	686
51	Flue gas from GT (*) (1)	2780	560	1.05	-
52	Flue gas at stack (*) (1)	2780	133	atm	-

(*) Flowrate figure refers to one train (50% capacity)
(1) Flue gas molar composition: N_2: 73.65%; H_2O: 14.45%; O_2: 10.97%; CO_2: 0.16%; Ar: 0.77%.

5. Utility consumption

Main utility and chemical consumption of the plant is reported in the following tables, compared with the reference cases figure (in brackets). More specifically:

- Steam / BFW / condensate interface summary, shown in Table 3.
- Water consumption summary is reported in Table 4,
- Electrical consumption summary is shown in Table 5.

With respect to the reference case, the following considerations can be made:

- The introduction of the amine unit for achieving 98% capture rate mainly affects the consumption of low pressure steam, as a significant amount of steam is required from the regenerator reboiler of the unit. As for that, while LP steam excess is imported from the process unit to the combined cycle, in the present case LP steam has to be exported from the combined cycle, thus reducing the steam turbine power production. Minor differences in the LP steam balance are related to the small difference in the syngas preheating line.
- The higher CO_2 removal results in higher hydrogen content of the hydrogen rich fuel to the combined cycle. As for that, nitrogen required for syngas dilution slightly increases, and consequently also water and electric power consumption of the ASU.
- Cooling water consumption increases mainly for the requirement of the additional amine unit. The consumption related to the steam turbine and condenser is slightly lower due to the reduced steam flow expanded through the steam turbine.
- In addition to the increased power demand of both the ASU and the amine unit, the higher plant overall power consumption is mainly related to the increased power demand of the CO_2 compressors.
- Utilities consumption increases mainly due to the higher cooling water requirements.

Table 3. Case 4.2.1 – Steam/BFW/condensate interface summary

CLIENT:	IEA GHG
PROJECT:	CO2 capture at coal based power and hydrogen plants
LOCATION:	The Netherlands
FWI Nº:	1-BD-0681 A

REVISION	Rev.0		
DATE	July 2013		
ISSUED BY	GP		
CHECKED BY	NF		
APPROVED BY	LM		

Case 4.2.1 - GE based IGCC - Near zero emission - Steam and water balance

UNIT	DESCRIPTION UNIT	HP Steam barg 137 [t/h]	MP Steam barg 40 [t/h]	LP Steam barg 6.50 [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									
2100	**Air Separation Unit (ASU)**									
1000	**Gasification Section**	**-444.2**			**446.8**					**-2.5**
2200	**Syngas Treating and Conditioning Line**	**-91.2**	**-97.2**	**-106.8** ***(-102.2)***	**92.1**	**189.0**	**143.4** ***(140.1)***	**227.1**	**-48.1** ***(-49.5)***	**-308.2**
2300	**Acid Gas Removal & Amine Guard FS process**			**127.1** ***(64.0)***					**-127.1** ***(-64.0)***	**0.00**
2400	**Sulphur Recovery (SRU)**		**-7.9**			**8.7**			**-0.75**	**-0.08**
3000	**POWER ISLANDS UNITS**	**535.4**	**105.1**	**-35.3** ***(23.2)***	**-538.9**	**-197.7**	**-143.4** ***(-140.1)***	**-227.1**	**190.9** ***(129.2)***	
4000	**UTILITY and OFFSITE UNITS**			**15.0**					**-15.0**	**0.00**
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-310.9**

Notes: (1) Negative figures represent generation

Table 4. Case 4.2.1 – Water consumption summary

CLIENT:	IEAGHG
PROJECT:	CO2 capture at coal based power and H2 plants
LOCATION:	The Netherlands
FWI Nº:	1-BD-0681 A

Revision	0
Date	July 2013
ISSUED BY	GP
CHECKED BY	NF
APPR. BY	LM

Case 4.2.1 - GE based IGCC - Near zero emission - Water consumption summary

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water Primary system [t/h]	Cooling Water Secondary System [t/h]
	AIR SEPARATION UNIT (ASU)				
2100	Air Separation Unit				11300 *(11220)*
	GASIFICATION SECTION (GS)				
1000	Gasification	145			3870
2200	Syngas treatment and conditioning line				930
2300	Acid Gas Removal and Amine Guard FS Process		2.0 *(0.6)*		10150 *(6870)*
2400	Sulphur Recovery (SRU) - Tail gas treatment (TGT)				160
	CO_2 COMPRESSION				
2500	CO_2 Compression				6770 *(5850)*
	COMBINED CYCLE (CC)				
3100	Gas Turbines and Generator auxiliaries			52960 *(55510)*	780
3200	Heat Recovery Steam Generator				
3300	Steam Turbine and Generator auxiliaries		312.1 *(313.3)*		2000 *(2050)*
	Miscellanea				
	UTILITY UNITS (UU)				
4000	Cooling Water System	1636 *(1598)*			
4000	Demineralized/Condensate Recovery/Plant and Potable Water Systems	471	-314		
4000	Waste Water Treatment	-91.8			
4000	Balance of Plant (BOP)				400
	TOTAL CONSUMPTION	2160 *(2122)*	0.0	52960 *(55510)*	36360 *(31700)*

Note: Negative figures represent generation

Table 5. Case 4.2.1 – Electrical consumption summary

CLIENT:	IEAGHG	Rev.0
PROJECT:	CO2 capture at coal based power and H2 plants	Date: July 2013
LOCATION:	The Netherlands	ISSUED BY: GP
FWI Nº:	1-BD-0681 A	CHECKED BY: NF
		APPR. BY: LM

Case 4.2.1 - GE based IGCC - Near zero emission - Electrical consumption summary

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	AIR SEPARATION UNIT (ASU)	
2100	**MAC consumptions**	**124220**
2100	**BAC consumptions**	**12270**
2100	**Nitrogen compressors and miscellanea**	**37120** ***(35530)***
	GASIFICATION SECTION (GS)	
900	**Coal Receiving Handling and Storage**	**410**
1000	**Gasification**	**8790**
2200	**Syngas treatment and conditioning line**	**1250**
2300	**Acid Gas Removal and Amine Guard FS Process**	**21540** ***(20850)***
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**	**700**
2500	**CO_2 Compression**	**39970** ***(33970)***
	COMBINED CYCLE (CC)	
3100	**Gas Turbines auxiliaries**	**2000**
3200	**Heat Recovery Steam Generator**	**7490** ***(7530)***
3300	**Steam Turbine auxiliaries and excitation system**	**850**
3300	**Miscellanea**	**3210** ***(3120)***
	UTILITY UNITS (UU)	
4000	**Cooling Water System**	**10870** ***(10490)***
4000	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**730**
4000	**Balance of Plant (BOP)**	**1090**
	TOTAL CONSUMPTION	**272510** ***(263800)***

6. Overall performance

The following table shows the overall performance of Case 4.2.1, compared with the reference case performance.

CLIENT:	IEAGHG	REVISION	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	DATE	Jul-13
PROJECT No. :	1-BD-0681 A	MADE BY	GP
LOCATION :	The Netherlands	APPROVED BY	LM

Case 4.2.1 - High capture IGCC Plant Performance Summary

OVERALL PERFORMANCES		CASE 4.2.1	CASE 4.2 (reference)
Coal Flowrate (as received)	t/h	349.2	349.1
Coal LHV (as received)	kJ/kg	25870	25870
Coal HHV (as received)	kJ/kg	27060	27060
THERMAL ENERGY OF FEEDSTOCK(A)	**MWth (LHV)**	**2509**	**2509**
THERMAL ENERGY OF FEEDSTOCK(A')	**MWth (HHV)**	**2625**	**2625**
Thermal Power of Raw Syngas exit Scrubber (E)	MWth (LHV)	1785	1785
Thermal power of syngas to AGR	MWth (LHV)	1638	1638
Thermal Power of Clean Syngas to Gas Turbines (F)	MWth (LHV)	1600	1600
Syngas treatment efficiency (F/E*100)	% (LHV)	89.6	89.6
Gas turbines total electric power output	MWe	688.0	688.0
Steam turbine electric power output	MWe	433.4	443.8
Syngas expader	MWe	8.6	9.0
GROSS ELECTRIC POWER OUTPUT OF IGCC COMPLEX (C)	**MWe**	**1130**	**1141**
Gasification Section units consumption	MWe	32.7	32.0
ASU consumption	MWe	173.6	172.0
Combined Cycle units consumption	MWe	13.6	13.5
CO2 Compression and Dehydration unit consumption	MWe	39.97	34.0
Utility Units consumption	MWe	12.7	12.3
ELECTRIC POWER CONSUMPTION OF IGCC COMPLEX	**MWe**	**272.5**	**263.8**
NET ELECTRIC POWER OUTPUT OF IGCC	**MWe**	**857.5**	**877.0**
(Step-up transformer Eff. = 0.997) (B)	**MWe**	**854.9**	**874.3**
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	45.0	45.5
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**34.1**	**34.9**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	43.1	43.5
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**32.6**	**33.3**
Fuel Consumption per net power production	**MWth/MWe**	**2.94**	**2.87**
CO_2 emission per per net power production	**kg/MWh**	**13.3**	**93.7**

With respect to the reference case, the following consideration can be made:

- The negligible difference in the coal flowrate is related to the slightly lower AGR efficiency, as impurities of hydrogen and carbon monoxide remains in the CO_2 rich stream from the amine unit.
- The lower gross power production results from the lower electric power generated by the steam turbine, related to the increased steam demand of the process unit. The lower expander production is related to the lower purified syngas flowrate, as a higher amount of CO_2 is removed.
- Net electrical efficiency decreases of about 0.8 percentage points, due to the above consideration and to the increased electrical consumptions related to the required higher capture rate.

The following table shows the overall CO_2 balance and removal efficiency of Case 4.2.1, compared with the reference case.

	CASE 4.2.1	CASE 4.2 (reference)
CO_2 removal efficiency	**Equivalent flow of CO_2** kmol/h	**Equivalent flow of CO_2** kmol/h
INPUT		
Fuel Mix (Carbon AR)	18734	18730
TOTAL (A)	18734	18730
OUTPUT		
Slag + Waste water (B)	101	101
CO_2 product pipeline		
CO	7	7
CO_2	18265	16759
CH_4	0	0
COS	0	0
Total to storage (C)	18273	16766
Emission		
CO_2 + CO (Combined Cycle)	360	1862
TOTAL	18734	18730
Overall Carbon Capture, % ((B+C)/A)	98.1	90.1

7. Environmental impact

Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

7.1. Gaseous emissions

As for the reference case, main continuous emissions during normal operation are the combustion flue gases of the two trains of the combined cycle, from the combustion of the syngas in the two gas turbines. Table 6 summarises expected flow rate and concentration of the combustion flue gas from one train of the combined cycle. The differences in the flue gas composition with respect to the reference case are related to the lower carbon content of the syngas, due to the higher carbon removal efficiency target. The same minor and fugitive emissions, related to leakages within the handling of solid materials, are valid for these alternative systems.

Table 6. Case 4.2.1 – Plant emission during normal operation

Flue gas to HRSG stack	
Emission type	Continuous
Conditions	
Wet gas flowrate, kg/h	2,780,000
Flow, Nm^3/h (1)	2,677,700
Temperature, °C	133
Composition	(% vol)
Ar	0.77
N_2	73.65
O_2	10.97
CO_2	0.16
H_2O	14.45
Emission	mg/Nm^3 (1)
NOx	< 50
SOx	< 1
CO	< 100
Particulate	< 10

(1) Dry gas, O_2 content 15% vol.

7.2. Liquid effluents

As per the reference case, Main liquid effluents are the cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids, and the effluent from the Waste Water Treatment, which flows to an outside plant battery limits recipient.

Cooling Tower blow-down

Flowrate : 390 m^3/h

Waste Water Treatment blow-down

Flowrate : 162 m^3/h

7.3. Solid effluents

No difference is expected in the production of solid by-products with respect to the reference case.

8. Main equipment design changes

The overleaf equipment summary table shows the major design differences between the present Case 4.2.1 and the reference Case 4.2.

CLIENT: IEA GHG		REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
LOCATION: The Netherlands		DATE	June 13			
PROJ. NAME: CO2 capture at coal based power and hydrogen plants		ISSUED BY	GP			
CONTRACT N. 1-BD-0681 A		CHECKED BY	NF			
CASE: 4.2.1 - GE based IGCC - High capture case		APPROVED BY	LM			

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	Difference with respect to reference case
	UNIT 2100 - AIR SEPARATION UNIT (2X50%)					
	MP N_2 compressor (GAN) MP N_2 compressor - booster		Flowrate: 125000 Nm3/h Flowrate: 127560 Nm3/h	2 x 9750 kW 1250 kW		**Size changed** **Size changed**
	UNIT 2200 - Syngas Treatment and conditioning line (2x50%)					
EX - 2201	Syngas expander		Flowrate: 554700 Nm3/h	8800 kW		**Size changed**
	UNIT 2350 - Amine Guard FS Process Unit (1x100%)					
Z - 2351	**Amine Guard FS Process, including:** One amine absorber one amine stripper total carbon capture: 85.3%	Solvent: amine	Feed gas: 588,300 Nm3/h 54 barg 15 °C			**To be added**
	Unit 2500 - CO_2 compression Unit (2 x 50%)					
	CO2 compression Unit (2 x 50%)		Feed gas flowrate: 224300 Nm3/h			**Size changed (+ 16%)**
	Unit 3300 - Steam Turbine and Blowdown System (1 x 100%)					
ST - 3301	Steam Turbine (including steam turbine generator)		434 MWe			**Size changed**
E - 3301 P - 3301 A/B	Condenser Condensate Pump	 centrifugal, vertical	680 MWth 1865 m3/h x 110 m	 800 kW		**Size changed**
	Unit 4000 - Utility and Offsite					
CT - 4001	Cooling Tower Including Cooling water basin Raw Water CT make-up pump	Evaporative, Natural draft	1140 MWth Diameter: 155 m, Height: 210 m, Water inlet: 17 m			**Size changed**
P - 4001 A/B/C/D P - 4002 A/B/C	Cooling Water pumps (primary system) Cooling Water pumps (secondary system)	vertical vertical	13300 m3/h x 35 m 11950 m3/h x 35 m	1450 kW 1650 kW	*Four operating* *Three operating, one spare*	**Size changed** **Numebr and size changed**

CLIENT	:	IEAGHG
PROJECT NAME	:	CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
DOCUMENT NAME	:	CASE 5.3.1 – HYDROGEN AND POWER CO-PRODUCTION POWER ISLAND: PSA OFF-GAS FIRED BOILER - NEAR-ZERO EMISSION
FWI CONTRACT	:	1-BD-0681 A

ISSUED BY	:	N. FERRARI
CHECKED BY	:	L. MANCUSO
APPROVED BY	:	L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

1. Introduction

This chapter of the report includes all technical information relevant to Case 5.3.1 of the study, which is a gasification plant based on the GE technology, designed to produce hydrogen to be distributed to a hydrogen network.

Plant configuration is basically same as Case 5.3, though plant of Case 5.3.1 is designed to meet near-zero CO_2 emission target (around 98% carbon capture rate).

The description of the main process units and the reference Case 5.3 performance are covered respectively in chapter E and E.6 of this report; only plant design changes required to meet near-zero emission target are discussed in the following sections, together with the main plant performance results.

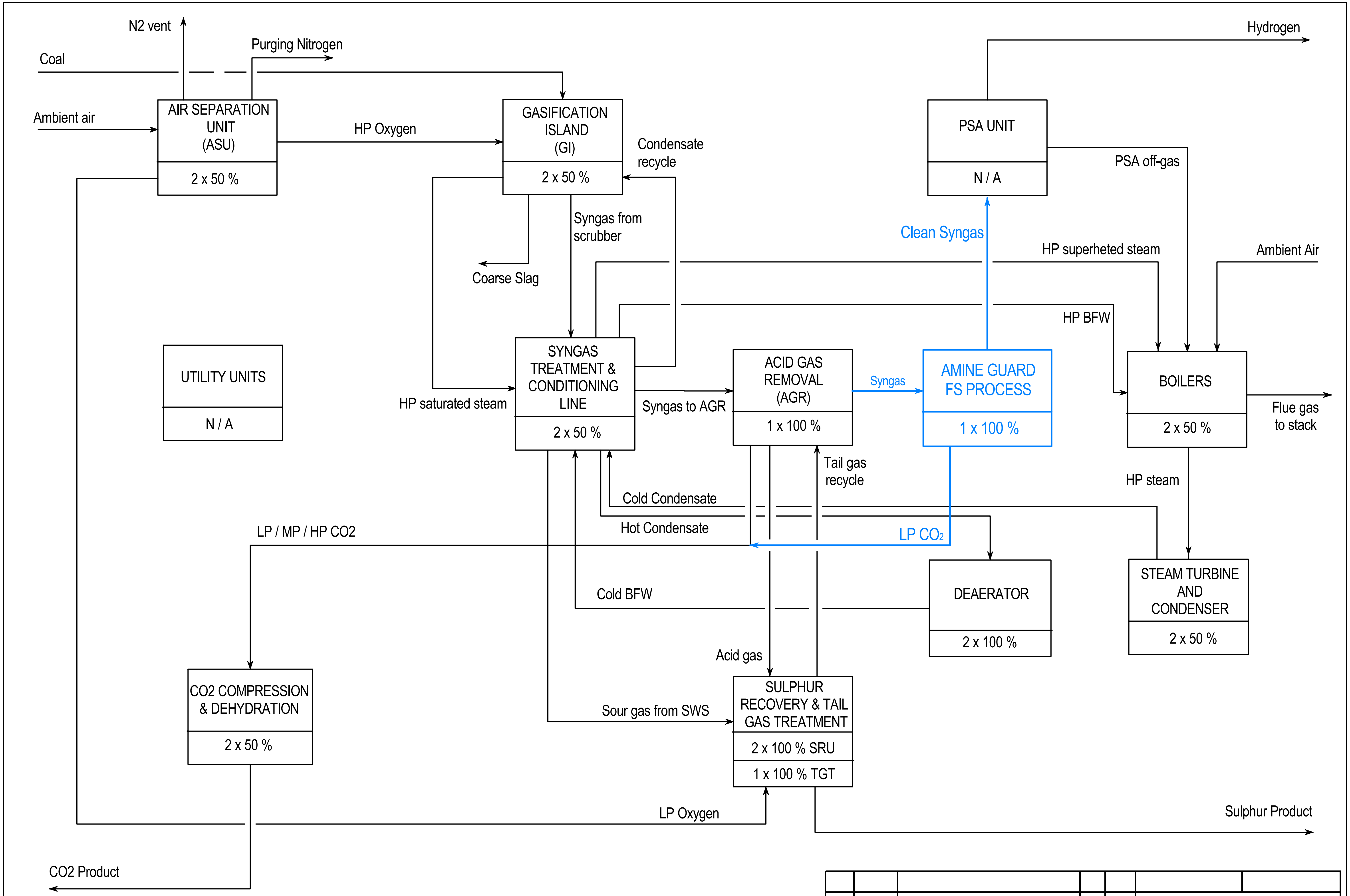
1.1. Process unit arrangement

The arrangement of the main units is reported in Table 1, together with the main differences with respect to the base case, as further discussed in the following sections. Reference is also made to the block flow diagram attached below.

Table 1. Case 4.2.1 – Unit arrangement

Unit	Description	Trains	Differences
900	Coal Handling & Storage	N/A	-
1000	Gasification Coal Grinding & Slurry Preparation Gasification and scrubber Black Water Flash Coarse Slag Handling Grey Water & Fines Handling	2 x 50%	-
2100	Air Separation Unit	2 x 50%	-
2200	Syngas Treatment and Conditioning Line	2 x 50%	Minor design changes: LP steam generation increases due to the higher plant requirements, downstream BFW and condensate pre-heater design slightly change
2250	Sour Water Stripper (SWS)	1 x 100%	-
2300	Acid Gas Removal Selexol	 1 x 100%	

Unit	Description	Trains	Differences
	Amine Guard FS Process	1 x 100%	Additional unit to meet near-zero emission target
2400	Sulphur Recovery Unit	2 x 100%	-
	Tail Gas Treatment	1 x 100%	
2500	CO_2 Compression & Drying	2 x 50%	Increase design capacity: additional CO_2-rich flow from amine unit
3000	Power Island PSA off-gas fired subcritical boiler Steam Turbine	 2 x 50% 2 x 50%	No significant design changes: negligible difference in the PSA off-gas composition and LHV
4000	Utility and Offsite	N/A	Minor changes in cooling water system capacity



0	Aug. 13		LC	LM	**UNIT:** Block Flow Diagram	
Rev.	Date	Comment	By	Appr	**CASE:** 5.3.1	Sheet 01 of 01

2. Process description

2.1. Overview

The description reported in this section focuses only on those units with a design different from that of the reference case, necessary to meet near-zero carbon emission target. Design changes are also reflected in the simplified Process Flow Diagrams (PFD) shown in section 3.

For all the other units, reference shall be made to the base case description, included in chapter E.6, section 2.

2.2. Unit 2200 – Syngas Treatment and Conditioning line

As for the base case, the syngas treatment unit is designed to meet the steam requirements of the gasification plant and to pre-heat condensate and BFW from the steam cycle to the maximum possible extent.

The main difference with respect to the base case is the additional LP steam consumption of the amine unit regenerator reboilers, resulting in an increased size of the steam generator in the syngas treatment line.

The design of the downstream heat-exchangers for condensate and BFW pre-heating is consequently also affected, as heat available from syngas for pre-heating of both the BFW and the condensate is lower.

2.3. Unit 2300 – Acid Gas Removal (AGR)

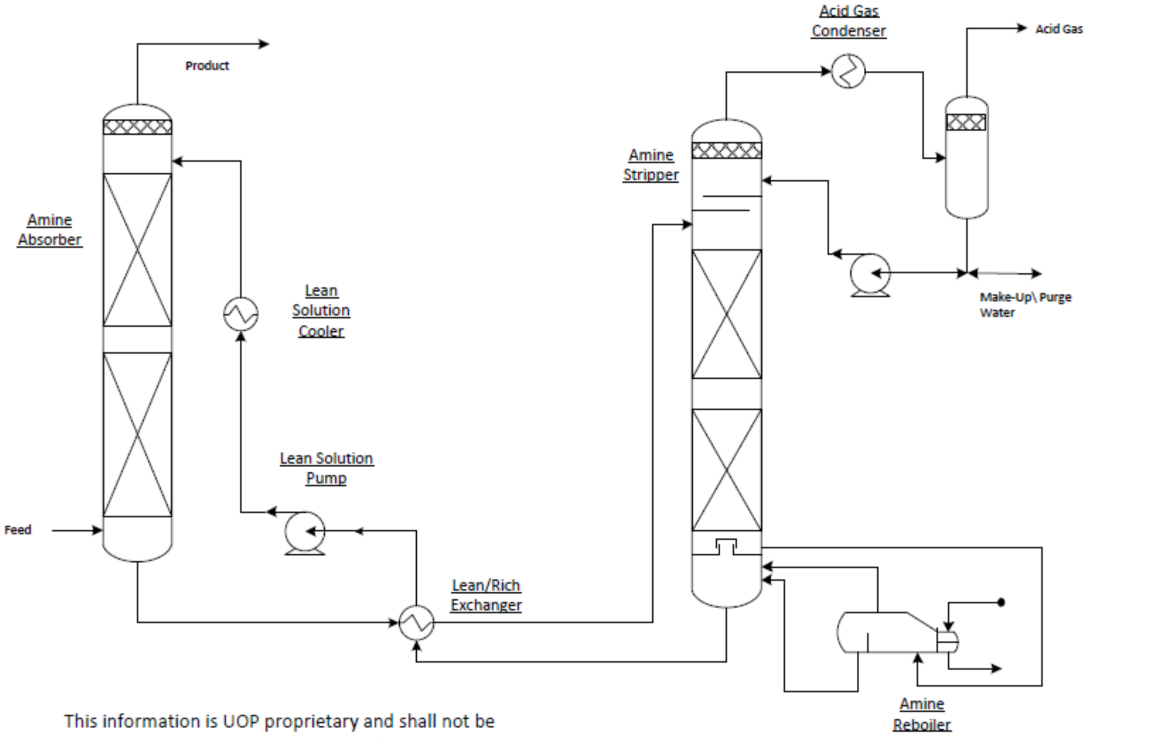
In the reference case, the AGR unit uses the Selexol physical solvent washing for the selective removal of H_2S and CO_2. Reference is made to Section E for the general information about the technology and detailed process description.

For the present near-zero CO_2 emission plant, an additional Amine Guard FS Process is included, processing the pre-treated (de-sulphurised and de-carbonized) syngas from the Selexol unit, in order to meet the desired overall 98% CO_2 removal efficiency.

2.3.1. *Amine Guard FS Process*

The following process description makes reference to the simplified process flow diagram shown in Figure 1.

Treated gas from AGR enters the unit battery limits, is routed to the bottom of the CO_2 Absorber and flows upward through packed beds where it contacts cooled lean solvent entering at the top of the tower via the Lean Solution Pump. The contact between the gas phase and liquid phase is enhanced as they pass through the packed beds, where CO_2 is transferred from the gas phase to the liquid phase. The treated gas then passes through de-entrainment devices at the top of the towers, exits the top of the CO_2 Absorber and finally reaches the Amine Guard FS unit battery limits.



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Note
Treated Gas Cooler (= Feed/Product Exhanger) and Water Wash Section (= Product KO Drum with Water Wash) are not shown on this simplified PFD.

Figure 1. Amine guard unit simplified process scheme

The rich solvent from the CO_2 Absorber is sent to the Lean/Rich in order to increase its temperature by heat exchange with the hot lean solvent from the Regenerator. The hot lean (regenerated) solvent is cooled in the Lean/Rich Exchanger before flowing to the Lean Solution Cooler. By cross-exchanging these streams, the Lean/Rich Exchanger significantly reduces the duties of the Lean Solvent Cooler and the Regenerator Reboiler. The heated solvent stream is sent to the Regenerator for complete thermal regeneration.

Solvent regeneration is accomplished in the Regenerator, where the remaining CO_2 is transferred from the liquid phase to the gas phase by contact with the steam generated in the Regenerator Reboiler. The Regenerator is composed of a lower section containing packed beds and an upper section containing several reflux trays, in order to contact the overhead vapour with the reflux water.

The rich solvent enters the Regenerator above the upper packed bed. After flashing, the solvent passes through a liquid distributor, and then flows down the packed bed in the stripping section releasing CO_2 after contact with the steam generated in the Regenerator Reboiler.

The steam and liberated gases exit the upper section of the Regenerator, and then flow upward to the trayed section of the column. The gas first passes through a demister and then into the trayed section, where the rising gas is contacted with counter-current flowing reflux water to cool and condense the hot overhead vapour and reduce solvent entrainment. The overhead stream passes through a de-entrainment device and exits the top of the column. The overhead gas then passes through the Reflux Condenser in order to recover the overhead steam. The liquid and vapour phases are separated in the Reflux Drum. The liquid is returned to the trayed section of the Regenerator via the Reflux Pump. The Acid Gas CO_2 rich stream (97.33% mol of $CO_{2)}$ is then sent to the CO_2 compression and drying unit, outside the battery limits, where it will be mixed to the LP CO_2 stream coming from AGR unit.

2.4. Unit 2500 – CO_2 compression and drying

As for the reference case, the unit is mainly composed of two eight inter-cooled compressors and dehydration packages, supplied by specialized Vendors. With respect to the reference case, the additional CO_2-rich stream at low pressure exiting the Amine Guard FS Process is mixed with the LP CO_2 stream coming from the Selexol unit, before being sent to the first compression stage.

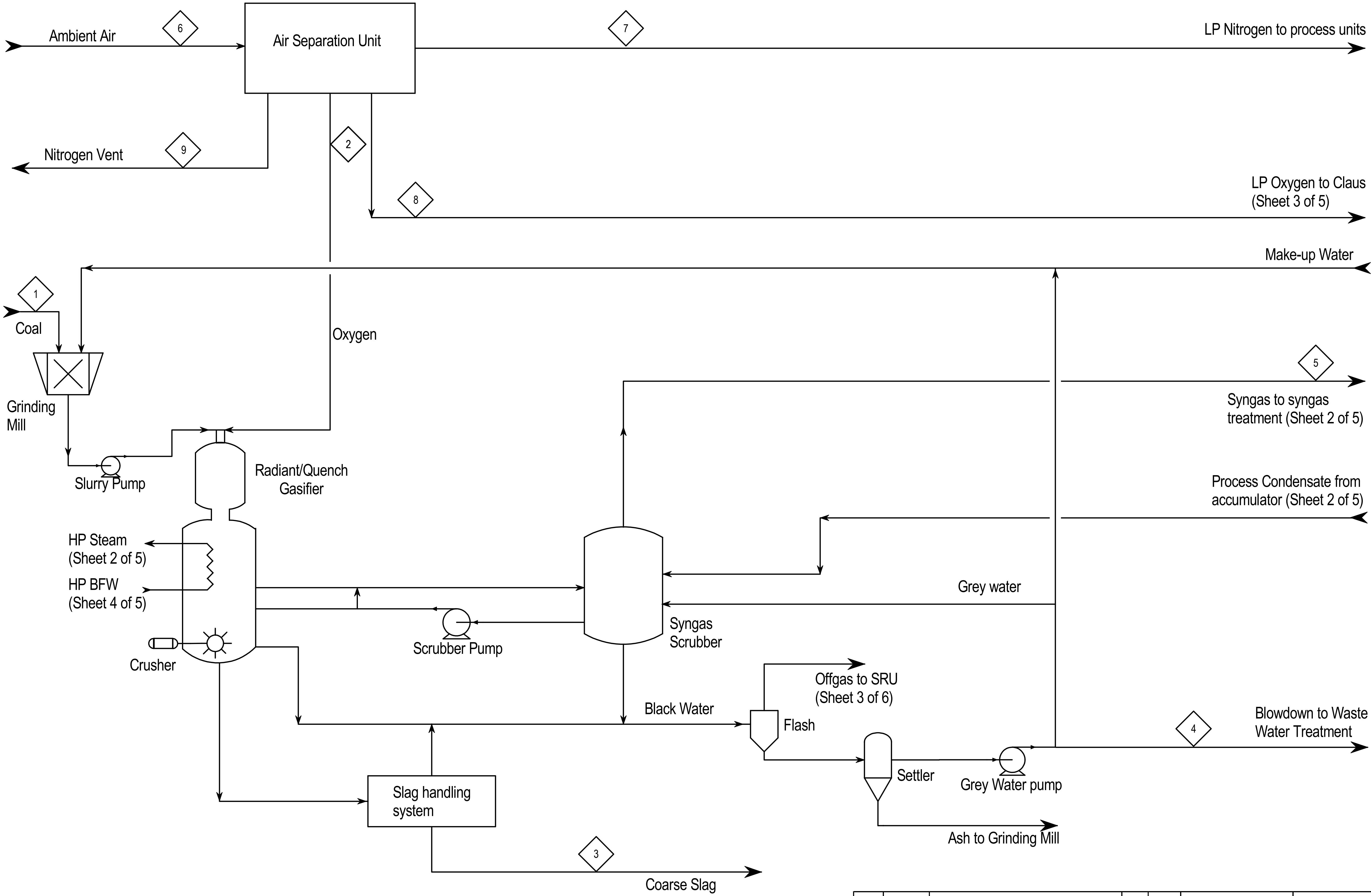
Following Table 2 summarises key stream data of this case, while main interconnections with the other units are shown in the process flow diagram.

Table 2. Case 5.3.1 – Key stream data

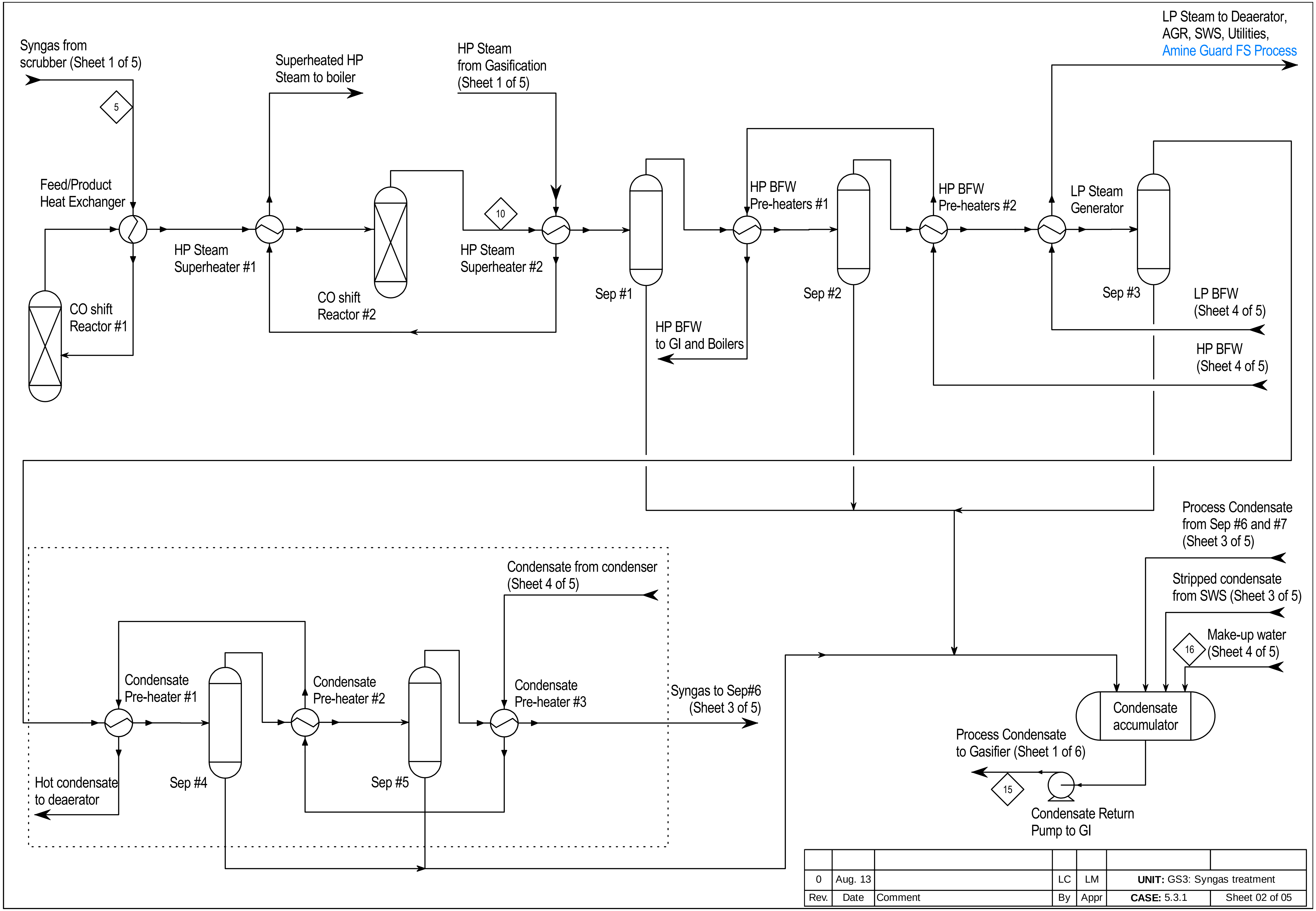
Stream	Flue gas to AGR	Flue gas to AGFS	Treated gas	Acid gas – CO_2 rich - from AGFS
Mass flowrate, kg/h	891,750	148,200	82,355	66,754
Molar flowrate, kmol/h	43,496	26,243	24,748	1,543
Composition (% vol)				
CO	0.61	0.98	1.04	-
N_2	2.27	3.73	3.95	0.01
H_2	54.73	89.55	94.94	0.38
CO_2	41.98	5.73	0.01	97.33
H_2O	0.14	0.01	0.06	2.27
H_2S	0.26	0	0	-

3. Process Flow Diagrams

Simplified Process Flow Diagrams of this case are attached to this section. Stream numbers refer to the heat and material balance shown in the next section.



0	Aug. 13		LC	LM	**UNIT:** GS2 - AS1: Gasification and ASU	
Rev.	Date	Comment	By	Appr	**CASE:** 5.3.1	Sheet 01 of 05



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HP Steam from Gasification (Sheet 1 of 5)
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0
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UNIT: GS3: Syngas treatment
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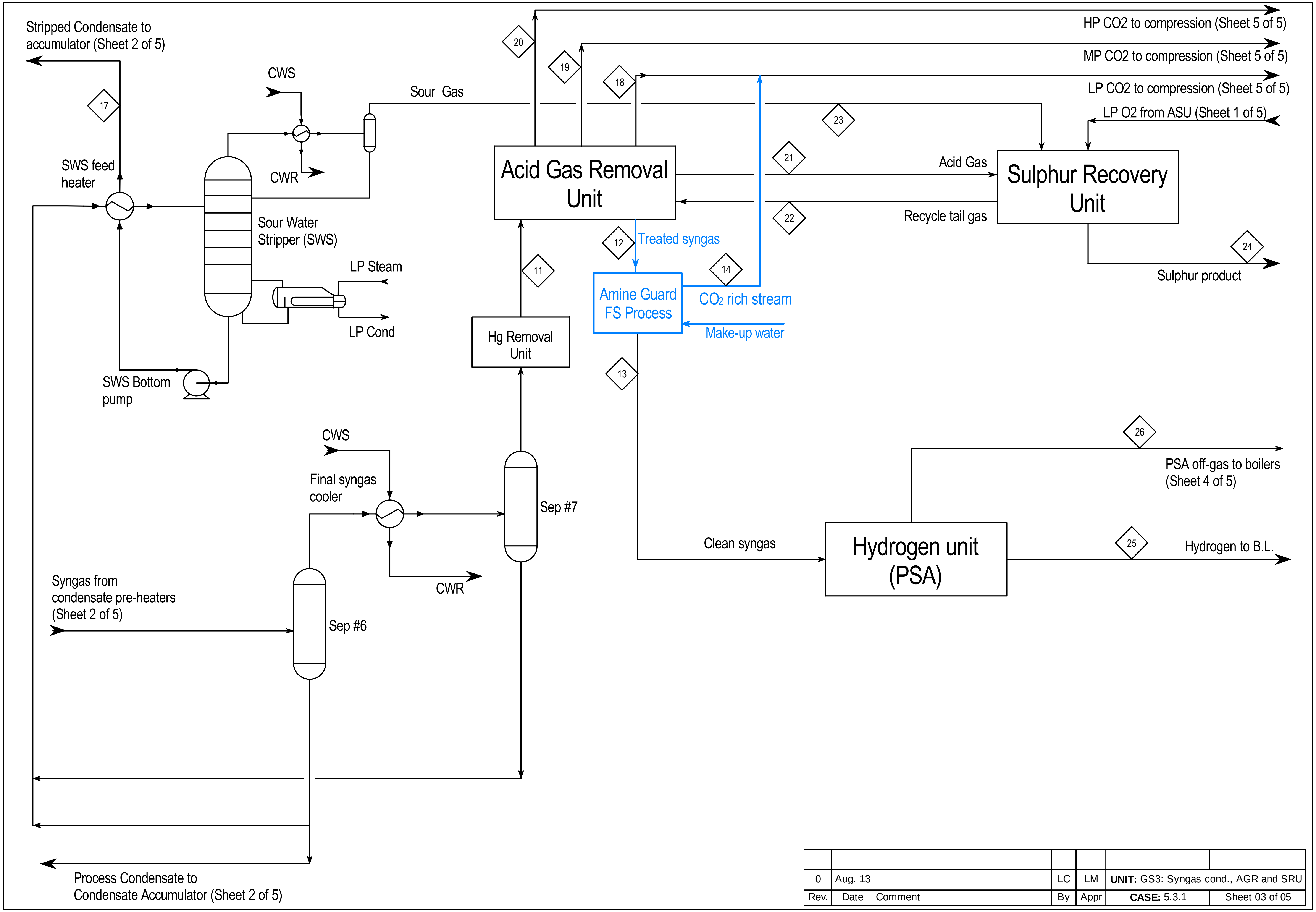
HP CO2 to compression (Sheet 5 of 5)
MP CO2 to compression (Sheet 5 of 5)
LP CO2 to compression (Sheet 5 of 5)
LP O2 from ASU (Sheet 1 of 5)
Stripped Condensate to accumulator (Sheet 2 of 5)
CWS
CWR
Sour Gas
SWS feed heater
Sour Water Stripper (SWS)
LP Steam
LP Cond
SWS Bottom pump
Acid Gas Removal Unit
Sulphur Recovery Unit
Acid Gas
Recycle tail gas
Treated syngas
Amine Guard FS Process
CO2 rich stream
Make-up water
Sulphur product
Hg Removal Unit
CWS
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UNIT: GS3: Syngas cond., AGR and SRU
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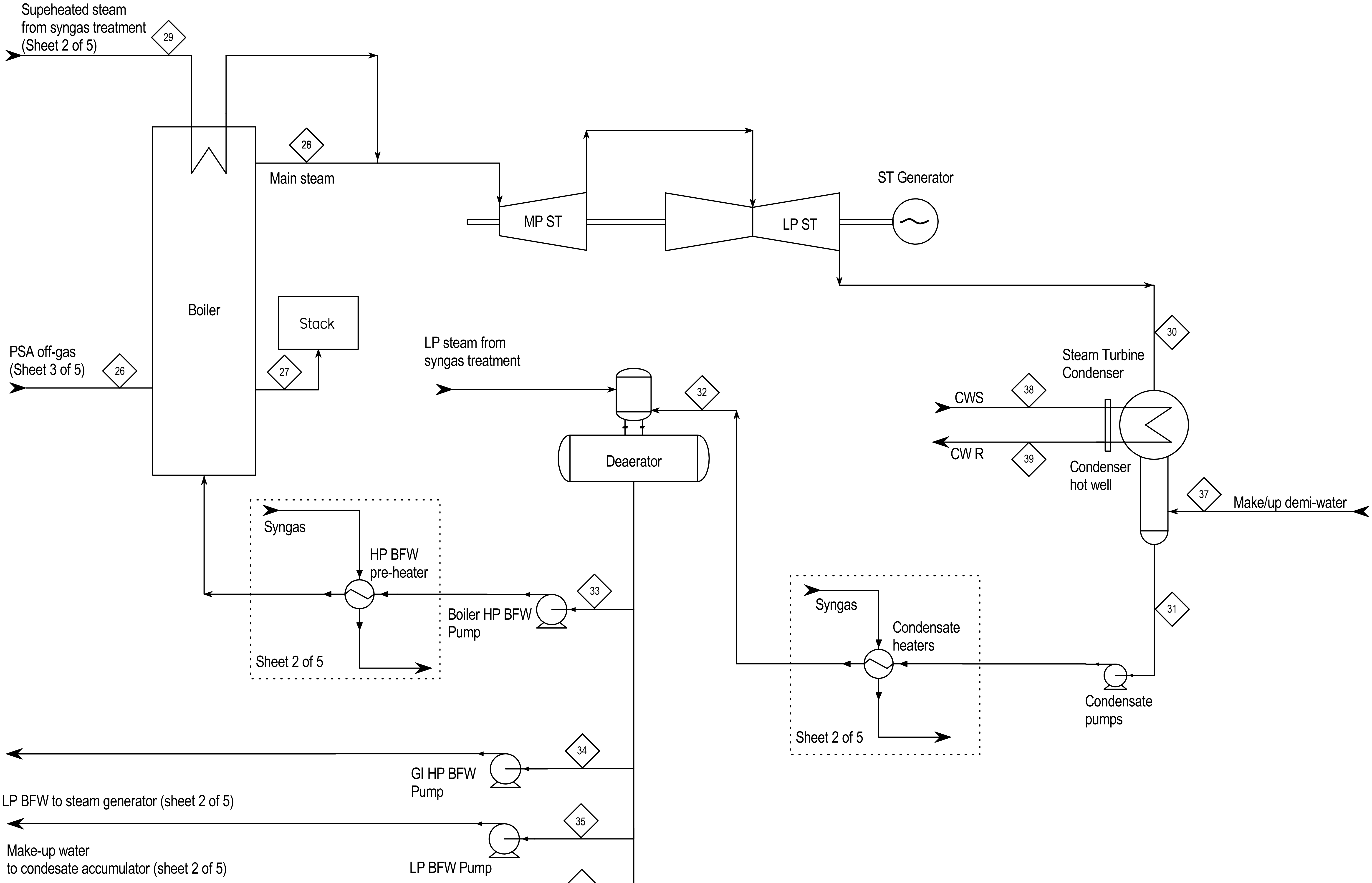
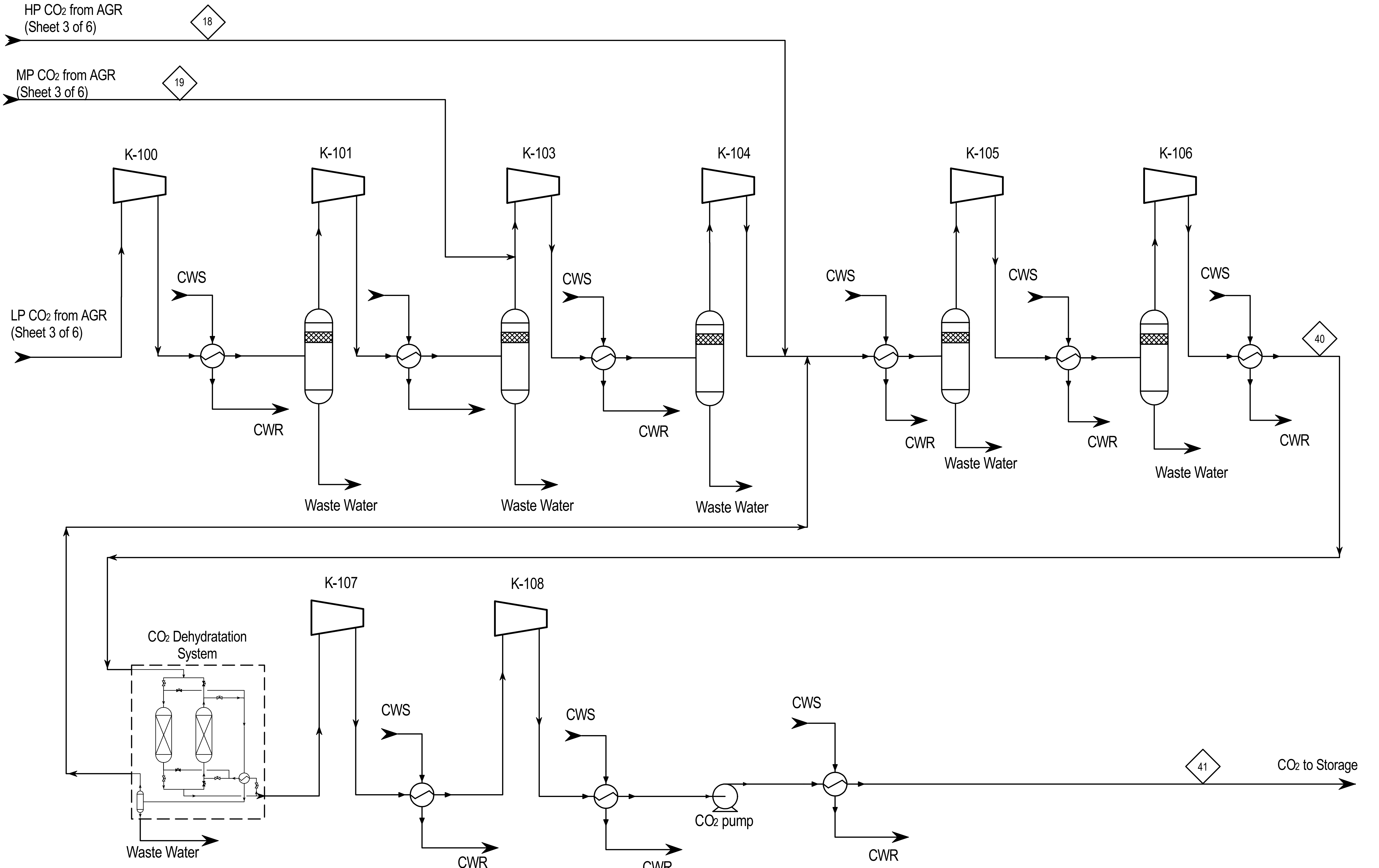


0	Aug. 13		LC	LM	**UNIT:** Boiler island and steam cycle	
Rev.	Date	Comment	By	Appr	**CASE:** 5.3.1	Sheet 04 of 05



0	Aug. 13		LC	LM	**UNIT:** CO2 compression	
Rev.	Date	Comment	By	Appr	**CASE:** 5.3.1	Sheet 05 of 05

4. Heat and Material Balance

Heat & Material Balances reported make reference to the simplified Process Flow Diagrams reported in section 3.

FOSTER WHEELER	HYDROGEN PRODUCTION - NEAR ZERO EMISSION CASE - Case 5.3.1 - H&M BALANCE					REVISION	0	1	2
	CLIENT :		IEAGHG			PREP.	NF		
	PROJECT NAME:		CO_2 capture at coal based power and hydrogen plants			CHECKED	LM		
	PROJECT NO:		1-BD-0681 A			APPROVED	LM		
	LOCATION:		The Netherlands			DATE	September 2013		

HEAT AND MATERIAL BALANCE
UNIT 1000 - Gasification Island

STREAM	1	2	3	4	5	15				
	Coal to Gasification Island	HP Oxygen to Gasification	Slag from Gasification	Effluent Water from Gasification	Syngas at Scrubber Outlet to Shift Reactor	Return condensate to gasification				
Temperature (°C)	AMB	10	80	AMB	N/D	157				
Pressure (bar)	ATM	75-80 (1)	ATM	ATM	64.6	70				
TOTAL FLOW	Solid		Solid + water							
Mass flow (kg/h)	349,100	323,000	87,400	94,500	1,154,000	493,200				
Molar flow (kmol/h)		10,025		5,250	58,004	27,385				
LIQUID PHASE										
Mass flow (kg/h)			43,700	94,500	-	493,200				
GASEOUS PHASE										
Mass flow (kg/h)		323,000			1,154,000					
Molar flow (kmol/h)		10,025			58,004					
Molecular Weight		32.22			-					
Composition (vol %)	%wt		50% moisture		dry basis					
H_2	C: 64.6%	-			35.80					
CO	H: 4.38%	-			42.80					
CO_2	O: 7.02%	-			17.80					
N_2	S: 0.86%	1.50			3.22					
O_2	N: 1.41%	95.00			0.00					
CH_4	Cl: 0.03%	-			0.00					
H_2S + COS	Moisture: 9.5%	-			0.38					
Ar	Ash: 12.20%	3.50			0.00					
HCN		-			0.00					
NH_3		-			0.00					
H_2O		-			-					

Notes: 1. FW Assumption

	HYDROGEN PRODUCTION - NEAR ZERO EMISSION CASE - Case 5.3.1 - H&M BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	NF		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	LM		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	September 2013		

HEAT AND MATERIAL BALANCE
UNIT 2100 - Air Separation Unit (ASU)

STREAM	6	2	7	8	9					
	Air Intake from Atmosphere	HP Oxygen to Gasification	LP Nitrogen to process unit	Oxygen to SRU	Nitrogen vent					
Temperature (°C)	Ambient	10	Ambient (°)	Ambient	Ambient					
Pressure (bar)	Ambient	75-80 (°)	7.5 (°)	6.0	Atmospheric					
TOTAL FLOW										
Mass flow (kg/h)	1,394,750	323,000	25,220	1,933	1,030,045					
Molar flow (kmol/h)	48,320	10,025	900	60	36,750					
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-					
GASEOUS PHASE										
Mass flow (kg/h)	1,394,750	323,000	25,220	1,933	1,030,045					
Molar flow (kmol/h)	48,320	10,025	900	60.0	36,750					
Molecular Weight	28.86	32.22	28.02	32.22	28.03					
Composition (vol %)										
H_2	-	-	-	-	-					
CO	-	-	-	-	-					
CO_2	0.04	-	-	-	0.05					
N_2	77.32	1.50	99.999	1.50	98.00					
O_2	20.75	95.00	0.001	95.00	1.00					
CH_4	-	-	-	-	-					
H_2S + COS	-	-	-	-	-					
Ar	0.92	3.50	-	3.50	0.25					
H_2O	0.97	-	-	-	0.70					

(°) FWI assumption

	HYDROGEN PRODUCTION - NEAR ZERO EMISSION CASE - Case 5.3.1 - H&M BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	NF		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	LM		
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	LOCATION:	The Netherlands	DATE	September 2013		

HEAT AND MATERIAL BALANCE
UNIT 2200 - Syngas cooling & Conditioning line

STREAM	5	10	11	13	15	16	17			
	Syngas at Scrubber Outlet to Shift Reactor	Syngas at Shift Reactor Outlet	Raw Syngas to Acid Gas Removal	HP Purified Syngas from AGR (amine unit)	Return Condensate to Gasification	BFW make-up to condensate accumulator	Stripped condensate from SWS			
Temperature (°C)	N/D	413	34	25	157	165	133			
Pressure (bar)	64.5	62.1	57	51	70	9.0	70			
TOTAL FLOW										
Mass flow (kg/h)	1,154,000	1,154,000	891,750	82,355	492,600	227,000	43,225			
Molar flow (kmol/h)	58,004	58,004	43,496	24,748	27,350	12,600	2,400			
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	492,600	227,000	43,225			
GASEOUS PHASE										
Mass flow (kg/h)	1,154,000	1,154,000	891,750	82,355	-	-	-			
Molar flow (kmol/h)	58,004	58,004	43,496	24,747	-	-	-			
Molecular Weight	21.58	19.90	20.50	3.33	-	-	-			
Composition (vol %)	(dry basis)									
H_2	35.80	41.04	54.73	94.94	-	-	-			
CO	42.80	0.46	0.61	1.04	-	-	-			
CO_2	17.80	31.54	41.98	0.01	-	-	-			
N_2	3.22	3.22	2.27	3.95	-	-	-			
O_2	0.00	0.00	-	-	-	-	-			
CH_4	0.00	0.00	-	-	-	-	-			
H_2S + COS	0.38	0.38	0.26	0.00	-	-	-			
Ar	0.00	0.00	-	-	-	-	-			
HCN	0.00	0.00	-	0.06	-	-	-			
NH_3	0.00	0.00	-	-	-	-	-			
H_2O	-	25.06	0.15	0.01	-	-	-			

	HYDROGEN PRODUCTION - NEAR ZERO EMISSION CASE - Case 5.3.1 - H&M BALANCE		REVISION	0	1	2
FOSTER WHEELER	CLIENT :	IEAGHG	PREP.	NF		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	LM		
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	LOCATION:	The Netherlands	DATE	September 2013		

HEAT AND MATERIAL BALANCE
UNIT 2300 - Acid Gas Removal (AGR)

STREAM	11	12	13	14	18	19	20	21	22	
	Raw Syngas from Syngas Cooling	Treated syngas from AGR (Selexol)	HP Purified Syngas to PSA	Acid gas to compression from amine unit	LP CO2 to Compression	MP CO2 to Compression	HP CO2 to Compression	Acid Gas to SRU & TGT	Recycle Tail Gas from SRU	
Temperature (°C)	34	15	25	40	-9	-1	8	21	35	
Pressure (bar)	57	53	51	2	2.5	6.6	20.3	1.6	56.5	
TOTAL FLOW										
Mass flow (kg/h)	891,750	148,200	82,355	66,769	163,504	407,913	167,385	9,831	5,804	
Molar flow (kmol/h)	43,496	26,243	24,748	1,543	3,718	9,290	4,068	293	161	
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-	-	-	-	-	
GASEOUS PHASE										
Mass flow (kg/h)	891,750	148,200	82,355	66,769	163,504	407,913	167,385	9,831	5,804	
Molar flow (kmol/h)	43,496	26,243	24,747	1,543	3,718	9,290	4,068	293	161	
Molecular Weight	20.5	5.65	3.32	43.27	44.0	43.9	41.1	33.6	36.1	
Composition (vol %)										
H_2	54.73	89.55	94.94	0.38	-	0.20	6.66	14.69	17.65	
CO	0.61	0.98	1.04	0.00	-	0.01	0.16	0.25	-	
CO_2	41.98	5.73	0.01	97.34	99.87	99.73	92.95	42.76	77.90	
N_2	2.27	3.73	3.95	0.01	-	-	0.19	0.38	0.69	
O_2	-	-	-	0.00	-	-	-	-	-	
CH_4	-	-	-	0.00	-	-	-	-	-	
H_2S + COS	0.26	0.00	0.00	0.00	-	-	-	41.30	3.76	
Ar	-	-	-	0.00	-	-	-	-	-	
HCN	-	0.01	-	2.27	-	-	-	-	-	
NH_3	-	-	-	0.00	-	-	-	-	-	
H_2O	0.15		0.01		0.13	0.06	0.04	0.61	-	

FOSTER WHEELER	HYDROGEN PRODUCTION - NEAR ZERO EMISSION CASE - Case 5.3.1 - H&M BALANCE		REVISION	0	1	2
	CLIENT :	IEAGHG	**PREP.**	NF		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**CHECKED**	LM		
	PROJECT NO:	1-BD-0681 A	**APPROVED**	LM		
	LOCATION:	The Netherlands	**DATE**	September 2013		

HEAT AND MATERIAL BALANCE

UNIT 2400 - Sulfur Recovery Unit (SRU) & Tail Gas Treatment (TGT)

STREAM	8	21	22	23	24					
	Oxygen to SRU	**Acid Gas from AGR Unit**	**Claus Tail Gas to AGR Unit**	**Sour Gas from Sour water stripper**	**Product Sulphur**					
Temperature (°C)	Ambient	21	35	80	-					
Pressure (bar)	6.0	1.6	56.5	4	-					
TOTAL FLOW										
Mass flow (kg/h)	1,933	9,831	5,804	170	3,000					
Molar flow (kmol/h)	60	293	161	4.5	-					
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-					
GASEOUS PHASE										
Mass flow (kg/h)	1,933	9,831	5,804	170	-					
Molar flow (kmol/h)	60	293	161	4.5	-					
Molecular Weight	32.2	33.6	36.1	38.0	-					
Composition (vol %)										
H_2	-	14.69	17.65	0.84	-					
CO	-	0.25	-	0.03	-					
CO_2	-	42.76	77.90	75.60	-					
N_2	1.50	0.38	0.69	0.24	-					
O_2	95.00	-	-	-	-					
CH_4	-	-	-	-	-					
H_2S + COS	-	41.31	3.76	2.95	-					
Ar	3.50	-	-	-	-					
HCN										
NH_3		0.00	-	7.85	-					
H_2O	-	0.61	-	12.49						

	HYDROGEN PRODUCTION - NEAR ZERO EMISSION CASE - Case 5.3.1 - H&M BALANCE		REVISION	0	1	2
	CLIENT :	IEAGHG	**PREP.**	NF		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	**CHECKED**	LM		
	PROJECT NO:	1-BD-0681 A	**APPROVED**	LM		
	LOCATION:	The Netherlands	**DATE**	September 2013		

HEAT AND MATERIAL BALANCE

Unit 2500 - CO2 Compression and Drying

STREAM	18	19	20	14	40	41				
	LP CO2 to Compression	MP CO2 to Compression	HP CO2 to Compression	Acid gas to compression from amine unit	CO_2 to drying package	CO_2 to storage				
Temperature (°C)	-9	-1	8	40	26	30				
Pressure (bar)	2.5	6.6	20.3	2	39.8	110.0				
TOTAL FLOW										
Mass flow (kg/h)	163,504	407,913	167,385	66,769	894,150	804,540				
Molar flow (kmol/h)	3,718	9,290	4,068	1,543	20,686	18,568				
LIQUID PHASE										
Mass flow (kg/h)	-	-	-	-	-	-				
GASEOUS PHASE										
Mass flow (kg/h)	163,504	407,913	167,385	66,769	894,150	804,540				
Molar flow (kmol/h)	3,718	9,290	4,068	1,543	20,686	18,568				
Molecular Weight	44.0	43.9	41.1	43.27	43.2	43.3				
Composition (vol %)										
H_2	0.0	0.20	6.66	0.38	1.59	1.59				
CO	0.0	0.00	0.16	0.00	0.04	0.04				
CO_2	99.87	99.74	92.95	97.34	98.09	98.33				
N_2	0.0	0.00	0.19	0.01	0.04	0.04				
O_2	0.0	0.00	0.00	0.00	0.00	0.00				
CH_4	0.0	0.00	0.00	0.00	0.00	0.00				
H_2S + COS	0.0	0.00	0.00	0.00	0.00	0.00				
Ar	0.0	0.00	0.00	0.00	0.00	0.00				
HCN	0.0	0.00	0.00	2.27	0.00	0.00				
NH_3	0.0	0.00	0.00	0.00	0.00	0.00				
H_2O	0.13	0.06	0.04		0.24	0.00				

	HYDROGEN PRODUCTION - NEAR ZERO EMISSION CASE - Case 5.3.1 - H&M BALANCE		REVISION	0	1	2
	CLIENT :	IEAGHG	PREP.	NF		
	PROJECT NAME:	CO_2 capture at coal based power and hydrogen plants	CHECKED	LM		
	PROJECT NO:	1-BD-0681 A	APPROVED	LM		
	LOCATION:	The Netherlands	DATE	September 2013		

HEAT AND MATERIAL BALANCE
UNIT 2600 - Hydrogen Production Unit

STREAM	12	23	24							
	Syngas to PSA	High-purity Hydrogen	PSA off-gas to Boiler							
Temperature (°C)	25	20	10							
Pressure (bar)	53	52	5							
TOTAL FLOW										
Mass flow (kg/h)	82,355	44,430	37,925							
Molar flow (kmol/h)	24,748	20,780	3,968							
LIQUID PHASE										
Mass flow (kg/h)	-	-	-							
GASEOUS PHASE										
Mass flow (kg/h)	82,355	44,430	37,925							
Molar flow (kmol/h)	24,748	20,780	3,968							
Molecular Weight	3.32	2.14	9.6							
Composition (vol %)										
H_2	94.94	99.53	51.61							
CO	1.04	-	4.72							
CO_2	0.01	-	27.50							
N_2	3.95	0.47	16.11							
O_2	-	-	-							
CH_4	-	-	-							
H_2S + COS	0.00	-	0.00							
Ar	-	-	-							
HCN	0.06	-	-							
NH_3	-	-	-							
H_2O	0.01	-	0.06							

H_2 PRODUCTION - NEAR ZERO EMISSION CASE - Case 5.3.1 - H&MB		REVISION	0	
CLIENT :	IEAGHG	**PREP.**	NF	
PROJECT NAME:	CO_2 capture at coal based power and H2 plants	**CHECKED**	LM	
PROJECT NO:	1-BD-0681 A	**APPROVED**	LM	
LOCATION:	The Netherlands	**DATE**	Sept. 2013	

HEAT AND MATERIAL BALANCE

Unit 3000 - Power Island (*)

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Entalphy kJ/kg
26	PSA off-gas to Boiler	19.0	10	5.0	-
27	Flue gas from boiler (1)	128	140-150	AMB	-
28	Boiler Main Steam	99.9	550	110.0	3492
29	HP Steam from process unit	265.5	408	115.0	3090
30	Steam to Condenser	358.4	29	0.04	2197
31	Condensate to Process Units	472.1	28	0.04	117
32	Condensate to Deaerator	548.6	155	7.2	654
33	HP BFW to Pumps (Boiler)	100.9	166	7.2	702
34	HP BFW to Pumps (G.I.)	268.6	166	7.2	702
35	LP BFW to steam generator	85.7	166	7.2	702
36	BFW make-up to gasification	113.5	166	7.2	702
37	Make-up water	113.7	15	6.0	64
38	Water Supply to Steam Condenser	16171	15	4.0	63
39	Water Return from Steam Condenser	16171	26	3.5	109

(*) Flowrate figure refers to one train (50% capacity)

(1) Flue gas molar composition at stack: N_2: 67.4%; H_2O: 29.0%; O_2: 0.3%; CO_2: 15.4%; Ar: 0.7%.

5. Utility consumption

Main utility and chemical consumption of the plant is reported in the following tables, compared with the reference cases figure (in brackets). More specifically:

- Steam / BFW / condensate interface summary, shown in Table 3.
- Water consumption summary is reported in Table 4,
- Electrical consumption summary is shown in Table 5.

With respect to the reference case, the following considerations can be made:

- The introduction of the amine unit for achieving 98% capture rate mainly affects the consumption of low pressure steam, as a significant amount of steam is required from the regenerator reboiler of the unit. As for that, additional LP steam has to be generated in the syngas treatment unit
- Cooling water consumption increases. In fact the higher cooling water requirements, related mainly to the amine unit and the increased consumption of the CO_2 compression train, overcome the reduced consumption in the syngas treatment line, due to the additional heat that is removed from the syngas upstream the final cooling water cooler to match the higher steam consumptions.
- In addition to the increased power demand of both the ASU and the amine unit, the higher plant overall power consumption is mainly related to the increased power demand of the CO_2 compressors.

Table 3. Case 5.3.1 – Steam/BFW/condensate interface summary

FOSTER WHEELER	CLIENT: IEAGHG PROJECT: CO2 capture at coal based power and H2 plants LOCATION: The Netherlands FWI Nº: 1-BD-0681 A	REVISION	Rev.0
		DATE	August 2013
		ISSUED BY	LC
		CHECKED BY	NF
		APPROVED BY	LM

Case 5.3.1 - H2 production plant - Near zero emission - Steam and water balance

UNIT	DESCRIPTION UNIT	HP Steam barg 110	MP Steam barg 40	LP Steam barg 6.50	HP BFW	MP BFW	LP BFW	condensate recovery	Losses
		[t/h]	[t/h]	[t/h]	[t/h]	[t/h]	[t/h]	[t/h]	[t/h]
	PROCESS UNITS								
2100	**Air Separation Unit (ASU)**								
1000	**Gasification Section**	**-517.1** ***(-531.9)***			**522.3** ***(537.2)***				**-5.2**
2200	**Syngas Treating and Conditioning Line**			**-160.2** ***(-96.1)***			**400.2** ***(335.3)***	**-11.1**	**-228.9** ***(-228.1)***
2300	**Acid Gas Removal & Amine Guard FS process**			**127.1** ***(64.0)***				**-127.1** ***(-64.0)***	**0.00**
2400	**Sulphur Recovery (SRU)**			**-8.0**			**8.8**		**0.80**
3000	**POWER ISLANDS UNITS**	**517.1** ***(531.9)***		**-26.1** ***(25.1)***	**-522.3** ***(-537.2)***		**-400.2** ***(-335.3)***	**153.1** ***(90.1)***	**-2.0**
4000	**UTILITY and OFFSITE UNITS**			**15.0**				**-15.0**	**0.00**
	BALANCE	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**236.9** ***(236.3)***

Notes: (1) Negative figures represent generation

Table 4. Case 5.3.1 – Water consumption summary

CLIENT:	IEAGHG
PROJECT:	CO2 capture at coal based power and H2 plants
LOCATION:	The Netherlands
FWI Nº:	1-BD-0681 A
Revision	0
Date	August 2013
ISSUED BY	LC
CHECKED BY	NF
APPR. BY	LM

Case 5.3.1 - H2 production plant - Near zero emission - Water consumption summary

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Cooling Water Primary system [t/h]	Cooling Water Secondary System [t/h]
	AIR SEPARATION UNIT (ASU)				
2100	Air Separation Unit				9810
	GASIFICATION SECTION (GS)				
1000	Gasification	145			3870
2200	Syngas treatment and conditioning line				1210 *(3370)*
2300	Acid Gas Removal and Amine Guard FS Process		2.0 *(0.6)*		10150 *(6870)*
2400	Sulphur Recovery (SRU) - Tail gas treatment (TGT)				160
	CO_2 COMPRESSION				
2500	CO_2 Compression				6770 *(5850)*
	STEAM CYCLE				
	Steam Turbine and Generator auxiliaries		236.9 *(236.2)*	32340 *(33080)*	1290 *(1320)*
	Condenser				
4000	**UTILITY UNITS (UU)**				
	Cooling Water System	1181 *(1164)*			
	Demineralized/Condensate Recovery/Plant and Potable Water Systems	358 *(355)*	239 *(237)*		
	Waste Water Treatment	-96.6			
	Balance of Plant (BOP)				400
	TOTAL CONSUMPTION	1588 *(1567)*	0.0	32340 *(33080)*	33350 *(31650)*

Note: Negative figures represent generation

Table 5. Case 5.3.1 – Electrical consumption summary

CLIENT:	IEAGHG	Rev.0
PROJECT:	CO2 capture at coal based power and H2 plants	Date: July 2013
LOCATION:	The Netherlands	ISSUED BY: GP
FWI Nº:	1-BD-0681 A	CHECKED BY: NF
		APPR. BY: LM

Case 5.3.1 - H2 production plant - Near zero emission - Electrical consumption summary

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW]
	AIR SEPARATION UNIT (ASU)	
2100	**MAC consumptions**	**124220**
	BAC consumptions	**12270**
	Miscellanea	**1000**
	GASIFICATION SECTION (GS)	
900	**Coal Receiving Handling and Storage**	**410**
1000	**Gasification**	**8790**
2200	**Syngas treatment and conditioning line**	**910**
2300	**Acid Gas Removal and Amine Guard FS Process**	**21530** ***(20850)***
2400	**Sulphur Recovery (SRU) - Tail gas treatment (TGT)**	**700**
2500	**CO_2 Compression**	**39970** ***(33970)***
	STEAM CYCLE	
3100	**Condensate and BFW pumps**	**5070** ***(5000)***
3200	**Bolier**	**1010** ***(1020)***
3300	**Steam Turbine auxiliaries and excitation system**	**400**
3300	**Miscellanea**	**2730** ***(2660)***
	UTILITY UNITS (UU)	
4000	**Cooling Water System**	**8190** ***(8080)***
4000	**Demineralized/Condensate Recovery/Plant and Potable Water Systems**	**730**
4000	**Balance of Plant (BOP)**	**1060**
	TOTAL CONSUMPTION	**228990** ***(217180)***

6. Overall performance

The following table shows the overall performance of Case 5.3.1, compared with the reference case performance.

FOSTER WHEELER

CLIENT:	IEAGHG	**REVISION**	0
PROJECT NAME:	CO2 capture at coal based power and hydrogen plants	**DATE**	Aug-13
PROJECT No. :	1-BD-0681 A	**MADE BY**	LC
LOCATION :	The Netherlands	**APPROVED BY**	LM

Case 5.3.1 - H_2 Plant Performance Summary

OVERALL PERFORMANCES			
		CASE 5.3.1	**CASE 5.3 (reference)**
Coal Flowrate (as received)	t/h	349.1	349.1
Coal LHV (as received)	kJ/kg	25870	25870
Coal HHV (as received)	kJ/kg	27060	27060
THERMAL ENERGY OF FEEDSTOCK	**MWth (LHV)**	**2509**	**2509**
THERMAL ENERGY OF FEEDSTOCK	**MWth (HHV)**	**2624**	**2624**
Thermal Power of Raw Syngas exit Scrubber	MWth (LHV)	1785	1785
Thermal power of syngas to AGR	MWth (LHV)	1638	1638
Thermal Power of Clean Syngas to Hydrogen PSA	MWth (LHV)	1600	1600
Thermal Power of offgas to boiler island	MWth (LHV)	210	210
HYDROGEN PRODUCTION	**Nm3/h**	**465700**	**465700**
Thermal Power of Hydrogen	**MWth (LHV)**	**1390**	**1390**
Steam turbine electric power output	MWe	253.4	259.1
GROSS ELECTRIC POWER OUTPUT OF STEAM CYCLE	**MWe**	**253.4**	**259.1**
Gasification Section units consumption	MWe	32.3	31.7
ASU consumption	MWe	137.5	137.5
Steam Cycle auxiliaries consumption	MWe	9.2	9.1
CO2 Compression and Dehydration unit consumption	MWe	40.0	34.0
Utility Units consumption	MWe	10.0	9.8
ELECTRIC POWER CONSUMPTION OF GASIFICATION COMPLEX	**MWe**	**229.0**	**222.0**
NET ELECTRIC POWER OUTPUT OF IGCC (Step-up transformer Eff. = 0.997)	**MWe**	**24.3**	**37.0**
CO_2 emission per net power production (*)	**kg/MWh**	**18.1**	**93.7**

(*) Referred to the net power production fo case 4.2

With respect to the reference case, the following consideration can be made:

- Gross power production is lower due to the higher steam required by the additional amine unit. In fact, the additional steam generation reduces the heat available in the syngas cooling for BFW pre-heating, resulting in a lower steam production in the gasifier and in the boiler.
- The net power output decreases, due to the above consideration and to the increased electrical consumptions (around +3%) related to the required higher capture rate.

The following Table shows the overall CO_2 balance and removal efficiency of Case 5.3.1, compared with the reference case.

	CASE 5.3.1	**CASE 5.3 (reference)**
CO_2 removal efficiency	**Equivalent flow of CO_2** kmol/h	**Equivalent flow of CO_2** kmol/h
INPUT		
Fuel Mix (Carbon AR)	18730	18730
TOTAL (A)	18730	18730
OUTPUT		
Slag + Waste water (B)	101	101
CO_2 product pipeline		
CO	7	7
CO_2	18261	16759
CH_4	0	0
COS	0	0
Total to storage (C)	18269	16766
Emission		
CO_2 + CO (Combined Cycle)	360	1862
TOTAL	18730	18730
Overall Carbon Capture, % ((B+C)/A)	98.1	90.1

7. Environmental impact

Main gaseous emissions, liquid effluents, and solid wastes from the plant are summarized in the following sections.

7.1. Gaseous emissions

As for the reference case, main continuous emissions during normal operation are the flue gases from the boilers' stack. Table 6 summarises expected flow rate and concentration of the combustion flue gas from both the boiler included in the power island. The differences in the flue gas composition with respect to the reference case are related to the lower carbon content of the PSA-offgas, due to the higher carbon removal efficiency target. The same minor and fugitive emissions, related to leakages within the handling of solid materials, are valid for these alternative systems.

Table 6. Case 5.3.1 – Plant emission during normal operation

Flue gas to Boiler stack	
Emission type	Continuous
Conditions	
Wet gas flowrate, kg/h	255,900
Flow, Nm^3/h (1)	218,000
Temperature, °C	140-150
Composition	(% vol)
Ar	0.70
N_2	67.37
O_2	0.31
CO_2	2.63
H_2O	28.99
Emission	mg/Nm^3 (1)
NOx	< 150
SOx	< 10
Particulate	< 10

(1) Dry gas, O_2 content 6% vol.

7.2. Liquid effluents

As per the reference case, Main liquid effluents are the cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids, and the effluent from the Waste Water Treatment, which flows to an outside plant battery limits recipient.

Cooling Tower blow-down

Flowrate : 280 m^3/h

Waste Water Treatment effluent

Flowrate : 125 m^3/h

7.3. Solid effluents

No difference is expected in the production of solid by-products with respect to the reference case.

8. Main equipment design changes

The overleaf equipment summary table shows the major design differences between the present Case 5.3.1 and the reference Case 5.3.

FOSTER WHEELER	CLIENT: IEAGHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: 5.3.1 - H2 production plant- High capture case	REVISION DATE ISSUED BY CHECKED BY APPROVED BY	Rev.: Draft August 13 LC NF LM	Rev.: 1	Rev.2	Rev.3

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	Difference with respect to reference case
	UNIT 2200 - Syngas Treatment and conditioning line (2x50%)					
	LP steam generator BFW pre-heaters Condensate pre-heater Final syngas cooler					**Size increased** **Size increased** **Size increased** **Size decreased**
	UNIT 2350 - Amine Guard FS Process Unit (1x100%)					
Z - 2351	**Amine Guard FS Process, including:** One amine absorber one amine stripper total carbon capture: 85.3%	Solvent: amine	Feed gas: 588,200 Nm3/h 54 barg 15 °C			**To be added**
	Unit 2500 - CO_2 compression Unit (2 x 50%)					
	CO2 compression Unit (2 x 50%)		Feed gas flowrate: 224300 Nm3/h			**Size changed (+ 16%)**

CLIENT	:	IEAGHG
PROJECT NAME	:	CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
DOCUMENT NAME	:	ECONOMICS
FWI CONTRACT	:	1-BD-0681 A

ISSUED BY	:	L. CASTRONUOVO
CHECKED BY	:	N. FERRARI
APPROVED BY	:	L. MANCUSO

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENTS

1. Introduction

Purpose of this chapter is to present the results of the economic analysis, carried out to evaluate the Levelized Cost of Electricity (LCOE) and the CO_2 Avoidance Cost (CAC) of the study cases, or the Levelized Cost of Hydrogen (LCOH) production for the hydrogen and power co-production cases.

Capital cost and operating & maintenance (O&M) costs for the different cases have been evaluated and are presented in this chapter, along with the results of the financial model.

All economical inputs used to perform this analysis are set in accordance with the economic bases reported in chapter B of this report.

Due to the possible floating of some economic input data, an exhaustive sensitivity analysis is also performed and presented in this chapter on key parameters such as:

- Fuel cost,
- Plant life (project duration),
- Discount rate,
- Costs related to CO_2 emission or transport & storage.

A full economical assessment is made for all the main study cases, whose major characteristics are summarized in the overleaf Table 1, consisting of: three (3) pulverised boiler based plants (Case 1 to Case 3), three (3) IGCC-based plants (Case 4.1 to Case 4.3) and three (3) hydrogen and power co-production plants (Case 5.1 to Case 5.3).

For the sensitivity cases of the study, made to assess woody biomass co-firing, near-zero emissions and sensitivity to alternative types of cooling system, a delta capital cost with respect to the relevant reference case is also evaluated and presented in this chapter. The sensitivity study cases are listed in Table 2.

All the technical features of these cases are given in the previous chapters of the report. The following sections provide the results of the economical modelling only.

Table 1. Study cases

Type	Case	Plant type	CO_2 capture target	Key technological features
Boiler-based	Case 1 (reference)	SC PC	-	• Alstom Wet limestone scrubbing FGD
	Case 2	SC PC w CCS	90%	• Alstom Wet limestone scrubbing FGD • CANSOLV solvent scrubbing (post-comb. capture)
	Case 3	Oxy-SC PC	90%	• FW Energie Circulating Fluid Bed Scrubber CFBS FGD technology • Air Products' Cryogenic Purification Unit
IGCC-based	Case 4.1	IGCC	90%	• Shell Coal Gasification Process withSyngas Cooler • UOP Selexol solvent scrubbing • Two (2) F-class gas turbines (~275 MWe eq. NG)
	Case 4.2	IGCC	90%	• General Electric, Radiant Syngas Cooler • UOP Selexol solvent scrubbing • Two (2) F-class gas turbines (~275 MWe eq. NG)
	Case 4.3	IGCC	90%	• MHI, Air-Blown two-stage entrained-bed gasifier • UOP Selexol solvent scrubbing • Two (2) MHI 701 F4 gas turbines
H_2 & Power	Case 5.1	IGCC + H_2 (PSA)	90%	• General Electric, Radiant Syngas Cooler • UOP Selexol solvent scrubbing • Two (2) E-class gas turbines (~ 130 MWe eq. NG)
	Case 5.2	IGCC + H_2 (PSA)	90%	• General Electric, Radiant Syngas Cooler • UOP Selexol solvent scrubbing • Two (2) frame 6 (~ 77 MWe eq. NG)
	Case 5.3	Gasification + Boiler + H_2 (PSA)	90%	• General Electric, Radiant Syngas Cooler • UOP Selexol solvent scrubbing • Off-gas based Boiler to mostly cover auxiliary power demand of the plant

Table 2. - Sensitivity study cases

Case	Plant type	CO_2 capture target	Key technological features
Case 2.1	SC PC w CCS	100	As Case 2 + woody biomass co-firing (zero CO_2 emission)
Case 3.1	Oxy-SC PC	98-99%	As Case 3 + Air Products' PRISM membranes
Case 4.2.1	IGCC	98-99%	As Case 4.2 + additional MDEA solvent scrubbing
Case 5.3.1	Gasification + Boiler + H_2 (PSA)	98-99%	As Case 5.3 + additional MDEA solvent scrubbing
Case 1(SW)	SC PC	-	As Case 1, with seawater cooling
Case 1(AC)	SC PC	-	As Case 1, with air cooling
Case 2(SW)	SC PC w CCS	90%	As Case 2, with seawater cooling
Case 2(AC)	SC PC w CCS	90%	As Case 2, with air cooling
Case 3(SW)	Oxy-SC PC	90%	As Case 3, with seawater cooling
Case 3(AC)	Oxy-SC PC	90%	As Case 3, with air cooling
Case 4.2 (SW)	IGCC	90%	As Case 4.2, with seawater cooling
Case 4.2 (AC)	IGCC	90%	As Case 4.2, with air cooling

2. Capital cost

2.1. Definitions

Main cost estimating basis are described in chapter B of this report. This section provides details on the Total Capital Requirement (TCR), also named as Total Investment Cost (TIC), of the various study cases.

TCR is defined in general accordance with the White Paper "*Toward a common method of cost estimation for CO_2 capture and storage at fossil fuel power plants*", (March 2013), produced collaboratively by authors from EPRI, IEAGHG, Carnegie Mellon University, MIT, IEA, GCCSI and Vattenfall.

The **Total Capital Requirement** (**TCR**) is defined as the sum of:

- Total Plant Cost (**TPC**)
- Interest during construction
- Spare parts cost
- Working capital
- Start-up costs
- Owner's costs.

The Total Plant Cost (TPC) is the installed cost of the plant, including contingencies.

The TPC of the different study cases is presented in the following sections, broken down into the following main process units:

- SC-PC-based cases:
    - Solids handling
    - Boiler
    - DeNOx
    - FGD
    - Steam Cycle
    - CO_2 capture (Post-combustion capture cases)
    - CO_2 compression and dehydration (Oxy-combustion cases)
    - ASU (Oxy-combustion cases)
    - Utilities & offsites (including cooling system, electrical system, process and waste water system and other offsites).
- Gasification-based cases (power or power and hydrogen co-production):
    - Solids handling
    - Gasification Island
    - ASU

- Syngas treatment and conditioning line
- AGR
- SRU & TGT
- PSA (hydrogen cases)
- Combined Cycle (or Boiler Island)
- CO_2 compression and dehydration
- Utilities & offsites (e.g. cooling system, electrical system, demineralised water).

Moreover, for each process unit, the TPC is split into the following items, as further discussed in the next sections:

- Direct materials
- Construction
- EPC services
- Other costs
- Contingency.

2.2. Estimating methodology

The estimate is an AACE Class 4 estimate (accuracy range +35%/-15%), based on 2Q2013 price level, in euro (€).

2.2.1. Total Plant Cost

The estimating methodology used by FW for the evaluation of the Total Plant Cost (TPC) items of the process units is described in the following sections.

Direct materials

For each different process unit, direct materials are estimated using company in-house database or conceptual estimating models.

Where detailed and sized equipment list has been developed, K-base (commercially available software) run has been made for the equipment estimate. For units having capacity only, cost is based on previous estimates done for similar units, by scaling up or down (as applicable) the cost on capacity ratio.

For some cases of the study, technology suppliers provided specific budgetary quotations for certain equipment or units of the plant, which have been used as basis for the estimate of the case. These include the following main systems or units:

- Gasification Island;
- CO_2 capture units (AGR);
- FGD.

Construction and EPC services

For each unit or block of units, construction and EPC services are factored on the direct materials costs; factor multipliers are based on FW in-house data from cost estimates made in the past for similar plants.

Other costs

Other costs mainly include:

- Temporary facilities;
- Freight, taxes and insurance;
- License fees.

Temporary facilities, freight, taxes, insurance and license fees are estimated as a percentage of the construction cost, in accordance with Foster Wheeler experience and in-house data bank.

Contingency

A project contingency is added to the capital cost to give a 50% probability of a cost over-run or under-run. For the accuracy considered in this study, FW's view is that contingency should be in the range of 10-15% of the total plant cost. 10% is assumed for this study for all the different units of the plant, for consistency with the other IEAGHG studies.

A process contingency is not added to the plant cost, because processes are not considered to be at very early stage of development and their design, performance, and costs are not highly uncertain.

2.2.2. *Total Capital Requirement*

As written before, Total Capital Requirement (TCR) is the sum of the TPC and following items:

- Interest during construction, assumed same as discount rate (8%).
- Spare parts cost, assumed as 0.5% of TPC.
- Working capital, including 30 days inventories of fuel and chemicals.
- Start-up costs, assumed as 2% of TPC, plus 25% of fuel cost for one month, plus 3 months O&M costs and 1 month of catalyst, chemicals etc.
- Owner's costs, assumed as 7% of TPC.

Further details on the above cost items are shown in chapter B of the report.

2.3. Total Plant Cost summary

Table 4 to Table 9 show the TPC of the different study cases listed in Table 1. Each table is followed by the related pie chart of the total plant cost to show the percentage weight of each unit on the overall capital cost of the plant.

Total Plant Cost and Total Capital Requirement figures for the different cases are also reported in the below table for summary purpose.

For the power production cases, the specific costs, defined as the ratio between either the TPC or the TCR and the net power output, are also reported.

Table 3. TPC and TCR of study cases

Type	Case	Total Plant Cost (TPC) (M€)	Total Capital Requirement (TCR) (M€)	Specific cost [TPC/Net Power] (€/kW)	Specific cost [TCR/Net Power] (€/kW)
Boiler-based	Case 1	1,490	1,943	1,447	1,887
	Case 2	2,279	2,961	2,771	3,600
	Case 3	2,301	2,986	2,761	3,583
IGCC-based	Case 4.1	2,538	3,497	3,157	4,350
	Case 4.2	2,688	3,705	3,074	4,238
	Case 4.3	2,629	3,625	3,046	4,200
H_2 & Power	Case 5.1	2,461	3,394	N/A	N/A
	Case 5.2	2,390	3,297	N/A	N/A
	Case 5.3	2,101	2,901	N/A	N/A

2.3.1. *SC PC-based cases*

The following tables and figures show the Total Plant Cost summary of the SC PC-based cases.

Table 4. Case 1 – Total Plant Cost

FOSTER WHEELER

CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
CASE 1 - SC PC WITHOUT CARBON CAPTURE

CONTRACT: 1-BD-0681A
CLIENT: IEA GHG
LOCATION: THE NETHERLANDS
DATE: MAY 2013
REV.: 0

POS.	DESCRIPTION	UNIT 1000 Feedstock & Solid Handling	UNIT 2000 Boiler Island	UNIT 2050 DeNOx	UNIT 2100 Flue Gas Desulfurization	UNIT 3000 Steam Cycle	UNIT 6000 Utility Units	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIAL	76,700,000	284,400,000	26,200,000	48,000,000 (3)	177,500,000	153,200,000	766,000,000	**1) Total Installed Power: 1077 MW Average Cost: 1,384 €/kW**
2	CONSTRUCTION	28,700,000	175,600,000	5,400,000	16,500,000	62,700,000	72,200,000	361,100,000	**2) Total Net Power: 1029 MW**
3	**DIRECT FIELD COST**	**105,400,000**	**460,000,000**	**31,600,000**	**64,500,000**	**240,200,000**	**225,400,000**	**1,127,100,000**	**Average Cost: 1,488 €/kW**
4	OTHER COSTS	6,100,000	31,400,000	1,400,000	3,600,000	13,500,000	14,000,000	70,000,000	**(3) Including 12 M€ for the gas-gas heater**
5	EPC SERVICES	14,700,000	64,400,000	4,400,000	9,100,000	33,600,000	31,500,000	157,700,000	
6	**TOTAL INSTALLED COST**	**126,200,000**	**555,800,000**	**37,400,000**	**77,200,000**	**287,300,000**	**270,900,000**	**1,354,800,000**	
7	PROJECT CONTINGENCY	12,600,000	55,600,000	3,700,000	7,800,000	28,700,000	27,100,000	135,500,000	
8	PROCESS CONTINGENCY	-	-	-	-	-	-	-	
9	**TOTAL PLANT COST**	**138,800,000**	**611,400,000**	**41,100,000**	**85,000,000**	**316,000,000**	**298,000,000**	**1,490,300,000**	

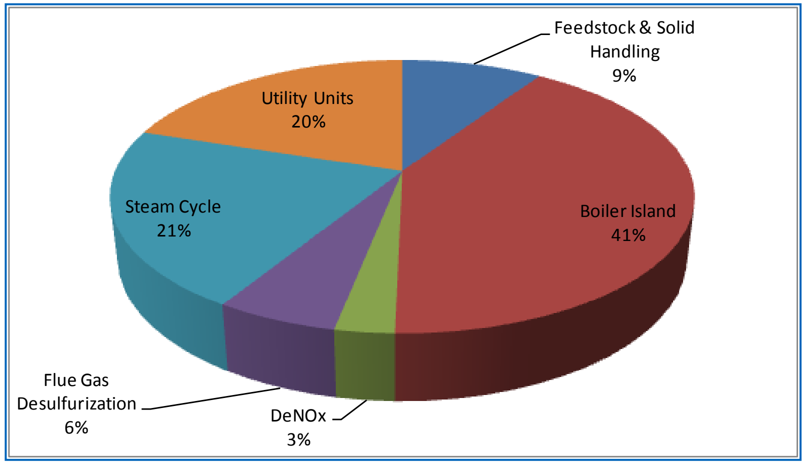

Figure 1. Case 1 – Unit percentage weight on TPC

Table 5. Case 2 – Total Plant Cost

FOSTER WHEELER

CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
CASE 2 - SC PC WITH CARBON CAPTURE

CONTRACT: 1-BD-0681A
CLIENT: IEA GHG
LOCATION: THE NETHERLANDS
DATE: MAY 2013
REV.: 0

POS.	DESCRIPTION	UNIT 1000 Feedstock & Solid Handling	UNIT 2000 Boiler Island	UNIT 2050 DeNOx	UNIT 2100 Flue Gas Desulfurization	UNIT 3000 Steam Cycle	UNIT 4000 CO2 Amine Absorption	UNIT 5000 CO2 Compression	UNIT 6000 Utility Units	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIAL	76,700,000	284,400,000	26,200,000	49,600,000 (3)	166,300,000	326,400,000	43,500,000	242,800,000	1,215,900,000	1) Total Installed Power: 958 MW
										-	Average Cost: 2,379 €/kW
2	CONSTRUCTION	28,700,000	175,600,000	5,400,000	18,500,000	62,700,000	86,200,000	31,400,000	102,600,000	511,100,000	
										-	2) Total Net Power: 822 MW
3	**DIRECT FIELD COST**	**105,400,000**	**460,000,000**	**31,600,000**	**68,100,000**	**229,000,000**	**412,600,000**	**74,900,000**	**345,400,000**	**1,727,000,000**	Average Cost: 2,772 €/kW
										-	
4	OTHER COSTS	6,100,000	31,400,000	1,400,000	4,200,000	13,200,000	21,000,000	5,300,000	20,700,000	103,300,000	(3) Including 12 M€ for the gas-gas heater
										-	
5	EPC SERVICES	14,700,000	64,400,000	4,400,000	9,600,000	32,100,000	57,900,000	10,500,000	48,300,000	241,900,000	
										-	
6	**TOTAL INSTALLED COST**	**126,200,000**	**555,800,000**	**37,400,000**	**81,900,000**	**274,300,000**	**491,500,000**	**90,700,000**	**414,400,000**	**2,072,200,000**	
										-	
7	PROJECT CONTINGENCY	12,600,000	55,600,000	3,700,000	8,100,000	27,400,000	49,200,000	9,100,000	41,400,000	207,100,000	
										-	
8	PROCESS CONTINGENCY	-	-	-	-	-	-	-	-	-	
										-	
9	**TOTAL PLANT COST**	**138,800,000**	**611,400,000**	**41,100,000**	**90,000,000**	**301,700,000**	**540,700,000**	**99,800,000**	**455,800,000**	**2,279,300,000**	

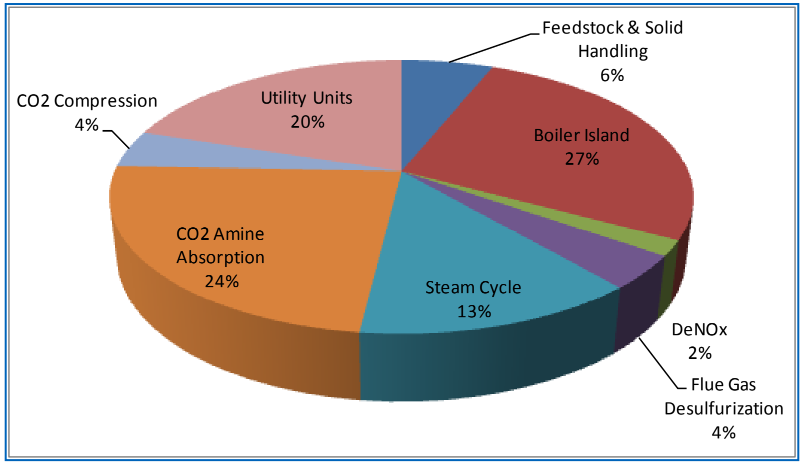

Figure 2. Case 2 – Unit percentage weight on TPC

Table 6. Case 3 – Total Plant Cost

CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
CASE 3 - OXYCOMBUSTION BOILER

CONTRACT: 1-BD-0681A
CLIENT: IEA GHG
LOCATION: THE NETHERLANDS
DATE: MAY 2013
REV.: 0

POS.	DESCRIPTION	UNIT 900 ASU	UNIT 1000 Feedstock & Solid Handling	UNIT 2000 Boiler Island	UNIT 2100 Flue Gas Desulfurization	UNIT 3000 Steam Cycle	UNIT 4000 CPU	UNIT 6000 Utility Units	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIAL	268,100,000	76,700,000	284,400,000	25,000,000	182,800,000	151,000,000	247,000,000	1,235,000,000	**1) Total Installed Power: 1101 MW** **Average Cost: 2,090 €/kW**
2	CONSTRUCTION	90,400,000	28,700,000	175,600,000	8,800,000	62,700,000	44,500,000	102,700,000	513,400,000	
3	**DIRECT FIELD COST**	**358,500,000**	**105,400,000**	**460,000,000**	**33,800,000**	**245,500,000**	**195,500,000**	**349,700,000**	**1,748,400,000**	**2) Total Net Power: 833 MW** **Average Cost: 2,762 €/kW**
4	OTHER COSTS	19,800,000	6,100,000	31,400,000	1,900,000	13,700,000	4,500,000	20,800,000	98,200,000	
5	EPC SERVICES	50,300,000	14,700,000	64,400,000	4,800,000	34,400,000	27,400,000	49,000,000	245,000,000	
6	**TOTAL INSTALLED COST**	**428,600,000**	**126,200,000**	**555,800,000**	**40,500,000**	**293,600,000**	**227,400,000**	**419,500,000**	**2,091,600,000**	
7	PROJECT CONTINGENCY	42,900,000	12,600,000	55,600,000	4,100,000	29,400,000	22,600,000	42,000,000	209,200,000	
8	PROCESS CONTINGENCY	-	-	-	-	-	-	-	-	
9	**TOTAL PLANT COST**	**471,500,000**	**138,800,000**	**611,400,000**	**44,600,000**	**323,000,000**	**250,000,000**	**461,500,000**	**2,300,800,000**	

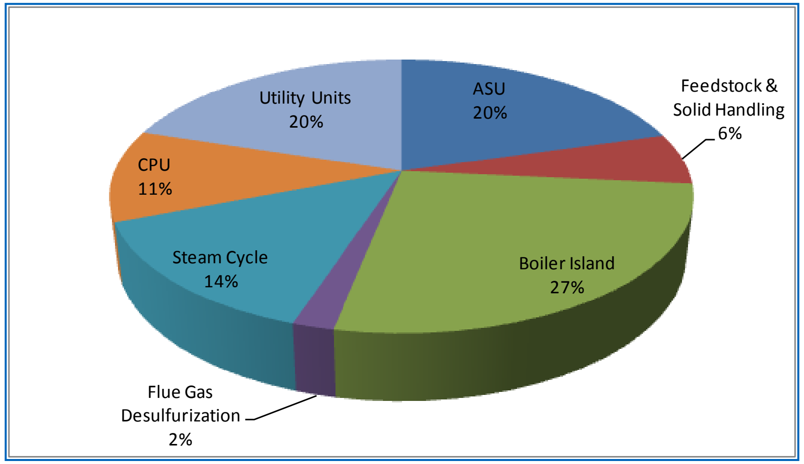

Figure 3. Case 3 – Unit percentage weight on TPC

2.3.2. IGCC-based cases

The following tables and figures show the Total Plant Cost summary of the IGCC-based cases.

Table 7. Case 4.1 – Total Plant Cost

FOSTER WHEELER

CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
CASE 4.1 - SHELL BASED IGCC with CARBON CAPTURE

CONTRACT: 1-BD-0681A
CLIENT: IEA GHG
LOCATION: THE NETHERLANDS
DATE: MAY 2013
REV.: 0

POS.	DESCRIPTION	UNIT 900 Solid Handling	UNIT 1000 Gasification Island	UNIT 2100 ASU	UNIT 2200 Syngas Treatment & Sour Water System	UNIT 2300 AGR	UNIT 2400 SRU & TGT	UNIT 2500 CO2 Compression	UNIT 3000 Combined Cycle	UNIT 4000 Utility & Offsites	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIALS	50,000,000	335,000,000	164,000,000	64,800,000	63,000,000	48,500,000	35,000,000	335,000,000	219,100,000	1,314,400,000	**1) Total Installed Power: 1063 MW** **Average Cost: 2,387 €/kW**
2	CONSTRUCTION	17,400,000	140,000,000	70,000,000	41,300,000	47,000,000	30,000,000	24,500,000	150,000,000	62,000,000	582,200,000	**2) Total Net Power: 807 MW**
3	**DIRECT FIELD COST**	**67,400,000**	**475,000,000**	**234,000,000**	**106,100,000**	**110,000,000**	**78,500,000**	**59,500,000**	**485,000,000**	**281,100,000**	**1,896,600,000**	**Average Cost: 3,145 €/kW**
4	OTHER COSTS	3,700,000	23,500,000	11,700,000	7,300,000	8,000,000	5,400,000	4,300,000	29,600,000	14,600,000	108,100,000	
5	EPC SERVICES	10,700,000	76,000,000	37,500,000	15,900,000	17,600,000	12,600,000	9,500,000	77,600,000	44,900,000	302,300,000	
6	**TOTAL INSTALLED COST**	**81,800,000**	**574,500,000**	**283,200,000**	**129,300,000**	**135,600,000**	**96,500,000**	**73,300,000**	**592,200,000**	**340,600,000**	**2,307,000,000**	
7	PROJECT CONTINGENCY	8,200,000	57,500,000	28,300,000	12,900,000	13,500,000	9,700,000	7,300,000	59,200,000	34,100,000	230,700,000	
8	PROCESS CONTINGENCY	-	-	-	-	-	-	-	-	-	-	
9	**TOTAL PLANT COST**	**90,000,000**	**632,000,000**	**311,500,000**	**142,200,000**	**149,100,000**	**106,200,000**	**80,600,000**	**651,400,000**	**374,700,000**	**2,537,700,000**	

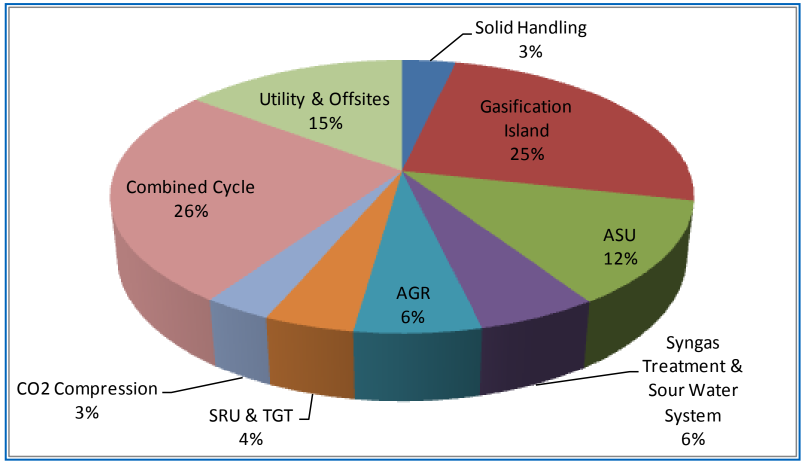

Figure 4. Case 4.1 – Unit percentage weight on TPC

Table 8. Case 4.2 – Total Plant Cost

CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
CASE 4.2 - GE BASED IGCC with CARBON CAPTURE

CONTRACT: 1-BD-0681A
CLIENT: IEA GHG
LOCATION: THE NETHERLANDS
DATE: MAY 2013
REV.: 0

POS.	DESCRIPTION	UNIT 900 Solid Handling	UNIT 1000 Gasification Island	UNIT 2100 ASU	UNIT 2200 Syngas Treatment & Sour Water System	UNIT 2300 AGR	UNIT 2400 SRU & TGT	UNIT 2500 CO2 Compression	UNIT 3000 Combined Cycle	UNIT 4000 Utility & Offsites	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIALS	55,000,000	345,000,000	194,000,000	67,350,000	64,000,000	52,000,000	36,400,000	348,000,000	232,400,000	1,394,150,000	**1) Total Installed Power: 1141 MW** **Average Cost: 2,356 €/kW**
2	CONSTRUCTION	19,700,000	145,000,000	80,000,000	41,700,000	49,000,000	33,000,000	25,500,000	156,000,000	65,000,000	614,900,000	
3	**DIRECT FIELD COST**	**74,700,000**	**490,000,000**	**274,000,000**	**109,050,000**	**113,000,000**	**85,000,000**	**61,900,000**	**504,000,000**	**297,400,000**	**2,009,050,000**	**2) Total Net Power: 874 MW** **Average Cost: 3,076 €/kW**
4	OTHER COSTS	4,200,000	24,300,000	13,500,000	7,500,000	8,300,000	5,900,000	4,400,000	30,700,000	15,400,000	114,200,000	
5	EPC SERVICES	12,000,000	78,400,000	43,900,000	16,400,000	18,200,000	13,600,000	9,800,000	80,700,000	47,500,000	320,500,000	
6	**TOTAL INSTALLED COST**	**90,900,000**	**592,700,000**	**331,400,000**	**132,950,000**	**139,500,000**	**104,500,000**	**76,100,000**	**615,400,000**	**360,300,000**	**2,443,750,000**	
7	PROJECT CONTINGENCY	9,100,000	59,300,000	33,100,000	13,300,000	13,900,000	10,500,000	7,600,000	61,500,000	36,000,000	244,300,000	
8	PROCESS CONTINGENCY	-	-	-	-	-		-	-	-	-	
9	**TOTAL PLANT COST**	**100,000,000**	**652,000,000**	**364,500,000**	**146,250,000**	**153,400,000**	**115,000,000**	**83,700,000**	**676,900,000**	**396,300,000**	**2,688,050,000**	

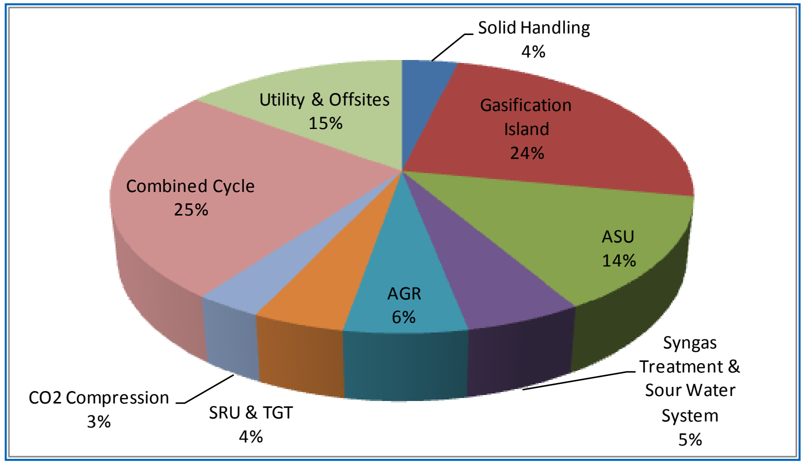

Figure 5. Case 4.2 – Unit percentage weight on TPC

Table 9. Case 4.3 – Total Plant Cost

FOSTER WHEELER

CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
CASE 4.3 - MHI BASED IGCC with CARBON CAPTURE

CONTRACT: 1-BD-0681A
CLIENT: IEA GHG
LOCATION: THE NETHERLANDS
DATE: MAY 2013
REV.: 0

POS.	DESCRIPTION	UNIT 900 Solid Handling	UNIT 1000 Gasification Island	UNIT 2100 ASU	UNIT 2200 Syngas Treatment	UNIT 2300 AGR	UNIT 2400 SRU & TGT	UNIT 2500 CO2 Compression	UNIT 3000 Combined Cycle	UNIT 4000 Utility & Offsites	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIALS	55,000,000	450,000,000	INCLUDED in UNIT 1000	105,000,000	93,000,000	55,000,000	37,000,000	335,000,000	227,350,000	1,357,350,000	**1) Total Installed Power: 1093 MW** **Average Cost: 2,405 €/kW**
2	CONSTRUCTION	19,700,000	190,000,000	INCLUDED in UNIT 1000	47,000,000	70,000,000	34,500,000	25,700,000	150,000,000	69,750,000	606,650,000	
3	**DIRECT FIELD COST**	**74,700,000**	**640,000,000**	**0**	**152,000,000**	**163,000,000**	**89,500,000**	**62,700,000**	**485,000,000**	**297,100,000**	**1,964,000,000**	**2) Total Net Power: 863 MW** **Average Cost: 3,046 €/kW**
4	OTHER COSTS	4,200,000	31,800,000	-	9,200,000	11,900,000	6,200,000	4,500,000	29,600,000	15,900,000	113,300,000	
5	EPC SERVICES	12,000,000	102,400,000	-	22,700,000	26,200,000	14,300,000	10,100,000	77,600,000	47,500,000	312,800,000	
6	**TOTAL INSTALLED COST**	**90,900,000**	**774,200,000**	**0**	**183,900,000**	**201,100,000**	**110,000,000**	**77,300,000**	**592,200,000**	**360,500,000**	**2,390,100,000**	
7	PROJECT CONTINGENCY	9,100,000	77,400,000	-	18,400,000	20,100,000	11,000,000	7,700,000	59,200,000	36,100,000	239,000,000	
8	PROCESS CONTINGENCY	-	-	-	-	-		-	-	-	-	
9	**TOTAL PLANT COST**	**100,000,000**	**851,600,000**	**0**	**202,300,000**	**221,200,000**	**121,000,000**	**85,000,000**	**651,400,000**	**396,600,000**	**2,629,100,000**	

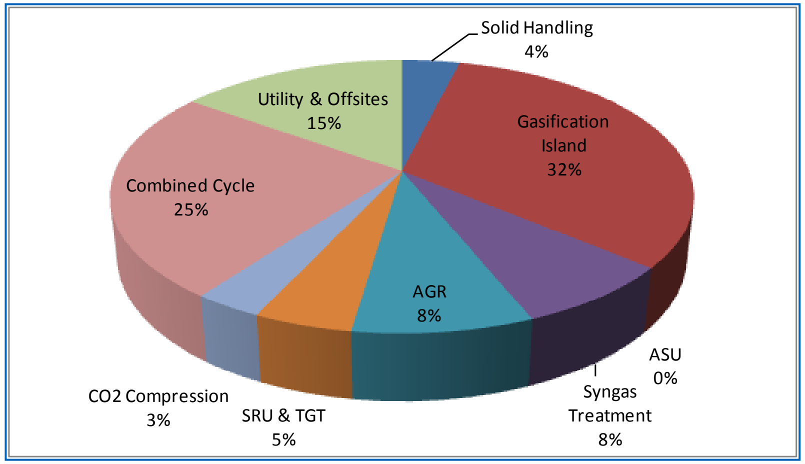

Figure 6. Case 4.3 – Unit percentage weight on TPC

2.3.3. Gasification based cases for H_2 and power co-production

The following tables and figures show the Total Plant Cost summary of the hydrogen and power co-production cases.

Table 10. Case 5.1 – Total Plant Cost

CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
CASE 5.1 - IGCC (GE Energy) HYDROGEN PRODUCTION - CLASS E GTs

CONTRACT: 1-BD-0681A
CLIENT: IEA GHG
LOCATION: THE NETHERLANDS
DATE: MAY 2013
REV.: 0

POS.	DESCRIPTION	UNIT 900 Solid Handling	UNIT 1000 Gasification Island	UNIT 2100 ASU	UNIT 2200 Syngas Treatment & Sour Water System	UNIT 2300 AGR	UNIT 2400 SRU & TGT	UNIT 2500 CO2 Compression	UNIT 2600 Hydrogen Production	UNIT 3000 Combined Cycle	UNIT 4000 Utility & Offsites	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIALS	55,000,000	345,000,000	194,000,000	67,350,000	64,000,000	52,000,000	36,400,000	13,000,000	250,000,000	196,800,000	1,273,550,000	
2	CONSTRUCTION	19,700,000	145,000,000	80,000,000	41,700,000	49,000,000	33,000,000	25,500,000	8,000,000	110,000,000	54,400,000	566,300,000	
3	**DIRECT FIELD COST**	**74,700,000**	**490,000,000**	**274,000,000**	**109,050,000**	**113,000,000**	**85,000,000**	**61,900,000**	**21,000,000**	**360,000,000**	**251,200,000**	**1,839,850,000**	
4	OTHER COSTS	4,200,000	24,300,000	13,500,000	7,500,000	8,300,000	5,900,000	4,400,000	1,400,000	21,800,000	12,900,000	104,200,000	
5	EPC SERVICES	12,000,000	78,400,000	43,900,000	16,400,000	18,200,000	13,600,000	9,800,000	3,300,000	57,600,000	40,100,000	293,300,000	
6	**TOTAL INSTALLED COST**	**90,900,000**	**592,700,000**	**331,400,000**	**132,950,000**	**139,500,000**	**104,500,000**	**76,100,000**	**25,700,000**	**439,400,000**	**304,200,000**	**2,237,350,000**	
7	PROJECT CONTINGENCY	9,100,000	59,300,000	33,100,000	13,300,000	13,900,000	10,500,000	7,600,000	2,600,000	43,900,000	30,400,000	223,700,000	
8	PROCESS CONTINGENCY	-	-	-	-	-		-	-	-	-	-	
9	**TOTAL PLANT COST**	**100,000,000**	**652,000,000**	**364,500,000**	**146,250,000**	**153,400,000**	**115,000,000**	**83,700,000**	**28,300,000**	**483,300,000**	**334,600,000**	**2,461,050,000**	

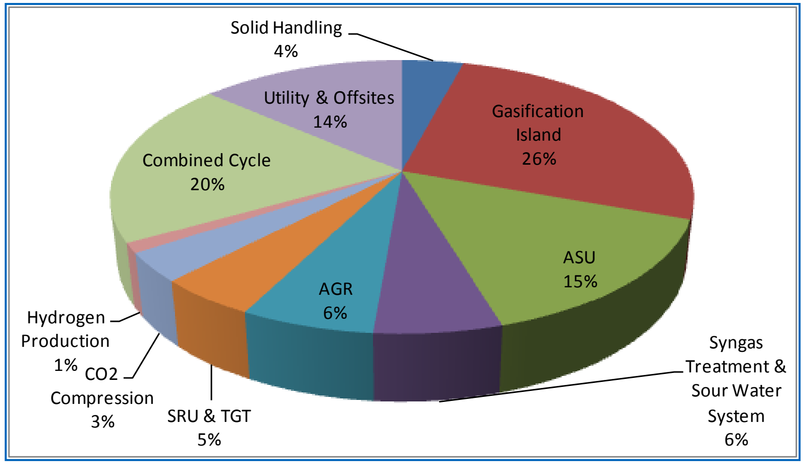

Figure 7. Case 5.1 – Unit percentage weight on TPC

Table 11. Case 5.2 – Total Plant Cost

CO_2 CAPTURE AT COAL BASED POWER AND HYDROGEN PLANTS
CASE 5.2 - IGCC (GE Energy) HYDROGEN PRODUCTION - FRAME 6 GTs

CONTRACT: 1-BD-0681A
CLIENT: IEA GHG
LOCATION: THE NETHERLANDS
DATE: SEPTEMBER 2013
REV.: 0

POS.	DESCRIPTION	UNIT 900 Solid Handling	UNIT 1000 Gasification Island	UNIT 2100 ASU	UNIT 2200 Syngas Treatment & Sour Water System	UNIT 2300 AGR	UNIT 2400 SRU & TGT	UNIT 2500 CO2 Compression	UNIT 2600 Hydrogen Production	UNIT 3000 Combined Cycle	UNIT 4000 Utility & Offsites	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIALS	55,000,000	345,000,000	194,000,000	67,350,000	64,000,000	52,000,000	36,400,000	19,000,000	212,000,000	189,800,000	1,234,550,000	
2	CONSTRUCTION	19,700,000	145,000,000	80,000,000	41,700,000	49,000,000	33,000,000	25,500,000	13,000,000	94,000,000	51,300,000	552,200,000	
3	**DIRECT FIELD COST**	**74,700,000**	**490,000,000**	**274,000,000**	**109,050,000**	**113,000,000**	**85,000,000**	**61,900,000**	**32,000,000**	**306,000,000**	**241,100,000**	**1,786,750,000**	
4	OTHER COSTS	4,200,000	24,300,000	13,500,000	7,500,000	8,300,000	5,900,000	4,400,000	2,200,000	18,600,000	12,300,000	101,200,000	
5	EPC SERVICES	12,000,000	78,400,000	43,900,000	16,400,000	18,200,000	13,600,000	9,800,000	5,000,000	48,900,000	38,500,000	284,700,000	
6	**TOTAL INSTALLED COST**	**90,900,000**	**592,700,000**	**331,400,000**	**132,950,000**	**139,500,000**	**104,500,000**	**76,100,000**	**39,200,000**	**373,500,000**	**291,900,000**	**2,172,650,000**	
7	PROJECT CONTINGENCY	9,100,000	59,300,000	33,100,000	13,300,000	14,000,000	10,400,000	7,600,000	3,900,000	37,400,000	29,200,000	217,300,000	
8	PROCESS CONTINGENCY	-	-	-	-	-		-	-	-	-	-	
9	**TOTAL PLANT COST**	**100,000,000**	**652,000,000**	**364,500,000**	**146,250,000**	**153,500,000**	**114,900,000**	**83,700,000**	**43,100,000**	**410,900,000**	**321,100,000**	**2,389,950,000**	

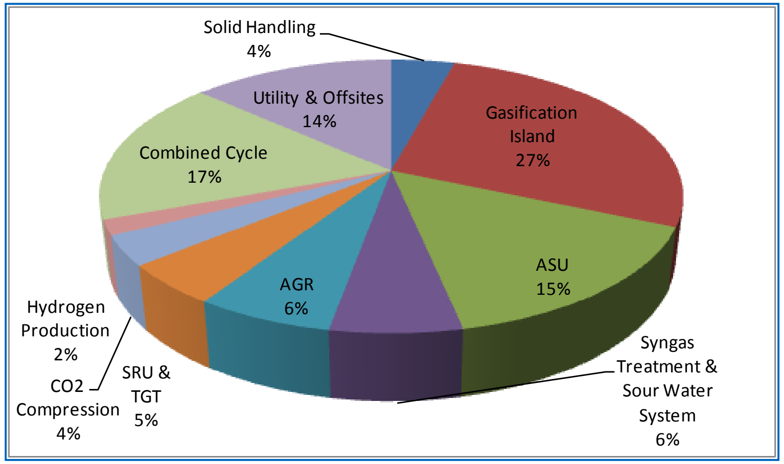

Figure 8. Case 5.2 – Unit percentage weight on TPC

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Table 12. Case 5.3 – Total Plant Cost

FOSTER WHEELER

CO_2 CAPTURE AT BASED POWER AND HYDROGEN PLANTS
CASE 5.3 - IGCC (GE Energy) HYDROGEN PRODUCTION - BOILER

CONTRACT: 1-BD-0681A
CLIENT: IEA GHG
LOCATION: THE NETHERLANDS
DATE: SEPTEMBER 2013
REV.: 0

POS.	DESCRIPTION	UNIT 900 Solid Handling	UNIT 1000 Gasification Island	UNIT 2100 ASU	UNIT 2200 Syngas Treatment & Sour Water System	UNIT 2300 AGR	UNIT 2400 SRU & TGT	UNIT 2500 CO2 Compression	UNIT 2600 Hydrogen Production	UNIT 3000 Steam Cycle (Boiler & ST)	UNIT 4000 Utility & Offsites	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIALS	55,000,000	345,000,000	194,000,000	67,350,000	64,000,000	52,000,000	36,400,000	27,000,000	82,000,000	165,700,000	1,088,450,000	
2	CONSTRUCTION	19,700,000	145,000,000	80,000,000	41,700,000	49,000,000	33,000,000	25,500,000	17,000,000	32,800,000	39,300,000	483,000,000	
3	**DIRECT FIELD COST**	**74,700,000**	**490,000,000**	**274,000,000**	**109,050,000**	**113,000,000**	**85,000,000**	**61,900,000**	**44,000,000**	**114,800,000**	**205,000,000**	**1,571,450,000**	
4	OTHER COSTS	4,200,000	24,300,000	13,500,000	7,500,000	8,300,000	5,900,000	4,400,000	3,000,000	6,700,000	10,100,000	87,900,000	
5	EPC SERVICES	12,000,000	78,400,000	43,900,000	16,400,000	18,200,000	13,600,000	9,800,000	7,100,000	18,400,000	32,800,000	250,600,000	
6	**TOTAL INSTALLED COST**	**90,900,000**	**592,700,000**	**331,400,000**	**132,950,000**	**139,500,000**	**104,500,000**	**76,100,000**	**54,100,000**	**139,900,000**	**247,900,000**	**1,909,950,000**	
7	PROJECT CONTINGENCY	9,100,000	59,300,000	33,100,000	13,300,000	14,000,000	10,400,000	7,600,000	5,400,000	14,000,000	24,800,000	191,000,000	
8	PROCESS CONTINGENCY	-	-	-	-	-		-	-	-	-	-	
9	**TOTAL PLANT COST**	**100,000,000**	**652,000,000**	**364,500,000**	**146,250,000**	**153,500,000**	**114,900,000**	**83,700,000**	**59,500,000**	**153,900,000**	**272,700,000**	**2,100,950,000**	

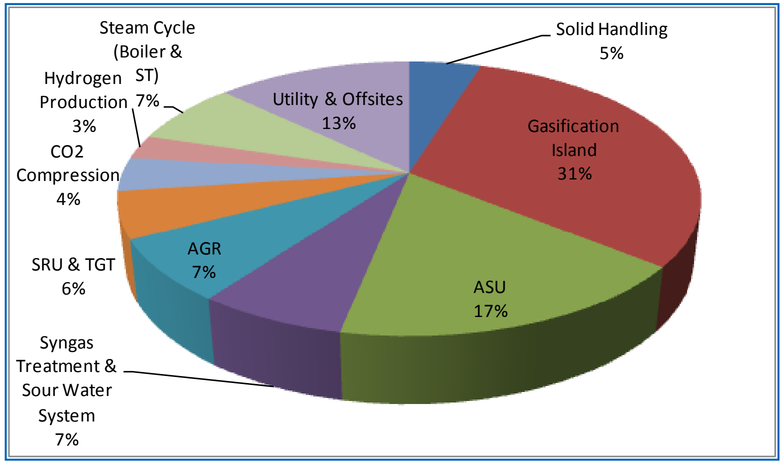


Figure 9. Case 5.3 – Unit percentage weight on TPC

2.3.4. Sensitivity cases

The following tables show the delta Total Plant Cost summary and its breakdown into process units of the sensitivity cases of the study listed in Table 2, made to assess woody biomass co-firing, near-zero emissions and sensitivity to alternative types of cooling system. Black figure represents the cost increase with respect to the reference case, while cost reductions are indicated with red figure in brackets.

Table 13. TPC variation for sensitivity cases

ESTIMATE CASE SUMMARY

CONTRACT: 1-BD-0681A
CLIENT: IEA GHG
LOCATION: THE NETHERLANDS
DATE: SEPTEMBER 2013
REV.: 0

CASE NUMBER	TOTAL COST - MAY 2013	DIRECT MATERIAL COST - EURO					OVERALL PROJECT - EURO			NOTES / REMARKS
		BASE	DELTA EQUIPMENT	DELTA BULK MATERIAL	TOTAL DELTA	TOTAL	TOTAL COST	DELTA COST	DELTA %	
CASE 1 - SC PC W/O CARBON CAPTURE - A.C. SENSITIVITY CASE	1,490,300,000	766,000,000	(29,700,000)	(3,000,000)	(32,700,000)	733,300,000	1,455,000,000	(35,300,000)	(2.4)	
CASE 1 - SC PC W/O CARBON CAPTURE - S.W. SENSITIVITY CASE	1,490,300,000	766,000,000	(8,800,000)	(3,000,000)	(11,800,000)	754,200,000	1,467,300,000	(23,000,000)	(1.5)	
CASE 2 - SC PC WITH CARBON CAPTURE - A.C. SENSITIVITY CASE	2,279,300,000	1,213,900,000	(27,700,000)	(3,000,000)	(30,700,000)	1,183,200,000	2,247,000,000	(32,300,000)	(1.4)	
CASE 2 - SC PC WITH CARBON CAPTURE - S.W. SENSITIVITY CASE	2,279,300,000	1,213,900,000	(11,100,000)	(3,000,000)	(14,100,000)	1,199,800,000	2,252,800,000	(26,500,000)	(1.2)	
CASE 2.1 - SC PC WITH CARBON CAPTURE - CO-FIRING WITH BIOMASS	2,279,300,000	1,213,900,000	23,800,000	5,000,000	28,800,000	1,242,700,000	2,333,400,000	54,100,000	2.4	
CASE 3 - OXYCOMBUSTION BOILER - A.C. SENSITIVITY CASE	2,300,800,000	1,235,000,000	(28,400,000)	(3,000,000)	(31,400,000)	1,203,600,000	2,267,600,000	(33,200,000)	(1.4)	
CASE 3 - OXYCOMBUSTION BOILER - S.W. SENSITIVITY CASE	2,300,800,000	1,235,000,000	(2,600,000)	(600,000)	(3,200,000)	1,231,800,000	2,294,800,000	(6,000,000)	(0.3)	
CASE 3.1 - OXYCOMBUSTION - NEAR ZERO EMISSION	2,300,800,000	1,235,000,000	25,000,000	INCLUDED	25,000,000	1,260,000,000	2,325,800,000	25,000,000	1.1	
CASE 4.2 - GE BASED IGCC - COOLING WATER SENSITIVITY CASE (A.C.)	2,688,050,000	1,394,150,000	(23,200,000)	(2,000,000)	(25,200,000)	1,368,950,000	2,660,500,000	(27,550,000)	(1.0)	
CASE 4.2 - GE BASED IGCC - COOLING WATER SENSITIVITY CASE (S.W.	2,688,050,000	1,394,150,000	(6,100,000)	(1,000,000)	(7,100,000)	1,387,050,000	2,674,400,000	(13,650,000)	(0.5)	
CASE 4.2.1 - GE BASED IGCC - HIGH CAPTURE CASE	2,688,050,000	1,394,150,000	21,900,000	4,000,000	25,900,000	1,420,050,000	2,738,000,000	49,950,000	1.9	
CASE 5.3.1 - HYDROGEN PRODUCTION PLANT - HIGH CAPTURE	2,100,950,000	1,088,450,000	21,000,000	4,000,000	25,000,000	1,113,450,000	2,149,200,000	48,250,000	2.3	

Table 14. Case 1 – Air cooling sensitivity case – Capex breakdown into process units

CLIENT: IEA GHG	REVISION	Rev.: Draft				Rev.: 1	Rev.2	Rev.3
LOCATION: The Netherlands	DATE	03-Jun-13						
PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	NF						
CONTRACT N. 1-BD-0681 A	CHECKED BY	LM						
CASE: 1 - SC PC without carbon capture - Air Cooled sensitivity case	APPROVED BY	LM						

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	BASE CASE EURO	AC CASE EURO	DELTA EURO	Difference with respect to reference case
	UNIT 3000 - STEAM CYCLE					**129,000,000**	**155,400,000**	**26,400,000**	
PK- 3001	**Steam Turbine and Generator Package**								
ST- 3001	Steam Turbine		1062 MWe			*111,000,000*	*111,000,000*	0	**Size changed**
PK- 3002	**Steam Condenser Package**								
~~E- 3001~~	~~Steam condenser~~		~~1055 MWth~~			*18,000,000*		(18,000,000)	**To be deleted**
AC- 3001	Air cooled Steam condenser		1070 MWth	100 x 90 kW			*44,400,000*	44,400,000	**To be added**
	COOLING SYSTEM					**57,400,000**	**1,300,000**	**(56,100,000)**	
AC- 6001	Closed loop air cooler		64 MWth	1700 kWe			*400,000*	400,000	**To be added**
P- 6002 A / B	Cooling Water Pumps (secondary system)	Centrifugal	6880 m3/h x 35 m	950	*One in operation, one spare*	*900,000*	*900,000*	0	**Size changed**
~~CT- 6001~~	~~**Cooling Tower**~~ ~~includind:~~ ~~Cooling water basin~~	~~Natural draft~~	~~1120 MWth~~			*40,000,000*		(40,000,000)	**To be deleted**
~~P- 6001 A/../F~~	~~Cooling Water Pumps (primary system)~~	~~Centrifugal~~	~~15000 m3/h x 35 m~~	~~1600~~	~~*Six in operation*~~	*15,000,000*		(15,000,000)	**To be deleted**
~~P- 6003 A / B~~	~~Cooling tower make-up pumps~~	~~centrifugal~~	~~1735 m3/h x 30 m~~	~~220~~		*300,000*		(300,000)	
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 9500 m3/h~~			*1,000,000*		(1,000,000)	
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					*100,000*		(100,000)	**To be deleted**
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					*100,000*		(100,000)	
TOTAL COST - EURO						**186,400,000**	**156,700,000**	**(29,700,000)**	

Table 15. Case 1 – Seawater cooling sensitivity case – Capex breakdown into process units

CLIENT: IEA GHG	REVISION	Rev.: Draft				Rev.: 1	Rev.2	Rev.3
LOCATION: The Netherlands	DATE	20-Jun-13						
PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	NF						
CONTRACT N. 1-BD-0681 A	CHECKED BY	LM						
CASE: 1 - SC PC without carbon capture - Sea Water sensitivity case	APPROVED BY	LM						

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	BASE CASE EURO	SW CASE EURO	DELTA EURO	Difference with respect to reference case
	UNIT 3000 - STEAM CYCLE					**129,000,000**	**147,000,000**	**18,000,000**	
PK- 3001	**Steam Turbine and Generator Package**								
ST- 3001	Steam Turbine		1091 MWe			*111,000,000*	*111,000,000*	0	**Size changed**
PK- 3002	**Steam Condenser Package**								
~~E- 3001~~	~~Steam condenser~~	~~Water cooled~~	~~1055 MWth~~			*18,000,000*		(18,000,000)	**To be deleted**
E- 3001	Steam condenser	Sea Water cooled	1040 MWth				*36,000,000*	36,000,000	**To be added**
	COOLING SYSTEM					**57,300,000**	**30,500,000**	**(26,800,000)**	
E- 6001	Closed cooling water cooler		65 MWth				*700,000*	700,000	**To be added**
P- 6001 A /.. / H	Sea Cooling Water Pumps	Centrifugal	17000 m3/h x 20 m	1600	*Eight in operation*		*20,000,000*	20,000,000	**To be added**
P- 6002 A / B	Machinery Cooling Water Pumps	Centrifugal	5150 m3/h x 35 m	800	*One in operation, one spare*	*900,000*	*800,000*	(100,000)	**Size changed**
	Seawater Intake						*9,000,000*	9,000,000	
~~CT- 6001~~	~~**Cooling Tower**~~ ~~includind:~~ ~~Cooling water basin~~	~~Natural draft~~	~~1120 MWth~~			*40,000,000*		(40,000,000)	**To be deleted**
~~P- 6001 A/.. /F~~	~~Cooling Water Pumps (primary system)~~	~~Centrifugal~~	~~15000 m3/h x 35 m~~	~~1600~~	~~*Six in operation*~~	*15,000,000*		(15,000,000)	**To be deleted**
~~P- 6003 A / B~~	~~Cooling tower make-up pumps~~	~~centrifugal~~	~~1735 m3/h x 30 m~~	~~220~~		*300,000*		(300,000)	
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 9500 m3/h~~			*1,000,000*		(1,000,000)	
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					*100,000*		(100,000)	**To be deleted**
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					*100,000*		(100,000)	
	TOTAL COST - EURO					**186,300,000**	**177,500,000**	**(8,800,000)**	

Table 16. Case 2 – Air cooling sensitivity case – Capex breakdown into process units

FOSTER WHEELER								
CLIENT: IEA GHG	REVISION	Rev.: Draft				Rev.: 1	Rev.2	Rev.3
LOCATION: The Netherlands	DATE	03-Jul-13						
PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	NF						
CONTRACT N. 1-BD-0681 A	CHECKED BY	LM						
CASE: 2 - SC PC with carbon capture - Air cooled sensitivity case	APPROVED BY	LM						

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	BASE CASE EURO	AC CASE EURO	DELTA EURO	Difference with respect to reference case
	UNIT 3000 - STEAM CYCLE					**119,000,000**	**142,200,000**	**23,200,000**	
PK- 3001	**Steam Turbine and Generator Package**								
ST- 3001	Steam Turbine		947 MWe			*105,000,000*	*105,000,000*	0	**Size changed**
PK- 3002	**Steam Condenser Package**								
~~E- 3001~~	~~Steam condenser~~	~~Water cooled~~	~~800 MWth~~			*14,000,000*		(14,000,000)	**To be deleted**
AC- 3001	Air cooled Steam condenser		780 MWth	70 x 90 kWe			*37,200,000*	37,200,000	**To be added**
	UNIT 4000 - CO2 CAPTURE					**-**	**2,000,000**	**2,000,000**	
~~E-~~ AC-001	Flue gas cooling water air cooler								
~~E-~~ AC-002	Wash water air cooler		Duty: 610 MWth (both train)				*2,000,000*	2,000,000	**Changed from CW cooler to air cooler**
~~E-~~ AC-004	Regenerator condenser								
~~E-~~ AC-006	Lean solution cooler								
	UNIT 5000 - CO2 COMPRESSION					**45,300,000**	**46,600,000**	**1,300,000**	
K - 5001 / 2	CO2 compression trains	Axial, Electrical Driven 4 Stages	180150 Nm3/h p in : 1,6 bar a p out : 75 bar a	32000	*Intercooling:* *Condensate from Power island*	*45,300,000*	*45,000,000*	(300,000)	**Size changed** **Intercooling medium changed**
AC - 5001 / 2 / 3 / 4	Intercooler	Air cooler	35 MWth per train	510 kWe	*Air cooled ~~Cooling Water~~*		*1,600,000*	1,600,000	
	COOLING SYSTEM					**55,800,000**	**1,600,000**	**(54,200,000)**	
AC- 6001	Closed loop air cooler		60 MWth	1600 kWe			*800,000*	800,000	**To be added**
P- 6002	Cooling Water Pumps (secondary system)	Centrifugal	6150 m3/h x 35 m	800	*~~Four~~ One in operation, one spare*		*800,000*	800,000	**Size and number changed**
~~CT- 6001~~	~~**Cooling Tower**~~ ~~includind:~~ ~~Cooling water basin~~	~~Natural draft~~	~~1500 MWth~~			*43,000,000*		(43,000,000)	**To be deleted**
~~P- 6001 A/../F~~	~~Cooling Water Pumps (primary system)~~	~~Centrifugal~~	~~16000 m3/h x 45 m~~	~~1800~~	*~~Four in operation~~*	*11,000,000*		(11,000,000)	**To be deleted**
~~P- 6003 A / B~~	~~Cooling tower make-up pumps~~	~~centrifugal~~	~~2370 m3/h x 30 m~~	~~300~~		*400,000*		(400,000)	
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 12000 m3/h~~			*1,200,000*		(1,200,000)	
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					*100,000*		(100,000)	
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					*100,000*		(100,000)	
	TOTAL COST - EURO					**220,100,000**	**192,400,000**	**(27,700,000)**	

Table 17. Case 2 – Seawater cooling sensitivity case – Capex breakdown into process units

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: 2 - SC PC with carbon capture - Sea Water sensitivity case	REVISION	Rev.: Draft				Rev.: 1	Rev.2	Rev.3
		DATE	03-Jul-13						
		ISSUED BY	NF						
		CHECKED BY	LM						
		APPROVED BY	LM						

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	BASE CASE EURO	SW CASE EURO	DELTA EURO	Difference with respect to reference case
	UNIT 3000 - STEAM CYCLE					**119,000,000**	**132,000,000**	**13,000,000**	
PK- 3001	**Steam Turbine and Generator Package**								
ST- 3001	Steam Turbine		970 MWe			*105,000,000*	*105,000,000*	0	**Size changed**
PK- 3002	**Steam Condenser Package**								
~~E- 3001~~	~~Steam condenser~~	~~Water cooled~~	~~800 MWth~~			*14,000,000*		(14,000,000)	**To be deleted**
E- 3001	Steam condenser	Sea Water cooled	772 MWth				*27,000,000*	27,000,000	**To be added**
	UNIT 5000 - CO2 COMPRESSION					**45,300,000**	**43,000,000**	**(2,300,000)**	
K - 5001 / 2	CO2 compression trains	Axial, Electrical Driven 4 Stages	180150 Nm3/h p in : 1,6 bar a p out : 75 bar a	29200	*Intercooling:* *Condensate from Power island* *Sea Water ~~Cooling Water~~*	*45,300,000*	*43,000,000*	(2,300,000)	**Size changed** **Intercooling medium changed**
	COOLING SYSTEM					**68,800,000**	**47,000,000**	**(21,800,000)**	
E- 6001	Closed cooling water cooler		670 MWth				*2,000,000*	2,000,000	**To be added**
P- 6001 A /.. / H	Sea Cooling Water Pumps (primary system)	Centrifugal	16500 m3/h x 20 m	1100	*Twelve in operation*		*24,000,000*	24,000,000	**To be added**
P- 6002 A/B/C/D/E	Cooling Water Pumps (secondary system)	Centrifugal	13500 m3/h x 35 m	1500	*Four in operation, one spare*	*13,000,000*	*12,000,000*	(1,000,000)	**Size changed**
	Seawater Intake						*9,000,000*	9,000,000	
~~CT- 6001~~	~~**Cooling Tower**~~ ~~includind:~~ ~~Cooling water basin~~	~~Natural draft~~	~~1500 MWth~~			*43,000,000*		(43,000,000)	**To be deleted**
~~P- 6001 A/.. /F~~	~~Cooling Water Pumps (primary system)~~	~~Centrifugal~~	~~16000 m3/h x 45 m~~	~~1800~~	~~*Four in operation*~~	*11,000,000*		(11,000,000)	**To be deleted**
~~P- 6003 A / B~~	~~Cooling tower make-up pumps~~	~~centrifugal~~	~~2370 m3/h x 30 m~~	~~300~~		*400,000*		(400,000)	
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 12000 m3/h~~			*1,200,000*		(1,200,000)	
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					*100,000*		(100,000)	**To be deleted**
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					*100,000*		(100,000)	
TOTAL COST - EURO						**233,100,000**	**222,000,000**	**(11,100,000)**	

Table 18. Case 2.1 – Biomass co-firing sensitivity case (near zero emission case)– Capex breakdown into process units

FOSTER WHEELER	CLIENT: IEA GHG	REVISION	Rev.: Draft				Rev.: 1	Rev.2	Rev.3
	LOCATION: The Netherlands	DATE	July 13						
	PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	GP						
	CONTRACT N. 1-BD-0681 A	CHECKED BY	NF						
	CASE: 2.1 - SC PC with carbon capture - co-firing with biomass	APPROVED BY	LM						

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	BASE CASE EURO	BIO-MASS CASE EURO	DELTA EURO	Difference with respect to reference case
	UNIT 1000 - FEEDSTOCK AND SOLID HANDLING					**76,700,000**	**86,700,000**	**10,000,000**	
	Coal handling		300 t/h						**Size changed (- 7.7%)**
	Biomass handling		86 t/h			*76,700,000*	*86,700,000*	10,000,000	**To be added**
	Limestone handling		8.5 t/h						**Size changed (- 7.6%)**
	Ash handling		39.7 t/h						**Size changed (- 5.0%)**
	Gypsum handling		15.8 t/h						**Size changed (- 6.5%)**
	UNIT 2000 - BOILER ISLAND					**284,400,000**	**292,900,000**	**8,500,000**	
PK - 2001	**Super Critical Boiler, including:**		Capacity: 2852 t/h main steam production Thermal input: 2500 MWth (HHV) / 2335 MWth (LHV) Main steam condition: 270 bar(a)/ 600°C Reheat steam condition: 60 bar(a)/ 620°C			*284,400,000*	*292,900,000*	8,500,000	**Size changes** - Feed system: + 20% - Flue gas system: + 4%
K - 2001	ID fan	Axial	Flowrate: 2870 x 10^3 Nm3/h Vol. Flow: 1100 m3/h Power consumption: 10835 kW						**Size changed (+ 3.6%)**
PK - 2002	**Flue gas cleaning system**	ESP							**Size changed (+ 3.6%)**
PK - 2003	**Flue gas stack**	cement stack							
	SCR System								
	UNIT 2100 - Flue Gas Desulphurization					**49,600,000**	**49,600,000**	**-**	
	Wet FGD system		Flue gas inlet flowrate: 2870 x 10^3 Nm3/h gypsum production: 15.8 t/h			*49,600,000*	*49,600,000*	0	**Size changed:** feed flowrate: +3.6% sorbent recirculation: -6.5%
	Gas-gas heat exchanger		Hot side flowrate: 2870 x 10^3 Nm3/h Cold side flowrate: 2450 x 10^3 Nm3/h						**Size changed**
	Unit 4000 - CO2 Amine Absorption Unit					**320,000,000**	**324,800,000**	**4,800,000**	
	CO_2 capture Unit		For each train (2x50%): Feed gas flowrate: 1450 x 10^3 Nm3/h			*320,000,000*	*324,800,000*	4,800,000	**Size changed (+ 1.5%)**
	Unit 5000 - CO2 compression Unit (2 x 50%)					**45,300,000**	**45,800,000**	**500,000**	
	CO2 compression Unit (2 x 50%)		Feed gas flowrate: 185000 Nm3/h			*45,300,000*	*45,800,000*	500,000	**Size changed (+ 0.8%)**
TOTAL COST - EURO						**776,000,000**	**799,800,000**	**23,800,000**	

Table 19. Case 3 – Air cooling sensitivity case – Capex breakdown into process units

FOSTER WHEELER	CLIENT: IEA GHG	REVISION	Rev.: Draft				Rev.: 1	Rev.2	Rev.3
	LOCATION: The Netherlands	DATE	Jun-13						
	PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	NF						
	CONTRACT N. 1-BD-0681 A	CHECKED BY	LM						
	CASE Case 3 - Oxycombustion boiler - Air cooled Sensitivity case	APPROVED BY	LM						

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	BASE CASE EURO	AC CASE EURO	DELTA EURO	Difference with respect to reference case
	UNIT 900 - AIR SEPARATION UNIT					**0**	**1,500,000**	**1,500,000**	
PK - 901 A/B/C	**Air Separation unit** Main Air Compressor				*Intercooling:* *Air Cooled ~~Cooling Water~~*		*1,500,000*	1,500,000	**Intercooling medium changed**
	UNIT 2000 - BOILER					**0**	**500,000**	**500,000**	
PK - 2003	**Indirect Contact Cooler** Contact cooler exchanger	Air Cooler ~~Water cooled~~	146 MWth	1860 kWe			*500,000*	500,000	**Size changed** **Intercooling medium changed**
	UNIT 3000 - STEAM CYCLE					**132,000,000**	**153,800,000**	**21,800,000**	
PK- 3001	**Steam Turbine and Generator Package**								
ST- 3001	Steam Turbine		1085 MWe		Condensate pressure: 5.2 kPa	*113,000,000*	*113,000,000*	0	**Size changed**
PK- 3002	**Steam Condenser Package**								
~~E- 3001~~	~~Steam condenser~~	~~Water cooled~~	~~1210 MWth~~			*19,000,000*		(19,000,000)	**To be deleted**
AC- 3001	Steam condenser	Air cooler	1220 MWth	110 x 90 kWe			*40,800,000*	40,800,000	**To be added**
	COOLING SYSTEM					**58,000,000**	**5,800,000**	**(52,200,000)**	
AC - 6001	Closed loop air cooler		*65 MWth*	1770 kWe			*800,000*	800,000	**To be added**
P- 6002 A/B	Cooling Water Pumps (secondary system)	Centrifugal	7500 m3/h x 35 m	1700	*One in operation, one spare*		*5,000,000*	5,000,000	**To be added**
~~CT- 6001~~	~~**Cooling Tower**~~ ~~including:~~ ~~Cooling water basin~~	~~Natural draft~~	~~1550 MWth~~			*40,000,000*		(40,000,000)	**To be deleted**
~~P- 6001 A/…/F~~	~~**Cooling Water Pumps (primary system)**~~	~~Centrifugal~~	~~16000 m3/h x 35 m~~	~~1900~~	~~*Six in operation*~~	*17,000,000*		(17,000,000)	**To be deleted**
~~P- 6003 A/B~~	~~**Cooling tower make up pumps**~~	~~Centrifugal~~	~~2400 m3/h x 30 m~~	~~300~~		*400,000*		(400,000)	**To be deleted**
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 2950 m3/h~~			*400,000*		(400,000)	
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					*100,000*		(100,000)	**To be deleted**
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					*100,000*		(100,000)	
	TOTAL COST - EURO					**190,000,000**	**161,600,000**	**(28,400,000)**	

Table 20. Case 3 – Seawater cooling sensitivity case – Capex breakdown into process units

FOSTER WHEELER								
CLIENT: IEA GHG	REVISION	Rev.: Draft				Rev.: 1	Rev.2	Rev.3
LOCATION: The Netherlands	DATE	18-Jun-13						
PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	NF						
CONTRACT N. 1-BD-0681 A	CHECKED BY	LM						
CASE Case 3 - Oxycombustion boiler - Sea Water Sensitivity case	APPROVED BY	LM						

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	BASE CASE EURO	AC CASE EURO	DELTA EURO	Difference with respect to reference case
	UNIT 900 - AIR SEPARATION UNIT					**0**	**1,500,000**	**1,500,000**	
PK - 901 A/B/C	**Air Separation unit**								
	Main Air Compressor				*Intercooling:* *Sea Water Cooled* ~~*Cooling Water*~~		*1,500,000*	1,500,000	**Intercooling medium changed**
	UNIT 2000 - BOILER					**0**	**500,000**	**500,000**	
PK - 2003	**Indirect Contact Cooler**								
	Contact cooler exchanger	Sea Water Cooled ~~Water cooled~~	146 MWth				*500,000*	500,000	**Size changed** **Intercooling medium changed**
	UNIT 3000 - STEAM CYCLE					**133,000,000**	**153,000,000**	**20,000,000**	
PK- 3001	**Steam Turbine and Generator Package**								
ST- 3001	Steam Turbine		1115 MWe		Condensate pressure: 3.0 kPa	*113,000,000*	*113,000,000*	0	**Size changed**
PK- 3002	**Steam Condenser Package**								
~~E- 3001~~	~~Steam condenser~~	~~Water cooled~~	~~1210 MWth~~			*20,000,000*		(20,000,000)	**To be deleted**
E- 3001	Steam condenser	Sea Water cooled	1190 MWth				*40,000,000*	40,000,000	**To be added**
	COOLING SYSTEM					**59,300,000**	**34,700,000**	**(24,600,000)**	
E - 6001	Closed Cooling Water cooler		*67 MWth*				*800,000*	800,000	**To be added**
P- 6001 A/…/H	Sea Cooling Water Pumps (primary system)	Centrifugal	16500 m3/h x 20 m	1150	*Twelve in operation*		*24,000,000*	24,000,000	**To be added**
P- 6002 A/B	Cooling Water Pumps (secondary system)	Centrifugal	5500 m3/h x 35 m	1250	*One in operation, one spare*		*900,000*	900,000	**To be added**
	Seawater Intake						*9,000,000*	9,000,000	
~~CT- 6001~~	~~**Cooling Tower**~~ ~~including:~~ ~~Cooling water basin~~	~~Natural draft~~	~~1550 MWth~~			*42,000,000*		(42,000,000)	**To be deleted**
~~P- 6001 A/…/F~~	~~**Cooling Water Pumps (primary system)**~~	~~Centrifugal~~	~~16000 m3/h x 35 m~~	~~1900~~	~~*Six in operation*~~	*16,000,000*		(16,000,000)	**To be deleted**
~~P- 6003 A/B~~	~~**Cooling tower make up pumps**~~	~~Centrifugal~~	~~2400 m3/h x 30 m~~	~~300~~		*500,000*		(500,000)	**To be deleted**
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 2950 m3/h~~			*600,000*		(600,000)	
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					*100,000*		(100,000)	**To be deleted**
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					*100,000*		(100,000)	
	TOTAL COST - EURO					**192,300,000**	**189,700,000**	**(2,600,000)**	

Table 21. Case 3.1 – Near Zero Emission sensitivity case – Capex breakdown into process units

CLIENT: IEA GHG
LOCATION: The Netherlands
PROJ. NAME: CO2 capture at coal based power and hydrogen plants
CONTRACT N. 1-BD-0681 A
CASE: 3.1 - Oxycombustion SC PC - Near Zero Emission

REVISION	Rev.: Draft				Rev.: 1	Rev.2	Rev.3
DATE	Jul-13						
ISSUED BY	NF						
CHECKED BY	LM						
APPROVED BY	LM						

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor Rating [kW]	Remarks	BASE CASE EURO	NEAR ZERO CASE EURO	DELTA EURO	Difference with respect to reference case
	AIR SEPARATION UNIT					**0**	**0**	**0**	
PK - 901 A/B/C	**Air Separation unit**		3 x 5555 t/d		*Oxygen feed: -4% with respect to base*				**No changes in ASU size**
	CO2 COMPRESSION AND PURIFICATION					**250,000,000**	**275,000,000**	**25,000,000**	
PK - 4001	**Sour compression section**		Dry flue gas: 24,510 kmol/h 3.8% vol H_2O			250,000,000	275,000,000	25,000,000	**Size changed**
	Including:								
	- Raw flue gas compressors (two stages)			*100 MWe*					**Size changed**
	- Contacting column with liquid pump around for sulphuric and nitric acid removal								
	- Flue gas cooler downstream compressor								
	BFW heater		*26 MWth*						**Size changed**
	Condensate heater		*27 MWth*						**Size changed**
PK - 4002	**Dual Bed essicant system**								**Size changed**
PK - 4003	**Cold box for inerts removal**								
	Including:								
	- Main heat exchangers								
	- CO2 liquid separator								
	- CO2 distillation column								
	- CO2 compressors and coolers			*32 MWe*					**Size changed**
	- Inerts heater								
	- Inerts expander			*11.5 MWe*					**Size changed**
	- Overhead recycle compressors			*1.0 MWe*					
	COOLING SYSTEM					**0**	**0**	**0**	
CT- 6001	**Cooling Tower** including: Cooling water basin	Natural draft	1565 MWth						
P- 6002 A/B/C	**Cooling Water Pumps (secondary system)**	Centrifugal	14000 m3/h x 45 m	2250 kW	*Two operating, one spare*				**Size changed**
TOTAL COST D&E BASIS - EURO						**250,000,000**	**275,000,000**	**25,000,000**	

Table 22. Case 4.2 – Air cooling sensitivity case – Capex breakdown into process units

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 4.2 - GE based IGCC - Cooling water sensitivity (AC)	REVISION	Rev 0		Rev.1	Rev.2	Rev.3
		DATE	May 2013				
		ISSUED BY	NF				
		CHECKED BY	LM				
		APPROVED BY	LM				

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	Remarks	BASE CASE EURO	AC CASE EURO	DELTA EURO	Difference with respect to reference case
	UNIT 2100 - AIR SEPARATION UNIT					**41,850,000**	**42,750,000**	**900,000**	
	Main Air compressors (MAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 595600 Nm3/h	69500 kW	*Intercooling: Air cooling ~~Cooling Water~~*	*35,250,000*	*34,750,000*	(500,000)	**Size changed Intercooling medium changed**
	Booster air compressors (BAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 238200 Nm3/h	7500 kW	*Intercooling: Air cooling ~~Cooling Water~~*	*6,600,000*	*7,500,000*	900,000	**Intercooling medium changed**
	MP N2 compressors (GAN)	Electric motor driven, centrifugal, with intercooling	Flowrate: 257000 Nm3/h	19000 kW	*Intercooling: Air cooling ~~Cooling Water~~*		*500,000*	500,000	**Intercooling medium changed**
	UNIT 2200 - SYNGAS TREATMENT					**300,000**	**500,000**	**200,000**	
~~**E-2209**~~	~~Final syngas cooler~~	~~Shell & Tube~~				*300,000*		(300,000)	**To be deleted**
AC-2201	Final syngas cooler	Air cooler	4 MWth	45 kWe	*each train*		*500,000*	500,000	**To be added**
	UNIT 2250 - SWS					**300,000**	**800,000**	**500,000**	
	~~Sour water stripper condenser~~	~~Shell & Tube~~				*300,000*		(300,000)	**To be deleted**
AC-2251	Sour water stripper condenser	Air cooler					*800,000*	800,000	**To be added**
	UNIT 2300 - AGR					**0**	**3,000,000**	**3,000,000**	
	Water cooled heat exchangers and refrigerator condenser in AGR will be replaced with air cooling. Total installed rated capcity: 550 Mwe						*3,000,000*	3,000,000	
	UNIT 2500 - CO2 COMPRESSION					**16,000,000**	**15,300,000**	**(700,000)**	
C-2501	CO_2 Compressors	Centrifugal, Electrical Driven, 8 intercooled Stages	187610 Nm3/h p in: 2,45 bar a p out: 80 bar a	17000 kW	*Intercooling: Air cooling ~~Cooling Water~~*	*16,000,000*	*15,300,000*	(700,000)	**Size changed Intercooling medium changed**
	UNIT 3300 - STEAM TURBINE					**80,000,000**	**101,800,000**	**21,800,000**	
Z-3301	**Steam Turbine & Condenser Package**								
ST-3301	Steam Turbine		435 MWe			67,000,000	67,000,000	0	**Size changed**
~~E-3303~~	~~Steam Condenser~~		~~710 MWth~~		~~Water cooled~~	*13,000,000*		(13,000,000)	**To be deleted**
AC-3301	Steam Condenser	air cooled	715 MWth	65 x 90 kWe			34,800,000	34,800,000	**To be added**
G-3402	Steam Turbine Generator		570 MVA				Included	Included	**Size changed**

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 4.2 - GE based IGCC - Cooling water sensitivity (AC)	

REVISION	Rev 0				Rev.1	Rev.2	Rev.3
DATE	May 2013						
ISSUED BY	NF						
CHECKED BY	LM						
APPROVED BY	LM						

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	Remarks	BASE CASE EURO	AC CASE EURO	DELTA EURO	Difference with respect to reference case
	COOLING SYSTEM					**55,100,000**	**6,400,000**	**(48,700,000)**	
AC-4001	Closed loop air cooler		90 MWth	2500 kWe			1,000,000	1,000,000	**To be added**
P-4002A/B/C	Cooling Water pumps (secondary system)	Vertical	14000 m3/h x 35 m	1600 kW		6,500,000	5,400,000	(1,100,000)	**Size changed**
~~CT-4001~~	~~Cooling Tower~~ ~~Including Cooling water basin~~	~~Evaporative, Natural draft~~	~~Total heat duty 1070 MWth~~			38,000,000		(38,000,000)	**To be deleted**
~~P-4001A/B/C/D~~	~~Cooling Water pumps (primary system)~~	~~Vertical~~	~~13880 m3/h x 35 m~~	~~1600 kW~~		9,000,000		(9,000,000)	**To be deleted - 4 Operating + 1 Spare**
~~P-4003A/B~~	~~Raw water pumps (make-up)~~	~~centrifugal~~	~~1690 m3/h x 35 m~~	~~200 kW~~		500,000		(500,000)	**To be deleted - 2 Operating + 1 Spare**
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 8500 m3/h~~			900,000		(900,000)	
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					100,000		(100,000)	**To be deleted**
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					100,000		(100,000)	
	TOTAL COST - EURO					**193,250,000**	**170,050,000**	**(23,200,000)**	

Table 23. Case 4.2 – Seawater cooling sensitivity case – Capex breakdown into process units

FOSTER WHEELER	CLIENT: IEA GHG LOCATION: The Netherlands PROJ. NAME: CO2 capture at coal based power and hydrogen plants CONTRACT N. 1-BD-0681 A CASE: Case 4.2 - GE based IGCC - Cooling water sensitivity (SW)	REVISION	Rev 0				Rev.1	Rev.2	Rev.3
		DATE	May 2013						
		ISSUED BY	NF						
		CHECKED BY	LM						
		APPROVED BY	LM						

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	motor rating [kW]	Remarks	BASE CASE EURO	SW CASE EURO	DELTA EURO	Difference with respect to reference case
	UNIT 2100 - AIR SEPARATION UNIT					**41,850,000**	**42,750,000**	**900,000**	
	Main Air compressors (MAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 595600 Nm3/h	69500 kW	*Intercooling:* *Sea Water ~~Cooling Water~~*	*35,250,000*	*34,750,000*	(500,000)	**Size changed** **Intercooling medium changed**
	Booster air compressors (BAC)	Electric motor driven, centrifugal, with intercooling	Flowrate: 238200 Nm3/h	7500 kW	*Intercooling:* *Sea Water ~~Cooling Water~~*	*6,600,000*	*7,500,000*	900,000	**Intercooling medium changed**
	MP N2 compressors (GAN)	Electric motor driven, centrifugal, with intercooling	Flowrate: 257000 Nm3/h	19000 kW	*Intercooling:* *Sea Water ~~Cooling Water~~*		*500,000*	500,000	**Intercooling medium changed**
	UNIT 2500 - CO2 COMPRESSION					**16,000,000**	**15,300,000**	**(700,000)**	
C-2501	CO_2 Compressors	Centrifugal, Electrical Driven, 8 intercooled Stages	187610 Nm3/h p in: 2,45 bar a p out: 80 bar a	17000 kW	*Intercooling:* *Sea Water ~~Cooling Water~~*	*16,000,000*	*15,300,000*	(700,000)	**Size changed** **Intercooling medium changed**
	UNIT 3300 - STEAM TURBINE					**80,000,000**	**93,000,000**	**13,000,000**	
Z-3301	**Steam Turbine & Condenser Package**								
ST-3301	Steam Turbine		455 MWe			67,000,000	67,000,000	0	**Size changed**
~~E-3303~~	~~Steam Condenser~~		~~710 MWth~~		~~Water cooled~~	*13,000,000*		(13,000,000)	**To be deleted**
E-3303	Steam Condenser		730 MWth		Sea Water cooled Inlet water temperature 12°C Water temperature rise 7°C		26,000,000	26,000,000	**To be added**
G-3402	Steam Turbine Generator		600 MVA				Included	Included	**Size changed**
	COOLING SYSTEM					**55,100,000**	**35,800,000**	**(19,300,000)**	
E-4001	Closed cooling loop exchanger		145 MWth				*1,400,000*	1,400,000	**To be added**
P-4001A÷H	Sea Cooling Water pumps (primary system)	Vertical	18000 m3/h x 20 m	1250 kW	***Eight in operation***		*20,000,000*	20,000,000	**To be added**
P-4002A/B/C	Cooling Water pumps (secondary system)	Vertical	14000 m3/h x 35 m	1600 kW		6,500,000	*5,400,000*	(1,100,000)	**Size changed**
	Seawater Intake						*9,000,000*	9,000,000	
~~CT-4001~~	~~Cooling Tower~~ ~~Including Cooling water basin~~	~~Evaporative,~~ ~~Natural draft~~	~~Total heat duty~~ ~~1070 MWth~~			38,000,000		(38,000,000)	**To be deleted**
~~P-4001A/B/C/D~~	~~Cooling Water pumps (primary system)~~	~~Vertical~~	~~13880 m3/h x 35 m~~	~~1600 kW~~		9,000,000		(9,000,000)	**To be deleted**
~~P-4003A/B~~	~~Raw water pumps (make-up)~~	~~centrifugal~~	~~1690 m3/h x 35 m~~	~~200 kW~~		500,000		(500,000)	**To be deleted**
	~~**Cooling Water Filtration Package**~~ ~~Cooling Water Sidestream Filters~~		~~Capacity: 8500 m3/h~~			900,000		(900,000)	**To be deleted**
	~~**Sodium Hypochlorite Dosing Package**~~ ~~Sodium Hypochlorite storage tank~~ ~~Sodium Hypochlorite dosage pumps~~					100,000		(100,000)	
	~~**Antiscalant Package**~~ ~~Dispersant storage tank~~ ~~Dispersant dosage pumps~~					100,000		(100,000)	
	TOTAL COST - EURO					**192,950,000**	**186,850,000**	**(6,100,000)**	

Table 24. Case 4.2.1 – Near Zero Emission sensitivity case – Capex breakdown into process units

FOSTER WHEELER	CLIENT: IEA GHG	REVISION	Rev.: Draft			Rev.: 1	Rev.2	Rev.3
	LOCATION: The Netherlands	DATE	June 13					
	PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	GP					
	CONTRACT N. 1-BD-0681 A	CHECKED BY	NF					
	CASE: 4.2.1 - GE based IGCC - High capture case	APPROVED BY	LM					

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	BASE CASE EURO	HIGH CAPTURE EURO	DELTA EURO	Difference with respect to reference case
	UNIT 2100 - AIR SEPARATION UNIT (2X50%)					**22,000,000**	**23,100,000**	**1,100,000**	
	MP N_2 compressor (GAN)		Flowrate: 250250 Nm3/h	19500 kW		*19,000,000*	*19,500,000*	500,000	**Size changed**
	MP N_2 compressor - booster		Flowrate: 127560 Nm3/h	1250 kW		*3,000,000*	*3,600,000*	600,000	**Size changed**
	UNIT 2200 - Syngas Treatment and conditioning line (2x50%)					**10,000,000**	**8,800,000**	**(1,200,000)**	
EX - 2201	Syngas expander		Flowrate: 554700 Nm3/h	8800 kW		*10,000,000*	*8,800,000*	(1,200,000)	**Size changed**
	UNIT 2350 - Amine Guard FS Process Unit (1x100%)					**0**	**19,200,000**	**19,200,000**	
Z - 2351	**Amine Guard FS Process, including:** One amine absorber one amine stripper total carbon capture: 85.3%	Solvent: amine	Feed gas: 588,200 Nm3/h 54 barg 15 °C				*19,200,000*	19,200,000	**To be added**
	Unit 2500 - CO_2 compression Unit (2 x 50%)					**16,200,000**	**18,000,000**	**1,800,000**	
	CO2 compression Unit (2 x 50%)		Feed gas flowrate: 224300 Nm3/h			*16,200,000*	*18,000,000*	1,800,000	**Size changed (+ 16%)**
	Unit 3300 - Steam Turbine and Blowdown System (1 x 100%)					**80,000,000**	**79,700,000**	**(300,000)**	
ST - 3301	Steam Turbine (including steam turbine generator)		434 MWe			*67,000,000*	*67,000,000*	0	**Size changed**
E - 3301	Condenser		680 MWth			*13,000,000*	*12,700,000*	(300,000)	**Size changed**
P - 3301 A/B	Condensate Pump	centrifugal, vertical	1865 m3/h x 110 m	800 kW					
	Unit 4000 - Utility and Offsite					**55,300,000**	**56,600,000**	**1,300,000**	
CT - 4001	Cooling Tower Including Cooling water basin Raw Water CT make-up pump	Evaporative, Natural draft	1140 MWth			*40,000,000*	*41,000,000*	1,000,000	**Size changed**
P - 4001 A/B/C/D	Cooling Water pumps (primary system)	vertical	13300 m3/h x 35 m	1450 kW	*Four operating*	*9,000,000*	*8,500,000*	(500,000)	**Size changed**
P - 4002 A/B/C	Cooling Water pumps (secondary system)	vertical	11950 m3/h x 35 m	1650 kW	*Three operating, one spare*	*6,300,000*	*7,100,000*	800,000	**Numebr and size changed**
	TOTAL COST - EURO					**183,500,000**	**205,400,000**	**21,900,000**	

Table 25. Case 5.3.1 – Near Zero Emission sensitivity case – Capex breakdown into process units

FOSTER WHEELER	CLIENT: IEA GHG	REVISION	Rev.: Draft				Rev.: 1	Rev.2	Rev.3
	LOCATION: The Netherlands	DATE	August 13						
	PROJ. NAME: CO2 capture at coal based power and hydrogen plants	ISSUED BY	LC						
	CONTRACT N. 1-BD-0681 A	CHECKED BY	NF						
	CASE: 5.3.1 - H2 production plant- High capture case	APPROVED BY	LM						

MAIN EQUIPMENT CHANGES

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	Remarks	BASE CASE EURO	HIGH CAPTURE EURO	DELTA EURO	Difference with respect to reference case
	UNIT 2200 - Syngas Treatment and conditioning line (2x50%)					**0**	**0**	**0**	
	LP steam generator BFW pre-heaters Condensate pre-heater Final syngas cooler							0	**Size increased** **Size increased** **Size increased** **Size decreased**
	UNIT 2350 - Amine Guard FS Process Unit (1x100%)					**0**	**19,200,000**	**19,200,000**	
Z - 2351	**Amine Guard FS Process, including:** One amine absorber one amine stripper total carbon capture: 85.3%	Solvent: amine	Feed gas: 588,200 Nm3/h 54 barg 15 °C				19,200,000	19,200,000	**To be added**
	Unit 2500 - CO_2 compression Unit (2 x 50%)					**16,200,000**	**18,000,000**	**1,800,000**	
	CO2 compression Unit (2 x 50%)		Feed gas flowrate: 224300 Nm3/h			16,200,000	18,000,000	1,800,000	**Size changed (+ 16%)**
	TOTAL COST - EURO					**16,200,000**	**37,200,000**	**21,000,000**	

2.3.5. Utilities and Offsite brake-down

The following table provides, for each plant-type assessed in the study, a break-down of the major Utilities and Offsite, mainly including cooling system, electrical systems, process and waste water systems.

Table 26. Break-down of U&O

UTILITY & OFFSITES COST

CONTRACT: 1-BD-0681A
CLIENT: IEA GHG
LOCATION: THE NETHERLANDS
DATE: SEPTEMBER 2013
REV.: 0

POS.	DESCRIPTION	CASE 1		CASE 2		CASE 3		CASE 4.1		CASE 4.2		CASE 4.1		CASE 5.1		CASE 5.2		CASE 5.3		NOTES / REMARKS
		EURO	%	EURO	%	EURO	%	EURO	%	EURO	%	EURO	%	EURO	%	EURO	%	EURO	%	
1	COOLING WATER SYSTEM	174,800,000	58.7	265,900,000	58.3	269,800,000	58.5	177,000,000	47.2	193,500,000	48.8	201,000,000	50.7	160,700,000	48.0	162,200,000	50.5	148,700,000	54.5	
2	RAW WATER SYSTEM	4,000,000	1.3	4,000,000	0.9	2,000,000	0.4	10,000,000	2.7	9,800,000	2.5	12,000,000	3.0	9,500,000	2.8	9,100,000	2.8	8,000,000	2.9	
3	DEMINERALIZED WATER SYSTEM	3,000,000	1.0	3,600,000	0.8	1,500,000	0.3	19,100,000	5.1	14,600,000	3.7	19,100,000	4.8	13,800,000	4.1	13,000,000	4.0	10,200,000	3.7	
4	ELECTRICAL SYSTEM	53,600,000	18.0	72,900,000	16.0	78,100,000	16.9	74,900,000	20.0	79,300,000	20.0	70,000,000	17.7	66,900,000	20.0	56,600,000	17.6	37,600,000	13.8	
5	WASTE WATER SYSTEM	23,800,000	8.0	50,100,000	11.0	50,800,000	11.0	45,000,000	12.0	47,600,000	12.0	45,000,000	11.3	40,200,000	12.0	38,500,000	12.0	32,700,000	12.0	
6	OTHERS	38,800,000	13.0	59,300,000	13.0	59,300,000	12.8	48,700,000	13.0	51,500,000	13.0	49,500,000	12.5	43,500,000	13.0	41,700,000	13.0	35,500,000	13.0	
7	**TOTAL - EURO**	**298,000,000**	**100.0**	**455,800,000**	**100.0**	**461,500,000**	**100.0**	**374,700,000**	**100.0**	**396,300,000**	**100.0**	**396,600,000**	**100.0**	**334,600,000**	**100.0**	**321,100,000**	**100.0**	**272,700,000**	**100.0**	

3. Operating and Maintenance costs

The definition of the Operating and Maintenance (O&M) costs is given in chapter B of the report. Following sections provide estimated operating and maintenance costs for the different cases, which are generally allocated as:

- Variable costs;
- Fixed costs.

However, accurately distinguishing the variable and fixed costs is not always feasible. 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.

3.1. Variable costs

Following tables show variable costs for the study cases listed in Table 1 and the near-zero emission cases listed in Table 2, including following main cost items:

- Feedstock
- Raw water make-up
- Solvents
- Catalysts
- Chemicals.

The consumption of the various items and the corresponding costs are yearly, based on the expected equivalent availability of the plant (90% / 85% capacity factor respectively for boiler and gasification based cases). Reference values for coal and main consumables prices are summarized in the table below.

Item	Unit	Cost
Coal	€/GJ (LHV)	2.5
Biomass	€/t, dry	100
Raw process water	€/m^3	0.2
Ash, slag, gypsum, and sulphur net disposal cost	€/t	0
CO_2 transport and storage	€/t CO_2 stored	10
CO_2 emission cost	€/t CO_2 emitted	0

The following tables report a summary of the variable costs for all the cases of the study.

Yearly Variable Costs - SCPC-based cases

Revision:	0	1	
Date:	June 2013	August 2013	
Issued by:	LC	LC	
Approved by:	LM	LM	

Yearly Operating hours = 7884		Case 1 SC-PC without CO_2 capture			Case 2 SC-PC with CO_2 capture			Case 3 Oxy SC-PC with CO_2 capture		
Consumables	**Unit Cost**	**Consumption** Hourly	Yearly	**Oper. Costs**	**Consumption** Hourly	Yearly	**Oper. Costs**	**Consumption** Hourly	Yearly	**Oper. Costs**
	€/t	kg/h	t/y	€/y	kg/h	t/y	€/y	kg/h	t/y	€/y
Feedstock										
Coal	64.7	325,000	2,562,300	165,716,800	325,000	2,562,300	165,716,800	325,000	2,562,300	165,716,800
Auxiliary feedstock										
Limestone (Case 1 & 2)	20.0	8,852	69,788	1,395,800	9,215	72,651	1,453,000		0	0
Lime (Case 3)	45.0	-		0	-		0	6,951	54,802	2,466,100
Make-up water	0.20	1,658,000	13,071,672	2,614,300	2,095,000	16,516,980	3,303,400	2,033,000	16,028,172	3,205,600
Catalysts	not displayable	-	-	3,806,100	-	-	4,241,700	-	-	0
Chemicals (including Solvents)	not displayable	-	-	1,683,000	-	-	(1) 10,494,900	-	-	453,600
Waste Disposal										
Slag disposal (wet)	0.0	0.0	0	0	0.0	0	0	0.0	0	0
Solvent disposal	not displayable	-	-	0	-	-	983,700	-	-	0
TOTAL YEARLY OPERATING COSTS	**Euro/year**			**175,216,000**			**186,193,500**			**171,842,100**

(1) Based on FW's assumption: specific solvent cost of 5 €/kg

Yearly Variable Costs - IGCC-based cases

Revision:	0	1	
Date:	June 2013	August 2013	
Issued by:	LC	LC	
Approved by:	LM	LM	

Yearly Operating hours = 7446		Case 4.1 IGCC with CO_2 capture (Shell)			Case 4.2 IGCC with CO_2 capture (GE)			Case 4.3 IGCC with CO_2 capture (MHI)		
Consumables	**Unit Cost**	**Consumption** Hourly	Yearly	**Oper. Costs**	**Consumption** Hourly	Yearly	**Oper. Costs**	**Consumption** Hourly	Yearly	**Oper. Costs**
	€/t	kg/h	t/y	€/y	kg/h	t/y	€/y	kg/h	t/y	€/y
Feedstock										
Coal	64.7	314,913	2,344,842	151,652,700	349,146	2,599,739	168,138,100	345,110	2,569,690	166,194,700
Fluxant (Limestone)	20.0	9,120	67,905	1,358,100	0	0	0	0	0	0
Auxiliary feedstock										
Make-up water	0.20	2,020,000	15,040,920	3,008,200	2,122,000	15,800,412	3,160,100	2,328,000	17,334,288	3,466,900
Catalysts	not displayable	-	-	4,332,450	-	-	3,081,250	-	-	6,426,000
Chemicals (including Solvents[1])	not displayable	-	-	3,252,950	-	-	3,511,350	-	-	4,267,850
Waste Disposal										
Slag disposal (wet)	0.0	0.0	0	0	0.0	0	0	0.0	0	0
Solvent disposal	-	-	-	0	-	-	0	-	-	0
TOTAL YEARLY OPERATING COSTS	**Euro/year**			**163,604,400**			**177,890,800**			**180,355,450**

(1) Solvent cost and make-up: confidential information

FOSTER WHEELER	Yearly Variable Costs - H_2 and power co-production cases									
Revision:	0	1								
Date:	June 2013	August 2013								
Issued by:	LC	LC								
Approved by:	LM	LM								
Yearly Operating hours = 7446		Case 5.1 IGCC (GE) / Hydrogen Production with CO_2 capture - 9E GTs			Case 5.2 IGCC (GE) / Hydrogen Production with CO_2 capture - 6F GTs			Case 5.3 IGCC (GE) / Hydrogen Production with CO2 capture - Boiler		
Consumables	**Unit Cost**	**Consumption**		**Oper. Costs**	**Consumption**		**Oper. Costs**	**Consumption**		**Oper. Costs**
		Hourly	Yearly		Hourly	Yearly		Hourly	Yearly	
	€/t	kg/h	t/y	€/y	kg/h	t/y	€/y	kg/h	t/y	€/y
Feedstock										
Coal	64.7	349,146	2,599,739	168,138,100	349,146	2,599,739	168,138,100	349,146	2,599,739	168,138,100
Fluxant (Limestone)	20.0	0	0	0	0	0	0	0	0	0
Auxiliary feedstock										
Make-up water	0.20	1,872,000	13,938,912	2,787,800	1,761,000	13,112,406	2,622,500	1,562,000	11,630,652	2,326,100
Catalysts	not displayable	-	-	3,081,250	-	-	3,081,250	-	-	3,081,250
Chemicals (including Solvents[1])	not displayable	-	-	3,511,350	-	-	3,511,350	-	-	3,511,350
Waste Disposal										
Slag disposal (wet)	0.0	0.0	0	0	0.0	0	0	0.0	0	0
Solvent disposal	-	-	-	0	-	-	0	-	-	0
TOTAL YEARLY OPERATING COSTS	**Euro/year**			**177,518,500**			**177,353,200**			**177,056,800**

(1) Solvent cost and make-up: confidential information

FOSTER WHEELER	Yearly Variable Costs - Near zero emission cases												
Revision:	1												
Date:	January 2014												
Issued by:	GP												
Approved by:	LM												
Yearly Operating hours = 7884		Case 2.1 SC-PC with CO_2 capture - biomass cofiring			Case 3.1 Oxy SC-PC with CO_2 capture			Case 4.2.1 IGCC with CO_2 capture (GE) - hgh capture			Case 5.3.1 IGCC (GE) / Hydrogen Production with CO2 capture - Boiler - high capture		
Consumables	**Unit Cost**	**Consumption**		**Oper. Costs**	**Consumption**		**Oper. Costs**	**Consumption**		**Oper. Costs**	**Consumption**		**Oper. Costs**
		Hourly	Yearly		Hourly	Yearly		Hourly	Yearly		Hourly	Yearly	
	€/t	kg/h	t/y	€/y	kg/h	t/y	€/y	kg/h	t/y	€/y	kg/h	t/y	€/y
Feedstock													
Coal	64.7	300,600	2,369,930	153,275,200	325,000	2,562,300	165,716,800	349,200	2,600,143	168,164,300	349,146	2,599,739	168,138,100
Biomass	50.0	86,400	681,178	34,058,900	0	0	0	0	0	0	0	0	0
Auxiliary feedstock													
Limestone (Case 1 & 2)	20.0	8,600	67,802	1,356,000	0	0	0	2,160,000	16,083,360	3,216,700	1,588,000	11,824,248	2,364,800
Lime (Case 3)	45.0	-			6,600	52,034	2,341,500	0	0	0			
Make-up water	0.20	2,050,000	16,162,200	3,232,400	2,053,000	16,185,852	3,237,200	-	-	3,081,250	-	-	3,081,250
Catalysts (including membranes)	not displayable	-	-	4,241,700	-	-	900000 (1)	-	-	3,538,550	-	-	3,538,550
Chemicals (including Solvents)	not displayable	-	-	10,691,100	-	-	453,600	0	0	0	0	0	0
Waste Disposal								-	-	0	-	-	0
Slag disposal (wet)	0.0	0	0	0	0	0	0	0	0	0	0	0	0
Solvent disposal	not displayable	-	-	1,007,100	-	-	0	0	0	178,000,800	0	0	177,122,700
TOTAL YEARLY OPERATING COSTS	**Euro/year**			**207,862,400**			**171,749,100**			**178,000,800**			**180,355,450**

(1) Based on FW's assumption

3.2. Fixed costs

Fixed costs include:

- Operating Labour Costs
- Overhead Charges
- Maintenance Costs.

3.2.1. Operating Labour costs

The plants of the different study cases can be virtually divided into the following main areas of operation:

- SC-PC plants:
  - Boiler island & flue gas treatment
  - Steam Cycle & Utilities.
- Gasification plants:
  - Air Separation Unit (ASU)
  - Gasification and Process Units, including Syngas Treatment and Conditioning Line, AGR, SRU & TGT, CO_2 Compression , PSA, etc.
  - Combined Cycle & Utilities.

The same division is reflected in the design of the centralized control room, which has the same number of main DCS control groups, each one equipped with a number of control stations, from where the operation of the units of each area is controlled.

The area responsible and his assistant supervise each area of operation; both are daily position. The shift superintendent and the electrical assistant are common for the different 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 take into account the service outsourcing. Plant maintenance personnel like the instrument specialists perform routine maintenance and resolve emergency problems.

The yearly cost of the direct labour is calculated assuming for each individual an average cost equal to 60,000 Euro/year, referred to year 2013.

The following tables report the labour force for the different configurations, along with the direct labour cost.

Table 27. Case 1 – Operating Labor costs

Case 1				
	Boiler Island & Flue Gas Treatment	Power Island & Utilities	TOTAL	Notes
OPERATION				
Area Responsible	1	1	2	daily position
Assistant Area Responsible	1	1	2	daily position
Shift Superintendent	5		5	1 position per shift
Electrical Assistant	5		5	1 position per shift
Shift Supervisor	5	5	10	2 positions per shift
Control Room Operator	10	10	20	4 positions per shift
Field Operator	15	15	30	8 positions per shift
Subtotal			**74**	
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
Subtotal			**4**	
TOTAL			**95**	

Cost for personnel

Yearly individual average cost = 60.000 Euro/year

Total cost = 5.700.000 Euro/year

Table 28. Case 2, 2.1, 3 and 3.1 – Operating Labor costs

Case 2 - 2.1 - 3 - 3.1				
	Boiler Island & Flue Gas Treatment	Power Island & Utilities	TOTAL	Notes
OPERATION				
Area Responsible	1	1	2	daily position
Assistant Area Responsible	1	1	2	daily position
Shift Superintendent	5		5	1 position per shift
Electrical Assistant	5		5	1 position per shift
Shift Supervisor	5	5	10	2 positions per shift
Control Room Operator	10	10	20	4 positions per shift
Field Operator	15	25	40	8 positions per shift
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
Subtotal			**4**	
TOTAL			**105**	

Cost for personnel

Yearly individual average cost = 60,000 Euro/year

Total cost = 6,300,000 Euro/year

Table 29. Case 4 and 5 – Operating Labor costs

Case 4.1 - 4.2 - 4.2.1 - 4.3 - 5.1 - 5.2 - 5.3 - 5.3.1					
	ASU	**Gasification**	**Power Island & Utilities**	**TOTAL**	**Notes**
OPERATION					
Area Responsible	1	1	1	3	daily position
Assistant Area Responsible	1	1	1	3	daily position
Shift Superintendent		5		5	1 position per shift
Electrical Assistant		5		5	1 position per shift
Shift Supervisor	5	5	5	15	3 positions per shift
Control Room Operator	5	10	10	25	5 positions per shift
Field Operator	5	30	20	55	10 positions per shift
Subtotal				**111**	
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
Subtotal				**6**	
TOTAL				**133**	
Cost for personnel					
Yearly individual average cost =		60,000	Euro/year		
Total cost =		7,980,000	Euro/year		

3.2.2. Overhead charges

All other company services not directly involved in the operation of the plant fall in this category, such as:

- Management;
- Administration;
- Personnel services;
- Technical services.

These services vary widely from company to company and are also dependent on the type and complexity of the operation. It is assumed that this cost is equal to 30 % of the operating labour and maintenance cost.

3.2.3. Maintenance costs

A precise evaluation of the cost of maintenance would require a breakdown of the costs amongst the numerous components and packages of the plant. Since these costs are all strongly dependent on the type of equipment selected and statistical maintenance data provided by the selected vendors, this type of evaluation of the maintenance cost is premature at study level.

For this reason the annual maintenance cost of the plant is estimated as a percentage of the Total Plant Cost of each case, as shown in the following:

SC PC based cases	1.5%
Gasification based cases	2.5%

In general, estimates can be separately expressed as maintenance labour and maintenance materials. A maintenance labour to materials ratio of 40:60 can be statistically considered for this breakdown.

The yearly maintenance cost for all cases of the study is reported in the following Table 30, with reference to year 2013.

Table 30. Maintenance costs (reference year: 2013)

Type	Case	Maintenance (%)	Total Plant Cost (M€)	Maintenance (M€/year)
Boiler-based	**Case 1**	1.5	1,490	22.4
	Case 2	1.5	2,279	34.0
	Case 2.1	1.5	2,333	35.0
	Case 3	1.5	2,301	34.5
	Case 3.1	1.5	2,325	34.9
IGCC-based	**Case 4.1**	2.5	2,538	63.4
	Case 4.2	2.5	2,688	67.2
	Case 4.2.1	2.5	2,738	68.5
	Case 4.3	2.5	2,629	65.7
H_2 & Power	**Case 5.1**	2.5	2,461	61.5
	Case 5.2	2.5	2,390	59.8
	Case 5.3	2.5	2,101	52.5
	Case 5.3.1	2.5	2,149	53.7

3.3. Summary

The following tables report the summary of O&M costs for the different cases.

FOSTER WHEELER	CO_2 CAPTURE AT COAL FIRED POWER PLANTS SCPC-BASED CASES O&M COSTS (2013)		
	Case 1 €/year	Case 2 €/year	Case 3 €/year
Fixed Costs			
Direct labour	5,700,000	6,300,000	6,300,000
Adm./gen overheads	4,392,500	5,992,700	6,031,400
Insurance & Local taxes	14,903,000	22,793,000	23,008,000
Maintenance	22,354,500	34,189,500	34,512,000
Subtotal	**47,350,000**	**69,275,200**	**69,851,400**
Variable Costs (Availability = 90%)			
Feedstock	167,112,600	167,169,800	168,182,900
Water Makeup	2,614,300	3,303,400	3,205,600
Catalyst	3,806,100	4,241,700	0
Chemicals (including Solvent)	1,683,000	10,494,900	453,600
Waste disposal (incl. Solvent)	0	983,700	0
Subtotal	**175,216,000**	**186,193,500**	**171,842,100**
TOTAL O&M COSTS	**222,566,000**	**255,468,700**	**241,693,500**

FOSTER WHEELER	CO_2 CAPTURE AT COAL FIRED POWER PLANTS IGCC-BASED CASES O&M COSTS (2013)		
	Case 4.1 €/year	Case 4.2 €/year	Case 4.3 €/year
Fixed Costs			
Direct labour	7,980,000	7,980,000	7,980,000
Adm./gen overheads	10,007,100	10,458,200	10,281,300
Insurance & Local taxes	25,377,000	26,880,500	26,291,000
Maintenance	63,442,500	67,201,300	65,727,500
Subtotal	**106,806,600**	**112,520,000**	**110,279,800**
Variable Costs (Availability = 85%)			
Feedstock	153,010,800	168,138,100	166,194,700
Water Makeup	3,008,200	3,160,100	3,466,900
Catalyst	4,332,450	3,081,250	6,426,000
Chemicals (including Solvent)	3,252,950	3,511,350	4,267,850
Waste disposal (incl. Solvent)	0	0	0
Subtotal	**163,604,400**	**177,890,800**	**180,355,450**
TOTAL O&M COSTS	**270,411,000**	**290,410,800**	**290,635,250**

FOSTER WHEELER	CO_2 CAPTURE AT COAL FIRED POWER PLANTS H_2 & POWER CO-PRODUCTION CASES O&M COSTS (2013)		
	Case 5.1 €/year	**Case 5.2** €/year	**Case 5.3** €/year
Fixed Costs			
Direct labour	7,980,000	7,980,000	7,980,000
Adm./gen overheads	9,777,200	9,563,900	8,696,900
Insurance & Local taxes	24,610,500	23,899,500	21,009,500
Maintenance	61,526,300	59,748,800	52,523,800
Subtotal	**103,894,000**	**101,192,200**	**90,210,200**
Variable Costs (Availability = 85%)			
Feedstock	168,138,100	168,138,100	168,138,100
Water Makeup	2,787,800	2,622,500	2,326,100
Catalyst	3,081,250	3,081,250	3,081,250
Chemicals (including Solvent)	3,511,350	3,511,350	3,511,350
Waste disposal (incl. Solvent)	0	0	0
Subtotal	**177,518,500**	**177,353,200**	**177,056,800**
TOTAL O&M COSTS	**281,412,500**	**278,545,400**	**267,267,000**

FOSTER WHEELER	CO_2 CAPTURE AT COAL FIRED POWER PLANTS NEAR ZERO EMISSION CASES O&M COSTS (2013)			
	Case 2.1 €/year	**Case 3.1** €/year	**Case 4.2.1** €/year	**Case 5.3.1** €/year
Fixed Costs				
Direct labour	6,300,000	6,300,000	7,980,000	7,980,000
Adm./gen overheads	6,090,100	6,076,400	10,608,000	8,841,600
Insurance & Local taxes	23,334,000	23,258,000	27,380,000	21,492,000
Maintenance	35,001,000	34,887,000	68,450,000	53,730,000
Subtotal	**70,725,100**	**70,521,400**	**114,418,000**	**92,043,600**
Variable Costs (Availability = 90%)				
Feedstock	188,690,100	168,058,300	168,164,300	168,138,100
Water Makeup	3,232,400	3,237,200	3,216,700	2,364,800
Catalyst (including membranes)	4,241,700	900,000	3,081,250	3,081,250
Chemicals (including Solvent)	10,691,100	453,600	3,538,550	3,538,550
Waste disposal (incl. Solvent)	1,007,100	0	0	0
Subtotal	**207,862,400**	**172,649,100**	**178,000,800**	**177,122,700**
TOTAL O&M COSTS	**278,587,500**	**243,170,500**	**292,418,800**	**269,166,300**

4. Financial analysis

4.1. Objective of the economic modelling

The economic modelling is a simplified financial analysis that estimates, for each case, the Levelized Cost of Electricity (LCOE) and the CO_2 Avoidance Cost (CAC), based on specific macroeconomic assumptions.
For the hydrogen and power co-production cases, the Levelized Cost of Hydrogen (LCOH) production is also estimated.

The LCOE and the LCOH predictions are calculated under the assumption of obtaining a zero Net Present Value (NPV) for the project, corresponding to an Internal Rate of Return (IRR) equal to the Discount Rate (DR). Therefore, the financial analysis is a high-level economical evaluation only, while the rigorous project profitability for the specific case is beyond the scope of the present study.

4.2. Definitions

4.2.1. *Levelized Cost Of Electricity (LCOE) and Levelized Cost Of Hydrogen (LCOH)*

The Cost of Electricity (COE) in power production plants is defined as the selling price at which electricity must be generated to reach the break even at the end of the plant lifetime for a targeted rate of return.

However, with the purpose of screening different technology alternatives, the levelized value of the cost of electricity (LCOE) is commonly preferred to the year-by-year data. The LCOE is defined as the uniform annual amount which returns the same net present value as the year-by-year amounts.

In this analysis, long-term inflation assumptions and price/cost variations throughout the project life-time are not considered and, therefore, the COE matches with the LCOE.

The same considerations apply to the hydrogen and power co-production cases, where the power selling price is valued at the cost of production of the base case with power production only (Case 4.2, GE-based IGCC).

4.2.2. *Cost of CO_2 avoidance*

For the power production cases, the CO_2 Avoidance Cost (CAC) is calculated by comparing the costs and specific emissions of a plant with CCS with those of the reference case without CCS. For a power generation plant, it is defined as follows:

$$CO_2 \text{ Avoidance Cost (CAC)} = \frac{LCOE_{CCS} - LCOE_{Reference}}{CO_2Emissions_{\ Reference} - CO_2Emissions_{\ CCS}}$$

where:

Cost of CO_2 avoidance is expressed in Euro per tonne of CO_2
LCOE is expressed in Euro per kWh
CO_2 emissions is expressed in tonnes of CO_2 per kWh.

The selected reference case for the evaluation of the CAC is Case 1, i.e. the conventional SC-PC power plant without capture of the generated carbon dioxide.

4.3. Macroeconomic bases

The economic assumptions and macroeconomic bases are reported in chapter B of the report. These mainly include:

- Reference dates and construction period,
- Financial leverage,
- Discount rate,
- Interests during construction,
- Spare parts cost,
- Working capital,
- Start-up cost,
- Owner's cost,
- Insurance cost,
- Local taxes and fees,
- Decommissioning cost.

The principal financial bases assumed for the financial modelling are reported also hereafter for reader's convenience:

ITEM	DATA
Type of fuel	Bituminous Coal at 2.5 €/GJ (LHV)
Discount Rate	8%
Capacity factor (SC-PC/Gasification based)	90% / 85%
CO_2 transport & storage cost	10 €/t $_{STORED}$
CO_2 emission cost	0 €/t $_{EMITTED}$
Inflation Rate	Constant Euro
Currency	Euro reported in 2Q2013

4.4. Financial analysis results

This section summarizes the results of the financial analysis performed for all cases of the study, based on the input data reported above.

Figure 10 to Figure 14 report the LCOE, LCOH and CAC for all study cases. LCOE and LCOH figures also show the relative weight of:

- Capital investment,
- Fixed O&M,
- Variable O&M,
- Fuel,
- CO_2 transportation & storage,
- CO_2 emission.

A summary of the economical modelling results is also reported in the following Table 31 and Table 32.

Table 31. Financial results summary: LCOE and CO_2 avoidance cost

Case	Description	LCOE €/MWh	CO_2 emission avoidance cost €/t
Case 1	SC-PC w/o CCS	52.0	-
Case 2	SC-PC w/CCS	94.7	65.4
Case 2.1	SC-PC w/CCS near zero emission	100.5	65.1
Case 3	OXY SC-PC	91.6	60.8
Case 3.1	OXY SC-PC near zero emission	94.2	58.3
Case 4.1	IGCC (Shell)	116.5	98.9
Case 4.2	IGCC (GEE)	114.4	95.8
Case 4.2.1	IGCC (GEE) near zero emission	119.2	92.5
Case 4.3	IGCC (MHI)	114.5	97.4

For the power production cases, the results of the economic analysis clearly show that for the cases with carbon capture and for each plant type, i.e. for the coal boilers and IGCCs based alternatives, both the LCOE and the CAC fall in a narrow range of variation, especially considering the accuracy level of the investment cost (+35%/-15%).

Table 32. Financial result summary: LCOH[(1)]

Case	Description	LCOH[(1).] c€/Nm^3
Case 5.1	H_2&Power production: 2 x E-class GTs	19.5
Case 5.2	H_2&Power production: 2 x frame 6 GTs	18.3
Case 5.3	H_2&Power production: 2 x Boiler	17.3
Case 5.3.1	H_2&Power production: 2 x Boiler – near zero emission	18.1

(1) Assuming LCOE = 114.4 €/MWh as per reference Case 4.2 (power production only)

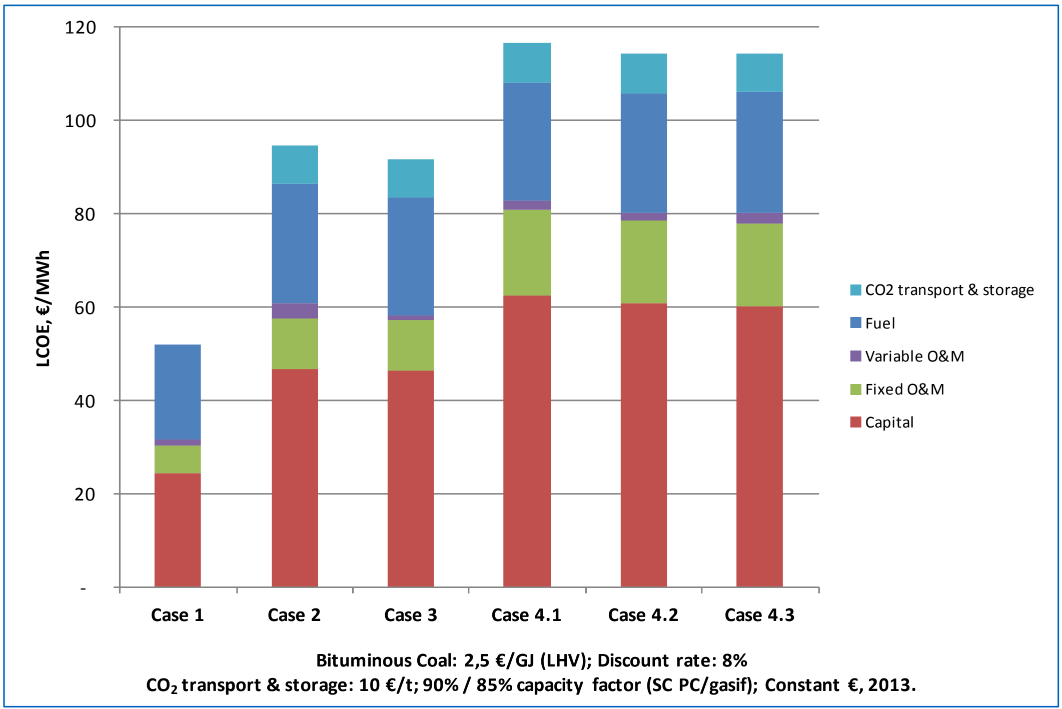


Figure 10. LCOE for all power production cases

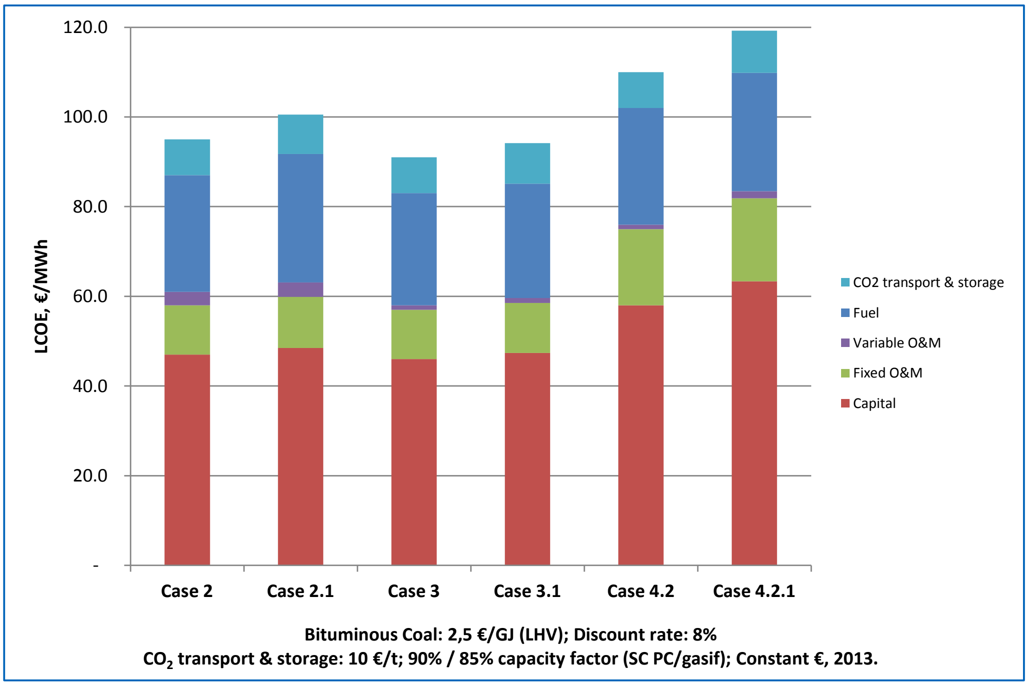


Figure 11. LCOE for all power production – near zero emission cases

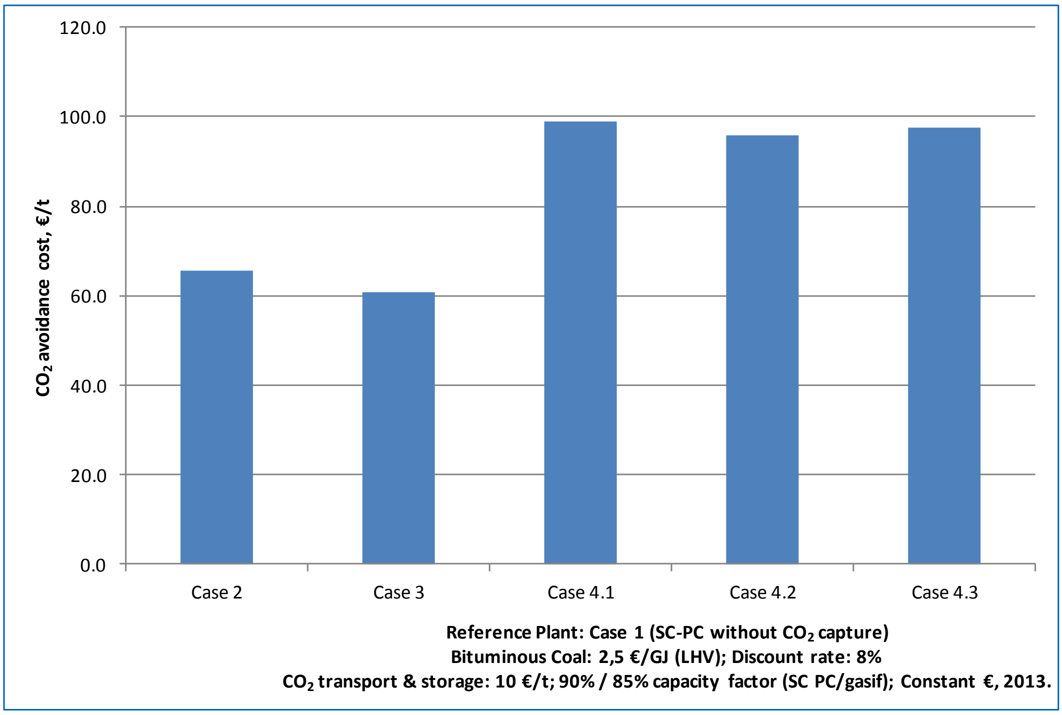


Figure 12. Cost of CO_2 avoidance for all power production cases

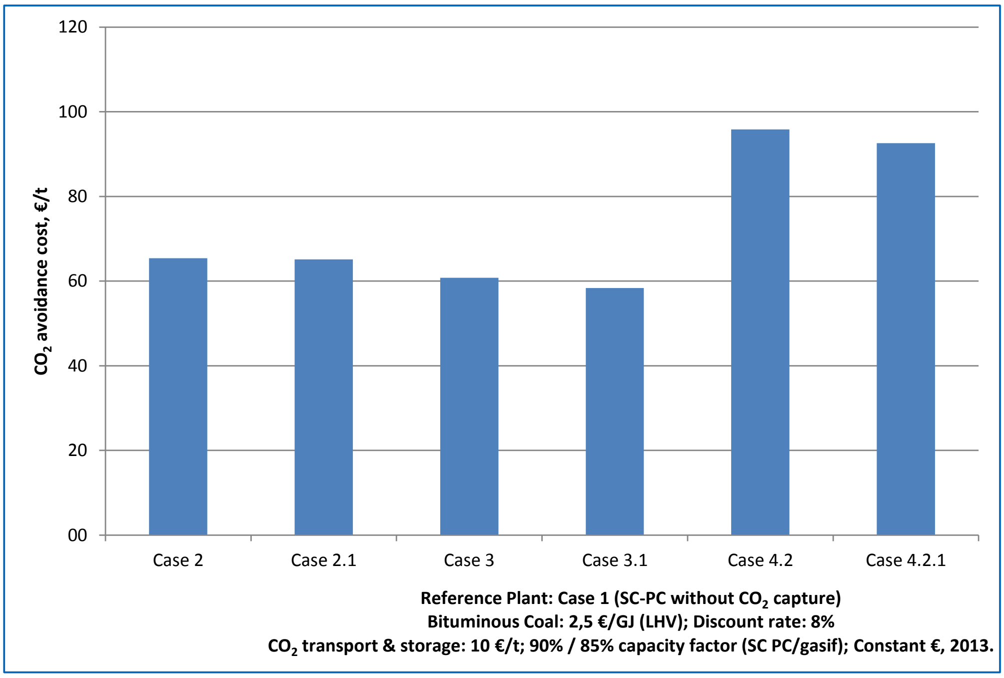


Figure 13. Cost of CO_2 avoidance for all power production – near zero emission cases

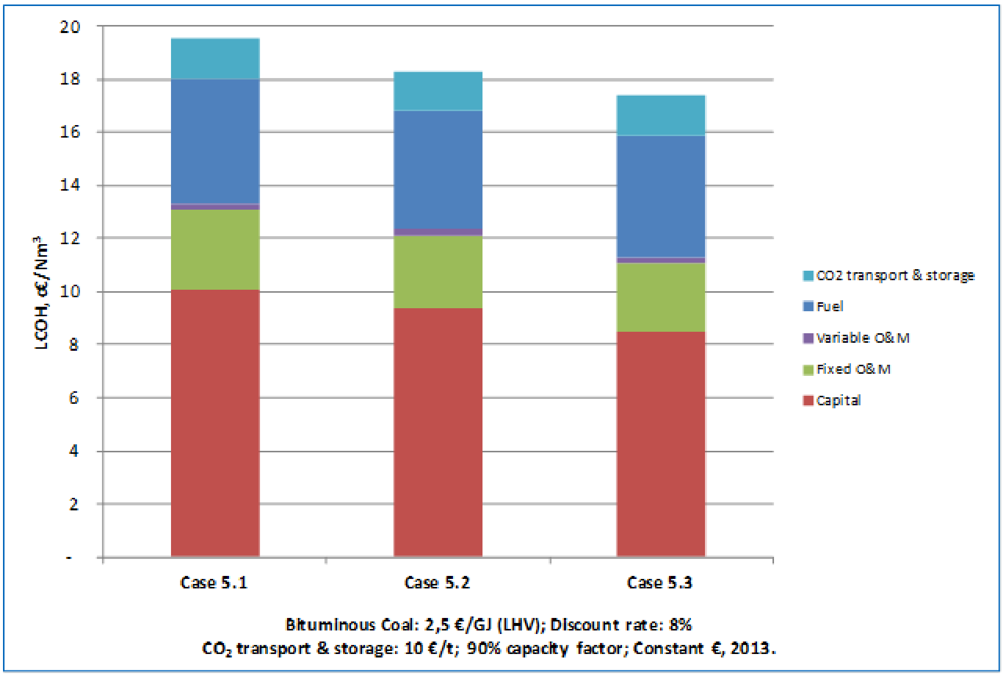


Figure 14. LCOH for all power and hydrogen co-production cases

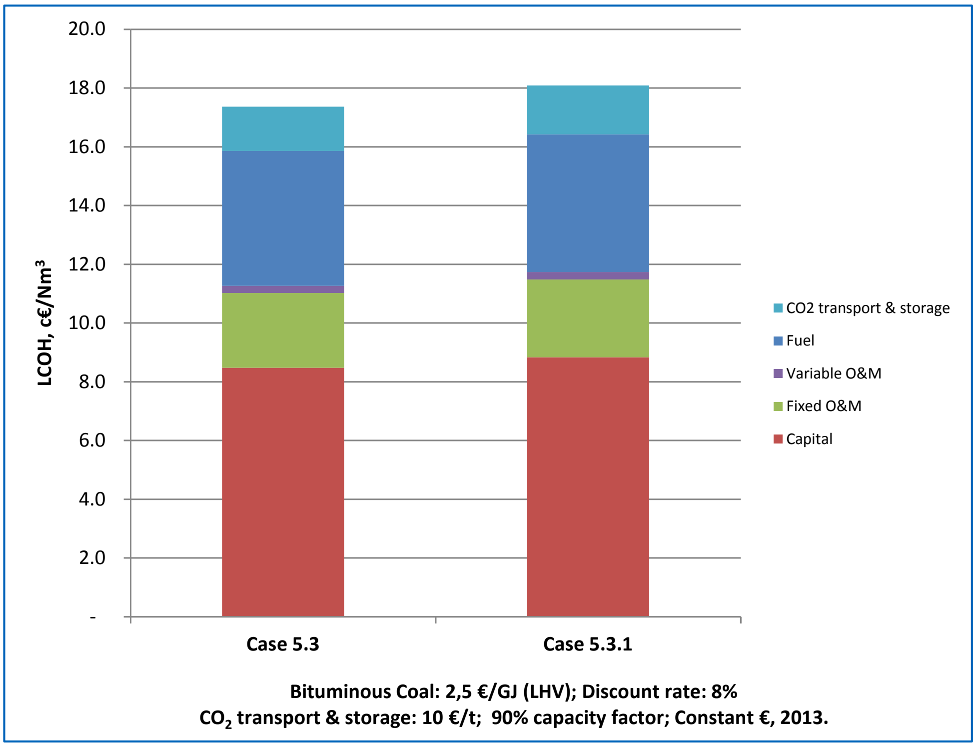


Figure 15. LCOH for near zero emission - power and hydrogen co-production case

4.5. Sensitivity analysis

This section summarizes the results of the sensitivity analyses performed to estimate the LCOE and the CO_2 Avoidance Cost of the different study cases, versus the variation of the following main economical parameters:

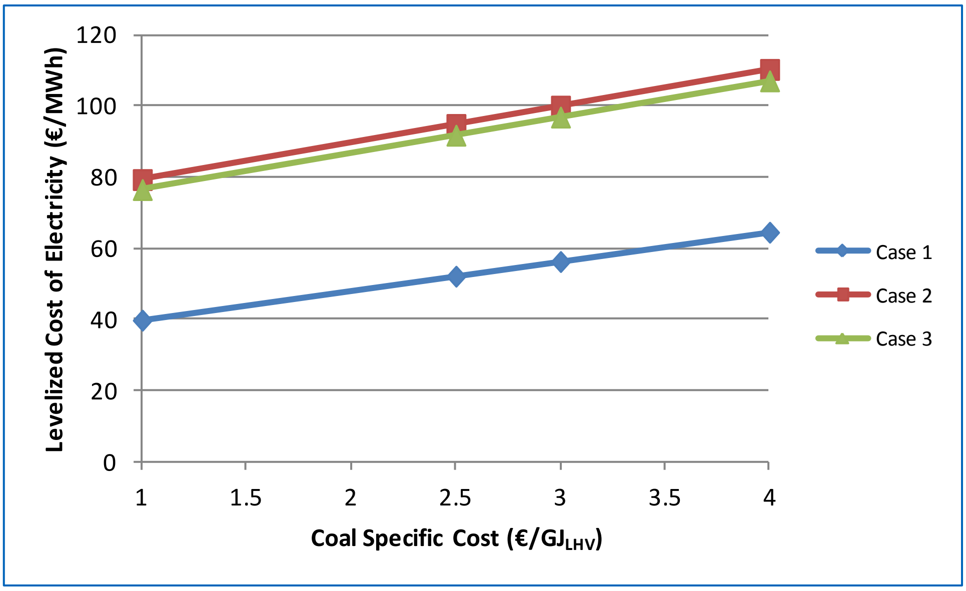
- Coal cost,
- Discount rate,
- Plant life (project duration),
- CO_2 transport & storage cost,
- CO_2 emission cost,
- Load factor.

The sensitivity range has been selected in accordance with the study requirement, of which the following table represents a summary.

Sensitivity relevant to all cases			
Criteria	**Unit**	**Base Case**	**Sensitivity Range**
Fuel Price Coal	€/GJ (LHV)	2.5	1 - 4
Discount rate	%	8	5 - 10
Plant life	years	25	25 - 40
CO_2 transport & storage	€/t stored	10	0 - 20
CO_2 emission costs	€/t emitted	0	0 - 100
Capacity factor USC-PC IGCC	 % %	 90 85	 50 – 90 50 – 90
Sensitivity analyses relevant to Case 5.1 / 5.2 / 5.3			
Electricity selling price	€/MWh	114.4	114 - 150

4.5.1. *Coal cost sensitivity*

LCOE



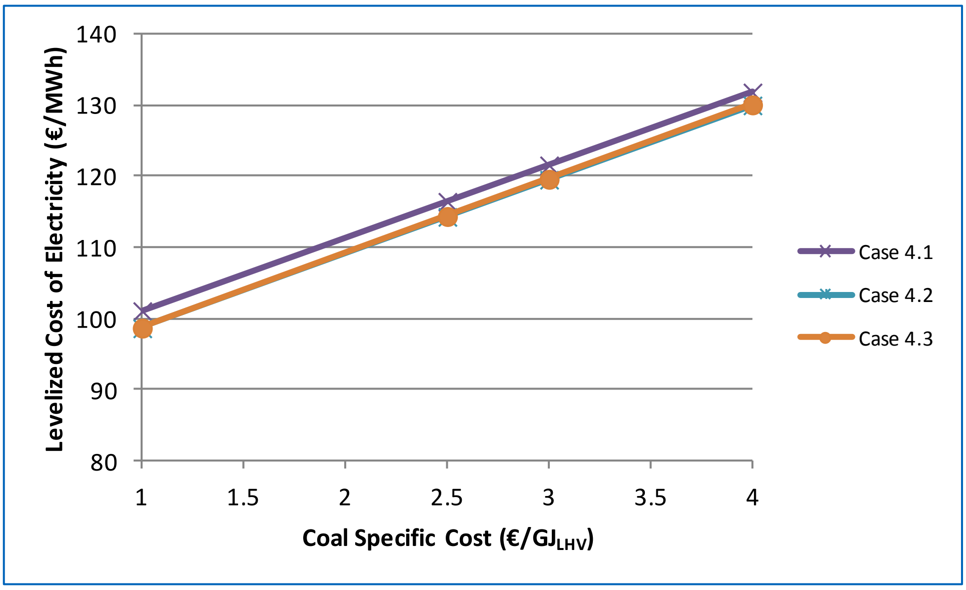
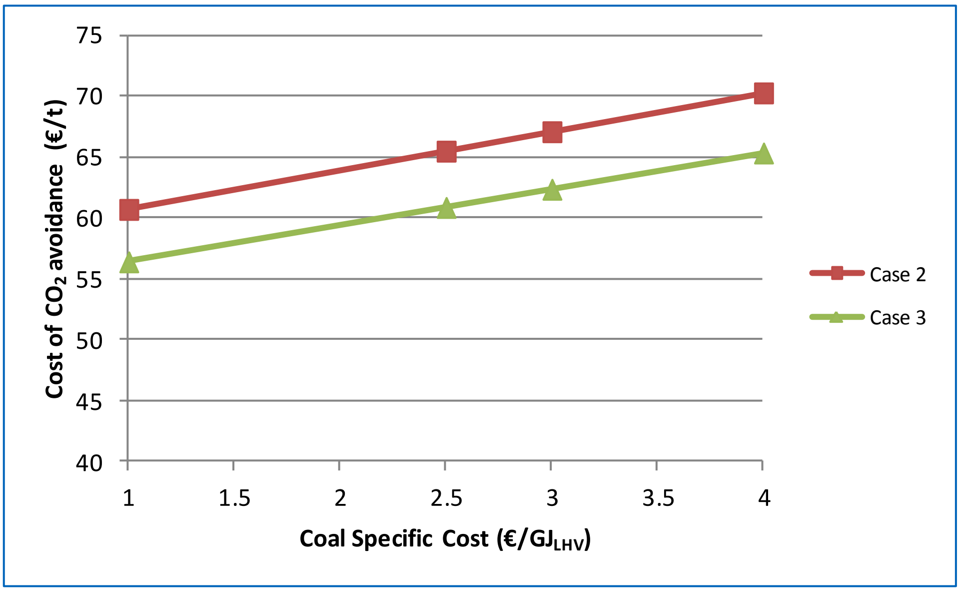


Figure 16: LCOE variation as function of coal price

CO_2 emission avoidance cost



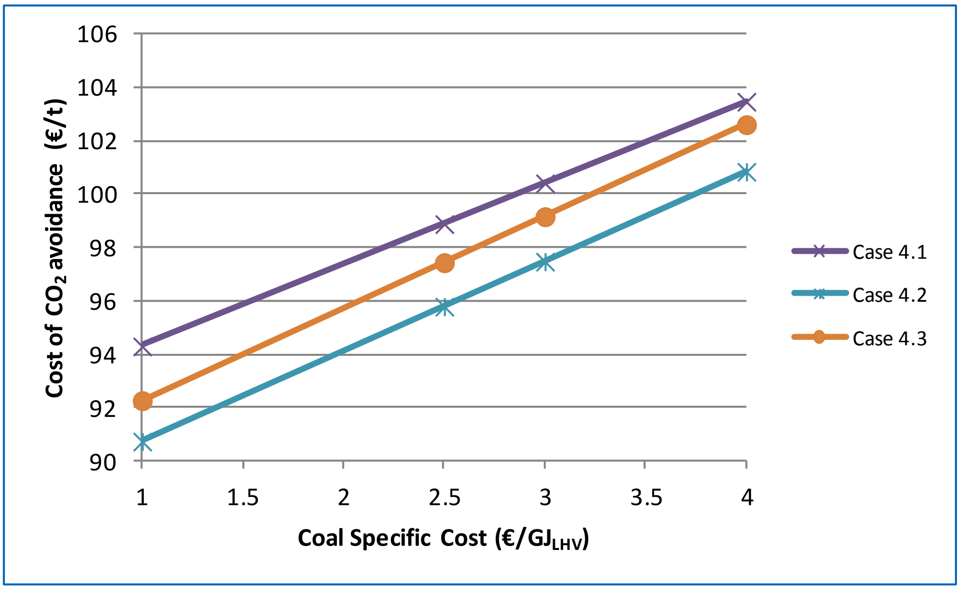


Figure 17: CO_2 emission avoidance cost variation as function of coal price

LCOH

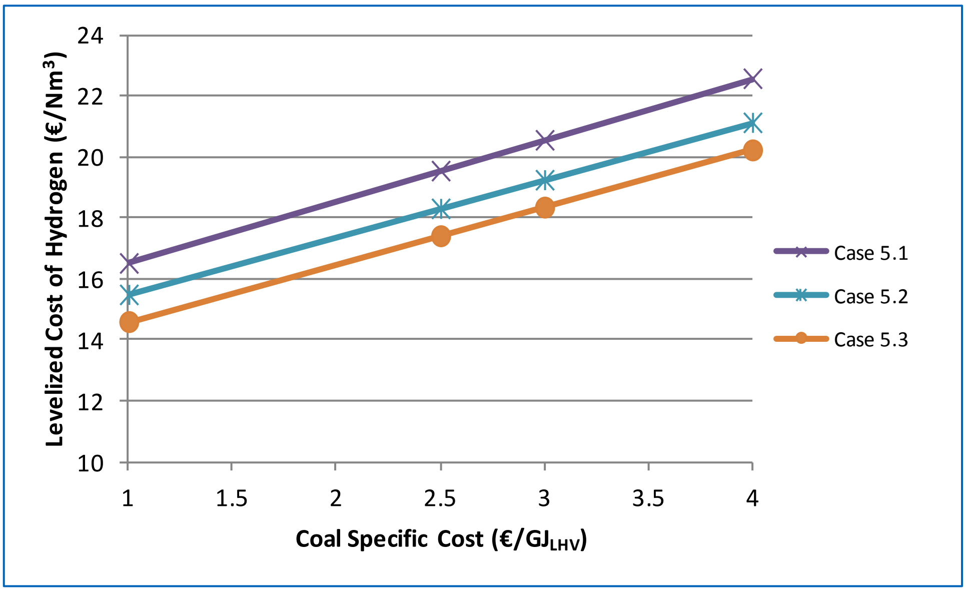
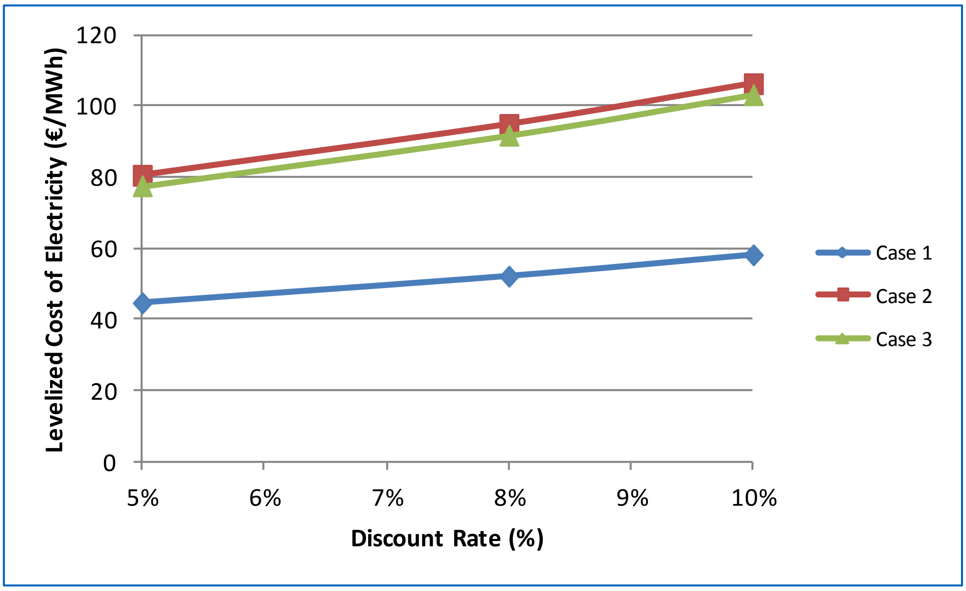


Figure 18: LCOH variation as function of coal price

4.5.2. Discount rate variation

LCOE



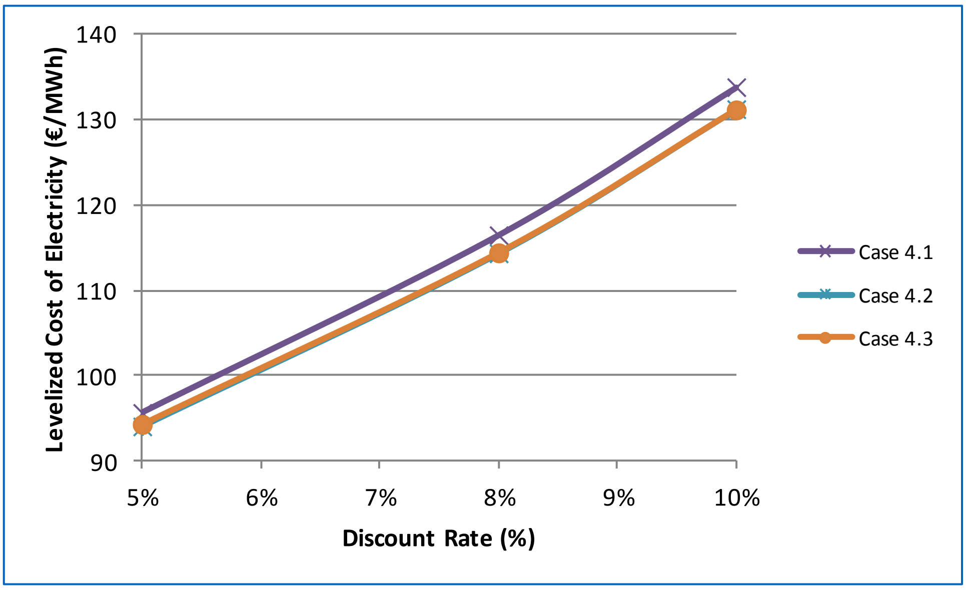
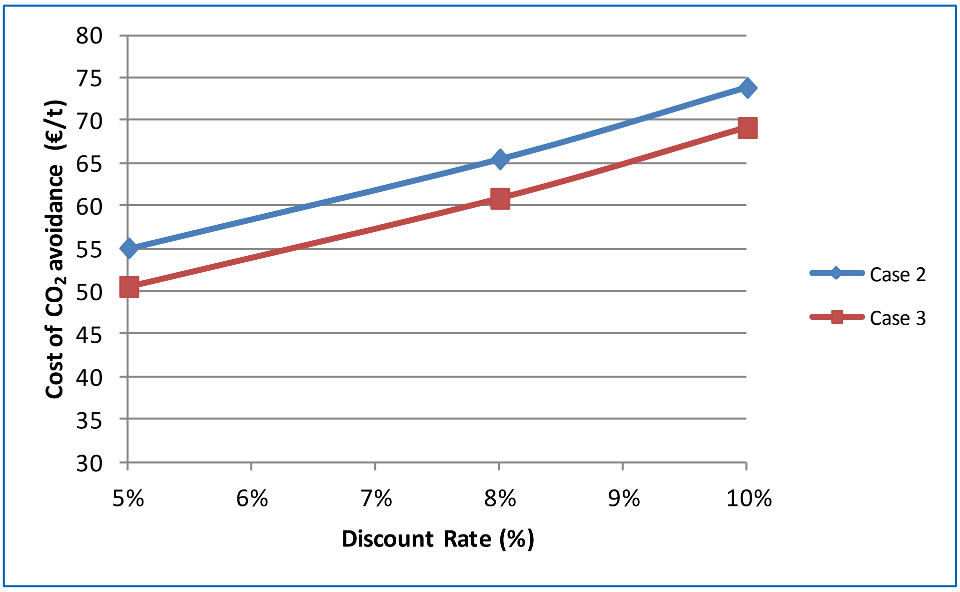


Figure 19: LCOE variation as function of discount rate

CO_2 emission avoidance cost



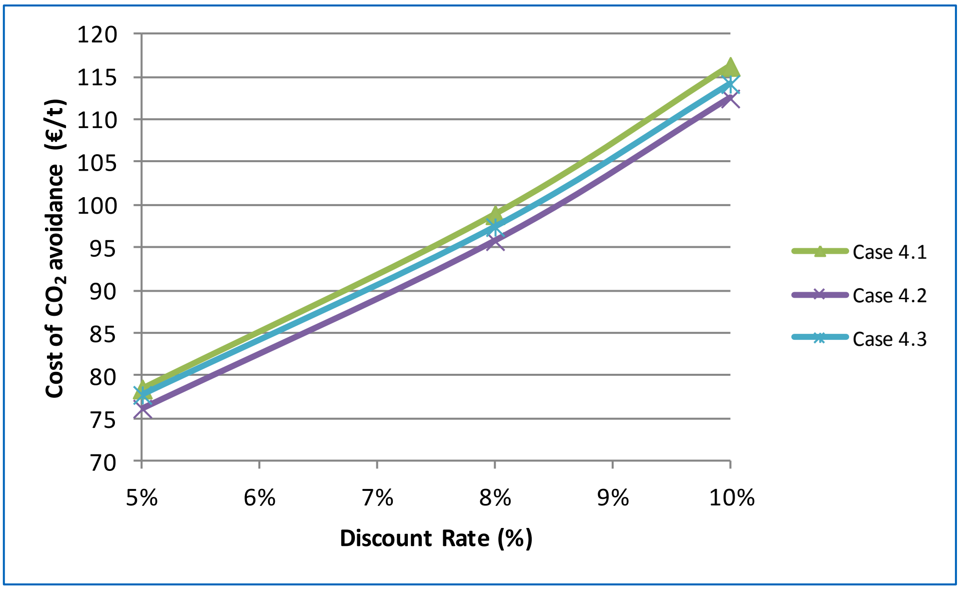


Figure 20: CO_2 emission avoidance cost variation as function of discount rate

LCOH

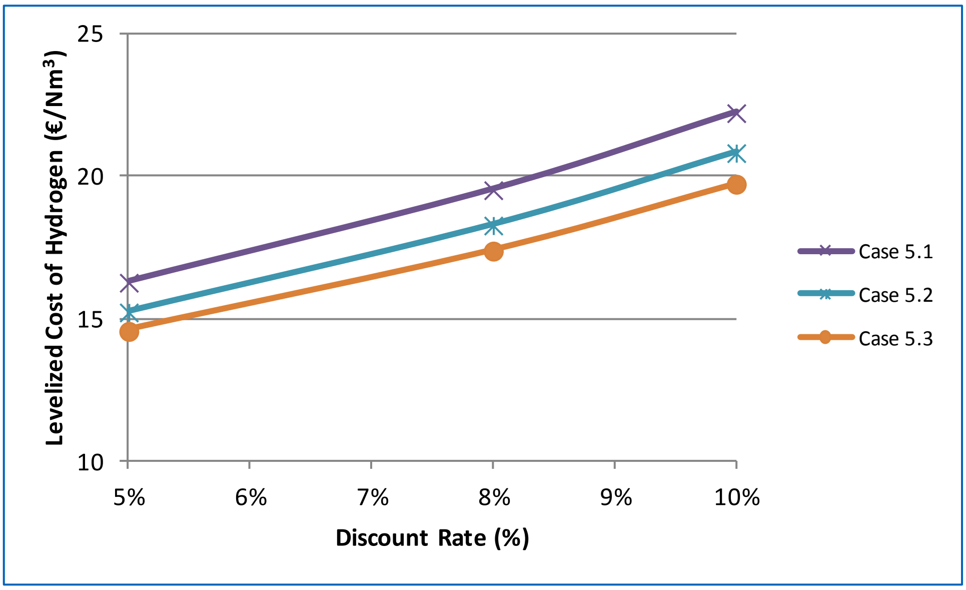
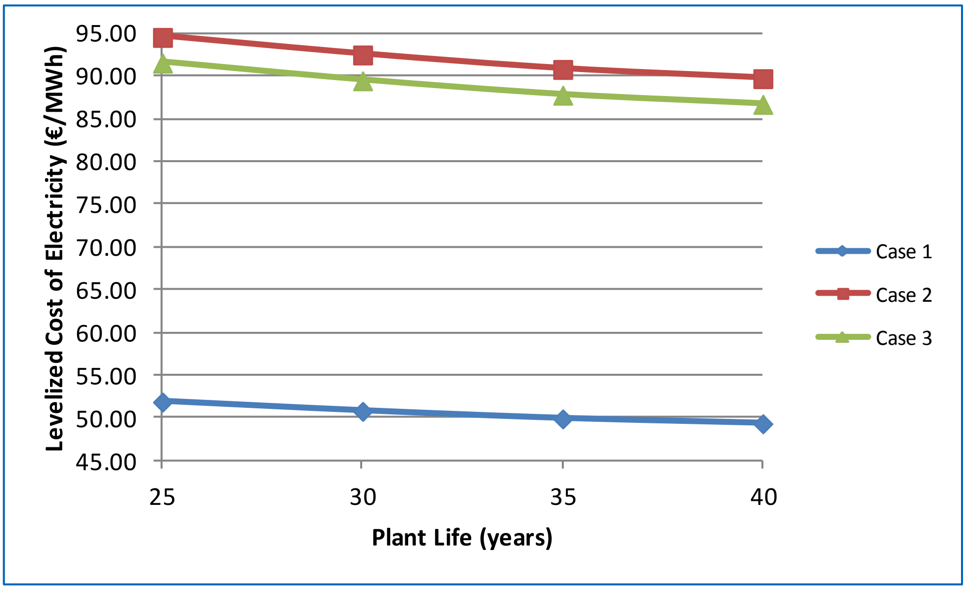


Figure 21: LCOH variation as function of discount rate

4.5.3. *Plant life*

LCOE



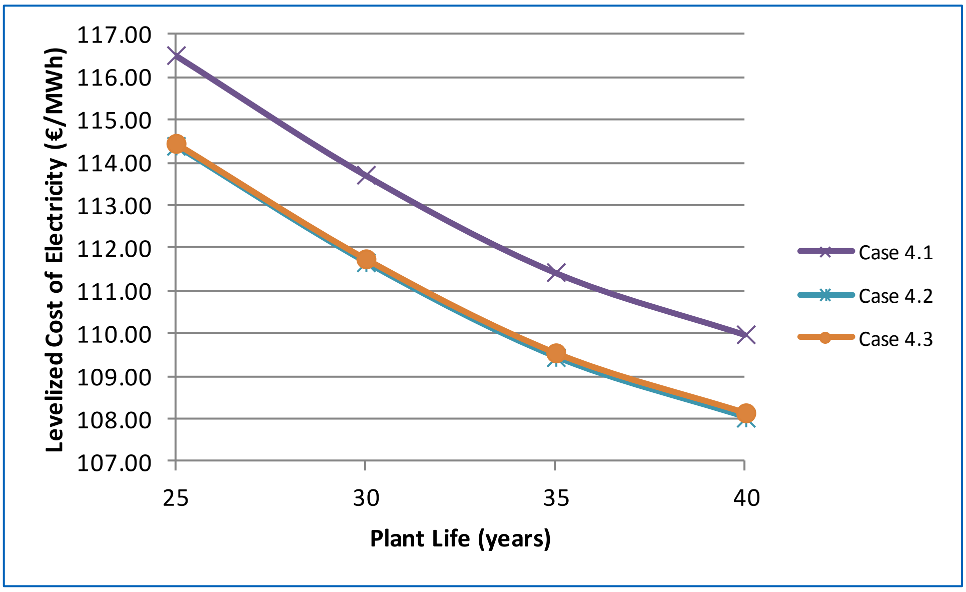
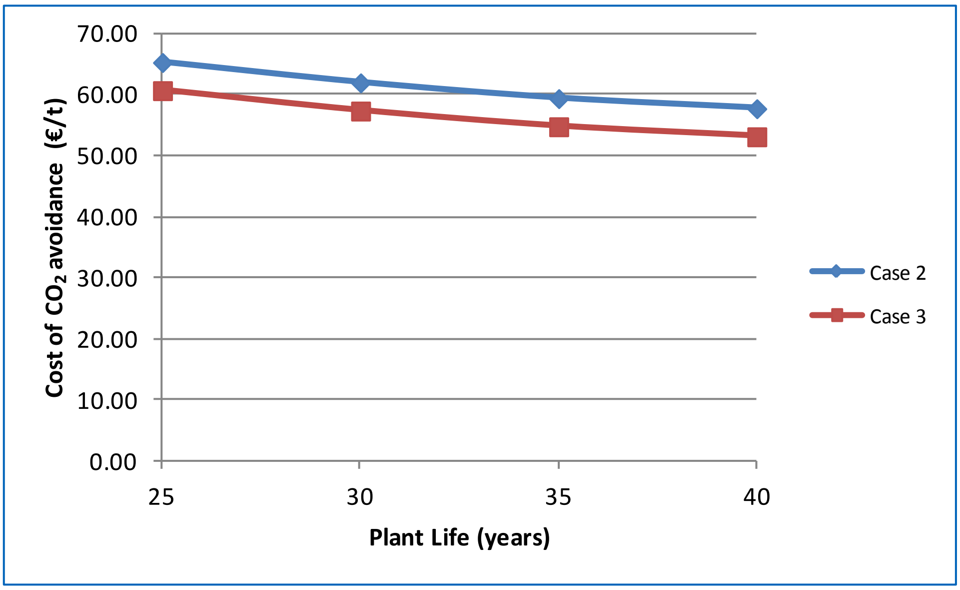


Figure 22: LCOE variation as function of plant life (project duration)

CO_2 emission avoidance cost



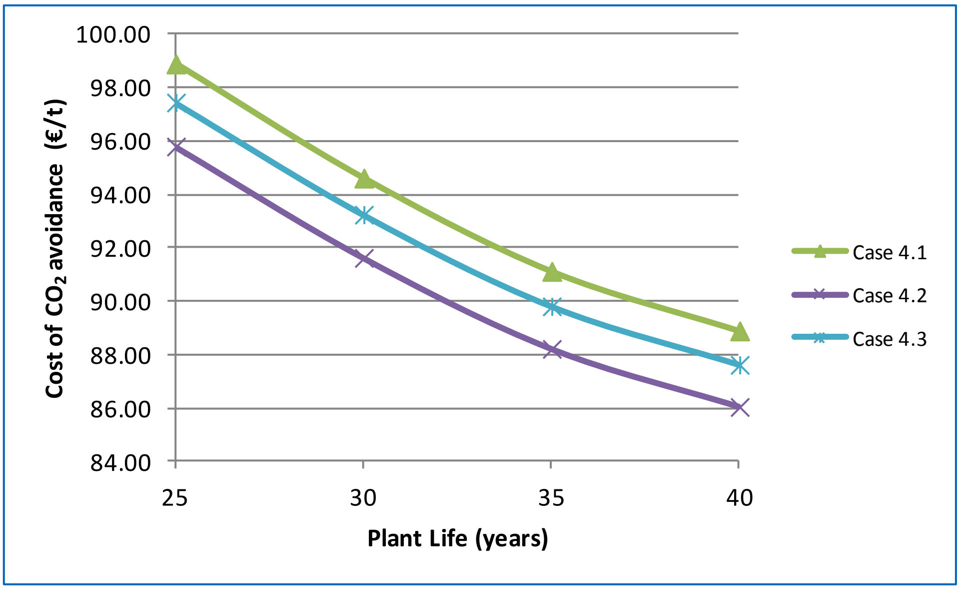


Figure 23: CO_2 emission avoidance cost variation as function of plant life (project duration)

LCOH

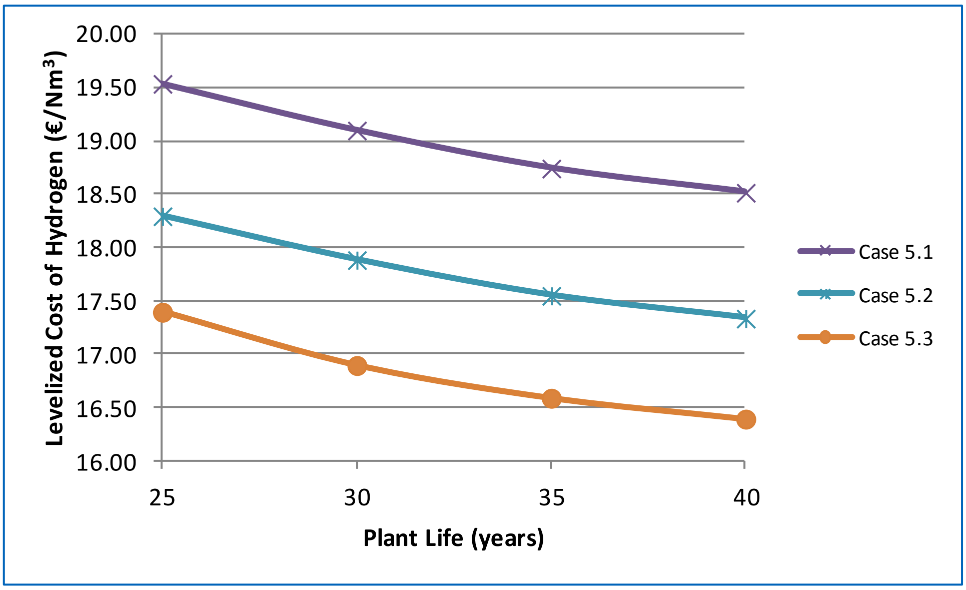
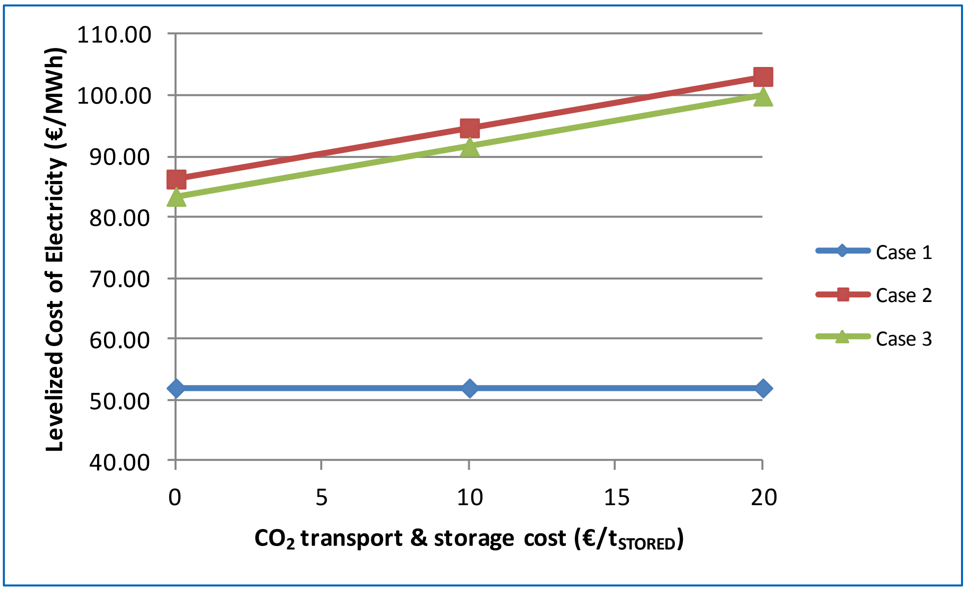


Figure 24: LCOH variation as function of plant life (project duration)

4.5.4. <u>*CO_2 transport & storage cost*</u>

<u>*LCOE*</u>



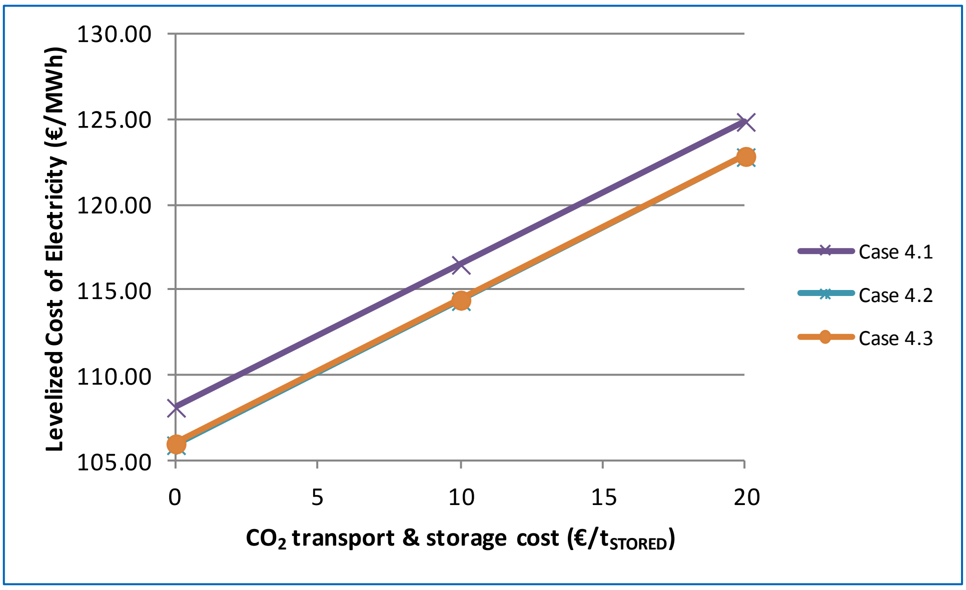
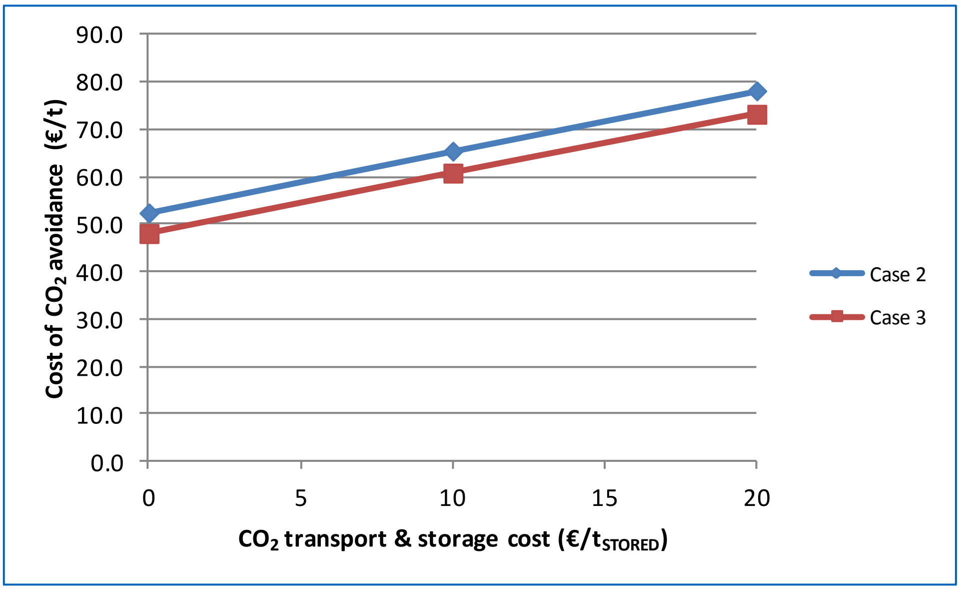


Figure 25: LCOE variation as function of CO_2 transport & storage cost

CO_2 emission avoidance cost



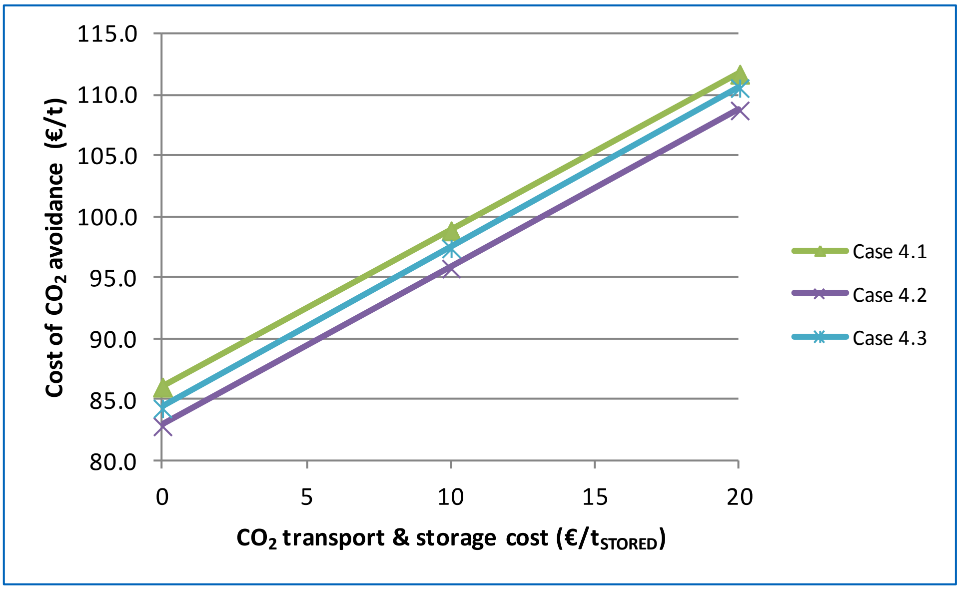


Figure 26: CO_2 emission avoidance cost variation as function of CO_2 transport & storage cost

LCOH

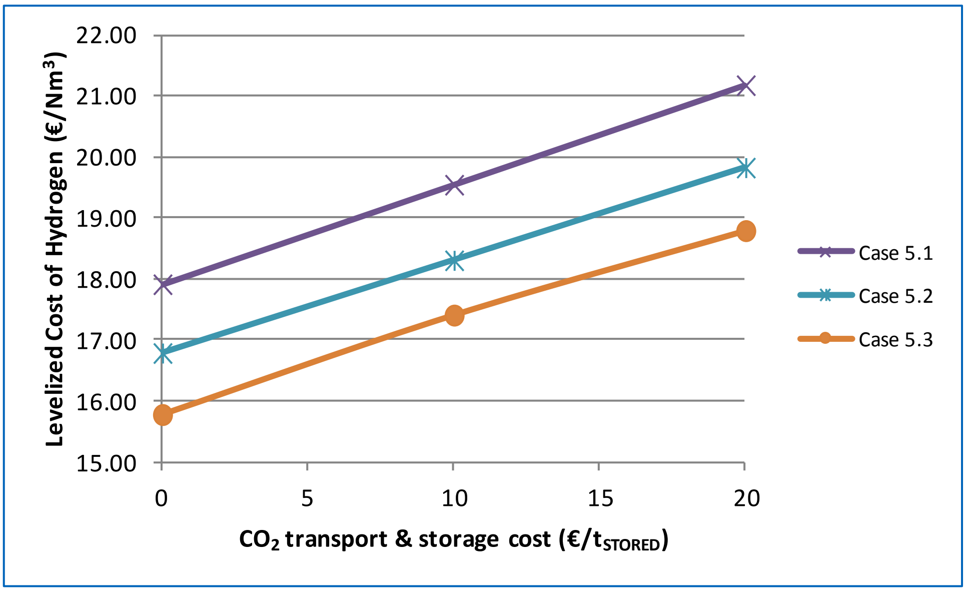
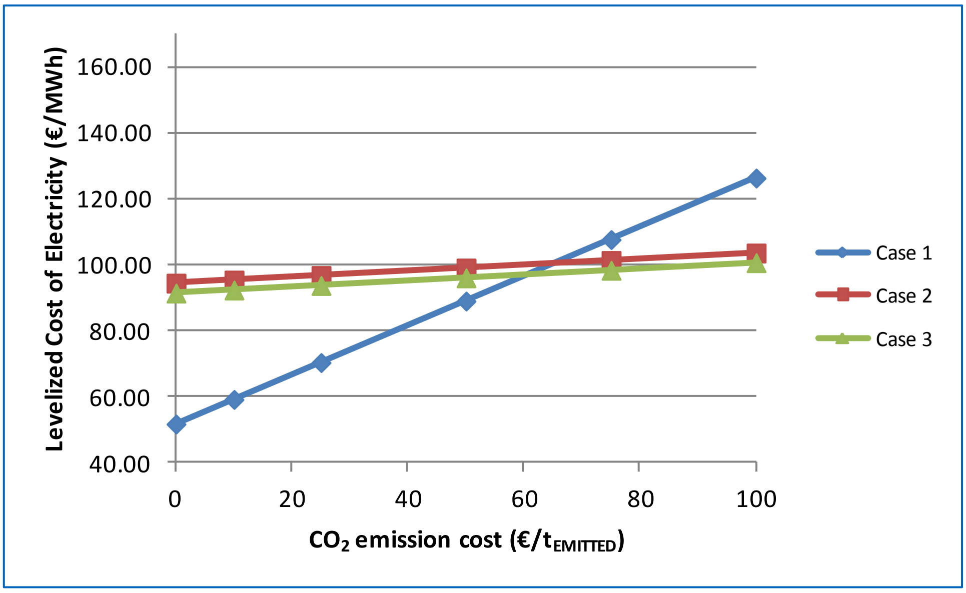


Figure 27: LCOH variation as function of CO_2 transport & storage cost

4.5.5. <u>CO_2 emission cost</u>

<u>LCOE</u>



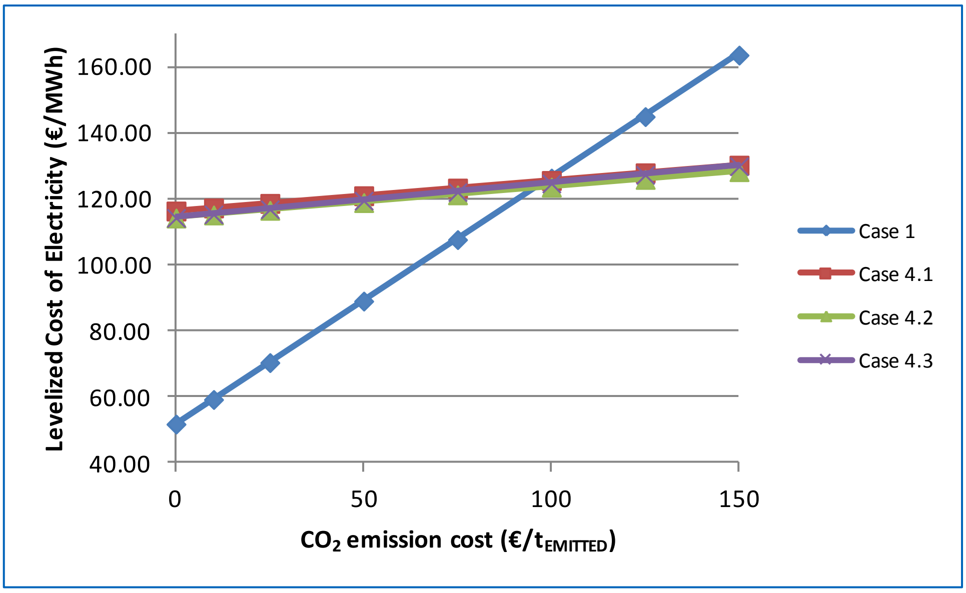


Figure 28: LCOE variation as function of CO_2 emission cost

<u>CO_2 emission avoidance cost</u>

The CO_2 emission avoidance cost in neutral to the variation of CO_2 emission cost.

<u>LCOH</u>

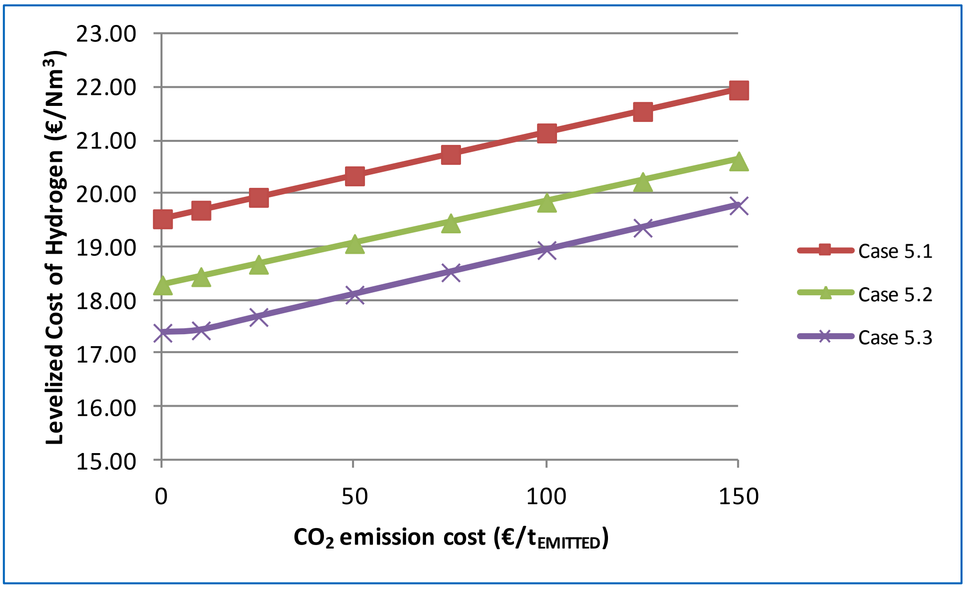
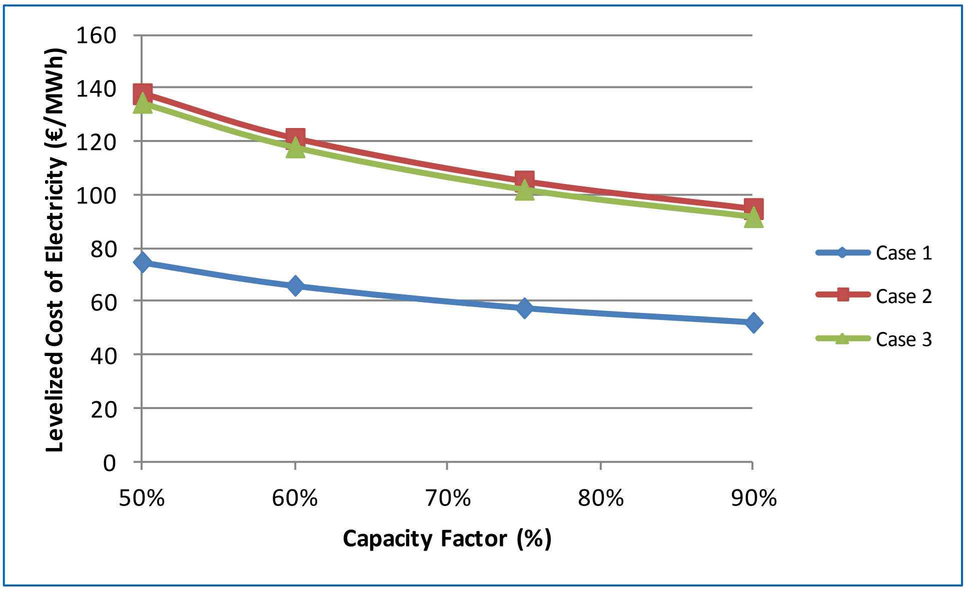


Figure 29: LCOH variation as function of CO_2 emission cost

4.5.6. Load factor

LCOE



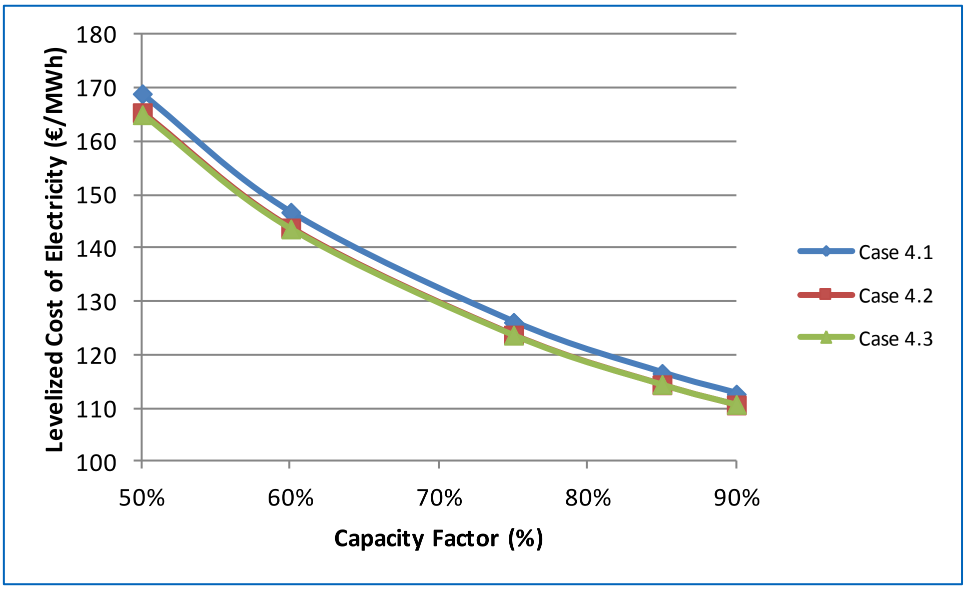


Figure 30: LCOE variation as function of plant load factor

CO_2 emission avoidance cost

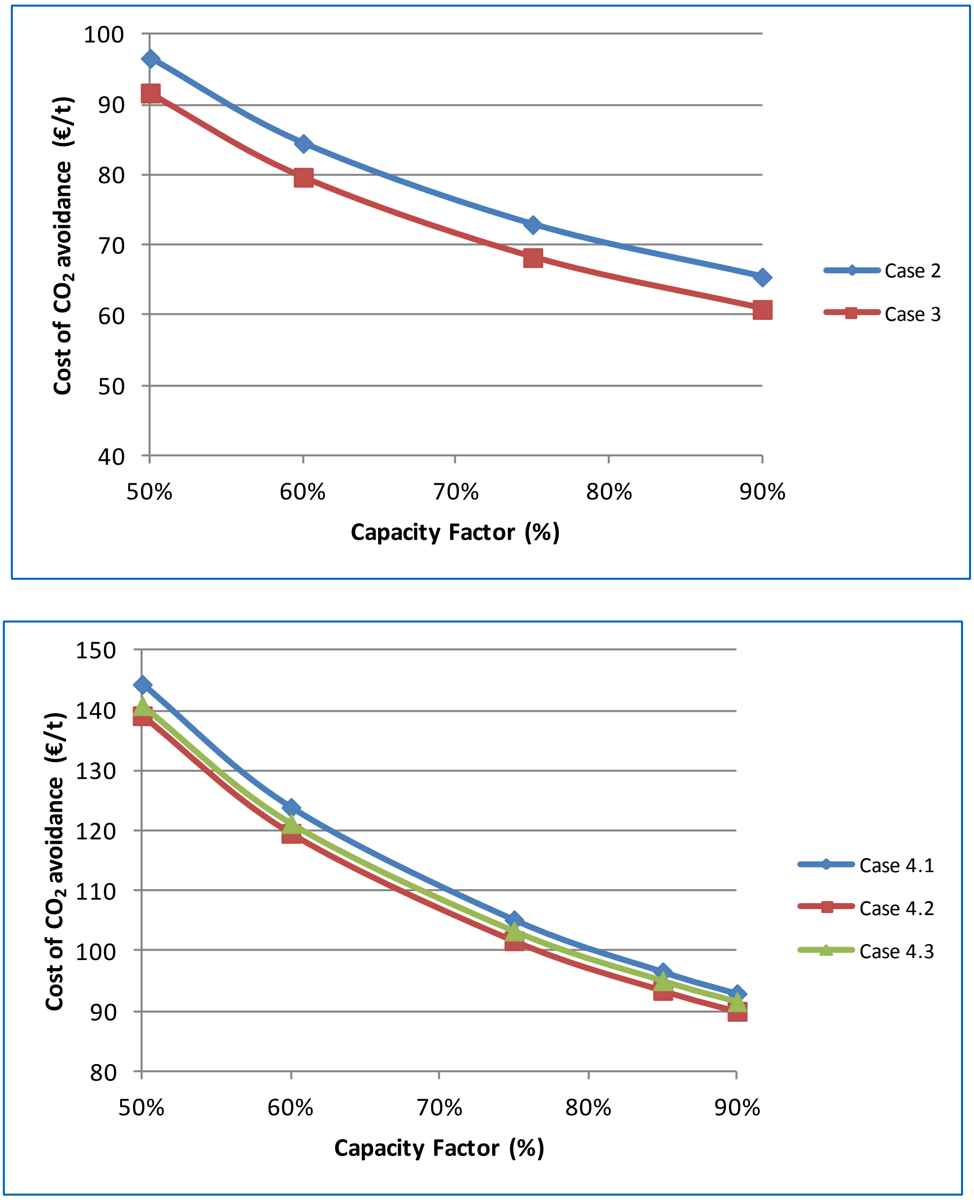


Figure 31: CO_2 emission avoidance cost variation as function of plant load factor

LCOH

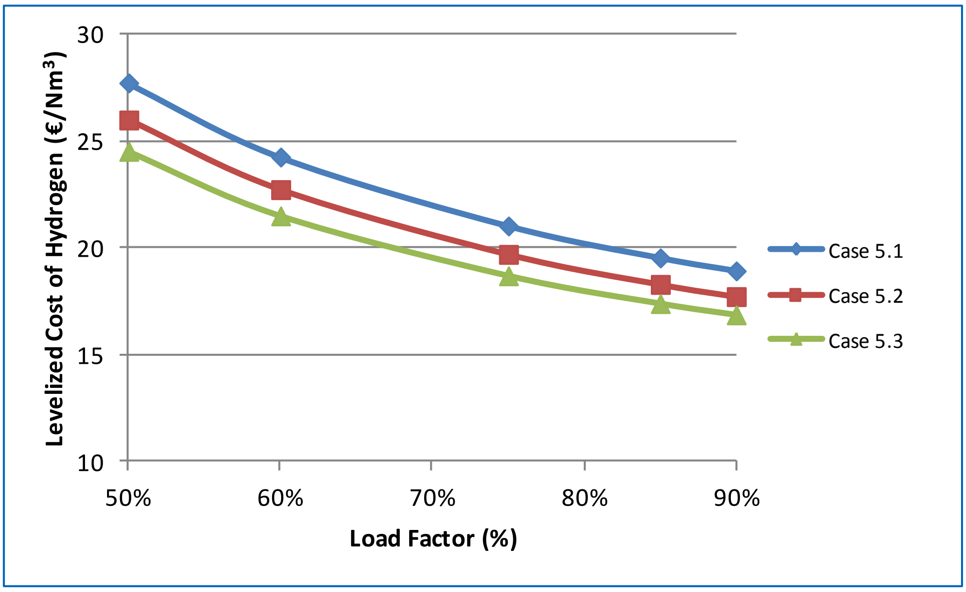


Figure 32: LCOH variation as function of plant load factor

4.5.7. *Electricity selling price (Case 5.1 / 5.2 / 5.3)*

LCOH

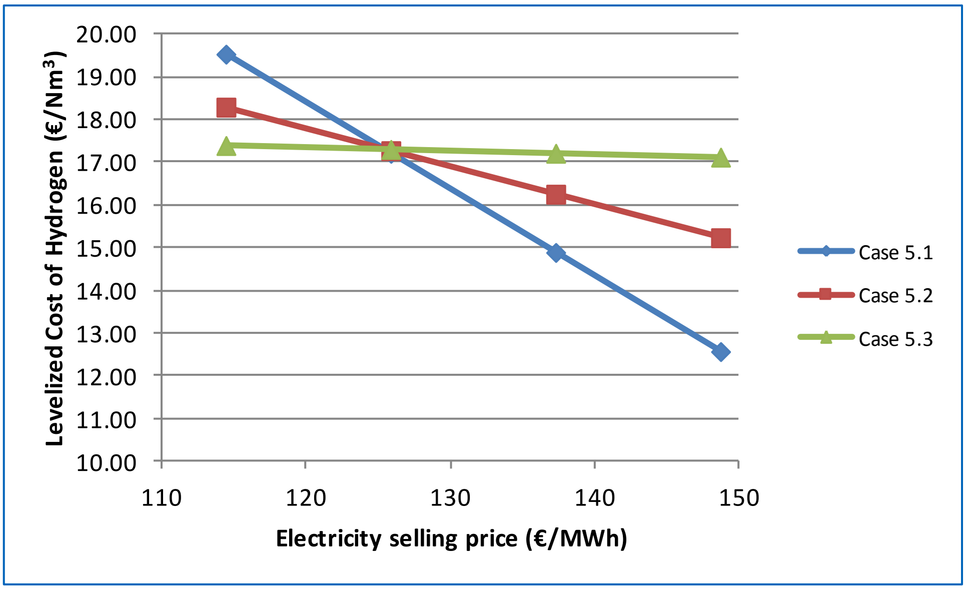


Figure 33: LCOH variation as function of electricity selling price