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IEAGHG Technical Report
2020-07
July 2020

Update Techno-Economic Benchmarks for Fossil Fuel-Fired Power Plants with CO_2 Capture

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ACKNOWLEDGEMENTS AND CITATIONS

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The report should be cited in literature as follows:

'IEAGHG, "Update techno-economic benchmarks for fossil fuel-fired power plants with CO_2 capture", 2020/07, July 2020.'

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UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO_2 CAPTURE

Key Messages

- IEAGHG updates its techno-economic studies periodically to examine the impact of developments and improvements made to core components, of changes made to system design, or when the fiscal environment may have materially altered.
- In the present case, benchmarks were updated for both coal-fired and natural gas-fired power plants with CCS, primarily to:
    - Investigate the techno-economic impact of markedly increasing the capture rates to achieve near-zero CO_2 emissions;

  And then, in addition, to:
    - Explore the technological and economic benefits of recent improvements that may have been made to ultra-supercritical pulverised coal (USC PC) and natural-gas combined cycle (NGCC) technologies; and
    - Examine the benefits of flue gas recirculation in the natural gas-fired cases, and the trade-offs between efficiency and flexibility in the coal-fired cases.
- Benchmarks were updated against a study published in 2018[1], where prices were based on 3Q2016. The update study used 3Q2018 prices.
- With little significant technology improvement in the interim two years, the performance of USC PC plant in the current study was very similar to that in the earlier study. Over the same period, however, H-class GT (gas turbine) developments had led to a 1%-point efficiency improvement in NGCC plant.
- Due to the concentration of CO_2 in the flue gas from coal-based plants, the levelised cost of electricity (LCOE) increases by more than 80% as the CO_2 capture rate is increased from zero to 90%. For both the unabated USC PC case and the 90% capture case, the LCOEs were 1 to 2% higher than the costs in the earlier study. Despite significantly increased CAPEX, the increases in LCOE were tempered by lower prices for limestone and coal.
- Although the estimated CAPEX for NGCC was around 5% lower, the higher costs of maintenance and higher gas price resulted in LCOEs for the baseline (reference) case and the 90%-capture case being 1 to 3% higher than comparable cases in the earlier study. A decrease in the CO_2 avoidance cost (CAC) was attributable to the slightly higher reference LCOE (i.e. with no capture).
- For both natural gas-fired and coal-fired plants, increasing the CO_2 recovery from 90% to 99% (USC PC) and 98.5% (NGCC) yielded only modest increases in the CAC – 5% (NGCC) and 4.3% (USCPC).
- Flue gas recirculation was found to be a particularly effective option to reduce the costs associated with carbon capture on NGCC plants. Recirculation of around 50% of the exhaust gas to the gas turbine inlet led to a higher CO_2 content and the need for less flue gas to be treated, leading to substantial savings in the CAPEX and OPEX of the capture unit. For the 90% and 98.5% capture rate cases, the LCOE decreased by 2-3%, whilst the CAC was reduced by between 8 and 12%.

[1] IEAGHG, "Effects of plant location on the costs of CO_2 capture", 2018/04, April 2018.

- There are good reasons to expect the techno-economic performance of NGCC plants with CCS to improve further in the future. First, new materials are emerging for application in the gas turbine that could lead to net increases in electrical efficiency of more than 2%-points for both the unabated and 98.5% capture rate cases. Second, technology enhancements for oxy-fuel gas turbine designs could reduce the LCOE by 13%. Finally, integration of a molten carbonate fuel cell (MCFC) with an NGCC not only increases the power output but could also raise the efficiency to close to 60% - with an LCOE of €64.4/MWh.
- The operating flexibility of USC PC and NGCC cases with capture was explored. As shown in an earlier IEAGHG study[2], 'solvent storage' and 'on/off capture' remained viable options, whereas the present cost of 'battery energy storage' made it unattractive for use at scale.
- While operating flexibility is a valuable service in the contemporary energy market, there is a trade-off with efficiency. This trade off was investigated for coal-fired power plants. It was found that the 700°C steam temperatures targeted in advanced-USC PC plants were not particularly compatible with good operating flexibility. It was envisaged that conventional USC PC designs would remain the technology of choice for flexible operation within grids with highly variable demand, such grids becoming more common.

Background to the study

CCS has long been recognised as a key component of an effective mitigation strategy to decarbonise the power and industrial sectors. Commercial deployment of the technology, however, has been slow and must accelerate if it is to achieve its potential and contribute effectively to mitigating climate change.

Much effort in recent years has been focused on improving the technical performance of plants with CO_2 capture, targeted particularly at integrating the host plant with the capture equipment and at reducing the associated energy penalty. In parallel with making these improvements, minimising the CAPEX and OPEX of CO_2 capture is also essential.

A recent IEAGHG study[3] has shown that the 90% cap in capture rate that has been adopted virtually ubiquitously in energy and climate models and by the CCS community, from R&D through pilot scale testing, to the large-scale demonstration plants currently in operation, is an artificial cap. It is clearly established that there are no technology barriers to prevent operation at capture rates consistent with net zero CO_2 emissions[4].

Scope of Work

Given this background, a techno-economic assessment of coal and natural gas-fired power plants was performed to examine the impact of operating at capture rates much higher than

[2] IEAGHG, "Operating flexibility of power plants with CCS", 2012/06, June 2012.

[3] IEAGHG, "Towards zero emissions CCS from power stations using higher capture rates or biomass", 2019/02, March 2019.

[4] At capture rates that lead to net zero CO_2 emissions, the power station is CO_2 neutral, i.e. the only CO_2 emitted is that contained in the incoming combustion air. For USC PC plants, the capture rate would be approximately 99.7% and for NGCC plants, approximately 99%.

90%, which has been the predominant capture rate used in previous IEAGHG assessments. The technological and economic benefits of process improvements and technology enhancements were also explored.

The study focused on USC PC and NGCC power plants, with and without CO_2 capture. Post combustion capture based on solvent scrubbing, which is currently the commercially leading option for capture on both pulverised coal and natural gas-fired power plants, was the capture technology of choice for the study.

Besides the development of updated benchmark cases for near-zero CO_2 emission, potential improvements to the flexible operation of plants with CO_2 capture were also analysed. This was achieved by updating the key outcomes from an earlier IEAGHG study[2] that addressed operating flexibility, where approaches such as solvent storage were applied. In addition, possible efficiency improvements in USC PC and NGCC power plants with capture that may result from technological progress and innovative design were also discussed.

The study was undertaken at Amec Foster Wheeler Italiana, a Wood Company, by a team led by Vicenzo Tota.

Findings of the Study

Study cases

Benchmark cases

The benchmark plant configurations for both the NGCC and USC PC cases were based on commercially available, state-of-the-art designs. Key features for the flue gas desulphurisation (FGD) and CO_2 capture units were common throughout the study cases, as defined, e.g. in the 2018 study[1]. Performance and cost data for other items of equipment were drawn from trade and scientific literature. Two designs of capture unit were studied: one to operate at 90% CO_2 capture, a value that provides a direct comparison with previous IEAGHG studies; and the other to operate at much higher capture rates. Selection of the high capture rate value was limited only by techno-economic considerations, i.e. at very high capture rates, experience has shown that the solvent regeneration duty grows exponentially. For this study, the 'high' capture rates (for both the USC PC and NGCC cases) were selected as the values just prior to the point at which very small increases in capture rate were coupled with significant additional CAPEX expenditure. Shell Cansolv CO_2 capture technology, the capture technology adopted for this study, uses two different solvents, one to treat gas turbine exhaust and the other to treat the exhaust from coal combustion. Due to the different shapes of the % cost vs. capture rate curves, the values selected were as follows: 98.5% capture rate for the NGCC configurations and 99% capture rate for the USC PC configurations. The basic cases studied, the benchmark plants, are shown in Table 1.

Table 1. **Benchmark plants**

	Case	Description	Key features
NG fired	Case 1	NGCC w/o CCS	• Two generic H-class gas turbines • One common steam turbine
	Case 2	NGCC with CCS	• Two generic H-class gas turbines • One common steam turbine • CANSOLV post-combustion capture with 90% CO_2 recovery
	Case 2.1	NGCC with CCS – High capture case	• Two generic H-class gas turbines • One common steam turbine • CANSOLV post-combustion capture with 98.5% CO_2 recovery
Coal fired	Case 3	USC PC w/o CCS	• Generic state-of-art supercritical USC PC boiler • Wet limestone scrubbing FGD
	Case 4	USC PC with CCS	• Generic state-of-art supercritical USC PC boiler • Wet limestone scrubbing FGD • CANSOLV post-combustion capture with 90% CO_2 recovery
	Case 4.1	USC PC with CCS – High capture case	• Generic state-of-art supercritical USC PC boiler • Wet limestone scrubbing FGD • CANSOLV post-combustion capture with 99% CO_2 recovery

The USC PC plants are based on state-of-the-art steam conditions (27 MPa/600°C/620°C), conditions common to a number of the more recent coal-fired power plants in Europe and Japan.

The natural gas plants are based on a generic gas turbine, with operating conditions and performance obtained by averaging H-class GT data received from the vendors that agreed to support this study, namely General Electric, Ansaldo Energia and Mitsubishi Hitachi Power Systems. This approach was adopted considering the varying performance and capacities of the different turbines, which fall within the following ranges:

- Thermal input: 1,035 – 1,298 MWth
- Shaft power output: 462 – 575 MWe
- Flue gas flowrate: 2790 – 3700 t/h
- Gross electrical efficiency (LHV):
    - Simple cycle: 41 – 44%
    - Combined cycle: 60 – 64%
- Heat rate: 8,114 – 8,789 kJ/kWh

The net power output of the USC PC plant without capture is 1,033 MWe and for the NGCC plant, 1,506 MWe. The NGCC plant capacity, for the cases with and without CCS, was selected to fully load two (2) heavy duty H-class gas turbines.

Sensitivity cases

The economic impacts/performance advantages of technical improvements to the benchmark cases were examined. The sensitivity cases explored were:

- The impact of flue gas recirculation (FGR) – or, as it is also referred to, exhaust gas recirculation (EGR) – on NGCC.
- An update to results from a previous IEAGHG report[2] on the techno-economics of methods to improve the operational flexibility of power plants with carbon capture.
- The potential impacts of medium-term improvements to power generation technologies.

Sensitivity cases for the NGCC plants are reported in Table 2.

Table 2. **NGCC sensitivity cases**

	Case	**Description**	**Key features**
FGR	Case 2.2	NGCC with CCS and flue gas recirculation	• Case 2 configuration • Capture rate 90% • FGR ratio: 50%
	Case 2.3	NGCC with CCS and flue gas recirculation – High capture case	• Case 2.1 configuration • Capture rate 98.5% • FGR ratio: 50%
Improving flexibility	Case 2.1a	NGCC with CCS and solvent storage	• Case 2.1 configuration • 98.5% capture rate • Lean/rich solvent storage system
	Case 2.1b	NGCC with ON/OFF CCS	• Case 2.1 configuration • 98.5% capture rate • Capable of unabated power production
	Case 2.1c	NGCC with CCS and BESS	• Case 2.1 configuration • 98.5% capture rate • 430 MWh battery energy storage system
Future improvements	Case 2.4	Advancements in GT materials	• Case 1 configuration • Two generic next-gen GT
	Case 2.5	Oxy-fired NGCC with CCS	• Two generic oxy-fired gas turbines based on H-class • One common steam turbine • Cryogenic post-combustion carbon purification
	Case 2.6	NGCC with MCFC	• Two generic H-class gas turbines • One common steam turbine • Use of Molten Carbonate Fuel Cells in combined cycle • Cryogenic post-combustion carbon purification

Sensitivity cases for coal-fired plants are as follows in Table 3.

Table 3. **USC PC sensitivity cases**

	Case	**Description**	**Key features**
Improving flexibility	Case 4.1a	USC PC with CCS and solvent storage	• Case 4.1 configuration • 99% capture rate • Lean/rich solvent storage system
	Case 4.1b	USC PC with ON/OFF CCS	• Case 4.1 configuration • 99% capture rate • Capable of unabated power production
	Case 4.1c	USC PC with CCS and BESS	• Case 4.1 configuration • 99% capture rate • 260 MWh battery energy storage system
Future improvements	A-USC	Impact of steam conditions on boiler design	• Literature-supported analysis • Impact of advanced ultra-supercritical (700°C) steam conditions • Choice of materials • Impact on design • Impact on flexible operation

Common basis for analysis

As for previous IEAGHG techno-economic studies, IEAGHG's standard technical and economic criteria were used.

Technical basis of design

The fictional plant location is a coastal site in the north-east of the Netherlands, with no major site preparation required.

The bituminous coal used for the study was based on an Eastern Australian internationally traded open-cast coal, assumed delivered from a port to the plant site by train. The natural gas used in the NGCC plants, as well as that used as start-up or back-up fuel by the coal-based power station, was delivered from a high-pressure pipeline – with the natural gas specifications defined in the IEAGHG criteria.

CO_2 is delivered from the plant site to the pipeline at:

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

As per EU directives 2010/75/EU (Part 2 of Annex V), the overall gaseous emissions from the plant do not exceed the limits shown in Table 4.

For the USC PC plants with CO_2 capture, significantly higher desulphurisation efficiency is required from the FGD system in order to limit solvent degradation in the downstream absorber washing column. In this case, the FGD plant is designed to meet an SO_2 removal efficiency of approximately 98.5%.

Table 4. **Emissions limits**

	USC PC based cases[1]	**NGCC 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	(3)
CO	-	≤ 100 mg/Nm^3
Particulate	≤ 10 mg/Nm^3	(3)

Note: (1) Emission expressed in mg/Nm^3 @6% O_2, dry basis.
(2) Emission expressed in mg/Nm^3 @ 15% O_2 volume dry
(3) Not included in the EU directive as assumed negligible in gas turbine plants

Economic estimate

All the cases consider the Netherlands as location and a 3Q2018 price basis. The economic estimates are based on results from an earlier IEAGHG study[1], updated to reflect advancements in technology and more information at disposal.

Capital cost definition. Plant capital costs have been evaluated as Total Plant Cost (TPC) and Total Capital Requirement (TCR), defined in accordance with the IEAGHG White Paper[5].

The Total Plant Cost (TPC) is the installed cost of the plant, including project contingencies. The Total Capital Requirement (TCR) is defined as the sum of the TPC, interest during construction, spare parts costs, working capital, start-up costs and owner's costs.

The TPC of the different study cases is broken down into the main process units that compose the plants and, for each process unit, the TPC is split into direct materials, construction, EPC services, other costs and contingency. The estimate is in euros (€), based on 3Q2018 price level. Overall estimate accuracy is in the range of +35%/-15% (AACE Class 4).

LCOE and CAC definition. The LCOE is defined as the uniform annual price that returns the same net present value as the year-by-year prices. In this analysis, long-term inflation assumptions and price/cost variations throughout the project life-time were not considered.

The CAC is calculated by comparing the costs and specific emissions of a plant with CCS with those of the reference case without CCS, as defined below:

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

where:

CAC is expressed in Euro per tonne of CO_2 (€/t CO_2)

[5] IEAGHG, "Toward a common method of cost estimation for CO_2 capture and storage at fossil fuel power plants", 2013/TR2, March 2013 (www.ieaghg.org/publications/technical-reports).

LCOE is expressed in Euro per MWh (€/MWh)
CO_2 emissions are expressed in tonnes of CO_2 per MWh (t CO_2/MWh).

For each case with capture, the CAC is evaluated considering as reference case the relevant benchmark case without capture.

Main financial bases. The main financial bases common through all the study cases to run the economic models are reported in Table 5.

Table 5. **Financial bases**

ITEM	DATA
Discount Rate	8%
Financial leverage	100% debt
Capacity factor (USC-PC / NGCC)	90% / 93%
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 3Q2018

Updated benchmark on natural gas-fired power plants

Benchmark plant performances and economics

Performances for the NGCC cases are summarised in the following table. For the capture cases, the plant is redesigned with a modified steam cycle (for LP steam export to the capture unit). This allowed the best plant efficiency to be achieved.

Table 6. **Reference plant performance**

		Case 1 NGCC w/o capture	Case 2 NGCC w/ capture 90%	Case 2.1 NGCC w/ capture 98.5%
OVERALL PERFORMANCE				
Fuel flowrate	t/h	187	187	187
Thermal input (1)	MWth	2418	2418	2418
Auxiliary power demand (2)	MWe	23.9	84.3	87.8
Net Electric Power Output	MWe	1506.0	1344.2	1316.0
Net Electrical Efficiency (1)	%	62.3	55.6	54.4
CO_2 CAPTURE PERFORMANCE				
CO_2 capture rate	%	-	90.0	98.5
CO_2 to atmosphere	kg/MWh	331.3	36.9	5.6

Notes: (1) – LHV basis.
(2) – Including step-up transformer losses

Compared to the earlier results[1] for no CCS and 90% capture rate, a 1% to 2%-point increase in efficiency is found, which is attributed to advances made in the interim on H-class machines.

The key economic results in terms of capital costs, LCOE and CAC are summarised below.

Table 7. **NGCC plant benchmark cases economic and financial results**

		Case 1	Case 2	Case 2.1
		NGCC w/o capture	NGCC w capture 90%	NGCC w capture 98.5%
Total Plant Cost (TPC)	(M€)	905	1597	1684
Total Capital Requirement (TCR)	(M€)	1206	2121	2236
Specific cost [TPC/net power]	(€/kW)	601	1188	1280
Specific cost [TCR/net power**]**	(€/kW)	801	1578	1699
LCOE	(€/MWh)	48.2	68.9	72.2
CAC	(€/t)	-	69.98	73.54

In Figure 1, the economic results are compared against those presented in the 2018 report.

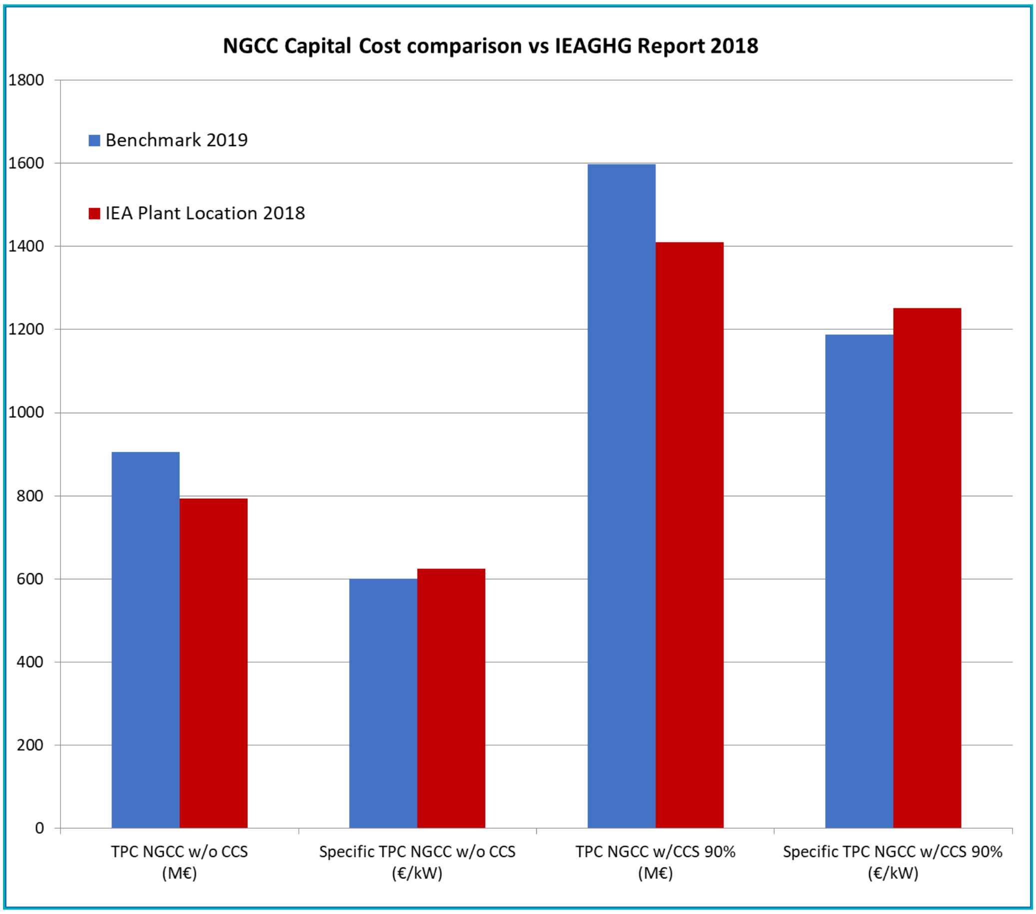

Figure 1. Comparison of NGCC plant costs vs IEA GHG report 2018/4

The TPC is about 14% higher (due to the larger capacity) but, thanks to economy of scale on larger plants, the specific cost (€/kW) is 5% lower.

In the following graph, the financial results are compared against the earlier study.

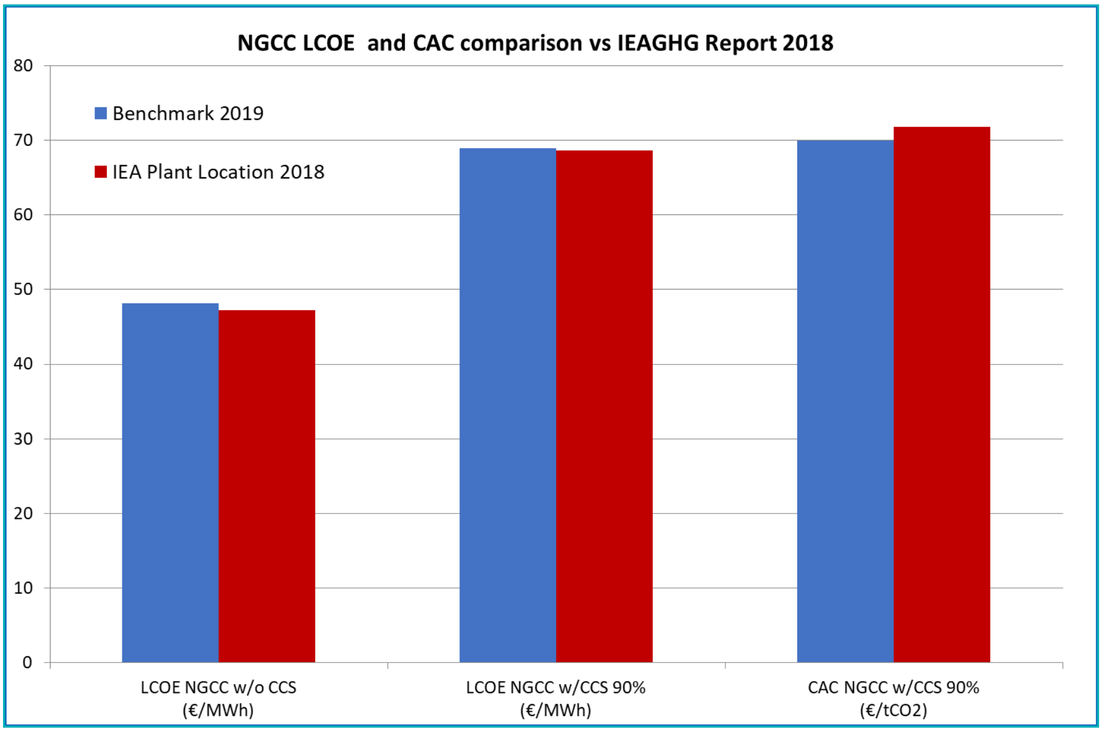

Figure 2. Comparison of NGCC financial results vs IEA GHG report 2018/4

The LCOE is up to 2% higher, attributable to changes incurred since the previous study. Of particular note, the fuel and maintenance costs are both higher than was the case in the 2018 study, impacting negatively on the LCOE. If the same costs were applied to both studies, the LCOE results would be lower for the current update.

The CAC shows a 3% decrease compared to previous study, a relatively small difference that may be attributed to the higher LCOE.

The case with the higher capture rate highlights an underlying economy of scale: a reduction in CO_2 emissions by almost a factor of 10 gives rise to an increase in the CAC of just 5%.

Flue gas recirculation in natural gas-fired plants with CO_2 storage

For this study, Cases 2 and 2.1 were re-evaluated with FGR technology added (as illustrated qualitatively in the diagram below), where 50%[6] of the flue gas is recirculated back to the GT compressor via ducting, cooling and use of a booster fan, which results in a two-fold effect:

1. The exhaust gas is richer in CO_2 (by a factor of two), and
2. Only a half of the exhaust gas needs to be processed by the capture unit.

As a result, the size of the capture unit may be reduced greatly, while maintaining the same level of emission reduction. This is counteracted by an increase in the capital cost of the power island unit (to account for the extra equipment needed for FGR) and a reduction in efficiency (more inert gas is fed to the GT combustor). While as much as possible of the flue gas is

[6] According to Ansaldo (though other vendors may advise differently), FGR could be as high as 50% without adversely affecting combustion.

recycled, the amount is limited by the need for the combustion to be stable and still reasonably efficient.

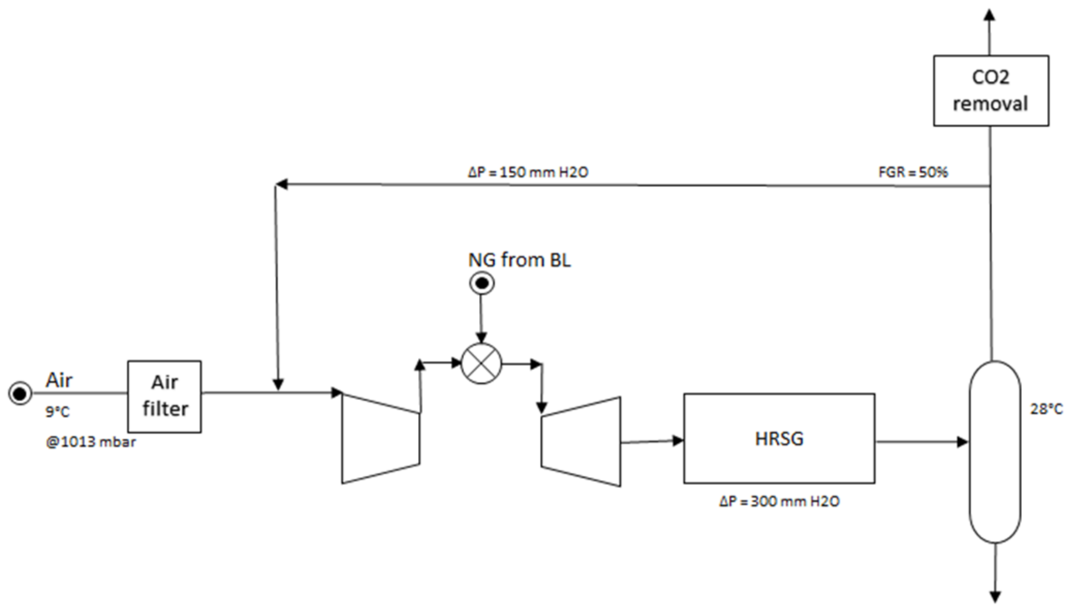

Figure 3. Schematic diagram of NGCC with FGR

Consequently, as noted above, an FGR of 50% was applied to explore the performance of the generic gas turbine at 90% and 98.5% capture rates with the results summarised in Table 8.

Table 8. **NGCC + capture with FGR**

		Case 2.2 NGCC w. FGR 90%	Case 2.3 NGCC w. FGR 98.5%
OVERALL PERFORMANCE			
Fuel flowrate	**t/h**	185	185
Thermal input[1]	**MWth**	2390	2390
Auxiliary power demand[2]	**MWe**	78.6	82.2
Net Electric Power Output	**MWe**	1340.5	1320.7
Net Electrical Efficiency[1]	**%**	56.1	55.3
CO_2 CAPTURE PERFORMANCE			
CO_2 capture rate	**%**	90.0	98.5
CO_2 to atmosphere	**kg/MWh**	35.2	3.3

Notes: (1) – LHV basis.
(2) – Including step-up transformer losses

Thanks to the downsizing of the absorber and related components, a slight advantage in terms of efficiency is present as less parasitic load is required by the capture unit.

The key economic and financial results for fuel gas recirculation cases are reported below.

Table 9. **NGCC + capture with FGR plant cases: Economic and financial results**

		Case 2.2 NGCC w. FGR 90%	Case 2.3 NGCC w. FGR 98.5%
Total Plant Cost (TPC)	(M€)	1510	1568
Total Capital Requirement (TCR)	(M€)	2005	2080
Specific cost [TPC/net power]	(€/kW)	1127	1187
Specific cost [TCR/net power]	(€/kW)	1495	1575
LCOE	(€/MWh)	67.3	69.9
CAC	(€/t)	65.20	65.56

For comparison, the following figure shows the LCOE results for the cases with and without FGR.

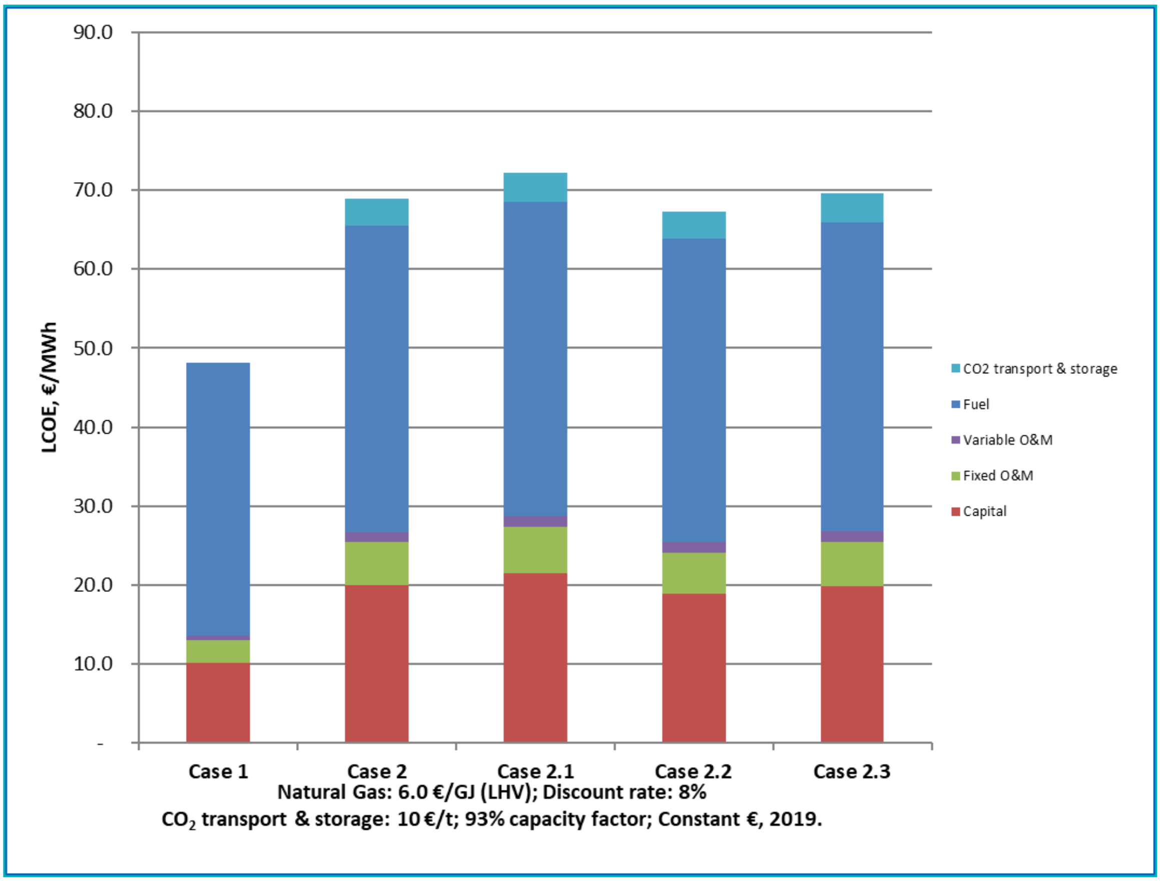

Figure 4. LCOE for the main NGCC study cases

From these results, it is evident that FGR offers significant advantages to the economics of post-combustion capture on NGCC power plants. The TPC savings are due to the lower cost of the capture unit, a result mainly of the smaller absorber column (while the CO_2 captured is roughly the same, the absorber column treats half the flue gas flowrate and can be downsized). The cost of the additional equipment required for FGR is outstripped by the advantages obtained from the better capture unit economics, making FGR a potentially valuable application for near-zero emission natural gas-fired power plants.

Updated benchmark for coal-fired power plants

Benchmark plant performances and economics

The performances of the reference plants for the coal-fired steam cycle are summarised in the following table. For the capture cases, the plant is redesigned with a modified steam cycle (to account for the LP steam needs of the capture unit) to deliver the best plant efficiency.

Table 10. **Reference plant performance**

		Case 3 USC PC w/o capture	**Case 4** USC PC w/ capture 90%	**Case 4.1** USC PC w/ capture 99%
OVERALL PERFORMANCE				
Fuel flowrate	t/h	325	325	325
Thermal input (1)	MWth	2335	2335	2335
Auxiliary power demand (2)	MWe	47.1	135.7	145.8
Net Electric Power Output	MWe	1033.4	825.9	1316.0
Net Electrical Efficiency (1)	%	44.2	35.4	33.5
CO_2 CAPTURE PERFORMANCE				
CO_2 capture rate	%	-	90.0	99.0
CO_2 to atmosphere	kg/MWh	742.5	92.6	9.8

Notes: (1) – LHV basis.
(2) – Including step-up transformer losses

Compared with the earlier study[1], no appreciable increase in efficiency was noted as little notable progress had been made to the USC PC technology in the interim.

The key economic and financial results, including capital costs, LCOE and CAC are summarised below in Table 11.

Table 11. **USC PC plant benchmark cases economic and financial results**

		Case 3	Case 4	Case 4.1
		USC PC w/o capture	**USC PC w/ capture 90%**	**USC PC w/ capture 99%**
Total Plant Cost (TPC)	(M€)	1560.8	2384.6	2437.5
Total Capital Requirement (TCR)	(M€)	2033.8	3097.0	3165.0
Specific cost [TPC/net power]	(€/kW)	1510.4	2887.3	3111.5
Specific cost [TCR/net power**]**	(€/kW)	1968.1	3749.9	4040.7
LCOE	(€/MWh)	53.3	97.3	105.1
CAC	(€/t)	-	67.7	70.6

In Figure 5, the economic results are plotted against those from the 2018 study.

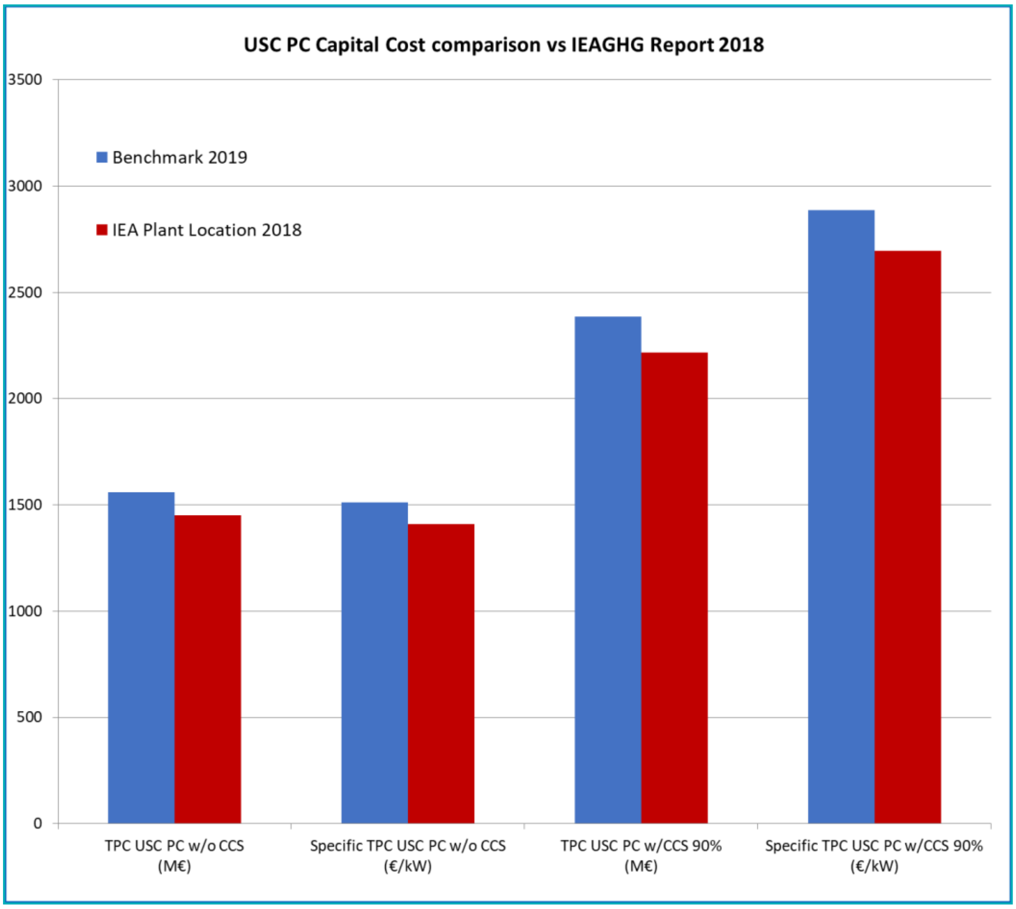

Figure 5. Comparison of USC PC plant costs vs IEA GHG report 2018/4

Compared to the previous study, the TPC is about 8% higher for both the no capture and the 90% capture cases. The specific cost is 7% higher for no capture and 8% lower for the cases with CO_2 capture. This is mainly due to the cost escalation factor since 3Q2016 (which was the price level basis for the 2018 study) and the slightly enhanced steam condition (i.e. the higher main steam pressure).

In the following graph, the financial results are compared against those obtained in the earlier study.

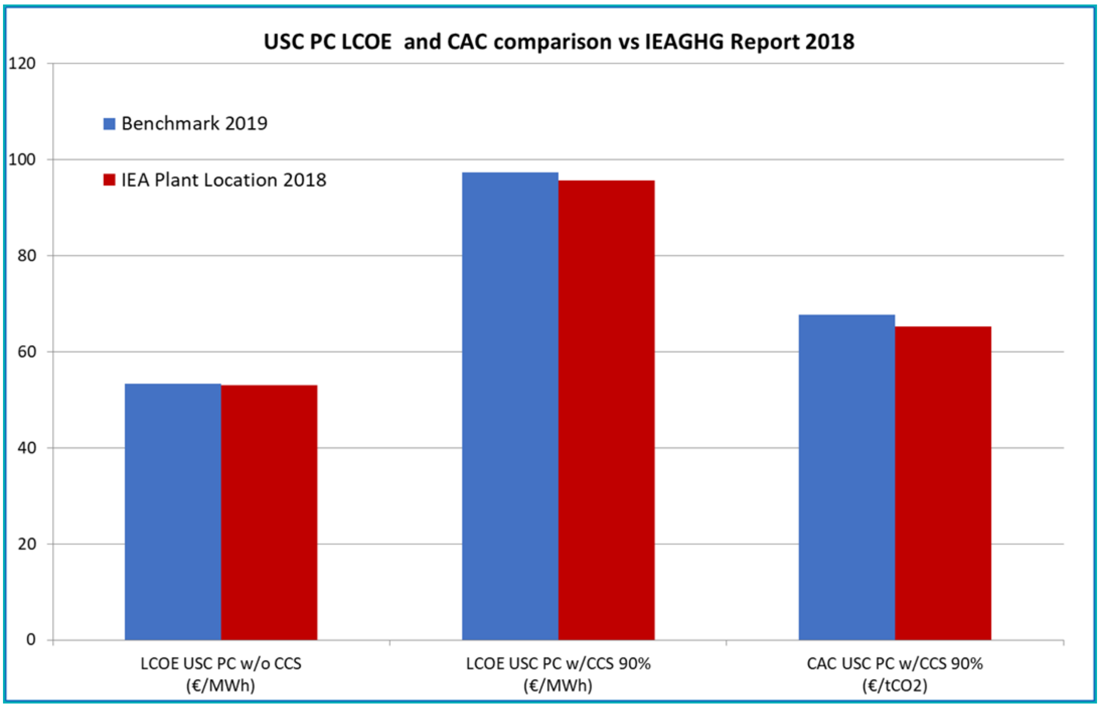

Figure 6. Comparison of USC PC financial results vs IEA GHG report 2018/4

Compared to the 2018 results[1], the LCOE in the current study is 1 to 2% higher. The CAC is 3% higher.

The lower fuel and limestone costs benefit the current updated study and mean that, despite the inflation in capital costs and no improvement in efficiency, there is only a small increase in the LCOE.

And again, with nearly a 10%-point increase in the capture rate, the CAC increases by just 4.3%. This confirms the presence of the economy of scale identified in the NGCC case when designing for capture rates greater than 90%.

In Figure 7, the breakdown of the LCOEs for the USC PC benchmark cases is shown.

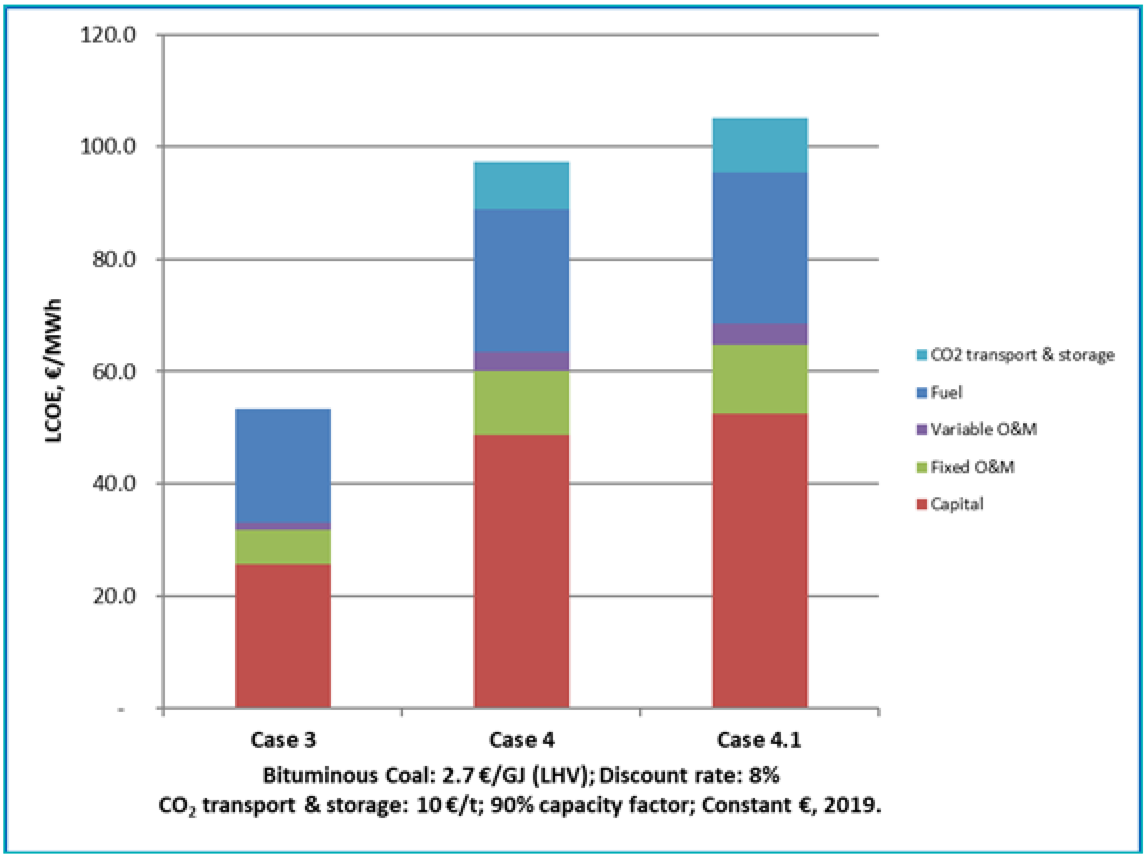

Figure 7. LCOE for main USC PC study cases

Improving the operating flexibility of plants with CO_2 capture

The introduction of post-combustion CO_2 capture and compression facilities to plants imposes additional constraints to flexible operation, where equipment, such as the stripper and reboiler, may limit the capacity to make frequent start-ups/shutdowns[7], due to the time required to pre-heat the regeneration column and related reboilers.

In this section, the results obtained from modifications to benchmark Case 2.1 (NGCC + 98.5% capture) and Case 4.1 (USC PC + 99% capture) to improve the operating flexibility are presented. For each new case, performances are assessed and capital investment evaluated.

Operating flexibility has become more important as, increasingly, energy demand can fluctuate heavily on an hourly basis. The figures below show idealised demand curves for the NGCC and USC PC cases, which served as the basis for the flexibility modifications studied.

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[7] Other important parameters that relate to flexible operation are the minimum load (at which each plant can operate safely) and the maximum ramp rates (relating to both increasing and decreasing load). Investigation of these parameters was not included in this study.

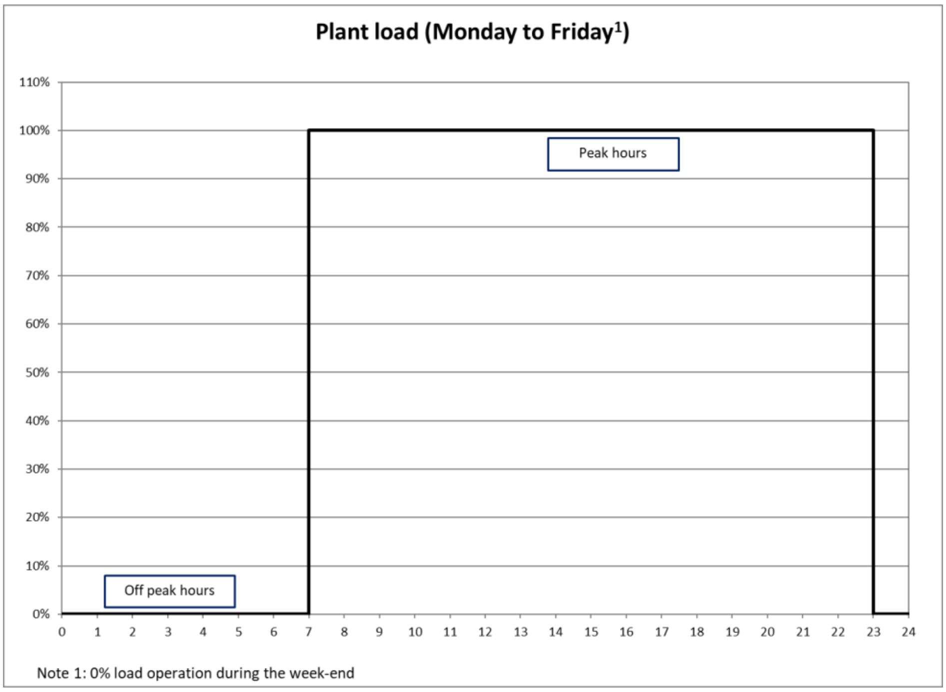

Figure 8. Daily NGCC plant load

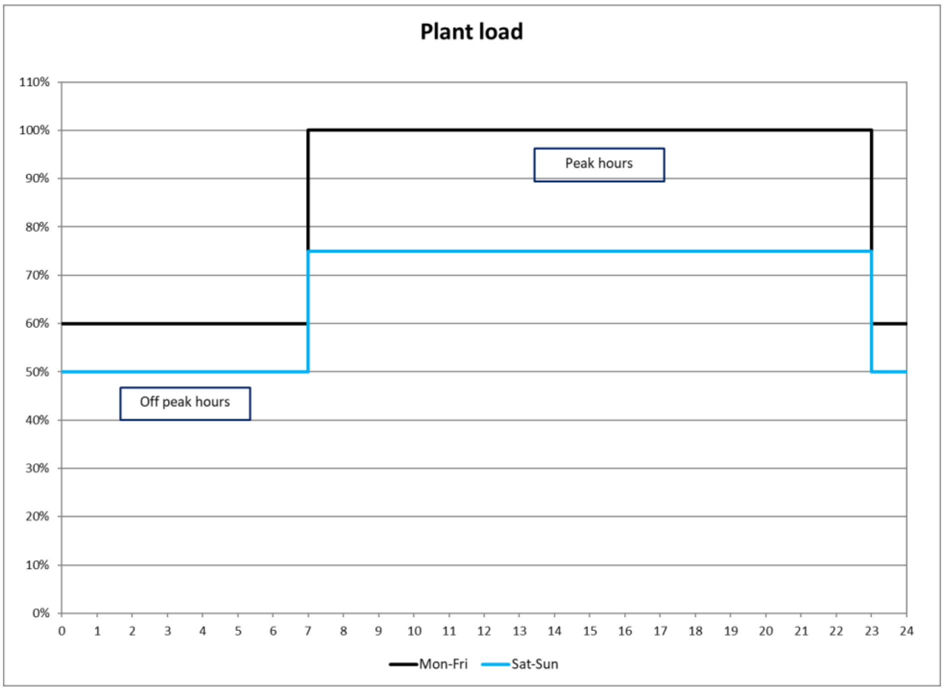

Figure 9. Daily USC PC plant load

Three main approaches to improve the operational flexibility were considered:

Rich/lean solvent storage system. The concept of this system is, while continuing to capture CO_2 as long as the plant is running, to store CO_2 rich solvent during periods when profitability is high. This avoids the energy penalty (cost) of regeneration during these periods. The stored solvent is then regenerated during periods of low demand. The amount stored is subject to techno-economic considerations, i.e. it depends on the storage volume available and the heat available. While different sub-scenarios were developed, in this summary only those that yielded the lowest and most feasible storage tank volume are presented. Furthermore, solvent storage can be designed to reduce reboiler size. By tweaking the peak load storage percentages, it is possible to ensure that the amount of stored solvent to be regenerated at any time will be lower than the amount of solvent circulating during 100% load on the capture unit.

Variable CO_2 capture (on/off) option. Due to fluctuations in carbon allowances from ever-changing regulations on CO_2 emissions, it may be more attractive economically to not run the CO_2 capture plant and pay the penalty (e.g. carbon tax) on the strength of more electricity sold. To do this, the plant needs to be able to run both in abated and unabated mode. This is achieved by designing the steam turbine to admit the entire steam generation flow, while operating in sliding mode when the capture unit is online and some steam extraction is required.

Integration of a Battery Energy Storage System (BESS). A modified demand curve more representative of actual fluctuations was considered, in which a 2-hour peak in demand is present at the end of each working day. This is representative of the latest trends, where often a peak is registered between the hours of 18:00 and 20:00, due mainly to an increase in residential consumption. The peak is assumed to be 15% higher than base load. While it is unlikely that a power plant would be sized for this specific scenario, an alternative could be to integrate a Battery Energy Storage System (BESS) – sized at 430 MWh for the NGCC and 260 MWh for USC PC cases – which can be charged overnight (in the case of USC PC, by running the plant at a load higher than demand).

The results obtained for the three approaches are summarised in the following table.

Table 12. **Summary of flexibility-improving modifications on power plants with CCS plants**

	NGCC Case TPC (M€)	**NGCC Plant Cost Δ% vs Case 2.1**	**USC PC Case TPC** (M€)	**USC PC Plant Cost Δ% vs Case 4.1**	**Features**
Solvent Storage	1709	+1.48%	2452	+1.00%	- Reduced reboiler size - Leverage highly profitable selling periods - An issue with excess energy overnight (NGCC case only) - Results governed by the particular demand curve
On/off CO_2 capture	1708	+1.42%	2455	+1.01%	- Leverage fluctuations in CO_2 allowances - Fully operational with capture unit offline - Lower efficiency if capture unit operating
Integration of energy storage	1990	+18.17%	2635	+8.10%	- Allows short demand peaks to be covered without oversizing

Solvent storage appears to show advantages but, in the specific case of NGCC, if plants are not turned off overnight (as they are expected to be), issues arise with excess electricity being produced while the stored solvent is regenerated. This is not an issue for USC PC.

Additionally, by reducing the reboiler size, the choice of regeneration rate is limited, effectively making the operating envelope of the plant less tolerant to changes over time in the demand curve (effectively reducing operating flexibility).

While the on/off capture unit involves very little extra CAPEX, it is detrimental to the normal operating efficiency (provided that normally the capture unit is on-line). By forcing the steam turbine to operate in sliding pressure mode to address a lower steam load than design (when exporting steam for solvent reclamation), up to 0.3%-points of net cycle efficiency are lost.

Energy storage is an interesting solution for flexibility as it does not impact plant performance. However, the current cost of BESS makes it unattractive if large energy storage capacities are required.

Further examination of operating flexibility

As part of the study scope, two specific analyses were performed that relate to the operating flexibility of power plant:

1. The impact of higher steam conditions, as used in Advanced USC PC power plants, on operating flexibility was assessed;
2. The trade-offs between flexibility and efficiency were evaluated through a simplified financial analysis.

The following paragraphs report the main results of these specific analyses.

Advanced USC PC: Impact of steam conditions on plant flexibility. With little information from boiler designers, manufacturers and suppliers forthcoming, the analysis undertaken was based on information drawn from the literature. It focuses on progress being made with coal-fired components operating at advanced ultra-supercritical (A-USC) steam conditions, i.e. at steam temperatures of 700/720°C (HP/RH), and assesses the potential impacts on plant operating flexibility. It is noted that this technology is still under development, with new alloys being developed and tested. Moreover, flue gas treatment systems, such as flue gas desulphurisation (FGD), are not flexibility bottlenecks for the plant and are not impacted by steam cycle conditions.

Plant components expected to require new materials due to the enhanced steam conditions are highlighted in Figure .

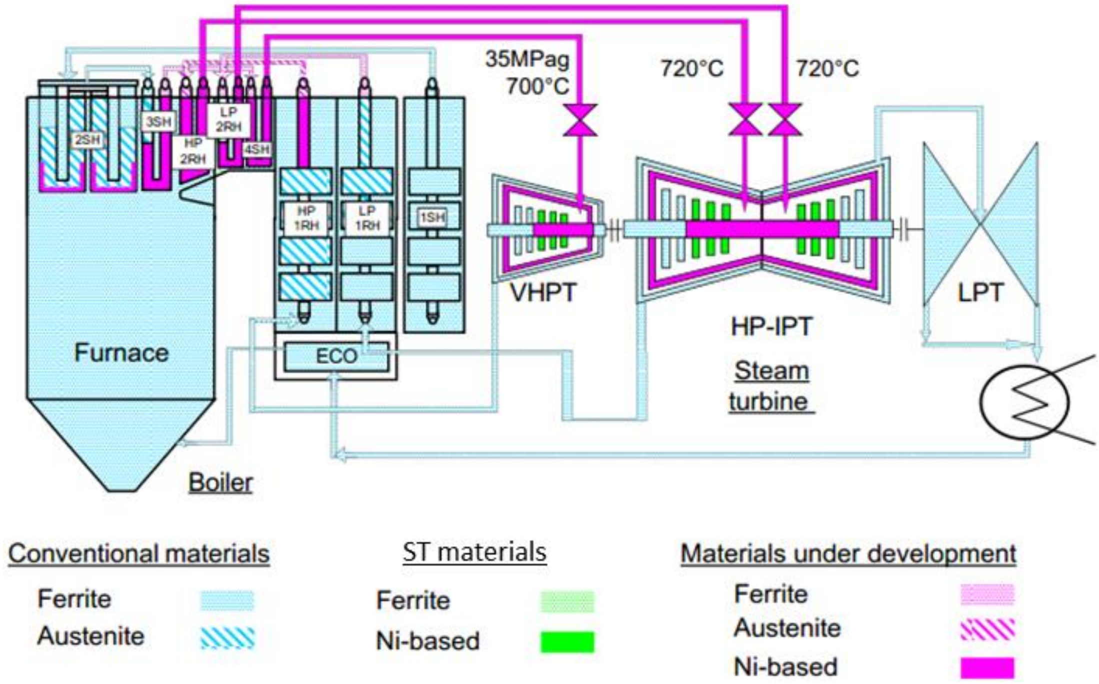

Figure 10. From M. Fukuda, Advanced USC technology development in Japan. Elsevier Ltd, 2016, depicting the areas (purple) that are impacted by A-USC conditions.

Preliminary results of the research effort indicate that, due to Ni-based alloys having lower conductivity and a higher thermal expansion coefficient, thermal stresses within thick-walled tubes are potentially higher. This forces ramp-up times to be slower than current state-of-art USC PC plants, leading to poorer flexibility, as illustrated by the increase in plant start-up times (+35% for cold start-up, +45% for warm start-up and +13% for hot start-up).

It is possible that, in future, the more severe steam conditions will be pursued only when the highest possible efficiency is desired, while standard USC PC designs will remain the choice for flexible operation within the modern power grid that includes intermittent technologies and is subject to highly variable demand.

Trade-offs between flexibility and efficiency in coal fired power plants. Mechanisms to enhance operating flexibility are based on modifications to plant design and on the operating approach that aims to maximize power production during peak times (when the electricity price is high) with the option to reduce plant efficiency during off-peak times (when the electricity price is low).

For the various scenarios simulated, the economic attractiveness – in terms of how long it took to pay back the associated additional CAPEX – of the technical solutions has been assessed.

Four market scenarios were considered:

Table 13. **Considered market scenario prices**

Market Scenarios (prices in €/MWh)		
	LOW variability of electricity price between peak and off-peak	**HIGH variability of electricity price between peak and off-peak**
LOW price level	**Scenario L1** Peak: 70 Off-peak (working): 60 Weekend: 55	**Scenario L2** Peak: 70 Off-peak (working): 50 Weekend: 40
HIGH price level	**Scenario H1** Peak: 90 Off-peak (working): 75 Weekend: 65	**Scenario H2** Peak: 90 Off-peak (working): 60 Weekend: 40

The magnitude of the gap between prices at peak time and off-peak time may be representative of the penetration of intermittent renewable energy sources (especially solar) in the electricity market, with their lower availability to produce power during off-peak periods (typically at night).

Regarding price level, the low level is intended to roughly represent the current average wholesale market price in the EU. For power plants with CO_2 capture, the high scenario may be interpreted as a scenario where the CO_2 captured is more adequately remunerated.

For each market scenario, sensitivity analysis has been carried out using the variable capture (on/off) option (Case 4.1b), where carbon pricing is used to assess the impact of not capturing the CO_2 during peak time.

The following carbon price levels were used:

- LOW: €10/t;
- MEDIUM: €25/t;
- HIGH: €40/t.

For each case, the simplified financial calculation of the pay-back is based on the differential CAPEX (with respect to reference case), and the differential OPEX (cost and revenues). The differential OPEX is calculated considering the changes in revenues, variable costs and maintenance costs.

The main results are shown in the following table.

Table 14. **Financial results summary according to market scenario**

			Market scenarios			
			L1	**L2**	**H1**	**H2**
Case 4.1a - Scenario 1	Delta CAPEX	M€	85.8	85.8	85.8	85.8
	Delta OPEX*	M€/y	13.5	11.3	20.3	16.8
	Pay-back time	years	7.0	7.7	4.3	5.2
Case 4.1a - Scenario 2	Delta CAPEX	M€	14.5	14.5	14.5	14.5
	Delta OPEX*	M€/y	8.9	7.6	13.1	10.9
	Pay-back time	years	2.0	2.0	1.2	1.4
Case 4.1b - LOW carbon tax	Delta CAPEX	M€	17.8	17.8	17.8	17.8
	Delta OPEX*	M€/y	27.6	27.7	44.6	44.8
	Pay-back time	years	1.0	0.7	0.4	0.4
Case 4.1b - MEDIUM carbon tax	Delta CAPEX	M€	17.8	17.8	17.8	17.8
	Delta OPEX*	M€/y	-19.8	-19.7	-2.8	-2.6
	Pay-back time	years	N/A	N/A	N/A	N/A
Case 4.1b - HIGH carbon tax	Delta CAPEX	M€	17.8	17.8	17.8	17.8
	Delta OPEX*	M€/y	-67.2	-67.1	-50.2	-50.0
	Pay-back time	years	N/A	N/A	N/A	N/A
Case 4.1c	Delta CAPEX	M€	197.9	197.9	197.9	197.9
	Delta OPEX*	M€/y	-0.2	-0.2	1.1	1.1
	Pay-back time	years	N/A	N/A	185.2	184.1

** A positive figure indicates an increased operating margin (revenues minus costs) with respect to the reference non-flexible case*

The following conclusions may be drawn from the results:

- The most attractive flexibility case from a simplified financial standpoint is Case 4.1a (Solvent Storage Scenario 2), independent of the market scenario considered. This case is characterised by a 'sensible' reduction of the regenerator sizing in the CO_2 capture unit, i.e. a 12% decrease. However, on the one hand the plant is flexible with respect to the assumed electricity demand curve but, on the other hand, the downsizing of the regenerator could represent a significant operating constraint should the demand curve change.
- The variable capture (on/off) option (Case 4.1b) is very sensitive to the carbon pricing level. The pay-back time is excellent only in the LOW carbon pricing scenario, whereas in the MEDIUM and HIGH carbon pricing scenarios, the additional investment is not paid back at all.
- Case 4.1c (energy storage via batteries) has a very high additional CAPEX, which is not paid back in the modeled market scenario and is likely to be very difficult to pay back under any market scenario. The specific cost of battery storage remains

unattractive, especially at the scale of plant considered in this study. The attractiveness of this option, as studied in the present work, relies heavily on future cost reductions.

- The financial performances of the cases tend to improve at higher electricity price levels, where the beneficial effects of flexibility are amplified.
- The results of the analysis are marginally sensitive to the magnitude of price variability between peak-time and off-peak time, as a significant portion of the revenues from the sale of electricity is concentrated during peak-time.

Outlook for future technology improvements

Improvements of natural gas-fired power plants

The impact of three potential mid-term technological improvements that may be marketed in the near future were assessed. The improvements were selected based on their current development status and perceived likelihood of finding large-scale application in the medium term.

Improvements in GT materials. Following recent R&D activities at NASA, Rolls-Royce and others to progress the development of new materials for gas turbines, it is reasonable to assume that heavy-duty GTs will soon employ Ceramic Matrix Composite (CMC) materials for the first-stage stator and rotor blades and fourth-generation Ni-based single crystal blades for the downstream cooled stages. Compared to the reference H-class gas turbine used in this study, it is assumed that the adoption of CMC materials would allow the average material temperature of the first stage blades to be increased by 150°C. As far as the subsequent cooled states are concerned, an average blade metal temperature increase of 50°C is assumed with the use of more advanced single crystal materials. This would allow a higher compression ratio and a higher turbine inlet temperature (TIT) to be employed, raising the GT efficiency.

Based on this, the performance of future NGCC plant has been predicted with a configuration comprising 2xGT, 2xHRSG and 1xST. In unabated power production, the new cycle shows a +2.3%-points increase in net electrical efficiency compared with Case 1. With a 98.5% capture rate, the new plant recorded an increase of +2.2%-points in net electrical efficiency compared with Case 2.1.

SCOC-CC – oxy-fired turbines. Findings presented in an earlier IEAGHG study[8] on oxy-combustion were updated following introduction of the new class H gas turbine technologies. In the newly designed plant, two generic H-class GTs fitted for oxy-combustion are equipped with one HRSG each to feed a common ST. Oxygen is provided by a cryogenic distillation air separation unit (ASU) and CO_2 recovery is performed via cryogenic separation.

The resulting net electrical efficiency is 50.9% on an LHV basis, while TPC, LCOE and CAC are respectively €1,931M, €80.5/MWh and €100.2/t CO_2. Compared to the figures presented in the earlier study for the semi-closed oxy-combustion combined cycle (SCOC-CC), which resulted in an LCOE of €92.8/MWh and a CAC of €97.9/tCO_2, the LCOE decreased by more than 13% while the CAC increased by 2.3%. While this represents a significant reduction in LCOE, the advances are limited to the gas turbine/combined cycle section. This is the reason why no significant benefits are found in the CAC. Also, compared to the base CO_2 capture options, there is still a significant gap in techno-economic performance. The significant

[8] IEAGHG, "Oxy-Combustion Turbine Power Plants, 2015/05, August, 2015.

quantity of oxygen required hinders both plant performance and economics due to a large and expensive (both economically and energetically) ASU.

Molten carbonate fuel cells. A molten carbon fuel cell (MCFC) allows the CO_2 present in GT exhaust gases to be used for energy production, provided that a source of hydrogen is available (in the case presented, natural gas and steam were used for steam reforming).

In particular, MCFCs are suitable for high temperature applications and, being able to use carbon oxides as "fuels", achieve best in class efficiency. Their reaction mechanism allows red-ox reactions to be performed on CO_2 to produce energy, provided the cell is fed with H_2 in some way. A recent development, where an MCFC is combined with an NGCC is of particular interest. Here, the hydrogen is sourced from natural gas steam reforming, using MCFC waste heat. The MCFC, besides contributing to power generation, allows the CO_2 to be separated from the NGCC flue gas as a CO_2-rich stream, which then requires a relatively simple means of purification (such as cryogenic technology). The recovered syngas (mainly H_2 and CO) can be re-employed as auxiliary fuel.

The simplified flow scheme of the adopted plant configuration is shown in Figure 3.

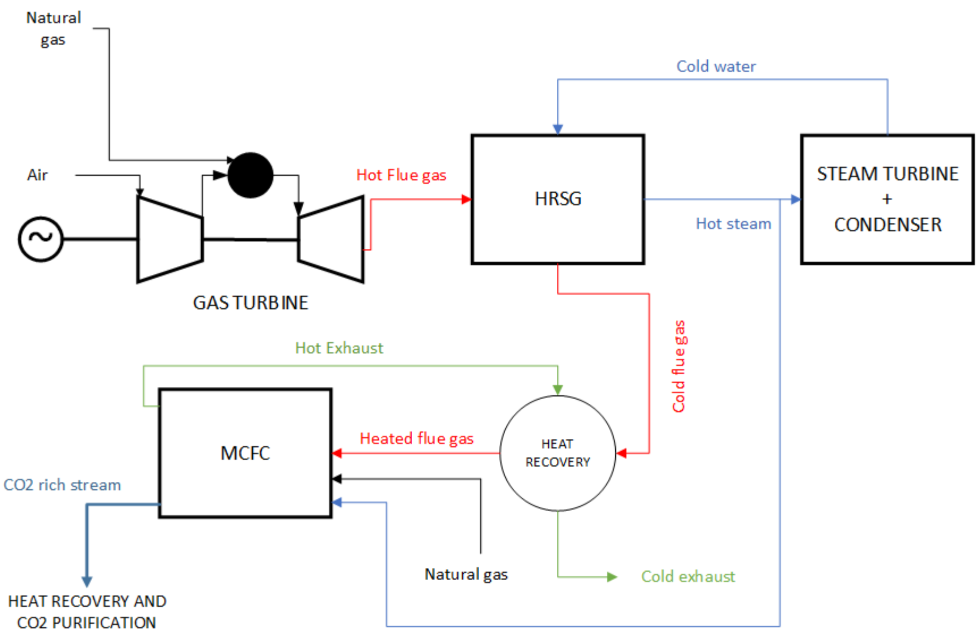

Figure 3. Simplified "retrofit" scheme of a GT+MCFC combined cycle

This design shows a power output of 1727.5 MWe of power output with an efficiency of 57.7%. This drives a very promising techno-economic performance, with an LCOE of €64.4/MWh.

While there are currently no MCFC installations at this scale yet in operation, and this study did not delve into possible engineering-related issues, results are promising. Further development to overcome the challenges of bringing this technology to the market must be encouraged.

Expert Review Comments

A review was undertaken by a number of international experts. The draft report was very well received, with reviewers remarking on the valuable contribution made in providing an update of the techno-economic performances of both coal-fired and natural gas-fired power plants. In particular, it was noted that the results were in good agreement with those from the earlier IEAGHG study[3], which concluded that near-zero emissions from CCS power plants is possible at a limited marginal cost increase relative to the cost of a conventional process with 90% capture.

During the external review process, a comment was raised regarding the efficacy of Cansolv's solvent management system. In late 2015, IEAGHG published a report[9] that summarised SaskPower's experience and learnings during the first full year of operation. In it, the following comment was made:

> *"The Amine Purification Units have been particularly difficult to manage. It is uncertain whether this is due to vendor design or an EPC implementation issue. Managing this concern is part of the construction deficiency rectification schedule for 2015."*

While it is noted that the nature of Cansolv's operations at Boundary Dam remains proprietary and, furthermore, any detailed information relating to this operation lies outside the remit of the present study, a representative of Shell Cansolv was approached for comment. Shell Cansolv reported that solvent consumption costs had indeed been higher than anticipated at Boundary Dam. While the amine recovery efficiency had operated better than design, with higher than anticipated CO_2 capture and lower energy consumption, the degradation rate of the absorbent had been higher than expected. It was emphasised that these results were particular to Boundary Dam. For other plants, the absorbent used may not be the same, operating conditions may differ and the design of the reclaimer may also differ. In summary, Shell Cansolv is confident that the numbers provided to support this study remain valid.

All comments and suggestions made by the reviewers were addressed by the authors. Except where comments and suggestions lay outside the scope of the study, corrections and additions were made to the text as needed.

Conclusions

With IEAGHG techno-economic studies carried out just two years apart, the performance of the USC PC plant in the current study was very similar to that in the earlier study, noting little in the way of significant technology innovation entering practice in the interim two years. Financial figures remained close to those previously presented, noting that 3Q2016 prices were used for the earlier work and 3Q2018 prices for the current study. The resulting LCOE of €53.3/MW for the unabated design and €97.3/MW for 90% capture case translate to a 1–2% increase over the costs for the previous study, the increase being softened by the lower prices for limestone and coal, which heavily favour the current study despite the increased CAPEX, where capital investment and specific costs were 8% higher. While a more rapid transition to advanced-USC conditions would lead to better performance, this could well have a negative impact on operating flexibility, a valuable service in the contemporary energy market. Due to the amount of CO_2 in the flue gas from coal-based plants, carbon capture has a major impact on LCOE. As the CO_2 capture rate is increased from zero to 90%, the LCOE increases by more than 80%.

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[9] IEAGHG, "Integrated carbon capture and storage project at SaskPower's Boundary Dam Power Station", 2015/06, October 2015.

Over the period since the previous study was undertaken, H-class GT developments had led to a 1%-point efficiency improvement. Despite the estimated specific investment being around 5% lower, the higher costs of maintenance and higher gas price resulted in the baseline LCOE (at €48.2/MW) and the 90%-capture LCOE (at €68.9/MW) being 1-3% higher than the comparable cases in the earlier study. The perceived improvement of the CAC is attributable to the higher reference LCOE (i.e. with no capture).

For both natural gas-fired and coal-fired plants, increasing the CO_2 recovery from 90% to much higher capture rates yielded but a modest increase in CAC. For NGCC cases, the CAC increased by 5%, while for the USC PC cases, a 4.3% increase was found. This simply highlights the case for pushing for more aggressive CO_2 capture rates.

Regarding NGCC plants:

- Flue gas recirculation is shown to be an effective option to reduce the costs associated with carbon capture and storage. Recirculation of around 50% of the exhaust gas to the gas turbine inlet leads to a higher CO_2 content and the need for less flue gas to be treated, leading to substantial savings in the CAPEX and OPEX of the capture unit. For both capture rate scenarios, there is a decrease of 2-3% in the LCOE, whilst the CAC is reduced by 8-12%.
- Looking at possible future developments to improve the techno-economic performance of NGCC plants with CCS, three options have been investigated:
  a) Regarding **new material developments** applicable to GTs, the assumption related to the use of CMC materials for the first stage blade and fourth generation Ni-based single crystal blades for the downstream cooled stages leads to an increase in net electrical efficiency compared to reference cases of +2.3%-points for the unabated case and +2.2%-points for the abated case at 98.5% capture rate.
  b) **Oxy-fuel gas turbine designs** (SCOC-CC) benefit from technology advancements, especially in terms of LCOE. The LCOE is reduced by 13%, whilst the CAC remains basically unchanged as the technology advancements are mainly related to the combined cycle. Compared to the base CO_2 capture options, however, the oxy-fuel designs are still hampered by the prohibitive costs of oxygen supply from the large, energy intensive air separation units.
  c) The **integration of a molten carbonate fuel cells** with an NGCC increases power output and leads to very efficient CO_2 capture in the fuel cell. The design studied shows excellent performances, with 1727.5 MWe output and an efficiency of 57.7%. This promises and extremely good techno-economic performance, with an LCOE of €64.4/MWh.

Options to improve the operating flexibility was undertaken via an update of the key findings of previous works for IEAGHG. In particular, three options were explored:

- On the face of it, **solvent storage** in the CO_2 capture unit appeared advantageous but, in the natural-gas case, where plants are normally expected to be turned off overnight, issues were introduced relating to the excess energy produced overnight while regenerating solvent storage. This is not the case for USC PC plants, which are expected to turn-down overnight. Moreover, by reducing the reboiler size, a limit is placed on the regeneration rate, effectively placing a limiting factor on the operating envelope of the plant should the demand curve change over time (which, counterproductively would have the effect of reducing operating flexibility).

- Adopting an **on/off capture unit** involves very little extra CAPEX but is disadvantageous in terms of normal operation efficiency (assuming that, normally, the capture unit is on-line). Also, the attractiveness of this option is expected to be strictly related to the carbon price in force.
- **Energy storage** is an interesting solution for flexibility as it has no impact on plant performance. The current cost of BESS, however, makes it unattractive for the scale of plant considered in this study.

Regarding the operating flexibility of coal power plants, Wood has carried out two specific analyses, leading to the following main outcome:

- A literature review was undertaken on the impacts of the enhanced steam conditions, such as those being used in developing advanced-USC PC (A-USC PC) plants, on operating flexibility. Preliminary results indicate that, due to the lower conductivity and higher thermal expansion coefficient of nickel-based alloys, the thermal stresses within the thick-walled tubes would potentially be higher. This would result in slower ramp-up times than current state-of-art USC PC plants, leading to poorer flexibility, exemplified by the increase of plant start-up times (+35% for cold start-up, +45% for warm start-up and +13% for hot start-up). It is envisaged that in future plants with severe steam conditions will be pursued only when the highest possible efficiency is desired, while more conventional USC PC designs would remain the technology of choice for flexible operation within a grid with highly variable demand scenario due, e.g. to the presence of intermittent renewables such as solar and wind that can fluctuate heavily in energy production according to weather).

- In terms of trade-off between operating flexibility and efficiency, all the solutions analysed in the study to enhance operating flexibility, are based on modifications to the design/operation of the plant in order to maximize power production during peak time by penalising plant efficiency during off-peak time. The flexibility case showing the best attractiveness from a simplified financial standpoint is the Solvent Storage, in the scenario where the regeneration sizing reduction is the highest possible (i.e. 12%), with pay-back times in the range of 1÷2 years. It is again remarked that, with this option, on one hand the plant is flexible with respect to the assumed electricity demand curve, but, on the other hand, the downsizing of the regeneration could represent a significant operating constraint in case the demand curve changed. Also, it is confirmed that the variable capture (On/Off) option is very sensitive to the considered carbon pricing level. The pay-back time is excellent only in the Low carbon pricing scenario, increasing steeply as far as the assumed carbon pricing is raised.

  Energy storage via batteries has a very high additional CAPEX, which is not paid back in the modelled market scenarios. The specific cost of battery storage is still unattractive, especially at the large scales considered in this study. The attractiveness of this option strictly relies upon future cost improvements of this technologies.

  It is highlighted that the financial performance of the cases tends to improve at higher electricity price levels, whilst it is marginally sensitive to the magnitude of price variability between peak-time and off-peak time.

Recommendations

Most previous techno-economic studies, including those commissioned by IEAGHG, have presented costs (LCOE and CAC) that apply to a CO_2 capture rate of 90%. The results from this study demonstrate clearly that, in theory, both coal- and gas-fired power plants with CO_2 capture can achieve net-zero CO_2 emissions at a relatively modest increase in the costs for 90% CO_2 capture. It is now important that these findings are tested in practice, i.e. in CCS plants at scale.

It is essential that the broader energy and financial communities understand the potential of CCUS in an environment where yet more stringent demands will be made on technologies to meet the challenge of climate change. In the longer term, it is clear that the residual emissions from a 90% capture rate will not be compatible with the level of reductions needed to achieve the aims of the Paris Agreement. This is because, in a net-zero world, the residual emissions will also have to be mitigated. These messages will be communicated by IEAGHG at all possible opportunities.

Suggestions for further work

It is important that the costs of capture are updated regularly. This will include monitoring of CCUS projects in operation or in the pipeline, as well as relevant technological developments. While consideration of the value of a technology is gaining traction, the relative cost of a technology (to other candidate power generation technologies) is currently the metric most often used in practice to select a technology for deployment. As the cost (or value) of a technology, together with its environmental impact, will become increasingly more significant, it will be important that techno-economic data be kept reasonably up-to-date.

Further updates will be undertaken by IEAGHG as the technology or financial landscapes change.

CLIENT	:	IEAGHG
PROJECT NAME	:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO_2 CAPTURE
DOCUMENT NAME	:	EXECUTIVE SUMMARY
CONTRACT N°	:	1-BD-1046 A

ISSUED BY	:	M. MENSI
CHECKED BY	:	V. TOTA
APPROVED BY	:	V. TOTA

Date	Revised Pages	Issued by	Checked by	Approved by

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GLOSSARY

CCS	Carbon Capture and Storage
NGCC	Natural Gas Combined Cycle
USC PC	Ultrasupercritical Pulverised Coal
FGR	Flue Gas Recirculation
EGR	Exhaust Gas Recirculation
CCU	Carbon Capture Unit
CMC	Ceramic Matrix Composite
ASU	Air Separation Unit
MCFC	Molten Carbonate Fuel Cell
TPC	Total Plant Cost
TIC	Total Installed Cost
MEL	Minimum Environmental Load
GT	Gas Turbine
ST	Steam Turbine

1. Background and objectives of the study

Carbon capture and storage (CCS) has long been recognised as a key component of an effective mitigation strategy to decarbonise the power and industrial sectors. For many reasons, however, the commercial deployment of CCS has been slow and must accelerate if the technology is to achieve its potential and contribute effectively to mitigating climate change.

Much effort in recent years has been focused on improving the technical performance of plants with CO_2 capture, targeted particularly at integrating the host plant with the capture equipment and at reducing the associated energy penalty. Importantly, effort has also been focused on reducing the capital and operating costs of CO_2 capture.

Moreover, a recent IEAGHG study[1] has shown that the 90% cap in capture rate that has been adopted virtually ubiquitously in energy and climate models and by the CCS community, from R&D through pilot scale testing to the large-scale demonstration plants currently in operation, is actually an artificial cap. It was clearly demonstrated that there were no technology barriers to prevent operation at capture rates approaching 100%.

With these premises, IEAGHG contracted Amec Foster Wheeler Italiana, a Wood Company, to perform a technical and economical assessment of coal and natural gas fired power plants, taking into account the benefits of recent technology improvements.

The study has focused on *ultra-supercritical pulverised coal (USC PC) boiler* and *natural gas combined cycle (NGCC)* power plants, with and without CO_2 capture. *Post combustion capture based on solvent scrubbing* only has been considered in this study, which is currently the commercially leading option for capture on both pulverised coal and natural gas-fired power plants.

Besides the development of updated benchmark cases for near-zero emission fossil-fuel fired power plants, Wood analysed potential mid-term improvements to the flexible operation of the updated benchmark plants via various approaches such as solvent storage. This was done by updating the key outcomes from an earlier IEAGHG study that addressed operating flexibility. Additionally, Wood discussed possible efficiency improvements in CCS power plants in the mid-term scenario due to technological progress and innovative designs.

[1] IEAGHG, "Towards zero emissions CCS from power stations using higher capture rates or biomass", 2019/02, March 2019.

2. Study cases

2.1. Benchmark cases

Wood and IEAGHG agreed on benchmark plant designs (both for NGCC and USC PC technologies) as reference plant configuration based on current state-of-art technologies commercially available for these types of power plants. Key design features and technology suppliers for the flue gas desulphurisation and CO_2 capture units are common throughout all the study cases and they derive from former published IEAGHG studies. Other units or equipment performance and costs are designed open-art. Two different capture unit designs were studied: a 90% CO_2 recovery scenario, which is a common target and that provides direct comparison with previous work, and a high capture rate scenario. This high capture rate scenario was only limited by techno-economic considerations: Wood experienced that solvent regeneration duty required grows exponentially at high capture rates (higher solvent richness in CO_2 and higher circulating flowrate). This affects thermal reclaimer sizing. Wood decided to limit capture rate before the point where diminishing returns determine a significant CAPEX extra expenditure for very small increases in capture rate. Cansolv technologies uses two different solvents for treatment of different flue gases (one solvent is used for gas turbines exhaust, another solvent is used for coal combustion exhaust) and this leads to different results in terms of selected point (different shape of the %cost vs capture rate curve): Wood settled on a 98.5% capture rate for NGCC configurations and a 99% capture rate for USC PC configurations.

Table 1. Benchmark plants

	Case	Description	Key features
NG fired	Case 1	NGCC w/o CCS	• Two generic H-class gas turbines • One common steam turbine
	Case 2	NGCC with CCS	• Two generic H-class gas turbines • One common steam turbine • CANSOLV post-combustion capture with 90% CO_2 recovery
	Case 2.1	NGCC with CCS – High capture case	• Two generic H-class gas turbines • One common steam turbine • CANSOLV post-combustion capture with 98.5% CO_2 recovery
Coal fired	Case 3	USC PC w/o CCS	• Generic state-of-art supercritical USC PC boiler • Wet limestone scrubbing FGD
	Case 4	USC PC with CCS	• Generic state-of-art supercritical USC PC boiler • Wet limestone scrubbing FGD • CANSOLV post-combustion capture with 90% CO_2 recovery
	Case 4.1	USC PC with CCS – High capture case	• Generic state-of-art supercritical USC PC boiler • Wet limestone scrubbing FGD • CANSOLV post-combustion capture with 99% CO_2 recovery

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.

Natural gas plants are based on a generic gas turbine defined, in terms of performance and size, in collaboration with Politecnico di Milano. The GT represents the averaged H-class GT data received from vendors that agreed to support this study: 9HA.02 by General Electric, GT-36 by Ansaldo Energia and M701J by Mitsubishi Hitachi Power Systems. This approach has been adopted consideringthe varying performance and capacity of the different turbines, which fall in the following ranges:

- Thermal input: 1,035 – 1,298 MWth
- Shaft power output: 462 – 575 MWe
- Flue gas flowrate: 2790 – 3700 t/h

- Gross electrical efficiency
  - Simple cycle: 41 – 44%
  - Combined cycle: 60 – 64%
- Heat rate: 8,114 – 8,789 kJ/kWh

The net power output of the pulverised coal plant without capture is around 1,000 MWe. The NGCC plant capacity of the cases with and without CCS is selected in order to fully load two (2) heavy duty H-class gas turbines.

2.2. Sensitivity cases

Different modifications to the candidate benchmark case have been carried out as sensitivity cases. The economic impacts/technical advantages of these technical improvements to the benchmark cases are discussed.

Besides the update of benchmark cases, the study presents:

- The impact of Flue Gas Recirculation (FGR, interchangeable terminology with EGR which stands for Exhaust Gas Recirculation) on NGCC power plant performances and economics.
- Updated techno-economic considerations on how to improve operational flexibility of power plants with carbon capture to partially update the work presented in *"Operating flexibility of power plants with CCS"* (2011, Foster Wheeler) with the state of art technologies.
- Considerations on mid-term future advancements on power generation technologies.

Sensitivity cases for natural gas-fired plants are reported in Table 2.

Table 2. NGCC sensitivity cases

<table>
<tr><th></th><th>Case</th><th>Description</th><th>Key features</th></tr>
<tr><td rowspan="2">FGR</td><td>Case 2.2</td><td>NGCC with CCS and flue gas recirculation</td><td>• Case 2 configuration
• Capture rate 90%
• FGR recirculation ratio: 50%</td></tr>
<tr><td>Case 2.3</td><td>NGCC with CCS and flue gas recirculation – High capture case</td><td>• Case 2.1 configuration
• Capture rate 98.5%
• FGR recirculation ratio: 50%</td></tr>
<tr><td rowspan="3">Improving flexibility</td><td>Case 2.1a</td><td>NGCC with CCS and solvent storage</td><td>• Case 2.1 configuration
• 98.5% capture rate
• Lean/rich solvent storage system</td></tr>
<tr><td>Case 2.1b</td><td>NGCC with ON/OFF CCS</td><td>• Case 2.1 configuration
• 98.5% capture rate
• Capable of unabated power production</td></tr>
<tr><td>Case 2.1c</td><td>NGCC with CCS and BESS</td><td>• Case 2.1 configuration
• 98.5% capture rate
• 430 MWh battery energy storage system</td></tr>
<tr><td rowspan="3">Future improvements</td><td>Case 2.4</td><td>Advancements in GT materials</td><td>• Case 1 configuration
• Two generic next-gen GT</td></tr>
<tr><td>Case 2.5</td><td>Oxy-fired NGCC with CCS</td><td>• Two generic oxy-fired gas turbines based on H-class
• One common steam turbine
• Cryogenic post-combustion carbon purification</td></tr>
<tr><td>Case 2.6</td><td>NGCC with MCFC</td><td>• Two generic H-class gas turbines
• One common steam turbine
• Use of Molten Carbonate Fuel Cells in combined cycle
• Cryogenic post-combustion carbon purification</td></tr>
</table>

Sensitivity cases for coal-fired plants are reported in Table 3.

Table 3. USC PC sensitivity cases

	Case	Description	Key features
Improving flexibility	Case 4.1a	USC PC with CCS and solvent storage	• Case 4.1 configuration • 99% capture rate • Lean/rich solvent storage system
	Case 4.1b	USC PC with ON/OFF CCS	• Case 4.1 configuration • 99% capture rate • Capable of unabated power production
	Case 4.1c	USC PC with CCS and BESS	• Case 4.1 configuration • 99% capture rate • 260 MWh battery energy storage system
Future improvements	A-USC	Impact of steam conditions on boiler design	• Literature-supported analysis • Impact of advanced ultrasupercritical (700 °C) steam conditions • Choice of materials • Impact on design • Impact on flexible operation

3. Common basis

In this section, the fundamental technical and economic basis adopted for this study are summarized.

3.1. Technical basis of design

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.

The main fuel of the different plants is bituminous coal type, based on an Eastern Australian internationally traded open-cast coal, assumed delivered from a port to the plant site by unit trains.

Natural gas is the main fuel for the NGCC based power plants and it is used also as start-up or plant back-up fuel for the coal-based power station. Natural gas is delivered to the plant battery limits from a highpressure pipeline. Natural gas specifications were agreed on with IEAGHG.

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

	USC PC based cases (1)	**NGCC based cases (2)**
NO_X (as NO_2)	≤ 150 mg/Nm³	≤ 50 mg/Nm³
SO_X (as SO_2)	≤ 150 mg/Nm³	(3)
CO	-	≤ 100 mg/Nm³
Particulate	≤ 10 mg/Nm³	(3)

Note: (1) Emission expressed in mg/Nm³ @6% O_2, dry basis.
(2) Emission expressed in mg/Nm³ @ 15% O_2 volume dry
(3) Not included in the EU directive as assumed negligible in gas turbine plants

3.2. Economic estimate

All the cases presented in this study are developed considering the Netherlands as location and on a 3Q2018 price basis. Estimate accuracy is in the range of +35%/-15% (i.e. Class IV in accordance with AACE International Cost Estimate Classification System).

The economic estimate uses as starting point the results from IEAGHG report 2018/4 "*Effect of plant location on CO_2 capture*" updated to reflect advancements in technology and more information at disposal.

3.2.1. Capital cost definition

Plant capital costs have been evaluated as Total Plant Cost (TPC) and Total Capital Requirement (TCR) defined in accordance with the IEAGHG White Paper[2].

The Total Plant Cost (TPC) is the installed cost of the plant, including project contingencies. The Total Capital Requirement (TCR) is defined as the sum of the Total Plant Cost (TPC), interest during construction, spare parts cost, working capital, start-up costs and owner's costs.

The TPC of the different study cases is broken down into the main process units that compose the plants and, for each process unit, the TPC is split into direct materials, construction, EPC services, other costs and contingency. The estimate is in euros (€), based on 3Q2016 price level. Overall estimate accuracy is in the range of +35%/-15% (AACE Class 4).

3.2.2. LCOE and CAC definition

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 comparing different 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.

[2] IEAGHG,, "Toward a common method of cost estimation for CO_2 capture and storage at fossil fuel power plants", 2013/TR2, March 2013 (www.ieaghg.org/publications/technical-reports).

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, as defined below:

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

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.

For each case with capture, the CAC is evaluated considering as reference case, its relevant benchmark case without capture.

3.2.3. *Main financial bases*

The main financial bases common through all the study cases to run the economic models are reported in the below table.

Table 4. Financial bases

ITEM	DATA
Discount Rate	8%
Financial leverage	100% debt
Capacity factor (SC-PC/ NGCC)	90% / 93%
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 3Q2018

4. Updated benchmark on natural gas-fired power plants

4.1. Benchmark plant performances and economics

The performances of the reference plants for the natural gas-fired combined cycle are summarised in the following table. For the cases where post-combustion capture is present, plant is redesigned to work with the modified steam cycle (due to LP steam export for the capture unit). This allows to achieve the best plant efficiency and compare the cases on an even field.

Table 5. Reference plant performance

		Case 1 NGCC w/o CCS	Case 2 NGCC w/ CCS	Case 2.1 NGCC w/ CCS high rate
OVERALL PERFORMANCE				
Fuel flowrate	**t/h**	187	187	187
Thermal input (1)	**MWth**	2418	2418	2418
Auxiliary power demand (2)	**MWe**	23.9	84.3	87.8
Net Electric Power Output	**MWe**	1506.0	1344.2	1316.0
Net Electrical Efficiency (1)	**%**	62.3	55.6	54.4
CO_2 CAPTURE PERFORMANCE				
CO_2 capture rate	**%**	-	90.0	98.5
CO_2 to atmosphere	**kg/MWh**	331.3	36.9	5.6

Notes: (1): LHV basis.
(2): Including step-up transformer losses

Compared to the recent results on both no CCS and 90% capture rate configurations presented in IEAGHG report 2018/4 "*Effect of plant location on CO_2 capture*", a 1% to 2%-point increase in efficiency is appreciated. This is attributed to the iterative advancements on H-class machines.

The key economic results in terms of capital costs, levelised cost of electricity (LCOE) and cost of CO_2 avoidance (CAC) are summarised in this section.

Main figures are reported in the below table.

Table 6. NGCC plant benchmark cases economic and financial results

Case			Case 1	Case 2	Case 2.1
Description			**NGCC w/o CCS**	**NGCC w/CCS 90%**	**NGCC w/CCS 98.5%**
Total Plant Cost (TPC)		(M€)	905	1597	1684
Total Capital Requirement (TCR)		(M€)	1206	2121	2236
Specific cost	[TPC/Net Power]	(€/kW)	601	1188	1280
Specific cost	[TCR/Net Power]	(€/kW)	801	1578	1699
LCOE		(€/MWh)	48.2	68.9	72.2
CO_2 emission and avoidance cost		(€/t)	-	69.98	73.54

In the following graph, economic results are compared against the figures presented in IEAGHG Technical Report 2018/4.

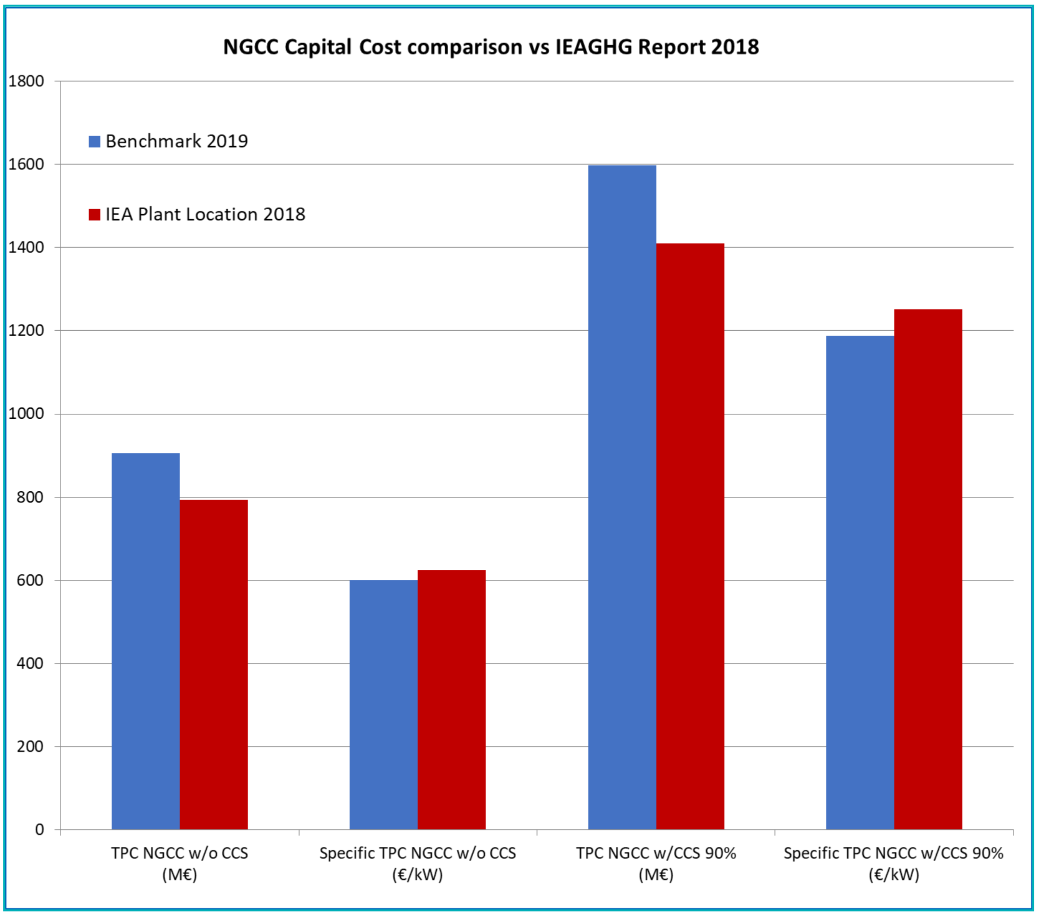

Figure 1. Comparison of NGCC plant costs vs IEA GHG report 2018/4

Compared to the previous study, TPC is about 14% higher (due to the larger capacity), but the specific cost is playing at favour here, thanks to economy of scale on larger plants, showing a 5% decrease.

In the following graph, financial results are compared against the figures presented in IEA GHG Technical Report 2018/4, "*Effect of plant location on CO_2 capture*"

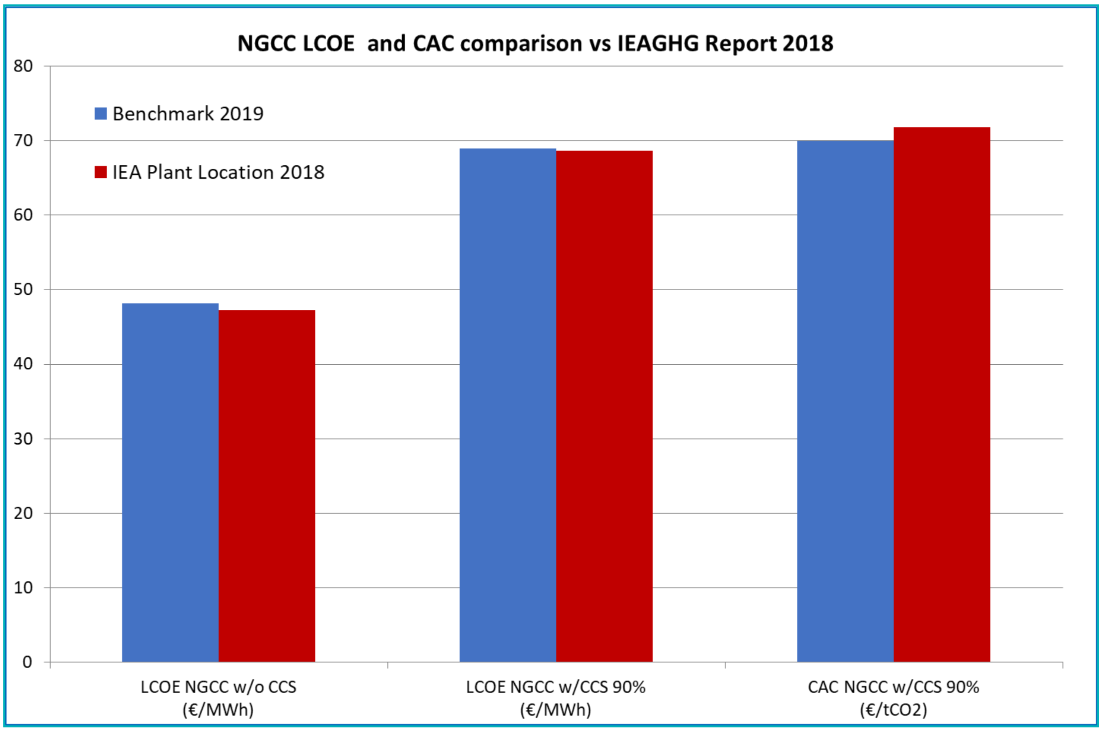

Figure 2. Comparison of NGCC financial results vs IEA GHG report 2018/4

Compared to the recent results presented in IEAGHG Technical Report 2018/4 "*Effect of plant location on CO_2 capture*", LCOE is up to 2% higher. The reason is attributable to the different study basis. In particular, compared to the 2018 report, fuel cost and maintenance costs are increased negatively impacting LCOE. If the same basis were applied to both studies, LCOE results would favour the updated benchmark.

Cost of carbon avoidance presents a 3% decrease compared to last study, but this small difference can be attributed to the different LCOE only, which affects the relative financial impact of the capture unit.

Moving towards higher capture rates is highlighted the presence of underlying economies of scale to leverage: a 5% CAC increase is experienced when increasing by almost 10%-points the sequestrated CO_2.

4.2. Flue gas recirculation in natural gas-fired plants with CO_2 storage

In the following section, benchmark cases 2 and 2.1 are re-evaluated by including exhaust gas recirculation technology: by recirculating part of the flue gas back to the

GT compressor via means of appropriate ducting, cooling and use of a booster fan results in a two-fold effect:

1. Exhaust gas is richer in CO_2 (about twice as much)
2. Only half of the exhaust gas flowrate needs to be processed by the capture unit

This allows to reduce the sizing of the capture unit greatly while maintaining the same level of emission reduction. This is counteracted by an increase in capital cost of the power island unit (to account for the extra equipment needed for FGR) and a reduction of efficiency (more inert gases fed to the GT combustor). Amount of flue gas that can be recycled is as much as possible but limited by the need to have a stable and still reasonably efficient combustion.
Thanks to the data received by Ansaldo (only vendor that supported Wood in this specific inquiry), it was possible to estimate the FGR behaviour of the generic gas turbine with 50% FGR (value suggested by Ansaldo, but can change from vendor to vendor), in collaboration with PoliMI. With this new set of performances, Wood developed the 90% and 98.5% capture rate configuration using the same basis as the benchmark cases.

The performances of the reference plants for the natural gas-fired combined cycle are summarised in the following table.

Table 7. NGCC with FGR plant performance

		Case 2.2 FGR NGCC w/ CCS	Case 2.3 FGR NGCC w/ CCS high rate
OVERALL PERFORMANCE			
Fuel flowrate	**t/h**	185	185
Thermal input (1)	**MWth**	2390	2390
Auxiliary power demand (2)	**MWe**	78.6	82.2
Net Electric Power Output	**MWe**	1340.5	1320.7
Net Electrical Efficiency (1)	**%**	56.1	55.3
CO_2 CAPTURE PERFORMANCE			
CO_2 capture rate	**%**	90.0	98.5
CO_2 to atmosphere	**kg/MWh**	35.2	3.3

Notes: (1): LHV basis.
(2): Including step-up transformer losses

Thanks to the downsizing of the absorber and related components, a slight advantage in terms of efficiency is present as less parasitic load are required by the capture unit.

The key economic and financial results for fuel gas recirculation cases are reported in the below table.

Table 8. NGCC with FGR plant cases economic and financial results

Case			**Case 2.2**	**Case 2.3**
Description			**FGR NGCC w/ CCS 90%**	**FGR NGCC w/ CCS 98.5%**
Total Plant Cost (TPC)		(M€)	1510	1568
Total Capital Requirement (TCR)		(M€)	2005	2080
Specific cost	[TPC/Net Power]	(€/kW)	1127	1187
Specific cost	[TCR/Net Power]	(€/kW)	1495	1575
LCOE		(€/MWh)	67.3	69.9
CO_2 emission and avoidance cost		(€/t)	65.20	65.56

LCOE results are compared to the ones obtained for non-FGR configurations to draw conclusions.

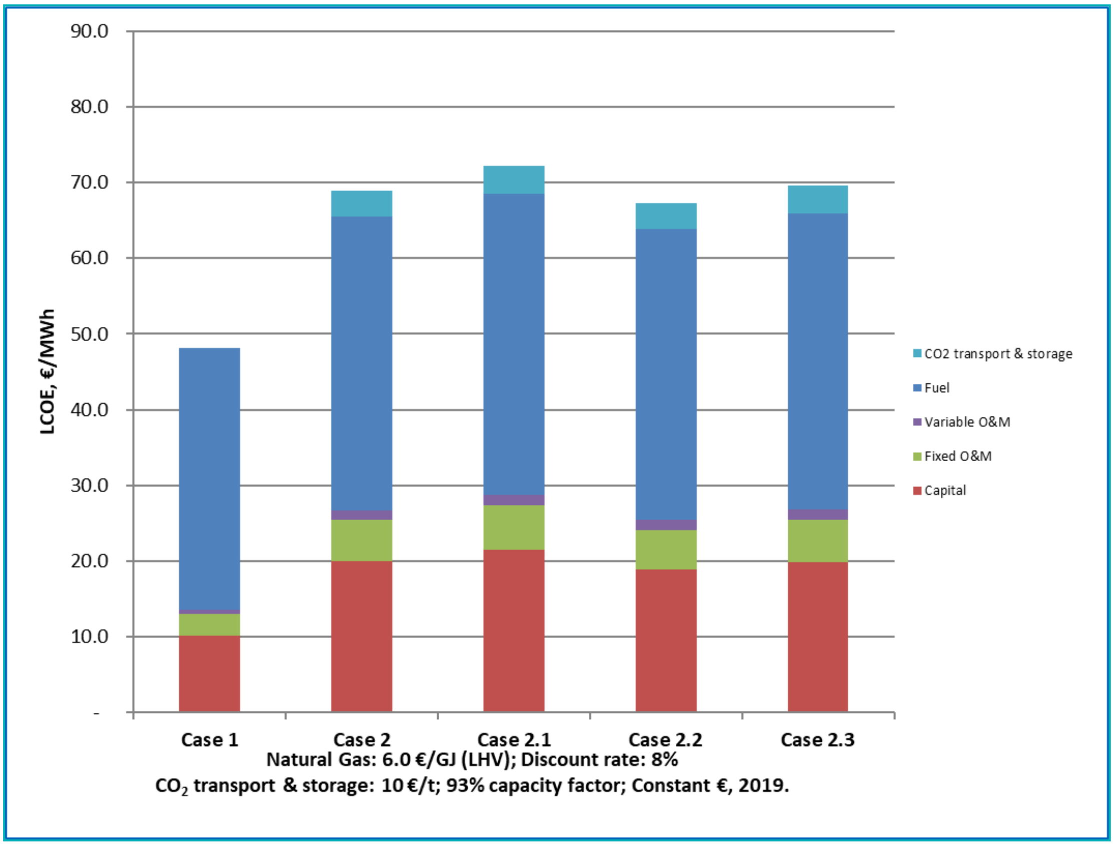

Figure 3. LCOE for main NGCC study cases

From this result it is evident that flue gas recirculation may represent a convenient improvement on the economics of post-combustion capture natural gas power plants: the TPC savings are due to the savings on the capture unit mainly thanks to smaller adsorber column (while the CO_2 to be sequestrated is roughly the same and thus not changing the solvent circuit, the adosrber column treats half the flue gas flowrate and can be downsized). The cost of extra equipment for flue gas recirculation is covered by the advantages obtained from the better CCU economics, making FGR a noteworthy solution for near-zero emissions natural gas-fired power plants.

5. Updated benchmark for coal-fired power plants

5.1. Benchmark plant performances and economics

The performances of the reference plants for the coal-fired steam cycle are summarised in the following table. For the cases where post-combustion capture is considered, plant is redesigned to work with the modified steam cycle (due to LP steam export for the capture unit). This allows to achieve the best plant efficiency.

Table 9. Reference plant performance

		Case 3 USC PC w/o CCS	Case 4 USC PC w/ CCS	Case 4.1 USC PC w/ CCS high rate
OVERALL PERFORMANCE				
Fuel flowrate	**t/h**	325	325	325
Thermal input (1)	**MWth**	2335	2335	2335
Auxiliary power demand (2)	**MWe**	47.1	135.7	145.8
Net Electric Power Output	**MWe**	1033.4	825.9	1316.0
Net Electrical Efficiency (1)	**%**	44.2	35.4	33.5
CO_2 CAPTURE PERFORMANCE				
CO_2 capture rate	**%**	-	90.0	99.0
CO_2 to atmosphere	**kg/MWh**	742.5	92.6	9.8

Notes: (1): LHV basis.
(2): Including step-up transformer losses

Compared to the recent results presented in IEAGHG report 2018/4 "*Effect of plant location on CO_2 capture*", no appreciable increase in efficiency is appreciated as USC PC technology did not make particular progress on performances.
The key economic results in terms of capital costs, levelised cost of electricity (LCOE) and cost of CO_2 avoidance (CAC) are summarised in this section.
The key economic and financial results for the coal-fired benchmark cases are reported in the below table.

Table 10. USC PC plant benchmark cases economic and financial results

Case			Case 3	Case 4	Case 4.1
Description			**USC PC w/o CCS**	**USC PC w/CCS 90%**	**USC PC w/CCS 99%**
Total Plant Cost (TPC)		(M€)	1560.8	2384.6	2437.5
Total Capital Requirement (TCR)		(M€)	2033.8	3097	3165
Specific cost	[TPC/Net Power]	(€/kW)	1510.4	2887.3	3111.5
Specific cost	[TCR/Net Power]	(€/kW)	1968.1	3749.9	4040.7
LCOE		(€/MWh)	53.3	97.3	105.1
CO_2 emission and avoidance cost		(€/t)	-	67.68	70.60

In the following graph, economic results are compared against the figures presented in IEAGHG report 2018/4.

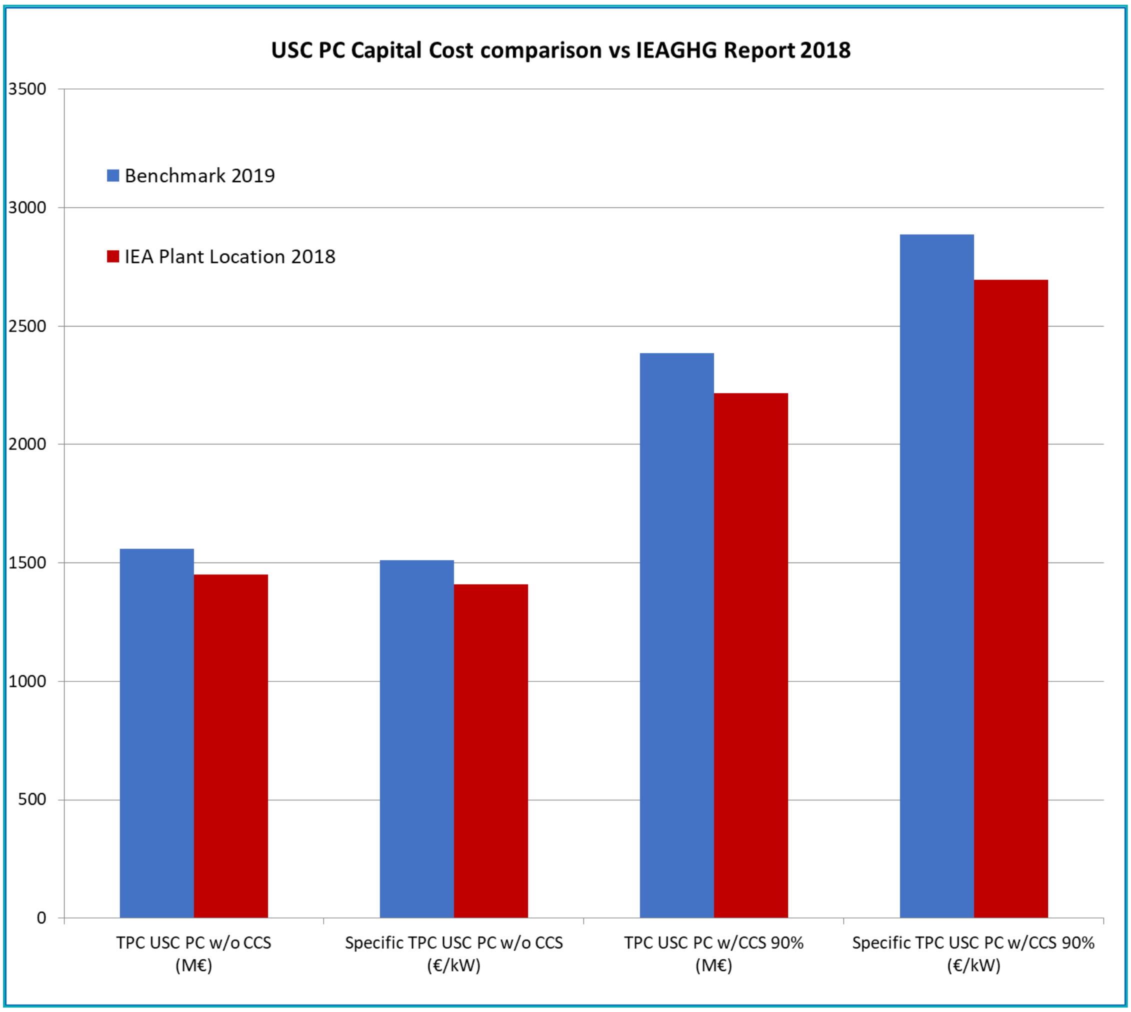

Figure 4. Comparison of USC PC plant costs vs IEA GHG report 2018/4

Compared to the previous study, TPC is about 8% higher for both no capture and 90% capture cases. Specific cost is 7% higher for no capture and 8% lower for cases with carbon capture. This is mainly due to the cost escalation factor since 2016 (price level basis of the previous study) and the slightly enhanced steam condition (i.e. higher Main Steam pressure).

In the following graph, financial results are compared against the figures presented in IEA GHG report 2018/4.

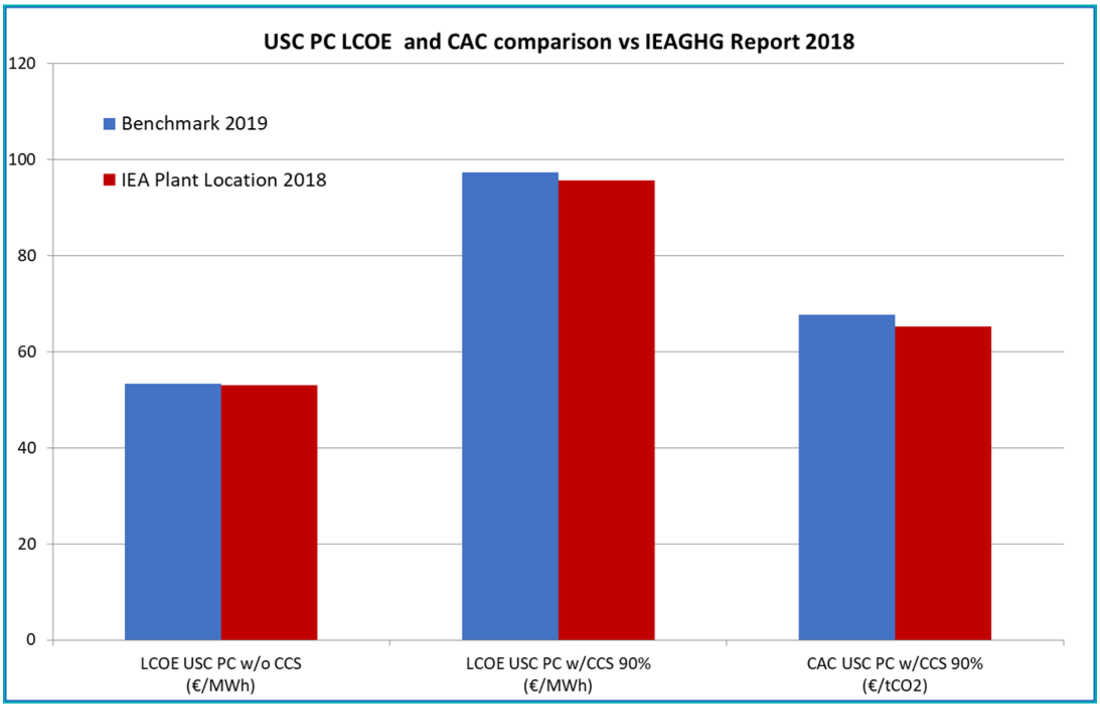

Figure 5. Comparison of USC PC financial results vs IEA GHG report 2018/4

Compared to the recent results presented in IEAGHG report 2018/4 "*Effect of plant location on CO_2 capture*", LCOE is 1 to 2% higher. Cost of carbon avoidance presents a 3% increase compared to last study.

The main differences in study basis are a lower fuel cost and a lower price for limestone that should benefit the LCOE. Indeed, lower operating costs allow the LCOE increase to not be significant despite the inflation of capital expenses without a return in efficiency.

Again, with an almost 10%-point increase of capture rate, the CAC is increased by only 4.3%. This confirms the presence of an exploitable economy of scale in designing above 90% capture rate.

Below figures shows the LCOE breakdown for the USC PC benchmark cases.

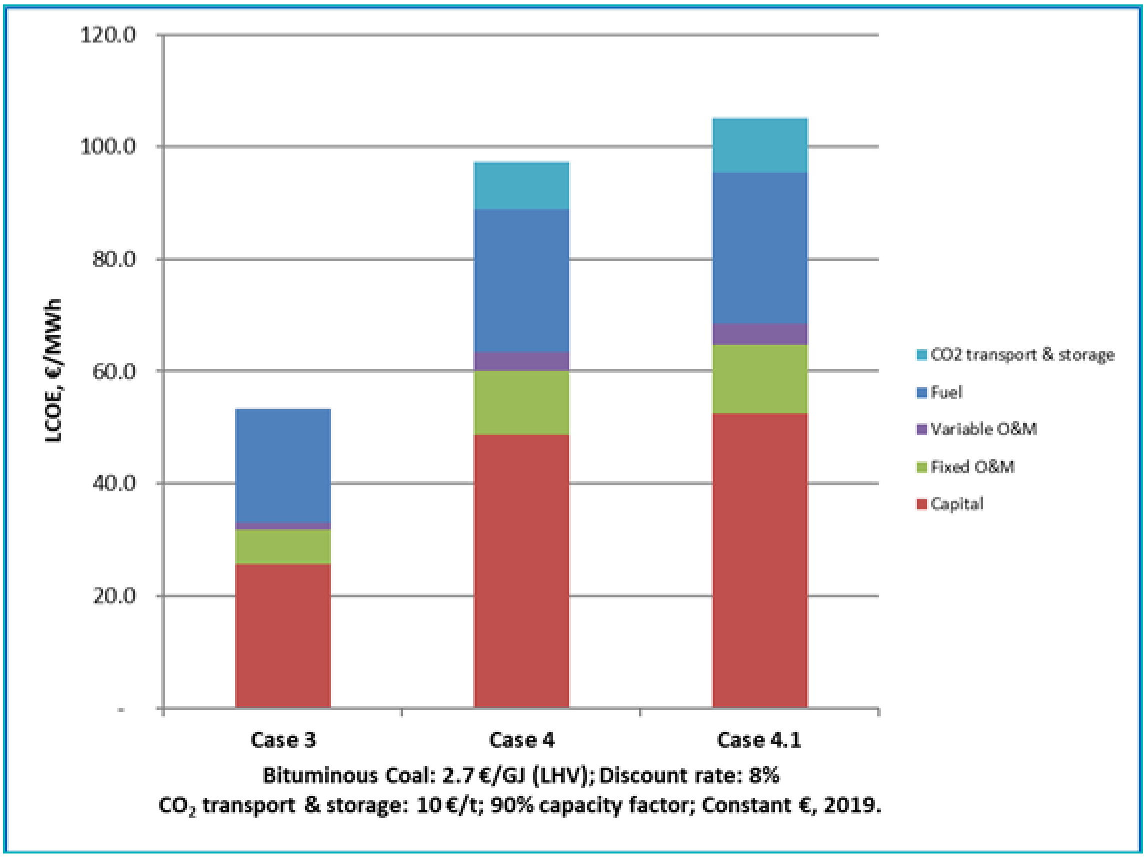

Figure 6. LCOE for main USC PC study cases

6. Improving operative flexibility of power plants with CO_2 capture

In the following section the results obtained from different modifications to benchmark case 2.1 and case 4.1 are presented. The aim is to improve the operative flexibility of the power plant, and for each case performances have been reassessed and capital investment re-evaluated.
Operating flexibility is important since the modern energy market fluctuates heavily in demand on an hourly basis. Figures below reports the assumed demand curve for both NGCC and USC PC cases, which served as basis for the development of the studied flexibility modifications.

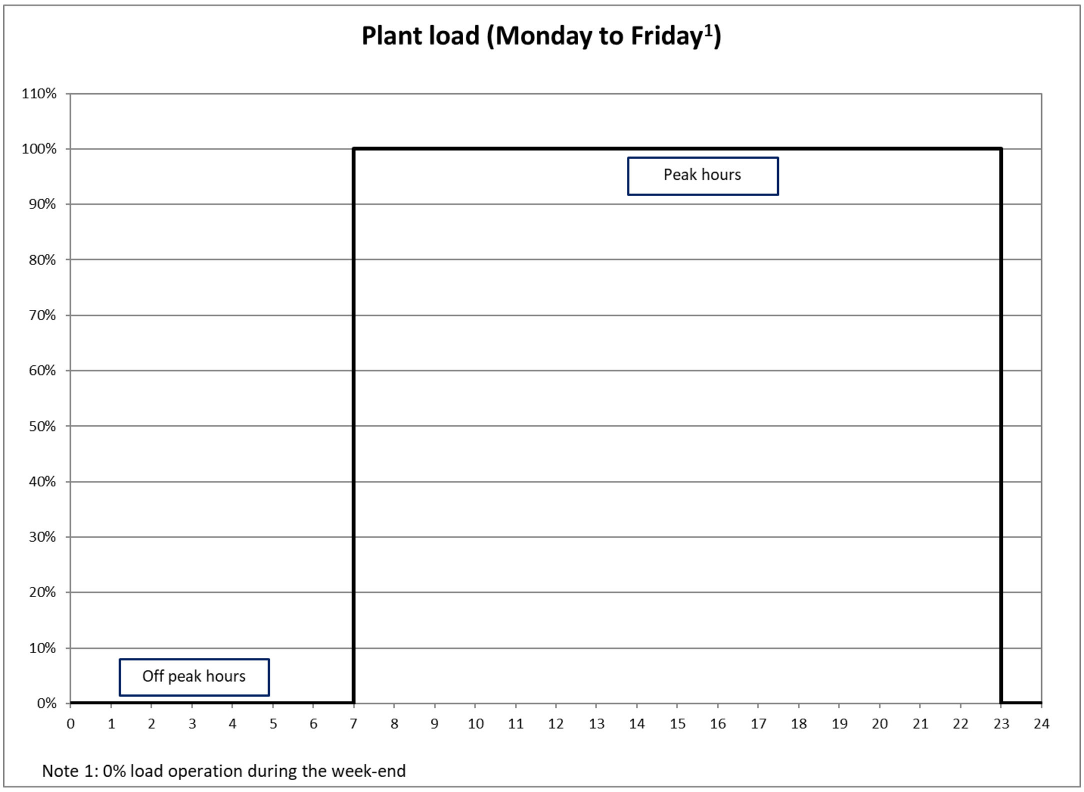

Figure 7. Daily NGCC plant load

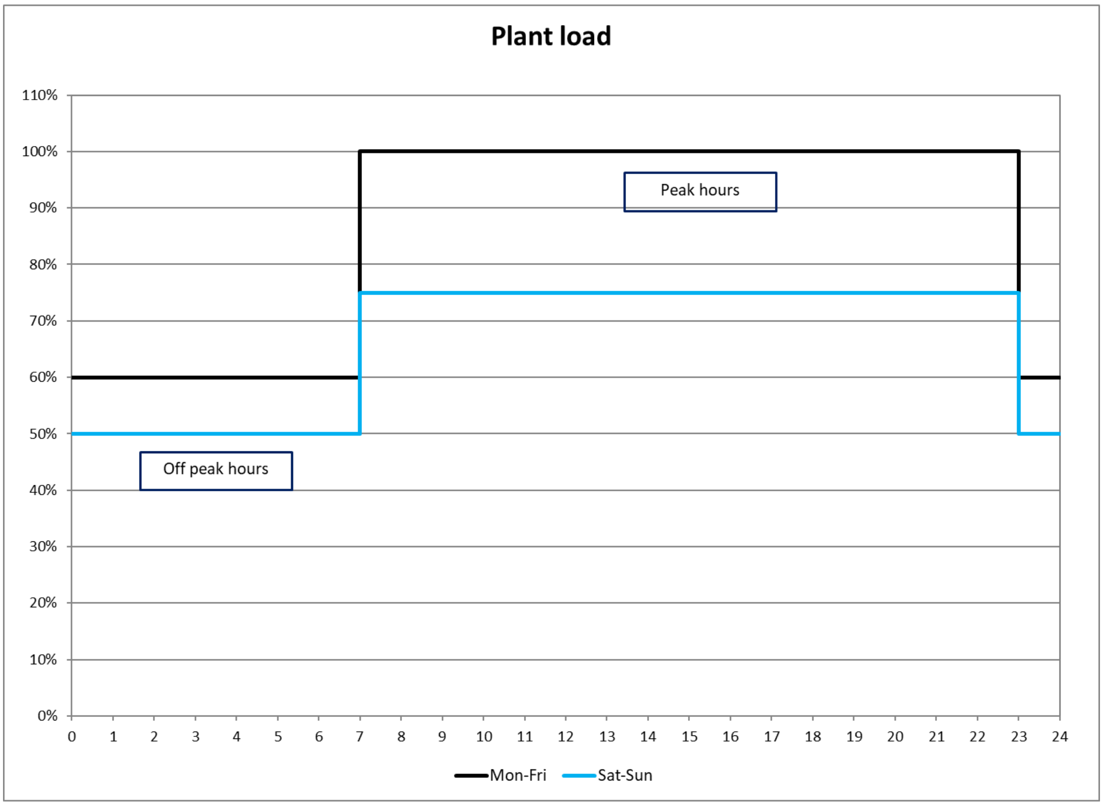

Figure 8. Daily USC PC plant load

Three main approaches to flexible operation improving were considered.

1. To improve flexibility in electric power export to leverage favourable fluctuations in high demand from grid, it is possible to implement a rich/lean solvent storage system. The concept of this system is to keep capturing CO_2 anytime the plant is running but while storing rich solvent during high profitability periods to avoid the energy penalty of regeneration. The stored solvent can then be regenerated during low demands periods. Amount stored is a result of techno-economic considerations according to storage area available and available heat. Different sub-scenarios were developed: in this summary only the scenarios that yielded the lowest and most feasible tank area are presented. Solvent storage can be designed to reduce reboiler size: by tweaking the peak load storage percentages, it is possible to ensure that the amount of storage to be regenerated at any time will be lower than the circulating solvent during 100% load of the capture unit.
2. Due to fluctuations in carbon allowance from an ever-changing regulation on emission, it might happen that it is more economically attractive to not run

CO_2 capture and pay the carbon tax with the strength of more energy sold. To do this, the plant needs to be able to run both in abated and unabated mode. This is achieved by designing the steam turbine to admit the entire steam generation flow, while operating in sliding mode when the capture unit is online and the steam extraction is required.

3. Wood considered a modified demand curve which is more representative of the actual fluctuations in which a 2-hours peak is present at the end of each work day. This is representative of the latest trends where usually a peak is registered at 18:00-20:00, especially due to an increased residential consumption. Peak is assumed to be 15% extra compared to plant base load. It is unlikely that a power plant will be sized for this specific scenario. An alternative could be to integrate a Battery Energy Storage System (BESS) (sized to 430 MWh for the NGCC and 260 MWh for USC PC), which can be charged overnight (in the case of USC PC, by running the plant at extra load than demand).

Table below summarizes the results obtained.

Table 11. Summary of flexibility-improving modifications on power plants with CCS plants

Description	NGCC Case TPC (M€)	NGCC Plant Cost Δ% vs Case 2.1	USC PC Case TPC (M€)	USC PC Plant Cost Δ% vs Case 4.1	Features
Solvent Storage	1709	+1.48%	2452	+1%	- Reduced reboiler size - Leverage of highly profitable selling periods - Issue with excess energy overnight (NGCC only) - Is fitted to a certain demand curve
Variable CO_2 capture	1708	+1.42%	2455	+1.01%	- Leverage of CO_2 allowance fluctuations - Fully operational at offline CCU - Lower efficiency if CCU ON
Energy storage	1990	+18.17%	2635	+8.1%	- Allows to cover short demand peaks without oversizing

Solvent storage looks advantageous but, in the specific case of NG, where plants are expected to be turned off overnight, it introduces issues with excess energy produced overnight while regenerating solvent storage. This issue is not present for USC PC. Moreover, by reducing the reboiler size, the plant is limited in terms of choice of regeneration rate, effectively adding a limiting factor to the operating envelope of the plant by changes over time of the demand curve (effectively reducing operative flexibility).

Design for on/off capture unit involves very little extra CAPEX but is detrimental in terms of normal operation efficiency (provided that normally the CCU is on-line): .by forcing the gas turbine to operate in sliding pressure at reduced steam load than its design during steam export for solvent reclaiming, up to 0.3%-points of net cycle efficiency are lost.

Energy storage is an interesting solution for flexibility as it does not impact plant performance, but the current cost of BESS can make it unattractive if large capacities are required.

As part of the study scope, Wood carried out two specific analyses relate to the operating flexibility of power plant:

1. Evaluate the trade-offs between flexibility and efficiency through a simplified financial analysis;
2. Assess the impacts of higher steam conditions, as used in Advanced USC PC power plants, on operating flexibility.

The following paragraphs report the main results of these specific analyses.

6.1. Advanced USC PC: Impact of steam conditions on plant flexibility

For the execution of this task, Wood tried to get support from various USC PC boilers designers and manufacturers, recognizing that the main possible impact of varying steam conditions in terms of plant flexibility are related to boiler components. Flue gas treatment systems like FGD are not the flexibility bottleneck for the plant and are not impacted by steam cycle conditions. However, the contacted Suppliers have been reluctant in sharing any useful information on this topic, which appears to be considered critical for the further development of the technology.

Hence, Wood has based the review on the limited amount of information available in literature about the progress made on advanced ultra-supercritical steam conditions (700/720 °C HP/RH steam temperature) in coal fired boilers and the potential impacts on plant operating flexibility. It is remarked that this technology is still under development as new alloys are developed and tested.

The plant components that are expected to require new materials due to the enhanced steam conditions are highlighted in Figure 9.

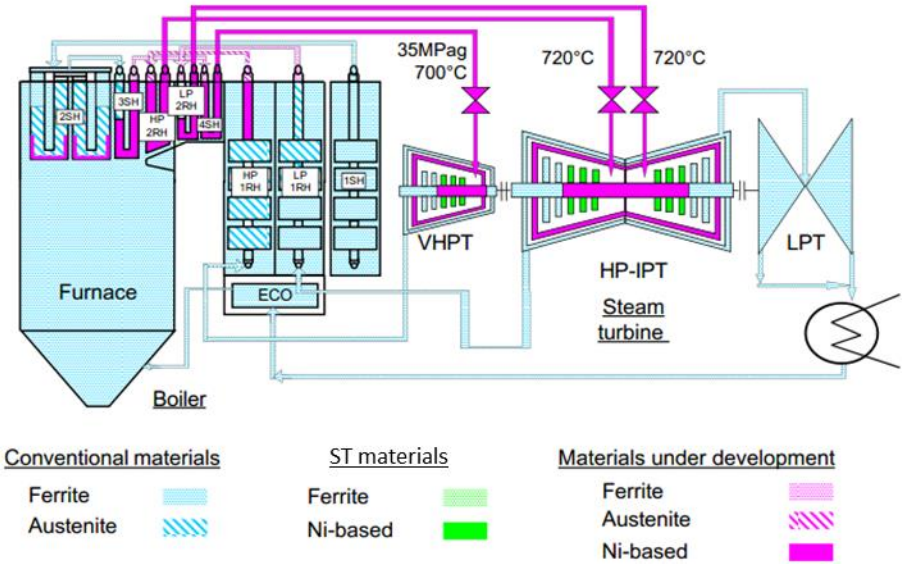

Figure 9. Figure from M. Fukuda, Advanced USC technology development in Japan. Elsevier Ltd, 2016, depicting the areas (purple) that are impacted by A-USC conditions.

Preliminary results of the research effort show that, due to Ni-based alloys having lower conductivity and higher thermal expansion coefficient, thermal stresses within thick-walled tubes are potentially higher. This forces ramp up times to be slower than current state-of-art USC PC plants, leading to worse flexibility, as shown by the increase of plant start-up times (+35% for cold start up, +45% for warm and +13% for hot)

It is possible that in future severe steam conditions plants will be pursued only when the highest possible efficiency is desired, while standard USC PC designs will remain the choice for flexible operation within a grid demand scenario of high variability (due to renewables like solar and wind that can fluctuate heavily in energy production according to weather).

6.2. Trade-offs between flexibility and efficiency in coal fired power plants

A specific analysis has been carried out for coal fired power plants to evaluate the trade-off between flexibility and efficiency. In fact, all the analysed solutions to enhance operating flexibility are based on modifications to the design and the operating approach of the plant in order to maximize power production during peak time (when electricity price should be high) by penalising plant efficiency during off-peak time (when electricity price should be low).

The qualitative and quantitative analysis has assessed the economic attractiveness of the technical solutions, i.e. in terms of pay-back time of the associated extra-CAPEX to enhance operating flexibility, for various simulated scenarios of the electricity market.

The following four market scenarios are considered:

Table 12. Considered market scenario prices

Market Scenarios (prices in €/MWh)		
	LOW variability of electricity price between peak and off-peak	**HIGH variability of electricity price between peak and off-peak**
LOW price level	**Scenario L1** Peak: 70 Off-peak (working): 60 Weekend: 55	**Scenario L2** Peak: 70 Off-peak (working): 50 Weekend: 40
HIGH price level	**Scenario H1** Peak: 90 Off-peak (working): 75 Weekend: 65	**Scenario H2** Peak: 90 Off-peak (working): 60 Weekend: 40

It is remarked that the magnitude of the gap between peak time and off-peak time prices may be representative of the penetration of renewable energy sources (especially solar) in the electricity market, with their lower availability to produce power during off-peak periods (typically in the night-time).
Regarding price level, the low level is intended to roughly represent current average wholesale market price in EU. For power plants with CO2 capture, the high scenario can be instead interpreted as a scenario where the CO2 capture is more adequately remunerated.

For each market scenario a sensitivity has been carried out regarding carbon pricing for the Variable Capture option, in which carbon pricing is used to assess the penalties of not capturing the CO2 during peak time.
The following carbon price levels have been used:

- LOW: 10 €/t;
- MEDIUM: 25 €/t;

- HIGH: 40 €/t.

For each flexibility case, the simplified financial calculation of the pay-back is based on differential CAPEX with respect to reference case, and differential OPEX (cost and revenues). The differential OPEX is calculated considering the changes in revenues, variable costs and maintenance costs.

The main results are shown in the following table.

Table 13. Financial results summary according to market scenario

			Market scenarios			
			L1	L2	H1	H2
Case 4.1a - Scenario 1	Delta CAPEX	M€	85.8	85.8	85.8	85.8
	Delta OPEX*	M€/y	13.5	11.3	20.3	16.8
	Pay-back time	years	7.0	7.7	4.3	5.2
Case 4.1a - Scenario 2	Delta CAPEX	M€	14.5	14.5	14.5	14.5
	Delta OPEX*	M€/y	8.9	7.6	13.1	10.9
	Pay-back time	years	2.0	2.0	1.2	1.4
Case 4.1b - LOW carbon tax	Delta CAPEX	M€	17.8	17.8	17.8	17.8
	Delta OPEX*	M€/y	27.6	27.7	44.6	44.8
	Pay-back time	years	1.0	0.7	0.4	0.4
Case 4.1b - MEDIUM carbon tax	Delta CAPEX	M€	17.8	17.8	17.8	17.8
	Delta OPEX*	M€/y	-19.8	-19.7	-2.8	-2.6
	Pay-back time	years	N/A	N/A	N/A	N/A
Case 4.1b - HIGH carbon tax	Delta CAPEX	M€	17.8	17.8	17.8	17.8
	Delta OPEX*	M€/y	-67.2	-67.1	-50.2	-50.0
	Pay-back time	years	N/A	N/A	N/A	N/A
Case 4.1c	Delta CAPEX	M€	197.9	197.9	197.9	197.9
	Delta OPEX*	M€/y	-0.2	-0.2	1.1	1.1
	Pay-back time	years	N/A	N/A	185.2	184.1

** A positive figure indicates an increased operating margin (revenues minus costs) with respect to the reference non-flexible case*

The following remarks can be drawn from the analysis results:

- The flexibility case showing the best attractiveness from a simplified financial standpoint is Case 4.1a – Solvent Storage Scenario 2, independently of the market scenario considered. It is remarked that this case is characterized by a sensible reduction of the regeneration section sizing in the CO2 capture unit, i.e. 12% decrease. Consequently, on one hand the plant is flexible with respect to the assumed electricity demand curve, but, on the other hand, the downsizing of the regeneration could represent a significant operating constraint in case the demand curve changed.

- The variable capture (On/Off) option (case 4.1b) is very sensitive to the considered carbon pricing level. The pay-back time is excellent only in the Low carbon pricing scenario, whereas in the Medium and High carbon pricing scenarios the additional investment is not paid back at all.

- Case 4.1c (Energy Storage via batteries) has a very high additional CAPEX, which is not paid back in the modeled market scenario and it is expected to be very difficult to pay back in any market scenarios. The specific cost of battery storage is still unattractive, especially at the large scales considered in this study. The attractiveness of this option, as studied in the present work, strictly relies upon future cost improvements of this technologies.

- The financial performance of the cases tends to improve at higher electricity price levels, as the beneficial effects of flexibility are amplified at higher electricity selling prices.

- The results of the analysis are marginally sensitive to the magnitude of price variability between peak-time and off-peak time, as a significant portion of the revenues from electricity sale is concentrated during peak-time as per considered weekly demand curve.

7. Outlook of future power generation technological improvements

7.1. Improvements of natural gas-fired power plants

Wood predicted the impact of three different mid-term technological improvements that might be marketed in the near future. In this section the results are briefly discussed. Department of Energy of Politecnico di Milano was involved with the development of these scenarios. These technologies were selected based on their current development status and perceived likelihood to find large-scale applications in a mid-term future.

7.1.1. *Improvements in GT materials*

Following recent R&D focus from NASA, Rolls Royce and other companies, given the recent progresses in the development of new materials suitable for gas turbines, it is reasonable to assume that in a near-term future heavy-duty GTs will employ CMC (Ceramic Matrix Composite) materials for the first-stage stator and rotor blades and fourth generation Ni-based single crystal blades for the downstream cooled stages. Compared to the reference H-class gas turbine, it is assumed that adopting CMC materials allows increasing the average material temperature of the first stage blades by 150 °C. As far as the subsequent cooled states are concerned, an average blade metal temperature increase of 50 °C is assumed with the use of more advanced single crystal materials. This allows to employ higher compression ratio and higher TIT, increasing GT efficiency.

Based on this, performance of future gas turbines has been predicted and a 2xGT, 2xHRSG and 1xST combined cycle designed around it.
In unabated power production, the new cycle has shown a +2.3%-points increase in net electrical efficiency compared to case 1. Provided with a 98.5% recovery rate CANSOLV capture unit, the new plant recorded a +2.2%-points increase in net electrical efficiency compared to case 2.1.

7.1.2. *SCOC CC – Oxy-fired gas turbines*

Wood updated the findings presented in IEAGHG report 2015/05 *"Oxy-combustion turbine power plants"* with the new class H gas turbine technologies. In the newly designed plant, two generic H-class GTs fitted for oxy-combustion are equipped with one HRSG each to feed a common ST. Oxygen is provided by a cryogenic distillation air separation unit (ASU) and CO_2 recovery is performed via cryogenic separation.

The resulting net electrical efficiency is 50.9% on a LHV basis, while TPC, LCOE and CAC are respectively 1931 M€ 80.5 €/MWh and 100.2 €/t. Compared to the figures presented in IEAGHG Report 2015/05 for the SCOC-CC (which resulted in an LCOE of 92.8 €/MWh and a CAC of 97.9 €/tCO2), LCOE decreased by more than 13% while the CAC increased by 2.3%. While this is a significant progress in LCOE reduction, the advancements are limited to the gas turbine/combined cycle section. This is the reason why no significant benefits are found in the CAC. Also, compared to the base CO2 capture options, there is still a significant gap in techno-economic performance. The significant quantity of oxygen required hinders the plant performance and economics due to a large and expensive (both economically and energetically) ASU.

7.1.3. *Molten carbonate fuel cells*

Molten carbonate fuel cells allow to use the CO_2 in GT exhaust gases for energy production, provided that a source of hydrogen is guaranteed (in the presented case, natural gas and steam were used for steam reforming).

In particular, Molten Carbon Fuel Cells (MCFCs) are suitable for high temperature applications, being able to use carbon oxides as “fuels” and achieving the best in class efficiency. Their reaction mechanism allows to perform red-ox reactions on CO_2 to produce energy, provided that the cell is fed with H_2 in some way. In particular, an integration with combined cycles recently started development in which hydrogen is provided via natural gas steam reforming (performed by MCFC waste heat) and the cell, besides contributing to power generation, allows to separate CO_2 from the flue gas in a stream which needs a relatively simple purification method (like cryogenic technology). The recovered syngas (mainly H2 and CO) can be re-employed as auxiliary fuel.
The simplified flow scheme of the adopted plant configuration is shown in Figure 10.

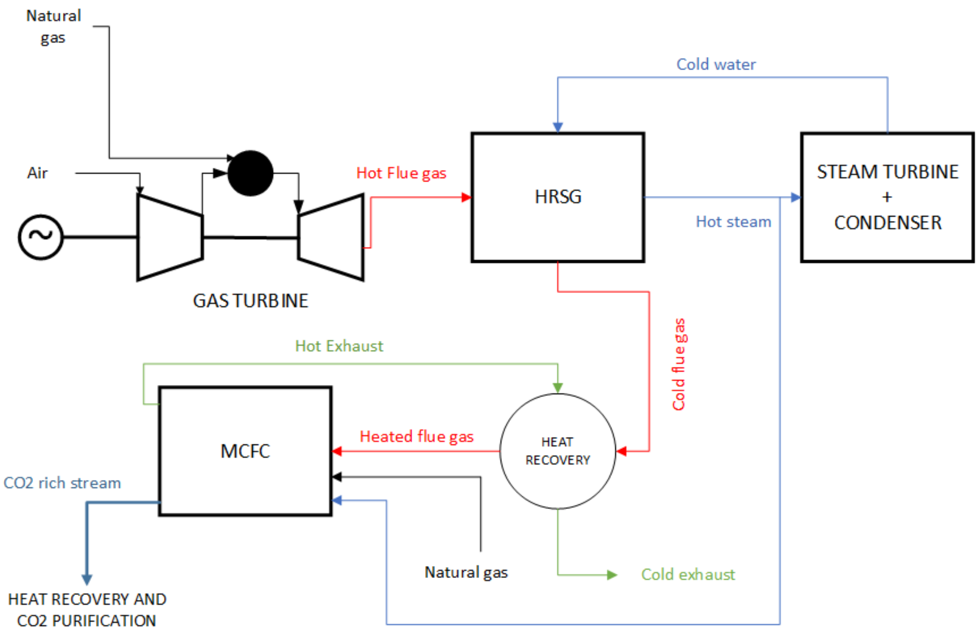

Figure 10. Simplified "retrofit" scheme of a GT+MCFC combined cycle

This design shows a power output of 1727.5 MWe of power output with a 57.7% efficiency. This drives a very promising techno-economic performance, with an LCOE of 64.4 €/MWh.

While there are currently no MCFC installations at this scale and this study did not delve into engineering related issues, the results are promising, and it will be worth to further develop the technology to overcome the engineering challenges of its realization.

8. Summary of study findings

The primary conclusions of the technical and economic assessments made in this study are given in this section.

No difference in performance was evident in ultrasupercritical pulverised coal plants compared to IEAGHG Report 2018/4, as no significant consolidated technology progress has been achieved. Financial figures remained close to those previously presented: the resulting LCOE of 53.3 €/MW for unabated design and of 97.3 €/MW for 90% translate in a 1÷2% increase from the previous work.the increase being smoothed by the lower price for limestone and coal as per agreed design basis, which heavily favours financial results despite the higher CAPEX: (capital investment and specific costs increased by 8%). To pursue better performances, a more rapid transition to advanced USC conditions is required, bearing in mind that this could have an impact on operating flexibility, which is regarded as valuable in the contemporary energy market. Due to the amount of CO_2 in coal-based plants flue gas, carbon capture and storage brings a large impact on LCOE (from no capture plant to a 90% recovery capture unit the LCOE increases by more than 80%).

H-class GT developments brought a 1%-point efficiency improvement. Compared to the results of IEAGHG 2018/4, despite the lower estimated specific investment cost (approx. -5%), the agreed basis on economic parameters (namely cost of maintenance and of natural gas) did not allow to obtain a better baseline LCOE (48.2 €/MW) than the value presented in the previous work, resulting in a higher LCOE by 1÷3% across the board. The perceived improvement of the cost of CO_2 avoided is attributable to the higher reference LCOE (i.e. without CCS).

For both Natural gas and Coal fired plants, increasing the CO_2 recovery from 90% to very high capture rates yielded a relatively small increase in CO_2 avoidance cost: for NGCC cases the CAC increased by 5%, while for USC PC cases a 4.3% increase is found. This highlights that pushing for more aggressive carbon capture rates can be advantageous.

Regarding NGCC plants, the results of specific analyses show that:

- Flue gas recirculation proves to be an effective design option in reducing costs associated with carbon capture and storage; the partial (approx.. 50%) recirculation of the exhaust gas to gas turbine inlet, to raise CO_2 content and treat lower flue gas flowrates, lead to substantial savings in the capture unit

CAPEX and OPEX. For both capture rate scenarios, a decrease of 2÷3% in LCOE is appreciated, whilst the CAC is reduced by 8÷12%.

- Looking at possible future developments to improve the techno-economic performance of NGCC plants with CCS, three options have been investigated:
  a) Regarding new material developments applicable to GTs, the assumption related to the use of CMC materials for the first stage blade and fourth generation Ni-based single crystal blades for the downstream cooled stages leads to an increase in net electrical efficiency compared to reference cases of +2.3%-points for the unabated case and +2.2%-points for the abated case at 98.5% capture rate.
  b) Oxy-fuel gas turbine designs (SGOCC) benefit from the technology advancement, especially in terms of LCOE with a reduction of 13% (whilst the CAC is basically unchanged as the technology advancements are mainly related to the combined cycle), but, compared to the base CO_2 capture options, are still hindered by prohibitive costs for oxygen supply due to large and energy-consuming air separation units.
  c) The integration of Molten Carbon Fuel Cells with the Combined Cycle increases the power output and allows efficient CO_2 capture in the fuel cells, at the energetic expense of additional Natural gas consumption. This design shows brilliant performances at 1727.5 MWe of power output with a 57.7% efficiency. This drives a promising techno-economic performance, with an LCOE of 64.4 €/MWh.

An update of the key findings of previous works for IEAGHG around the options to improve operating flexibility of fossil fuel power plants with CO_2 capture has been also carried out.
Solvent storage in the CO_2 capture unit looks advantageous but, in the specific case of NG, were plants are expected to be turned off overnight, it introduces issues with excess energy produced overnight while regenerating solvent storage. This issue is not present for USC PC plants that are expected to turn-down overnight. Moreover, by reducing the reboiler size, the plant is limited in terms of choice of regeneration rate, effectively adding a limiting factor to the operating envelope of the plant in case of changes over time of the demand curve (effectively reducing operative flexibility).
Designing for an on/off capture unit involves very little extra CAPEX but is disadvantageous in terms of normal operation efficiency (provided that normally the CCU is on-line). Also, the attractiveness of this option is expected to be strictly related to the carbon pricing level, which is a measure of the penalties associated to leverage on the possibility not to capture the CO_2 during peak-time.

Energy storage is an interesting solution for flexibility as it does not impact plant performance, but the current cost of BESS currently makes it unattractive for large capacities considered in this study.

Regarding operating flexibility of coal power plants, Wood has carried out two specific analyses, leading to the following main outcome:

- Preliminary results of a literature review around the impacts of enhanced steam conditions, as per Advance USC PC plants design, onto operating flexibility show that, due to lower conductivity and higher thermal expansion coefficient of the required materials (i.e. Ni-based alloys), thermal stresses within thick-walled tubes are potentially higher. This drives slower ramp up times than current state-of-art USC PC plants, leading to worse flexibility, as shown by the increase of plant start-up times (+35% for cold start up, +45% for warm and +13% for hot). It is envisaged that in future plants with severe steam conditions will be pursued only when the best possible efficiency is desired, while more conventional USC PC designs will remain the choice for flexible operation within a grid demand scenario of high variability (due to renewables like solar and wind that can fluctuate heavily in energy production according to weather).
- In terms of trade trade-off between operating flexibility and efficiency, all the solutions analysed in the study to enhance operating flexibility are based on modifications to the design/operation of the plant in order to maximize power production during peak time by penalising plant efficiency during off-peak time. The flexibility case showing the best attractiveness from a simplified financial standpoint is the Solvent Storage, in the scenario where the regeneration sizing reduction is the highest possible (i.e. 12%), with pay-back times in the range of 1÷2 years. It is again remarked that, with this option,on one hand the plant is flexible with respect to the assumed electricity demand curve, but, on the other hand, the downsizing of the regeneration could represent a significant operating constraint in case the demand curve changed. Also, it is confirmed that the variable capture (On/Off) option is very sensitive to the considered carbon pricing level. The pay-back time is excellent only in the Low carbon pricing scenario, increasing steeply as far as the assumed carbon pricing is raised.

  Energy Storage via batteries has a very high additional CAPEX, which is not paid back in the modelled market scenarios. The specific cost of battery storage is still unattractive, especially at the large scales considered in this study. The attractiveness of this option strictly relies upon future cost improvements of this technologies.

It is highlighted that the financial performance of the cases tends to improve at higher electricity price levels, whilst it is marginally sensitive to the magnitude of price variability between peak-time and off-peak time.

CLIENT	:	IEAGHG
PROJECT NAME	:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO_2 CAPTURE
DOCUMENT NAME	:	GENERAL INFORMATION
CONTRACT N°	:	1-BD-1046 A

ISSUED BY : N. FERRARI
CHECKED BY : P. COTONE
APPROVED BY : P. COTONE

Date	Revised Pages	Issued by	Checked by	Approved by

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GLOSSARY

CCS	Carbon Capture and Storage
NGCC	Natural Gas Combined Cycle
USC PC	Ultrasupercritical Pulverised Coal
FGR	Flue Gas Recirculation
EGR	Exhaust Gas Recirculation
CCU	Carbon Capture Unit
CMC	Ceramic Matrix Composite
ASU	Air Separation Unit
MCFC	Molten Carbonate Fuel Cell
TPC	Total Plant Cost
TIC	Total Installed Cost
MEL	Minimum Environmental Load
GT	Gas Turbine
ST	Steam Turbine

1. Background and objective of the study

Carbon capture and storage (CCS) has long been recognised as a key component of an effective mitigation strategy to decarbonise the power and industrial sectors. For many reasons, however, the commercial deployment of CCS has been slow and must accelerate if the technology is to achieve its potential and contribute effectively to mitigating climate change.

Much effort in recent years has been focused on improving the technical performance of plants with CO_2 capture, targeted particularly at integrating the host plant with the capture equipment and at reducing the associated energy penalty. Importantly, effort has also been focused on reducing the capital and operating costs of CO_2 capture.

With these premises, IEAGHG has contracted Amec Foster Wheeler Italiana, a Wood Company, to perform a technical and economical assessment of coal and natural gas fired power plants, taking into account the benefits of recent technology improvements.

The study has focused on *ultra-supercritical pulverised coal (USC PC) boiler* and *natural gas combined cycle (NGCC)* power plants, with and without CO_2 capture. *Post combustion capture based on solvent scrubbing* only has been considered within this study, which is currently the commercially leading option for capture at both pulverised coal and natural gas fired power plants.

HOLD, to be completed later

1.1. Structure of the report

The study report is structured as follows:

Chapter A: Executive summary

Chapter B: General information for the plant design, including process design criteria and Basic Engineering and Design Data (BEDD), cost estimating criteria and methodology and main definition and basis for financial evaluation.

Chapter C: General description of the common process units of the NGCC plants with and without capture, including key information on NGCC plant capability to operate flexible and efficiently in the new electricity market.

Chapter C.1: Basic engineering information specific of the reference NGCC case without CO_2 capture, including plant performance, heat and mass balances, utility consumption summaries environmental impact and equipment summary.

Chapter C.2: Basic engineering information specific of the reference NGCC cases with CO_2 capture, including plant performance, heat and mass balances, utility consumption summaries environmental impact and equipment summary. Reference case with 90% CO_2 capture and high capture case are included and compared in this chapter.

Chapter C.3: Basic engineering information specific of the NGCC with flue gas recirculation cases, including plant performance, heat and mass balances, utility consumption summaries environmental impact and equipment summary. Two cases with 90% CO_2 capture and high capture case are included and compared in this chapter.

Chapter C.4: Details of the investment cost estimate, the operating and maintenance costs and the financial modelling results for the NGCC cases of the study.

Chapter C.5: Assessment of the options to improve operating flexibility of NGCC with CO_2 capture.

Chapter C.6: Assessment of on-going developments and the potential for further improvements in performance and costs of these plants.

Chapter D: General description of the common process units of the USC PC plants with and without capture, including key information on USC PC plant capability to operate flexible and efficiently in the new electricity market.

Chapter D.1: Basic engineering information specific of the reference USC PC case without CO_2 capture, including plant performance, heat and mass balances, utility consumption summaries environmental impact and equipment summary.

Chapter D.2: Basic engineering information specific of the reference USC PC case with CO_2 capture, including plant performance, heat and mass balances, utility consumption summaries environmental impact and equipment summary. Reference case with 90% CO_2 capture and high capture case are included and compared in this chapter.

Chapter D.3: Details of the investment cost estimate, the operating and maintenance costs and the financial modelling results for the USC PC cases of the study.

Chapter D.4: Assessment of the options to improve operating flexibility of USC PC with CO_2 capture.

Chapter D.5: Literature review and discussion of the impact on boiler design and flexibility of varying steam generation conditions, with a focus on advanced ultrasupercritical steam conditions.

2. Study cases

The list of the cases assessed in the study are presented hereafter, including the key technology features selected for the development of the reference cases, together with the chapter of the report where each case is discussed. Reference NGCC plants are listed in

Table 1, while Table 3 lists the reference USC PC cases main features.

Table 1. NGCC-based reference study cases

Reference Case	Chapter	Description	Key features
Case 1	C.1	NGCC w/o CCS	• Two generic H-class gas turbines • One common steam turbine • Cooling system based on natural draft cooling tower
Case 2	C.2	NGCC with CCS	• Two generic H-class gas turbines • One common steam turbine • CANSOLV post-combustion capture • Cooling system based on natural draft cooling tower • 90% capture rate
Case 2.1	C.2	NGCC with CCS – High capture case	• Two generic H-class gas turbines • One common steam turbine • CANSOLV post-combustion capture • Cooling system based on natural draft cooling tower • 98.5% capture rate

Table 2. NGCC-based sensitivity study cases

Sensitivity Case	Chapter	Description	Key features
Base load cases			
Case 2.2	C.3	NGCC with flue gas recirculation	• FGR recirculation ratio: 50% (1) • Capture rate: 90%
Case 2.3	C.3	NGCC with flue gas recirculation	• FGR recirculation ratio: 50% (1) • Capture rate: 98.5%
Improving flexibility of NGCC power plants with CCS			
Case 2.1a	C.5	NGCC with CCS and solvent storage	• 98.5% capture rate • Lean/rich solvent storage system
Case 2.1b	C.5	NGCC with ON/OFF CCS	• 98.5% capture rate • Capable of unabated power production
Case 2.1c	C.5	NGCC with CCS and BESS	• 98.5% capture rate • 430 MWh battery energy storage system
Mid-term future advancements in NGCC power plants			
Case 2.4	C.6	Advancements in GT materials	• Case 1 configuration • Two generic next-gen GT
Case 2.5	C.6	Oxy-fired NGCC with CCS	• Two generic oxy-fired gas turbines based on H-class • One common steam turbine • Cryogenic post-combustion carbon purification
Case 2.6	C.6	NGCC with MCFC	• Two generic H-class gas turbines • One common steam turbine • Use of Molten Carbonate Fuel Cells in combined cycle • Cryogenic post-combustion carbon purification • Standard class H GT

Note:
1) Flue gas recirculation ratio = Flue gas recirculation flowrate / Total flue gas from HRSG
2) Flexibility cases are developed considering Case 2.1 as reference case

Table 3. USC PC boiler-based reference study cases

Reference Case	Chapter	Description	Key features
Case 3	D.1	USC PC boiler w/o CCS	• Generic state-of-art supercritical USC PC boiler • Wet limestone scrubbing FGD • Cooling system based on natural draft cooling tower
Case 4	D.2	USC PC boiler with CCS	• Generic state-of-art supercritical USC PC boiler • Wet limestone scrubbing FGD • CANSOLV post-combustion capture • Cooling system based on natural draft cooling tower • 90% capture rate
Case 4.1	D.2	USC PC boiler with CCS - High capture case	• Generic state-of-art supercritical USC PC boiler • Wet limestone scrubbing FGD • CANSOLV post-combustion capture • Cooling system based on natural draft cooling tower • 99% capture rate

Table 4. USC PC boiler-based sensitivity study cases

Reference Case	**Chapter**	**Description**	**Key features**
Improving flexibility of USC PC power plants with CCS			
Case 4.1a	D.4	USC PC boiler with CCS and solvent storage	• Case 4.1 configuration • 99% capture rate • Lean/rich solvent storage system
Case 4.1b	D.4	USC PC boiler with ON/OFF CCS	• Case 4.1 configuration • 99% capture rate • Capable of unabated power production
Case 4.1c	D.4	USC PC boiler with CCS and BESS	• Case 4.1 configuration • 99% capture rate • 260 MWh Battery Energy Storage System
Mid-term future improvements on coal-fired boiler technology			
-	D.5	Impact of steam conditions on PC boiler design and flexibility	• Literature review • 99% capture rate • 260 MWh Battery Energy Storage System

Note:

3) For all flexibility cases, reference comparison case is case 4.1

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 site 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 5.

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 5. 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 the main fuel for the NGCC based power plants and it is used also as start-up or plant back-up fuel for the coal based power station. Natural gas is delivered to the plant battery limits from a high pressure pipeline.

The main characteristics of the natural gas are shown in the following Table 6.

Table 6. 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. *Limestone*

A reactive, amorphous limestone, whose composition is shown in the below table, is assumed for the design of the Flue Gas Desulphurization system, this latter based on the wet scrubbing technology for the coal fired power plant study cases.

	% 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 (cases with CO_2 capture)*

Plants are designed for a capture rate not less than 90% in the reference case and capture rate close to 99% for the high capture rate.

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

Table 7. CO_2 characteristics

CO_2 conditions at plant B.L.	
Pressure, MPa	11
Normal 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.

3.5. 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):

	USC PC based cases (1)	**NGCC 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	(3)
CO	-	≤ 100 mg/Nm^3
Particulate	≤ 10 mg/Nm^3	(3)

Note: (1) Emission expressed in mg/Nm^3 @6% O_2, dry basis.
(2) Emission expressed in mg/Nm^3 @ 15% O_2 volume dry
(3) Not included in the EU directive as assumed negligible in gas turbine plants

The "*Commissioning implementing decision 2017/1442 establishing best available techniques (BAT) conclusions, under Directive 2010/75/EU of the European Parliament and of the Council, for large combustion plants*" is also considered, as described below.

USC PC plant

According to the above document, the following BAT-associated emission levels (BAT-AELs, daily average) for emissions to air shall be targeted for new USC PC boiler based plant, with rated capacity higher than 300 MWth.

- NOx: 80 – 125 mg/Nm^3 @6% O_2, dry basis
- SOx: 25 – 110 mg/Nm^3 @6% O_2, dry basis
- Dust: 3 – 10 mg/Nm^3 @6% O_2, dry basis
- Mercury: 1 – 2 mg/Nm^3 @6% O_2, dry basis

NGCC plant

According to the above document, the following BAT-associated emission levels (BAT-AELs, daily average) for emissions to air shall be targeted for new NGCC plant, with rated capacity higher than 50 MWth.

- NOx: 15 – 40 mg/Nm^3 @15% O_2, dry basis
- CO: 5 – 30 mg/Nm^3 @15% O_2, dry basis. For plants with a net electrical efficiency (EE) greater than 55 % (as in the present study), a correction factor may be applied to the higher end of the range, corresponding to [higher end = 30] × EE/55, where EE is the net electrical energy efficiency of the plant determined at ISO baseload conditions.

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.

Apart from the cooling water system effluent, the process units of the plant do not produce significant liquid wastes. Blowdown streams from steam cycle, CO_2 removal unit scrubber and FGD are generally treated in a dedicated system to recover water to be recycled back to the plant as cooling tower make up, where possible, or discharged to the final receiver.

3.5.3. *Solid wastes*

The solid wastes of the USC PC-based cases are mainly:

- Bottom ash
- Fly Ash.

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

No significant solid waste is foreseen for the NGCC plant.

3.5.4. *Noise*

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

3.6. USC-PC-based cases: key features

3.6.1. Capacity

The nominal net power output of the reference USC PC plant 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 is same as 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 (only for plant with capture)
Unit 5000	CO_2 compression and dehydration (only for plant with capture)
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 and valves and steam ejectors are properly designed to meet the turndown. In any case also lower turndown can be accepted if the power plant is expected to operate at base load most of the time.

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 the chapter D.3 of the present study.

3.7. NGCC - key features

3.7.1. Capacity

The plant capacity of the cases with and without CCS is selected in order to fully load two (2) heavy duty H-class gas turbines.

3.7.2. Unit Arrangement

Unit 3100 Gas Turbine
Unit 3200 HRSG
Unit 3300 Steam Turbine
Unit 4000 CO_2 Amine Absorption (only for plant with capture)
Unit 5000 CO_2 compression (only for plant with capture)
Unit 6000 Utility & Offsite.

3.7.3. Minimum turndown

Gas Turbines can run at full-speed-no-load. However, the minimum load at which the gas turbine is able to operate, still meeting the environmental limits, in particular NO_X and CO emissions, is around 30-40%, depending on GT supplier.

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

For further details on minimum plant turndown and plant capability to operate flexible and efficiently at part load reference shall be made to chapter C.4 of the present study report.

3.8. 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
USC PC based	1st year of operation	65%
	2nd year of operation	85%
	3rd – 25th year of operation	90%
NGCC based	1st year of operation	75%
	2nd year of operation	89%
	3rd – 25th year of operation	93%

3.9. Cost estimating bases

The plant cost in this study is presented as Total Capital Requirement (TCR) and Total Plant Cost (TPC), in 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.

This section provides the definitions of the TCR and the TPC and of the detailed methodology applied for their definition. Main bases considered for the financial analysis are also reported.

3.9.1. Definitions

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.

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.

3.9.2. Currency

The estimate is in euro (€), based on 3Q2018 price level.

3.9.3. *Estimate accuracy*

Estimate accuracy is in the range of +35%/-15% (i.e. Class IV in accordance with AACE International Cost Estimate Classification System described in the following Table 6).

Table 8. Cost estimate classification matrix for the process industries
Ref. AACE International Recommended Practice No. 18R-97

ESTIMATE CLASS	**LEVEL OF PROJECT DEFINITION** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in Low and High ranges
Class 5	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgment or Analogy	Low: -20% to -50% High: +30% to +100%
Class 4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	Low: -15% to -30% High: +20% to +50%
Class 3	10% to 40%	Budget, Authorization or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	Low: -10% to -20% High: +10% to +30%
Class 2	30% to 70%	Control or Bid/Tender	Detailed Unit Cost with Forced Detailed Take-Off	Low: -5% to -15% High: +5% to +20%
Class 1	50% to 100%	Check estimate or Bid/Tender	Detailed Unit Cost with detailed Take-Off	Low: -3% to -10% High: +3% to +15%

3.9.4. *TPC estimating methodology*

The estimating methodology used by Wood for the evaluation of the Total Plant Cost (TPC) items of the process units is described in the following sections.

Reference cases cost estimate

The investment cost estimate of the reference cases has been derived from the data contained in the reference IEAGHG report 2018/4 "*Effect of plant location on CO_2 capture*". The cost is updated to reflect any of the technical modifications of the benchmark cases, as resulting from the market investigation done for the latest GT performances, the different steam conditions in the USC PC case and any update in the CO2 capture plant.

Cost level escalation is applied from the reference estimate cost level of 3Q2016 based on Wood in-house multiplicative factors. The methodology applied for the definition of the TPC of the reference study is described hereafter.

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.

Further details are enclosed in the reference IEAGHG report 2014/3 "*CO_2 capture at coal based power and hydrogen plants*".

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 Wood 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 Wood experience and in-house data bank.

Process contingency

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.

Sensitivity cases cost estimate

On the basis of a case-specific sized equipment list, showing equipment or unit added or modified with respect to the reference case, the investment cost of direct materials is evaluated by means of program runs performed with K-Base and for similar units, by scaling up or down (as applicable) the cost on capacity ratio. For the other costs (construction, engineering, etc.) the same percentages with respect to the direct materials as per the reference cases is applied.

3.9.5. *Project contingency*

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

For the accuracy considered in this study, Wood view is that contingency should be in the range of 10-15% of the total plant cost in The Netherlands. 10% is assumed for this study for all the different units of the plant, for consistency with the reference IEAGHG report 2014/3 "*CO_2 capture at coal based power and hydrogen plants*".

3.10. Financial analysis and TCR calculation bases

3.10.1. *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.

	USC PC cases / NGCC cases
Construction period (1)	3 years
Curve of capital expenditure	
Year	Investment cost %
1	20
2	45
3	35

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

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

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

3.10.3. *Discount rate*

Discount cash flow calculations are expressed at a discount rate of 8% for the reference plant.

3.10.4. *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.

3.10.5. *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.

3.10.6. *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.

3.10.7. *Start-up cost*

Start-up costs consist of:

- 2% 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.

3.10.8. *Owner's cost*

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.

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

3.10.9. *Insurance cost*

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

3.10.10. *Local taxes and fees*

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

3.10.11. *Decommissioning cost*

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.

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

Fixed operating costs 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 9 below.

Table 9. Feedstock and utilities cost

Item	Cost	Sensitivity
Coal, €/GJ (LHV)	2.5	1 – 4
Natural gas, €/GJ (LHV)	6	3 – 12
Limestone, €/t	20	
Raw water, €/m^3	0.2	
Ash and gypsum disposal cost, €/t	0	

3.11.2. *CO_2 related costs*

Reference figure for CO_2 transport and storage and CO_2 emission cost are listed below.

Item	Cost
CO_2 transport and storage, €/t CO_2 stored (1)	10
CO_2 emission cost, €/t CO_2 emitted	0

The reference cost for the CO_2 transport and storage is specified 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.

However, costs of CO_2 transport and storage are expected to differ substantially depending on the proximity to and the nature of storage sites and opportunities for EOR. A sensitivity to the overall costs of CO_2 transport and storage will be evaluated, taking also into account 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. net costs for EOR.

3.11.3. *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:

USC PC based cases	1.5%
NGCC based cases	2.2%

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.

USC 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 or FF)
  - Flue gas stack
- Flue Gas Desulphurisation, including gas-gas heat exchanger
- DeNOx system
- CO_2 capture plant (only for cases with capture)
- CO_2 compression and drying (only for cases with capture)

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

NGCC plant with / without post-combustion capture

Power Island, including:

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

Process Units, only for cases with capture, including:

- CO_2 capture plant
- CO_2 compression and drying

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

- Primary Cooling System (cooling tower, air cooling, sea water once through system) and Machinery Cooling Water systems;
- Demineralized, Condensate Recovery, Plant and Potable Water Systems;
- Back-up fuel system;
- Plant & Instrument Air systems;
- Waste Water Treatment;
- Firefighting system;
- Chemicals;
- 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

Reference is to be made to above section 3.4.1.

4.2.2. Process and utility streams

USC PC power plants with / without post-combustion capture

- Coal;
- FGD sorbent/FGD by-product/ashes;
- Natural gas;
- Waste water streams;
- Plant/Raw/Potable water;
- CO_2 rich stream (only for the cases with capture);
- Cooling tower make-up water / cooling tower blow-down

NGCC plant with post-combustion capture

- Natural gas;
- Plant/Raw/Potable water;
- CO_2 rich stream (only for the cases with capture);
- Cooling tower make-up water / cooling tower blow-down

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 System

Cooling tower, with fresh water make-up

Cooling water minimum approach to wet bulb temperature
- Natural draft (USC PC plant): 7 °C

Normal supply temperature
- Natural draft (USC PC plant): 15 °C

Primary system

Source : raw water in closed loop from cooling towers.
Service : for steam turbine condenser and CO_2 compression exchangers.

Operating pressure at condenser inlet:	3.0 bar
Mechanical design pressure:	6.0 bar
Maximum allowable ΔP for condenser:	0.5 bar
Maximum temperature difference at condenser:	11°C
Mechanical design temperature:	50°C
Turbine condenser minimum ΔT:	3°C
Turbine condenser conditions (USC PC)	
Temperature	29°C
Pressure	4.0 kPa
Turbine condenser conditions (NGCC)	
Temperature	27°C
Pressure	3.6 kPa

Secondary system

Source : raw water in closed loop from cooling tower (same as per condenser)
Service : for machinery cooling (different ΔP at users) and for all plant users other than steam turbine condenser and CO_2 compression exchangers

Operating pressure at User:	4.0 bar
Mechanical Design pressure:	8.0 bar

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

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:	40°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:	40°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:	40°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:	50°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 and BFW

USC PC power plant

Steam

The main characteristics of the steam at boiler battery limits are shown in the following table.

Table 10. USC PC cases: steam conditions

Main HP steam		
Pressure	bar	290
Temperature	°C	600
Hot reheat		
Pressure	bar	60
Temperature	°C	620

Boiler Feed Water

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

NGCC power plant

Steam

The main characteristics of the steam at the HRSG battery limits are shown in the following table.

Table 11. NGCC cases: steam conditions

High Pressure (HP) steam		
Pressure	bar	180
Temperature	°C	600
Medium Pressure (MP) steam		
Pressure	bar	40
Temperature	°C	585
Low Pressure (LP) steam		
Pressure	bar	4.5
Temperature	°C	250

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. *Chemicals (main)*

Chemical for BFW / steam generation

The following chemicals are used for BFW / steam generation conditioning:

- Amine for BFW pH control in the deaerator
- Phosphate injection in the steam drums
- Oxygen scavenger in the deaerator

Chemical for Capture unit

Soda (20%wt or 50% wt) is used for flue gas conditioning in the capture unit.

Chemicals for waste water treatment

The following main chemicals are used in the waste water treatment:

- Caustic Soda (20%wt)
- Hydrochloric Acid (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%wt (commercial grade)

4.3.6. *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. Software codes

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

- PROMAX v4.0 (by Bryan Research & Engineering Inc.): flue gas amine sweetening process for CO_2 removal.
- Gate Cycle v6.1.4 (by General Electric): Simulator of Power Island used for Steam Turbine and Preheating Line simulation.
- Aspen HYSYS v9.0 (by AspenTech): Process Simulator used for CO_2 compression and drying.
- GS: POLIMI's proprietary software, conceived for the prediction of gas turbine performances

4.5.1. *Gas turbine modelling with GS code*

In the evaluation of the thermal balances of new generation gas turbine, a crucial point is the evaluation of the performance of turbomachines, particularly the high temperature expander.

Politecnico di Milano has developed a calculation code, named "GS", conceived for the prediction of gas turbine performance at the design point. It performs the one-dimensional design of the turbine, aimed at establishing all the aerodynamic, thermodynamic, and geometric characteristics of each blade row. Proper correlations are then applied for the evaluation of the efficiency of the stages, while an accurate estimation of the blade cooling flow rates is considered by a model accounting for convective cooling in multi-passage internal channels with enhanced heat transfer surfaces, as well as film and Thermal Barrier Coating (TBC) cooling. Closed-loop cooling circuits can be simulated as well.

The calculation code can in principle be applied to the evaluation of oxy-fuel gas turbines since it is based on general correlations whose validity is independent from the working fluid properties. Two general basic assumptions are the following:

- The thermophysical properties of the working fluids are evaluated according to the ideal gas model (specific heat is calculated by NASA polynomials based on data of the JANAF tables [[1]]). This condition is closely verified for the usual operating range of gas turbine engines.

  Water and steam are treated as real fluid and their equation of state are taken from S.I. tables [[2]].

- Design parameters considered in the model are representative of the geometry employed in current "state of the art" gas turbine engines. Moreover, some critical coefficients have been calibrated to accurately predict the performance indexes of these machines.

Therefore, the current calculation model can be directly applied to the evaluation of the cooled expansion in components featuring conditions similar to those of the current commercial gas turbines (approximately turbine inlet temperature higher than 900°C, inlet pressure below 60 bar). If the above-mentioned conditions on temperatures and pressures are satisfied, the turbine calculation model can properly handle any working fluid composition.

Operational limits (e.g. TIT reduction) related to the change of the working fluid composition can be identified and margins deriving from a future technological improvement assessed.

The current cooled expansion model has been implemented in the GS code in 2002 [1]. Since that it has been extensively used for evaluation of gas turbine-based plants in many research projects. Among them, six FP7 collaborative projects awarded research teams including Politecnico di Milano (Caesar, Cachet II, Demoys, Democlock, Ascent, Matesa) and IEAGHG study report 2015/05 on Oxy-turbine power plants.

[1] Stull D.R. and Prophet H., Project Directors, JANAF Thermochemical Tables. 2nd Edition, U.S. National Bureau of Standards, Washington DC, USA, 1971.

[2] Schmidt E., Properties of Water and Steam in S.I. Units, Springer-Verlag, Berlin, Germany, 1982

CLIENT	:	IEAGHG
PROJECT NAME	:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO_2 CAPTURE
DOCUMENT NAME	:	BASIC INFORMATION ON NGCC PLANT ALTERNATIVES
CONTRACT N°	:	1-BD-1046 A

ISSUED BY	:	M. MENSI
CHECKED BY	:	V. TOTA
APPROVED BY	:	V. TOTA

Date	Revised Pages	Issued by	Checked by	Approved by

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ATTACHMENTS

GLOSSARY

CCS	Carbon Capture and Storage
NGCC	Natural Gas Combined Cycle
USC PC	Ultrasupercritical Pulverised Coal
FGR	Flue Gas Recirculation
EGR	Exhaust Gas Recirculation
CCU	Carbon Capture Unit
CMC	Ceramic Matrix Composite
ASU	Air Separation Unit
MCFC	Molten Carbonate Fuel Cell
TPC	Total Plant Cost
TIC	Total Installed Cost
MEL	Minimum Environmental Load
GT	Gas Turbine
ST	Steam Turbine

1. Introduction

The natural gas combined cycle (NGCC) plant considered for this study is based on the following configuration:

- Combined cycle, based on two natural gas fired, H-class gas turbines generating steam to be processed in one steam turbine;
- CO_2 capture unit;
- CO_2 compression and dehydration unit;

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 NGCC power plant, which are generally common to the conventional NGCC cases of the study. Chapters C.1 and C.2 of the report give basic engineering information for the reference case with and without CO_2 capture (both for reference case with 90% capture rate and high capture rate case), with the support of specific heat and mass balances, utility consumption summaries, etc, while the sensitivity cases are presented in chapter C.3 and C.4.

Sensitivity case based on the application of exhaust gas recirculation technology will be presented in Chapter C.3, while sensitivity cases to evaluate plant flexibility and the potential for future improvement in NGCC will be included in chapter C.5 and C.6.

Following Table 1 summarises the key technology features selected for the development of the reference cases, while Table 2 summarises the features that will be modified in each sensitivity case.

Table 1. NGCC-based reference study cases

Reference Case	Chapter	Description	Key features
Case 1	C.1	NGCC w/o CCS	• Two generic H-class gas turbines • One common steam turbine • Cooling system based on natural draft cooling tower
Case 2	C.2	NGCC with CCS	• Two generic H-class gas turbines • One common steam turbine • CANSOLV post-combustion capture • Cooling system based on natural draft

			cooling tower • 90% capture rate
Case 2.1	C.2	NGCC with CCS – High capture case	• Two generic H-class gas turbines • One common steam turbine • CANSOLV post-combustion capture • Cooling system based on natural draft cooling tower • 98.5% capture rate

Table 2. NGCC-based sensitivity study cases

Sensitivity Case	**Chapter**	**Description**	**Key features**
Base load cases			
Case 2.2	C.3	NGCC with flue gas recirculation	• FGR recirculation ratio: 50% (1) • Capture rate: 90%
Case 2.3	C.3	NGCC with flue gas recirculation	• FGR recirculation ratio: 50% (1) • Capture rate: 98.5%
Improving flexibility of NGCC power plants with CCS			
Case 2.1a	C.5	NGCC with CCS and solvent storage	• 98.5% capture rate • Lean/rich solvent storage system
Case 2.1b	C.5	NGCC with ON/OFF CCS	• 98.5% capture rate • Capable of unabated power production
Case 2.1c	C.5	NGCC with CCS and BESS	• 98.5% capture rate • 430 MWh battery energy storage system
Mid-term future advancements in near-zero emissions NGCC power plants			
Case 2.4	C.6	Advancements in GT materials	•
Case 2.5	C.6	Oxy-fired NGCC with CCS	• Two generic oxy-fired gas turbines based on H-class • One common steam turbine • Cryogenic post-combustion carbon purification
Case 2.6	C.6	NGCC with MCFC	• Two generic H-class gas turbines

			• One common steam turbine • Use of Molten Carbonate Fuel Cells in combined cycle • Cryogenic post-combustion carbon purification • Standard class H GT

Note:

1) Flue gas recirculation ratio = Flue gas recirculation flowrate / Total flue gas from HRSG
2) For all flexibility cases, reference comparison case is case 2.1

2. Basic information of main process units

2.1. Power Island

The combined cycle configuration selected for this case alternatives is based on two parallel trains, each composed of one generic H-Class equivalent gas turbine and one Heat Recovery Steam Generator (HRSG) that generates steam at 2 levels of pressure, plus a LP integrated deaerator. The generated steam feeds one condensing type steam turbine (ST), common to the two parallel trains.

2.1.1. Gas Turbine

Natural gas from the distribution grid is fed to the two gas turbines, after being metered and let-down to the pressure required by the gas turbine (around 40 barg). Natural gas is pre-heated to 220°C, using pre-heated MP Boiler Feed Water from the HRSG, and then combusted in the Gas Turbine to produce electric power. The combustion system of the gas turbine is Dry Low NOx type, so no steam or water injection is required for NOx control from the machine. The exhaust gases from the Gas Turbine are conveyed to the Heat Recovery Steam Generator, located downstream of the machine and connected by means of an exhaust duct.

H class Gat Turbine on the market

The following H-class gas turbine suppliers (listed in alphabetic order) are currently commercially ready to offer their H-Class machine on the 50 Hz market.

- Ansaldo: GT-36
- General Electric (GE): 9HA.01-.02
- Mitsubishi Heavy Industries (MHI): M701J
- Siemens: SGT5-8000H, SGT5-9000HL

Among the above listed suppliers, Ansaldo, GE and MHI have provided specific data for the development of this study case. The performance and capacity of the different turbine falls in the following range (at site conditions):

- Thermal input: 1,035 – 1,298 MWth
- Shaft power output: 462 – 575 MWe
- Flue gas flowrate: 2790 – 3700 t/h
- Gross electrical efficiency
  - Simple cycle: 41 – 44%
  - Combined cycle: 60 – 64%
- Heat rate: 8,114 – 8,789 kJ/kWh

For the purpose of this study, a generic gas turbine was defined in terms of performance and size in collaboration with POLIMI, trying to represent the average of the data received from Vendors

Performance figures are summarized in the following table.

Thermal input	MWth	1210
Shaft power output	MWe	527
Power output (at generator terminal)	MWe	520
Efficiency	%	43%
Heat Rate	kJ/kWh	8,370
Flue gas flowrate	t/h	3,505
Flue gas temperature	°C	641

Regarding the cases with Flue gas Recirculation, out of all the suppliers that participated in this study, only Ansaldo Energia provided turbine performances for this option.

Thanks to the data received by Ansaldo, it was possible to estimate the FGR behaviour of this generalised gas turbine also in the scenario with FGR, in collaboration with PoliMI.

2.1.2. *Heat Recovery Steam Generator*

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. The HRSG is equipped with Selective Catalyst Reduction system for NOx emission abatement in order to meet the environmental limits and to reduce the solvent degradation in the downstream capture unit.

Further details on steam generation conditions are listed in chapter B, section 4.3.3. The simplified process flow diagram of the HRSG is shown in Figure 1 (case w/o capture).

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;
- MP super-heater / HP economizer (2nd section) (in parallel arrangement);
- MP evaporator;
- HP economizer (1st section) / MP economizer (1st section) / LP super-heater (in parallel arrangement);
- LP evaporator, with integral deaerator;
- Condensate pre-heater.

In the cases with capture flue gas from the HRSG outlet are sent to a gas – gas heater for heating the decarbonised gas from the top of the absorber.

Cold condensate coming from the condenser is mixed with the condensate from the gas heater and then fed to the condensate pre-heater coil. After the preheating section, hot condensate and condensate recovered from the CO_2 regenerator reboiler are fed to the degassing tower of the LP Steam Drum.

The LP Steam drum liquid level is maintained by controlling the hot condensate flowrate through a dedicated control valve. Generated steam is superheated in the LP superheater coil and sent to the LP section of the Steam Turbine at a temperature of close to the MP exhaust temperature. In the cases with capture, the LP steam drum operating pressure is sliding, according to minimum steam pressure requirement of the reboiler in the CO_2 removal unit.

The boiler feed water for the HP and MP is directly taken from the LP steam drum and delivered to the relevant sections by means of dedicated HP and MP boiler feed water pumps.

HP boiler feed water flows through the HP economizer coils and feeds the HP steam drum. Level in the HP steam drum is maintained by adjusting the position of the relevant BFW control valve through a three-element logic: steam drum level, steam and feed water flowrates.

The HP steam drum operating pressure is sliding, according to ambient conditions and cycle load, with a normal operating value of 185 bar. Generated steam is superheated in the HP superheater coils and sent to the HP section of the Steam Turbine.

To control the maximum value of the HP superheated steam final temperature (600 °C maximum), an intermediate attemperator is foreseen. Cooling medium is HP BFW taken on the HP BFW pumps discharge and adjusted through a dedicated temperature control valve.

MP boiler feed water flows through the MP economizer coil and feeds the MP steam drum. Level in the MP steam drum is maintained by adjusting the position of the relevant BFW control valve through a three-element logic: steam drum level, steam and feed water flowrates.

The MP steam drum operating pressure is sliding, according to ambient conditions and cycle load, with a normal operating value of 40 barg. Generated steam is superheated in the MP superheater coil and mixed with the exhaust steam of the HP section of the Steam Turbine. The resulting stream is fed to the re-heater coils and sent to the MP section of the Steam Turbine.

To control the maximum value of the MP reheated steam final temperature (585°C maximum), an intermediate attemperator is foreseen. Cooling medium is MP BFW taken from the MP BFW pumps and adjusted through a dedicated temperature control valve.

In case of high level inside steam drums during start-up phases, drum overflows can be discharged to the Intermittent Blow Down Drum through dedicated overflow lines with relevant control valves.

Cycle water quality is controlled by injection of chemicals and steam drums blow-downs. Continuous blow-down is foreseen for HP and MP steam drums, while intermittent blow-down has been foreseen for HP, MP and LP steam drums.

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 balanced with LP steam drum. Steam fraction from blow down flashing is recovered to the LP steam system while the remaining liquid fraction 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. Steam fraction from blow down flashing inside the atmospheric blow-down drum is discharged to the atmosphere through the relevant vent line, while the remaining liquid fraction is sent to the waste water treatment system through the drain line.

In the cases with capture, a gas-gas heater is included in the HRSG tail end in order to heat-up the decarbonised gas from the absorber of the CO_2 capture unit above their dew point.

Figure 2 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).

SCR system

A Selective Catalyst Reduction system is installed to reduce NOx emission. The gas turbine burner achieves a value close to the EU emission limit for the plant with capture. However, emission limits may be exceeded in the plant with CO2 capture due to the reduced flue gas flowrate from the absorber. The SCR ensures meeting the environmental limit and, as NOx content increases solvent degradation in the capture unit, allows decreasing the annual solvent make-up.

A 60% NOx removal system is considered for this study execution, with a maximum ammonia slip of 5 ppm at all operating conditions. The SCR is installed in the proper optimum range for catalyst activity. Minimum temperature is around 300°C, therefore SCR catalyst can be located downstream the HP evaporator or downstream the MP super-heater / HP economizer (2nd section), the final position shall be selected with catalyst vendor during project execution.

Figure 1. HRSG simplified process flow diagram

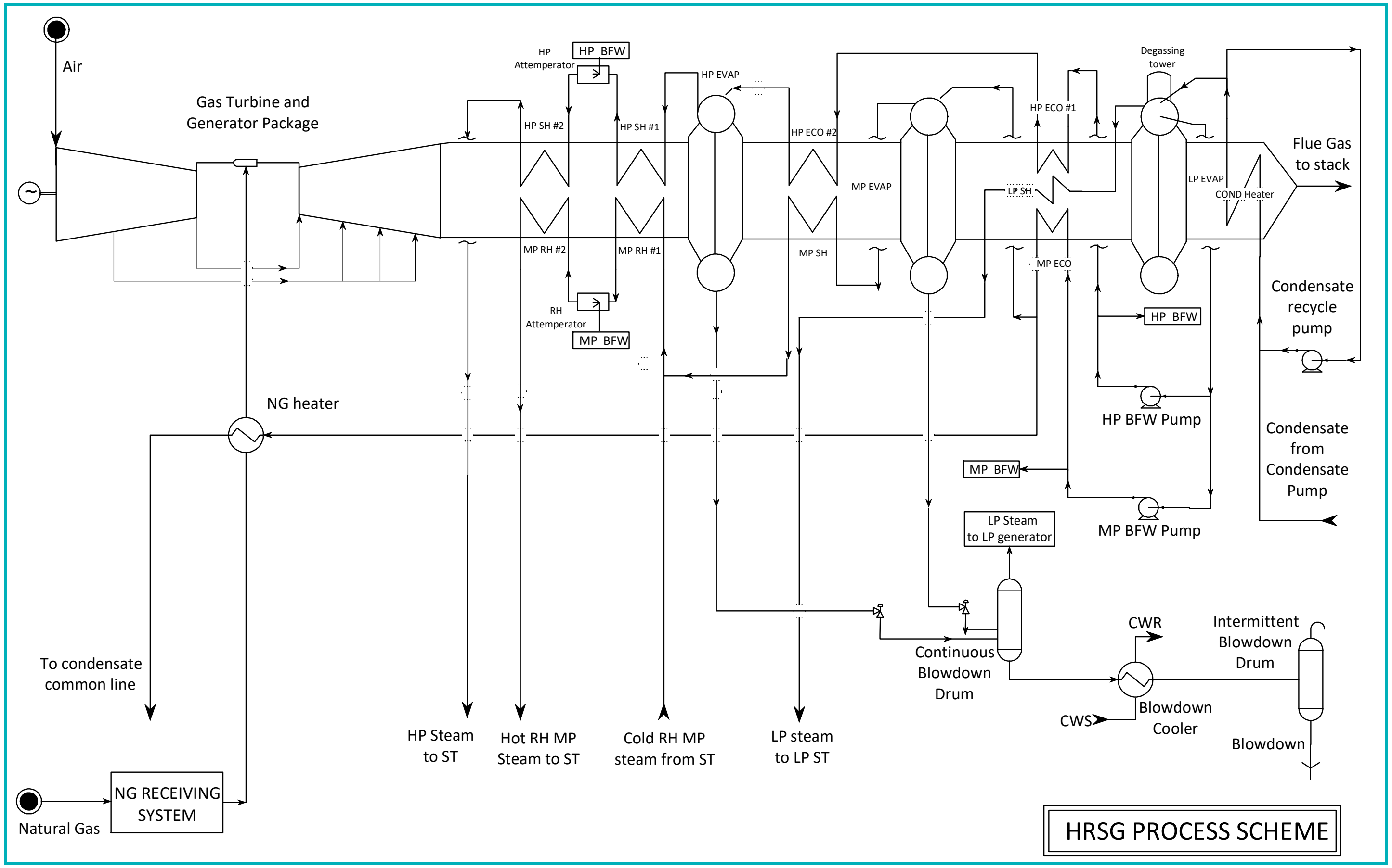
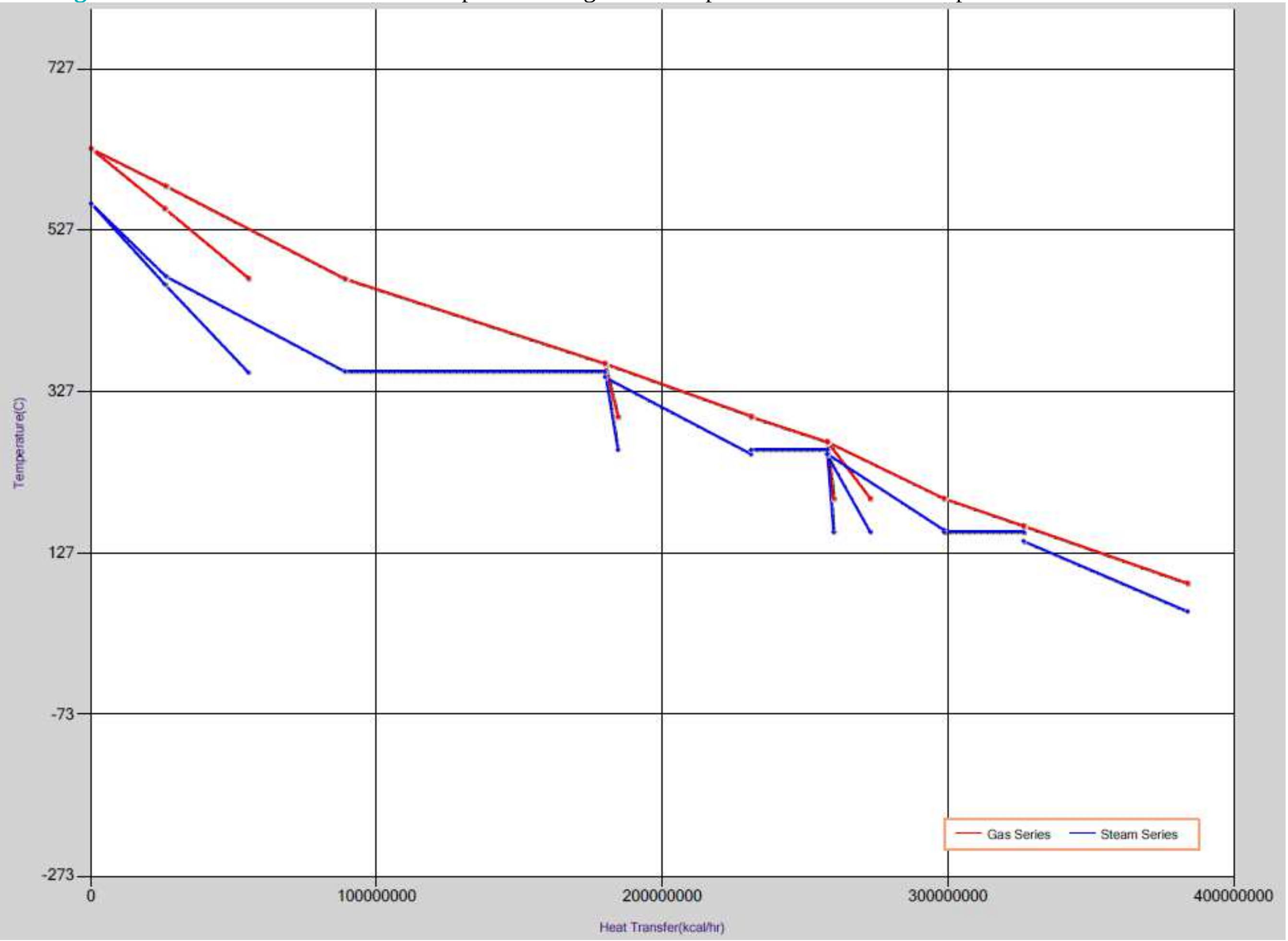


Figure 2. HRSG Heat Transfer vs. Temperature diagram. Multiple lines are due to how parallel coils are modelled.



2.1.3. *Steam turbine and condenser*

The following process description makes reference to the simplified process flow diagram shown in Figure 3 (case w/o capture).

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 HP steam turbine admission valves adjust their stroke to maintain the HP Steam Drum operating pressure above a minimum value, depending on GT load and ambient conditions, to ensure the proper separation of steam and water in the generation drum of the HRSGs. Therefore, pressure at the steam turbine inlet is sliding, according to the process conditions of the HRSG.

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 MP module of the steam turbine is normally floating, depending on the turbine hydraulic.

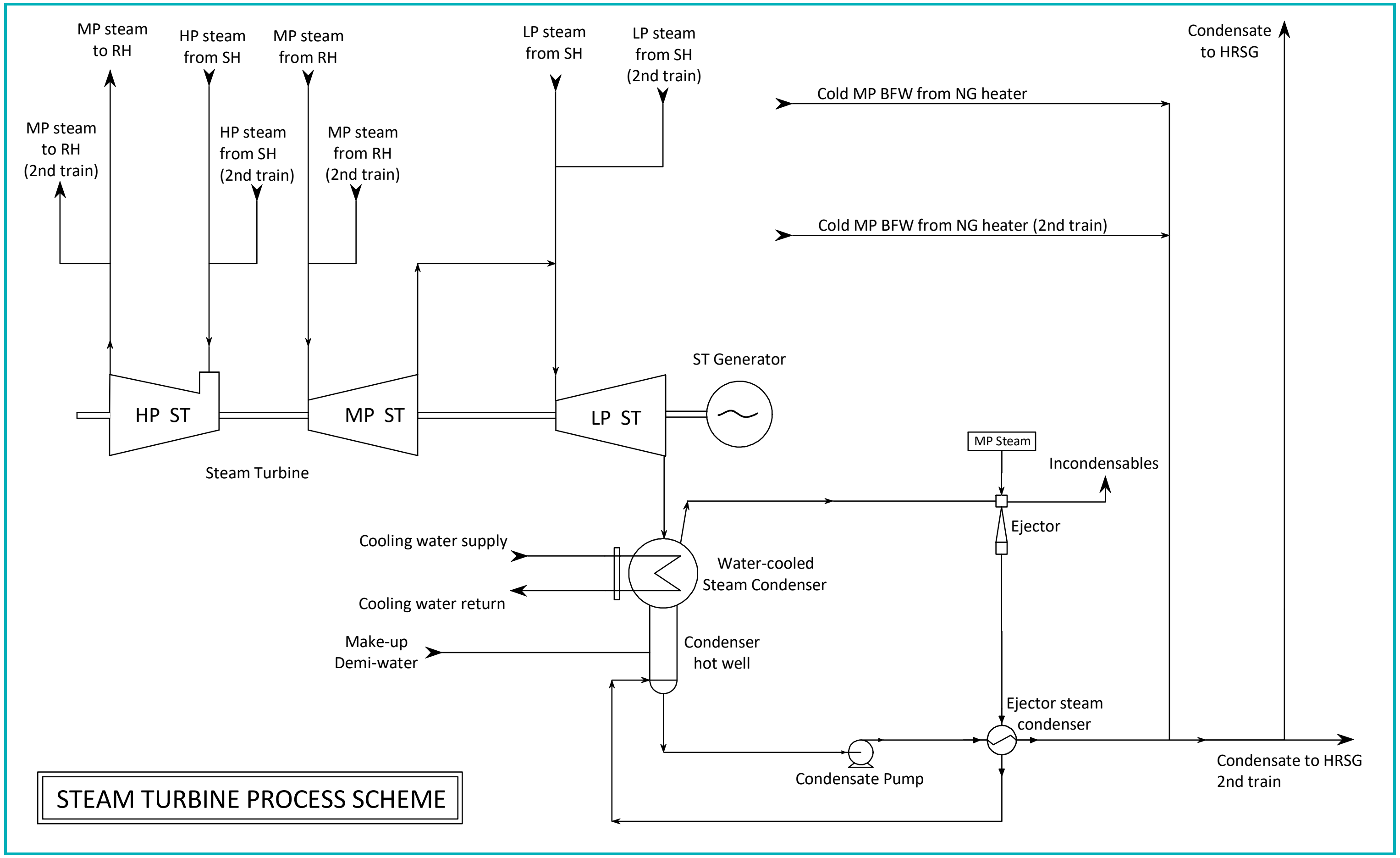
In cases with capture, the LP steam produced in the HRSG is sent to the LP steam header to feed the process. As the LP steam generated by the HRSG LP Drum is not enough to satisfy the requirement of the regenerator reboiler, the LP steam extraction is placed on the crossover of the MP/LP modules of the Steam Turbine to access the LP exhaust from the MP module as well. The LP admission valves adjust their stroke to maintain the minimum pressure requirement of the reboiler in the CO_2 removal unit. The LP steam directed to the reboiler is successively desuperheated with MP BFW.

The wet steam at the outlet of the LP module is finally routed to the steam condenser.

The condensate stream is extracted from the steam condenser by means of two, motor-driven and vertical condensate pumps (one operating and one in stand-by). The condensate is then used to condense the steam from the vacuum ejectors. Then, the condensate is pumped back to the HRSGs.

In case of steam turbine trip, live HP steam is bypassed to the MP manifold by means of a dedicated let-down station, while MP steam and excess of LP steam are also let down and then sent directly into the condenser neck.

Figure 3. Steam Turbine simplified process flow diagram



2.2. CO_2 capture unit (Cases 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 NGCC plants based on F and H class machine, 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.
- **Baker Hughes GE**: 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 CO_2 scrubbing process, using an amine-based solvent. Cansolv is a subsidiary of Shell Global Solutions group.
- **McDermott**: McDermott fused in recent years with CB&I, acquiring all the knowledge of CB&I and ABB Lummus licensed MEA scrubbing technologies. Currently, McDermott acts as a full EPC contractor for clean natural gas fired power plants at low environmental impact through its NET Power divison.
- **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 CO2**: it offers the LCDesign CCS Capture System™, which is a pre-engineered, pre-built and modularly constructed unit 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.

Amongst the above listed suppliers, Cansolv has provided specific data to develop the boiler case with 90% carbon capture during the execution of the IEAGHG 2018/03 "*Effect of Plant location on cost of CO_2 capture*". For this study purpose, Shell Cansolv confirmed that no update has been made with respect to the performance provided in 2016, therefore the capture unit performance for the reference case with 90% capture (case 2) are still applicable.

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 the NGCC with CO_2 capture (90% capture rate) of the study, only for the information that the supplier has authorized for disclosure.

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, as the data have been slightly adjusted and optimised during study execution either by either Cansolv or Amec Foster Wheeler Italiana. 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 the attachment and in the chapter relevant to the specific study cases is limited to the information that Cansolv have authorized for disclosure.

2.3. CO_2 compression and dehydration (Cases 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 80 bar by means of electrically driven seven-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 fifth 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.

2.4. Utility and Offsite units

2.4.1. *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.

2.4.2. *Natural gas metering and conditioning station*

Natural gas at 70 barg from network is filtered and metered and let-down to the operating conditions required by the gas turbine (around 34-36 barg).

The fuel will be metered by fiscal meters and the gas pressure will be reduced to match the required values for the gas turbine. In order to avoid freezing or condensation issues, a preheating section is provided upstream the reduction station.

Filtering, metering section and let-down station will be based on 3 x 50% configuration, two lines in normal operation and one spare in active stand-by, to ensure reliability and on-line maintenance.

2.4.3. *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.

2.4.4. *Firefighting 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 firefighting 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.

2.4.5. *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.

2.4.6. *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 CO_2 capture unit (case B), steam cycle and demineralised water unit eluate
- 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 potentially oily contaminated water
- Treatment facilities for the potentially dust contaminated water
- Treatment facilities for not contaminated water
- Treatment facilities for the sanitary wastewater.

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. Cansolv post-combustion capture technology

Shell Cansolv

Post Combustion CANSOLV CO_2 Capture Unit

Technical Study

Presented to:
AMEC FW

TECHNICAL STUDY

June 2016 | T0741A-S37FR-401-R0

Executive Summary

Shell Cansolv is pleased to present to AMEC Foster Wheeler (AMEC FW) this technical study.

AMEC FW is interested in evaluating the application of CANSOLV CO_2 capture technology to treat the flue gas from two natural gas combined cycle (NGCC) plants at different locations. Based on the information provided by AMEC FW, Shell Cansolv is presenting CO_2 capture unit designs operating with with CANSOLV DC-201 Absorbent for NGCC plants.

The following information has been provided in this report which was specified in the Request for Quotation:

- Process Description
- Process Flow Diagram showing an overview of the major pieces of equipment
- Description of CO_2 product purity
- High level heat & material balance summary
- Major equipment list
- Utility consumption table including steam, electrical power, cooling water, DM water and caustic
- Estimate of initial absorbent fill quantity, annual consumption

Table of Contents

1. CO_2 Capture Units Design Basis

1.2 Process Line-up and Battery Limits

Shell Cansolv's process design is based on the available process design parameters, given in the RFQ document provided by AMEC FW.

Two Carbon Capture Units will be designed to treat flue gas from 2 requested NGCC cases summarized in Table 1. The base case is sized with cooling water and alternative one with air cooler. The Figure 1 below shows the proposed process line-up within the Carbon Capture Unit. The dotted block outlines the battery limits of the Shell Cansolv scope of work. The CO_2 Capture Units are designed for 90% CO_2 capture.

The resulting pure CO_2 product exiting the Shell Cansolv battery limits will be compressed and dehydrated and sent to the downstream process pipeline which is outside of the scope of this study. The treated flue gas from the absorption section will be released to atmosphere. The liquid effluent from the DCC requires minimal treatment and in the case of NGCC units can be reused as process water. 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.

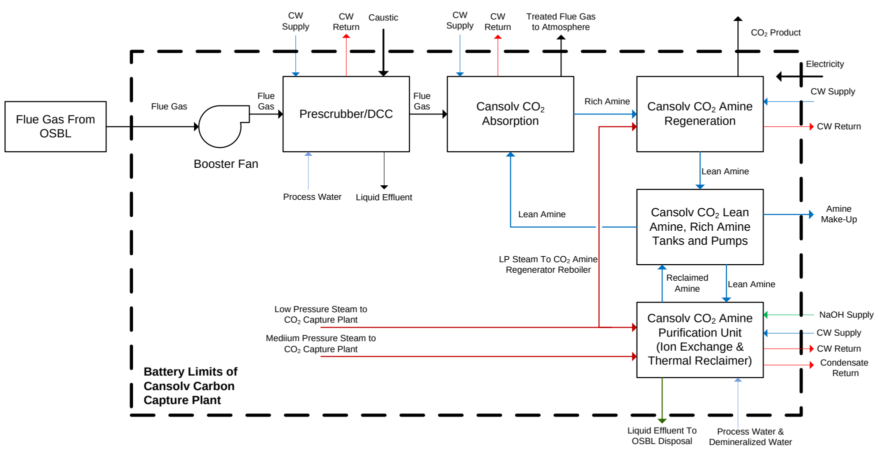


Figure 1: Battery Limits of CANSOLV Technical Study (enclosed by black dashed lines above)

Table 1: Flue Gas Specification

Flue Gas Composition		**Base**	**Alternative**
Ar	Vol%	0.88	0.89
CO_2	Vol%	4.32	4.24
H_2O	Vol%	9.06	8.06
N_2	Vol%	74.11	74.83
O_2	Vol%	11.64	11.97
NO_x	-	< 40 mg/Nm^3	< 40 mg/Nm^3
Flow Rate	t/hr	3187	1805
Temperature	°C	90	90
Pressure	barg	0.01	0.01

1.3 Available Utilities

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

Table 2: Available Utilities

Utility	**Unit**	**Specification**
Low Pressure Steam Pressure	barg	4.5 (Min 3.4)
Low Pressure Steam Temp.	°C	165 (max270)
Cooling Water Supply Temp.	°C	15
Cooling Water Return Temp*.	°C	25
Caustic Soda Concentration*	wt%	40
Demineralised water Pressure*	barg	4
Demineralised water Temp. *	°C	30

*Recommended conditions by Shell Cansolv

1.4 Assumptions/ Design Philosophy based on technical information available

For the purpose of this technical study, the following assumptions are taken to develop the design basis:

1. NO_2 content: the proportion of NO_2 is assumed to be 5% of total NO_x content. This assumption is based on actual flue gas composition data from active CO_2 capture projects. NO_X level in the flue gas can be reduced to few ppmv by having SCR unit at upstream of the capture unit. For the purpose of this study, it is assumed that NOx level is reduced to 4 ppmv downstream of a SCR unit which results

in 0.2 ppmv of NO_2 at the inlet of the Absorber. In case of having 40 ppmv NOx which leads to 2 ppmv of NO_2 to the CO_2 capture unit, an additional 30% amine make up would be foreseen in OPEX.
2. CANSOLV DC-201 Unit is designed including a degradation inhibitor to minimize the absorbent loss. The applied inhibitor is part of the CANSOLV DC-201 recent development.
3. Liquid entrainment from DCC is assumed to be negligible since it is equipped with a chevron type mist eliminator.
4. The Design Temperature approach between the hot lean absorbent and the hot rich absorbent is assumed to be 5°C. Similar approaches have been guaranteed for comparable projects by specific Heat Exchanger Vendors, using Plate & Frame Heat Exchangers.
5. No significant levels of Unburned Hydrocarbons (UHC) is assumed 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.
6. As specified in process description, structured packing has been installed in both the absorber and stripper tower to minimize the pressure drop.
7. No design features are foreseen for winterization.
8. Equipment size limitations have been based on previous reference projects. These limitations are indicated in the Equipment List but can be changed based on AMEC FW experience
9. The achievable turndown based on the current design concept is 50%.
10. CO is not absorbed by the solvent and will breakthrough from the top of absorber. No significant impact has been observed in the past for CO.

2. PROCESS DESCRIPTION – Proposed Process Arrangement

Shell Cansolv CO_2 Capture System comprises the following major components: Booster Fan, Direct Contact Cooler (DCC), CO_2 Absorber Column, CO_2 Stripper Column, , Lean/Rich Heat Exchangers, Reboilers and Absorbent Purification Unit (APU). The process description refers to the Preliminary Process Flow Diagram (PFD) presented in Appendix I.

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

The flue gas from OSBL is sent to a Booster Fan in order to provide enough pressure to drive the flue gas through the Carbon Capture Unit. Following the Booster Fan, the gas is sent to the DCC, to sub-cool the flue gas before sending it to the CO_2 Absorber. Sub-cooling the flue gas will improve CO_2 absorption capacity of the absorbent. The preliminary DCC design includes a DCC Cooler to sub-cool the flue gas down to 30°C for base case and 42°C for alternative case, in order to reduce the required absorbent circulation rate and thus energy consumption and CAPEX of the CANSOLV unit.

CO_2 Absorption

The flue gas exits the DCC and is ducted to the CO_2 Absorber. CO_2 absorption from the flue gas occurs by counter-current contact with CANSOLV Absorbent DC-201 (for NGCC) in a vertical multi-level packed-bed tower, namely the CO_2 Absorber. The gas entering the absorption section of the column will have sufficient pressure to overcome the pressure drop in the column packing before being discharged at the top of the CO_2 Absorber stack.

The Lean Absorbent Pumps deliver CO_2 lean absorbent through the Lean Absorbent Cooler 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 maintain an overall water balance in the CANSOLV absorbent DC inventory and to enhance the CO_2 removal performance of the absorbent and.

For NGCC application, the low inlet CO_2 concentration results in a moderate temperature increase in the absorber and the intercooler is not required.

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.

CO_2 Water Wash Section

A water wash packed bed section is included at the top of the CO_2 Absorber to capture volatile or entrained absorbent and to condense water to maintain the water balance in the system. Wash water is drawn from a chimney tray and is re-circulated to the top of the packed section, via the Water Wash Cooler, by the Water Wash Pumps. The Wash Water Cooler reduces the temperature of circulating wash water, which minimizes water loss and enhances capture efficiency of the volatile absorbent. Water condensed from the flue gas into the wash water section overflows from the chimney tray to the CO_2 absorption section below. The treated flue gas leaving the Water Wash Section, flows upwards to the stack and is released to atmosphere. The design flue gas outlet temperature is selected such that the required water make-up rate is minimized.

CO_2 Absorbent Regeneration

The rich absorbent is collected in the bottom sump of the CO_2 Absorber and is pumped by the CO_2 Rich Absorbent Pumps and heated in the CO_2 Lean/Rich Exchangers to recover heat from the hot lean absorbent discharged from CO_2 Regenerator. Rich absorbent is piped to the top of the CO_2 Stripper for absorbent regeneration and CO_2 recovery. The rich absorbent enters the column under the CO_2 top packing section and flows onto a gallery tray that allows for disengagement of any vapor from the rich absorbent before it flows down to the two stripping packing sections under the gallery tray. The rich absorbent is depleted of CO_2 by water vapor generated in the Regenerator Reboilers which flows in an upward direction counter-current to the rich absorbent.

Lean absorbent flowing from the bottom packing section of the CO_2 Regenerator is collected on a chimney tray and gravity fed to the Regenerator Reboilers. Water vapor and lean amine flow by thermosyphon effect from the reboilers back to the CO_2 Regenerator sump, underneath the chimney tray. Water vapor flows upwards through the chimney tray to strip the CO_2 while the lean absorbent collects in the bottom sump.

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

The regenerator overhead gas is partially condensed in the Regenerator Condensers. The partially condensed two phase mixture gravity flows to the CO_2 Reflux Accumulator where the two phases separate. The reflux water is collected and returned via the Reflux Pumps to the regenerator rectification section. The CO_2 product gas is piped to the CO_2 Compression System (OSBL). The pressure of the Regenerator is controlled by the product CO_2 discharge control valve.

The flow of steam to the reboiler is proportional to the rich absorbent flow sent to the CO_2 Regenerator. The set-point of the low pressure steam flow controller feeding the Regenerator Reboilers is also dependent on the regenerator top temperature controller. The steam to absorbent 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.

Absorbent Purification Unit

Over time the absorbent in the CO_2 Capture System accumulates Heat Stable Salts (HSS), as well as non-ionic amine degradation products, that must be removed from the absorbent. This is achieved through thermal reclamation. Depending on the absorbent used and application an Ion Exchange package (IX) can also be used for bulk HSS removal upstream of the thermal reclaimer. In this study, the IX package is applied in DC-201 line-up for NGCC capture unit.

The IX package 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, which is then inactivated for further CO_2 absorption. Although a certain level of HSS is required within the absorbent in order to have sufficient driving force for the operation of IX package, excess HSS must be removed.

The purpose of the Thermal Reclaimer Unit is to remove the non-ionic degradation products as well as HSS from the active absorbent. The thermal reclaimer unit distills the absorbent 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 absorbent exiting the IX package and fed to the Thermal Reclaimer Unit. 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 absorbent 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 absorbent. The reclaimed absorbent is send to the Lean Absorbent Tank. The separated degradation products are stored in a storage tank, where it is diluted and cooled with process water. Diluted residues are periodically disposed of offsite, typically via incineration.

3. CO_2 CAPTURE SYSTEM SPECIFICATIONS

3.1 Process Flow Diagram

The preliminarily process flow diagrams are presented in Appendix I.

3.2 Heat and Material Balance

The preliminary Heat and material balances outlining major streams are given in Appendix II for each of the cases.

3.3 Preliminary sized Equipment List

The Preliminary Process Equipment Lists are given in Appendix III.

3.4 CO_2 Product Specification

The 90% capture rate mentioned in RFQ is obtained by treating the complete full gas flow with a capture efficiency of 90%. The characteristics of the CO_2 product gas exiting the CANSOLV capture unit, on a wet basis, are as follows:

Table 3: CO_2 product gas characteristics

Parameter	Unit	CO2 product
Temperature	°C	30
Pressure	kPa(g)	98
Composition		
CO_2	wt %	99.1
H_2O	wt %	0.1
Amine	ppmv	<0.05

Absorbent Make-Up Rate

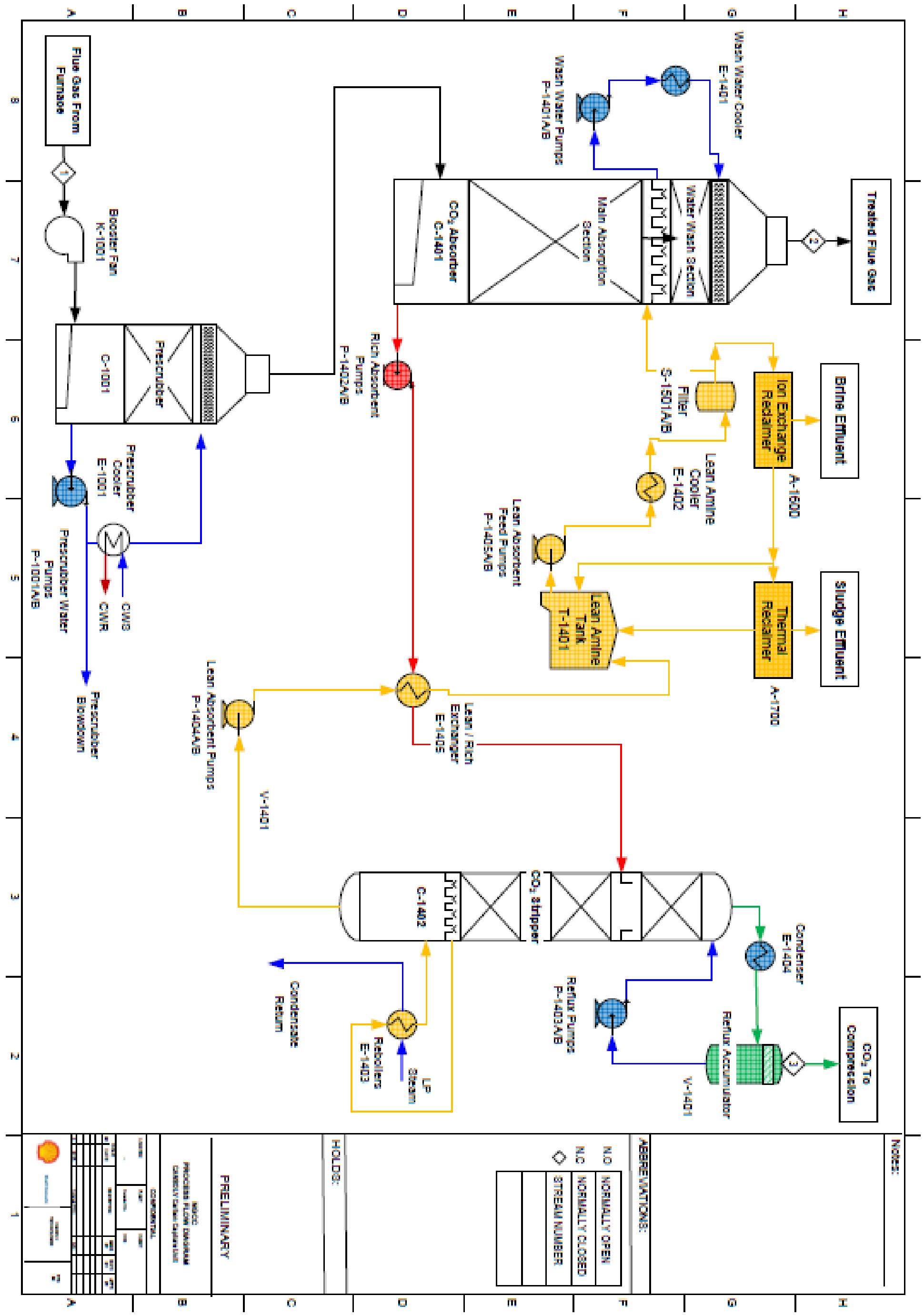
Absorbent make-up rate for CO_2 systems is dependent on flue gas composition and its contaminants. Absorbent make-up rate based on the assumed NO_2 ingress for CANSOLV DC-201 absorbent is reported in Appendix IV.

3.5 Utilities and Chemical Consumptions

Utilities and Chemical consumption along with effluent summary are presented in Appendix IV. The provided information on utilities can be used to estimate the consumable costs.

Related to estimated yearly cost for system maintenance it can be assumed that capture plant maintenance coincides with power plant maintenance and requires no additional staff.

Appendix I – Process Flow Diagram



Appendix II – Heat and Material Balance

Base Case

Stream ->		<1>	<2>	<3>
Parameters	Unit	Feed Gas	Treated Gas	CO2 Product from Ref. Acc.
Temperature	°C	90	30	30
Pressure	kPag	1.0	0.2	97.9
Flow Rate	Nm3/hr	2,497,422	2,264,277	100,025
Molar Flow	kg-mole/hr	112,354	101,957	4,462
Mass Flow	kg/hr	3,187,198	2,886,350	193,928
Composition				
N2 [Note 1]	mol%	75.0	82.6	-
CO2	mol%	4.3	0.5	97.9
O2	mol%	11.6	12.8	-
H2O	mol%	9.1	4.1	2.1
NOx	ppmv	4.0	3.8	-

1) Argon is included in nitrogen content.

Alternative Case

Stream ->		<1>	<2>	<3>
Parameters	Unit	Feed Gas	Treated Gas	CO2 Product from Ref. Acc.
Temperature	°C	90	41	38
Pressure	kPag	1.0	0.2	98
Flow Rate	Nm3/hr	1,408,860	1,345,434	56,037
Molar Flow	kg-mole/hr	63,388	60,560	2,499
Mass Flow	kg/hr	1,804,597	1,690,767	107,907
Composition				
N2 Note 1	mol%	75.7	79.3	-
CO2	mol%	4.2	0.4	96.8
O2	mol%	12.0	12.5	-
H2O	mol%	8.1	7.8	3.2
NOx	ppmv	4	3.8	-

1) Argon is included in nitrogen content.

Appendix VII – Business Profile

Shell Cansolv

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

Shell Cansolv 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.

Shell Cansolv 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 Shell Cansolv. The company now operates as a wholly owned subsidiary of SGSI.

Shell Cansolv maintains an office and an R&D laboratory in Montreal, Canada and an office in Beijing, China. As a subsidiary of Shell Global Solutions, Shell Cansolv 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 VIII.

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 neighbours or facilities at risk.

Find more information at: www.shell.com/shellcansolv and www.shell.com

Appendix VIII – Technology Experience / History

Development History

Shell Cansolv's CO_2 capture technology development and deployment history follows along the same pathway as its SO_2 technology:

1) Laboratory testing and Piloting Campaigns on real flue gas
2) Small scale demonstration
3) Commercial deployment:
   a. Small scale commercialization
   b. Large scale commercialization

Laboratory Testing and Piloting Campaigns on Real Flue Gas

Laboratory testing started with the objective of characterizing the properties of new and innovative amine molecules while developing new degradation inhibitors. After approximately 4 years of research, a first generation absorbent formulation was developed, tailored for oxidative post combustion applications and combining the following advantages:

1) Excellent CO_2 loading capacity
2) Ease of regeneration with lower energy
3) High resilience against oxidative and thermal degradation
4) Low corrosivity

During this time a mobile pilot plant was constructed for the purposes of piloting the technology. Over 10,000 hours of piloting ensued. Table 1 includes all piloting campaigns pursued over the years.

Table 4: Piloting Campaigns

Application	Dates	Description
Natural Gas Fired Boiler	March 04 – June 04	Pilot tests at Paprican's* Headquarters. The CO_2 concentration in the inlet gas was 12%vol and the recovery rate was 75%. The recovered CO_2 was produced as water-saturated gas from the solvent stripper and was dried before compression and storage in a CO_2 accumulator. * Paprican: Pulp & Paper Research Institute of Canada
Coal Fired Boiler	November 2005	Pilot tests at Smurfit-Stone's West Point Pulp & Paper Mill. The coal-fired boiler was equipped with an effective ESP, which removed most of the particulate matter. The pilot prescrubber quenched the gases and removed parts of the remaining particulates. The SO_2 was also removed before the gas entered the absorber for CO_2 absorption. It was confirmed that coal fired applications can be dealt with properly without creating any adverse effects on the Cansolv process. The CO_2 concentration in the inlet and treated gas were 12%vol 5%vol.
Coal Fired Boiler	Feb. 06	Pilot tests at NSC (Nippon Steel Corporation). Inlet concentration was 22%, and recovery rate was 65%.
Coal Fired Power Plant	July 06 - Sept. 06	Pilot tests at Saskpower's Poplar River Power Plant (Saskatchewan, Canada). The inlet gas concentration was 12% and the recovery rate was 90%.
Natural Gas Fired Cogeneration	May 07 - Sept 07	The CANSOLV CO_2 Capture™ process has been retained by a Shell-Statoil joint venture as one of the three leading CO_2 capture technologies in the world. Cansolv solvent was be tested during extensive pilot plant trials in Risavika (Norway), as part of the technology selection process for one of the largest offshore CO_2-EOR projects to date.
Blast Furnace	April 07	Pilot tests at NSC (Nippon Steel Corporation). Inlet concentration was 22%, and recovery rate was 90%.
Cement Kiln	Jan 08-Feb 08	Pilot tests at a Cement plant. Inlet concentration was 22%, and recovery rate was varied from 45% to 90%.
Natural Gas Fired	May 12	SINTEF 1 ton/day Tiller pilot facility (Trondheim, Norway).The optimal lean flow reboiler duty was 3.3 MJ/kg CO_2 captured for the natural gas case (4.5 vol% CO_2) and 3.1 MJ/kg for the recirculation case (13.5 vol% CO_2).
Blast Furnace	Nov 11	Pilot tests at NSC (Nippon Steel Corporation). Two gas conditions were studied: 22.5% CO_2 (flue gas from Blast Furnace) and 13.5% CO_2 (diluted gas). Optimum regeneration energy at 90% CO_2 capture was 2.7 GJ/ton CO_2 (without any heat loss correction) for both cases with the use of two of the three Intercooling sections.
Coal Fired Boiler	Aug 12-Oct 12	NCCC Power Plant in Wilsonville, Alabama under standard coal combustion conditions. The flue gas composition was ~13.0% CO_2 and the total CO_2 capture was ~ 8 Ton CO_2/day. Optimum regeneration energy at 90% CO_2 capture was 2.3 GJ/ton CO_2 (without any heat loss correction).
Diluted gas from Coal Fired Boiler	July 13 – Oct 13	NCCC Power Plant in Wilsonville, Alabama under diluted coal combustion conditions. The flue gas composition was ~4.0% CO_2 and the total CO_2 capture was ~ 5 Ton CO_2/day. Optimum regeneration energy at 90% CO_2 capture was 3.3 GJ/ton CO_2 (without any heat loss correction).
Natural Gas Fired Cogeneration	Oct 14-	Demonstration test at TCM, Mongstad, Norway. Inlet concentration is 4%, and recovery rate is 90%. Start-up in Oct 14.

Small Scale Demonstration: RWE Aberthaw

In 2009, Shell Cansolv and RWE nPower entered into a contract to develop a CO_2 capture demonstration program. Shell Cansolv designed and supplied the technology, the absorbents and the modularized Integrated SO_2 / CO_2 Capture Plant. RWE hosted the demonstration at their Aberthaw coal fired power station in South Wales; providing the utilities and the flue gas to be treated, and the operating team.

Commercial deployment

Table 2 describes the commercial size CANSOLV CO_2 capture plants.

Table 5: Commercial size CANSOLV CO2 Plants

Parameter	Units	Lanxess CISA	SaskPower
Size of Project (at 100% availability)	**TPY of CO_2**	62,100	1,200,000
Location	**-**	New Castle, South Africa	Estevan, Saskatchewan
Type of Application	**-**	Natural Gas Boiler	Coal Fired Boiler
Bulk SO_2 Removal	**-**	Caustic	Cansolv DS
Solvent Type	**-**	Cansolv Absorbent DC-103	Cansolv Absorbent DC-103
Solvent Supplier	**-**	See Section 7.2	
CO_2 Use	**-**	Sodium Dichromate Production	Enhanced Oil Recovery
Volume of CO_2	**TPD of CO_2**	170	3,288
Pressure of CO_2	**psig**	220	2280
Distance CO_2 Conveyed	**Miles**	1	60
Engineering Partner	**-**	PPTech pty	SNC-Lavalin Inc
Constructor	**-**	PPTech pty	SNC-Lavalin Inc
Performance Guarantees	**-**	See Section 10	
Duration of Operation	**Start-Up Date**	Aug-13	Sep-14
Current Status of Facility	**-**	Operating	Operating

The following sections describe each project in more details.

Small scale commericlization: Lanxess CISA CO_2 Recovery & Infrastructure Project

Shell Cansolv signed an agreement with Lanxess CISA Pty (Lanxess) to license a regenerable CANSOLV CO_2 Capture System for use at their chrome chemicals production facility in Newcastle, South Africa. To guarantee independent and stable production of sodium dichromate, Lanxess CISA invested in a facility which burns local natural gas in a new boiler to produce steam and generate a stream of flue gas from which CO_2 is captured and used for the dichromate process. Lanxess CISA became consequently self-sufficient on both steam and CO_2. The project was executed in only 20 months, from Engineering Kick-Off Meeting to Plant Start-Up. The EPC services were performed by local engineering firm Process Plant Technology (PPTech), a company which has been active in the South African chemical industry since 1974.

The plant was started in August 2013 and successfully completed the performance warranty test run in September 2013. The CO_2 capture plant has been running smoothly since then. The plant meets all performance requirements, and in most cases the results are considerably better than design.

The Lanxess CISA CO_2 Capture Plant design includes an enhanced process line-up that maximizes energy recovery and minimizes the amount of steam required to regenerate the absorbent. Its unique control philosophy enables the system operation to rapidly and automatically adapt the CO_2 Capture to the CO_2 Demand of the sodium dichromate batch process. The CO_2 capture plant also includes an enhanced Thermal Reclaimer Design that maximizes Amine Recovery. The absorber design minimizes emissions of amine and associated degradation products.

The following pictures show the completed CO_2 Recovery plant at Lanxess CISA, including the New Boiler, CO_2 Compressors, Cooling Tower, Condensate Tank, etc.

Large scale commercialization: *SaskPower Boundary Dam ICCS Demonstration Project*

The know-how, experience and lessons learned achieved through the complete realization of the world's first coal fired post-combustion CO_2 capture plant consolidates the assurances that scale-up challenges are very well understood by Shell Cansolv and can be appropriately mitigated for new large scale projects. All of the learnings available from the SaskPower project will be directly relevant and available for future projects. Shell Cansolv is uniquely able to account for these lessons learned and incorporate the appropriate considerations through each phase of the project, from basic engineering design to commissioning and start-up. Given the fact that the SaskPower Boundary Dam project is the largest CO_2 capture project in the world today – future clients benefit by having the most reduced scale-up risk available on the market today.

Project Description

Unit 3 of the Boundary Dam Power Station was an aging asset in the SaskPower fleet and was subject to the new federal regulations on the reduction of carbon dioxide (CO_2) emissions from coal-fired power plants. According to the current projections, the upgrades to the unit will extend its useful power production life by 30 years. At full capacity, the SaskPower Integrated Carbon Capture and Storage (ICCS) Demonstration Project captures over one million metric tons of CO_2 per year, reflecting a 90% CO_2 capture rate for the 139 MW coal-fired unit. The captured CO_2 is compressed and transported through pipelines to Cenovus Energy who uses the CO_2 for Enhanced Oil Recovery (EOR) activities in the Weyburn oil field. Weyburn is recognized as the largest geological CO_2 storage project in the world. Meanwhile, all the sulfur dioxide (SO_2) present in the flue gas is recovered and used for production of sulphuric acid to be sold as a valuable by-product.

Process Description

The Cansolv process line-up for the SaskPower BD3 ICCS Project uses regenerable amine-based absorbents to capture both SO_2 and CO_2, which means that no direct waste by-products are generated.

It also includes a particular design enhancement: The heat integration of Shell Cansolv's innovative combined SO_2/CO_2 capture system helps to reduce energy requirements associated with carbon capture. With this approach, the Capture Plant steam requirement is significantly reduced.

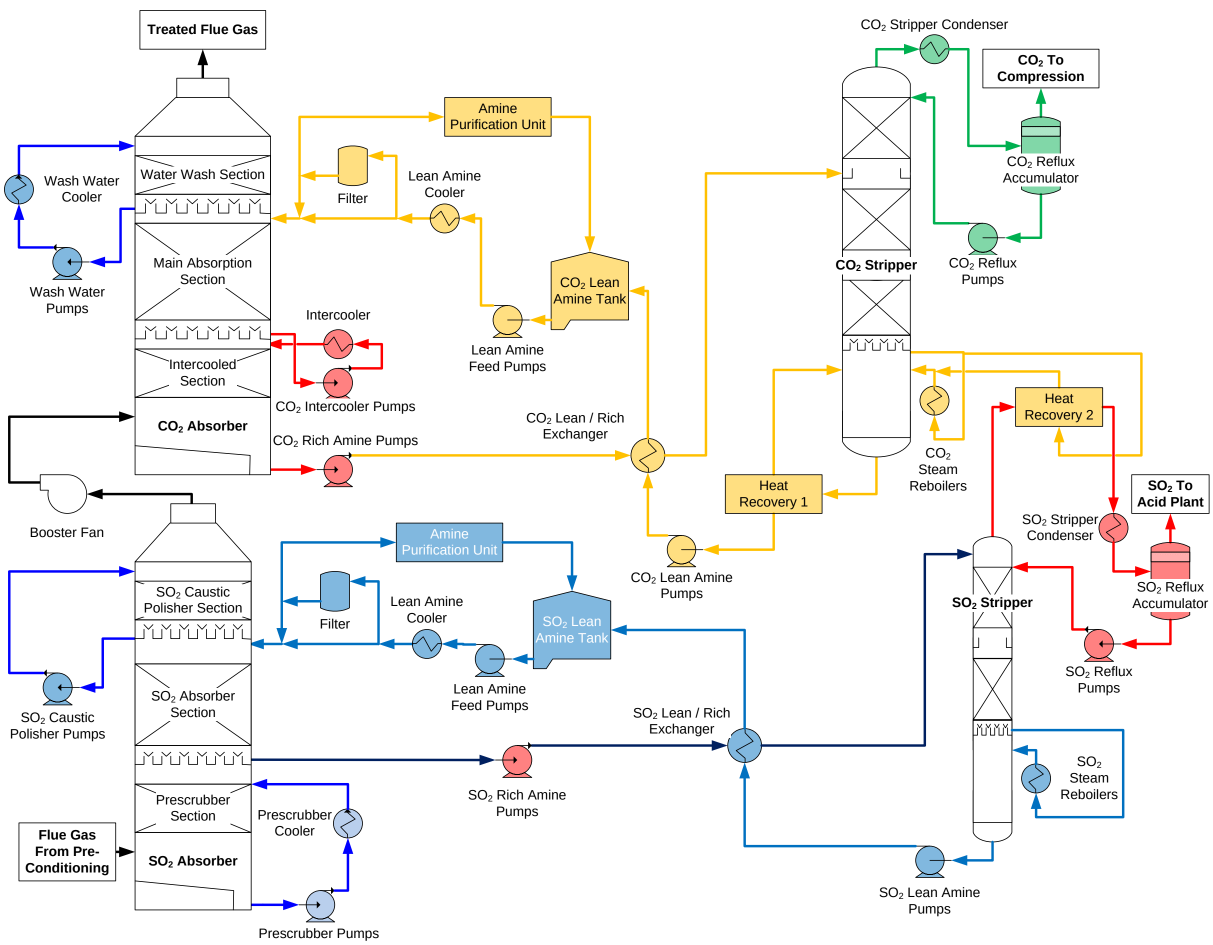


Figure 2: Cansolv process line-up for the SaskPower BD3 ICCS Project

Shell Cansolv Contribution to the Project

Above and beyond being the process licensor, technology provider and amine supplier for both the flue gas desulphurization and CO_2 capture processes; Shell Cansolv has provided a multitude of products and services to SaskPower. In particular Shell Cansolv has:

1) Supplied modular amine filtration and amine purification units;
2) Reviewed detailed engineering documents and vendor drawings;
3) Developed and reviewed training material and provided training to the operators;
4) Helped environmental permitting efforts by conducting thorough biodegradability, toxicity and ecotoxicity tests;
5) Managed technology evaluations to identify the best available waste water treatment solution;

6) Advised and supported organization, preparation and execution of commissioning and start-up;
7) Helped prepare and register safety data sheets used for operation and maintenance;
8) Reviewed standard operating procedures;
9) Offered specialized support of experts from the wider Shell organization;
10) Supported successful start-up through specific project assurance activities;
11) Provided council to optimize overall process performance

Shell Cansolv has also established a Joint Development Agreement with SaskPower to tackle with specific long term development and optimization activities.

Project Status Update

Compressed CO_2 was supplied to the pipeline for the first time on September 2014. Table 3 summarizes the major milestones of the SaskPower Boundary Dam CCS Demonstration Project.

Table 6: Major Saskpower BD3 CCS Demonstration Project milestones

Milestone	Date	Notes
FEED complete	November 2009	Completed
Project Award	March 2010	Completed
Detailed Design	December 2010	Completed
Long Lead item Procurement	December 2010	Completed
Financial Investment Decision	May 2011	Completed
Start of Construction	May 2011	Completed
Construction Completion	May 2013	Completed
Commissioning & Start-Up	October 2014	Completed
Achieving nominal CO_2 Production goal	2016	On target

Delivery of CO2 Stripper

Installation of Abso

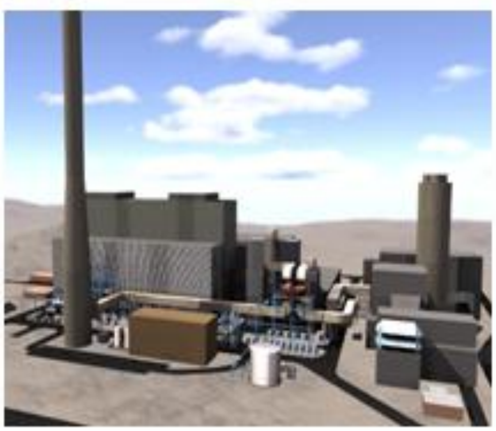
Completed installation – July 2013

First Plume - Sept 2014

Peterhead CCS Project

The UK Department of Energy & Climate Change (DECC) selected the Peterhead CCS project as one of the winners of the UK CCS Competition in March 2013. A Front End Engineering & Design (FEED) contract was executed between Shell and DECC in February of 2014, and FEED was completed in late 2015. Unfortunately, the UK government subsequently withdrew funding support for the project, leading to its cancellation. However, the completion of FEED and associated testing allowed for continued enhancement of the Cansolv CO_2 capture process.

The Peterhead CCS Project had the objective to be the world's first commercial scale demonstration of CO_2 capture, transport and offshore geological storage from a (post combustion) gas-fired power station. For this project, Shell joined forces with SSE CCS Limited, a wholly owned subsidiary of SSE Generation Ltd, the UK's leading generator of renewable energy.



The projected plant was intended to capture approximately 1 million tonnes of CO_2 per year, for a ten year period, from the output of one of the existing three gas turbines, downstream of the Heat Recovery and Steam Generator (HRSG) – ~400MWe output (pre CCS retrofit).

Shell Cansolv CO_2 Capture technology highlights

- Employing new DC-201 Solvent
- Simplified Line-Up (no interstage cooling, no Heat Integration)
- Strong drive for minimized environmental impacts
- High CO_2 recovery (up to 90%+)
- Over 1MM tpy CO_2
- High Purity CO_2 ("EOR & Sequestration ready")

Company History with CO_2 compression

Both Shell Cansolv and Royal Dutch Shell have been involved in CCS projects where CO_2 Compressors have been designed, installed and/or commissioned (Boundary Dam, Gorgon, Quest, Peterhead). Inside the Shell group, a rotations team is dedicated to large scale rotating equipment common within Shell projects, and their learnings and expertise are available for application in this project.

CLIENT : IEAGHG
PROJECT NAME : UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO_2 CAPTURE
DOCUMENT NAME : REFERENCE CASE 1: NGCC WITHOUT CCS
CONTRACT N° : 1-BD-1046 A

ISSUED BY : M. MENSI
CHECKED BY : V. TOTA
APPROVED BY : V. TOTA

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

GLOSSARY

CCS	Carbon Capture and Storage
NGCC	Natural Gas Combined Cycle
USC PC	Ultrasupercritical Pulverised Coal
FGR	Flue Gas Recirculation
EGR	Exhaust Gas Recirculation
CCU	Carbon Capture Unit
CMC	Ceramic Matrix Composite
ASU	Air Separation Unit
MCFC	Molten Carbonate Fuel Cell
TPC	Total Plant Cost
TIC	Total Installed Cost
MEL	Minimum Environmental Load
GT	Gas Turbine
ST	Steam Turbine

1. Introduction

This chapter of the report includes all technical information relevant to Case 1 of the study, which is a conventional natural gas combined cycle without carbon capture, located in the reference location (The Netherlands). The plant is designed to fire natural gas, whose characteristic is shown in chapter B, and produce electric power for export to the external grid.

The selected NGCC plant configuration is based on two parallel trains, each composed of one generic H-Class equivalent gas turbine and one Heat Recovery Steam Generator (HRSG) that generates steam at 2 levels of pressure, plus a LP integrated deaerator. The generated steam feeds one condensing type steam turbine (ST), common to the two parallel trains.

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
3000	Power Island	N/A
3100	Gas Turbine	2 x 50%
3200	HRSG	2 x 50%
3300	Steam Turbine	1 x 100%
6000	Utility and Offsite	N/A
	Natural draft cooling tower	1 x 100%

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 3000 – Power Island

Technical information relevant to these packages is reported in chapter C, section 2.1. 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.

Case specific main operating conditions which are affected by the location selection, i.e. ambient conditions and cooling system, are reported below.

Gas Turbine

At the site conditions of the reference case the gas turbine generates 520 MWe, which an efficiency of 43%.

HRSG

The exhaust gases from the gas turbine enter the HRSG at 641°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.

Details on steam generation conditions are listed in chapter B, section 4.3.3. The final exhaust gas temperature to the stack of the HRSG is 90°C.

Condenser

The exhaust stream from the LP section of the steam turbine is routed to a water-cooled steam condenser, which main conditions are listed below.

Cooling water approach	3°C
Condenser temperature	29°C
Condenser pressure	4.0 kPa

2.3. 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:

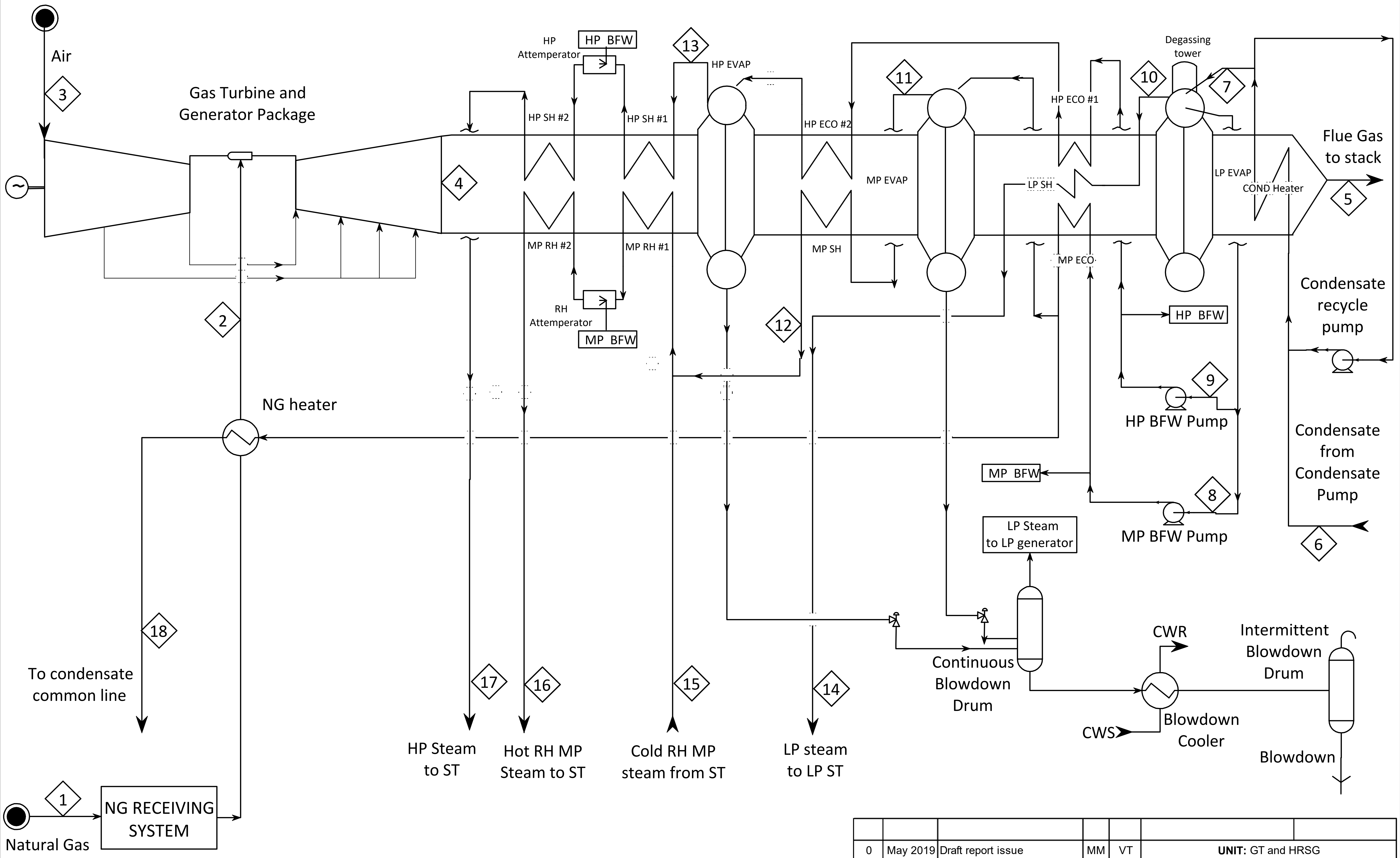
- Cooling Water system, based on one natural draft cooling tower, using fresh water as make-up water.

- Natural gas metering and conditioning station;
- Raw water system;
- Demineralised water plant;
- Firefighting system;
- Instrument and Plant air;
- Waste water treatment.

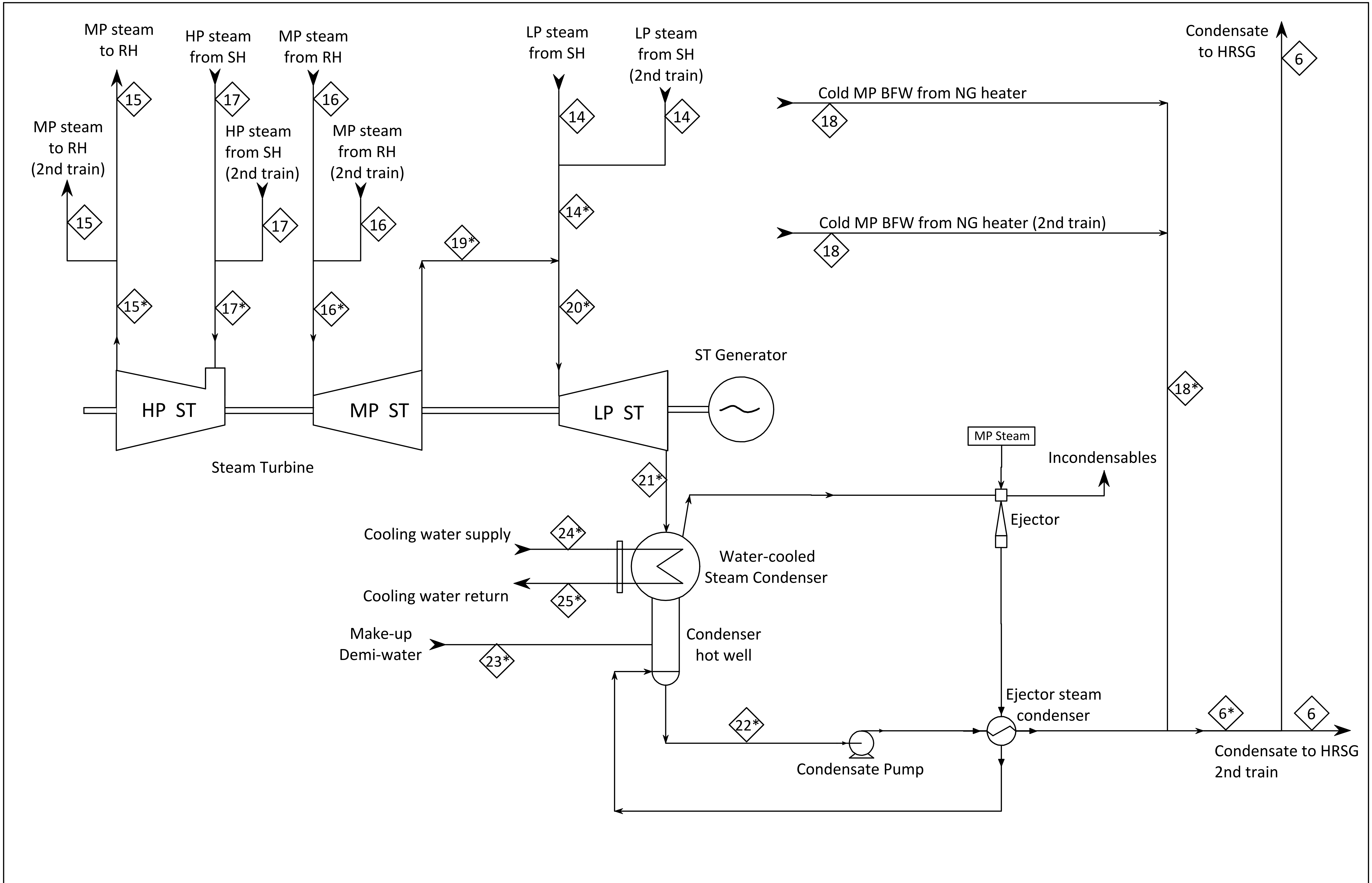
Process descriptions of the above systems are enclosed in chapter C, section 2.4.

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 2019	Draft report issue	MM	VT	**UNIT:** GT and HRSG	
Rev.	Date	Comment	By	Appr	**Case 1**	Sheet 01 of 02



0	May 2019	Draft report issue	MM	VT	**UNIT:** Steam turbine and condenser	
Rev.	Date	Comment	By	Appr	**Case1**	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.

	HEAT AND MATERIAL BALANCE		REVISION	0		
wood.	CLIENT :	IEAGHG	PREP.	MM		
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	AC		
	PROJECT NO:	1-BD-1046 A	APPROVED	VT		
	CASE:	Case 1 - NG CC w/o CCS	DATE	may-19		

HEAT AND MATERIAL BALANCE

Stream	Description		Flowrate t/h	Temperature °C	Pressure bar a	Enthalpy kJ/kg
1	Natural Gas	(note 3)	93.6	20	70.0	-
2	Heated Natural Gas to Gas Turbine	(note 3)	93.6	220	68.0	-
3	Air to Gas Turbine	(note 4)	3411.4	9	1.013	-
4	Gas Turbine Exhaust	(note 5)	3505.0	641	1.033	-
5	Flue gases to Stack	(note 5)	3505.0	90	1.015	-
6	Condensate to Condensate Heater		607.2	29	8.0	36
7	Heated Condensate to Deareator		787.0	55	8.0	39
8	Degassed Condensate to MP BFW Pump		140.7	159	6.0	25
9	Degassed Condensate to HP BFW Pump		432.4	159	6.0	25
10	LP Steam to LP Superheater		33.8	159	6.0	2512
11	MP Steam to MP Superheater		86.3	248	38.5	2571
12	Superheated MP Steam to MP Reheater #1		86.3	359	37.7	190
13	HP Steam to HP Superheater #1		430.2	359	185.0	2781
14	LP Steam to LP Steam Turbine		33.8	250	5.0	46
15	Cold RH MP Steam from Steam Turbine		427.0	357	37.2	187
16	Hot RH MP Steam to ST		513.3	600	35.6	202
17	HP Steam to Steam Turbine		430.2	600	180.1	796
18	Cold MP BFW to condensate common line		54.0	50	58.5	249
19*	LP Exhaust from MP Steam Turbine		1030.9	303	4.5	49
20*	Total LP Steam to LP Steam Turbine		1098.6	299	4.5	48
21*	Exhaust steam to Steam Condenser		1098.6	27	0.04	2348
22*	Condensate to Condensate Pump		1106.3	27	0.04	3
23*	Demineralized water make-up to Condenser Hot-Well		5.8	9	1.034	5
24*	Cooling Water Supply		53484.9	15	3.0	14
25*	Cooling Water Return		53484.9	26	2.5	13

Notes:
1) Streams marked up with * correspond to the total flow of two trains. The remaining figures are referred to single train
2) Enthalpy is shown for water streams only (steam, BFW, condensate)
3) Composition: CH_4 89%, C_2H_6 7%, C_3H_8 1%, C_4H_{10} 0.1%, C_5H_{12} 0.01%, CO_2 2%, N_2 0.89%
4) 80% Relative Humidity
5) Composition: O_2 11.1%, CO_2 4.6%, N_2 74%, Ar 0.9%, H_2O 9.4%,

5. Utility and chemicals consumption

Main utility consumption of the process and utility units is reported in the following tables. More specifically:

- Water consumption is shown in Table 2.
- Electrical consumption is shown in Table 3.

Table 2. Case 1 – Water consumption summary

CLIENT:	IEA GHG	REVISION	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	DATE	may-19
PROJECT No. :	1-BD-1046 A	MADE BY	MM
LOCATION :	Netherlands	APPROVED BY	VT

NG CC Plant without carbon capture
Case 1

WATER CONSUMPTION

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Primary Cooling Water System [t/h]	Secondary Cooling Water System [t/h]
3000	POWER ISLAND (Steam Turbine)				
3100	Gas Turbine Auxiliaries				2040
3200	Heat Recovery Steam Generator				20
3300	Steam Turbine auxiliaries	-5.8	5.8		2270
	Condenser			53490	
	CO_2 CAPTURE UNIT				
4000	CO_2 capture unit				
5000	CO_2 compression				
6000	UTILITY and OFFSITE UNITS				
	Cooling Water System	1040			
	Demineralized water unit	9	-5.8		
	Balance of plant				50
	BALANCE	1044	0	53490	4380

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

Table 3. Case 1 – Electrical consumption summary

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**DATE**	may-19
PROJECT No. :	1-BD-1046 A	**MADE BY**	MM
LOCATION :	Netherlands	**APPROVED BY**	VT

ELECTRICAL CONSUMPTION

UNIT	**DESCRIPTION UNIT**	**Absorbed Electric Power [kW]** Case 1
3000	**POWER ISLAND**	
3100	Gas turbine Auxiliaries	**2190**
3200	Heat Recovery Steam Generator	**8160**
3300	Steam Turbine Auxiliaries	**1700**
	Miscellanea	-
	CO_2 CAPTURE UNIT	**540**
4000	CO_2 Capture Unit	
5000	CO_2 Compression	
6000	**UTILITY and OFFSITE UNITS**	
	Cooling Water System	**6670**
	Balance of Plant	**150**
	BALANCE	**19,410**

6. Overall Performance

The following table shows the overall performance of Case 1.

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**DATE**	may-19
PROJECT No. :	1-BD-1046 A	**MADE BY**	MM
LOCATION :	Netherlands	**APPROVED BY**	VT

OVERALL PERFORMANCES

		Case 1
Fuel flow rate (A.R.)	t/h	187
Fuel HHV (A.R.)	kJ/kg	46502
Fuel LHV (A.R.)	kJ/kg	51473
THERMAL ENERGY OF FEEDSTOCK (based on LHV) (A)	**MWth**	**2418**
THERMAL ENERGY OF FEEDSTOCK (based on HHV) (A')	**MWth**	**2677**
Gas turbine power output (@ gen terminals)	MWe	1040.0
Steam turbine power output (@ gen terminals)	MWe	489.9
GROSS ELECTRIC POWER OUTPUT (@ gen terminals) (C)	**MWe**	**1529.929**
Power Islands consumption	MWe	12.6
Utility & Offsite Units consumption	MWe	6.8
CO2 Capture and compression unit	MWe	-
ELECTRIC POWER CONSUMPTION	**MWe**	**19.4**
NET ELECTRIC POWER OUTPUT	**MWe**	**1510.5**
(Step Up transformer efficiency = 0.997%) (B)	MWe	**1506.0**
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**63.3%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**62.3%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**57.2%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**56.3%**
Equivalent CO_2 flow in fuel	kmol/h	11268.6
Captured CO_2	kmol/h	0
CO_2 removal efficiency	**%**	**0.0%**
Fuel Consumption per net power production	**MWth/MWe**	**1.61**
CO_2 emission per net power production	**kg/MWh**	**331.3**

7. Environmental impact

The NGCC plant design is based on advanced technologies that allow to reach high electrical generation efficiency, while minimizing impact to the environment. Main gaseous emissions and liquid effluents 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 HRSG. Table 4 summarizes the expected flue gases flowrate and composition from one HRSG.

Table 4. Case 1 – Plant emission during normal operation (one HRSG)

Flue gas to stack	
Emission type	Continuous
Conditions	
Wet gas flowrate, kg/h	3,505,000
Flow, Nm^3/h (1)	3,659,400
Temperature, °C	90
Composition	(% vol)
Ar	0.906
N_2	74.015
O_2	11.096
CO_2	4.586
H_2O	9.422
Emission	mg/Nm^3 (1)
NOx	< 50
CO	< 50

(1) Dry gas, O_2 content 15% vol.

7.2. Liquid effluents

The NGCC plant does not produce significant liquid waste. HRSG blow-down is recovered as make-up in the cooling tower basin, so main liquid effluent is the cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids, and the eluate from the demineralised water unit, as summarised in Table 5. No process streams are fed to the WWT.

Table 5. Case 1 – Plant liquid effluent during normal operation

Plant effluent at BL	
Cooling Tower blow-down	248.5 m^3/h
Eluate from demi plant	3 m^3/h

7.3. Solid effluents

The plant does not produce significant solid waste.

8. Equipment list

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

	CLIENT:	IEAGHG	REVISION	Rev.0	Rev.1	Rev.2	Rev.3
	LOCATION:	The Netherlands	DATE	may-19			
	PROJ. NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	ISSUED BY	MM			
	CONTRACT N.	1-BD-1046 A	CHECKED BY	AC			
	CASE	1 - NG CC plant without CCS	APPROVED BY	VT			

EQUIPMENT LIST

Units Summary

UNIT 3100	**GAS TURBINE**
UNIT 3200	**HRSG**
UNIT 3300	**STEAM TURBINE**
UNIT 6000	**UTILITY AND OFFSITE**

		REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
CLIENT:	IEAGHG	DATE	may-19			
LOCATION:	The Netherlands	ISSUED BY	MM			
PROJ. NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED BY	AC			
CONTRACT N:.	1-BD-1046 A	APPROVED BY	VT			
CASE:	1 - NG CC plant without CCS					

EQUIPMENT LIST
Unit 3000 - Power Island

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	GAS TURBINE (UNIT 3100)							
PK- 3101-1/2	**Gas turbine and Generator Package**							***2 x 50% gas turbine package***
	Gas turbine		1040 MW					*One per train, two in total*
								Including:
								Lube oil system
								Cooling system
								Idraulic control system
								Electrical generator and relevant auxiliaries
	Performance Heaters	Multitube Enhanched HE	12310 kWth					
	HEAT RECOVERY STEAM GENERATOR (UNIT 3200)							
PK- 3201-1/2	**Heat recovery steam generator**	Horizontal, Natural Circulated, 3 Pressure Levels, Simple Recovery, Reheated						***2 x 50% HRSG package***
	Each including:							
D- 3201	HP steam drum		HPS generation: 430 t/h					
D- 3201	MP steam drum		MPS generation: 87 t/h					
D- 3201	LP steam drum with degassing section		LPS generation: 34 t/h					
E- 3201	HP Superheater 2nd section							
E- 3202	MP Reheater 2nd section							
E- 3203	HP Superheater 1st section							
E- 3204	MP Reheater 1st section							
E- 3205	HP Evaporator							
E- 3206	MP Superheater							
E- 3207	HP Economizer 2nd section							
E- 3208	LP Superheater							
E- 3209	MP Evaporator							
E- 3210	HP Economizer 1st section							
E- 3211	MP Economizer							
E- 3212	LP Evaporator							
E- 3213	Condensate heater							
X- 3201	HP steam desuperheater							
X- 3202	MP steam desuperheater							
X- 3203	Flue gas stack	cement stack						*Including silencer*
X- 3204	Continuous emission monitoring system							
	HEAT RECOVERY STEAM GENERATOR (UNIT 3200)							
	PUMPS		**Q [m3/h] x H [m]**					
P- 3201 A/B	HP BFW pumps	Centrifugal	493 m3/h x 3810 m	4190 kW				*One operating one spare, per each train*
P- 3202 A/B	MP BFW pumps	Centrifugal	159.8 m3/h x 502 m	280 kW				*One operating one spare, per each train*
	HEAT EXCHANGER							
	Blowdown cooler							
	DRUM							
	Continuous Blowdown drum							
	Intermittent Blowdown drum							
	PACKAGES (Common to both train)							
PK- 3202	**Fluid Sampling Package**							
PK- 3203	**Phosphate Injection Package**							
	Phosphate storage tank							
	Phosphate dosage pumps							*One operating one spare*
PK- 3204	**Oxygen scavenger Injection Package**							
	Oxygen scavenger storage tank							
	Oxygen scavenger dosage pumps							*One operating one spare*
PK- 3204	**Amine Injection Package**							
	Amine storage tank							
	Amine dosage pumps							*One operating one spare*
	STEAM TURBINE (UNIT 3300)							
PK- 3001	**Steam Turbine and Generator Package**							
ST- 3301	Steam Turbine		490 MWe					*Including:*
								Lube oil system
								Cooling system
								Idraulic control system
								Drainage system
								Seals system
								Drainage system
								Electrical generator and relevant auxiliaries
E- 3301 A/B	Inter/After Condenser							
E- 3302	Gland Condenser							
PK- 3002	**Steam Condenser Package**							*Including:*
E- 3001	Steam condenser		683 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**							
P- 3003 A/B	Condensate pump	Centrifugal	1108 m3/h x 150 m	800 kW				*One operating one spare, electric motor*

CLIENT:	IEAGHG			REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3	wood.
LOCATION:	The Netherlands			DATE	may-19				
PROJ. NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE			ISSUED BY	MM				
CONTRACT N:.	1-BD-1046 A			CHECKED BY	AC				
CASE:	1 - NG CC plant without CCS			APPROVED BY	VT				

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	740 MWth					
	PUMPS		**Q [m³/h] x H [m]**					
P- 6001 A/B/C/D	Cooling Water Pumps (primary system)	Centrifugal	14700 x 36	1626			superduplex	*Four in operation*
P- 6002 A/B/C/D	Cooling Water Pumps (secondary system)	Centrifugal	4800 x 46	610			superduplex	*Four in operation, one spare*
P- 6003 A/B	Cooling tower make-up pumps	Centrifugal	1040 x 36	160				*One in operation, one spare*
	PACKAGES							
	Cooling Water Filtration Package Cooling Water Sidestream Filters		Capacity: 6400 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		240 m3					*24 hour storage*
P- 6004 A/B	Raw water pumps to RO	Centrifugal	10 m3/h x 50 m	5.5				*One in operation, one spare*
	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		150 m3					*24 hour storage*
P- 6006 A/B	Demin water pump	Centrifugal	6 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							
	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 : EFFECTS OF PLANT LOCATION ON COSTS OF CO_2 CAPTURE
DOCUMENT NAME : REFERENCE CASE 2: NGCC WITH CCS
CONTRACT N° : 1-BD-1046 A

ISSUED BY : M.MENSI
CHECKED BY : V.TOTA
APPROVED BY : V.TOTA

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

GLOSSARY

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EGR	Exhaust Gas Recirculation
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CMC	Ceramic Matrix Composite
ASU	Air Separation Unit
MCFC	Molten Carbonate Fuel Cell
TPC	Total Plant Cost
TIC	Total Installed Cost
MEL	Minimum Environmental Load
GT	Gas Turbine
ST	Steam Turbine

1. Introduction

This chapter of the report includes all technical information relevant to Case 2 and 2.1 of the study, both being a conventional natural gas combined cycle with amine-based solvent washing carbon capture, located in the reference location (The Netherlands). The plant is designed to fire natural gas, whose characteristic is shown in chapter B, and produce electric power for export to the external grid.

The two cases are based on different capture rate: case 2 is the reference case with 90% CO_2 capture, while case 2.1 is based on high capture rate of 98.5%.

The selected NGCC plant configuration is based on two parallel trains, each composed of one generic H-Class equivalent gas turbine and one Heat Recovery Steam Generator (HRSG) that generates steam at 2 levels of pressure, plus a LP integrated deaerator. The generated steam feeds one condensing type steam turbine (ST), common to the two parallel trains.

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
3000	Power Island	N/A
3100	Gas Turbine	2 x 50%
3200	HRSG	2 x 50%
3300	Steam Turbine	1 x 100%
4000	CO_2 Amine Absorption Unit	
	Flue gas quencher	2 x 50%
	Absorber	2 x 50%
	Regenerator	2 x 50%
5000	CO_2 compression	2 x 50%
6000	Utility and Offsite	N/A
	Natural draft cooling tower	1 x 100%

1.2. Capture rate selection

This chapter summarises the performance of the NGCC plant at the two different capture rates.

The reference case 2 is based on 90% capture rate in order to provide the update of the benchmark case of the previous IEAGHG report 2018/4 "*Effect of plant location on CO_2 capture*".

The high capture case 2.1 is developed as recent researches have highlighted that 90% capture rate will not allow meeting the < 2°C temperature increase target and indicates that targeting 98-99% CO_2 capture will would not dramatically increase the cost of capture providing the capture unit is originally designed for this capture rate.

The additional cost for capture is related to the additional investment cost (e.g. larger regenerator, increased solvent circulation flowrate, increased reboiler surface, CO_2 compressor capacity) as well as to the increased energy demand in terms of the additional steam required by reboiler and the additional power consumptions of the capture and compression unit.

The table below reports the steam consumption and the regenerator size at different capture rate. As also shown the graph, steam consumption (and also regenerator diameter) shows a not linear behaviour with respect to the capture rate, and start increasing more rapidly between 98% and 99% capture rate.

Capture rate	**Reboiler duty**	**Stripper Diameter**
90% capture	-	-
98.5% capture	+ 24%	+9%
99% capture	+ 39%	+14%

Based on these results, 98.5% capture rate is selected for the development of the high capture case for this study (namely case 2.1).

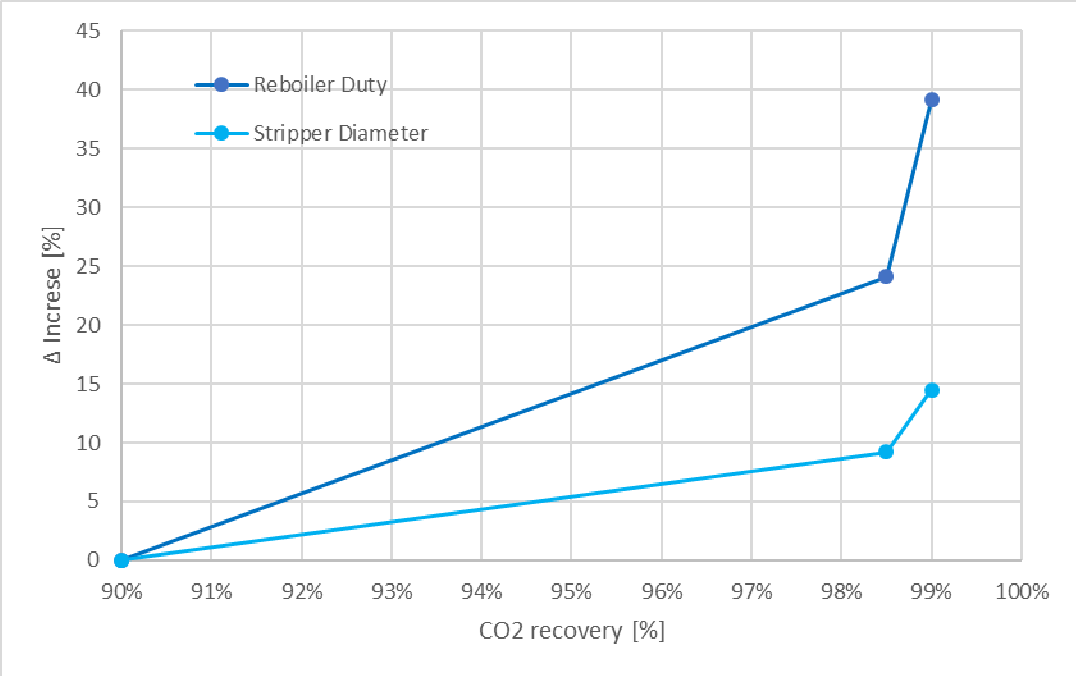


Figure 1. Reboiler duty vs. capture rate

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 3000 – Power Island

Technical information relevant to these packages is reported in chapter C, section 2.1. 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.

Case specific main operating conditions are reported below.

Gas Turbine

At the site conditions of the reference case the gas turbine generates 520 MWe, which an efficiency of 43%.

HRSG

The exhaust gases from the gas turbine enter the HRSG at 641°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. Details on steam generation conditions are listed in chapter B, section 4.3.3. The temperature of the exhaust gas from the HRSG 105°C. Prior entering the capture unit, flue gases are cooled down to 85°C in the gas-gas heater against decarbonised flue gas from the absorber.

Condenser

The exhaust stream from the LP section of the steam turbine is routed to a water-cooled steam condenser, which main conditions are listed below.

Cooling water approach	3°C
Condenser temperature	29°C
Condenser pressure	4.0 kPa

2.3. 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 D, section 2.2. Flue gas from the gas-gas heater coils in the HRSG enters the CO_2

capture unit at 70°C. Decarbonised flue gas from the absorber, saturated at around 32°C, are heated up to around 70°C in the gas-gas heater coil of the HRSG.

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.

2.4. Unit 5000 – CO_2 Compression and drying

The process description of CO_2 Compression and drying package is reported in chapter C, section 2.3.

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.

2.5. 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:

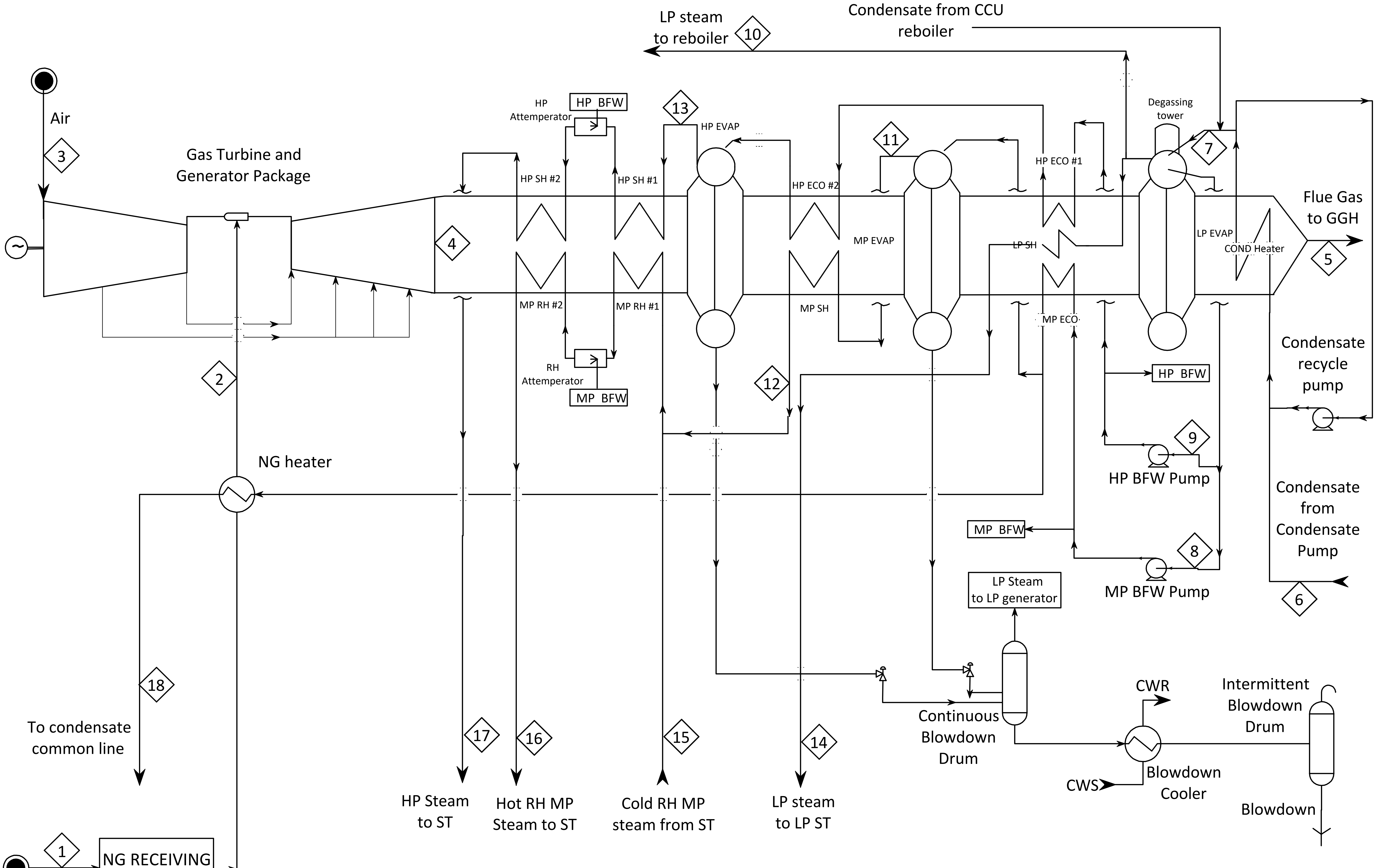
- Cooling Water system, based on one natural draft cooling towers, using fresh water as make-up water.

- Natural gas metering and conditioning station
- Raw water system;
- Demineralised water plant;
- Firefighting system;
- Instrument and Plant air;
- Waste water treatment.

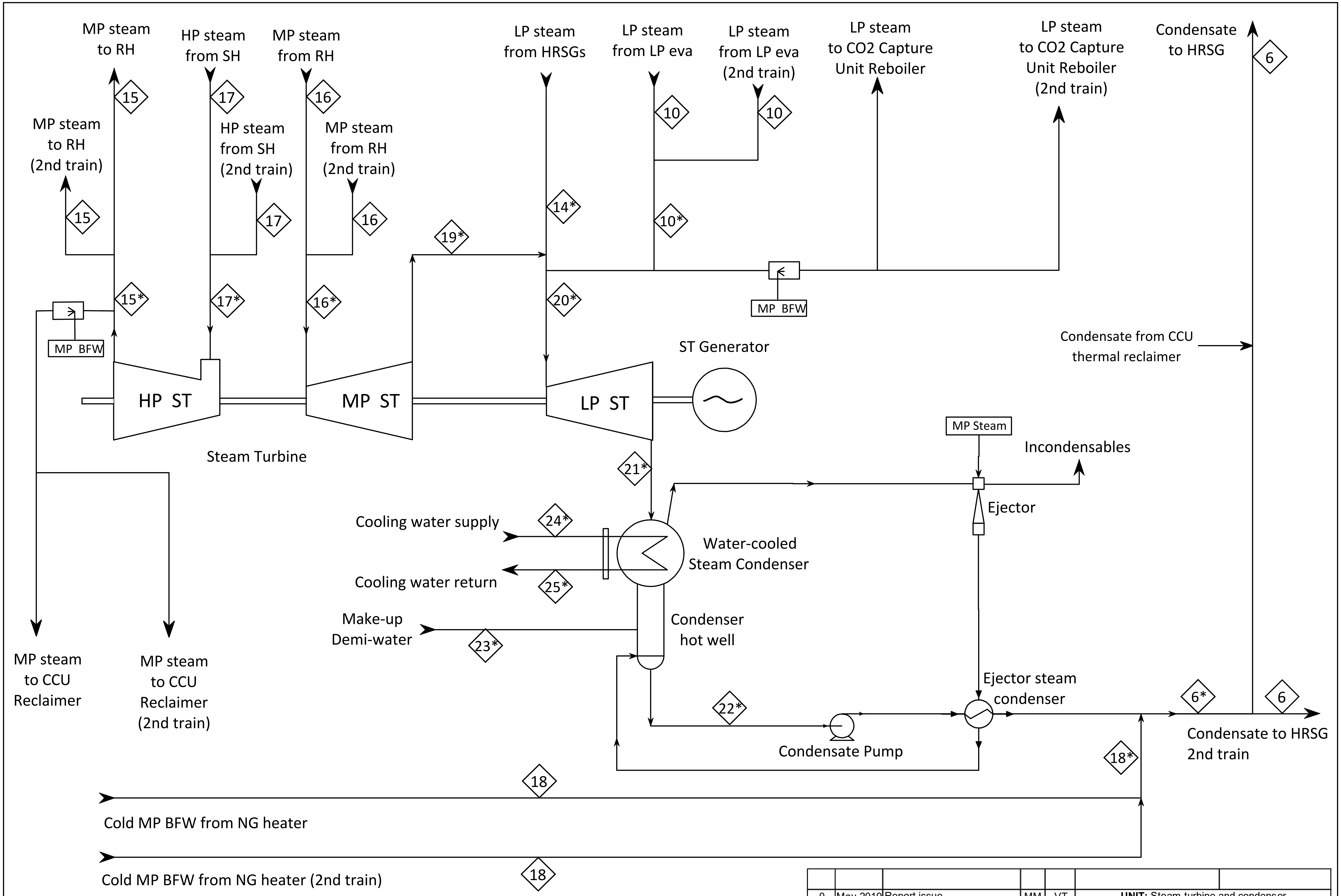
Process descriptions of the above systems are enclosed in chapter C, section 2.4.

3. Process Flow Diagrams

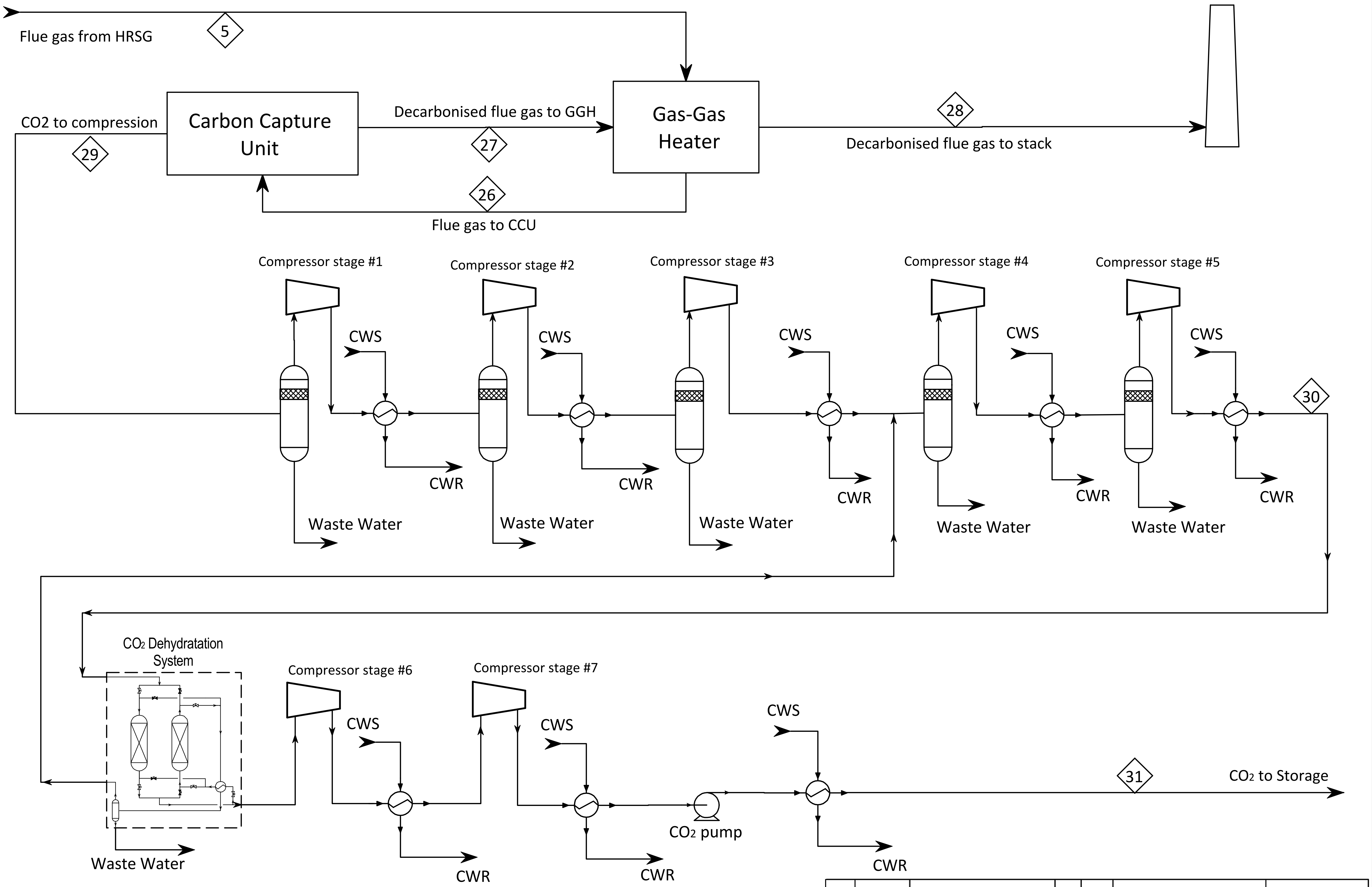
Simplified Process Flow Diagrams of this case are attached to this section. Stream numbers refer to the heat and material balance shown in the next section.



0	May 2019	Report issue	MM	VT	**UNIT:** GT and HRSG	
Rev.	Date	Comment	By	Appr	**Cases 2 - 2.1**	Sheet 01 of 03



0	May 2019	Report issue	MM	VT	**UNIT:** Steam turbine and condenser	
Rev.	Date	Comment	By	Appr	**Cases 2 - 2.1**	Sheet 02 of 03



0	May 2019	Report issue	MM	VT	**UNIT:** CO2 capture and compression	
Rev.	Date	Comment	By	Appr	**Cases 2 - 2.1**	Sheet 03 of 03

4. Heat and Material Balance

Heat & Material Balances here below reported make reference to the Process Flow Diagrams of section 3.

	HEAT AND MATERIAL BALANCE		REVISION	0		
wood.	CLIENT :	IEAGHG	PREP.	MM		
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	AC		
	PROJECT NO:	1-BD-1046 A	APPROVED	VT		
	CASE:	Case 2 - NG CC with CCS 90% capture rate	DATE	may-19		

HEAT AND MATERIAL BALANCE

Stream	Description		Flowrate t/h	Temperature °C	Pressure bar a	Enthalpy kJ/kg
1	Natural Gas	(note 3)	93.6	20	35	-
2	Heated Natural Gas to Gas Turbine	(note 3)	93.6	220	33	-
3	Air to Gas Turbine	(note 4)	3411.4	9	1.013	-
4	Gas Turbine Exhaust	(note 5)	3505.0	641	1.033	-
5	Flue gases to G-G Heater	(note 5)	3505.0	105	1.015	-
6	Condensate to Condensate Heater		342.4	31	8	37
7	Heated Condensate to Deareator		621.0	62	8	40
8	Degassed Condensate to MP BFW Pump		140.7	159	6	25
9	Degassed Condensate to HP BFW Pump		432.3	159	6	25
10	LP Steam to LP Superheater		0.0	159	6	2512
11	MP Steam to MP Superheater		86.3	248	38	2571
12	Superheated MP Steam to MP Reheater #1		86.3	359	38	190
13	HP Steam to HP Superheater #1		430.2	359	185	2781
14	LP Steam to LP Steam Turbine		47.6	159	6	41
15	Cold RH MP Steam from Steam Turbine		427.0	357	37	187
16	Hot RH MP Steam to ST		513.3	600	36	202
17	HP Steam to Steam Turbine		430.2	600	180	796
18	Cold MP BFW to condensate common line		54.0	50	58	249
19*	LP Exhaust from MP Steam Turbine		1030.9	327	6	55
20*	Total LP Steam to LP Steam Turbine		627.5	312	6	54
21*	Exhaust steam to Steam Condenser		627.5	27	0.04	2338
22*	Condensate to Condensate Pump		635.3	27	0.04	3
23*	Demineralized water make-up to Condenser Hot-Well		5.8	9	1.034	5
24*	Cooling Water Supply		30442.8	15	3.0	14
25*	Cooling Water Return		30442.8	26	2.5	13
26	Flue gas to Carbon Capture Unit (Note 5)		3505.0	70	1.011	-
27	Treated gas to Gas-Gas Heater (Note 6)		3278.3	32	1.015	-
28	Treated gas to stack (Note 6)		3278.3	70	1.013	-
29	CO_2 to compression (Note 7)		0.2	30	2.0	-
30	CO_2 to drying package (Note 8)		249.9	26	35	-
31	CO_2 to long term storage		224.6	30	110.0	-

Notes:

1) Streams marked up with * correspond to the total flow of two trains. The remaining figures are referred to single train
2) Enthalpy is shown for water streams only (steam, BFW, condensate)
3) Composition: CH4 89%, C2H6 7%, C3H8 1%, C4H10 0.1%, C5H12 0.01%, CO2 2%, N2 0.89%
4) 80% Relative Humidity
5) Composition: O2 11.1%, CO2 4.6%, N2 74%, Ar 0.9%, H2O 9.4%,
6) Composition: O2 12.8%, CO2 0.5%, N2 80.9%, Ar 1%, H2O 4.9%,
7) Water content: 2.1% v/v
8) Water content: 0.2% v/v

wood.	HEAT AND MATERIAL BALANCE		REVISION	0		
	CLIENT :	IEAGHG	PREP.	MM		
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	AC		
	PROJECT NO:	1-BD-1046 A	APPROVED	VT		
	CASE:	Case 2.1 - NG CC with CCS 98.5% capture rate	DATE	may-19		

HEAT AND MATERIAL BALANCE

Stream	Description		Flowrate t/h	Temperature °C	Pressure bar a	Enthalpy kJ/kg
1	Natural Gas	(note 3)	93.6	20	70	-
2	Heated Natural Gas to Gas Turbine	(note 3)	93.6	220	68	-
3	Air to Gas Turbine	(note 4)	3411.4	9	1.013	-
4	Gas Turbine Exhaust	(note 5)	3505.0	641	1.033	-
5	Flue gases to G-G Heater	(note 5)	3505.0	110	1.015	-
6	Condensate to Condensate Heater		276.1	32	8	37
7	Heated Condensate to Deareator		621.7	70	8	40
8	Degassed Condensate to MP BFW Pump		140.7	159	6	25
9	Degassed Condensate to HP BFW Pump		432.3	159	6	25
10	LP Steam to LP Superheater		0.0	159	6	2512
11	MP Steam to MP Superheater		86.3	248	38	2571
12	Superheated MP Steam to MP Reheater #1		86.3	359	38	190
13	HP Steam to HP Superheater #1		430.2	359	185	2781
14	LP Steam to LP Steam Turbine		48.3	159	6	41
15	Cold RH MP Steam from Steam Turbine		427.0	357	37	187
16	Hot RH MP Steam to ST		513.3	600	36	202
17	HP Steam to Steam Turbine		430.2	600	180	796
18	Cold MP BFW to condensate common line		54.0	50	58	249
19*	LP Exhaust from MP Steam Turbine		1030.9	327	6	55
20*	Total LP Steam to LP Steam Turbine		508.7	312	6	53
21*	Exhaust steam to Steam Condenser		508.7	27	0.04	2338
22*	Condensate to Condensate Pump		516.5	27	0.04	7
23*	Demineralized water make-up to Condenser Hot-Well		5.8	9	1.034	5
24*	Cooling Water Supply		24698.3	15	3.0	14
25*	Cooling Water Return		24698.3	26	2.5	13
26	Flue gas to Carbon Capture Unit (Note 5)		3505.0	74	1.011	-
27	Treated gas to Gas-Gas Heater (Note 6)		3257.0	33	1.015	-
28	Treated gas to stack (Note 6)		3257.0	74	1.013	-
29	CO_2 to compression (Note 7)		248.0	30	2.0	-
30	CO_2 to drying package (Note 8)		273.4	26	35	-
31	CO_2 to long term storage		245.8	30	110.0	-

Notes:
1) Streams marked up with * correspond to the total flow of two trains. The remaining figures are referred to single train
2) Enthalpy is shown for water streams only (steam, BFW, condensate)
3) Composition: CH4 89%, C2H6 7%, C3H8 1%, C4H10 0.1%, C5H12 0.01%, CO2 2%, N2 0.89%
4) 80% Relative Humidity
5) Composition: O2 11.1%, CO2 4.6%, N2 74%, Ar 0.9%, H2O 9.4%,
6) Composition: O2 12.8%, CO2 0.1%, N2 81.1%, Ar 1%, H2O 5.1%,
7) Water content: 2.1% v/v
8) Water content: 0.2% v/v

5. Utility and chemicals consumption

Main utility consumption of the process and utility units is reported in the following tables.

Table 2. Case 2 – Water consumption summary

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**DATE**	mar-19
PROJECT No. :	1-BD-1046 A	**MADE BY**	MM
LOCATION :	Netherlands	**APPROVED BY**	VT

NG CC Plant with CCS 90% capture rate
Case 2

WATER CONSUMPTION

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Primary Cooling Water System [t/h]	Secondary Cooling Water System [t/h]
3000	**POWER ISLAND (Steam Turbine)**				
3100	Gas Turbine Auxiliaries				**2040**
3200	Heat Recovery Steam Generator				**20**
3300	Steam Turbine auxiliaries	**-5.8**	**5.8**		**1800**
	Condenser			**30610**	
	CO_2 CAPTURE UNIT				
4000	CO_2 capture unit				
			29		**55590**
5000	CO_2 compression				
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water System	**1617**			
	Demineralized water unit	**53**	**-34.8**		
	Waste Water Treatment	**-228**			
	Balance of plant				**50**
	BALANCE	**1436**	**0**	**30610**	**59500**

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

Table 3. Case 2.1 – Water consumption summary

CLIENT:	IEA GHG	REVISION	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	DATE	mar-19
PROJECT No. :	1-BD-1046 A	MADE BY	MM
LOCATION :	Netherlands	APPROVED BY	VT

NG CC Plant with CCS 98.5% capture rate
Case 2.1

WATER CONSUMPTION

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Primary Cooling Water System [t/h]	Secondary Cooling Water System [t/h]
3000	POWER ISLAND (Steam Turbine)				
3100	Gas Turbine Auxiliaries				2040
3200	Heat Recovery Steam Generator				20
3300	Steam Turbine auxiliaries	-5.8	5.8		1690
	Condenser			24700	
	CO_2 CAPTURE UNIT				
4000	CO_2 capture unit		29		62390
5000	CO_2 compression				
6000	UTILITY and OFFSITE UNITS				
	Cooling Water System	1636			
	Demineralized water unit	53	-34.8		
	Waste Water Treatment	-211			
	Balance of plant				50
	BALANCE	1472	0	24700	66190

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

Table 4. Case 2 and 2.1 – Electrical consumption summary

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**DATE**	may-19
PROJECT No. :	1-BD-1046 A	**MADE BY**	MM
LOCATION :	Netherlands	**APPROVED BY**	VT

ELECTRICAL CONSUMPTION

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW] Case 2	Absorbed Electric Power [kW] Case 2.1
3000	**POWER ISLAND**		
3100	Gas turbine Auxiliaries	**2190**	**2190**
3200	Heat Recovery Steam Generator	**8120**	**8100**
3300	Steam Turbine Auxiliaries	**1180**	**1060**
	Miscellanea	**540**	**540**
	CO_2 CAPTURE UNIT		
4000	CO_2 Capture Unit	**55223**	**58562**
5000	CO_2 Compression		
6000	**UTILITY and OFFSITE UNITS**		
	Cooling Water System	**12550**	**12890**
	Balance of Plant	**450**	**450**
	BALANCE	**80,253**	**83,792**

6. Overall Performance

The following table shows the overall performance of Case 2 and case 2.1.

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**DATE**	may-19
PROJECT No. :	1-BD-1046 A	**MADE BY**	MM
LOCATION :	Netherlands	**APPROVED BY**	VT

OVERALL PERFORMANCES

		Case 2 90% CO2 rec.	Case 2.1 98.5% CO2 rec.
Fuel flow rate (A.R.)	t/h	187	187
Fuel HHV (A.R.)	kJ/kg	46502	46502
Fuel LHV (A.R.)	kJ/kg	51473	51473
THERMAL ENERGY OF FEEDSTOCK (based on LHV) (A)	**MWth**	**2418**	**2417**
THERMAL ENERGY OF FEEDSTOCK (based on HHV) (A')	**MWth**	**2677**	**2676**
Gas turbine power output (@ gen terminals)	MWe	1040.0	1040.0
Steam turbine power output (@ gen terminals)	MWe	388.5	363.7
GROSS ELECTRIC POWER OUTPUT (@ gen terminals) (C)	**MWe**	**1428.5**	**1403.7**
Power Islands consumption	MWe	12.0	11.9
Utility & Offsite Units consumption	MWe	13.0	13.3
CO2 Capture and compression unit	MWe	55.2	58.6
ELECTRIC POWER CONSUMPTION	**MWe**	**80.3**	**83.8**
NET ELECTRIC POWER OUTPUT	**MWe**	**1348.3**	**1319.9**
(Step Up transformer efficiency = 0.997%) (B)	MWe	**1344.2**	**1316.0**
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**59.1%**	**58.1%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**55.6%**	**54.4%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**53.4%**	**52.5%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**50.2%**	**49.2%**
Fuel Consumption per net power production	**MWth/MWe**	**1.80**	**1.84**
CO_2 emission per net power production	**kg/MWh**	**36.9**	**5.6**

The following table shows the overall CO_2 balance and removal efficiency of Cases 2 & 2.1.

CO_2 removal efficiency	**Equivalent flow of CO_2**	
	Case 2 90% CO2 rec.	Case 2.1 98.5% CO2 rec.
	kmol/h	kmol/h
INPUT		
FUEL CARBON CONTENT (A)	11269	11269
CO_2 in air (B)	67	67
OUTPUT		
Carbon losses (D)	0	0
CO_2 flue gas content	11336	11336
Total to storage (C)	10264	11192
Emission	1072	144
TOTAL	11336	11336
Overall Carbon Capture, % ((C+D)/(A+B))	90.5	98.7

7. Environmental impact

The NGCC plant design is based on advanced technologies that allow to reach high electrical generation efficiency, while minimizing impact to the environment. Main gaseous emissions and liquid effluents 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 top of the absorber. Table 5 summarizes the expected flue gases flowrate and composition from each train.

Table 5. Cases 2 and 2.1 – Plant emission during normal operation

Flue gas to stack	**Case 2**	**Case 2.1**
Emission type	Continuous	Continuous
Conditions		
Wet gas flowrate, kg/h	3,280,000	3,257,000
Flow, Nm^3/h (1)	3,124,000	3,083,000
Temperature, °C	70	74
Composition	(% vol)	(% vol)
Ar	0.97	0.97
N_2	80.93	81.07
O_2	12.78	12.80
CO_2	0.46	0.06
H_2O	4.86	5.10
Emission	mg/Nm^3 (1)	mg/Nm^3 (1)
NOx	< 50 mg/Nm^3	< 50 mg/Nm^3
CO	< 50 mg/Nm^3	< 50 mg/Nm^3

(1) Dry gas, O_2 content 15% vol.

7.2. Liquid effluents

The NGCC plant does not produce significant liquid waste. CO_2 capture and compression unit blow-downs are treated to recover water, so main liquid effluent is cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids, and the waste water from WWT (including the eluate from the demineralised water unit). Steam cycle blowdown is entirely recovered as cooling tower make-up.

Table 6 summarises main plant liquid effluent to be discharge to the final destination (e.g. river), and the main unit blowdown to be treated in the WWT in order to recover water and reduce plant raw water make-up.

Table 6. Case 2 and 2.1 – Plant liquid effluent during normal operation

Plant effluent at BL	**Case 2**	**Case 2.1**
Cooling Tower blow-down	386 m^3/h	391 m^3/h
Waste water from WWT + eluate from demi plant	5 m^3/h	5 m^3/h
Waste Water treatment inlet stream		
CO_2 capture unit blow-down (*)	108 m^3/h	108 m^3/h

(*) Net blowdown, already reduced by the part of the treated water recycled back to the absorber. Separated figure not shown due to confidentiality issues

7.3. Solid effluents

The plant does not produce significant solid waste.

8. Equipment list

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

	CLIENT: IEAGHG	REVISION	Rev.0	Rev.1	Rev.2	Rev.3	
	LOCATION: The Netherlands	DATE	may-19				
	PROJ. NAME: UPDATE TECHNO-ECONOMIC BENCHMARKS	ISSUED BY	MM				
	CONTRACT N. 1-BD-1046 A	CHECKED BY	AC				
	CASE 2 - NG CC plant with 90% CCS	APPROVED BY	VT				

EQUIPMENT LIST
Units Summary

UNIT 3100	**GAS TURBINE**
UNIT 3200	**HRSG**
UNIT 3300	**STEAM TURBINE**
UNIT 4000	**$C0_2$ AMINE ABSORPTION**
UNIT 5000	**$C0_2$ COMPRESSION**
UNIT 6000	**UTILITY AND OFFSITE**

CLIENT:	IEAGHG	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
LOCATION:	The Netherlands	DATE	may-19			
PROJ. NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	ISSUED BY	MM			
CONTRACT N:.	1-BD-1046 A	CHECKED BY	AC			
CASE:	2 - NG CC plant with 90% CCS	APPROVED BY	VT			

EQUIPMENT LIST
Unit 3000 - Power Island

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	GAS TURBINE (UNIT 3100)							
PK- 3101-1/2	**Gas turbine and Generator Package**							***2 x 50% gas turbine package***
	Gas turbine		1040 MW					*One per train, two in total*
								Including:
								Lube oil system
								Cooling system
								Idraulic control system
								Electrical generator and relevant auxiliaries
	Performance Heaters	Multitube Enhanched HE	12310 kWth					
	HEAT RECOVERY STEAM GENERATOR (UNIT 3200)							
PK- 3201-1/2	**Heat recovery steam generator**	Horizontal, Natural Circulated, 3 Pressure Levels, Simple Recovery, Reheated						***2 x 50% HRSG package***
	Each including:							
D- 3201	HP steam drum		HPS generation: 430 t/h					
D- 3201	MP steam drum		MPS generation: 86 t/h					
D- 3201	LP steam drum with degassing section		LPS generation: 47 t/h					
E- 3201	HP Superheater 2nd section							
E- 3202	MP Reheater 2nd section							
E- 3203	HP Superheater 1st section							
E- 3204	MP Reheater 1st section							
E- 3205	HP Evaporator							
E- 3206	MP Superheater							
E- 3207	HP Economizer 2nd section							
E- 3208	LP Superheater							
E- 3209	MP Evaporator							
E- 3210	HP Economizer 1st section							
E- 3211	MP Economizer							
E- 3212	LP Evaporator							
E- 3213	Condensate heater							
X- 3201	HP steam desuperheater							
X- 3202	MP steam desuperheater							
X- 3203	Flue gas stack	cement stack						*Including silencer*
X- 3204	Continuous emission monitoring system							
	HEAT RECOVERY STEAM GENERATOR (UNIT 3200)							
	PUMPS		**Q [m3/h] x H [m]**					
P- 3201 A/B	HP BFW pumps	Centrifugal	491.7 m3/h x 3788 m	4170 kW				*One operating one spare, per each train*
P- 3202 A/B	MP BFW pumps	Centrifugal	160 m3/h x 491 m	280 kW				*One operating one spare, per each train*
	HEAT EXCHANGER							
	Blowdown cooler							
	GAS-GAS HEAT EXCHANGER		Hot side flowrate: 2663 x10^3 Nm3/h Cold side flowrate: 2504 x10^3 Nm3/h Duty: 34.7 MWth					*One per each train*
	DRUM							
	Continuous Blowdown drum							
	Intermittent Blowdown drum							
	PACKAGES (Common to both train)							
PK- 3202	**Fluid Sampling Package**							
PK- 3203	**Phosphate Injection Package**							
	Phosphate storage tank							
	Phosphate dosage pumps							*One operating one spare*
PK- 3204	**Oxygen scavenger Injection Package**							
	Oxygen scavenger storage tank							
	Oxygen scavenger dosage pumps							*One operating one spare*
PK- 3204	**Amine Injection Package**							
	Amine storage tank							
	Amine dosage pumps							*One operating one spare*
	STEAM TURBINE (UNIT 3300)							
PK- 3001	**Steam Turbine and Generator Package**							
ST- 3301	Steam Turbine		389 MWe					*Including:*
								Lube oil system
								Cooling system
								Idraulic control system
								Drainage system
								Seals system
								Drainage system
								Electrical generator and relevant auxiliaries
E- 3301 A/B	Inter/After Condenser							
E- 3302	Gland Condenser							
PK- 3002	**Steam Condenser Package**							*Including:*
E- 3001	Steam condenser		390 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**							
P- 3003 A/B	Condensate pump	Centrifugal	638 m3/h x 150 m	450 kW				*One operating one spare, electric motor*

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CASE:	2 - NG CC plant with 90% CCS					

EQUIPMENT LIST
Unit 4000 - CO2 Capture Unit

	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: 2770200 Nm3/h CO2 product: 116000 Nm3/h 98% purity Treated gas flowrate: 2602900 Nm3/h CO2 capture rate: 90%					2 x 50%
	PUMPS							
	For each train:							
K001	Flue gas Blower							
P001-A/B	Prescrubber water circulation pumps							
P002-A/B	Prescrubber polishing pumps							
P003-A/B	Absorber intercoolers pumps							
P004-A/B	Wash water pumps							
P005-A/B	Rich amine pumps							
P006-A/B	Stripper reflux pumps							
P007-A/B	Lean amine pumps							
P008-A/B	Amine feed pump							
P009	Make up amine pump							
P010-A/B	Steam condensate return pumps							
	DRUMS / COLUMNS / TANKS							
	For each train:							
D-001	Direct contact cooler (square)							
D-002	CO2 absorber							
D-003	CO2 stripper							
V-001	Stripper reflux drum							
V-002	Steam condensate drum							
T-001	Lean amine tank							
V-003	Lean amine flash tank							
	HEAT EXCHANGERS							
	For each train:							
E-001	DCC cooler							
E-002	Wash Water cooler							
E-003	Lean / rich exchanger							
E-004	Stripper condenser							
E-005	Stripper reboiler							
E-006	Lean amine cooler							
E-007	Absorber intercooler							
	MISCELLANEA							
	For each train:							
F-001	Lean amine filter							
F-002	Amine purification unit							
F-003	Thermal reclaimer							
F-004	CO2 Lean Absorbent Flash MVR system							

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wood.

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	116000 Nm3/h P in: 2 bar a P out: 80 bar a	17523.81 kW				Intercooling: Condensate from Power island Cooling Water
	PUMPS		**Q,m3/h x H,m**					
P - 5001	CO_2 Pump	Centrifugal	315 m3/h x 450 m	400 kW				Liquid CO2 product, per each train: Flowrate: 225 t/h; 111 bar a; 30°C
	PACKAGE							
PK - 5001	CO_2 drying package							

Note 1: Equipment shown are for one train only

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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	**Cooling Tower** including: Cooling water basin	Natural draft	1150 MWth					
	PUMPS		**Q [m^3/h] x H [m]**					
P- 6001 A/B/C/D	Cooling Water Pumps (primary system)	Centrifugal	11200 x 36	1241			superduplex	*Four in operation*
P- 6002 A/B/C/D	Cooling Water Pumps (secondary system)	Centrifugal	13100 x 46	610			superduplex	*Four in operation, one spare*
P- 6003 A/B	Cooling tower make-up pumps	centrifugal	1620 x 36	250				*One in operation, one spare*
	PACKAGES							
	Cooling Water Filtration Package Cooling Water Sidestream Filters		Capacity: 9900 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		1280 m3					*24 hour storage*
P- 6004 A/B	Raw water pumps to RO	centrifugal	53 m3/h x 50 m	11				*One in operation, one spare*
	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		150 m3					*24 hour storage*
P- 6006 A/B	Demin water pump	centrifugal	6 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							
	MISCELLANEA							
	Plant air compression skid							
	Emergency diesel generator system							
	Waste water treatment system							
	Electrical equipment							
	Buildings							
	Auxiliary boiler							
	Condensate Polishing system							

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EQUIPMENT LIST

Units Summary

UNIT 3100	**GAS TURBINE**
UNIT 3200	**HRSG**
UNIT 3300	**STEAM TURBINE**
UNIT 4000	**$C0_2$ AMINE ABSORPTION**
UNIT 5000	**$C0_2$ COMPRESSION**
UNIT 6000	**UTILITY AND OFFSITE**

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EQUIPMENT LIST

Unit 3000 - Power Island

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	GAS TURBINE (UNIT 3100)							
PK- 3101-1/2	**Gas turbine and Generator Package**							***2 x 50% gas turbine package***
	Gas turbine		1040 MW					*One per train, two in total*
								Including:
								Lube oil system
								Cooling system
								Idraulic control system
								Electrical generator and relevant auxiliaries
	Performance Heaters	Multitube Enhanched HE	12310 kWth					
	HEAT RECOVERY STEAM GENERATOR (UNIT 3200)							
PK- 3201-1/2	**Heat recovery steam generator**	Horizontal, Natural Circulated, 3 Pressure Levels, Simple Recovery, Reheated						***2 x 50% HRSG package***
	Each including:							
D- 3201	HP steam drum		HPS generation: 430 t/h					
D- 3201	MP steam drum		MPS generation: 86 t/h					
D- 3201	LP steam drum with degassing section		LPS generation: 48 t/h					
E- 3201	HP Superheater 2nd section							
E- 3202	MP Reheater 2nd section							
E- 3203	HP Superheater 1st section							
E- 3204	MP Reheater 1st section							
E- 3205	HP Evaporator							
E- 3206	MP Superheater							
E- 3207	HP Economizer 2nd section							
E- 3208	LP Superheater							
E- 3209	MP Evaporator							
E- 3210	HP Economizer 1st section							
E- 3211	MP Economizer							
E- 3212	LP Evaporator							
E- 3213	Condensate heater							
X- 3201	HP steam desuperheater							
X- 3202	MP steam desuperheater							
X- 3203	Flue gas stack	cement stack						*Including silencer*
X- 3204	Continuous emission monitoring system							
	HEAT RECOVERY STEAM GENERATOR (UNIT 3200)							
	PUMPS		**Q [m3/h] x H [m]**					
P- 3201 A/B	HP BFW pumps	Centrifugal	491.7 m3/h x 3788 m	4170 kW				*One operating one spare, per each train*
P- 3202 A/B	MP BFW pumps	Centrifugal	160 m3/h x 491 m	280 kW				*One operating one spare, per each train*
	HEAT EXCHANGER							
	Blowdown cooler							
	GAS-GAS HEAT EXCHANGER		Hot side flowrate: 2663 x10^3 Nm3/h Cold side flowrate: 2487 x10^3 Nm3/h Duty: 36.7 MWth					*One per each train*
	DRUM							
	Continuous Blowdown drum							
	Intermittent Blowdown drum							
	PACKAGES (Common to both train)							
PK- 3202	**Fluid Sampling Package**							
PK- 3203	**Phosphate Injection Package**							
	Phosphate storage tank							
	Phosphate dosage pumps							*One operating one spare*
PK- 3204	**Oxygen scavenger Injection Package**							
	Oxygen scavenger storage tank							
	Oxygen scavenger dosage pumps							*One operating one spare*
PK- 3204	**Amine Injection Package**							
	Amine storage tank							
	Amine dosage pumps							*One operating one spare*
	STEAM TURBINE (UNIT 3300)							
PK- 3001	**Steam Turbine and Generator Package**							
ST- 3301	Steam Turbine		364 MWe					*Including:*
								Lube oil system
								Cooling system
								Idraulic control system
								Drainage system
								Seals system
								Drainage system
								Electrical generator and relevant auxiliaries
E- 3301 A/B	Inter/After Condenser							
E- 3302	Gland Condenser							
PK- 3002	**Steam Condenser Package**							*Including:*
E- 3001	Steam condenser		316 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**							
P- 3003 A/B	Condensate pump	Centrifugal	520 m3/h x 150 m	375 kW				*One operating one spare, electric motor*

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EQUIPMENT LIST
Unit 4000 - CO2 Capture Unit

	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: 2770200 Nm3/h CO2 product: 116000 Nm3/h 98% purity Treated gas flowrate: 2716500 Nm3/h CO2 capture rate: 90%					2 x 50%
	PUMPS							
	For each train:							
K001	Flue gas Blower							
P001-A/B	Prescrubber water circulation pumps							
P002-A/B	Prescrubber polishing pumps							
P003-A/B	Absorber intercoolers pumps							
P004-A/B	Wash water pumps							
P005-A/B	Rich amine pumps							
P006-A/B	Stripper reflux pumps							
P007-A/B	Lean amine pumps							
P008-A/B	Amine feed pump							
P009	Make up amine pump							
P010-A/B	Steam condensate return pumps							
	DRUMS / COLUMNS / TANKS							
	For each train:							
D-001	Direct contact cooler (square)							
D-002	CO2 absorber							
D-003	CO2 stripper							
V-001	Stripper reflux drum							
V-002	Steam condensate drum							
T-001	Lean amine tank							
V-003	Lean amine flash tank							
	HEAT EXCHANGERS							
	For each train:							
E-001	DCC cooler							
E-002	Wash Water cooler							
E-003	Lean / rich exchanger							
E-004	Stripper condenser							
E-005	Stripper reboiler							
E-006	Lean amine cooler							
E-007	Absorber intercooler							
	MISCELLANEA							
	For each train:							
F-001	Lean amine filter							
F-002	Amine purification unit							
F-003	Thermal reclaimer							
F-004	CO2 Lean Absorbent Flash MVR system							

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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	128000 Nm3/h P in: 2 bar a P out: 80 bar a	19172.2 kW				Intercooling: Condensate from Power island Cooling Water
	PUMPS		**Q,m3/h x H,m**					
P - 5001	CO_2 Pump	Centrifugal	360 m3/h x 450 m	450 kW				Liquid CO2 product, per each train: Flowrate: 249 t/h; 111 bar a; 30°C
	PACKAGE							
PK - 5001	CO_2 drying package							

Note 1: Equipment shown are for one train only

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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	**Cooling Tower** including: Cooling water basin	Natural draft	1160 MWth					
	PUMPS		**Q [m^3/h] x H [m]**					
P- 6001 A/B/C/D	Cooling Water Pumps (primary system)	Centrifugal	13600 x 36	1502			superduplex	*Four in operation*
P- 6002 A/B/C/D	Cooling Water Pumps (secondary system)	Centrifugal	14600 x 46	610			superduplex	*Four in operation, one spare*
P- 6003 A/B	Cooling tower make-up pumps	centrifugal	1637 x 36	250				*One in operation, one spare*
	PACKAGES							
	Cooling Water Filtration Package Cooling Water Sidestream Filters		Capacity: 10000 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		1280 m3					*24 hour storage*
P- 6004 A/B	Raw water pumps to RO	centrifugal	53 m3/h x 50 m	11				*One in operation, one spare*
	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		150 m3					*24 hour storage*
P- 6006 A/B	Demin water pump	centrifugal	6 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							
	MISCELLANEA							
	Plant air compression skid							
	Emergency diesel generator system							
	Waste water treatment system							
	Electrical equipment							
	Buildings							
	Auxiliary boiler							
	Condensate Polishing system							

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DOCUMENT NAME : REFERENCE CASE 3: NGCC WITH CCS AND FGR
CONTRACT N° : 1-BD-1046 A

ISSUED BY : M. MENSI
CHECKED BY : V. TOTA
APPROVED BY : V. TOTA

Date	Revised Pages	Issued by	Checked by	Approved by

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GLOSSARY

CCS	Carbon Capture and Storage
NGCC	Natural Gas Combined Cycle
USC PC	Ultrasupercritical Pulverised Coal
FGR	Flue Gas Recirculation
EGR	Exhaust Gas Recirculation
CCU	Carbon Capture Unit
CMC	Ceramic Matrix Composite
ASU	Air Separation Unit
MCFC	Molten Carbonate Fuel Cell
TPC	Total Plant Cost
TIC	Total Installed Cost
MEL	Minimum Environmental Load
GT	Gas Turbine
ST	Steam Turbine

1. Introduction

This chapter of the report includes all technical information relevant to Case 2.2 and 2.3 of the study, both being a conventional natural gas combined cycle with amine-based solvent washing carbon capture and partial flue gas recirculation, located in the reference location (The Netherlands). The plant is designed to fire natural gas, whose characteristic is shown in chapter B, and produce electric power for export to the external grid.

The two cases are designed for different capture rates: case 2.2 is the reference case with 90% CO_2 capture, while case 2.3 is based on high capture rate of 98.5%.

In summary, the selected NGCC plant configuration of the two case 2.2 and 2.3 is in summary the same as cases 2 and 2.1 respectively (ref. to section C.1), with the addition of a partial Flue Gas Recirculation from the outlet of the HRSG to the suction of the GT compressor. At the same capture rate, this recirculation will drive a a sensible reduction of the flue gas flow through the absorber with a higher CO2 content, leading to savings to the capital cost of this section of the CO2 absorption unit. The other techno-economic impacts will be taken into account to evaluate the overall techno-economic performance of theses cases in comparison to the corresponding cases With CCS without FGR.

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
3000	Power Island	N/A
3100	Gas Turbine	2 x 50%
3200	HRSG	2 x 50%
3300	Steam Turbine	1 x 100%
4000	CO_2 Amine Absorption Unit	
	Flue gas quencher	2 x 50%
	Absorber	2 x 50%

Unit	Description	Trains
	Regenerator	2 x 50%
5000	CO_2 compression	2 x 50%
6000	Utility and Offsite	N/A
	Natural draft cooling tower	1 x 100%

1.2. Capture rate selection

The capture rates for cases 2.2 and 2.3 are the same as cases 2 and 2.1 respectively, in order to allow a straightforward comparison with the base cases without FGR.

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 3000 – Power Island

Technical information relevant to these packages is reported in chapter C, section 2.1. 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.

Case specific main operating conditions are reported below.

Gas Turbine

At the site conditions of the reference case the gas turbine generates 498 MWe, with an efficiency of 41.73%. This performance estimate takes into account partial exhaust gas recycle from the inlet of the CO2 capture Unit, as described in para 2.3. downstream Air Intake Filter. The cooled Flue Gas is routed to Gas Turbine Compressor suction, downstream Air Intake Filter, through a dedicated fan, keeping the GT exhaust pressure loss identical to the case without FGR.

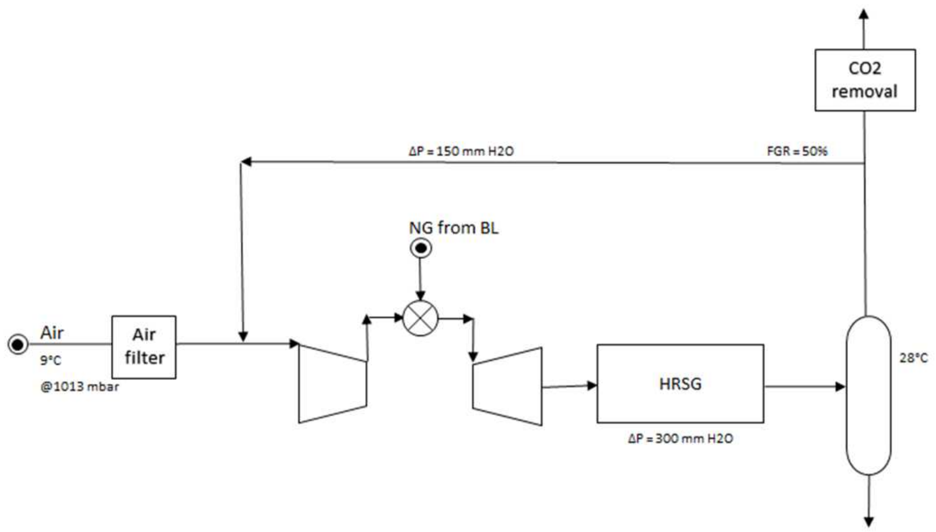
The following key parameter have been considered for the definition of the gas turbine performance.

- Same H-class machine considered for Cases 2 and 2.1. No major design modifications are included with respect to the reference case without FGR.
- Flue gas recirculation ratio, expressed as flue gas recirculated to total flue gas through HRSG is selected to meet an O2 content of 3% at GT exhaust, in line with the information provided by Ansaldo Energia; the resulting recirculation ratio is approx. 47%
- Flue gas recycle temperature at mixing point with ambient air at GT compressor suction is 30°C.
- Compression ratio corrected to keep the same GT compressor basic geometry as the reference case without FGR.
- Volumetric air flow corrected for different Cp/Cv with respect to the reference case without FGR.
- Same TIT as reference case without FGR, by means of a tuning of the first turbine stages blades cooling system

HRSG

The exhaust gases from the gas turbine enter the HRSG at 662°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. Details on steam generation conditions are listed in chapter B, section 4.3.3. The temperature of the exhaust gas from the HRSG 105°C. Prior entering the capture unit, flue gases are cooled down to around 85°C in the gas-gas heater against decarbonised flue gas from the absorber (please refer to attached H&MBs for actual case specific temperatures).

At the inlet of Carbone Capture the flue gas is then further cooled in the flue gas quencher (Direct Contact Cooler), after which the flue gas is split in two streams, one going to the CO2 Absorber and the other one being recycled to Gas Turbine Compressor suction, downstream Air Intake Filter. The scheme here below is qualitative only.



Condenser

The exhaust stream from the LP section of the steam turbine is routed to a water-cooled steam condenser, which main conditions are listed below.

Cooling water approach	3°C
Condenser temperature	29°C
Condenser pressure	4.0 kPa

2.3. 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 D, section 2.2. Flue gas from the gas-gas heater coils in the HRSG enters the CO_2 capture unit at around 85°C and is further cooled in the flue gas quencher (Direct Contact Cooler), after which the flue gas is split in two streams, one going to the CO2 Absorber and the other one being recycled to Gas Turbine Compressor suction. Decarbonised flue gas from the absorber, saturated at around 30°C, are heated up to around 85°C in the gas-gas heater coil of the HRSG.

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.

2.4. Unit 5000 – CO_2 Compression and drying

The process description of CO_2 Compression and drying package is reported in chapter C, section 2.3.

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.

2.5. 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.

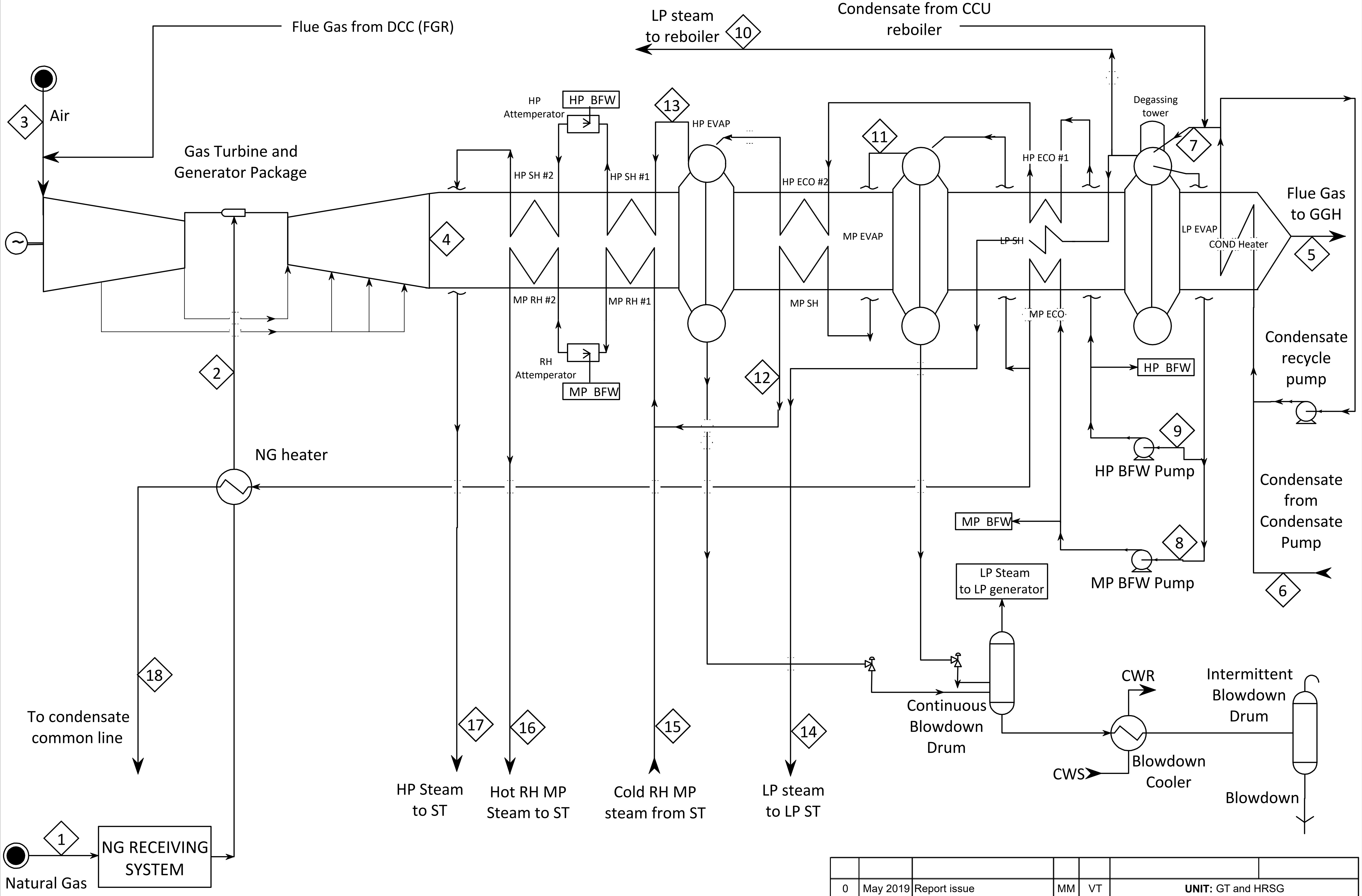
The main utility units include:

- Cooling Water system, based on one natural draft cooling towers, using fresh water as make-up water
- Natural gas metering and conditioning station
- Raw water system;
- Demineralised water plant;
- Firefighting system;
- Instrument and Plant air;
- Waste water treatment.

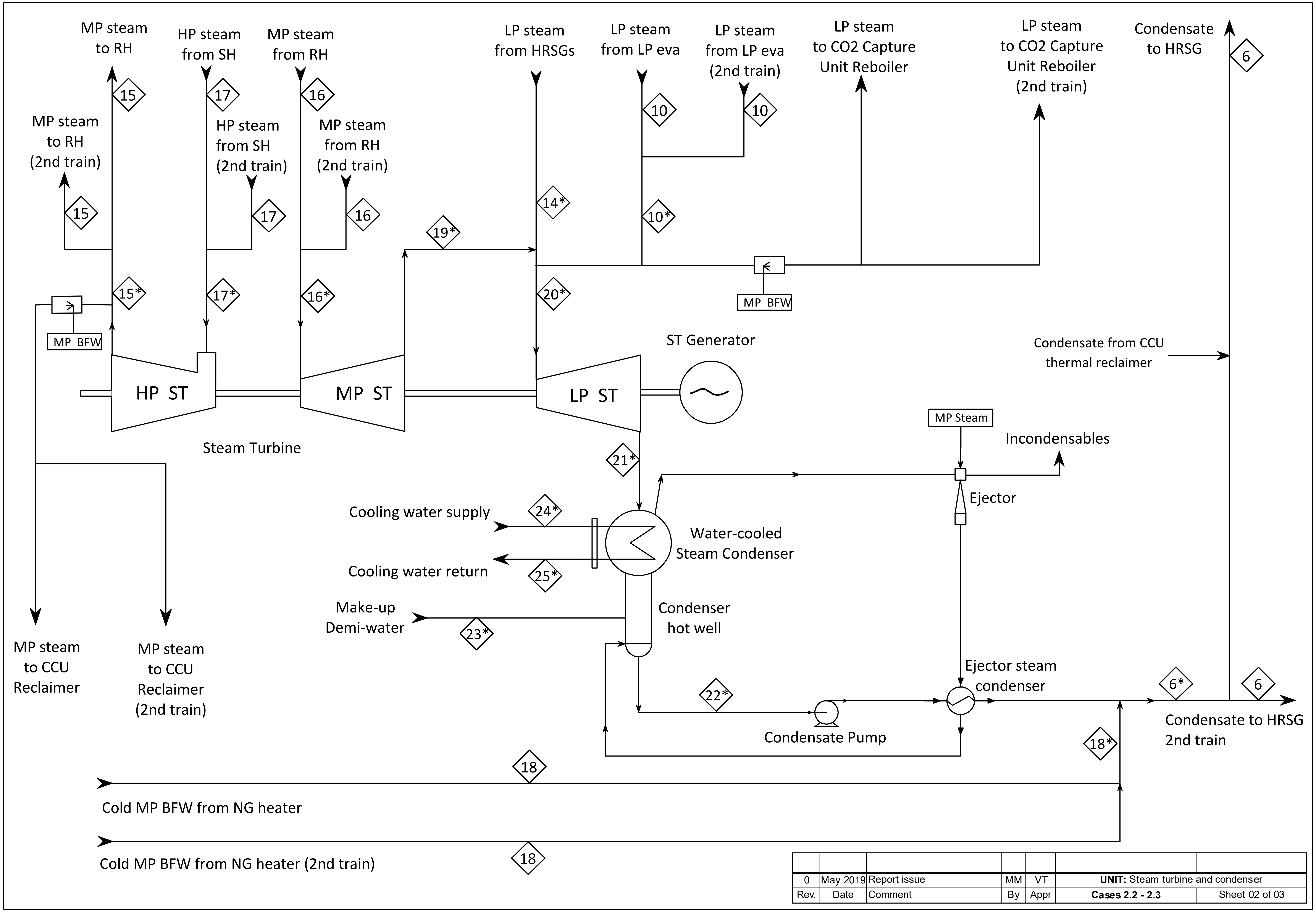
Process descriptions of the above systems are enclosed in chapter C, section 2.4.

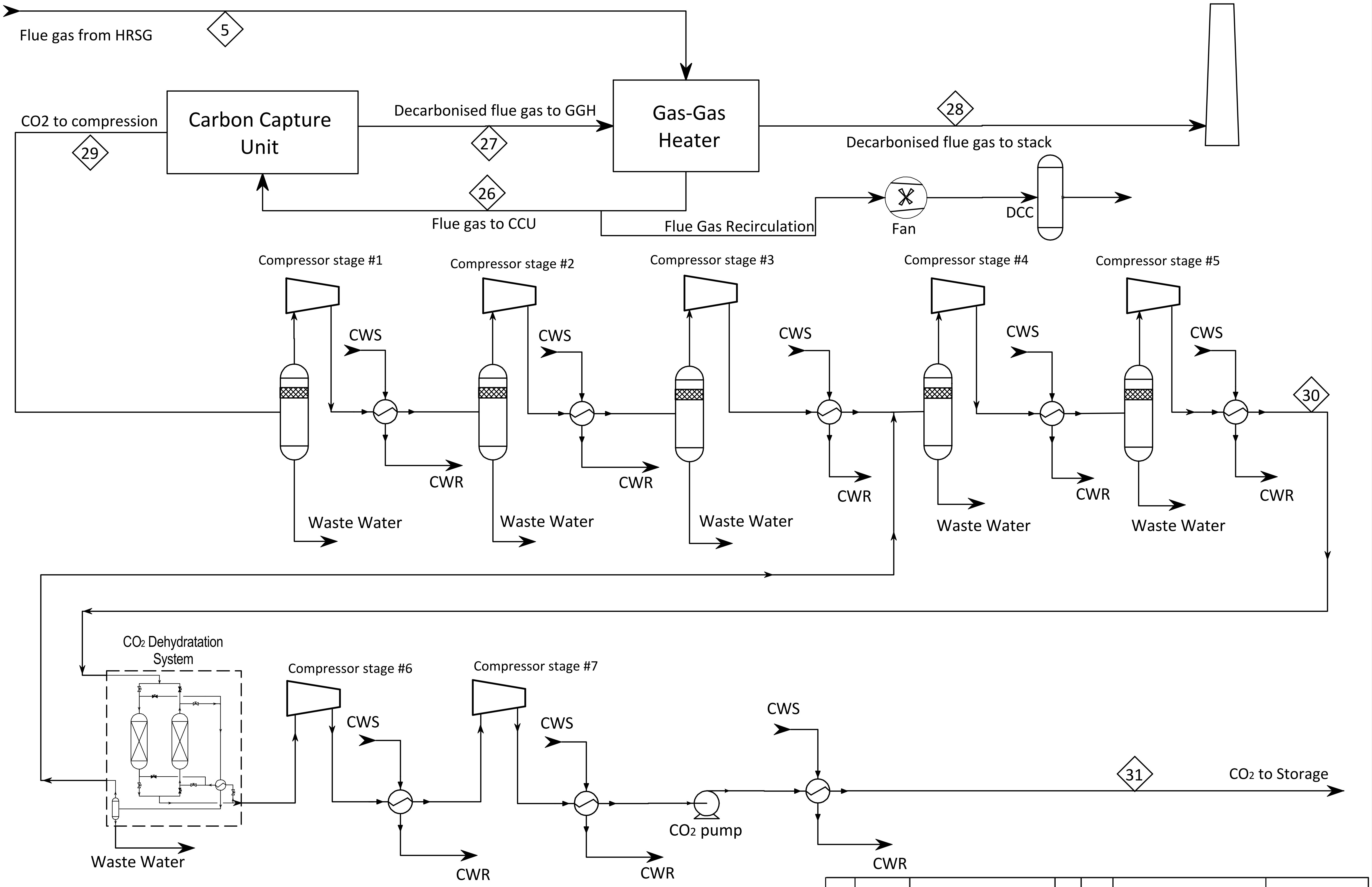
3. Process Flow Diagrams

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 2019	Report issue	MM	VT	**UNIT:** GT and HRSG	
Rev.	Date	Comment	By	Appr	**Cases 2.2 - 2.3**	Sheet 01 of 03


MP steam to RH
HP steam from SH
MP steam from RH
LP steam from HRSGs
LP steam from LP eva
LP steam from LP eva (2nd train)
LP steam to CO2 Capture Unit Reboiler
LP steam to CO2 Capture Unit Reboiler (2nd train)
Condensate to HRSG
MP steam to RH (2nd train)
HP steam from SH (2nd train)
MP steam from RH (2nd train)
15
17
16
10
6
14*
10*
19*
15*
17*
16*
20*
MP BFW
MP BFW
ST Generator
Condensate from CCU thermal reclaimer
HP ST
MP ST
LP ST
Steam Turbine
MP Steam
Incondensables
21*
Ejector
Cooling water supply
24*
Water-cooled Steam Condenser
Cooling water return
25*
Make-up Demi-water
23*
Condenser hot well
MP steam to CCU Reclaimer
MP steam to CCU Reclaimer (2nd train)
Ejector steam condenser
6*
22*
Condensate Pump
Condensate to HRSG 2nd train
18*
18
Cold MP BFW from NG heater
Cold MP BFW from NG heater (2nd train)
0
May 2019
Report issue
MM
VT
UNIT: Steam turbine and condenser
Rev.
Date
Comment
By
Appr
Cases 2.2 - 2.3
Sheet 02 of 03



0	May 2019	Report issue	MM	VT	**UNIT:** CO2 capture and compression	
Rev.	Date	Comment	By	Appr	**Cases 2.2 - 2.3**	Sheet 03 of 03

4. Heat and Material Balance

Heat & Material Balances here below reported make reference to the Process Flow Diagrams of section 3.

wood.	HEAT AND MATERIAL BALANCE		REVISION	0		
	CLIENT :	IEAGHG	PREP.	MM		
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	AC		
	PROJECT NO:	1-BD-1046 A	APPROVED	VT		
	CASE:	Case 2.2 - FGR with CCS 90% capture rate	DATE	may-19		

HEAT AND MATERIAL BALANCE

Stream	Description		Flowrate t/h	Temperature °C	Pressure bar a	Enthalpy kJ/kg
1	Natural Gas	(note 3)	92.5	20	70	-
2	Heated Natural Gas to Gas Turbine	(note 3)	92.5	220	68	-
3	Air to Gas Turbine	(note 4)	1698.8	9	1.013	-
4	Gas Turbine Exhaust	(note 5)	3425.0	662	1.033	-
5	Flue gases to G-G Heater	(note 5)	3425.0	105	1.015	-
6	Condensate to Condensate Heater		388.2	30	8	37
7	Heated Condensate to Deareator		627.9	57	8	40
8	Degassed Condensate to MP BFW Pump		128.1	159	6	25
9	Degassed Condensate to HP BFW Pump		467.4	159	6	25
10	LP Steam to LP Superheater		0.0	159	6	2512
11	MP Steam to MP Superheater		74.3	248	38	2571
12	Superheated MP Steam to MP Reheater #1		74.3	359	38	190
13	HP Steam to HP Superheater #1		465.0	359	185	2781
14	LP Steam to LP Steam Turbine		32.1	159	6	41
15	Cold RH MP Steam from Steam Turbine		461.7	357	37	187
16	Hot RH MP Steam to ST		536.0	600	36	202
17	HP Steam to Steam Turbine		465.0	600	180	796
18	Cold MP BFW to condensate common line		53.4	50	58	249
19*	LP Exhaust from MP Steam Turbine		1076.7	327	6	55
20*	Total LP Steam to LP Steam Turbine		713.4	317	6	54
21*	Exhaust steam to Steam Condenser		713.4	27	0.04	2338
22*	Condensate to Condensate Pump		721.4	27	0.04	7
23*	Demineralized water make-up to Condenser Hot-Well		6.0	9	1.034	5
24*	Cooling Water Supply		34708.9	15	3.0	14
25*	Cooling Water Return		34708.9	26	2.5	13
26	Flue gas to Carbon Capture Unit (Note 5)		1791.3	82	1.011	-
27	Treated gas to Gas-Gas Heater (Note 6)		1562.2	28	1.015	-
28	Treated gas to stack (Note 6)		1562.2	82	1.013	-
29	CO_2 to compression (Note 7)		229.0	30	2.0	-
30	CO_2 to drying package (Note 8)		252.5	26	35	-
31	CO_2 to long term storage		226.9	30	110.0	-

Notes:

1) Streams marked up with * correspond to the total flow of two trains. The remaining figures are referred to single train
2) Enthalpy is shown for water streams only (steam, BFW, condensate)
3) Composition: CH4 89%, C2H6 7%, C3H8 1%, C4H10 0.1%, C5H12 0.01%, CO2 2%, N2 0.89%
4) 80% Relative Humidity
5) Composition: O2 11.1%, CO2 4.6%, N2 74%, Ar 0.9%, H2O 9.4%,
6) Composition: O2 12.8%, CO2 0.1%, N2 81.1%, Ar 1%, H2O 5.1%,
7) Water content: 2.1% v/v
8) Water content: 0.2% v/v

	HEAT AND MATERIAL BALANCE		REVISION	0		
wood.	CLIENT :	IEAGHG	PREP.	MM		
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	AC		
	PROJECT NO:	1-BD-1046 A	APPROVED	VT		
	CASE:	Case 2.3 - FGR with CCS 98.5% capture rate	DATE	may-19		

HEAT AND MATERIAL BALANCE

Stream	Description		Flowrate t/h	Temperature °C	Pressure bar a	Enthalpy kJ/kg
1	Natural Gas	(note 3)	92.5	20	70	-
2	Heated Natural Gas to Gas Turbine	(note 3)	92.5	220	68	-
3	Air to Gas Turbine	(note 4)	1698.8	9	1.013	-
4	Gas Turbine Exhaust	(note 5)	3425.0	662	1.033	-
5	Flue gases to G-G Heater	(note 5)	3425.0	110	1.015	-
6	Condensate to Condensate Heater		344.8	31	8	37
7	Heated Condensate to Deareator		625.7	62	8	40
8	Degassed Condensate to MP BFW Pump		128.1	159	6	25
9	Degassed Condensate to HP BFW Pump		467.4	159	6	25
10	LP Steam to LP Superheater		0.0	159	6	2512
11	MP Steam to MP Superheater		74.3	248	38	2571
12	Superheated MP Steam to MP Reheater #1		74.3	359	38	190
13	HP Steam to HP Superheater #1		465.0	359	185	2781
14	LP Steam to LP Steam Turbine		30.0	159	6	41
15	Cold RH MP Steam from Steam Turbine		461.7	357	37	187
16	Hot RH MP Steam to ST		536.0	600	36	202
17	HP Steam to Steam Turbine		465.0	600	180	796
18	Cold MP BFW to condensate common line		53.4	50	58	249
19*	LP Exhaust from MP Steam Turbine		1076.7	327	6	55
20*	Total LP Steam to LP Steam Turbine		635.7	318	6	54
21*	Exhaust steam to Steam Condenser		635.7	27	0.04	2338
22*	Condensate to Condensate Pump		643.6	27	0.04	7
23*	Demineralized water make-up to Condenser Hot-Well		6.0	9	1.034	5
24*	Cooling Water Supply		30932.2	15	3.0	14
25*	Cooling Water Return		30932.2	26	2.5	13
26	Flue gas to Carbon Capture Unit (Note 5)		1791.3	86	1.011	-
27	Treated gas to Gas-Gas Heater (Note 6)		1540.6	29	1.015	-
28	Treated gas to stack (Note 6)		1540.6	86	1.013	-
29	CO_2 to compression (Note 7)		250.6	30	2.0	-
30	CO_2 to drying package (Note 8)		276.3	26	35	-
31	CO_2 to long term storage		248.4	30	110.0	-

Notes:
1) Streams marked up with * correspond to the total flow of two trains. The remaining figures are referred to single train
2) Enthalpy is shown for water streams only (steam, BFW, condensate)
3) Composition: CH4 89%, C2H6 7%, C3H8 1%, C4H10 0.1%, C5H12 0.01%, CO2 2%, N2 0.89%
4) 80% Relative Humidity
5) Composition: O2 3%, CO2 9.1%, N2 76.1%, Ar 0.9%, H2O 10.9%,
6) Composition: O2 3.6%, CO2 0.2%, N2 91.4%, Ar 1%, H2O 3.9%,
7) Water content: 2.1% v/v
8) Water content: 0.2% v/v

5. Utility and chemicals consumption

Main utility consumption of the process and utility units is reported in the following tables.

Table 2. Case 2.2 – Water consumption summary

CLIENT:	IEA GHG	REVISION	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	DATE	may-19
PROJECT No. :	1-BD-1046 A	MADE BY	MM
LOCATION :	Netherlands	APPROVED BY	VT

NG CC FGR Plant with CCS 90% capture rate
Case 2.2

WATER CONSUMPTION

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Primary Cooling Water System [t/h]	Secondary Cooling Water System [t/h]
3000	POWER ISLAND (Steam Turbine)				
3100	Gas Turbine Auxiliaries				1950
3200	Heat Recovery Steam Generator				20
3300	Steam Turbine auxiliaries	-6.0	6.0		1960
	Condenser			34710	
	CO_2 CAPTURE UNIT				
4000	CO_2 capture unit				
			29		31890
5000	CO_2 compression				
6000	UTILITY and OFFSITE UNITS				
	Cooling Water System	1269			
	Demineralized water unit	53	-35.0		
	Waste Water Treatment	-183			
	Balance of plant				50
	BALANCE	1133	0	34710	35870

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

Table 3. Case 2.3 – Water consumption summary

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**DATE**	may-19
PROJECT No. :	1-BD-1046 A	**MADE BY**	MM
LOCATION :	Netherlands	**APPROVED BY**	VT

NG CC FGR Plant with CCS 98.5% capture rate
Case 2.3

WATER CONSUMPTION

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Primary Cooling Water System [t/h]	Secondary Cooling Water System [t/h]
3000	**POWER ISLAND (Steam Turbine)**				
3100	Gas Turbine Auxiliaries				**1950**
3200	Heat Recovery Steam Generator				**20**
3300	Steam Turbine auxiliaries	**-6.0**	**6.0**		**1890**
	Condenser			**30930**	
	CO_2 CAPTURE UNIT				
4000	CO_2 capture unit				
			29		**36530**
5000	CO_2 compression				
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water System	**1283**			
	Demineralized water unit	**53**	**-35.0**		
	Waste Water Treatment	**-182**			
	Balance of plant				**50**
	BALANCE	**1148**	**0**	**30930**	**40440**

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

Table 4. Case 2.2 and 2.3 – Electrical consumption summary

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**DATE**	may-19
PROJECT No. :	1-BD-1046 A	**MADE BY**	MM
LOCATION :	Netherlands	**APPROVED BY**	VT

ELECTRICAL CONSUMPTION

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW] Case 2.2	Absorbed Electric Power [kW] Case 2.3
3000	**POWER ISLAND**		
3100	Gas turbine Auxiliaries	**2100**	**2100**
3200	Heat Recovery Steam Generator	**8680**	**8680**
3300	Steam Turbine Auxiliaries	**1300**	**1220**
	Miscellanea	**5540**	**5540**
	CO_2 CAPTURE UNIT		
4000	CO_2 Capture Unit	**47095**	**50539**
5000	CO_2 Compression		
6000	**UTILITY and OFFSITE UNITS**		
	Cooling Water System	**9410**	**9680**
	Balance of Plant	**450**	**450**
	BALANCE	**74,575**	**78,209**

6. Overall Performance

The following table shows the overall performance of Case 2.2 and case 2.3.

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**DATE**	may-19
PROJECT No. :	1-BD-1046 A	**MADE BY**	MM
LOCATION :	Netherlands	**APPROVED BY**	VT

OVERALL PERFORMANCES

		Case 2.2 FGR 90% CO2 rec.	Case 2.3 FGR 98.5% CO2 rec.
Fuel flow rate (A.R.)	t/h	185	185
Fuel HHV (A.R.)	kJ/kg	46502	46502
Fuel LHV (A.R.)	kJ/kg	51473	51473
THERMAL ENERGY OF FEEDSTOCK (based on LHV) (A)	**MWth**	**2390**	**2390**
THERMAL ENERGY OF FEEDSTOCK (based on HHV) (A')	**MWth**	**2645**	**2645**
Gas turbine power output (@ gen terminals)	MWe	996.6	996.6
Steam turbine power output (@ gen terminals)	MWe	422.5	406.3
GROSS ELECTRIC POWER OUTPUT (@ gen terminals) (C)	**MWe**	**1419.1**	**1402.9**
Power Islands consumption	MWe	17.6	17.5
Utility & Offsite Units consumption	MWe	9.9	10.1
CO2 Capture and compression unit	MWe	47.1	50.5
ELECTRIC POWER CONSUMPTION	**MWe**	**74.6**	**78.2**
NET ELECTRIC POWER OUTPUT	**MWe**	**1344.5**	**1324.7**
(Step Up transformer efficiency = 0.997%) (B)	MWe	**1340.5**	**1320.7**
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**59.4%**	**58.7%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**56.1%**	**55.3%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**53.6%**	**53.0%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**50.7%**	**49.9%**
Fuel Consumption per net power production	**MWth/MWe**	**1.78**	**1.81**
CO_2 emission per net power production	**kg/MWh**	**35.2**	**3.3**

The following table shows the overall CO_2 balance and removal efficiency of Cases 2.2 & 2.3.

CO_2 removal efficiency	**Equivalent flow of CO_2**	
	Case 2.2 FGR 90% CO2 rec.	Case 2.3 FGR 98.5% CO2 rec.
	kmol/h	kmol/h
INPUT		
FUEL CARBON CONTENT (A)	11136	11136
CO_2 in air (B)	201	201
OUTPUT		
Carbon losses (D)	0	0
CO_2 flue gas content	11337	11337
Total to storage (C)	10121	11165
Emission	1216	172
TOTAL	11337	11337
Overall Carbon Capture, % ((C+D)/(A+B))	89.3	98.5

7. Environmental impact

The NGCC plant design is based on advanced technologies that allow to reach high electrical generation efficiency, while minimizing impact to the environment. Main gaseous emissions and liquid effluents 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 top of the absorber. Table 5 summarizes the expected flue gases flowrate and composition.

Table 5. Cases 2.2 and 2.3 – Plant emission during normal operation

Flue gas to stack	**Case 2**	**Case 2.1**
Emission type	Continuous	Continuos
Conditions		
Wet gas flowrate, kg/h	1,563,000	1,541,000
Flow, Nm^3/h (1)	3,465,000	3,425,000
Temperature, °C	82	86
Composition	(% vol)	
Ar	1.03	1.04
N_2	90.58	91.37
O_2	3.53	3.57
CO_2	1.09	0.15
H_2O	3.75	3.85
Emission	mg/Nm^3 (1)	mg/Nm^3 (1)
NOx	< 50 mg/Nm^3	< 50 mg/Nm^3
CO	< 100 mg/Nm^3	< 100 mg/Nm^3

(1) Dry gas, O_2 content 15% vol.

7.2. Liquid effluents

The NGCC plant does not produce significant liquid waste. CO_2 capture and compression unit blow-down is treated to recover water, so main liquid effluent is cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids, and the waste water from WWT (including the eluate from the demineralised water unit). Steam cycle blowdown is entirely recovered as cooling tower make-up.

Table 6 summarises main plant liquid effluent to be discharge to the final destination (e.g. river), and the main unit blowdown to be treated in the WWT in order to recover water and reduce plant raw water make-up.

Table 6. Case 2.2 and 2.3 – Plant liquid effluent during normal operation

Plant effluent at BL	**Case 2.2**	**Case 2.3**
Cooling Tower blow-down	303 m^3/h	307 m^3/h
Waste water from WWT + eluate from demi plant	4 m^3/h	4 m^3/h
Waste Water treatment inlet stream		
CO_2 capture unit blow-down (*)	83 m^3/h	83 m^3/h

(*) Net blowdown, already reduced by the part of the treated water recycled back to the absorber. Separated figure not shown due to confidentiality issues

7.3. Solid effluents

The plant does not produce significant solid waste.

8. Equipment list

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

wood.	CLIENT: IEAGHG	REVISION	Rev.0	Rev.1	Rev.2	Rev.3	
	LOCATION: The Netherlands	DATE	may-19				
	PROJ. NAME: UPDATE TECHNO-ECONOMIC BENCHMARKS	ISSUED BY	MM				
	CONTRACT N. 1-BD-1046 A	CHECKED BY	AC				
	CASE 2.2 - FGR plant with 90% CCS	APPROVED BY	VT				

EQUIPMENT LIST

Units Summary

UNIT 3100	**GAS TURBINE**
UNIT 3200	**HRSG**
UNIT 3300	**STEAM TURBINE**
UNIT 4000	**$C0_2$ AMINE ABSORPTION**
UNIT 5000	**$C0_2$ COMPRESSION**
UNIT 6000	**UTILITY AND OFFSITE**

		REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
CLIENT:	IEAGHG	DATE	may-19			
LOCATION:	The Netherlands					
PROJ. NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	ISSUED BY	MM			
CONTRACT N:.	1-BD-1046 A	CHECKED BY	AC			
CASE:	2.2 - FGR plant with 90% CCS	APPROVED BY	VT			

wood.

EQUIPMENT LIST
Unit 3000 - Power Island

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	GAS TURBINE (UNIT 3100)							
PK- 3101-1/2	**Gas turbine and Generator Package**							***2 x 50% gas turbine package***
	Gas turbine		1000 MW					*One per train, two in total*
								Including:
								Lube oil system
								Cooling system
								Idraulic control system
								Electrical generator and relevant auxiliaries
	Performance Heaters	Multitube Enhanched HE	12165 kWth					
	HEAT RECOVERY STEAM GENERATOR (UNIT 3200)							
PK- 3201-1/2	**Heat recovery steam generator**	Horizontal, Natural Circulated, 3 Pressure Levels, Simple Recovery, Reheated						***2 x 50% HRSG package***
	Each including:							
D- 3201	HP steam drum		HPS generation: 465 t/h					
D- 3201	MP steam drum		MPS generation: 75 t/h					
D- 3201	LP steam drum with degassing section		LPS generation: 32 t/h					
E- 3201	HP Superheater 2nd section							
E- 3202	MP Reheater 2nd section							
E- 3203	HP Superheater 1st section							
E- 3204	MP Reheater 1st section							
E- 3205	HP Evaporator							
E- 3206	MP Superheater							
E- 3207	HP Economizer 2nd section							
E- 3208	LP Superheater							
E- 3209	MP Evaporator							
E- 3210	HP Economizer 1st section							
E- 3211	MP Economizer							
E- 3212	LP Evaporator							
E- 3213	Condensate heater							
X- 3201	HP steam desuperheater							
X- 3202	MP steam desuperheater							
X- 3203	Flue gas stack	cement stack						*Including silencer*
X- 3204	Continuous emission monitoring system							
	HEAT RECOVERY STEAM GENERATOR (UNIT 3200)							
	PUMPS		**Q [m3/h] x H [m]**					
P- 3201 A/B	HP BFW pumps	Centrifugal	540 m3/h x 2363 m	4510 kW				*One operating one spare, per each train*
P- 3202 A/B	MP BFW pumps	Centrifugal	145 m3/h x 491 m	250 kW				*One operating one spare, per each train*
	HEAT EXCHANGER							
	Blowdown cooler							
	GAS-GAS HEAT EXCHANGER		Hot side flowrate: 2584 x10^3 Nm3/h Cold side flowrate: 1193 x10^3 Nm3/h Duty: 21.8 MWth					*One per each train*
	Flue gas blower for FGR		dP = 150 mmwc					*One each train, downstream GGH*
	DRUM							
	Continuous Blowdown drum							
	Intermittent Blowdown drum							
	PACKAGES (Common to both train)							
PK- 3202	**Fluid Sampling Package**							
PK- 3203	**Phosphate Injection Package**							
	Phosphate storage tank							
	Phosphate dosage pumps							*One operating one spare*
PK- 3204	**Oxygen scavenger Injection Package**							
	Oxygen scavenger storage tank							
	Oxygen scavenger dosage pumps							*One operating one spare*
PK- 3204	**Amine Injection Package**							
	Amine storage tank							
	Amine dosage pumps							*One operating one spare*
	STEAM TURBINE (UNIT 3300)							
PK- 3001	**Steam Turbine and Generator Package**							
ST- 3301	Steam Turbine		423 MWe					*Including:*
								Lube oil system
								Cooling system
								Idraulic control system
								Drainage system
								Seals system
								Drainage system
								Electrical generator and relevant auxiliaries
E- 3301 A/B	Inter/After Condenser							
E- 3302	Gland Condenser							
PK- 3002	**Steam Condenser Package**							*Including:*
E- 3001	Steam condenser		443 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**							
P- 3003 A/B	Condensate pump	Centrifugal	722 m3/h x 150 m	500 kW				*One operating one spare, electric motor*

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CONTRACT N:.	1-BD-1046 A	APPROVED BY	VT			
CASE:	2.2 - FGR plant with 90% CCS					

EQUIPMENT LIST
Unit 4000 - CO2 Capture Unit

	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: 1403500 Nm3/h CO2 product: 117100 Nm3/h 98% purity Treated gas flowrate: 1247100 Nm3/h CO2 capture rate: 90%					2 x 50%
	PUMPS							
	For each train:							
K001	Flue gas Blower							
P001-A/B	Prescrubber water circulation pumps							
P002-A/B	Prescrubber polishing pumps							
P003-A/B	Absorber intercoolers pumps							
P004-A/B	Wash water pumps							
P005-A/B	Rich amine pumps							
P006-A/B	Stripper reflux pumps							
P007-A/B	Lean amine pumps							
P008-A/B	Amine feed pump							
P009	Make up amine pump							
P010-A/B	Steam condensate return pumps							
	DRUMS / COLUMNS / TANKS							
	For each train:							
D-001	Direct contact cooler (square)							
D-002	CO2 absorber							
D-003	CO2 stripper							
V-001	Stripper reflux drum							
V-002	Steam condensate drum							
T-001	Lean amine tank							
V-003	Lean amine flash tank							
	HEAT EXCHANGERS							
	For each train:							
E-001	DCC cooler							
E-002	Wash Water cooler							
E-003	Lean / rich exchanger							
E-004	Stripper condenser							
E-005	Stripper reboiler							
E-006	Lean amine cooler							
E-007	Absorber intercooler							
	MISCELLANEA							
	For each train:							
F-001	Lean amine filter							
F-002	Amine purification unit							
F-003	Thermal reclaimer							
F-004	CO2 Lean Absorbent Flash MVR system							

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CONTRACT N:.	1-BD-1046 A	CHECKED BY	AC			
CASE:	2.2 - FGR plant with 90% CCS	APPROVED BY	VT			

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	117100 Nm3/h P in: 2 bar a P out: 80 bar a	17703.94 kW				Intercooling: Condensate from Power island Cooling Water
	PUMPS		**Q,m3/h x H,m**					
P - 5001	CO_2 Pump	Centrifugal	320 m3/h x 450 m	425 kW				Liquid CO2 product, per each train: Flowrate: 227 t/h; 111 bar a; 30°C
	PACKAGE							
PK - 5001	CO_2 drying package							

Note 1: Equipment shown are for one train only

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CONTRACT N:.	1-BD-1046 A	APPROVED BY	VT			
CASE:	2.2 - FGR plant with 90% CCS					

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	900 MWth					
	PUMPS		**Q [m^3/h] x H [m]**					
P- 6001 A/B/C/D	Cooling Water Pumps (primary system)	Centrifugal	12700 x 36	1407			superduplex	*Four in operation*
P- 6002 A/B/C/D	Cooling Water Pumps (secondary system)	Centrifugal	13200 x 46	610			superduplex	*Four in operation, one spare*
P- 6003 A/B	Cooling tower make-up pumps	centrifugal	1270 x 36	200				*One in operation, one spare*
	PACKAGES							
	Cooling Water Filtration Package Cooling Water Sidestream Filters		Capacity: 7800 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		2210 m3					*24 hour storage*
P- 6004 A/B	Raw water pumps to RO	centrifugal	92 m3/h x 50 m	15				*One in operation, one spare*
	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		150 m3					*24 hour storage*
P- 6006 A/B	Demin water pump	centrifugal	6 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							
	MISCELLANEA							
	Plant air compression skid							
	Emergency diesel generator system							
	Waste water treatment system							
	Electrical equipment							
	Buildings							
	Auxiliary boiler							
	Condensate Polishing system							

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	CONTRACT N. 1-BD-1046 A	CHECKED BY	AC				
	CASE 2.3 - FGR plant with 98.5% CCS	APPROVED BY	VT				

EQUIPMENT LIST

Units Summary

UNIT 3100	**GAS TURBINE**
UNIT 3200	**HRSG**
UNIT 3300	**STEAM TURBINE**
UNIT 4000	**$C0_2$ AMINE ABSORPTION**
UNIT 5000	**$C0_2$ COMPRESSION**
UNIT 6000	**UTILITY AND OFFSITE**

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EQUIPMENT LIST
Unit 3000 - Power Island

ITEM	DESCRIPTION	TYPE	SIZE	Motor rating [kW]	P des [barg]	T des [°C]	Materials	Remarks
	GAS TURBINE (UNIT 3100)							
PK- 3101-1/2	**Gas turbine and Generator Package**							***2 x 50% gas turbine package***
	Gas turbine		1000 MW					*One per train, two in total*
								Including:
								Lube oil system
								Cooling system
								Idraulic control system
								Electrical generator and relevant auxiliaries
	Performance Heaters	Multitube Enhanched HE	12165 kWth					
	HEAT RECOVERY STEAM GENERATOR (UNIT 3200)							
PK- 3201-1/2	**Heat recovery steam generator**	Horizontal, Natural Circulated, 3 Pressure Levels, Simple Recovery, Reheated						***2 x 50% HRSG package***
	Each including:							
D- 3201	HP steam drum		HPS generation: 465 t/h					
D- 3201	MP steam drum		MPS generation: 75 t/h					
D- 3201	LP steam drum with degassing section		LPS generation: 30 t/h					
E- 3201	HP Superheater 2nd section							
E- 3202	MP Reheater 2nd section							
E- 3203	HP Superheater 1st section							
E- 3204	MP Reheater 1st section							
E- 3205	HP Evaporator							
E- 3206	MP Superheater							
E- 3207	HP Economizer 2nd section							
E- 3208	LP Superheater							
E- 3209	MP Evaporator							
E- 3210	HP Economizer 1st section							
E- 3211	MP Economizer							
E- 3212	LP Evaporator							
E- 3213	Condensate heater							
X- 3201	HP steam desuperheater							
X- 3202	MP steam desuperheater							
X- 3203	Flue gas stack	cement stack						*Including silencer*
X- 3204	Continuous emission monitoring system							
	HEAT RECOVERY STEAM GENERATOR (UNIT 3200)							
	PUMPS		**Q [m3/h] x H [m]**					
P- 3201 A/B	HP BFW pumps	Centrifugal	540 m3/h x 2363 m	4510 kW				*One operating one spare, per each train*
P- 3202 A/B	MP BFW pumps	Centrifugal	145 m3/h x 491 m	250 kW				*One operating one spare, per each train*
	HEAT EXCHANGER							
	Blowdown cooler							
	GAS-GAS HEAT EXCHANGER		Hot side flowrate: 2584 x10^3 Nm3/h Cold side flowrate: 1177x10^3 Nm3/h Duty: 22.7 MWth					*One per each train*
	Flue gas blower for FGR		dP = 150 mmwc					*One each train, downstream GGH*
	DRUM							
	Continuous Blowdown drum							
	Intermittent Blowdown drum							
	PACKAGES (Common to both train)							
PK- 3202	**Fluid Sampling Package**							
PK- 3203	**Phosphate Injection Package**							
	Phosphate storage tank							
	Phosphate dosage pumps							*One operating one spare*
PK- 3204	**Oxygen scavenger Injection Package**							
	Oxygen scavenger storage tank							
	Oxygen scavenger dosage pumps							*One operating one spare*
PK- 3204	**Amine Injection Package**							
	Amine storage tank							
	Amine dosage pumps							*One operating one spare*
	STEAM TURBINE (UNIT 3300)							
PK- 3001	**Steam Turbine and Generator Package**							
ST- 3301	Steam Turbine		407 MWe					*Including:*
								Lube oil system
								Cooling system
								Idraulic control system
								Drainage system
								Seals system
								Drainage system
								Electrical generator and relevant auxiliaries
E- 3301 A/B	Inter/After Condenser							
E- 3302	Gland Condenser							
PK- 3002	**Steam Condenser Package**							*Including:*
E- 3001	Steam condenser		395 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**							
P- 3003 A/B	Condensate pump	Centrifugal	722 m3/h x 150 m	500 kW				*One operating one spare, electric motor*

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CASE:	2.3 - FGR plant with 98.5% CCS	APPROVED BY	VT			

EQUIPMENT LIST
Unit 4000 - CO2 Capture Unit

	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: 1403500 Nm3/h CO2 product: 128200 Nm3/h 98% purity Treated gas flowrate: 1236400 Nm3/h CO2 capture rate: 98.5%					2 x 50%
	PUMPS							
	For each train:							
K001	Flue gas Blower							
P001-A/B	Prescrubber water circulation pumps							
P002-A/B	Prescrubber polishing pumps							
P003-A/B	Absorber intercoolers pumps							
P004-A/B	Wash water pumps							
P005-A/B	Rich amine pumps							
P006-A/B	Stripper reflux pumps							
P007-A/B	Lean amine pumps							
P008-A/B	Amine feed pump							
P009	Make up amine pump							
P010-A/B	Steam condensate return pumps							
	DRUMS / COLUMNS / TANKS							
	For each train:							
D-001	Direct contact cooler (square)							
D-002	CO2 absorber							
D-003	CO2 stripper							
V-001	Stripper reflux drum							
V-002	Steam condensate drum							
T-001	Lean amine tank							
V-003	Lean amine flash tank							
	HEAT EXCHANGERS							
	For each train:							
E-001	DCC cooler							
E-002	Wash Water cooler							
E-003	Lean / rich exchanger							
E-004	Stripper condenser							
E-005	Stripper reboiler							
E-006	Lean amine cooler							
E-007	Absorber intercooler							
	MISCELLANEA							
	For each train:							
F-001	Lean amine filter							
F-002	Amine purification unit							
F-003	Thermal reclaimer							
F-004	CO2 Lean Absorbent Flash MVR system							

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CASE:	2.3 - FGR plant with 98.5% CCS	APPROVED BY	VT			

wood.

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	128200 Nm3/h P in: 2 bar a P out: 80 bar a	19375 kW				Intercooling: Condensate from Power island Cooling Water
	PUMPS		**Q,m3/h x H,m**					
P - 5001	CO_2 Pump	Centrifugal	350 m3/h x 450 m	450 kW				Liquid CO2 product, per each train: Flowrate: 249 t/h; 111 bar a; 30°C
	PACKAGE							
PK - 5001	CO_2 drying package							

Note 1: Equipment shown are for one train only

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CASE:	2.3 - FGR plant with 98.5% CCS					

wood.

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	910 MWth					
	PUMPS		**Q [m^3/h] x H [m]**					
P- 6001 A/B/C/D	Cooling Water Pumps (primary system)	Centrifugal	11300 x 36	1254			superduplex	*Four in operation*
P- 6002 A/B/C/D	Cooling Water Pumps (secondary system)	Centrifugal	14800 x 46	610			superduplex	*Four in operation, one spare*
P- 6003 A/B	Cooling tower make-up pumps	centrifugal	1285 x 36	200				*One in operation, one spare*
	PACKAGES							
	Cooling Water Filtration Package Cooling Water Sidestream Filters		Capacity: 7800 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		2210 m3					*24 hour storage*
P- 6004 A/B	Raw water pumps to RO	centrifugal	92 m3/h x 50 m	15				*One in operation, one spare*
	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		150 m3					*24 hour storage*
P- 6006 A/B	Demin water pump	centrifugal	6 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							
	MISCELLANEA							
	Plant air compression skid							
	Emergency diesel generator system							
	Waste water treatment system							
	Electrical equipment							
	Buildings							
	Auxiliary boiler							
	Condensate Polishing system							
	Flue gas blower for FGR		dP = 150 mmwc					*One each train, downstream GGH*

CLIENT : IEAGHG
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DOCUMENT NAME : ECONOMICS OF NGCC PLANT ALTERNATIVES
CONTRACT N° : 1-BD-1046 A

ISSUED BY : M. MENSI
CHECKED BY : V. TOTA
APPROVED BY : V. TOTA

Date	Revised Pages	Issued by	Checked by	Approved by

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GLOSSARY

CCS	Carbon Capture and Storage
NGCC	Natural Gas Combined Cycle
USC PC	Ultrasupercritical Pulverised Coal
FGR	Flue Gas Recirculation
EGR	Exhaust Gas Recirculation
CCU	Carbon Capture Unit
CMC	Ceramic Matrix Composite
ASU	Air Separation Unit
MCFC	Molten Carbonate Fuel Cell
TPC	Total Plant Cost
TIC	Total Installed Cost
MEL	Minimum Environmental Load
GT	Gas Turbine
ST	Steam Turbine

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.

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.

In this section, a full economical assessment is made for all the NGCC main study cases, whose major characteristics are summarized in the overleaf Table 1, consisting of: three (3) NGCC-based plants (Case 1 to Case 2.1), and two (2) NGCC-based plants with flue gas recirculation (Case 2.2 to Case 2.3).

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
NGCC-based	Case 1 (reference)	NGCC	-	• Two generic H-class gas turbines • One common steam turbine • Cooling system based on natural draft cooling tower
NGCC-based	Case 2	NGCC w CCS	90%	• Two generic H-class gas turbines • One common steam turbine • CANSOLV post-combustion capture • Cooling system based on natural draft cooling tower • 90% capture rate
NGCC-based	Case 2.1	NGCC w CCS	98.5%	• Two generic H-class gas turbines • One common steam turbine • CANSOLV post-combustion capture • Cooling system based on natural draft cooling tower • 98.5% capture rate
FGR NGCC-based	Case 2.2	NGCC w CCS and FGR	90%	• Two generic H-class gas turbines • One common steam turbine • CANSOLV post-combustion capture • Cooling system based on natural draft cooling tower • 90% capture rate • FGR recirculation ratio: 47.7% (1)
FGR NGCC-based	Case 2.3	NGCC w CCS and FGR	98.5%	• Two generic H-class gas turbines • One common steam turbine • CANSOLV post-combustion capture • Cooling system based on natural draft cooling tower • 98.5% capture rate • FGR recirculation ratio: 47.7% (1)

Note:
1) Flue gas recirculation ratio = Flue gas recirculation flowrate / Total flue gas from HRSG

2. Capital cost

2.1. Definitions

This section provides the details of the Total Capital Requirement (TCR), also named Total Investment Cost (TIC), and the Total Plant Cost (TPC) of the various study cases. The main cost estimating bases and detailed estimate methodology are described in chapter B. Main bases considered for the financial analysis are reported hereafter.

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:

- Combined Cycle
- CO_2 capture (Post-combustion capture cases B)
- CO_2 compression (Post-combustion capture cases B)
- Utilities units

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 1Q2019 price level, in euro (€).

2.2.1. Total Plant Cost

The starting point for investment cost estimate has been the information contained in the reference IEAGHG report 2018/4 "Effect of plant location on CO2 capture". The cost is updated to reflect any technological developments and the technical modifications of the benchmark cases, as resulting from the market investigation done mainly for the Gas Turbine and the CO2 capture plant.

The estimating methodology used by Wood 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.

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 Wood 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 Wood experience and in-house data bank.

Process contingency

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. *Project contingency*

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

For the accuracy considered in this study, Wood view is that contingency should be in the range of 10-15% of the total plant cost in The Netherlands. 10% is assumed for this study for all the different units of the plant, for consistency with the reference IEAGHG report 2014/3 "*CO_2 capture at coal based power and hydrogen plants*".

2.2.3. *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.

Discount rate

Discount cash flow calculations are expressed at a discount rate of 8% for the reference plant.

2.3. Total Plant Cost summary

The TPC of the different natural gas fired power plant study cases listed in Table 1 is shown in the following tables.
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 natural gas fired cases are also reported for summary purpose in the below Table 2.

Table 2. NGCC plant cases TPC and TCR

Type	Case	Total Plant Cost (TPC) (M€)	Total Capital Requirement (TCR) (M€)	Specific cost [TPC/Net Power] (€/kW)	Specific cost [TCR/Net Power] (€/kW)
NGCC based	**Case 1**	905	1206	601	801
	Case 2	1597	2121	1188	1578
	Case 2.1	1684	2236	1280	1699
FGR NGCC based	**Case 2.2**	1510	2005	1127	1495
	Case 2.3	1568	2080	1187	1575

2.3.1. *NGCC based cases*

The following tables and figures show the Total Plant Cost summary of the NGCC based cases.

Table 3. Case 1 – Total Plant Cost

wood.	Case 1 (NGCC without CCS)			CONTRACT: 1-BD-1046A CLIENT: IEAGHG LOCATION: THE NETHERLANDS DATE: MAY 2019 REV.: 0	
POS.	**DESCRIPTION**	**UNIT 3000** **Combined Cycle**	**UNIT 6000** **Utility Units**	**TOTAL COST EURO**	**NOTES / REMARKS**
1	DIRECT MATERIAL	420,500,000	85,000,000	505,500,000	1) Gross power output: MW 1530 Specific cost €/kW : 592
2	CONSTRUCTION	147,200,000	59,500,000	206,700,000	2) Total Net Power : MW 1506
3	**DIRECT FIELD COST**	**567,700,000**	**144,500,000**	**712,200,000**	Specific cost €/kW : 601
4	OTHER COSTS	22,700,000	8,300,000	31,000,000	
5	EPC SERVICES	62,400,000	17,200,000	79,600,000	EXCLUSIONS
6	**TOTAL INSTALLED COST**	**652,800,000**	**170,000,000**	**822,800,000**	Spare parts Inventories of fuel and chemicals
7	PROJECT CONTINGENCY	65,300,000	17,000,000	82,300,000	Start-up costs Insurance
8	PROCESS CONTINGENCY	EXCLUDED	EXCLUDED	-	Local taxes and fees
12	**TOTAL PLANT COST**	**718,100,000**	**187,000,000**	**905,100,000**	

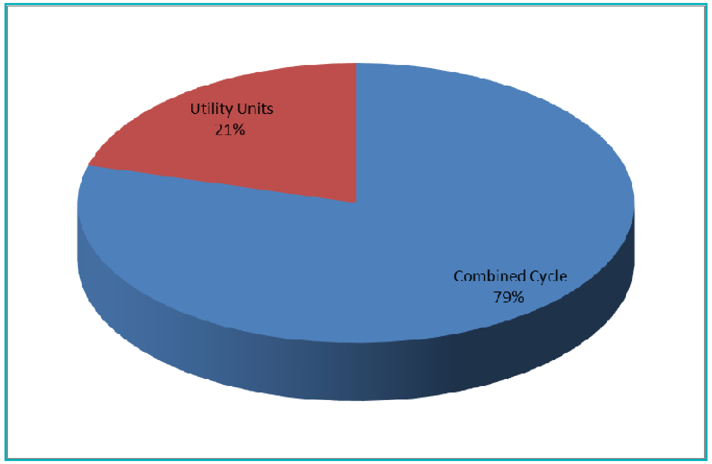

Figure 1. Case 1 – Unit percentage weight on TPC

Table 4. Case 2 – Total Plant Cost

wood.	Case 2 (NGCC with CCS - 90% CO2 capture rate)					CONTRACT: 1-BD-1046A CLIENT: IEAGHG LOCATION: THE NETHERLANDS DATE: MAY 2019 REV.: 0
POS.	**DESCRIPTION**	**UNIT 3000** **Combined Cycle**	**UNIT 4000** **CO2 Capture Unit**	**UNIT 5000** **CO2 Compression Unit**	**UNIT 6000** **Utility Units**	**TOTAL COST EURO**
1	DIRECT MATERIAL	411,600,000	320,800,000	30,700,000	116,900,000	880,000,000
2	CONSTRUCTION	144,100,000	112,300,000	23,000,000	81,800,000	361,200,000
3	**DIRECT FIELD COST**	**555,700,000**	**433,100,000**	**53,700,000**	**198,700,000**	**1,241,200,000**
4	OTHER COSTS	22,200,000	23,800,000	4,000,000	11,500,000	61,500,000
5	EPC SERVICES	61,100,000	57,400,000	7,500,000	23,550,000	149,550,000
6	**TOTAL INSTALLED COST**	**639,000,000**	**514,300,000**	**65,200,000**	**233,750,000**	**1,452,250,000**
7	PROJECT CONTINGENCY	63,900,000	51,400,000	6,500,000	23,400,000	145,200,000
8	PROCESS CONTINGENCY	EXCLUDED	EXCLUDED	EXCLUDED	EXCLUDED	-
12	**TOTAL PLANT COST**	**702,900,000**	**565,700,000**	**71,700,000**	**257,150,000**	**1,597,450,000**

NOTES / REMARKS

1) Gross power output MW : 1429
Specific cost €/kW : 1,118

2) Total Net Power MW : 1344
Specific cost €/kW : 1,188

EXCLUSIONS
Spare parts
Inventories of fuel and chemicals
Start-up costs
Insurance
Local taxes and fees

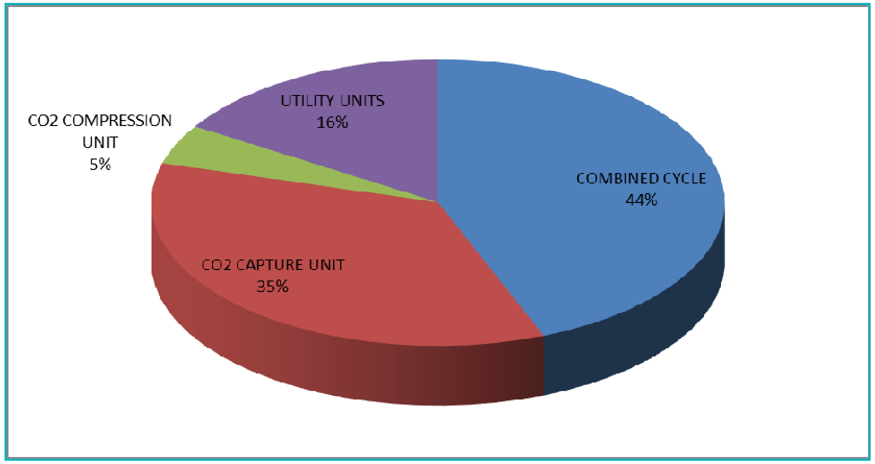

Figure 2. Case 2 – Unit percentage weight on TPC

Table 5. Case 2.1 – Total Plant Cost

Case 2.1
(NGCC with CCS - 98.5% CO_2 capture rate)

CONTRACT: 1-BD-1046A
CLIENT: IEAGHG
LOCATION: THE NETHERLANDS
DATE: MAY 2019
REV.: 0

POS.	DESCRIPTION	UNIT 3000 Combined Cycle	UNIT 4000 CO2 Capture Unit	UNIT 5000 CO2 Compression Unit	UNIT 6000 Utility Units	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIAL	406,700,000	372,100,000	32,700,000	116,900,000	928,400,000	1) Gross power output MW : 1404 Specific cost €/kW : 1,200
2	CONSTRUCTION	142,300,000	130,200,000	24,500,000	81,800,000	378,800,000	
3	**DIRECT FIELD COST**	**549,000,000**	**502,300,000**	**57,200,000**	**198,700,000**	**1,307,200,000**	2) Total Net Power MW : 1316 Specific cost €/kW : 1,280
4	OTHER COSTS	22,000,000	27,600,000	4,300,000	11,500,000	65,400,000	
5	EPC SERVICES	60,400,000	66,600,000	8,000,000	23,550,000	158,550,000	EXCLUSIONS
6	**TOTAL INSTALLED COST**	**631,400,000**	**596,500,000**	**69,500,000**	**233,750,000**	**1,531,150,000**	Spare parts Inventories of fuel and chemicals
7	PROJECT CONTINGENCY	63,100,000	59,700,000	7,000,000	23,400,000	153,200,000	Start-up costs Insurance
8	PROCESS CONTINGENCY	EXCLUDED	EXCLUDED	EXCLUDED	EXCLUDED	-	Local taxes and fees
12	**TOTAL PLANT COST**	**694,500,000**	**656,200,000**	**76,500,000**	**257,150,000**	**1,684,350,000**	

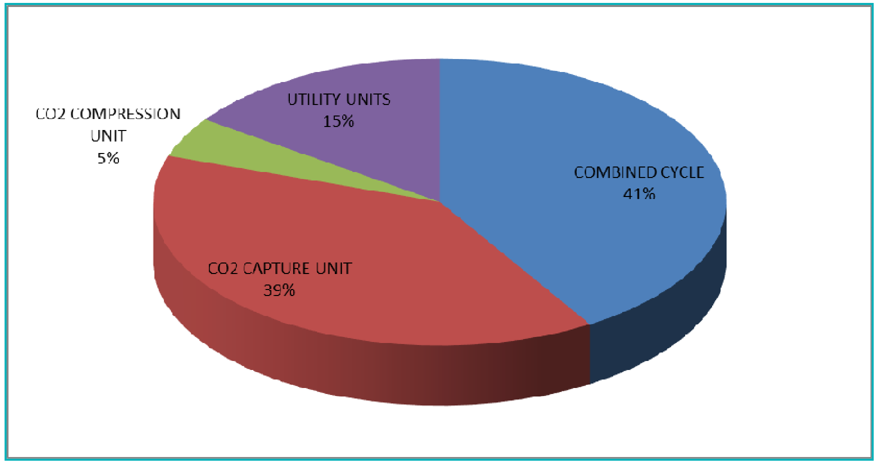

Figure 3. Case 2.1 – Unit percentage weight on TPC

2.3.2. *FGR NGCC based cases*

The following tables and figures show the Total Plant Cost summary of the Flue Gas Recirculation NGCC based cases.

Table 6. Case 2.2 – Total Plant Cost

	Case 2.2 (NGCC with CCS and FGR - 90% CO2 capture rate)						CONTRACT: 1-BD-1046A CLIENT: IEAGHG LOCATION: THE NETHERLANDS DATE: MAY 2019 REV.: 0
POS.	DESCRIPTION	UNIT 3000 Combined Cycle	UNIT 4000 CO2 Capture Unit	UNIT 5000 CO2 Compression Unit	UNIT 6000 Utility Units	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIAL	420,100,000	260,300,000	32,900,000	116,900,000	830,200,000	1) Gross power output MW : 1419 Specific cost €/kW : 1,065
2	CONSTRUCTION	147,000,000	91,100,000	24,700,000	81,800,000	344,600,000	2) Total Net Power MW : 1341
3	**DIRECT FIELD COST**	**567,100,000**	**351,400,000**	**57,600,000**	**198,700,000**	**1,174,800,000**	Specific cost €/kW : 1,127
4	OTHER COSTS	22,700,000	19,300,000	4,300,000	11,500,000	57,800,000	
5	EPC SERVICES	62,400,000	46,600,000	8,100,000	23,550,000	140,650,000	EXCLUSIONS
6	**TOTAL INSTALLED COST**	**652,200,000**	**417,300,000**	**70,000,000**	**233,750,000**	**1,373,250,000**	Spare parts Inventories of fuel and chemicals
7	PROJECT CONTINGENCY	65,200,000	41,700,000	7,000,000	23,400,000	137,300,000	Start-up costs Insurance
8	PROCESS CONTINGENCY	EXCLUDED	EXCLUDED	EXCLUDED	EXCLUDED	-	Local taxes and fees
12	**TOTAL PLANT COST**	**717,400,000**	**459,000,000**	**77,000,000**	**257,150,000**	**1,510,550,000**	

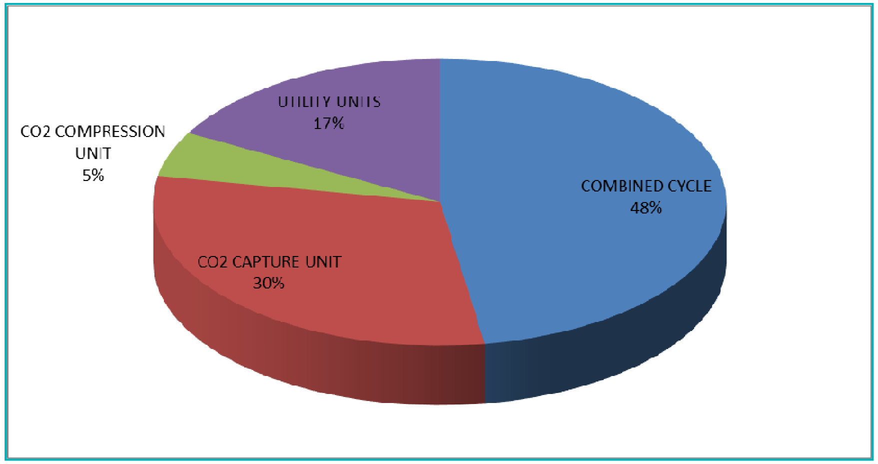

Figure 4. Case 2.2 – Unit percentage weight on TPC

Table 7. Case 2.3 – Total Plant Cost

Case 2.3
(NGCC with CCS and FGR - 98.5% CO2 capture rate)

CONTRACT: 1-BD-1046A
CLIENT: IEAGHG
LOCATION: THE NETHERLANDS
DATE: MAY 2019
REV.: 0

POS.	DESCRIPTION	UNIT 3000 Combined Cycle	UNIT 4000 CO2 Capture Unit	UNIT 5000 CO2 Compression Unit	UNIT 6000 Utility Units	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIAL	417,100,000	292,800,000	35,100,000	116,900,000	861,900,000	1) Gross power output MW : 1403
							Specific cost €/kW : 1,118
2	CONSTRUCTION	146,000,000	102,500,000	26,300,000	81,800,000	356,600,000	
							2) Total Net Power MW : 1321
3	**DIRECT FIELD COST**	**563,100,000**	**395,300,000**	**61,400,000**	**198,700,000**	**1,218,500,000**	Specific cost €/kW : 1,187
4	OTHER COSTS	22,500,000	21,700,000	4,600,000	11,500,000	60,300,000	
5	EPC SERVICES	61,900,000	52,400,000	8,600,000	23,550,000	146,450,000	
							EXCLUSIONS
6	**TOTAL INSTALLED COST**	**647,500,000**	**469,400,000**	**74,600,000**	**233,750,000**	**1,425,250,000**	Spare parts
							Inventories of fuel and chemicals
7	PROJECT CONTINGENCY	64,800,000	46,900,000	7,500,000	23,400,000	142,600,000	Start-up costs
							Insurance
8	PROCESS CONTINGENCY	EXCLUDED	EXCLUDED	EXCLUDED	EXCLUDED	-	Local taxes and fees
12	**TOTAL PLANT COST**	**712,300,000**	**516,300,000**	**82,100,000**	**257,150,000**	**1,567,850,000**	

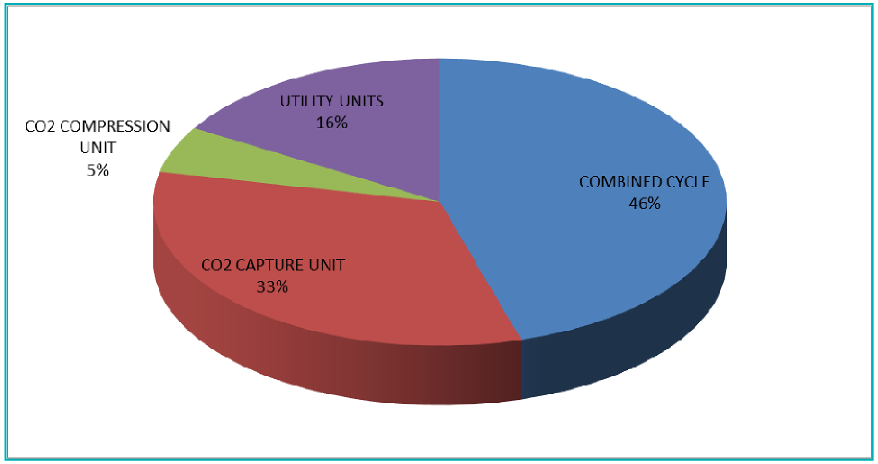

Figure 5. Case 2.3 – Unit percentage weight on TPC

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 bariable costs for the natural gas fired study cases listed in Table 1, 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 (93% capacity factor for combined cycle). Reference values for feedstock and main consumables prices are summarized in chapter B.

Item	Unit	Cost
Natural gas	€/GJ (LHV)	6
Raw process water	€/m^3	0.2
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 natural gas fired cases of the study.

Yearly Variable Costs

Yearly Operating hours = 8147		Case 1			Case 2			Case 2.1		
Consumables	**Unit Cost** €/t	**Consumption** Hourly kg/h	Yearly t/y	**Oper. Costs** €/y	**Consumption** Hourly kg/h	Yearly t/y	**Oper. Costs** €/y	**Consumption** Hourly kg/h	Yearly t/y	**Oper. Costs** €/y
Feedstock										
Natural Gas	279.0	187,200	1,525,081	425,515,900	187,200	1,525,081	425,515,900	187,200	1,525,081	425,515,900
Auxiliary feedstock										
Make-up water	0.20	1,044,000	8,505,259	1,701,100	1,436,000	11,698,805	2,339,800	1,472,000	11,992,090	2,398,400
Catalysts	not displayable	-	-	3,272,700	-	-	3,272,700	-	-	3,272,700
Chemicals (including Solvents)	not displayable	-	-	1,559,700	-	- (1)	7,052,200	-	- (1)	7,931,100
Waste Disposal										
Solvent disposal	not displayable	-	-	0	-	-	659,400	-	-	764,500
TOTAL YEARLY OPERATING COSTS	**Euro/year**			**432,049,400**			**438,840,000**			**439,882,600**

(1) Based on Wood's assumption: specific solvent cost of 5 €/kg

Yearly Variable Costs

Yearly Operating hours = 8147		Case 1			Case 2.2			Case 2.3		
Consumables	**Unit Cost** €/t	**Consumption** Hourly kg/h	Yearly t/y	**Oper. Costs** €/y	**Consumption** Hourly kg/h	Yearly t/y	**Oper. Costs** €/y	**Consumption** Hourly kg/h	Yearly t/y	**Oper. Costs** €/y
Feedstock										
Natural Gas	279.0	187,200	1,525,081	425,515,900	185,000	1,507,158	420,515,200	185,000	1,507,158	420,515,200
Auxiliary feedstock										
Make-up water	0.20	1,044,000	8,505,259	1,701,100	1,154,000	9,401,407	1,880,300	1,168,000	9,515,462	1,903,100
Catalysts	not displayable	-	-	3,272,700	-	-	3,272,700	-	-	3,272,700
Chemicals (including Solvents)	not displayable	-	-	1,559,700	-	- (1)	7,072,700	-	- (1)	7,959,900
Waste Disposal										
Solvent disposal	not displayable	-	-	0	-	-	665,900	-	-	772,900
TOTAL YEARLY OPERATING CO[S]	**Euro/year**			**432,049,400**			**433,406,800**			**434,423,800**

(1) Based on Wood's assumption: specific solvent cost of 5 €/kg

3.2. Fixed costs

Fixed costs include:

- Operating Labour Costs
- Overhead Charges
- Maintenance Costs.

3.2.1. Operating Labour costs

A single main area of operation has been identified for the NGCC cases, i.e. the Combined cycle & Utilities (including CO_2 capture unit)

The area responsible and his assistant supervise the area of operation; both are daily position. The shift superintendent and the electrical assistant 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 of 60,000 €/year, referred to year 2019.

The following tables report the labour force for the different configurations, along with the direct labour cost.

Table 8. Case 1 – Operating Labor Cost

Case 1			
	Power Island & Utilities	**TOTAL**	**Notes**
OPERATION			
Area Responsible	1	1	daily position
Assistant Area Responsible	1	1	daily position
Shift Supervisor	5	5	2 positions per shift
Control Room Operator	10	10	4 positions per shift
Field Operator	10	10	8 positions per shift
Subtotal		**27**	
MAINTENANCE			
Mechanical group	4	4	daily position
Instrument group	4	4	daily position
Electrical group	3	3	daily position
Subtotal		**11**	
LABORATORY			
Superintendent+Analysts	2	2	daily position
Subtotal		**2**	
TOTAL		**40**	
Cost for personnel			
Yearly individual average	60,000	Euro/year	
Total cost =	2,400,000	Euro/year	

Table 9. Case 2, 2.1, 2.2 and 2.3 – Operating Labor Costs

Case 2, 2.1, 2.2 and 2.3			
	Power Island & Utilities	**TOTAL**	**Notes**
OPERATION			
Area Responsible	1	1	daily position
Assistant Area Responsible	1	1	daily position
Shift Supervisor	5	5	2 positions per shift
Control Room Operator	15	15	4 positions per shift
Field Operator	15	15	8 positions per shift
Subtotal		**37**	
MAINTENANCE			
Mechanical group	4	4	daily position
Instrument group	4	4	daily position
Electrical group	3	3	daily position
Subtotal		**11**	
LABORATORY			
Superintendent+Analysts	2	2	daily position
Subtotal		**2**	
TOTAL		**50**	
Cost for personnel			
Yearly individual average	60,000	Euro/year	
Total cost =	3,000,000	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
- 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.

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 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. The percentage figures considered for the NGCC based cases is 2.2%. Maintenance labour is assumed to be 40% of the overall maintenance cost.

The yearly maintenance cost for all cases of the study is reported in the following Table 10, with reference to year 2019.

Table 10. Maintenance costs (reference year: 2019)

Type	Case	Maintenance (%)	Total Plant Cost (M€)	Maintenance (M€/year)
NGCC-based	**Case 1**	2.2	905	19.9
	Case 2	2.2	1,597	35.1
	Case 2.1	2.2	1,684	37,0
FGR NGCC-based	**Case 2.2**	2.2	1,510	33.2
	Case 2.3	2.2	1,568	34.5

3.3. Summary

The following tables report the summary of O&M costs for the different cases.

O&M COSTS	Case 1 €/year	Case 2 €/year	Case 2.1 €/year
Fixed Costs			
Direct labour	2,400,000	3,000,000	3,000,000
Adm./gen overheads	3,109,500	5,117,300	5,346,700
Insurance & Local taxes	9,051,000	15,974,500	16,843,500
Maintenance	19,912,200	35,143,900	37,055,700
Subtotal	**34,472,700**	**59,235,700**	**62,245,900**
Variable Costs (Availability = 90%)			
Feedstock	425,515,900	425,515,900	425,515,900
Water Makeup	1,701,100	2,339,800	2,398,400
Catalyst	3,272,700	3,272,700	3,272,700
Chemicals (including Solvent)	1,559,700	7,052,200	7,931,100
Waste disposal (incl. Solvent)	0	659,400	764,500
Subtotal	**432,049,400**	**438,840,000**	**439,882,600**
TOTAL O&M COSTS	**466,522,100**	**498,075,700**	**502,128,500**

O&M COSTS	Case 1 €/year	Case 2.2 €/year	Case 2.3 €/year
Fixed Costs			
Direct labour	2,400,000	3,000,000	3,000,000
Adm./gen overheads	3,109,500	4,887,900	5,039,100
Insurance & Local taxes	9,051,000	15,105,500	15,678,500
Maintenance	19,912,200	33,232,100	34,492,700
Subtotal	**34,472,700**	**56,225,500**	**58,210,300**
Variable Costs (Availability = 90%)			
Feedstock	425,515,900	420,515,200	420,515,200
Water Makeup	1,701,100	1,880,300	1,903,100
Catalyst	3,272,700	3,272,700	3,272,700
Chemicals (including Solvent)	1,559,700	7,072,700	7,959,900
Waste disposal (incl. Solvent)	0	665,900	772,900
Subtotal	**432,049,400**	**433,406,800**	**434,423,800**
TOTAL O&M COSTS	**466,522,100**	**489,632,300**	**492,634,100**

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.

The LCOE prediction is 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)

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.

4.2.2. Cost of CO_2 avoidance

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

$$CO_2 \text{ Avoidance Cost (CAC)} = \frac{\text{LCOE}_{\text{CCS}} - \text{LCOE}_{\text{NoCCS}}}{CO_2\text{Emissions}_{\text{NoCCS}} - CO_2\text{Emissions}_{\text{CCS}}}$$

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.

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
Discount Rate	Reference: 8%
Capacity factor (NGCC)	93%
CO_2 transport & storage cost	10 €/t $_{\text{STORED}}$
CO_2 emission cost	0 €/t $_{\text{EMITTED}}$
Inflation Rate	Constant Euro
Currency	Euro reported in 1Q2019

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.

A summary of the economical modelling results, in terms of LCOE and CAC, is reported in Table 11 for NGCC cases, developed with 8% discount rate.

Figure 6 and Figure 7 report LCOE and CAC bar chart showing the relative weight of:

- Capital investment,
- Fixed O&M,
- Variable O&M,
- Fuel,
- CO_2 transportation & storage,

Table 11. Financial results summary: LCOE and CO_2 avoidance cost

Case	Description	LCOE €/MWh	CO_2 emission avoidance cost €/t
Case 1	NGCC w/o CCS	48.2	-
Case 2	NGCC w/CCS 90%	68.9	69.98
Case 2.1	NGCC w/CCS 98.5%	72.2	73.54
Case 2.2	FGR NGCC w/CCS 90%	67.3	65.20
Case 2.3	FGR NGCC w/CCS 98.5%	69.9	65.56

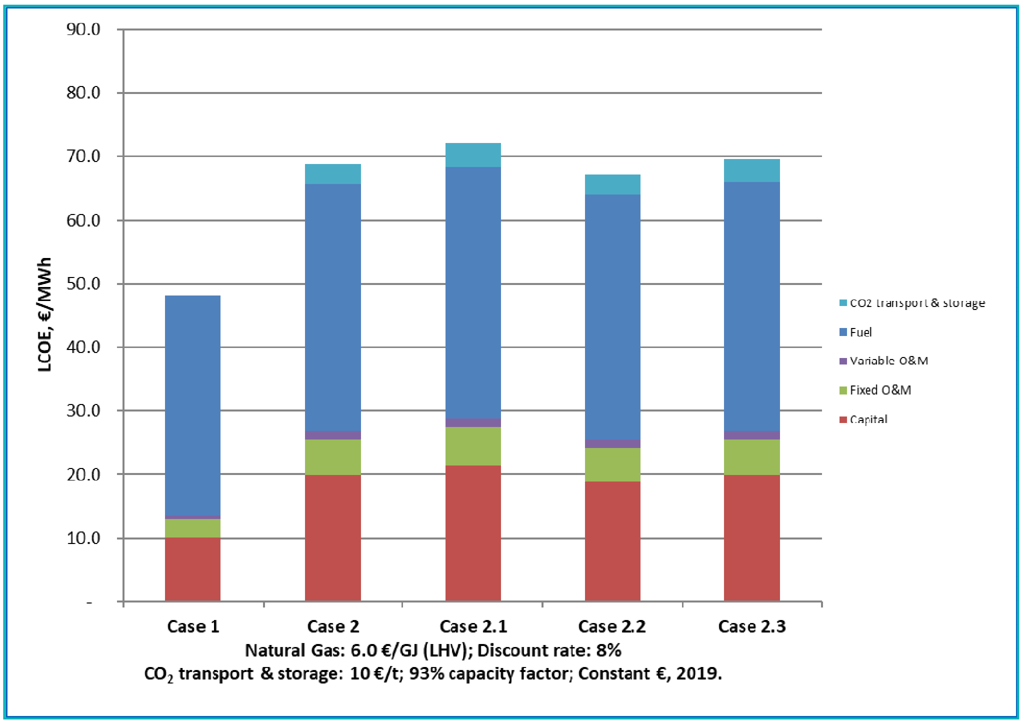

Figure 6. LCOE for all NGCC study cases

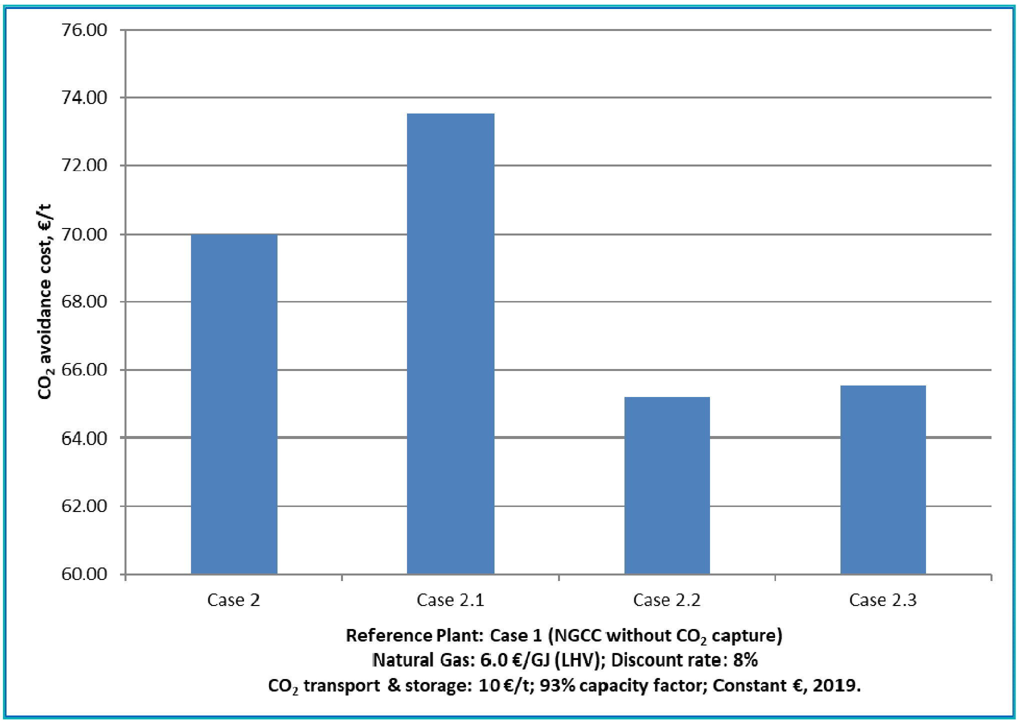

Figure 7. CAC for all NGCC study cases with CO2 capture

The results show that flue gas recirculation comes out as an attractive technique to implement in a combined cycle plant with associated carbon capture process.

The benefits of FGR are dual: on one side, the minor flowrate (but richer in terms of carbon dioxide) sent to the absorber column allows to foresee a smaller column and greatly reduce the capital investment on the capture unit, while capturing roughly the same quantity of CO2. On the other side, it is technically easier to treat flue gases that are enriched in the target species: this allows for lower solvent circulation and inventory as well as reduced energy penalty thanks to a lower reboiler duty (thus steam export) required for regeneration. Ultimately, this leads both to an advantage in terms of capture unit CAPEX and net power production, overcoming the adverse effects of both the increased CAPEX on the power island (due to extra ducting, oversizing of the DCC and need for a flue gas blower, all necessary to recirculate exhaust gases) and the lower efficiency of the gas turbine while operating in this configuration.

The results also show the economic impacts of enhancing CO2 capture rate from 90% to 98.5%. For the reference cases with CO2 capture (without FGR) the LCOE increases by 4.7% while the CAC by 5%. These effects are smoothed for the capture cases with FGR, i.e. +3.5% for LCOE and +0.5% for CAC, as the economic impacts of higher CO2 capture are typically concentrated in the CAPEX and the OPEX of CO2 capture unit, that has got a lower relative weight for both CAPEX and OPEX in the cases with FGR.

CLIENT	:	IEAGHG
PROJECT NAME	:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO_2 CAPTURE
DOCUMENT NAME	:	FLEXIBILITY OF NGCC WITH CCS
CONTRACT N°	:	1-BD-1046 A

ISSUED BY	:	M.MENSI
CHECKED BY	:	V.TOTA
APPROVED BY	:	V.TOTA

Date	Revised Pages	Issued by	Checked by	Approved by

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GLOSSARY

CCS	Carbon Capture and Storage
NGCC	Natural Gas Combined Cycle
USC PC	Ultrasupercritical Pulverised Coal
FGR	Flue Gas Recirculation
EGR	Exhaust Gas Recirculation
CCU	Carbon Capture Unit
CMC	Ceramic Matrix Composite
ASU	Air Separation Unit
MCFC	Molten Carbonate Fuel Cell
TPC	Total Plant Cost
TIC	Total Installed Cost
MEL	Minimum Environmental Load
GT	Gas Turbine
ST	Steam Turbine

1 Introduction

The introduction of the post-combustion CO_2 capture and compression facilities in NGCC plants impose additional constraints to a flexible operation, where certain equipment, like stripper and reboiler, may limit the capacity to make frequent start-ups/shut-downs, due to the time required to pre-heat the regeneration column and the related reboilers.

Also, the requirement for the power plants to operate flexibly in the power market, is nowadays strongly conditioned by the massive increase of the renewable technologies and their variable capability to produce power for the electrical grid.

The main objective of this chapter is to update the key assessments shown in the IEAGHG Report 2012/06 *"Operating flexibility of power plants with CCS"*, to reflect from one end the technology improvements of the key plant components from 2011 to 2018, and also to include a more up-to date operating flexibility requirements.

The considerations shown in this section are based on the assumption that these plant types will be requested to operate in the mid merit market, thus participating to the first step of the variable electricity according to an assumed weekly demand curve.

In the specific case of natural gas fired combined cycle, the assumed weekly demand curve is reported in Figure 1.

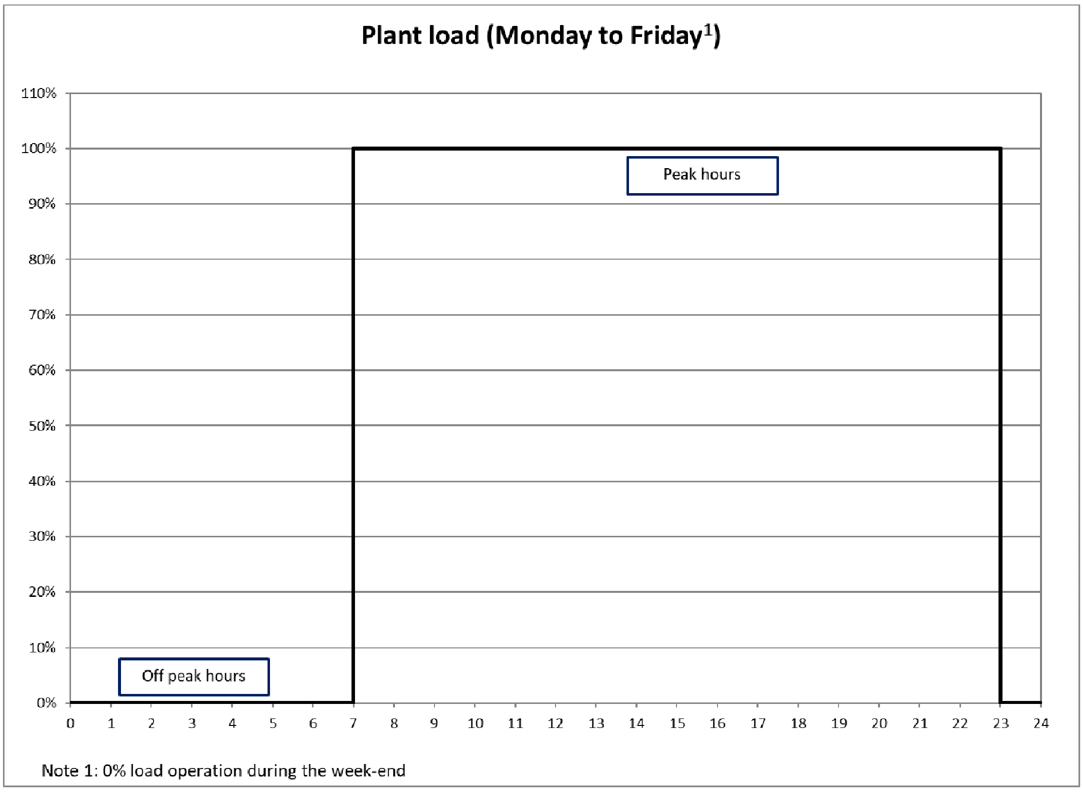

Figure 1. Daily NGCC plant load

From the above graph, it can be drawn that the NGCC plants will be maintained at base load for 80 hours per week, while being shutdown during the remaining 88 hours.

1.1 Study cases

The capability of these plant types for a flexible operation is mainly affected by the constraints related to CO_2 capture and compression units, as well as the transportation pipeline. To investigate these main features, the following cases are presented in Table 1.

Table 1. NGCC power plant flexibility cases

Case	Name	Description
2.1a	Solvent Storage	This case considers the rich/lean solvent storage, in order to minimize the plant power consumption and increase the overall power production during peak load demand period.
2.1b	Variable Capture	This case evaluates the possibility of tuning ON/OFF the CO_2 capture in the plant, depending on the possible CO_2 allowance cost fluctuations.
2.1c	Energy storage	This case evaluates the possibility of incorporating a BESS (Battery Energy Storage System) within the power plant to cover a daily 2-hours peak in the evening.

The reference case for this flexibility study is Case 2.1, which indicates a natural gas combined cycle with 98.5% CO_2 recovery.

For each case and sub-scenario investigated, Wood produced a comparative summary of performances, equipment size and additional equipment required put against the reference Case 2.1. From this information, estimates of the total CAPEX of the plant incorporating the proposed modification were developed.

2 Case 2.1a – Solvent Storage

2.1 Introduction

Case 2.1a assesses how the operating flexibility of NGCC's with post-combustion capture improves when solvent storage tanks are installed in the plant, allowing temporary storage of rich and lean solvent.

Solvent storage techniques allow to decouple the power plant and the CO_2 absorption from the CO_2 regeneration and compression units, while continuously capturing the CO_2 from the flue gases. In addition, the solvent regeneration and CO_2 compression, with their associated energy penalties, can be operated during low electricity demand periods, while maximizing the electricity production when the market requires a higher electricity generation.

2.2 Description of the cases

This alternative is assessed considering one whole week of plant operation, based on the grid demand cycling trend summarised in section 0.

To maximize the energy production, the rich solvent can be partially or even totally stored during the 80 hours per week of peak load operation, when the plant is at base-load, while the regeneration of stored solvent can be made during the remaining 88 hours per week of off-peak load operation. With this strategy, the solvent flowrates from and to the storage are balanced in one week of plant operation.

During peak electricity demand, when the market requires the maximum amount of electricity, the power plant is operated at base load by making the full capture of the CO_2 from the flue gas in the absorber column, while the solvent regeneration and CO_2 compression sections are at low or even no load, thus reducing the energy penalties in the plant.

Depending on the regeneration load, only a certain amount of the CO_2-rich solvent from the absorber column is fed to the regenerator, while the remainder is stored in dedicated storage tanks. As a consequence, part of the lean solvent required for the CO_2 capture in the absorber is not available from the regenerator, whilst it is taken from the relevant storage tanks.

During off-peak electricity demand, i.e. when lower electricity selling prices reduce the revenues of the plant, the NGCC plant shall be operated in order to regenerate the rich solvent stored in the tanks and refill the lean amine storage tanks. The minimum load the combined cycle can run at is fixed by the minimum environmental load of the gas turbine, i.e. 40% as assumed in the study.

During night and week-end the combined cycle is in operation with one gas turbine only at its minimum load. The steam generated in the HRSG is entirely used in the regenerator reboiler, i.e. the steam turbine and the condenser are by-passed.
The power plant at minimum load is capable to provide approximately 68% of the steam required by the regenerator reboiler of the reference case, thus limiting the solvent regeneration capacity.

It has to be noted that in this condition, the gas turbine power output exceeds the internal consumption of the plant, while, for the NGCC plants, no power production is required during low electricity demand period. The possibility to deliver energy in the network during low demand periods should be agreed with the grid operator. It would be possible to utilise this period to charge a BESS (battery energy storage system) for higher electricity export during the day). An assessment on using BESSs is provided later in this chapter.

The scenarios shown in the following sections, each characterised by a different regeneration load during high electricity demand period, have been investigated, in order to evaluate the most convenient operating conditions. Compared to the previous report by Wood as formerly Foster Wheeler, IEAGHG Report 2012/06 *"Operating flexibility of power plants with CCS"*, Wood restrained from assessing some scenarios that were found to be unfeasible (i.e. having complete shutdown of the regeneration and compression units is not realistic, as the required tank area is extremely large).

The main operating parameters for each possible scenario are also summarised in Table 2

Table 2. NGCC - Solvent Storage Scenarios

Scenario: Solvent storage for NGCC		No solvent storage Reference scenario	43% solvent storage Scenario 1	10% solvent storage Scenario 2	36.5% solvent storage Scenario 3
Daily full load operation (80 hours/week) Plant Load 100%					
Power island operating condition					
GT Load	-	2x100%	2x100%	2x100%	2x100%
GT power output	MWe	1040.0	1040.0	1040.0	1040.0
ST power output	MWe	363.7	419.2	377.6	416.2
Net power output	MWe	1315.9	1396.0	1338.1	1389.3
CO2 Capture Unit operating condition		**absorber 100% regenerator 100%**	**absorber 100% regenerator 57%**	**absorber 100% regenerator 90%**	**absorber 100% regenerator 63.5%**
Nightly part load operation (88 hours/week)					
Power island operating condition					
GT Load	-	2x0%	1x40%	1x40%	1x40%
GT power output	MWe	0.0	210.0	210.0	210.0
ST power output	MWe	0.0	0.0	0.0	0.0
Net power output	MWe	0.0	153.0	171.1	153.2
CO2 Capture Unit operating condition		**absorber 0% regenerator 0%**	**absorber 31% regenerator 70%**	**absorber 31% regenerator 39%**	**absorber 31% regenerator 63.5%**
Regenerator design					
Regenerator size respect to reference case		-	70%	90%	63.5%
Storage tanks					
Rich solvent			2 x 56'300 m3 D = 65 m x H = 17 m)	2 x 12'500 m3 D = 35 m x H = 13 m)	2 x 53'000 m3 D = 63 m x H = 17 m)
Lean solvent			2 x 56'300 m3 D = 65 m x H = 17 m)	2 x 12'500 m3 D = 35 m x H = 13 m)	2 x 53'000 m3 D = 63 m x H = 17 m)
Tank Area (as % of plant plot area)			43%	18%	41%
Consideration					
			FEATURES Highest power generation Very large tanks Maximum possible storage	**FEATURES** Slightly better power generation Reasonably sized tanks Smaller reboiler Derived from economic considerations	**FEATURES** Smallest reboiler possible Very large tanks

2.2.1 *Scenario 1 - Lowest possible regeneration during peak time*

In this scenario, the energy production during peak demand periods is maximized by storing the maximum allowable amount of solvent: this amount is defined by the total available steam (thus regenerating power) available from one HRSG when one GT is running at MEL (Minimum Environmental Load) in the span of the 88 off-peak weekly hours. Therefore, this alternative shows the highest increase of the daily net power production with respect to the reference case.

In this condition, the reboiler size needs to be only 70% of the reference case design. On the other hand, large tanks and a large storage area are required to operate in this condition.

2.2.2 *Scenario 2 - 90% regeneration load during peak time*

. In this case, during peak time, 90% of the rich solvent from the absorber is fed to the regenerator, while the remainder is stored in a dedicated tank. In the same way

10% of the lean solvent required for the absorption is taken from the storage tanks. This configuration allows to contain the area and the volume required for the solvent storage tanks within reasonable limits.

2.2.3 *Scenario 3 - Smallest possible reboiler*

In this scenario, starting from the limit fixed by scenario 1, regenerator load was increased until both peak and off-peak operations shared the same regenerator load. This situation represents the smallest possible regeneration section design. While storage space required decreased compared to scenario 1, it remained quite large.

2.3 Scenario 1 – Lowest possible regeneration during peak time

For this scenario, steam production from a single HRSG with the related gas turbine operating at 40% load (to comply with its minimum environmental load) is assessed.
Steam turbine is completely bypassed to be able to export the whole steam production for solvent regeneration: this allows to have excess thermal duty considering the amount used to regenerate the solvent coming from the absorber during this operating scenario. This excess thermal duty sets the boundary to how much solvent is physically possible to store while being able to regenerate it during off-peak hours.

According to a process simulation, the HRSG provides 315.7 MWth worth of steam from the flue gas of a 40% load GT. This allows to run the reboiler at 70% load during off-peak operation, allowing us to store 43% of the solvent coming from the absorber column during peak load operation.

In this situation, two large storage tanks are needed for each service (two for lean solvent, two for rich solvent). In Figure 2 the total tank content weekly variation is reported.

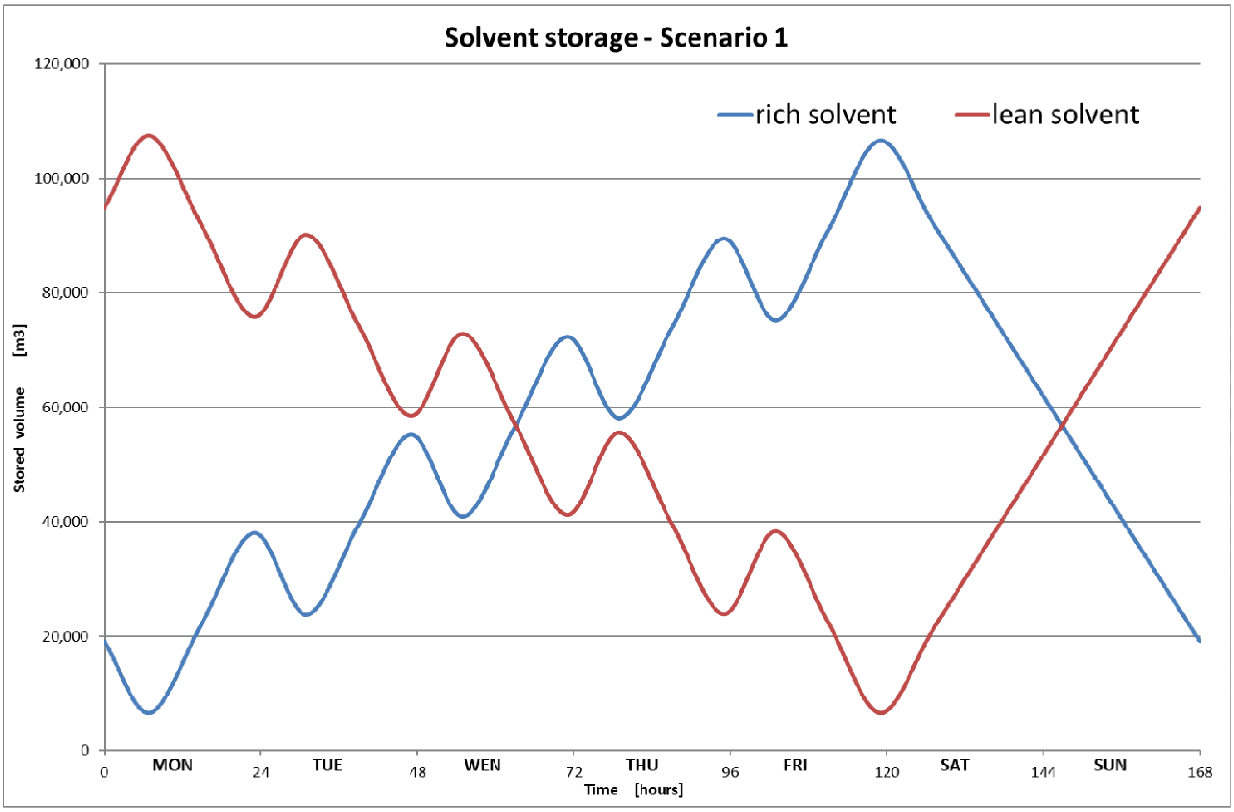

Figure 2. Weekly solvent storage cycle for scenario 1

2.3.1 *Performances*

Performance comparison between the current flexibility scenario and the reference Case 2.1 is shown below in Table 3.

Table 3. Scenario 1 performance report

NGCC with CCS - 98.5% CO2 recovery - Solvent storage system				
Scenario 1 - Lowest possible regeneration during peak				
		Reference case	2 GT 100% (57% regen)	1 GT 40% (70% regen)
PLANT THERMAL INPUT				
Natural Gas Flowrate	t/h	187.2	187.2	37.4
Natural Gas LHV	MJ/kg	46.50	46.50	46.50
Thermal Energy of Natural Gas (LHV basis)	MWth	2417.5	2417.5	483.5
PLANT ELECTRICAL OUTPUT				
Electric Power Output at Generator				
Gas Turbine	MWe	1040.0	1040.0	210.0
Steam Turbine	MWe	363.7	419.2	-
Total	**MWe**	**1403.7**	**1459.2**	**210.0**
Gross Electrical Efficiency (LHV basis)	%	58.1	60.4	43.4
Auxilliary Electrical Consumption				
Power Plant	MWe	11.9	13.7	6.0
Balance of Plant	MWe	13.3	13.3	13.3
CO_2 Capture & Compression	MWe	58.6	33.4	41.0
Electric Power Consumption of the Plant	MWe	83.8	60.4	60.3
Net Electrical Power Output (Step-up transformer 0.998)	**MWe**	**1315.9**	**1396.0**	**149.4**
Net Electrical Efficiency (LHV basis) [A]	%	54.4	57.7	30.9
CO_2 EMISSION				
Equivalent CO_2 flow in Natural Gas	kmol/h	11268.6	11268.6	2253.7
Captured CO_2	kmol/h	11099.6	11099.6	2231.2
Removal efficiency	%	98.5	98.5	99.0
CO_2 emission	**kg/s**	**2.07**	**2.07**	**0.28**
Specific CO_2 emissions per MWe net produced	**kg/MWh**	**5.6**	**5.6**	**6.6**

2.3.2 *Equipment list*

A comparative equipment list between Case 2.1 and the current scenario is reported below in Table 4.

Table 4. Scenario 1 comparative equipment list

Solvent storage for NGCC			
Unit 3000 - Power Island			
Equipment	**Reference plant**	**Scenario 1**	**Remarks**
Steam turbine	364 MWe Gross	420 MWe Gross	
Steam turbine condenser	316 MWth	482 MWth	Cooling water heat exchanger tubes: titanium; shell: CS
Condensate pump	315 kW 625 m3/h x 128 m	475 kW 1023 m3/h x 129 m	One operating, one spare
Unit 4000 - CO_2 Capture Unit			
Equipment	**Reference plant**	**Scenario 1**	**Remarks**
Regeneration section	CO_2 outlet flow = 11,107 kmol/h Reboiler duty = 453 MW th	CO_2 outlet flow =7,800 kmol/h Reboiler duty = 318 MW th	Including: - stripper - stripper packing - stripper bottom pumps - surplus water pump - amine filter package - reclaimer - semilean flash drum - cross exchanger - flash preheater - overhead stripper condenser - stripper reboiler - lean solvent cooler
Rich solvent storage tank *(for flexible operation)*	not foreseen	2 x 56'300 m3 (Diameter: 65 m H: 17 m)	Floating roof atmospheric storage tank Material: CS with internal lining
Lean solvent storage tank *(for flexible operation)*	not foreseen	2 x 56'300 m3 (Diameter: 65 m H: 17 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Rich solvent storage pumps	not foreseen	4 x 300 kW 1080 m3/h x 70 m	One pump in operation, one spare for each rich solvent tank
Lean solvent storage pumps	not foreseen	4 x 335 kW 1100 m3/h x 80 m	One pump in operation, one spare for each lean solvent tank
Unit 5000 - CO_2 Compression Unit			
Equipment	**Reference plant**	**Scenario 1**	**Remarks**
Compression package *(2x50% train)*	CO2 flow = 125,000 Nm3/h each train	CO2 flow = 88,000 Nm3/h each train	Including: - four stage compressor - intercoolers - dryers - CO2 pumps

2.3.3 *Investment costs*

A summary of the total CAPEX for this plant configuration developed from the previously shown comparative equipment list is reported in Table 5.

Table 5. Case 2.1a Scenario 1 – Total Plant Cost

wood.	Case 2.1a - Scenario 1 (NGCC with CCS - 98.5% CO2 capture rate - Solvent storage)					CONTRACT: 1-BD-1046A CLIENT: IEAGHG LOCATION: THE NETHERLANDS DATE: MAY 2019 REV.: 0
POS.	**DESCRIPTION**	**UNIT 3000** **Combined Cycle**	**UNIT 4000** **CO2 Capture Unit**	**UNIT 5000** **CO2 Compression Unit**	**UNIT 6000** **Utility Units**	**TOTAL COST EURO**	**NOTES / REMARKS**
1	DIRECT MATERIAL	417,400,000	381,700,000	25,600,000	116,900,000	941,600,000	1) Gross power output MW : 1459 Specific cost €/kW : 1,187
2	CONSTRUCTION	146,100,000	156,400,000	20,500,000	81,800,000	404,800,000	2) Total Net Power MW : 1396
3	**DIRECT FIELD COST**	**563,500,000**	**538,100,000**	**46,100,000**	**198,700,000**	**1,346,400,000**	Specific cost €/kW : 1,241
4	OTHER COSTS	22,500,000	27,400,000	3,500,000	11,500,000	64,900,000	
5	EPC SERVICES	62,000,000	71,300,000	6,500,000	23,550,000	163,350,000	EXCLUSIONS
6	**TOTAL INSTALLED COST**	**648,000,000**	**636,800,000**	**56,100,000**	**233,750,000**	**1,574,650,000**	Spare parts Inventories of fuel and chemicals
7	PROJECT CONTINGENCY	64,800,000	63,700,000	5,600,000	23,400,000	157,500,000	Start-up costs Insurance
8	PROCESS CONTINGENCY	EXCLUDED	EXCLUDED	EXCLUDED	EXCLUDED	-	Local taxes and fees
12	**TOTAL PLANT COST**	**712,800,000**	**700,500,000**	**61,700,000**	**257,150,000**	**1,732,150,000**	

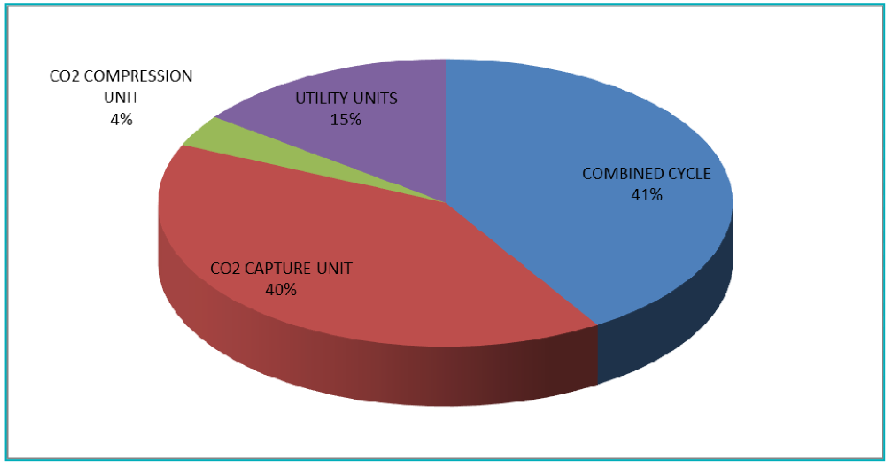

Figure 3. Case 2.1a Scenario 1 – Unit percentage weight on TPC

2.4 Scenario 2 – 90% regeneration load during peak time

For this scenario, peak time regeneration was arbitrarily changed to achieve a reasonably compact storage area requirement.
In this situation, two much smaller storage tanks are needed for each service (two for lean solvent, two for rich solvent). The required tank area is close to 15% of an average combined cycle plot area. In Figure 4 the total tank content weekly variation is reported.

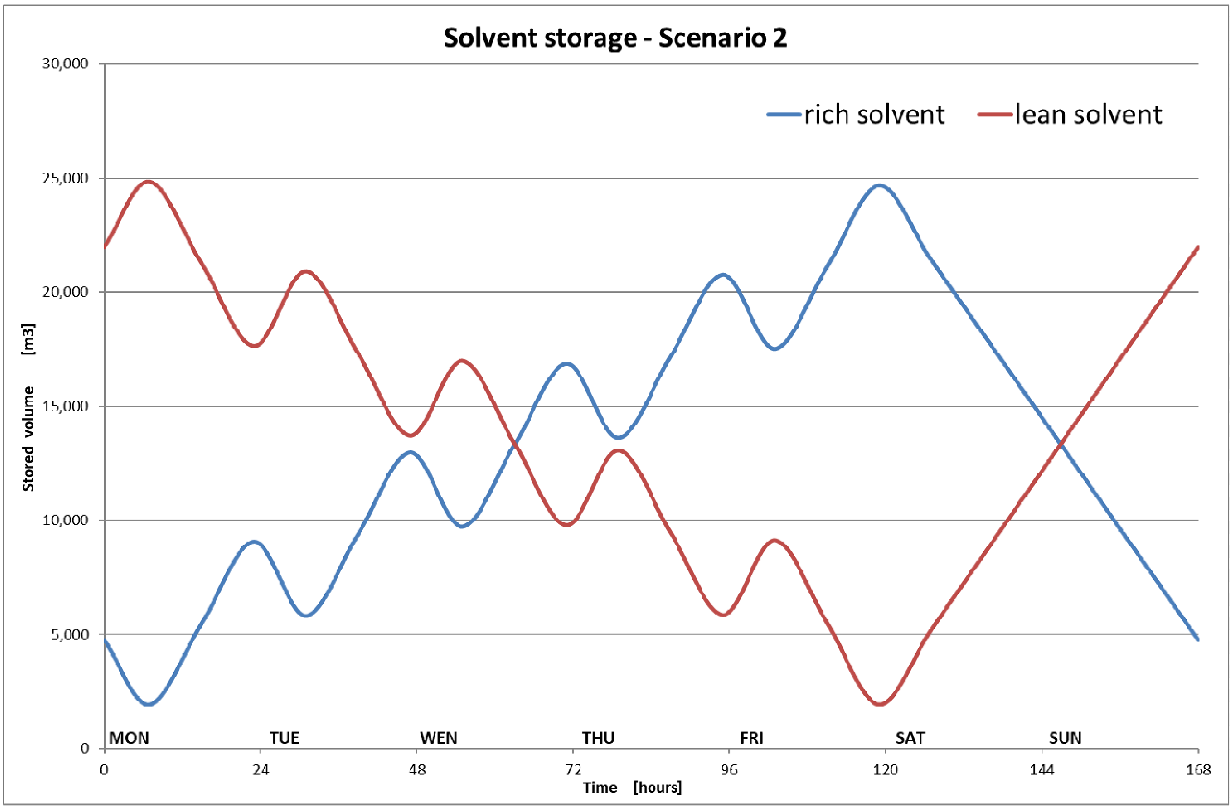

Figure 4. Weekly solvent storage cycle for scenario 2

2.4.1 *Performances*

Performance comparison between the current flexibility scenario and the reference Case 2.1 is shown below in Table 6.

Table 6. Scenario 2 performance report

NGCC with CCS - 98.5% CO2 recovery - Solvent storage system				
Scenario 2 - 90% regeneration load during peak time				
OVERALL PLANT PERFORMANCES				
		Reference case	2 GT 100% (90% regen)	1 GT 40% (39% regen)
PLANT THERMAL INPUT				
Natural Gas Flowrate	t/h	187.2	187.2	37.4
Natural Gas LHV	MJ/kg	46.50	46.50	46.50
Thermal Energy of Natural Gas (LHV basis)	MWth	2417.5	2417.5	483.5
PLANT ELECTRICAL OUTPUT				
Electric Power Output at Generator				
Gas Turbine	MWe	1040.0	1040.0	210.0
Steam Turbine	MWe	363.7	377.6	-
Total	**MWe**	**1403.7**	**1417.6**	**210.0**
Gross Electrical Efficiency (LHV basis)	%	58.1	58.6	43.4
Auxilliary Electrical Consumption				
Power Plant	MWe	11.9	10.7	6.0
Balance of Plant	MWe	13.3	13.3	13.3
CO_2 Capture & Compression	MWe	58.6	52.7	22.9
Electric Power Consumption of the Plant	MWe	83.8	76.8	42.1
Net Electrical Power Output (Step-up trasformer 0.998)	**MWe**	**1315.9**	**1338.1**	**167.6**
Net Electrical Efficiency (LHV basis) [A]	%	54.4	55.4	34.7
CO_2 EMISSION				
Equivalent CO_2 flow in Natural Gas	kmol/h	11268.6	11268.6	2253.7
Captured CO_2	kmol/h	11099.6	11099.6	2231.2
Removal efficiency	%	98.5	98.5	99.0
CO_2 emission	**kg/s**	**2.07**	**2.07**	**0.28**
Specific CO_2 emissions per MW net produced	**t/MWh**	**5.6**	**5.6**	**5.9**

2.4.2 Equipment list

A comparative equipment list between Case 2.1 and the current scenario is reported below in Table 7.

Table 7. Scenario 2 comparative equipment list

Solvent storage for NGCC			
Unit 3000 - Power Island			
Equipment	**Reference plant**	**Scenario 2**	**Remarks**
Steam turbine	364 MWe Gross	378 MWe Gross	
Steam turbine condenser	316 MWth	351 MWth	Cooling water heat exchanger tubes: titanium; shell: CS
Condensate pump	315 kW 625 m3/h x 128 m	335 kW 745 m3/h x 128 m	One operating, one spare
Unit 4000 - CO_2 Capture Unit			
Equipment	**Reference plant**	**Scenario 2**	**Remarks**
Regeneration section	CO_2 outlet flow = 11,107 kmol/h Reboiler duty = 453 MW th	CO_2 outlet flow = 10,000 kmol/h Reboiler duty = 408 MW th	Including: - stripper - stripper packing - stripper bottom pumps - surplus water pump - amine filter package - reclaimer - semilean flash drum - cross exchanger - flash preheater - overhead stripper condenser - stripper reboiler - lean solvent cooler
Rich solvent storage tank *(for flexible operation)*	not foreseen	2 x 12'500 m3 (Diameter: 35 m H: 13 m)	Floating roof atmospheric storage tank Material: CS with internal lining
Lean solvent storage tank *(for flexible operation)*	not foreseen	2 x 12'500 m3 (Diameter: 35 m H: 13 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Rich solvent storage pumps	not foreseen	4 x 75 kW 245 m3/h x 70 m each	One pump in operation, one spare for each rich solvent tank
Lean solvent storage pumps	not foreseen	4 x 90 kW 250 m3/h x 80 m each	One pump in operation, one spare for each lean solvent tank
Unit 5000 - CO_2 Compression Unit			
Equipment	**Reference plant**	**Scenario 2**	**Remarks**
Compression package *(2x50% train)*	CO2 flow = 125,000 Nm3/h each train	CO2 flow = 112,000 Nm3/h each train	Including: - four stage compressor - intercoolers - dryers - CO2 pumps

2.4.3 *Investment costs*

A summary of the total CAPEX for this plant configuration developed from the previously shown comparative equipment list is reported in Table 8.

Table 8. Case 2.1a Scenario 2 – Total Plant Cost

wood.	Case 2.1a - Scenario 2 (NGCC with CCS - 98.5% CO2 capture rate - Solvent storage)						CONTRACT: 1-BD-1046A CLIENT: IEAGHG LOCATION: THE NETHERLANDS DATE: MAY 2019 REV.: 0
POS.	DESCRIPTION	UNIT 3000 Combined Cycle	UNIT 4000 CO2 Capture Unit	UNIT 5000 CO2 Compression Unit	UNIT 6000 Utility Units	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIAL	409,300,000	375,700,000	30,300,000	116,900,000	932,200,000	1) Gross power output MW : 1418 Specific cost €/kW : 1,210
2	CONSTRUCTION	143,300,000	151,500,000	22,700,000	81,800,000	399,300,000	2) Total Net Power MW : 1338
3	**DIRECT FIELD COST**	**552,600,000**	**527,200,000**	**53,000,000**	**198,700,000**	**1,331,500,000**	Specific cost €/kW : 1,282
4	OTHER COSTS	22,100,000	28,300,000	4,000,000	11,500,000	65,900,000	
5	EPC SERVICES	60,800,000	69,900,000	7,400,000	23,550,000	161,650,000	EXCLUSIONS
6	**TOTAL INSTALLED COST**	**635,500,000**	**625,400,000**	**64,400,000**	**233,750,000**	**1,559,050,000**	Spare parts Inventories of fuel and chemicals
7	PROJECT CONTINGENCY	63,600,000	62,500,000	6,400,000	23,400,000	155,900,000	Start-up costs Insurance
8	PROCESS CONTINGENCY	EXCLUDED	EXCLUDED	EXCLUDED	EXCLUDED	-	Local taxes and fees
12	**TOTAL PLANT COST**	**699,100,000**	**687,900,000**	**70,800,000**	**257,150,000**	**1,714,950,000**	

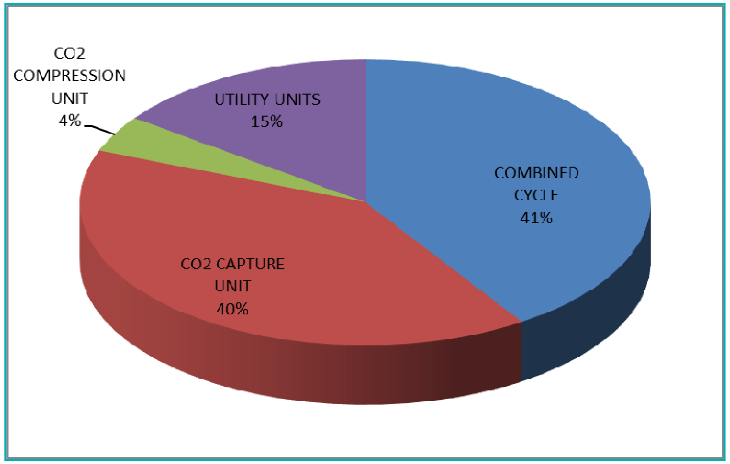

Figure 5. Case 2.1a Scenario 2 – Unit percentage weight on TPC

2.5 Scenario 3 – Smallest possible reboiler

For this scenario, starting from scenario 1, peak regeneration load was subsequently increased by small amounts until peak and off-peak reboiler loads are roughly the same.
In this situation, two relatively large storage tanks are still needed for each service (two for lean solvent, two for rich solvent, but we can achieve the lowest possible cost on the CO_2 regeneration and compression units thanks to downsizing. In Figure 6 the total tank content weekly variation is reported.

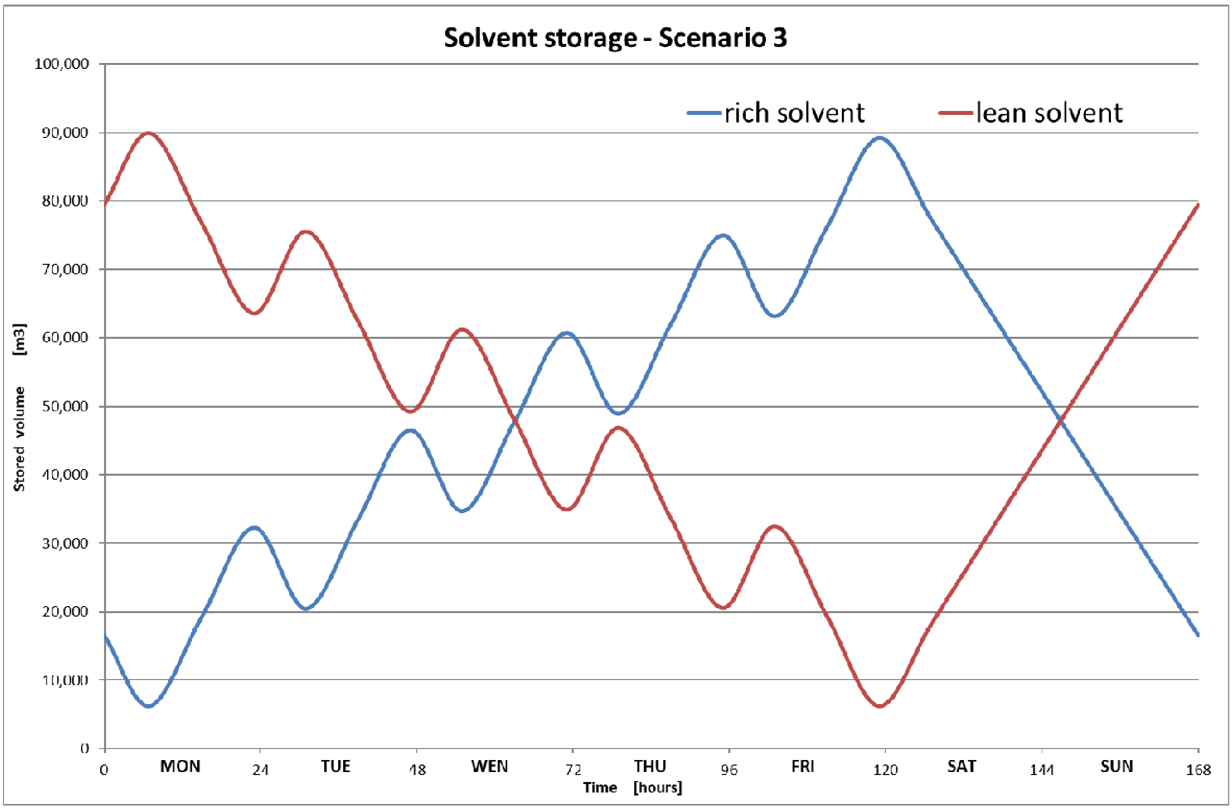

Figure 6. Weekly solvent storage cycle for scenario 3

2.5.1 *Performances*

Performance comparison between the current flexibility scenario and the reference Case 2.1 is shown below in Table 9.

Table 9. Scenario 3 performance report

NGCC with CCS - 98.5% CO2 recovery - Solvent storage system				
Scenario 3 - Smallest possible reboiler				
OVERALL PLANT PERFORMANCES				
		Reference case	2 GT 100% (63.6% regen)	1 GT 40% (63.5% regen)
PLANT THERMAL INPUT				
Natural Gas Flowrate	t/h	187.2	187.2	37.4
Natural Gas LHV	MJ/kg	46.50	46.50	46.50
Thermal Energy of Natural Gas (LHV basis)	MWth	2417.5	2417.5	483.5
PLANT ELECTRICAL OUTPUT				
Electric Power Output at Generator				
Gas Turbine	MWe	1040.0	1040.0	210.0
Steam Turbine	MWe	363.7	416.2	-
Total	**MWe**	**1403.7**	**1456.2**	**210.0**
Gross Electrical Efficiency (LHV basis)	%	58.1	60.2	43.4
Auxilliary Electrical Consumption				
Power Plant	MWe	11.9	13.6	6.0
Balance of Plant	MWe	13.3	13.3	13.3
CO_2 Capture & Compression	MWe	58.6	37.2	37.2
Electric Power Consumption of the Plant	MWe	83.8	64.1	56.5
Net Electrical Power Output (Step-up trasformer 0.998)	**MWe**	**1315.9**	**1389.3**	**153.2**
Net Electrical Efficiency (LHV basis) [A]	%	54.4	57.5	31.7
CO2 EMISSION				
Equivalent CO2 flow in Natural Gas	kmol/h	11268.6	11268.6	2253.7
Captured CO2	kmol/h	11099.6	11099.6	2231.2
Removal efficiency	%	98.5	98.5	99.0
CO2 emission	**kg/s**	**2.07**	**2.07**	**0.28**
Specific CO2 emissions per MW net produced	**t/MWh**	**5.6**	**5.6**	**6.5**

2.5.2 *Equipment list*

A comparative equipment list between Case 2.1 and the current scenario is reported below in Table 10.

Table 10. Scenario 3 comparative equipment list

Solvent storage for NGCC			
Unit 3000 - Power Island			
Equipment	**Reference plant**	**Scenario 3**	**Remarks**
Steam turbine	364 MWe Gross	416 MWe Gross	
Steam turbine condenser	316 MWth	454 MWth	Cooling water heat exchanger tubes: titanium; shell: CS
Condensate pump	315 kW 625 m3/h x 128 m	450 kW 960 m3/h x 129 m	One operating, one spare
Unit 4000 - CO_2 Capture Unit			
Equipment	**Reference plant**	**Scenario 3**	**Remarks**
Regeneration section	CO_2 outlet flow = 11,107 kmol/h Reboiler duty = 453 MW th	CO_2 outlet flow = 7,050 kmol/h Reboiler duty = 288 MW th	Including: - stripper - stripper packing - stripper bottom pumps - surplus water pump - amine filter package - reclaimer - semilean flash drum - cross exchanger - flash preheater - overhead stripper condenser - stripper reboiler - lean solvent cooler
Rich solvent storage tank *(for flexible operation)*	not foreseen	2 x 53'000 m3 (Diameter: 63 m H: 17 m)	Floating roof atmospheric storage tank Material: CS with internal lining
Lean solvent storage tank *(for flexible operation)*	not foreseen	2 x 53'000 m3 (Diameter: 63 m H: 17 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Rich solvent storage pumps	not foreseen	4 x 250 kW 890 m3/h x 70 m	One pump in operation, one spare for each rich solvent tank
Lean solvent storage pumps	not foreseen	4 x 280 kW 900 m3/h x 80 m	One pump in operation, one spare for each lean solvent tank
Unit 5000 - CO_2 Compression Unit			
Equipment	**Reference plant**	**Scenario 3**	**Remarks**
Compression package *(2x50% train)*	CO2 flow = 125,000 Nm3/h each train	CO2 flow = 80,000 Nm3/h each train	Including: - four stage compressor - intercoolers - dryers - CO2 pumps

2.5.3 *Investment costs*

A summary of the total CAPEX for this plant configuration developed from the previously shown comparative equipment list is reported in Table 11.

Table 11. Case 2.1a Scenario 3 – Total Plant Cost

wood.	Case 2.1a - Scenario 3 (NGCC with CCS - 98.5% CO2 capture rate - Solvent storage)						CONTRACT: 1-BD-1046A CLIENT: IEAGHG LOCATION: THE NETHERLANDS DATE: MAY 2019 REV.: 0
POS.	**DESCRIPTION**	**UNIT 3000** **Combined Cycle**	**UNIT 4000** **CO2 Capture Unit**	**UNIT 5000** **CO2 Compression Unit**	**UNIT 6000** **Utility Units**	**TOTAL COST EURO**	**NOTES / REMARKS**
1	DIRECT MATERIAL	416,800,000	373,200,000	22,400,000	116,900,000	929,300,000	1) Gross power output MW : 1456 Specific cost €/kW : 1,174
2	CONSTRUCTION	145,900,000	152,800,000	19,000,000	81,800,000	399,500,000	2) Total Net Power MW : 1389
3	**DIRECT FIELD COST**	**562,700,000**	**526,000,000**	**41,400,000**	**198,700,000**	**1,328,800,000**	Specific cost €/kW : 1,230
4	OTHER COSTS	22,500,000	26,800,000	3,100,000	11,500,000	63,900,000	
5	EPC SERVICES	61,900,000	69,700,000	5,800,000	23,550,000	160,950,000	EXCLUSIONS
6	**TOTAL INSTALLED COST**	**647,100,000**	**622,500,000**	**50,300,000**	**233,750,000**	**1,553,650,000**	Spare parts Inventories of fuel and chemicals
7	PROJECT CONTINGENCY	64,700,000	62,300,000	5,000,000	23,400,000	155,400,000	Start-up costs Insurance
8	PROCESS CONTINGENCY	EXCLUDED	EXCLUDED	EXCLUDED	EXCLUDED	-	Local taxes and fees
12	**TOTAL PLANT COST**	**711,800,000**	**684,800,000**	**55,300,000**	**257,150,000**	**1,709,050,000**	

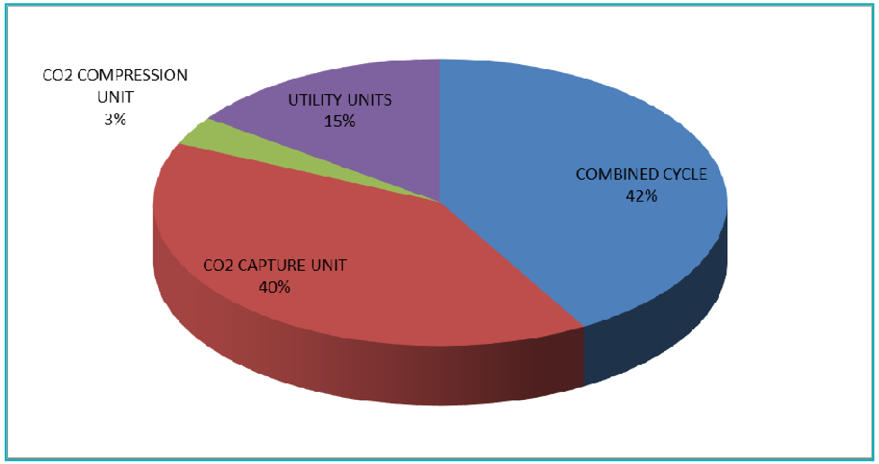

Figure 7. Case 2.1a Scenario 3 – Unit percentage weight on TPC

3 Case 2.1b – Variable Capture

3.1 Introduction

This Case 2.1b shows how NGCC plants with post-combustion capture of the CO_2 can also be maintained in continuous operation without operating the carbon capture and compression sections.

Depending on possible CO_2 emission allowances cost, this operating flexibility may improve the economics of the plant, because of its resulting higher power production.

3.2 Description of the cases

Flexible CO_2 capture operation is particularly suited for post-combustion CO_2 capture systems, as it is possible to totally by-pass the CO_2 capture unit, directly venting to atmosphere the flue gas from the HRSG similarly to a conventional NGCC plant without carbon capture. When the capture unit is bypassed, around 470 t/h of CO_2 are released to the atmosphere instead of being captured and compressed.

In this operating mode, the energy penalties related to the CO_2 capture and compression units, as well as the steam requirement for solvent generation, are avoided, leading to an overall higher plant net power production.

As no heat is required by the regenerator boiler, the low-pressure steam from the steam generators and the exhaust steam from the MP module of the steam turbine are used to generate additional power in the LP module.

The resulting LP steam entering this section of the machine is much larger than the flowrate of the reference case. Therefore, the low-pressure steam turbine module, the condenser and condensate system shall be properly designed to accommodate the increased steam flow during unabated mode. The power plant was designed to operate efficiently in this condition, while allowing partial load operation when CO_2 is captured and compressed.

3.3 Results

In the following pages, techno-economic results obtained for this configuration are reported.

3.3.1 *Performances*

Performance comparison between the current flexibility scenario and the reference Case 2.1 is shown below in Table 12.

Table 12. Case 2.1b performance report

NGCC with CCS - 98.5% CO2 recovery - Variable CO2 capture				
ON/OFF CCU capability				
OVERALL PLANT PERFORMANCES				
		Reference case	CCU OFF	CCU ON
Natural Gas Flowrate	t/h	187.2	187.2	187.2
Natural Gas LHV	kJ/kg	46502.0	46502.0	46502.0
THERMAL ENERGY OF FEEDSTOCK (based on NG LHV) (A)	**MWt**	**2418.1**	**2418.1**	**2418.1**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**1403.7**	**1507.9**	**1399.7**
POWER PLANT PERFORMANCES				
Power Islands consumption	MWe	11.9	13.0	13.0
Utility & Units consumptions	MWe	13.3	15.0	15.0
CO_2 Capture Unit + Compression	MWe	58.6	0.0	58.6
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**83.8**	**28.0**	**86.6**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**1319.9**	**1479.9**	**1313.1**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**58.0**	**62.4**	**57.9**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**54.6**	**61.2**	**54.3**
CO_2 emission	**kg/s**	**2.07**	**128.80**	**2.07**
Specific CO_2 emissions per MW net produced	**t/MWh**	**5.6**	**313.3**	**5.6**

3.3.2 *Equipment list*

A comparative equipment list between Case 2.1 and the current scenario is reported below in Table 13.

Table 13. Case 2.1b comparative equipment list

Unit 3000 - Power Island			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Steam turbine	370 MWe gross	470 MWe gross	
Steam turbine condenser	320 MWth	690 MWth	Sea water heat exchanger tubes: titanium; shell: CS
Condensate pumps	1 x 375 KW 520 m3 x 150 m	1 x 800 KW 1100 m3 x 150 m	One operating one spare

3.3.3 *Investment costs*

A summary of the total CAPEX for this plant configuration developed from the previously shown comparative equipment list is reported in Table 14.

Table 14. Case 2.1b – Total Plant Cost

wood.	Case 2.1b (NGCC with CCS - 98.5% CO2 capture rate - ON/OFF CCU capabilities)						CONTRACT: 1-BD-1046A CLIENT: IEAGHG LOCATION: THE NETHERLANDS DATE: MAY 2019 REV.: 0
POS.	**DESCRIPTION**	**UNIT 3000** **Combined Cycle**	**UNIT 4000** **CO2 Capture Unit**	**UNIT 5000** **CO2 Compression Unit**	**UNIT 6000** **Utility Units**	**TOTAL COST EURO**	**NOTES / REMARKS**
1	DIRECT MATERIAL	420,500,000	372,100,000	32,700,000	116,900,000	942,200,000	1) Max gross power output MW : 1510 Specific cost €/kW : 1,131
2	CONSTRUCTION	147,200,000	130,200,000	24,500,000	81,800,000	383,700,000	2) Max total Net Power MW : 1480
3	**DIRECT FIELD COST**	**567,700,000**	**502,300,000**	**57,200,000**	**198,700,000**	**1,325,900,000**	Specific cost €/kW : 1,154
4	OTHER COSTS	22,700,000	27,600,000	4,300,000	11,500,000	66,100,000	
5	EPC SERVICES	62,400,000	66,600,000	8,000,000	23,550,000	160,550,000	EXCLUSIONS
6	**TOTAL INSTALLED COST**	**652,800,000**	**596,500,000**	**69,500,000**	**233,750,000**	**1,552,550,000**	Spare parts Inventories of fuel and chemicals
7	PROJECT CONTINGENCY	65,300,000	59,700,000	7,000,000	23,400,000	155,400,000	Start-up costs Insurance
8	PROCESS CONTINGENCY	EXCLUDED	EXCLUDED	EXCLUDED	EXCLUDED	-	Local taxes and fees
12	**TOTAL PLANT COST**	**718,100,000**	**656,200,000**	**76,500,000**	**257,150,000**	**1,707,950,000**	

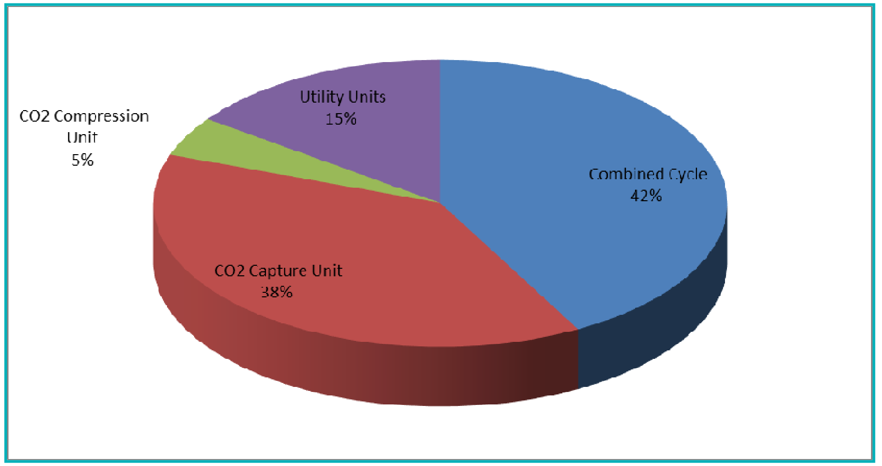

Figure 8. Case 2.1b – Unit percentage weight on TPC

4 Case 2.1c – Energy storage

4.1 Introduction

This Case 2.1c shows coupling of NGCC plants with post-combustion capture of the CO_2 together with a Battery Energy Storage System – BESS.

This approach might become attractive in the future, as it allows to cover short and extreme peak demand without designing the plant for that specific situation.

4.2 Description of the cases

To develop this case, a slightly modified electricity demand weekly curve – shown in Figure 9 - was used.

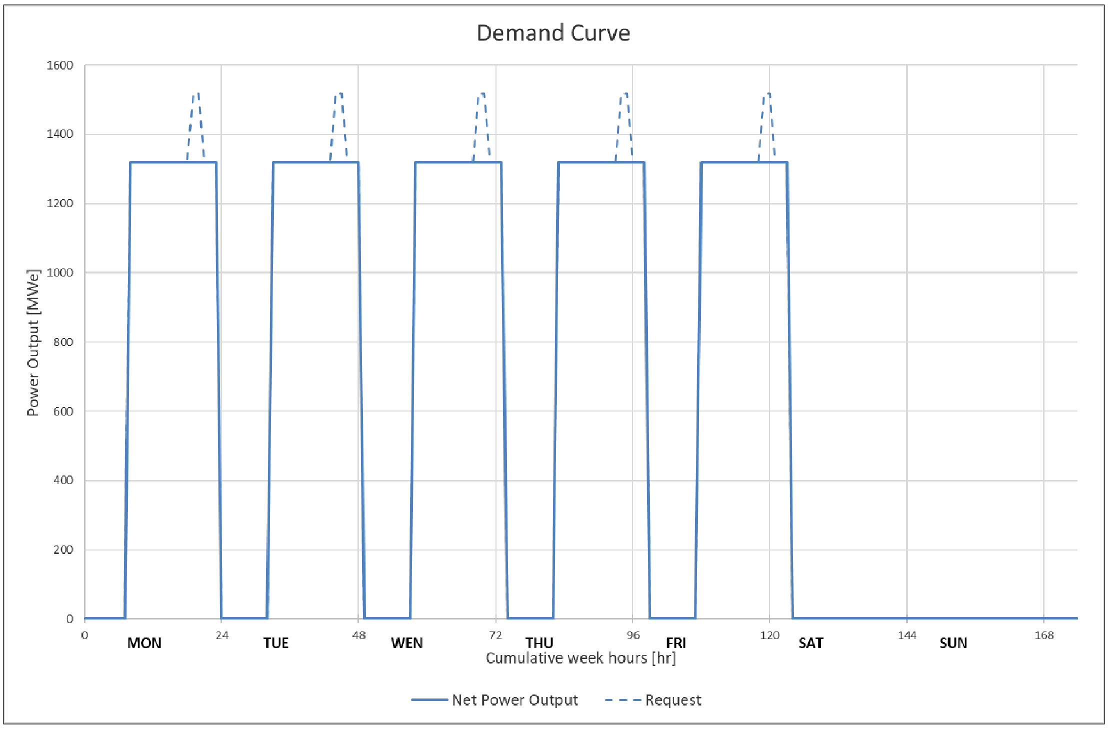

Figure 9. Case 2.1c – Modified weekly energy demand curve

This situation assumes that during the week, there is a peak in electricity demand (about +15% plant net power output request) for two hours in the evening, due to people coming back from work and the sun setting.

In this scenario, it does not make sense to design the plant for 2 hours per day, 5 days a week operation. It is more interesting to investigate the possibility to use a large scale battery energy storage system.

The batteries should be chosen in capacity to provide the required extra peak energy, and they can be charged overnight, by running for a limited time (1.35 hours) a single train at MEL before shutting down for the night period.

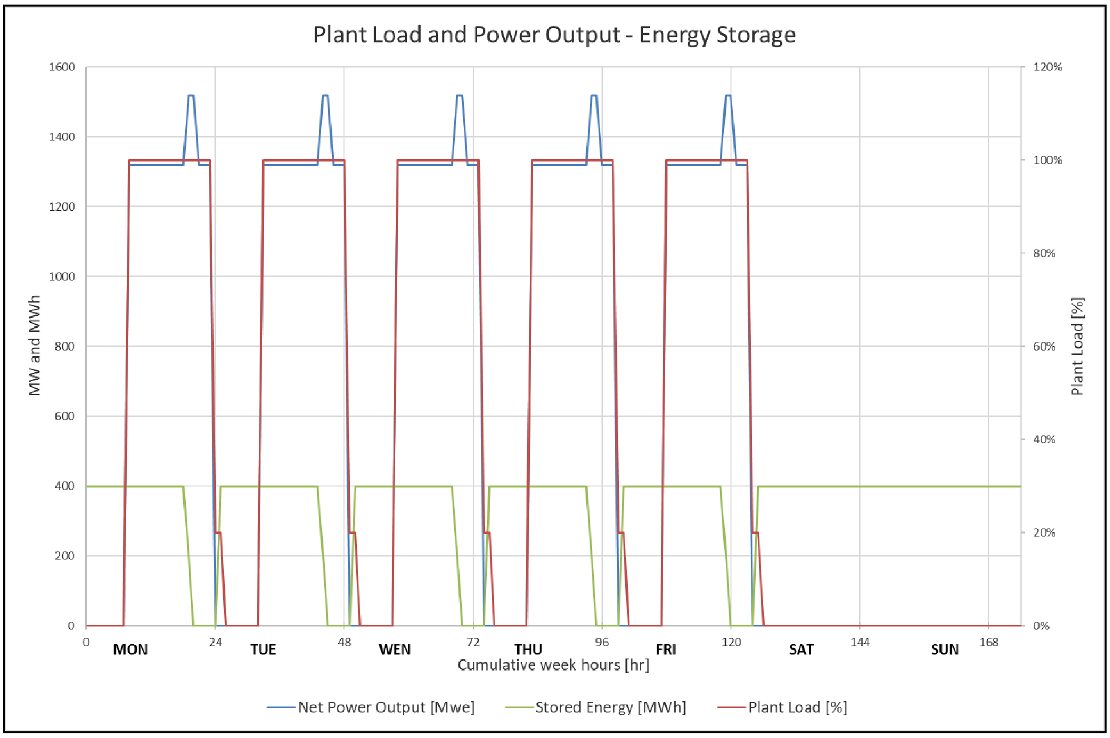

Figure 10. Case 2.1c – Weekly Plant Load and Power Output

In Figure 10, plant load, plant power output and battery charge status are shown over the course of the week. Note how the plant load drops to 20% for a short time (and the stored energy rises back to 400 MWh) before finally shutting down for the night.

4.3 Results

In the following pages, techno-economic results obtained for this configuration are reported. For this calculation, Wood did not account for specific losses and inefficiencies that are involved in the charge/discharge cycle of a battery (only storage oversizing to account for degradation (reduction of capacity) of 7% as per industry standard). The reasons for this is that the information is not easily available as vendors have no commercial experience yet in such a large scale of BESS.

4.3.1 Performances

Performance comparison between the current flexibility scenario and the reference Case 2.1 is shown below in Table 15.

Table 15. Case 2.1c performance report

Case 2.1c - Battery Energy Storage Systems applied to NGCC					
OVERALL PERFORMANCES OF AN NGCC PLANT WITH BESS					
OVERALL PLANT PERFORMANCES					
		Base Load	Weekday peak (2hr)	Weekday charging (1hr 21m)	Nights and WE
Natural Gas Flowrate	t/h	187.2	187.2	49.2	0.0
Natural Gas LHV	kJ/kg	46502.0	46502.0	46502.0	0.0
THERMAL ENERGY OF FEEDSTOCK (based on NG LHV) (A)	**MWt**	**2418.1**	**2418.1**	**636.0**	**0.0**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**1403.7**	**1403.7**	**328.2**	**0.0**
POWER PLANT PERFORMANCES					
Power Islands consumption	MWe	11.9	11.9	3.1	0.0
Utility & Units consumptions	MWe	13.3	13.3	3.5	0.0
CO_2 Capture Unit + Compression	MWe	58.6	58.6	58.6	0.0
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**83.8**	**83.8**	**65.2**	**0.0**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**1319.9**	**1319.9**	**263.0**	**0.0**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**58.0**	**58.0**	**51.6**	**N.A.**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**54.6**	**54.6**	**41.3**	**N.A.**
BESS Energy Storage Flow	**MWe**	**-**	**200.0**	**-263.0**	**0.0**
Actual NET ELECTRIC POWER OUTPUT	**MWe**	**1319.9**	**1519.9**	**0.0**	**0.0**
CO_2 emission	**kg/s**	**2.07**	**2.07**	**0.28**	**0.00**
Specific CO_2 emissions per MW net produced	**kg/MWh**	**5.6**	**5.6**	**3.8**	**N.A.**

4.3.2 Equipment list

A comparative equipment list between Case 2.1 and the current scenario is reported below in Table 16. This equipment list and the following economic estimate are based on the assumption that the single cells composing the BESS are independently air-cooled. This is common practice for commercial installation, but for a installed storage of this size (first of a kind) water cooling may be preferable. In that case, adjustments to cooling system and cooling tower design are needed.

Table 16. Case 2.1c comparative equipment list

Unit 6000 - Utility Units			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Battery Energy Storage System	Not foreseen	430 MWh	Including: - Lithium Ion battery packs - Auxiliary equipment - Cooling circuit - Control system

4.3.3 *Investment costs*

A summary of the total CAPEX for this plant configuration developed from the previously shown comparative equipment list is reported in Table 17.

Table 17. Case 2.1c – Total Plant Cost

wood.	Case 2.1c (NGCC with CCS - 98.5% CO2 capture rate - and Battery Energy Storage System)						CONTRACT: 1-BD-1046A CLIENT: IEAGHG LOCATION: THE NETHERLANDS DATE: MAY 2019 REV.: 0

POS.	DESCRIPTION	UNIT 3000 Combined Cycle	UNIT 4000 CO2 Capture Unit	UNIT 5000 CO2 Compression Unit	UNIT 6000 Utility Units	UNIT 7000 BESS	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIAL	406,700,000	372,100,000	32,700,000	116,900,000	178,900,000	1,107,300,000	1) Gross power output MW : 1404 Specific cost €/kW : 1,418
2	CONSTRUCTION	142,300,000	130,200,000	24,500,000	81,800,000	62,600,000	441,400,000	2) Total Net Power MW : 1316
3	**DIRECT FIELD COST**	**549,000,000**	**502,300,000**	**57,200,000**	**198,700,000**	**241,500,000**	**1,548,700,000**	Specific cost €/kW : 1,512
4	OTHER COSTS	22,000,000	27,600,000	4,300,000	11,500,000	9,700,000	75,100,000	
5	EPC SERVICES	60,400,000	66,600,000	8,000,000	23,550,000	26,600,000	185,150,000	EXCLUSIONS
6	**TOTAL INSTALLED COST**	**631,400,000**	**596,500,000**	**69,500,000**	**233,750,000**	**277,800,000**	**1,808,950,000**	Spare parts Inventories of fuel and chemicals
7	PROJECT CONTINGENCY	63,100,000	59,700,000	7,000,000	23,400,000	27,800,000	181,000,000	Start-up costs Insurance
8	PROCESS CONTINGENCY	EXCLUDED	EXCLUDED	EXCLUDED	EXCLUDED	EXCLUDED	-	Local taxes and fees
12	**TOTAL PLANT COST**	**694,500,000**	**656,200,000**	**76,500,000**	**257,150,000**	**305,600,000**	**1,989,950,000**	

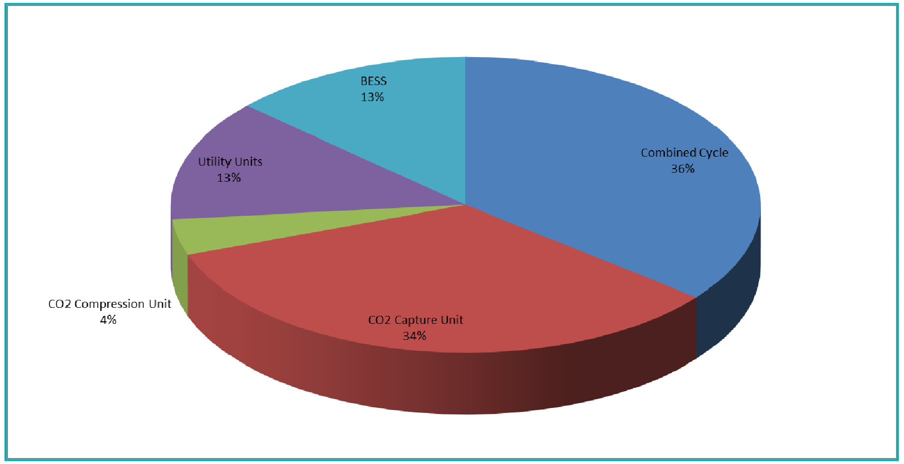

Figure 11. Case 2.1c – Unit percentage weight on TPC

5 Conclusions

In this chapter, different ways to improve and leverage the flexibility of natural gas-fired power plants were presented. Results are summarized in table below.

Table 18. Summary of flexibility-improving modifications on NG power plants with CCS

Description	Case 2.1 TPC (M€)	NGCC Plant Cost Δ% vs Case 2.1	Features
Solvent Storage	1709	+1.48%	- Reduced reboiler size - Leverage of highly profitable selling periods - Issue with excess energy overnight (NGCC only) - Is fitted to a certain demand curve
Variable CO_2 capture	1708	+1.42%	- Leverage of CO_2 allowance fluctuations - Fully operational at offline CCU - Lower efficiency if CCU ON
Energy storage	1990	+18.17%	- Allows to cover short demand peaks without oversizing

Solvent storage can be used to leverage periods of high profitability in selling the produced energy by increasing the net power output at peak load (where energy is sold at a higher cost). Solvent storage can also be used to reduce the size of the regeneration section. The drawbacks of this approach are bifold: on one hand, the grid does not expect the NGCC to be operating at off-peak and agreements need to be made to sell the resulting excess energy produced during overnight solvent regeneration, even with plant at minimum load. On the other hand, reducing the size of the reboiler allows to leverage electricity price at different times of the day but also bound the design to a specific demand curve which might change.

The capability to operate both in abated and unabated mode is obviously an increase in flexibility, and the associated additional CAPEX requirement is relatively low (approx. +2%). However, the actual ability to financially leverage this is expected to be bound to fluctuations in either carbon allowance from regulations or application of a “carbon tax” which is subject to change over the course of the plant life span.

Case 2.1c (Energy Storage via batteries) has a very high additional CAPEX, which is challenging to pay back. A significant bonus payment for the extra peak energy would be needed to justify the investment. The attractiveness of this option, as studied in the present work, strictly relies upon future cost improvements of this technologies.

CLIENT : IEAGHG
PROJECT NAME : UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO_2 CAPTURE
DOCUMENT NAME : FUTURE IMPROVEMENTS OF GAS-FIRED POWER PLANTS
CONTRACT N° : 1-BD-1046 A

ISSUED BY : M.MENSI
CHECKED BY : V.TOTA
APPROVED BY : V.TOTA

Date	Revised Pages	Issued by	Checked by	Approved by

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GLOSSARY

CCS	Carbon Capture and Storage
NGCC	Natural Gas Combined Cycle
USC PC	Ultrasupercritical Pulverised Coal
FGR	Flue Gas Recirculation
EGR	Exhaust Gas Recirculation
CCU	Carbon Capture Unit
CMC	Ceramic Matrix Composite
ASU	Air Separation Unit
MCFC	Molten Carbonate Fuel Cell
TPC	Total Plant Cost
TIC	Total Installed Cost
MEL	Minimum Environmental Load
GT	Gas Turbine
ST	Steam Turbine

1 Introduction

In this chapter, the future advancements in natural gas-fired power generation plants, with particular attention on those coupled with a carbon capture and sequestration unit, are investigated and discussed.

Improvements analyzed can go in two directions: either progress towards achieving higher thermal efficiencies in power generation or improve the parasitic load and cost of capturing carbon.

Higher thermal efficiencies in power generation can be achieved by progress made on power generation technology. Discovery and development of new materials allows to push for more severe conditions (in terms of temperature and pressure) both on gas turbine side and steam cycle side. Wood collaborated with the Department of Energy of Politecnico di Milano (POLIMI) to develop estimates on future gas turbine mid-term achievable performances. This was possible thanks to the software “GS”, a calculation tool developed by the faculty, which allows for detailed aero-thermodynamic analysis of gas turbines. Estimates on mid-term performances can be made by taking reasonable assumptions of future design parameters (i.e. combustion temperature).

The other path that can be taken is to increase the efficiency of plants implementing CCS by reducing their efficiency decay in comparison to those producing unabated power. As the most significant efficiency loss is represented by the heat required for solvent regeneration, finding alternatives to solvent-based carbon capture can prove attractive. In this sense, oxy-turbine power plants and the use of molten carbonate fuel cells allow for exhaust gas purification via cryogenic compression.

2 Case 2.4 - Gas turbine technology development

2.1 Introduction

To evaluate mid-term upcoming gas turbine performance improvements thanks to technology and material progress, Wood co-operated with the Department of Energy within Politecnico di Milano.

The faculty developed a software called "GS" which allows detailed aero-thermodynamic analysis for gas turbines by performing calculations of velocity triangles, blading geometry, cooling flow rates in each blade portion etc.
This allows to evaluate realistic mid-term scenario performances by making reasonable assumptions on critical design criteria (i.e. one could foresee an increase in combustion temperature thanks to new alloys being used for the combustion chamber).

In the following paragraphs, the assumptions made are presented and the results obtained discussed.

2.2 Recent development of gas turbine materials

Since the early 2000s, single crystal materials and thermal barrier coatings have been used for the vanes and buckets of the first stage of large industrial gas turbines [1]. Ni-based single crystal superalloys can be classified depending on their metallurgical composition into four categories, called "generations". First generation superalloys (e.g., Renè N4, SRR99, PWA 1480) feature higher contents of Al, Ti, Ta aimed at hardening the "gamma prime phase". Second generation superalloys (e.g., CMSX 4, Rene N5, PWA 1484) feature about 3% (weight basis) of Re while in third generation superalloys (e.g., CMSX 10, Rene N6) this content doubles (about 6% wt.). Fourth generation superalloys (e.g., MC-NG, EPM-102, TMS-162) contain also ruthenium [2].

Concerning heavy-duty gas turbines, initially reference single crystal materials were nickel-based second generation superalloys, such as CMSX-4 used for the Alstom GT 24/26 reheated gas turbine[3], "René N5" for the GE 7H (steam-cooled) gas turbine, and the "PWA-1483" for the V84/V94.3A Siemens gas turbines [1]. According to [3], newer-generation F-, H- and J- class heavy duty gas turbines use superalloys like MAR-M-509 (Cobalt based), CMSX-4, MAR-M-247, Renè 108 and MGA 2400 for the first stage nozzle vane, and PWA 1483SC, CMSX-4, MGA1400DS for the first stage rotor blades. In addition to the high creep strength, they must feature a good hot corrosion resistance, an important requisite for industrial gas turbines.

Third and fourth generation single crystal super-alloys have been developed and used in engines for aircraft propulsion applications. Examples are Rene N6, CMSX 10, TMS 75 and TMS 80. According to [4], TMS 75 and TMS 80 feature an increase of creep durable temperature in the range 60-70 °C with respect to CMSX-4. Another novel single crystal super-alloy with similar creep resistance and higher thermal fatigue life is MGA1700 recently developed by Mistubishi in collaboration with the National Institute for Materials Science [5]. According to MHI researchers, single crystal materials with such high properties are essential for the development of the “1700 °C-class” gas turbines.

Current R&D activities of NASA, General Electric, Rolls-Royce and other leading companies and research institutes focus on the introduction of Ceramic Matrix Composites (CMC) for the hot turbine sections (shroud, vanes, buckets, etc). CMCs consist of ceramic fibers embedded into a ceramic matrix. For gas turbine applications, SiC (silicon carbide) is considered the most promising ceramic for the fibers and the matrix. CMCs are typically classified on the basis of the matrix manufacturing processes into four types: Chemical Vapor Infiltration (CVI), Solid Phase Infiltration (SPI), Polymer Impregnation and Pyrolysis (PIP), and Melt Infiltration (MI). Compared to superalloys, CMCs offer a considerably higher creep resistance and considerably lower weight (approx. one third of superalloy density) [6]. High temperature oxidation issues, causing the oxidation of Si-based ceramics to form SiO_2 and the consequent volatilization of the SiO_2 as gaseous species, can be addressed by using appropriate environmental barrier coatings [7]. GE has started the development of CMC early in 90’s focusing on melt infiltrated (MI) composite systems (MI-CMC) [7]. The database generated from the material testing was used to design turbine hot gas path components, namely the shroud and combustor liner, utilizing the CMC materials. The feasibility of using such MI CMC materials in gas turbine engines was demonstrated via combustion rig testing of turbine shrouds and combustor liners, and through field engine tests. Successful rig tests were performed with material temperatures up to 1200 °C. This result seems to be confirmed by later studies, e.g., [8], which indicate that production-ready CMC can withstand material temperatures up to 1250 °C for structural applications. Today, CMC is used for the hot section shrouds of the “CFM-LEAP” engines developed within a joint venture of GE and Safran Aircraft Engines and in service since August 2016 [9] on Airbus A320neo and Boeing 737 MAX. GE is planning and testing the use of CMC also for the vanes of the new GE9X aero-engine [10] as well as for the blades of heavy-duty gas turbines with the target of reaching 65% combined cycle efficiency [11]. NASA 2018 [12] is developing a novel CMC material (including fibers, matrix and environmental barrier coating) capable of withstanding temperatures up to 2700 °F (approx. 1480 °C).

2.3 Assumed design changes

Given the recent progresses in the development of CMC materials suitable for gas turbines, it is reasonable to assume that in a near-term future heavy-duty GTs will employ CMC materials for the first-stage stator and rotor blades and fourth generation single crystal blades for the downstream cooled stages. Compared to the reference H-class gas turbine, we assume that adopting CMC (in place of single crystal Ni-based alloys) for the first stage blades allows increasing the average material temperature of the blades by 150 °C. As far as the subsequent cooled states are concerned, an average blade metal temperature increase of 50 °C is assumed as a consequence of the use of more advanced single crystal materials.

As far as the gas turbine engine is concerned, the possibility of operating with higher blade material temperatures opens two options:

(i) increasing the turbine inlet temperature at fixed mass flow rate of the cooling flows (with a gain in efficiency due to the higher maximum cycle temperature)

(ii) Reducing the mass flow rate of the cooling flows for fixed turbine inlet temperature (with a gain in efficiency due to the lower mixing losses) [13].

In this study we assumed to increase the turbine inlet temperature so as to have the same mass flow rate of the chargeable cooling flows (i.e. the flows used in the rows after the first nozzle) of the reference H-class gas turbine. Since the increase of the turbine inlet temperature would lead to an excessively high (and suboptimal) turbine outlet temperature, the pressure ratio of the gas turbine has been increased with the aim of maximizing the net electric efficiency of the combined cycle and limiting the turbine outlet temperature below 660 °C. This was achieved by the following:

- Compression ratio: 30
- TIT (Turbine Inlet Temperature): 1668 °C

As far as the heat recovery steam cycle is concerned, the steam superheating and reheating temperatures have been raised to 620 °C, by considering the possibility to employ higher grade steels like S304H (already in use for state-of-the-art ultra-supercritical steam cycles) or THOR115, especially developed for such an application.

2.4 Developed plants

Politecnico di Milano provided figures for GT and simple combined cycle performances. Wood used this data to develop two different cases.

Case 2.4a is a two GT+HRSG trains with a common steam turbine, comparable to benchmark Case 1 of this report.
Case 2.4b is equipped with two CANSOLV carbon capture units, one for each HRSG, and designed for 98.5% CO_2 recovery. This is a configuration comparable to benchmark Case 2.1 of this report.

Table 1. Summary of the developed cases with an assumed future GT

Case	Description	Features	Comparable to
Case 2.4a	Next-gen NGCC w/o CCS	• Two next-gen class GT with dedicated HRSG • One common ST	Case 1
Case 2.4b	Next-gen NGCC with CCS – High capture	• Two next-gen class GT with dedicated HRSG • One common ST • CANSOLV post-combustion capture technology • CO_2 recovery: 98.5%	Case 2.1

2.5 Results

Performance figures for both presented configurations were developed and compared to the equivalent benchmark cases. The results are summarized in the following tables.

Table 2. Performance comparison of Case 1 vs Case 2.4a

CLIENT:	IEA GHG	REVISION	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	DATE	jul-19
PROJECT No. :	1-BD-1046 A	MADE BY	MM
LOCATION :	Netherlands	APPROVED BY	VT

OVERALL PERFORMANCES		Case 1	Case 2.4a
Fuel flow rate (A.R.)	t/h	187	231
Fuel HHV (A.R.)	kJ/kg	46502	46502
Fuel LHV (A.R.)	kJ/kg	51473	51473
THERMAL ENERGY OF FEEDSTOCK (based on LHV) (A)	**MWth**	**2418**	**2982**
THERMAL ENERGY OF FEEDSTOCK (based on HHV) (A')	**MWth**	**2677**	**3301**
Gas turbine power output (@ gen terminals)	MWe	1040.0	1360.0
Steam turbine power output (@ gen terminals)	MWe	489.9	599.7
GROSS ELECTRIC POWER OUTPUT (@ gen terminals) (C)	**MWe**	**1529.9**	**1959.7**
Power Islands consumption	MWe	12.6	15.2
Utility & Offsite Units consumption	MWe	6.8	13.0
CO2 Capture and compression unit	MWe	-	-
ELECTRIC POWER CONSUMPTION	**MWe**	**19.4**	**28.2**
NET ELECTRIC POWER OUTPUT	**MWe**	**1510.5**	**1931.5**
(Step Up transformer efficiency = 0.997%) (B)	MWe	**1506.0**	**1925.7**
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**63.3%**	**65.7%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**62.3%**	**64.6%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**57.2%**	**59.4%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**56.3%**	**58.3%**
Fuel Consumption per net power production	**MWth/MWe**	**1.61**	**1.55**
CO_2 emission per net power production	**kg/MWh**	**331.3**	**319.3**

Table 3. Performance comparison of Case 2.1 vs Case 2.4b

CLIENT:	IEA GHG	REVISION	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	DATE	jul-19
PROJECT No. :	1-BD-1046 A	MADE BY	MM
LOCATION :	Netherlands	APPROVED BY	VT

OVERALL PERFORMANCES

		Case 2.1 98.5% CO2 rec.	Case 2.4b 98.5% CO2 rec.
Fuel flow rate (A.R.)	t/h	187	231
Fuel HHV (A.R.)	kJ/kg	46502	46502
Fuel LHV (A.R.)	kJ/kg	51473	51473
THERMAL ENERGY OF FEEDSTOCK (based on LHV) (A)	**MWth**	**2417**	**2982**
THERMAL ENERGY OF FEEDSTOCK (based on HHV) (A')	**MWth**	**2676**	**3301**
Gas turbine power output (@ gen terminals)	MWe	1040.0	1360.0
Steam turbine power output (@ gen terminals)	MWe	363.7	445.3
GROSS ELECTRIC POWER OUTPUT (@ gen terminals) (C)	**MWe**	**1403.7**	**1805.3**
Power Islands consumption	MWe	11.9	14.3
Utility & Offsite Units consumption	MWe	13.3	25.4
CO2 Capture and compression unit	MWe	58.6	72.2
ELECTRIC POWER CONSUMPTION	**MWe**	**83.8**	**111.9**
NET ELECTRIC POWER OUTPUT	**MWe**	**1319.9**	**1693.3**
(Step Up transformer efficiency = 0.997%) (B)	MWe	**1316.0**	**1688.2**
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**58.1%**	**60.5%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**54.4%**	**56.6%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**52.5%**	**54.7%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**49.2%**	**51.1%**
Fuel Consumption per net power production	**MWth/MWe**	**1.84**	**1.77**
CO_2 emission per net power production	**kg/MWh**	**5.6**	**4.2**

2.6 Observations

As illustrated by the performance summaries, next-gen gas turbines are expected to provide unprecedented efficiencies figures.
Even without advancements in post-combustion solvent-based carbon capture technologies, the efficiency benefit is significant even in the configuration equipped with CCS (about 2% extra).

More efficient machines are inherently beneficial on an environmental perspective due to their ability to limit fuel consumptions and related CO_2 emissions to produce a defined amount of energy.

2.7 References

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3 Case 2.5 - Oxy-combustion turbines in combined cycle

3.1 Introduction

Oxy-turbines are a promising approach to tackling the issue of carbon emission. Due to using oxygen in place of air for the combustion, outlet gas composition is enriched in carbon dioxide thanks to the lack of nitrogen (which acts as a diluent). This is enhanced by the possibility to partially recycle the flue gas to the gas turbine. Richness in carbon dioxide opens up the possibility to different carbon capture technologies.

The oxy-turbine power plant is a combination of several process units. The main process blocks of the plant are the following:

- Oxy-turbine power island;
- Air Separation Unit;
- 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.

For this report, an update on the results obtained in IEA GHG Report 2015/05 (*"Oxy-combustion turbine power plants"*) was executed.

The studied plant is asemi-closed oxy-combustion combined cycle (SCOC-CC) plant, with cryogenic purification and separation of the carbon dioxide. The plant is designed to fire natural gas and produce electric power for export to the external grid.

The selected SCOC-CC plant configuration is based on two parallel trains, each composed of one H-class equivalent oxy-fired gas turbine and one heat recovery steam generator (HRSG), generating steam at three levels of pressure, including a LP integrated deaerator. The generated steam feeds one steam turbine of water-cooled and condensing type, common to the two parallel trains. The reference combined cycle and gas turbine are the one of Case 1 – NGCC benchmark case of this report.

Politecnico di Milano was involved in the realization of this design, as GS proven fundamental to assess performances of the oxy-fired GT.

3.2 Process description

3.2.1 Unit 3000 - Power island

The power island is composed of:

- Two H-class equivalent oxy-fired gas turbines.
- Two heat recovery steam generators (HRSG), generating steam at two levels of pressure, plus a LP integrated deaerator.
- Two recycle gas indirect contact cooling systems.
- One steam turbine water-cooled and condensing type, common to the two parallel trains.

The natural gas from the let-down and metering station is heated using heat available from the CO_2 compression in the CPU and using hot HP BFW before entering the burners of the gas turbine at 220 °C.

No SCR system was considered in the design and economic assessment due to the very low amount of N_2 fed to the system.

Oxygen is delivered from the ASU at the required pressure level and heated using heat available from the raw gas compressor in the CPU before entering the burners of the gas turbine at 200°C.

The pressure ratio of the SCOC-CC is higher than the one of an equivalent standard air blown commercial plant. Turbine inlet pressure has been selected to bring about the same exhaust temperature with respect to the reference benchmark plant. An exhaust pressure slightly higher than the ambient pressure (to avoid leakages into the CO_2 loop) has been selected so as to keep the design of the turbomachines closer to the current standards.

The gas turbine recycle flowrate is fixed by two design requirements to:

- control the combustion outlet temperature;
- provide the required cooling flow to the gas turbine blade in order to control the blade metal temperature;

The exhaust gases from the gas turbine enter the HRSG at 641°C. The HRSG recovers heat available from the exhaust gas producing steam at three different pressure levels equivalent to the reference benchmark case.

The final exhaust gases are cooled down in a conventional contact cooler to the minimum temperature allowed by the cooling medium available. Most of the flue gas at 28°C from the top of the contact column (around 93%) is recycled back to the gas turbine compressors, while the remaining stream is sent to the downstream CO_2 purification and compression unit.

The combined cycle is thermally integrated with the other process units in order to maximize the net electrical efficiency of the plant. In particular, heat available at high temperature level from the oxy-turbine cycle is used to provide heat required in the CPU mainly for TSA regenerator heating and inert gas heating before expansion, while heat available at low temperature level in the CO_2 compressor intercoolers is used for oxygen and natural gas heating in order to enhance gas turbine efficiency.

The following interfaces have been considered:

- Natural gas is heated using as heating medium compressed CO_2 from the final compression before being sent to unit B.L.
- Oxygen is heated using as heating medium raw flue gas from the first compression stage (1-15 bar) in the CPU.
- Saturated HP water is used as heating medium in the TSA regenerator heater of the CPU. Cold water from the exchanger is sent to the LP degassing section of each HRSG.

3.2.2 *Unit 4000 - CO_2 compression and purification*

This unit is mainly composed of the following systems:

- Raw flue gas compression (1 - 34 bar);
- TSA unit;
- Auto-refrigerated inerts removal, including distillation column to meet the maximum oxygen content limit in the CO_2 product;
- The remaining part of the compression system up to 110 bar.

Technical information relevant to this system is reported in chapter D, section 2.3, while 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.

3.2.3 *Unit 5000 - Air Separation Unit*

Each 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 and 64 bar. Oxygen pressure is set by the requirement of the gas turbine combustor.

The oxygen flowrate is selected in order to lead the combustion reaction with an oxygen excess of 3% with respect to the stoichiometric, including the amount of oxygen in the recycle flowrate from the compressor.

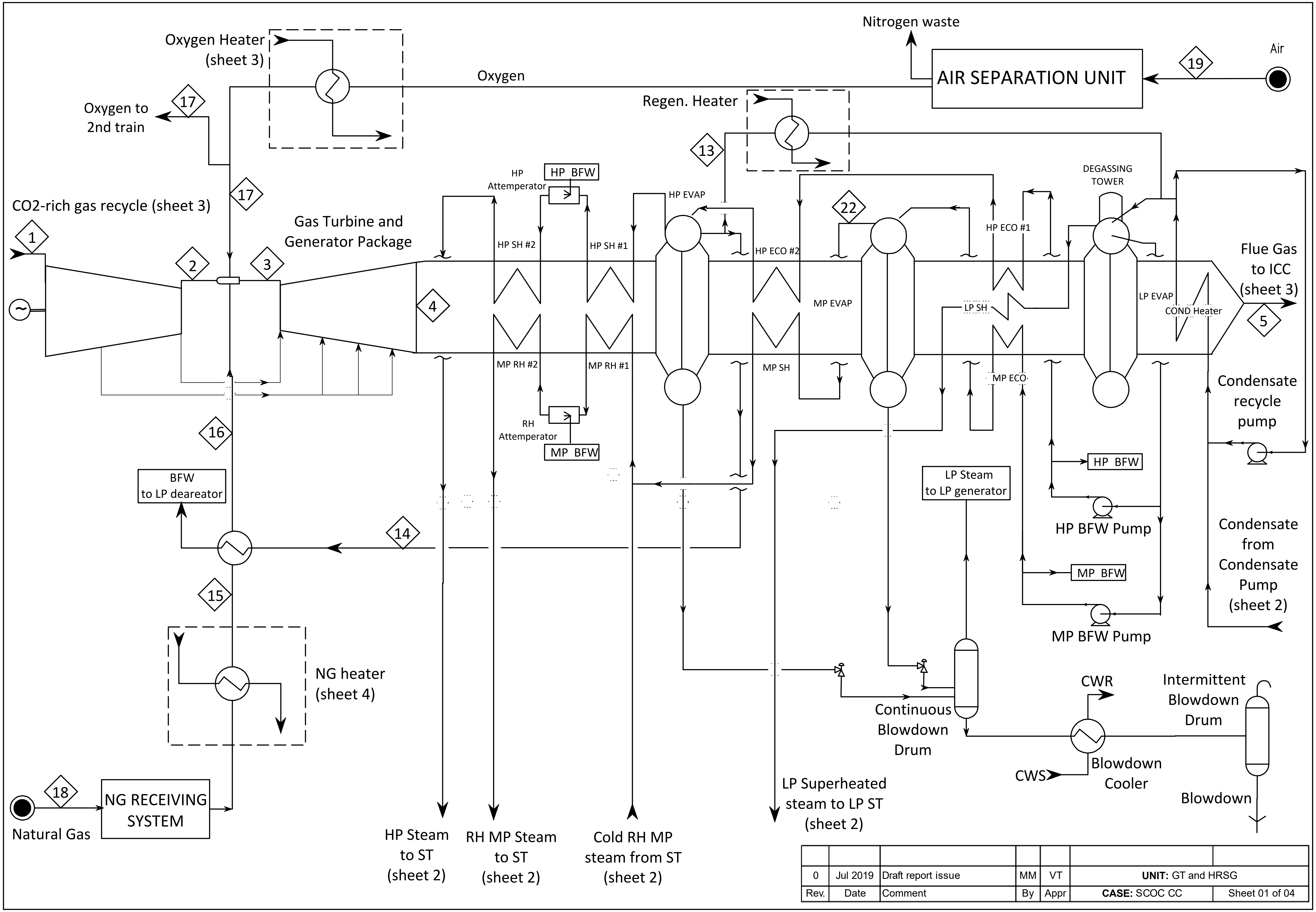
Due to the size of the plant, the total amount of oxygen to provide is more than 17,000 ton/day. Considering market-available ASU sizes, 4x25% units at 4400 ton/day have been considered.

3.2.4 *Unit 6000 - Utility Units*

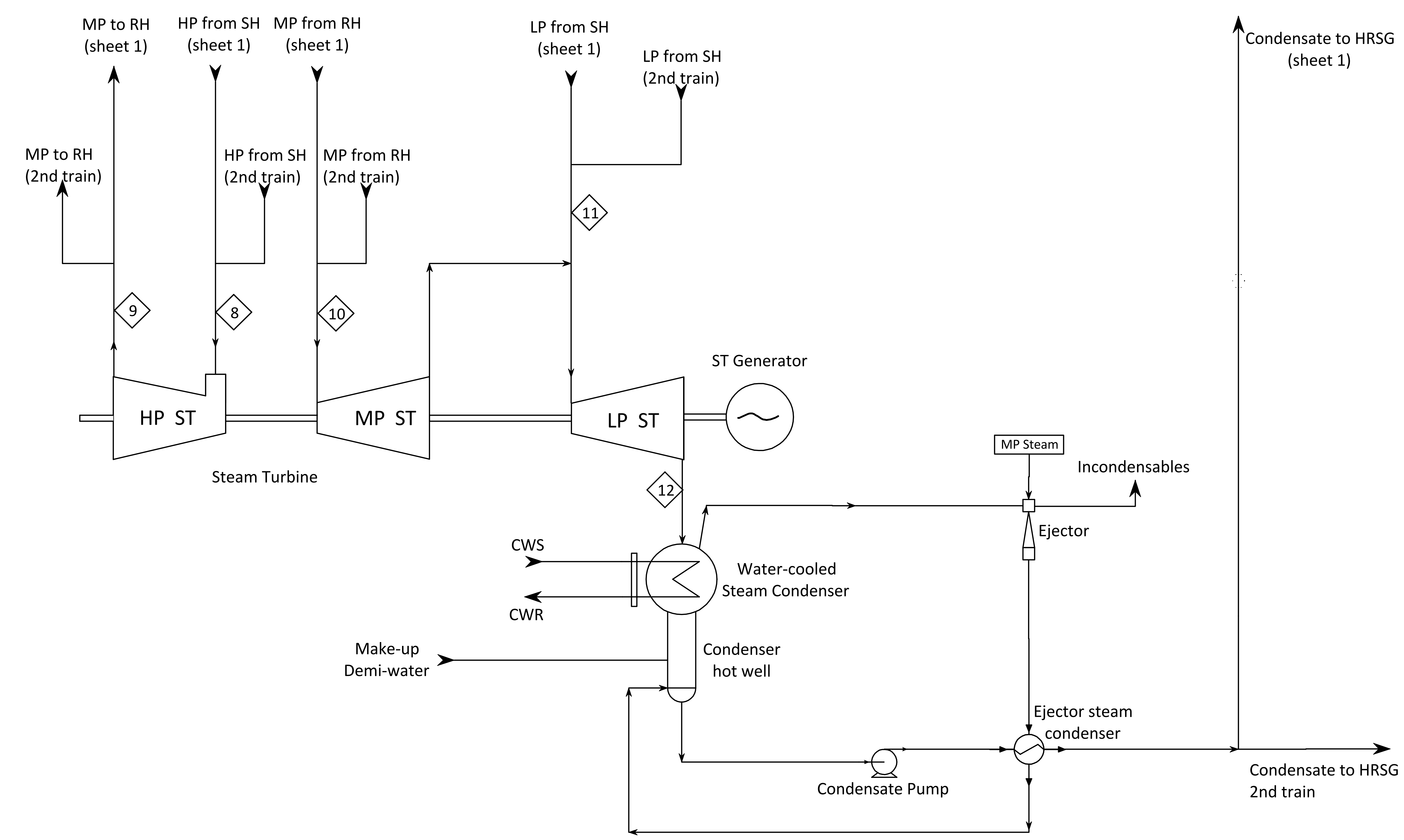
Changes on utility requirements compared to the reference combined cycle have been assessed to correctly account for parasitic loads and utility consumptions. Thanks to appropriate heat integration the vast majority of the impact is taken care by the other units designs.

3.3 Process flow diagram

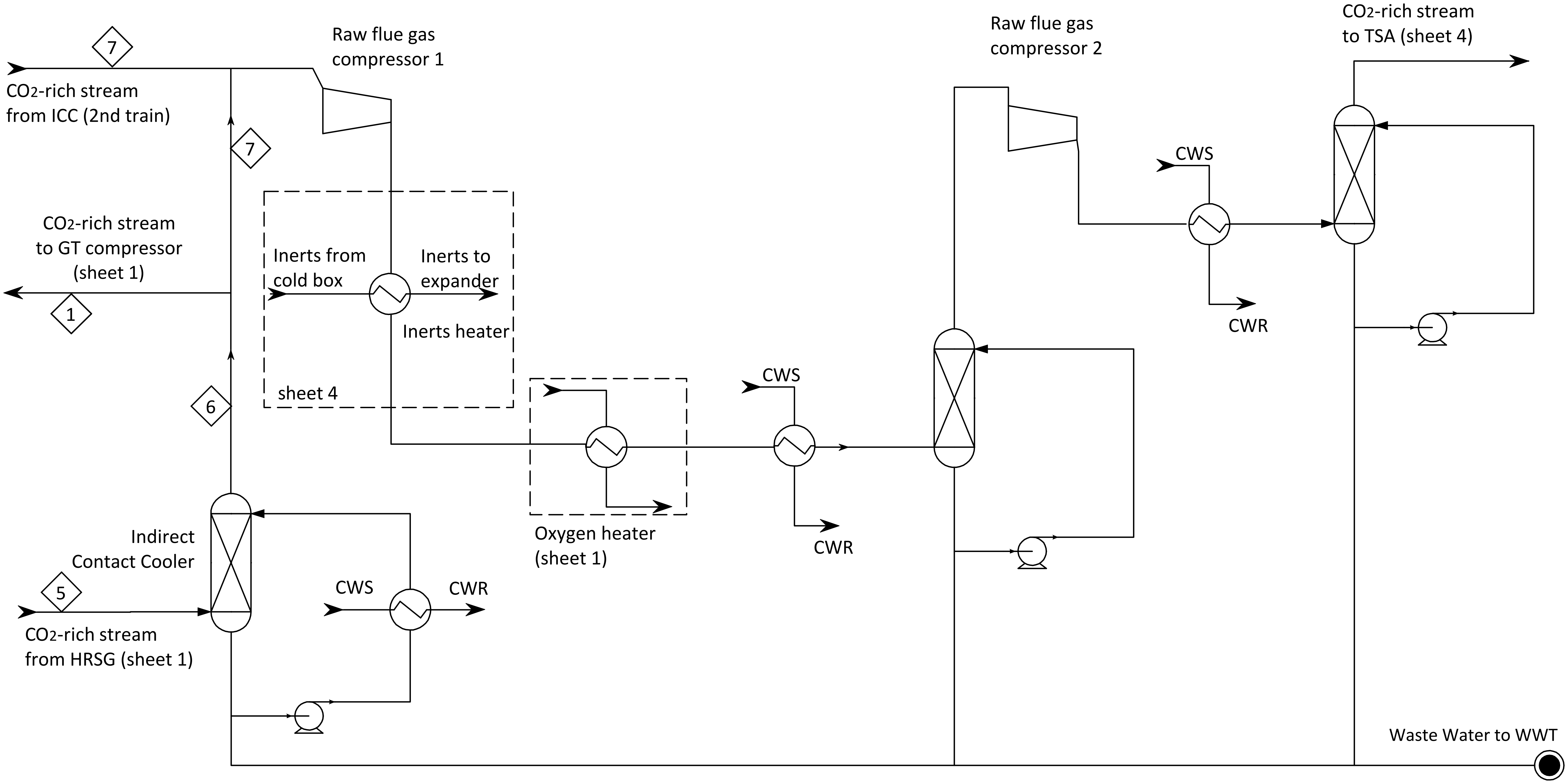
In the following pages, process flow diagram for the whole SCOC-CC are reported.



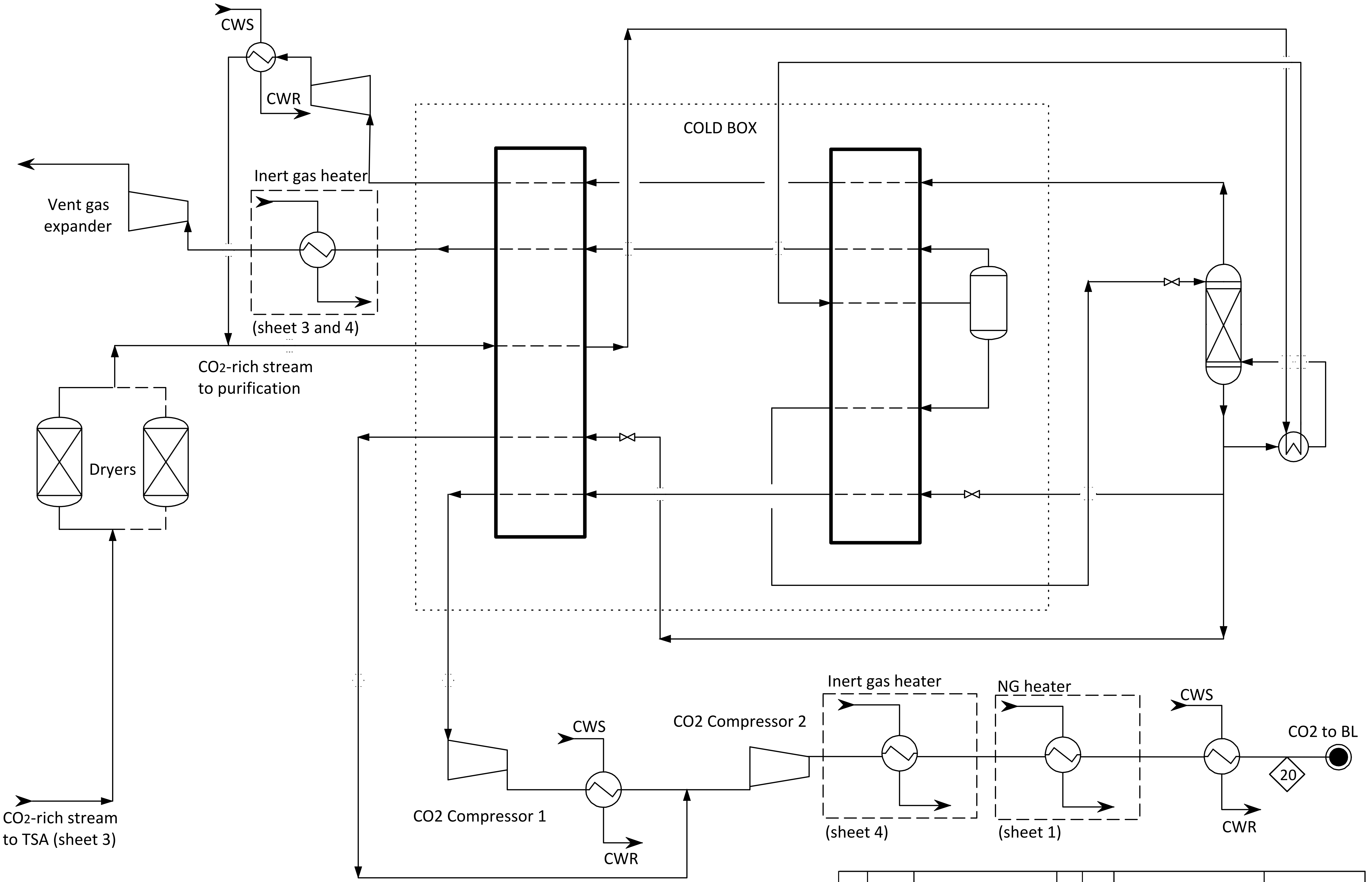
0	Jul 2019	Draft report issue	MM	VT	**UNIT:** GT and HRSG	
Rev.	Date	Comment	By	Appr	**CASE:** SCOC CC	Sheet 01 of 04



0	Jul 2019	Draft report issue	MM	VT	**UNIT:** Steam turbine and condenser	
Rev.	Date	Comment	By	Appr	**CASE:** SCOC CC	Sheet 02 of 04



0	Jul 2019	Draft report issue	MM	VT	**UNIT:** CO_2 purification - compression section	
Rev.	Date	Comment	By	Appr	**CASE:** SCOC CC	Sheet 03 of 04



0	Jul 2019	Draft report issue	MM	VT	**UNIT:** CO2 purification - inerts removal section	
Rev.	Date	Comment	By	Appr	**CASE:** SCOC CC	Sheet 04 of 04

3.4 Heat and mass balance

In the following page, the heat and mass balance for the SCOC combined cycle is reported. The HMB refers to the PFD shown in paragraph 3.3.

	HEAT AND MATERIAL BALANCE		REVISION	0		
wood.	CLIENT :	IEAGHG	PREP.	MM		
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	AC		
	PROJECT NO:	1-BD-1046 A	APPROVED	VT		
	CASE:	Oxy-turbine SCOC CC	DATE	jul-2019		

HEAT AND MATERIAL BALANCE

Stream	Description		Flowrate t/h	Temperature °C	Pressure bar a	Enthalpy kJ/kg
1	CO2-rich gas recycle	(note 5)	3228.7	28	1.03	-
2	Compressed CO2-rich gas	(note 5)	2102.2	452	63.18	-
3	Hot flue gas to turbine	(note 6)	2555.2	1648	61.29	-
4	Gas Turbine Exhaust	(note 7)	3681.7	641	1.07	-
5	Flue gas to Indirect Contact Cooler	(note 7)	3681.7	79	1.03	-
6	CO2-rich flue gas from Indirect Contact Cooler	(note 5)	3495.3	28	1.03	-
7	CO2-rich flue gas to purification unit	(note 5)	266.6	28	1.03	-
8	Total HP steam to HP steam turbine		1028.2	600	170.20	
9	Cold RH from HP steam turbine		1017.9	388	43.00	
10	Hot RH to MP steam turbine		1091.6	601	39.56	
11	Total LP steam to LP steam turbine		110.7	300	5.52	
12	LP turbine exhaust to condenser		1204.2	29	0.04	
13	HP BFW to TSA bed regeneration		3.8	359	185.00	
14	HP BFW to natural gas performance heater		15.8	359	185.00	
15	Natural gas from CO2 purification natural gas heater		93.6	155	70.00	-
16	Natural gas to gas turbine		93.6	220	70.00	-
17	Oxygen to gas turbine	(note 1)	359.4	200	63.18	-
18	Fuel from B.L.	(note 3)	93.6	20	70.00	-
19	Air to Air Separation Unit	(note 4)	3155.3	9	1.01	-
20	CO2 to long term storage	(note 8)	487.4	50	110.00	-

Notes:

1) Oxygen purity: 97% mol
2) Enthalpy is shown for water streams only (steam, BFW, condensate)
3) Composition: CH_4 89%, C_2H_6 7%, C_3H_8 1%, C_4H_{10} 0.1%, C_5H_{12} 0.01%, CO_2 2%, N_2 0.89%
4) 80% Relative Humidity
5) Composition: O_2 0.56%, CO_2 89.68%, N_2 2.52%, Ar 3.56%, H_2O 3.66%,
6) Composition: O_2 0.48%, CO_2 75.62%, N_2 2.24%, Ar 3.00%, H_2O 18.73%,
7) Composition: O_2 0.5%, CO_2 79.68%, N_2 2.23%, Ar 3.16%, H_2O 14.42%,
8) Carbon dioxide purity: 99.51% mol

3.5 Overall performances

The following table reports the overall performances for the SCOC combined cycle examined.

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**DATE**	jul-19
PROJECT No. :	1-BD-1046 A	**MADE BY**	MM
LOCATION :	Netherlands	**APPROVED BY**	VT

OVERALL PERFORMANCES

		SCOC CC
Fuel flow rate (A.R.)	t/h	187
Fuel HHV (A.R.)	kJ/kg	46502
Fuel LHV (A.R.)	kJ/kg	51473
THERMAL ENERGY OF FEEDSTOCK (based on LHV) (A)	**MWth**	**2418**
THERMAL ENERGY OF FEEDSTOCK (based on HHV) (A')	**MWth**	**2677**
Gas turbine power output (@ gen terminals)	MWe	1055.8
Steam turbine power output (@ gen terminals)	MWe	523.6
GROSS ELECTRIC POWER OUTPUT (@ gen terminals) (C)	**MWe**	**1579.4**
Power Islands consumption	MWe	12.0
Utility & Offsite Units consumption	MWe	17.7
CO2 purification unit	MWe	73.3
Air separation unit	MWe	242.2
ELECTRIC POWER CONSUMPTION	**MWe**	**345.2**
NET ELECTRIC POWER OUTPUT	**MWe**	**1234.2**
(Step Up transformer efficiency = 0.997%) (B)	MWe	**1230.5**
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**65.3%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**50.9%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**59.0%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**46.0%**
Equivalent CO_2 flow in fuel	kmol/h	11271.3
Captured CO_2	kmol/h	11029
CO_2 removal efficiency	**%**	**97.8%**
Fuel Consumption per net power production	**MWth/MWe**	**1.97**
CO_2 emission per net power production	**kg/MWh**	**8.7**

3.6 Economics

Wood prepared a cost estimate of the SCOC CC plant to provide a LCOE value updated to account for the new class H turbine technology. The main results are reported in Table 4 and Table 5.

Table 4. CAPEX result summary for SCOC CC compared to main benchmark 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)
Benchmark cases	Case 1	905	1206	601	801
	Case 2.1	1684	2236	1280	1699
SCOC CC	Case 2.5	1931	2560	1569	2080

Table 5. LCOE and CAC result summary for SCOC CC compared to main benchmark cases

Case	LCOE (€/MWh)	CO_2 emission avoidance cost €/t
Case 1	48.2	-
Case 2.1	72.2	73.54
Case 2.5	80.5	100.22

The capital cost breakdown of this configuration is reported in the following page. While the technology is promising, the large amount of oxygen required translates to an energy-demanding and expensive air separation unit (37% of capital cost) constituted of 4x25% units at 4400 ton/day of O_2 production each. If a cheaper source of high purity oxygen is available, the configuration becomes really attractive due to a CO_2 purification section which is cheaper than a solvent-based capture unit while having a lower energy penalty associated (no steam required).

Compared to the figures presented in IEAGHG Report 2015/05 *"Oxy-combustion turbine power plants"* for the SCOC-CC (which resulted in an LCOE of 92.8 €/MWh and a CAC of 97.9 €/t_{CO2}), LCOE decreased by more than 13% while the CAC increased by 2.3%.

The lower LCOE can be attributed to newer H-class gas turbines and a lower natural gas price by study basis compared to Report 2015/05. This highlights how the significant improvement is on the gas turbine: high efficiency H-class machine are economically more attractive than previous generation gas turbines.

Due to no significant advancements on air separation technology and cryogenic CO_2 purification, no reduction of CAC is found as the both the reference case (no capture) and the oxy-fired case benefits of the technology improvements wiht similar magnitude, e.g. the reference LCOE is lower than the past value (the reference combined cycle in IEAGHG Report 2015/05 *“Oxy-combustion turbine power plants”* had an LCOE of 67 €/MWh).

Table 6. SCOC CC – Total Plant Cost

CAPEX
SCOC CC with cryogenic CCS

CONTRACT:	1-BD-1046A
CLIENT:	IEAGHG
LOCATION:	THE NETHERLANDS
DATE:	JULY 2019
REV.:	0

POS.	DESCRIPTION	UNIT 3000 Combined Cycle	UNIT 4000 CO2 Purification Unit	UNIT 5000 Air Separation Unit	UNIT 6000 Utility Units	TOTAL COST EURO	NOTES / REMARKS
1	DIRECT MATERIAL	464,700,000	92,100,000	316,600,000	116,900,000	990,300,000	1) Gross power output MW : 1579 Specific cost €/kW : 1,223
2	CONSTRUCTION	162,600,000	32,200,000	176,900,000	81,800,000	453,500,000	2) Total Net Power MW : 1231
3	**DIRECT FIELD COST**	**627,300,000**	**124,300,000**	**493,500,000**	**198,700,000**	**1,443,800,000**	Specific cost €/kW : 1,569
4	OTHER COSTS	25,100,000	6,800,000	148,050,000	11,500,000	191,450,000	
5	EPC SERVICES	69,000,000	16,500,000	11,350,500	23,550,000	120,400,500	EXCLUSIONS
6	**TOTAL INSTALLED COST**	**721,400,000**	**147,600,000**	**652,900,500**	**233,750,000**	**1,755,650,500**	Spare parts Inventories of fuel and chemicals
7	PROJECT CONTINGENCY	72,100,000	14,800,000	65,300,000	23,400,000	175,600,000	Start-up costs Insurance
8	PROCESS CONTINGENCY	EXCLUDED	EXCLUDED	EXCLUDED	EXCLUDED	-	Local taxes and fees
12	**TOTAL PLANT COST**	**793,500,000**	**162,400,000**	**718,200,500**	**257,150,000**	**1,931,250,500**	

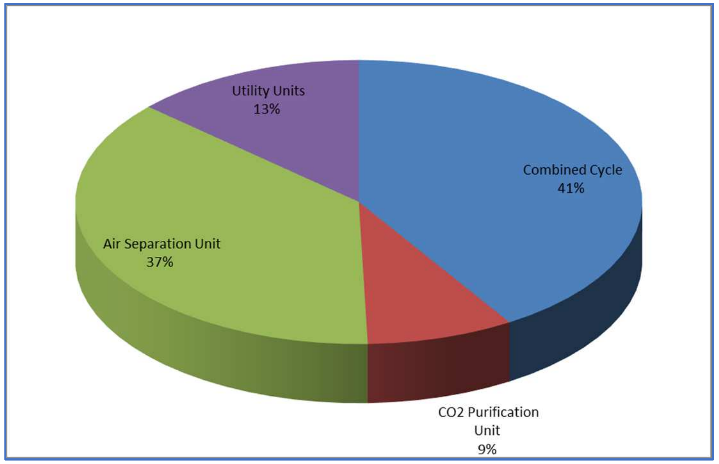


Figure 1. SCOC CC – Unit percentage weight on TPC

4 Case 2.6 - Molten Carbonate Fuel Cells in Combined Cycles

4.1 Introduction

The biggest challenge in CO_2 sequestration is to deal with the high energy penalty associated with it: solvent-based technologies require significant quantities of steam for solvent regeneration, which is taken from the one destined to power generation in a steam turbine effectively reducing the capacity of the plant. Oxy-combustion systems do have a positive impact on the cost of CO_2 recovery thanks to the higher concentration of carbon dioxide which allows for other techniques to be implemented, but large-scale oxygen production costs (both economically and energetically) makes this approach unattractive as of now.

A possible development is found within fuel cells, more specifically the currently-researched molten carbonate fuel cells (MCFC). MCFCs are a high temperature type of fuel cell which achieves the best in class efficiency and able to use carbon oxides as “fuels”. Their reaction mechanism allows to perform red-ox reactions on CO_2 to produce energy, provided that the cell is fed with H_2 in some way. In particular, an integration with combined cycles recently started development in which hydrogen is provided via natural gas steam reforming (performed by MCFC waste heat) and the cell, besides contributing to power generation, allows to separate CO_2 from the flue gas in a stream which needs purification, but where it is at a concentration that allows alternative methods (like cryogenic technology).

4.2 Molten carbonate fuel cells in combined cycles

Each MCFC is a single unit capable of up to 2-3 MWel of power production. Companies have been performing installations of up to 60 MWel capacity. The operating temperature of a fuel cell is between 600 and 700 °C
In a molten carbonate fuel cell, we can distinguish different reactions happening in the cathode and anode side of the cells. In the cathode, where GT exhaust gases (hot) are fed, carbon dioxide is consumed to produce carbonate ions. This then migrates through ab electrolyte (a mixture of alkaline carbonates constituting a molten salt) promoting an external electric current and reaching the anode, where the hydrogen is oxidized and carbon dioxide released. Below the global reactions:

$$H_2 + CO_3^{2-} \rightarrow H_2O + CO_2 + 2e^- \qquad (anode)$$

$$1/2\, O_2 + CO_2 + 2e^- \rightarrow CO_3^{2-} \qquad (cathode)$$

Inside the anode, where natural gas is fed, the necessary hydrogen is produced via NG steam reforming and WSG[1] reaction.

$$CH_4 + H_2O + heat \rightarrow 3H_2 + CO \qquad (NG\ steam\ reforming)$$

$$CO + H_2O \leftrightarrow H_2 + CO_2 + 44.48\ MJ/kmol_{CO} \qquad (WGS)$$

The heat required for steam reforming is provided by the waste heat of the fuel cell itself. A simplified scheme is depicted in Figure 2.

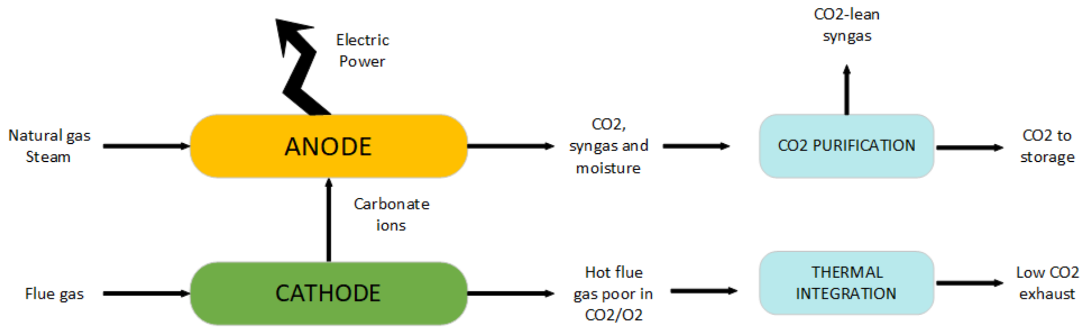


Figure 2. Simplified scheme of a MCFC

As seen from the scheme, downstream of the fuel cell we have two streams: one is the residual flue gas, which is stripped of most oxygen and carbon dioxide but is hot and can be recovered in various ways. The stream leaving the anode on the other hand is composed of carbon dioxide, unreacted syngas and some moisture. By drying and cryogenic separation, it is possible to separate first the water, then the CO_2 from the rest. This leaves a stream of mainly syngas which can be used as fuel in the gas turbine combustor.

[1] Water-Gas Shift, an equilibrium reaction between carbon monoxide/water and carbon dioxide/hydrogen.

4.3 Alternative MCFC integrations in combined cycles

There are various ways to implement MCFC in a combined cycle. The thing that must be achieved is to have the flue gas entering the cathode hot. Due to this, there are two main configurations possible.

- **Fully integrated:** as the flue gas enters the cell hot and leaves the cell still hot, in case of a greenfield project it is possible to place the MCFC between the GT and the HRSG. This approach allows the best thermal integration and best efficiency, but the engineering aspect of it can be challenging due to the amount of high temperature ducting to connect the gas turbine exhaust to the MCFC and the cell exhaust to the HRSG. This configuration is roughly represented in Figure 3.

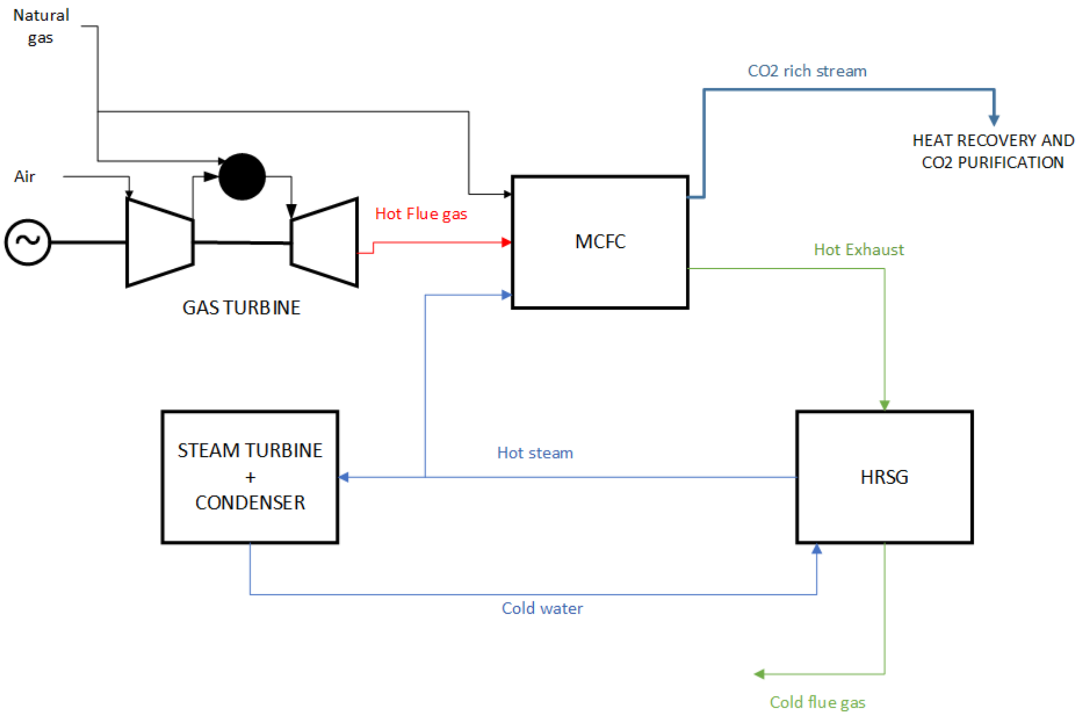


Figure 3. Simplified fully-integrated scheme of a GT+MCFC combined cycle

- **Retrofit configuration:** In this configuration the MCFC is placed downstream of the HRSG. This means that the available exhaust gases are cold, thus heat recovered from MCFC exhaust needs to be used for pre-heating the HRSG exhaust. While this configuration might not be the most efficient, it is the easiest to engineer. This configuration is roughly represented in Figure 4.

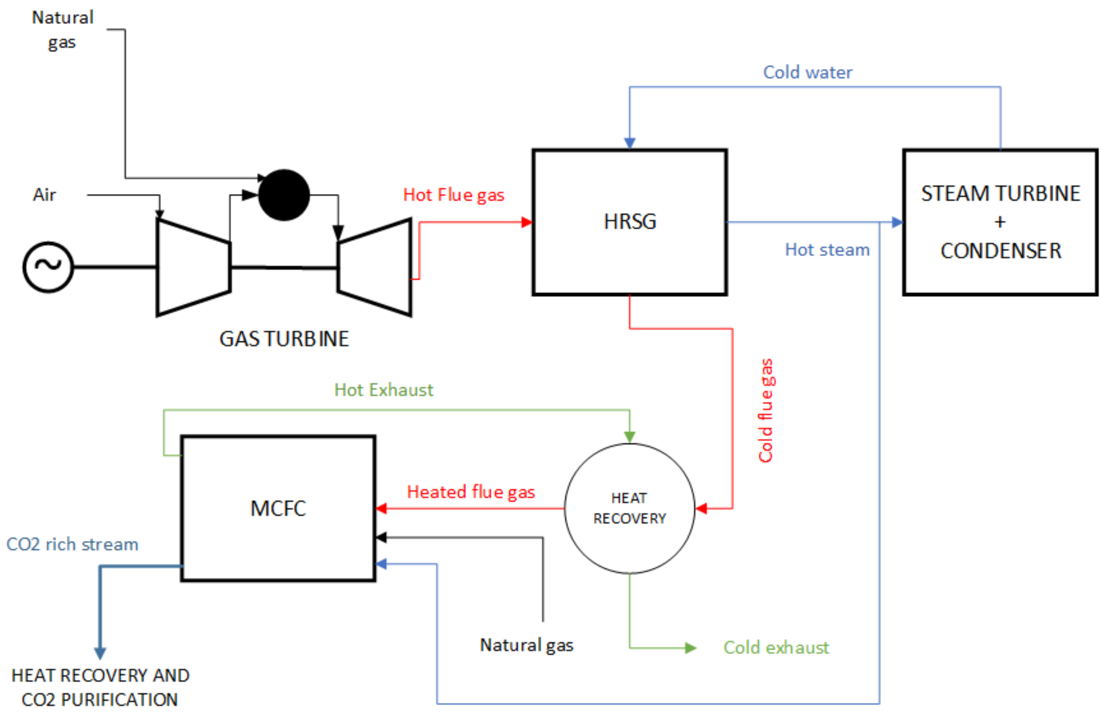


Figure 4. Simplified "retrofit" scheme of a GT+MCFC combined cycle

In the scope of this report, the configuration assumed is the retrofit-like one. Nevertheless, the hypothesis of a greenfield design is maintained.

This allows to retain the advantage of being able to freely integrate the HRSG, the MCFC and the heat recovery system without the engineering issue of the fully-integrated design: to split and distribute hot GT exhaust gases within the different single units of the MCFC installation to then reroute them in one stream is not only challenging but also expensive.

4.4 Process description

In the decided plant configuration, a combined cycle equivalent to benchmark case 1 is installed and integrated with molten carbonate fuel cell systems in the retrofit configuration, one for each HRSG. Each fuel cell has a dedicated CO_2 purification unit.
The configuration is as reported in the following table:

Table 7. NGCC with MCFC – Unit arrangement

Description	Trains
Gas Turbine	2 x 50%
HRSG	2 x 50%
Steam Turbine	1 x 100%
Molten carbonate fuel cell	2 x 50%
CO_2 purification and compression unit	2 x 50%
Natural draft cooling tower	1 x 100%

For the description relevant to the combined cycle section, please refer to paragraph 2.3 of chapter C: "Basic information on NGCC plant alternatives". The main differences are:

- An LP extraction is foreseen on the low-pressure section of the steam turbine to provide steam for natural gas steam reforming.
- Natural gas is preheated via hot syngas recycle and by heat integration with the anodic exhaust of the fuel cell. No MP BFW is needed for performance heating.
- No SCR is foreseen due to small amounts of NO_x not impacting significantly MCFC performance. The fuel cell is also able to remove small quantities of nitrogen components from the flue gas as presented in literature (Kawase et. Al, *"Effects of NH_3 and NO_x on the performance of MCFCs"*, 2002)

The fuel cell is integrated in this way: flue gas leaving the HRSG is fed to the fuel cell cathode after being pre-heated against the treated flue gas leaving the fuel cell itself and by subsequent combustion of a small recycled portion of recovered syngas.
From the fuel cell, treated flue gas leaves from the cathode and is used in the aforementioned heat recovery before being emitted to the atmosphere. Hot anodic

discharge goes into a thermal recovery system where it is used as heating medium for the natural gas fuel cell feed system before being used for GT fuel preheating and then cooled for water separation. From there, it enters the cryogenic separation and compression unit.

From the CO_2 purification unit, the CO_2 rich stream is sent to appropriate underground storage while the recovered mixture of syngas and unrecovered carbon dioxide is partially recycled to the GT combustor, partially used in HRSG exhaust heating and part recycled to the fuel cell natural gas system to ensure sufficient hydrogen content.

4.5 Process Flow Diagrams

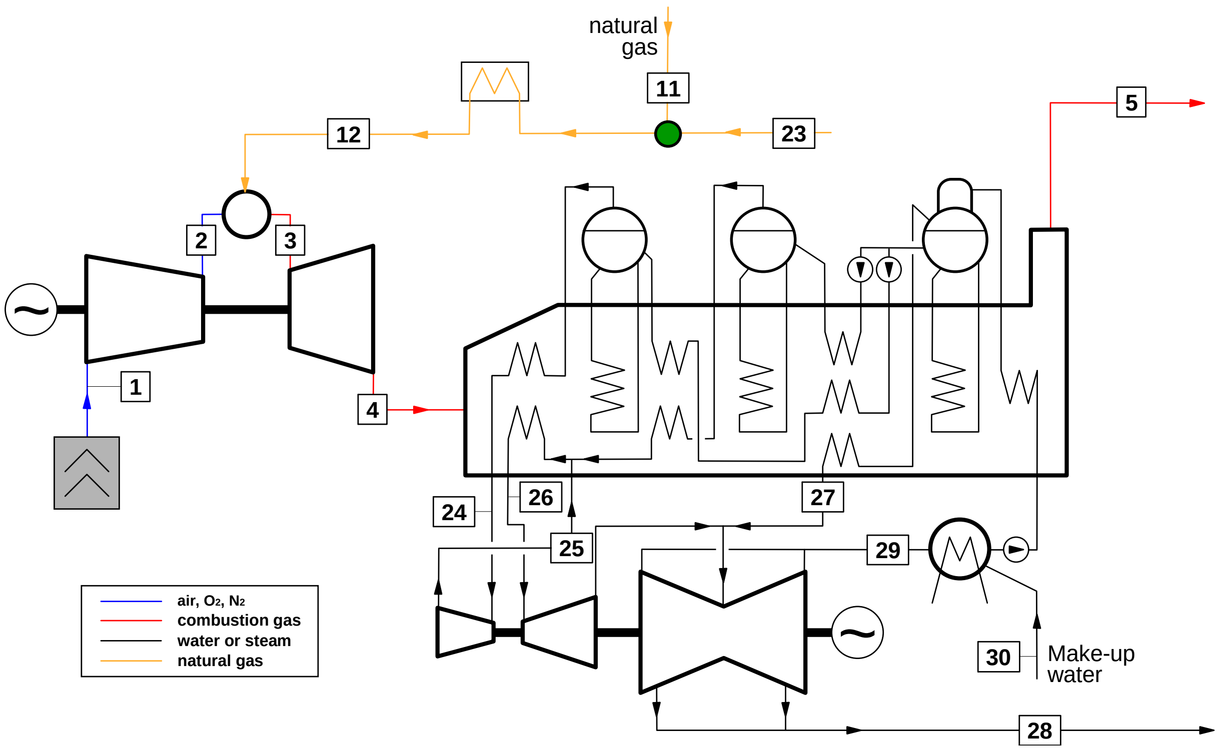


Figure 5. GT, HRSG and ST system. For clarity, only one train is reported in the figure

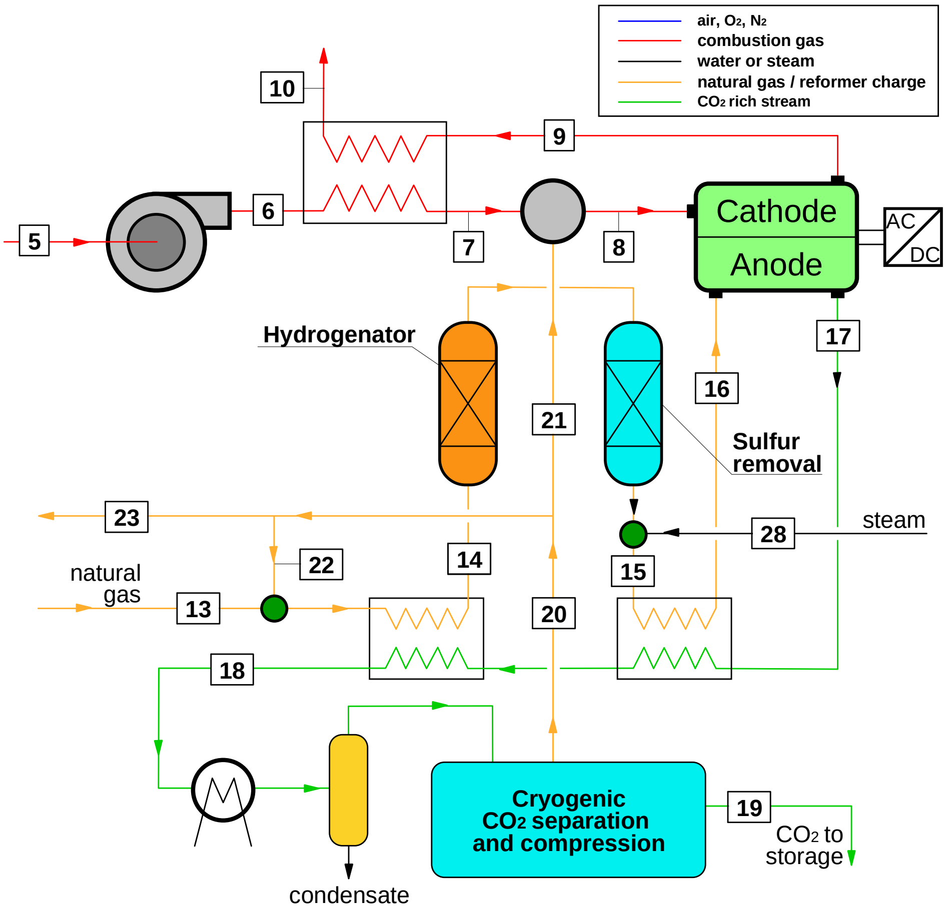


Figure 6. MCFC and CO_2 separation units. For clarity, only one train is reported in the figure

4.6 Heat and mass balance

In the following page, the heat and mass balance for the combined cycle with MCFC is reported. The HMB refers to the PFD shown in paragraph 4.5.

HEAT AND MATERIAL BALANCE		REVISION	0	1
CLIENT :	IEAGHG	PREP.	MM	
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	VT	
PROJECT NO:	1-BD-1046 A	APPROVED	VT	
CASE:	Combined Cycle with MCFC	DATE	July 2019	

HEAT AND MATERIAL BALANCE

STREAM	1	2	3	4	5	6	7	8	9
	Air Intake from Atmosphere	Air to Combustor	Hot Flue Gas to Turbine	GT Exhaust	Exhaust Gas from HRSG	Boosted Exhaust Gases	Cold Reheat from Steam Cycle	Hot Flue Gas to Cell Cathode	Hot Flue Gas from Cell Cathode
Temperature, °C	AMB	456	1648	641	84	91	550	580	619
Pressure (bar)	ATM	23.74	23.02	1.05	1.01	1.07	1.07	1.07	1.05
TOTAL FLOW									
Mass flow (kg/h)	3,411,360	2,659,860	2,759,724	3,511,260	3,511,260	3,511,260	3,511,260	3,518,532	3,232,872
Molar flow (kmol/h)	118,162	92,131	82,720	123,873	123,807	123,806	123,806	124,111	116,970
LIQUID PHASE									
Mass flow (kg/h)									
GASEOUS PHASE									
Mass flow (kg/h)	3,411,360	2,659,860	2,759,724	3,511,260	3,511,260	3,511,260	3,511,260	3,518,532	3,232,872
Molar flow (kmol/h)	118,162	92,131	82,720	123,873	123,807	123,806	123,806	124,111	116,970
MW (kg/kmol)	28.87	28.87	33.36	28.35	28.36	28.36	28.36	28.35	27.64
Composition (vol %)									
Ar	0.92%	0.92%	0.87%	0.88%	0.88%	0.88%	0.88%	0.88%	0.93%
CH_4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C_2H_6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C_3H_8	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C_4H_{10}	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	0.03%	0.03%	5.85%	4.63%	4.63%	4.63%	4.63%	4.78%	1.00%
H_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
H_2O	0.91%	0.91%	11.74%	9.46%	9.46%	9.46%	9.46%	9.72%	10.31%
N_2	77.38%	77.38%	77.38%	73.88%	73.90%	73.90%	73.90%	73.72%	78.22%
O_2	20.76%	20.76%	20.76%	11.10%	11.13%	11.13%	11.13%	10.90%	9.54%
APPLICABLE NOTES									

Note 1: This stream is the total combined flow of two trains.

Note 2: Two phase flow.

wood.	HEAT AND MATERIAL BALANCE		REVISION	0	1
	CLIENT :	IEAGHG	PREP.	MM	
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	VT	
	PROJECT NO:	1-BD-1046 A	APPROVED	VT	
	CASE:	Combined Cycle with MCFC	DATE	July 2019	

HEAT AND MATERIAL BALANCE

STREAM	10	11	12	13	14	15	16	17	18
	Treated Exhaust Gas to ATM	Natural Gas to GT	Natural Gas and Syngas Mixture to GT	Natural Gas Feed for MCFC	Inlet to Hydrogenator	Desulfurised NG/Steam Mixture to Pre-heat	NG/Steam Mixture to Anode	Exhaust from Anode	Exhaust to Water Removal and CO_2 Separation
Temperature, °C	129.5	9	39	9	300	300	450	619	526
Pressure (bar)	1.01	70.00	35.00	70.00	34.30	1.15	1.13	1.09	1.05
TOTAL FLOW									
Mass flow (kg/h)	3,232,872	90,076	99,882	25,719	38,081	102,280	102,280	387,936	387,936
Molar flow (kmol/h)	116,970	4,994	5,751	1,428	2,374	5,937	5,937	13,736	13,736
LIQUID PHASE									
Mass flow (kg/h)									
GASEOUS PHASE									
Mass flow (kg/h)	3,232,872	90,076	99,882	25,719	38,081	102,280	102,280	387,936	387,936
Molar flow (kmol/h)	116,970	4,994	5,751	1,428	2,374	5,937	5,937	13,736	13,736
MW (kg/kmol)	27.64	18.04	17.37	18.02	16.04	17.23	17.23	28.24	28.24
Composition (vol %)									
Ar	0.93%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CH_4	0.00%	89.00%	77.39%	89.00%	53.53%	21.40%	21.40%	0.00%	0.00%
C_2H_6	0.00%	7.00%	6.09%	7.00%	4.21%	1.68%	1.68%	0.00%	0.00%
C_3H_8	0.00%	1.00%	0.87%	1.00%	0.60%	0.24%	0.24%	0.00%	0.00%
C_4H_{10}	0.00%	0.11%	0.10%	0.11%	0.07%	0.03%	0.03%	0.00%	0.00%
CO	0.00%	0.00%	3.62%	0.00%	11.06%	4.42%	4.42%	4.57%	4.57%
CO_2	1.00%	2.00%	2.86%	2.00%	4.61%	1.84%	1.84%	43.85%	43.85%
H_2	0.00%	0.00%	8.19%	0.00%	25.00%	9.99%	9.99%	10.28%	10.28%
H_2O	10.31%	0.00%	0.00%	0.00%	0.00%	60.03%	60.03%	41.14%	41.14%
N_2	78.22%	0.97%	0.89%	0.89%	0.92%	0.37%	0.37%	0.16%	0.16%
O_2	9.54%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
APPLICABLE NOTES									

Note 1: This stream is the total combined flow of two trains.
Note 2: Two phase flow.

wood.	HEAT AND MATERIAL BALANCE		REVISION	0	1
	CLIENT :	IEAGHG	PREP.	MM	
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	VT	
	PROJECT NO:	1-BD-1046 A	APPROVED	VT	
	CASE:	Combined Cycle with MCFC	DATE	July 2019	

HEAT AND MATERIAL BALANCE

STREAM	19	20	21	22	23	24	25	26	27
	CO_2 to Storage	Recovered Syngas and Residual CO_2	Recovered Syngas to Cathode Inlet Heater	Recycled Syngas to Anode Natural Gas	Syngas to GT Inlet Fuel Mixer	HP Steam to Steam Turbine	Cold RH to HRSG	Hot RH to Steam Turbine	LP Steam to Steam Turbine
Temperature, °C	35	285	285	285	285	600	388	600	300
Pressure (bar)	1.05	35.00	35.00	35.00	35.00	170.20	43.00	39.56	5.52
TOTAL FLOW									
Mass flow (kg/h)	256,608	17,064	7,259	12,361	9,805	946,014	936,554	1,028,813	125,573
Molar flow (kmol/h)	5,832	1,306	555	946	750	52,510	51,985	57,106	6,970
LIQUID PHASE									
Mass flow (kg/h)									
GASEOUS PHASE									
Mass flow (kg/h)	256,608	17,064	7,259	12,361	9,805	946,014	936,554	1,028,813	125,573
Molar flow (kmol/h)	5,832	1,306	555	946	750	52,510	51,985	57,106	6,970
MW (kg/kmol)	44.00	13.07	13.07	13.07	13.07	18.02	18.02	18.02	18.02
Composition (vol %)									
Ar	0.00%	0.00%	0.00%	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%
C_2H_6	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C_3H_8	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
C_4H_{10}	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CO	0.05%	27.74%	27.74%	27.74%	27.74%	0.00%	0.00%	0.00%	0.00%
CO_2	99.95%	8.55%	8.55%	8.55%	8.55%	0.00%	0.00%	0.00%	0.00%
H_2	0.00%	62.74%	62.74%	62.74%	62.74%	0.00%	0.00%	0.00%	0.00%
H_2O	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%	100.00%	100.00%	100.00%
N_2	0.00%	0.97%	0.97%	0.97%	0.97%	0.00%	0.00%	0.00%	0.00%
O_2	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
APPLICABLE NOTES						1	1	1	1

Note 1: This stream is the total combined flow of two trains.
Note 2: Two phase flow.

wood.	HEAT AND MATERIAL BALANCE		REVISION	0	1
	CLIENT :	IEAGHG	PREP.	MM	
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	VT	
	PROJECT NO:	1-BD-1046 A	APPROVED	VT	
	CASE:	Combined Cycle with MCFC	DATE	July 2019	

HEAT AND MATERIAL BALANCE

STREAM	28	29	30						
	LP Steam Extraction to MCFC	LP Turbine Exhaust to Condenser	Demiwater Make-Up						
Temperature, °C	144.65	29	AMB						
Pressure (bar)	1.15	0.04	ATM						
TOTAL FLOW									
Mass flow (kg/h)	140,285	1,014,101	140,285						
Molar flow (kmol/h)	7,787	56,289	7,787						
LIQUID PHASE									
Mass flow (kg/h)		97,354	140,285						
GASEOUS PHASE									
Mass flow (kg/h)	140,285	916,748							
Molar flow (kmol/h)	7,787	56,289							
MW (kg/kmol)	18.02	18.02	18.02						
Composition (vol %)									
Ar	0.00%	0.00%	0.00%						
CH_4	0.00%	0.00%	0.00%						
C_2H_6	0.00%	0.00%	0.00%						
C_3H_8	0.00%	0.00%	0.00%						
C_4H_{10}	0.00%	0.00%	0.00%						
CO	0.00%	0.00%	0.00%						
CO_2	0.00%	0.00%	0.00%						
H_2	0.00%	0.00%	0.00%						
H_2O	100.00%	100.00%	100.00%						
N_2	0.00%	0.00%	0.00%						
O_2	0.00%	0.00%	0.00%						
APPLICABLE NOTES	1	1, 2							

Note 1: This stream is the total combined flow of two trains.
Note 2: Two phase flow.

4.7 Overall performances

The following table reports the overall performances for the combined cycle with MCFC examined.

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**DATE**	jul-19
PROJECT No. :	1-BD-1046 A	**MADE BY**	MM
LOCATION :	Netherlands	**APPROVED BY**	VT

OVERALL PERFORMANCES

		CC with MCFC
Fuel flow rate (A.R.)	t/h	232
Fuel HHV (A.R.)	kJ/kg	46502
Fuel LHV (A.R.)	kJ/kg	51473
THERMAL ENERGY OF FEEDSTOCK (based on LHV) (A)	**MWth**	**2995**
THERMAL ENERGY OF FEEDSTOCK (based on HHV) (A')	**MWth**	**3315**
Gas turbine power output (@ gen terminals)	MWe	1043.4
Steam turbine power output (@ gen terminals)	MWe	487.3
MCFC power output (@ gen terminals)	MWe	357.8
GROSS ELECTRIC POWER OUTPUT (@ gen terminals) (C)	**MWe**	**1888.5**
Power Islands consumption	MWe	27.5
Utility & Offsite Units consumption	MWe	14.5
CO2 purification unit	MWe	113.8
ELECTRIC POWER CONSUMPTION	**MWe**	**155.8**
NET ELECTRIC POWER OUTPUT	**MWe**	**1732.7**
(Step Up transformer efficiency = 0.997%) (B)	MWe	**1727.5**
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**63.1%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**57.7%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**57.0%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**52.1%**
Equivalent CO_2 flow in fuel	kmol/h	13941.0
Captured CO_2	kmol/h	12771
CO_2 removal efficiency	**%**	**91.6%**
Fuel Consumption per net power production	**MWth/MWe**	**1.73**
CO_2 emission per net power production	**kg/MWh**	**29.8**

4.8 Economics

Wood developed investment costs and LCOE for the discussed configuration. Chapter B study basis were applied, with the addition of a currently expected installed cost for the MCFC equipment, sourced from a literature study (*"Molten Carbonate Fuel Cells for Retrofitting Postcombustion CO_2 Capture in Coal and Natural Gas Power Plants"*, Spinelli et al., 2018).

In the table below the results are reported and are compared to relevant benchmark cases. Comparison is carried on the 90% capture basis, as this is the actual value that this configuration is able to sequestrate (due to the overlap of the capture efficiency to fuel cell utilization, a cryogenic plant able to separate 97% of CO_2 from anode outlet corresponds to a 90% capture on a fuel carbon content basis).

Table 8. CAPEX result summary for MCFC compared to main benchmark 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)
Benchmark cases	**Case 1**	905	1206	601	801
	Case 2	1684	2236	1280	1699
FGR Case	**Case 2.2**	1510	2005	1127	1495
MCFC Case	**Case 2.6**	1839	2441	1065	1413

Table 9. LCOE and CAC result summary for MCFC compared to main benchmark cases

Case	LCOE (€/MWh)	CO_2 emission avoidance cost €/t
Case 1	48.2	-
Case 2	68.9	69.98
Case 2.2	67.3	65.20
Case 2.6	64.4	53.70

Below, the comparison is presented graphically.

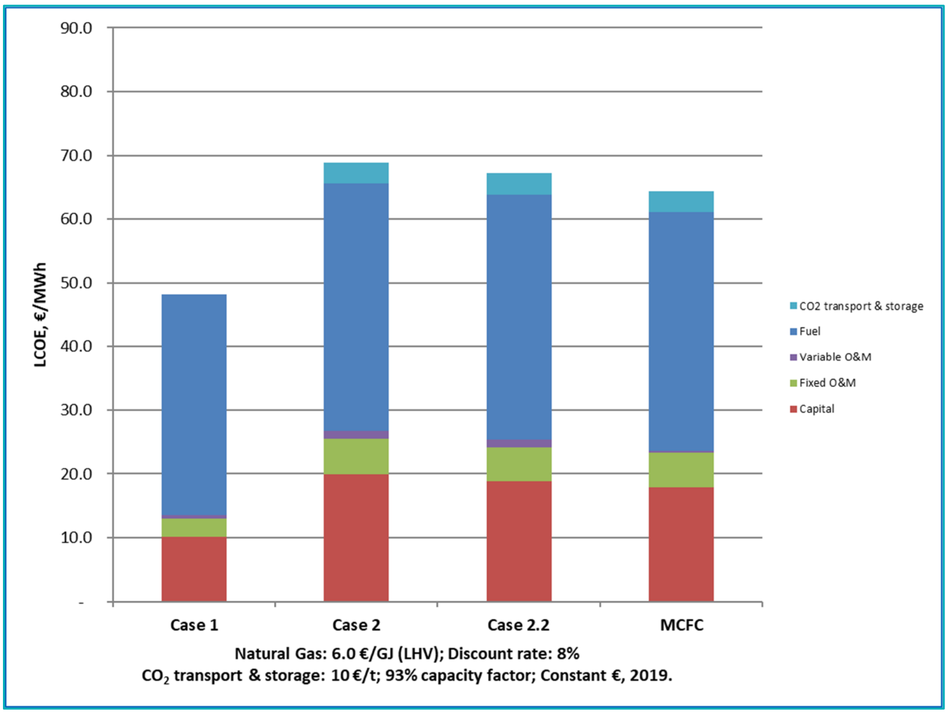


Figure 7. LCOE breakdown comparison for MCFC vs other 90% recovery cases

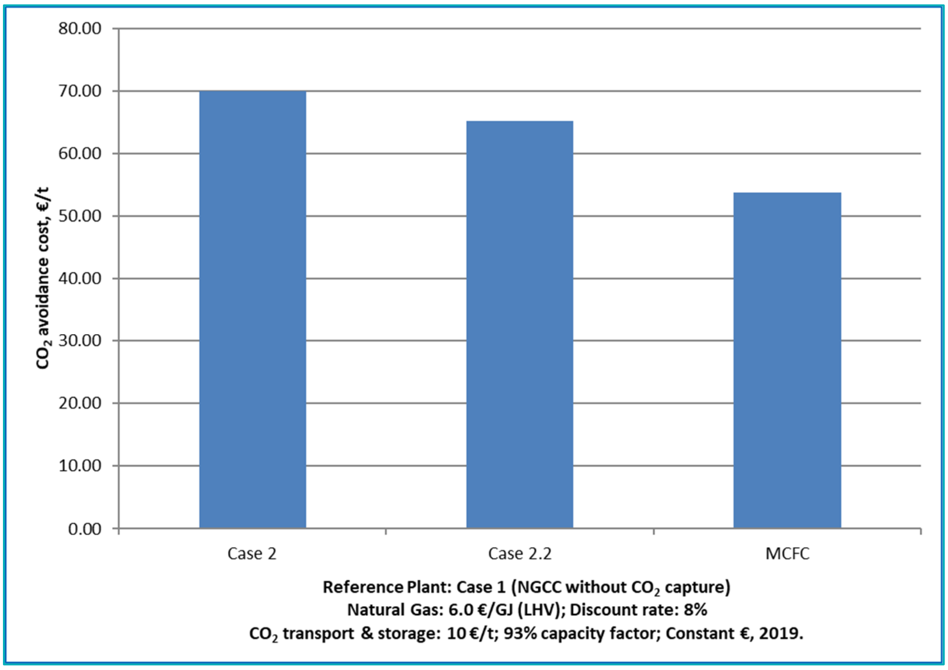


Figure 8. CAC comparison for MCFC vs other 90% recovery cases

4.9 Observations

Thanks to the dual effect of both contributing to energy production and removing the penalty related to steam export for solvent regeneration, the use of MCFCs in combined cycle is very attractive in terms of performances. While the improvement potential is much higher, the gains are still off-set by the high electric energy requirement of cryogenic separation at this scale. Also, very high capture rates are hard to obtain due to the recovery efficiency overlap between the cryogenic separation and the fuel cell utilization.

Nevertheless, the preliminary economic considerations that Wood performed show a very promising alternative to solvent-based post combustion capture solutions. The assumed installed cost of the MCFC package is in line with the current market offer. According to predictions found in the previously cited paper (*"Molten Carbonate Fuel Cells for Retrofitting Postcombustion CO_2 Capture in Coal and Natural Gas Power Plants"*, Spinelli et al., 2018) for the next years, an installed cost reduction by >50% will be achievable for large capacity installations, which would make this solution even more economically attractive. It is important to remind that this level of study is not able to account for engineering challenges to provide a 357.8 MWe MCFC park: this size would be a first of a kind by a large margin from the highest installed units currently.

CLIENT : IEAGHG
PROJECT NAME : UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO_2 CAPTURE
DOCUMENT NAME : BASIC INFORMATION ON USC PC PLANT ALTERNATIVES
CONTRACT N° : 1-BD-1046 A

ISSUED BY : P. ANTICO
CHECKED BY : N. FERRARI
APPROVED BY : P. COTONE

Date	Revised Pages	Issued by	Checked by	Approved by

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ATTACHMENTS

GLOSSARY

CCS	Carbon Capture and Storage
NGCC	Natural Gas Combined Cycle
USC PC	Ultrasupercritical Pulverised Coal
FGR	Flue Gas Recirculation
EGR	Exhaust Gas Recirculation
CCU	Carbon Capture Unit
CMC	Ceramic Matrix Composite
ASU	Air Separation Unit
MCFC	Molten Carbonate Fuel Cell
TPC	Total Plant Cost
TIC	Total Installed Cost
MEL	Minimum Environmental Load
GT	Gas Turbine
ST	Steam Turbine

1. Introduction

The ultra-supercritical pulverised coal (USC 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 D is to provide a general description of the major blocks of the USC PC power plant, which are generally common to the conventional USC PC boiler-based cases of the study. Chapters D.1 and D.2 of the report give basic engineering information for the reference cases with and without CO_2 capture (both for reference case with 90% capture rate and high capture rate case), with the support of specific heat and mass balances, utility consumption summaries, etc, while the sensitivity cases to evaluate plant flexibility are presented in chapter D.4. In chapter D.5 Wood executed a literature review of the impact on design and flexibility of Advanced-USC steam conditions.

Following Table 1 summarises the key technology features selected for the development of the reference cases. Table 2 summarises the sensitivity cases studied.

Table 1. USC PC boiler-based reference study cases

Reference Case	Chapter	Description	Key features
Case 3	D.1	USC PC boiler w/o CCS	• Generic state-of-art supercritical PC boiler • Wet limestone scrubbing FGD • Cooling system based on natural draft cooling water
Case 4	D.2	USC PC boiler with CCS	• Generic state-of-art supercritical PC boiler

			• Wet limestone scrubbing FGD • CANSOLV post-combustion capture • Cooling system based on natural draft cooling tower. • 90% capture rate
Case 4.1	D.2	USC PC boiler with CCS – High capture rate	• Generic state-of-art supercritical PC boiler • Wet limestone scrubbing FGD • CANSOLV post-combustion capture • Cooling system based on natural draft cooling tower. • 99% capture rate

Table 2. USC PC boiler-based sensitivity cases

Reference Case	Chapter	Description	Key features
Improving flexibility of USC PC power plants with CCS			
Case 4.1a	D.4	USC PC boiler with CCS and solvent storage	• Case 4.1 configuration • 99% capture rate • Lean/rich solvent storage system
Case 4.1b	D.4	USC PC boiler with ON/OFF CCS	• Case 4.1 configuration • 99% capture rate • Capable of unabated power production
Case 4.1c	D.4	USC PC boiler with CCS and BESS	• Case 4.1 configuration • 99% capture rate • 260 MWh Battery Energy Storage System
Mid-term future improvements on coal-fired boiler technology			
-	D.5	Impact of steam conditions on PC boiler design and flexibility	• Literature review • 99% capture rate

Note:

1) For all flexibility cases, reference comparison case is case 4.1

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 3 and to minimize the NOx content (less than 20 ppmv) at the inlet to the carbon capture unit for Case 4.

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.

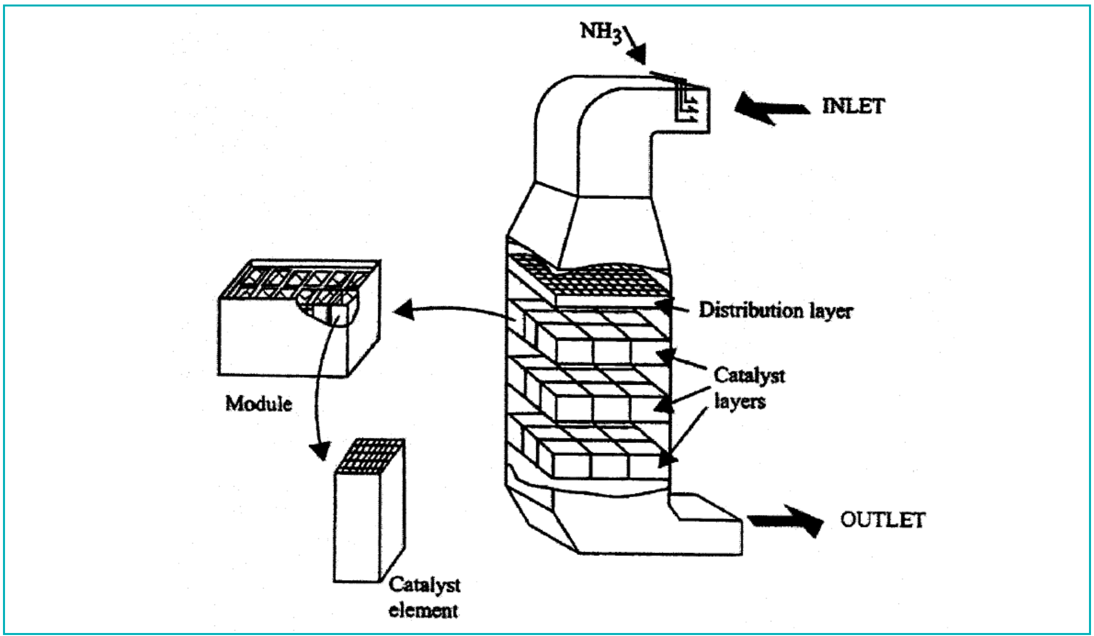


Figure 1 - SCR system

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.

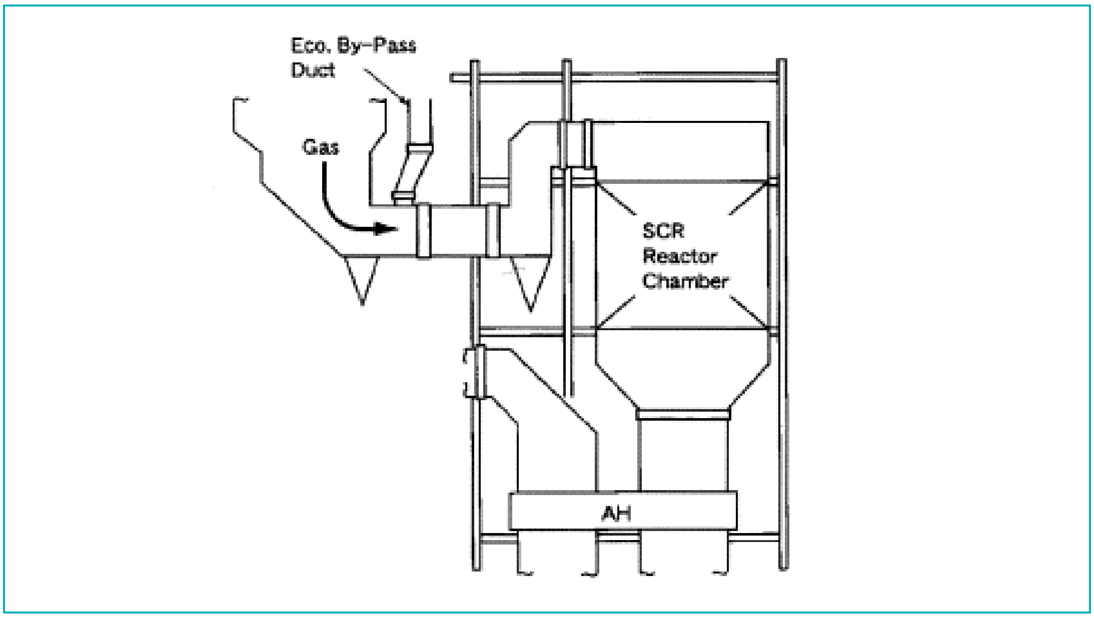


Figure 2. SCR in conventional boilers

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 3 and to reduce at the maximum extent the SO_X entering the carbon capture unit for Case 4, in order to minimize solvent degradation in the downstream absorber column.

Wet limestone scrubber technology is selected as are the most widely used of all the FGD systems, accounting for about 80% of all the installed capacity. Limestone feedstock is readily available in large quantities in most locations and can either be ground on site or provided pre-ground. Gypsum product 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.

For the purpose of this study, the performance of the FGD system are estimated based on the technical offer provided by Alstom of the IEAGHG study 2014/3 "*CO_2 capture at coal based power and hydrogen plants*" for the boiler based reference cases with and without CO_2 capture. A generic description of a wet limestone scrubber technology is reported hereafter.

2.4.1. Wet Flue Gas Desulphurization (WFGD) system

The unit description makes reference to the simplified scheme reported in the following Figure 3.

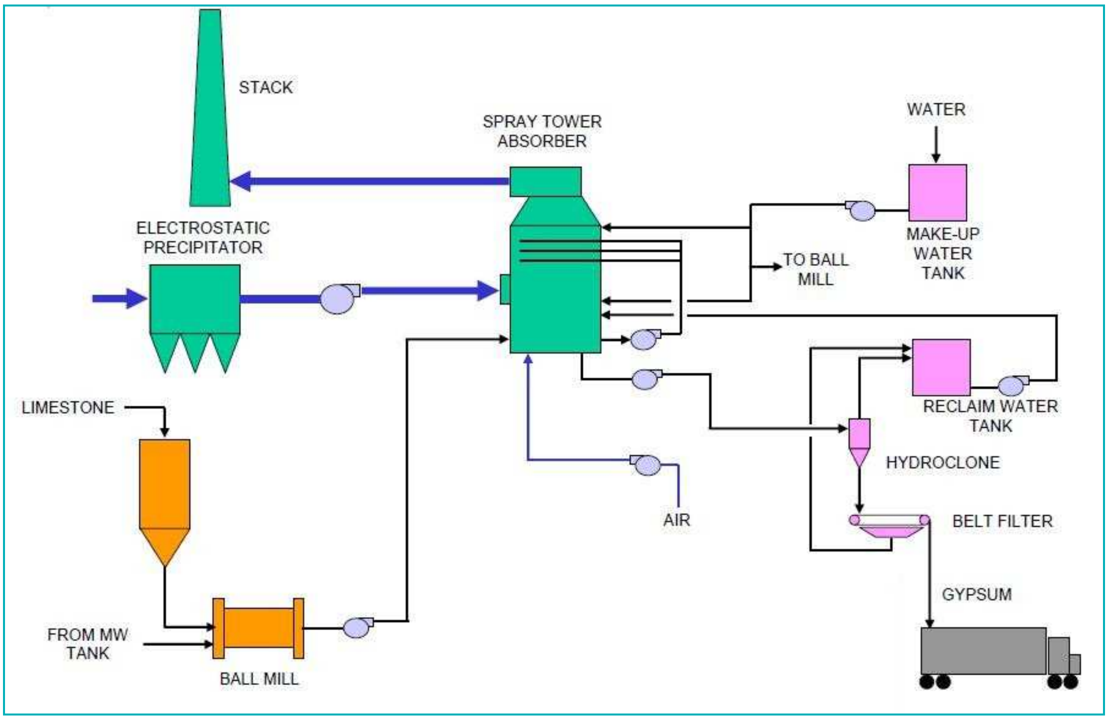


Figure 3. Wet FGD process diagram

Ground limestone reagent is used to react with SO_2 in the flue gas producing a gypsum (calcium sulphate dehydrate) by-product.

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 the required sulphur removal efficiency.

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.

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).

2.5. Mercury removal systems

At present, 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 USC PC boiler based cases of this study.

Despite mercury removal systems not being included in the present work, 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.

<u>Hg formation in coal fired power plant</u>

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.

<u>Flue gas treatment technologies to reduce Hg emissions</u>

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+} adsorbed 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.

<u>Hg reduction by systems designed for metal removal</u>

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 (Cases 4)

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 NGCC plants based on F and H class machine, 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.
- **Baker Hughes GE**: 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 CO_2 scrubbing process, using an amine-based solvent. Cansolv is a subsidiary of Shell Global Solutions group.
- **McDermott**: McDermott fused in recent years with CB&I, acquiring all the knowledge of CB&I and ABB Lummus licensed MEA scrubbing technologies. Currently, McDermott acts as a full EPC contractor for clean natural gas fired power plants at low environmental impact through its NET Power divison.
- **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 CO2**: it offers the LCDesign CCS Capture System™, which is a pre-engineered, pre-built and modularly constructed unit 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.

Amongst the above listed suppliers, Cansolv has provided specific data to develop the boiler case with 90% carbon capture during the execution of the IEAGHG study 2014/3 "*CO_2 capture at coal based power and hydrogen plants*". For this study purpose, Shell Cansolv confirmed that no update has been made with respect to the performance provided in 2014, therefore the capture unit performance for the reference case with 90% capture (case 4) are still applicable.

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 the USC-PC with CO_2 capture (90% capture rate) of the study, only for the information that the supplier has authorized for disclosure.

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, as the data have been slightly adjusted and optimised during study execution either by either Cansolv or Amec Foster Wheeler Italiana. 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 the attachment and in the chapter relevant to the specific study cases is limited to the information that Cansolv have authorized for disclosure.

2.7. CO_2 compression and dehydration (Case 4)

The compression and dehydration units 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 75-80 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. USC PC without CO_2 capture (Case 3)

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:	290 bar; 600°C
MP turbine inlet:	60 bar; 620°C

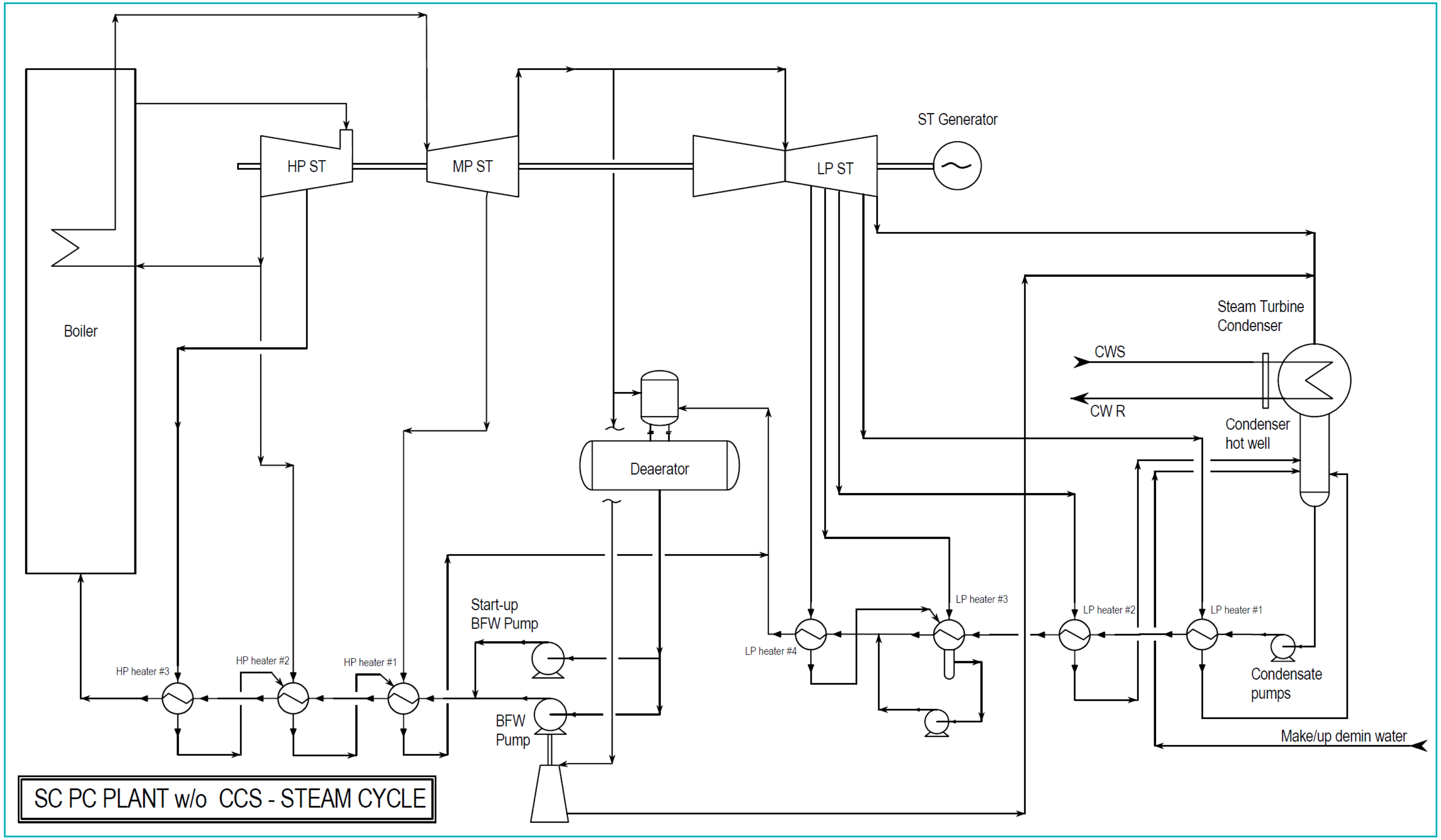
Exhaust steam from the MP turbines then flows into the double flow LP turbine system and finally downward into the water-cooled condenser at 4.0 kPa, corresponding to 29°C.

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
LP heater #3
LP heater #4
LP heater #2
LP heater #1
HP heater #3
HP heater #2
HP heater #1
Condensate pumps
Make/up demin water
SC PC PLANT w/o CCS - STEAM CYCLE

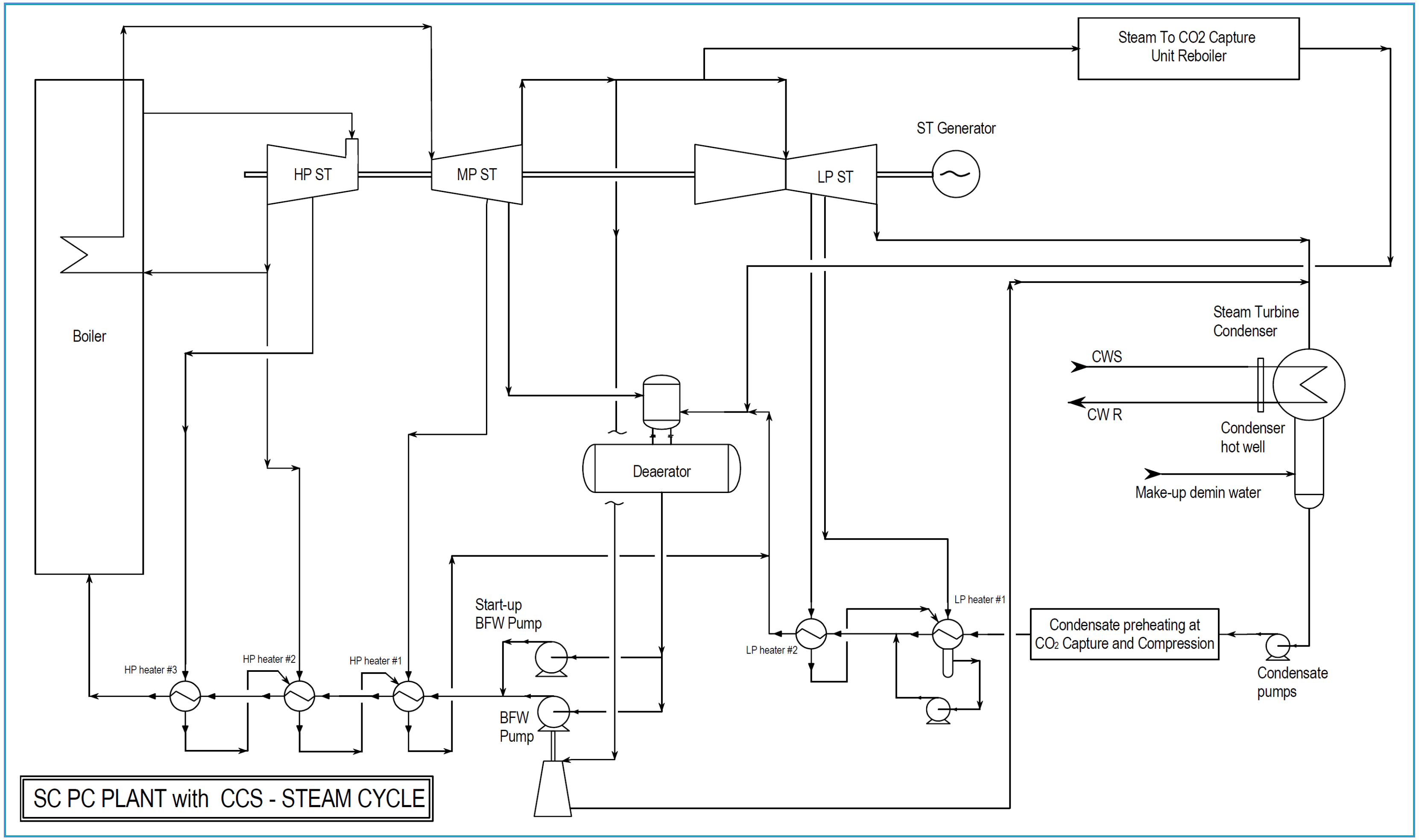
2.8.2. USC PC with CO_2 capture (Case 4)

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 3, 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 3, 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 Cases 3 without capture.


Steam To CO2 Capture
Unit Reboiler
ST Generator
HP ST
MP ST
LP ST
Boiler
Steam Turbine
Condenser
CWS
CW R
Deaerator
Condenser
hot well
Make-up demin water
Start-up
BFW Pump
LP heater #1
LP heater #2
Condensate preheating at
CO₂ Capture and Compression
HP heater #3
HP heater #2
HP heater #1
BFW
Pump
Condensate
pumps
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. *Firefighting 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 firefighting 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
- Blow-down from CO_2 capture unit (case 4), steam cycle and demineralised water unit eluate
- 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. Cansolv post-combustion capture technology

![Cansolv]

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	

TABLE OF CONTENTS

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):

Item	Section
Unit process description	4
Simplified Process Diagram	Appendix I
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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.

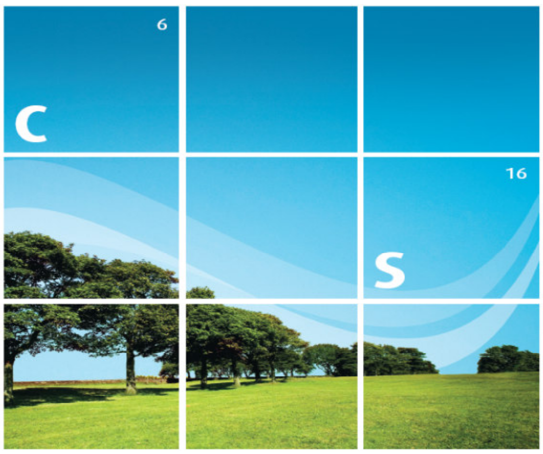
It is CTI's mission to be a leading global provider of high efficiency air pollution control and capture solutions. We want our patented technology to serve as the benchmark for stationary source air emission abatement around the world. Our commitment is to providing custom designed economic solutions 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^oC has been assumed. The process fluids (flue gas, absorbent) are cooled to 30^oC 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

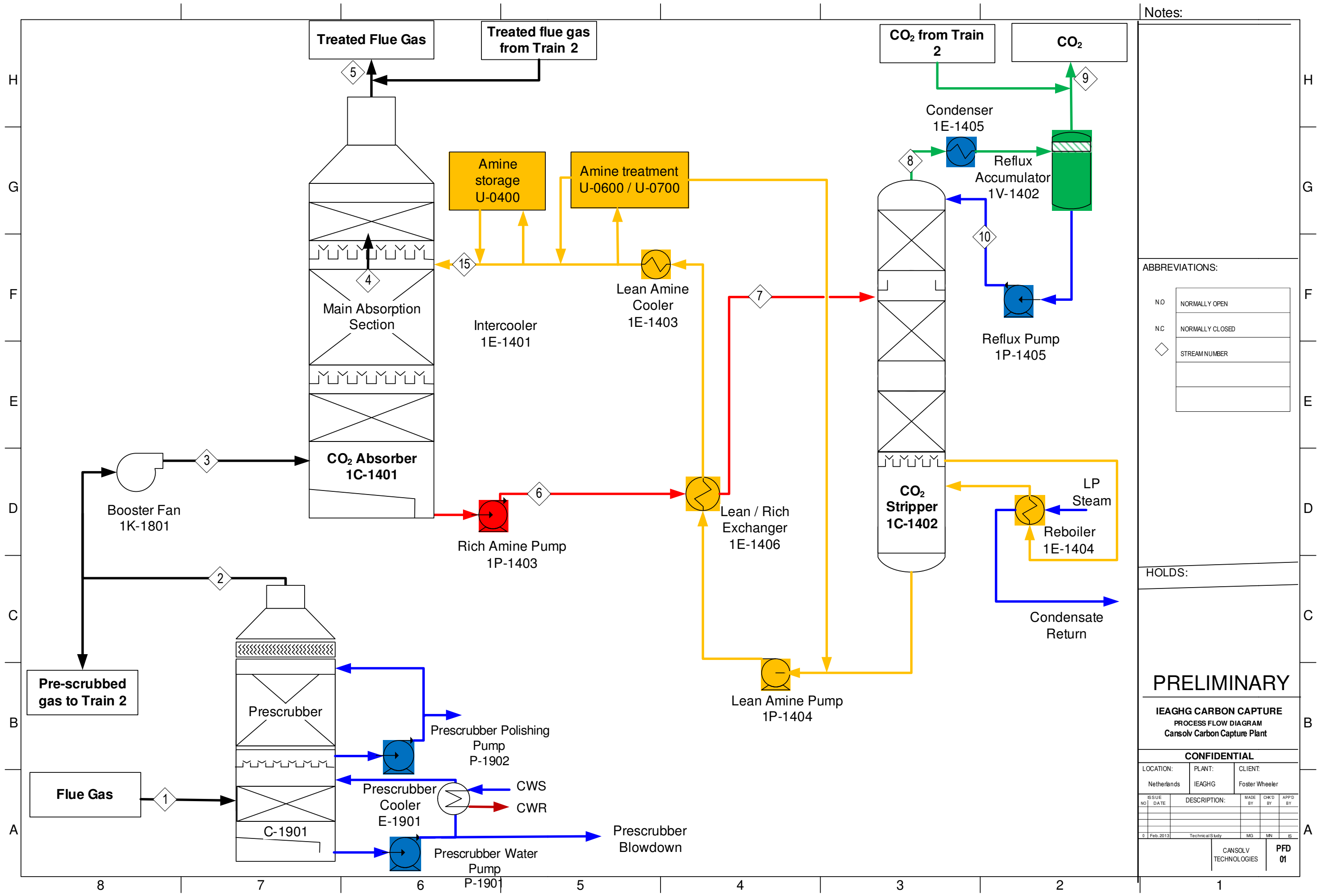
Absorbent degradation is the main cause of Cansolv CO_2 absorbent losses. Degradation products are removed in the APU. Absorbent entrainment into the flue gas and the product gas is minimal. The rectification section in the CO_2 Stripper captures absorbent vapour in the reflux water stream, returning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

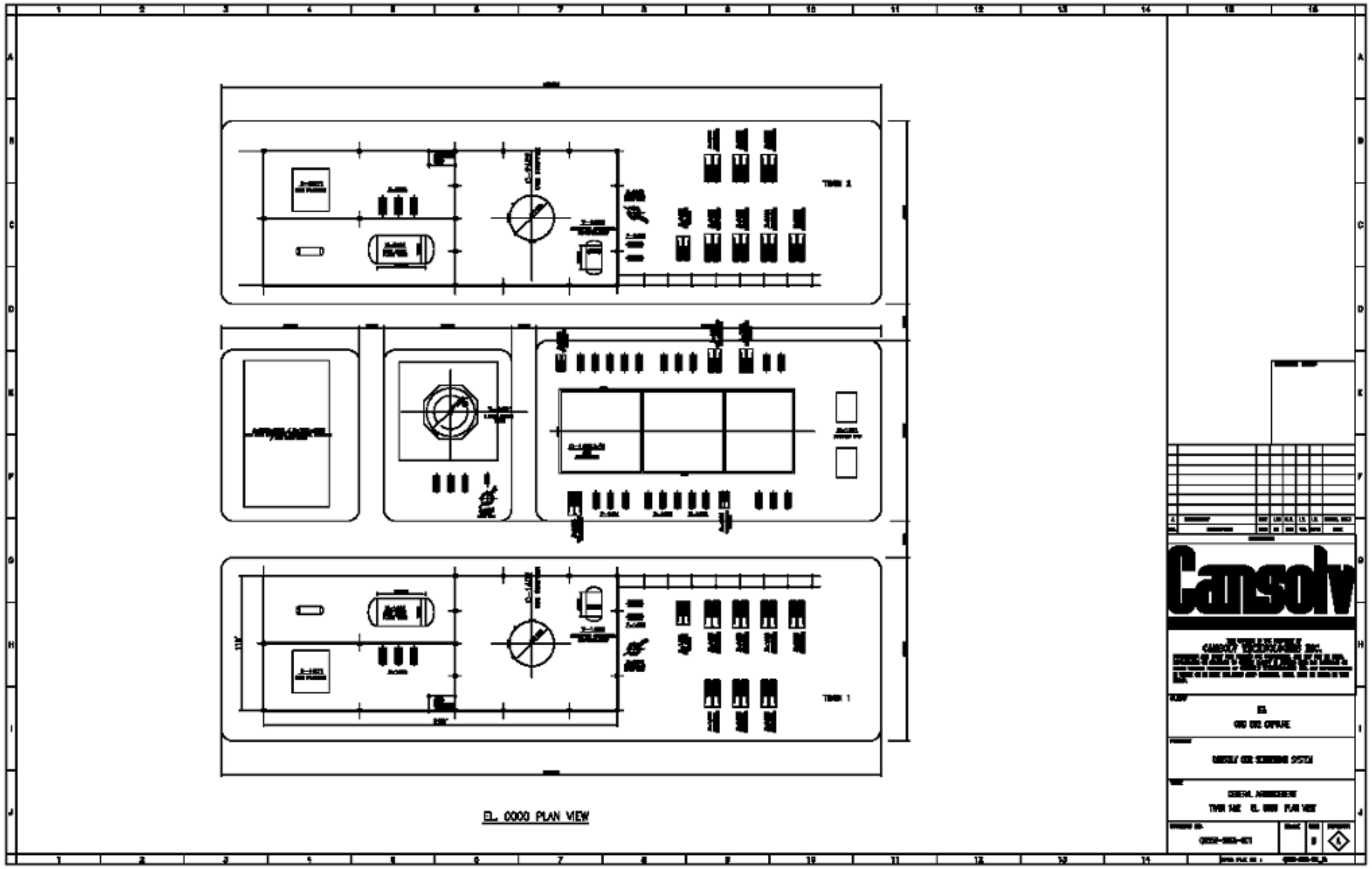
Please contact Cansolv Technologies Inc (CTI) for details.

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 2^{nd} Generation Solvents for CO_2 Post Combustion Capture

Cansolv has established a comprehensive framework to steer development of 2^{nd} 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.

CLIENT	:	IEAGHG
PROJECT NAME	:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO_2 CAPTURE
DOCUMENT NAME	:	REFERENCE CASE 3: USC PC WITHOUT CCS
CONTRACT N°	:	1-BD-1046 A

ISSUED BY	:	P. ANTICO
CHECKED BY	:	N. FERRARI
APPROVED BY	:	P. COTONE

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

GLOSSARY

CCS	Carbon Capture and Storage
NGCC	Natural Gas Combined Cycle
USC PC	Ultrasupercritical Pulverised Coal
FGR	Flue Gas Recirculation
EGR	Exhaust Gas Recirculation
CCU	Carbon Capture Unit
CMC	Ceramic Matrix Composite
ASU	Air Separation Unit
MCFC	Molten Carbonate Fuel Cell
TPC	Total Plant Cost
TIC	Total Installed Cost
MEL	Minimum Environmental Load
GT	Gas Turbine
ST	Steam Turbine

1. Introduction

This chapter of the report includes all technical information relevant to Case 3 of the study, which is a supercritical pulverised coal (USC PC) fired steam plant without carbon capture, located in the reference location (The Netherlands). The plant is designed to process bituminous Eastern Australian coal, whose characteristic is shown in dedicated section 3.3.1 of chapter B, and produce electric power for export to the external grid.

The configuration of the USC 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 D 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 3 – Unit arrangement

Unit	Description	Trains
1000	Storage and Handling of solid materials	N/A
2000	USC 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
	Natural draft cooling tower	1 x 100%

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 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.

2.3. 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 D, sections 2.2 and 2.3 respectively. For this Case 3, 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 3, flue gas desulphurisation is required to meet the plant overall environmental SOx limit of 150 mg/Nm^3 (6% volume O_2, dry).

Wet scrubbing technology is selected for the development of this study case. Technical information relevant to this system is reported in chapter D, section 2.4.1.

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.

<u>Gas-gas heat (GGH) exchanger</u>

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 D, section 2.8.1.

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.

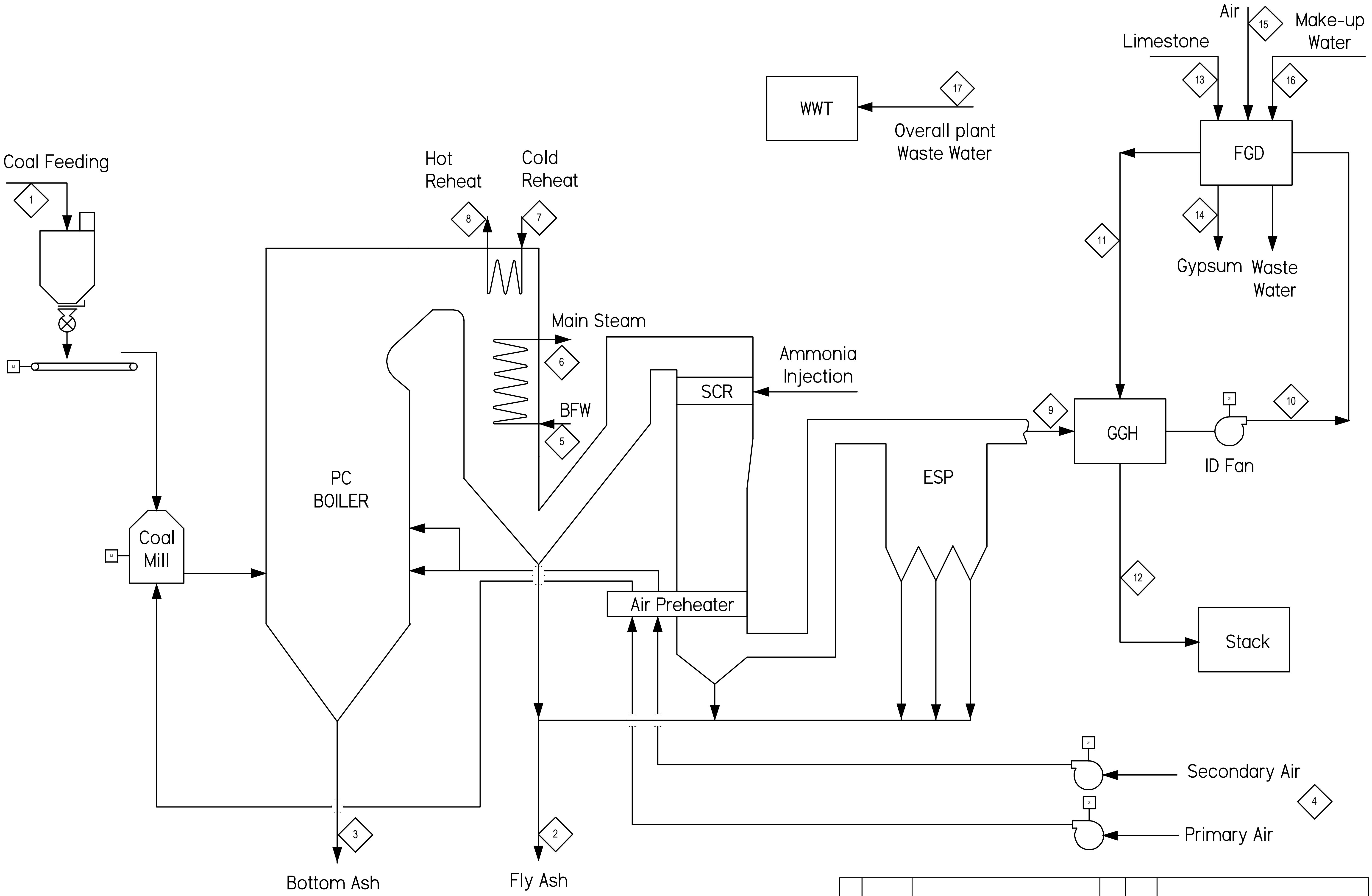
The main utility units include:

- Cooling Water system, based on one natural draft cooling tower, using fresh water as make-up water.
- Raw water system;
- Demineralised water plant;
- Firefighting system;
- Instrument and Plant air;
- Waste water treatment.

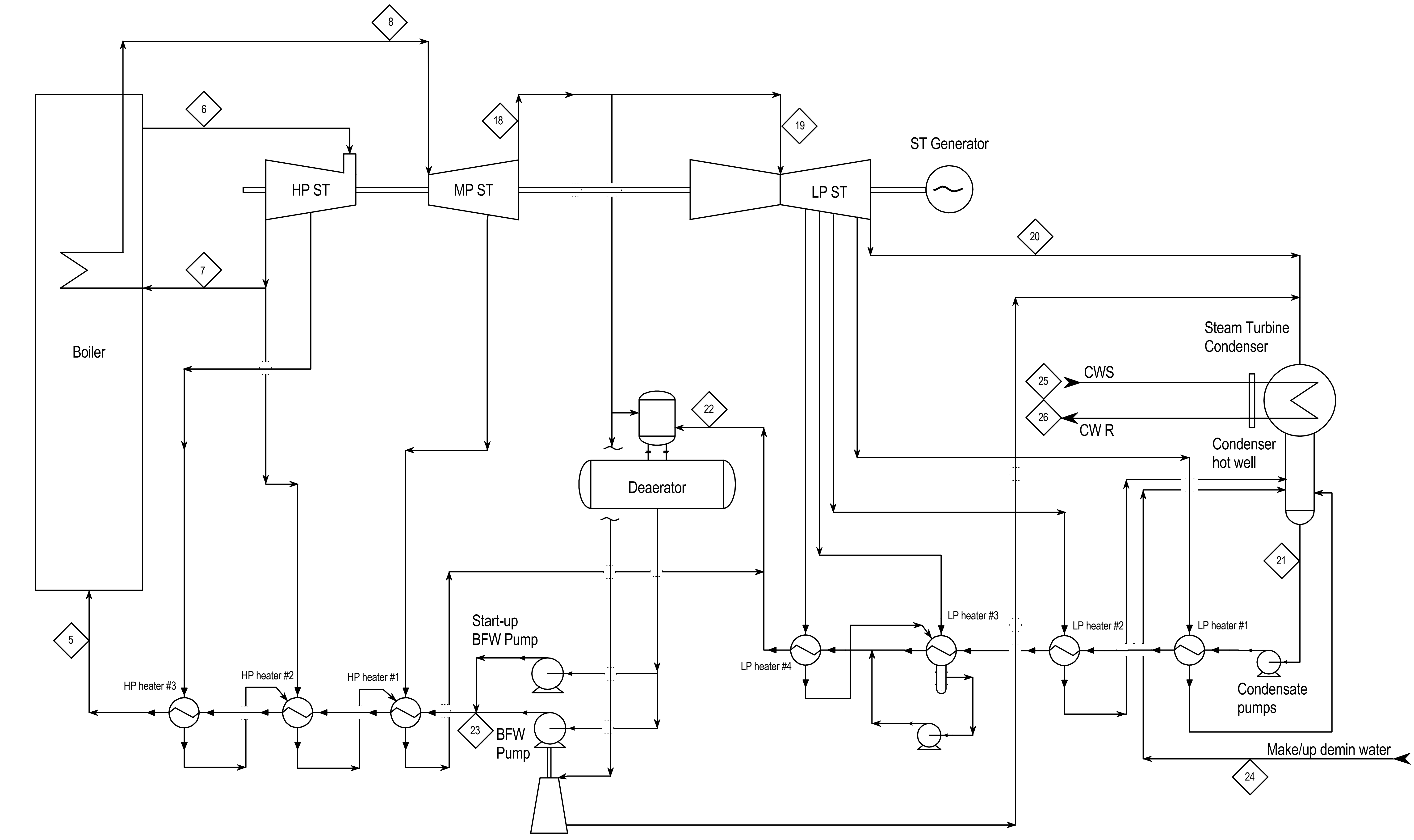
Process descriptions of the above systems are enclosed in chapter D, section 2.9.

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 2019	Draft	MM	VT	**UNIT:** Boiler Island	
Rev.	Date	Comment	By	Appr	**Case 3**	Sheet 01 of 02



0	May 2019	Draft	MM	VT	**UNIT:** Steam Cycle	
Rev.	Date	Comment	By	Appr	**Case 3**	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.

wood.	HEAT AND MATERIAL BALANCE		REVISION	0	1
	CLIENT :	IEAGHG	PREP.	PA	
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	NF	
	PROJECT NO:	1-BD-1046 A	APPROVED	PC	
	CASE:	Case 3 - SC PC w/o CCS	DATE	May 2019	

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 Steam Cycle	Hot Reheat to Steam Turbine	
Temperature, °C	AMB	AMB	AMB	9	290	600	355	620	
Pressure (bar)	ATM	ATM	ATM	1.01	340	290	63	61	
TOTAL FLOW	Solid	Solid	Solid						
Mass flow (kg/h)	325,000	29,200	12,500	3,383,300	2,870,000	2,870,000	2,410,000	2,410,000	
Molar flow (kmol/h)				117,260	159,300	159,300	133,800	133,800	
LIQUID PHASE									
Mass flow (kg/h)					2,870,000				
GASEOUS PHASE									
Mass flow (kg/h)				3,383,300		2,870,000	2,410,000	2,410,000	
Molar flow (kmol/h)				117,260		159,300	133,800	133,800	
MW (kg/kmol)				28.85		18.02	18.02	18.02	
Composition (vol %)	% wt (AR)								
H_2O	C: 64.60%			1.05%	100.00%	100.00%	100.00%	100.00%	
CO_2	H: 4.38%			0.03%	0.00%	0.00%	0.00%	0.00%	
N_2	S: 0.86%			77.27%	0.00%	0.00%	0.00%	0.00%	
Ar	O: 7.02%			0.92%	0.00%	0.00%	0.00%	0.00%	
O_2	N: 1.41%			20.73%	0.00%	0.00%	0.00%	0.00%	
SO_2	Ash: 12.20%			0.00%	0.00%	0.00%	0.00%	0.00%	
Total	Moisture: 9.50%			100.00%	100.00%	100.00%	100.00%	100.00%	
Emissions (note 1)									
SO_x	-	-	-	-	-	-	-	-	-
NO_x	-	-	-	-	-	-	-	-	-
Particulate	-	-	-	-	-	-	-	-	-

Note 1: mg/Nm^3, dry basis 6% vol O_2

HEAT AND MATERIAL BALANCE		REVISION	0	1
CLIENT :	IEAGHG	PREP.	PA	
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	NF	
PROJECT NO:	1-BD-1046 A	APPROVED	PC	
CASE:	Case 3 - SC PC w/o CCS	DATE	May 2019	

HEAT AND MATERIAL BALANCE
UNIT 2100 - FLUE GAS DESULPHURIZATION

STREAM	9	10	11	12	13	14	15	16	
	Flue gas from ESP to GGH	Flue gas to FGD	Treated gas from FGD to GGH	Treated gas to stack	Limestone to FGD	Product Gypsum	Oxidation Air	Make up water to FGD	
Temperature, °C	132	90	47	90	AMB	AMB	AMB	AMB	
Pressure (bar)	-	-	-	-	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	16,170	8,655	85,000	
Molar flow (kmol/h)	123,410	123,410	127,460	127,460			300	4,720	
LIQUID PHASE									
Mass flow (kg/h)								85,000	
GASEOUS PHASE									
Mass flow (kg/h)	3,667,000	3,667,000	3,740,700	3,740,700			8,660		
Molar flow (kmol/h)	123,410	123,410	127,460	127,460			300		
MW (kg/kmol)	29.71	29.71	29.35	29.35			28.85		
Composition (vol %)									
H_2O	8.16%	8.16%	10.88%	10.88%			1.05%	100.00%	
CO_2	14.06%	14.06%	13.68%	13.68%			0.03%	0.00%	
N_2	73.55%	73.55%	71.40%	71.40%			77.27%	0.00%	
Ar	0.87%	0.87%	0.85%	0.85%			0.92%	0.00%	
O_2	3.28%	3.28%	3.20%	3.20%			20.73%	0.00%	
SO_2	0.07%	0.07%	0.01%	0.01%			0.00%	0.00%	
Total	100.00%	100.00%	100.00%	100.00%			100.00%	100.00%	
Emissions (note 1)									
SO_x	1,897	1,897	SO2: 36 ppm SO3: 17 ppm	SO2: 36 ppm SO3: 17 ppm	-	-	-	-	
NO_x	150	150	150	150	-	-	-	-	
Particulate	10	10	10	10	-	-	-	-	

Note 1: mg/Nm^3, dry basis 6% vol O_2

	HEAT AND MATERIAL BALANCE		REVISION	0	1
wood.	**CLIENT :**	IEAGHG	PREP.	PA	
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	NF	
	PROJECT NO:	1-BD-1046 A	APPROVED	PC	
	CASE:	Case 3 - SC PC w/o CCS	DATE	May 2019	

HEAT AND MATERIAL BALANCE
UNIT 3000 - STEAM CYCLE

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Enthalpy kJ/kg
5	BFW to Boiler	2870	290	340	1278
6	HP Steam to Steam Turbine	2870	600	290	3456
7	Cold reheat to Boiler	2410	355	63	3050
8	Hot reheat to Steam Turbine	2410	620	61	3705
18	MP Steam Turbine exhaust	2140	285	6	3031
19	Steam to LP Steam Turbine	1953	285	5.9	3031
20	LP Steam Turbine exhaust	1572	29	0.04	2292
21	Condensate	1940	29	0.04	121
22	LP preheated Condensate	2820	142	9.5	598
23	BFW to preheating	2870	156	340	679
17	Make up water	5	9	0.04	38
24	Cooling water inlet	82251	15	4.0	63
25	Cooling water outlet	82251	26	3.5	109

5. Utility and chemicals consumption

Main utility consumption of the process and utility units is reported in the following tables.

Table 2. Case 3 – Water consumption summary

CLIENT:	IEA GHG	REVISION	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	DATE	may-19
PROJECT No. :	1-BD-1046 A	MADE BY	PA
LOCATION :	Netherlands	APPROVED BY	NF

SC PC Plant w/o carbone capure
Case 3

WATER CONSUMPTION

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Primary Cooling Water System [t/h]	Secondary Cooling Water System [t/h]
1000	FEEDSTOCK AND SOLID HANDLING				
	Solid Receiving, Handling and storage				
2000	BOILER ISLAND and FLUE GAS TREATMENT				
	Boiler island				
	Flue Gas Desulphurization (FGD)	85			
3000	POWER ISLAND (Steam Turbine)				
	Steam Turbine and Auxiliaries		5		4980
	Condenser			82260	
6000	UTILITY and OFFSITE UNITS				
	Cooling Water System	1570			
	Demineralized water unit	8	-5		
	Waste Water Treatment and Condensate Recovery	-10			
	Balance of plant				100
	BALANCE	1653	0	82260	5080

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

Table 3. Case 3 – Electrical consumption summary

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**DATE**	may-19
PROJECT No. :	1-BD-1046 A	**MADE BY**	PA
LOCATION :	Netherlands	**APPROVED BY**	NF

ELECTRICAL CONSUMPTION

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW] Case 3
1000	FEEDSTOCK AND SOLID HANDLING	
	Solid Receiving, Handling and storage	**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	**2600**
	Condensate and feedwater system	**1250**
	Miscellanea	**600**
6000	UTILITY and OFFSITE UNITS	
	Cooling Water System	**9960**
	Balance of plant	**1440**
	BALANCE	**44,020**

Table 4. Case 3 – Sorbent and chemicals consumption

	Consumption
Limestone injection to the FGD	8.85 t/h
Ammonia solution to SCR [(1)]	4.49 t/h

(1) 25%wt ammonia solution

6. Overall Performance

The following table shows the overall performance of Case 3.

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**DATE**	may-19
PROJECT No. :	1-BD-1046 A	**MADE BY**	PA
LOCATION :	Netherlands	**APPROVED BY**	NF

OVERALL PERFORMANCES

		Case 3
Fuel flow rate (A.R.)	t/h	325
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	1080.5
GROSS ELECTRIC POWER OUTPUT (C)	**MWe**	**1080.5**
Feedstock and solids handling	MWe	3.3
Boiler Island, including FGD	MWe	24.8
Power Islands consumption	MWe	4.5
Utility & Offsite Units consumption	MWe	11.4
ELECTRIC POWER CONSUMPTION	**MWe**	**44.0**
NET ELECTRIC POWER OUTPUT	**MWe**	**1036.5**
(Step Up transformer efficiency = 0.997%) (B)	MWe	**1033.4**
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**46.3%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**44.2%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**44.2%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**42.3%**
Fuel Consumption per net power production	**MWth/MWe**	**2.26**
CO_2 emission per net power production	**kg/MWh**	**742.5**

7. Environmental impact

The USC 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 emissions mainly consist 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	3,740,000
Flow, Nm^3/h (1)	2,956,000
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 3 – 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 process plant does not produce significant liquid waste. FGD unit and steam cycle blow-down are 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, and the waste water from WWT (including the eluate from the demineralised water unit).

Table 7 summarises main plant liquid effluent to be discharge to the final destination (e.g. river), and the main unit blowdown to be treated in the WWT in order to recover water and reduce plant raw water make-up.

Table 7. Case 3 – Plant liquid effluent during normal operation

Plant effluent at BL	
Cooling Tower blow-down	375 m^3/h
Waste water from WWT+ eluate from demi plant	8 m^3/h
Waste Water treatment inlet stream	
FGD blow-down	10 m^3/h
Polishing blowdown	5 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 exists, 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. Equipment list

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

wood.	CLIENT: IEAGHG	REVISION	Rev.0	Rev.1	Rev.2	Rev.3	
	LOCATION: The Netherlands	DATE	may-19				
	PROJ. NAME: UPDATE TECHNO-ECONOMIC BENCHMARKS	ISSUED BY	PA				
	CONTRACT N. 1-BD-1046 A	CHECKED BY	NF				
	CASE 3 - SC PC plant without CCS	APPROVED BY	PC				

EQUIPMENT LIST

Units Summary

UNIT 100	**COAL AND ASH STORAGE AND HANDLING**
UNIT 200	**BOILER ISLAND**
UNIT 300	**FGD AND GYPSUM HANDLING PLANT**
UNIT 500	**STEAM CYCLE**
UNIT 600	**$C0_2$ AMINE ABSORPTION**
UNIT 700	**$C0_2$ COMPRESSION**
UNIT 800	**UTILITY AND OFFSITE**

		REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
CLIENT:	IEAGHG	DATE	may-19			
LOCATION:	The Netherlands	ISSUED BY	PA			
PROJ. NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED BY	NF			
CONTRACT N:.	1-BD-1046 A	APPROVED BY	PC			
CASE:	3 - SC PC plant without CCS					

wood.

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:325t/h					
	- Wagon tipper							
	- 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: 9t/h					30 days storage
	- Wagon tipper		Limestone storage volume 6000 m3					
	- Receiving Hopper, vibratory feeder and vet extractor							
	- Conveyor	Belt						
	- Transfer Tower	enclosed						
	- Limestone Storage	Silos						
	- Conveyor	Belt						
	- Limestone Sampling System	Swing Hammer						
	- Separator System	Magnetc Plates						
	- Transfer Tower	enclosed						
	- Conveyor	Belt with tipper						
	- Limestone Bunker							*For daily storage*
	- Filters							
	- Fan							
	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: 29.2 t/h					*14 days storage capacity*
	- Pneumatic conveying system		Fly Ash Storage volume: 14000 m3					
	- Compressors							
	- Filters							
	- Fans							
	GYPSUM SYSTEM							
	Including:		Capacity: 16.2 t/h					
	- Storage unit		Storage volume: 9000 m3					*30 days storage capacity*
	- Conveyors							*1 operating, 1 spare*

CLIENT:	IEAGHG			REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3	wood.
LOCATION:	The Netherlands			DATE	may-19				
PROJ. NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE			ISSUED BY	PA				
CONTRACT N:.	1-BD-1046 A			CHECKED BY	NF				
CASE:	3 - SC PC plant without CCS			APPROVED BY	PC				

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: 2870 t/h main steam production Thermal input: 2443 MWth (HHV) / 2335 MWth (LHV) Main steam condition: 290 bar(a)/600 °C Reheat steam condition: 60 bar(a)/620 °C					Boiler package including: - Coal mill - Fuel Feeding system - One Fired Boiler Furnace -Low NOx burners system including main - Economizers/super heater coils, water wall - Reheating coils - Air pre-heater - Ash collection hoppers - Combustion air fans with electric motor - Ash collection hoppers - Start-up system - Flue gas ducts - Bottom Ash cooling devices
K - 2001	**ID fan**	Axial	Total Flowrate: 2766 x 10^3 Nm3/h Total Vol. Flow: 1072 m3/s Total Power consumption: 10090 kW					
PK - 2002	**Flue gas cleaning system**	ESP						
PK - 2003	**Flue gas stack**	cement stack						
PK - 2004	**Continuous emission monitoring system**							
	SCR SYSTEM - UNIT 2050							
	SCR system Including: - Reactor casing - Catalyst - Bypass system - Ammonia injection equipment - Handling equipment - Control System							

CLIENT:	IEAGHG	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3		
LOCATION:	The Netherlands	DATE	may-19					
PROJ. NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	ISSUED BY	PA					
CONTRACT N:.	1-BD-1046 A	CHECKED BY	NF					
CASE:	3 - SC PC plant without CCS	APPROVED BY	PC					

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: 92.1 %					
	GAS-GAS HEATER							
	Gas-gas heat exchanger		Hot side flowrate: 2766 x10^3 Nm3/h Cold side flowrate: 2857 x10^3 Nm3/h Duty: 42.9 MWth					

CLIENT:	IEAGHG	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3	
LOCATION:	The Netherlands	DATE	may-19				
PROJ. NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	ISSUED BY	PA				
CONTRACT N:.	1-BD-1046 A	CHECKED BY	NF				
CASE:	3 - SC PC plant without CCS	APPROVED BY	PC				

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		1080.5 MWe *HP admission:* *2870 t/h @ 290 bar* *Hot reheat admission:* *2410 t/h @ 60 bar* *LP admission:* *1962 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		1050 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**							
	HEAT EXCHANGERS		**Duty (kW)**		Shell/tube	Shell/tube		
E- 3002	BFW Economiser #1							
E- 3003	BFW Economiser #2							
E- 3003	BFW Economiser #3							
E- 3004	Condensate heater #3							
E- 3005	Condensate heater #4							
	PUMPS		**Q [m³/h] x H [m]**					
P- 3001	BFW pumps	Centrifugal Steam driven	3130 m3/h x 3733 m	35000 kWe equivalent				*One operating*
P- 3002	BFW pump	Centrifugal	40% MCR					*For start-up, electric motor*
P- 3003 A/B	Condensate pump	Centrifugal	2530 m3/h x 171 m	1600				*One operating one spare, electric motor*
	VESSEL							
D- 3001	Dearator	Horizontal						

		REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
CLIENT:	IEAGHG	DATE	may-19			
LOCATION:	The Netherlands	ISSUED BY	PA			
PROJ. NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED BY	NF			
CONTRACT N:.	1-BD-1046 A	APPROVED BY	PC			
CASE:	3 - SC PC plant without CCS					

wood.

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					
	PUMPS		**Q [m^3/h] x H [m]**					
P- 6001 A/B/C/D	Cooling Water Pumps (primary system)	Centrifugal	15000 x 35	1600			superduplex	*Four in operation*
P- 6002 A/B/C/D	Cooling Water Pumps (secondary system)	Centrifugal	5100 x 45	800			superduplex	*Four in operation, one spare*
P- 6003 A/B	Cooling tower make-up pumps	centrifugal	1570 x 31	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							
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	5.5				*One in operation, one spare*
P- 6005 A/B	Raw water pump to FGD (make-up)	centrifugal	95 m3/h x 42 m	18.5				*One in operation, one spare*
	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		120 m3					*24 hour storage*
P- 6006 A/B	Demin water pump	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							
	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	:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO_2 CAPTURE
DOCUMENT NAME	:	REFERENCE CASE 4: USC PC WITH CCS
CONTRACT N°	:	1-BD-1046 A

ISSUED BY	:	P. ANTICO
CHECKED BY	:	N. FERRARI
APPROVED BY	:	P. COTONE

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

GLOSSARY

CCS	Carbon Capture and Storage
NGCC	Natural Gas Combined Cycle
USC PC	Ultrasupercritical Pulverised Coal
FGR	Flue Gas Recirculation
EGR	Exhaust Gas Recirculation
CCU	Carbon Capture Unit
CMC	Ceramic Matrix Composite
ASU	Air Separation Unit
MCFC	Molten Carbonate Fuel Cell
TPC	Total Plant Cost
TIC	Total Installed Cost
MEL	Minimum Environmental Load
GT	Gas Turbine
ST	Steam Turbine

1. Introduction

This chapter of the report includes all technical information relevant to Case 4 and 4.1 of the study, both being a supercritical pulverised coal (SC PC) fired steam plant with amine-based solvent washing for carbon capture, located in the reference location (The Netherlands). The plant is designed to process bituminous Eastern Australian coal, whose characteristic is shown in dedicated section of chapter B, and produce electric power for export to the external grid.

The two cases are based on different capture rate: case 4 is the reference case with 90% CO2 capture, while case 4.1 is based on high capture rate of 99%.

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 D.1 of this report).

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

1.1. Process unit arrangement

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

Table 1. Cases 4 – 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%
4000	CO_2 Amine Absorption Unit	

Unit	Description	Trains
	Flue gas quencher	2 x 50%
	Absorber	2 x 50%
	Regenerator	2 x 50%
5000	CO_2 compression	2 x 50%
6000	Utility and Offsite	N/A
	Natural draft cooling tower	2 x 50%

1.2. Capture rate selection

This chapter summarises the performance of the SC-PC plant at the two different capture rates.

The reference case 4 is based on 90% capture rate in order to provide the update of the benchmark case of the previous IEAGHG report 2018/4 "*Effect of plant location on CO_2 capture*".

The high capture case 4.1 is developed as recent researches have highlighted that 90% capture rate will not allow meeting the < 2°C temperature increase target and indicates that targeting 98-99% CO_2 capture will would not dramatically increase the cost of capture providing the capture unit is originally designed for this capture rate.

The additional cost for capture is related to the additional investment cost (e.g. larger regenerator, increased solvent circulation flowrate, increased reboiler surface, CO_2 compressor capacity) as well as to the increased energy demand in terms of the additional steam required by reboiler and the additional power consumptions of the capture and compression unit.

The table below reports the steam consumption and the regenerator size at different capture rate. As also shown the graph, steam consumption (and also regenerator diameter) increases smoothly even above 98.5%.

Capture rate	Reboiler duty	Stripper Diameter
90% capture	-	-
98.5% capture	+ 21.3 %	+10 %
99% capture	+ 25.9 %	+11.7%

Based on these results, 99% capture rate is selected for the development of the high capture case for this study (namely case 4.1).

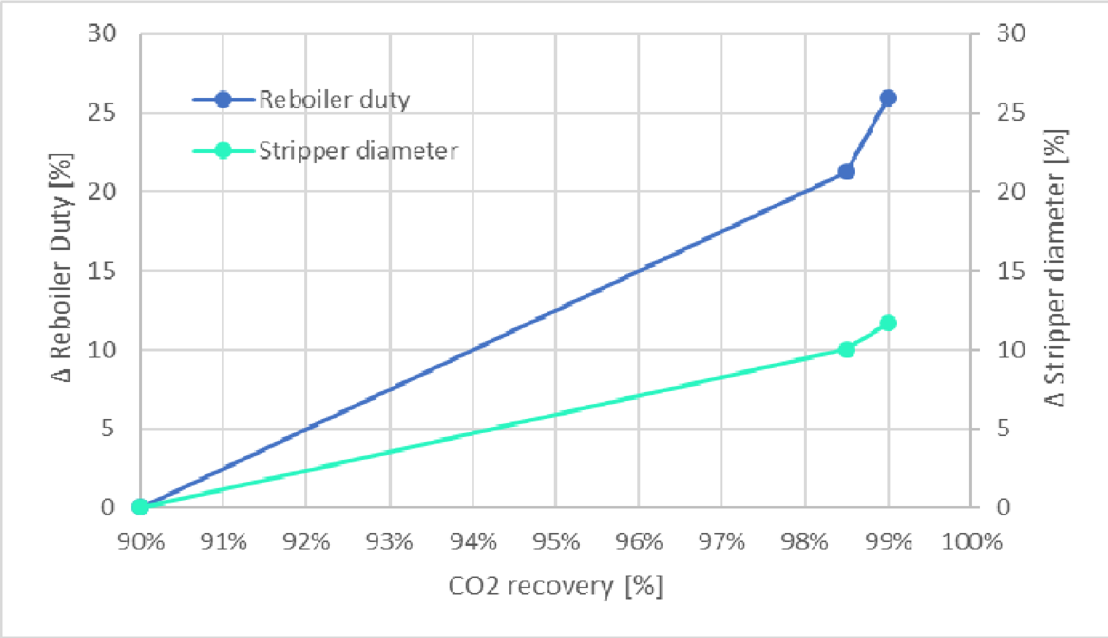


Figure 1. Reboiler duty and stripper diameter vs. capture rate

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 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.

2.3. 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 D, 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 the plants 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.

Wet scrubbing technology is selected for the development of this study case. Technical information relevant to this system is reported in chapter D, section 2.4.1.

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 D, section 2.8.2.

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 D, 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.

2.7. Unit 5000 – CO_2 Compression and drying

The process description of CO_2 Compression and drying package is reported in chapter D, section 2.7.

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.

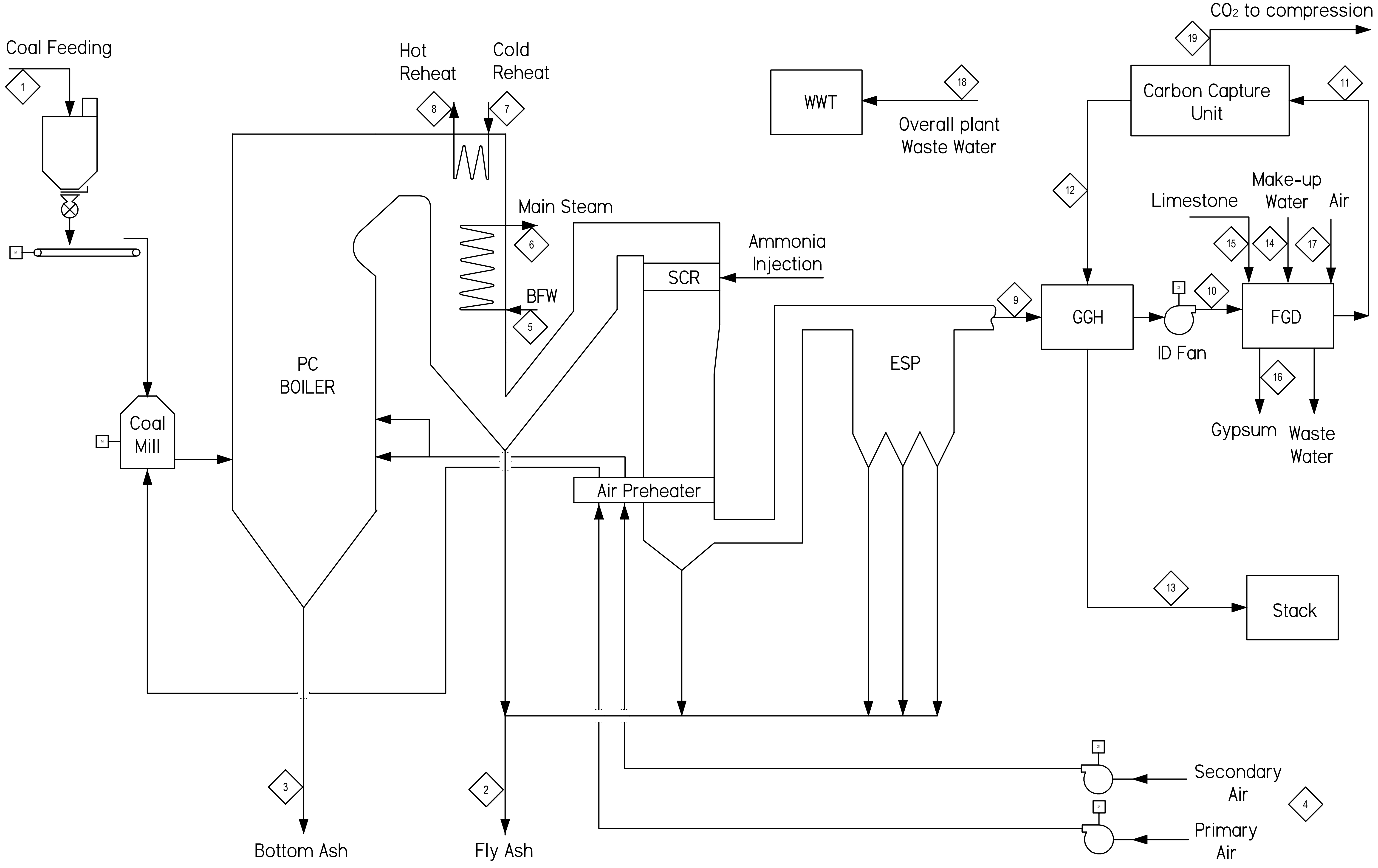
The main utility units include:

- Cooling Water system, based on two natural draft cooling towers, using fresh water as make-up water.
- Raw water system;
- Demineralised water plant;
- Firefighting system;
- Instrument and Plant air;
- Waste water treatment.

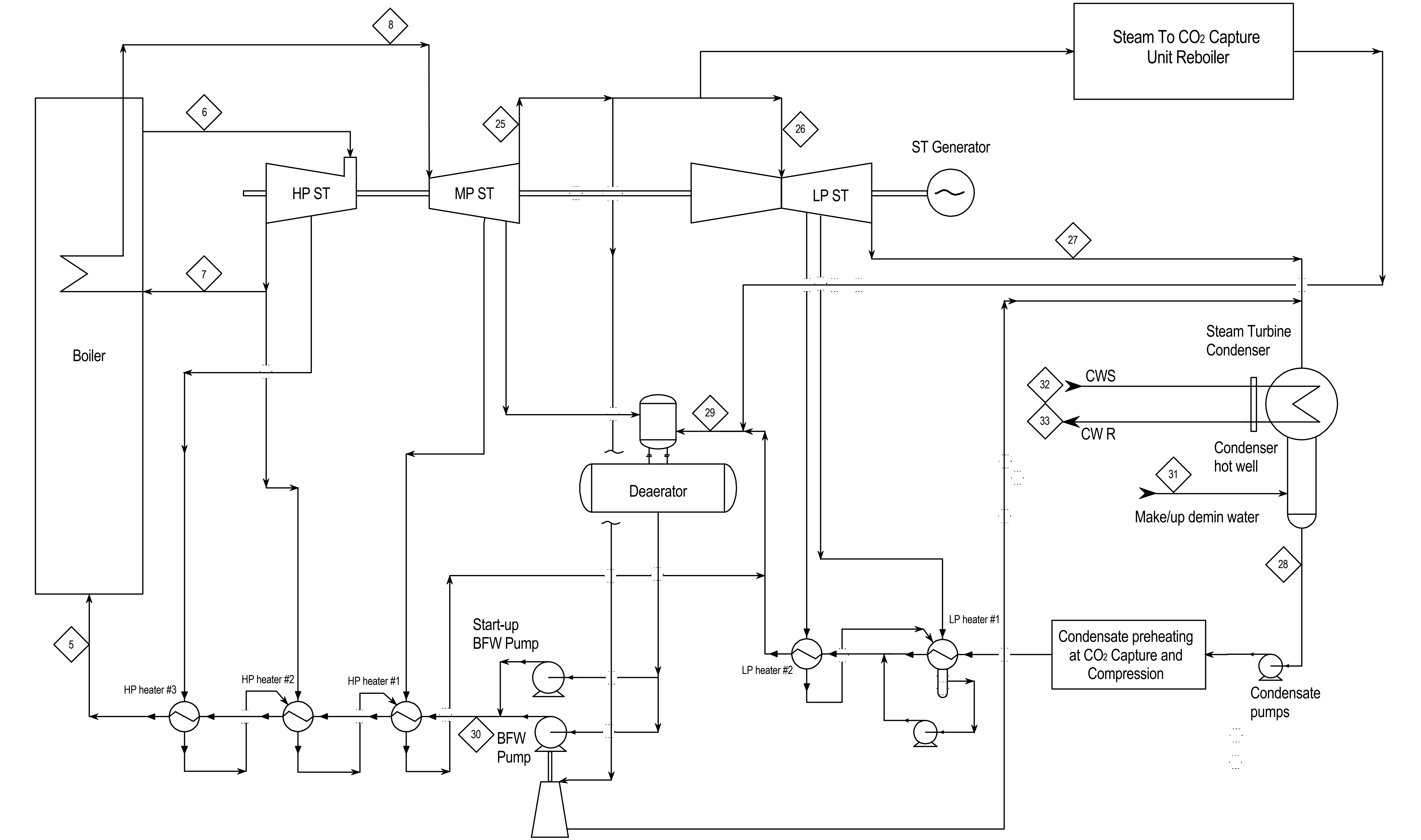
Process descriptions of the above systems are enclosed in chapter D, section 2.9.

3. Process Flow Diagrams

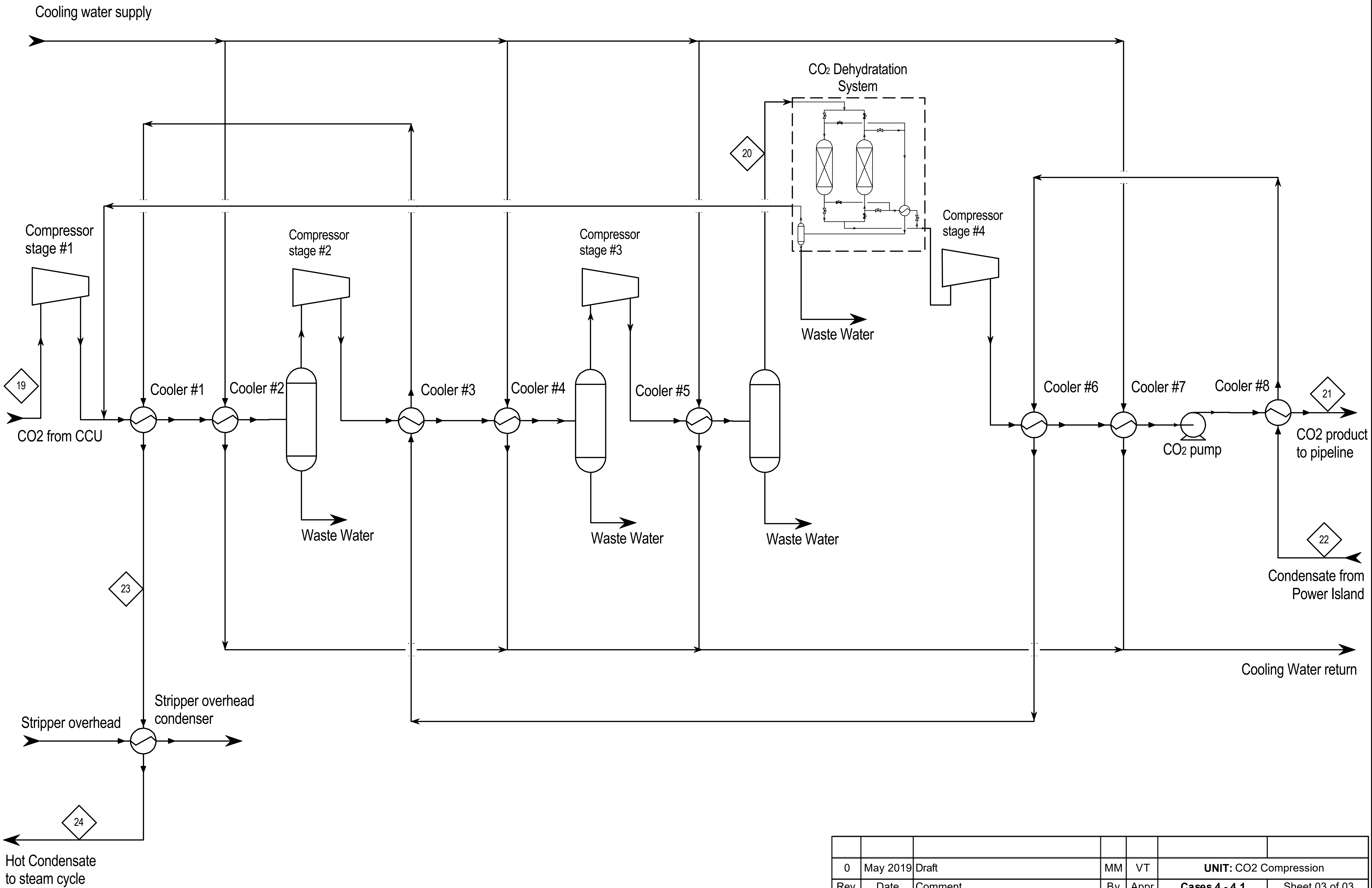
Simplified Process Flow Diagrams of this case are attached to this section. Stream numbers refer to the heat and material balance shown in the next section.



0	May 2019	Draft	MM	VT	**UNIT:** Boiler Island	
Rev.	Date	Comment	By	Appr	**Cases 4 - 4.1**	Sheet 01 of 03



0	May 2019	Draft	MM	VT	**UNIT:** Steam Cycle	
Rev.	Date	Comment	By	Appr	**Cases 4 - 4.1**	Sheet 02 of 03



0	May 2019	Draft	MM	VT	**UNIT:** CO2 Compression	
Rev.	Date	Comment	By	Appr	**Cases 4 - 4.1**	Sheet 03 of 03

4. Heat and Material Balance

Heat & Material Balances here below reported make reference to the Process Flow Diagrams of section 3.

	HEAT AND MATERIAL BALANCE		REVISION	0	1
wood.	CLIENT :	IEAGHG	PREP.	PA	
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	NF	
	PROJECT NO:	1-BD-1046 A	APPROVED	PC	
	CASE:	Case 4 - SC PC with CCS (90% capture rate)	DATE	May 2019	

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 Steam Cycle	Hot Reheat to Steam Turbine	
Temperature, °C	AMB	AMB	AMB	9	290	600	355	620	
Pressure (bar)	ATM	ATM	ATM	1.01	340	290	63	61	
TOTAL FLOW	Solid	Solid	Solid						
Mass flow (kg/h)	325,000	29,200	12,500	3,383,300	2,860,000	2,860,000	2,444,800	2,444,800	
Molar flow (kmol/h)				117,260	158,700	158,700	135,700	135,700	
LIQUID PHASE									
Mass flow (kg/h)					2,860,000				
GASEOUS PHASE									
Mass flow (kg/h)				3,383,300		2,860,000	2,444,800	2,444,800	
Molar flow (kmol/h)				117,260		158,700	135,700	135,700	
MW (kg/kmol)				28.85		18.02	18.02	18.02	
Composition (vol %)	% wt (AR)								
H_2O	C: 64.60%			1.05%	100.00%	100.00%	100.00%	100.00%	
CO_2	H: 4.38%			0.03%	0.00%	0.00%	0.00%	0.00%	
N_2	S: 0.86%			77.27%	0.00%	0.00%	0.00%	0.00%	
Ar	O: 7.02%			0.92%	0.00%	0.00%	0.00%	0.00%	
O_2	N: 1.41%			20.73%	0.00%	0.00%	0.00%	0.00%	
SO_2	Ash: 12.20%			0.00%	0.00%	0.00%	0.00%	0.00%	
Total	Moisture: 9.50%			100.00%	100.00%	100.00%	100.00%	100.00%	
Emissions (note 1)									
SO_x	-	-	-	-	-	-	-	-	-
NO_x	-	-	-	-	-	-	-	-	-
Particulate	-	-	-	-	-	-	-	-	-

Note 1: mg/Nm^3, dry basis 6% vol O_2

	HEAT AND MATERIAL BALANCE		REVISION	0	1
wood.	CLIENT :	IEAGHG	PREP.	PA	
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	NF	
	PROJECT NO:	1-BD-1046 A	APPROVED	PC	
	CASE:	Case 4 - SC PC with CCS (90% capture rate)	DATE	May 2019	

HEAT AND MATERIAL BALANCE
UNIT 2100 - FLUE GAS DESULPHURIZATION

STREAM	9	10	11	12	13	14	15	16	17	
	Flue gas from ESP to GGH	Flue gas to FGD	Treated gas from FGD to CCU	Treated gas from CCU to GGH	Treated gas to stack	Make up water to FGD	Limestone to FGD	Product Gypsum	Oxidation Air	
Temperature, °C	132	90	47	43	95	AMB	AMB	AMB	AMB	
Pressure (bar)	-	-	-	-	-	ATM	ATM	ATM	ATM	
TOTAL FLOW							Solid	Solid		
Mass flow (kg/h)	3,666,800	3,666,800	3,741,000	2,965,000	2,965,000	85,000	9,200	16,900	9,100	
Molar flow (kmol/h)	123,400	123,400	127,470	107,110	107,110				316	
LIQUID PHASE										
Mass flow (kg/h)						85,000				
GASEOUS PHASE										
Mass flow (kg/h)	3,666,800	3,666,800	3,741,000	2,965,000	2,965,000				9,100	
Molar flow (kmol/h)	123,400	123,400	127,470	107,110	107,110				316	
MW (kg/kmol)	29.71	29.71	29.35	27.68	27.68				28.85	
Composition (vol %)										
H_2O	8.16%	8.16%	10.88%	8.62%	8.62%				1.11%	
CO_2	14.06%	14.06%	13.68%	1.59%	1.59%				0.03%	
N_2	73.55%	73.55%	71.40%	84.98%	84.98%				77.22%	
Ar	0.87%	0.87%	0.84%	1.00%	1.00%				0.92%	
O_2	3.28%	3.28%	3.20%	3.81%	3.81%				20.72%	
SO_2	0.07%	0.07%	0.00%	0.00%	0.00%				0.00%	
Total	100.00%	100.00%	100.00%	100.00%	100.00%				100.00%	
Emissions (note 1)										
SO_x	1,897	1,897	SO2: 10 ppm SO3: 13 ppm	< 1 ppm	< 1 ppm	-	-	-	-	
NO_x	130	130	130	150	150	-	-	-	-	
Particulate	7	7	7	15	15	-	-	-	-	

Note 1: mg/Nm^3, dry basis 6% vol O_2

wood.	HEAT AND MATERIAL BALANCE		REVISION	0
	CLIENT :	IEAGHG	PREP.	PA
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	NF
	PROJECT NO:	1-BD-1046 A	APPROVED	PC
	CASE:	Case 4 - SC PC with CCS (90% capture rate)	DATE	May 2019

HEAT AND MATERIAL BALANCE
UNIT 5000 - CO_2 COMPRESSION

STREAM	19	20	21	22	23	24
	CO_2 to compression	CO_2 to drying package	CO_2 to long term storage	Condensate from power island	Preheated condensate to stripper condenser	Preheated condensate to power island
Temperature, °C	30	26	30	40	60	89
Pressure (bar)	2	30.3	110	14.5	14	13.5
TOTAL FLOW						
Mass flow (kg/h)	698,680	770,200	691,000	1,310,000	1,310,000	1,310,000
Molar flow (kmol/h)	16,075	17,520	15,700	72,700	72,700	72,700
LIQUID PHASE			Supercritical state			
Mass flow (kg/h)			691,000	1,310,000	1,310,000	1,310,000
GASEOUS PHASE						
Mass flow (kg/h)	698,680	770,200				
Molar flow (kmol/h)	16,075	17,520				
MW (kg/kmol)	43.46	43.96				
Composition (vol %)						
H_2O	2.10%	0.18%	0.00%	100.00%	100.00%	100.00%
CO_2	97.88%	99.80%	100.00%	0.00%	0.00%	0.00%
N_2	0.02%	0.02%	0.00%	0.00%	0.00%	0.00%
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
O_2	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%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Emissions (note 1)						
SO_x	-	-	-	-	-	-
NO_x	-	-	-	-	-	-
Particulate	-	-	-	-	-	-

Note 1: mg/Nm^3, dry basis 6% vol O_2

wood.	HEAT AND MATERIAL BALANCE		REVISION	0	1
	CLIENT :	IEAGHG	**PREP.**	PA	
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**CHECKED**	NF	
	PROJECT NO:	1-BD-1046 A	**APPROVED**	PC	
	CASE:	Case 4 - SC PC with CCS (90% capture rate)	**DATE**	May 2019	

HEAT AND MATERIAL BALANCE
UNIT 3000 - STEAM CYCLE

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Enthalpy kJ/kg
5	BFW to Boiler	2860	290	340	1278
6	HP Steam to Steam Turbine	2860	600	290	3456
7	Cold reheat to Boiler	2445	355	63	3050
8	Hot reheat to Steam Turbine	2445	620	61	3705
18	MP Steam Turbine exhaust	2099	275	6	3010
19	Steam to LP Steam Turbine	1237	275	5.0	3013
20	LP Steam Turbine exhaust	1115	29	0.04	2273
21	Condensate	1303	29	0.04	121
22	LP preheated Condensate	2903	143	9.5	602
23	BFW to preheating	2860	156	340	679
17	Make up water	5	9	0.04	38
24	Cooling water inlet	60400	15	4.0	63
25	Cooling water outlet	60400	26	3.5	109

wood.	HEAT AND MATERIAL BALANCE		REVISION	0	1
	CLIENT :	IEAGHG	**PREP.**	PA	
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**CHECKED**	NF	
	PROJECT NO:	1-BD-1046 A	**APPROVED**	PC	
	CASE:	Case 4.1 - SC PC with CCS (99% capture rate)	**DATE**	May 2019	

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 Steam Cycle	Hot Reheat to Steam Turbine	
Temperature, °C	AMB	AMB	AMB	9	290	600	355	620	
Pressure (bar)	ATM	ATM	ATM	1.01	340	290	63	61	
TOTAL FLOW	Solid	Solid	Solid						
Mass flow (kg/h)	325,000	29,200	12,500	3,383,300	2,860,000	2,860,000	2,444,800	2,444,800	
Molar flow (kmol/h)				117,260	158,700	158,700	135,700	135,700	
LIQUID PHASE									
Mass flow (kg/h)					2,860,000				
GASEOUS PHASE									
Mass flow (kg/h)				3,383,300		2,860,000	2,444,800	2,444,800	
Molar flow (kmol/h)				117,260		158,700	135,700	135,700	
MW (kg/kmol)				28.85		18.02	18.02	18.02	
Composition (vol %)	% wt (AR)								
H_2O	C: 64.60%			1.05%	100.00%	100.00%	100.00%	100.00%	
CO_2	H: 4.38%			0.03%	0.00%	0.00%	0.00%	0.00%	
N_2	S: 0.86%			77.27%	0.00%	0.00%	0.00%	0.00%	
Ar	O: 7.02%			0.92%	0.00%	0.00%	0.00%	0.00%	
O_2	N: 1.41%			20.73%	0.00%	0.00%	0.00%	0.00%	
SO_2	Ash: 12.20%			0.00%	0.00%	0.00%	0.00%	0.00%	
Total	Moisture: 9.50%			100.00%	100.00%	100.00%	100.00%	100.00%	
Emissions (note 1)									
SO_x	-	-	-	-	-	-	-	-	-
NO_x	-	-	-	-	-	-	-	-	-
Particulate	-	-	-	-	-	-	-	-	-

Note 1: mg/Nm^3, dry basis 6% vol O_2

wood.	HEAT AND MATERIAL BALANCE		REVISION	0	1
	CLIENT :	IEAGHG	PREP.	PA	
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	NF	
	PROJECT NO:	1-BD-1046 A	APPROVED	PC	
	CASE:	Case 4.1 - SC PC with CCS (99% capture rate)	DATE	May 2019	

HEAT AND MATERIAL BALANCE
UNIT 2100 - FLUE GAS DESULPHURIZATION

STREAM	9	10	11	12	13	14	15	16	17	
	Flue gas from ESP to GGH	Flue gas to FGD	Treated gas from FGD to CCU	Treated gas from CCU to GGH	Treated gas to stack	Make up water to FGD	Limestone to FGD	Product Gypsum	Oxidation Air	
Temperature, °C	132	90	47	43	98	AMB	AMB	AMB	AMB	
Pressure (bar)	-	-	-	-	-	ATM	ATM	ATM	ATM	
TOTAL FLOW							Solid	Solid		
Mass flow (kg/h)	3,666,800	3,666,800	3,741,000	2,805,500	2,805,500	85,000	9,200	16,900	9,100	
Molar flow (kmol/h)	123,400	123,400	127,470	100,460	100,460				316	
LIQUID PHASE										
Mass flow (kg/h)						85,000				
GASEOUS PHASE										
Mass flow (kg/h)	3,666,800	3,666,800	3,741,000	2,805,500	2,805,500				9,100	
Molar flow (kmol/h)	123,400	123,400	127,470	100,460	100,460				316	
MW (kg/kmol)	29.71	29.71	29.35	27.93	27.93				28.85	
Composition (vol %)										
H_2O	8.16%	8.16%	10.88%	4.10%	4.10%				1.11%	
CO_2	14.06%	14.06%	13.68%	0.17%	0.17%				0.03%	
N_2	73.55%	73.55%	71.40%	90.60%	90.60%				77.22%	
Ar	0.87%	0.87%	0.84%	1.07%	1.07%				0.92%	
O_2	3.28%	3.28%	3.20%	4.06%	4.06%				20.72%	
SO_2	0.07%	0.07%	0.00%	0.00%	0.00%				0.00%	
Total	100.00%	100.00%	100.00%	100.00%	100.00%				100.00%	
Emissions (note 1)										
SO_x	1,897	1,897	SO2: 10 ppm SO3: 13 ppm	< 1 ppm	< 1 ppm	-	-	-	-	
NO_x	130	130	130	150	150	-	-	-	-	
Particulate	7	7	7	15	15	-	-	-	-	

Note 1: mg/Nm^3, dry basis 6% vol O_2

wood.	HEAT AND MATERIAL BALANCE		REVISION	0
	CLIENT :	IEAGHG	PREP.	PA
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	NF
	PROJECT NO:	1-BD-1046 A	APPROVED	PC
	CASE:	Case 4.1 - SC PC with CCS (99% capture rate)	DATE	May 2019

HEAT AND MATERIAL BALANCE
UNIT 5000 - CO_2 COMPRESSION

STREAM	19	20	21	22	23	24
	CO_2 to compression	CO_2 to drying package	CO_2 to long term storage	Condensate from power island	Preheated condensate to stripper condenser	Preheated condensate to power island
Temperature, °C	30	26	30	40	60	89
Pressure (bar)	2	30.3	110	14.5	14	13.5
TOTAL FLOW						
Mass flow (kg/h)	766,500	679,163	759,600	1,150,000	1,150,000	1,150,000
Molar flow (kmol/h)	17,634	15,449	17,260	63,900	63,900	63,900
LIQUID PHASE			Supercritical state			
Mass flow (kg/h)			759,600	1,150,000	1,150,000	1,150,000
GASEOUS PHASE						
Mass flow (kg/h)	766,500	679,163				
Molar flow (kmol/h)	17,634	15,449				
MW (kg/kmol)	43.46	43.96				
Composition (vol %)						
H_2O	2.10%	0.18%	0.00%	100.00%	100.00%	100.00%
CO_2	97.88%	99.80%	100.00%	0.00%	0.00%	0.00%
N_2	0.02%	0.02%	0.00%	0.00%	0.00%	0.00%
Ar	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
O_2	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%
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
Emissions (note 1)						
SO_x	-	-	-	-	-	-
NO_x	-	-	-	-	-	-
Particulate	-	-	-	-	-	-

Note 1: mg/Nm^3, dry basis 6% vol O_2

	HEAT AND MATERIAL BALANCE		REVISION	0	1
	CLIENT :	IEAGHG	PREP.	PA	
	PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	CHECKED	NF	
	PROJECT NO:	1-BD-1046 A	APPROVED	PC	
	CASE:	Case 4.1 - SC PC with CCS (99% capture rate)	DATE	May 2019	

HEAT AND MATERIAL BALANCE
UNIT 3000 - STEAM CYCLE

Stream	Description	Flowrate t/h	Temperature °C	Pressure bar a	Enthalpy kJ/kg
5	BFW to Boiler	2860	290	340	1278
6	HP Steam to Steam Turbine	2860	600	290	3456
7	Cold reheat to Boiler	2445	355	63	3050
8	Hot reheat to Steam Turbine	2445	620	61	3705
18	MP Steam Turbine exhaust	2108	275	6	3010
19	Steam to LP Steam Turbine	1038	275	5.0	3013
20	LP Steam Turbine exhaust	960	29	0.04	2273
21	Condensate	1149	29	0.04	121
22	LP preheated Condensate	2938	145	9.5	611
23	BFW to preheating	2860	156	340	679
17	Make up water	5	9	0.04	38
24	Cooling water inlet	53100	15	4.0	63
25	Cooling water outlet	53100	26	3.5	109

5. Utility and chemicals consumption

Main utility consumption of the process and utility units is reported in the following tables.

Table 2. Cases 4 – Water consumption summary

CLIENT:	IEA GHG	REVISION	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	DATE	may-19
PROJECT No. :	1-BD-1046 A	MADE BY	PA
LOCATION :	Netherlands	APPROVED BY	NF

SC PC Plant with carbon capture Case 4
90% CO2 rec.

WATER CONSUMPTION

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Primary Cooling Water System [t/h]	Secondary Cooling Water System [t/h]
1000	FEEDSTOCK AND SOLID HANDLING				
	Solid Receiving, Handling and storage				
2000	BOILER ISLAND and FLUE GAS TREATMENT				
	Boiler island				
	Flue Gas Desulphurization (FGD)	85			
3000	POWER ISLAND (Steam Turbine)				
	Steam Turbine and Auxiliaries		5		4430
	Condenser			60400	
	CO_2 CAPTURE UNIT				
4000	CO_2 capture unit		2		53080
5000	CO_2 compression				
6000	UTILITY and OFFSITE UNITS				
	Cooling Water System	2180			
	Demineralized water unit	10	-7		
	Waste Water Treatment and Condensate Recovery	-90			
	Balance of plant				100
	BALANCE	2185	0	60400	57610

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

Table 3. Cases 4.1 – Water consumption summary

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**DATE**	may-19
PROJECT No. :	1-BD-1046 A	**MADE BY**	PA
LOCATION :	Netherlands	**APPROVED BY**	NF

SC PC Plant with carbon capure Case 4.1
99% CO2 rec.

WATER CONSUMPTION

UNIT	DESCRIPTION UNIT	Raw Water [t/h]	Demi Water [t/h]	Primary Cooling Water System [t/h]	Secondary Cooling Water System [t/h]
1000	**FEEDSTOCK AND SOLID HANDLING**				
	Solid Receiving, Handling and storage				
2000	**BOILER ISLAND and FLUE GAS TREATMENT**				
	Boiler island				
	Flue Gas Desulphurization (FGD)	**85**			
3000	**POWER ISLAND (Steam Turbine)**				
	Steam Turbine and Auxiliaries		**5**		**4280**
	Condenser			**53200**	
	CO_2 CAPTURE UNIT				
4000	CO_2 capture unit		**2**		**65060**
5000	CO_2 compression				
6000	**UTILITY and OFFSITE UNITS**				
	Cooling Water System	**2250**			
	Demineralized water unit	**10**	**-7**		
	Waste Water Treatment and Condensate Recovery	**-90**			
	Balance of plant				**100**
	BALANCE	**2255**	**0**	**53200**	**69440**

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

Table 4. Cases 4 & 4.1 – Electrical consumption summary

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**DATE**	may-19
PROJECT No. :	1-BD-1046 A	**MADE BY**	PA
LOCATION :	Netherlands	**APPROVED BY**	NF

ELECTRICAL CONSUMPTION

UNIT	DESCRIPTION UNIT	Absorbed Electric Power [kW] Case 4 90% CO2 rec.	Absorbed Electric Power [kW] Case 4.1 99% CO2 rec.
1000	**FEEDSTOCK AND SOLID HANDLING**		
	Solid Receiving, Handling and storage	**3350**	**3350**
2000	**BOILER ISLAND and FLUE GAS TREATMENT**		
	Boiler island (including ID fan)	**22370**	**22370**
	Flue Gas Desulphurization (FGD)	**4000**	**4000**
3000	**POWER ISLAND (Steam Turbine)**		
	Steam Turbine Auxiliaries	**3300**	**3300**
	Condensate and feedwater system	**920**	**840**
	Miscellanea	**600**	**600**
	CO_2 CAPTURE UNIT		
4000	CO_2 capture unit	**82230**	**91680**
5000	CO_2 Compression		
6000	**UTILITY and OFFSITE UNITS**		
	Cooling Water System	**14980**	**15890**
	Balance of plant	**1440**	**1440**
	BALANCE	**133,190**	**143,470**

Table 5. Cases 4 & 4.1 – Sorbent and chemicals consumption

	Consumption
Limestone injection to the FGD	9.2 t/h
Ammonia solution to SCR [(1)]	4.7 t/h
NaOH to CO_2 capture unit [(2)]	250 kg/h

(1) 25%wt ammonia solution

(2) 50%wt. Amec Foster Wheeler Italiana estimate

6. Overall Performance

The following table shows the overall performance of Cases 4 and 4.1.

CLIENT:	IEA GHG	**REVISION**	0
PROJECT NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	**DATE**	may-19
PROJECT No. :	1-BD-1046 A	**MADE BY**	PA
LOCATION :	Netherlands	**APPROVED BY**	NF

OVERALL PERFORMANCES

		Case 4 90% CO2 rec.	Case 4.1 99% CO2 rec.
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	961.6	929.2
GROSS ELECTRIC POWER OUTPUT (C)	**MWe**	**961.6**	**929.2**
Feedstock and solids handling	MWe	3.4	3.4
Boiler Island, including FGD	MWe	26.4	26.4
Power Islands consumption	MWe	4.8	4.7
Utility & Offsite Units consumption	MWe	16.4	17.3
CO2 Capture and compression unit	MWe	82.2	91.7
ELECTRIC POWER CONSUMPTION	**MWe**	**133.2**	**143.5**
NET ELECTRIC POWER OUTPUT	**MWe**	**828.4**	**785.7**
(Step Up transformer efficiency = 0.997%) (B)	MWe	**825.9**	**783.4**
Gross electrical efficiency (C/A x 100) (based on LHV)	**%**	**41.2%**	**39.8%**
Net electrical efficiency (B/A x 100) (based on LHV)	**%**	**35.4%**	**33.5%**
Gross electrical efficiency (C/A' x 100) (based on HHV)	**%**	**39.4%**	**38.0%**
Net electrical efficiency (B/A' x 100) (based on HHV)	**%**	**33.8%**	**32.1%**
Fuel Consumption per net power production	**MWth/MWe**	**2.83**	**2.98**
CO_2 emission per net power production	**kg/MWh**	**92.6**	**9.8**

The following table shows the overall CO_2 balance and removal efficiency of Cases 4 & 4.1 .

CO_2 removal efficiency	**Equivalent flow of CO_2**	
	Case 4 90% CO2 rec.	Case 4.1 99% CO2 rec.
	kmol/h	kmol/h
INPUT		
FUEL CARBON CONTENT (A)	17495	17495
FROM the DeSOX reaction + CO_2 in air (B)	109	109
OUTPUT		
Carbon losses (D)	166	166
CO_2 flue gas content	17438	17438
Total to storage (C)	15700	17264
Emission	1738	174
TOTAL	17604	17604
Overall Carbon Capture, % ((C+D)/(A+B))	90	99

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 6 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 7 these emissions mainly consist of air containing particulate.

Table 6. Cases 4 & 4.1 – Plant emission during normal operation

Flue gas to stack	**Case 4**	**Case 4.1**
Emission type	Continuous	Continuous
Conditions		
Wet gas flowrate, kg/h	2,965,000	2,805,500
Flow, Nm^3/h (1)	2,515,000	2,517,000
Temperature, °C	95	95
Composition	(% vol)	(% vol)
Ar	1.00	1.00
N_2	84.98	90.60
O_2	3.80	4.06
CO_2	1.59	0.17
H_2O	8.62	4.10
NOx	< 50 mg/Nm^3 (1)	< 50 mg/Nm^3 (1)
SOx	< 1 ppmv	< 1 ppmv
Particulate	< 15 mg/Nm^3 (1)	< 15 mg/Nm^3 (1)

(1) Dry gas, O_2 content 6% vol.

Table 7. Cases 4 – 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 process plant does not produce significant liquid waste. Plant blow-downs (e.g. FGD, CO_2 capture and compression unit, steam cycle) are treated to recover water, so main liquid effluent is cooling tower continuous blow-down, necessary to prevent precipitation of dissolved solids, and the waste water from WWT (including the eluate from the demineralised water unit).

Table 8 summarises main plant liquid effluent to be discharge to the final destination (e.g. river), and the main unit blowdown to be treated in the WWT in order to recover water and reduce plant raw water make-up.

Table 8. Cases 4 – Plant liquid effluent during normal operation

Plant effluent at BL	**Case 4**	**Case 4.1**
Cooling Tower blow-down	520 m^3/h	540 m^3/h
Waste water from WWT + eluate from demi plant	8 m^3/h	8 m^3/h
Waste Water treatment inlet stream		
CO_2 capture unit blow-down (*)	82 m^3/h	82 m^3/h
FGD blow-down	10 m^3/h	10 m^3/h
Polishing blowdown	5 m^3/h	5 m^3/h

(*) Net blowdown, already reduced by the part of the treated water recycled back to the absorber. Separated figure not shown due to confidentiality issues

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 exists, 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. Equipment list

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

wood.	CLIENT: IEAGHG	REVISION	Rev.0	Rev.1	Rev.2	Rev.3	
	LOCATION: The Netherlands	DATE	may-18				
	PROJ. NAME: UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	ISSUED BY	PA				
	CONTRACT N. 1-BD-1046 A	CHECKED BY	NF				
	CASE 4 - SC PC with carbon capture	APPROVED BY	PC				

EQUIPMENT LIST

Units Summary

UNIT 100	**COAL AND ASH STORAGE AND HANDLING**
UNIT 200	**BOILER ISLAND**
UNIT 300	**FGD AND GYPSUM HANDLING PLANT**
UNIT 500	**STEAM CYCLE**
UNIT 600	**$C0_2$ AMINE ABSORPTION**
UNIT 700	**$C0_2$ COMPRESSION**
UNIT 800	**UTILITY AND OFFSITE**

CLIENT:	IEAGHG	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3
LOCATION:	The Netherlands	DATE	may-18			
PROJ. NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	ISSUED BY	PA			
CONTRACT N:.	1-BD-1046 A	CHECKED BY	NF			
CASE:	4 - SC PC with carbon capture	APPROVED BY	PC			

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:325t/h					
	- Wagon tipper							
	- 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: 9.2t/h					30 days storage capacity
	- Wagon tipper		Limestone storage volume 6100 m3					
	- Receiving Hopper, vibratory feeder and vet extractor							
	- Conveyor	Belt						
	- Transfer Tower	enclosed						
	- Limestone Storage	Silos						
	- Conveyor	Belt						
	- Limestone Sampling System	Swing Hammer						
	- Separator System	Magnetc Plates						
	- Transfer Tower	enclosed						
	- Conveyor	Belt with tipper						
	- Limestone Bunker							*For daily storage*
	- Filters							
	- Fan							
	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: 29.2 t/h					*14 days storage capacity*
	- Pneumatic conveying system		Fly Ash Storage volume: 14000 m3					
	- Compressors							
	- Filters							
	- Fans							
	GYPSUM SYSTEM							
	Including:		Capacity: 16.9 t/h					
	- Storage unit		Storage volume: 9360 m3					*30 days storage capacity*
	- Conveyors							*1 operating, 1 spare*

CLIENT:	IEAGHG	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3	wood.
LOCATION:	The Netherlands	DATE	may-18				
PROJ. NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	ISSUED BY	PA				
CONTRACT N:.	1-BD-1046 A	CHECKED BY	NF				
CASE:	4 - SC PC with carbon capture	APPROVED BY	PC				

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: 2860 t/h main steam production Thermal input: 2443 MWth (HHV) / 2335 MWth (LHV) Main steam condition: 290 bar(a)/600 °C Reheat steam condition: 60 bar(a)/620 °C					Boiler package including: - Coal mill - Fuel Feeding system - One Fired Boiler Furnace -Low NOx burners system including main - Economizers/super heater coils, water wall - Reheating coils - Air pre-heater - Ash collection hoppers - Combustion air fans with electric motor - Ash collection hoppers - Start-up system - Flue gas ducts - Bottom Ash cooling devices
K - 2001	**ID fan**	Axial	Total Flowrate: 2766 x 10^3 Nm3/h Total Vol. Flow: 1072 m3/h Total Power consumption: 10530 kW					
PK - 2002	**Flue gas cleaning system**	ESP						
PK - 2003	**Flue gas stack**	cement stack						
PK - 2004	**Continuous emission monitoring system**							
	SCR SYSTEM - UNIT 2050							
	SCR system Including: - Reactor casing - Catalyst - Bypass system - Ammonia injection equipment - Handling equipment - Control System							

CLIENT: IEAGHG			REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3	wood.
LOCATION: The Netherlands			DATE	may-18				
PROJ. NAME: UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE			ISSUED BY	PA				
CONTRACT N:. 1-BD-1046 A			CHECKED BY	NF				
CASE: 4 - SC PC with carbon capture			APPROVED BY	PC				

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					

CLIENT:	IEAGHG	REVISION	Rev.: Draft	Rev.: 1	Rev.2	Rev.3	wood.
LOCATION:	The Netherlands	DATE	may-18				
PROJ. NAME:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO2 CAPTURE	ISSUED BY	PA				
CONTRACT N:.	1-BD-1046 A	CHECKED BY	NF				
CASE:	4 - SC PC with carbon capture	APPROVED BY	PC				

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		962 MWe *HP admission:* *2860 t/h @ 290 bar* *Hot reheat admission:* *2445 t/h @ 60 bar* *LP admission:* *1237 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		771 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**							
	HEAT EXCHANGERS		**Duty (kW)**		Shell/tube	Shell/tube		
E- 3002	BFW Economiser #1							
E- 3003	BFW Economiser #2							
E- 3003	BFW Economiser #3							
E- 3004	Condensate heater #3							
E- 3005	Condensate heater #4							
	PUMPS		**Q [m^3/h] x H [m]**					
P- 3001	BFW pumps	Centrifugal Steam driven	3119 m3/h x 3733 m	36000 kWe equivalent				*One operating*
P- 3002	BFW pump	Centrifugal	40% MCR					*For start-up, electric motor*
P- 3003	BFW to desuperheater pump	Centrifugal	97 m3/h x 42 m	18.5				*One operating, electric motor*
P- 3004 A/B	Condensate pump	Centrifugal	1710 m3/h x 170 m	1120				*One operating one spare, electric motor*
	VESSEL							
D- 3001	Dearator	Horizontal						

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CASE:	4 - SC PC with carbon capture	APPROVED BY	PC				

EQUIPMENT LIST
Unit 4000 - CO2 Capture Unit

	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: 1428500 Nm3/h CO2 product: 180000 Nm3/h; 98% purity Treated gas florate: 1200000 Nm3/h CO2 capture rate: 90 %					2 x 50%
	PUMPS							
	For each train:							
K001	Flue gas Blower							
P001-A/B	Prescrubber water circulation pumps							
P002-A/B	Prescrubber polishing pumps							
P003-A/B	Absorber intercoolers pumps							
P004-A/B	Wash water pumps							
P005-A/B	Rich amine pumps							
P006-A/B	Stripper reflux pumps							
P007-A/B	Lean amine pumps							
P008-A/B	Amine feed pump							
P009	Make up amine pump							
P010-A/B	Steam condensate return pumps							
	DRUMS / COLUMNS / TANKS							
	For each train:							
D-001	Direct contact cooler (square)							
D-002	CO2 absorber							
D-003	CO2 stripper							
V-001	Stripper reflux drum							
V-002	Steam condensate drum							
T-001	Lean amine tank							
V-003	Lean amine flash tank							
	HEAT EXCHANGERS							
	For each train:							
E-001	DCC cooler							
E-002	Wash Water cooler							
E-003	Lean / rich exchanger							
E-004	Stripper condenser							
E-005	Stripper reboiler							
E-006	Lean amine cooler							
E-007	Absorber intercooler							
	MISCELLANEA							
	For each train:							
F-001	Lean amine filter							
F-002	Amine purification unit							
F-003	Thermal reclaimer							
F-004	CO2 Lean Absorbent Flash MVR system							

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CASE:	4 - SC PC with carbon capture					

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	180000 Nm3/h p in: 1.6 bar a p out: 75 bar a	30000 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

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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	Cooling Tower including: Cooling water basin	Natural draft	1510 MWth					
	PUMPS		Q [m^3/h] x H [m]					
P- 6001 A/B/C/D	Cooling Water Pumps (primary system)	Centrifugal	15092 x 35	1700			superduplex	*Four in operation*
P- 6002 A/B/C/D	Cooling Water Pumps (secondary system)	Centrifugal	14407 x 45	2100			superduplex	*Four in operation, one spare*
P- 6003 A/B	Cooling tower make-up pumps	centrifugal	2162 x 32	300				*One in operation, one spare*
	PACKAGES							
	Cooling Water Filtration Package Cooling Water Sidestream Filters		Capacity: 11800 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		2520 m3					*24 hour storage*
P- 6004 A/B	Raw water pumps to RO	centrifugal	10 m3/h x 50 m	7.5				*One in operation, one spare*
P- 6005 A/B	Raw water pump to FGD (make-up)	centrifugal	95 m3/h x 40 m	18.5				*One in operation, one spare*
	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- 6006 A/B	Demin water pump	centrifugal	10 m3/h x 40 m	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							

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EQUIPMENT LIST

Units Summary

UNIT 100	**COAL AND ASH STORAGE AND HANDLING**
UNIT 200	**BOILER ISLAND**
UNIT 300	**FGD AND GYPSUM HANDLING PLANT**
UNIT 500	**STEAM CYCLE**
UNIT 600	**$C0_2$ AMINE ABSORPTION**
UNIT 700	**$C0_2$ COMPRESSION**
UNIT 800	**UTILITY AND OFFSITE**

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CASE:	4.1 - SC PC with carbon capture					

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:325t/h					
	- Wagon tipper							
	- 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: 9.2t/h					30 days storage capacity
	- Wagon tipper		Limestone storage volume 6100 m3					
	- Receiving Hopper, vibratory feeder and vet extractor							
	- Conveyor	Belt						
	- Transfer Tower	enclosed						
	- Limestone Storage	Silos						
	- Conveyor	Belt						
	- Limestone Sampling System	Swing Hammer						
	- Separator System	Magnetc Plates						
	- Transfer Tower	enclosed						
	- Conveyor	Belt with tipper						
	- Limestone Bunker							*For daily storage*
	- Filters							
	- Fan							
	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: 29.2 t/h					*14 days storage capacity*
	- Pneumatic conveying system		Fly Ash Storage volume: 14000 m3					
	- Compressors							
	- Filters							
	- Fans							
	GYPSUM SYSTEM							
	Including:		Capacity: 16.9 t/h					
	- Storage unit		Storage volume: 9360 m3					*30 days storage capacity*
	- Conveyors							*1 operating, 1 spare*

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CASE:	4.1 - SC PC with carbon capture					

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: 2860 t/h main steam production Thermal input: 2443 MWth (HHV) / 2335 MWth (LHV) Main steam condition: 290 bar(a)/600 °C Reheat steam condition: 60 bar(a)/620 °C					Boiler package including: - Coal mill - Fuel Feeding system - One Fired Boiler Furnace -Low NOx burners system including main - Economizers/super heater coils, water wall - Reheating coils - Air pre-heater - Ash collection hoppers - Combustion air fans with electric motor - Ash collection hoppers - Start-up system - Flue gas ducts - Bottom Ash cooling devices
K - 2001	**ID fan**	Axial	Total Flowrate: 2766 x 10^3 Nm3/h Total Vol. Flow: 1072 m3/h Total Power consumption: 10530 kW					
PK - 2002	**Flue gas cleaning system**	ESP						
PK - 2003	**Flue gas stack**	cement stack						
PK - 2004	**Continuous emission monitoring system**							
	SCR SYSTEM - UNIT 2050							
	SCR system Including: - Reactor casing - Catalyst - Bypass system - Ammonia injection equipment - Handling equipment - Control System							

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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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CASE:	4.1 - SC PC with carbon capture	APPROVED BY	PC			

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		933 MWe *HP admission:* *2860 t/h @ 290 bar* *Hot reheat admission:* *2445 t/h @ 60 bar* *LP admission:* *1038 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		691 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**							
	HEAT EXCHANGERS		**Duty (kW)**		Shell/tube	Shell/tube		
E- 3002	BFW Economiser #1							
E- 3003	BFW Economiser #2							
E- 3003	BFW Economiser #3							
E- 3004	Condensate heater #3							
E- 3005	Condensate heater #4							
	PUMPS		**Q [m^3/h] x H [m]**					
P- 3001	BFW pumps	Centrifugal Steam driven	3119 m3/h x 3733 m	36000 kWe equivalent				*One operating*
P- 3002	BFW pump	Centrifugal	40% MCR					*For start-up, electric motor*
P- 3003	BFW to desuperheater pump	Centrifugal	125 m3/h x 42 m	22				*One operating, electric motor*
P- 3004 A/B	Condensate pump	Centrifugal	1530 m3/h x 172 m	950				*One operating one spare, electric motor*
	VESSEL							
D- 3001	Dearator	Horizontal						

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EQUIPMENT LIST
Unit 4000 - CO2 Capture Unit

	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: 1428500 Nm3/h CO2 product: 200000 Nm3/h; 98% purity Treated gas florate: 1125000 Nm3/h CO2 capture rate: 99 %					2 x 50%
	PUMPS							
	For each train:							
K001	Flue gas Blower							
P001-A/B	Prescrubber water circulation pumps							
P002-A/B	Prescrubber polishing pumps							
P003-A/B	Absorber intercoolers pumps							
P004-A/B	Wash water pumps							
P005-A/B	Rich amine pumps							
P006-A/B	Stripper reflux pumps							
P007-A/B	Lean amine pumps							
P008-A/B	Amine feed pump							
P009	Make up amine pump							
P010-A/B	Steam condensate return pumps							
	DRUMS / COLUMNS / TANKS							
	For each train:							
D-001	Direct contact cooler (square)							
D-002	CO2 absorber							
D-003	CO2 stripper							
V-001	Stripper reflux drum							
V-002	Steam condensate drum							
T-001	Lean amine tank							
V-003	Lean amine flash tank							
	HEAT EXCHANGERS							
	For each train:							
E-001	DCC cooler							
E-002	Wash Water cooler							
E-003	Lean / rich exchanger							
E-004	Stripper condenser							
E-005	Stripper reboiler							
E-006	Lean amine cooler							
E-007	Absorber intercooler							
	MISCELLANEA							
	For each train:							
F-001	Lean amine filter							
F-002	Amine purification unit							
F-003	Thermal reclaimer							
F-004	CO2 Lean Absorbent Flash MVR system							

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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	200000 Nm3/h p in: 1.6 bar a p out: 75 bar a	33000 kW				Intercooling: Condensate from Power island Cooling Water
	PUMPS		**Q,m3/h x H,m**					
P - 5001	CO_2 Pump	centrifugal	550 x 530	750 kW				Liquid CO2 product, per each train: Flowrate: 380 t/h; 110 bar a; 30°C
	PACKAGE							
PK - 5001	CO_2 drying package							

Note 1: Equipment shown are for one train only

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CASE:	4.1 - SC PC with carbon capture					

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	1576 MWth					
	PUMPS		**Q [m^3/h] x H [m]**					
P- 6001 A/B/C/D	Cooling Water Pumps (primary system)	Centrifugal	13514 x 35	1700			superduplex	*Four in operation*
P- 6002 A/B/C/D	Cooling Water Pumps (secondary system)	Centrifugal	17367 x 45	2100			superduplex	*Four in operation, one spare*
P- 6003 A/B	Cooling tower make-up pumps	centrifugal	2263 x 32	300				*One in operation, one spare*
	PACKAGES							
	Cooling Water Filtration Package Cooling Water Sidestream Filters		Capacity: 12352 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		2520 m3					*24 hour storage*
P- 6004 A/B	Raw water pumps to RO	centrifugal	10 m3/h x 50 m	7.5				*One in operation, one spare*
P- 6005 A/B	Raw water pump to FGD (make-up)	centrifugal	95 m3/h x 40 m	18.5				*One in operation, one spare*
	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- 6006 A/B	Demin water pump	centrifugal	10 m3/h x 40 m	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							

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DOCUMENT NAME	:	ECONOMICS OF USC PC PLANT ALTERNATIVES
CONTRACT N°	:	1-BD-1046 A

ISSUED BY	:	M. MENSI
CHECKED BY	:	V. TOTA
APPROVED BY	:	V. TOTA

Date	Revised Pages	Issued by	Checked by	Approved by

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GLOSSARY

CCS	Carbon Capture and Storage
NGCC	Natural Gas Combined Cycle
USC PC	Ultrasupercritical Pulverised Coal
FGR	Flue Gas Recirculation
EGR	Exhaust Gas Recirculation
CCU	Carbon Capture Unit
CMC	Ceramic Matrix Composite
ASU	Air Separation Unit
MCFC	Molten Carbonate Fuel Cell
TPC	Total Plant Cost
TIC	Total Installed Cost
MEL	Minimum Environmental Load
GT	Gas Turbine
ST	Steam Turbine

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.

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.

In this section, a full economical assessment is made for all the main study cases based on USC PC boilers, whose major characteristics are summarized in the overleaf Table 1.

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

Case	Plant type	CO_2 capture target	Key technological features
Case 3	D.1	USC PC boiler w/o CCS	• Generic state-of-art supercritical PC boiler • Wet limestone scrubbing FGD • Cooling system based on natural draft cooling water
Case 4	D.2	USC PC boiler with CCS	• Generic state-of-art supercritical PC boiler • Wet limestone scrubbing FGD • CANSOLV post-combustion capture • Cooling system based on natural draft cooling tower. • 90% capture rate
Case 4.1	D.2	USC PC boiler with CCS – High capture rate	• Generic state-of-art supercritical PC boiler • Wet limestone scrubbing FGD • CANSOLV post-combustion capture • Cooling system based on natural draft cooling tower. • 99% capture rate

2. Capital cost

2.1. Definitions

This section provides the details of the Total Capital Requirement (TCR), also named Total Investment Cost (TIC), and the Total Plant Cost (TPC) of the various study cases. The main cost estimating bases and detailed estimate methodology are described in chapter B. Main bases considered for the financial analysis are reported hereafter.

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:

- Combined Cycle
- CO_2 capture (Post-combustion capture cases B)
- CO_2 compression (Post-combustion capture cases B)
- Utilities units

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 1Q2019 price level, in euro (€).

2.2.1. Total Plant Cost

The starting point for investment cost estimate has been the information contained in the reference IEAGHG report 2018/4 “Effect of plant location on CO2 capture”. The cost is updated to reflect any technological developments and the technical modifications of the benchmark cases, as resulting from the market investigation done mainly for the Steam Conditions of the USC PC power plant and the CO2 capture plant.

The estimating methodology used by Wood 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.

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 Wood 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 Wood experience and in-house data bank.

Process contingency

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. Project contingency

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

For the accuracy considered in this study, Wood view is that contingency should be in the range of 10-15% of the total plant cost in The Netherlands. 10% is assumed for this study for all the different units of the plant, for consistency with the reference IEAGHG report 2014/3 "*CO_2 capture at coal based power and hydrogen plants*".

2.2.3. 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.

Discount rate

Discount cash flow calculations are expressed at a discount rate of 8% for the reference plant.

2.3. Total Plant Cost summary

The TPC of the different natural gas fired power plant study cases listed in Table 1 is shown in the following tables. 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 natural gas fired cases are also reported for summary purpose in the below Table 2.

Table 2. USC PC plant cases TPC and TCR

Case	**Total Plant Cost (TPC)** (M€)	**Total Capital Requirement (TCR)** (M€)	**Specific cost** [TPC/Net Power] (€/kW)	**Specific cost** [TCR/Net Power] (€/kW)
Case 3	1560.8	2033.8	1510	1968
Case 4	2384.6	3097	2887	3750
Case 4.1	2437.5	3165	3111	4041

Table 3. Case 3 – Total Plant Cost

	Case 3 (USC PC without CCS)	
		CONTRACT: 1-BD-1046A CLIENT: IEA GHG LOCATION: THE NETHERLANDS DATE: MAY 2019 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	78.800.000	298.000.000	27.000.000	49.400.000	182.400.000	157.400.000	793.000.000	1) Gross Power Output [MW]: 1080,5
									Specific Cost 1445 €/kWe
2	CONSTRUCTION	30.800.000	187.900.000	5.800.000	17.700.000	67.100.000	77.300.000	386.600.000	
									2) Net Power Output [MW]: 1033,4
3	**DIRECT FIELD COST**	**109.600.000**	**485.900.000**	**32.800.000**	**67.100.000**	**249.500.000**	**234.700.000**	**1.179.600.000**	Specific Cost 1511 €/kWe
4	OTHER COSTS	6.400.000	33.400.000	1.600.000	3.800.000	14.200.000	14.700.000	74.100.000	
5	EPC SERVICES	15.400.000	68.000.000	4.700.000	9.300.000	35.000.000	32.900.000	165.300.000	
									EXCLUSIONS
6	**TOTAL INSTALLED COST**	**131.400.000**	**587.300.000**	**39.100.000**	**80.200.000**	**298.700.000**	**282.300.000**	**1.419.000.000**	Spare parts
									Inventories of fuel and chemicals
7	PROJECT CONTINGENCY	13.100.000	58.700.000	3.900.000	8.000.000	29.900.000	28.200.000	141.800.000	Start-up costs
									Insurance
8	PROCESS CONTINGENCY	-	-	-	-	-	-	-	Local taxes and fees
9	**TOTAL PLANT COST**	**144.500.000**	**646.000.000**	**43.000.000**	**88.200.000**	**328.600.000**	**310.500.000**	**1.560.800.000**	

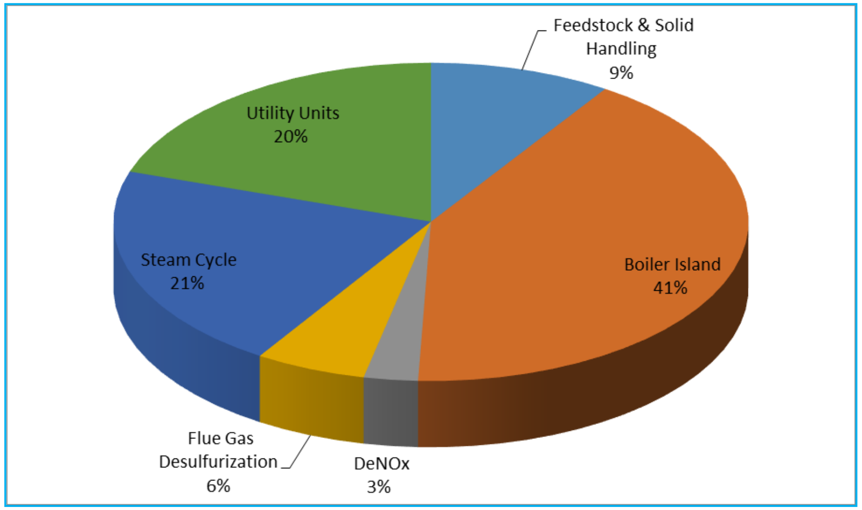

Figure 1. Case 3 – Unit percentage weight on TPC

Table 4. Case 4 – Total Plant Cost

wood.

Case 4
(USC PC with CCS - 90% CO2 capture rate)

CONTRACT:	1-BD-1046A
CLIENT:	IEA GHG
LOCATION:	THE NETHERLANDS
DATE:	MAY 2019
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	78.800.000	298.000.000	27.000.000	50.900.000	174.200.000	335.300.000	44.800.000	249.500.000	1.258.500.000	1) Gross Power Output [MW]:	961,6
										-	Specific Cost	2480 €/kWe
2	CONSTRUCTION	30.800.000	187.900.000	5.800.000	20.000.000	67.100.000	92.300.000	33.600.000	109.800.000	547.300.000		
											2 Net Power Output [MW]:	825,9
3	**DIRECT FIELD COST**	**109.600.000**	**485.900.000**	**32.800.000**	**70.900.000**	**241.300.000**	**427.600.000**	**78.400.000**	**359.300.000**	**1.805.800.000**	Specific Cost	2888 €/kWe
4	OTHER COSTS	6.400.000	33.400.000	1.600.000	4.100.000	13.900.000	22.100.000	5.800.000	21.800.000	109.100.000		
5	EPC SERVICES	15.400.000	68.000.000	4.700.000	9.900.000	33.700.000	60.000.000	11.000.000	50.300.000	253.000.000		
											EXCLUSIONS	
6	**TOTAL INSTALLED COST**	**131.400.000**	**587.300.000**	**39.100.000**	**84.900.000**	**288.900.000**	**509.700.000**	**95.200.000**	**431.400.000**	**2.167.900.000**	Spare parts	
											Inventories of fuel and chemicals	
7	PROJECT CONTINGENCY	13.100.000	58.700.000	3.900.000	8.500.000	28.900.000	51.000.000	9.500.000	43.100.000	216.700.000	Start-up costs	
											Insurance	
8	PROCESS CONTINGENCY	-	-	-	-	-	-	-	-	-	Local taxes and fees	
										-		
9	**TOTAL PLANT COST**	**144.500.000**	**646.000.000**	**43.000.000**	**93.400.000**	**317.800.000**	**560.700.000**	**104.700.000**	**474.500.000**	**2.384.600.000**		

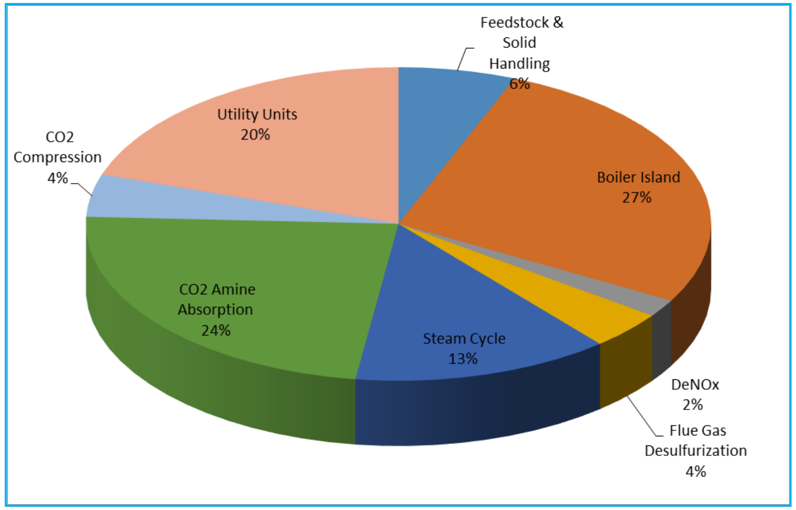

Figure 2. Case 4 – Unit percentage weight on TPC

Table 5. Case 4.1 – Total Plant Cost

wood.	Case 4.1 (USC PC with CCS - 99% CO2 capture rate)									CONTRACT: 1-BD-1046A CLIENT: IEA GHG LOCATION: THE NETHERLANDS DATE: MAY 2019 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	78.800.000	298.000.000	27.000.000	50.900.000	170.200.000	362.800.000	47.900.000	253.000.000	1.288.600.000	1) Gross Power Output [MW]: 929,2
										-	Specific Cost 2624 €/kWe
2	CONSTRUCTION	30.800.000	187.900.000	5.800.000	20.000.000	65.600.000	99.900.000	36.000.000	111.400.000	557.400.000	
											2 Net Power Output [MW]: 783,4
3	**DIRECT FIELD COST**	**109.600.000**	**485.900.000**	**32.800.000**	**70.900.000**	**235.800.000**	**462.700.000**	**83.900.000**	**364.400.000**	**1.846.000.000**	Specific Cost 3112 €/kWe
4	OTHER COSTS	6.400.000	33.400.000	1.600.000	4.100.000	13.700.000	23.900.000	6.100.000	22.000.000	111.200.000	
5	EPC SERVICES	15.400.000	68.000.000	4.700.000	9.900.000	33.000.000	64.900.000	11.800.000	51.000.000	258.700.000	
											EXCLUSIONS
6	**TOTAL INSTALLED COST**	**131.400.000**	**587.300.000**	**39.100.000**	**84.900.000**	**282.500.000**	**551.500.000**	**101.800.000**	**437.400.000**	**2.215.900.000**	Spare parts
											Inventories of fuel and chemicals
7	PROJECT CONTINGENCY	13.100.000	58.700.000	3.900.000	8.500.000	28.300.000	55.200.000	10.200.000	43.700.000	221.600.000	Start-up costs
											Insurance
8	PROCESS CONTINGENCY	-	-	-	-	-	-	-	-	-	Local taxes and fees
										-	
9	**TOTAL PLANT COST**	**144.500.000**	**646.000.000**	**43.000.000**	**93.400.000**	**310.800.000**	**606.700.000**	**112.000.000**	**481.100.000**	**2.437.500.000**	

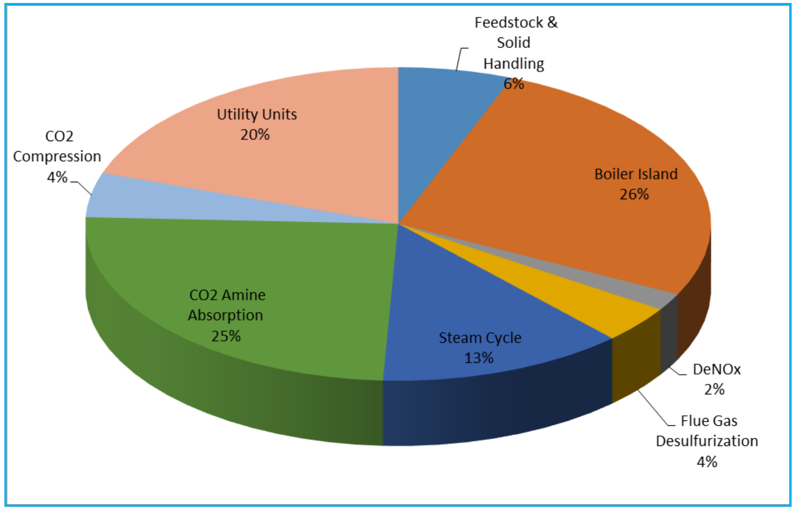

Figure 3. Case 4.1 – Unit percentage weight on TPC

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 bariable costs for the natural gas fired study cases listed in Table 1, 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% capacity factor for USC PC power plant). Reference values for feedstock and main consumables prices are summarized in chapter B.

Item	Unit	Cost
Coal	€/GJ (LHV)	2.5
Limestone	€/t	20
Raw process water	€/m^3	0.2
Ash and gypsum 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 table reports a summary of the variable costs for all the coal fired cases of the study.

wood.	Yearly Variable Costs									
Yearly Operating hours = 7884		Case 3			Case 4			Case 4.1		
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	20.0	8,850	69,773	1,395,500	9,200	72,533	1,450,700	9,200	72,533	1,450,700
Make-up water	0.20	1,653,000	13,032,252	2,606,500	2,185,000	17,226,540	3,445,300	2,255,000	17,778,420	3,555,700
Catalysts	not displayable	-	-	3,806,100	-	-	4,241,700	-	-	4,241,700
Chemicals (including Solvents)	not displayable	-	-	1,683,000	-	- (1)	10,476,000	-	- (1)	11,479,500
Waste Disposal										
Ash disposal	0.0	41,750	329,157	0	41,750	329,157	0	41,750	329,157	0
Solvent disposal	not displayable	-	-	0	-	-	981,000	-	-	1,101,600
TOTAL YEARLY OPERATING CO$	**Euro/year**			**175,207,900**			**186,311,500**			**187,546,000**

(1) Based on Wood's assumption: specific solvent cost of 5 €/kg

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 based on USC PC plants can be virtually divided into the following main areas of operation:

- Boiler island & flue gas treatment
- Steam Cycle & Utilities, including CO_2 capture unit

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 of 60,000 €/year, referred to year 2019.

The following tables report the labour force for the different configurations, along with the direct labour cost.

Table 6. Case 3– Operating Labor Cost

Case 3				
	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 7. Case 4 and 4.1 – Operating Labor Costs

Case 4 and 4.1				
	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

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
- 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.

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 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. The percentage figures considered for the USC PC plant cases is 1.5%. Maintenance labour is assumed to be 40% of the overall maintenance cost.

The yearly maintenance cost for all cases of the study is reported in the following Table 8, with reference to year 2019.

Table 8. Maintenance costs (reference year: 2019)

Type	Case	Maintenance (%)	Total Plant Cost (M€)	Maintenance (M€/year)
NGCC-based	**Case 3**	1.5	1,561	23.4
	Case 4	1.5	2,385	35.8
	Case 4.1	1.5	2,438	36.6

3.3. Summary

The following tables report the summary of O&M costs for the different cases.

O&M COSTS	Case 3 €/year	Case 4 €/year	Case 4.1 €/year
Fixed Costs			
Direct labour	5,700,000	6,300,000	6,300,000
Adm./gen overheads	4,519,400	6,182,300	6,277,500
Insurance & Local taxes	15,608,000	23,846,000	24,375,000
Maintenance	23,412,000	35,769,000	36,562,500
Subtotal	**49,239,400**	**72,097,300**	**73,515,000**
Variable Costs (Availability = 90%)			
Feedstock	167,112,300	167,167,500	167,167,500
Water Makeup	2,606,500	3,445,300	3,555,700
Catalyst	3,806,100	4,241,700	4,241,700
Chemicals (including Solvent)	1,683,000	10,476,000	11,479,500
Waste disposal (incl. Solvent)	0	981,000	1,101,600
Subtotal	**175,207,900**	**186,311,500**	**187,546,000**
TOTAL O&M COSTS	**224,447,300**	**258,408,800**	**261,061,000**

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.

The LCOE prediction is 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)

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.

4.2.2. Cost of CO_2 avoidance

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

$$CO_2 \text{ Avoidance Cost (CAC)} = \frac{\text{LCOE}_{\text{CCS}} - \text{LCOE}_{\text{NoCCS}}}{CO_2\text{Emissions}_{\text{NoCCS}} - CO_2\text{Emissions}_{\text{CCS}}}$$

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.

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
Discount Rate	Reference: 8%
Capacity factor (SC-PC)	90%
CO_2 transport & storage cost	10 €/t $_{STORED}$
CO_2 emission cost	0 €/t $_{EMITTED}$
Inflation Rate	Constant Euro
Currency	Euro reported in 1Q2019

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.

A summary of the economical modelling results, in terms of LCOE and CAC, is reported in Table 9 for USC PC cases, developed with 8% discount rate.

Figure 4 and Figure 5 report LCOE and CAC bar chart showing the relative weight of:

- Capital investment,
- Fixed O&M,
- Variable O&M,
- Fuel,
- CO_2 transportation & storage,

Table 9. Financial results summary: LCOE and CO_2 avoidance cost

Case	Description	LCOE €/MWh	CO_2 emission avoidance cost €/t
Case 3	USC-PC w/o CCS	53.3	-
Case 4	USC-PC w/CCS 90%	97.3	67.68
Case 4.1	USC-PC w/CCS 99%	105.1	70.60

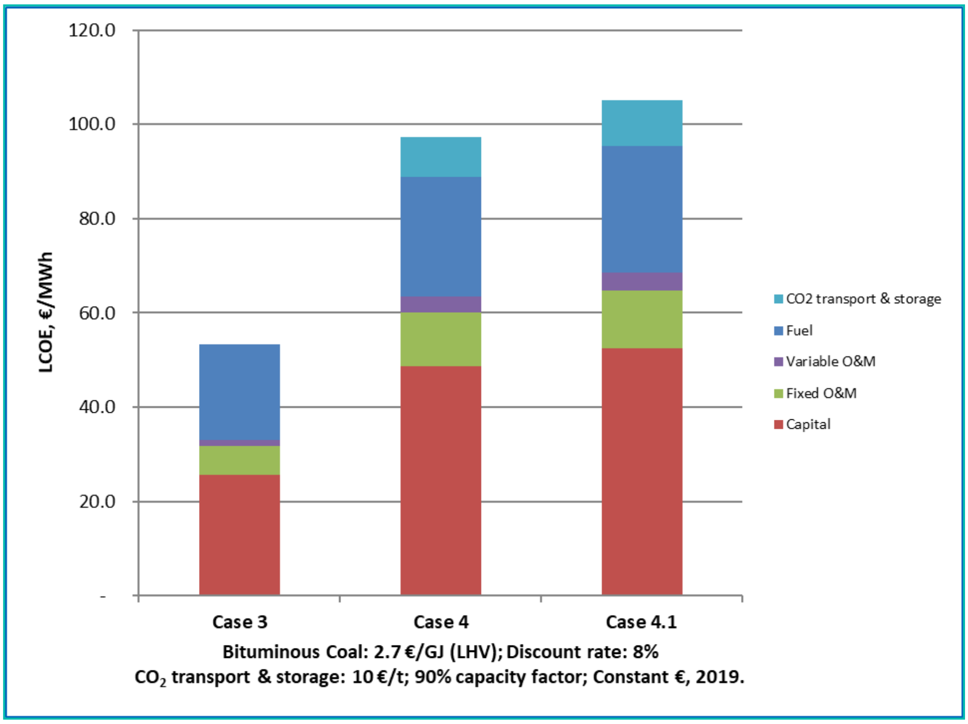

Figure 4. LCOE for all USC-PC study cases

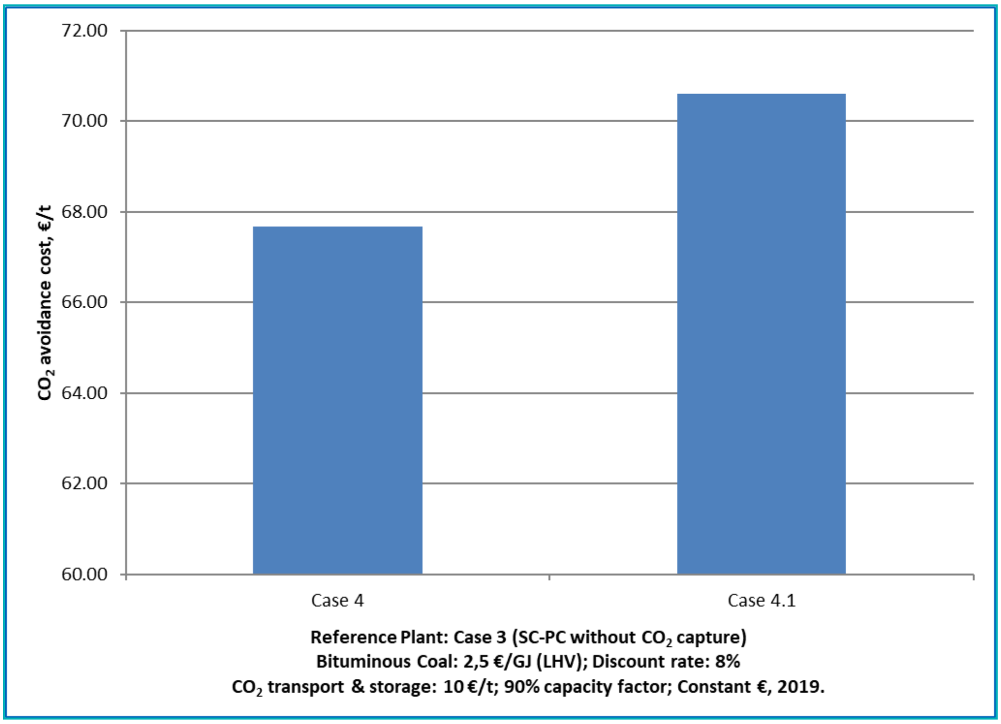

Figure 5. CAC for all USC-PC study cases with CO2 capture

The results also show the economic impacts of enhancing CO2 capture rate from 90% to 99%. The LCOE increases by 8% while the CAC by 4.3%.

CLIENT	:	IEAGHG
PROJECT NAME	:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO_2 CAPTURE
DOCUMENT NAME	:	FLEXIBILITY OF USC PC WITH CCS
CONTRACT N°	:	1-BD-1046 A

ISSUED BY	:	M.MENSI
CHECKED BY	:	V.TOTA
APPROVED BY	:	V.TOTA

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

GLOSSARY

CCS	Carbon Capture and Storage
NGCC	Natural Gas Combined Cycle
USC PC	Ultrasupercritical Pulverised Coal
FGR	Flue Gas Recirculation
EGR	Exhaust Gas Recirculation
CCU	Carbon Capture Unit
CMC	Ceramic Matrix Composite
ASU	Air Separation Unit
MCFC	Molten Carbonate Fuel Cell
TPC	Total Plant Cost
TIC	Total Installed Cost
MEL	Minimum Environmental Load
GT	Gas Turbine
ST	Steam Turbine

1 Introduction

The introduction of the post-combustion CO_2 capture and compression facilities in USC PC plants impose additional constraints to a flexible operation, where certain equipment, like stripper and reboiler, may limit the capacity to make frequent start-ups/shut-downs, due to the time required to pre-heat the regeneration column and the related reboilers.

Also, the requirement for the power plants to operate flexibly in the power market, is nowadays strongly conditioned by the massive increase of the renewable technologies and their variable capability to produce power for the electrical grid.

The main objective of this chapter is to update the key assessments shown in the IEAGHG Report 2012/06) *"Operating flexibility of power plants with CCS"*, to reflect from one end the technology improvements of the key plant components from 2011 to 2018, and also to include a more up-to date operating flexibility requirements.

In the specific case of a coal fired power plant, the assumed weekly demand curve is reported in Figure 1.

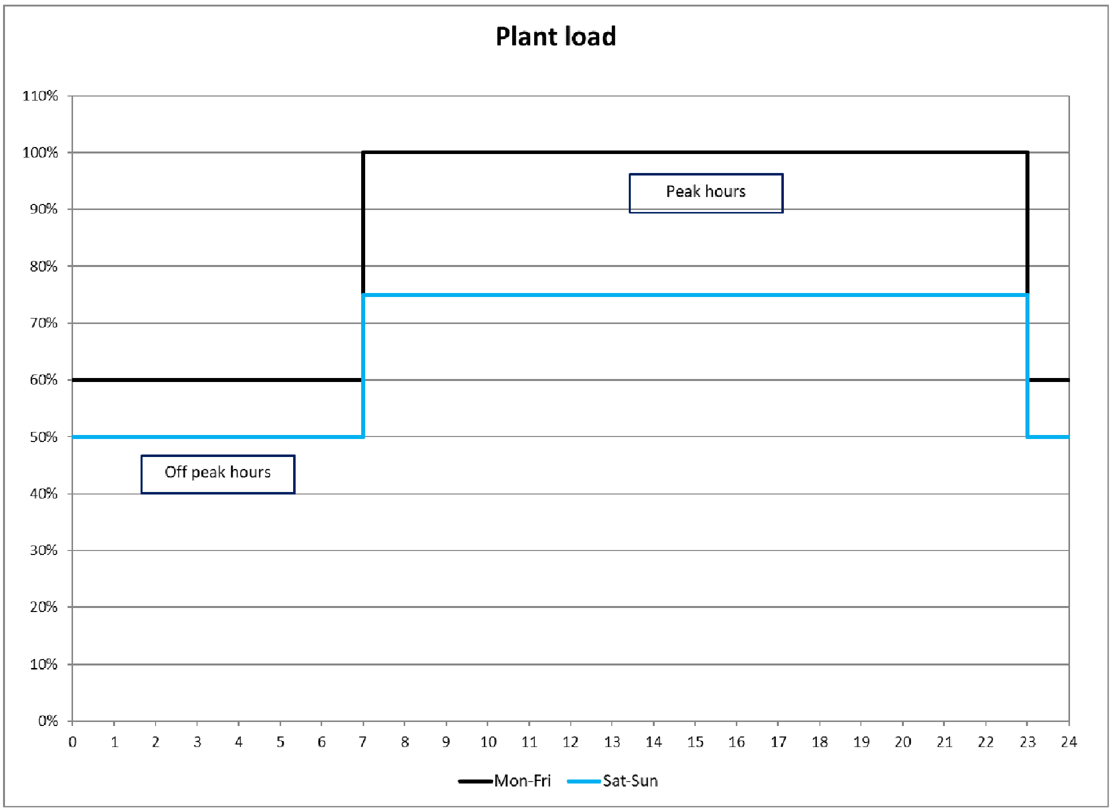

Figure 1. Daily USC PC plant load

From the above graph, it can be drawn that the USC PC plants will be maintained at base load between 7-23 in weekdays while turned down to 60% during the night. In the weekend, when demand is lower, the plant will run at 75% load during the day and will be turned down to 50% for the night.

1.1 Study cases

The capability of these plant types for a flexible operation is mainly affected by the constraints related to CO_2 capture and compression units, as well as the transportation pipeline. To investigate these main features, the following cases are presented in Table 1.

Table 1. NGCC power plant flexibility cases

Case	Name	Description
4.1a	Solvent Storage	This case considers the rich solvent storage, in order to minimize the plant power consumption and increase the overall power production during peak load demand period.
4.1b	Variable Capture	This case evaluates the possibility of tuning ON/OFF the CO2 capture in the plant, depending on the possible CO_2 allowance cost fluctuations.
4.1c	Energy storage	This case evaluates the possibility of incorporating a BESS (Battery Energy Storage System) within the power plant to cover a daily 2-hours peak in the evening.

The reference case for this flexibility study is Case 4.1, which indicates a USC pulverised coal plant with 99% CO_2 recovery.
For each case and sub-scenario investigated, Wood produced a comparative summary of performances, equipment size and additional equipment required put against the reference Case 4.1. From this information, estimates of the total CAPEX of the plant incorporating the proposed modification were developed.

2 Case 4.1a – Solvent Storage

2.1 Introduction

Case 4.1a assesses how the operating flexibility of USC PC plans with post-combustion capture improves when solvent storage tanks are installed in the plant, allowing temporary storage of rich and lean solvent.

Solvent storage techniques allow to decouple the power plant and the CO_2 absorption from the CO_2 regeneration and compression units, while continuously capturing the CO_2 from the flue gases. In addition, the solvent regeneration and CO_2 compression, with their associated energy penalties, can be operated during low electricity demand periods, while maximizing the electricity production when the market requires a higher electricity generation.

2.2 Description of the cases

This alternative is assessed considering one whole week of plant operation, based on the grid demand cycling trend summarised in section 0.

To maximize the energy production, the rich solvent can be partially or even totally stored during the 80 hours per week of peak load operation, when the plant is at base-load, while the regeneration of stored solvent can be made during the remaining 88 hours per week of off-peak load operation. With this strategy, the solvent flowrates from and to the storage are balanced in one week of plant operation.

During peak electricity demand, when the market requires the maximum amount of electricity, the power plant is operated at base load by making the full capture of the CO_2 from the flue gas in the absorber column, while the solvent regeneration and CO_2 compression sections are at low or even no load, thus reducing the energy penalties in the plant.

Depending on the regeneration load, only a certain amount of the CO_2-rich solvent from the absorber column is fed to the regenerator, while the remainder is stored in dedicated storage tanks. As a consequence, part of the lean solvent required for the CO_2 capture in the absorber is not available from the regenerator, whilst it is taken from the relevant storage tanks.

During off-peak electricity demand, i.e. when lower electricity selling prices reduce the revenues of the plant, the USC PC plant shall be operated in order to regenerate the rich solvent stored in the tanks and refill the lean amine storage tanks. To achieve

this, the plant needs to be run at such a load that extra solvent regeneration is done while the net power export to the grid is maintained according to demand curve.
Any excess steam produced should be diverted to the LP section of the steam turbine.

The scenarios shown in the following sections, each characterised by a different regeneration load during high electricity demand period, have been investigated, in order to evaluate the most convenient operating conditions. Compared to the previous report by Wood as formerly Foster Wheeler, IEAGHG Report 2012/06) *"Operating flexibility of power plants with CCS"*, Wood restrained from assessing some scenarios that were found to be unfeasible (i.e. having complete shutdown of the regeneration and compression units is not realistic, as the required tank area is extremely large).

The main operating parameters for each possible scenario are also summarised in Table 2

Table 2. USC PC - Solvent Storage Scenarios

Scenario: peak hours regenerator operating condition		No solvent storage Reference scenario	25% solvent storage Scenario 1	14% solvent storage Scenario 2
Daily full load operation (80 hours/week) Plant Load 100%				
Power island operating condition				
Boiler load	-	100%	100%	100%
ST power output	MWe	929.2	967.9	952.9
Net power output	MWe	783.4	847.1	822.2
CO2 Capture Unit operating condition		**absorber 100% regenerator 100%**	**absorber 100% regenerator 75%**	**absorber 100% regenerator 86%**
Nightly part load operation (40 hours/week) Plant Load 60%				
Power island operating condition				
Boiler load	-	63%	73.5%	69.5%
ST power output	MWe	564.5	638.0	608.8
Net power output	MWe	468.0	508.2	493.9
CO2 Capture Unit operating condition		**absorber 63% regenerator 63%**	**absorber 73.5% regenerator 100%**	**absorber 69.5% regenerator 86%**
Weekend part load operation (32 hours/week) Plant Load 75%				
Power island operating condition				
Boiler load	-	77%	86.5%	82.0%
ST power output	MWe	694.6	772.6	739.7
Net power output	MWe	580.9	636.1	618.4
CO2 Capture Unit operating condition		**absorber 77% regenerator 77%**	**absorber 86.5% regenerator 100%**	**absorber 82% regenerator 86%**
Nightly Weekend part load operation (16 hours/week) Plant Load 50%				
Power island operating condition				
Boiler load	-	55%	65.0%	60.5%
ST power output	MWe	486.5	550.7	516.6
Net power output	MWe	393.8	427.7	410.3
CO2 Capture Unit operating condition		**absorber 55% regenerator 55%**	**absorber 65% regenerator 97.4%**	**absorber 60.5% regenerator 81.6%**
Regenerator design				
Regenerator size respect to reference case		-	100%	86%
Storage tanks				
Rich solvent			2 x 71'600 m3 D = 73 m x H = 17 m	2 x 37'300 m3 D = 73 m x H = 17 m
Lean solvent			2 x 71'600 m3 D = 73 m x H = 17 m	2 x 37'300 m3 D = 73 m x H = 17 m
Tank Area (as % of plant plot area)			20%	12%
Consideration				
			FEATURES Higher power production during peak load period	**FEATURES** Lower reboiler investment costs

2.2.1 *Scenario 1 – Solvent storage to increase power production*

This case studies the plant configuration obtained by keeping the same reboiler size as the design case. Therefore, with the added investment of storage tanks and necessary pumps, this represents the maximum achievable peak power production with a "retrofit" storage system.

2.2.2 *Scenario 2 – Solvent storage to reduce reboiler size*

This scenario finds the operating design that allows to have the smallest reboiler possible. This is achieved by rising the regeneration load during peak power production of scenario 1 and adjusting reboiler load during offpeak hours until they roughly match. With this approach, the target is to have capital cost savings on the solvent regeneration and CO_2 compression sections.

2.3 Scenario 1 – Solvent storage to increase power production

For this scenario, reboiler size is left unchanged and it is assumed that during most of the off-peak runtime the regeneration section operates at 100% load (thanks to the combination of both the stored solvent and the solvent used to capture the flue gas at partial load). This allows minimum regeneration during normal peak operation, maximising power production

In this situation, two large storage tanks are needed for each service (two for lean solvent, two for rich solvent). In Figure 2 the total tank content weekly variation is reported.

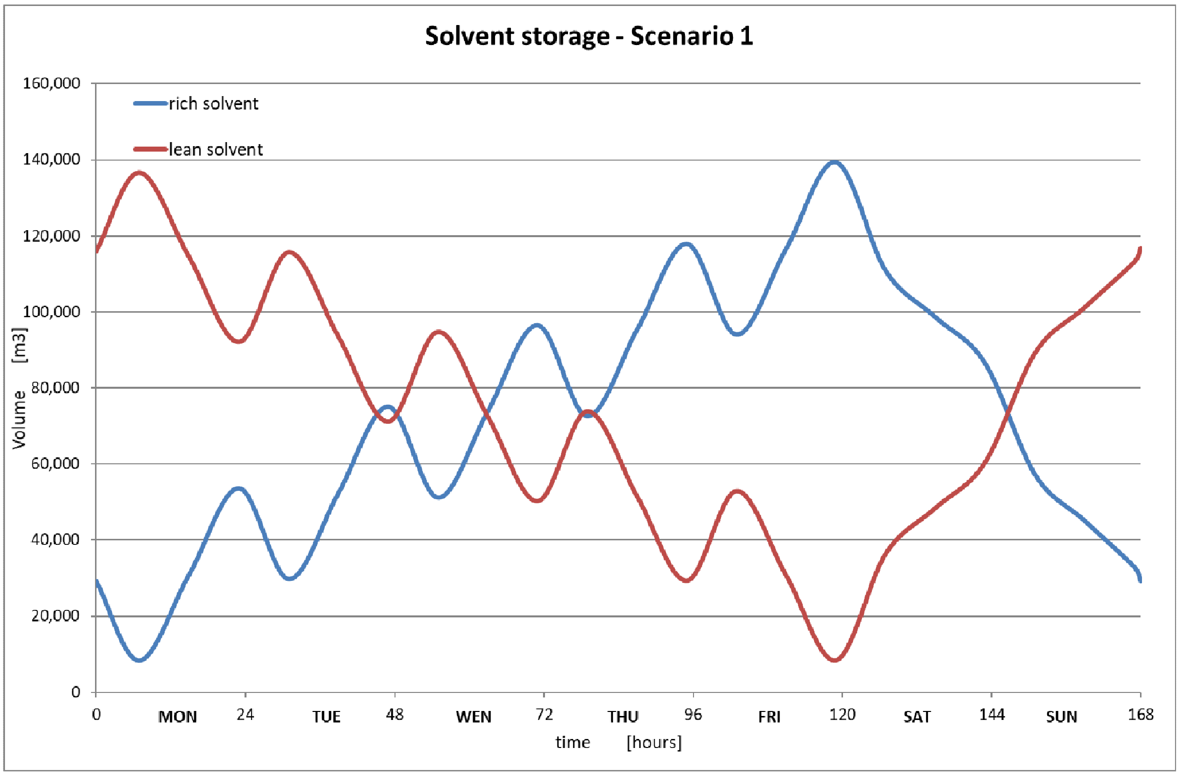

Figure 2. Weekly solvent storage cycle for scenario 1

2.3.1 *Performances*

Performance comparison between the current flexibility scenario and the reference Case 4.1 is shown below in Table 3.

Table 3. Scenario 1 performance report

USC PC Plant - 99% CO2 recovery - Solvent storage system						
Scenario 1 - Solvent storage to increase power production						
OVERALL PLANT PERFORMANCES						
		Reference case	Weekday peak	Weekday offpeak	Weekend peak	Weekend offpeak
Coal Flowrate (fresh, air dried basis)	t/h	325.0	325.0	238.9	281.1	211.3
Coal LHV (air dried basis)	kJ/kg	25870.0	25870.0	25870.0	25870.0	25870.0
Main steam flow	kg/s	794.0	794.0	553.9	669.3	481.1
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2335.5**	**2335.5**	**1716.6**	**2020.2**	**1518.1**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**929.2**	**967.9**	**638.0**	**772.6**	**550.7**
POWER PLANT PERFORMANCES						
Feedstock and solids handling	MWe	3.4	3.4	2.5	2.9	2.2
Boiler Island, including FGD	MWe	26.4	26.4	19.4	22.8	17.1
Power Islands consumption	MWe	4.7	5.0	3.5	4.1	3.1
Utility consumptions	MWe	17.3	17.3	12.7	15.0	11.3
CO_2 Capture Unit + Compression	MWe	91.7	68.8	91.7	91.7	89.3
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**143.5**	**120.9**	**129.8**	**136.5**	**123.0**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**783.4**	**847.1**	**508.2**	**636.1**	**427.7**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**39.8**	**41.4**	**37.2**	**38.2**	**36.3**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33.5**	**36.3**	**29.6**	**31.5**	**28.2**
CO_2 emission	**kg/s**	**2.13**	**2.13**	**1.57**	**1.84**	**1.39**
Specific CO_2 emissions per MW net produced	**kg/MWh**	**9.8**	**9.1**	**11.1**	**10.4**	**11.7**

2.3.2 Equipment list

A comparative equipment list between Case 4.1 and the current scenario is reported below in Table 4.

Table 4. Scenario 1 comparative equipment list

Solvent storage for USC PC			
Unit 3000 - Steam turbine island package			
Equipment	**Reference plant**	**Scenario 1**	**Remarks**
Steam turbine	930 MWe Gross	970 MWe Gross	
Steam turbine condenser	678 MWth	775 MWth	Sea water heat exchanger tubes: titanium; shell: CS
Condensate pump	2 x 950 kW 1530 m3/h x 172 m	2 x 1120 kW 1710 m3/h x 172 m	One operating, one spare
Unit 4000 - CO_2 Capture Unit			
Equipment	**Reference plant**	**Scenario 1**	**Remarks**
Regeneration section	CO_2 outlet flow = 17,300 kmol/h Reboiler duty = 605 MW th	No changes in terms of design condition	Including: - stripper - stripper packing - stripper bottom pumps - surplus water pump - amine filter package - reclaimer - semilean flash drum - cross exchanger - flash preheater - overhead stripper condenser - stripper reboiler - lean solvent cooler
Rich solvent storage tank *(for flexible operation)*	not foreseen	2 x 71'200 m3 (Diameter: 73 m H: 17 m)	Floating roof atmospheric storage tank Material: CS with internal lining
Lean solvent storage tank *(for flexible operation)*	not foreseen	2 x 71'200 m3 (Diameter: 73 m H: 17 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Rich solvent storage pumps	not foreseen	4 x 560 kW 2010 m3/h x 70 m	One pump in operation, one spare for each rich solvent tank
Lean solvent storage pumps	not foreseen	4 x 630 kW 1977 m3/h x 80 m	One pump in operation, one spare for each lean solvent tank
Unit 5000 - CO_2 Compression Unit			
Equipment	**Reference plant**	**Scenario 1**	**Remarks**
Compression package *(2x50% train)*	CO2 flow = 387,000 Nm3/h each train	No changes in terms of design condition	Including: - four stage compressor - intercoolers - dryers - CO2 pumps

2.3.3 Investment costs

A summary of the total CAPEX for this plant configuration developed from the previously shown comparative equipment list is reported in Table 5.

Table 5. Case 2.1a Scenario 1 – Total Plant Cost

wood.

Case 4.1a - Scenario 1
(USC PC with CCS - 99% CO2 capture rate)

CONTRACT:	1-BD-1046A
CLIENT:	IEA GHG
LOCATION:	THE NETHERLANDS
DATE:	MAY 2019
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	78,800,000	298,000,000	27,000,000	50,900,000	175,200,000	408,600,000	47,900,000	253,000,000	1,339,400,000	1) Gross Power Output [MW]:	967.9
										-	Specific Cost	2607 €/kWe
2	CONSTRUCTION	30,800,000	187,900,000	5,800,000	20,000,000	67,600,000	112,500,000	36,000,000	111,400,000	572,000,000		
											2 Net Power Output [MW]:	847.1
3	**DIRECT FIELD COST**	**109,600,000**	**485,900,000**	**32,800,000**	**70,900,000**	**242,800,000**	**521,100,000**	**83,900,000**	**364,400,000**	**1,911,400,000**	Specific Cost	2979 €/kWe
4	OTHER COSTS	6,400,000	33,400,000	1,600,000	4,100,000	14,100,000	26,900,000	6,100,000	22,000,000	114,600,000		
5	EPC SERVICES	15,400,000	68,000,000	4,700,000	9,900,000	34,100,000	73,100,000	11,800,000	51,000,000	268,000,000		
											EXCLUSIONS	
6	**TOTAL INSTALLED COST**	**131,400,000**	**587,300,000**	**39,100,000**	**84,900,000**	**291,000,000**	**621,100,000**	**101,800,000**	**437,400,000**	**2,294,000,000**	Spare parts	
											Inventories of fuel and chemicals	
7	PROJECT CONTINGENCY	13,100,000	58,700,000	3,900,000	8,500,000	29,100,000	62,100,000	10,200,000	43,700,000	229,300,000	Start-up costs	
											Insurance	
8	PROCESS CONTINGENCY	-	-	-	-	-	-	-	-	-	Local taxes and fees	
										-		
9	**TOTAL PLANT COST**	**144,500,000**	**646,000,000**	**43,000,000**	**93,400,000**	**320,100,000**	**683,200,000**	**112,000,000**	**481,100,000**	**2,523,300,000**		

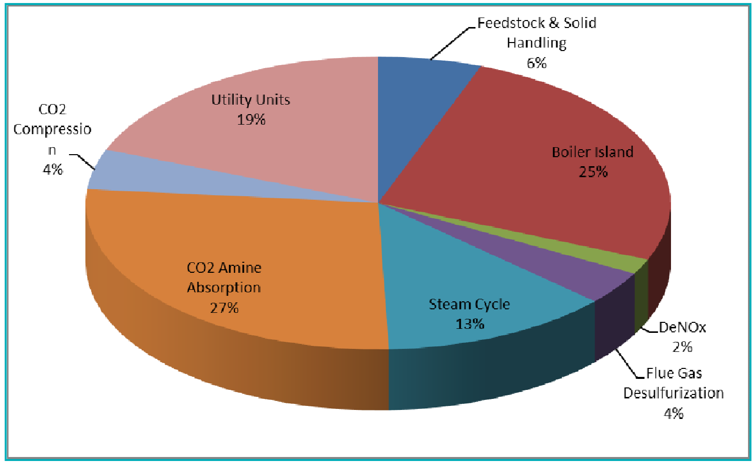

Figure 3. Case 2.1a Scenario 1 – Unit percentage weight on TPC

2.4 Scenario 2 – Solvent storage to reduce reboiler size

For this scenario, peak time regeneration was slightly raised until regeneration values between peak and off load were similar.

In this situation, the reboiler for the regeneration section can be downsized accordingly. Due to the lower storage of solvent, two much smaller storage tanks are needed for each service (two for lean solvent, two for rich solvent). In Figure 4 the total tank content weekly variation is reported.

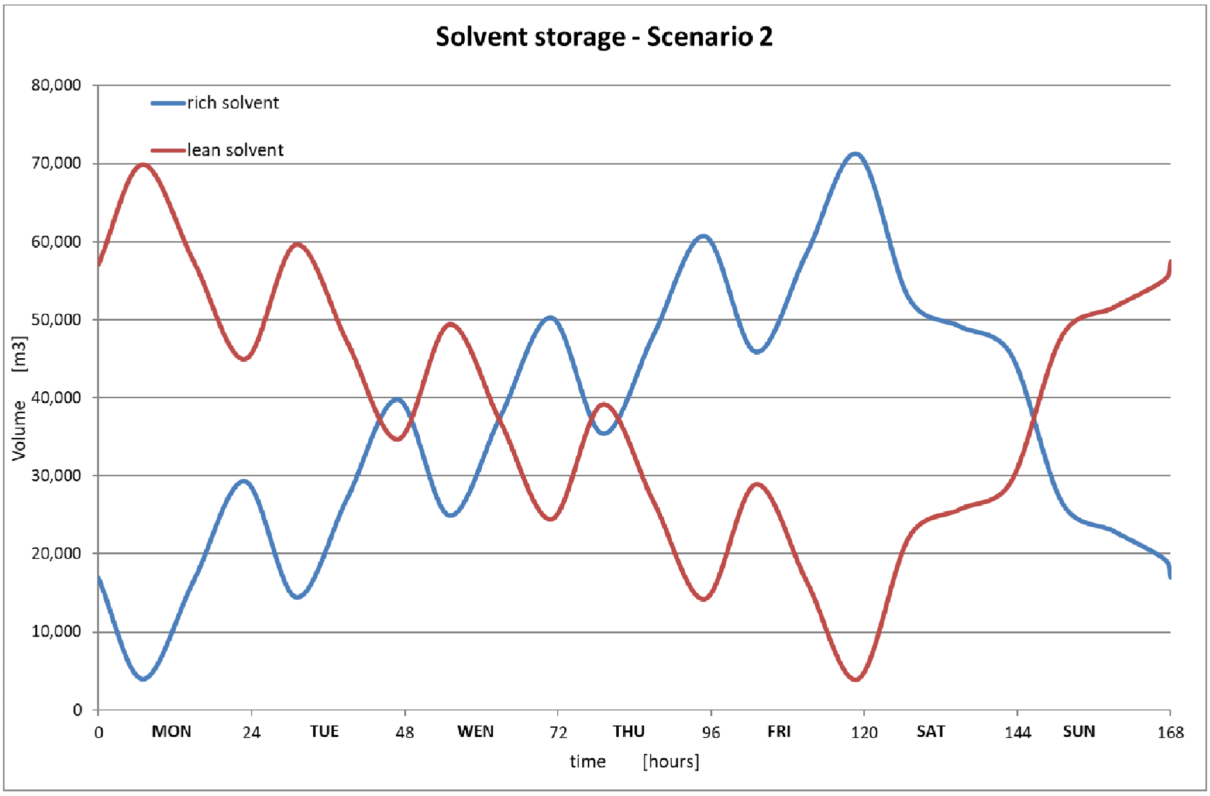

Figure 4. Weekly solvent storage cycle for scenario 2

2.4.1 *Performances*

Performance comparison between the current flexibility scenario and the reference Case 4.1 is shown below in Table 6.

Table 6. Scenario 2 performance report

USC PC Plant - 99% CO2 recovery - Solvent storage system						
Scenario 2 - Solvent storage to reduce reboiler size						
OVERALL PLANT PERFORMANCES						
		Reference case	Weekday peak	Weekday offpeak	Weekend peak	Weekend offpeak
Coal Flowrate (fresh, air dried basis)	t/h	325.0	325.0	225.9	266.5	196.6
Coal LHV (air dried basis)	kJ/kg	25870.0	25870.0	25870.0	25870.0	25870.0
Main steam flow	kg/s	794.0	794.0	519.3	628.8	443.3
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2335.5**	**2335.5**	**1623.2**	**1915.1**	**1413.0**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**929.2**	**952.9**	**608.8**	**739.7**	**516.6**
POWER PLANT PERFORMANCES						
Feedstock and solids handling	MWe	3.4	3.4	2.4	2.8	2.1
Boiler Island, including FGD	MWe	26.4	26.4	18.3	21.6	16.0
Power Islands consumption	MWe	4.7	4.7	3.3	3.9	2.9
Utility & Units consumptions	MWe	17.3	17.3	12.0	14.2	10.5
CO2 Capture Unit + Compression	MWe	91.7	78.8	78.8	78.8	74.8
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**143.5**	**130.6**	**114.8**	**121.3**	**106.3**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**783.4**	**822.2**	**493.9**	**618.4**	**410.3**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**39.8**	**40.8**	**37.5**	**38.6**	**36.6**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33.5**	**35.2**	**30.4**	**32.3**	**29.0**
CO2 emission	**kg/s**	**2.13**	**2.13**	**1.48**	**1.75**	**1.29**
Specific CO2 emissions per MW net produced	**kg/MWh**	**9.8**	**9.3**	**10.8**	**10.2**	**11.3**

2.4.2 *Equipment list*

A comparative equipment list between Case 4.1 and the current scenario is reported below in Table 7.

Table 7. Scenario 2 comparative equipment list

Solvent storage for USC PC			
Unit 3000 - Steam turbine island package			
Equipment	**Reference plant**	**Scenario 2**	**Remarks**
Steam turbine	930 MWe Gross	953 MWe Gross	
Steam turbine condenser	678 MWth	732 MWth	Sea water heat exchanger tubes: titanium; shell: CS
Condensate pump	2 x 950 kW 1530 m3/h x 172 m	2 x 1000 kW 1615 m3/h x 172 m	One operating, one spare
Unit 4000 - CO_2 Capture Unit			
Equipment	**Reference plant**	**Scenario 2**	**Remarks**
Regeneration section	CO_2 outlet flow = 17,300 kmol/h Reboiler duty = 605 MW th	CO_2 outlet flow = 14,900 kmol/h Reboiler duty = 520 MW th	Including: - stripper - stripper packing - stripper bottom pumps - surplus water pump - amine filter package - reclaimer - semilean flash drum - cross exchanger - flash preheater - overhead stripper condenser - stripper reboiler - lean solvent cooler
Rich solvent storage tank *(for flexible operation)*	not foreseen	2 x 37'300 m3 (Diameter: 50 m H: 19 m)	Floating roof atmospheric storage tank Material: CS with internal lining
Lean solvent storage tank *(for flexible operation)*	not foreseen	2 x 37'300 m3 (Diameter: 50 m H: 19 m)	Floating roof atmospheric storage tank Material: CS + 3mm CA
Rich solvent storage pumps	not foreseen	4 x 355 kW 1300 m3/h x 70 m each	One pump in operation, one spare for each rich solvent tank
Lean solvent storage pumps	not foreseen	4 x 400 kW 1290 m3/h x 80 m each	One pump in operation, one spare for each lean solvent tank
Unit 5000 - CO_2 Compression Unit			
Equipment	**Reference plant**	**Scenario 2**	**Remarks**
Compression package *(2x50% train)*	CO2 flow = 387,000 Nm3/h each train	CO2 flow = 333,000 Nm3/h each train	Including: - four stage compressor - intercoolers - dryers - CO2 pumps

2.4.3 Investment costs

A summary of the total CAPEX for this plant configuration developed from the previously shown comparative equipment list is reported in Table 8.

Table 8. Case 4.1a Scenario 2 – Total Plant Cost

wood.	Case 4.1a - Scenario 2 (USC PC with CCS - 99% CO2 capture rate - Solvent storage)	
	CONTRACT:	1-BD-1046A
	CLIENT:	IEA GHG
	LOCATION:	THE NETHERLANDS
	DATE:	MAY 2019
	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	78,800,000	298,000,000	27,000,000	50,900,000	173,200,000	376,900,000	41,700,000	253,000,000	1,299,500,000	1) Gross Power Output [MW]: 952.9
										-	Specific Cost 2574 €/kWe
2	CONSTRUCTION	30,800,000	187,900,000	5,800,000	20,000,000	66,800,000	103,700,000	31,400,000	111,400,000	557,800,000	
											2 Net Power Output [MW]: 822.2
3	**DIRECT FIELD COST**	**109,600,000**	**485,900,000**	**32,800,000**	**70,900,000**	**240,000,000**	**480,600,000**	**73,100,000**	**364,400,000**	**1,857,300,000**	Specific Cost 2983 €/kWe
4	OTHER COSTS	6,400,000	33,400,000	1,600,000	4,100,000	13,900,000	24,800,000	5,300,000	22,000,000	111,500,000	
5	EPC SERVICES	15,400,000	68,000,000	4,700,000	9,900,000	33,600,000	67,400,000	10,300,000	51,000,000	260,300,000	
											EXCLUSIONS
6	**TOTAL INSTALLED COST**	**131,400,000**	**587,300,000**	**39,100,000**	**84,900,000**	**287,500,000**	**572,800,000**	**88,700,000**	**437,400,000**	**2,229,100,000**	Spare parts
											Inventories of fuel and chemicals
7	PROJECT CONTINGENCY	13,100,000	58,700,000	3,900,000	8,500,000	28,800,000	57,300,000	8,900,000	43,700,000	222,900,000	Start-up costs
											Insurance
8	PROCESS CONTINGENCY	-	-	-	-	-	-	-	-	-	Local taxes and fees
										-	
9	**TOTAL PLANT COST**	**144,500,000**	**646,000,000**	**43,000,000**	**93,400,000**	**316,300,000**	**630,100,000**	**97,600,000**	**481,100,000**	**2,452,000,000**	

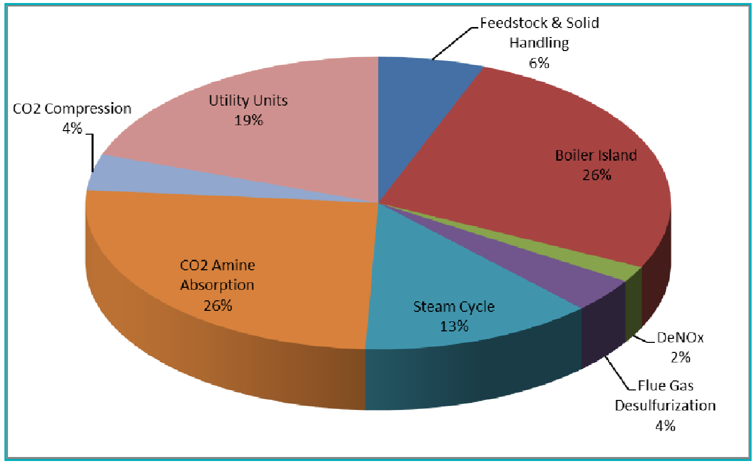

Figure 5. Case 2.1a Scenario 2 – Unit percentage weight on TPC

3 Case 4.1b – Variable Capture

3.1 Introduction

This Case 4.1b shows how USC PC plants with post-combustion capture of the CO_2 can also be maintained in continuous operation without operating the carbon capture and compression sections.

Depending on possible CO_2 emission allowances cost, this operating flexibility may improve the economics of the plant, because of its resulting higher power production.

3.2 Description of the cases

Flexible CO_2 capture operation is particularly suited for post-combustion CO_2 capture systems, as it is possible to totally by-pass the CO_2 capture unit, directly venting to atmosphere the flue gas from the coal furnace similarly to a conventional USC PC plant without carbon capture. When the capture unit is bypassed, around 770 t/h of CO_2 are released to the atmosphere instead of being captured and compressed.

In this operating mode, the energy penalties related to the CO_2 capture and compression units, as well as the steam requirement for solvent regeneration, are avoided, leading to an overall higher plant net power production.

As no heat is required by the regenerator boiler, the low-pressure steam from the exhaust steam from the MP module of the steam turbine are used to generate additional power in the LP module.

The resulting LP steam entering this section of the machine is much larger than the flowrate of the reference case. Therefore, the low-pressure steam turbine module, the condenser and condensate system shall be properly designed to accommodate the increased steam flow during unabated mode. The power plant was designed to operate efficiently in this condition, while allowing partial load operation when CO_2 is captured and compressed.

3.3 Results

In the following pages, techno-economic results obtained for this configuration are reported.

3.3.1 Performances

Performance comparison between the current flexibility scenario and the reference Case 4.1 is shown below in Table 9.

Table 9. Case 4.1b performance report

USC PC with CCS - 99% CO2 recovery - Variable CO2 capture				
ON/OFF CCU capability				
OVERALL PLANT PERFORMANCES				
		Reference case	CCU OFF	CCU ON
Coal Flowrate (fresh, air dried basis)	t/h	325.0	325.0	325.0
Coal LHV (air dried basis)	kJ/kg	25870.0	25870.0	25870.0
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2335.5**	**2335.5**	**2335.5**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**929.2**	**1066.4**	**924.5**
POWER PLANT PERFORMANCES EXCLUDING CO_2 RECOVERY				
Feedstock and solids handling	MWe	3.4	3.4	3.4
Boiler Island, including FGD	MWe	26.4	26.4	26.4
Power Islands consumption	MWe	4.7	6.0	6.0
Utility & Units consumptions	MWe	17.3	18.0	18.0
CO_2 Capture Unit + Compression	MWe	91.7	-	91.7
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**143.5**	**53.8**	**145.5**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**783.4**	**1012.6**	**779.0**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**39.8**	**45.7**	**39.6**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33.5**	**43.4**	**33.4**
CO_2 emission	**kg/s**	**2.13**	**213.13**	**2.13**
Specific CO_2 emissions per MW net produced	**t/MWh**	**9.8**	**757.7**	**9.8**

3.3.2 *Equipment list*

A comparative equipment list between Case 4.1 and the current scenario is reported below in Table 10.

Table 10. Case 4.1b comparative equipment list

Unit 3000 -Power Island			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
Steam turbine	933 MWe gross	1070 MWe gross	
Steam turbine condenser	691 MWth	1064 MWth	Sea water heat exchanger tubes: titanium; shell: CS
Condensate pumps	1 x 950 KW 1530 m3 x 172 m	1 x 1600 KW 2330 m3 x 174 m	One operating one spare

3.3.3 *Investment costs*

A summary of the total CAPEX for this plant configuration developed from the previously shown comparative equipment list is reported in Table 11.

Table 11. Case 4.1b – Total Plant Cost

wood.	Case 4.1b (USC PC with CCS - 99% CO2 capture rate - On/Off capabilities for CCU)									CONTRACT: 1-BD-1046A CLIENT: IEA GHG LOCATION: THE NETHERLANDS DATE: MAY 2019 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	78,800,000	298,000,000	27,000,000	50,900,000	182,400,000	362,800,000	47,900,000	253,000,000	1,300,800,000	1) Gross Power Output [MW]: 1066.4
										-	Specific Cost 2303 €/kWe
2	CONSTRUCTION	30,800,000	187,900,000	5,800,000	20,000,000	67,100,000	99,900,000	36,000,000	111,400,000	558,900,000	
											2 Net Power Output [MW]: 1012.6
3	**DIRECT FIELD COST**	**109,600,000**	**485,900,000**	**32,800,000**	**70,900,000**	**249,500,000**	**462,700,000**	**83,900,000**	**364,400,000**	**1,859,700,000**	Specific Cost 2425 €/kWe
4	OTHER COSTS	6,400,000	33,400,000	1,600,000	4,100,000	14,200,000	23,900,000	6,100,000	22,000,000	111,700,000	
5	EPC SERVICES	15,400,000	68,000,000	4,700,000	9,900,000	35,000,000	64,900,000	11,800,000	51,000,000	260,700,000	
											EXCLUSIONS
6	**TOTAL INSTALLED COST**	**131,400,000**	**587,300,000**	**39,100,000**	**84,900,000**	**298,700,000**	**551,500,000**	**101,800,000**	**437,400,000**	**2,232,100,000**	Spare parts
											Inventories of fuel and chemicals
7	PROJECT CONTINGENCY	13,100,000	58,700,000	3,900,000	8,500,000	29,900,000	55,200,000	10,200,000	43,700,000	223,200,000	Start-up costs
											Insurance
8	PROCESS CONTINGENCY	-	-	-	-	-	-	-	-	-	Local taxes and fees
										-	
9	**TOTAL PLANT COST**	**144,500,000**	**646,000,000**	**43,000,000**	**93,400,000**	**328,600,000**	**606,700,000**	**112,000,000**	**481,100,000**	**2,455,300,000**	

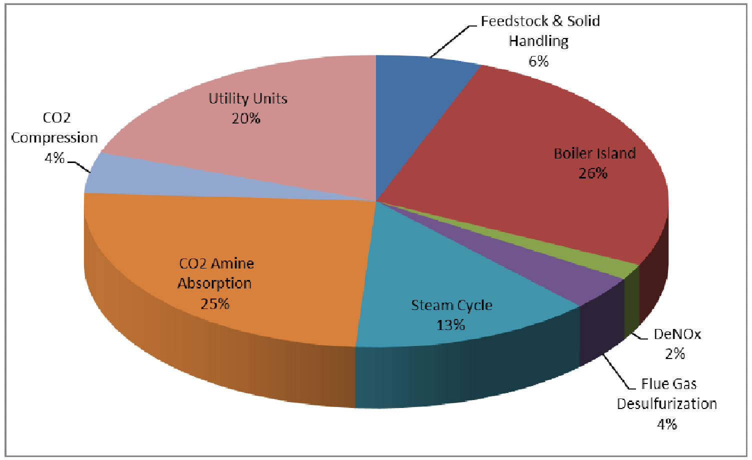

Figure 6. Case 4.1b – Unit percentage weight on TPC

4 Case 4.1c – Energy storage

4.1 Introduction

This Case 4.1c shows coupling of USC PC plants with post-combustion capture of the CO_2 together with a Battery Energy Storage System – BESS.

This approach might become attractive in the future, as it allows to cover short and extreme peak demand without designing the plant for that specific situation.

4.2 Description of the cases

To develop this case, a slightly modified electricity demand weekly curve – shown in Figure 7 - was used.

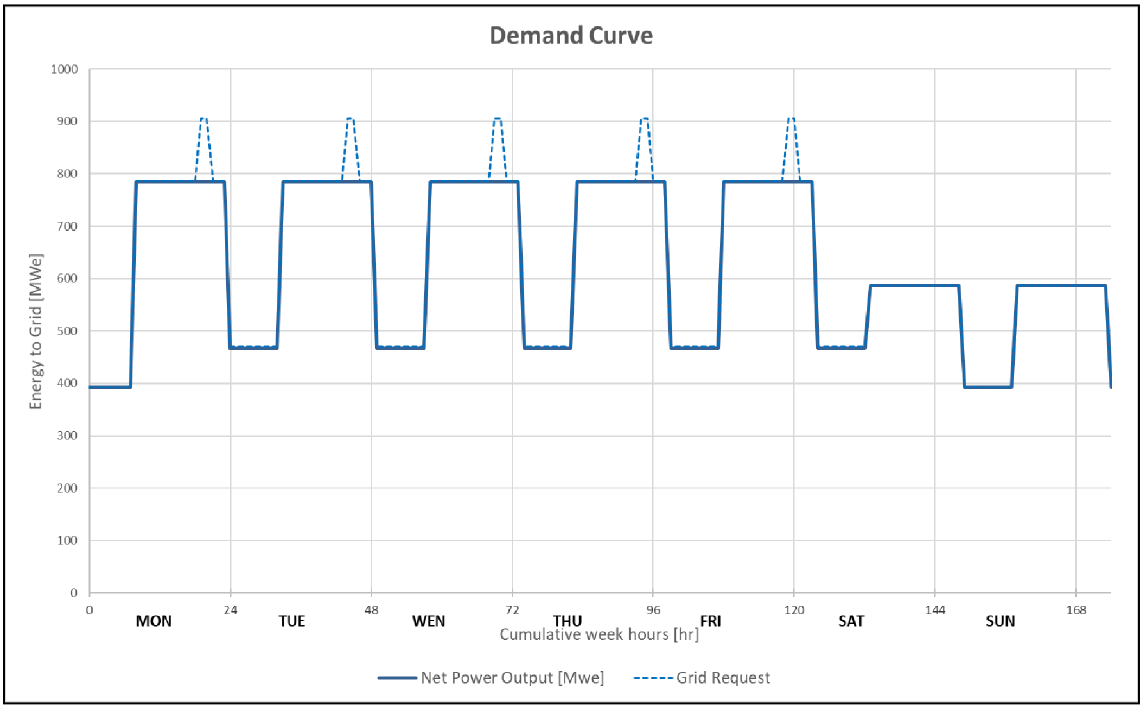

Figure 7. Case 4.1c – Modified weekly energy demand curve

This situation assumes that during the week, there is a peak in electricity demand (about +15% plant net power output request) for two hours in the evening, due to people coming back from work and the sun setting.

In this scenario, it does not make sense to design the plant for 2 hours, 5 days a week operation. It is more interesting to investigate the possibility to use a large-scale battery energy storage system.

The batteries should be chosen in capacity to provide the required extra peak energy, and they can be charged overnight by running the plant at a slightly higher load during weekday off-peak hours.

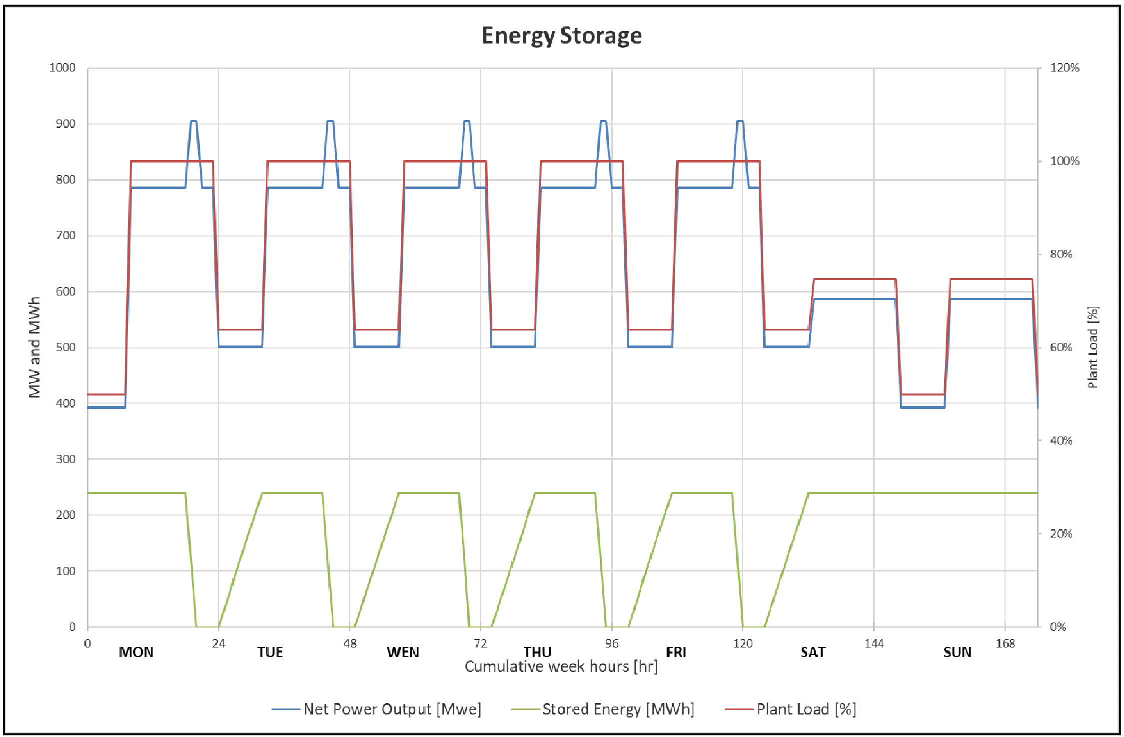

Figure 8. Case 4.1c – Weekly Plant Load and Power Output

In Figure 8, plant load, plant power output and battery charge status are shown over the course of the week. Compared to the equivalent NGCC case, here battery happens during the course of the night since there is no need to shut the plant down as soon as possible. Detailed load figures are reported in Table 12.

Table 12. Case 4.1c conditions summary

USC PC		Reference Case	240 MWh Energy Storage
Weekday daytime operation (70 hours/week)			
Power island operating condition			
Boiler thermal load	-	100%	100%
Net power output	MWe	785.7	785.7
Plant Load		**100%**	**100%**
Daily peak operation (10 hours/week)			
Power island operating condition			
Boiler thermal load	-	100%	100%
Net power output	MWe	785.7	905.7
Plant Load		**100%**	**100%**
Weekday nighttime operation (40 hours/week)			
Power island operating condition			
Boiler thermal load	-	62%	66%
Net power output	MWe	470.5	470.5
Plant Load		**60%**	**60%**
Weekend daytime operation (32 hours/week)			
Power island operating condition			
Boiler thermal load	-	77%	77%
Net power output	MWe	586.3	586.3
Plant Load		**75%**	**75%**
Weekend nighttime operation (16 hours/week)			
Power island operating condition			
Boiler thermal load	-	53%	53%
Net power output	MWe	392.2	392.2
Plant Load		**50%**	**50%**
Consideration			
		The power island should be sized for the 2 hours a day peak load but it is not attractive	By increasing the boiler load it is possible to charge the BESS during mon-fri nights for use during peak hours

4.3 Results

In the following pages, techno-economic results obtained for this configuration are reported. For this calculation, Wood did not account for specific losses and inefficiencies that are involved in the charge/discharge cycle of a battery (only storage oversizing to account for degradation (reduction of capacity) of 7% as per industry standard). The reason for this is that the information is not easily available as vendors have no commercial experience in such a large scale of BESS.

4.3.1 *Performances*

Performance comparison between the current flexibility scenario and the reference Case 4.1 is shown below in Table 13.

Table 13. Case 4.1c performance report

Case 4.1c - Battery Energy Storage Systems applied to USC PC						
OVERALL PERFORMANCES OF AN NGCC PLANT WITH BESS						
OVERALL PLANT PERFORMANCES						
		Base Load	Weekday peak	Weekday offpeak	Weekend peak	Weekend offpeak
Coal Flowrate (fresh, air dried basis)	t/h	325.0	325.0	214.5	250.3	172.3
Coal LHV (air dried basis)	kJ/kg	25870.0	25870.0	25870.0	25870.0	25870.0
Main steam flow	kg/s	794.0	794.0	489.5	584.5	381.9
THERMAL ENERGY OF FEEDSTOCK (based on coal LHV) (A)	**MWt**	**2335.5**	**2335.5**	**1541.4**	**1798.3**	**1237.8**
GROSS ELECTRIC POWER OUTPUT OF POWER PLANT (D)	**MWe**	**929.2**	**929.2**	**595.6**	**696.7**	**468.3**
POWER PLANT PERFORMANCES						
Feedstock and solids handling	MWe	3.4	3.4	2.2	2.6	1.8
Boiler Island, including FGD	MWe	26.4	26.4	17.4	20.3	14.0
Power Islands consumption	MWe	4.7	5.0	3.1	3.6	2.5
Utility & Units consumptions	MWe	17.3	17.3	11.4	13.3	9.2
CO_2 Capture Unit + Compression	MWe	91.7	91.7	60.5	70.6	48.6
ELECTRIC POWER CONSUMPTION OF POWER PLANT	**MWe**	**143.5**	**143.8**	**94.6**	**110.4**	**76.1**
NET ELECTRIC POWER OUTPUT OF POWER PLANT (C)	**MWe**	**785.7**	**785.4**	**501.0**	**586.3**	**392.2**
Gross electrical efficiency (D/A *100) (based on coal LHV)	**%**	**39.8**	**39.8**	**38.6**	**38.7**	**37.8**
Net electrical efficiency (C/A*100) (based on coal LHV)	**%**	**33.6**	**33.6**	**32.5**	**32.6**	**31.7**
BESS Energy Storage Flow	**MWe**	**-**	**120.0**	**-30.0**	**-**	**-**
Actual NET ELECTRIC POWER OUTPUT	**MWe**	**785.7**	**905.4**	**471.0**	**586.3**	**392.2**
CO_2 emission	**kg/s**	**2.12**	**2.12**	**1.40**	**1.63**	**1.12**
Specific CO_2 emissions per MW net produced	**kg/MWh**	**9.7**	**8.4**	**10.7**	**10.0**	**10.3**

4.3.2 *Equipment list*

A comparative equipment list between Case 4.1 and the current scenario is reported below in Table 14. This equipment list and the following economic estimate are based on the assumption that the single cells composing the BESS are independently air-cooled. This is common practice for commercial installation, but for a installed storage of this size (first of a kind) water cooling may be preferable. In that case, adjustments to cooling system and cooling tower design are needed.

Table 14. Case 4.1c comparative equipment list

Unit 7000 - Battery Energy Storage Solution			
Equipment	**Reference plant**	**Flexible plant**	**Remarks**
BESS Package	Not foreseen	260 MWh Battery	Including: - Lithium Ion battery packs - Auxiliary equipment - Cooling circuit - Control system

4.3.3 *Investment costs*

A summary of the total CAPEX for this plant configuration developed from the previously shown comparative equipment list is reported in Table 15.

Table 15. Case 4.1c – Total Plant Cost

wood.

Case 4.1c
(USC PC with CCS - 99% CO2 capture rate - Battery Energy Storage System)

CONTRACT:	1-BD-1046A
CLIENT:	IEA GHG
LOCATION:	THE NETHERLANDS
DATE:	MAY 2019
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	UNIT 7000 BESS	TOTAL COST EURO	NOTES / REMARKS	
1	DIRECT MATERIAL	78,800,000	298,000,000	27,000,000	50,900,000	170,200,000	362,800,000	47,900,000	253,000,000	107,800,000	1,396,400,000	1) Gross Power Output [MW]:	929.2
											-	Specific Cost	2837 €/kWe
2	CONSTRUCTION	30,800,000	187,900,000	5,800,000	20,000,000	65,600,000	99,900,000	36,000,000	111,400,000	42,200,000	599,600,000		
												2 Net Power Output [MW]:	783.4
3	**DIRECT FIELD COST**	**109,600,000**	**485,900,000**	**32,800,000**	**70,900,000**	**235,800,000**	**462,700,000**	**83,900,000**	**364,400,000**	**150,000,000**	**1,996,000,000**	Specific Cost	3365 €/kWe
4	OTHER COSTS	6,400,000	33,400,000	1,600,000	4,100,000	13,700,000	23,900,000	6,100,000	22,000,000	8,800,000.00	120,000,000		
5	EPC SERVICES	15,400,000	68,000,000	4,700,000	9,900,000	33,000,000	64,900,000	11,800,000	51,000,000	21,100,000	279,800,000		
												EXCLUSIONS	
6	**TOTAL INSTALLED COST**	**131,400,000**	**587,300,000**	**39,100,000**	**84,900,000**	**282,500,000**	**551,500,000**	**101,800,000**	**437,400,000**	**179,900,000**	**2,395,800,000**	Spare parts	
												Inventories of fuel and chemicals	
7	PROJECT CONTINGENCY	13,100,000	58,700,000	3,900,000	8,500,000	28,300,000	55,200,000	10,200,000	43,700,000	17,990,000	239,590,000	Start-up costs	
												Insurance	
8	PROCESS CONTINGENCY	-	-	-	-	-	-	-	-	-	-	Local taxes and fees	
											-		
9	**TOTAL PLANT COST**	**144,500,000**	**646,000,000**	**43,000,000**	**93,400,000**	**310,800,000**	**606,700,000**	**112,000,000**	**481,100,000**	**197,890,000**	**2,635,390,000**		

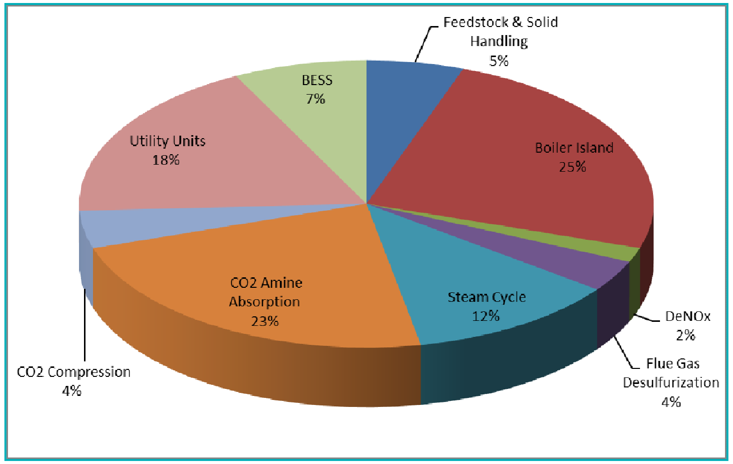

Figure 9. Case 4.1c – Unit percentage weight on TPC

5 Trade-offs between efficiency and flexibility

5.1 Introduction

The previous sections examined the options for improving the operational flexibility of coal-fired power plants, assessing performance and capital cost of various solutions.

All the analysed solutions are based on modifications to the design and the operating approach of the plant in order to maximize power production during peak time (when electricity price should be high) by penalising plant efficiency during off-peak time (when electricity price should be low).

As part of the study, a deeper economic analysis of these flexibility cases has also been performed, to assess the trade-offs between plant efficiency and operational flexibility of these plant types for various simulated scenarios of the electricity market.
The qualitative and quantitative analysis will focus on the assessment of the technical solutions, evaluating their economic attractiveness, e.g. in terms of pay-back time.

The main assumptions and results of this analysis are presented in the following paragraphs.

5.2 Electricity Market Scenarios

As far as operating flexibility is concerned, market scenarios can be categorised based on the level of wholesale electricity price and the variability of the price between peak time and off-peak time.

It is remarked that the magnitude of the gap between peak time and off-peak time pries may be representative of the penetration of renewable energy sources (especially solar) in the electricity market. The higher their penetration, the lower the availability of plants that can produce power during off-peak periods (typically in the night-time). This can explain an increase of off-peak electricity price, as recorded in many countries over the last years.
Regarding price level, the low level is intended to roughly represent current average wholesale market price in EU. For power plants with CO_2 capture, the high scenario can be instead interpreted as a scenario where the CO_2 capture is more adequately remunerated.

The following four market scenarios are therefore considered:

Table 16. Assumed electricity market scenarios (prices in €/MWh)

Market Scenarios (prices in €/MWh)		
	LOW variability of electricity price between peak and off-peak	**HIGH variability of electricity price between peak and off-peak**
LOW electricity price level	**Scenario L1** Peak: 70 Off-peak (working): 60 Weekend: 55	**Scenario L2** Peak: 70 Off-peak (working): 50 Weekend: 40
HIGH electricity price level	**Scenario H1** Peak: 90 Off-peak (working): 75 Weekend: 65	**Scenario H2** Peak: 90 Off-peak (working): 60 Weekend: 40

For each market scenario a sensitivity has been carried out regarding Carbon pricing for the Variable Capture option, in which carbon pricing is used to assess the penalties of not capturing the CO_2 during peak time.
The following carbon price levels have been assumed:

- LOW: 10 €/t,;
- MEDIUM: 25 €/t;
- HIGH: 40 €/t.

5.3 Main results

For each flexibility case, the simplified financial calculation is based on differential CAPEX with respect to reference case, as estimated in the previous sections of this chapter, and differential OPEX (cost and revenues). The differential OPEX is calculated considering the changes in revenues (based on given electricity prices), variable costs and maintenance costs, whilst it is assumed that all the other fixed cost are the same as the reference case.
The simplified financial assessment has ultimately estimated the pay-back time of the associated extra-CAPEX to enhance operating flexibility
The main results are shown in

Table 17.

Table 17. Main results of flexibility cases simplified financial model

			Market scenarios			
			L1	L2	H1	H2
Case 4.1a - Scenario 1	Delta CAPEX	M€	85.8	85.8	85.8	85.8
	Delta OPEX*	M€/y	13.5	11.3	20.3	16.8
	Pay-back time	years	7.0	7.7	4.3	5.2
Case 4.1a - Scenario 2	Delta CAPEX	M€	14.5	14.5	14.5	14.5
	Delta OPEX*	M€/y	8.9	7.6	13.1	10.9
	Pay-back time	years	2.0	2.0	1.2	1.4
Case 4.1b - LOW carbon tax	Delta CAPEX	M€	17.8	17.8	17.8	17.8
	Delta OPEX*	M€/y	27.6	27.7	44.6	44.8
	Pay-back time	years	1.0	0.7	0.4	0.4
Case 4.1b - MEDIUM carbon tax	Delta CAPEX	M€	17.8	17.8	17.8	17.8
	Delta OPEX*	M€/y	-19.8	-19.7	-2.8	-2.6
	Pay-back time	years	N/A	N/A	N/A	N/A
Case 4.1b - HIGH carbon tax	Delta CAPEX	M€	17.8	17.8	17.8	17.8
	Delta OPEX*	M€/y	-67.2	-67.1	-50.2	-50.0
	Pay-back time	years	N/A	N/A	N/A	N/A
Case 4.1c	Delta CAPEX	M€	197.9	197.9	197.9	197.9
	Delta OPEX*	M€/y	-0.2	-0.2	1.1	1.1
	Pay-back time	years	N/A	N/A	185.2	184.1

** A positive figure indicates an increased operating margin (revenues minus costs) with respect to the reference non-flexible case*

The following remarks can be drawn from the analysis results:

- The flexibility case showing the best attractiveness from a simplified financial standpoint is Case 4.1a – Solvent Storage Scenario 2, independently on the market scenario considered. It is remarked that this case is characterized by a sensible reduction of the regeneration section sizing in the CO_2 capture unit, i.e. 12% decrease. Consequently, on one hand the plant is flexible with respect to the assumed electricity demand curve, but, on the other hand, the downsizing of the regeneration could represent a significant operating constraint in case the demand curve changed.

- The variable capture (On/Off) option (case 4.1b) is very sensitive to the considered carbon pricing level. The pay-back time is excellent only in the Low carbon pricing scenario, whereas in the Medium and High carbon pricing scenarios the additional investment is not paid back at all.

- Case 4.1c (Energy Storage via batteries) has a very high additional CAPEX, which is not paid back in the modeled market scenario and it is expected to be very difficult to pay back in any market scenarios. The specific cost of battery storage is still unattractive, especially at the large scales considered in this study. The attractiveness of this option, as studied in the present work, strictly relies upon future cost improvements of this technologies.

- The financial performance of the cases tends to improve at higher electricity price levels, as the beneficial effects of flexibilization are amplified at higher electricity selling prices.

- The results of the analysis are marginally sensitive to the magnitude of price variability between peak-time and off-peak time, as a significant portion of the revenues form electricity sale is concentrated during peak-time as per considered weekly demand curve.

CLIENT	:	IEAGHG
PROJECT NAME	:	UPDATE TECHNO-ECONOMIC BENCHMARKS FOR FOSSIL FUEL-FIRED POWER PLANTS WITH CO_2 CAPTURE
DOCUMENT NAME	:	IMPACT OF STEAM CONDITIONS IN USC PC POWER PLANTS
CONTRACT N°	:	1-BD-1046 A

ISSUED BY	:	M.MENSI
CHECKED BY	:	V.TOTA
APPROVED BY	:	V.TOTA

Date	Revised Pages	Issued by	Checked by	Approved by

TABLE OF CONTENT

GLOSSARY

CCS	Carbon Capture and Storage
NGCC	Natural Gas Combined Cycle
USC PC	Ultrasupercritical Pulverised Coal
FGR	Flue Gas Recirculation
EGR	Exhaust Gas Recirculation
CCU	Carbon Capture Unit
CMC	Ceramic Matrix Composite
ASU	Air Separation Unit
MCFC	Molten Carbonate Fuel Cell
TPC	Total Plant Cost
TIC	Total Installed Cost
MEL	Minimum Environmental Load
GT	Gas Turbine
ST	Steam Turbine

1 Introduction

The main objective of this chapter is to discuss the impact of more sever steam conditions, driven by energy efficiency enhancement, onto pulverized coal power plants operating flexibility. The considerations shown in this section are a collection of in-house experiences and information available (and currently studied) in literature.

In general, the most sought-after improvements in the pulverized coal sub-sector are:

- Achieving greater efficiencies
- Improving the flexibility

Both of these approaches are important. Greater thermal efficiency would allow for inherently greener processes thanks to a lower thermal input required to obtain a set electric power output, and improving the thermal efficiency of the power plant is historically done mainly by raising steam conditions (see Figure 1).

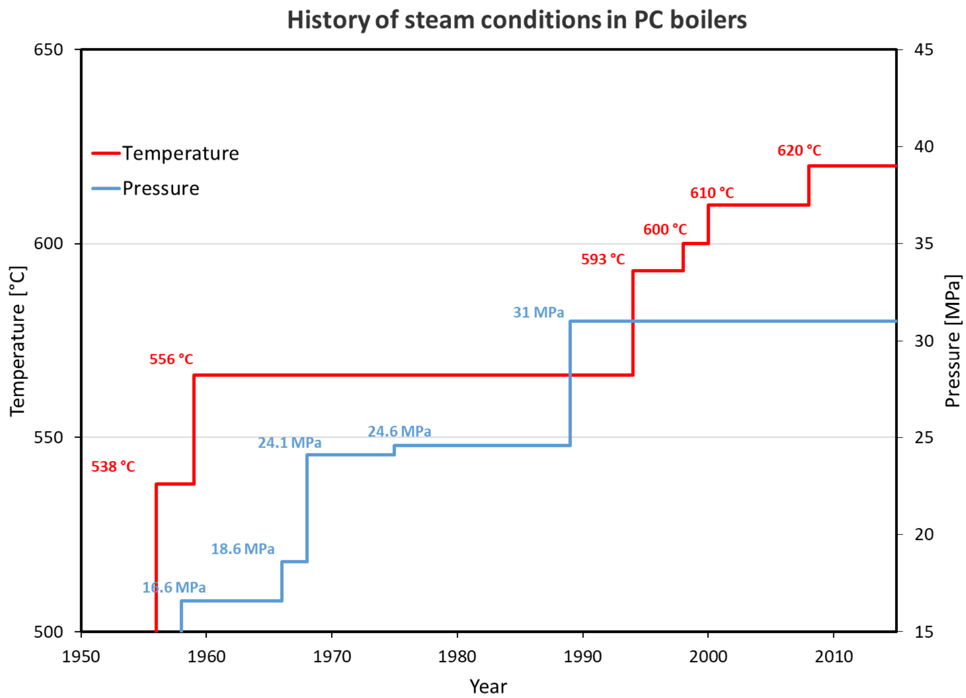

Figure 1. Evolution of PC boilers steam conditions in Japan. Data from [1].

Due to the greater contribution that renewables satisfy within the energy demand, conventional power plants are also required to meet stiff flexibility needs: certain types of renewable energies (i.e. wind and solar) are heavily susceptible to environmental conditions which affect the energy supply (directly correlated to the amount of sunlight available and the strength and speed of the winds in a certain moment of the day).

In pursuit of thermal efficiencies, development efforts are being invested into Advanced Ultra-SuperCritical (A-USC) steam generation for coal fired boilers. A-USC conditions refer to temperatures of 700/720 °C (but developers are aiming to achieve much higher) and 360 bar pressures, compared to the more traditional 600/620 °C and 290 bar.

Designing this kind of power plant introduced challenges on material selection and component design. In this chapter, an overview of the current material research is presented and the ability of the plant to operate in a flexible energy market is discussed.

2 Design considerations of A-USC PC power plants

Advanced USC PC plants go beyond the standard ultra-supercritical steam conditions to reach temperatures of 700/720 °C (but developers are aiming to achieve much higher) and 360 bar pressures, compared to the more traditional 600/620 °C and 290 bar.

This technology is currently in development and highly sought-after for the greater plant thermal efficiency it brings. Many different works in the year-span from 2011 to today have been published. In recent years, Japan has been leading the research in this field [1]. Research programs in both Europe and in the U.S. (respectively, the THERMIE AD700 program and the DOE Boiler Materials for Ultrasupercritical Coal Power Plants) are also pushing the research on materials with thermal capabilities up to 760 °C by involving boiler, steam turbine and valve producers [2].

Pushing steam generation above 700 °C and at such a high pressure involves significant changes in the engineering of the boiler, most notably in the material choice. This opened a wide range of research activities on development and characterization of new alloys specifically for this application.

These severe operating conditions allow for greater thermal efficiency compared to standard 600 °C configuration, but to be able to work at these values particular materials need to be used for plant design. Changing materials and operating envelope not only translates in a CAPEX increase, but the capability of the plant of flexible operation may be also affected.

2.1 Materials for Advanced USC PC plants

To achieve these operating conditions, new materials have been developed. In particular, good candidates for advanced USC conditions are Nickel-based alloys, however many other materials are being developed and tested by large research conglomerates (i.e. the MACPLUS European Programme [3], which involves different manufacturers).

When designing for new operating conditions, several parts of the plant might need to be revised. but only a limited number of components will have to work in contact with the advanced ultra-supercritical conditions and require new materials (see Figure 2).

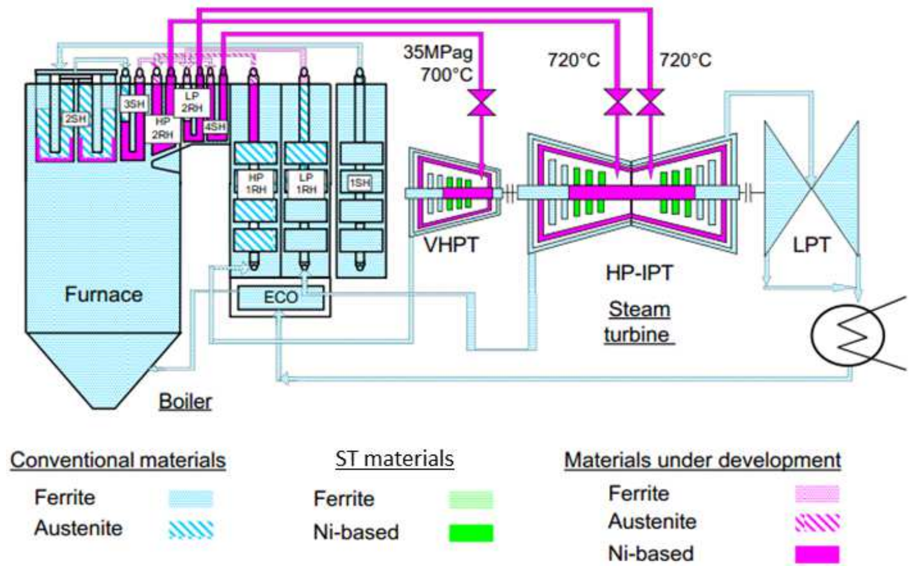

Figure 2. Figure from [1] depicting the areas (purple) that are impacted by A-USC conditions.

It is possible to highlight which areas are most critical and use the new high-end and expensive materials only in those areas for cost saving. Notably, the main areas we can identify are the boiler, the steam turbine and other items like valves and wielding in the high temperature circuits.

2.1.1 Boiler candidate materials

Superheaters and reheaters materials need to be able to withstand the new steam generation temperatures of more than 700 °C and pressures of about 360 bar. To do that, unconventional materials are needed. Ni-based alloys have been identified as the candidate material for this application.

Each candidate material needs to be tested for the most common root causes of damage in the boiler components by going through the following steps:

1. **Creep behaviour:** creep stress is tested by maintaining a thermal load for a certain number of hours. This test is replicated for different temperatures to form a Stress/Temperature curve for different test durations.
2. **Fatigue test:** thermal load is applied in a cyclic manner until creep rupture is encountered. This type of test allows to understand the capability of the plant to turndown and turnup its capacity and assess operational flexibility.
3. **Steam oxidation test:** long exposure to steam at design temperatures and observation of the oxidized scale formation.
4. **Hot corrosion test:** measurement of mass heat loss rate from salt corrosion in design temperature conditions.

Thanks to the work of MHPS[1] supporting research in Japan, comprehensive summary work on multiple alloys is available in literature [1].

Table 1. Candidate materials for A-USC boilers.

Alloy name	Type	Composition
HR6W	Ni-based	45-Ni-23Cr-7W
HR35	Ni-based	50Ni-30Cr-4W-Ti
Alloy 617	Ni-based	Ni-22Cr-12Co-9Mo-Ti-Al
Alloy 263	Ni-based	Ni-20Cr-20Co-6Mo-Ti-Al
Alloy 740	Ni-based	Ni-25Cr-20Co-2Nb-Ti-Al
Alloy 141	Ni-based	Ni-20Cr-10Mo-Ti-Al
High-B-9Cr steel	Ferritic steel	9Cr-3W-3Co-Nb-V-B
Low-C-9Cr steel	Ferritic steel	0.035C-9Cr-2.4W-1.8Co-Nb-V
SAVE12AD	Ferritic steel	9Cr-3W-2.6Co-Nb-V-B

Plenty of literature was produced regarding the results of those test for various A-USC application candidate materials. Below, some relevant work is reported.

- Alloy 263 [4] is a Ni-Co-Cr-Mo-Ti-Al alloy widely used in aerospace applications. Its performance is extremely attractive, but the production cost for this steel and poor workability for large components makes it prohibitive for power applications.
- Fe-Ni-Cr alloys [5] are more commmon and represented the starting point for new superalloys development but cannot aim to working temperatures above 750 °C.
- HR6W and GH984 alloys where the investigated thanks to better workability and competitive price, but insufficient creep resistance above 700 °C was found. These served as starting point for the development of precipitate-treated alloys [6].

A comparison of the stress for rupture between various kind of alloys is reported in Figure 3.

[1] Mitsubishi Hitachi Power Systems

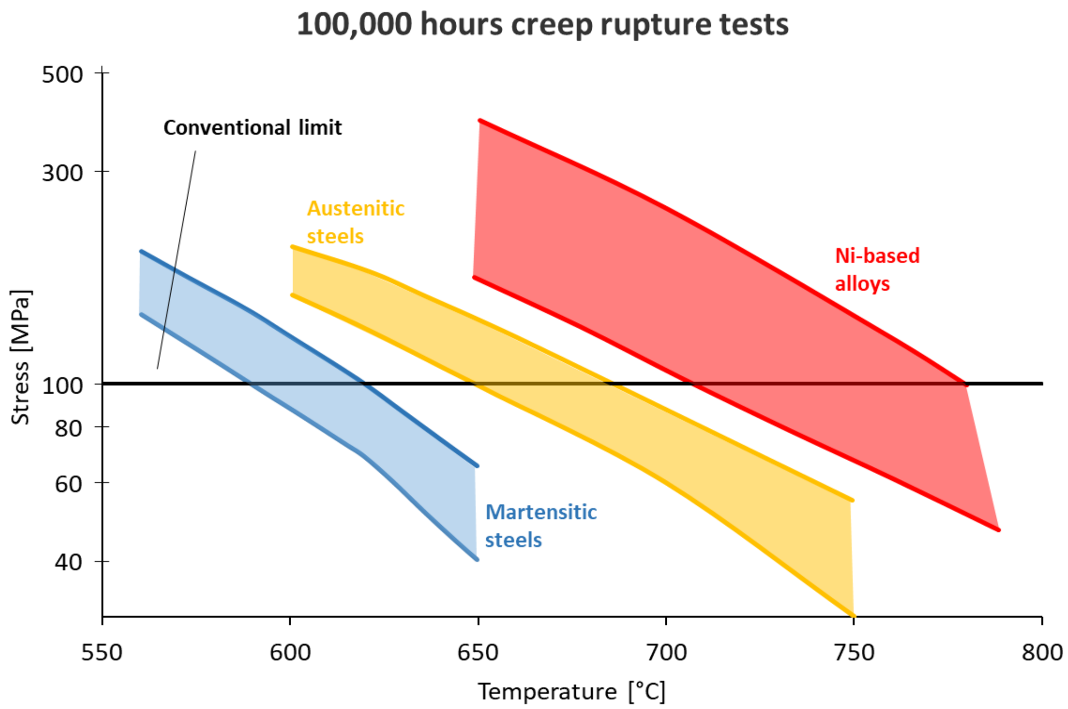

Figure 3. 10^5 h creep rupture test results on different materials at different temperatures. Data from [7].

The conventional limit line (100 MPa) is the minimum creep rupture stress admissible at the design conditions and is widely accepted as an industry standard. The above figure demonstrates then that Nickel-based alloys are adequate for the conditions that the boiler must sustain at A-USC conditions.

Nickel-based alloys have at the same time a lower thermal conductivity and a higher coefficient of linear expansion (see Figure 4 and Figure 5) compared to classical martensitic steels which are currently used in combined cycles [8].

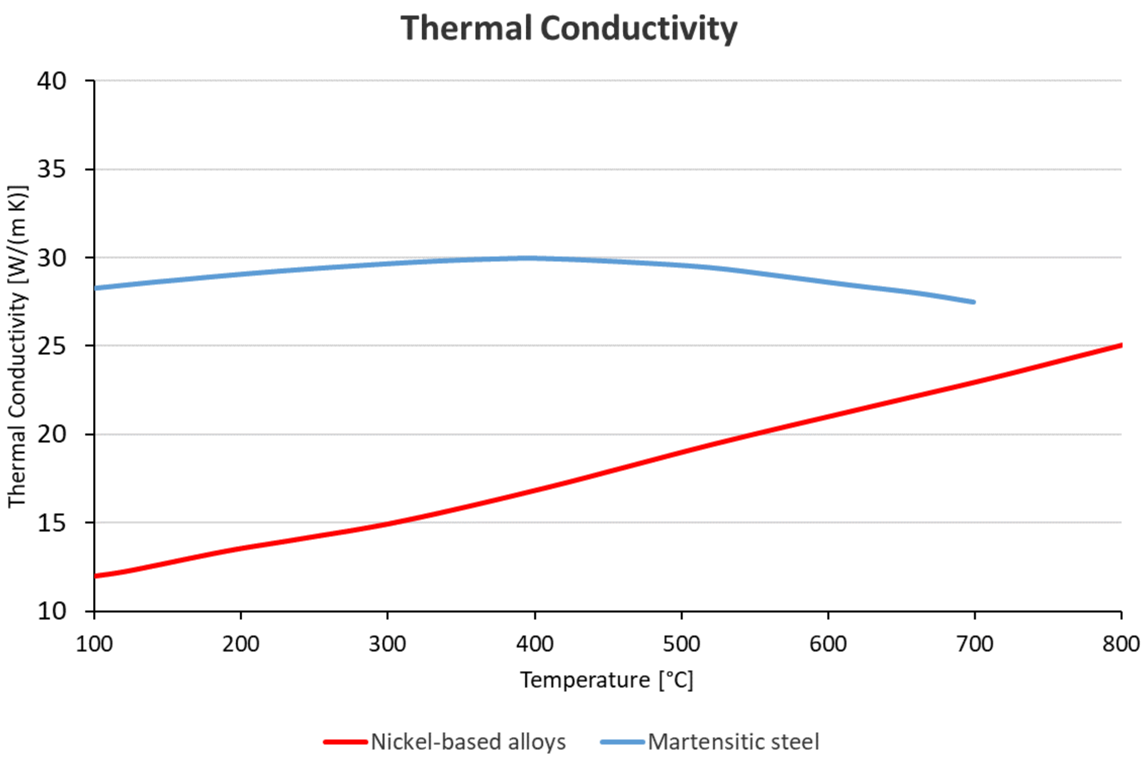

Figure 4. Thermal conductivity of Ni-based alloys vs martensitic steel. Data from [9].

The increased linear expansion coefficient means that great care should be given to ensuring that the Nickel alloy parts have enough room to dilate and contract with temperature fluctuations. The lower thermal conductivity also indicates that temperature gradients are more sever in a pipe of Ni-based alloy, which means that thermal stresses are going to be high. Boiler and piping design need to account for this and choose a thickness such that these stresses are minimized.

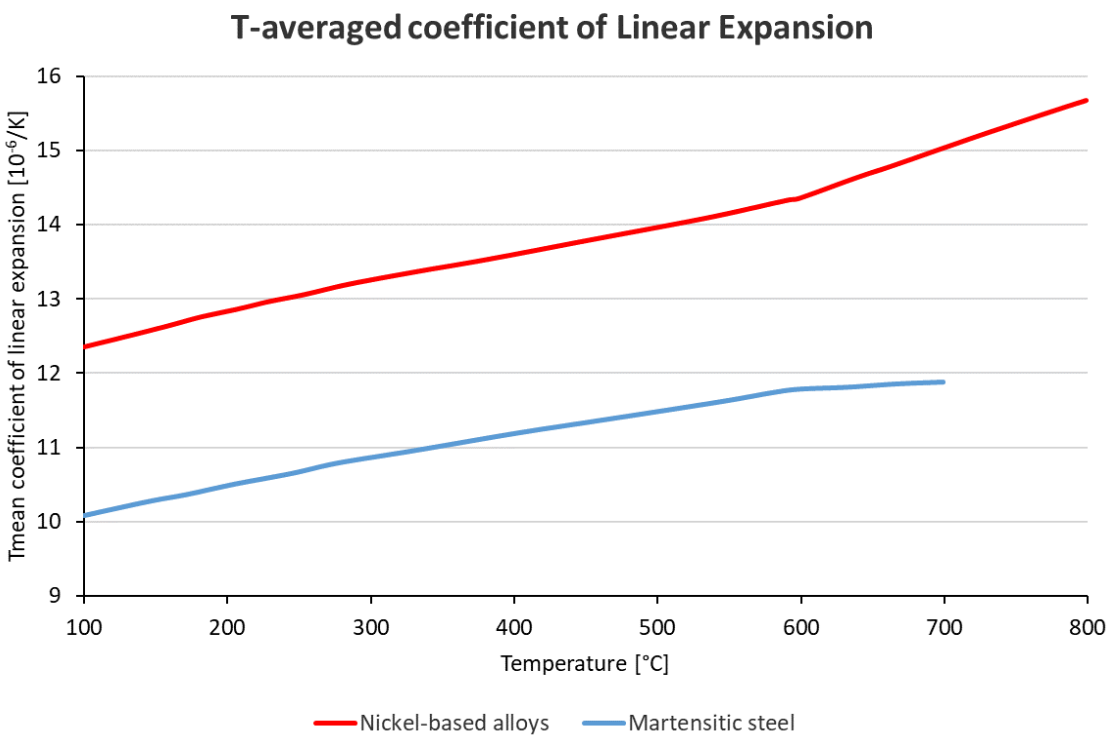

Figure 5. Thermal coefficient of linear expansion of Ni-based alloys vs martensitic steel. Data from [9].

, These features will have an impact on components behaviour in relation to the operating flexibility of the plant. This will be further discussed in para. 3.

In the aforementioned studies, materials undergone several manufacturability tests to produce sample pipes and headers. This was fundamental to study welding behaviour, as welded spots are critical weak points.

Compared to ferric steels, Nickel alloys showed good resilience to steam oxidation and hot corrosion thanks to the high chromium content.

2.1.2 Steam turbine candidate materials

As the HP SH and RH steam from the boiler entering the steam turbine is at much more severe conditions (with respect to a normal USC case), turbine casing and rotor materials for the high and medium pressure sections need to be revised accordingly.

Based on the results of tests to possibly cast different materials [1], the most promising candidates are reported in Table 2.

Table 2. Candidate materials for A-USC steam turbines.

Alloy name	Temperature level	Composition
FENIX-700	700 °C	42Ni-16Cr-2Nb-1.2Al-1.71Ti-Fe
LTES700R	> 700 °C	Ni-12Cr-6.2Mo-7W-1.5Al-0.9Ti-0.03C
TOS1X	> 720 °C	Ni-18Cr-12.5Co-9Mo-1.25Al-1.35Ti-0.1Ta-0.3Nb.0.07C

These Nickel based alloys, rich in chromium, present creep characteristics similar to those investigated for the boiler section, but present easier manufacturability and a wider range of possible welding technologies [10].

Ffield tests are presently under executions for new steam turbine materials.

2.1.3 *Other areas of interest*

As these are critical spots, it is important to remind that understanding the behavior of different welding joints, which can be achieved with different materials and technologies, is vital to making progress to investigate the alternatives.

Another important factor to take into account is the instruments acting on lines at A-USC conditions. Development of high temperature valves to regulate the steam flow is mandatory, as their reliability is fundamental for safe and stable operation of the power plant. Currently, research is investigating the use of the same Ni-based alloys for instruments.

3 Flexible operation of Advanced USC-PC Power Plants

Assessing how changing the steam cycle conditions impacts flexible operation is of high importance in the current energy market scenario.

Energy demand has been historically periodic, fluctuating over the course of the day and of the year according to the habits of the end-users. In recent years, due to the surge of renewable energy sources this periodicity became unpredictable: according to the availability in a specific moment of energy coming from the likes wind and solar plants (which are affected by meteorological conditions), the electricity demand that must be fulfilled by conventional controllable fossil fuel-fired power plants can fluctuate significantly. With this outlook, the capability of fossil fuel-fired power plants to turn up and down their capacity in the fastest way possible is fundamental. Thus, while pursuing operating conditions that allow for higher thermal efficiencies it is important to re-assess the capability of the newly designed plant to work in a flexible operating envelope.

Velocity (and more in general capability) of fast turndown/turnups in capacity is limited by the capabilities of the materials involved. These operations put the materials through cycling stress and fatigue. There are mainly two natures:

- Thermal
- Mechanical

Thermal fatigue is due to frequent temperature variations and can occur through the growth of existing flaws or incipient cracks. This phenomenon is especially relevant in power plants since it is also accompanied by creep formation and corrosion. Fatigue is influenced by a variety of factors, like temperatures, nature of the material and local piece thickness. Materials are tested for fatigue life via a standardized procedure.

Thermal cycling also is the root cause of mechanical stresses. Thermal expansion can cause the system to expand too much compared to surrounding elements and lead to cracking. This kind of phenomenon can be experienced also in heat exchangers due to differential expansion if two different materials are used.

Besides these issues directly related to materials, flexible operation also affects the characteristics of the flue gas: low load implies lower exit temperatures and higher risk of corrosion in the cold-end of the system. Gas temperature is also an issue in Selective Catalytic Reduction systems design, as the catalyst is active at specific ranges of temperature and is placed accordingly in the system, but due to lower load the temperature profile can be modified. Means to hinder these issues are continuously developed.

3.1 Impact on operating flexibility of A-USC condition design

As mentioned in 2.1.1, Ni alloys have a higher thermal expansion coefficient and lower thermal conductivity. This means that temperature gradients within thick walled components (like steam headers) is severe, leading to significant increase in thermal stresses especially at these operating conditions.

To limit these stresses, start-up times are expected to be slower than those achievable with traditional 600 °C USC PC plants [1]. In Figure 6, start-up times for advanced plants are estimated.

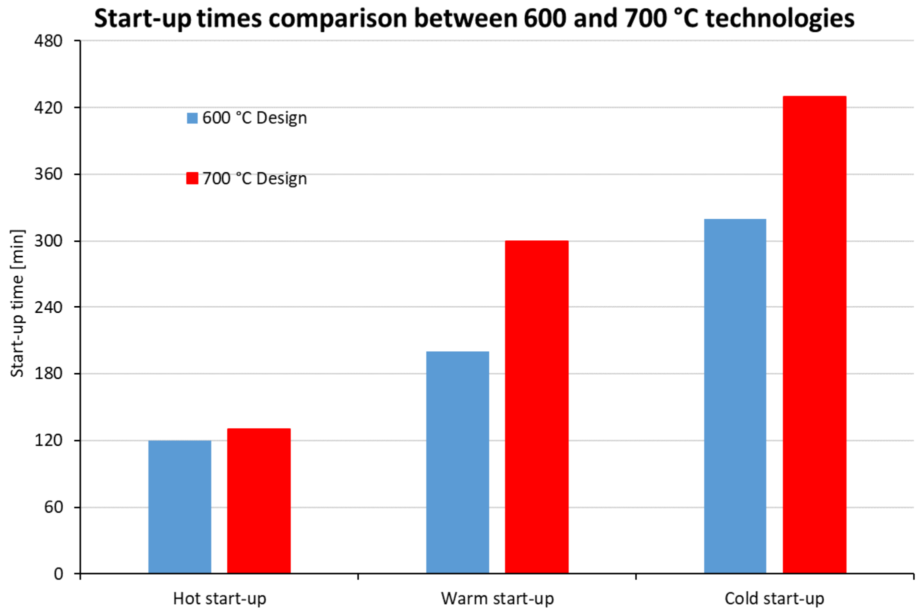

Figure 6. Comparison of start-up times for USC (600 °C) and A-USC (700 °C) pulverised coal plants. Data from [9].

In Figure 7, estimated curves for A-USC PC plant start-up are reported.

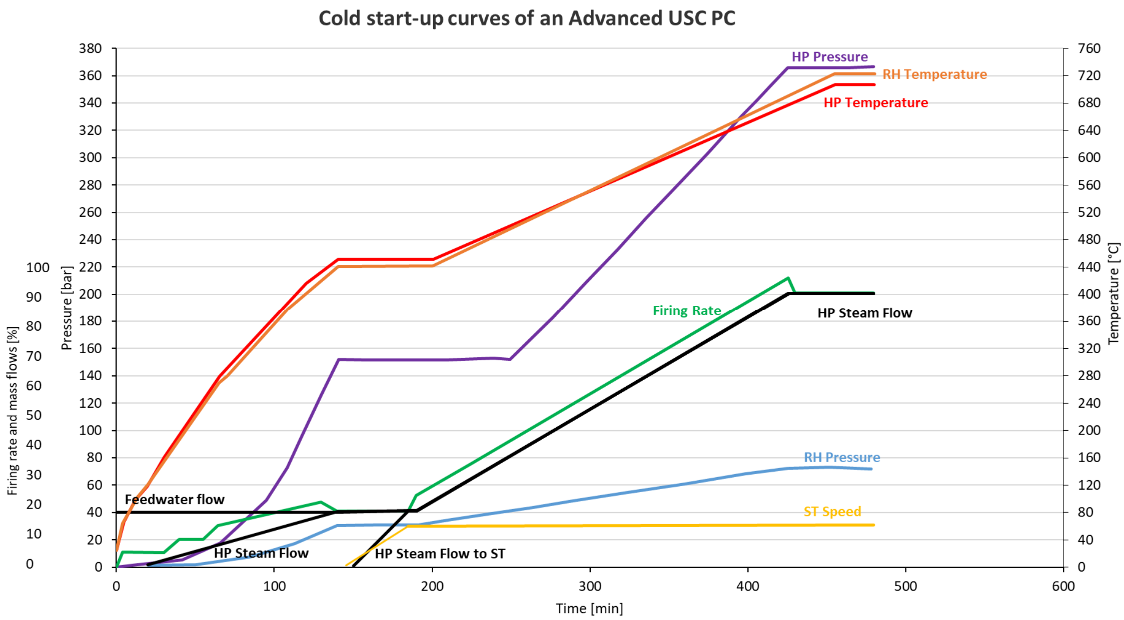

Figure 7. Cold start-up ramps curves for an advanced ultra-supercritical (700 °C) pulverised coal plant. Data from [9].

4 Conclusions

Current development of advanced ultra-supercritical coal plants indicates that the technology is technically feasible. Materials required are considered expensive, and development of cheaper alternatives will benefit greatly the economic attractiveness of this design.

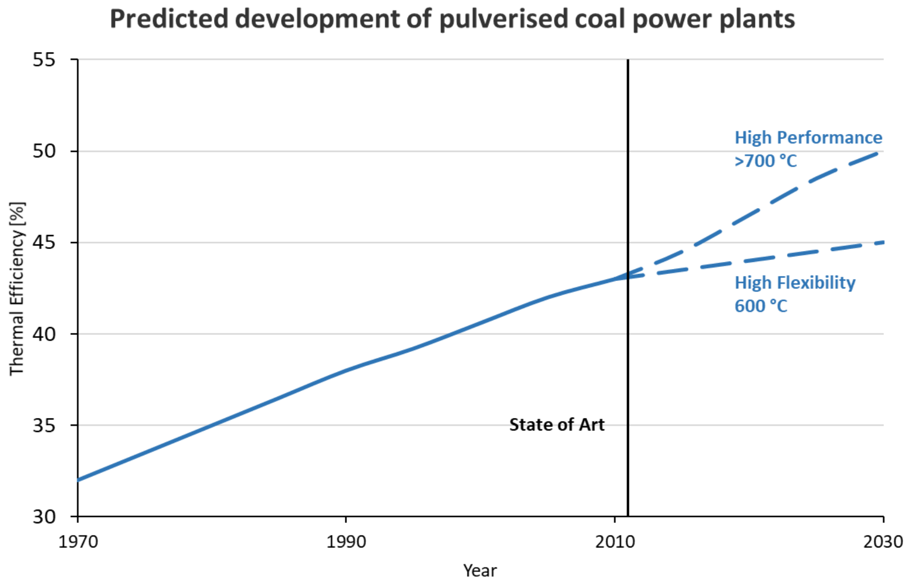

Figure 8. Predicted future development of coal-based boilers [11].

Due to severe operating conditions, the required thickness for thick-walled components and the thermal characteristics of the used materials, flexible load operation is downgraded compared to conventional coal fired USC plants: the increased ramp up and ramp down times inhibits the capability of the plant to follow an ever-floating energy demand.

Assuming that material research will not be able to provide a "best of both worlds" solution, based on the specific electricity market targeted, a > 700°C A-USC cycle shall be considered if the best possible performance is the most sought-after factor. Contrary, if the ability to flexibly match a fluctuating energy demand is deemed more important, 600 °C conventional technology is preferred.

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