Programme Area: Carbon Capture and Storage

Project: Benchmark Refresh

Title: WP6 CCS Benchmark Refresh 2013 Phase A Report

Abstract:

The ETI engaged Foster Wheeler to execute its CCS Benchmark Refresh Project. The main purpose of this further study work is to provide additional benchmarking and performance analysis of next generation carbon capture technologies for combined cycle gas turbines (CCGTs) building upon those evaluated and reported in previous phases of CCS study work that Foster Wheeler had executed with ETI. This Phase A Report includes: ·An assessment of materially significant changes from the previous CCGT benchmark, together with documentation of the assumptions used in development of the new benchmark; An assessment of appropriate EGR rates fulfilling the above criteria appropriate exhaust gas recycle (EGR) rates which could potentially be used in CCGTs with CCS;· Presentation of the technical and economic performance and deliverables for each of the benchmark cases.

Context:

This project refreshed and extended techno-economic studies of current generation (benchmark) CO2 capture technologies for gas fired power stations and provided comparable information on one or more next generation technologies. It produced a new benchmark incorporating exhaust gas recycle and provided robust, independent and directly comparable technology assessments of specific technologies being considered for further demonstration.

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WP6 - CCS Benchmark Refresh 2013
Phase A Report

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ATTACHMENTS

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1. EXECUTIVE SUMMARY

1.1 Introduction

The ETI has engaged Foster Wheeler to execute its CCS Benchmark Refresh 2013 Project. The main purpose of this further study work is to provide additional benchmarking and performance analysis of next generation carbon capture technologies building upon those evaluated and reported in previous phases of CCS study work that Foster Wheeler has executed with ETI.

1.2 Scope

Phase A of the Project involves two tasks:

Task 1: Combined Cycle Gas Turbine (CCGT) Benchmark Refresh

Review and update of the WP1 CCGT flowsheet to include more accurate representation of:

- current mass-market gas turbines, based on published performance data;
- pressure profile through the HRSG and downstream equipment.

Task 2: Exhaust Gas Recycle (EGR) Benchmark

Develop a new benchmark for the CCGT/CCS case which recycles combustion exhaust gas to the gas turbine inlet. Develop designs for two EGR rates:

- An intermediate rate; and
- A rate representing an optimum for EGR, as agreed with ETI.

This Phase A Report includes:

- An assessment of materially significant changes from the previous CCGT benchmark, together with documentation of the assumptions used in development of the new benchmark;
- An assessment of appropriate EGR rates fulfilling the above criteria;
- Presentation of the technical and economic performance and deliverables for each of the benchmark cases.

In Phase B of this project, the technical and economic performance of alternative carbon capture technologies will be assessed against these new benchmarks.

1.3 Task 1 – CCGT Benchmark

1.3.1 CCGT Benchmark Performance Results

Table 1-1 Summary Performance Figures for CCGT Benchmark Cases

		CCGT with 90% CO_2 Capture		CCGT without CO_2 Capture	
		100% Load	**40% Load**	**100% Load**	**40% Load**
Total gross installed capacity	MWe	967.9	421.2	1068.0	472.0
Total auxiliary loads	MWe	97.1	64.4	22.4	14.8
Net Power Export	MWe	870.8	356.8	1045.6	457.2
Net Efficiency (LHV)	%	48.6	39.2	58.3	50.3
Carbon capture rate	%	90.0	90.0	0	0
Total CO_2 captured	tpd	7913	4020	0	0
Total CO_2 emitted	tpd	883	445	8796	4464
CO_2 emissions	g CO_2/kWh_{Net}	42.2	51.9	350.5	406.8

Table 1-2 Economic Figures for CCGT Benchmark Cases

		CCGT with 90% CO_2 Capture		CCGT without CO_2 Capture	
		100% Load	**40% Load**	**100% Load**	**40% Load**
Total CAPEX	GB£M	997	997	548	548
CAPEX efficiency	GB£/kWh	1145	2795	524	1197
Total OPEX – incl. fuel	GB£M p.a.	313.4	180.5	296.6	164.4
Total OPEX – excl. fuel	GB£M p.a.	45.1	44.4	28.3	28.3
OPEX – incl. fuel	GB£ p.a. / kW_{Net}	359.9	505.9	283.7	359.6
OPEX – excl. fuel	GB£ p.a. / kW_{Net}	51.8	124.5	27.1	61.9
Levelised Cost of Electricity CO_2 emission cost = £0 / te CO_2 CO_2 emission cost = £20 / te CO_2 CO_2 emission cost = £40 / te CO_2 CO_2 emission cost = £60 / te CO_2	 £ / MWh_{Net} £ / MWh_{Net} £ / MWh_{Net} £ / MWh_{Net}	 69.1 70.0 70.8 71.7	 118.8 119.8 120.9 121.9	 47.7 54.7 61.7 68.7	 70.1 78.3 86.4 94.6
Cost of CO_2 Captured CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	56.8	103.6	n/a	n/a
Cost of CO_2 Avoided CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	69.7	137.1	n/a	n/a

1.3.2 Assessment of changes from previous CCGT Benchmark

The Technical Performance Report included in Attachment 6 provides a detailed assessment of materially significant changes from the previous CCGT benchmark, together with documentation of the assumptions used in development of the new benchmark.

Table 1-3 summarises the key performance figures for the refreshed CCGT benchmark case compared with the WP1 CCGT benchmark cases with and without 90% CO_2 capture.

The impacts of each of the changes can be summarised as follows:

<u>Gas Turbine Changes</u>:

- increase in GT power output,
- increased heat rate (due to apparent error in Gatecycle library),
- increased GT exhaust temperature,
- increased GT exhaust pressure,

- ➢ decrease in GT efficiency

Blower Changes:

- decreased suction pressure
- increased ∆P
- increased flow rate
- decreased efficiency
- ➢ increase in blower power and overall parasitic load

CO_2 Capture Level

- capture level decreased from 90.9 to 90.0%
- ➢ quantity of CO_2 captured increase (5.2%) lower than plant capacity increase (6.3%)

CO_2 Compressor Motor Efficiency

- compressor motor efficiency decreased from 100% to 95%
- ➢ CO_2 compression and dehydration unit power increase (11%) higher than plant capacity increase (6.3%)

Table 1-3 Summary of Technical Performance for Original and Refreshed Benchmarks at 100% GT Load

		M701G (library)		M701G2 (GTW)		M701F5 (GTW)	
		WP3 90% CO_2 Capture	WP1 0% CO_2 Capture	WP3 90% CO_2 Capture	WP1 0% CO_2 Capture	WP6 90% CO_2 Capture	WP6 0% CO_2 Capture
Total installed gross capacity	MWe	954.6	1037.6	908.1	1003.1	967.9	1068.0
- Gas Turbines	MWe	729.1	729.1	692.0	692.0	739.0	739.0
- Steam Turbine	MWe	225.5	308.5	216.0	311.1	228.9	328.9
Total auxiliary loads	MWe	110.6	46.9	88.6	22.1	97.1	22.4
- Power Island	MWe	39.2	40.1	13.3	15.6	13.2	15.6
- Acid Gas Removal	MWe	32.8	0.0	35.4	0.0	40.0	0.0
- CO_2 Compression	MWe	28.6	0.0	28.7	0.0	31.7	0.0
- Others	MWe	10.0	6.7	11.1	6.5	12.1	6.8
Net Power Export	MWe	844.0	990.8	819.5	981.0	870.8	1045.6
Net Efficiency (LHV)	%	50.05	58.76	48.51	58.07	48.58	58.33
Heat Rate	kJ/kWh	7192.3	6127.0	7421.6	6199.6	7410.6	6172.1
CC Energy Penalty	% points	8.70		9.56		9.75	
Total Fuel Feed Rate	tpd	3070.4	3070.4	3076.3	3076.3	3264.1	3264.1
Total Carbon in Fuel	tpd	2257.8	2257.8	2262.2	2262.2	2400.3	2400.3
Total Carbon Captured	tpd	2053.5	0.0	2057.2	0.0	2159.4	0.0
Total CO_2 Emissions	tpd	749.0	8273.8	751.2	8795.6	882.6	8795.6
Carbon Capture Rate	%	90.9	0.0	90.9	0.0	90.0	0.0
Carbon Efficiency	gCO_2/kWh	37.0	347.9	38.9	352.1	42.2	350.5

1.4 Task 2 – EGR Benchmark

1.4.1 Assessment of EGR Rates

A simplified modelling approach was used to investigate the appropriate rates to use for EGR, simulating the performance of the GT system, and predicting the exhaust gas composition with a portion of the exhaust gas stream cooled to 24°C and recycled back to the GT inlet.

The Intermediate Case

This case was chosen to provide intermediate oxygen concentration at the GT inlet (19%) which were considered to present moderate development risks for the GT. The resulting EGR rate was approximately 19%.

The "Optimum" Case

For CCS applications, high EGR ratios are desirable to maximise the CO_2 content in the exhaust gas and minimise the mass flow through the CO_2 capture plant. However, there is a maximum feasible rate of EGR which can be achieved without compromising flame stability and increasing emissions.

GE has demonstrated complete combustion in a DLN F-class combustion system operating at 35% EGR using existing technology without major modifications.

It can be assumed that 35% EGR represents the current state of EGR development in F-class turbines, but that this may be extended in future through developments in turbine technology specifically for CCS projects.

Table 1-4 Preliminary GT Inlet/Exhaust Conditions at selected EGR Levels

	Task 1 0% EGR		Intermediate 19% EGR		"Optimum" 35% EGR	
	GT Oxidant	GT Exhaust	GT Oxidant	GT Exhaust	GT Oxidant	GT Exhaust
Pressure (kPa)	101	105	101	104	101	104
Temperature (°C)	10	613	13	597	15	603
Mass rate (kg/h)	4991402	5127404	5231285	5362805	5108933	5238702
Mole % Oxygen	20.82	11.01	18.92	9.92	16.42	7.38
Mole % CO2	0.03	4.64	1.06	5.29	2.47	6.68

1.4.2 Estimating M701F5 Turbine Performance with EGR

It is necessary to develop a method of estimating the performance of the MHI M701F5 turbine at a variety of exhaust gas recycle rates.

Given a coherent set of user defined input data, the Gatecycle model can predict the performance and exhaust conditions, which can then be used within HYSYS to model the HRSG and capture plant performance.

By calculating performance curves of the M701G library turbine at varying levels of EGR, correlations were identified, and applied to the Task 1 CCGT benchmark performance figures for the M701F5 turbine (at 0% EGR), in order to derive input data at 19% and 35% EGR.

Table 1-5 Gatecycle Input Parameters for M701F5 Turbine at selected EGR Levels

	Task 1 0% EGR	Intermediate 19% EGR	"Optimum" 35% EGR
Electric Power (kW)	369521	365308	361681
Heat Rate (Btu/kWh)	8276	8329	8374
Exhaust flow rate (kg/s)	712.1	704.8	698.6
Exhaust Temp (°C)	613	618	621

1.4.3 EGR Benchmark Performance Results

There are two variables which impact the plant technical and economic performance with increasing % EGR:

- Total flue gas CO_2 concentration increases and volumetric flow decreases.
- Total CO_2 molar flow decreases slightly because the GT demands slightly less fuel.

The plant performance trends can be seen in Table 1-6, while the cost impact of increasing % EGR can be seen in Table 1-7.

With increasing % EGR, there is a decrease in the power island gross power output, but at the same time, the total auxiliary loads also decrease. This results in only a modest improvement in the plant overall LHV efficiency with EGR, of 0.39 and 0.6 % points relative to the 0% EGR case efficiency of 48.58%. There is also a very small (0.2%) increase in the total net power output with EGR.

The power island capital cost increases with increasing EGR since the additional DCC for the EGR cases has been included in the Power Island scope. The CO_2 capture DCC, absorber and blower decrease in size significantly with EGR, resulting in a significant reduction in the CO_2 capture unit capital cost. The impact on the overall plant total project capital cost is therefore quite significant, with a 3.2% and 7.1% reduction for the 18% EGR and 35% EGR cases respectively.

The total operating costs at 100% GT load reduce with EGR by 0.7% and 1.4% for the 18% EGR and 35% EGR cases respectively. At 40% GT load the operating cost reduction is more significant at 2.1% and 4.3% for the 18% EGR and 35% EGR cases respectively. This is due to the slightly higher efficiency at turndown in the EGR cases.

Since both the total capital and the total operating costs reduce with increasing EGR, so does the levelised cost of electricity (LCOE). However, the reduction in the LCOE is quite modest, since, for gas plants, over the plant lifetime the price of fuel is much more significant than the capital cost of the original plant. The LCOE reduces by 1.7% and 3.3% for the 18% EGR and 35% EGR cases respectively.

The LCOE reduction is more significant at 40% GT load, reducing by 4.0% and 7.6% for the 18% EGR and 35% EGR cases respectively. However, it should also be remembered that the LCOE at part load is much higher than when operating the plant at full load (£118.8/MWh_{Net} at 40% GT load versus £69.1/MWh_{Net} at 100% GT load with 90% CCS and without EGR).

Table 1-6 Technical Performance Figures for CCGT with EGR

		0% EGR	0% EGR	18% EGR	35% EGR	0% EGR	0% EGR	18% EGR	35% EGR
		0% CCS	90% CCS	90% CCS	90% CCS	0% CCS	90% CCS	90% CCS	90% CCS
		100% GT	100% GT	100% GT	100% GT	40% GT	40% GT	40% GT	40% GT
Power									
Total gross installed capacity	MWe	1068.0	967.9	964.2	957.1	472.0	421.2	420.9	418.7
Gas Turbine (s)	MWe	739.0	739.0	731.0	723.4	295.6	295.6	287.5	279.9
Steam Turbine	MWe	328.9	228.9	233.2	233.8	176.4	125.6	133.4	138.7
Total auxiliary loads	MWe	22.4	97.1	90.8	84.0	14.8	64.4	59.0	53.7
Power Island	MWe	15.6	13.2	13.4	13.6	10.4	9.7	9.9	10.1
Flue Gas Blower	MWe	0.0	37.2	30.1	23.6	0.0	28.9	23.4	18.3
Acid Gas Removal/DCC	MWe	0.0	2.8	2.7	2.5	0.0	2.8	2.7	2.5
Alternative Technology	MWe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2 compression	MWe	0.0	31.7	31.7	31.5	0.0	16.1	15.8	15.4
Others	MWe	6.8	12.1	12.8	12.9	4.4	6.9	7.2	7.3
Net Power Export	**MWe**	**1045.6**	**870.8**	**873.4**	**873.1**	**457.2**	**356.8**	**362.0**	**365.0**
Net Efficiency (LHV)	**%**	**58.33**	**48.58**	**48.97**	**49.18**	**50.25**	**39.21**	**40.71**	**41.98**
Heat Rate	kJ/kWh	6172	7411	7352	7320	7164	9181	8843	8576
CC Energy Penalty	% points	0.00	9.75	9.31	8.96	0.00	11.04	10.78	9.78
Carbon Balance									
Total carbon in feeds	tpd	2400.3	2400.3	2388.4	2376.9	1218.3	1218.3	1190.6	1164.3
Total carbon captured	tpd	0.0	2159.4	2156.5	2139.9	0.0	1096.9	1071.7	1049.0
Total carbon emissions	tpd	2400.3	240.9	231.9	237.1	1218.3	121.3	118.9	115.3
Carbon capture rate	%	0.0	90.0	90.3	90.0	0.0	90.0	90.0	90.1
Carbon efficiency	g CO2/kWh	350.5	42.2	40.5	41.5	406.8	51.9	50.1	48.2

Table 1-7 Economic Performance Figures for CCGT with EGR

		0% EGR	0% EGR	18% EGR	35% EGR	0% EGR	0% EGR	18% EGR	35% EGR
		0% CCS	90% CCS	90% CCS	90% CCS	0% CCS	90% CCS	90% CCS	90% CCS
		100% GT	100% GT	100% GT	100% GT	40% GT	40% GT	40% GT	40% GT
Power									
Net Power Export	**MWe**	**1045.6**	**870.8**	**873.4**	**873.1**	**457.2**	**356.8**	**362.0**	**365.0**
Net Efficiency (LHV)	**%**	**58.33**	**48.58**	**48.97**	**49.18**	**50.25**	**39.21**	**40.71**	**41.98**
Economic Performance									
Total CAPEX	GB£M	547.5	997.2	965.7	926.3	547.5	997.2	965.7	926.3
Power Island	**GB£M**	**474.5**	**474.5**	**480.5**	**491.0**	**474.5**	**474.5**	**480.5**	**491.0**
Acid Gas Removal	**GB£M**	**0.0**	**322.9**	**290.3**	**246.4**	**0.0**	**322.9**	**290.3**	**246.4**
CO_2 compression	GB£M	0.0	61.5	61.5	61.5	0.0	61.5	61.5	61.5
Others	GB£M	73.0	138.2	133.4	127.4	73.0	138.2	133.4	127.4
CAPEX efficiency	**GB£/kW_{Net}**	**523.6**	**1145.1**	**1105.6**	**1061.0**	**1197.5**	**2795.1**	**2667.9**	**2537.7**
Total OPEX – incl. fuel	GB£M p.a.	296.6	313.4	311.1	308.9	164.4	180.5	176.7	172.7
		268.3	268.3	266.9	265.8	136.1	136.1	133.2	130.3
Total OPEX – excl. fuel	GB£M p.a.	28.3	45.1	44.2	43.1	28.3	44.4	43.5	42.4
OPEX – incl. fuel	GB£ p.a. /	283.7	359.9	356.2	353.8	359.6	505.9	488.2	473.1
OPEX – excl. fuel	GB£ p.a. /	27.1	51.8	50.6	49.4	61.9	124.5	120.2	116.2
Levelised Cost of Electricity		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO_2 emission cost = £0 / te CO_2	**£ / MWh_{Net}**	**47.7**	**69.1**	**67.9**	**66.8**	**70.1**	**118.8**	**114.0**	**109.7**
Cost of CO_2 Captured									
CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	n/a	56.8	51.9	47.9	n/a	103.6	96.1	86.8
Cost of CO_2 Avoided									
CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	n/a	69.7	63.0	57.8	n/a	137.1	125.2	109.8

2. INTRODUCTION

The Energy Technologies Institute (ETI) is a public private partnership between global industry members - BP, Caterpillar, EDF, E.ON, Rolls-Royce and Shell with the UK government. The ETI brings together projects that accelerate the development of affordable, clean, secure technologies needed to help the UK meet its' legally binding 2050 targets. The ETI's mission is to accelerate the development, demonstration and eventual commercial deployment of a focused portfolio of energy technologies, which will increase energy efficiency, reduce greenhouse gas emissions and help achieve energy and climate change goals.

The ETI has engaged Foster Wheeler to execute its CCS Benchmark Refresh 2013 Project. The main purpose of this further study work is to provide additional benchmarking and performance analysis of next generation carbon capture technologies building upon those evaluated and reported in previous phases of CCS study work that Foster Wheeler has executed with ETI.

2.1 Scope of Study

The scope of the CCS Benchmark Refresh 2013 Project is presented in four distinct tasks over two phases.

<u>Phase A – Benchmark Refresh</u>

Task 1: Combined Cycle Gas Turbine (CCGT) Benchmark Refresh

Task 2: Exhaust Gas Recycle Benchmark

<u>Phase B – Technology Assessments</u>

Task 3: Inventys Technology Refresh

Task 4: (Optional) Alternative Next Generation Technology Assessment

2.2 Scope of Phase A

Together Tasks 1 and 2 constitute Phase A of the Project.

2.2.1 Task 1 - Combined Cycle Gas Turbine (CCGT) Benchmark Refresh

Review of the WP1 CCGT flowsheet, and updating it to include any technology updates, specifically including the following:

- review of the assumed performance of the Mitsubishi M701G2 gas turbines against manufacturer's and published data, with the aim of providing an accurate representation of current mass-market gas turbines (from MHI, GE or Siemens)
- review of the pressure drop profile in the heat recovery steam generator ("HRSG") and downstream equipment, and consideration of whether a fan is required to overcome pressure losses.

Using the WP1 CCGT case as the basis for technical development of a revised CCGT benchmark in Task 1, modify the process simulation model to incorporate the updated gas turbine performance data, the pressure drop profile in the HRSG and downstream equipment, and any other changes as agreed with ETI.

Use the process model to generate a revised heat and material balance at 100% load and at 40% load for the CCGT Benchmark Case. Take utility supply, specifically steam and power into account in the overall process performance.

Generate technical performance data for CCGT Benchmark for 90% and 0% capture.

Technical Performance Report

With visibility of the impact that these changes have made on the technical performance of the CCGT Benchmark schemes, provide an assessment of any materially significant changes for both the 90% capture and 0% capture cases in a Technical Performance Report. Show the agreed basis of the new CCGT benchmark in the report for development of (and/or comparison with) the other Tasks.

2.2.2 Task 2 - Exhaust Gas Recycle Benchmark

Develop a new benchmark for the CCGT/CCS case which recycles combustion exhaust gas to the gas turbine inlet ("EGR"), as shown in Figure 1.

The intention is to increase the percentage of CO_2 in the gas turbine and hence reduce the size of the capture plant. The key here is to examine the effect of EGR on the performance of the gas turbine (GT).

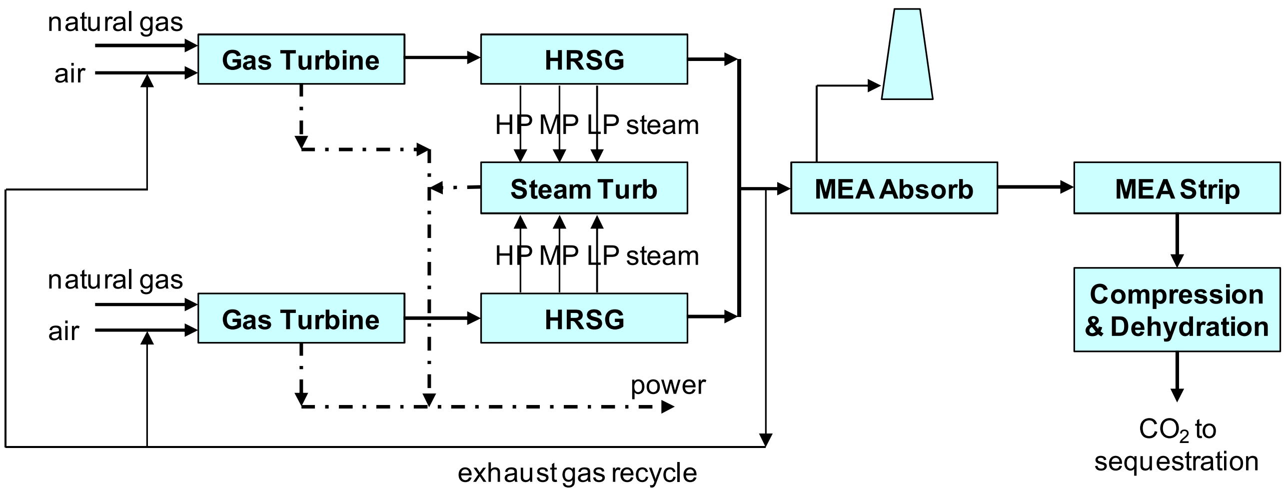


Figure 2-1 – CCGT with EGR and Post Combustion CO_2 Capture

Following agreement of the new CCGT benchmark in Task 1, and based on the feedback from the gas turbine vendors, develop the process simulation model to incorporate exhaust gas recycle, including any additional equipment required, at 90% capture. Deploy the same amine system as the original benchmark for the designs, resized as appropriate for the increased CO_2 concentration. Cool the gas before recycle. Develop designs for two EGR rates:

- A rate providing GT inlet conditions representing modest GT development risks. This choice will examine the O_2 outlet concentrations, inlet and outlet temperatures, etc. ; and
- A rate representing an optimum for EGR, as agreed with ETI.

Use the process model to generate heat and material balances at 100% load and at 40% load for the EGR Benchmark Cases. Take utility supply, specifically steam and power into account in the overall process performance. Where beneficial integrate the added equipment into the rest of the flowsheet, including reuse of low grade heat from the offgas.

Generate technical performance data for each of the EGR cases for 90% and 0% capture.

2.2.3 Cost Estimate

Produce equipment factored capital cost estimates for each of the cases, based on sized equipment lists. Produce the estimates on a consistent basis with the WP1 cost estimate (UK£, 2009 Q1 basis, ±40% accuracy) and present as a breakdown of costs at a main unit / block level.

Produce operating cost estimates for each evaluation case based on the combination of technical definition and capital cost estimate.

2.2.4 Phase A (Techno-Economic Assessment) Report

Collate the deliverables for each of the benchmark cases and present them in the Phase A Report, including the following for each case:

- Process description and block level process flow scheme drawings;
- Heat and material balance for key streams at 100% and 40% load;
- Summary of scheme performance figures on a block-by-block level at 40% and 100% load including;
    - Overall gross and net power output figures;
    - Individual block power demand figures;
    - Overall CO_2 capture (quantity and capture level);
    - Overall thermal efficiency (LHV basis);
    - Feedstock composition and feed rate;
    - Utility summary;
    - Assumed entry conditions for CO_2 compression system.
- Statement of key assumptions and uncertainties;
- ±40% Equipment factored CAPEX estimate, including a breakdown of costs at a main unit / block level. Estimate basis Q1 2009 UK£;
- Operating cost estimate, including contribution of adsorbents, catalysts and chemicals costs, maintenance (factored from CAPEX), direct labour and general overheads.

3. TASK 1 - CCGT BENCHMARK

3.1 Combined Cycle Gas Turbine (CCGT) with 90% CO_2 Capture

3.1.1 Introduction

The overall process scheme was based upon a natural gas fired combined cycle gas turbine (CCGT) using two Mitsubishi Heavy Industries (MHI) M701F5 gas turbines featuring dry low NOx (DLN) burners, each with downstream heat recovery steam generator (HRSG), and common single steam turbine generator (STG), CO_2 capture unit and CO_2 compression and dehydration unit.

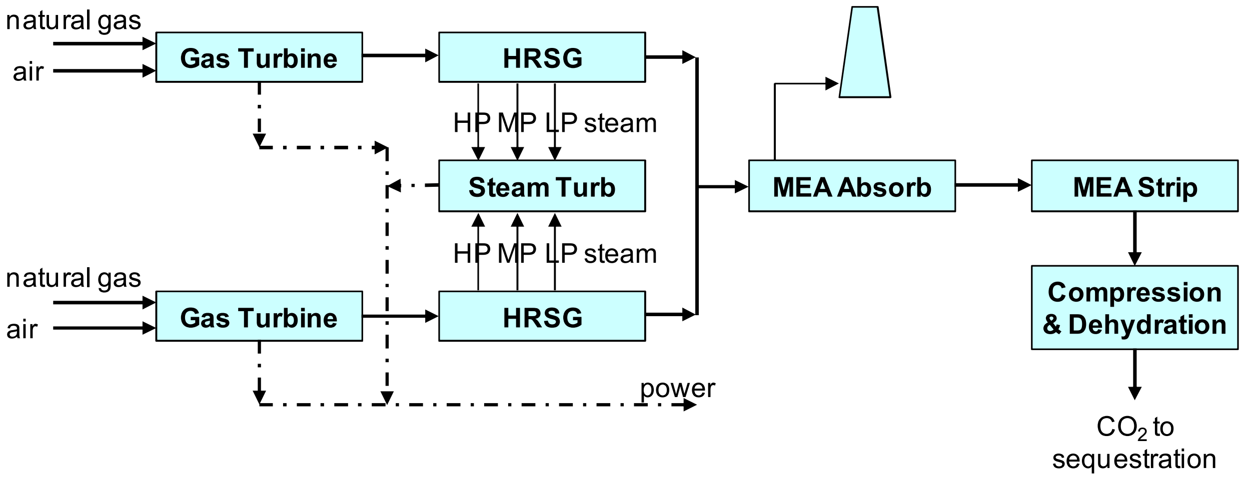


Figure 3-1 CCGT with Post Combustion CO_2 Capture

In this case the natural gas feed rate was set to ensure full utilisation of the gas turbines with the supporting and downstream equipment items sized to process the generated gas turbine exhaust gas. The process conditions, including stream flows, pressures, temperatures and compositions, were produced to reflect this sizing basis. Key features of the configuration include:

- Power Island Unit – comprising of two parallel trains, each with one Mitsubishi Heavy Industries (MHI) M701F5 50 Hz gas turbine and one heat recovery steam generator (HRSG), connected to a single condensing steam turbine, using seawater cooling.
- Acid Gas Removal Unit – CO_2 removal scheme developed using in-house information on the basis of an MEA-based process such as Fluor Econamine FG+ CO_2 recovery technology.
- CO_2 Compression and Drying Units – dehydration and multi-stage compression to 150 barg.

The carbon capture scheme is configured with three trains of MEA absorption, two trains of stripping and two trains of CO_2 compression and drying. The absorption trains are sized based upon the maximum size of the absorption column in the region of 15m diameter (larger column diameters up to 20m have been suggested where the vessel can be constructed on-site). The number of stripping trains was selected based upon the heat input required for the stripper reboilers with a maximum total reboiler duty of 200 MW_{th} per train (this is based upon 4 x 50 MW_{th} reboilers located around the column base). The number of CO_2 compression trains was selected based upon in-house knowledge of commercially available equipment and to keep a consistent order of compressor size with other benchmark cases (from WP1).

The lean/rich solvent exchanger, also known as the cross-over exchanger, is another very large and key equipment item in the post-combustion carbon capture scheme. This duty is most commonly met using a plate and frame type heat exchanger in the smaller scale plants currently in operation. A feature of this type of exchanger is its relative simplicity of scale up, achieved by adding frames and increasing the area of each frame. While it is unlikely that a heat exchanger of this type has yet been operated at the scale required for the benchmark cases, previous Foster Wheeler work with technology providers has shown that the sizes envisaged in this study are not infeasible (this case was calculated to require 2 x 21870m^2 heat transfer surface area exchangers with a duty of 115MW each).

3.1.2 Plant Performance

The plant performance for this case was assessed at both 100% load and 40% load, as summarised in the table below:

Table 3-1 Performance Figures for CCGT with 90% CO_2 Capture

		100% Load	40% Load
Power			
Total gross installed capacity	MWe	967.9	421.2
Gas Turbine (s)	MWe	739.0	295.6
Steam Turbine	MWe	228.9	125.6
Others	MWe	0.0	0.0
Total auxiliary loads	MWe	97.1	64.4
Power Island	MWe	13.2	9.7
Flue Gas Blower	MWe	37.2	28.9
Acid Gas Removal	MWe	2.8	2.8
CO_2 compression	MWe	31.7	16.1
Others	MWe	12.1	6.9
Net Power Export	MWe	870.8	356.8
Net Efficiency (LHV)	%	48.6	39.2
Heat Rate	kJ/kWh	7411	9181
Flows			
Total fuel feed rate	tpd	3264	1657
Water consumption	tpd	3566	1834
Cooling water (once through)	tpd	1,851,274	1,022,976
Carbon Balance			
Total carbon in feeds	tpd	2400	1218
Total carbon captured	tpd	2159	1097
Carbon capture rate	%	90.0	90.0
Total CO_2 captured	tpd	7913	4020
Total CO_2 emitted	tpd	883	445
CO_2 emissions	g CO_2/kWh$_{Net}$	42.2	51.9

3.1.3 Process Description

Gas Turbines, Heat Recovery Steam Generators and Steam Turbine

The power island is based on two Mitsubishi Heavy Industries (MHI) M701F5 natural gas fed gas turbines, each with its own heat recovery steam generator (HRSG). The two HRSGs are identical and are configured to generate steam at three pressure levels with full reheat of medium pressure steam. A single steam turbine receives the steam from both HRSGs and is equipped with a vacuum condenser and condensate treatment.

Natural gas is received from across the plant battery limits via a metering station before being heated against MP boiler feed water (BFW) and fed to the gas turbines (GTs).

The GT exhaust gases flow to the Heat Recovery Steam Generator, without additional duct firing. The thermal energy of the exhaust gases is used to raise and superheat steam at 3 pressure levels as well as preheating condensate and heating the BFW. The flue gases, at approximately 93°C, leaving the HRSG are pressurised using a blower in order to overcome the pressure drop through the MEA based Acid Gas Removal unit. Once the CO_2 has been removed the flue gases are reheated against the hot flue gas from the HRSG to cool the gas entering the AGRU and ensure that the treated flue gases are warm enough for dispersion via the stack.

The coil sequence in the HRSG is summarised as follows:

- 2nd HP Superheater
- 2nd MP Reheater
- 1st HP Superheater
- 1st MP Reheater
- HP Evaporator
- MP Superheater
- 2nd HP Economiser
- MP Evaporator
- LP Superheater
- MP Economiser
- 1st HP Economiser
- LP Evaporator
- LP Economiser
- Condensate Preheater

Condensate from the steam turbine condenser is preheated and deaerated using LP steam in the deaerator. Boiler feed water from the deaerator is pumped up to the three pressure levels required by the boiler feed water pumps.

In the HP circuit the BFW is pumped to approximately 14,000 kPa, passing through the 1st and 2nd HP Economiser into the HP Steam Drum. Water from the HP Steam Drum passes through the HP Evaporator coil generating saturated HP steam which returns to the HP Steam Drum before passing through the 1st and 2nd HP Superheaters and then to the HP inlet of the Steam Turbine.

The MP BFW pumps pump BFW to approximately 3000 kPa, through the MP Economiser and into the MP Steam Drum. Water from the MP Steam Drum passes through the MP Evaporator generating MP steam which is returned to the MP Steam Drum before entering the MP Superheater. Exhaust steam from the HP stage Steam Turbine are combined with superheated MP steam which is subsequently further superheated in the 1st and 2nd MP Reheaters before being routed to the MP stage of the Steam Turbine.

Desuperheaters between the two HP superheaters and the two MP reheaters use boiler feed water to control the second superheater outlet temperatures to 565ºC for both pressure levels.

The LP BFW pumps pump the BFW to approximately 450 kPa, through the LP Economiser and into the LP Steam Drum. Water from the LP Steam Drum passes through the LP Evaporator generating LP steam which is returned to the LP Steam Drum before entering the LP Superheater. The superheated LP Steam is then split, with a portion being used to supply the heat required for the Stripper reboiler in the AGRU, and the remaining LP Steam being routed to the LP inlet of the Steam Turbine.

The exhaust gases from the LP stage of the steam turbine are combined with condensate from the Natural Gas Preheater and the condensate return from the AGRU Stripper Reboiler before being fully condensed against seawater in the Vacuum Condenser. The vacuum condensate is then returned to the Vacuum Condensate Pumps completing the circuit.

<u>CO_2 Removal</u>

A blower boosts the flue gas pressure sufficiently to overcome the pressure drop in the direct contact cooler (DCC) and absorption column. In the DCC much of the water present in the flue gas stream condenses as the gas is cooled to 50°C. The condensate is then recirculated through a cooler and returned to the contact tower. A small quantity of sodium hydroxide is added to the recirculating water in order to ensure that the remaining SO_2 in the flue gas is removed to meet the <10 ppm specification to prevent excessive solvent losses. Precipitates and excess water are removed from the system to waste water treatment.

In the lower portion of the absorption column the flue gas is contacted with semi-lean and then lean amine which absorbs approximately 90% of the CO_2 content of the flue gas. This section also incorporates an extraction and cooling loop in order to ensure the cooler conditions which are more favourable to CO_2 absorption. In the top of the column the flue gas is washed with water to prevent solvent losses to the atmosphere. The flue gas is routed back to the gas / gas heat exchanger in the FGD unit, to ensure its temperature is sufficient for dispersion, then is released to atmosphere via the stack.

The CO_2-rich solvent stream exits the bottom of the absorber column and is pumped to approximately 5 bara. The stream is then split, with approximately 25% of the flow passing through 2 stages of heating against warmer solvent streams before being flashed at a pressure of 1.3 bara. The semi lean solvent from the flash drum is then cooled against rich solvent and returned to the absorption column with the cooled extracted solvent. The remaining rich solvent is heated against lean solvent in the cross over exchanger and introduced to the stripper column.

In the stripper column the CO_2 desorbs from the rich solvent as it is heated producing a stream of hot lean solvent from the bottom of the stripper. This lean solvent is cooled against rich solvent and returned to the absorption column. The stripper overheads are cooled to 30°C, condensing a significant quantity of water, some of which is returned to the stripper as reflux with the rest being sent to treatment or recovery.

<u>CO_2 Compression and Drying</u>

The acid gas resulting from the semi lean amine flash is compressed in the first of 8 compression stages, after which it is cooled and passed through a knock out drum.

After the first compression stage the main CO_2 stream from the stripper column is added to the flashed acid gas stream for all the subsequent compression steps. Between each of the next 4 steps is a cooler and knock out drum, and the CO_2 is compressed up to a pressure of 25 bara.

The CO_2 is then dried by molecular sieve adsorption to reach the specification of <50 ppmv moisture. Two dehydration vessels are required since one bed will be in use whilst the second bed will be in regeneration. The regeneration cycle uses a slipstream of dried gas exiting the operating molecular sieve bed. The gas is heated using the returning regeneration gas exiting the molecular sieve bed in regeneration. It is further heated under temperature control in an electric heater before entering the bed in a counter flow direction. The wet gas leaving the bed is cooled against incoming gas, any condensed water is separated in a knock out drum before it is passed through a fines filter and returned upstream of the 3rd stage compressor. The absorbent regeneration process takes several hours. When complete the heater is bypassed and the bed is cooled down over several hours before return to operation.

The final 3 compression stages include intercoolers and an after cooler and result in a final CO_2 product at specification of 150 barg and 30°C.

Balance of Plant

The key balance of plant requirements for this scheme are the cooling water supply systems. A very large flow of cooling water is required to supply the steam turbine vacuum condenser. This duty is supplied using sea water in a once through flow scheme.

The AGRU and CO_2 compression and drying units also require a significant quantity of cooling medium. Where this cannot be supplied using heat integration within or between the process units, cooling water is required. This cooling water is supplied as fresh cooling water in a closed circuit. The fresh water system is cooled against sea water.

Facilities are also required for storage and make-up of the MEA based solvent to the AGRU. Reuse and treatment of the numerous, mainly small, water streams produced from the cooling of water saturated gas streams are integrated with the units where possible. Streams containing contaminants such as MEA are routed to an effluent treatment system.

3.1.4 Plant Turndown

Overall plant performance has been assessed at turndown using a GT power output of 40%. GT performance at 40% power output was estimated using in-house performance curves for a similar turbine firing natural gas at reduced load.

The gas turbine operates less efficiently at turndown, consuming proportionally more fuel and air, and delivering proportionally more exhaust gas to the HRSG and capture plant. In turn, this will mean the HRSG is able to raise proportionally more steam, which results in the following effects:

GT Power Output	40%
Fuel Consumption (mass)	51%
Air Consumption (mass)	78%
GT Exhaust Flow (mass)	77%
HRSG Steam Raised	64%
Capture Plant Turndown	51%

Capture Plant Steam Usage	51%
ST Power Output	55%
Net Power Output	41%

3.1.5 Capital Cost, Operating Cost and Economics

The economic results are outlined in the table below:

Table 3-2 Economic Figures for CCGT with 90% CO_2 Capture

		100% Load	40% Load
Total CAPEX	GB£M	997.2	997.2
Power Island	GB£M	474.5	474.5
Acid Gas Removal	GB£M	322.9	322.9
CO_2 compression	GB£M	61.5	61.5
Others	GB£M	138.2	138.2
CAPEX efficiency	GB£/kW_{Net}	1145	2795
Total OPEX – incl. fuel	GB£M p.a.	313.4	180.5
Total OPEX – excl. fuel	GB£M p.a.	45.1	44.4
OPEX – incl. fuel	GB£ p.a. / kW_{Net}	359.9	505.9
OPEX – excl. fuel	GB£ p.a. / kW_{Net}	51.8	124.5
Levelised Cost of Electricity			
CO_2 emission cost = £0 / te CO_2	£ / MWh_{Net}	69.1	118.8
CO_2 emission cost = £20 / te CO_2	£ / MWh_{Net}	70.0	119.8
CO_2 emission cost = £40 / te CO_2	£ / MWh_{Net}	70.8	120.9
CO_2 emission cost = £60 / te CO_2	£ / MWh_{Net}	71.7	121.9
Cost of CO_2 Captured			
CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	56.8	103.6
Cost of CO_2 Avoided			
CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	69.7	137.1

3.1.6 Key Assumptions and Uncertainties

Many assumptions have already in discussed in the proceeding sections hence are only summarised below:

- GTW 2013 performance data combined with the GTW rule of thumb for GT performance derating for ambient temperature is a good guide for establishing representative GT performance for our basis of design (±0.25% since the middle of the suggested range was selected)
- Testing the impact of a number of variables using the M701G library gas turbine in Gatecycle will give performance impacts which can be used to extrapolate the anticipated impact of the same variables for the M701F5 machine. (For Task 1 this was limited to the impact of increasing the GT exhaust gas pressure.)
- The GT behaviour at 40% turndown was modelled using curves for a different machine from Foster Wheeler recent experience, it is therefore assumed that the M701G2 will respond in a similar way to this reference machine (this includes an assumption that the air compressor can only turn down to 78% load, as was the case for the reference machine).
- The GT turndown calculation for the reference machine.
- HRSG pressure drop is assumed to be a typical value for a Frame 9 HRSG of 0.02 bar.
- Polytropic efficiency of the flue gas blower is assumed to be 85%.

- Motor efficiencies for blowers, pumps and compressors are all assumed to be 95%.
- Transformer losses have been assumed to be 0.3% which assumes a single step up transformer is used for all three generators.
- BFW make-up in the Power Island is assumed to be 1% of the total water circulation rate.
- For the 40% turndown case it is assumed that cooling water pumps, blowers and compressors all turndown in line with the unit load as there will be multiple pumps in each set. The solvent pumps are assumed to turndown using minimum flow recycle.
- Typical figures for pressure drop have been assumed throughout the scheme in order to arrive at a reasonable pressure profile in the absence of specifics such as plot layout and elevations.

3.2 CCGT without CO_2 Capture

3.2.1 Introduction

A natural gas CCGT without CO_2 capture was developed, using the same configuration and natural gas feed rate as the CCGT with CO_2 capture case, but excluding the Acid Gas Removal and CO_2 Compression and Drying Units.

The overall process scheme was based upon a natural gas fired combined cycle gas turbine (CCGT) using two Mitsubishi Heavy Industries (MHI) M701F5 gas turbines featuring dry low NOx (DLN) burners, each with downstream heat recovery steam generator (HRSG), and common single steam turbine generator (STG).

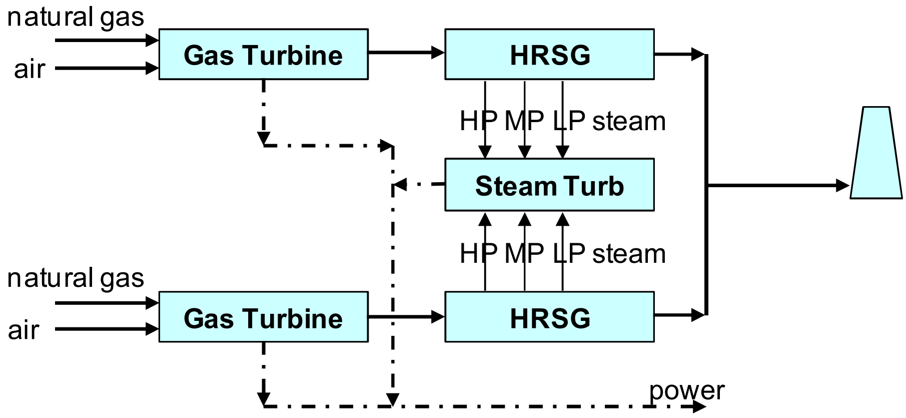


Figure 3-2 CCGT without CO_2 Capture

3.2.2 Plant Performance

The plant performance for this case was assessed at both 100% load and 40% load, as summarised in the table below:

Table 3-3 Performance Figures for CCGT without CO_2 Capture

		100% Load	40% Load
Power			
Total gross installed capacity	MWe	1068.0	472.0
Gas Turbine (s)	MWe	739.0	295.6
Steam Turbine	MWe	328.9	176.4
Others	MWe	0.0	0.0
Total auxiliary loads	MWe	22.4	14.8
Power Island	MWe	15.6	10.4
Flue Gas Blower	MWe	0.0	0.0
Acid Gas Removal	MWe	0.0	0.0
CO_2 compression	MWe	0.0	0.0
Others	MWe	6.8	4.4
Net Power Export	MWe	1045.6	457.2
Net Efficiency (LHV)	%	58.3	50.3
Heat Rate	kJ/kWh	6172	7164
Flows			
Total fuel feed rate	tpd	3264	1657
Water consumption	tpd	204	131
Cooling water (once through)	tpd	1,219,104	746,755

Carbon Balance			
Total carbon in feeds	tpd	2400	1218
Total carbon captured	tpd	0	0
Carbon capture rate	%	0.0	0.0
Total CO_2 captured	tpd	0	0
Total CO_2 emitted	tpd	8796	4464
CO_2 emissions	g CO_2/ kWh_{Net}	350.5	406.8

3.2.3 Process Description

Gas Turbines, Heat Recovery Steam Generators and Steam Turbine

The power island is based on two Mitsubishi Heavy Industries (MHI) M701F5 natural gas fed gas turbines, each with its own heat recovery steam generator (HRSG). The two HRSGs are identical and are configured to generate steam at three pressure levels with full reheat of medium pressure steam. A single steam turbine receives the steam from both HRSGs and is equipped with a vacuum condenser and condensate treatment.

Natural gas is received from across the plant battery limits via a metering station before being heated against MP boiler feed water (BFW) and fed to the gas turbines (GTs).

The GT exhaust gases flow to the Heat Recovery Steam Generator, without additional duct firing. The thermal energy of the exhaust gases is used to raise and superheat steam at 3 pressure levels as well as preheating condensate and heating the BFW. The flue gases, at approximately 93 °C, leaving the HRSG are released to the atmosphere via a stack equipped with damper and continuous emissions monitoring.

The coil sequence in the HRSG is summarised as follows:

- 2nd HP Superheater
- 2nd MP Reheater
- 1st HP Superheater
- 1st MP Reheater
- HP Evaporator
- MP Superheater
- 2nd HP Economiser
- MP Evaporator
- LP Superheater
- MP Economiser
- 1st HP Economiser
- LP Evaporator
- LP Economiser
- Condensate Preheater

Condensate from the steam turbine condenser is preheated and deaerated using LP steam in the deaerator. Boiler feed water from the deaerator is pumped up to the three pressure levels required by the boiler feed water pumps.

In the HP circuit the BFW is pumped to approximately 14,000 kPa, passing through the 1st and 2nd HP Economiser into the HP Steam Drum. Water from the HP Steam Drum passes through the HP Evaporator coil generating saturated HP steam which returns to the HP Steam Drum before passing through the 1st and 2nd HP Superheaters and then to the HP inlet of the Steam Turbine.

The MP BFW pumps pump BFW to approximately 3000 kPa, through the MP Economiser and into the MP Steam Drum. Water from the MP Steam Drum passes through the MP Evaporator generating MP steam which is returned to the MP Steam Drum before entering the MP Superheater. Exhaust steam from the HP stage Steam Turbine are combined with superheated MP steam which is subsequently further superheated in the 1st and 2nd MP Reheaters before being routed to the MP stage of the Steam Turbine.

Desuperheaters between the two HP superheaters and the two MP reheaters use boiler feed water to control the second superheater outlet temperatures to 565°C for both pressure levels.

The LP BFW pumps pump the BFW to approximately 450 kPa, through the LP Economiser and into the LP Steam Drum. Water from the LP Steam Drum passes through the LP Evaporator generating LP steam which is returned to the LP Steam Drum before entering the LP Superheater. The superheated LP Steam is then routed to the LP inlet of the Steam Turbine.

The exhaust gases from the LP stage of the steam turbine are combined with condensate from the Natural Gas Preheater before being fully condensed against seawater in the Vacuum Condensate Condenser. The vacuum condensate is then returned to the Vacuum Condensate Pumps completing the circuit.

Balance of Plant

The key balance of plant requirements for this scheme are the cooling water supply systems. A very large flow of cooling water is required to supply the steam turbine vacuum condenser. This duty is supplied using sea water in a once through flow scheme. Any other cooling duties are supplied using fresh cooling water, which is itself cooled against sea water.

3.2.4 Plant Turndown

Overall plant performance has been assessed at turndown using a GT power output of 40%. GT performance at 40% power output was estimated using in-house performance curves for a similar turbine firing natural gas at reduced load.

The gas turbine operates less efficiently at turndown, consuming proportionally more fuel and air, and delivering proportionally more exhaust gas to the HRSG. In turn, this will mean the HRSG is able to raise proportionally more steam, which results in the following effects:

GT Power Output	40%
Fuel Consumption	51%
Air Consumption	78%
GT Exhaust Flow	77%
HRSG Steam Raised	64%
ST Power Output	54%
Net Power Output	44%

3.2.5 Capital Cost, Operating Cost and Economics

The economic results are outlined in the table below:

Table 3-4 Economic Figures for CCGT without CO_2 Capture

		100% Load	40% Load
Total CAPEX	GB£M	547.5	547.5
Power Island	GB£M	474.5	474.5
Acid Gas Removal	GB£M	0.0	0.0
CO_2 compression	GB£M	0.0	0.0
Others	GB£M	73.0	73.0
CAPEX efficiency	GB£/ kW_{Net}	524	1197
Total OPEX – incl. fuel	GB£M p.a.	296.6	164.4
Total OPEX – excl. fuel	GB£M p.a.	28.3	28.3
OPEX – incl. fuel	GB£ p.a. / kW_{Net}	283.7	359.6
OPEX – excl. fuel	GB£ p.a. / kW_{Net}	27.1	61.9
Levelised Cost of Electricity CO_2 emission cost = £0 / te CO_2 CO_2 emission cost = £20 / te CO_2 CO_2 emission cost = £40 / te CO_2 CO_2 emission cost = £60 / te CO_2	 £ / MWh_{Net} £ / MWh_{Net} £ / MWh_{Net} £ / MWh_{Net}	 47.7 54.7 61.7 68.7	 70.1 78.3 86.4 94.6
Cost of CO_2 Captured CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	n/a	n/a
Cost of CO_2 Avoided CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	n/a	n/a

3.2.6 Key Assumptions and Uncertainties

For this case the assumptions are identical to the case with CO_2 capture shown in Section 3.1.6.

3.3 Technical Performance Assessment Findings

The Technical Performance Report included in Attachment 6 provides a detailed assessment of materially significant changes from the previous CCGT benchmark, together with documentation of the assumptions used in development of the new benchmark. This can be summarised as follows.

3.3.1 Review of Gas Turbine Performance Data

Attempts have been made to contact each of the major GT vendors to discuss the suitability and performance of their machines for both post-combustion capture and EGR modes of operation. Unfortunately, their responses have not been positive.

This performance data from GTW must be modified to take into account the site conditions assumed in the basis of design, and to raise the GT exhaust pressure slightly following the HRSG pressure drop review.

After additional scrutiny of the WP1/WP3 Gatecycle models it has become apparent that the M701G Gatecycle library performance data differs significantly from the published M701G2 data in GTW. In order to compare the GTW data with the Gatecycle library data, temperature/performance modifications were applied to the published M701G2 data, to provide an alternative prediction of the machine performance at our basis of design conditions.

MHI recommended that the performance of their M701F5 machine has superseded the M701G2 used in our WP1 benchmark, as published in GTW 2013 data.

A comparison of the performance data for the MHI M701G machine used to develop the WP1 Benchmark versus the predicted performance data for both the MHI M701G2 and M701F5 machines is given below.

Table 3-5 – Original and Refreshed GT Performance Data

	WP1 M701G	GTW M701G2	WP6 M701F5
Electric power (net of gen. losses only), kW	364,550	346,024	369,521
Heat Rate, Btu/kWh	8254	8330	8276
Exhaust flow rate, lb/s	1525	1625	1570
Exhaust temperature, °F	1124	1089	1136
Exhaust Pressure, kPa (abs)	103.5	103.5	105.3

Note: Performance at BoD conditions (10°C)

The figures show that there is a moderate but significant improvement in GT performance which can be achieved by updating the original CCGT benchmark cases with a new state-of-the-art GT, despite the raised exhaust pressure.

3.3.2 Review of Pressure Drop Profile in the HRSG and Downstream Equipment

The WP1 CCGT benchmark case shows no pressure drop between the GT exhaust and the blower inlet. This oversimplification resulted in an underestimation of the blower power, which is a significant contributor to the total parasitic load of the plant.

<u>HRSG Pressure Drop</u>

In-house experience within FW (Madrid office and Fired Heaters) has confirmed that an HRSG pressure drop of 0.02 barg is appropriate.

As such, it is recommended for the updated benchmark that we use a blower suction pressure of 0.02 barg, an HRSG pressure drop of 0.02 bar, and an increased gas turbine exhaust pressure of 0.04 barg.

Blower Efficiency

The original benchmark design model included an assumption of polytropic efficiency of 91.25%. The origin of this figure is uncertain, so a revised assumption of 85% is recommended based on advice from both FW in-house rotating equipment specialists and Howdens.

Using the recommended suction and discharge pressures above, together with a polytropic efficiency of 85%, the revised blower power would be 17,683 kW.

3.3.3 Development of the New CCGT Benchmark

Table 3-6 summarises the key performance figures for the refreshed CCGT benchmark case compared with the WP1 CCGT benchmark cases with and without 90% CO_2 capture.

The impacts of each of the changes can be summarised as follows:

Gas Turbine Changes:

- increase in GT power output,
- increased heat rate (due to apparent error in Gatecycle library),
- increased GT exhaust temperature,
- increased GT exhaust pressure,
- ➢ decrease in GT efficiency

Blower Changes:

- decreased suction pressure
- increased ΔP
- increased flow rate
- decreased efficiency
- ➢ increase in blower power and overall parasitic load

CO_2 Capture Level

- capture level decreased from 90.9 to 90.0%
- ➢ quantity of CO_2 captured increase (5.2%) lower than plant capacity increase (6.3%)

CO_2 Compressor Motor Efficiency

- compressor motor efficiency decreased from 100% to 95%
- ➢ CO_2 compression and dehydration unit power increase (11%) higher than plant capacity increase (6.3%)

Table 3-6 Summary of Technical Performance for Original and Refreshed Benchmarks at 100% GT Load

		M701G (library)		M701G2 (GTW)		M701F5 (GTW)	
		WP3 90% CO_2 Capture	WP1 0% CO_2 Capture	WP3 90% CO_2 Capture	WP1 0% CO_2 Capture	WP6 90% CO_2 Capture	WP6 0% CO_2 Capture
Total installed gross capacity	MWe	954.6	1037.6	908.1	1003.1	967.9	1068.0
- Gas Turbines	MWe	729.1	729.1	692.0	692.0	739.0	739.0
- Steam Turbine	MWe	225.5	308.5	216.0	311.1	228.9	328.9
Total auxiliary loads	MWe	110.6	46.9	88.6	22.1	97.1	22.4
- Power Island	MWe	39.2	40.1	13.3	15.6	13.2	15.6
- Acid Gas Removal	MWe	32.8	0.0	35.4	0.0	40.0	0.0
- CO_2 Compression	MWe	28.6	0.0	28.7	0.0	31.7	0.0
- Others	MWe	10.0	6.7	11.1	6.5	12.1	6.8
Net Power Export	MWe	844.0	990.8	819.5	981.0	870.8	1045.6
Net Efficiency (LHV)	%	50.05	58.76	48.51	58.07	48.58	58.33
Heat Rate	kJ/kWh	7192.3	6127.0	7421.6	6199.6	7410.6	6172.1
CC Energy Penalty	% points	8.70		9.56		9.75	
Total Fuel Feed Rate	tpd	3070.4	3070.4	3076.3	3076.3	3264.1	3264.1
Total Carbon in Fuel	tpd	2257.8	2257.8	2262.2	2262.2	2400.3	2400.3
Total Carbon Captured	tpd	2053.5	0.0	2057.2	0.0	2159.4	0.0
Total CO_2 Emissions	tpd	749.0	8273.8	751.2	8795.6	882.6	8795.6
Carbon Capture Rate	%	90.9	0.0	90.9	0.0	90.0	0.0
Carbon Efficiency	gCO_2/kWh	37.0	347.9	38.9	352.1	42.2	350.5

<u>Overall Impact on Performance between WP1/3 (library) and WP6 Benchmarks</u>

The above changes and individual impacts come together to produce the following overall changes between the original WP1 and WP3 benchmarks and the refreshed WP6 benchmarks (at 100% GT load):

- total plant fuel input has increased by 6.3% due to changing the GT model data from the M701G2 to the M701F5;
- net power output has increased by 26.8 MWe and 54.8 MWe (or an increase of 3.2% and 5.5%) for the 90% and 0% carbon capture cases respectively;
- LHV net efficiency has decreased by 1.47 %-points and 0.43 %-points to 48.58% and 58.33% for the 90% and 0% carbon capture cases respectively;
- the carbon capture energy penalty has increased relative to the WP1 and WP3 benchmarks by 1.05 %-points from 8.70 % points to 9.75 %-points;
- the carbon footprint of the power generation scheme has increased from 37.0 gCO_2/kWh_{net} to 42.2 gCO_2/kWh_{net} relative to the WP1 and WP3 benchmarks (347.9 gCO_2/kWh_{net} to 350.5 gCO_2/kWh_{net} in the cases without carbon capture) due to the decrease in overall LHV efficiency.
  i.e. the increased fuel rate per unit of power has now resulted in more CO_2 production per unit of power).

Impact on Performance between WP1/3 (GTW) and WP6 Benchmarks

An apparent error in the Gatecycle Library data heat rate and GT auxiliaries figures led to the generation of a revised WP1 and WP3 simulation in order to investigate the differences between the overall plant performance based on the Gatecycle library machine and the M701G2 as shown in Gas Turbine World 2013.

Advice was sought from experts in power systems based in FW's Milan office, who suggested that it is normal for the total auxiliaries in a CCGT (without capture) to be approximately 2% of the total gross power output. The simulations and performance calculations were therefore modified to reflect this lower parasitic load.

The main features changing from the library data to the GTW data for the WP1 and WP3 benchmarks are:

- 0.2% increase in fuel requirement;
- 5.1% decrease in GT power generation;
- 4.2% decrease and 0.8% increase in ST power generation for the with and without CO_2 capture cases respectively;
- 25.9 MWe and 25 MWe reduction in power island parasitic load for the with and without CO_2 capture cases respectively (due to a very high GT auxiliaries figure in the Library data);
- 2.9% and 1% decrease in net power production for the with and without CO_2 capture cases respectively;
- 1.6% point and 0.7% point decrease in net LHV efficiency for the with and without CO_2 capture cases respectively;
- A 0.9 % point increase in the energy penalty of CO_2 capture.

3.3.4 Conclusions

The results above show that there has been a significant value in revisiting the CCGT benchmark cases originally developed in 2009 and 2010 and applying a higher degree of interrogation to all input data used. This work has identified areas for improvement in:

- GT performance data
- Blower power
- HRSG pressure profile
- CO_2 compression power
- CO_2 capture level

The overall changes can be attributed to two key steps:

- Changing from using Gatecycle library data (for the M701G turbine) to Gas Turbine World 2013 data (for the M701G2 turbine).
  The main impact of changing to the GTW data was to reduce the GT output and overall net power production. This reduced the expected net efficiency by 1.5% points.
- Changing from the M701G2 turbine data to the M701F5 turbine data based on MHI's recommendation.
  The absolute performance of the M701F5 gas turbine is better than that of the M701G2 gas turbine, and almost equivalent to the original M701G (library) turbine output.

In order to improve upon the benchmarks further it would be essential to obtain the assistance of one or more of the vendors of Frame 9 scale gas turbines. Unfortunately, this study has found that these vendors are currently reluctant to commit resource to work of this nature until a firm project prospect is identified as a focus for their efforts.

4. TASK 2 - EXHAUST GAS RECYCLE BENCHMARKS

4.1 Development of Exhaust Gas Recycle Benchmarks

In developing the new benchmarks for the CCGT/CCS case with EGR, an assessment of two rates was required:

- An intermediate rate providing GT inlet conditions representing modest GT development risks; and
- A rate representing an optimum for EGR.

4.1.1 Modelling of EGR Rates

For the purposes of this assessment, the EGR rate is defined as follows:

$$\text{EGR Rate} = \frac{\text{volume flow of recirculated exhaust gas}}{\text{volume flow of exhaust gas from HRSG}}$$

In order to model the CCGT system with EGR, a simplified Gatecycle simulation was developed using the library data for the MHI M701G turbine. By simulating the performance of the CCGT system, the exhaust gas composition could be predicted, with a portion of the exhaust gas stream cooled and recycled back to the GT inlet. Using a 10°C approach temperature to the cooling water temperature of 14°C, gives an EGR temperature of 24°C after cooling.

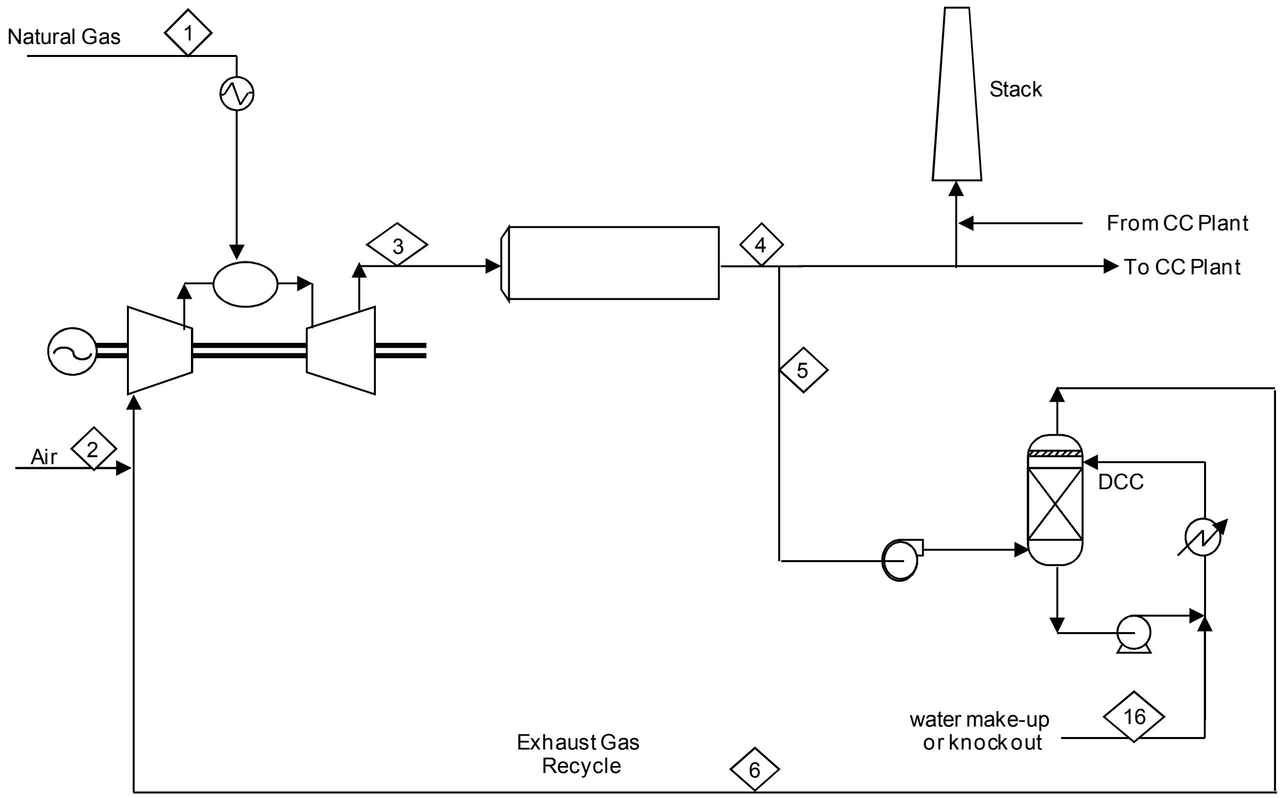


Figure 4-1 Simplified CCGT with EGR Flowsheet

This simplified modelling approach was used to investigate the appropriate rates to use for EGR, and did not include the specific GT modifications to represent the MHI M701F5 turbine performance and the HRSG pressure drop as outlined in Section 3.3. These will be included in the more detailed modelling of the full cases in sections 4.2 to 4.6.

Selection of the Intermediate Case

The Intermediate case was chosen such that the oxygen concentration at the GT inlet represented modest development risks for the GT.

The oxygen concentration of the GT inlet for this case was assumed to be 19%.

Using the modelling described above, the EGR Rate was varied such that the oxygen concentration at the GT inlet was also 19%. The resulting EGR rate was approximately 19%.

Selection of the "Optimum" Case

EGR involves using exhaust gases (with depleted oxygen levels) to replace part of the combustion air in the GT inlet. For the CCS application, high EGR ratios are desirable to maximise the CO_2 content in the exhaust gas and minimise the mass flow through the CO_2 capture plant. However, there is a maximum feasible rate of EGR which can be achieved without compromising flame stability due to low oxygen concentration in the flame anchoring region and increasing emissions from incomplete combustion.

Oxygen enrichment of the combustion air would require an air separation unit, which would incur significant capital cost, parasitic load and operational inflexibility. As such, oxygen enrichment was discounted form this study.

The published articles on EGR (see references) have found that the effect of EGR on the components including the power outputs and efficiency is not very large, and that while NOx emissions are reduced by EGR, CO emissions increase due to decreasing O_2 content.

GE has demonstrated complete combustion in a DLN F-class combustion system operating at 35% EGR using existing technology without major modifications.

Further, GE believe that this could be pushed up to 40% whilst maintaining the lean blow out margins with minor modifications to change the level of pre-mixing, control systems, and introduction of pilots.

As such, it can be assumed that 35% EGR represents the current state of EGR development in F-class turbines, but that this may be extended in future through developments in turbine technology specifically for CCS projects.

Results

Preliminary modelling produced the following results for the GT oxidant and exhaust streams at the selected EGR rates of 19% and 35%. These are compared against the same data for the GT without EGR based on the (more detailed) modelling completed in Task 1.

As the EGR modelling is developed in more detail for the Task 2 Benchmarks, the key attributes that will be maintained are:

- "Optimum" Case - 35% EGR
- "Intermediate Case" – 19% Oxygen in GT inlet.

As such, the results shown in the Table 4-1 may not exactly match the benchmark results.

Table 4-1 Preliminary GT Inlet/Exhaust Conditions at selected EGR Levels

	Task 1 0% EGR		Intermediate 19% EGR		"Optimum" 35% EGR	
	GT Oxidant	GT Exhaust	GT Oxidant	GT Exhaust	GT Oxidant	GT Exhaust
Pressure (kPa)	101	105	101	104	101	104
Temperature (°C)	10	613	13	597	15	603
Mass rate (kg/h)	4991402	5127404	5231285	5362805	5108933	5238702
Mole % Oxygen	20.82	11.01	18.92	9.92	16.42	7.38
Mole % Nitrogen	77.60	74.18	77.96	74.84	78.72	75.39
Mole % CO2	0.03	4.64	1.06	5.29	2.47	6.68
Mole % Argon	0.93	0.89	0.93	0.89	0.94	0.90
Mole % H2O	0.61	9.29	1.12	9.05	1.46	9.65
Molar rate (kmol/hr)	173009	180728	180783	188449	176006	183558

4.1.2 Estimating M701F5 Turbine Performance with EGR

It is necessary to develop a method of estimating the performance of the MHI M701F5 turbine at a variety of exhaust gas recycle rates.

Given a coherent set of user defined input data, the Gatecycle model can predict the performance and exhaust conditions, which can then be used within HYSYS to model the capture plant performance.

By calculating performance curves for the M701G library turbine at varying levels of EGR, the following correlations have been identified:

Heat Rate (Btu/KWh) $= 0.026x^2 + 2.778x + 8481$

Gross Power (kW) $= -158.7x + 280756$

Exhaust Flow (kg/s) $= -0.388x + 752$

Exhaust Temp (°C) $= 0.003x^2 + 0.228x + 592$

where x = EGR level = e.g. 35%

To confirm the results, similar correlations were calculated for the performance of the M701F library turbine, with no significant difference (<1%) identified between the trends for the relevant input data at either 19% and 35%.

Using the GT Performance figures from the Task 1 CCGT benchmark which have been derived for the M701F5 turbine at 0% EGR, together with the correlations above, we can derive the following initial input data for the Gatecycle models at 19% and 35% EGR.

Table 4-2 Gatecycle Input Parameters for M701F5 Turbine at selected EGR Levels

	Task 1 0% EGR	Intermediate 19% EGR	"Optimum" 35% EGR
Electric Power (kW)	369521	365308	361681
Heat Rate (Btu/kWh)	8276	8329	8374
Exhaust flow rate (kg/s)	712.1	704.8	698.6
Exhaust Temp (°C)	613	618	621

The calculation method employed by Gatecycle uses the user specified values for net power generation, heat rate, exhaust flow and exhaust temperature to define the GT performance and calculate the subsequent overall power island performance.

Specifying these variables means that the air stream flow rate or, in the EGR cases, the oxidant stream flow rate (made up of air and cooled recycled flue gas), is a function of the exhaust flow rate and heat rate. Consequently the detailed power island model had to be converged manually by specifying the GT oxidant feed stream composition and temperature to match the resultant GT exhaust gas plus fresh air stream composition from the previous iteration.

This process resulted in a slightly different final value of EGR for the optimum case of 18.05% in order to ensure that the oxygen concentration in the GT inlet was consistent with the Intermediate Case value.

4.1.3 Capture Plant equipment sizing with increasing levels of EGR

There are two variables which impact the CO_2 capture and compression equipment size when EGR is increasingly applied to the benchmark system design:

- Total flue gas CO_2 concentration increases and volumetric flow decreases.
- Total CO_2 molar flow decreases slightly because the GT demands slightly less fuel with increasing EGR.

To account for the potential benefits in terms of reduced equipment sizes and parasitic loads as the percentage of EGR is increased, heat and material balances and utility summaries have been developed based on the flue gas flow rate and composition for each case assessed (at full load). The equipment within the CO_2 capture and compression equipment has been resized and recosted (equipment was not resized for the turndown cases) for the flue gas flow rate and composition particular to the individual case.

Due to the flue gas total volumetric flow rate decrease the CO_2 capture plant blower, DCC and absorber decrease in size as %EGR increases.

The remaining CO_2 capture and compression equipment size is dependant only on the molar flow rate of CO_2 to be captured because this, in turn, determines the optimum solvent molar flow rate. (The solvent lean and rich loading should not be a variable in this kind of comparative study as it is independent of the upstream technology being assessed.) Since the CO_2 molar flow decreases slightly with increasing %EGR, the size of this equipment all decreases slightly with increasing %EGR.

However, as EGR is added, an additional DCC is required (included in the Power Island scope) to cool the exhaust gas recycle prior to mixing with the fresh air at the GT compressor inlet. The size of this additional DCC increases with increasing EGR and slightly offsets the capital cost benefit of reducing capture plant equipment size.

4.2 CCGT with 35% EGR and 90% CO_2 capture

4.2.1 Introduction

A natural gas CCGT with EGR and CO_2 capture was developed, using the same configuration and natural gas feed rate as the CCGT with CO_2 capture case, and including a recycle of 35% of the exhaust gas to the gas turbine inlet. This increases the percentage of CO_2 in the gas turbine and reduces the size of the capture plant with the 35% figure representing the maximum demonstrated, and thus optimal, currently achievable level of EGR. Levels above 35% risk flame instability and begin to approach the limit of available LP steam for solvent regeneration.

The overall process scheme was based upon a natural gas fired combined cycle gas turbine (CCGT) using two Mitsubishi Heavy Industries (MHI) M701F5 gas turbines featuring dry low NOx (DLN) burners, each with downstream heat recovery steam generator (HRSG), and common single steam turbine generator (STG), CO_2 capture unit and CO_2 compression and dehydration unit.

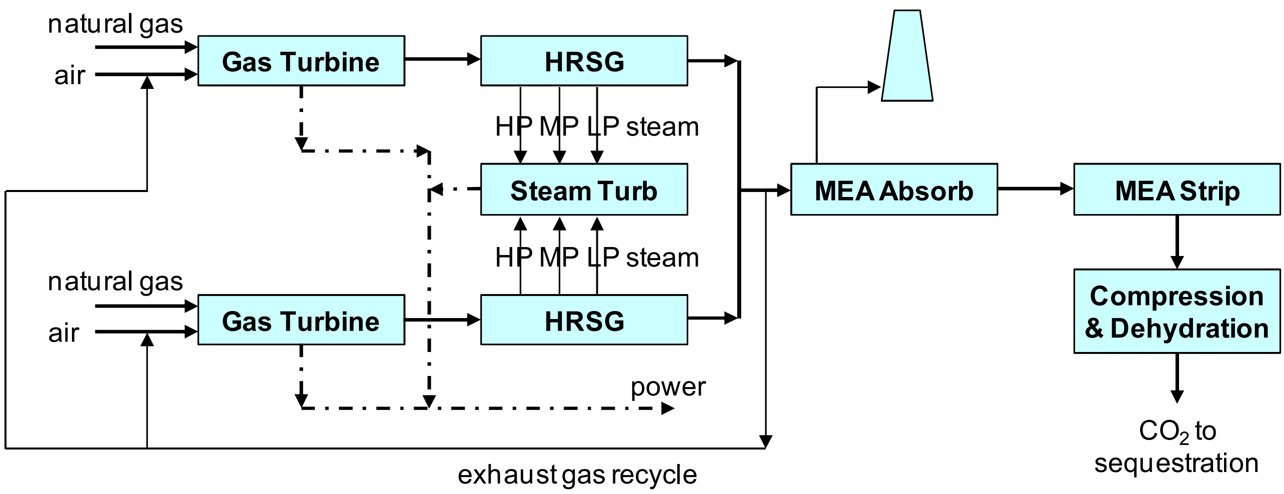


Figure 4-2 CCGT with EGR and Post Combustion CO_2 Capture

This case differs from the CCGT Benchmark without EGR by having a smaller volumetric flow rate and increased concentration of CO_2 in the CO_2 capture plant feed (but with nearly unchanged CO_2 mass rate). This results is reduced blower power and reduced diameter of the direct contact cooler and absorption column in the CO_2 capture plant. However, it also involves an additional direct contact cooler and additional low pressure ducting to cool and return the recycle to the air compressor inlet. These additional items have been included in the Power Island scope.

4.2.2 Plant Performance

The plant performance for this case was assessed at both 100% load and 40% load, as summarised in the table below:

Table 4-3 Performance Figures for CCGT with 35% EGR and 90% CO_2 Capture

		100% Load	40% Load
Power			
Total gross installed capacity	MWe	957.1	418.7
Gas Turbine (s)	MWe	723.4	279.9
Steam Turbine	MWe	233.8	138.7
Others	MWe	0.0	0.0
Total auxiliary loads	MWe	84.0	53.7
Power Island	MWe	13.6	10.1
Flue Gas Blower	MWe	23.6	18.3
Acid Gas Removal	MWe	2.5	2.5
CO_2 compression	MWe	31.5	15.4
Others	MWe	12.9	7.3
Net Power Export	MWe	873.1	365.0
Net Efficiency (LHV)	%	49.18	41.98
Heat Rate	kJ/kWh	7320	8576
Flows			
Total fuel feed rate	tpd	3232.3	1583.3
Water consumption	tpd	3562	1843
Cooling water (once through)	tpd	1,961,856	1,103,069
Carbon Balance			
Total carbon in feeds	tpd	2376.9	1164.3
Total carbon captured	tpd	2139.9	1049.0
Carbon capture rate	%	90.0	90.1
Total CO_2 captured	tpd	7841.4	3844.1
Total CO_2 emitted	tpd	868.7	422.5
CO_2 emissions	g CO_2/kWh$_{Net}$	41.5	48.2

4.2.3 Process Description

<u>Gas Turbines, Heat Recovery Steam Generators and Steam Turbine</u>

The power island is based on two Mitsubishi Heavy Industries (MHI) M701F5 natural gas fed gas turbines, each with its own heat recovery steam generator (HRSG). The two HRSGs are identical and are configured to generate steam at three pressure levels with full reheat of medium pressure steam. A single steam turbine receives the steam from both HRSGs and is equipped with a vacuum condenser and condensate treatment.

Natural gas is received from across the plant battery limits via a metering station before being heated against MP boiler feed water (BFW) and fed to the gas turbines (GTs).

The GT exhaust gases flow to the Heat Recovery Steam Generator, without additional duct firing. The thermal energy of the exhaust gases is used to raise and superheat steam at 3 pressure levels as well as preheating condensate and heating the BFW. The flue gases, at approximately 93 °C, leaving the HRSG are pressurised using a blower in order to overcome the pressure drop through the MEA based Acid Gas Removal unit. Once the CO_2 has been removed the flue gases are reheated against the hot flue gas from the HRSG to cool the gas entering the AGRU and ensure that the treated flue gases are warm enough for dispersion via the stack.

The coil sequence in the HRSG is summarised as follows:

- 2nd HP Superheater
- 2nd MP Reheater
- 1st HP Superheater
- 1st MP Reheater
- HP Evaporator
- MP Superheater
- 2nd HP Economiser
- MP Evaporator
- LP Superheater
- MP Economiser
- 1st HP Economiser
- LP Evaporator
- LP Economiser
- Condensate Preheater

Condensate from the steam turbine condenser is preheated and deaerated using LP steam in the deaerator. Boiler feed water from the deaerator is pumped up to the three pressure levels required by the boiler feed water pumps.

In the HP circuit the BFW is pumped to approximately 14,000 kPa, passing through the 1st and 2nd HP Economiser into the HP Steam Drum. Water from the HP Steam Drum passes through the HP Evaporator coil generating saturated HP steam which returns to the HP Steam Drum before passing through the 1st and 2nd HP Superheaters and then to the HP inlet of the Steam Turbine.

The MP BFW pumps pump BFW to approximately 3000 kPa, through the MP Economiser and into the MP Steam Drum. Water from the MP Steam Drum passes through the MP Evaporator generating MP steam which is returned to the MP Steam Drum before entering the MP Superheater. Exhaust steam from the HP stage Steam Turbine are combined with superheated MP steam which is subsequently further superheated in the 1st and 2nd MP Reheaters before being routed to the MP stage of the Steam Turbine.

Desuperheaters between the two HP superheaters and the two MP reheaters use boiler feed water to control the second superheater outlet temperatures to 565ºC for both pressure levels.

The LP BFW pumps pump the BFW to approximately 450 kPa, through the LP Economiser and into the LP Steam Drum. Water from the LP Steam Drum passes through the LP Evaporator generating LP steam which is returned to the LP Steam Drum before entering the LP Superheater. The superheated LP Steam is then split, with a portion of being used to supply the heat required for the Stripper reboiler in the AGRU, and the remaining LP Steam being routed to the LP inlet of the Steam Turbine.

The exhaust gases from the LP stage of the steam turbine are combined with condensate from the Natural Gas Preheater and the condensate return from the AGRU Stripper Reboiler before being fully condensed against seawater in the Vacuum Condensate Condenser. The vacuum condensate is then returned to the Vacuum Condensate Pumps completing the circuit.

Exhaust Gas Recycle

The exhaust gases are divided with 65% of the exhaust gas flow continuing on to the CO_2 capture plant while the remaining 35% is recycled. This flue gas is cooled by direct contact with a circulating water stream, which in turned is cooled against sea water. The flue gas is cooled to 24°C which also results in knock out of some water from the exhaust gas. The cooled recycled flue gas is them mixed with fresh air and fed to the GT air compressor inlet.

CO_2 Removal

A blower boosts the flue gas pressure sufficiently to overcome the pressure drop in the direct contact cooler (DCC) and absorption column. In the DCC much of the water present in the flue gas stream condenses as the gas is cooled to 50°C. The condensate is then recirculated through a cooler and returned to the contact tower. A small quantity of sodium hydroxide is added to the recirculating water in order to ensure that the remaining SO_2 in the flue gas is removed to meet the <10 ppm specification to prevent excessive solvent losses. Precipitates and excess water are removed from the system to waste water treatment.

In the lower portion of the absorption column the flue gas is contacted with semi-lean and then lean amine which absorbs approximately 90% of the CO_2 content of the flue gas. This section also incorporates an extraction and cooling loop in order to ensure the cooler conditions which are more favourable to CO_2 absorption. In the top of the column the flue gas is washed with water to prevent solvent losses to the atmosphere. The flue gas is routed back to the gas / gas heat exchanger in the FGD unit, to ensure its temperature is sufficient for dispersion, then is released to atmosphere via the stack.

The CO_2-rich solvent stream exits the bottom of the absorber column and is pumped to approximately 5 bara. The stream is then split, with approximately 25% of the flow passing through 2 stages of heating against warmer solvent streams before being flashed at a pressure of 1.3 bara. The semi lean solvent from the flash drum is then cooled against rich solvent and returned to the absorption column with the cooled extracted solvent. The remaining rich solvent is heated against lean solvent in the cross over exchanger and introduced to the stripper column.

In the stripper column the CO_2 desorbs from the rich solvent as it is heated producing a stream of hot lean solvent from the bottom of the stripper. This lean solvent is cooled against rich solvent and returned to the absorption column. The stripper overheads are cooled to 30°C, condensing a significant quantity of water, some of which is returned to the stripper as reflux with the rest being sent to treatment or recovery.

CO_2 Compression and Drying

The acid gas resulting from the semi lean amine flash is compressed in the first of 8 compression stages, after which it is cooled and passed through a knock out drum. After the first compression stage the main CO_2 stream from the stripper column is added to the flashed acid gas stream for all the subsequent compression steps. Between each of the next 4 steps is a cooler and knock out drum, and the CO_2 is compressed up to a pressure of 25 bara.

The CO_2 is then dried by molecular sieve adsorption to reach the specification of <50 ppmv moisture. Two dehydration vessels are required since one bed will be in use whilst the second bed will be in regeneration. The regeneration cycle uses a slipstream of dried gas exiting the operating molecular sieve bed. The gas is heated using the returning regeneration gas exiting the molecular sieve bed in regeneration. It is further heated under temperature control in an electric heater before entering the bed in a counter flow direction. The wet gas leaving the bed is cooled against incoming gas, any condensed water is separated in a knock out drum before it is passed through a fines filter and returned upstream of the 3rd stage compressor. The absorbent regeneration process takes several hours. When complete the heater is bypassed and the bed is cooled down over several hours before return to operation.

The final 3 compression stages include intercoolers and an after cooler and result in a final CO_2 product at specification of 150 barg and 30°C.

Balance of Plant

The key balance of plant requirements for this scheme are the cooling water supply systems. A very large flow of cooling water is required to supply the steam turbine vacuum condenser. This duty is supplied using sea water in a once through flow scheme.

The AGRU and CO_2 compression and drying units also require a significant quantity of cooling medium. Where this cannot be supplied using heat integration within or between the process units, cooling water is required. This cooling water is supplied as fresh cooling water in a closed circuit. The fresh water system is cooled against sea water.

Facilities are also required for storage and make-up of the MEA based solvent to the AGRU. Reuse and treatment of the numerous, mainly small, water streams produced from the cooling of water saturated gas streams are integrated with the units where possible. Streams containing contaminants such as MEA are routed to an effluent treatment system.

4.2.4 Plant Turndown

Overall plant performance has been assessed at turndown using a GT power output of 40%. GT performance at 40% power output was estimated using in-house performance curves for a similar turbine firing natural gas at reduced load.

The gas turbine operates less efficiently at turndown, consuming proportionally more fuel and air, and delivering proportionally more exhaust gas to the HRSG and capture plant. In turn, this will mean the HRSG is able to raise proportionally more steam, which results in the following effects:

GT Power Output	40%
Fuel Consumption	49%
Air Consumption	77%
GT Exhaust Flow	77%
HRSG Steam Raised	64%
Capture Plant Turndown	49%
Capture Plant Steam Usage	46%
ST Power Output	59%
Net Power Output	42%

4.2.5 Capital Cost, Operating Cost and Economics

The economic results are outlined in the table below:

Table 4-4 Economic Figures for CCGT with 35% EGR and 90% CO_2 Capture

		100% Load	40% Load
Total CAPEX	GB£M	926.3	926.3
Power Island	GB£M	491.0	491.0
Acid Gas Removal	GB£M	246.4	246.4
CO_2 compression	GB£M	61.5	61.5
Others	GB£M	127.4	127.4
CAPEX efficiency	GB£/kWh	1061	2538
Total OPEX – incl. fuel	GB£M p.a.	308.9	172.7
Total OPEX – excl. fuel	GB£M p.a.	43.1	42.4
OPEX – incl. fuel	GB£ p.a. / kW_{Net}	353.8	473.1
OPEX – excl. fuel	GB£ p.a. / kW_{Net}	49.4	116.2
Levelised Cost of Electricity			
CO_2 emission cost = £0 / te CO_2	£ / MWh_{Net}	66.8	109.7
CO_2 emission cost = £20 / te CO_2	£ / MWh_{Net}	67.6	110.6
CO_2 emission cost = £40 / te CO_2	£ / MWh_{Net}	68.5	111.6
CO_2 emission cost = £60 / te CO_2	£ / MWh_{Net}	69.3	112.6
Cost of CO_2 Captured			
CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	47.9	86.8
Cost of CO_2 Avoided			
CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	57.8	109.8

4.2.6 Key Assumptions and Uncertainties

For this case the CCGT with CO_2 Capture without EGR also apply and are detailed in 3.1.6. Additional assumptions relevant for the EGR cases are:

- Testing the impact of a number of variables using the M701G library gas turbine in Gatecycle will give performance impacts which can be used to extrapolate the anticipated impact of the same variables for the M701F5 machine. (For Task 2 this includes the impact of varying the level of exhaust gas recycle.)
- For the 40% GT load cases it is assumed that the same level of derating will apply as applies to the cases without EGR.
- There is potential for reuse of low grade heat in most normal CCGT power plants with carbon capture, however, the temperature range of available heat from the exhaust gas recycle (93°C down to 24°C) is not of an easily useable quality within either the power island or the CO_2 capture and compression plants. This level of heat could be used in the power island to replace or reduce the duty of either the condensate preheater coil or condensate exchanger, or it could be used to provide heat input to an Organic Rankine Cycle to produce additional power. Investigation of any of these options and their integration into the overall scheme, and subsequent impact on operational flexibility would require a considerable amount of development and optimisation work in order to produce meaningful results. It was therefore assumed that while low-grade heat reuse might be applicable, it was not possible to include a meaningful design within the scope of this project.

4.3 CCGT with 35% EGR without CO_2 Capture

4.3.1 Introduction

A natural gas CCGT with EGR and without CO_2 capture was developed, using the same configuration and natural gas feed rate as the CCGT with 35% EGR and CO_2 capture case, but excluding the Acid Gas Removal and CO_2 Compression and Drying Units.

This case is a theoretical case for performance benchmarking only, as application of EGR does not serve a purpose without a CO_2 capture plant.

The overall process scheme was based upon a natural gas fired combined cycle gas turbine (CCGT) using two Mitsubishi Heavy Industries (MHI) M701F5 gas turbines featuring dry low NOx (DLN) burners, each with downstream heat recovery steam generator (HRSG), and common single steam turbine generator (STG).

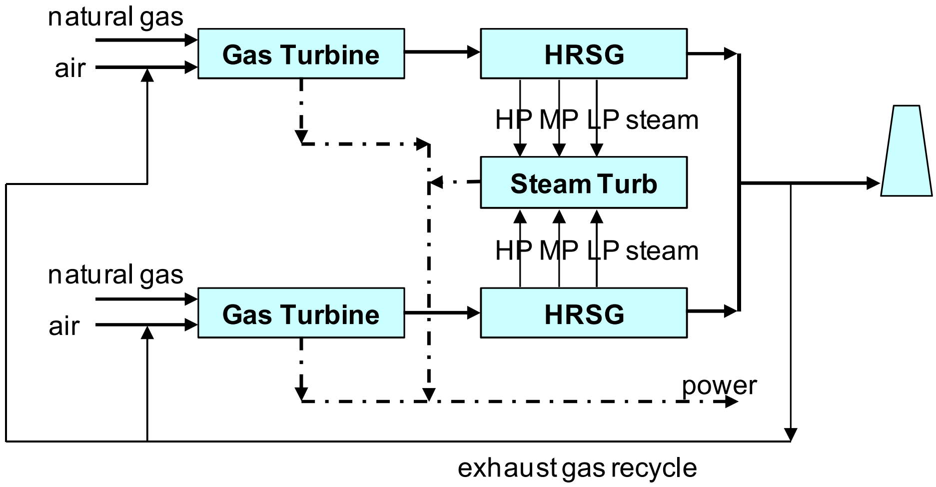


Figure 4-3 CCGT with EGR without CO_2 Capture

4.3.2 Plant Performance

The plant performance for this case was assessed at both 100% load and 40% load, as summarised in the table below:

Table 4-5 Performance Figures for CCGT with 35% EGR without CO_2 Capture

		100% Load	40% Load
Power			
Total gross installed capacity	MWe	1054.7	466.1
Gas Turbine (s)	MWe	723.4	279.9
Steam Turbine	MWe	331.4	186.1
Others	MWe	0.0	0.0
Total auxiliary loads	MWe	22.6	16.0
Power Island	MWe	14.8	10.6
Flue Gas Blower	MWe	0.0	0.0
Acid Gas Removal	MWe	0.0	0.0
CO_2 compression	MWe	0.0	0.0
Others	MWe	7.9	5.4
Net Power Export	MWe	1032.1	450.1
Net Efficiency (LHV)	%	58.14	51.76
Heat Rate	kJ/kWh	6192	6956

Flows			
Total fuel feed rate	tpd	3232.3	1583.3
Water consumption	tpd	202	130
Cooling water (once through)	tpd	1,396,690	749,256
Carbon Balance			
Total carbon in feeds	tpd	2376.9	1164.3
Total carbon captured	tpd	0.0	0.0
Carbon capture rate	%	0.0	0.0
Total CO_2 captured	tpd	0.0	0.0
Total CO_2 emitted	tpd	8710.2	4266.6
CO_2 emissions	g CO_2/ kWh_{Net}	351.6	395.0

4.3.3 Process Description

Gas Turbines, Heat Recovery Steam Generators and Steam Turbine

The power island is based on two Mitsubishi Heavy Industries (MHI) M701F5 natural gas fed gas turbines, each with its own heat recovery steam generator (HRSG). The two HRSGs are identical and are configured to generate steam at three pressure levels with full reheat of medium pressure steam. A single steam turbine receives the steam from both HRSGs and is equipped with a vacuum condenser and condensate treatment.

Natural gas is received from across the plant battery limits via a metering station before being heated against MP boiler feed water (BFW) and fed to the gas turbines (GTs).

The GT exhaust gases flow to the Heat Recovery Steam Generator, without additional duct firing. The thermal energy of the exhaust gases is used to raise and superheat steam at 3 pressure levels as well as preheating condensate and heating the BFW. The flue gases, at approximately 93 °C, leaving the HRSG are released to the atmosphere via a stack equipped with damper and continuous emissions monitoring.

The coil sequence in the HRSG is summarised as follows:

- 2nd HP Superheater
- 2nd MP Reheater
- 1st HP Superheater
- 1st MP Reheater
- HP Evaporator
- MP Superheater
- 2nd HP Economiser
- MP Evaporator
- LP Superheater
- MP Economiser
- 1st HP Economiser
- LP Evaporator
- LP Economiser
- Condensate Preheater

Condensate from the steam turbine condenser is preheated and deaerated using LP steam in the deaerator. Boiler feed water from the deaerator is pumped up to the three pressure levels required by the boiler feed water pumps.

In the HP circuit the BFW is pumped to approximately 14,000 kPa, passing through the 1st and 2nd HP Economiser into the HP Steam Drum. Water from the HP Steam Drum passes through the HP Evaporator coil generating saturated HP steam which returns to the HP Steam Drum before passing through the 1st and 2nd HP Superheaters and then to the HP inlet of the Steam Turbine.

The MP BFW pumps pump BFW to approximately 3000 kPa, through the MP Economiser and into the MP Steam Drum. Water from the MP Steam Drum passes through the MP Evaporator generating MP steam which is returned to the MP Steam Drum before entering the MP Superheater. Exhaust steam from the HP stage Steam Turbine are combined with superheated MP steam which is subsequently further superheated in the 1st and 2nd MP Reheaters before being routed to the MP stage of the Steam Turbine.

Desuperheaters between the two HP superheaters and the two MP reheaters use boiler feed water to control the second superheater outlet temperatures to 565°C for both pressure levels.

The LP BFW pumps pump the BFW to approximately 450 kPa, through the LP Economiser and into the LP Steam Drum. Water from the LP Steam Drum passes through the LP Evaporator generating LP steam which is returned to the LP Steam Drum before entering the LP Superheater. The superheated LP Steam is then routed to the LP inlet of the Steam Turbine.

The exhaust gases from the LP stage of the steam turbine are combined with condensate from the Natural Gas Preheater before being fully condensed against seawater in the Vacuum Condensate Condenser. The vacuum condensate is then returned to the Vacuum Condensate Pumps completing the circuit.

Exhaust Gas Recycle

The exhaust gases are divided with 65% of the exhaust gas flow continuing on to the stack while the remaining 35% is recycled. This flue gas is cooled by direct contact with a circulating water stream, which in turned is cooled against sea water. The flue gas is cooled to 24°C which also results in knock out of some water from the exhaust gas. The cooled recycled flue gas is them mixed with fresh air and fed to the GT air compressor inlet.

Balance of Plant

The key balance of plant requirements for this scheme are the cooling water supply systems. A very large flow of cooling water is required to supply the steam turbine vacuum condenser. This duty is supplied using sea water in a once through flow scheme. Any other cooling duties are supplied using fresh cooling water, which is itself cooled against sea water.

4.3.4 Plant Turndown

Overall plant performance has been assessed at turndown using a GT power output of 40%. GT performance at 40% power output was estimated using in-house performance curves for a similar turbine firing natural gas at reduced load.

The gas turbine operates less efficiently at turndown, consuming proportionally more fuel and air, and delivering proportionally more exhaust gas to the HRSG. In turn, this will mean the HRSG is able to raise proportionally more steam, which results in the following effects:

GT Power Output	40%
Fuel Consumption	49%
Air Consumption	77%

GT Exhaust Flow	77%
HRSG Steam Raised	64%
ST Power Output	56%
Net Power Output	44%

4.3.5 Capital Cost, Operating Cost and Economics

The economic results are outlined in the table below:

Table 4-6 Economic Figures for CCGT with 35% EGR without CO_2 Capture

		100% Load	40% Load
Total CAPEX	GB£M	586.3	586.3
Power Island	GB£M	508.1	508.1
Acid Gas Removal	GB£M	0.0	0.0
CO_2 compression	GB£M	0.0	0.0
Others	GB£M	78.2	78.2
CAPEX efficiency	GB£/kWh	568	1303
Total OPEX – incl. fuel	GB£M p.a.	295.9	160.3
Total OPEX – excl. fuel	GB£M p.a.	30.1	30.1
OPEX – incl. fuel	GB£ p.a. / kW_{Net}	286.7	356.2
OPEX – excl. fuel	GB£ p.a. / kW_{Net}	29.2	66.9
Levelised Cost of Electricity			
CO_2 emission cost = £0 / te CO_2	£ / MWh_{Net}	48.9	71.6
CO_2 emission cost = £20 / te CO_2	£ / MWh_{Net}	55.9	79.5
CO_2 emission cost = £40 / te CO_2	£ / MWh_{Net}	62.9	87.4
CO_2 emission cost = £60 / te CO_2	£ / MWh_{Net}	70.0	95.3
Cost of CO_2 Captured			
CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	n/a	n/a
Cost of CO_2 Avoided			
CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	n/a	n/a

4.3.6 Key Assumptions and Uncertainties

Key assumptions for this case are identical for those for the with CO_2 capture case, detailed in Section 4.2.6.

4.4 CCGT with 18% EGR and 90% CO_2 capture

4.4.1 Introduction

A natural gas CCGT with EGR and CO_2 capture was developed, using the same configuration and natural gas feed rate as the CCGT with CO_2 capture case, and including a recycle of 18% of the exhaust gas to the gas turbine inlet. This increases the percentage of CO_2 in the gas turbine and reduces the size of the capture plant.

The overall process scheme was based upon a natural gas fired combined cycle gas turbine (CCGT) using two Mitsubishi Heavy Industries (MHI) M701F5 gas turbines featuring dry low NOx (DLN) burners, each with downstream heat recovery steam generator (HRSG), and common single steam turbine generator (STG), CO_2 capture unit and CO_2 compression and dehydration unit.

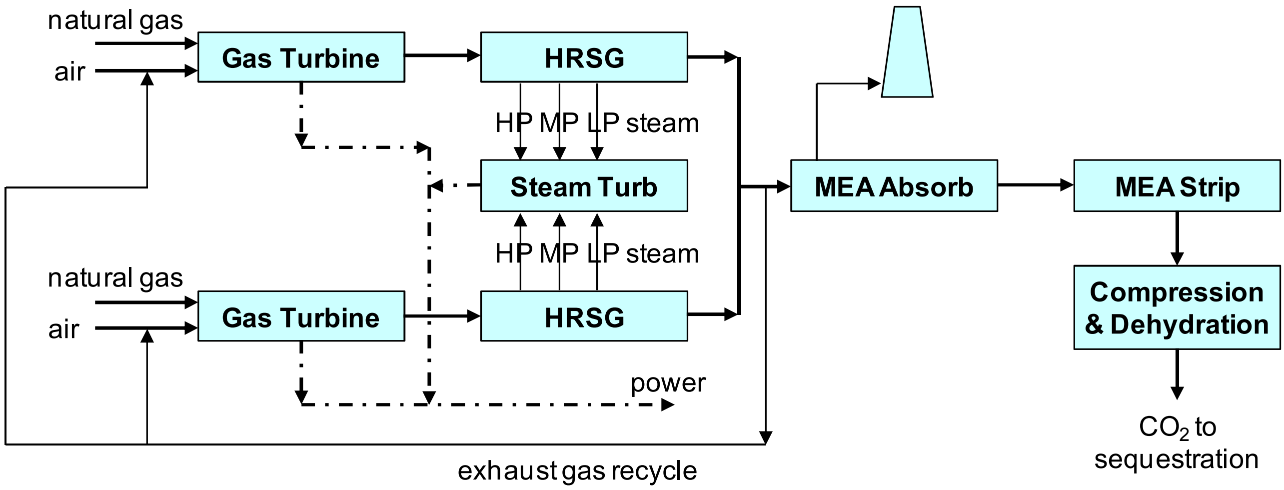


Figure 4-4 CCGT with EGR and Post Combustion CO_2 Capture

This case, with 18.05% EGR results in an oxygen content in the GT air compressor inlet which is the same as the oxygen content in the GT inlet for the Intermediate Case technology case.

This case differs from the CCGT Benchmark without EGR by having a smaller volumetric flow rate and increased concentration of CO_2 in the CO_2 capture plant feed (but with nearly unchanged CO_2 mass rate). This results is reduced blower power and reduced diameter of the direct contact cooler and absorption column in the CO_2 capture plant. However, it also involves an additional direct contact cooler and additional low pressure ducting to cool and return the recycle to the air compressor inlet. These additional items have been included in the Power Island scope.

4.4.2 Plant Performance

The plant performance for this case was assessed at both 100% load and 40% load, as summarised in the table below:

Table 4-7 Performance Figures for CCGT with 18% EGR and 90% CO_2 Capture

		100% Load	40% Load
Power			
Total gross installed capacity	MWe	964.2	420.9
Gas Turbine (s)	MWe	731.0	287.5
Steam Turbine	MWe	233.2	133.4
Others	MWe	0.0	0.0
Total auxiliary loads	MWe	90.8	59.0
Power Island	MWe	13.4	9.9
Flue Gas Blower	MWe	30.1	23.4
Acid Gas Removal	MWe	2.7	2.7
CO_2 compression	MWe	31.7	15.8
Others	MWe	12.8	7.2
Net Power Export	MWe	873.4	362.0
Net Efficiency (LHV)	%	48.97	40.71
Heat Rate	kJ/kWh	7352	8843
Flows			
Total fuel feed rate	tpd	3247.9	1619.1
Water consumption	tpd	3562	1843
Cooling water (once through)	tpd	1,945,229	1,075,188
Carbon Balance			
Total carbon in feeds	tpd	2388.4	1190.6
Total carbon captured	tpd	2156.5	1071.7
Carbon capture rate	%	90.3	90.0
Total CO_2 captured	tpd	7902.3	3927.2
Total CO_2 emitted	tpd	849.8	435.6
CO_2 emissions	g CO_2/kWh_{Net}	40.5	50.1

4.4.3 Process Description

<u>Gas Turbines, Heat Recovery Steam Generators and Steam Turbine</u>

The power island is based on two Mitsubishi Heavy Industries (MHI) M701F5 natural gas fed gas turbines, each with its own heat recovery steam generator (HRSG). The two HRSGs are identical and are configured to generate steam at three pressure levels with full reheat of medium pressure steam. A single steam turbine receives the steam from both HRSGs and is equipped with a vacuum condenser and condensate treatment.

Natural gas is received from across the plant battery limits via a metering station before being heated against MP boiler feed water (BFW) and fed to the gas turbines (GTs).

The GT exhaust gases flow to the Heat Recovery Steam Generator, without additional duct firing. The thermal energy of the exhaust gases is used to raise and superheat steam at 3 pressure levels as well as preheating condensate and heating the BFW. The flue gases, at approximately 93 °C, leaving the HRSG are pressurised using a blower in order to overcome the pressure drop through the MEA based Acid Gas Removal unit. Once the CO_2 has been removed the flue gases are reheated against the hot flue gas from the HRSG to cool the gas entering the AGRU and ensure that the treated flue gases are warm enough for dispersion via the stack.

The coil sequence in the HRSG is summarised as follows:

- 2nd HP Superheater
- 2nd MP Reheater
- 1st HP Superheater
- 1st MP Reheater
- HP Evaporator
- MP Superheater
- 2nd HP Economiser
- MP Evaporator
- LP Superheater
- MP Economiser
- 1st HP Economiser
- LP Evaporator
- LP Economiser
- Condensate Preheater

Condensate from the steam turbine condenser is preheated and deaerated using LP steam in the deaerator. Boiler feed water from the deaerator is pumped up to the three pressure levels required by the boiler feed water pumps.

In the HP circuit the BFW is pumped to approximately 14,000 kPa, passing through the 1st and 2nd HP Economiser into the HP Steam Drum. Water from the HP Steam Drum passes through the HP Evaporator coil generating saturated HP steam which returns to the HP Steam Drum before passing through the 1st and 2nd HP Superheaters and then to the HP inlet of the Steam Turbine.

The MP BFW pumps pump BFW to approximately 3000 kPa, through the MP Economiser and into the MP Steam Drum. Water from the MP Steam Drum passes through the MP Evaporator generating MP steam which is returned to the MP Steam Drum before entering the MP Superheater. Exhaust steam from the HP stage Steam Turbine are combined with superheated MP steam which is subsequently further superheated in the 1st and 2nd MP Reheaters before being routed to the MP stage of the Steam Turbine.

Desuperheaters between the two HP superheaters and the two MP reheaters use boiler feed water to control the second superheater outlet temperatures to 565ºC for both pressure levels.

The LP BFW pumps pump the BFW to approximately 450 kPa, through the LP Economiser and into the LP Steam Drum. Water from the LP Steam Drum passes through the LP Evaporator generating LP steam which is returned to the LP Steam Drum before entering the LP Superheater. The superheated LP Steam is then split, with a portion of being used to supply the heat required for the Stripper reboiler in the AGRU, and the remaining LP Steam being routed to the LP inlet of the Steam Turbine.

The exhaust gases from the LP stage of the steam turbine are combined with condensate from the Natural Gas Preheater and the condensate return from the AGRU Stripper Reboiler before being fully condensed against seawater in the Vacuum Condensate Condenser. The vacuum condensate is then returned to the Vacuum Condensate Pumps completing the circuit.

Exhaust Gas Recycle

The exhaust gases are divided with 65% of the exhaust gas flow continuing on to the CO_2 capture plant while the remaining 35% is recycled. This flue gas is cooled by direct contact with a circulating water stream, which in turned is cooled against sea water. The flue gas is cooled to 24°C which also results in knock out of some water from the exhaust gas. The cooled recycled flue gas is them mixed with fresh air and fed to the GT air compressor inlet.

CO_2 Removal

A blower boosts the flue gas pressure sufficiently to overcome the pressure drop in the direct contact cooler (DCC) and absorption column. In the DCC much of the water present in the flue gas stream condenses as the gas is cooled to 50°C. The condensate is then recirculated through a cooler and returned to the contact tower. A small quantity of sodium hydroxide is added to the recirculating water in order to ensure that the remaining SO_2 in the flue gas is removed to meet the <10 ppm specification to prevent excessive solvent losses. Precipitates and excess water are removed from the system to waste water treatment.

In the lower portion of the absorption column the flue gas is contacted with semi-lean and then lean amine which absorbs approximately 90% of the CO_2 content of the flue gas. This section also incorporates an extraction and cooling loop in order to ensure the cooler conditions which are more favourable to CO_2 absorption. In the top of the column the flue gas is washed with water to prevent solvent losses to the atmosphere. The flue gas is routed back to the gas / gas heat exchanger in the FGD unit, to ensure its temperature is sufficient for dispersion, then is released to atmosphere via the stack.

The CO_2-rich solvent stream exits the bottom of the absorber column and is pumped to approximately 5 bara. The stream is then split, with approximately 25% of the flow passing through 2 stages of heating against warmer solvent streams before being flashed at a pressure of 1.3 bara. The semi lean solvent from the flash drum is then cooled against rich solvent and returned to the absorption column with the cooled extracted solvent. The remaining rich solvent is heated against lean solvent in the cross over exchanger and introduced to the stripper column.

In the stripper column the CO_2 desorbs from the rich solvent as it is heated producing a stream of hot lean solvent from the bottom of the stripper. This lean solvent is cooled against rich solvent and returned to the absorption column. The stripper overheads are cooled to 30°C, condensing a significant quantity of water, some of which is returned to the stripper as reflux with the rest being sent to treatment or recovery.

CO_2 Compression and Drying

The acid gas resulting from the semi lean amine flash is compressed in the first of 8 compression stages, after which it is cooled and passed through a knock out drum. After the first compression stage the main CO_2 stream from the stripper column is added to the flashed acid gas stream for all the subsequent compression steps. Between each of the next 4 steps is a cooler and knock out drum, and the CO_2 is compressed up to a pressure of 25 bara.

The CO_2 is then dried by molecular sieve adsorption to reach the specification of <50 ppmv moisture. Two dehydration vessels are required since one bed will be in use whilst the second bed will be in regeneration. The regeneration cycle uses a slipstream of dried gas exiting the operating molecular sieve bed. The gas is heated using the returning regeneration gas exiting the molecular sieve bed in regeneration. It is further heated under temperature control in an electric heater before entering the bed in a counter flow direction. The wet gas leaving the bed is cooled against incoming gas, any condensed water is separated in a knock out drum before it is passed through a fines filter and returned upstream of the 3rd stage compressor. The absorbent regeneration process takes several hours. When complete the heater is bypassed and the bed is cooled down over several hours before return to operation.

The final 3 compression stages include intercoolers and an after cooler and result in a final CO_2 product at specification of 150 barg and 30°C.

Balance of Plant

The key balance of plant requirements for this scheme are the cooling water supply systems. A very large flow of cooling water is required to supply the steam turbine vacuum condenser. This duty is supplied using sea water in a once through flow scheme.

The AGRU and CO_2 compression and drying units also require a significant quantity of cooling medium. Where this cannot be supplied using heat integration within or between the process units, cooling water is required. This cooling water is supplied as fresh cooling water in a closed circuit. The fresh water system is cooled against sea water.

Facilities are also required for storage and make-up of the MEA based solvent to the AGRU. Reuse and treatment of the numerous, mainly small, water streams produced from the cooling of water saturated gas streams are integrated with the units where possible. Streams containing contaminants such as MEA are routed to an effluent treatment system.

4.4.4 Plant Turndown

Overall plant performance has been assessed at turndown using a GT power output of 40%. GT performance at 40% power output was estimated using in-house performance curves for a similar turbine firing natural gas at reduced load.

The gas turbine operates less efficiently at turndown, consuming proportionally more fuel and air, and delivering proportionally more exhaust gas to the HRSG and capture plant. In turn, this will mean the HRSG is able to raise proportionally more steam, which results in the following effects:

GT Power Output	40%
Fuel Consumption	50%
Air Consumption	78%
GT Exhaust Flow	77%
HRSG Steam Raised	63%
Capture Plant Turndown	50%
Capture Plant Steam Usage	49%
ST Power Output	57%
Net Power Output	41%

4.4.5 Capital Cost, Operating Cost and Economics

The economic results are outlined in the table below:

Table 4-8 Economic Figures for CCGT with 18% EGR and 90% CO_2 Capture

		100% Load	40% Load
Total CAPEX	GB£M	965.7	965.7
Power Island	GB£M	480.5	480.5
Acid Gas Removal	GB£M	290.3	290.3
CO_2 compression	GB£M	61.5	61.5
Others	GB£M	133.4	133.4
CAPEX efficiency	GB£/kWh	1106	2668
Total OPEX – incl. fuel	GB£M p.a.	311.1	176.7
Total OPEX – excl. fuel	GB£M p.a.	44.2	43.5
OPEX – incl. fuel	GB£ p.a. / kW_{Net}	356.2	488.2
OPEX – excl. fuel	GB£ p.a. / kW_{Net}	50.6	120.2
Levelised Cost of Electricity			
CO_2 emission cost = £0 / te CO_2	£ / MWh_{Net}	67.9	114.0
CO_2 emission cost = £20 / te CO_2	£ / MWh_{Net}	68.8	115.0
CO_2 emission cost = £40 / te CO_2	£ / MWh_{Net}	69.6	116.0
CO_2 emission cost = £60 / te CO_2	£ / MWh_{Net}	70.4	117.0
Cost of CO_2 Captured			
CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	51.9	96.1
Cost of CO_2 Avoided			
CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	63.0	125.2

4.4.6 Key Assumptions and Uncertainties

Key assumptions for this case are identical for those for the 35% EGR case, detailed in Section 4.2.6.

4.5 CCGT with 18% EGR without CO_2 Capture

4.5.1 Introduction

A natural gas CCGT with EGR and without CO_2 capture was developed, using the same configuration and natural gas feed rate as the CCGT with 18% EGR and CO_2 capture case, but excluding the Acid Gas Removal and CO_2 Compression and Drying Units.

This case is a theoretical case for performance benchmarking only, as application of EGR does not serve a purpose without a capture plant.

The overall process scheme was based upon a natural gas fired combined cycle gas turbine (CCGT) using two Mitsubishi Heavy Industries (MHI) M701F5 gas turbines featuring dry low NOx (DLN) burners, each with downstream heat recovery steam generator (HRSG), and common single steam turbine generator (STG).

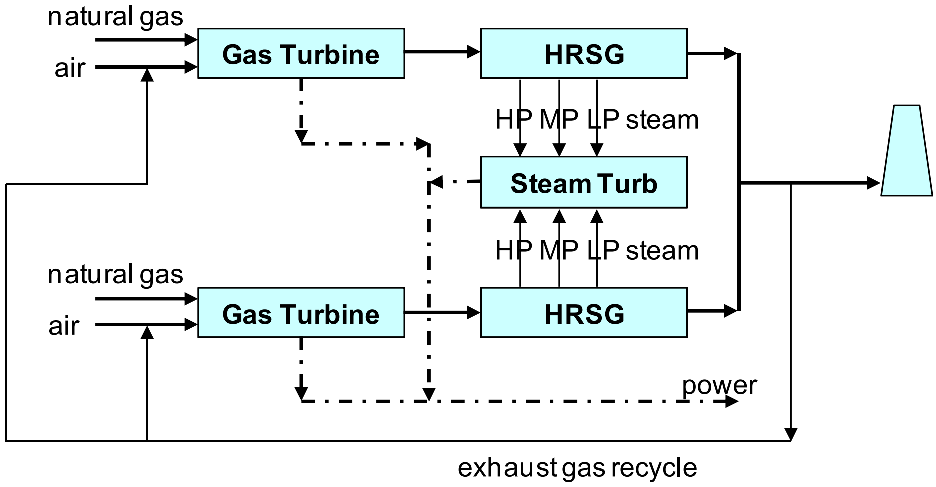


Figure 4-5 CCGT with EGR without CO_2 Capture

4.5.2 Plant Performance

The plant performance for this case was assessed at both 100% load and 40% load, as summarised in the table below:

Table 4-9 Performance Figures for CCGT with 18% EGR without CO_2 Capture

		100% Load	40% Load
Power			
Total gross installed capacity	MWe	1061.1	473.5
Gas Turbine (s)	MWe	731.0	287.5
Steam Turbine	MWe	330.1	185.9
Others	MWe	0.0	0.0
Total auxiliary loads	MWe	21.5	15.7
Power Island	MWe	14.7	10.6
Flue Gas Blower	MWe	0.0	0.0
Acid Gas Removal	MWe	0.0	0.0
CO_2 compression	MWe	0.0	0.0
Others	MWe	6.8	5.1
Net Power Export	MWe	1039.6	457.8
Net Efficiency (LHV)	%	58.28	51.48
Heat Rate	kJ/kWh	6177	6992

Flows			
Total fuel feed rate	tpd	3247.9	1619.1
Water consumption	tpd	203	132
Cooling water (once through)	tpd	1,289,890	806,990
Carbon Balance			
Total carbon in feeds	tpd	2388.4	1190.6
Total carbon captured	tpd	0.0	0.0
Carbon capture rate	%	0.0	0.0
Total CO_2 captured	tpd	0.0	0.0
Total CO_2 emitted	tpd	8752.1	4362.9
CO_2 emissions	g CO_2/ kWh_{Net}	350.8	397.1

4.5.3 Process Description

Gas Turbines, Heat Recovery Steam Generators and Steam Turbine

The power island is based on two Mitsubishi Heavy Industries (MHI) M701F5 natural gas fed gas turbines, each with its own heat recovery steam generator (HRSG). The two HRSGs are identical and are configured to generate steam at three pressure levels with full reheat of medium pressure steam. A single steam turbine receives the steam from both HRSGs and is equipped with a vacuum condenser and condensate treatment.

Natural gas is received from across the plant battery limits via a metering station before being heated against MP boiler feed water (BFW) and fed to the gas turbines (GTs).

The GT exhaust gases flow to the Heat Recovery Steam Generator, without additional duct firing. The thermal energy of the exhaust gases is used to raise and superheat steam at 3 pressure levels as well as preheating condensate and heating the BFW. The flue gases, at approximately 93 °C, leaving the HRSG are released to the atmosphere via a stack equipped with damper and continuous emissions monitoring.

The coil sequence in the HRSG is summarised as follows:

- 2nd HP Superheater
- 2nd MP Reheater
- 1st HP Superheater
- 1st MP Reheater
- HP Evaporator
- MP Superheater
- 2nd HP Economiser
- MP Evaporator
- LP Superheater
- MP Economiser
- 1st HP Economiser
- LP Evaporator
- LP Economiser
- Condensate Preheater

Condensate from the steam turbine condenser is preheated and deaerated using LP steam in the deaerator. Boiler feed water from the deaerator is pumped up to the three pressure levels required by the boiler feed water pumps.

In the HP circuit the BFW is pumped to approximately 14,000 kPa, passing through the 1st and 2nd HP Economiser into the HP Steam Drum. Water from the HP Steam Drum passes through the HP Evaporator coil generating saturated HP steam which returns to the HP Steam Drum before passing through the 1st and 2nd HP Superheaters and then to the HP inlet of the Steam Turbine.

The MP BFW pumps pump BFW to approximately 3000 kPa, through the MP Economiser and into the MP Steam Drum. Water from the MP Steam Drum passes through the MP Evaporator generating MP steam which is returned to the MP Steam Drum before entering the MP Superheater. Exhaust steam from the HP stage Steam Turbine are combined with superheated MP steam which is subsequently further superheated in the 1st and 2nd MP Reheaters before being routed to the MP stage of the Steam Turbine.

Desuperheaters between the two HP superheaters and the two MP reheaters use boiler feed water to control the second superheater outlet temperatures to 565°C for both pressure levels.

The LP BFW pumps pump the BFW to approximately 450 kPa, through the LP Economiser and into the LP Steam Drum. Water from the LP Steam Drum passes through the LP Evaporator generating LP steam which is returned to the LP Steam Drum before entering the LP Superheater. The superheated LP Steam is then routed to the LP inlet of the Steam Turbine.

The exhaust gases from the LP stage of the steam turbine are combined with condensate from the Natural Gas Preheater before being fully condensed against seawater in the Vacuum Condensate Condenser. The vacuum condensate is then returned to the Vacuum Condensate Pumps completing the circuit.

<u>Exhaust Gas Recycle</u>

The exhaust gases are divided with 65% of the exhaust gas flow continuing on to the stack while the remaining 35% is recycled. This flue gas is cooled by direct contact with a circulating water stream, which in turned is cooled against sea water. The flue gas is cooled to 24°C which also results in knock out of some water from the exhaust gas. The cooled recycled flue gas is them mixed with fresh air and fed to the GT air compressor inlet.

<u>Balance of Plant</u>

The key balance of plant requirements for this scheme are the cooling water supply systems. A very large flow of cooling water is required to supply the steam turbine vacuum condenser. This duty is supplied using sea water in a once through flow scheme. Any other cooling duties are supplied using fresh cooling water, which is itself cooled against sea water.

4.5.4 Plant Turndown

Overall plant performance has been assessed at turndown using a GT power output of 40%. GT performance at 40% power output was estimated using in-house performance curves for a similar turbine firing natural gas at reduced load.

The gas turbine operates less efficiently at turndown, consuming proportionally more fuel and air, and delivering proportionally more exhaust gas to the HRSG. In turn, this will mean the HRSG is able to raise proportionally more steam, which results in the following effects:

GT Power Output	40%
Fuel Consumption	50%
Air Consumption	78%

GT Exhaust Flow	77%
HRSG Steam Raised	65%
ST Power Output	56%
Net Power Output	44%

4.5.5 Capital Cost, Operating Cost and Economics

The economic results are outlined in the table below:

Table 4-10 Economic Figures for CCGT with 18% EGR without CO_2 Capture

		100% Load	40% Load
Total CAPEX	GB£M	574.4	574.4
Power Island	GB£M	497.8	497.8
Acid Gas Removal	GB£M	0.0	0.0
CO_2 compression	GB£M	0.0	0.0
Others	GB£M	76.6	76.6
CAPEX efficiency	GB£/kWh	553	1255
Total OPEX – incl. fuel	GB£M p.a.	296.5	162.7
Total OPEX – excl. fuel	GB£M p.a.	29.5	29.5
OPEX – incl. fuel	GB£ p.a. / kW_{Net}	285.2	355.4
OPEX – excl. fuel	GB£ p.a. / kW_{Net}	28.4	64.4
Levelised Cost of Electricity CO_2 emission cost = £0 / te CO_2 CO_2 emission cost = £20 / te CO_2 CO_2 emission cost = £40 / te CO_2 CO_2 emission cost = £60 / te CO_2	 £ / MWh_{Net} £ / MWh_{Net} £ / MWh_{Net} £ / MWh_{Net}	 48.4 55.4 62.4 69.4	 70.6 78.5 86.5 94.4
Cost of CO_2 Captured CO_2 emission cost = £ 0 / te CO_2	 £ / te CO_2	 n/a	 n/a
Cost of CO_2 Avoided CO_2 emission cost = £ 0 / te CO_2	 £ / te CO_2	 n/a	 n/a

4.5.6 Key Assumptions and Uncertainties

Key assumptions for this case are identical for those for the with CO_2 capture case, detailed in Section 4.2.6.

5. EVALUATION BASES

5.1 Technical Evaluation Basis

The Basis of Design document given in Attachment 1 has been used as the technical basis on which each option has been evaluated, including:

- plant location;
- site conditions;
- plant capacity;
- plant (climatic) operating conditions;
- feedstock, product and utility availability and specifications; and
- environmental emissions basis.

<u>CO_2 Capture Rate</u>

Each carbon dioxide abated case will be designed to achieve a target carbon capture level of at least 90%, defined as:

$$CO_2 \text{ Capture Rate (\%)} = \frac{100 \times \text{Moles carbon contained in the } CO_2 \text{ product}}{\text{Moles carbon contained in the natural gas feed}}$$

5.2 Capital Cost Estimating Basis

<u>Introduction</u>

The Estimates contained within this study report have been based on the technical definition for each of the benchmark cases considered. The estimate methodology is largely based on in-house data, available from previous work undertaken by Foster Wheeler for similar plants.

For all of the cases reported the source estimate data has been adjusted to provide figures on a consistent and comparable 1st quarter 2009 (1Q2009) UK Basis.

Estimates prepared using this methodology and associated qualifications/exclusions are normally considered to have an accuracy of +/-40%.

<u>Currency</u>

The estimates are reported in GB Pounds (GB£).

When in-house data is available in a different currency, the following Currency Conversion rates have been used for conversion:

Base Currency	Exchange Rate
GB£ 1	US$ 1.53
GB£ 1	€ 1.12

Basis

Equipment estimates are developed using FW's indexed Aspentech Capital Cost Estimator (ACCE) estimating programme and in-house data for more complex specialist equipment.

All other costs, including bulks associated with the project are factored from the equipment costs.

No Site specific costs have been included. Consistent with the Basis of Design, the site has been assumed to be a generic site clear and level and free from underground obstructions. These Estimates reflect a 1Q2009 UK site basis with no allowance for future escalation.

Format

The Work Breakdown Structure (WBS) used for the estimates is as follows:

- Acid Gas Removal
- CO_2 compression and dehydration
- Power Block
- Utilities & Offsites

The Utilities & Offsites area includes the following major items, as appropriate:

- Interconnecting piping
- Electrical Switchgear/Transformers
- 275 kV cables to new switchyard
- DCS system
- Seawater Intake/Pumping/Outfall System
- Demineralised Water system
- BFW Chemical Injection
- Condensate Polishing Package
- Water treatment
- Flare Package
- N_2 Package
- Instrument/Utility Air Package
- Fire fighting system

Major Equipment

The majority of equipment item costs have been generated using the ACCE estimating program indexed to reflect Foster Wheeler's experience of market conditions.

For some specialised major equipment items not covered by the ACCE database, costs have been based on in-house data and published cost data from licensors.

The main supplier/licensor budget prices, received for previous works carried out by Foster Wheeler, mainly include the following unit/equipment:

- Dehydration Package;
- Power Island including the following
    - HRSG
    - Steam Turbine
    - Gas turbine

Direct Bulk Materials

The estimated material costs reflect worldwide procurement, therefore no allowance for possible savings by locally purchasing of direct materials and associated reductions in shipping costs have been made.

The bulk material costs have been factored from the major equipment costs using factors derived from a more detailed study for a very similar plant. These costs include for the following

- Piping
- Instruments
- Electricals
- Catalysts & Chemicals

Direct Material & Labour Contracts

Costs are allowed based on factors derived from earlier similar projects. Cost include for the following.

- Tankage
- Civil, Steelwork & Buildings
- Protective cover

Labour only contracts

Costs are allowed based on factors derived from earlier similar projects. Cost include for the following.

- Equipment erection
- Piping Fabrication & Erection
- E&I Installation
- Scaffolding
- Pre-commissioning trade labour assistance

Indirect Costs

Costs are allowed based on factors derived from earlier similar projects. Cost include for the following.

- Temporary facilities
- Heavy Lifts
- Commissioning
- Vendor's engineers

EPC Contracts

Costs are allowed based on factors derived from earlier similar projects. Cost include for the following.

- Engineering services (Including FEED engineering)
- Construction Management

Escalation

The estimates have been escalated depending on the date of the reference project, based on Foster Wheeler experience. No allowance has been made for future escalation.

Land Costs

Land Costs have been included as specified by ETI at a rate of 5% of the total installed costs for all cases

Owners Costs

Owners costs have been included as specified by ETI at a rate of 10% of the total installed costs for all cases.

Contingency

Contingency has been included as specified by ETI at a rate of 25% of the total installed costs for all cases.

Exclusions

The following costs have been specifically been excluded from the capital cost estimates:

- Import Duties;
- Capital / Insurance Spares;
- Financing;
- Royalties & Process Guarantees;
- Piling;
- Removal of unseen/unidentified underground obstructions;
- Operating costs (which are covered separately);
- Statutory Authority & Utility Company Costs & permits;

- Currency Fluctuations;
- PMC Costs;
- Contractors Fees;
- Contractors All Risk Insurance;
- Taxes;
- Metal pricing movements.

5.3 Operating and Maintenance Cost Estimating Basis

Introduction

Operating and Maintenance (O&M) costs include the following:

- Chemicals;
- Catalyst;
- Solvents;
- Direct labour;
- Maintenance;
- Administration and General Overheads.

O&M costs are generally allocated as variable and fixed costs. Variable operating costs are directly proportional to the amount of kilowatt-hours produced and are referred as incremental costs. They may be expressed in £/kWh. Fixed operating costs are essentially independent of the quantity of kilowatt-hours produced. They may be expressed in £/h or £/year.

5.3.1 Variable costs

The variable costs include the consumption of catalysts, chemicals and solvents. These costs are annual, based on the expected equivalent availability of the plant. The variable costs mainly include the following:

- Fuel (natural gas);

  A natural gas price of £265/ has been assumed.
- Solvent (MEA) consumption for the chemical or physical removal of the acid gases;
- Chemicals for water/steam treatment and waste water treatment; and
- Waste disposal.

CO_2 Emissions Costs

In addition, any costs associated with CO_2 emissions will impact the operating costs of the facility. LCOE has been calculated for each case using emissions costs of £0/te, £20/te, £40/te and £60/te.

5.3.2 Fixed costs

The fixed costs mainly include the following:

- Direct labour;
- Administration and general overheads;
- Maintenance.

Direct Labour

The yearly cost of the direct labour has been calculated assuming, for each individual, an average cost equal to £50,000 / year. The number of personnel engaged for the different alternatives has been evaluated on the basis of the following tables.

Table 5-1– Personnel of Combined Cycle Gas Turbine plants

Operation	**Total**	**Notes**
Area Responsible	1	daily position
Assistant Area Responsible	1	daily position
Electrical Assistant	5	1 shift position
Shift Supervisor	5	1 shift position
Control Room Operator	10	2 shift position
Field Operator	10	2 shift position
Subtotal	**32**	
Maintenance		
Mechanical group	3	daily position
Instrument group	3	daily position
Electrical group	2	daily position
Subtotal	**8**	
Laboratory		
Superintendent + Analysts	**4**	daily position
Total	**40**	

The number of personnel required for the Combined Cycle Gas Turbine plants with post-combustion CO_2 capture has been considered as 60.

Administration and General Overheads

These costs include all other Company services not directly involved in the operation of the Complex, such as:

- Management;
- Personnel services;
- Technical services;
- Clerical staff.

These services vary widely from company to company and are also dependent on the type and complexity of the operation.

Based on EPRI, Technical Assessment Guide for the Power Industry, an amount equal to 30% of the direct labour cost has been considered.

Maintenance

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

Since these costs are all strongly dependent on the type of equipment selected and statistical maintenance data provided by the selected Supplier, this type of evaluation of the maintenance cost is premature at this stage of the study.

For this reason, the annual maintenance cost of the Complex has been estimated as a percentage of the installed capital cost of the facilities.

Different percentage factors have been applied to the different units, based on the following criteria:

- 2.5% for gaseous and liquid handling units;
- 1.7% for utilities and offsites;
- 5.0% for the Power Island (to take into account the gas turbine maintenance cost based on the assumption of a Long Term Service Agreement with the selected gas turbine manufacturer).

5.4 Economic Basis

For the purposes of economic modelling and calculation of the Levelised Cost of Electricity (LCOE), the following assumptions have been made for all cases.

- A plant availability of 85% has been assumed, which equates to an on-stream time of 7446 hrs per year. A reduced availability has been taken into account for in years 1 (65%) and year 2 (75%).
- Costs of insurance and local taxes have been assumed at 2% of the Total Installed Cost.
- Capital Expenditure has been assumed to be spread over a three year period in the following spread:
  - Year -3 = 25%
  - Year -2 = 45%
  - Year -1 = 30%
- A discount rate of 10% has been assumed.
- A project life of 20 years has been assumed.
- All costs associated with transport and storage of CO_2 have been assumed to be outside of the scope of the calculated LCOE.

CO_2 Emissions Costs

In addition, any costs associated with CO_2 emissions will impact the economics of the facility. LCOE has been calculated for each case using emissions costs of £0/te, £20/te, £40/te and £60/te.

6. ASSESSMENT OF THE EFFECT OF INCREASING EGR RATE

6.1 Introduction

There are two variables which impact the CO_2 capture and compression equipment size when EGR is increasingly applied to the benchmark system design:

- Total flue gas CO_2 concentration increases and volumetric flow decreases.
- Total CO_2 molar flow decreases slightly because the GT demands slightly less fuel with increasing EGR.

The effect on the equipment sizing when EGR is increasingly applied to the system can be summarised as follows:

- Due to decrease in the flue gas total volumetric flow rate, the CO2 capture plant blower, DCC and absorber decrease in size as %EGR increases.
- Due to the slight decrease in molar flow of CO2 with increasing EGR, the remaining CO2 capture and compression equipment slightly decrease in size as %EGR increases.
- Due to the increasing flow of exhaust gas around the recycle, the DCC on the EGR stream within the Power Island increases in size as %EGR increases.

The plant performance trends can be seen in Table 6-1 while the cost impact of increasing % EGR can be seen in Table 6-2.

6.2 Plant Performance with Increasing Levels of EGR

6.2.1 Power Island Performance

The GT power output is reduced by 2.1% with 35% EGR (and 1.0% with 18% EGR), from the case without EGR. It is likely that this is due to the change in total mass and / or volume flow through the machine as increasing EGR changes the composition, temperature and molecular weight of the oxidant stream.

The enthalpy of the exhaust gas is increased with increasing EGR which results in an increase in steam turbine power output of 2.1% with 35% EGR (and 1.9% with 18% EGR) due to an increase in the exhaust temperature and molecular weight. The balance of plant parasitic load increases slightly with increasing EGR due to the increase in total water flow rate around the system, due to the additional steam production.

Both the decrease in GT performance and the increase in ST performance are significantly more marked in the 40% GT load cases, however it can be seen that the efficiency penalty at turndown is slightly reduced in the EGR cases.

6.2.2 CO_2 Capture, Compression and Balance of Plant Performance

The power required by the flue gas blower is significantly reduced as the % EGR increases, with a 36.6% reduction in power demand for the 35% EGR case.

The remaining power requirement is for solvent pumps and this reduced in line with the slight reduction in CO_2 molar flow, and hence solvent molar flow. It was assumed that these pumps operate in partial recycle during plant turndown, thus the power absorbed by these pumps at 40% GT load is unchanged from the 100% GT load case.

The steam requirement of the solvent stripper reboiler is not significantly impacted by the % EGR, but reduces slightly in line with the slight reduction in the total CO_2 molar flow due to the reduction in fuel used in the GT with increasing EGR.

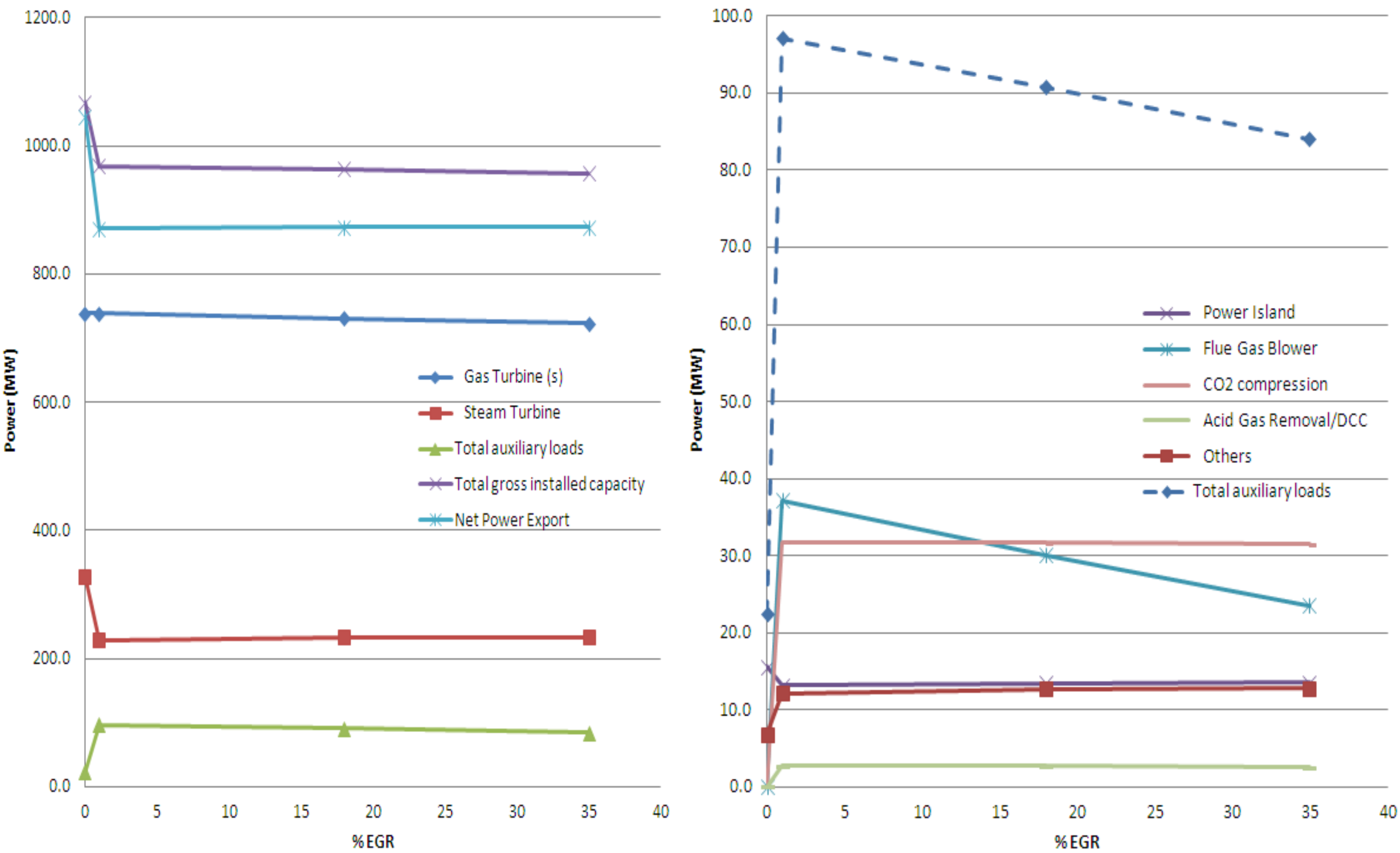
The power required by the CO_2 compressor is reduced in the same way as the solvent flow rate and stripper heat load are reduced, due to the reduced CO_2 molar flow at increasing EGR.

The balance of plant parasitic load increases with increasing % EGR, mainly due to the increased cooling water pumping requirement with increasing EGR. Additional cooling is required for the EGR DCC and for the steam turbine condenser with increasing EGR.

6.2.3 Overall Plant Performance

With increasing % EGR, there is a decrease in the power island gross power output, but at the same time, the total auxiliary loads also decrease. This results in only a modest improvement in the plant overall LHV efficiency with EGR, of 0.39 and 0.6 % points relative to the 0% EGR case efficiency of 48.58%. There is also a very small (0.2%) increase in the total net power output with EGR.

Figure 6-1 – (a) Overall Plant Technical Performance and (b) Auxiliary Load Changes with Increasing %EGR



As an additional benefit, it is likely that adding EGR will result in a reduction in both the NO_X and oxygen content of the flue gas, which should decrease the rate of solvent degradation. At this stage of development, it is not possible to quantify this effect, which would be dependent on the chemistry of the specific licensor's solvent.

6.3 Economic Performance with Increasing levels of EGR

6.3.1 Capital Cost with Increasing EGR

The additional direct contact cooler for the EGR cases has been included in the Power Island scope, thus the capital cost of the power island increases with increasing EGR, by 1.3% and 3.5% for the 18% EGR and 35% EGR cases respectively.

The diameter of the direct contact cooler and absorber and the size of the flue gas blower in the CO_2 capture plant are significantly reduced with increasing EGR, resulting in a significant reduction in the total CAPEX of the CO_2 capture unit with EGR, by 10.0% and 23.7% for the 18% EGR and 35% EGR cases respectively.

The impact on the overall plant CAPEX is therefore quite significant with a 3.2% and 7.1% reduction for the 18% EGR and 35% EGR cases respectively.

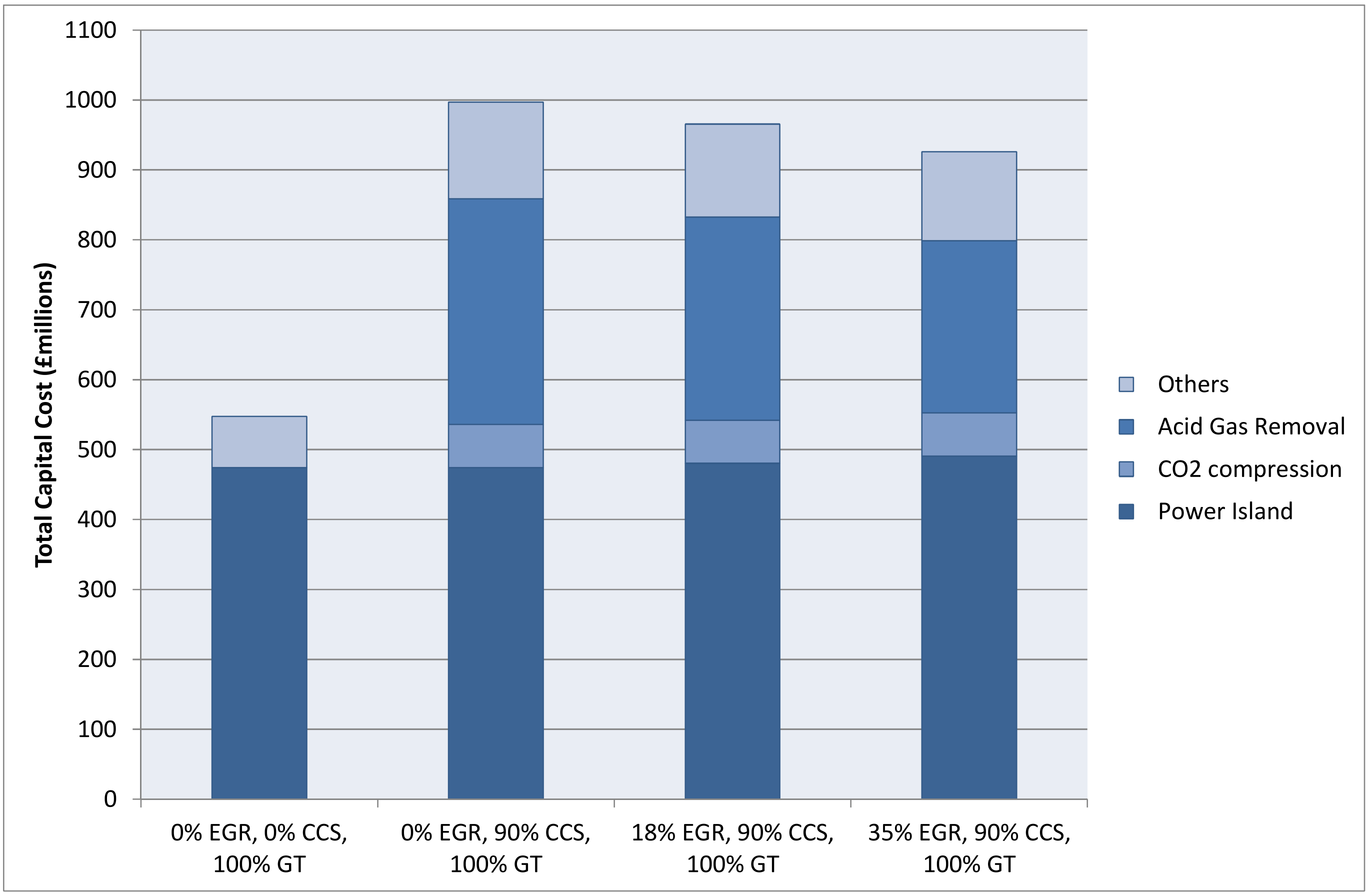


Figure 6-2: Total Project Capital Cost with Increasing EGR

6.3.2 Operating Cost with Increasing EGR

The operating costs vary largely in line with the variation in fuel requirement since the fuel flow rate is lower in the cases with increasing EGR. In addition to the fuel cost reduction, there is also a small reduction in the fixed operating costs since several of these are related to the total capital cost. The total operating costs reduce with EGR by 0.7% and 1.4% for the 18% EGR and 35% EGR cases respectively.

At 40% GT load the operating cost reduction is more significant at 2.1% and 4.3% for the 18% EGR and 35% EGR cases respectively. This is due to the slightly higher efficiency at turndown in the EGR cases.

6.3.3 Levelised Cost of Electricity with Increasing EGR

Since both the total capital and the total operating costs reduce with increasing EGR, so does the levelised cost of electricity (LCOE). However, the reduction in the LCOE is quite modest, since, for gas plants, over the plant lifetime the price of fuel is much more significant than the capital cost of the original plant. The LCOE reduces by 1.7% and 3.3% for the 18% EGR and 35% EGR cases respectively.

It should be noted that the LCOE reduction with increasing EGR is more significant at 40% GT load, since the total operating cost at 40% GT load is improved more than in the 100% GT load cases. Thus the LCOE reduces by 4.0% and 7.6% for the 18% EGR and 35% EGR cases respectively at 40% GT load. However, it should be remembered that the LCOE at part load operation is very substantially higher to begin with than when operating the plant at full load (£118.8/MWh_{Net} at 40% GT load versus £69.1/MWh_{Net} at 100% GT load with 90% CCS and without EGR).

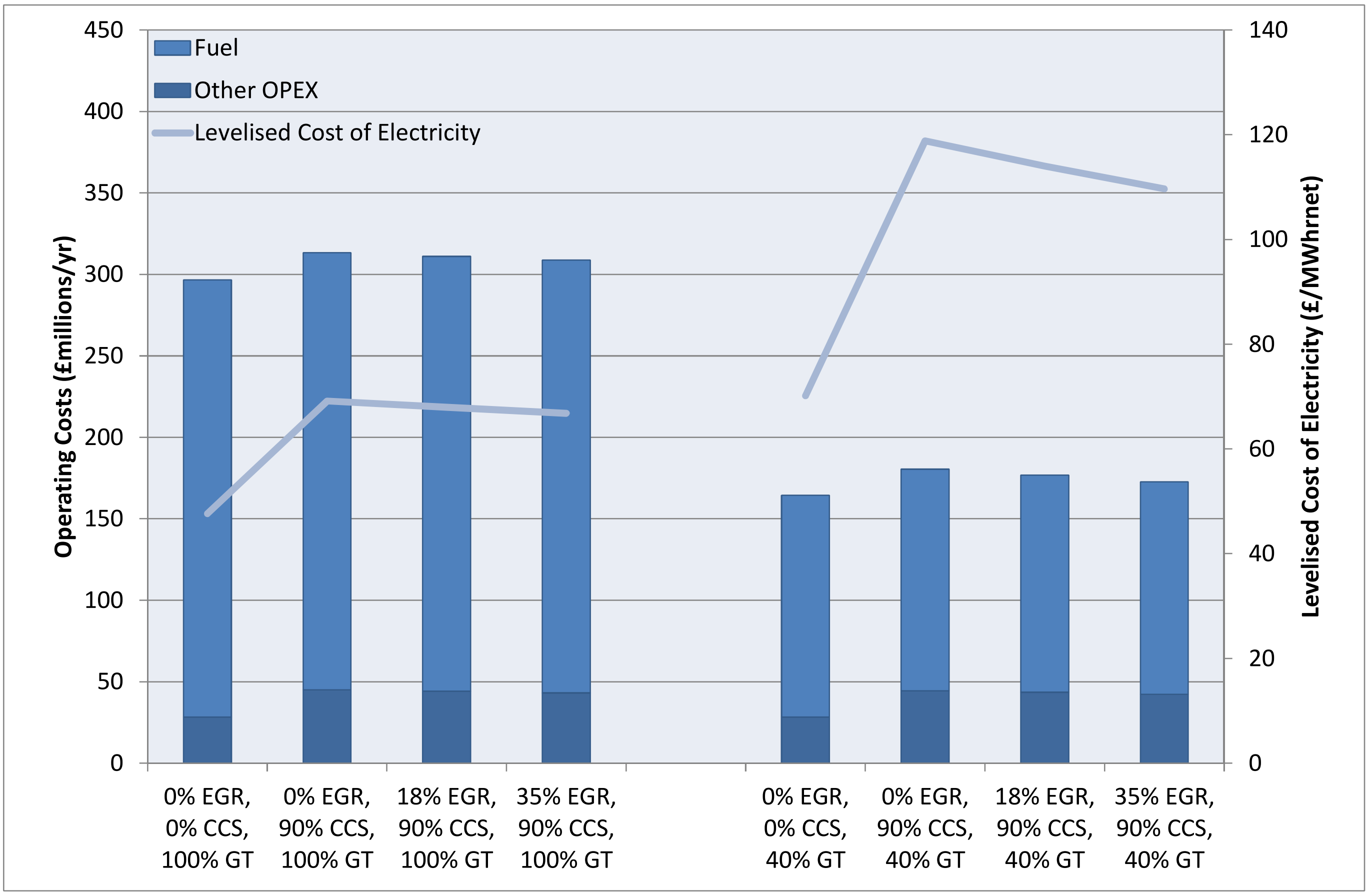


Figure 6-3: Operating Costs and LCOE with Increasing EGR

Table 6-1 Technical Performance Figures for CCGT with EGR

		0% EGR 0% CCS 100% GT	0% EGR 90% CCS 100% GT	18% EGR 90% CCS 100% GT	35% EGR 90% CCS 100% GT	0% EGR 0% CCS 40% GT	0% EGR 90% CCS 40% GT	18% EGR 90% CCS 40% GT	35% EGR 90% CCS 40% GT
Power									
Total gross installed capacity	MWe	1068.0	967.9	964.2	957.1	472.0	421.2	420.9	418.7
Gas Turbine (s)	MWe	739.0	739.0	731.0	723.4	295.6	295.6	287.5	279.9
Steam Turbine	MWe	328.9	228.9	233.2	233.8	176.4	125.6	133.4	138.7
Total auxiliary loads	MWe	22.4	97.1	90.8	84.0	14.8	64.4	59.0	53.7
Power Island	MWe	15.6	13.2	13.4	13.6	10.4	9.7	9.9	10.1
Flue Gas Blower	MWe	0.0	37.2	30.1	23.6	0.0	28.9	23.4	18.3
Acid Gas Removal/DCC	MWe	0.0	2.8	2.7	2.5	0.0	2.8	2.7	2.5
Alternative Technology	MWe	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO2 compression	MWe	0.0	31.7	31.7	31.5	0.0	16.1	15.8	15.4
Others	MWe	6.8	12.1	12.8	12.9	4.4	6.9	7.2	7.3
Net Power Export	**MWe**	**1045.6**	**870.8**	**873.4**	**873.1**	**457.2**	**356.8**	**362.0**	**365.0**
Net Efficiency (LHV)	**%**	**58.33**	**48.58**	**48.97**	**49.18**	**50.25**	**39.21**	**40.71**	**41.98**
Heat Rate	kJ/kWh	6172	7411	7352	7320	7164	9181	8843	8576
CC Energy Penalty	% points	0.00	9.75	9.31	8.96	0.00	11.04	10.78	9.78
Carbon Balance									
Total carbon in feeds	tpd	2400.3	2400.3	2388.4	2376.9	1218.3	1218.3	1190.6	1164.3
Total carbon captured	tpd	0.0	2159.4	2156.5	2139.9	0.0	1096.9	1071.7	1049.0
Total carbon emissions	tpd	2400.3	240.9	231.9	237.1	1218.3	121.3	118.9	115.3
Carbon capture rate	%	0.0	90.0	90.3	90.0	0.0	90.0	90.0	90.1
Carbon efficiency	g CO2/kWh	350.5	42.2	40.5	41.5	406.8	51.9	50.1	48.2

Table 6-2 Economic Performance Figures for CCGT with EGR

		0% EGR	0% EGR	18% EGR	35% EGR	0% EGR	0% EGR	18% EGR	35% EGR
		0% CCS	90% CCS	90% CCS	90% CCS	0% CCS	90% CCS	90% CCS	90% CCS
		100% GT	100% GT	100% GT	100% GT	40% GT	40% GT	40% GT	40% GT
Power									
Net Power Export	**MWe**	**1045.6**	**870.8**	**873.4**	**873.1**	**457.2**	**356.8**	**362.0**	**365.0**
Net Efficiency (LHV)	**%**	**58.33**	**48.58**	**48.97**	**49.18**	**50.25**	**39.21**	**40.71**	**41.98**
Economic Performance									
Total CAPEX	GB£M	547.5	997.2	965.7	926.3	547.5	997.2	965.7	926.3
Power Island	**GB£M**	**474.5**	**474.5**	**480.5**	**491.0**	**474.5**	**474.5**	**480.5**	**491.0**
Acid Gas Removal	**GB£M**	**0.0**	**322.9**	**290.3**	**246.4**	**0.0**	**322.9**	**290.3**	**246.4**
CO_2 compression	GB£M	0.0	61.5	61.5	61.5	0.0	61.5	61.5	61.5
Others	GB£M	73.0	138.2	133.4	127.4	73.0	138.2	133.4	127.4
CAPEX efficiency	**GB£/kW$_{Net}$**	**523.6**	**1145.1**	**1105.6**	**1061.0**	**1197.5**	**2795.1**	**2667.9**	**2537.7**
Total OPEX – incl. fuel	GB£M p.a.	296.6	313.4	311.1	308.9	164.4	180.5	176.7	172.7
		268.3	268.3	266.9	265.8	136.1	136.1	133.2	130.3
Total OPEX – excl. fuel	GB£M p.a.	28.3	45.1	44.2	43.1	28.3	44.4	43.5	42.4
OPEX – incl. fuel	GB£ p.a. /	283.7	359.9	356.2	353.8	359.6	505.9	488.2	473.1
OPEX – excl. fuel	GB£ p.a. /	27.1	51.8	50.6	49.4	61.9	124.5	120.2	116.2
Levelised Cost of Electricity		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO_2 emission cost = £0 / te CO_2	**£ / MWh$_{Net}$**	**47.7**	**69.1**	**67.9**	**66.8**	**70.1**	**118.8**	**114.0**	**109.7**
Cost of CO_2 Captured									
CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	n/a	56.8	51.9	47.9	n/a	103.6	96.1	86.8
Cost of CO_2 Avoided									
CO_2 emission cost = £ 0 / te CO_2	£ / te CO_2	n/a	69.7	63.0	57.8	n/a	137.1	125.2	109.8

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ATTACHMENT 1
BASIS OF DESIGN

Contract No.:	1.17.13058
Client's Name:	The Energy Technologies Institute
Project Title:	Hydrogen Storage and Flexible Turbine Systems
Project Location:	Generic UK

REVISION	**Rev O1 (Draft)**				
DATE	26 July 2013				
ORIG. BY	T. Abbott	Tim Abbott			
CHKD BY	S. Ferguson	Ferguson			
APP. BY	T. Abbott	Tim Abbott			

WP6 - CCS Benchmark Refresh 2013
Basis of Design

CONTENTS

1. INTRODUCTION

The ETI has engaged Foster Wheeler to execute its CCS Benchmark Refresh 2013 Project. The main purpose of this further study work is to provide additional benchmarking and performance analysis of next generation carbon capture technologies building upon those evaluated and reported in previous phases of CCS study work that Foster Wheeler has executed with ETI.

This purpose of this Basis of Design document is to provide a clear and consistent basis on which to evaluate each option in support of the study.

2. PLANT LOCATION

The site is assumed to be a green field coastal location on the NE coast of the UK, with adjacent deep sea access.

3. SITE CONDITION

An assumed clear level obstruction (both under and above ground) free site is considered, without the need for any required special civil works.

4. PLANT CAPACITY

Each case will be designed to produce electric energy (800 MWe nominal gross capacity without CO_2 capture) to be delivered to the UK National grid. For each of the Benchmarks considered, the design capacity will vary, determined by the full design capacity of key equipment items, for example, in the case of CCGT schemes the full ”appetite” of the selected gas turbines.

5. PLANT OPERATING CONDITIONS

The following climatic conditions marked (*) shall be considered reference conditions for plant performance evaluation across all WP6 cases. Individual case deliverables will be produced at reference conditions only.

Atmospheric pressure:		1013 mbar (*)
Relative humidity:	average:	average 60% (*)
		maximum: 95%
		minimum: 40%
Ambient temperatures:		average 10°C (*)
		summer 30°C
		minimum -10°C

6. CARBON DIOXIDE CAPTURE RATE

Each carbon dioxide abated case will be designed to achieve a target carbon capture level of at least 90%, defined as:

$$CO_2 \text{ Capture Rate (\%)} = \frac{100 \times \text{Moles carbon contained in the } CO_2 \text{ product}}{\text{Moles carbon contained in the natural gas feed}}$$

7. FEEDSTOCK, PRODUCT AND UTILITY SUPPLIES

The streams available at plant battery limits are the following:

- Natural gas;
- CO_2 product;
- Sea water supply;
- Sea water return;
- Plant/raw/potable water; and
- Chemicals (including amine).

Other utilities, including demineralised water, boiler feed water, instrument and plant air, oxygen and nitrogen will be generated within the complex where necessary and will be available for use at the required conditions.

8. FEEDSTOCK SPECIFICATIONS

8.1 Natural Gas

Natural gas NTS connection is available.

Natural gas feedstock specification (as NTS spec):

H_2S Content	Not more than 5 mg/m^3
Total Sulphur Content	Not more than 50 mg/m^3
Hydrogen Content	Not more than 0.1% (molar)
Oxygen Content	Not more than 0.001% (molar)
Hydrocarbon Dewpoint	Not more than -2^{o}C, at any pressure up to 85 bar(g)
Water Dewpoint	Not more than -10^{o}C, at 85 bar(g) (or the actual delivery pressure)
Wobbe Number (real gross dry)	Between 48.14 MJ/m^3 and 51.41 MJ/m^3 (at standard temperature and pressure) and in compliance with ICF and SI limits as listed below
Incomplete Combustion Factor	Not more than 0.48
Soot Index	Not more than 0.60
Gross Calorific Value (real gross dry)	Between 36.9 MJ/m^3 and 42.3 MJ/m^3 (at standard temperature and pressure) and in compliance with ICF and SI limits described above, subject to a 1 MJ/m^3 variation.
Inerts	Not more than 7.0mol%, subject to: Carbon Dioxide content – not more than 2.0mol% Nitrogen content – not more than 5.0mol%

Contaminants	Gas shall not contain solid or liquid material which may interfere with the integrity or operation of pipes or any gas appliance within the meaning of the Regulation 2(1) of the Gas Safety (Use of) Regulations 1998 that a consumer could reasonably be expected to operate.
Delivery Temperature	Between 1^{o}C and 38^{o}C
Odour	Gas delivered shall have no odour that might contravene the statutory obligation “not to transmit or distribute any gas at a pressure below 7 bar(g) which does not possess a distinctive and characteristic odour”.

8.2 Back up fuel/power

Natural gas (as detailed in section 8.1) is available for back-up fuel.

National Grid electrical grid connection is available for “black start” power requirement scenarios.

9. PRODUCT SPECIFICATIONS

9.1 Carbon Dioxide

Carbon dioxide produced from the plant will be dried and compressed to 150 bar(g) for export from the facility. Product carbon dioxide conditions will be:

Pressure:	150 bar(g)
Temperature:	$\leq$ 30°C

The target carbon dioxide export specification is based on the requirements for EOR.

H_2O	< 50 ppmv
CO_2	> 97 vol%
SO_2	< 50 ppm
H_2S	< 50 ppm
CO	< 3 vol%
Ar	< 3 vol%
O_2	100 ppmv
N_2	< 3 vol%
H_2	< 3 vol%
CH_4	< 2 vol%
COS	< 50ppm

9.2 Power

Power will be generated from the complex at 275 kV and will be transmitted to an assumed existing HV substation for connection onto the UK National Grid. It is assumed that National Grid electrical grid connection is available.

Electric Power

Net Power Output	800 MWe nominal capacity
Voltage	275 kV
Frequency	50 Hz

10. UTILITY SUPPLIES

10.1 Seawater cooling system

The primary cooling system is sea water in a once through system. Services will include the steam turbine condenser and the seawater/closed loop interchanger. Seawater supply assumed to be clear filtered and chlorinated, without suspended solids and organic matter. Seawater supply from a new intake and a seawater outfall will be required as part of the complex.

The following seawater conditions marked (*) shall be considered reference conditions for plant performance evaluation across all WP6 cases. Individual case deliverables will be produced at reference conditions only.

Seawater conditions:

Average supply temperature:	10°C (*)
Average return temperature:	18°C (*)
Operating pressure at Condenser inlet:	3 bar(g)
Maximum allowable ΔP for Condenser:	0.7 bar

10.2 Closed loop water cooling system

The secondary cooling system is a closed loop, seawater cooled cooling water system. All cooling services, with the exception of the steam turbine vacuum condenser, will be placed on this system. This system cools the closed loop water against seawater. The make-up water to the system shall be demineralised water stabilized and conditioned.

The following closed loop water conditions marked (*) shall be considered reference conditions for plant performance evaluation across all WP6 cases. Individual case deliverables will be produced at reference conditions only.

Closed loop cooling water conditions:

Average supply temperature:	14°C (*)
Average return temperature:	24°C (*)
Seawater/closed loop water interchanger ΔT:	4°C (*)
Operating pressure at users:	3.0 bar(g)
Maximum allowable ΔP for users:	1.5 bar

11. ENVIRONMENTAL EMISSION BASIS

The overall gaseous emissions basis for the study cases are as follows:

	CCGT(2)
NOx (as NO_2),mg/Nm^3:	≤ 50
Particulate, mg/Nm^3:	≤ 5
CO, mg/Nm^3:	≤ 20

Notes:

(1) @ 6% O_2 vol dry

(2) @ 15% O_2 vol dry

12. OUTLINE SCHEME DESCRIPTIONS

12.1 Natural Gas CCGT Power Plant with Amine Solvent Post-Combustion CO_2 Capture

The overall process scheme will be based upon a natural gas fired combined cycle gas turbine (CCGT) using two Frame F class gas turbines, each with downstream heat recovery steam generator (HRSG), and common single steam turbine generator (STG), CO_2 capture unit and CO_2 compression and dehydration unit.

In this case this natural gas feed rate will be set to ensure full utilisation of the gas turbines with the supporting and downstream equipment items sized to process the generated gas turbine exhaust gas. The process conditions, including stream flows, pressures, temperatures and compositions, will be produced to reflect this sizing basis. Key features of the configuration include:

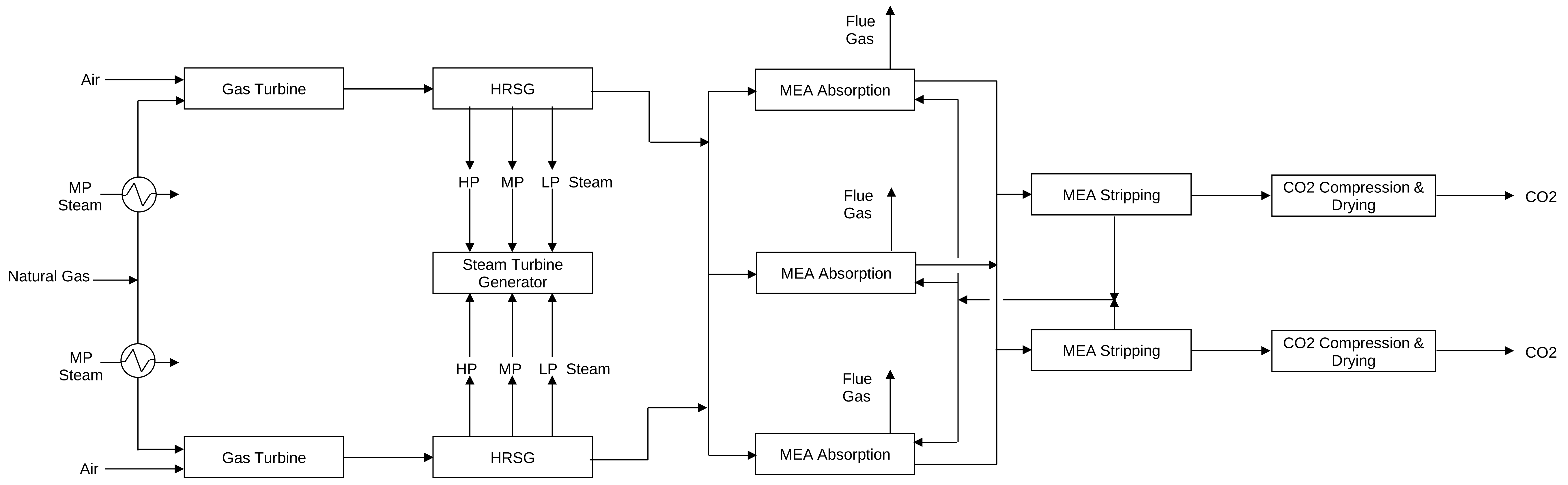
- Power Island Unit – comprising of two parallel trains, each with one F class 50 Hz gas turbine and one heat recovery steam generator (HRSG), connected to a single condensing steam turbine, using seawater cooling.
- Acid Gas Removal Unit – carbon dioxide removal scheme developed using in-house information on the basis of an MEA-based process such as Fluor Econamine carbon dioxide recovery technology.
- Carbon Dioxide Compression and Drying Units – dehydration and compression to 150 barg based on in-house knowledge of commercially available equipment.

12.2 Natural Gas CCGT Power Plant without CO_2 Capture

An equivalent Natural Gas CCGT without CO_2 capture will be developed. This will be based upon the same configuration as above, with the exclusion of the AGR and CO_2 compression and drying units. The case will use the same natural gas feed rate as the Natural Gas CCGT Power Plant with CO_2 capture case.

ATTACHMENT 2
HEAT AND MATERIAL BALANCES

1. CCGT with 90% CO_2 Capture
   a. 100% Load
   b. 40% Load
2. CCGT without CO_2 Capture
   a. 100% Load
   b. 40% Load
3. CCGT with 35% EGR and 90% CO_2 Capture
   a. 100% Load
   b. 40% Load
4. CCGT with 35% EGR without CO_2 Capture
   a. 100% Load
   b. 40% Load
5. CCGT with 18% EGR and 90% CO_2 Capture
   a. 100% Load
   b. 40% Load
6. CCGT with 18% EGR without CO_2 Capture
   a. 100% Load
   b. 40% Load



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Block Flow Diagram

FOSTER WHEELER ENERGY

CASE: Natural Gas Combined Cycle Power Plant with 90% Post Combustion CO2 Capture

DWG. NO.: XXXX-XX-XXX

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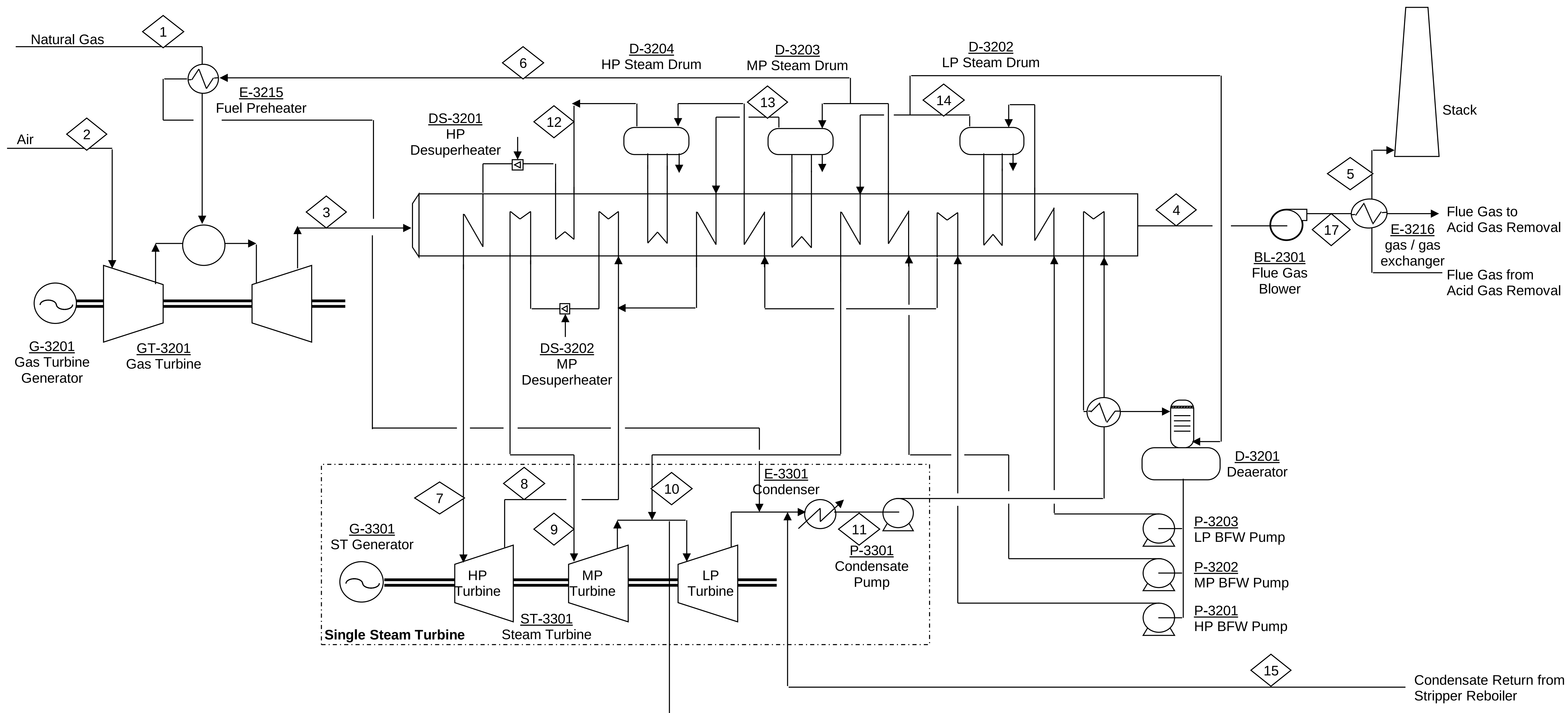

2 GTs each with own HRSG, deaerator and BFW pumps in parallel
with a single ST and condenser
Flows shown below are for the full facility capacity

Stream Name	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Pressure (kPa)	3447	101	105	103	102	2918	13980	2801	2689	417	3.5	13980	2918	435	417	400
Temperature (°C)	1.0	10.0	613.4	93.3	80.0	212.3	566.0	327.0	565.6	203.4	24.5	336.5	232.3	146.6	203.4	133.5
Mass rate (kg/h)	136002	4991402	5127404	5127404	4660576	83254	598254	598254	698991	64623	846868	598254	100737	84262	493200	493200
Mole % Oxygen	0.00	20.82	11.01	11.01	11.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Nitrogen	1.47	77.60	74.18	74.18	79.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % CO2	0.68	0.03	4.64	4.64	0.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Methane	87.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Argon	0.00	0.93	0.89	0.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Ethane	7.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Propane	2.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	0.00	0.61	9.29	9.29	7.67	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molar rate (kmol/hr)	7419	173009	180723	180723	167647	4620	33199	33199	38790	3586	46996	33199	5590	4676	27370	27370

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Power Generation

FOSTER WHEELER ENERGY

CASE: Natural Gas Combined Cycle Power Plant with 90% Post Combustion CO2 Capture

DWG. NO.: XXXX-XX-XXX

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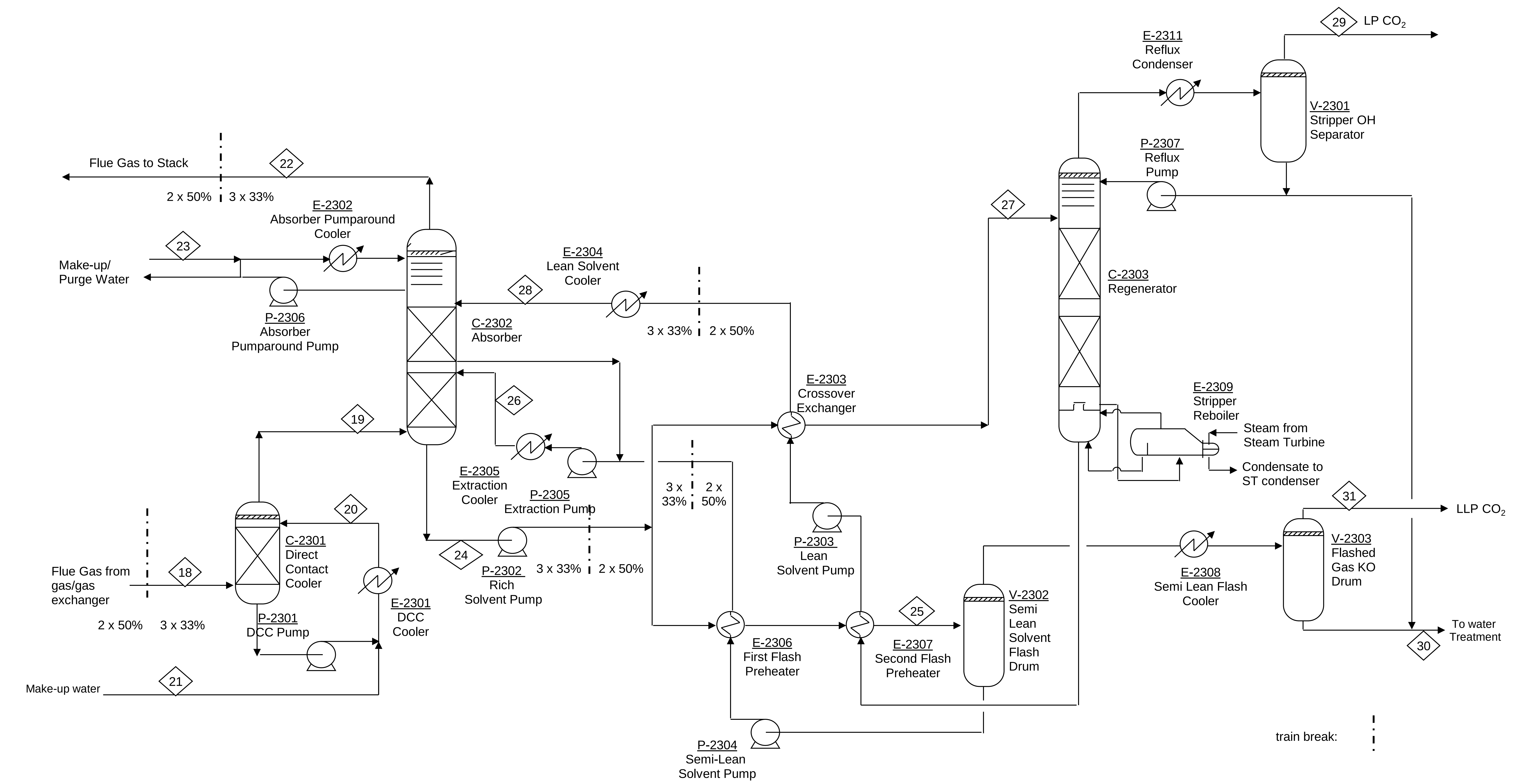

3 Trains of CO2 absorption, 2 trains of stripping and 2 trains of compression are required
Flows shown below are for the full facility capacity

Stream	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Pressure (kPa)	125	115	110	415	485	103	110	110	130	348	453	140	138	110	110
Temperature (°C)	116.4	82.0	49.8	30.0	50.1	41.3	10.0	51.8	103.0	30.0	93.0	30.0	30.0	32.4	35.0
Mass rate (kg/h)	5127404	5127404	5195652	144000	68247	4660622	64800	7803777	2341133	7228467	5462644	5029200	292212	125118	42060
Mole % CO2	4.64	4.64	4.54	0.00	0.00	0.50	0.00	5.00	5.00	3.98	5.00	2.25	96.88	0.06	94.80
Mole % Oxygen	11.01	11.01	10.78	0.00	0.00	11.87	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.02
Mole % Nitrogen	74.17	74.17	72.65	0.00	0.00	79.96	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.07
Mole % Argon	0.89	0.89	0.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % MEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.77	10.77	11.17	10.77	11.53	0.00	0.49	0.00
Mole % H2O	9.29	9.29	11.15	100.00	100.00	7.67	100.00	84.22	84.22	84.85	84.22	86.22	3.09	99.45	5.12
Molar rate (kmol/hr)	180723	180723	184511	7993	3788	167650	3597	325748	97724	302968	228023	213424	6764	6859	986

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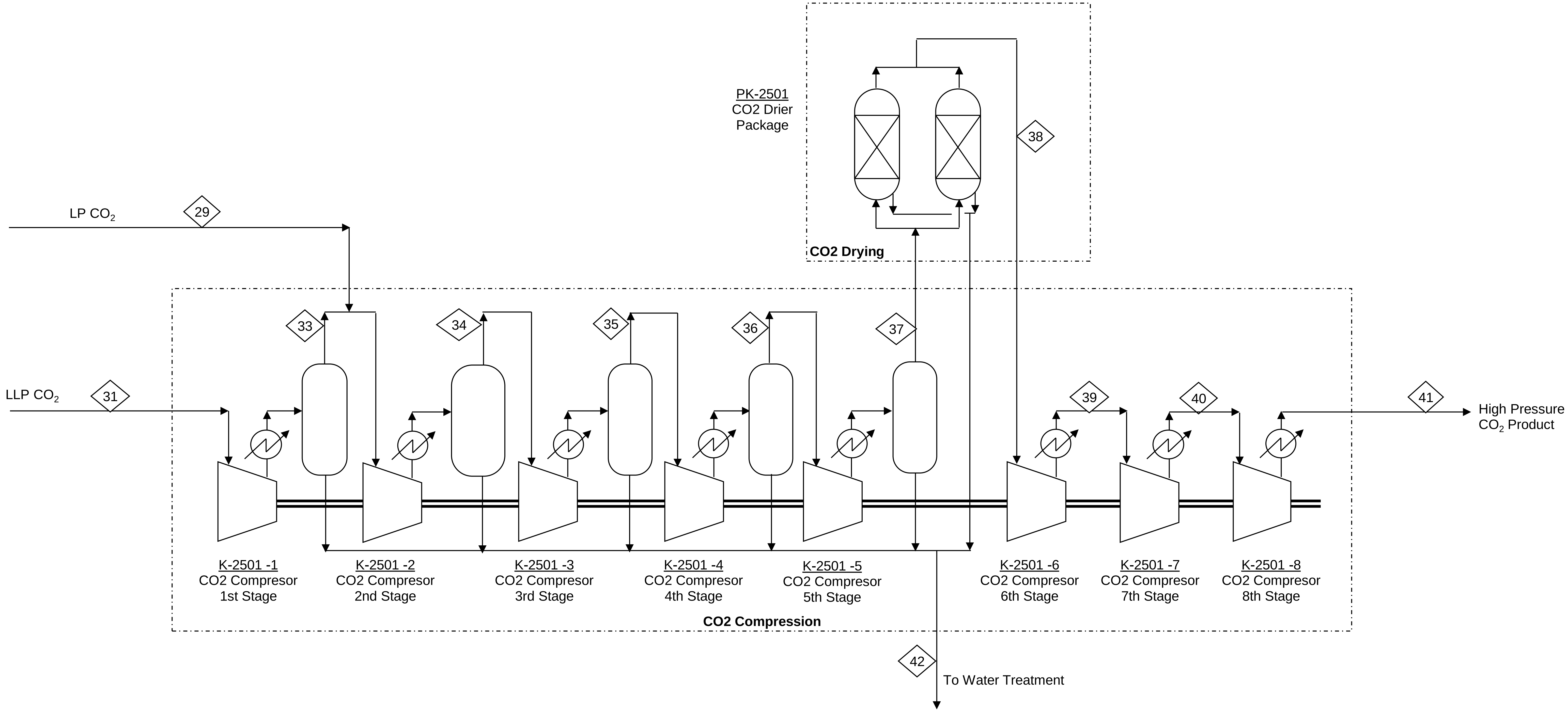
CO2 Capture

FOSTER WHEELER ENERGY

CASE: Natural Gas Combined Cycle Power Plant with 90% Post Combustion CO2 Capture

DWG. NO.: XXXX-XX-XXX REV: A1



Flows shown below are for the full facility capacity

Stream Name	33	34	35	36	37	38	39	40	41	42
Pressure (kPa)	138	270	530	1140	2490	2390	5490	9990	15090	138
Temperature (°C)	24.0	24.0	24.0	24.0	24.0	25.0	24.0	55.0	30.0	23.9
Mass rate (kg/h)	41523	331136	330403	366901	366702	366429	329786	329786	329786	4701
Mole % CO2	97.74	98.83	99.36	99.65	99.78	99.96	99.96	99.96	99.96	0.24
Mole % Oxygen	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00
Mole % Nitrogen	0.07	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00
Mole % MEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	2.17	1.13	0.60	0.31	0.18	0.00	0.00	0.00	0.00	99.76
Molar rate (kmol/hr)	956	7576	7535	8353	8342	8327	7494	7494	7494	260

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CO2 Compression & Dehydration

FOSTER WHEELER ENERGY

CASE: Natural Gas Combined Cycle Power Plant with 90% Post Combustion CO2 Capture

DWG. NO.: XXXX-XX-XXX

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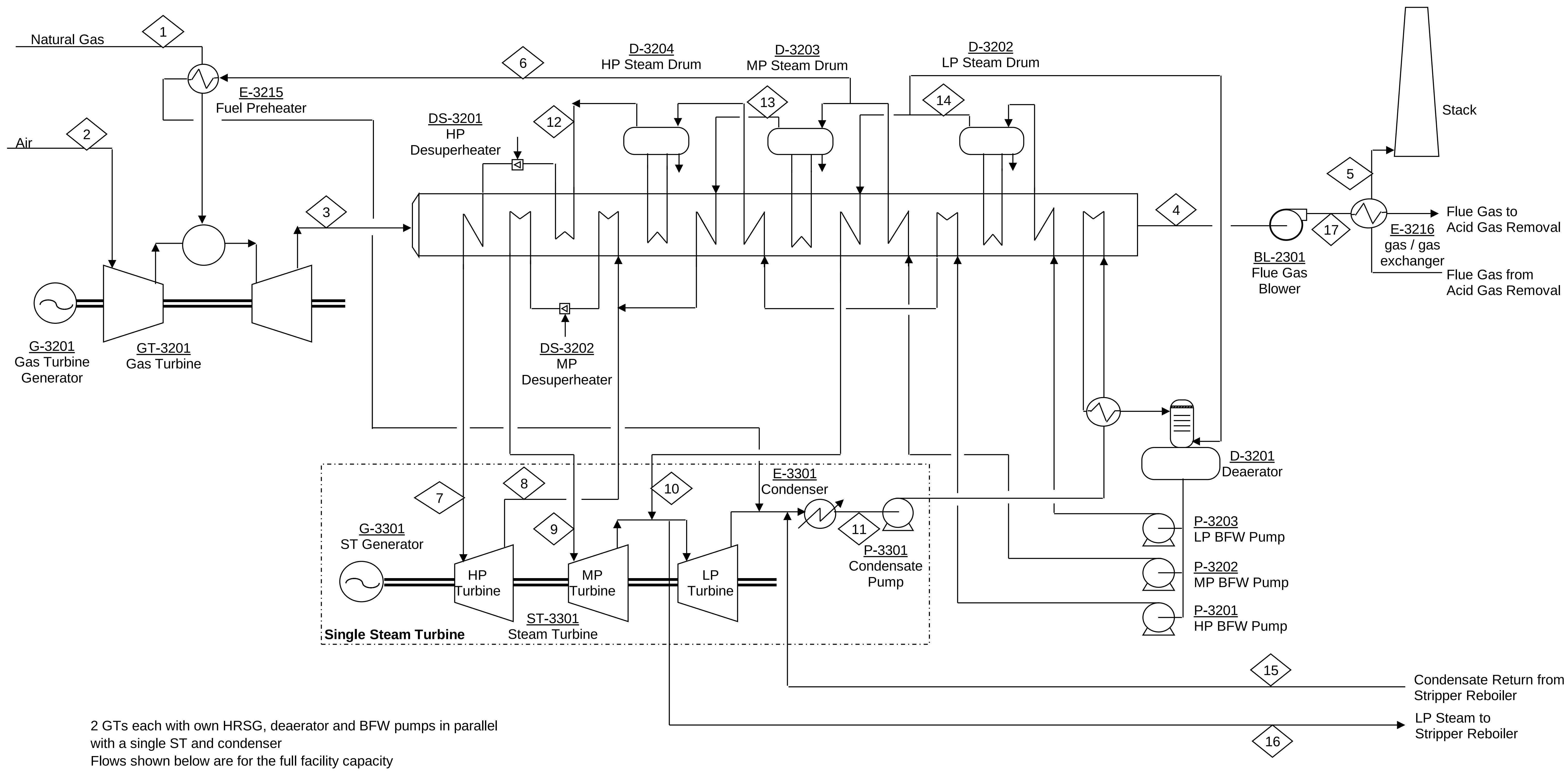

2 GTs each with own HRSG, deaerator and BFW pumps in parallel
with a single ST and condenser
Flows shown below are for the full facility capacity

TURNDOWN CASE - 40% LOAD

Stream Name	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Pressure (kPa)	3447	101	105	103	102	1754	7561	1614	1547	326	3.2	7561	1754	339	326	400
Temperature (°C)	1.0	10.0	502.6	97.1	80.0	189.2	496.3	285.6	489.4	186.7	23.1	291.1	205.8	137.7	186.7	133.5
Mass rate (kg/h)	69028	3897094	3966122	3966122	3773450	70823	334187	334187	419881	49804	540508	334188	42848	59238	254376	254376
Mole % Oxygen	0.00	20.82	11.01	11.01	14.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Nitrogen	1.47	77.60	74.18	74.18	77.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % CO2	0.68	0.03	4.64	4.64	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Methane	87.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Argon	0.00	0.93	0.89	0.89	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Ethane	7.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Propane	2.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	0.00	0.61	9.29	9.29	7.57	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molar rate (kmol/hr)	3766	135079	139795	139795	135260	3930	18545	18545	23301	2764	29995	18545	2378	3287	14116	14116

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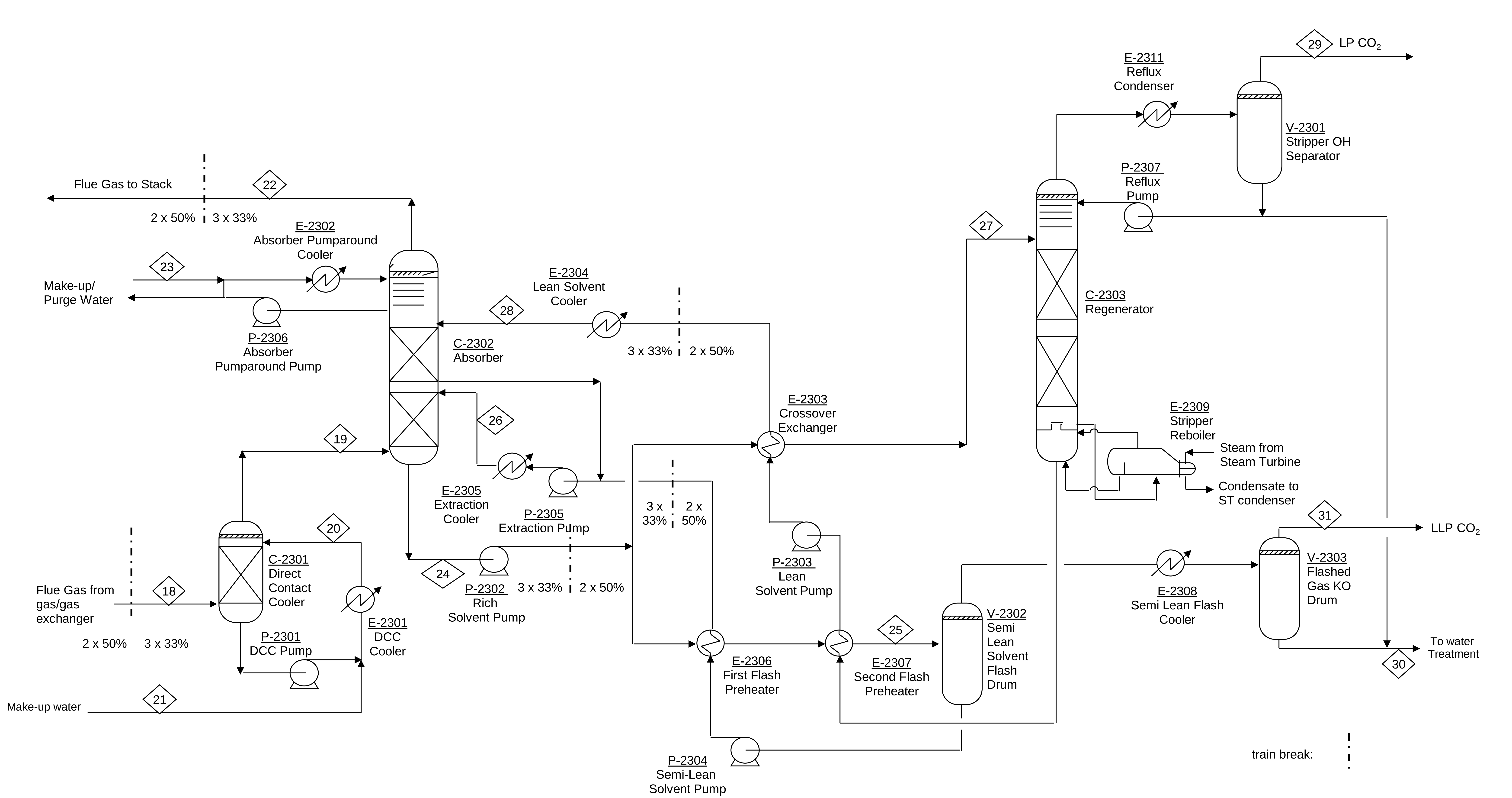
Power Generation	CASE: Natural Gas Combined Cycle Power Plant with 90% Post Combustion CO2 Capture
FOSTER WHEELER ENERGY	DWG. NO.: XXXX-XX-XXX — REV: 01



3 Trains of CO2 absorption, 2 trains of stripping and 2 trains of compression are required
Flows shown below are for the full facility capacity

TURNDOWN CASE - 40% LOAD

Stream	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Pressure (kPa)	125	115	110	415	485	103	110	110	130	348	453	140	138	110	110
Temperature (°C)	120.7	84.1	45.1	30.0	45.3	41.2	10.0	47.0	103.0	30.0	93.0	30.0	30.0	32.4	35.0
Mass rate (kg/h)	3966122	3966122	3981562	73339	65360	3773793	33005	3930320	1179096	3669373	2751224	2561422	148930	62848	20976
Mole % CO2	3.07	3.07	3.00	0.00	0.00	0.34	0.00	5.06	5.06	3.87	5.06	2.25	96.88	0.06	94.79
Mole % Oxygen	14.33	14.33	13.97	0.00	0.00	14.72	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.03
Mole % Nitrogen	75.31	75.31	73.40	0.00	0.00	77.35	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.07
Mole % Argon	0.90	0.90	0.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % MEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.93	10.93	11.24	10.93	11.53	0.00	0.49	0.00
Mole % H2O	6.38	6.38	8.76	100.00	100.00	7.59	100.00	84.01	84.01	84.88	84.01	86.22	3.09	99.45	5.12
Molar rate (kmol/hr)	138940	138940	141318	4071	3628	135279	1832	163499	49050	153761	114450	108699	3447	3446	492

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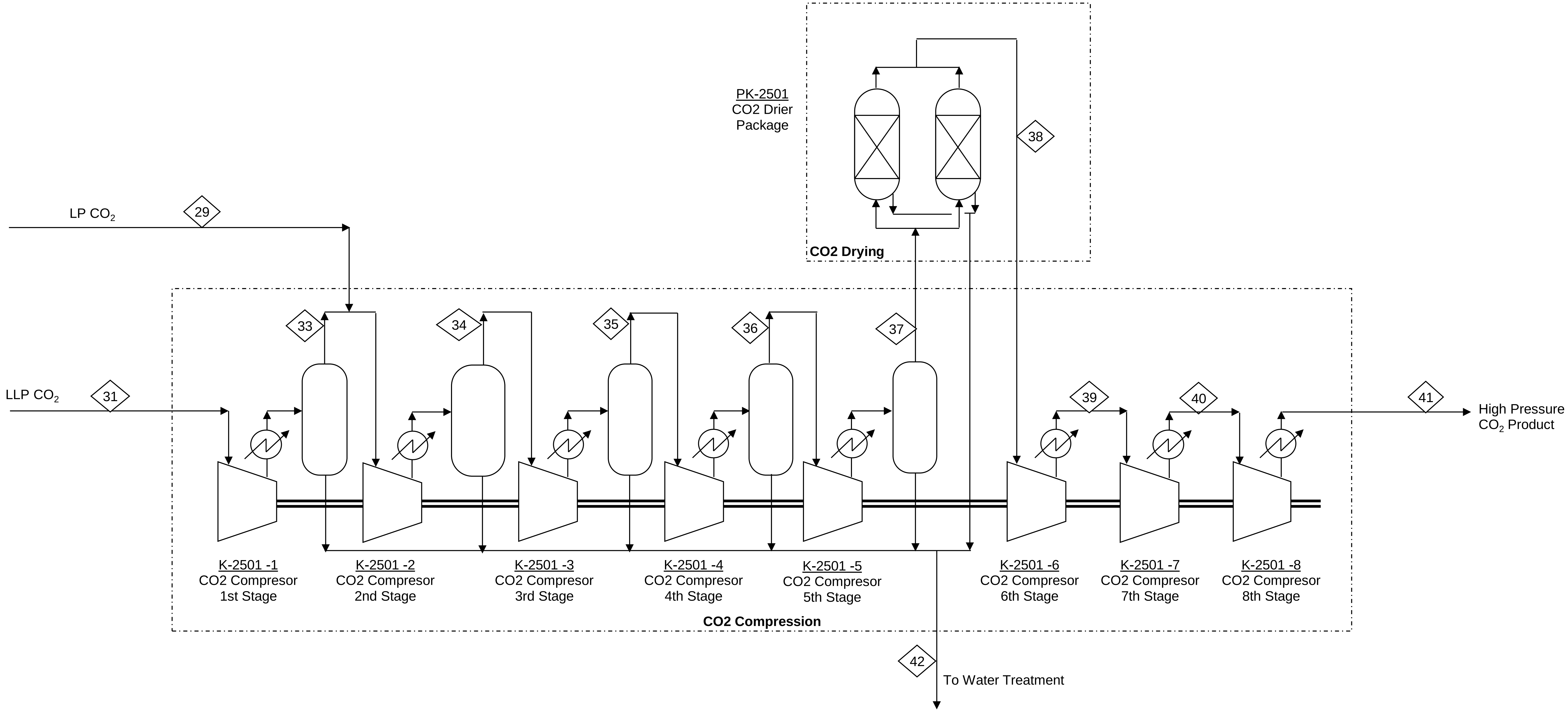
CO2 Capture	CASE: Natural Gas Combined Cycle Power Plant with 90% Post Combustion CO2 Capture
FOSTER WHEELER ENERGY	DWG. NO.: XXXX-XX-XXX — REV: 01



Flows shown below are for the full facility capacity

TURNDOWN CASE - 40% LOAD

Stream Name	33	34	35	36	37	38	39	40	41	42
Pressure (kPa)	138	270	530	1140	2490	2390	5490	9990	15090	138
Temperature (°C)	24.0	24.0	24.0	24.0	24.0	25.0	24.0	55.0	30.0	23.9
Mass rate (kg/h)	20709	168316	167944	186380	186279	186140	167526	167526	167526	2385
Mole % CO2	97.73	98.83	99.36	99.65	99.78	99.96	99.96	99.96	99.96	0.24
Mole % Oxygen	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00
Mole % Nitrogen	0.07	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00
Mole % MEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	2.17	1.13	0.60	0.31	0.18	0.00	0.00	0.00	0.00	99.76
Molar rate (kmol/hr)	477	3851	3830	4243	4238	4230	3807	3807	3807	132

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Turndown @ 40% Load

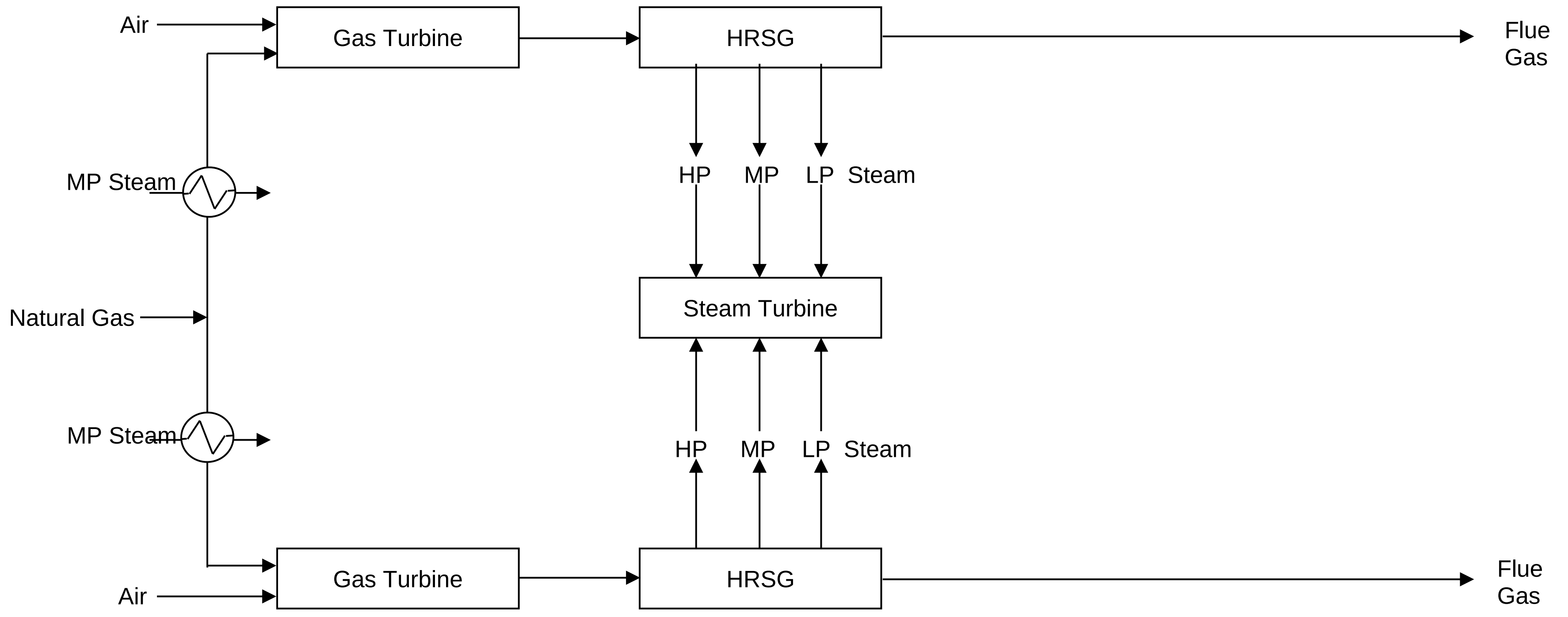
CASE: Natural Gas Combined Cycle Power Plant with 90% Post Combustion CO2 Capture

CO2 Compression & Dehydration

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



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Block Flow Diagram

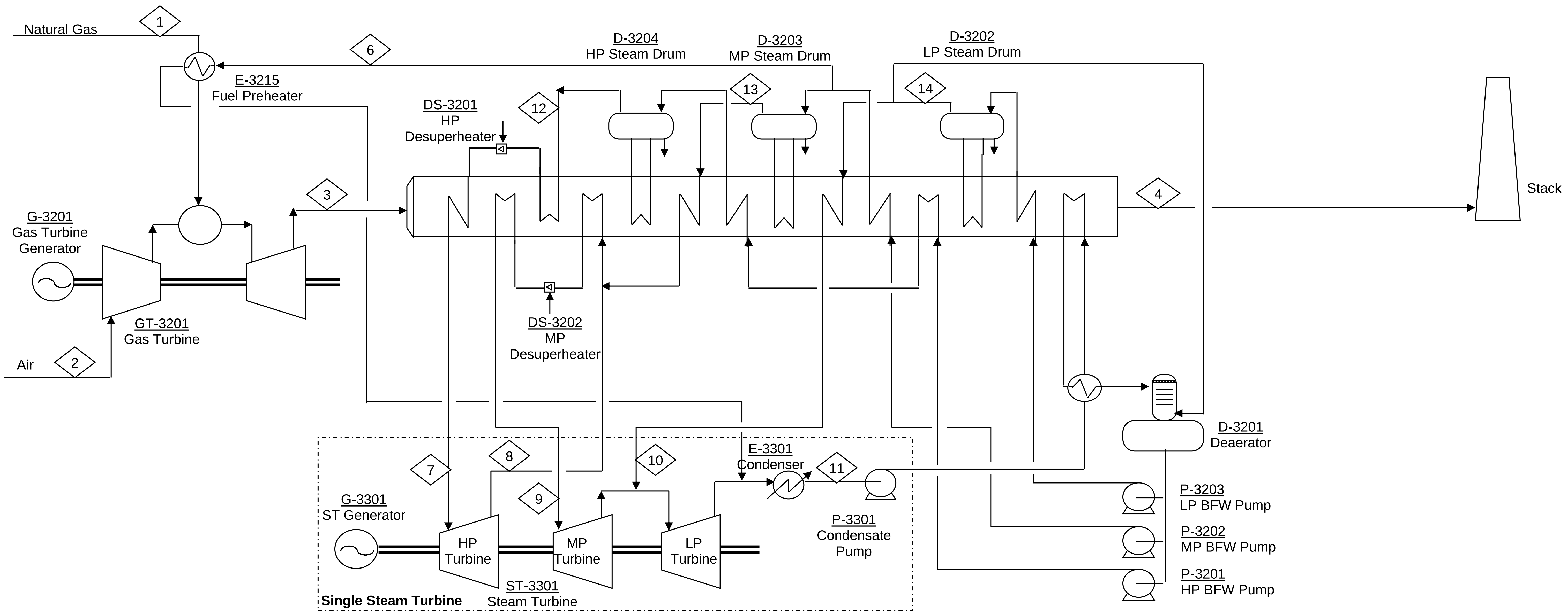
FOSTER WHEELER ENERGY

CASE:

Natural Gas Combined Cycle Power Plant without CO2 Capture

DWG. NO.: XXXX-XX-XXX

REV: A1



2 GTs each with own HRSG, deaerator and BFW pumps in parallel
with a single ST and condenser
Flows shown below are for the full facility capacity

Stream Name	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Pressure (kPa)	3447	101	105	103		2918	13980	2801	2689	417	3.5	13980	2918	435		
Temperature (°C)	1.0	10.0	613.4	93.3		212.3	566.0	327.0	565.6	203.4	24.5	336.5	232.3	146.6		
Mass rate (kg/h)	136002	4991402	5127404	5127404		83253	598255	598255	698991	64623	846867	598255	100737	84262		
Mole % Oxygen	0.00	20.82	11.01	11.01		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % Nitrogen	1.47	77.60	74.18	74.18		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % CO2	0.68	0.03	4.64	4.64		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % Methane	87.08	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % Hydrogen	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % Argon	0.00	0.93	0.89	0.89		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % Ethane	7.83	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % Propane	2.94	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % H2O	0.00	0.61	9.29	9.29		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00		
Molar rate (kmol/hr)	7419	173009	180723	180723		4620	33199	33199	38790	3586	33200	33200	5590	4676		

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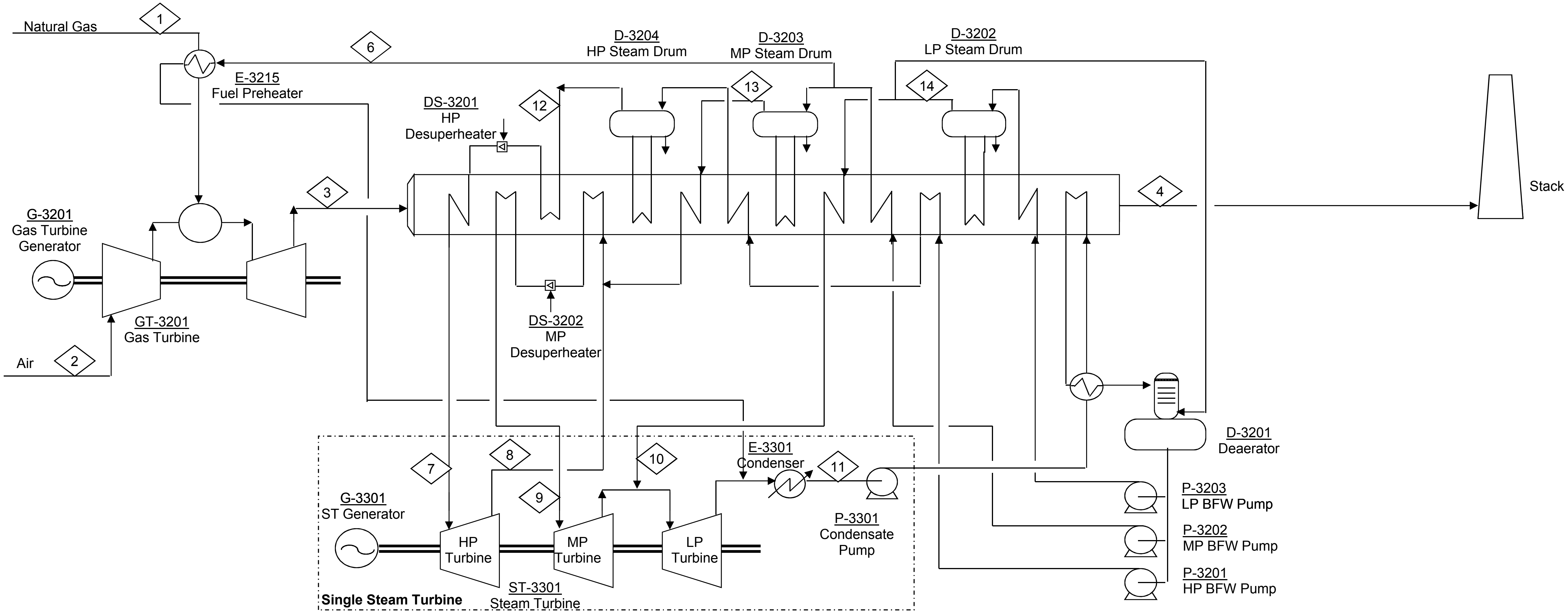
Power Generation

FOSTER WHEELER ENERGY

CASE: Natural Gas Combined Cycle Power Plant without CO2 Capture

DWG. NO.: XXXX-XX-XXX

REV: A1



2 GTs each with own HRSG, deaerator and BFW pumps in parallel
with a single ST and condenser
Flows shown below are for the full facility capacity

TURNDOWN CASE - 40% LOAD

Stream Name	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Pressure (kPa)	3447	101	105	103		1750	7560	1609	1542	248	2.7	7560	1750	268		
Temperature (°C)	1.0	10.0	502.6	92.1		189.0	496.4	285.3	489.4	180.7	20.4	291.0	205.7	129.7		
Mass rate (kg/h)	69028	3897094	3966122	3966122		70808	334106	334107	419786	55149	545745	334105	85678	70083		
Mole % Oxygen	0.00	20.82	11.01	11.01		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % Nitrogen	1.47	77.60	74.18	74.18		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % CO2	0.68	0.03	4.64	4.64		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % Methane	87.08	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % Hydrogen	0.00	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % Argon	0.00	0.93	0.89	0.89		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % Ethane	7.83	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % Propane	2.94	0.00	0.00	0.00		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
Mole % H2O	0.00	0.61	9.29	9.29		100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00		
Molar rate (kmol/hr)	3766	135079	139795	139795		3929	18541	18541	23296	3060	30285	18541	4755	3889		

REV	DATE	TITLE	BY	CHK	APP
01	22/10/13	FIRST ISSUE	SEF	RR	TA

REVISIONS

CCS BENCHMARK REFRESH 2013

Turndown @ 40% Load

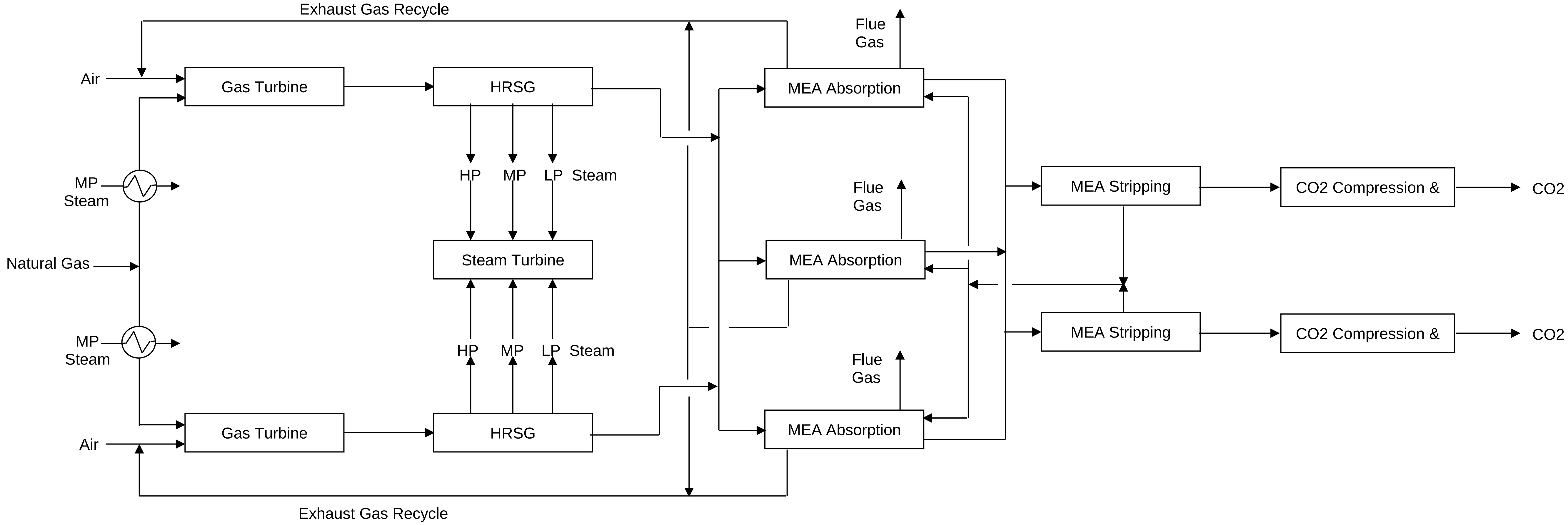
CASE: Natural Gas Combined Cycle Power Plant without CO2 Capture

Power Generation

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



01	22/10/13	FIRST ISSUE	SEF	RR	TA
REV	DATE	TITLE	BY	CHK	APP

REVISIONS

CCS BENCHMARK REFRESH 2013

CASE:

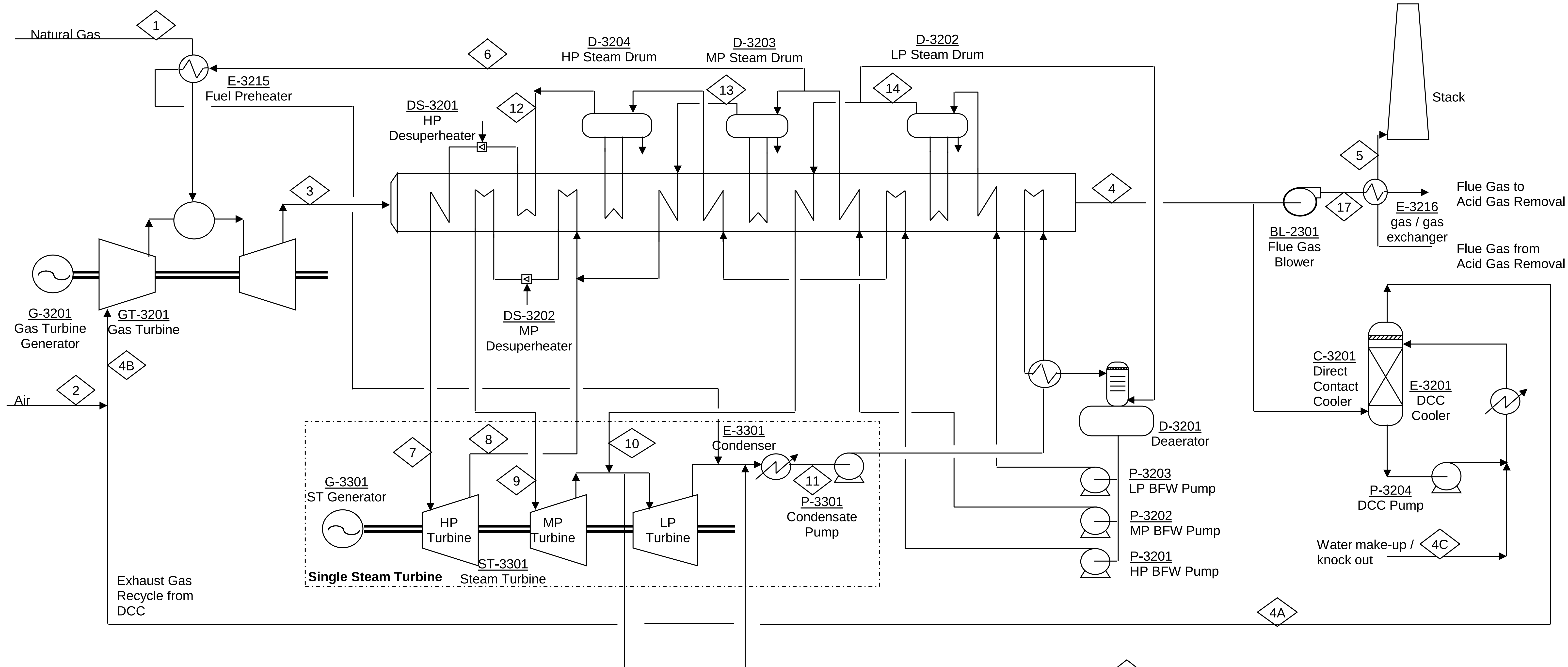
Block Flow Diagram

Natural Gas Combined Cycle Power Plant with 35% EGR and 90% Post-Combustion CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



2 GTs each with own HRSG, deaerator and BFW pumps in parallel
with a single ST and condenser
Flows shown below are for the full facility capacity

Stream Name	1	2	3	4	4A	4B	4C	5	6	7	8	9	10	11	12	13	14
Pressure (kPa)	3447	101	105	103	102	101	101	102	2918	13980	2801	2689	417	4	13980	2918	435
Temperature (°C)	1.0	10.0	621.4	93.3	24.0	14.9	24.0	80	212.3	566.0	327.0	565.6	203.4	24.5	336.5	232.3	146.6
Mass rate (kg/h)	134681	3213377	5029654	5029654	1681595	4894973	78407	2854602	78222	610007	610007	704658	59129	842010	610008	94649	80535
Mole % Oxygen	0.00	20.82	9.14	9.14	9.80	18.92	0.00	7.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Nitrogen	1.47	77.60	74.80	74.80	80.17	78.19	0.00	84.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % CO2	0.68	0.03	5.69	5.69	6.09	1.10	0.00	0.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Methane	87.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Argon	0.00	0.93	0.90	0.90	0.96	0.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Ethane	7.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Propane	2.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	0.00	0.61	9.47	9.47	2.98	0.85	100.00	7.91	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molar rate (kmol/hr)	7347	111380	176805	176805	57599	168969	4351	103198	4341	33852	33852	39104	3281	46726	33852	5252	4469

REV	DATE	TITLE	BY	CHK	APP
01	22/10/13	FIRST ISSUE	SEF	RR	TA

REVISIONS

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CASE:

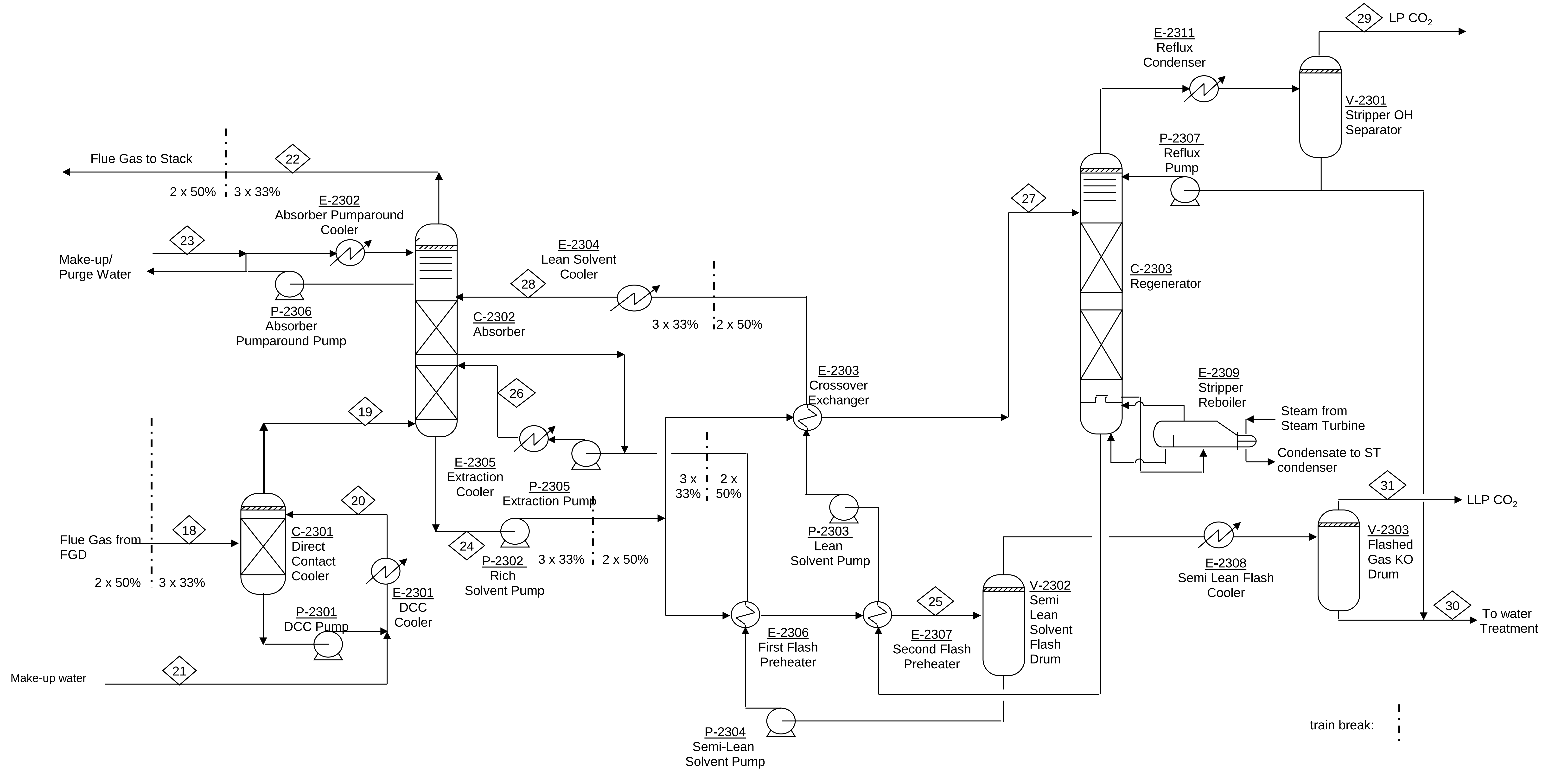
Power Generation

Natural Gas Combined Cycle Power Plant with 35% EGR and 90% Post-Combustion CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



3 Trains of CO2 absorption, 2 trains of stripping and 2 trains of compression are required
Flows shown below are for the full facility capacity

Stream Name	15	16	17	18	19	20	21	22	23
Pressure (kPa)	400	417	125	115	110	415	485	103	110
Temperature (°C)	133.5	293.3	116.2	83.5	50.5	30.0	50.9	41.9	10.0
Mass rate (kg/h)	474336	474336	3269274	3269274	3312138	142128	42864	2854772	63958
Mole % CO2	0.00	0.00	7.23	7.23	7.08	0.00	0.00	0.97	0.00
Mole % Oxygen	0.00	0.00	6.42	6.42	6.29	0.00	0.00	7.12	0.00
Mole % Nitrogen	0.00	0.00	75.74	75.74	74.20	0.00	0.00	84.00	0.00
Mole % Argon	0.00	0.00	0.91	0.91	0.89	0.00	0.00	0.00	0.00
Mole % MEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	100.00	100.00	9.70	9.70	11.54	100.00	100.00	7.91	100.00
Molar rate (kmol/hr)	26323	26323	114453	114453	116832	7889	2379	103203	3550

Stream Name	24	25	26	27	28	29	30	31
Pressure (kPa)	110	130	348	453	140	138	110	110
Temperature (°C)	51.4	103.0	30.0	93.0	30.0	30.0	32.5	35.0
Mass rate (kg/h)	7007876	2102363	6487962	4905513	4536000	287320	126851	44238
Mole % CO2	5.21	5.21	4.67	5.21	2.25	96.89	0.06	94.81
Mole % Oxygen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Mole % Nitrogen	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.06
Mole % Argon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % MEA	10.86	10.86	11.25	10.86	11.53	0.00	0.50	0.00
Mole % H2O	83.93	83.93	84.07	83.93	86.22	3.09	99.44	5.12
Molar rate (kmol/hr)	291441	87432	269480	204009	192494	6650	6952	1037

REV	DATE	TITLE	BY	CHK	APP
01	22/10/13	FIRST ISSUE	SEF	RR	TA

REVISIONS

CCS BENCHMARK REFRESH 2013

CASE:

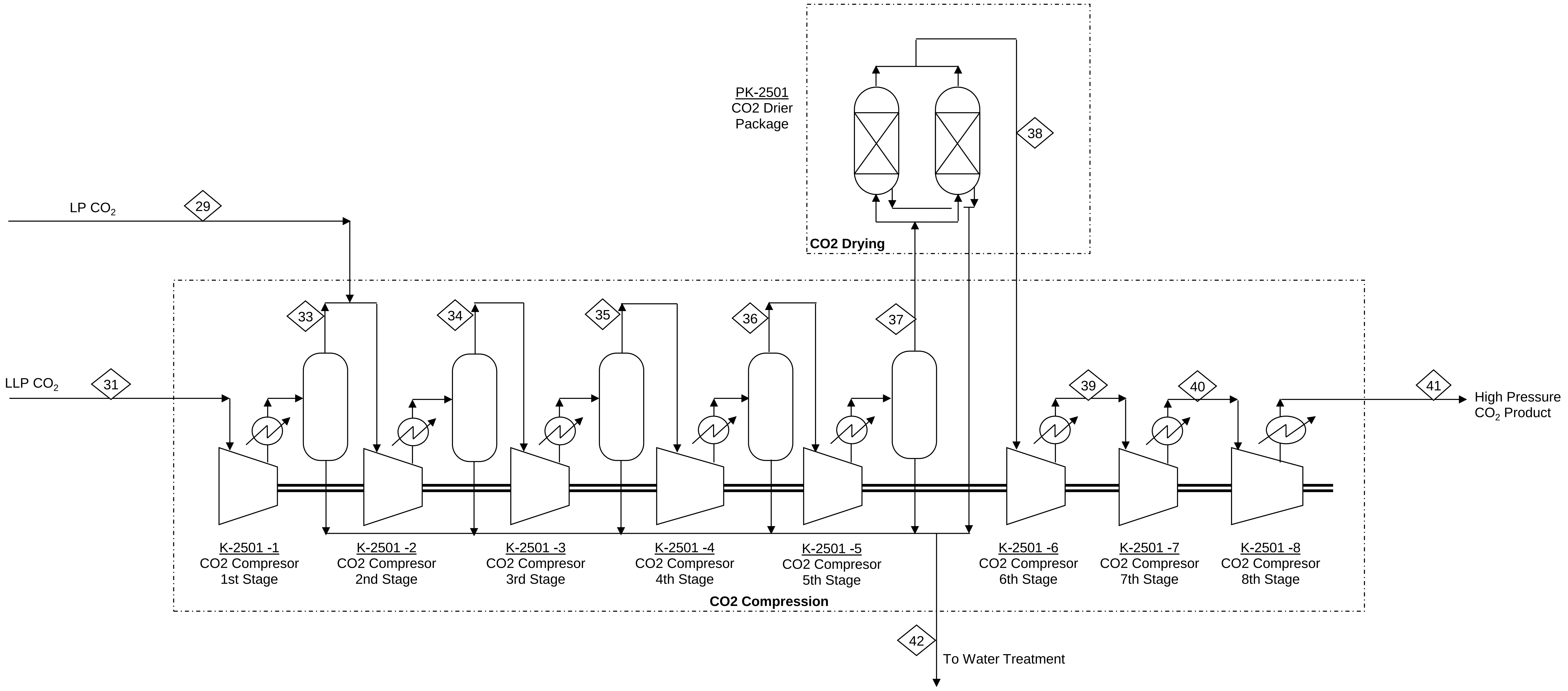
CO2 Capture

Natural Gas Combined Cycle Power Plant with 35% EGR and 90% Post-Combustion CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



Flows shown below are for the full facility capacity

Stream Name	33	34	35	36	37	38	39	40	41	42
Pressure (kPa)	138	270	530	1140	2490	2390	5490	9990	15090	138
Temperature (°C)	24.0	24.0	24.0	24.0	24.0	25.0	24.0	55.0	30.0	23.9
Mass rate (kg/h)	43674	328425	327698	363568	363371	363100	326790	326790	326790	4682
Mole % CO2	97.76	98.84	99.37	99.66	99.79	99.97	99.97	99.97	99.97	0.24
Mole % Oxygen	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Nitrogen	0.06	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00
Mole % Argon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % MEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	2.17	1.13	0.60	0.31	0.18	0.00	0.00	0.00	0.00	99.76
Molar rate (kmol/hr)	1005	7514	7473	8277	8266	8251	7426	7426	7426	259

REV	DATE	TITLE	BY	CHK	APP
01	22/10/13	FIRST ISSUE	SEF	RR	TA

REVISIONS

CCS BENCHMARK REFRESH 2013

CASE:

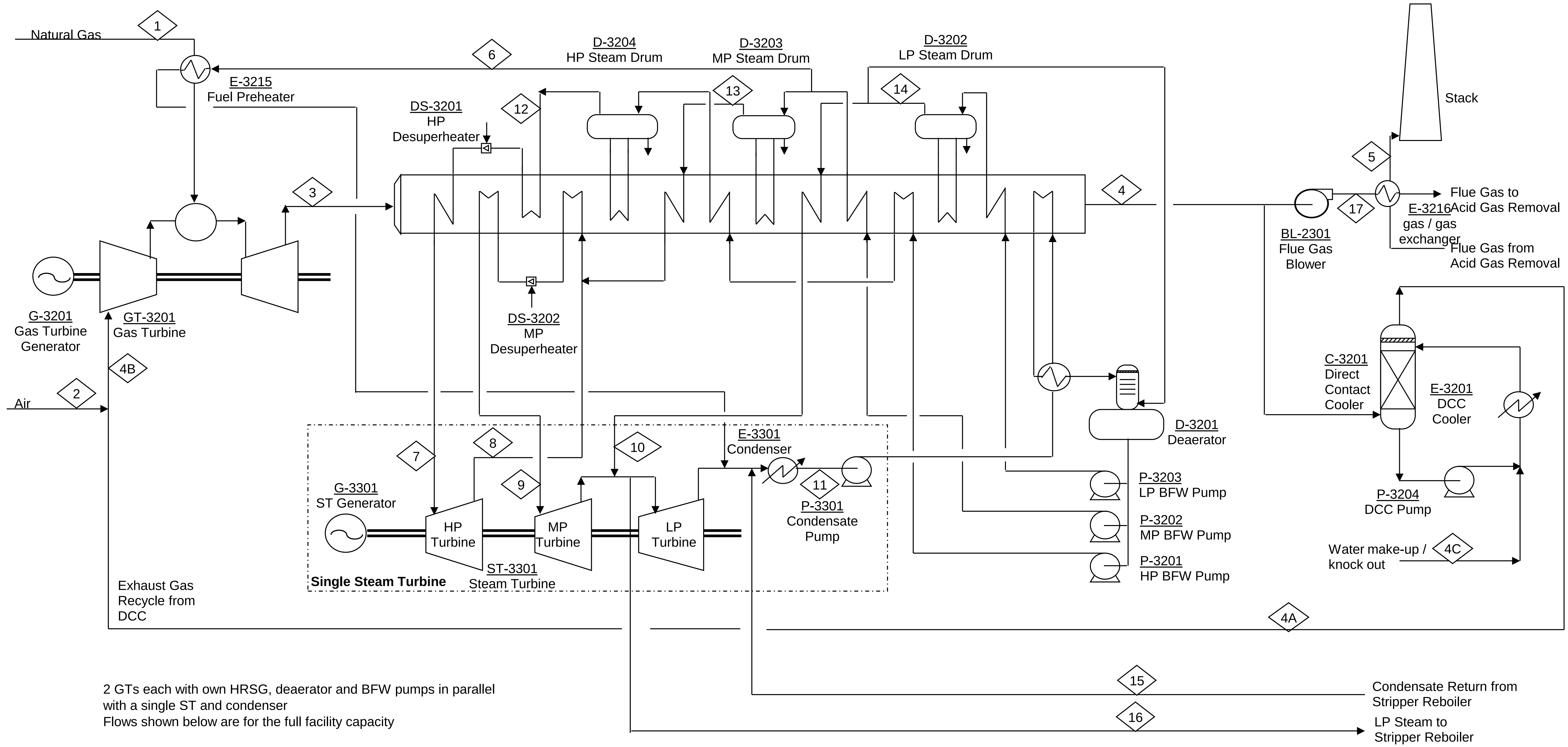
CO2 Compression & Dehydration

Natural Gas Combined Cycle Power Plant with 35% EGR and 90% Post-Combustion CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



2 GTs each with own HRSG, deaerator and BFW pumps in parallel
with a single ST and condenser
Flows shown below are for the full facility capacity

TURNDOWN CASE - 40% LOAD

Stream Name	1	2	3	4	4A	4B	4C	5	6	7	8	9	10	11	12	13	14
Pressure (kPa)	3447	101	105	103	102	101	101	102	1804	7812	1664	1595	366	3	7812	1804	378
Temperature (°C)	1.0	10.0	510.6	97.9	24.0	14.9	24.0	80	189.7	521.8	304.9	527.2	189.2	22.1	293.3	207.2	141.6
Mass rate (kg/h)	65973	2483505	3868344	3868344	1318866	3802372	34914	2334332	67357	342286	342289	423640	44523	535462	342035	81502	52404
Mole % Oxygen	0.00	20.82	10.99	10.99	11.44	17.25	0.00	11.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Nitrogen	1.47	77.60	76.55	76.55	79.71	78.76	0.00	79.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % CO2	0.68	0.03	4.98	4.98	5.18	2.04	0.00	0.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Methane	87.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Argon	0.00	0.93	0.92	0.92	0.96	0.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Ethane	7.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Propane	2.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	0.00	0.61	6.56	6.56	2.70	1.00	100.00	7.94	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molar rate (kmol/hr)	3599	86082	134779	134779	45256	130934	1938	83984	3738	18995	18995	23509	2471	29715	18981	4523	2908

REV	DATE	TITLE	BY	CHK	APP
01	22/10/13	FIRST ISSUE	SEF	RR	TA

REVISIONS

CCS BENCHMARK REFRESH 2013

Turndown @ 40% Load

CASE:

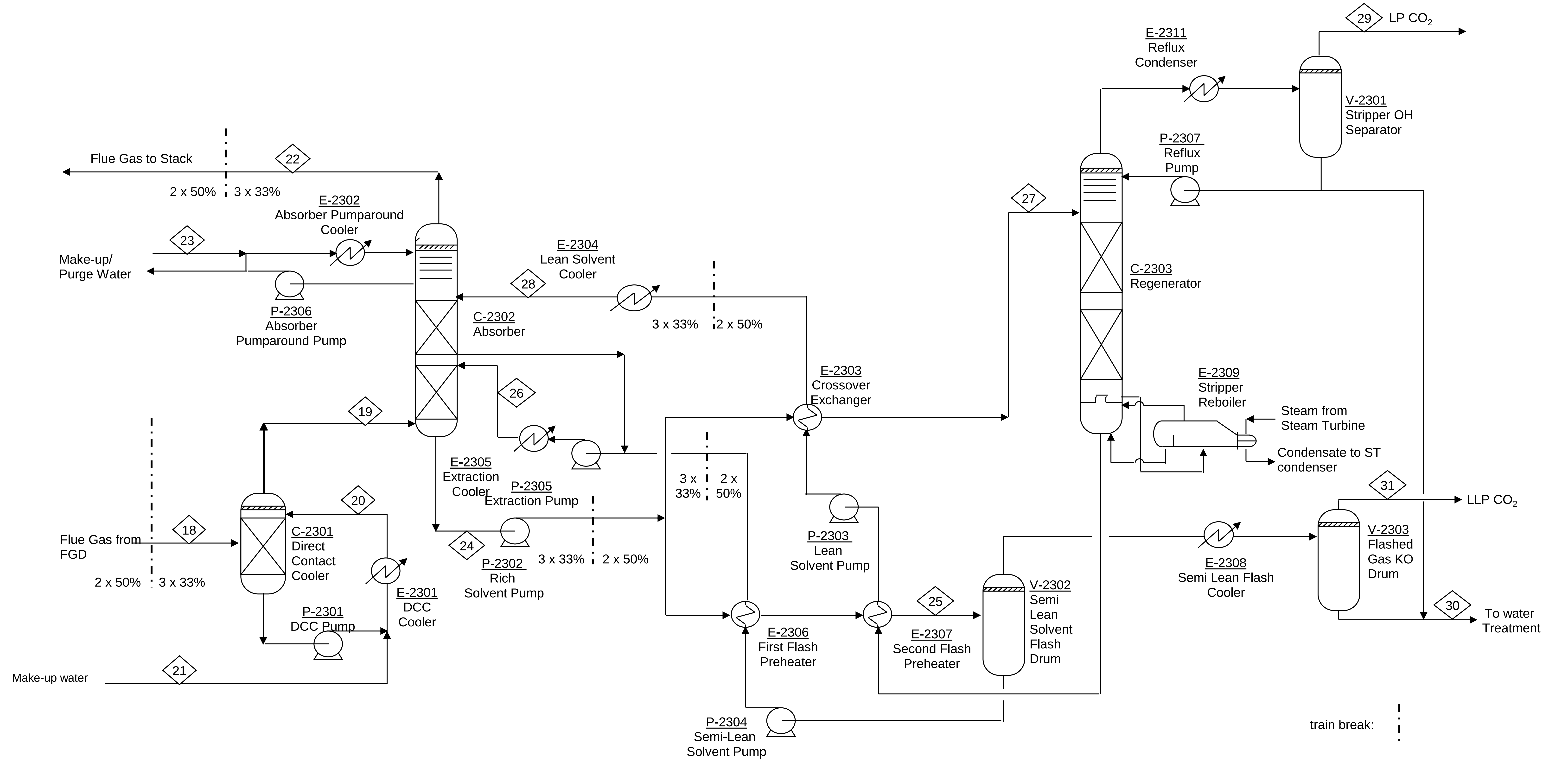
Power Generation

Natural Gas Combined Cycle Power Plant with 35% EGR and 90% Post-Combustion CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



3 Trains of CO2 absorption, 2 trains of stripping and 2 trains of compression are required

Flows shown below are for the full facility capacity

TURNDOWN CASE - 40% LOAD

Stream Name	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Pressure (kPa)	400	366	125	115	110	415	485	103	110	110	130	348	453	140	138	110	110
Temperature (°C)	133.5	308.2	121.0	86.0	45.7	30.0	45.8	42.0	10.0	47.6	103.0	30.0	93.0	30.0	30.0	32.4	35.0
Mass rate (kg/h)	220104	220104	2514424	2514424	2557407	43200	42983	2334332	33703	3628181	1088454	3367701	2539727	2368800	140272	65071	22181
Mole % CO2	0.00	0.00	4.98	4.98	4.85	0.00	0.00	0.74	0.00	5.22	5.22	4.65	5.22	2.25	96.88	0.06	94.80
Mole % Oxygen	0.00	0.00	10.99	10.99	10.70	0.00	0.00	11.46	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.02
Mole % Nitrogen	0.00	0.00	76.55	76.55	74.52	0.00	0.00	79.85	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.06
Mole % Argon	0.00	0.00	0.92	0.92	0.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % MEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.98	10.98	11.31	10.98	11.53	0.00	0.52	0.00
Mole % H2O	100.00	100.00	6.56	6.56	9.04	100.00	100.00	7.94	100.00	83.80	83.80	84.04	83.80	86.22	3.09	99.42	5.12
Molar rate (kmol/hr)	12214	12214	87607	87607	89993	2398	2386	83984	1871	150542	45163	139773	105380	100525	3247	3565	520

REV	DATE	TITLE	BY	CHK	APP
01	22/10/13	FIRST ISSUE	SEF	RR	TA

REVISIONS

CCS BENCHMARK REFRESH 2013

Turndown @ 40% Load

CASE:

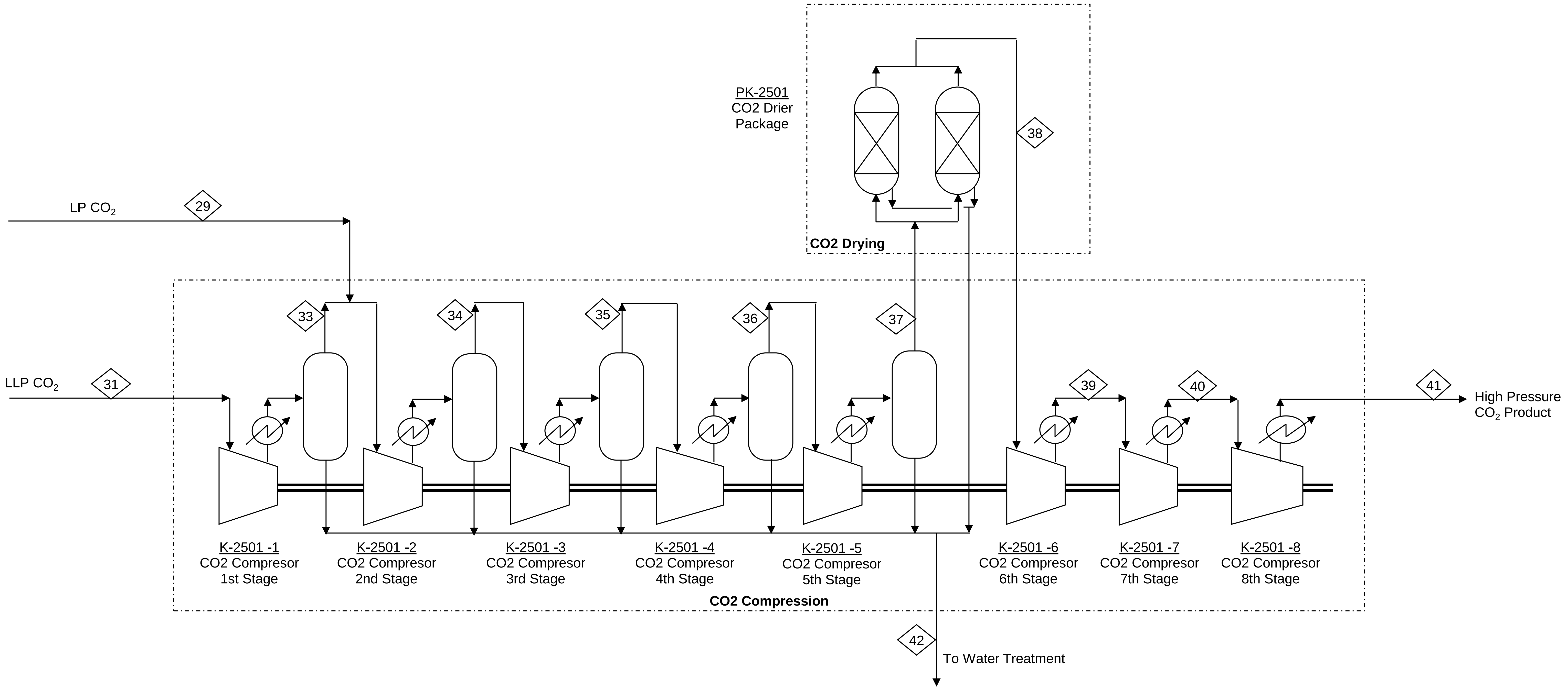
CO2 Capture

Natural Gas Combined Cycle Power Plant with 35% EGR and 90% Post-Combustion CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO. XXXX-XX-XXX

REV. 01



Flows shown below are for the full facility capacity

TURNDOWN CASE - 40% LOAD

Stream Name	33	34	35	36	37	38	39	40	41	42
Pressure (kPa)	138	270	530	1140	2490	2390	5490	9990	15090	138
Temperature (°C)	24.0	24.0	24.0	24.0	24.0	25.0	24.0	55.0	30.0	24.0
Mass rate (kg/h)	21899	160914	160558	178239	178143	178010	160209	160209	160209	2299
Mole % CO2	97.75	98.83	99.36	99.65	99.78	99.96	99.96	99.96	99.96	0.24
Mole % Oxygen	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00
Mole % Nitrogen	0.06	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00
Mole % Argon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % MEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	2.17	1.13	0.60	0.31	0.18	0.00	0.00	0.00	0.00	99.76
Molar rate (kmol/hr)	504	3681	3662	4058	4053	4045	3641	3641	3641	127

REV	DATE	TITLE	BY	CHK	APP
01	22/10/13	FIRST ISSUE	SEF	RR	TA

REVISIONS

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CASE: Turndown @ 40% Load

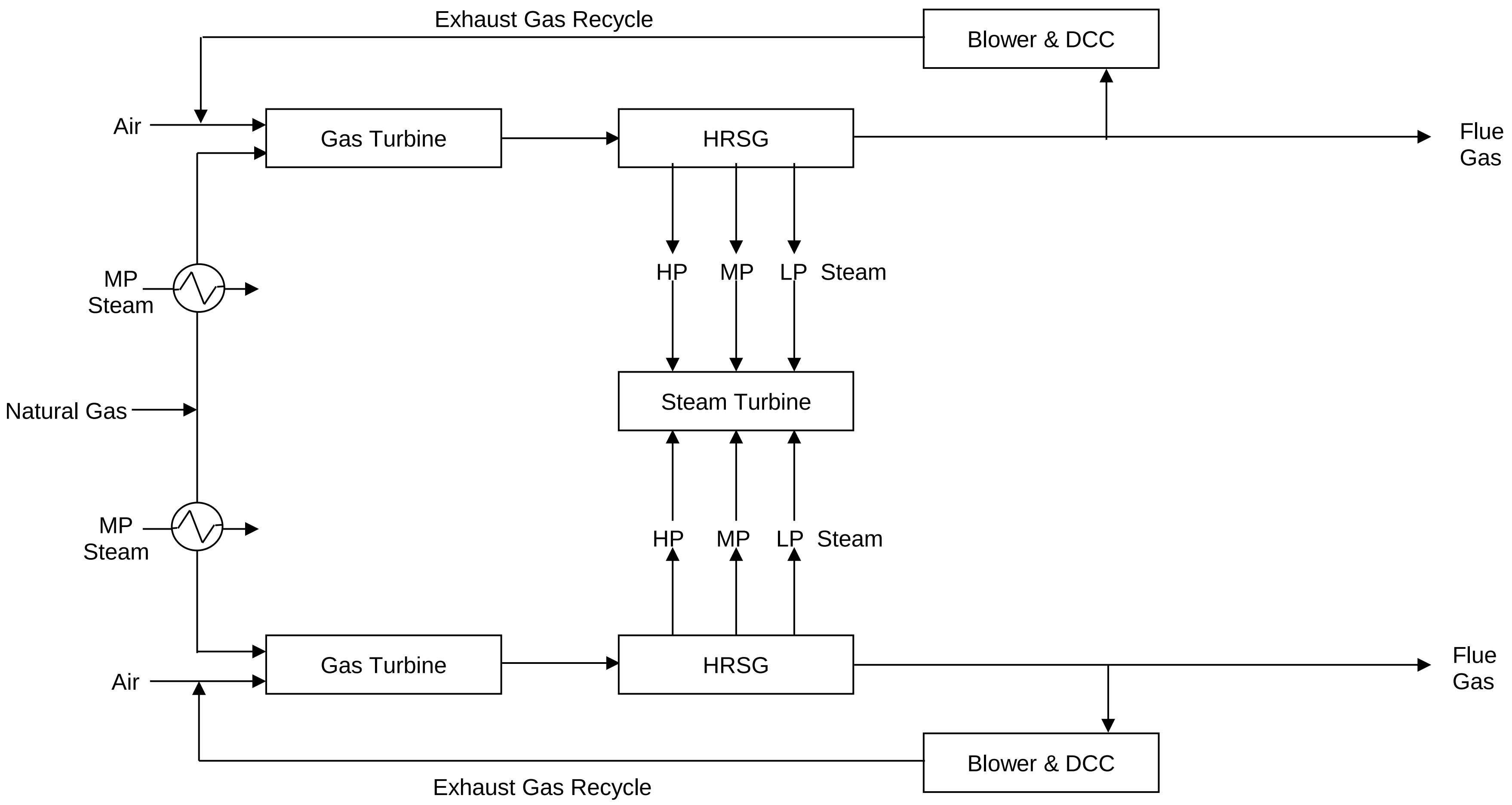
CO2 Compression & Dehydration

Natural Gas Combined Cycle Power Plant with 35% EGR and 90% Post-Combustion CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



01	22/10/13	FIRST ISSUE	SEF	RR	TA
REV	DATE	TITLE	BY	CHK	APP

REVISIONS

CCS BENCHMARK REFRESH 2013

Block Flow Diagram

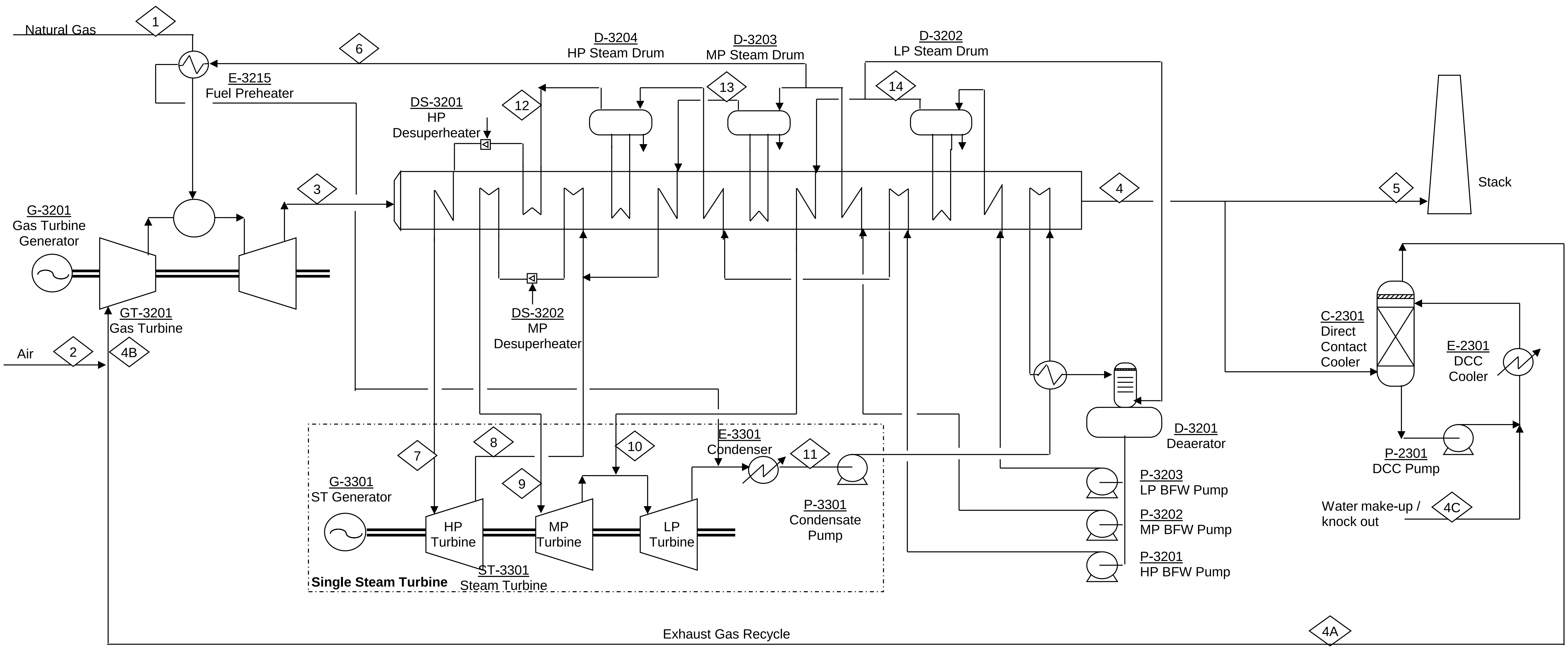
FOSTER WHEELER ENERGY

CASE:

Natural Gas Combined Cycle Power Plant with 35% EGR without CO2 Capture

DWG. NO.: XXXX-XX-XXX

REV: 01



2 GTs each with own HRSG, deaerator and BFW pumps in parallel
with a single ST and condenser
Flows shown below are for the full facility capacity

Stream Name	1	2	3	4	4A	4B	4C	5
Pressure (kPa)	3447	101	105	103	102	101	101	103
Temperature (°C)	1.0	10.0	621.4	93.3	24.0	14.9	24.0	93
Mass rate (kg/h)	134681	3213377	5029654	5029654	1681595	4894973	78407	3269274
Mole % Oxygen	0.00	20.82	9.14	9.14	9.80	18.92	0.00	9.14
Mole % Nitrogen	1.47	77.60	74.80	74.80	80.17	78.19	0.00	74.80
Mole % CO2	0.68	0.03	5.69	5.69	6.09	1.10	0.00	5.69
Mole % Methane	87.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Argon	0.00	0.93	0.90	0.90	0.96	0.94	0.00	0.90
Mole % Ethane	7.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Propane	2.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	0.00	0.61	9.47	9.47	2.98	0.85	100.00	9.47
Molar rate (kmol/hr)	7347	111380	176805	176805	57599	168969	4351	114453

Stream Name	6	7	8	9	10	11	12	13	14
Pressure (kPa)	2918	13980	2801	2689	417	4	13980	2918	435
Temperature (°C)	212.3	566.0	327.0	565.6	203.4	24.5	336.5	232.3	146.6
Mass rate (kg/h)	78222	610007	610007	704656	59129	842009	610008	94649	3128550
Mole % Oxygen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Nitrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % CO2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Methane	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Argon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Ethane	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Propane	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molar rate (kmol/hr)	4341	33852	33852	39104	3281	46726	33852	5252	173615

REV	DATE	TITLE	BY	CHK	APP
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REVISIONS

CCS BENCHMARK REFRESH 2013

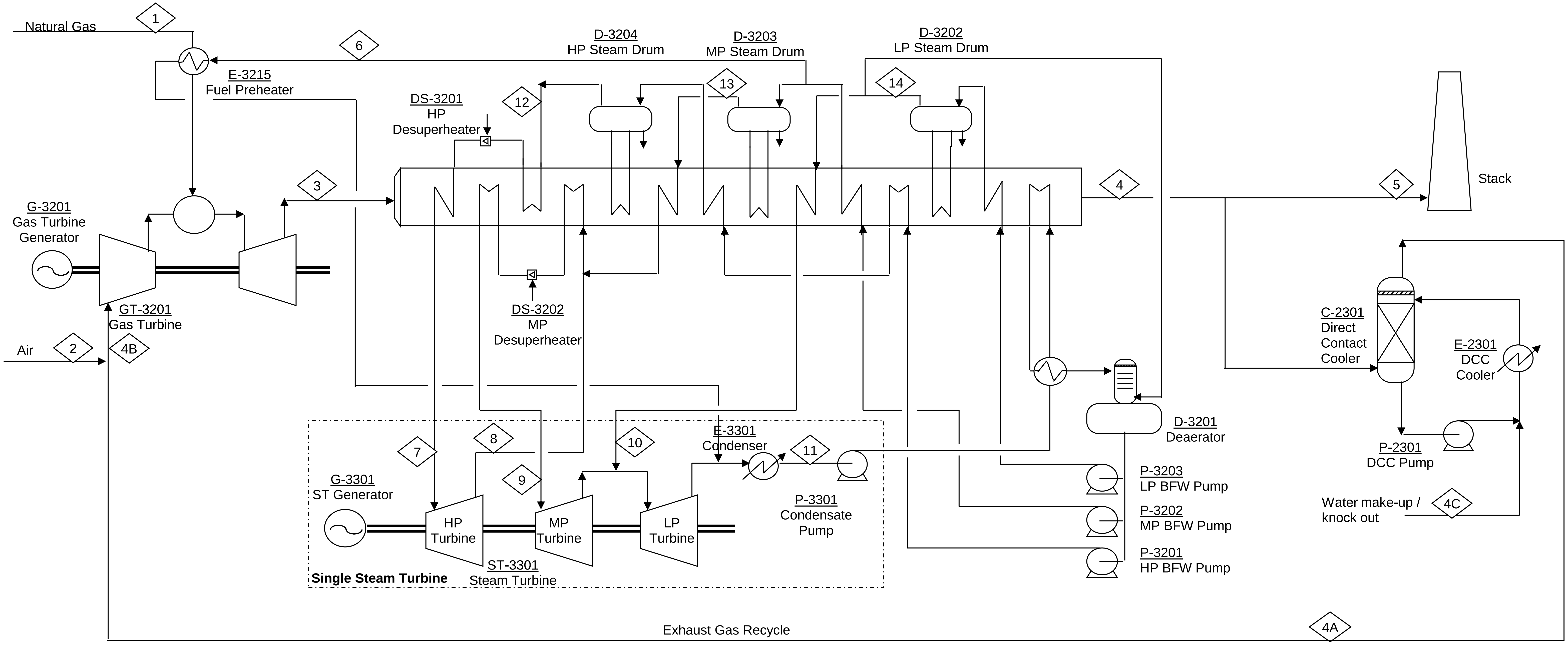
Power Generation

FOSTER WHEELER ENERGY

CASE: Natural Gas Combined Cycle Power Plant with 35% EGR without CO2 Capture

DWG. NO.: XXXX-XX-XXX

REV: 01



2 GTs each with own HRSG, deaerator and BFW pumps in parallel
with a single ST and condenser
Flows shown below are for the full facility capacity

TURNDOWN CASE - 40% LOAD

Stream Name	1	2	3	4	4A	4B	4C	5	6	7	8	9	10	11	12	13	14
Pressure (kPa)	3447	101	105	103	102	101	101	103	1791	7748	1651	1583	254	3	7748	1791	275
Temperature (°C)	1.0	10.0	510.6	92.0	24.0	14.9	24.0	92.0	189.5	521.6	304.9	527.3	180.7	20.4	292.7	206.9	130.6
Mass rate (kg/h)	65973	2483449	3868344	3868344	1318923	3802372	34858	2514563	67135	342391	342391	423668	51922	542767	342408	81233	66616
Mole % Oxygen	0.00	20.82	10.99	10.99	11.44	17.25	0.00	10.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Nitrogen	1.47	77.60	76.55	76.55	79.71	78.76	0.00	76.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % CO2	0.68	0.03	4.98	4.98	5.18	2.04	0.00	4.98	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Methane	87.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Argon	0.00	0.93	0.92	0.92	0.96	0.95	0.00	0.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Ethane	7.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Propane	2.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	0.00	0.61	6.56	6.56	2.70	1.00	100.00	6.56	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molar rate (kmol/hr)	3599	86080	134779	134779	45258	130934	1934	87611	3726	19001	19001	23511	2881	30120	19002	4508	3697

REV	DATE	TITLE	BY	CHK	APP
01	22/10/13	FIRST ISSUE	SEF	RR	TA

REVISIONS

CCS BENCHMARK REFRESH 2013

Turndown @ 40% Load

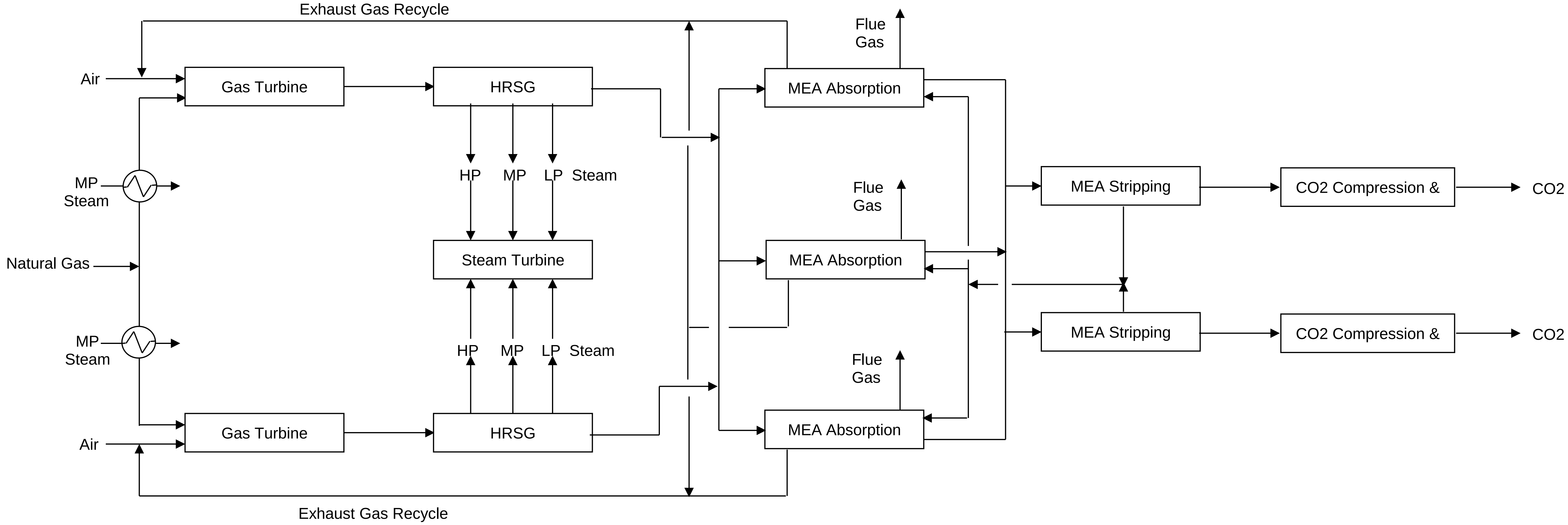
Power Generation

CASE: Natural Gas Combined Cycle Power Plant with 35% EGR without CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



01	22/10/13	FIRST ISSUE	SEF	RR	TA
REV	DATE	TITLE	BY	CHK	APP

REVISIONS

CCS BENCHMARK REFRESH 2013

CASE:

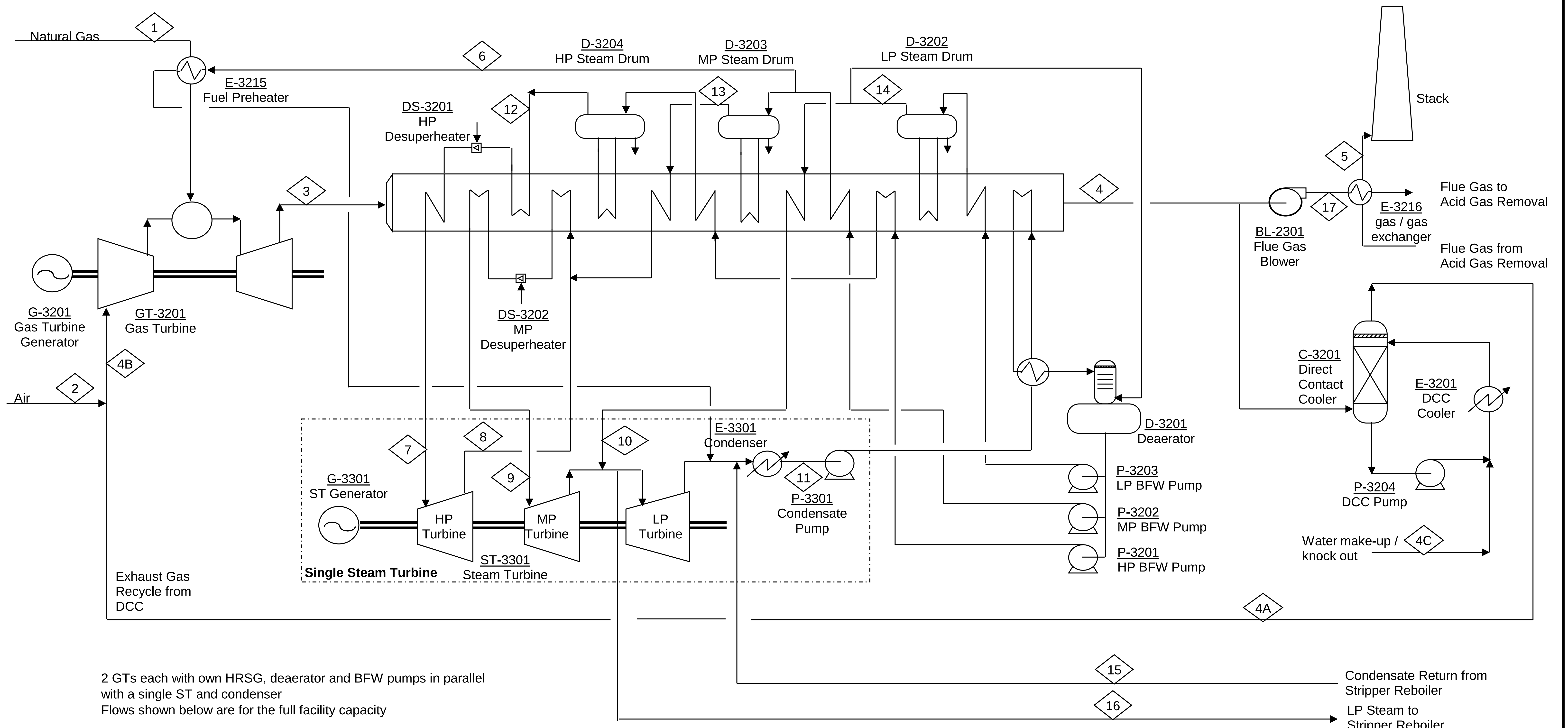
Block Flow Diagram

Natural Gas Combined Cycle Power Plant with 18% EGR and 90% Post-Combustion CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



2 GTs each with own HRSG, deaerator and BFW pumps in parallel
with a single ST and condenser
Flows shown below are for the full facility capacity

Stream Name	1	2	3	4	4A	4B	4C	5	6	7	8	9	10	11	12	13	14
Pressure (kPa)	3447	101	105	103	102	101	101	102	2918	13980	2801	2689	417	4	13980	2918	435
Temperature (°C)	1.0	10.0	617.7	93.3	24.0	12.4	24.0	80	212.3	566.0	327.0	565.6	203.4	24.5	336.5	232.3	146.6
Mass rate (kg/h)	135329	4065092	5076994	5076994	876573	4941665	39657	3697599	80582	604293	604293	701797	61777	844157	604294	97504	82305
Mole % Oxygen	0.00	20.82	9.14	9.14	9.80	18.92	0.00	10.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Nitrogen	1.47	77.60	74.80	74.80	80.17	78.19	0.00	82.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % CO2	0.68	0.03	5.69	5.69	6.09	1.10	0.00	0.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Methane	87.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Argon	0.00	0.93	0.90	0.90	0.96	0.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Ethane	7.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Propane	2.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	0.00	0.61	9.47	9.47	2.98	0.85	100.00	7.21	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molar rate (kmol/hr)	7382	140902	178469	178469	30025	170581	2201	133094	4472	33535	33535	38945	3428	46846	33535	5411	4567

REV	DATE	TITLE	BY	CHK	APP
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REVISIONS

CCS BENCHMARK REFRESH 2013

CASE:

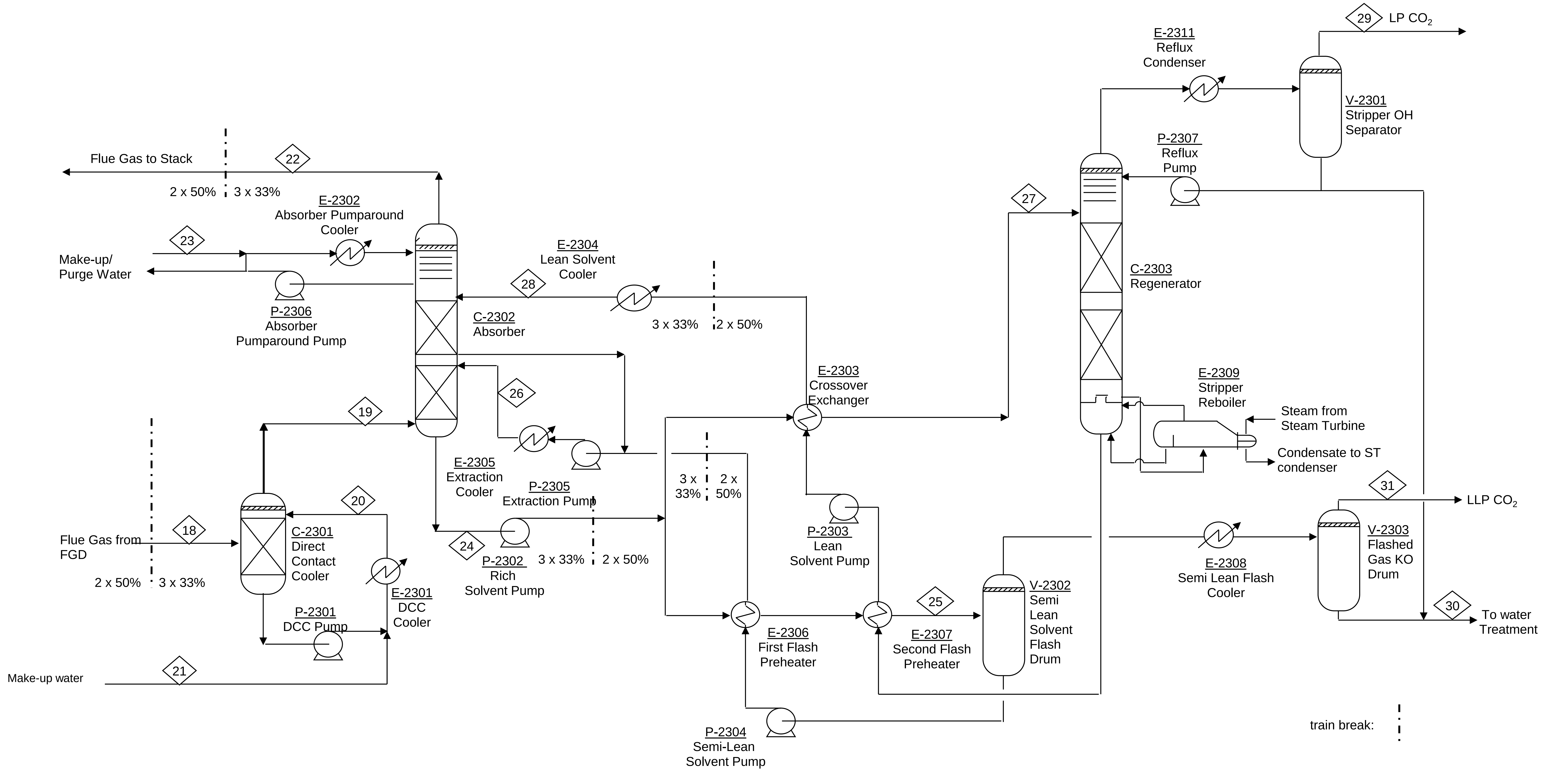
Power Generation

Natural Gas Combined Cycle Power Plant with 18% EGR and 90% Post-Combustion CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



3 Trains of CO2 absorption, 2 trains of stripping and 2 trains of compression are required
Flows shown below are for the full facility capacity

Stream Name	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Pressure (kPa)	400	566	125	115	110	415	485	103	110	110	130	348	453	140	138	110	110
Temperature (°C)	133.5	292.9	116.4	81.7	50.0	30.0	50.4	40.1	10.0	52.1	103.0	30.0	93.0	30.0	30.0	32.5	35.0
Mass rate (kg/h)	479160	479160	4160597	4160597	4214085	142920	53488	3697649	64318	7649135	2294741	7084986	5354395	4932000	290503	126794	43663
Mole % CO2	0.00	0.00	5.69	5.69	5.58	0.00	0.00	0.56	0.00	5.07	5.07	4.05	5.07	2.25	96.88	0.06	94.80
Mole % Oxygen	0.00	0.00	9.14	9.14	8.96	0.00	0.00	10.04	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.01
Mole % Nitrogen	0.00	0.00	74.80	74.80	73.31	0.00	0.00	82.19	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.06
Mole % Argon	0.00	0.00	0.90	0.90	0.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % MEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.79	10.79	11.18	10.79	11.53	0.00	0.50	0.00
Mole % H2O	100.00	100.00	9.47	9.47	11.28	100.00	100.00	7.21	100.00	84.14	84.14	84.77	84.14	86.22	3.09	99.44	5.12
Molar rate (kmol/hr)	26590	26590	146257	146257	149225	7933	2969	133095	3570	318986	95696	296641	223290	209299	6724	6949	1023

01	22/10/13	FIRST ISSUE	SEF	RR	TA
REV	DATE	TITLE	BY	CHK	APP

REVISIONS

CCS BENCHMARK REFRESH 2013

CASE:

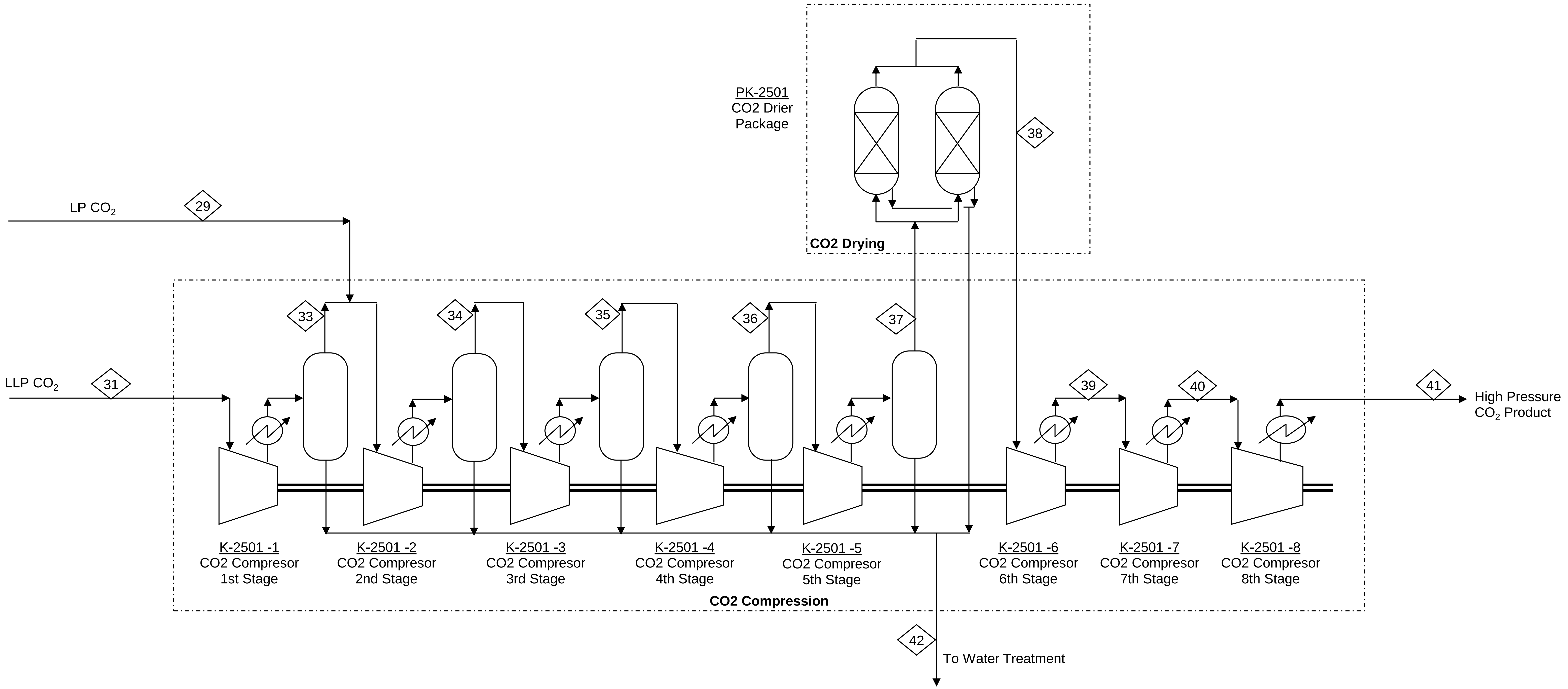
CO2 Capture

Natural Gas Combined Cycle Power Plant with 18% EGR and 90% Post-Combustion CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



Flows shown below are for the full facility capacity

Stream Name	33	34	35	36	37	38	39	40	41	42
Pressure (kPa)	138	270	530	1140	2490	2390	5490	9990	15090	138
Temperature (°C)	24.0	24.0	24.0	24.0	24.0	25.0	24.0	55.0	30.0	23.9
Mass rate (kg/h)	43106	331016	330284	366401	366203	365930	329337	329337	329337	4711
Mole % CO2	97.75	98.83	99.36	99.65	99.78	99.96	99.96	99.96	99.96	0.24
Mole % Oxygen	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00
Mole % Nitrogen	0.07	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00
Mole % Argon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % MEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	2.17	1.13	0.60	0.31	0.18	0.00	0.00	0.00	0.00	99.76
Molar rate (kmol/hr)	992	7573	7532	8342	8331	8316	7484	7484	7484	261

REV	DATE	TITLE	BY	CHK	APP
01	22/10/13	FIRST ISSUE	SEF	RR	TA

REVISIONS

CCS BENCHMARK REFRESH 2013

CASE:

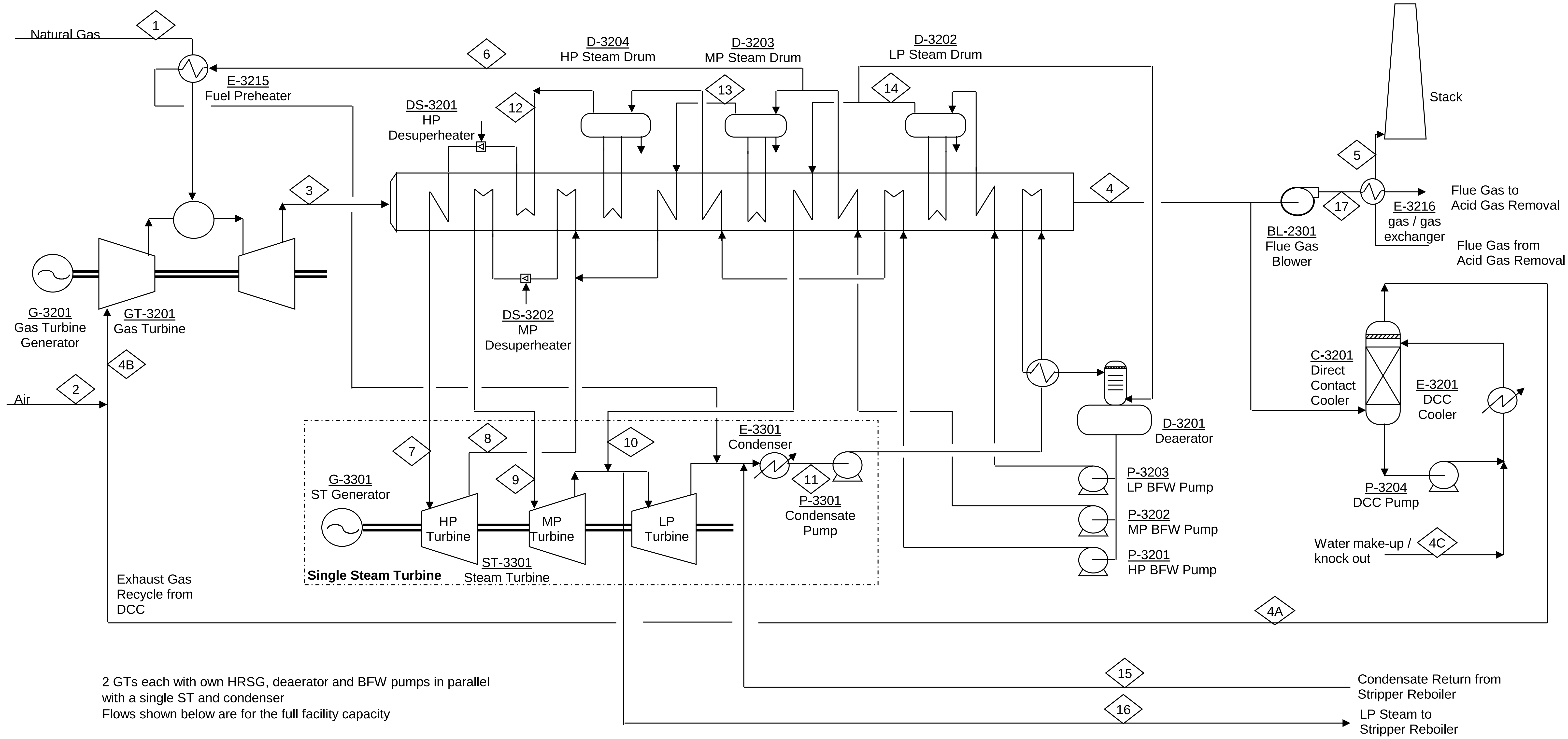
CO2 Compression & Dehydration

Natural Gas Combined Cycle Power Plant with 18% EGR and 90% Post-Combustion CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



2 GTs each with own HRSG, deaerator and BFW pumps in parallel
with a single ST and condenser
Flows shown below are for the full facility capacity

TURNDOWN CASE - 40% LOAD

Stream Name	1	2	3	4	4A	4B	4C	5	6	7	8	9	10	11	12	13	14
Pressure (kPa)	3447	101	105	103	102	101	101	102	1782	7571	1645	1579	342	3	7571	1782	354
Temperature (°C)	1.0	10.0	506.8	97.2	24.0	12.4	24.0	80	189.8	498.8	289.6	526.4	187.8	21.7	291.1	206.6	139.3
Mass rate (kg/h)	67461	3159007	3915360	3915360	688892	3847899	17768	3019704	68315	337187	337187	419822	47330	535460	337211	82661	56287
Mole % Oxygen	0.00	20.82	13.15	13.15	13.67	19.52	0.00	13.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Nitrogen	1.47	77.60	75.74	75.74	78.78	77.94	0.00	78.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % CO2	0.68	0.03	3.75	3.75	3.89	0.75	0.00	0.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Methane	87.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Argon	0.00	0.93	0.91	0.91	0.94	0.93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Ethane	7.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Propane	2.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	0.00	0.61	6.45	6.45	2.70	0.85	100.00	7.56	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molar rate (kmol/hr)	3680	109496	136903	136903	23735	132970	986	108363	3791	18712	18712	23298	2627	29715	18713	4587	3124

REV	DATE	TITLE	BY	CHK	APP
01	22/10/13	FIRST ISSUE	SEF	RR	TA

REVISIONS

CCS BENCHMARK REFRESH 2013

Turndown @ 40% Load

CASE:

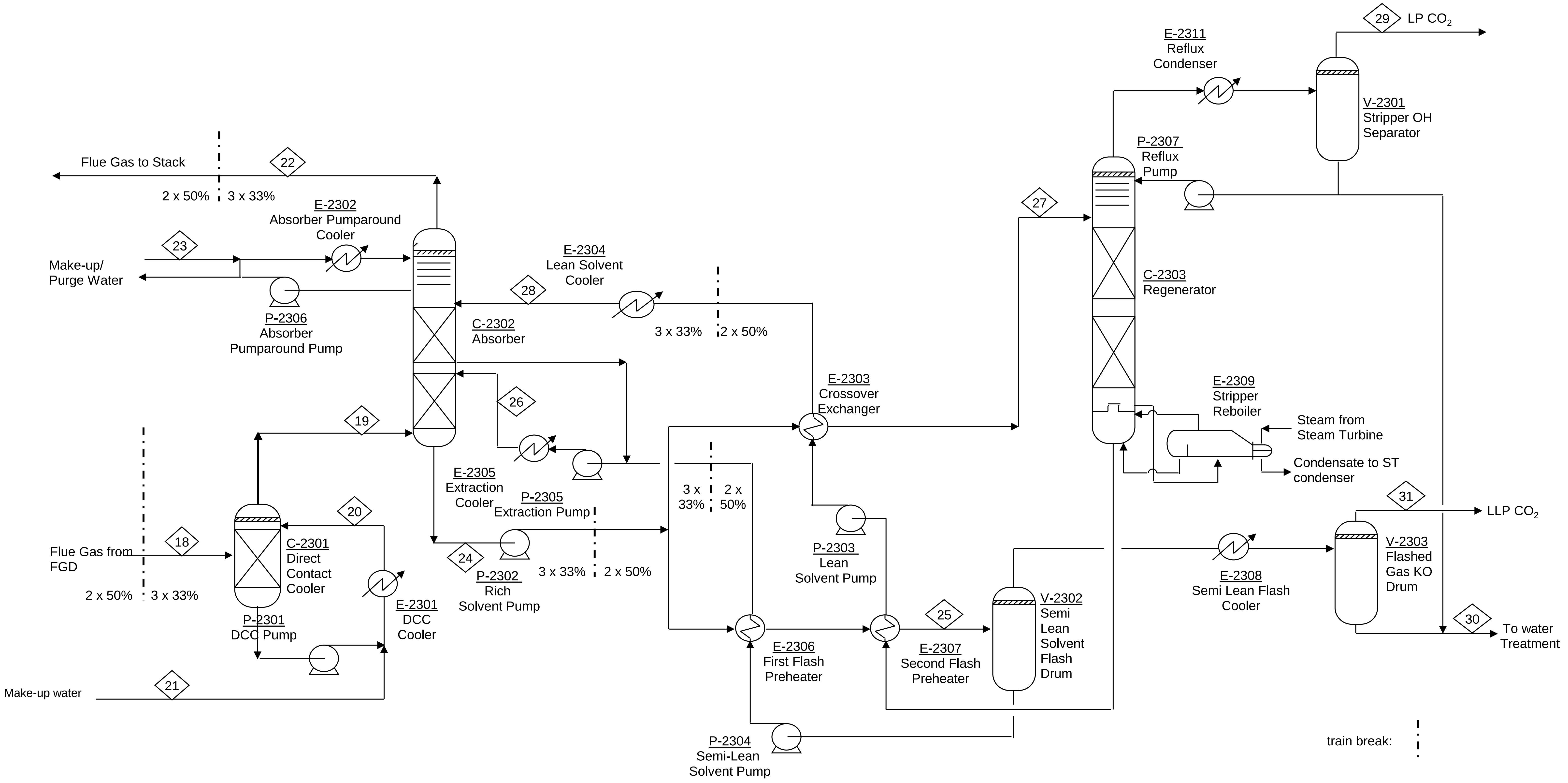
Power Generation

Natural Gas Combined Cycle Power Plant with 18% EGR and 90% Post-Combustion CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



3 Trains of CO2 absorption, 2 trains of stripping and 2 trains of compression are required
Flows shown below are for the full facility capacity

TURNDOWN CASE - 40% LOAD

Stream Name	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31
Pressure (kPa)	400	574	125	115	110	415	485	103	110	110	130	348	453	140	138	110	110
Temperature (°C)	133.5	300.4	120.7	84.4	45.3	30.0	45.4	41.1	10.0	47.2	103.0	30.0	93.0	30.0	30.0	32.4	35.0
Mass rate (kg/h)	235728	235728	3208638	3208638	3261757	60480	53120	3019704	32486	3777937	1133381	3522496	2644556	2462400	144679	62826	21369
Mole % CO2	0.00	0.00	3.75	3.75	3.65	0.00	0.00	0.41	0.00	5.12	5.12	4.04	5.12	2.25	96.88	0.06	94.79
Mole % Oxygen	0.00	0.00	13.15	13.15	12.81	0.00	0.00	13.61	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.02
Mole % Nitrogen	0.00	0.00	75.74	75.74	73.80	0.00	0.00	78.42	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.07
Mole % Argon	0.00	0.00	0.91	0.91	0.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % MEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.94	10.94	11.26	10.94	11.53	0.00	0.50	0.00
Mole % H2O	100.00	100.00	6.45	6.45	8.85	100.00	100.00	7.56	100.00	83.93	83.93	84.70	83.93	86.22	3.09	99.44	5.12
Molar rate (kmol/hr)	13081	13081	112192	112192	115141	3357	2949	108363	1803	157023	47107	147302	109916	104497	3349	3443	501

REV	DATE	TITLE	BY	CHK	APP
01	22/10/13	FIRST ISSUE	SEF	RR	TA

REVISIONS

CCS BENCHMARK REFRESH 2013

Turndown @ 40% Load

CASE:

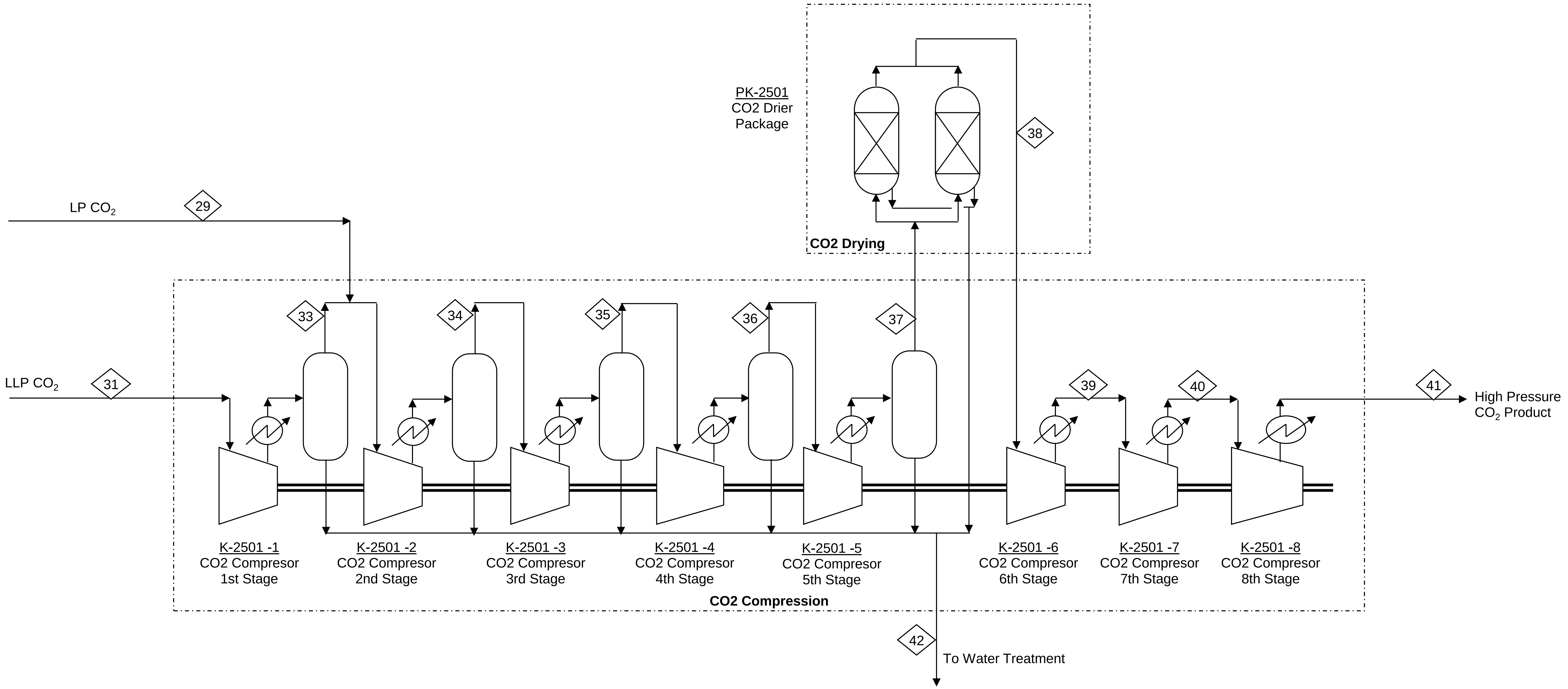
CO2 Capture

Natural Gas Combined Cycle Power Plant with 18% EGR and 90% Post-Combustion CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



Flows shown below are for the full facility capacity

TURNDOWN CASE - 40% LOAD

Stream Name	33	34	35	36	37	38	39	40	41	42
Pressure (kPa)	138	270	530	1140	2490	2390	5490	9990	15090	138
Temperature (°C)	24.0	24.0	24.0	24.0	24.0	25.0	24.0	55.0	30.0	23.9
Mass rate (kg/h)	21096	164485	164121	182098	181999	181863	163677	163677	163677	2338
Mole % CO2	97.74	98.83	99.36	99.65	99.78	99.96	99.96	99.96	99.96	0.24
Mole % Oxygen	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00
Mole % Nitrogen	0.07	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00
Mole % Argon	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % MEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	2.17	1.13	0.60	0.31	0.18	0.00	0.00	0.00	0.00	99.76
Molar rate (kmol/hr)	486	3763	3743	4146	4140	4133	3720	3720	3720	129

REV	DATE	TITLE	BY	CHK	APP
01	22/10/13	FIRST ISSUE	SEF	RR	TA

REVISIONS

CCS BENCHMARK REFRESH 2013

Turndown @ 40% Load

CASE:

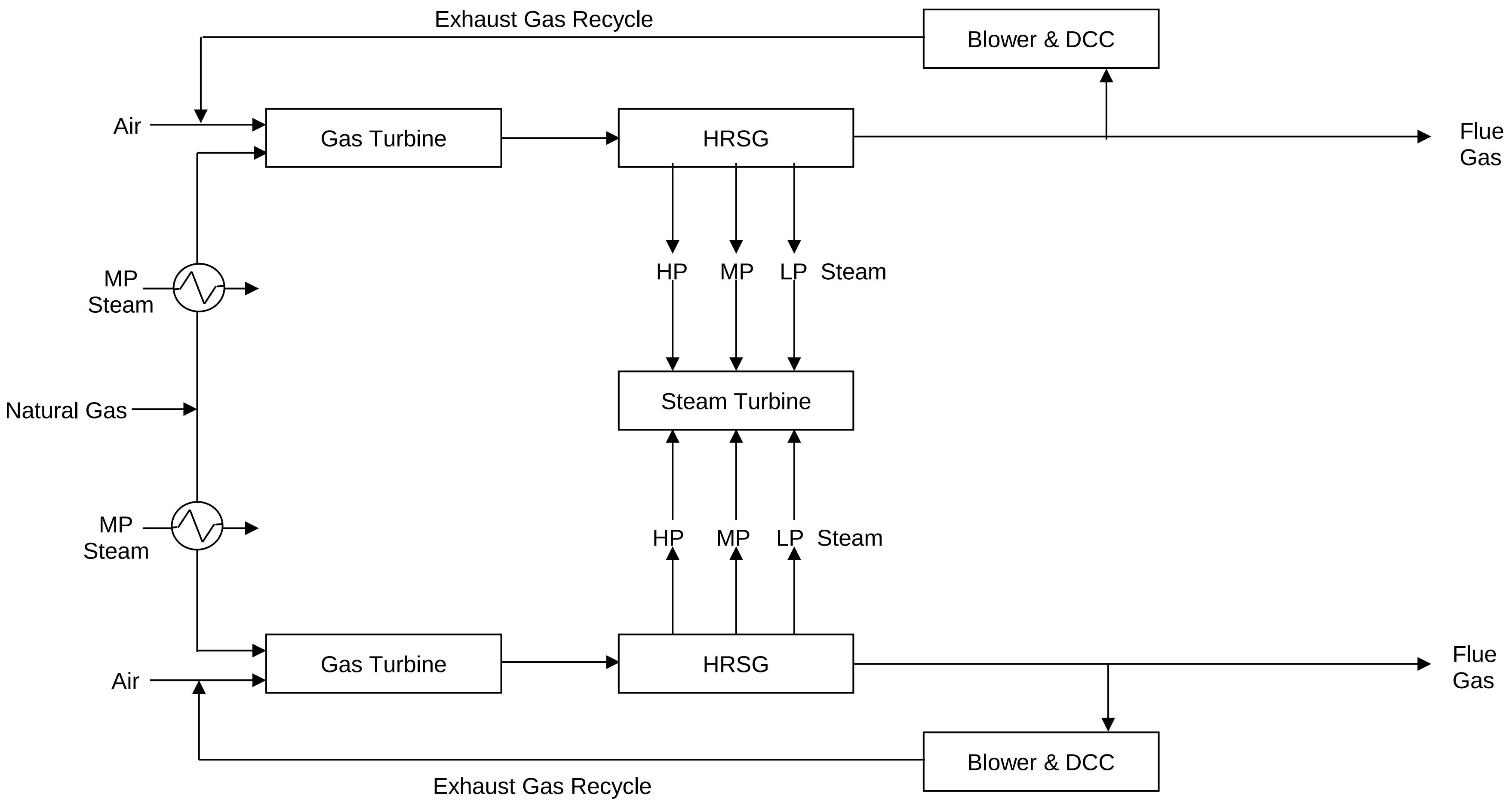
CO2 Compression & Dehydration

Natural Gas Combined Cycle Power Plant with 18% EGR and 90% Post-Combustion CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



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CCS BENCHMARK REFRESH 2013

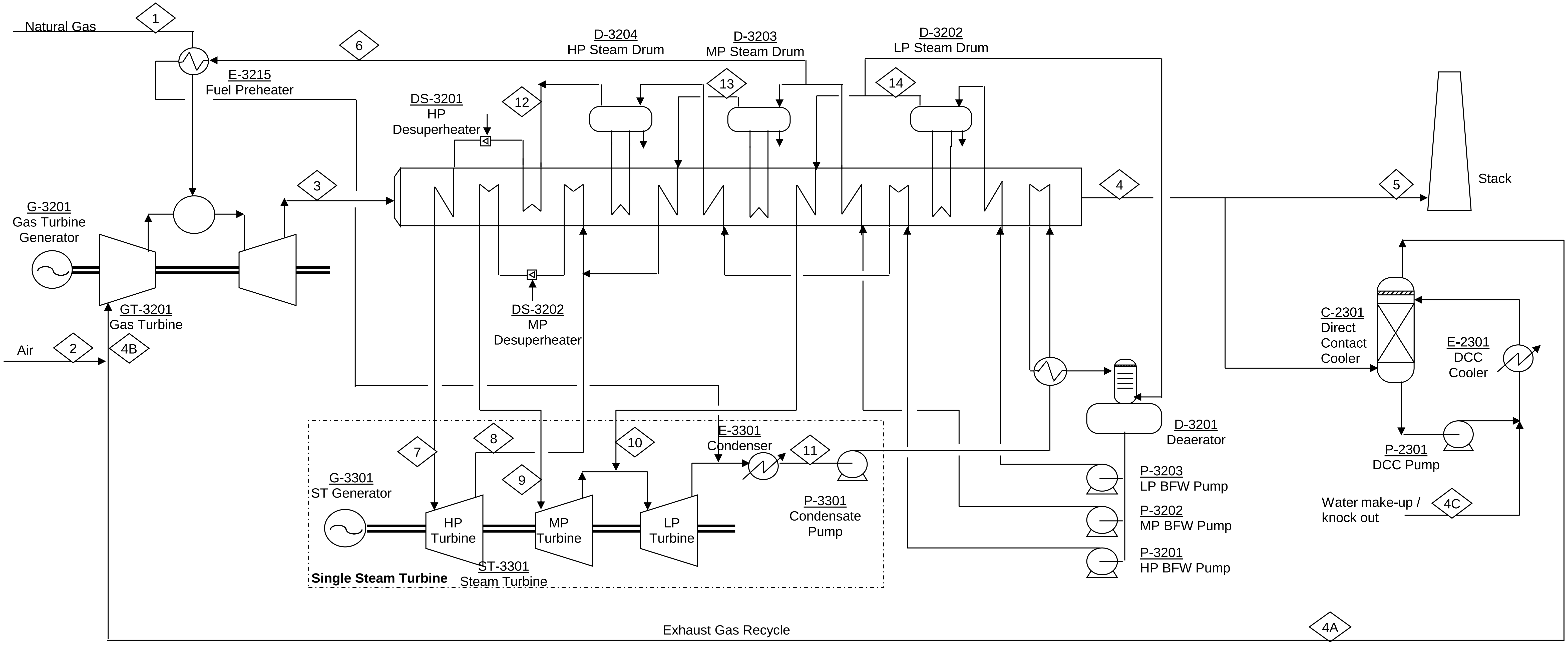
Block Flow Diagram

FOSTER WHEELER ENERGY

CASE: Natural Gas Combined Cycle Power Plant with 18% EGR without CO2 Capture

DWG. NO.: XXXX-XX-XXX

REV: 01



2 GTs each with own HRSG, deaerator and BFW pumps in parallel
with a single ST and condenser
Flows shown below are for the full facility capacity

Stream Name	1	2	3	4	4A	4B	4C	5	6	7	8	9	10	11	12	13	14
Pressure (kPa)	3447	101	105	103	102	101	101	103	2918	13980	2801	2689	417	4	13980	2918	435
Temperature (°C)	1.0	10.0	617.7	93.3	24.0	12.4	24.0	93	212.3	566.0	327.0	565.6	203.4	24.5	336.5	232.3	146.6
Mass rate (kg/h)	135329	4065092	5076994	5076994	876573	4941665	39657	4160597	80582	604293	604293	701798	61778	844158	604293	97505	3128550
Mole % Oxygen	0.00	20.82	9.14	9.14	9.80	18.92	0.00	9.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Nitrogen	1.47	77.60	74.80	74.80	80.17	78.19	0.00	74.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % CO2	0.68	0.03	5.69	5.69	6.09	1.10	0.00	5.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Methane	87.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Argon	0.00	0.93	0.90	0.90	0.96	0.94	0.00	0.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Ethane	7.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Propane	2.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	0.00	0.61	9.47	9.47	2.98	0.85	100.00	9.47	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molar rate (kmol/hr)	7382	140902	178469	178469	30025	170581	2201	146257	4472	33535	33535	38945	3428	46846	33535	5411	173615

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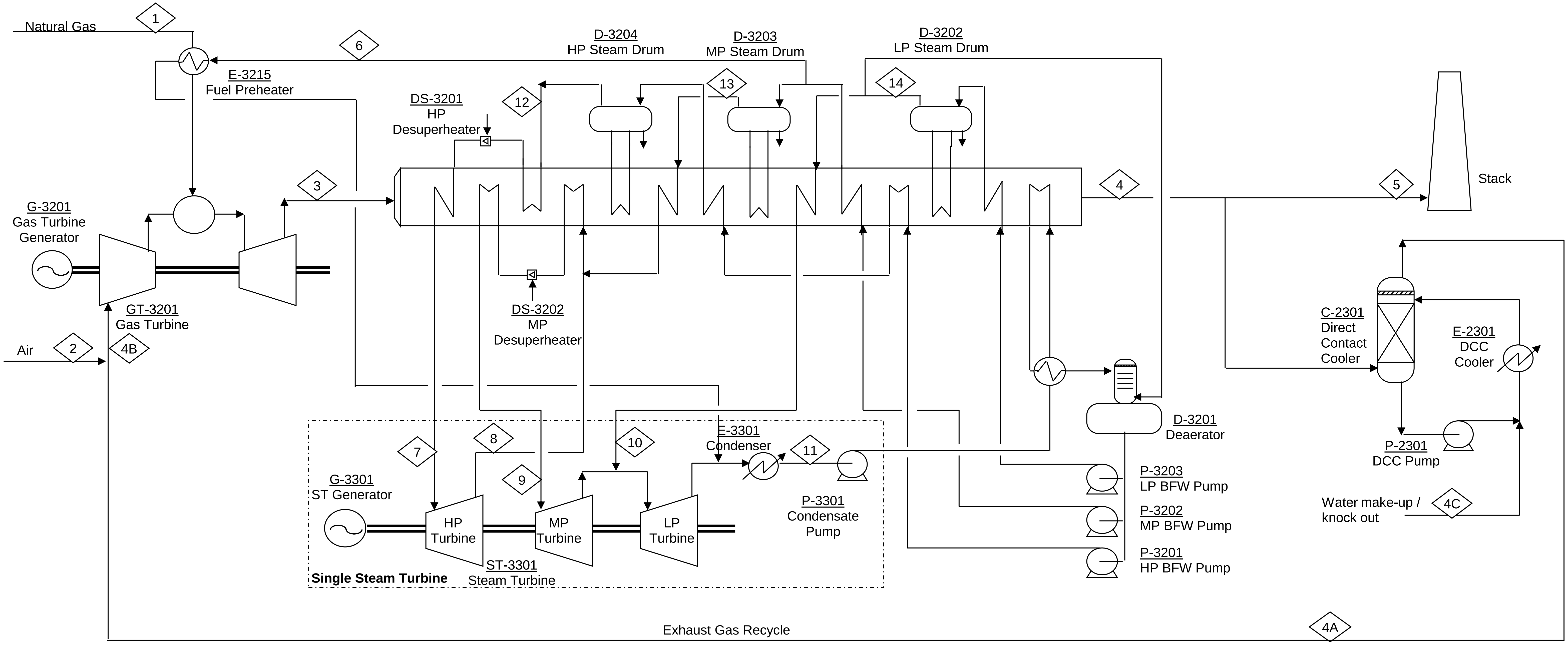
Power Generation

CASE: Natural Gas Combined Cycle Power Plant with 18% EGR without CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01



2 GTs each with own HRSG, deaerator and BFW pumps in parallel
with a single ST and condenser
Flows shown below are for the full facility capacity

TURNDOWN CASE - 40% LOAD

Stream Name	1	2	3	4	4A	4B	4C	5	6	7	8	9	10	11	12	13	14
Pressure (kPa)	3447	101	105	103	102	101	101	103	1795	7764	1657	1589	255	3	7764	1795	275
Temperature (°C)	1.0	10.0	506.8	92.1	24.0	12.4	24.0	92.1	189.7	520.1	303.9	526.3	181.2	20.4	292.9	207.0	130.6
Mass rate (kg/h)	67461	3159275	3915720	3915720	688984	3848259	17741	3208995	68862	340333	340333	423660	53518	546041	340347	83323	68032
Mole % Oxygen	0.00	20.82	13.16	13.16	13.68	19.53	0.00	13.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Nitrogen	1.47	77.60	75.78	75.78	78.82	77.98	0.00	75.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % CO2	0.68	0.03	3.75	3.75	2.71	0.75	0.00	3.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Methane	87.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Argon	0.00	0.93	0.86	0.86	0.90	0.89	0.00	0.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Ethane	7.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % Propane	2.94	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole % H2O	0.00	0.61	6.45	6.45	2.71	0.85	100.00	6.45	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Molar rate (kmol/hr)	3680	109505	136938	136938	23743	33696	985	112223	3821	18886	18886	23511	2970	30302	18887	4624	3775

REV	DATE	TITLE	BY	CHK	APP
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REVISIONS

CCS BENCHMARK REFRESH 2013

Turndown @ 40% Load

Power Generation

CASE: Natural Gas Combined Cycle Power Plant with 18% EGR without CO2 Capture

FOSTER WHEELER ENERGY

DWG. NO.: XXXX-XX-XXX

REV: 01

ATTACHMENT 3
UTILITY SUMMARIES

1. CCGT with 90% CO_2 Capture
   a. 100% Load
   b. 40% Load
2. CCGT without CO_2 Capture
   a. 100% Load
   b. 40% Load
3. CCGT with 35% EGR and 90% CO_2 Capture
   a. 100% Load
   b. 40% Load
4. CCGT with 35% EGR without CO_2 Capture
   a. 100% Load
   b. 40% Load
5. CCGT with 18% EGR and 90% CO_2 Capture
   a. 100% Load
   b. 40% Load
6. CCGT with 18% EGR without CO_2 Capture
   a. 100% Load
   b. 40% Load

FOSTER WHEELER ENERGY LIMITED
UTILITIES BALANCE SUMMARY

CCGT with 90% CO_2 Capture - 100% GT Load

CLIENT:	The Energy Technologies Institute								
CONTRACT:	13074	REV	O1	O2	O3				SHEET
NAME:	CCS Benchmark Refresh 2013	DATE	09/08/2013	24/09/2013	22/10/2013				1 OF 1
		ORIG. BY	SEF	SEF	SEF				
		APP. BY	TA	TA	TA				

	DESCRIPTION	ELECTRIC POWER (kWh/h)	Steam (T/h)			Condensate	Sea Cooling water	Fresh Cooling water	Process Water	Demin water	BFW	REMARKS	REV
		Electric Oper. Load	HP Steam 139 barg	MP Steam 26 barg	LP Steam 3 barg	T/h	T/h	T/h	T/h	T/h	T/h		
	Process Units												
	Acid Gas Removal Unit (MEA)	-40023	0	0	-495.0	495.0	0	-37846	-140	0	0	Note 4	
	CO_2 Compression & Drying	-31731	0	0	0	0	0	-4768	0	0	0		
	Process Units Total	-71754	0	0	-495	495	0	-42614	-140	0	0		
	Power Island												
	Gas Turbine (Note 1)	-8060	0	0	0	0	0	0	0	0	0		
	HRSGs	0	598.3	699.0	64.6	-1341.9	0	0	0	-8.5	0		
	Steam Turbine (Note 2)	-5158	-598.3	-699.0	430.4	846.9	-23892	0	0	0	0		
	Power Generation Units (Note 3)	967927	0	0	0	0	0	0	0	0	0		
	Power Island Total	954710	0	0	495	-495	-23892	0	0	-8.5	0		
	Offsites & Utilities												
	Demin Plant	-25								8.5			
	Sea Cooling Water	-8855					77136						
	Fresh Cooling Water	-2451					-53244	42614					
	Utility water	-12							140				
	Fire Water System	-40											
	Condensate Treatment	-58											
	Waste Water Treatment	-100											
	Flare	0											
	Storage	0											
	Buildings	-600											
	Others	0											
	Offsites & Utilities Total	-12140	0	0	0	0	23892	42614	140	8.5	0		
	Grand Total	**870816**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		

NOTES
1. Includes auxiliary and transformer losses.
2. Includes Steam and water cycle balance of plant and transformer losses.
3. Net of generator losses
4. 62.2 tph intermittent LPS required during solvent reclaimation mode.

FOSTER WHEELER ENERGY LIMITED
UTILITIES BALANCE SUMMARY

CCGT with 90% CO_2 Capture - 40% GT Load

CLIENT: The Energy Technologies Institute
CONTRACT: 13074
NAME: CCS Benchmark Refresh 2013

							SHEET
REV	O1						
DATE	22/10/2013						1 OF 1
ORIG. BY	SEF						
APP. BY	TA						

DESCRIPTION	ELECTRIC POWER (kWh/h)	Steam (T/h)			Condensate	Sea Cooling water	Fresh Cooling water	Process Water	Demin water	BFW	REMARKS	REV
	Electric Oper. Load	HP Steam 139 barg	MP Steam 26 barg	LP Steam 3 barg	T/h	T/h	T/h	T/h	T/h	T/h		
Process Units												
Acid Gas Removal Unit (MEA)	-31725	0	0	-254.4	254.4	0	-17383	-71	0	0	Note 4	
CO_2 Compression & Drying	-16123	0	0	0	0	0	-2422	0	0	0		
Process Units Total	-47847	0	0	-254	254	0	-19805	-71	0	0		
Power Island												
Gas Turbine (Note 1)	-6729	0	0	0	0	0	0	0	0	0		
HRSGs	0	334.2	419.9	49.8	-794.9	0	0	0	-5.4	0		
Steam Turbine (Note 2)	-2990	-334.2	-419.9	204.6	540.5	-17845	0	0	0	0		
Power Generation Units (Note 3)	421203	0	0	0	0	0	0	0	0	0		
Power Island Total	411483	0	0	254	-254	-17845	0	0	-5.4	0		
Offsites & Utilities												
Demin Plant	-25								5.4			
Sea Cooling Water	-4889					42624						
Fresh Cooling Water	-1148					-24779	19805					
Utility water	-12							71				
Fire Water System	-40											
Condensate Treatment	-58											
Waste Water Treatment	-100											
Flare	0											
Storage	0											
Buildings	-600											
Others	0											
Offsites & Utilities Total	-6873	0	0	0	0	17845	19805	71	5.4	0		
Grand Total	**356763**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		

NOTES
1. Includes auxiliary and transformer losses.
2. Includes Steam and water cycle balance of plant and transformer losses.
3. Net of generator losses
4. 62.2 tph intermittent LPS required during solvent reclaimation mode.

FOSTER WHEELER ENERGY LIMITED
UTILITIES BALANCE SUMMARY

CCGT without CO_2 Capture - 100% GT Load

CLIENT: The Energy Technologies Institute
CONTRACT: 13074
NAME: CCS Benchmark Refresh 2013

							SHEET
REV	O1	O2	O3				1 OF 1
DATE	09/08/2013	02/09/2013	22/10/2013				
ORIG. BY	SEF	SEF	SEF				
APP. BY	TA	TA	TA				

	DESCRIPTION	ELECTRIC POWER (kW)	Steam (T/h)			Condensate	Sea Cooling water	Fresh Cooling water	Process Water	Demin water	BFW	REMARKS	REV
		Electric Oper. Load	HP Steam 139 barg	MP Steam 26 barg	LP Steam 3 barg	T/h	T/h	T/h	T/h	T/h	T/h		
	Process Units												
	Acid Gas Removal Unit (MEA)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		
	CO_2 Compression & Drying	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		
	Process Units Total	0	0	0	0	0	0	0	0	0	0		
	Power Island												
	Gas Turbine (Note 1)	-8060	0	0	0	0	0	0	0	0	0		
	HRSGs	0	598.3	699.0	64.6	-846.9	0	0	0	8.5	0		
	Steam Turbine (Note 2)	-6469	-598.3	-699.0	-64.6	846.9	-49053	0	0	0	0		
	Power Generation Units (Note 3)	1067991	0.0	0.0	0.0	0.0	0.0	0	0	0	0		
	Power Island Total	1053463	0	0	0	0	-49053	0	0	8.5	0		
	Offsites & Utilities												
	Demin Plant	-25								-8.5			
	Sea Cooling Water	-5608					49053						
	Fresh Cooling Water	0											
	Utility water	0											
	Fire Water System	-40											
	Condensate Treatment	-58											
	Waste Water Treatment	-100											
	Flare	0											
	Storage	0											
	Buildings	-1000											
	Others	0											
	Offsites & Utilities Total	-6831	0	0	0	0	49053	0	0	-8.5	0		
	Grand Total	**1046631**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		

NOTES
1. Includes auxiliary and transformer losses.
2. Includes Steam and water cycle balance of plant and transformer losses.
3. Net of generator losses

FOSTER WHEELER ENERGY LIMITED
UTILITIES BALANCE SUMMARY

CCGT without CO_2 Capture - 40% GT Load

CLIENT: The Energy Technologies Institute
CONTRACT: 13074
NAME: CCS Benchmark Refresh 2013

							SHEET
REV	O1						1 OF 1
DATE	22/10/2013						
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APP. BY	TA						

DESCRIPTION	ELECTRIC POWER (kWh/h)	Steam (T/h)			Condensate	Sea Cooling water	Fresh Cooling water	Process Water	Demin water	BFW	REMARKS	REV
	Electric Oper. Load	HP Steam 139 barg	MP Steam 26 barg	LP Steam 3 barg	T/h	T/h	T/h	T/h	T/h	T/h		
Process Units												
Acid Gas Removal Unit (MEA)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		
CO_2 Compression & Drying	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		
Process Units Total	0	0	0	0	0	0	0	0	0	0		
Power Island												
Gas Turbine (Note 1)	-6729	0	0	0	0	0	0	0	0	0		
HRSGs	0	334.2	419.9	55.2	-545.8	0	0	0	-5.5	0		
Steam Turbine (Note 2)	-3658	-334.2	-419.9	-55.2	545.8	-31115	0	0	0	0		
Power Generation Units (Note 3)	295795	0	0	0	0	0	0	0	0	0		
Power Island Total	285408	0	0	0	0	-31115	0	0	-5.5	0		
Offsites & Utilities												
Demin Plant	-25.0								5.5			
Sea Cooling Water	-3556.8					31114.8						
Fresh Cooling Water	0.0											
Utility water	0.0											
Fire Water System	-40.0											
Condensate Treatment	-58.0											
Waste Water Treatment	-100.0											
Flare	0.0											
Storage	0.0											
Buildings	-1000.0											
Others	0.0											
Offsites & Utilities Total	-4780	0	0	0	0	31115	0	0	5.5	0		
Grand Total	**280628**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		

NOTES
1. Includes auxiliary and transformer losses.
2. Includes Steam and water cycle balance of plant and transformer losses.
3. Net of generator losses

FOSTER WHEELER ENERGY LIMITED
UTILITIES BALANCE SUMMARY

CCGT with 35% EGR & 90% CO_2 Capture - 100% GT Load

CLIENT:	The Energy Technologies Institute								
CONTRACT:	13074	REV	O1						SHEET
NAME:	CCS Benchmark Refresh 2013	DATE	22/10/2013						1 OF 1
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		APP. BY	TA						

	DESCRIPTION	ELECTRIC POWER (kWh/h)	Steam (T/h)			Condensate	Sea Cooling water	Fresh Cooling water	Process Water	Demin water	BFW	REMARKS	REV
		Electric Oper. Load	HP Steam 139 barg	MP Steam 26 barg	LP Steam 3 barg	T/h	T/h	T/h	T/h	T/h	T/h		
	Process Units												
	Acid Gas Removal Unit (MEA)	-26101	0	0	-461.5	461.5	0	-33305	-140	0	0	Note 4	
	CO_2 Compression & Drying	-31474	0	0	0	0	0	-4729	0	0	0		
	Process Units Total	-57576	0	0	-462	462	0	-38034	-140	0	0		
	Power Island												
	EGR Recycle Cooling	-339	0	0	0	0	0	-7394	78	0	0		
	Gas Turbine (Note 1)	-8013	0	0	0	0	0	0	0	0	0		
	HRSGs	0	611.3	699.1	58.7	-1300.4	0	0	0	-8.4	0		
	Steam Turbine (Note 2)	-5251	-611.3	-699.1	402.8	838.9	-24908	0	0	0	0		
	Power Generation Units (Note 3)	957114	0	0	0	0	0	0	0	0	0		
	Power Island Total	943512	0	0	462	-462	-24908	-7394	78	-8.4	0		
	Offsites & Utilities												
	Demin Plant	-25								8.4			
	Sea Cooling Water	-9384					81744						
	Fresh Cooling Water	-2636					-56836	45428					
	Utility water	-12							140				
	Fire Water System	-40											
	Condensate Treatment	-58											
	Waste Water Treatment	-100							-78				
	Flare	0											
	Storage	0											
	Buildings	-600											
	Others	0											
	Offsites & Utilities Total	-12855	0	0	0	0	24908	45428	62	8.4	0		
	Grand Total	**873081**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		

NOTES
1. Includes auxiliary and transformer losses.
2. Includes Steam and water cycle balance of plant and transformer losses.
3. Net of generator losses
4. 62.2 tph intermittent LPS required during solvent reclaimation mode.

FOSTER WHEELER ENERGY LIMITED
UTILITIES BALANCE SUMMARY

CCGT with 35% EGR & 90% CO_2 Capture - 40% GT Load

CLIENT: The Energy Technologies Institute
CONTRACT: 13074
NAME: CCS Benchmark Refresh 2013

REV	O1						SHEET
DATE	22/10/2013						1 OF 1
ORIG. BY	SEF						
APP. BY	TA						

DESCRIPTION	ELECTRIC POWER (kWh/h)	Steam (T/h)			Condensate	Sea Cooling water	Fresh Cooling water	Process Water	Demin water	BFW	REMARKS	REV
	Electric Oper. Load	HP Steam 139 barg	MP Steam 26 barg	LP Steam 3 barg	T/h	T/h	T/h	T/h	T/h	T/h		
Process Units												
Acid Gas Removal Unit (MEA)	-20793	0	0	-220.0	220.0	0	-14973	-71	0	0	Note 4	
CO_2 Compression & Drying	-15436	0	0	0	0	0	-2318	0	0	0		
Process Units Total	-36229	0	0	-220	220	0	-17292	-71	0	0		
Power Island												
EGR Recycle Cooling	-224	0	0	0	0	0	-4103	32	0	0		
Gas Turbine (Note 1)	-6682	0	0	0	0	0	0	0	0	0		
HRSGs	0	342.7	423.7	44.5	-755.3	0	0	0	-5.4	0		
Steam Turbine (Note 2)	-3169	-342.7	-423.7	175.6	535.2	-19195	0	0	0	0		
Power Generation Units (Note 3)	418662	0	0	0	0	0	0	0	0	0		
Power Island Total	408811	0	0	220	-220	-19195	-4103	32	-5.4	0		
Offsites & Utilities												
Demin Plant	-25								5.4			
Sea Cooling Water	-5273					45961						
Fresh Cooling Water	-1241					-26766	21395					
Utility water	-12							71				
Fire Water System	-40											
Condensate Treatment	-58											
Waste Water Treatment	-100							-32				
Flare	0											
Storage	0											
Buildings	-600											
Others	0											
Offsites & Utilities Total	-7349	0	0	0	0	19195	21395	39	5.4	0		
Grand Total	**365233**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		

NOTES

1. Includes auxiliary and transformer losses.
2. Includes Steam and water cycle balance of plant and transformer losses.
3. Net of generator losses
4. 62.2 tph intermittent LPS required during solvent reclaimation mode.

FOSTER WHEELER ENERGY LIMITED
UTILITIES BALANCE SUMMARY

CCGT with 35% EGR without CO_2 Capture - 100% GT Load

CLIENT: The Energy Technologies Institute
CONTRACT: 13074
NAME: CCS Benchmark Refresh 2013

							SHEET
REV	O1						1 OF 1
DATE	22/10/2013						
ORIG. BY	SEF						
APP. BY	TA						

DESCRIPTION	ELECTRIC POWER (kW)	Steam (T/h)			Condensate	Sea Cooling water	Fresh Cooling water	Process Water	Demin water	BFW	REMARKS	REV
	Electric Oper. Load	HP Steam 139 barg	MP Steam 26 barg	LP Steam 3 barg	T/h	T/h	T/h	T/h	T/h	T/h		
Process Units												
Acid Gas Removal Unit (MEA)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		
CO_2 Compression & Drying	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		
Process Units Total	0	0	0	0	0	0	0	0	0	0		
Power Island												
EGR Recycle Cooling	-229	0	0	0	0	-9166	0	78	0	0		
Gas Turbine (Note 1)	-8013	0	0	0	0	0	0	0	0	0		
HRSGs	0	610.0	703.2	59.1	-842.0	0	0	0	-8.4	0		
Steam Turbine (Note 2)	-6527	-610.0	-703.2	-59.1	842.0	-49030	0	0	0	0		
Power Generation Units (Note 3)	1054716	0	0	0	0	0	0	0	0	0		
Power Island Total	1039948	0	0	0	0	-58195	0	78	-8.4	0		
Offsites & Utilities												
Demin Plant	-25								8.4			
Sea Cooling Water	-6654					58195						
Fresh Cooling Water	0											
Utility water	0											
Fire Water System	-40											
Condensate Treatment	-58											
Waste Water Treatment	-100							-78				
Flare	0											
Storage	0											
Buildings	-1000											
Others	0											
Offsites & Utilities Total	-7877	0	0	0	0	58195	0	-78	8.4	0		
Grand Total	**1032071**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		

NOTES
1. Includes auxiliary and transformer losses.
2. Includes Steam and water cycle balance of plant and transformer losses.
3. Net of generator losses

FOSTER WHEELER ENERGY LIMITED
UTILITIES BALANCE SUMMARY

CCGT with 35% EGR without CO_2 Capture - 40% GT Load

CLIENT: The Energy Technologies Institute
CONTRACT: 13074
NAME: CCS Benchmark Refresh 2013

REV	O1						SHEET
DATE	22/10/2013						1 OF 1
ORIG. BY	SEF						
APP. BY	TA						

DESCRIPTION	ELECTRIC POWER (kWh/h)	Steam (T/h)			Condensate	Sea Cooling water	Fresh Cooling water	Process Water	Demin water	BFW	REMARKS	REV
	Electric Oper. Load	HP Steam 139 barg	MP Steam 26 barg	LP Steam 3 barg	T/h	T/h	T/h	T/h	T/h	T/h		
Process Units												
Acid Gas Removal Unit (MEA)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		
CO_2 Compression & Drying	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		
Process Units Total	0	0	0	0	0	0	0	0	0	0		
Power Island												
EGR Recycle Cooling	-148	0	0	0	0	-5190	0	32	0	0		
Gas Turbine (Note 1)	-6682	0	0	0	0	0	0	0	0	0		
HRSGs	0	342.4	423.7	51.9	-542.8	0	0	0	-5.4	0		
Steam Turbine (Note 2)	-3803	-342.4	-423.7	-51.9	542.8	-31219	0	0	0	0		
Power Generation Units (Note 3)	466073	0	0	0	0	0	0	0	0	0		
Power Island Total	455587	0	0	0	0	-36409	0	32	-5.4	0		
Offsites & Utilities												
Demin Plant	-25								5.4			
Sea Cooling Water	-4163					36409						
Fresh Cooling Water	0											
Utility water	0											
Fire Water System	-40											
Condensate Treatment	-58											
Waste Water Treatment	-100							-32				
Flare	0											
Storage	0											
Buildings	-1000											
Others	0											
Offsites & Utilities Total	-5386	0	0	0	0	36409	0	-32	5.4	0		
Grand Total	**450201**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		

NOTES
1. Includes auxiliary and transformer losses.
2. Includes Steam and water cycle balance of plant and transformer losses.
3. Net of generator losses

FOSTER WHEELER ENERGY LIMITED
UTILITIES BALANCE SUMMARY

CCGT with 18% EGR & 90% CO_2 Capture - 100% GT Load

CLIENT: The Energy Technologies Institute
CONTRACT: 13074
NAME: CCS Benchmark Refresh 2013

							SHEET
REV	O1						1 OF 1
DATE	22/10/2013						
ORIG. BY	SEF						
APP. BY	TA						

DESCRIPTION	ELECTRIC POWER (kWh/h)	Steam (T/h)			Condensate	Sea Cooling water	Fresh Cooling water	Process Water	Demin water	BFW	REMARKS	REV
	Electric Oper. Load	HP Steam 139 barg	MP Steam 26 barg	LP Steam 3 barg	T/h	T/h	T/h	T/h	T/h	T/h		
Process Units												
Acid Gas Removal Unit (MEA)	-32862	0	0	-479.2	479.2	0	-36538	-140	0	0	Note 4	
CO_2 Compression & Drying	-31714	0	0	0	0	0	-4765	0	0	0		
Process Units Total	-64576	0	0	-479	479	0	-41303	-140	0	0		
Power Island												
EGR Recycle Cooling	-175	0	0	0	0	0	-3762	40	0	0		
Gas Turbine (Note 1)	-8035	0	0	0	0	0	0	0	0	0		
HRSGs	0	604.3	701.8	61.8	-1323.3	0	0	0	-8.4	0		
Steam Turbine (Note 2)	-5229	-604.3	-701.8	417.4	844.2	-24671	0	0	0	0		
Power Generation Units (Note 3)	964195	0	0	0	0	0	0	0	0	0		
Power Island Total	950756	0	0	479	-479	-24671	-3762	40	-8.4	0		
Offsites & Utilities												
Demin Plant	-25								8.4			
Sea Cooling Water	-9304					81051						
Fresh Cooling Water	-2614					-56381	45065					
Utility water	-12							140				
Fire Water System	-40											
Condensate Treatment	-58											
Waste Water Treatment	-100							-40				
Flare	0											
Storage	0											
Buildings	-600											
Others	0											
Offsites & Utilities Total	-12753	0	0	0	0	24671	45065	100	8	0		
Grand Total	**873427**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		

NOTES
1. Includes auxiliary and transformer losses.
2. Includes Steam and water cycle balance of plant and transformer losses.
3. Net of generator losses
4. 62.2 tph intermittent LPS required during solvent reclaimation mode.

FOSTER WHEELER ENERGY LIMITED
UTILITIES BALANCE SUMMARY

CCGT with 18% EGR & 90% CO_2 Capture - 40% GT Load

CLIENT: The Energy Technologies Institute
CONTRACT: 13074
NAME: CCS Benchmark Refresh 2013

REV	O1						SHEET
DATE	22/10/2013						1 OF 1
ORIG. BY	SEF						
APP. BY	TA						

DESCRIPTION	ELECTRIC POWER (kWh/h)	Steam (T/h)			Condensate	Sea Cooling water	Fresh Cooling water	Process Water	Demin water	BFW	REMARKS	REV
	Electric Oper. Load	HP Steam 139 barg	MP Steam 26 barg	LP Steam 3 barg	T/h	T/h	T/h	T/h	T/h	T/h		
Process Units												
Acid Gas Removal Unit (MEA)	-26104	0	0	-235.7	235.7	0	-16466	-71	0	0	Note 4	
CO_2 Compression & Drying	-15763	0	0	0	0	0	-2367	0	0	0		
Process Units Total	-41867	0	0	-236	236	0	-18834	-71	0	0		
Power Island												
EGR Recycle Cooling	-118	0	0	0	0	0	-2138	17	0	0		
Gas Turbine (Note 1)	-6705	0	0	0	0	0	0	0	0	0		
HRSGs	0	337.2	419.8	47.3	-771.2	0	0	0	-5.4	0		
Steam Turbine (Note 2)	-3088	-337.2	-419.8	188.4	535.5	-18562	0	0	0	0		
Power Generation Units (Note 3)	420943	0	0	0	0	0	0	0	0	0		
Power Island Total	411150	0	0	236	-236	-18562	-2138	17	-5.4	0		
Offsites & Utilities												
Demin Plant	-25.0								5.4			
Sea Cooling Water	-5140.0					44800						
Fresh Cooling Water	-1216.8					-26238	20972					
Utility water	-12.0							71				
Fire Water System	-40.0											
Condensate Treatment	-58.0											
Waste Water Treatment	-100.0							-17				
Flare	0.0											
Storage	0.0											
Buildings	-600.0											
Others	0.0											
Offsites & Utilities Total	-7192	0	0	0	0	18562	20972	55	5	0		
Grand Total	**362091**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**		

NOTES
1. Includes auxiliary and transformer losses.
2. Includes Steam and water cycle balance of plant and transformer losses.
3. Net of generator losses
4. 62.2 tph intermittent LPS required during solvent reclaimation mode.

FOSTER WHEELER ENERGY LIMITED
UTILITIES BALANCE SUMMARY

CCGT with 18% EGR without CO_2 Capture - 100% GT Load

CLIENT:	The Energy Technologies Institute										
CONTRACT:	13074	REV	O1						SHEET		
NAME:	CCS Benchmark Refresh 2013	DATE	22/10/2013						1 OF 1		
		ORIG. BY	SEF								
		APP. BY	TA								

DESCRIPTION	ELECTRIC POWER (kW)	Steam (T/h)			Condensate	Sea Cooling water	Fresh Cooling water	Process Water	Demin water	BFW	REMARKS	REV
	Electric Oper. Load	HP Steam 139 barg	MP Steam 26 barg	LP Steam 3 barg	T/h	T/h	T/h	T/h	T/h	T/h		
Process Units												
Acid Gas Removal Unit (MEA)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		
CO_2 Compression & Drying	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		
Process Units Total	0	0	0	0	0	0	0	0	0	0		
Power Island												
EGR Recycle Cooling	-175	0	0	0	0	-4716	0	40	0	0		
Gas Turbine (Note 1)	-8035	0	0	0	0	0	0	0	0	0		
HRSGs	0	604.3	701.8	61.8	-844.2	0	0	0	8.4	0		
Steam Turbine (Note 2)	-6498	-604.3	-701.8	-61.8	844.2	-49030	0	0	0	0		
Power Generation Units (Note 3)	1061100	0	0	0	0	0	0	0	0	0		
Power Island Total	1046391	0	0	0	0	-53745	0	40	8.4	0		
Offsites & Utilities												
Demin Plant	-25								-8.4			
Sea Cooling Water	-5606					53745						
Fresh Cooling Water	0											
Utility water	0											
Fire Water System	-40											
Condensate Treatment	-58											
Waste Water Treatment	-100							-40				
Flare	0											
Storage	0											
Buildings	-1000											
Others	0											
Offsites & Utilities Total	-6829	0	0	0	0	53745	0	-40	-8.4	0		
Grand Total	**1039562**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**		

NOTES
1. Includes auxiliary and transformer losses.
2. Includes Steam and water cycle balance of plant and transformer losses.
3. Net of generator losses

FOSTER WHEELER ENERGY LIMITED
UTILITIES BALANCE SUMMARY

CCGT with 18% EGR without CO_2 Capture - 40% GT Load

CLIENT: The Energy Technologies Institute
CONTRACT: 13074
NAME: CCS Benchmark Refresh 2013

							SHEET
REV	O1						
DATE	22/10/2013						1 OF 1
ORIG. BY	SEF						
APP. BY	TA						

DESCRIPTION	ELECTRIC POWER (kWh/h)	Steam (T/h)			Condensate	Sea Cooling water	Fresh Cooling water	Process Water	Demin water	BFW	REMARKS	REV
	Electric Oper. Load	HP Steam 139 barg	MP Steam 26 barg	LP Steam 3 barg	T/h	T/h	T/h	T/h	T/h	T/h		
Process Units												
Acid Gas Removal Unit (MEA)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		
CO_2 Compression & Drying	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a		
Process Units Total	0	0	0	0	0	0	0	0	0	0		
Power Island												
EGR Recycle Cooling	-73	0	0	0	0	-2510	0	16	0	0		
Gas Turbine (Note 1)	-6705	0	0	0	0	0	0	0	0	0		
HRSGs	0	340.3	423.7	53.5	-546.0	0	0	0	-5.5	0		
Steam Turbine (Note 2)	-3797	-340.3	-423.7	-53.5	546.0	-31313	0	0	0	0		
Power Generation Units (Note 3)	473450	0	0	0	0	0	0	0	0	0		
Power Island Total	462875	0	0	0	0	-33823	0	16	-5.5	0		
Offsites & Utilities												
Demin Plant	-25								5.5			
Sea Cooling Water	-3867					33823						
Fresh Cooling Water	0											
Utility water	0											
Fire Water System	-40											
Condensate Treatment	-58											
Waste Water Treatment	-100							-16				
Flare	0											
Storage	0											
Buildings	-1000											
Others	0											
Offsites & Utilities Total	-5090	0	0	0	0	33823	0	-16	5	0		
Grand Total	**457784**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**		

NOTES
1. Includes auxiliary and transformer losses.
2. Includes Steam and water cycle balance of plant and transformer losses.
3. Net of generator losses

ATTACHMENT 4
CAPITAL COST ESTIMATES

1. CCGT with 90% CO_2 Capture
2. CCGT without CO_2 Capture
3. CCGT with 35% EGR and 90% CO_2 Capture
4. CCGT with 35% EGR without CO_2 Capture
5. CCGT with 18% EGR and 90% CO_2 Capture
6. CCGT with 18% EGR without CO_2 Capture

Project No : 13074
Client : ETI
Project : CCS Benchmark Refresh 2013
Location : UK

Rev : 1
Date : Jun-14
By : KN

CCGT with 90% Carbon Capture

COST CODE	DESCRIPTION		Acid Gas Removal Million's GBP	CO2 Compression (to 150 Bar) Million's GBP	Power Block Million's GBP	U&O Million's GBP	Total Million's GBP
	MAJOR EQUIPMENT		98.7	20.9	190.9	13.8	324.3
	DIRECT BULK MATERIALS		34.3	5.3	57.6	17.8	115.1
	DIRECT MATERIAL & LABOUR CONTRACTS		11.4	0.9	21.8	28.9	63.0
	LABOUR ONLY CONTRACTS		46.5	9.3	32.1	22.7	110.6
	INDIRECTS		14.7	2.9	21.9	5.4	44.8
	EPC CONTRACTS		25.1	4.7	14.6	10.0	54.4
	INSTALLED COST		230.7	44.0	338.9	98.7	712.3
	LAND COSTS	5%	11.5	2.2	16.9	4.9	35.6
	OWNERS COSTS	10%	23.1	4.4	33.9	9.9	71.2
	CONTINGENCY	25%	57.7	11.0	84.7	24.7	178.1
	TOTAL PROJECT COST		322.9	61.5	474.5	138.2	997.2

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneos 1 Q 2009

Project No : 13074
Client : ETI
Project : Carbon Capture Study
Location : UK

Rev : '1'
Date : JUNE 2014
By : KDN
Printed: 09-Jun-14

CCGT with 90% Carbon Capture
Acid Gas Removal

Equipment Number	Description	Cost Carried Forward 2009 Basis GBP	Comments
1/2BL-2301	Flue Gas Blower	10,702,400	
1~3C-2301	Direct contact cooler	9,328,500	
1~3C-2301P	Direct contact cooler Packing	6,528,600	SS Structured Packing
1~3C-2302	Absorption Column	9,637,700	
1~3C-2302P1	Absorption Packing 1	19,029,300	SS Structured Packing
1~3C-2302P2	Absorption Packing 2	2,779,700	SS Structured Packing
1/2C-2303	Stripper Column	1,298,200	
1/2C-2303T	Stripper Column Trays	281,500	
1/2V-2301	Stripper OH Separator	385,300	
1/2V-2302	Semi-Lean Solvent Flash Drum	190,800	
1/2V-2303	Flashed Gas KO Pot	77,900	
1~3E-2301	DCC Cooler	788,700	
1~3E-2302	Absorber Pump Around Cooler	68,600	
1/2E-2303	Cross Over Exchanger	6,892,200	
1~3E-2304	Lean Solvent Cooler	2,655,700	
1~3E-2305	Extraction Cooler	3,201,100	
1/2E-2306	First Flash Preheater	5,847,100	
1/2E-2307	Second Flash Preheater	3,275,100	
1/2E-2308	Semi Lean Flash Cooler	462,800	
1/2E-2309A~C	Stripper Reboiler	2,719,400	
1/2E-2310	Solvent Reclaimer	171,000	
1/2E-2311	Reflux Cooler	713,500	
1/2E-2312	Gas / Gas Exchanger (2 x 50% Train)	6,446,500	
1~3P-2301A/B	DCC Cooler Pump	221,900	
1~3P-2302A~D	Rich Solvent Pump	915,800	
1~3P-2303A~D	Lean Solvent Pump	1,296,000	
1~3P-2304A~C	Semi-Lean Solvent Pump	523,300	
1~3P-2305A~D	Extraction Pump	858,600	
1~3P-2306A/B	Absorber Pumparound Pump	212,200	
1/2P-2307A/B	Stripper Reflux Pump	154,100	
1/2F-2301	DCC Circulation Water Filter	93,400	
1/2F-2302	Absorber Wash Water Filter	180,000	
1/2F-2303	Lean Solvent Filter	645,800	
1/2PK-2301	Soda Ash Injection Package	90,000	
		98,672,700	

Back-escalation Factor: 0.90
USD/GBP: 0.66
EUR/GBP: 0.74

Project No : 13074
Client : ETI
Project : Carbon Capture Study
Location : UK

Rev : '1'
Date : JUNE 2014
By : KDN
Printed: 09-Jun-14

CCGT with 90% Carbon Capture
CO2 Compression

Equipment Number	Description	Cost Carried Forward 2009 Basis GBP	Comments
	CO2 Compression Package	18,682,900	
1/2K-2501-1	CO2 Compressor Stage 1	-	Part of CO2 Compression Package
1/2K-2501-2	CO2 Compressor Stage 2	-	Part of CO2 Compression Package
1/2K-2501-3	CO2 Compressor Stage 3	-	Part of CO2 Compression Package
1/2K-2501-4	CO2 Compressor Stage 4	-	Part of CO2 Compression Package
1/2K-2501-5	CO2 Compressor Stage 5	-	Part of CO2 Compression Package
1/2K-2501-6	CO2 Compressor Stage 6	-	Part of CO2 Compression Package
1/2K-2501-7	CO2 Compressor Stage 7	-	Part of CO2 Compression Package
1/2K-2501-8	CO2 Compressor Stage 8	-	Part of CO2 Compression Package
1/2V-2501	CO2 Compressor Stage 1 KO Pot	-	Part of CO2 Compression Package
1/2V-2502	CO2 Compressor Stage 2 KO Pot	-	Part of CO2 Compression Package
1/2V-2503	CO2 Compressor Stage 3 KO Pot	-	Part of CO2 Compression Package
1/2V-2504	CO2 Compressor Stage 4 KO Pot	-	Part of CO2 Compression Package
1/2V-2505	CO2 Compressor Stage 5 KO Pot	-	Part of CO2 Compression Package
1/2D-2501A/B	Dehydration Bed #1 & 2	-	Part of Drier Package
1/2E-2501	CO2 Compressor Stage 1 Cooler	-	Part of CO2 Compression Package
1/2E-2502	CO2 Compressor Stage 2 Cooler	-	Part of CO2 Compression Package
1/2E-2503	CO2 Compressor Stage 3 Cooler	-	Part of CO2 Compression Package
1/2E-2504	CO2 Compressor Stage 4 Cooler	-	Part of CO2 Compression Package
1/2E-2505	CO2 Compressor Stage 5 Cooler	-	Part of CO2 Compression Package
1/2E-2506	CO2 Compressor Stage 6 Cooler	-	Part of CO2 Compression Package
1/2E-2507	CO2 Compressor Stage 7 Cooler	-	Part of CO2 Compression Package
1/2E-2508	CO2 Product Cooler	1,070,300	
1/2E-2509	Regen. Gas Electric Heater	-	Part of Drier Package
1/2E-2510	Regen. Gas Feed/Product Exchanger	-	Part of Drier Package
1/2F-2501	Dehydration Fines Filter	-	Part of Drier Package
1/2F-2502	Regeneration Fines Filter	-	Part of Drier Package
1/2PK-2501	CO2 Drier Package	1,162,800	
		20,916,000	

Back-escalation Factor: 0.90
USD/GBP: 0.66
EUR/GBP: 0.74

Project No : 13074
Client : ETI
Project : Carbon Capture Study
Location : UK

Rev : '1'
Date : JUNE 2014
By : KDN
Printed: 09-Jun-14

CCGT with 90% Carbon Capture
Power Block

Equipment Number	Description	Cost Carried Forward 2009 Basis GBP	Comments
1/2GT-3201	Gas Turbine (2 x 50% Train)	112,372,100	Type M701F5 369.52MW
	HRSG (2 x 50% Train)	34,845,800	
1/2D-3201	Deaerator (2 x 50% Train)	-	Part of HRSG
1/2P-3201A/B	HP BFW Pumps (4 x 50% Train)	2,653,200	
1/2P-3202A/B	MP BFW Pumps (4 x 50% Train)	1,168,900	
1/2P-3203A/B	LP BFW Pumps (4 x 50% Train)	201,600	
1/2D-3204	HP Steam Drum (2 x 50% Train)	-	Part of HRSG
1/2D-3203	MP Steam Drum (2 x 50% Train)	-	Part of HRSG
1/2D-3202	LP Steam Drum (2 x 50% Train)	-	Part of HRSG
1/2E-3215	Fuel Gas Preheater (2 x 50% Train)	147,600	
1E-3301	Vacuum Condenser (1 x 100% Train)	10,896,600	
1P-3301A/B/C	Condensate Pumps (1 x 100% Train)	169,000	
	Continuous Blowdown Drum	41,600	
	Intermittent Blowdown Drum	260,800	
	GT Purge Vessel	829,000	
	Continuous Blowdown Cooler	71,600	
1ST-3301	Steam Turbine (1 x 100% Train)	27,285,200	
1Z-3201	Stack (1 x 100%)	-	Part of HRSG
		190,943,000	

Back-escalation Factor: 0.90
USD/GBP: 0.66
EUR/GBP: 0.74

Project No : 13074		Rev :	0
Client : ETI		Date :	Oct-13
Project : CCS Benchmark Refresh 2013		By :	AV
Location : UK			

CCGT with No Carbon Capture

COST CODE	DESCRIPTION		Power Block Million's GBP	U&O Million's GBP	Total Million's GBP
	MAJOR EQUIPMENT		190.9	8.5	199.4
	DIRECT BULK MATERIALS		57.6	10.6	68.2
	DIRECT MATERIAL & LABOUR CONTRACTS		21.8	18.5	40.3
	LABOUR ONLY CONTRACTS		32.1	8.3	40.4
	INDIRECTS		21.9	3.0	24.9
	EPC CONTRACTS		14.6	3.3	17.9
	INSTALLED COST		338.9	52.2	391.1
	LAND COSTS	5%	16.9	2.6	19.6
	OWNERS COSTS	10%	33.9	5.2	39.1
	CONTINGENCY	25%	84.7	13.0	97.8
	TOTAL PROJECT COST		474.5	73.0	547.5

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneos 1 Q 2009

Project No : 13074			Rev :	1
Client : ETI			Date :	Jun-14
Project : CCS Benchmark Refresh 2013			By :	KN
Location : UK				

CCGT with 35% EGR and 90% Carbon Capture

COST CODE	DESCRIPTION		Acid Gas Removal Million's GBP	CO2 Compression (to 150 Bar) Million's GBP	Power Block Million's GBP	U&O Million's GBP	Total Million's GBP
	MAJOR EQUIPMENT		75.3	20.9	197.6	13.0	306.8
	DIRECT BULK MATERIALS		26.2	5.3	59.6	16.7	107.8
	DIRECT MATERIAL & LABOUR CONTRACTS		8.7	0.9	22.5	27.3	59.4
	LABOUR ONLY CONTRACTS		35.5	9.3	33.2	20.2	98.2
	INDIRECTS		11.2	2.9	22.6	5.1	41.7
	EPC CONTRACTS		19.2	4.7	15.1	8.8	47.8
	INSTALLED COST		176.0	44.0	350.7	91.0	661.7
	LAND COSTS	5%	8.8	2.2	17.5	4.6	33.1
	OWNERS COSTS	10%	17.6	4.4	35.1	9.1	66.2
	CONTINGENCY	25%	44.0	11.0	87.7	22.8	165.4
	TOTAL PROJECT COST		246.4	61.5	491.0	127.4	926.4

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneos 1 Q 2009

Project No : 13074		Rev :	0
Client : ETI		Date :	Oct-13
Project : CCS Benchmark Refresh 2013		By :	AV
Location : UK			

CCGT with 35% EGR and No Carbon Capture

COST CODE	DESCRIPTION		Power Block Million's GBP	U&O Million's GBP	Total Million's GBP
	MAJOR EQUIPMENT		204.5	9.1	213.5
	DIRECT BULK MATERIALS		61.7	11.3	73.0
	DIRECT MATERIAL & LABOUR CONTRACTS		23.3	19.8	43.2
	LABOUR ONLY CONTRACTS		34.4	8.9	43.3
	INDIRECTS		23.4	3.2	26.6
	EPC CONTRACTS		15.6	3.5	19.1
	INSTALLED COST		362.9	55.9	418.8
	LAND COSTS	5%	18.1	2.8	20.9
	OWNERS COSTS	10%	36.3	5.6	41.9
	CONTINGENCY	25%	90.7	14.0	104.7
	TOTAL PROJECT COST		508.1	78.2	586.3

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneos 1 Q 2009

Project No : 13074		Rev :	1
Client : ETI		Date :	Jun-14
Project : CCS Benchmark Refresh 2013		By :	KN
Location : UK			

CCGT with 18% EGR and 90% Carbon Capture

COST CODE	DESCRIPTION		Acid Gas Removal **Million's GBP**	CO2 Compression (to 150 Bar) **Million's GBP**	Power Block **Million's GBP**	U&O **Million's GBP**	Total **Million's GBP**
	MAJOR EQUIPMENT		88.7	20.9	193.4	13.4	316.4
	DIRECT BULK MATERIALS		30.8	5.3	58.3	17.3	111.9
	DIRECT MATERIAL & LABOUR CONTRACTS		10.2	0.9	22.1	28.2	61.3
	LABOUR ONLY CONTRACTS		41.8	9.3	32.5	21.6	105.2
	INDIRECTS		13.2	2.9	22.1	5.3	43.4
	EPC CONTRACTS		22.6	4.7	14.8	9.5	51.6
	INSTALLED COST		207.3	44.0	343.2	95.3	689.8
	LAND COSTS	5%	10.4	2.2	17.2	4.8	34.5
	OWNERS COSTS	10%	20.7	4.4	34.3	9.5	69.0
	CONTINGENCY	25%	51.8	11.0	85.8	23.8	172.5
	TOTAL PROJECT COST		290.3	61.5	480.5	133.4	965.7

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneos 1 Q 2009

Project No : 13074	Rev :	0
Client : ETI	Date :	Oct-13
Project : CCS Benchmark Refresh 2013	By :	AV
Location : UK		

CCGT with 18% EGR and No Carbon Capture

COST CODE	DESCRIPTION		Power Block Million's GBP	U&O Million's GBP	Total Million's GBP
	MAJOR EQUIPMENT		200.3	8.9	209.2
	DIRECT BULK MATERIALS		60.5	11.1	71.5
	DIRECT MATERIAL & LABOUR CONTRACTS		22.8	19.4	42.3
	LABOUR ONLY CONTRACTS		33.7	8.7	42.4
	INDIRECTS		22.9	3.2	26.1
	EPC CONTRACTS		15.3	3.4	18.8
	INSTALLED COST		355.6	54.7	410.3
	LAND COSTS	5%	17.8	2.7	20.5
	OWNERS COSTS	10%	35.6	5.5	41.0
	CONTINGENCY	25%	88.9	13.7	102.6
	TOTAL PROJECT COST		497.8	76.6	574.5

Notes
1) Major Equipment is inclusive of costs up to FOB
2) Direct Bulk Materials includes Piping, Instrumentation, Electrical, Catalyst & Chemicals, Spares and Shipping costs
3) Direct Material & Labour Contracts includes Civil, Steelwork, Building and Protective Cover
4) Labour Only Contracts includes Mechanical, Electrical & Instrumentation, Pre-commisioning Trade Labour Support and Scaffolding Labour costs
5) Indirects includes Temporary Facilities, Heavy Lifts, Commissioning Services and Vendors Engineers
6) EPC Contracts covers Engineering, Procurement and Construction Management
7) Costs are instantaneos 1 Q 2009

ATTACHMENT 5
OPERATING COST ESTIMATES

Maintenance Costs

Task 1 – CCGT Benchmark Refresh

Complex Section	Maint %	CCGT w 90% CC 100% Load Capital Cost UK£ (Million)	CCGT w 90% CC 100% Load Maint. p.a UK£ (Million)	CCGT w 90% CC 40% Load Capital Cost UK£ (Million)	CCGT w 90% CC 40% Load Maint. p.a UK£ (Million)	CCGT No CC 100% Load Capital Cost UK£ (Million)	CCGT No CC 100% Load Maint. p.a UK£ (Million)	CCGT No CC 40% Load Capital Cost UK£(Million)	CCGT No CC 40% Load Maint. p.a UK£(Million)
AGR + CO2 Compression	2.5%	275	7	275	7	0	0	0	0
Power Island	5.0%	339	17	339	17	339	17	339	17
Common Facilities (offsites and utilities)	1.7%	99	2	99	2	52	1	52	1
TOTAL		712	**25.5**	712	**25.5**	391	**17.8**	391.1	**17.8**
		Overall Maint. % =		Overall Maint. % =		Overall Maint. % =		Overall Maint. % =	
		3.58		3.58		4.56		4.56	

Task 2 – EGR Benchmark @ 35% EGR

Complex Section	Maint %	CCGT w 35% EGR 90% CC 100% Load Capital Cost UK£(Million)	CCGT w 35% EGR 90% CC 100% Load Maint. p.a UK£(Million)	CCGT w 35% EGR 90% CC 40% Load Capital Cost UK£(Million)	CCGT w 35% EGR 90% CC 40% Load Maint. p.a UK£(Million)	CCGT w 35% EGR No CC 100% Load Capital Cost UK£(Million)	CCGT w 35% EGR No CC 100% Load Maint. p.a UK£(Million)	CCGT w 35% EGR No CC 40% Load Capital Cost UK£(Million)	CCGT w 35% EGR No CC 40% Load Maint. p.a UK£(Million)
AGR + CO2 Compression	2.5%	220	6	220	6	0	0	0	0
Power Island	5.0%	351	18	351	18	363	18	363	18
Common Facilities (offsites and utilities)	1.7%	91	2	91	2	56	1	56	1
TOTAL		662	**24.6**	662	**24.6**	419	**19.1**	419	**19.1**
		Overall Maint. % =		Overall Maint. % =		Overall Maint. % =		Overall Maint. % =	
		3.71		3.71		4.56		4.56	

Task 2 – EGR Benchmark @ 18% EGR

Complex Section	Maint %	CCGT w 18% EGR 90% CC 100% Load Capital Cost UK£(Million)	CCGT w 18% EGR 90% CC 100% Load Maint. p.a UK£(Million)	CCGT w 18% EGR 90% CC 40% Load Capital Cost UK£ (Million)	CCGT w 18% EGR 90% CC 40% Load Maint. p.a UK£ (Million)	CCGT w 18% EGR No CC 100% Load Capital Cost UK£ (Million)	CCGT w 18% EGR No CC 100% Load Maint. p.a UK£ (Million)	CCGT w 18% EGR No CC 40% Load Capital Cost UK£(Million)	CCGT w 18% EGR No CC 40% Load Maint. p.a UK£(Million)
AGR + CO2 Compression	2.5%	251	6	251	6	0	0	0	0
Power Island	5.0%	343	17	343	17	356	18	356	18
Common Facilities (offsites and utilities)	1.7%	95	2	95	2	55	1	55	1
TOTAL		690	**25.1**	690	**25.1**	410	**18.7**	410.3	**18.7**
		Overall Maint. % =		Overall Maint. % =		Overall Maint. % =		Overall Maint. % =	
		3.63		3.63		4.56		4.56	

Total Operating and Maintenance Costs

Task 1 – CCGT Benchmark Refresh

	Task 1 - CCGT Benchmark Refresh			
	CCGT w 90% CC 100% Load	CCGT w 90% CC 40% Load	CCGT No CC 100% Load	CCGT No CC 40% Load
	Million UK£ p.a	Million UK£ p.a	Million UK£ p.a	Million UK£ p.a
Fixed Costs				
Direct Labour	3.00	3.00	2.00	2.00
Administration / General Overheads	0.90	0.90	0.60	0.60
Maintenance	25.49	25.49	17.83	17.83
Insurance & Local Taxes Allowance	14.25	14.25	7.82	7.82
SUB TOTAL	**43.6**	**43.6**	**28.3**	**28.3**
Variable Costs				
Feedstock	268.4	136.2	268.4	136.2
Solvent, Catalysts and Chemicals	1.41	0.73	0.00	0.00
Waste Disposal	0.00	0.00	0.00	0.00
TOTAL	**313.4**	**180.5**	**296.6**	**164.4**

Task 2 – EGR Benchmark @ 35% EGR

	Task 2 - EGR Benchmark @ 35%			
	CCGT w 35% EGR 90% CC 100% Load	CCGT w 35% EGR 90% CC 40% Load	CCGT w 35% EGR No CC 100% Load	CCGT w 35% EGR No CC 40% Load
	Million UK£ p.a	Million UK£ p.a	Million UK£ p.a	Million UK£ p.a
Fixed Costs				
Direct Labour	3.00	3.00	2.00	2.00
Administration / General Overheads	0.90	0.90	0.60	0.60
Maintenance	24.58	24.58	19.10	19.10
Insurance & Local Taxes Allowance	13.23	13.23	8.38	8.38
SUB TOTAL	**41.7**	**41.7**	**30.1**	**30.1**
Variable Costs				
Feedstock	265.8	130.2	265.8	130.2
Solvent, Catalysts and Chemicals	1.40	0.72	0.00	0.00
Waste Disposal	0.00	0.00	0.00	0.00
TOTAL	**308.9**	**172.7**	**295.9**	**160.3**

Task 2 – EGR Benchmark @ 18% EGR

	Task 2 - EGR Benchmark @ 18%			
	CCGT w 18% EGR 90% CC 100% Load	CCGT w 18% EGR 90% CC 40% Load	CCGT w 18% EGR No CC 100% Load	CCGT w 18% EGR No CC 40% Load
	Million UK£ p.a	Million UK£ p.a	Million UK£ p.a	Million UK£ p.a
Fixed Costs				
Direct Labour	3.00	3.00	2.00	2.00
Administration / General Overheads	0.90	0.90	0.60	0.60
Maintenance	25.06	25.06	18.71	18.71
Insurance & Local Taxes Allowance	13.80	13.80	8.21	8.21
SUB TOTAL	**42.8**	**42.8**	**29.5**	**29.5**
Variable Costs				
Feedstock	267.0	133.2	267.0	133.2
Solvent, Catalysts and Chemicals	1.41	0.73	0.00	0.00
Waste Disposal	0.00	0.00	0.00	0.00
TOTAL	**311.1**	**176.7**	**296.5**	**162.7**

ATTACHMENT 6
TECHNICAL PERFORMANCE REPORT

ATTACHMENT 7
EQUIPMENT LISTS

1. CCGT with 90% CO2 Capture
2. CCGT without CO_2 Capture
3. CCGT with 35% EGR and 90% CO_2 Capture
4. CCGT with 35% EGR without CO_2 Capture
5. CCGT with 18% EGR and 90% CO_2 Capture
6. CCGT with 18% EGR without CO_2 Capture

FOSTER WHEELER
ENERGY LTD
READING

EQUIPMENT LIST - CCGT CASE with 90% CCS & 0% EGR

REV	BY	APPROVED	DATE
ORIG			
01	SEF		10/09/2013
02			
03			

UNIT NAME:	MEA Unit & CO2 Compression
UNIT No.:	100
CLIENT:	The Energies Technology Institute
PROJECT:	CCS BENCHMARK REFRESH 2013
CONTRACT	13074
DOCUMENT No.:	
CASE SUMMARY	Natural Gas Combined Cycle Power Plant with 90% Post Combustion CO2 Capture

NOTES

FOSTER WHEELER ENERGY LTD.	EQUIPMENT LIST FOR COMPRESSORS	Rev.	ORIG	REV 01	REV 02	
	Client: The Energies Technology Institute — Contract No: 13074	Ch'd	SEF			SHEET 2 of 8
	Description: CCS BENCHMARK REFRESH 2013	App.	SEF			
	Unit No: 2300/2500 MEA Unit & CO2 Compression	Date	10/09/2013			

EQUIPMENT NUMBER	DESCRIPTION	COMPRESSOR TYPE(1)/ SUB-TYPE	No.off x DUTY %	DRIVE TYPE OP./SPARE	ACTUAL CAPACITY m^3/hr	Cp/Cv INLET/ OUTLET	DIFF. PRESS. bar	PRESSURE INLET/OUTLET bara bara	TURB.DRIVE STEAM PRESS. barg	COMPRESSIBILITY INLET/OUTLET	POWER EST/RATED kW	MATERIAL CASING	MOLECULAR WEIGHT	REMARKS	REV
1/2 BL-2301	Flue Gas Blower	Blower	2 x 50%	electric	2,663,319	1.379 / 1.376	0.22	1.04 / 1.25	n/a	0.999 / 0.999	17683	304 SS	28.37		01
1/2 K-2501-1	CO2 Compressor Stage 1	Centrifugal	2 x 50%	electric	11,402	1.284 / 1.278	0.38	1.10 / 1.48	n/a	0.994 / 0.994	129	304 SS	42.67		01
1/2 K-2501-2	CO2 Compressor Stage 2	Centrifugal	2 x 50%	electric	69,830	1.286 / 1.272	1.4	1.38 / 2.80	n/a	0.992 / 0.991	2502	304 SS	43.23		01
1/2 K-2501-3	CO2 Compressor Stage 3	Centrifugal	2 x 50%	electric	34,143	1.296 / 1.284	2.7	2.7 / 5.4	n/a	0.985 / 0.983	2341	304 SS	43.71		01
1/2 K-2501-4	CO2 Compressor Stage 4	Centrifugal	2 x 50%	electric	17,042	1.313 / 1.304	6.2	5.3 / 11.5	n/a	0.970 / 0.966	2590	CS	43.85		01
1/2 K-2501-5	CO2 Compressor Stage 5	Centrifugal	2 x 50%	electric	8,462	1.360 / 1.362	14	11.4 / 25.0	n/a	0.934 / 0.928	2809	CS	43.92		01
1/2 K-2501-6	CO2 Compressor Stage 6	Centrifugal	2 x 50%	electric	3,340	1.493 / 1.512	31	23.9 / 55.0	n/a	0.859 / 0.856	2490	CS	44.00		01
1/2 K-2501-7	CO2 Compressor Stage 7	Centrifugal	2 x 50%	electric	1,016	2.883 / 2.439	45	54.9 / 100.0	n/a	0.602 / 0.645	1250	CS	44.00		01
1/2 K-2501-8	CO2 Compressor Stage 8	Centrifugal	2 x 50%	electric	512	4.318 / 2.887	51	99.9 / 151.0	n/a	0.500 / 0.578	795	CS	44.00		01

Notes: **1. AC - Air Compressor GC - Gas Compressor FN - Fan**

FOSTER WHEELER ENERGY LTD.

EQUIPMENT LIST FOR VESSELS

Client:	The Energies Technology Institute	Contract No: 13074	Rev.	ORIG	REV 01	REV 02
Description:	CCS BENCHMARK REFRESH 2013		Ch'd	SEF		
Unit No:	2300/2500	MEA Unit & CO2 Compression	App.	SEF		
			Date	10/09/2010		

EQUIPMENT NUMBER	DESCRIPTION	VESSEL TYPE(1)/ SUB-TYPE	No.off x DUTY %	DIMENSIONS ID m	DIMENSIONS HEIGHT T/T m	TOTAL VOLUME m^3	V/H (2)	DESIGN CONDITIONS TEMP ^oC	DESIGN CONDITIONS PRESS barg	DESIGN CONDITIONS VACUUM FVPRESS bara	INTERNALS TYPE/No.OFF PACKED VOL. m^3 / PACKED HGT mm	MATERIALS OF CONST'N SHELL MAT./LINING/ CA	MATERIALS OF CONST'N INTERNALS MAT./LINING/ CA	REMARKS	REV
1/2/3 C-2301	Direct contact cooler	TW	3 x 33%	14.77	29.53	5901.24	V	107	3.5	1.013	Random Packing 916 10000	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding	Packing: 10m Mellapak 250X	01
1/2/3 C-2302	Absorption Column	TW	3 x 33%	15.58	27.00	6134	V	75	3.5	1.013	Random Packing 2670 / 390 14000 / 2000	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding	Packing: 14m Mellapak 250X / 2m Mellapak 250Y	01
1/2 C-2303	Stripper Column	TW	2 x 50%	7.51	17.20	872	V	143	3.5	1.013	Trays / 14	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2301	Stripper OH Separator	VT	2 x 50%	3.53	7.06	81	V	55	3.5	1.013	Wire Mesh Pad 0.98 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2302	Semi-Lean Solvent Flash Drum	VT	2 x 50%	2.61	5.22	33	V	128	3.5	1.013	Wire Mesh Pad 0.54 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2303	Flashed Gas KO Pot	VT	2 x 50%	1.44	2.88	5.5	V	60.0	3.5	1.013	Wire Mesh Pad 0.16 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2501	CO2 Compressor Stage 1 KO Pot	VT	2 x 50%	1.33	2.66	4.3	V	49.0	3.5	1.013	Wire Mesh Pad 0.14 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2502	CO2 Compressor Stage 2 KO Pot	VT	2 x 50%	3.18	6.36	58.9	V	49	3.5	1.013	Wire Mesh Pad 0.79 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2503	CO2 Compressor Stage 3 KO Pot	VT	2 x 50%	2.40	4.80	25.3	V	49	4.7	1.013	Wire Mesh Pad 0.45 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2504	CO2 Compressor Stage 4 KO Pot	VT	2 x 50%	2.00	4.00	14.7	V	49	11.4	1.013	Wire Mesh Pad 0.31 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01

Notes:

1. TW - Single Diameter Tower DDT - Double Diameter Tower HT - Horizontal Tank AT - Agitated Tank VT - Vertical Tank

2. V - Vertical H - Horizontal

FOSTER WHEELER ENERGY LTD.	EQUIPMENT LIST FOR VESSELS			Rev.	ORIG	REV 01	REV 02	
	Client:	The Energies Technology Institute	Contract No: 13074	Ch'd	SEF			SHEET 4 of 8
	Description:	CCS BENCHMARK REFRESH 2013		App.	SEF			
	Unit No:	2300/2500	MEA Unit & CO2 Compression	Date	10/09/2010			

EQUIPMENT NUMBER	DESCRIPTION	VESSEL TYPE(1)/ SUB-TYPE	No.off x DUTY %	DIMENSIONS ID m	DIMENSIONS HEIGHT T/T m	TOTAL VOLUME m^3	V/H (2)	DESIGN CONDITIONS TEMP ^oC	DESIGN CONDITIONS PRESS barg	DESIGN CONDITIONS VACUUM FVPRESS bara	INTERNALS TYPE/No.OFF PACKED VOL. m^3 / PACKED HGT mm	MATERIALS OF CONST'N SHELL MAT./LINING/ CA	MATERIALS OF CONST'N INTERNALS MAT./LINING/ CA	REMARKS	REV
1/2 V-2305	CO2 Compressor Stage 5 KO Pot	VT	2 x 50%	1.60	3.20	7.5	V	49	26.3	1.013	Wire Mesh Pad 0.20 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 D-2501 A/B	Dehydration Bed #1 & 2	VT	4 x 25%								Molecular Sieve / /			By Drier Package Vendor	

Notes:
1. TW - Single Diameter Tower DDT - Double Diameter Tower HT - Horizontal Tank AT - Agitated Tank VT - Vertical Tank
2. V - Vertical H - Horizontal

FOSTER WHEELER ENERGY LTD.	EQUIPMENT LIST FOR HEAT EXCHANGERS	Rev.	ORIG	REV 01	REV 02	
	Client: The Energies Technology Institute Contract No: 13074	Ch'd	SEF			SHEET 5 of 8
	Description: CCS BENCHMARK REFRESH 2013	App.	SEF			
	Unit No: 2300/2500 MEA Unit & CO2 Compression	Date	16/09/2010			

EQUIPMENT NUMBER	DESCRIPTION	EXCHANGER TYPE(1)/ SUB-TYPE	No.off x DUTY %	No.OF SHELLS (ST)	TEMA TYPE(ST)/ HEADER CONST(AC) (2)	RATE(3) kg/hr	DUTY MW	HEAT T'FER AREA(6) m^2	DESIGN CONDITIONS COLDSIDE(4) TEMP/PRESS ^oC / barg	HOTSIDE TEMP/PRESS ^oC /barg	MATERIAL PLATE/ SHELL	TUBE(ST/AC) HEAD(AC)	No.OF BAYS/FANS (AC)	FAN TYPES (5)	TOTAL FAN POWER kW	REMARKS	REV
1/2 E-3216	Gas/Gas Heat Exchanger	HE	2 x 50%	1	n/a	2563702	26.3	16531	105.0 / 4.7	141.4 / 3.5	CS	CS	n/a		n/a	like a combustion air preheater	01
1/2/3 E-2301	DCC Cooler	HE	3 x 33%	1	n/a	96676	1.2	934	49.0 / 4.7 (tubeside)	75.1 / 3.5	CS with 3mm min 304L cladding	316L	n/a		n/a		01
1/2/3 E-2302	Absorber Pump Around Cooler	HE	3 x 33%	1	n/a	12321	0.3	18	49.0 / 4.7 (tubeside)	66.8 / 3.5	CS	CS	n/a		n/a		01
1/2 E-2303	Cross Over Exchanger	HE	2 x 50%	1	n/a	2731311	114.9	21867	118.0 / 5.3	124.7 / 6.5	316L	316L	n/a		n/a	Plate & Frame	01
1/2/3 E-2304	Lean Solvent Cooler	HE	3 x 33%	4	n/a	4076281	48.7	2906	49.0 / 4.7 (tubeside)	82.8 / 5.5	316L	316L	n/a		n/a		01
1/2/3 E-2305	Extraction Cooler	HE	3 x 33%	4	n/a	4972952	59.5	3737	49.0 / 4.7 (tubeside)	79.6 / 4.2	316L	316L	n/a		n/a		01
1/2 E-2306	First Flash Preheater	HE	2 x 50%	4	n/a	1170562	37.0	11080	108.0 / 4.2 (tubeside)	128.1 / 5.3	316L	316L	n/a		n/a		01
1/2 E-2307	Second Flash Preheater	HE	2 x 50%	4	n/a	1170562	51.6	5957	128.0 / 3.5 (tubeside)	142.7 / 5.2	316L	316L	n/a		n/a		01
1/2 E-2308	Semi Lean Flash Cooler	HE	2 x 50%	4	n/a	1782565	21.3	528	49.0 / 4.7 (tubeside)	128.0 / 3.5	316L	316L	n/a		n/a		01
1/2 E-2309 A/B/C	Stripper Reboiler	RB	6 x 17%	3	n/a	946212	57.4	1391	142.7 / 3.5	325.0 / 4.7 (tubeside)	316L	316L	n/a		n/a		01
1/2 E-2310	Solvent Reclaimer	RB	2 x 50%	1	n/a	76581	34.5	230	173.9 / 3.5	172.9 / 6.2 (tubeside)	CS with 3mm min 304L cladding	316L	n/a		n/a	intermittent duty	01

Notes: **1. C - Condenser HE - Heat Exchanger RB - Reboiler STB - Steam Boiler 2. For Air Coolers CP - Cover Plate PT - Plug Type MT - Manifold Type BT - Billet Type**

3. Rate = Total Fluid Entering Coldside And Applies To Condensers, Boilers And Heaters. 4. Coldside Design Temp Equals Design Air Temp. For Air Coolers 5. I - Induced F - Forced

6. For Air-Coolers, this is Bare Tube Area

FOSTER WHEELER ENERGY LTD.	EQUIPMENT LIST FOR HEAT EXCHANGERS		Rev.	ORIG	REV 01	REV 02	
	Client:	The Energies Technology Institute Contract No: 13074	Ch'd	SEF			SHEET 6 of 8
	Description:	CCS BENCHMARK REFRESH 2013	App.	SEF			
	Unit No:	2300/2500 MEA Unit & CO2 Compression	Date	10/09/2010			

EQUIPMENT NUMBER	DESCRIPTION	EXCHANGER TYPE(1)/ SUB-TYPE	No.off x DUTY %	No.OF SHELLS (ST)	TEMA TYPE(ST)/ HEADER CONST(AC) (2)	RATE(3) kg/hr	DUTY MW	HEAT T'FER AREA(6) m^2	DESIGN CONDITIONS COLDSIDE(4) TEMP/PRESS °C / barg	DESIGN CONDITIONS HOTSIDE TEMP/PRESS °C /barg	MATERIAL PLATE/ SHELL	MATERIAL TUBE(ST/AC) HEAD(AC)	No.OF BAYS/FANS (AC)	FAN TYPE (5)	TOTAL FAN POWER kW	REMARKS	REV
1/2 E-2311	Reflux Cooler	HE	2 x 50%	2	n/a	3389602	40.5	1151	49.0 / 4.7 (tubeside)	115.8 / 3.5	CS with 3mm min 304L cladding	316L	n/a	n/a	n/a		01
1/2 E-2501	CO2 Compressor Stage 1 Cooler	HE	2 x 50%	1	n/a	31094	0.4	91	49.0 / 4.7 (tubeside)	84.7 / 3.5	CS with 3mm min 304L cladding	316L	n/a	n/a	n/a		01
1/2 E-2502	CO2 Compressor Stage 2 Cooler	HE	2 x 50%	1	n/a	306447	3.7	603	49.0 / 4.7 (tubeside)	114.5 / 3.5	CS with 3mm min 304L cladding	316L	n/a	n/a	n/a		01
1/2 E-2503	CO2 Compressor Stage 3 Cooler	HE	2 x 50%	1	n/a	226364	2.7	481	49.0 / 4.7 (tubeside)	##### / 6.1	CS with 3mm min 304L cladding	316L	n/a	n/a	n/a		01
1/2 E-2504	CO2 Compressor Stage 4 Cooler	HE	2 x 50%	1	n/a	285572	3.4	557	49.0 / 4.7 (tubeside)	115.2 / 12.2	CS with 3mm min 304L cladding	316L	n/a	n/a	n/a		01
1/2 E-2505	CO2 Compressor Stage 5 Cooler	HE	2 x 50%	1	n/a	304910	3.6	582	49.0 / 4.7 (tubeside)	117.5 / 26.5	CS with 6mm CA	316L	n/a	n/a	n/a		01
1/2 E-2506	CO2 Compressor Stage 6 Cooler	HE	2 x 50%	1	n/a	404316	4.8	717	49.0 / 4.7 (tubeside)	125.4 / 59	CS with 6mm CA	316L	n/a	n/a	n/a		01
1/2 E-2507	CO2 Compressor Stage 7 Cooler	HE	2 x 50%	1	n/a	191536	2.3	203	49 / 4.7 (tubeside)	100.0 / 105	CS with 6mm CA	316L	n/a	n/a	n/a		01
1/2 E-2508	CO2 Product Cooler	HE	2 x 50%	1	n/a	634358	7.6	999	49.0 / 4.7 (tubeside)	109.9 / 158	CS with 6mm CA	316L	n/a	n/a	n/a		01
1/2 E-2509	Regen. Gas Electric Heater	HE	2 x 50%													By Drier Package Vendor	
1/2E-2510	Regen. Gas Feed/Product Exchanger	HE	2 x 50%													By Drier Package Vendor	

Notes:
1. C - Condenser HE - Heat Exchanger RB - Reboiler STB - Steam Boiler 2. For Air Coolers CP - Cover Plate PT - Plug Type MT - Manifold Type BT - Billet Type
3. Rate = Total Fluid Entering Coldside And Applies To Condensers, Boilers And Heaters. 4. Coldside Design Temp Equals Design Air Temp. For Air Coolers 5. I - Induced F - Forced
6. For Air-Coolers, this is Bare Tube Area

FOSTER WHEELER ENERGY LTD.	EQUIPMENT LIST FOR PUMPS				Rev.	ORIG	REV 01	REV 02	
	Client:	The Energies Technology Institute	Contract No:	13074	Ch'd	SEF			SHEET 7 of 8
	Description:	CCS BENCHMARK REFRESH 2013			App.	SEF			
	Unit No:	2300/2500	MEA Unit & CO2 Compression		Date	10/09/2010			

EQUIPMENT NUMBER	DESCRIPTION	PUMP TYPE(1)/ SUB-TYPE	No.off x DUTY %	DRIVE TYPE (2) OP./SPARE	DESIGN CAPACITY m^3/hr	PUMP EFFIC'Y %	DIFF PRESSURE kPa	TURB. DRIVE STEAM P barg	OPERATING CONDS TEMP / SG / VISC'Y °C		cP	DESIGN CONDITIONS TEMP/PRESS °C	barg	POWER EST/RATED kW	MATERIAL CASING/ROTOR	REMARKS	REV
1/2/3 P-2301 A/B	DCC Cooler Pump	Centrifugal	6 x 33%	electric	28		379		50.0	0.988	0.544	75.0	5.35	3.9	316L SS / 316L SS	number of items tbc	01
1/2/3 P-2302 A/B/C/D	Rich Solvent Pump	Centrifugal	12 x 11%	electric	851		352		52.0	1.05	1.093	77.0	5.00	119	CS / CS	number of items tbc	01
1/2/3 P-2303 A/B/C/D	Lean Solvent Pump	Centrifugal	8 x 16.5%	electric	943		418		103.5	0.993	0.411	128.5	6.57	146	316L SS / 316L SS	number of items tbc	01
1/2/3 P-2304 A/B/C	Semi-Lean Solvent Pump	Centrifugal	6 x 25%	electric	608		224		103.0	1.013	0.427	128.0	3.59	50	CS / CS	number of items tbc	01
1/2/3 P-2305 A/B/C/D	Extraction Pump	Centrifugal	12 x 11%	electric	851		252		51.6	1.039	1.107	76.6	3.64	80	CS / CS	number of items tbc	01
1/2/3 P-2306 A/B	Absorber Pumparound Pump	Centrifugal	6 x 33%	electric	14		126		41.8	0.993	0.669	66.8	1.97	0.05	316L SS / 316L SS	number of items tbc	01
1/2 P-2306 A/B	Stripper Reflux Pump	Centrifugal	4 x 50%	electric	57		147		30.0	1.052	0.844	55.0	2.70	1.9	316L SS / 316L SS	number of items tbc	01

Notes: **1. Differential pressure to be confirmed after column design**

FOSTER WHEELER ENERGY LTD.	EQUIPMENT LIST FOR PACKAGE EQUIPMENT				Rev.	ORIG	REV 01	REV 02	
	Client:	The Energies Technology Institute	Contract No:	13074	Ch'd	SEF			SHEET 8 of 8
	Description:	CCS BENCHMARK REFRESH 2013			App.	SEF			
	Unit No:	2300/2500	MEA Unit & CO2 Compression		Date	10/09/2010			

EQUIPMENT NUMBER	DESCRIPTION	EQUIPMENT TYPE(1)/ SUB-TYPE	No.off x DUTY %	DRIVE TYPE (2) OP./SPARE	DIMENSIONS DIAM./HGT/ LENGTH mm	AREA mm^2	CAPACITY m^3	FLOW kg/hr	PRESS OPER./DIFF. barg / bar	DESIGN CONDS. TEMP/PRESS °C / barg	POWER EST/RATED kW	MATERIAL BODY/CA	COOL.TOWER WBT °C / APP °C / CWT °C (3)	REMARKS	REV
1/2 F-2301	DCC Circulation Water Filter	F	2 x 50%				3	25251	3.85 / 0.7			Shell: 304L SS Internals: 304 SS		Packing = Activated Carbon	01
1/2 F-2302	Absorber Wash Water Filter	F	2 x 50%				12.4	12321.1	0.122 / 0.1			Shell: 304L SS Internals: 304 SS		Packing = Activated Carbon	01
1/2 F-2303	Lean Solvent Filter	F	2 x 50%				103	102108	0.387 / 0.1			Shell: 304L SS Internals: 304 SS		Packing = Activated Carbon	01
1/2 F-2501	Dehydration Fines Filter	F	2 x 50%											By Drier Package Vendor	
1/2 F-2502	Regeneration Fines Filter	F	2 x 50%											By Drier Package Vendor	
1/2 PK-2301	Soda Ash Injection Package		2 x 50%												01
1/2 PK-2501	CO2 Drier Package	Mol Sieve	2 x 50%				3519 m3/h	183420 kg/h 0.075 wt% water	24.9 / 0.9					Product spec <50 ppmv water	01

Notes:
1. AD - Air Dryer CRY - Crystallizer CTW - Cooling Tower D - Dryer DC - Dust Collector DD - Drum Dryer E - Evaporator EG - Electrical Generator EJ - Ejector F - Filter FLR - Flare Stack HU - Heating Unit RD - Rotary Dryer RU - Refrigeration Unit STK - Stack TDS - Tray Drying System WFE - Wiped Film Evaporator WTS - Water Treatment System
2. VFD - Variable Frequency Motor Driver
3. WBT - Wet Bulb Temperature APP - Approach Temperature CWT - Cooling Water Inlet Temperature

FOSTER WHEELER ENERGY	CLIENT: ETI ECT TITLE: CCS BENCHMARK REFRESH 2013 CONTRACT: 13074	REVISION	0	1	2	3
		DATE	Sep-13			
		BY	RR			
		CHECKED	SEF			
		APPROVED				

CASE: NGCC POWER PLANT WITH 90% POST COMBUSTION CO_2 CAPTURE AND 0% EXHAUST GAS RECYCLE

Train	Item	Description	Specification	Remarks
1 - 2	GT-3201	Gas Turbine (2 x 50% Train)	369.52 MWe Output Turbine generator	MHI M701F5 machine
1 - 2		HRSG (2 x 50% Train)	409.76 MW Duty (14 Coils)	
1 - 2	D-3201	Deaerator (2 x 50% Train)	436.75 tph	part of HRSG package
1 - 2	P-3201 A/B	HP BFW Pumps (4 x 50% Train)	1443.3 kW, 330.6 m3/h, 28.4 barg suction, 139.0 barg discharge, CS	
1 - 2	P-3202 A/B	MP BFW Pumps (4 x 50% Train)	445.46 kW 431.8 m3/h, 3.34 barg suction, 28.4 barg discharge, CS	
1 - 2	P-3203 A/B	LP BFW Pumps (4 x 50% Train)	38.5 kW 477.9 m3/h, 2.49 barg suction, 3.34 barg discharge, CS	
1 - 2	D-3204	HP Steam Drum (2 x 50% Train)	299.13 tph	part of HRSG package
1 - 2	D-3203	MP Steam Drum (2 x 50% Train)	50.37 tph	part of HRSG package
1 - 2	D-3202	LP Steam Drum (2 x 50% Train)	42.13 tph	part of HRSG package
1 - 2	E-3215	Fuel Gas Preheater (2 x 50% Train)	8871 kW Duty, 68004 kg/h process stream flow, 326 m2 heat transfer area, Carbon Steel	
1 - 2	E-3216	Gas / Gas Exchanger (2 x 50% Train)	26330 kW Duty, 26.33MW, 2330288 kg/h flow, 16531 m3 heat transfer area	
1	E-3301	Vacuum Condenser (1 x 100% Train)	846.86 tph condensate; 3.5 kPa (abs), 470.51 MW, 48,556 m2 heat transfer area, Carbon Steel	REF. duty = 371.8 MW
1	P-3301 A/B/C	Condensate Pumps (1 x 100% Train)	423.43 tph condensate, 420.5 m3/h, 115.9 kW, -0.978 barg suction, 5.53 barg discharge, CS	
1	ST-3301	Steam Turbine (1 x 100% Train)	229.25 MWe Output Turbine generator; 140 bar, 566 ^oC; 27 bar, 565 ^oC; 4.2 bar, 292 ^oC	
1 - 2	Z-3201	Stack (2 x 50%)		part of HRSG package

FOSTER WHEELER ENERGY	CLIENT: ETI ECT TITLE: CCS BENCHMARK REFRESH 2013 CONTRACT: 13074	REVISION	0	1	2	3
		DATE	Sep-13			
		BY	RR			
		CHECKED	SEF			
		APPROVED				

CASE: NGCC POWER PLANT WITH 0% POST COMBUSTION CO_2 CAPTURE AND 0% EXHAUST GAS RECYCLE

Train	Item	Description	Specification	Remarks
1 - 2	GT-3201	Gas Turbine (2 x 50% Train)	369.52 MWe Output Turbine generator	MHI M701F5 machine
1 - 2		HRSG (2 x 50% Train)	409.76 MW Duty (14 Coils)	
1 - 2	D-3201	Deaerator (2 x 50% Train)	436.75 tph	part of HRSG package
1 - 2	P-3201 A/B	HP BFW Pumps (4 x 50% Train)	1443.3 kW, 330.6 m3/h, 28.4 barg suction, 139.0 barg discharge, CS	
1 - 2	P-3202 A/B	MP BFW Pumps (4 x 50% Train)	445.46 kW 431.8 m3/h, 3.34 barg suction, 28.4 barg discharge, CS	
1 - 2	P-3203 A/B	LP BFW Pumps (4 x 50% Train)	38.5 kW 477.9 m3/h, 2.49 barg suction, 3.34 barg discharge, CS	
1 - 2	D-3204	HP Steam Drum (2 x 50% Train)	299.13 tph	part of HRSG package
1 - 2	D-3203	MP Steam Drum (2 x 50% Train)	50.37 tph	part of HRSG package
1 - 2	D-3202	LP Steam Drum (2 x 50% Train)	42.13 tph	part of HRSG package
1 - 2	E-3215	Fuel Gas Preheater (2 x 50% Train)	8871 kW Duty, 68004 kg/h process stream flow, 326 m2 heat transfer area, Carbon Steel	
1	E-3301	Vacuum Condenser (1 x 100% Train)	846.86 tph condensate; 3.5 kPa (abs), 470.51 MW, 48,556 m2 heat transfer area, Carbon Steel	REF. duty = 371.8 MW
1	P-3301 A/B/C	Condensate Pumps (1 x 100% Train)	423.43 tph condensate, 420.5 m3/h, 115.9 kW, -0.978 barg suction, 5.53 barg discharge, CS	
1	ST-3301	Steam Turbine (1 x 100% Train)	328.9 MWe Output Turbine generator; 140 bar, 566 ^oC; 27 bar, 565 ^oC; 4.2 bar, 292 ^oC	
1 - 2	Z-3201	Stack (2 x 50%)		part of HRSG package

FOSTER WHEELER
ENERGY LTD
READING

EQUIPMENT LIST - CCGT CASE with 90% CCS & 35% EGR

REV	BY	APPROVED	DATE
ORIG			
01	SEF		07/10/2013
02			
03			

UNIT NAME:	MEA Unit
UNIT No.:	100
CLIENT:	The Energies Technology Institute
PROJECT:	CCS BENCHMARK REFRESH 2013
CONTRACT	13074
DOCUMENT No.:	
CASE SUMMARY	Natural Gas Combined Cycle Power Plant with 90% Post Combustion CO2 Capture 35% EGR
NOTES	

FOSTER WHEELER ENERGY LTD.	EQUIPMENT LIST FOR COMPRESSORS			Rev.	ORIG	REV 01	REV 02	SHEET 2 of 8
	Client:	The Energies Technology Institute	Contract No: 13074	Ch'd	SEF			
	Description:	CCS BENCHMARK REFRESH 2013		App.	SEF			
	Unit No:	2300/2500 MEA Unit		Date	07/10/2013			

EQUIPMENT NUMBER	DESCRIPTION	COMPRESSOR TYPE(1)/ SUB-TYPE	No.off x DUTY %	DRIVE TYPE OP./SPARE	ACTUAL CAPACITY m^3/hr	Cp/Cv INLET/ OUTLET	DIFF. PRESS. bar	PRESSURE INLET/OUTLET bara bara	TURB.DRIVE STEAM PRESS. barg	COMPRESSIBILITY INLET/OUTLET	POWER EST/RATED kW	MATERIAL CASING	MOLECULAR WEIGHT	REMARKS	REV
1/2 BL-2301	Flue Gas Blower	Blower	2 x 50%	electric	1,686,654	1.374 / 1.372	0.22	1.03 / 1.25	n/a	0.999 / 0.999	11196	304 SS	28.56		01
1/2 K-2501-1	CO2 Compressor Stage 1	Centrifugal	2 x 50%	electric	12,005	1.287 / 1.278	0.38	1.10 / 1.48	n/a	0.994 / 0.994	136	304 SS	42.67		01
1/2 K-2501-2	CO2 Compressor Stage 2	Centrifugal	2 x 50%	electric	69,212	1.286 / 1.272	1.4	1.38 / 2.80	n/a	0.992 / 0.991	2480	304 SS	43.23		01
1/2 K-2501-3	CO2 Compressor Stage 3	Centrifugal	2 x 50%	electric	33,849	1.296 / 1.284	2.7	2.7 / 5.4	n/a	0.985 / 0.983	2321	304 SS	43.71		01
1/2 K-2501-4	CO2 Compressor Stage 4	Centrifugal	2 x 50%	electric	16,895	1.313 / 1.304	6.2	5.3 / 11.5	n/a	0.970 / 0.966	2568	CS	43.85		01
1/2 K-2501-5	CO2 Compressor Stage 5	Centrifugal	2 x 50%	electric	8,381	1.360 / 1.362	14	11.4 / 25.0	n/a	0.934 / 0.928	2782	CS	43.92		01
1/2 K-2501-6	CO2 Compressor Stage 6	Centrifugal	2 x 50%	electric	3,308	1.493 / 1.512	31	23.9 / 55.0	n/a	0.859 / 0.856	2466	CS	44.00		01
1/2 K-2501-7	CO2 Compressor Stage 7	Centrifugal	2 x 50%	electric	1,006	2.884 / 2.440	45	54.9 / 100.0	n/a	0.602 / 0.645	1238	CS	44.00		01
1/2 K-2501-8	CO2 Compressor Stage 8	Centrifugal	2 x 50%	electric	507	4.320 / 2.887	51	99.9 / 151.0	n/a	0.500 / 0.578	787	CS	44.00		01

Notes: **1. AC - Air Compressor GC - Gas Compressor FN - Fan**

FOSTER WHEELER ENERGY LTD.	EQUIPMENT LIST FOR VESSELS	Rev.	ORIG	REV 01	REV 02	
	Client: The Energies Technology Institute Contract No: 13074	Ch'd	SEF			SHEET 3 of 8
	Description: CCS BENCHMARK REFRESH 2013	App.	SEF			
	Unit No: 2300/2500 MEA Unit	Date	07/10/2013			

EQUIPMENT NUMBER	DESCRIPTION	VESSEL TYPE(1)/ SUB-TYPE	No.off x DUTY %	DIMENSIONS ID m	DIMENSIONS HEIGHT T/T m	TOTAL VOLUME m^3	V/H (2)	DESIGN CONDITIONS TEMP ^oC	DESIGN CONDITIONS PRESS barg	DESIGN CONDITIONS VACUUM FVPRESS bara	INTERNALS TYPE/No.OFF PACKED VOL. m^3 / PACKED HGT mm	MATERIALS OF CONST'N SHELL MAT./LINING/ CA	MATERIALS OF CONST'N INTERNALS MAT./LINING/ CA	REMARKS	REV
1/2/3 C-2301	Direct contact cooler	TW	3 x 33%	11.79	23.58	3004.89	V	109	3.5	1.013	Random Packing 916 10000	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding	Packing: 10m Mellapak 250X	01
1/2/3 C-2302	Absorption Column	TW	3 x 33%	12.39	27.00	3754	V	75	3.5	1.013	Random Packing 1690 / 250 14000 / 2000	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding	Packing: 14m Mellapak 250X / 2m Mellapak 250Y	01
1/2 C-2303	Stripper Column	TW	2 x 50%	7.51	17.20	874	V	142	3.5	1.013	Trays / 14	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2301	Stripper OH Separator	VT	2 x 50%	3.50	7.00	78	V	55	3.5	1.013	Wire Mesh Pad 0.96 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2302	Semi-Lean Solvent Flash Drum	VT	2 x 50%	2.67	5.34	35	V	128	3.5	1.013	Wire Mesh Pad 0.56 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2303	Flashed Gas KO Pot	VT	2 x 50%	1.48	2.96	6.0	V	60.0	3.5	1.013	Wire Mesh Pad 0.17 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2501	CO2 Compressor Stage 1 KO Pot	VT	2 x 50%	1.37	2.74	4.7	V	49.0	3.5	1.013	Wire Mesh Pad 0.15 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2502	CO2 Compressor Stage 2 KO Pot	VT	2 x 50%	3.17	6.33	58.1	V	49	3.5	1.013	Wire Mesh Pad 0.79 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2503	CO2 Compressor Stage 3 KO Pot	VT	2 x 50%	2.66	4.80	31.6	V	49	4.7	1.013	Wire Mesh Pad 0.56 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2504	CO2 Compressor Stage 4 KO Pot	VT	2 x 50%	2.30	4.00	19.8	V	49	11.4	1.013	Wire Mesh Pad 0.42 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01

Notes:

1. TW - Single Diameter Tower DDT - Double Diameter Tower HT - Horizontal Tank AT - Agitated Tank VT - Vertical Tank

2. V - Vertical H - Horizontal

FOSTER WHEELER ENERGY LTD.

EQUIPMENT LIST FOR VESSELS

Client:	The Energies Technology Institute	Contract No:	13074		
Description:	CCS BENCHMARK REFRESH 2013				
Unit No:	2300/2500	MEA Unit			

Rev.	ORIG	REV 01	REV 02
Ch'd	SEF		
App.	SEF		
Date	07/10/2013		

EQUIPMENT NUMBER	DESCRIPTION	VESSEL TYPE(1)/ SUB-TYPE	No.off x DUTY %	DIMENSIONS ID m	HEIGHT T/T m	TOTAL VOLUME m^3	V/H (2)	DESIGN CONDITIONS TEMP ^oC	PRESS barg	VACUUM FVPRESS bara	INTERNALS TYPE/No.OFF PACKED VOL. m^3 / PACKED HGT mm	MATERIALS OF CONST'N SHELL MAT./LINING/ CA	INTERNALS MAT./LINING/ CA	REMARKS	REV
1/2 V-2305	CO2 Compressor Stage 5 KO Pot	VT	2 x 50%	1.86	3.20	10.4	V	49	26.3	1.013	Wire Mesh Pad 0.27 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 D-2501 A/B	Dehydration Bed #1 & 2	VT	4 x 25%								Molecular Sieve / /			By Drier Package Vendor	

Notes:
1. TW - Single Diameter Tower DDT - Double Diameter Tower HT - Horizontal Tank AT - Agitated Tank VT - Vertical Tank
2. V - Vertical H - Horizontal

FOSTER WHEELER ENERGY LTD.	**EQUIPMENT LIST FOR HEAT EXCHANGERS**	Rev.	ORIG	REV 01	REV 02	
	Client: The Energies Technology Institute **Contract No:** 13074	Ch'd	SEF			**SHEET** 5 **of** 8
	Description: CCS BENCHMARK REFRESH 2013	App.	SEF			
	Unit No: 2300/2500 MEA Unit	Date	07/10/2013			

EQUIPMENT NUMBER	DESCRIPTION	EXCHANGER TYPE(1)/ SUB-TYPE	No.off x DUTY %	No.OF SHELLS (ST)	TEMA TYPE(ST)/ HEADER CONST(AC) (2)	RATE(3) kg/hr	DUTY MW	HEAT T'FER AREA(6) m^2	DESIGN CONDITIONS COLDSIDE(4) TEMP/PRESS °C / barg	DESIGN CONDITIONS HOTSIDE TEMP/PRESS °C /barg	MATERIAL PLATE/ SHELL	MATERIAL TUBE(ST/AC) HEAD(AC)	No.OF BAYS/FANS (AC)	FAN TYPES (5)	TOTAL FAN POWER kW	REMARKS	REV
1/2 E-3216	Gas/Gas Heat Exchanger	HE	2 x 50%	1	n/a	1634637	16.0	9768	105.0 / 4.7	141.2 / 3.5	CS	CS	n/a		n/a	like a combustion air preheater	01
1/2/3 E-2301	DCC Cooler	HE	3 x 33%	1	n/a	99231	1.2	943	49.0 / 4.7 (tubeside)	75.9 / 3.5	CS with 3mm min 304L cladding	316L	n/a		n/a		01
1/2/3 E-2302	Absorber Pump Around Cooler	HE	3 x 33%	1	n/a	12212	0.3	18	49.0 / 4.7 (tubeside)	67.5 / 3.5	CS	CS	n/a		n/a		01
1/2 E-2303	Cross Over Exchanger	HE	2 x 50%	1	n/a	2452756	104.0	26504	118.0 / 5.3	123.2 / 6.5	316L	316L	n/a		n/a	Plate & Frame	01
1/2/3 E-2304	Lean Solvent Cooler	HE	3 x 33%	4	n/a	3351872	40.1	2475	49.0 / 4.7 (tubeside)	80.7 / 5.5	316L	316L	n/a		n/a		01
1/2/3 E-2305	Extraction Cooler	HE	3 x 33%	4	n/a	4049507	48.4	3154	49.0 / 4.7 (tubeside)	77.6 / 4.2	316L	316L	n/a		n/a		01
1/2 E-2306	First Flash Preheater	HE	2 x 50%	4	n/a	1051181	33.6	10112	108.0 / 4.2 (tubeside)	128.1 / 5.3	316L	316L	n/a		n/a		01
1/2 E-2307	Second Flash Preheater	HE	2 x 50%	4	n/a	1051181	50.2	7348	128.0 / 3.5 (tubeside)	142.9 / 5.2	316L	316L	n/a		n/a		01
1/2 E-2308	Semi Lean Flash Cooler	HE	2 x 50%	4	n/a	1860026	22.2	551	49.0 / 4.7 (tubeside)	128.0 / 3.5	316L	316L	n/a		n/a		01
1/2 E-2309 A/B/C	Stripper Reboiler	RB	6 x 17%	3	n/a	850703	55.2	1338	142.9 / 3.5	325.0 / 4.7 (tubeside)	316L	316L	n/a		n/a		01
1/2 E-2310	Solvent Reclaimer	RB	2 x 50%	1	n/a	68314	34.5	205	173.9 / 3.5	172.9 / 6.2 (tubeside)	CS with 3mm min 304L cladding	316L	n/a		n/a	intermittent duty	01

Notes:

1. C - Condenser HE - Heat Exchanger RB - Reboiler STB - Steam Boiler 2. For Air Coolers CP - Cover Plate PT - Plug Type MT - Manifold Type BT - Billet Type

3. Rate = Total Fluid Entering Coldside And Applies To Condensers, Boilers And Heaters. 4. Coldside Design Temp Equals Design Air Temp. For Air Coolers 5. I - Induced F - Forced

6. For Air-Coolers, this is Bare Tube Area

FOSTER WHEELER ENERGY LTD.	EQUIPMENT LIST FOR HEAT EXCHANGERS	Rev.	ORIG	REV 01	REV 02	
	Client: The Energies Technology Institute Contract No: 13074	Ch'd	SEF			SHEET 6 of 8
	Description: CCS BENCHMARK REFRESH 2013	App.	SEF			
	Unit No: 2300/2500 MEA Unit	Date	07/10/2013			

EQUIPMENT NUMBER	DESCRIPTION	EXCHANGER TYPE(1)/ SUB-TYPE	No.off x DUTY %	No.OF SHELLS (ST)	TEMA TYPE(ST)/ HEADER CONST(AC) (2)	RATE(3) kg/hr	DUTY MW	HEAT T'FER AREA(6) m^2	DESIGN CONDITIONS COLDSIDE(4) TEMP/PRESS °C / barg	DESIGN CONDITIONS HOTSIDE TEMP/PRESS °C /barg	MATERIAL PLATE/ SHELL	MATERIAL TUBE(ST/AC) HEAD(AC)	No.OF BAYS/FANS (AC)	FAN TYPE (5)	TOTAL FAN POWER kW	REMARKS	REV
1/2 E-2311	Reflux Cooler	HE	2 x 50%	2	n/a	3541527	42.4	1195	49.0 / 4.7 (tubeside)	116.6 / 3.5	CS with 3mm min 304L cladding	316L	n/a	n/a	n/a		01
1/2 E-2501	CO2 Compressor Stage 1 Cooler	HE	2 x 50%	1	n/a	32727	0.4	95	49.0 / 4.7 (tubeside)	84.7 / 3.5	CS with 3mm min 304L cladding	316L	n/a	n/a	n/a		01
1/2 E-2502	CO2 Compressor Stage 2 Cooler	HE	2 x 50%	1	n/a	303368	3.6	597	49.0 / 4.7 (tubeside)	114.5 / 3.5	CS with 3mm min 304L cladding	316L	n/a	n/a	n/a		01
1/2 E-2503	CO2 Compressor Stage 3 Cooler	HE	2 x 50%	1	n/a	224452	2.7	478	49.0 / 4.7 (tubeside)	###### / 6.1	CS with 3mm min 304L cladding	316L	n/a	n/a	n/a		01
1/2 E-2504	CO2 Compressor Stage 4 Cooler	HE	2 x 50%	1	n/a	282867	3.4	552	49.0 / 4.7 (tubeside)	115.2 / 12.2	CS with 3mm min 304L cladding	316L	n/a	n/a	n/a		01
1/2 E-2505	CO2 Compressor Stage 5 Cooler	HE	2 x 50%	1	n/a	302072	3.6	577	49.0 / 4.7 (tubeside)	117.5 / 26.5	CS with 6mm CA	316L	n/a	n/a	n/a		01
1/2 E-2506	CO2 Compressor Stage 6 Cooler	HE	2 x 50%	1	n/a	400581	4.8	711	49.0 / 4.7 (tubeside)	125.4 / 59	CS with 6mm CA	316L	n/a	n/a	n/a		01
1/2 E-2507	CO2 Compressor Stage 7 Cooler	HE	2 x 50%	1	n/a	189793	2.3	201	49 / 4.7 (tubeside)	100.0 / 105	CS with 6mm CA	316L	n/a	n/a	n/a		01
1/2 E-2508	CO2 Product Cooler	HE	2 x 50%	1	n/a	628434	7.5	991	49.0 / 4.7 (tubeside)	109.9 / 158	CS with 6mm CA	316L	n/a	n/a	n/a		01
1/2 E-2509	Regen. Gas Electric Heater	HE	2 x 50%													By Drier Package Vendor	
1/2E-2510	Regen. Gas Feed/Product Exchanger	HE	2 x 50%													By Drier Package Vendor	

Notes:
1. C - Condenser HE - Heat Exchanger RB - Reboiler STB - Steam Boiler 2. For Air Coolers CP - Cover Plate PT - Plug Type MT - Manifold Type BT - Billet Type
3. Rate = Total Fluid Entering Coldside And Applies To Condensers, Boilers And Heaters. 4. Coldside Design Temp Equals Design Air Temp. For Air Coolers 5. I - Induced F - Forced
6. For Air-Coolers, this is Bare Tube Area

PROJECT No.: 13074

FOSTER WHEELER ENERGY LTD.

EQUIPMENT LIST FOR PUMPS

Client:	The Energies Technology Institute	**Contract No:**	13074		
Description:	CCS BENCHMARK REFRESH 2013				
Unit No:	2300/2500 MEA Unit				

Rev.	**ORIG**	**REV 01**	**REV 02**
Ch'd	SEF		
App.	SEF		
Date	07/10/2013		

EQUIPMENT NUMBER	DESCRIPTION	PUMP TYPE(1)/ SUB-TYPE	No.off x DUTY %	DRIVE TYPE (2) OP./SPARE	DESIGN CAPACITY m^3/hr	PUMP EFFIC'Y %	DIFF PRESSURE kPa	TURB. DRIVE STEAM P barg	OPERATING CONDS TEMP / SG / VISC'Y °C		cP	DESIGN CONDITIONS TEMP/PRESS °C	barg	POWER EST/RATED kW	MATERIAL CASING/ROTOR	REMARKS	REV
1/2/3 P-2301 A/B	DCC Cooler Pump	Centrifugal	6 x 33%	electric	37		379		50.9	0.988	0.536	75.9	5.35	5.1	316L SS / 316L SS	number of items tbc	01
1/2/3 P-2302 A/B/C/D	Rich Solvent Pump	Centrifugal	12 x 11%	electric	814		353		51.4	1.052	1.114	76.4	5.00	106	CS / CS	number of items tbc	01
1/2/3 P-2303 A/B/C/D	Lean Solvent Pump	Centrifugal	8 x 16.5%	electric	839		419		98.1	0.995	0.448	123.1	6.57	130	316L SS / 316L SS	number of items tbc	01
1/2/3 P-2304 A/B/C	Semi-Lean Solvent Pump	Centrifugal	6 x 25%	electric	541		224		103.0	1.014	0.431	128.0	3.59	45	CS / CS	number of items tbc	01
1/2/3 P-2305 A/B/C/D	Extraction Pump	Centrifugal	12 x 11%	electric	759		253		52.6	1.045	1.101	77.6	3.65	71	CS / CS	number of items tbc	01
1/2/3 P-2306 A/B	Absorber Pumparound Pump	Centrifugal	6 x 33%	electric	14		126		42.5	0.993	0.660	67.5	1.97	0.05	316L SS / 316L SS	number of items tbc	01
1/2 P-2306 A/B	Stripper Reflux Pump	Centrifugal	4 x 50%	electric	60		147		30.0	1.052	0.844	55.0	2.70	2.0	316L SS / 316L SS	number of items tbc	01

Notes: **1. Differential pressure to be confirmed after column design**

FOSTER WHEELER ENERGY LTD.	EQUIPMENT LIST FOR PACKAGE EQUIPMENT			Rev.	ORIG	REV 01	REV 02	
	Client:	The Energies Technology Institute	Contract No: 13074	Ch'd	SEF			SHEET 8 of 8
	Description:	CCS BENCHMARK REFRESH 2013		App.	SEF			
	Unit No:	2300/2500	MEA Unit	Date	07/10/2013			

EQUIPMENT NUMBER	DESCRIPTION	EQUIPMENT TYPE(1)/ SUB-TYPE	No.off x DUTY %	DRIVE TYPE (2) OP./SPARE	DIMENSIONS DIAM./HGT/ LENGTH mm	AREA mm^2	CAPACITY m^3	FLOW kg/hr	PRESS OPER./DIFF. barg / bar	DESIGN CONDS. TEMP/PRESS °C / barg	POWER EST/RATED kW	MATERIAL BODY/CA	COOL.TOWER WBT °C / APP °C / CWT °C (3)	REMARKS	REV
1/2 F-2301	DCC Circulation Water Filter	F	2 x 50%				3	33088	3.85 / 0.7			Shell: 304L SS Internals: 304 SS		Packing = Activated Carbon	01
1/2 F-2302	Absorber Wash Water Filter	F	2 x 50%				12.3	12212.3	0.122 / 0.1			Shell: 304L SS Internals: 304 SS		Packing = Activated Carbon	01
1/2 F-2303	Lean Solvent Filter	F	2 x 50%				92	91085	0.387 / 0.1			Shell: 304L SS Internals: 304 SS		Packing = Activated Carbon	01
1/2 F-2501	Dehydration Fines Filter	F	2 x 50%											By Drier Package Vendor	
1/2 F-2502	Regeneration Fines Filter	F	2 x 50%											By Drier Package Vendor	
1/2 PK-2301	Soda Ash Injection Package		2 x 50%												01
1/2 PK-2501	CO2 Drier Package	Mol Sieve	2 x 50%				3486.08 m3/h	181692 kg/h 0.075 wt% water	24.9 / 0.9					Product spec <50 ppmv water	01

Notes: 1. AD - Air Dryer CRY - Crystallizer CTW - Cooling Tower D - Dryer DC - Dust Collector DD - Drum Dryer E - Evaporator EG - Electrical Generator EJ - Ejector F - Filter
FLR - Flare Stack HU - Heating Unit RD - Rotary Dryer RU - Refrigeration Unit STK - Stack TDS - Tray Drying System WFE - Wiped Film Evaporator WTS - Water Treatment System
2. VFD - Variable Frequency Motor Driver
3. WBT - Wet Bulb Temperature APP - Approach Temperature CWT - Cooling Water Inlet Temperature

FOSTER WHEELER ENERGY	CLIENT: ETI	REVISION	0	1	2	3
	ECT TITLE: CCS BENCHMARK REFRESH 2013	DATE	Oct-13			
	ONTRACT: 13074	BY	SEF			
		CHECKED				
		APPROVED				

CASE: NGCC POWER PLANT WITH 90% POST-COMBUSTION CO_2 CAPTURE AND 35% EXHAUST GAS RECYCLE

Train	Item	Description	Specification	Remarks
1 - 2	GT-3201	Gas Turbine (2 x 50% Train)	361.68 MWe Output Turbine generator	MHI M701F5 machine
1 - 2		HRSG (2 x 50% Train)	410.54 MW Duty (14 Coils)	
1 - 2	D-3201	Deaerator (2 x 50% Train)	435.26 tph	part of HRSG package
1 - 2	P-3201 A/B	HP BFW Pumps (4 x 50% Train)	1471.6 kW, 333.2 m3/h, 28.4 barg suction, 139.0 barg discharge, CS	
1 - 2	P-3202 A/B	MP BFW Pumps (4 x 50% Train)	445.85 kW 426.2 m3/h, 3.34 barg suction, 28.4 barg discharge, CS	
1 - 2	P-3203 A/B	LP BFW Pumps (4 x 50% Train)	38.4 kW 469.6 m3/h, 2.49 barg suction, 3.34 barg discharge, CS	
1 - 2	D-3204	HP Steam Drum (2 x 50% Train)	305.0 tph	part of HRSG package
1 - 2	D-3203	MP Steam Drum (2 x 50% Train)	47.32 tph	part of HRSG package
1 - 2	D-3202	LP Steam Drum (2 x 50% Train)	40.273 tph	part of HRSG package
1 - 2	E-3215	Fuel Gas Preheater (2 x 50% Train)	8785 kW Duty, 67341 kg/h process stream flow, 397 m2 heat transfer area, Carbon Steel	
1	E-3301	Vacuum Condenser (1 x 100% Train)	842.01 tph condensate; 3.5 kPa (abs), 238.92 MW, 33,724 m2 heat transfer area, Carbon Steel	ref. duty = 371.8 MW
1	P-3301 A/B/C	Condensate Pumps (3 x 50% pumps, 1 x 1	421.01 tph condensate, 422.17 m3/h, 115.2 kW, -0.978 barg suction, 5.53 barg discharge, CS	
1	ST-3301	Steam Turbine (1 x 100% Train)	235.39 MWe Output Turbine generator; 140 bar, 566 ^oC; 27 bar, 565 ^oC; 4.2 bar, 292 ^oC	
1 - 2	Z-3201	Stack (2 x 50%)		part of HRSG package
1 - 2	C-3201	Recycle DCC Column (2 x 50%)	3 sieve trays, 10.5m ID, 21m T/T, 2,160 tph water, 882,tph flue gas, CS with 3mm 304L cladding	
1 - 2	E-3217	Recycle DCC Cooler (2 x 50%)	44300 kW Duty, 2,160,000 kg/h process water flow, 8206 m2 HT area, 316SS tubes, shell	CS with 3mm 304L cladding
1 - 2	P-3204 A/B	Recycle DCC Pumps (6 x 25% Train)	80.5 kW 1103 m3/h, 0.02 barg suction, 2 barg discharge, SS	

FOSTER WHEELER ENERGY	CLIENT: ETI JECT TITLE: CCS BENCHMARK REFRESH 2013 CONTRACT: 13074	REVISION	0	1	2	3
		DATE	Oct-13			
		BY	SEF			
		CHECKED	RR			
		APPROVED	SEF			

CASE: NGCC POWER PLANT WITH 0% POST-COMBUSTION CO_2 CAPTURE AND 35% EXHAUST GAS RECYCLE

Train	Item	Description	Specification	Remarks
1 - 2	GT-3201	Gas Turbine (2 x 50% Train)	361.68 MWe Output Turbine generator	MHI M701F5 machine
1 - 2		HRSG (2 x 50% Train)	410.54 MW Duty (14 Coils)	
1 - 2	D-3201	Deaerator (2 x 50% Train)	435.26 tph	part of HRSG package
1 - 2	P-3201 A/B	HP BFW Pumps (4 x 50% Train)	1471.6 kW, 333.2 m3/h, 28.4 barg suction, 139.0 barg discharge, CS	
1 - 2	P-3202 A/B	MP BFW Pumps (4 x 50% Train)	445.85 kW 426.2 m3/h, 3.34 barg suction, 28.4 barg discharge, CS	
1 - 2	P-3203 A/B	LP BFW Pumps (4 x 50% Train)	38.4 kW 469.6 m3/h, 2.49 barg suction, 3.34 barg discharge, CS	
1 - 2	D-3204	HP Steam Drum (2 x 50% Train)	305.0 tph	part of HRSG package
1 - 2	D-3203	MP Steam Drum (2 x 50% Train)	47.32 tph	part of HRSG package
1 - 2	D-3202	LP Steam Drum (2 x 50% Train)	40.27 tph	part of HRSG package
1 - 2	E-3215	Fuel Gas Preheater (2 x 50% Train)	8785 kW Duty, 67341 kg/h process stream flow, 397 m2 heat transfer area, Carbon Steel	
1	E-3301	Vacuum Condenser (1 x 100% Train)	842.01 tph condensate; 3.5 kPa (abs), 470.286 MW, 66,385 m2 heat transfer area, Carbon Steel	REF. duty = 371.8 MW
1	P-3301 A/B/C	Condensate Pumps (3 x 50% pumps, 1 x 1	421.01 tph condensate, 422.17 m3/h, 115.2 kW, -0.978 barg suction, 5.53 barg discharge, CS	
1	ST-3301	Steam Turbine (1 x 100% Train)	331.354 MWe Output Turbine generator; 140 bar, 566 ^oC; 27 bar, 565 ^oC; 4.2 bar, 292 ^oC	
1 - 2	Z-3201	Stack (2 x 50%)		part of HRSG package
1 - 2	C-3201	Recycle DCC Column (2 x 50%)	3 sieve trays, 10.5m ID, 21m T/T, 2,160 tph water, 882,tph flue gas, CS with 3mm 304L cladding	
1 - 2	E-3217	Recycle DCC Cooler (2 x 50%)	44300 kW Duty, 2,160,000 kg/h process water flow, 8206 m2 HT area, 316SS tubes, shell	CS with 3mm 304L cladding
1 - 2	P-3204 A/B	Recycle DCC Pumps (6 x 25% Train)	80.5 kW 1103 m3/h, 0.02 barg suction, 2 barg discharge, SS	

FOSTER WHEELER ENERGY	CLIENT: ETI JECT TITLE: CCS BENCHMARK REFRESH 2013 CONTRACT: 13074	REVISION	0	1	2	3
		DATE	Oct-13			
		BY	SEF			
		CHECKED	RR			
		APPROVED	SEF			

CASE: NGCC POWER PLANT WITH 0% POST-COMBUSTION CO_2 CAPTURE AND 35% EXHAUST GAS RECYCLE

FOSTER WHEELER
ENERGY LTD
READING

EQUIPMENT LIST - CCGT CASE with 90% CCS & 18% EGR

REV	BY	APPROVED	DATE
ORIG			
01	SEF		07/10/2013
02			
03			

UNIT NAME:	MEA & CO2 Compression Unit
UNIT No.:	100
CLIENT:	The Energies Technology Institute
PROJECT:	CCS BENCHMARK REFRESH 2013
CONTRACT	13074
DOCUMENT No.:	
CASE SUMMARY	Natural Gas Combined Cycle Power Plant with 90% Post Combustion CO2 Capture 18% EGR
NOTES	

FOSTER WHEELER ENERGY LTD.	EQUIPMENT LIST FOR COMPRESSORS	Rev.	ORIG	REV 01	REV 02	
	Client: The Energies Technology Institute Contract No: 13074	Ch'd	SEF			SHEET 2 of 8
	Description: CCS BENCHMARK REFRESH 2013	App.	SEF			
	Unit No: 2300/2500 MEA & CO2 Compression Unit	Date	07/10/2013			

EQUIPMENT NUMBER	DESCRIPTION	COMPRESSOR TYPE(1)/ SUB-TYPE	No.off x DUTY %	DRIVE TYPE OP./SPARE	ACTUAL CAPACITY m^3/hr	Cp/Cv INLET/ OUTLET	DIFF. PRESS. bar	PRESSURE INLET/OUTLET bara bara	TURB.DRIVE STEAM PRESS. barg	COMPRESSIBILITY INLET/OUTLET	POWER EST/RATED kW	MATERIAL CASING	MOLECULAR WEIGHT	REMARKS	REV
1/2 BL-2301	Flue Gas Blower	Blower	2 x 50%	electric	2,155,333	1.377 / 1.374	0.22	1.03 / 1.25	n/a	0.999 / 0.999	14309	304 SS	28.45		01
1/2 K-2501-1	CO2 Compressor Stage 1	Centrifugal	2 x 50%	electric	11,850	1.287 / 1.278	0.38	1.10 / 1.48	n/a	0.994 / 0.994	135	304 SS	42.67		01
1/2 K-2501-2	CO2 Compressor Stage 2	Centrifugal	2 x 50%	electric	69,547	1.286 / 1.272	1.4	1.38 / 2.80	n/a	0.992 / 0.991	2492	304 SS	43.23		01
1/2 K-2501-3	CO2 Compressor Stage 3	Centrifugal	2 x 50%	electric	34,010	1.296 / 1.284	2.7	2.7 / 5.4	n/a	0.985 / 0.983	2332	304 SS	43.71		01
1/2 K-2501-4	CO2 Compressor Stage 4	Centrifugal	2 x 50%	electric	16,976	1.313 / 1.304	6.2	5.3 / 11.5	n/a	0.970 / 0.966	2580	CS	43.85		01
1/2 K-2501-5	CO2 Compressor Stage 5	Centrifugal	2 x 50%	electric	8,423	1.360 / 1.362	14	11.4 / 25.0	n/a	0.934 / 0.928	2796	CS	43.92		01
1/2 K-2501-6	CO2 Compressor Stage 6	Centrifugal	2 x 50%	electric	3,324	1.493 / 1.512	31	23.9 / 55.0	n/a	0.859 / 0.856	2478	CS	44.00		01
1/2 K-2501-7	CO2 Compressor Stage 7	Centrifugal	2 x 50%	electric	1,011	2.884 / 2.440	45	54.9 / 100.0	n/a	0.602 / 0.645	1245	CS	44.00		01
1/2 K-2501-8	CO2 Compressor Stage 8	Centrifugal	2 x 50%	electric	510	4.318 / 2.887	51	99.9 / 151.0	n/a	0.500 / 0.578	791	CS	44.00		01

Notes: **1. AC - Air Compressor GC - Gas Compressor FN - Fan**

FOSTER WHEELER ENERGY LTD.	EQUIPMENT LIST FOR VESSELS				Rev.	ORIG	REV 01	REV 02	
	Client:	The Energies Technology Institute	Contract No:	13074	Ch'd	SEF			SHEET 3 of 8
	Description:	CCS BENCHMARK REFRESH 2013			App.	SEF			
	Unit No:	2300/2500	MEA & CO2 Compression Unit		Date	07/10/2013			

EQUIPMENT NUMBER	DESCRIPTION	VESSEL TYPE(1)/ SUB-TYPE	No.off x DUTY %	DIMENSIONS ID m	DIMENSIONS HEIGHT T/T m	TOTAL VOLUME m^3	V/H (2)	DESIGN CONDITIONS TEMP ^oC	DESIGN CONDITIONS PRESS barg	DESIGN CONDITIONS VACUUM FVPRESS bara	INTERNALS TYPE/No.OFF PACKED VOL. m^3 / PACKED HGT mm	MATERIALS OF CONST'N SHELL MAT./LINING/ CA	MATERIALS OF CONST'N INTERNALS MAT./LINING/ CA	REMARKS	REV
1/2/3 C-2301	Direct contact cooler	TW	3 x 33%	13.30	26.61	4314.35	V	107	3.5	1.013	Random Packing 916 10000	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding	Packing: 10m Mellapak 250X	01
1/2/3 C-2302	Absorption Column	TW	3 x 33%	14.01	27.00	4883	V	75	3.5	1.013	Random Packing 2160 / 310 14000 / 2000	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding	Packing: 14m Mellapak 250X / 2m Mellapak 250Y	01
1/2 C-2303	Stripper Column	TW	2 x 50%	7.54	17.20	881	V	142	3.5	1.013	Trays / 14	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2301	Stripper OH Separator	VT	2 x 50%	3.51	7.02	79	V	55	3.5	1.013	Wire Mesh Pad 0.97 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2302	Semi-Lean Solvent Flash Drum	VT	2 x 50%	2.66	5.32	34	V	128	3.5	1.013	Wire Mesh Pad 0.55 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2303	Flashed Gas KO Pot	VT	2 x 50%	1.47	2.94	5.8	V	60.0	3.5	1.013	Wire Mesh Pad 0.17 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2501	CO2 Compressor Stage 1 KO Pot	VT	2 x 50%	1.36	2.72	4.6	V	49.0	3.5	1.013	Wire Mesh Pad 0.15 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2502	CO2 Compressor Stage 2 KO Pot	VT	2 x 50%	3.17	6.35	58.5	V	49	3.5	1.013	Wire Mesh Pad 0.79 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2503	CO2 Compressor Stage 3 KO Pot	VT	2 x 50%	2.67	4.80	31.8	V	49	4.7	1.013	Wire Mesh Pad 0.56 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 V-2504	CO2 Compressor Stage 4 KO Pot	VT	2 x 50%	2.30	4.00	19.9	V	49	11.4	1.013	Wire Mesh Pad 0.42 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01

Notes:
1. TW - Single Diameter Tower DDT - Double Diameter Tower HT - Horizontal Tank AT - Agitated Tank VT - Vertical Tank
2. V - Vertical H - Horizontal

FOSTER WHEELER ENERGY LTD.	EQUIPMENT LIST FOR VESSELS				Rev.	ORIG	REV 01	REV 02	
	Client:	The Energies Technology Institute	Contract No:	13074	Ch'd	SEF			SHEET 4 of 8
	Description:	CCS BENCHMARK REFRESH 2013			App.	SEF			
	Unit No:	2300/2500	MEA & CO2 Compression Unit		Date	07/10/2013			

EQUIPMENT NUMBER	DESCRIPTION	VESSEL TYPE(1)/ SUB-TYPE	No.off x DUTY %	DIMENSIONS ID m	DIMENSIONS HEIGHT T/T m	TOTAL VOLUME m^3	V/H (2)	DESIGN CONDITIONS TEMP ^oC	DESIGN CONDITIONS PRESS barg	DESIGN CONDITIONS VACUUM FVPRESS bara	INTERNALS TYPE/No.OFF PACKED VOL. m^3 / PACKED HGT mm	MATERIALS OF CONST'N SHELL MAT./LINING/ CA	MATERIALS OF CONST'N INTERNALS MAT./LINING/ CA	REMARKS	REV
1/2 V-2305	CO2 Compressor Stage 5 KO Pot	VT	2 x 50%	1.86	3.20	10.4	V	49	26.3	1.013	Wire Mesh Pad 0.27 100	CS with 3mm min 304L cladding	CS with 3mm min 304L cladding		01
1/2 D-2501 A/B	Dehydration Bed #1 & 2	VT	4 x 25%								Molecular Sieve / /			By Drier Package Vendor	

Notes:
1. TW - Single Diameter Tower DDT - Double Diameter Tower HT - Horizontal Tank AT - Agitated Tank VT - Vertical Tank
2. V - Vertical H - Horizontal

FOSTER WHEELER ENERGY LTD.	**EQUIPMENT LIST FOR HEAT EXCHANGERS**				**Rev.**	**ORIG**	**REV 01**	**REV 02**	
	Client:	The Energies Technology Institute	**Contract No:**	13074	**Ch'd**	SEF			**SHEET** 5 **of** 8
	Description:	CCS BENCHMARK REFRESH 2013			**App.**	SEF			
	Unit No:	2300/2500 MEA & CO_2 Compression Unit			**Date**	07/10/2013			

EQUIPMENT NUMBER	DESCRIPTION	EXCHANGER TYPE(1)/ SUB-TYPE	No.off x DUTY %	No.OF SHELLS (ST)	TEMA TYPE(ST)/ HEADER CONST(AC) (2)	RATE(3) kg/hr	DUTY MW	HEAT T'FER AREA(6) m^2	DESIGN CONDITIONS COLDSIDE(4) TEMP/PRESS ^oC / barg	DESIGN CONDITIONS HOTSIDE TEMP/PRESS ^oC /barg	MATERIAL PLATE/ SHELL	MATERIAL TUBE(ST/AC) HEAD(AC)	No.OF BAYS/FANS (AC)	FAN TYPES (5)	TOTAL FAN POWER kW	REMARKS	REV
1/2 E-3216	Gas/Gas Heat Exchanger	HE	2 x 50%	1	n/a	2080299	21.5	13441	105.0 / 4.7	141.4 / 3.5	CS	CS	n/a		n/a	like a combustion air preheater	01
1/2/3 E-2301	DCC Cooler	HE	3 x 33%	1	n/a	97252	1.2	935	49.0 / 4.7 (tubeside)	75.4 / 3.5	CS with 3mm min 304L cladding	316L	n/a		n/a		01
1/2/3 E-2302	Absorber Pump Around Cooler	HE	3 x 33%	1	n/a	12239	0.2	18	49.0 / 4.7 (tubeside)	65.6 / 3.5	CS	CS	n/a		n/a		01
1/2 E-2303	Cross Over Exchanger	HE	2 x 50%	1	n/a	2677197	111.9	23628	118.0 / 5.3	124.1 / 6.5	316L	316L	n/a		n/a	Plate & Frame	01
1/2/3 E-2304	Lean Solvent Cooler	HE	3 x 33%	4	n/a	3930462	47.0	2820	49.0 / 4.7 (tubeside)	82.4 / 5.5	316L	316L	n/a		n/a		01
1/2/3 E-2305	Extraction Cooler	HE	3 x 33%	4	n/a	4813072	57.6	3635	49.0 / 4.7 (tubeside)	79.4 / 4.2	316L	316L	n/a		n/a		01
1/2 E-2306	First Flash Preheater	HE	2 x 50%	4	n/a	1147370	36.0	10789	108.0 / 4.2 (tubeside)	128.1 / 5.3	316L	316L	n/a		n/a		01
1/2 E-2307	Second Flash Preheater	HE	2 x 50%	4	n/a	1147370	52.1	6532	128.0 / 3.5 (tubeside)	142.7 / 5.2	316L	316L	n/a		n/a		01
1/2 E-2308	Semi Lean Flash Cooler	HE	2 x 50%	4	n/a	1847889	22.1	547	49.0 / 4.7 (tubeside)	128.0 / 3.5	316L	316L	n/a		n/a		01
1/2 E-2309 A/B/C	Stripper Reboiler	RB	6 x 17%	3	n/a	926022	55.7	1351	142.7 / 3.5	325.0 / 4.7 (tubeside)	316L	316L	n/a		n/a		01
1/2 E-2310	Solvent Reclaimer	RB	2 x 50%	1	n/a	75009	34.5	225	173.9 / 3.5	172.9 / 6.2 (tubeside)	CS with 3mm min 304L cladding	316L	n/a		n/a	intermittent duty	01

Notes: **1. C - Condenser HE - Heat Exchanger RB - Reboiler STB - Steam Boiler 2. For Air Coolers CP - Cover Plate PT - Plug Type MT - Manifold Type BT - Billet Type**

3. Rate = Total Fluid Entering Coldside And Applies To Condensers, Boilers And Heaters. 4. Coldside Design Temp Equals Design Air Temp. For Air Coolers 5. I - Induced F - Forced

6. For Air-Coolers, this is Bare Tube Area

PROJECT No.: 13074

FOSTER WHEELER ENERGY LTD.

EQUIPMENT LIST FOR HEAT EXCHANGERS

Client: The Energies Technology Institute **Contract No:** 13074

Description: CCS BENCHMARK REFRESH 2013

Unit No: 2300/2500 MEA & CO2 Compression Unit

Rev.	ORIG	REV 01	REV 02
Ch'd	SEF		
App.	SEF		
Date	07/10/2013		

EQUIPMENT NUMBER	DESCRIPTION	EXCHANGER TYPE(1)/ SUB-TYPE	No.off x DUTY %	No.OF SHELLS (ST)	TEMA TYPE(ST)/ HEADER CONST(AC) (2)	RATE(3) kg/hr	DUTY MW	HEAT T'FER AREA(6) m^2	DESIGN CONDITIONS COLDSIDE(4) TEMP/PRESS ^oC / barg	DESIGN CONDITIONS HOTSIDE TEMP/PRESS ^oC /barg	MATERIAL PLATE/ SHELL	MATERIAL TUBE(ST/AC) HEAD(AC)	No.OF BAYS/FANS (AC)	FAN TYPE (5)	TOTAL FAN POWER kW	REMARKS	REV
1/2 E-2311	Reflux Cooler	HE	2 x 50%	2	n/a	3171553	38.0	1085	49.0 / 4.7 (tubeside)	115.1 / 3.5	CS with 3mm min 304L cladding	316L	n/a	n/a	n/a		01
1/2 E-2501	CO2 Compressor Stage 1 Cooler	HE	2 x 50%	1	n/a	32306	0.4	94	49.0 / 4.7 (tubeside)	84.7 / 3.5	CS with 3mm min 304L cladding	316L	n/a	n/a	n/a		01
1/2 E-2502	CO2 Compressor Stage 2 Cooler	HE	2 x 50%	1	n/a	304966	3.6	601	49.0 / 4.7 (tubeside)	114.5 / 3.5	CS with 3mm min 304L cladding	316L	n/a	n/a	n/a		01
1/2 E-2503	CO2 Compressor Stage 3 Cooler	HE	2 x 50%	1	n/a	225524	2.7	480	49.0 / 4.7 (tubeside)	114.5 / 6.1	CS with 3mm min 304L cladding	316L	n/a	n/a	n/a		01
1/2 E-2504	CO2 Compressor Stage 4 Cooler	HE	2 x 50%	1	n/a	284288	3.4	555	49.0 / 4.7 (tubeside)	115.2 / 12.2	CS with 3mm min 304L cladding	316L	n/a	n/a	n/a		01
1/2 E-2505	CO2 Compressor Stage 5 Cooler	HE	2 x 50%	1	n/a	303576	3.6	580	49.0 / 4.7 (tubeside)	117.5 / 26.5	CS with 6mm CA	316L	n/a	n/a	n/a		01
1/2 E-2506	CO2 Compressor Stage 6 Cooler	HE	2 x 50%	1	n/a	402556	4.8	714	49.0 / 4.7 (tubeside)	125.4 / 59	CS with 6mm CA	316L	n/a	n/a	n/a		01
1/2 E-2507	CO2 Compressor Stage 7 Cooler	HE	2 x 50%	1	n/a	190710	2.3	202	49 / 4.7 (tubeside)	100.0 / 105	CS with 6mm CA	316L	n/a	n/a	n/a		01
1/2 E-2508	CO2 Product Cooler	HE	2 x 50%	1	n/a	631577	7.6	996	49.0 / 4.7 (tubeside)	109.9 / 158	CS with 6mm CA	316L	n/a	n/a	n/a		01
1/2 E-2509	Regen. Gas Electric Heater	HE	2 x 50%													By Drier Package Vendor	
1/2E-2510	Regen. Gas Feed/Product Exchanger	HE	2 x 50%													By Drier Package Vendor	

Notes:

1. C - Condenser HE - Heat Exchanger RB - Reboiler STB - Steam Boiler 2. For Air Coolers CP - Cover Plate PT - Plug Type MT - Manifold Type BT - Billet Type

3. Rate = Total Fluid Entering Coldside And Applies To Condensers, Boilers And Heaters. 4. Coldside Design Temp Equals Design Air Temp. For Air Coolers 5. I - Induced F - Forced

6. For Air-Coolers, this is Bare Tube Area

FOSTER WHEELER ENERGY LTD.	EQUIPMENT LIST FOR PUMPS				Rev.	ORIG	REV 01	REV 02	
	Client:	The Energies Technology Institute	Contract No:	13074	Ch'd	SEF			SHEET 7 of 8
	Description:	CCS BENCHMARK REFRESH 2013			App.	SEF			
	Unit No:	2300/2500	MEA & CO2 Compression Unit		Date	07/10/2013			

EQUIPMENT NUMBER	DESCRIPTION	PUMP TYPE(1)/ SUB-TYPE	No.off x DUTY %	DRIVE TYPE (2) OP./SPARE	DESIGN CAPACITY m^3/hr	PUMP EFFIC'Y %	DIFF PRESSURE kPa	TURB. DRIVE STEAM P barg	OPERATING CONDS TEMP / SG / VISC'Y °C		cP	DESIGN CONDITIONS TEMP/PRESS °C	barg	POWER EST/RATED kW	MATERIAL CASING/ROTOR	REMARKS	REV
1/2/3 P-2301 A/B	DCC Cooler Pump	Centrifugal	6 x 33%	electric	33		379		50.3	0.988	0.541	75.3	5.35	4.6	316L SS / 316L SS	number of items tbc	01
1/2/3 P-2302 A/B/C/D	Rich Solvent Pump	Centrifugal	12 x 11%	electric	890		352		52.1	1.051	1.088	77.1	5.00	116	CS / CS	number of items tbc	01
1/2/3 P-2303 A/B/C/D	Lean Solvent Pump	Centrifugal	8 x 16.5%	electric	920		419		99.0	0.996	0.440	124.0	6.58	142	316L SS / 316L SS	number of items tbc	01
1/2/3 P-2304 A/B/C	Semi-Lean Solvent Pump	Centrifugal	6 x 25%	electric	594		224		103.0	1.013	0.428	128.0	3.59	49	CS / CS	number of items tbc	01
1/2/3 P-2305 A/B/C/D	Extraction Pump	Centrifugal	12 x 11%	electric	834		252		54.3	1.038	1.041	79.3	3.63	78	CS / CS	number of items tbc	01
1/2/3 P-2306 A/B	Absorber Pumparound Pump	Centrifugal	6 x 33%	electric	14		126		40.6	0.993	0.685	65.6	1.97	0.05	316L SS / 316L SS	number of items tbc	01
1/2 P-2306 A/B	Stripper Reflux Pump	Centrifugal	4 x 50%	electric	53		147		30.0	1.052	0.845	55.0	2.70	1.8	316L SS / 316L SS	number of items tbc	01

Notes: **1. Differential pressure to be confirmed after column design**

PROJECT No.: 13074

FOSTER WHEELER ENERGY LTD.	EQUIPMENT LIST FOR PACKAGE EQUIPMENT				Rev.	ORIG	REV 01	REV 02	
	Client:	The Energies Technology Institute	Contract No:	13074	Ch'd	SEF			SHEET 8 of 8
	Description:	CCS BENCHMARK REFRESH 2013			App.	SEF			
	Unit No:	2300/2500	MEA & CO_2 Compression Unit		Date	07/10/2013			

EQUIPMENT NUMBER	DESCRIPTION	EQUIPMENT TYPE(1)/ SUB-TYPE	No.off x DUTY %	DRIVE TYPE (2) OP./SPARE	DIMENSIONS DIAM./HGT/ LENGTH mm	AREA mm^2	CAPACITY m^3	FLOW kg/hr	PRESS OPER./DIFF. barg / bar	DESIGN CONDS. TEMP/PRESS °C / barg	POWER EST/RATED kW	MATERIAL BODY/CA	COOL.TOWER WBT °C / APP °C / CWT °C (3)	REMARKS	REV
1/2 F-2301	DCC Circulation Water Filter	F	2 x 50%				3	29811	3.85 / 0.7			Shell: 304L SS Internals: 304 SS		Packing = Activated Carbon	01
1/2 F-2302	Absorber Wash Water Filter	F	2 x 50%				12.3	12238.5	0.122 / 0.1			Shell: 304L SS Internals: 304 SS		Packing = Activated Carbon	01
1/2 F-2303	Lean Solvent Filter	F	2 x 50%				100	100012	0.387 / 0.1			Shell: 304L SS Internals: 304 SS		Packing = Activated Carbon	01
1/2 F-2501	Dehydration Fines Filter	F	2 x 50%											By Drier Package Vendor	
1/2 F-2502	Regeneration Fines Filter	F	2 x 50%											By Drier Package Vendor	
1/2 PK-2301	Soda Ash Injection Package		2 x 50%												01
1/2 PK-2501	CO_2 Drier Package	Mol Sieve	2 x 50%				3503 m3/h	182589.4 kg/h 0.075 wt% water	24.9 / 0.9					Product spec <50 ppmv water	01

Notes:

1. AD - Air Dryer CRY - Crystallizer CTW - Cooling Tower D - Dryer DC - Dust Collector DD - Drum Dryer E - Evaporator EG - Electrical Generator EJ - Ejector F - Filter FLR - Flare Stack HU - Heating Unit RD - Rotary Dryer RU - Refrigeration Unit STK - Stack TDS - Tray Drying System WFE - Wiped Film Evaporator WTS - Water Treatment System

2. VFD - Variable Frequency Motor Driver

3. WBT - Wet Bulb Temperature APP - Approach Temperature CWT - Cooling Water Inlet Temperature

FOSTER WHEELER ENERGY

CLIENT: ETI
ECT TITLE: CCS BENCHMARK REFRESH 2013
CONTRACT: 13074

REVISION	0	1	2	3
DATE	Oct-13			
BY	SEF			
CHECKED				
APPROVED				

CASE: NGCC POWER PLANT WITH 90% POST-COMBUSTION CO_2 CAPTURE AND 18% EXHAUST GAS RECYCLE

Train	Item	Description	Specification	Remarks
1 - 2	GT-3201	Gas Turbine (2 x 50% Train)	365.478 MWe Output Turbine generator	MHI M701F5 machine
1 - 2		HRSG (2 x 50% Train)	410.09 MW Duty (14 Coils)	
1 - 2	D-3201	Deaerator (2 x 50% Train)	435.88 tph	part of HRSG package
1 - 2	P-3201 A/B	HP BFW Pumps (4 x 50% Train)	1457.8 kW, 329.0 m3/h, 28.4 barg suction, 139.0 barg discharge, CS	
1 - 2	P-3202 A/B	MP BFW Pumps (4 x 50% Train)	445.55 kW 425.9 m3/h, 3.34 barg suction, 28.4 barg discharge, CS	
1 - 2	P-3203 A/B	LP BFW Pumps (4 x 50% Train)	38.4 kW 435.9 m3/h, 2.49 barg suction, 3.34 barg discharge, CS	
1 - 2	D-3204	HP Steam Drum (2 x 50% Train)	302.1 tph	part of HRSG package
1 - 2	D-3203	MP Steam Drum (2 x 50% Train)	48.75 tph	part of HRSG package
1 - 2	D-3202	LP Steam Drum (2 x 50% Train)	41.15 tph	part of HRSG package
1 - 2	E-3215	Fuel Gas Preheater (2 x 50% Train)	8827 kW Duty, 67665 kg/h process stream flow, 325 m2 heat transfer area, Carbon Steel	
1	E-3301	Vacuum Condenser (1 x 100% Train)	844.16 tph condensate; 3.5 kPa (abs), 236.6 MW, 33,724 m2 heat transfer area, Carbon Steel	ref. duty = 371.8 MW
1	P-3301 A/B/C	Condensate Pumps (3 x 50% pumps, 1 x 1	422.08 tph condensate, 423.24 m3/h, 115.5 kW, -0.978 barg suction, 5.53 barg discharge, CS	
1	ST-3301	Steam Turbine (1 x 100% Train)	233.2 MWe Output Turbine generator; 140 bar, 566 ^oC; 27 bar, 565 ^oC; 4.2 bar, 292 ^oC	
1 - 2	Z-3201	Stack (2 x 50%)		part of HRSG package
1 - 2	C-3201	Recycle DCC Column (2 x 50%)	3 sieve trays, 7.55m ID, 15.1m T/T, 1,116 tph water, 456,tph flue gas, CS with 3mm 304L cladding	
1 - 2	E-3217	Recycle DCC Cooler (2 x 50%)	22540 kW Duty, 1,116,000 kg/h process water flow, 4222 m2 HT area, 316SS tubes, shell	CS with 3mm 304L cladding
1 - 2	P-3204 A/B	Recycle DCC Pumps (6 x 25% Train)	41.6 kW 570 m3/h, 0.02 barg suction, 2 barg discharge, SS	

FOSTER WHEELER ENERGY	CLIENT: ETI JECT TITLE: CCS BENCHMARK REFRESH 2013 CONTRACT: 13074	REVISION	0	1	2	3
		DATE	Oct-13			
		BY	SEF			
		CHECKED				
		APPROVED				

CASE: NGCC POWER PLANT WITH 0% POST-COMBUSTION CO_2 CAPTURE AND 18% EXHAUST GAS RECYCLE

Train	Item	Description	Specification	Remarks
1 - 2	GT-3201	Gas Turbine (2 x 50% Train)	365.478 MWe Output Turbine generator	MHI M701F5 machine
1 - 2		HRSG (2 x 50% Train)	410.09 MW Duty (14 Coils)	
1 - 2	D-3201	Deaerator (2 x 50% Train)	435.89 tph	part of HRSG package
1 - 2	P-3201 A/B	HP BFW Pumps (4 x 50% Train)	1457.8 kW, 329.0 m3/h, 28.4 barg suction, 139.0 barg discharge, CS	
1 - 2	P-3202 A/B	MP BFW Pumps (4 x 50% Train)	445.55 kW 425.9 m3/h, 3.34 barg suction, 28.4 barg discharge, CS	
1 - 2	P-3203 A/B	LP BFW Pumps (4 x 50% Train)	38.4 kW 435.9 m3/h, 2.49 barg suction, 3.34 barg discharge, CS	
1 - 2	D-3204	HP Steam Drum (2 x 50% Train)	302.1 tph	part of HRSG package
1 - 2	D-3203	MP Steam Drum (2 x 50% Train)	48.75 tph	part of HRSG package
1 - 2	D-3202	LP Steam Drum (2 x 50% Train)	41.15 tph	part of HRSG package
1 - 2	E-3215	Fuel Gas Preheater (2 x 50% Train)	8827 kW Duty, 67665 kg/h process stream flow, 325 m2 heat transfer area, Carbon Steel	
1	E-3301	Vacuum Condenser (1 x 100% Train)	844.16 tph condensate; 3.5 kPa (abs), 470.3 MW, 67,026 m2 heat transfer area, Carbon Steel	ref. duty = 371.8 MW
1	P-3301 A/B/C	Condensate Pumps (3 x 50% pumps, 1 x 1	422.08 tph condensate, 423.24 m3/h, 115.5 kW, -0.978 barg suction, 5.53 barg discharge, CS	
1	ST-3301	Steam Turbine (1 x 100% Train)	330.144 MWe Output Turbine generator; 140 bar, 566 ^oC; 27 bar, 565 ^oC; 4.2 bar, 292 ^oC	
1 - 2	Z-3201	Stack (2 x 50%)		part of HRSG package
1 - 2	C-3201	Recycle DCC Column (2 x 50%)	3 sieve trays, 7.55m ID, 15.1m T/T, 1,116 tph water, 456,tph flue gas, CS with 3mm 304L cladding	
1 - 2	E-3217	Recycle DCC Cooler (2 x 50%)	22550 kW Duty, 1,116,000 kg/h process water flow, 2226 m2 HT area, 316SS tubes, shell	CS with 3mm 304L cladding
1 - 2	P-3204 A/B	Recycle DCC Pumps (6 x 25% Train)	41.6 kW 570 m3/h, 0.02 barg suction, 2 barg discharge, SS	