Programme Area: Carbon Capture and Storage

Project: Hydrogen Turbines

Title: Hydrogen Storage and Flexible Turbine Systems WP5 – Identification of a Representative System & Comparison of CCGT with CO2 Buffer Storage

Abstract:

The purpose and focus of the Hydrogen Turbines project is to improve the ETI’s understanding of the economics of flexible power generation systems comprising hydrogen production (with CCS), intermediate hydrogen storage (e.g. in salt caverns) and flexible turbines, and to provide data on the potential economics and technical requirements of such technology to refine overall energy system modelling inputs. The final deliverable (D2) comprises eight separate components. This document is D2 WP5 Report – identifying a representative hydrogen storage and flexible turbine system and providing a comparison to a baseline of a CCGT with post combustion carbon capture, either with or without CO2 storage buffering.

Context:

This £300k project, led by global engineering and construction company Amec Foster Wheeler, in collaboration with the BGS, assessed the economics of a range of flexible power generation systems which involve the production of hydrogen (with CCS) from coal, biomass or natural gas, its intermediate storage (e.g. in salt caverns deep underground) and production of power in flexible turbines. The work included mapping of potentially suitable hydrogen storage salt cavern sites in and around the UK and provided the ETI with a flexible economic modelling tool to assess the range of possible options. The ETI's energy system modelling work suggests that systems such as these could provide a valuable contribution to the future energy mix, filling the gap between base load nuclear plant and low carbon power generation.

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ORIG. BY	R. Ray	R. Ray	R. Ray			
CHKD BY	G. Skinner S Ferguson	G. Skinner S Ferguson	Ferguson			
APP. BY	T. Abbott	T. Abbott	Tom Abbott			

Hydrogen Storage and Flexible Turbine Systems
WP5 – Identification of a Representative System & Comparison of CCGT with CO_2 Buffer Storage

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DISCLAIMER

The information contained herein is provided by Foster Wheeler Energy Limited (FWEL) to Energy Technologies Institute LLP (ETI), solely to assist ETI in improving its understanding of flexible power generation systems comprising of hydrogen production, storage and turbines, and to enable ETI to refine its Energy System Modelling Environment (ESME) model.

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1. EXECUTIVE SUMMARY

1.1 Introduction

Fossil fuel based power generation currently plays a key part in providing for the UK's energy demands. The development and implementation of Carbon Capture and Storage (CCS) technologies is an important option in reducing the associated CO_2 emissions, but adding CCS to conventional power systems impacts their ability to respond to power demand fluctuations, since the column systems for CO_2 removal work best at steady state conditions and are inefficient in turndown operation. Adding intermediate storage of hydrogen-rich fuel gas to a pre-combustion carbon capture scheme could be an attractive way of achieving flexible low-carbon power generation for the UK: the upstream carbon capture system would normally operate at a steady, base load capacity for maximum efficiency, while the hydrogen store would provide buffer capacity to allow the downstream hydrogen based power generation scheme to respond to demand fluctuations.

The purpose and focus of this project is:

- To improve the ETI's understanding of the economics of flexible power generation systems comprising hydrogen production (with CCS), intermediate hydrogen storage (e.g. in salt caverns) and flexible turbines; and
- To focus on the potential, economics and technical requirements for salt cavern storage and flexible turbines, to enable refinement of the ETI Energy System Modelling Environment (ESME) model in order to confirm or adjust ESME findings.

1.2 Scope

This report covers the work undertaken in the execution of WP5 – Identification of a Representative Hydrogen Storage and Flexible Turbine System & Comparison of CCGT w. CO_2 buffer storage.

The aim of WP5 is to pull together the work in WP1-4 to identify and develop the configuration for a representative 'Hydrogen Storage and Flexible Turbine' system for UK application. The representative system will be compared to a baseline of a CCGT with post combustion carbon capture, either with or without CO_2 storage buffering. The CCGT case will be based on the results of the earlier study carried out by Foster Wheeler for the ETI.

The scope includes production of the following deliverables for the representative system:

- Design basis;
- Block flow diagram;
- Process description;
- Outline heat and mass balance;
- Outline utility summary;
- Outline project execution schedule;
- Capital and operating cost estimates; and
- Unit lifetimes and availability.

The scope includes the pipeline and wells to/from the storage facilities. Based on CO_2 flowrates calculated by Foster Wheeler, the estimated costs of CO_2 transportation and storage (provided by the ETI) are included within the overall estimates.

1.3 Key Findings of Work Package 5

The following items describe the key findings of this section of the Hydrogen Storage and Flexible Turbine Systems Project.

1.3.1 Identification of a Representative System

The first task within Work Package 5 was to identify a Representative System to be developed further and compared with a CCGT case. Agreement was reached at a review meeting through review of the capital costs and LCOE results arising from running a number of cases, followed by discussion of the relative merits of various options.

<u>Key Parameters Selected for the Representative System</u>

- East Yorkshire coastal location;
- 10km separation between syngas production plant/power island and storage caverns;
- Weekday Diurnal operation - 12hrs on / 12hrs off weekdays, off all weekend;
- 4 Gas Turbines (with 2 x Steam Turbines);
- Coal gasification technology in syngas production plant;
- CO_2 export cost of £10/te to reflect the operating cost of onshore/offshore transport & offshore storage ;
- Nitrogen from ASU used as dilution gas in gas turbine;
- No hydrogen export;
- Co-storage of nitrogen and hydrogen as a mixed gas.

<u>Key Parameters Selected for the CCGT Comparison Case</u>

- East Yorkshire coastal location;
- 10km separation between CCGTs and storage caverns;
- 4 Gas Turbines (with 2 x Steam Turbines);
- Weekday Diurnal operation - 12hrs on / 12hrs off weekdays, off all weekend;
- CO_2 export cost of £10/te to reflect the operating cost of onshore/offshore transport & offshore storage.

1.3.2 Development of the Representative System

Refer to Figure 2 – BFD for Representative System (page 23)

In the absence of a technology with a clear advantage over the others, and to show how coal compares with the CCGT at lower loads, gasification of coal has been selected as the hydrogen-rich syngas production route for the representative system. The process typically comprises coal milling and drying, gasification to form a synthesis gas (syngas), made up largely of hydrogen and carbon monoxide, shifting the syngas with steam to produce additional hydrogen and to convert the carbon monoxide to carbon dioxide (CO_2), heat recovery and separation of the syngas into a hydrogen-rich stream, a CO_2-rich stream and an H_2S-rich stream. Sulphur is then recovered from the H_2S-rich stream and the remaining components recycled to the syngas. The CO_2-rich stream is dried, compressed and exported for sequestration.

In this system, combined storage of hydrogen-rich syngas with nitrogen has been considered. Both the hydrogen-rich syngas stream and nitrogen gas from the Air Separation Unit are mixed before leaving the syngas production plant, which operates continuously.

The power island is operated intermittently with a weekday diurnal operational mode (producing peak power during weekdays for 12 hours per day). While the gas turbines are offline during weekends and weeknights, hydrogen-rich syngas is routed to the underground salt cavern storage facility. While gas turbines are online during weekdays, gas turbines receive mixed syngas/nitrogen gas from both underground storage and directly from the syngas production plant.

The power island comprises four GE Frame 9A Syngas turbines, combined with two steam turbines which produce approximately 1.3 GW net electricity under full load operation. As a result of the weekday diurnal operating regime producing power for only 60hrs per week, the long term average power generated is only 36% of the total power island capacity. It is not uncommon for load following plants in the UK to operate at this type of load factor.

Technical Performance

Table 1 summarises the key technical performance data for the representative case.

Table 1 - Summary of Technical Performance on a Long Term Basis with Weekly Diurnal Operation Regime of Power Island

Technical Performance			
	Feedstock Flow Rate	te/h	195.0
	Total Feedstock LHV	MWth	1408.6
	Carbon in Feeds	te/h	126.4
	Carbon Captured	te/h	113.7
	% Carbon Captured		90.0%
	CO_2 Captured	te/h	417.5
	Oxygen Consumption	te/h	146.8
Power Balance			
	Syngas Production Plant	**MWe**	**-71.0**
	Pre-treatment, Gasification & Shift	MWe	-12.8
	Heat Recovery & Steam Turbine	MWe	84.4
	Acid Gas Removal	MWe	-11.2
	CO_2 Dehydration and Compression	MWe	-35.9
	Sulphur Recovery and Tail Gas Treatment	MWe	-2.5
	Air Separation Unit	MWe	-49.0
	N_2/H_2 compression	MWe	-39.3
	Fresh Cooling Water	MWe	-1.4
	Sea Cooling Water	MWe	-3.5
	Cavern storage	**MWe**	**-38.1**
	Combined Syngas and N2 Compression	MWe	-51.5
	Combined Syngas and N2 Drying at Cavern Outlet	MWe	-0.2
	Combined Syngas and N2 Expansion Turbine	MWe	13.6
	Power Generation	**MWe**	**558.8**
	Offsites & Utilities	**MWe**	**-3.2**
	Total Continuous Power Import	**MWe**	**-112.4**

	Total Intermittent Power Export	**MWe**	**558.8**
	Net Power Export	**MWe**	**446.4**
	Net Plant Efficiency (LHV)		**31.7%**

The data shown represents the long term average mass and energy balance, with the syngas production plant operating continuously and the power island following weekly diurnal operation pattern.

Gasification plant efficiency for a steady state operation (without any underground storage) is reported in WP1 as 34.4%. Introducing mixed gas storage for flexible (weekly diurnal) peak power generation reduces the plant efficiency for the overall plant by 2.7 LHV efficiency % points. This lower efficiency is mainly attributable to the parasitic load required by the compressor to pressurize the mixed gas up to cavern storage pressure, not all of which can be recovered in the expansion turbine.

Availability

An initial plant availability of 85% has been assumed for the gasification plant. As the syngas plant is running continuously, unless additional capacity is installed, this will set the overall availability for the representative case system.

Project Execution Schedule

An indicative schedule has been prepared demonstrating the likely time-frame of the project (Attachment 4). The estimated duration of the project from the start of exploration and planning activities through the full project life cycle to a fully functional hydrogen production/power island and storage system is 10 years.

1.3.3 Development of the Baseline CCGT Case

The overall process scheme is based upon a two train natural gas fired combined cycle gas turbine (CCGT) system; each train comprises two MHI M701G2 natural gas fed 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.

The natural gas feed rate is 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 carbon capture scheme for each train is configured with three trains of MEA absorption, two trains of stripping and two trains of CO_2 compression and drying.

The plant performance data for the CCGT case have been evaluated at 90% carbon capture, based on the reference conditions for this study, with ambient temperature of 32°C (rather than 15°C used in the ETI CCS Benchmark study).

The baseline CCGT system is operated intermittently, following the same weekday diurnal operating pattern as the power island of the representative system.

CO_2 Buffer Storage

As the CCGT system operates intermittently, the CO_2 production from the system will also be intermittent, with CO_2 available for transport and long term storage for 12 hours a day, 5 days per week. This peak CO_2 flow requires pipeline diameters, topsides elements and wells to be designed for the full flow of CO_2, which will lead to an underutilised system. The operating frictional pressure drops in the transfer pipeline will also vary due to fluctuating nature of the flow – something that should be avoided if possible due to the complex phase behaviour of CO_2.

The concept of using salt caverns for CO_2 buffer storage is to maintain a relatively constant flowrate of CO_2 to offshore storage, and hence avoid the cost and operating challenges of designing long transfer pipelines and sequestration wells for peak CCS flows.

The salt cavern location for CO_2 buffer storage for this case is chosen as East Yorkshire, to be consistent with the representative case. The high cavern operating pressure (270 bara) at that location is suitable for storage of CO_2 as a supercritical fluid. A single cavern is sufficient for the buffering needs of the CCGT case.

While the CCGT system is operating, a steady flow of supercritical CO_2 is routed into the transmission pipeline system for permanent offshore storage. The remainder is pumped into the salt cavern at pressure for buffer storage. When the CCGT system is offline, CO_2 is withdrawn from the cavern and let down through a valve back into the transmission pipeline system.

Technical Performance

Table 2 represents the performance figures of the CCGT plant operating intermittently following weekly diurnal operation pattern.

Table 2 - Summary of Technical Performance for Baseline CCGT Case on a Long Term Basis with Weekly Diurnal Operation Regime

Technical Performance		Hourly Operating Basis	Long Term Basis - Weekly Diurnal Operational Mode
Feedstock Flow Rate	te/h	218.9	78.2
Total Feedstock LHV	MWth	2884.8	1030.3
Carbon in Feeds	te/h	160.9	57.5
Carbon Captured	te/h	145.3	51.9
% Carbon Captured		90.3%	90.3%
CO_2 Captured	te/h	532.6	190.2
Power Balance			
CCGT Gross Capacity	**MWe**	**1608.7**	**574.5**
Gas Turbines	MWe	1223.7	437.0
Steam Turbines	MWe	385.0	137.5
Auxiliary Loads	**MWe**	**-234.9**	**-83.9**
Power Island	MWe	-108.2	-38.6
Acid Gas removal	MWe	-60.8	-21.7
CO_2 Compression	MWe	-48.8	-17.4
Offsites and Utilities	MWe	-17.1	-6.1
Net Power Export	**MWe**	**1373.8**	**490.6**
Overall Plant Efficiency (LHV)		**47.6%**	**47.6%**

Using an ambient air temperature of 32°C for this study affects the overall performance of the system, as the gas turbine power output reduces with increased inlet air temperature.

Availability

A natural gas fired CCGT (without capture plant) may have a typical availability of over 95%, but an overall plant availability of 90% is assumed including the capture plant, and especially considering the effects that the weekly diurnal operating regime may have on the amine unit.

1.4 Overall Performance Results

Table 3 summarises the technical performance data for the coal gasification case and CCGT cases both with and without CO_2 buffer storage. Each is based on four gas turbines operating in a weekly diurnal operating regime to produce peak electricity. The coal gasification case assumes GE Frame 9A syngas variant turbines which require nitrogen diluent gas, whereas the CCGT cases assume use of natural gas fired MHI M701G2 gas turbines. In the coal gasification case, hydrogen-rich syngas is produced continuously in the syngas production plant, and mixed with nitrogen from the ASU in the proportion required for the gas turbines. CO_2 is captured and exported continuously from the syngas production plant. During periods when the gas turbines are not operating, the mixed gas is compressed and routed to underground salt cavern storage. During periods when the gas turbines are operating, the mixed gas direct from the syngas production plant together with an amount withdrawn from the cavern and let down through expansion turbines, is combusted in the power island to produce peak power.

In the CCGT cases, the entire scheme for flexible power generation is subjected to the flexible operating regime. The requirement for the amine plant to close down overnight and at weekends and the sequencing and timings of start-up activities will need to be studied with dynamic simulation, but no insuperable difficulties are expected, even taking into account the large size of the amine plant needed for a 300MW gas turbine. CO_2 is exported intermittently to offshore transport and permanent storage.

In the CCGT case with CO_2 buffer storage, the CO_2 export stream from the CCGT plant is buffered using a salt cavern. While the CCGT system is operating, a steady flow of supercritical CO_2 is routed into the transmission pipeline system for permanent offshore storage. The remainder is pumped into the salt cavern at pressure for buffer storage. When the CCGT system is offline, CO_2 is withdrawn from the cavern and let down through a valve back into the transmission pipeline system. By introducing a temporary storage of CO_2, a constant CO_2 transmission flow is maintained while CCGT system is operating intermittently. This allows the offshore transport and permanent storage facilities to be designed for the smaller, average flow rather than the intermittent peak flow.

The key differences between the technical performance, capital and operating costs and LCOE can be summarised as follows:

- The overall efficiency figures show that the natural gas fired CCGT case is more efficient (47.6%) than the coal gasification case (31.7%) due to the lower parasitic load requirement and higher gross power production by natural gas fired gas turbines. Higher parasitic demand for coal IGCC case can be attributed to the power required by the ASU and the mixed gas compressor to pressurise the gas up to the cavern pressure.
- Even with the operational uncertainty introduced by operating a CCGT with CO_2 capture plant in a flexible operating regime, a better overall availability is expected for the natural gas fired CCGT cases (90%) than the coal gasification and syngas-variant turbines (85%). This gives the CCGT cases a significant economic advantage over the gasification case.
- The CCGT case with CO_2 buffer storage has the lowest overall project capital cost of the three options at £2.2 billion. The CCGT without buffer storage has a very similar capital cost, within 1.5%, which is considered to be within the level of accuracy of the calculations.

Table 3 – Overall Summary Performance Data
(Long Term Basis with Weekly Diurnal Operating Regime)

		Coal Gasification	CCGT without CO_2 buffer storage	CCGT with CO_2 buffer storage
Technical Performance				
Feedstock Flow Rate	te/h	195.0	78.2	78.2
Total Feedstock LHV	MWth	1408.6	1030.3	1030.3
Syngas LHV	MWth	951.4	-	-
Carbon in Feeds	te/h	126.4	57.5	57.5
Carbon Captured	te/h	113.7	51.9	51.9
% Carbon Captured	%	90.0%	90.3%	90.3%
CO_2 captured	te/h	417.5	190.2	190.2
Oxygen Consumption	te/h	146.8	-	-
Availability	%	85%	90%	90%
Power Balance				
Process Plant Note 1	MWe	-71.0	-77.8	-77.8
Power Generation	MWe	558.8	574.5	574.5
Offsites & Utilities	MWe	-3.2	-6.1	-6.1
Cavern Plant	MWe	-38.1	-	-3.3
Combined gas Compression + Drying	MWe	-51.7	-	-3.3
Combined Gas Expansion Turbine	MWe	13.6	-	-
Total Continuous Power Import	MWe	-112.4	-	-
Total Intermittent Power Export	MWe	558.8	490.6	487.4
Net Power Export	MWe	446.5	490.6	487.4
Overall Plant Efficiency (LHV)	%	31.7%	47.6%	47.3%
Capital Costs				
Process Plant Capital (TPC)	Million £	882	1038	1038
Storage Cavern Capital (TPC)	Million £	435	-	85
Power Island Capital (TPC)	Million £	1074	895	895
Offshore CO2 Transport and Storage Capital (TPC)	Million £	251	300	183
Total scheme capital (TPC)	Million £	2641	2232	2201
Capital Intensity	Million £/MWe	4.73	4.55	4.52
Operating Costs				
Process Plant Opex Note 2	Million £/yr	144	-	-
Storage Cavern Opex	Million £/yr	25	-	3
Power Island Opex	Million £/yr	23	245	245
Cost of Import Electricity (continuous) Note 3	Million £/yr	68	-	2
Total operating cost of CO_2 disposal (per year) Note 4	Million £/yr	31	15	15
Total scheme OPEX	Million £/yr	291	260	265
OPEX intensity	Million £/yr/MWe	0.52	0.48	0.49
Simplified LCOE Estimate				
Project Life	years	30.0	30.0	30.0
Discount Rate	%	10%	10%	10%
LCOE Export (peak) – excluding Offshore T&S Capital	£/MWe	133.5	114.4	118.1

	LCOE Export (peak) – including Offshore T&S Capital	£/MWe	140.4	123.4	123.6

Notes 1: Process Plant includes the syngas production plant with CO2 capture unit for the Coal Gasification scheme and the Power Island with CO2 capture unit for the CCGT scheme.
2: Assuming a cost of coal of £70/te (0.94p/kWh), natural gas of $6.6/MMBTU (1.5p/kWh)
3: Assuming a cost of imported electricity of £72/MWh, from DECC, 2012.
4: The operating cost of onshore/offshore CO_2 transport & offshore storage

- The coal gasification case estimate gives a total project cost of £2641m, which is £440m more expensive than the CCGT case with CO_2 buffer storage. This is mainly due to the cost of constructing 4 salt caverns compared to 1 cavern required for CO_2 buffer storage; more expensive cavern topside processing equipment; and the capital cost difference between GE Frame 9A syngas variant gas turbines and natural gas fired MHI M701G2 gas turbines.
- The operating cost figures are heavily influenced by the price of the feedstock, where the difference between coal and natural gas prices results in higher costs for the CCGT cases. However, the costs of CO_2 emissions are higher for coal processes than gas. Also, the cost of importing electricity on a continuous basis to supply the parasitic load of the syngas production plant contributes a significant additional operating cost for the gasification case. Overall, the operating costs of the CCGT cases are therefore 9-11% lower than the gasification case.
- When offshore transport and storage costs are included in the LCOE calculation, the coal gasification case (£140.4/MWe) is 14% more expensive than the CCGT case (£123.4/MWe).
- The LCOE for the CCGT with and without buffer storage is almost equal when offshore transport and storage costs are included. This suggests that buffer storage of CO_2 as a means of stabilising the flows of CO_2 to storage and hence offsetting the costs of offshore facilities should not be ruled out. However, the increased stability of the flow of CO_2 to offshore storage may be a more important reason to consider implementing a CO_2 buffer store than cost alone.

Overall, the high LCOE of all of these schemes require electricity to be priced above £125/MWe for 60hrs/week throughout the year.

It may be possible to improve the LCOE of these schemes by operating for longer periods and hence reducing the size of the buffer storage. However, any regime where the power island/CCGT operates for longer periods of time would also have to sell its electricity over longer periods, and would have to sell some of that power at lower prices.

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's modelling, using its Energy System Modelling Environment ("ESME") shows that flexible power generation systems comprising hydrogen generation with Carbon Capture and Storage ("CCS"), intermediate storage (particularly using salt caverns) and flexible turbines are attractive components in a future UK Energy system. In such a system, hydrogen is supplied from coal and biomass fired gasifiers and steam methane reformers, with carbon dioxide ("CO_2") captured for storage. This permits the use at high load of capital intensive and relatively inflexible conversion and CCS equipment, filling hydrogen storage when power is not needed, and releasing hydrogen at short notice through turbines when power is at a premium. Superficially there are no barriers to using salt caverns as stores; as such stores are in use in the USA. However, these are for high value added applications and not for use in power where loss of efficiency is a more serious drawback. The ETI currently lacks sufficient data and knowledge to build a good representation of costs or efficiency (particularly relating to hydrogen storage) in ESME.

The purpose and focus of this project is:

- To improve the ETI's understanding of the economics of flexible power generation systems comprising hydrogen production (with CCS), intermediate hydrogen storage (e.g. in salt caverns) and flexible turbines; and
- To focus on the potential, economics and technical requirements for salt cavern storage and flexible turbines, to enable refinement of the ETI Energy System Modelling Environment (ESME) model in order to confirm or adjust ESME findings.

2.1 Scope of Study

The Hydrogen Storage and Flexible Turbine Systems Project is split into five work packages. The first three work packages (WP1, WP2 & WP3) are focused on data collection and research in order to derive a basis for techno-economic analysis in WP4. Using the output from the WP4 modelling, a representative system will be selected. In WP5, this representative system will be compared against a post combustion CCGT case:

- WP1 – Hydrogen Power Production;
- WP2 – Hydrogen Storage;
- WP3 – Supporting Studies;
- WP4 – Development of a Flexible Modelling Tool;
- WP5 – Identification of a Representative System and Comparison of CCGT with CO_2 Buffer Storage.

This report covers the work undertaken in the execution of WP5 – Identification of a Representative System and Comparison of CCGT with CO_2 buffer storage.

2.2 Scope of WP5 – Identification of a Representative System & Comparison of CCGT with CO_2 Buffer Storage

The aim of WP5 is to pull together the work in Work Packages 1 to 4 to identify and develop the configuration for a representative 'Hydrogen Storage and Flexible Turbine' system for UK application. The representative system will be compared to a baseline of a CCGT with post combustion carbon capture, either with or without CO_2 storage buffering. The CCGT case will be based on the results of the earlier study carried out by Foster Wheeler for the ETI.

The scope includes production of the following deliverables for the chosen representative system:

- Design basis;
- Block flow diagram;
- Process description;
- Outline heat and mass balance;
- Outline utility summaries;
- Unit lifetimes and availability;
- Capital and operating cost estimates; and
- Outline project execution schedule.

The scope of the facility consists of feedstock preparation and storage; gasification/reforming; hydrogen separation, compression and storage; CO_2 removal and compression; hydrogen-fired combined cycle power generation; power export; associated utility, offsites and infrastructure.

The scope includes the pipeline and wells to/from the storage facilities. Based on CO_2 flowrates calculated by Foster Wheeler, the estimated costs of CO_2 transportation and storage (provided by the ETI) are included within the overall estimates.

The WP5 report forms a part of the Final Report deliverables for the Hydrogen Storage and Flexible Turbine Systems Project.

3. IDENTIFICATION OF A REPRESENTATIVE SYSTEM

The first task within Work Package 5 was to identify a Representative System to be developed further and compared with a CCGT case. Agreement was reached at a review meeting through review of the capital costs and LCOE results arising from running a number of cases, followed by discussion of the relative merits of various options.

The key points that influenced the decision are outlined below:

Cost Variables	The cost variables given in the WP4 Modelling Basis document (import prices, export prices, project financial parameters) were accepted, with the exception of the CO_2 export price. CO_2 does not have a price as a saleable commodity at the plant battery limit. A CO_2 export price of -£10/te was agreed as a more representative of the costs of running the transport and storage parts of the plant.
Syngas Plant Technology	It was considered that a coal gasification case would provide a more interesting comparison with a natural gas fired CCGT case, and provide a larger CO2 capture flow. Biomass was not considered to be a useful addition, as substantial quantities of biomass would be required, and the economic case for biomass firing relies on additional, and as yet unclear, government policy and tax incentives.
No Hydrogen Export	Hydrogen export opportunities will not be considered, as there is no sensible comparison basis for the CCGT case.
Nitrogen as Diluent Gas	With a coal gasification case, an ASU is required in the syngas production plant. As such, co-incident nitrogen is the more obvious choice as a diluent in the gas turbine.
Co-storage of Mixed Gas	With production of both nitrogen and gasification syngas (which is only 89mol% hydrogen), and without any syngas/hydrogen export flow, there is no economic incentive to store these intermediates separately. Combined storage of the syngas and nitrogen as a 'turbine-ready' mixed gas is the cheaper option, minimising cavern numbers and pipelines/topside equipment requirements.
Location of Plant / Caverns	As in the WP4 modelling, it was agreed that the syngas production plant and power island facilities should be co-located to minimise interconnecting pipelines and maximise sharing of O&U facilities. It was proposed to reject the Teesside location since it gives rise to many small caverns, adding complication of integrating many caverns and because both the CAPEX and OPEX are higher. Cheshire and Yorkshire look similar in numerical results, however The Cheshire option would require a brine pipeline, is a relatively urban area with limited access to cooling water, and more challenging access

	to CO_2 storage in the East Irish Sea. East Yorkshire was preferred as it had the minimum number of caverns required, and it is coastal and more rural location, with proximity to sea water and CO_2 storage in the North Sea. The distance between the main plant and cavern was selected as 10km, which was considered reasonable in this region.
Number of Gas Turbines	4 GTs were proposed to improve economies of scale and simplify scaling of CCGT cases (based on 2 GTs with a combined ST).
GT Operating Regime	It was considered desirable to maximise the flexibility of the plant, and maximise the ratio of power island size to syngas production plant size. Effectively, this means producing syngas at a low rate and targeting a small number of peak times at which to generate electricity. It was also considered to be more interesting to use a different (and more complex) case than the modelling in WP4 had already examined. The agreed case was weekday diurnal operation – i.e. operating the power island to export power from 6am until 6pm Monday to Friday.

Overall, it was considered that this should demonstrate a good option for deploying this technology whilst still being a realistic case.

3.1 Key Parameters Selected for the Representative System

- East Yorkshire coastal location with 270 bara storage pressure;
- 10km separation between syngas production plant/power island and storage caverns;
- Weekday Diurnal operation - 12hrs on / 12hrs off weekdays, off all weekend;
- 4 GTs (2 x STs);
- Coal gasification technology in syngas production plant;
- CO_2 export cost of £10/te to reflect the operating cost of onshore/offshore transport & offshore storage;
- Nitrogen from ASU used as dilution gas in gas turbine;
- No hydrogen export;
- Co-storage of nitrogen and hydrogen as a mixed gas.

3.2 Key Parameters Selected for the CCGT Comparison Case

- East Yorkshire coastal location with 270 bara storage pressure;
- 10km separation between CCGTs and storage caverns;
- 4 GTs (2 x STs);
- Weekday Diurnal operation - 12hrs on / 12hrs off weekdays, off all weekend;
- CO_2 export cost of £10/te to reflect the operating cost of onshore/offshore transport & offshore storage;

4. DEVELOPMENT OF THE REPRESENTATIVE SYSTEM

Based on the key parameters outlined in section 3.1, and the Basis of Design for the project given in Attachment 1, the following deliverables have been developed for the chosen representative system:

- Block flow diagram;
- Process description;
- Outline heat and mass balance;
- Outline utility summaries;
- Unit lifetimes and availability;
- Outline project execution schedule; and
- Capital and operating cost estimates.

4.1 Introduction

Refer to Figure 2 – BFD for Representative System (page 23)

Gasification of coal has been selected as the hydrogen-rich syngas production route for the representative system. Gasification is one of the most widely studied routes for power generation using hydrogen rich gas from coal with carbon capture.

The process typically comprises coal milling and drying, gasification to form a synthesis gas (syngas), made up largely of hydrogen and carbon monoxide, shifting the syngas with steam to produce additional hydrogen and to convert the carbon monoxide to carbon dioxide (CO_2), heat recovery and separation of the syngas into a hydrogen-rich stream, a CO_2-rich stream and an H_2S-rich stream. Sulphur is then recovered from the H_2S-rich stream and the remaining components recycled to the syngas. The CO_2-rich stream is dried, compressed and exported for sequestration.

In this system, combined storage of hydrogen-rich syngas with nitrogen has been considered. Both the hydrogen-rich syngas stream and nitrogen gas from the Air Separation Unit are mixed before leaving the syngas production plant.

In this representative scheme, the power island is operated intermittently with a weekday diurnal operational mode (four Gas Turbines producing peak power during weekdays for 12 hours per day). The mixed syngas/nitrogen stream is combusted in gas turbines within the power island to produce power during periods of peak demand. The syngas production plant operates constantly to produce hydrogen rich gas. While the gas turbines are offline during weekends and weeknights, the mixed gas (hydrogen-rich syngas and nitrogen gas) is compressed and routed to the underground salt cavern storage facility. While gas turbines are online during weekdays, gas turbines receive mixed syngas/nitrogen gas from both underground storage and directly from the syngas production plant.

Figure 1 demonstrates the storage capacity variation within the salt cavern operating under weekly diurnal mode.

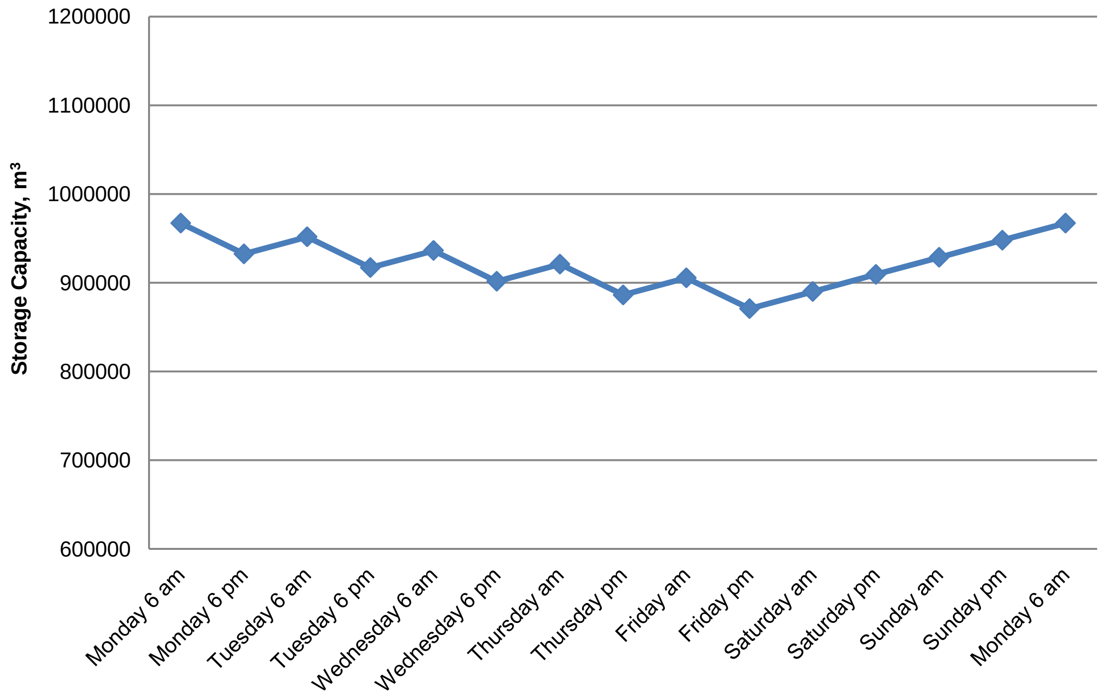


Figure 1: Salt Cavern storage capacity variation over weekly diurnal operation

4.2 Process Description & Operating Pattern

4.2.1 Syngas Production Plant Process Description

The following process description relates to a coal gasification process based on entrained-flow dry-feed gasification processes such as the Shell process.

Coal Milling and Drying

Raw coal as-received is milled and dried to a particle size typically <100 µm and water content <2%. Fluxant is added to adjust the ash melting temperature of the coal.

The pulverized coal and flux from the milling section is pressurized with high pressure nitrogen and fed into an entrained flow gasifier, in which it is gasified with oxygen.

Air Separation Unit (ASU)

The gasification oxygen is produced in an ASU which also provides nitrogen for use as fuel diluent in the power island downstream. The oxygen is produced by the ASU at a pressure of around 50 bara, which is higher than the gasifier pressure, while the nitrogen is produced at around 33 bara (same pressure as syngas produced by the syngas production unit). As combined storage option is chosen for this case, nitrogen is mixed with hydrogen-rich syngas.

Gasification and Syngas Cooling

The dry pulverised coal is gasified using oxygen with moderating steam to produce a raw synthesis gas (syngas) containing mainly CO and hydrogen.

The entrained flow gasifier is a membrane wall reactor installed inside a pressure vessel. In the membrane wall, absorbed heat is used to produce saturated MP steam. The operating temperature of the gasifier zone is about 1500-1600°C. At this temperature, ash from the coal is converted into molten slag, which runs down the gasifier walls to the slag removal zone, where it is contacted with water and solidifies. The operating pressure of the gasifier is 41 bar (abs).

Hot syngas from the gasifier is initially quenched with recycle syngas to approximately 800°C. The combined gas stream then enters a heat recovery steam generator comprising an HP steam superheater, an HP steam generator and an MP steam generator. The gas leaves the heat recovery steam generator duct at 270°C. The cooled gas then flows to a candle- type filter which removes most of the entrained solids. Finally the filtered gas is scrubbed with water in a wash column which removes the remaining fly ash as a slurry in the recirculating water, along with organic acids and ammonia.

Shift Conversion Unit

The cooled scrubbed syngas from the gasification unit at 145°C flows to the Shift Conversion Unit where CO and steam present in the syngas are converted to CO_2 and H_2. In addition, COS and HCN in the syngas are also hydrolysed.

There are three CO shift reactors in series. The syngas is first mixed with additional superheated MP steam and then preheated in the shift interchanger, recovering heat from the syngas leaving the third shift reactor. The syngas/MP mixture enters the first shift reactor at 270°C. The outlet stream at 500°C is used to generate HP and MP steam before entering the second shift reactor at 275°C. The gas leaving the second reactor at 318°C is used to generate additional MP steam, before entering the third reactor at 265°C. The gas leaving the third reactor at 272°C is used to preheat the shift feed as described above and to provide reboil heat for the downstream acid gas removal.

Acid Gas Removal Unit

The AGR Unit removes the H_2S and CO_2 from the shifted syngas by washing with a solvent (DEPG) in order to produce a hydrogen-rich fuel gas.

Rich solvent from the absorber is flashed in two stages in order to recover the dissolved CO_2 at two different pressures. The rich solvent from high pressure flash is routed to the H_2S Stripper where it is heated by LP steam to produce an H_2S-rich stream overhead product. This H_2S-rich stream is sent to a Claus-type Sulphur Recovery Unit (SRU). The low-pressure flash releases most of the dissolved CO_2, which is routed to the CO_2 Dehydration/Compression Unit.

After take-off of a small fraction (approx 8%) of the decarbonised hydrogen fuel gas product for firing of the HP and MP steam superheater, the remainder of the product syngas is mixed with the nitrogen from the ASU.

Sulphur Recovery Unit

The H_2S-rich acid gas from the AGR unit is treated in the Sulphur Recovery Unit (SRU) where H_2S in the acid gas is converted into elemental liquid sulphur.

The SRU comprises a thermal oxidation stage followed by two catalytic stages with elemental sulphur being removed between the stages by condensation. The tail gas from the SRU is hydrogenated to convert sulphur components into H_2S. After hydrogenation, the tail gas is quenched with process water, compressed and recycled back to the inlet of AGR absorber.

CO_2 Purification and Compression Unit

The CO_2 streams from AGR unit flow to the CO_2 Dehydration/Compression Unit where the CO_2 product is initially compressed to 34 bar (abs) and dried to < 50 ppmv water using a molecular sieve adsorption process, before being further compressed to 151 bar (abs) for export to sequestration.

Steam System

125 bar, 530°C steam (HP) and 45 bar, 530°C steam (MP) is generated in the gasification and shift units and superheated as described above in the fired steam superheater. These steam flows supply a condensing steam turbine generating electric power for internal plant use. About 40% of the inlet steam is extracted at 9 bar for miscellaneous heating duties.

4.2.2 Syngas Production Plant Capacity

UK power demand (as illustrated in Figure 9 of WP1 report) shows a significant reduction in power demand on a weekly basis, over the weekend, but also that the largest variation in demand is on a diurnal (day/night) basis. In this study, the decarbonised hydrogen-rich syngas/nitrogen gas mixture available from syngas production plant is stored and used flexibly for peak power production when national grid power demand is higher.

The syngas production plant is operated continuously to producing a constant stream of decarbonised hydrogen-rich syngas/nitrogen gas mixture. Whilst the power island is offline (during periods of low demand), this mixed gas is diverted to underground salt cavern for storage. The capacity of syngas production plant required is therefore dependent on the consumption of the power island - i.e. the number of turbines and the operating regime.

Table 4 shows the hydrogen rich syngas and nitrogen required for a single GE Frame 9F Syngas turbine operating at full load under steady state operation.

Table 4 - Typical Feed Rates of Hydrogen Rich Fuel and Dilution Nitrogen

	Syngas plant capacity	**ASU Capacity**
	Hydrogen Rich Fuel	Dilution Nitrogen
Flow Rate	10,218 kmol/h	9,731 kmol/h
	59,876 kg/h	272,562 kg/h
Molecular Weight (kg/kmol)	5.5	28.01
Composition (mol %)		
Hydrogen	89.31	0.0
Nitrogen	4.34	100.0
Carbon Monoxide	1.57	0.0
Carbon Dioxide	4.23	0.0
Water	0.16	0.0
Argon	0.39	0.0

For this representative system, the power island comprises four GE Frame 9F syngas variant turbines. The operating regime identified is weekly diurnal operation i.e. power island 12hrs on 5 days per week (12hrs off 5 nights per week, and off all weekend). When the four gas turbines are in operation, hydrogen-rich syngas and nitrogen will be delivered from both the syngas production plant and the salt cavern, to satisfy the requirement for full load operation of the gas turbines. Syngas plant capacity required for this representative case is reported in Table 5.

4.2.3 Underground Storage of Mixed Gas

As explained in WP2, the storage of a mixed gas is more cost effective than individual storage of syngas and nitrogen, so this has been selected for this representative case. Therefore, the hydrogen-rich syngas and nitrogen diluent gas is mixed in the syngas production plant and routed to the power island (when gas turbines are online producing peak power) or compressed using a multistage compressor to the pressure required for the storage cavern and routed to underground storage (when gas turbines are offline).

The location selected for underground storage is East Yorkshire, where the maximum cavern storage pressure is considered as 270 bara, and the maximum cavern size is approximately 300,000 m^3.

The amount of gas required to be stored in the cavern will vary depending on the operational mode of power island. Table 5 shows the syngas production plant and air separation unit (ASU) capacity required for weekly diurnal operation. Table 5 also reports the number of salt caverns required to store the mixed gas and the gas injection/withdrawal rate.

4.2.4 Cavern Storage Equipment

When operating an onshore salt cavern as a buffer store for mixed syngas/nitrogen, there will also be above ground equipment required in order to condition the gas entering or leaving the cavern. Figure 3 gives a schematic diagram of a typical above ground installation for an onshore salt cavern storing mixed gas (hydrogen-rich syngas+N2 gas) supplied from a syngas plant and delivered to a gas turbine located in the Power Island.

This includes:

<u>Filter</u> - to remove particulates

<u>Compressor</u> - the mixed gas from syngas production plant needs to be compressed from around 33 bara using a multistage compressor to overcome transfer losses and to attain storage pressure of 270bara.

<u>Heater at cavern inlet</u> - to avoid damaging cavern

<u>Metering stations</u> - at inlet and outlet of cavern to measure losses

<u>Water wash column</u> – at outlet of salt cavern to remove entrained salt

<u>Dehydration unit</u> - using TEG to avoid condensation in transfer pipeline

<u>Heating unit upstream of expansion turbine</u> - to avoid condensation in expansion turbine

<u>Expansion turbine</u> – the gas is let down through a valve to approx 200bara (due to equipment limitations) and then let down through an expansion turbine to recover power from the high pressure gas before sending it to the gas turbine at 30bara.

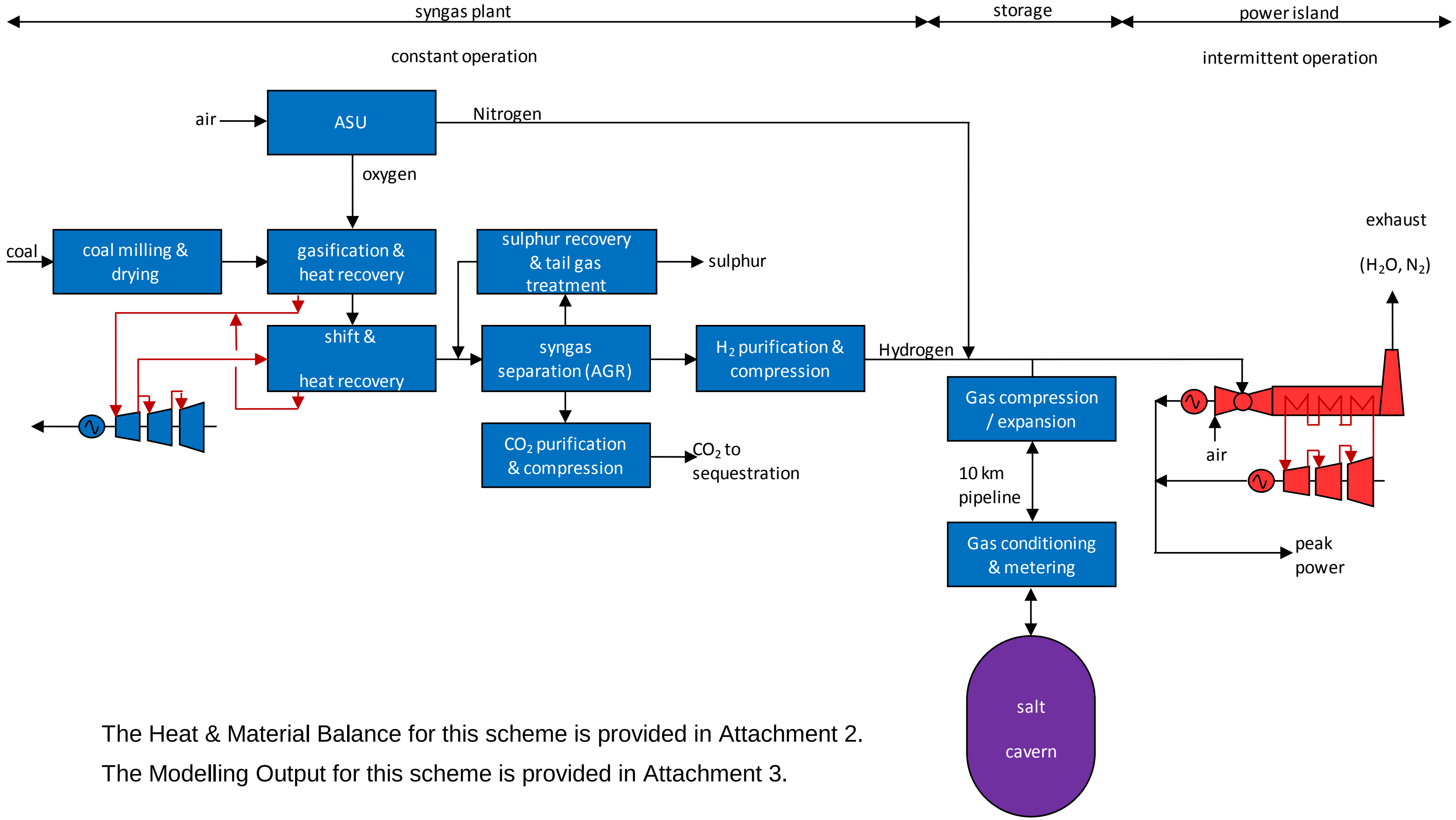
The compression station / heating unit / expansion turbine would be installed local to the syngas plant and power island. Other equipment would be installed local to the storage caverns.

4.2.5 Power Island

The power island comprises four GE Frame 9A Syngas turbines, combined with two steam turbines which produce approximately 1.3 GW net electricity under full load operation.

As discussed above, the operating pattern of the power island for this case is a weekday diurnal regime - 12hrs on for 5 days per week. As a result, the long term average power generated is only 36% of the total power island capacity.

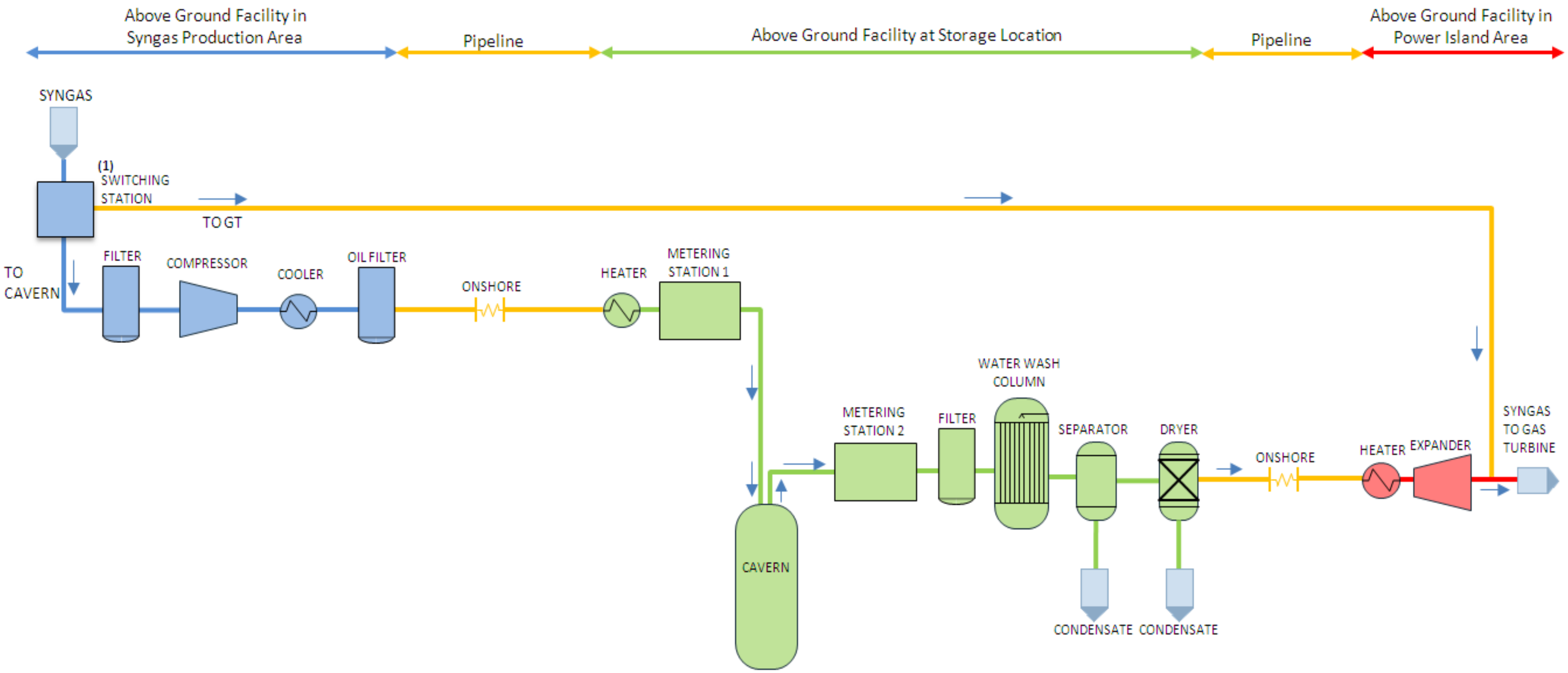
Figure 2 – BFD for Representative System – Coal-fed Gasification with CCS and Combined H_2 / N_2 Storage



The Heat & Material Balance for this scheme is provided in Attachment 2.

The Modelling Output for this scheme is provided in Attachment 3.

Figure 3 - BFD of a Typical Above Ground Installation for an Onshore Salt Cavern Storage Project



(1) When GT is offline, syngas from production plant is transferred to storage cavern only. When GT is online syngas is transferred from storage cavern and directly from production plant simultaneously.

(2) For the representative case, where the syngas production plant and the power island are co-located, a single bi-directional pipeline between the process plant area and storage area can be used.

Table 5 - Calculated Volume and Number of Salt Caverns (maximum cavern size 300,000 m3) required for combined (H2 + N2) gas at 270 bara and 30°C

Operating Mode	**Hours GT offline**	**Syngas Plant Capacity**	**ASU Capacity**	**Mixed Gas Capacity**	**Combined Store Volume**			**Combined Cavern Size**						
(4 GT)		kg/h H2 rich gas	kg/h N2 gas	kg/h H2 rich +N2 gas	Injection rate (m^3/hr)	Working Volume (m^3)	Total Volume (m^3)	no. of caverns	Actual Size of Cavern (m^3)	Cavern Size incl sump (m^3)	Cavern Diameter (m)	Cavern Length (m)	Rate of withdrawal (m^3/hr)	Combined gas to GT (kg/hr)
Reference Case (4 x GT 100% 24 hrs)	0	239,504	1,090,250	1,329,574	-	-	-	-	-	-	-	-	-	1,329,574
Weekly with 12/12 Diurnal (off weekends)	108	85,537	389,375	474,912	3011	322,357	968,040	4	242,010	302,512	51	151	5420	1,329,574

4.3 Technical Performance Results

Table 6 summarises the key technical performance data for the representative case. The data presented represents the long term average mass and energy balance, with the syngas production plant operating continuously and the power island following weekly diurnal operation pattern.

Table 6 - Summary of Technical Performance on a Long Term Basis with Weekly Diurnal Operation Regime of Power Island

Technical Performance			
	Feedstock Flow Rate	te/h	195.0
	Total Feedstock LHV	MWth	1408.6
	Carbon in Feeds	te/h	126.4
	Carbon Captured	te/h	113.7
	% Carbon Captured		90.0%
	CO_2 Captured	te/h	417.5
	Oxygen Consumption	te/h	146.8
Power Balance			
	Syngas Production Plant	**MWe**	**-71.0**
	Pre-treatment, Gasification & Shift	MWe	-12.8
	Heat Recovery & Steam Turbine	MWe	84.4
	Acid Gas Removal	MWe	-11.2
	CO_2 Dehydration and Compression	MWe	-35.9
	Sulphur Recovery and Tail Gas Treatment	MWe	-2.5
	Air Separation Unit	MWe	-49.0
	N_2/H_2 compression	MWe	-39.3
	Fresh Cooling Water	MWe	-1.4
	Sea Cooling Water	MWe	-3.5
	Cavern storage	**MWe**	**-38.1**
	Combined Syngas and N2 Compression	MWe	-51.5
	Combined Syngas and N2 Drying at Cavern Outlet	MWe	-0.2
	Combined Syngas and N2 Expansion Turbine	MWe	13.6
	Power Generation	**MWe**	**558.8**
	Offsites & Utilities	**MWe**	**-3.2**
	Total Continuous Power Import	**MWe**	**-112.4**
	Total Intermittent Power Export	**MWe**	**558.8**
	Net Power Export	**MWe**	**446.4**
	Net Plant Efficiency (LHV)		**31.7%**

Gasification plant efficiency for a steady state operation (without any underground storage) is reported in WP1 as 34.4%. Introducing mixed gas storage for flexible peak power generation reduces the plant efficiency for the overall plant by 2.7 LHV efficiency % points. This lower efficiency is mainly attributable to the parasitic load required by the compressor to pressurize the mixed gas up to storage pressure upstream of salt cavern, not all of which can be recovered in the expansion turbine.

Despite the lower efficiency, the price which can be attained for the intermittent electricity produced at peak times will be higher, which will offset the reduction in efficiency.

4.4 Availability and Life of Plant

Gasification Plant

The overall plant availability of syngas generation plant has tended to be <90%, due to the need for scheduled and unscheduled attention to high temperature parts of the gasifiers, particularly the burners and refractory linings. The licensors are continuously improving their technologies in these respects, but an initial plant availability of 85% has been assumed. As the syngas plant is running continuously, unless additional capacity is installed, this will set the overall availability for the representative case system. The life of most of the equipment and the gasification plant as a whole can be considered to be almost indefinite, at least 50 years.

Unlike natural gas fired plants, coal-fired power plants traditionally have large reserves of raw coal on site, stored on the ground. Historically these have proved invaluable, particularly during periods of industrial unrest. While conditions in the industry have changed, there could be resistance to any drastic cutting back of site coal reserves.

Power Island

The configuration of the Power Island is similar to a conventional natural gas fired combined cycle, except for the addition of preheating and power recovery expansion of the hydrogen/nitrogen fuel gas upstream the gas turbine. A natural gas fired combined cycle may have a typical availability of over 95%, but it is recommended that for our application this value is reduced for the first years of operation to 90%, to take account of initial delays in switching from natural gas to and from the hydrogen/nitrogen fuel gas, together with the time required for the operators to become familiar with operating the power recovery expander.

At least in initial operation of the facility, it is expected that the gas turbines will be started on natural gas fuel, with transition to firing on hydrogen/nitrogen fuel gas taking place after the gas turbine has been connected to the grid. It is difficult at this time to be sure how long this will take. Some gas turbine manufacturers have indicated 15-30 minutes from cold to grid connection, and in this time a certain amount of CO_2 will be emitted, due to firing of natural gas, albeit at low load. It is to be hoped that, as experience is accumulated, it will be possible to switch from natural gas to hydrogen/nitrogen fuel much sooner after start of firing, or even perhaps to start from cold using the hydrogen/nitrogen fuel, thereby almost eliminating use of natural gas with its attendant emission of CO_2.

4.5 Outline Project Execution Schedule

An indicative schedule has been prepared demonstrating the likely time-frame of the project. The scope of creating the storage cavern facilities, as well as providing the syngas production plant / power island, from selection & planning to ready for operation of the combined facilities, has been included.

See Attachment 4 for the Representative System Project Execution Schedule.

4.5.1 Project Life-cycle

The full project life cycle can be split into four main phases as outlined below. Each phase is different in terms of complexity and criticality and various factors have been considered in order to determine the best and the most likely work sequences and durations.

The full life cycle project execution phases are:

1. *The "Pre-FEED" Phase*
    a. This phase involves selecting a suitable site for the salt cavern construction and applying for planning permission to relevant governing authorities. Upon completion of this phase, a site will be selected with an understanding of depth and storage pressure of the proposed salt cavern. This phase will also identify the main contractor for the main packages of the storage and pipelines elements of the project.
    b. In parallel conceptual studies will take place for the main process plant (syngas production and power island), and the location will be determined, together with selection of the licensors for the main packages.
    c. As a conclusion to this phase an assessment of the time and cost of the project approximated to +/-30% will be made. The shareholders will receive sufficient information related to economics/finance to decide whether or not to proceed to the next phase.
2. *The "FEED" Phase*
    a. In this phase the planning and permitting will be further developed, through to full approval for the cavern storage facility and the main process plant sites.
    b. The design is developed in more detail, licensors will develop and issue design packages, from which FEED packages will be prepared.
    c. The design data produced enables the project team to achieve an approximation of the project time and costs to +/- 15%.
    d. The execution contracting strategy will be determined and ITB packages will to be prepared for potential main contractors for the EPC phase.
3. *The "EPC Bid" phase*
    a. In this phase, the ITB packages are sent out to potential main contractors for the various elements of the EPC phase, bids are received back and contracts are awarded depending on the relative attractiveness of the bids.
    b. At the end of this stage, the main workforce for the EPC phase will be defined and the scope split, providing a basis for detailed engineering, procurement and construction work to commence.
4. *The "Execution - EPC/Commissioning & Start-up" Phase*
    a. This phase refers to the project execution activities of the various project elements for storage, pipelines and the main process plant, from start of detailed design through materials procurement, subcontracting, construction, commissioning and start-up, to be ready for operations.

4.5.2 Qualifications and Assumptions

The following explanation describes the main qualifications and assumptions used during assessment of the Overall Project Duration.

- The durations of tasks shown in the schedule, are based on in-house information held by Foster Wheeler, based on historical project data, previous similar project experiences and material supply and installation benchmark data time frames.
- The plant final location, in respect to the H2 storage area and brine discharge, is another fundamental that could change the project durations, mainly due to the pipeline part of work that can vary considerably.
- A timescale in the region of 1.5 years is envisaged for delivery of this FEED phase. Following the FEED stage all the technical and commercial information leading to a determination of the CAPEX with an accuracy of +/-15% will be available for the Final Investment Decision (FID) to be made, before moving ahead with the Execution Phase. This is a major Milestone.
- The project execution strategy has been assumed to be based on a lump sum approach for the execution of the EPC Phases.
- EPC Tender Award encompasses a technical/commercial evaluation of potential EPC contractors. A duration of 1 year is envisaged
- The time span shown under procurement phase is inclusive of delivery at site.
- The duration of the activities shown may vary considerably depending on the period in which the project will be actually executed, mainly due to market conditions with regards to the materials supply and manpower availability.
- Only on-shore plant installation execution has been considered.
- It has been assumed that the plant will be handed over to operations in a system-wise manner as each system is completed. The mechanical completion date shown in the schedules refers to the last system to be mechanically complete and ready for commissioning and start-up.

4.5.3 Storage Facilities Schedule Specific Items

For the storage facilities the exploration/planning period is the most difficult to estimate due to the potential of several uncontrollable factors during the planning process that can jeopardize project deliveries schedule.

<u>Exploration</u>

One of the most critical activities to be executed in this phase is the Initial Site Investigation. The following main activities are required:

- Subsurface mapping;
- Seismic survey (either or both 2D and 3D) of the identified area;
- Drilling of at least one exploration well to prove the nature and properties of the halite and enclosing strata;
- Laboratory test of drill cuttings and core samples; and

- Interpretation and integration of data into a geological model which then will provide necessary information regarding the location, size, shape and composition of the salt beds in the immediate and surrounding areas.

Based on the data obtained following exploration activities, cavern development modelling should be performed which includes:

- Determination of a suitable depth for the cavern;
- Evaluation of operational size of the cavern;
- Pressure limits for storage; and
- Leaching programme.

Planning

Most applications for gas storage projects in salt caverns have gone to Public Inquiry, which introduces delays and therefore uncertainty in planning practices. A recent history of projects developed in the UK shows multiple delays to scheduled activities due to the planning application process. There is therefore a moderate level of uncertainty in the ability to gain planning consent for new proposed storage sites and hence investment.

Considering the aforementioned criticalities, a duration of three years has been estimated to deliver the approval, although it is possible that the total duration of the exploration and planning phase could be 6-7 years.

EPC Execution

For the EPC sub-phases of Engineering, Procurement, and Construction up to ready for operation, each Sub-Phase can be further split according to main Process/Area blocks in line with the Construction sequence.

The main Process/Area blocks identified are:

- Site preparation;
- Wellhead and drilling;
- Leaching facilities;
- Cavern construction;
- Above ground facilities;
- Pipelines; and
- De-brining and gas introduction.

The Engineering phase duration has been estimated in the range of 2.5 years, based on Foster Wheeler’s in-house statistical data of similar projects.

The Procurement phase duration has been estimated in the range of 4 years, from the first enquiry issue to the last material delivered at site. The first materials to be ordered will be those considered critical in terms of prospective lead time or related to the site preparation, well construction, wellhead, leaching facilities, water/brine pipelines, pumping stations and above ground facilities.

The construction phase duration has been estimated in the range of 5 years. Due to the nature of necessary underground works in an unknown/superficially explored area, the total duration could vary from 5 - 6 years depending on potential issues faced during the cavern formation phase.

These three sub-phases can be run in parallel to some degree, with the total EPC phase expected to last 6 years, including the start-up.

The main construction Process/Area blocks identified are listed below in order to outline the works necessary to progress alongside the project schedule:

Site Preparation

- Area clearance and landscaping;
- Access roads;
- Temporary construction facilities;
- Connection to power and water grid;
- Warehouses;
- Disposal areas (if required); and
- Pre-assembly shops.

Wellhead and Drilling

- Construction and installation of the facilities related to drilling of the boreholes to a designated depth below grade;
- Installation of the leaching tubes (water and brine), inlet/outlet gas tube and wellheads; and
- Installation of gas tubes for working gas.

Leaching Facilities

- Construction of pumping station for solution mining;
- Construction of control station; and
- Installation of balance of plant services (BOP - including Piping, E&I etc.).

Cavern Formation

- Introduction of injection water through the strings previously installed during the drilling phase;
- Injection of nitrogen blanket gas to control the cavern shape; and
- Extraction of brine.

Above Ground Facilities

- Installation of above ground gas processing facilities (e.g. metering, drying, etc);
- Construction of control station; and
- Installation of balance of plant services (BOP - including Piping, E&I etc.).

Seawater and Brine Pipelines

- Installation of pipelines for water injection and brine extraction.

Gas Pipelines

- Installation of pipeline(s) to transport gas between the main process plant to the storage cavern(s).

De-brining and Hydrogen Introduction

- Gas introduction for brine removal (through strings previously installed during the drilling phase); and
- Brine removal (through strings previously installed during the drilling phase).

For further explanation and justification for the timescales outlined above, reference should be made to the Project Execution Schedules sections of WP2 Report.

4.5.4 Main Process Plant Schedule Specific Items

The main process plant FEED is carried out in parallel with the storage facility FEED to allow for +/-15% cost estimate preparation ahead of financial sanction. Also an early Pre-FEED means that planning permission relating to the plant can be addressed with the storage facilities approvals.

Given the long durations associated with the cavern planning approvals and for the leaching and cavern formation operations, the overall critical path for the project clearly runs through the storage facilities schedule, as described in the previous section.

As the main process plant schedule overall duration is considerably shorter than for the storage facilities, it is advised that some time is allowed post "H2 Ready" as schedule contingency for the main process plant scope; 5 months has nominally been shown on the schedule. Building the plant earlier will have detrimental effect on cash-flow and will result in a plant needing to be maintained well in advance of its first use, which could impact warranty periods, etc. An alternative would be to have an earlier award and allow longer durations for engineering and slower procurement & construction phases - overall this would reduce schedule risk, but it should be remembered that equipment vendor data is required to complete the design and early orders of equipment could result in storage cost & preservation issues. The schedule detail should be further developed during the FEED phase as part of defining the execution strategy, ahead of project sanction.

As shown on the schedule, the critical path for the project execution of the main process plant is driven by the delivery time span of the main Long Lead Items.

<u>Long Lead Items</u>

- Gasifier Unit – 21 Months
- SRU Unit – 18 Months
- Compressors – 20 Months
- Titanium Plate Heat Exchanger – 18 Months
- Gas Turbine / Steam Turbine – 24 Months

For further explanation and justification for the timescales outlined above, reference should be made to the Project Execution Schedules sections of WP1 Report.

4.5.5 Summary of Overall Project Execution Schedules

Various factors have been considered in order to determine the best and the most likely work sequences and durations. Taking into account the possibility of parallel execution or at least a slight overlap of the above phases, the estimated duration of the project from the start of exploration and planning activities through the full project life cycle to a fully functional hydrogen production/power island and storage system is 10 years.

Table 7 – Project Execution Schedule Summary

Phase	**Duration (Years)**
Pre-FEED	1.5
FEED	1.5
EPC Bid/Award	1
EPCC / Start-up	6
Overall	**10**

5. DEVELOPMENT OF THE BASELINE CCGT CASE

Based on the key parameters outlined in section 3.2, and the Basis of Design for the project given in Attachment 1, the following deliverables have been developed for the baseline CCGT case in order to facilitate techno-economic comparison with the Representative System:

- Block flow diagram;
- Process description;
- Outline heat and mass balance;
- Outline utility summaries;
- Unit lifetimes and availability;
- Capital and operating cost estimates; and

5.1 Introduction

The overall process scheme is based upon two train natural gas fired combined cycle gas turbine (CCGT) system; each train comprises two G class 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.

The natural gas feed rate is 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, are produced to reflect this sizing basis. Key features of the configuration include:

- Power Island Unit – comprising of two parallel trains, each train with two G class 50 Hz gas turbines and two 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 compression to 150 barg based on in-house knowledge of commercially available equipment.

The carbon capture scheme for each train is configured with three trains of MEA absorption, two trains of stripping and two trains of CO_2 compression and drying.

The plant performance data for the CCGT case have been evaluated based on the reference conditions for this study, with ambient temperature of 32°C (rather than 15°C used in the previous CCS Benchmark study).

The baseline CCGT system is operated intermittently to produce power while demand is higher. It follows the same operating pattern as the power island of the representative system with a weekday diurnal operational mode. Four gas turbines and two steam turbines produce power for 12 hours per day, 5 days per week.

5.2 CCGT Process Description

Gas Turbines, Heat Recovery Steam Generators and Steam Turbine

The overall process scheme is based upon two identical trains.

Each train is based on two Mitsubishi Heavy Industries M701G2 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. Each train has got a single steam turbine receiving the steam from two 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 HRSG, 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, leaving the HRSG at approximately 93°C, 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 140 bara, 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 30 bara, through the MP Economiser and into the MP Steam Drum. Water from the MP Steam Drum passes through the MP Evaporator and generates 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 4.5 bara, through the LP Economiser and into the LP Steam Drum. Water from the LP Steam Drum passes through the LP Evaporator and generates 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.

CO_2 Removal

Flue gas is fed to a direct contact cooler (DCC) where much of the water present in the flue gas stream condenses as the gas is cooled to 30°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.

A blower then boosts the pressure of the cooled flue gas sufficiently to overcome the pressure drop in the absorption column. In the lower portion of the 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 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.

The absorption trains are sized based upon a maximum size of absorption column in the region of 15m diameter. 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 MWth per train - this is based upon 4 x 50 MWth reboilers located around the column base.

The lean/rich solvent exchanger, also known as the cross-over exchanger, is another very large 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 this case, 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 4 x 8190m^2 heat transfer surface area exchangers with a duty of 94.21 MW each).

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 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 being returned 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 30ºC.

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.

5.3 CO_2 Buffer Storage in an Underground Salt Cavern

The baseline CCGT system operates intermittently to satisfy peak power demand following the same operating regime as the power island of the representative system, with a weekday diurnal operational mode.

The carbon dioxide production from such system will also be intermittent, with CO_2 available for transport and long term storage for 12 hours a day, 5 days per week. There will be no CO_2 stream available during weekends and weeknights. This peak CO_2 flow requires pipeline diameters, topsides elements and wells to be designed for the full flow of CO_2, which will lead to an underutilised system. The operating frictional pressure drops in the transfer pipeline will vary due to fluctuating nature of the flow– something that should be avoided if possible due to the complex phase behaviour of CO_2.

The motivation for CO_2 buffer storage is to avoid the cost and operating challenges of designing long transfer pipelines and sequestration wells for peak CCS flows.

Salt caverns are an attractive option for buffer storage of CO_2 by which the intermittent flow pattern of peak CO_2 can be avoided. Because of their high deliverability and low impact on stored product composition (assuming a dry cavern is used rather than brine displacement), salt caverns can be used as a short term CO_2 storage buffer to maintain a relatively constant flowrate in long CO_2 pipelines and wells into sequestration reservoirs.

This would be achieved by routing part of the supercritical CO_2 into local salt cavern storage during times of peak production and releasing CO_2 from the salt cavern while CCGT system is offline. By introducing a temporary storage of CO_2, a constant CO_2 transmission flow can be maintained while CCGT system is operating intermittently.

5.3.1 CO_2 Buffer Storage Capacity

The salt cavern location for CO_2 buffer storage for this case is chosen as East Yorkshire, to be consistent with the representative case. The high cavern operating pressure (270 bara) at that location is suitable for storage of CO_2 as a supercritical fluid.

The volume of CO_2 to be stored and number of caverns required for CO_2 storage is presented in Table 8. .

By applying a temporary storage of CO_2, a constant flow of around 190 te/hr of CO_2 to offshore storage can be maintained.

5.3.2 Cavern Storage Equipment

When operating an onshore salt cavern as a buffer store for CO_2, there will also be above ground equipment required in order to condition the gas entering or leaving the cavern. Figure 5 gives a schematic diagram of a typical above ground installation for an onshore salt cavern storing supercritical CO_2.

This includes:

<u>Switching Station</u> – to control bi-directional flow

<u>Supercritical CO_2 pump</u> – multi-stage pump to increase the pressure of the CO_2 fluid from 151 bara to storage pressure of 270 bara

<u>Heater at cavern inlet</u> - to avoid damaging cavern

<u>Metering stations</u> - at inlet and outlet of cavern to measure losses

<u>Filter</u> - to remove particulates

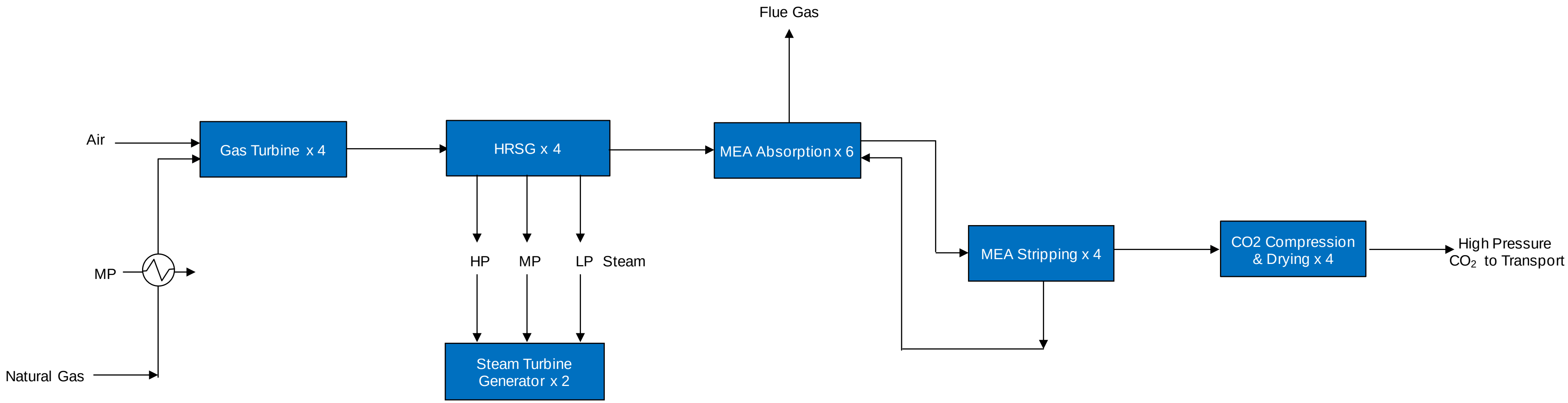
<u>Heating unit upstream of valve</u> - to avoid low temperatures in CO_2 export line

<u>Valve</u> – to reduce and control the pressure of the CO_2 back to export pressures around 151 bara

<u>Dryer</u> – molecular sieve dryer to absorb any residual water in the gas and prevent hydrates in CO_2 export system

The equipment would be installed local to the CO_2 buffer storage cavern.

Figure 4 – BFD for Representative System – Coal-fed Gasification with CCS and Combined H_2 / N_2 Storage



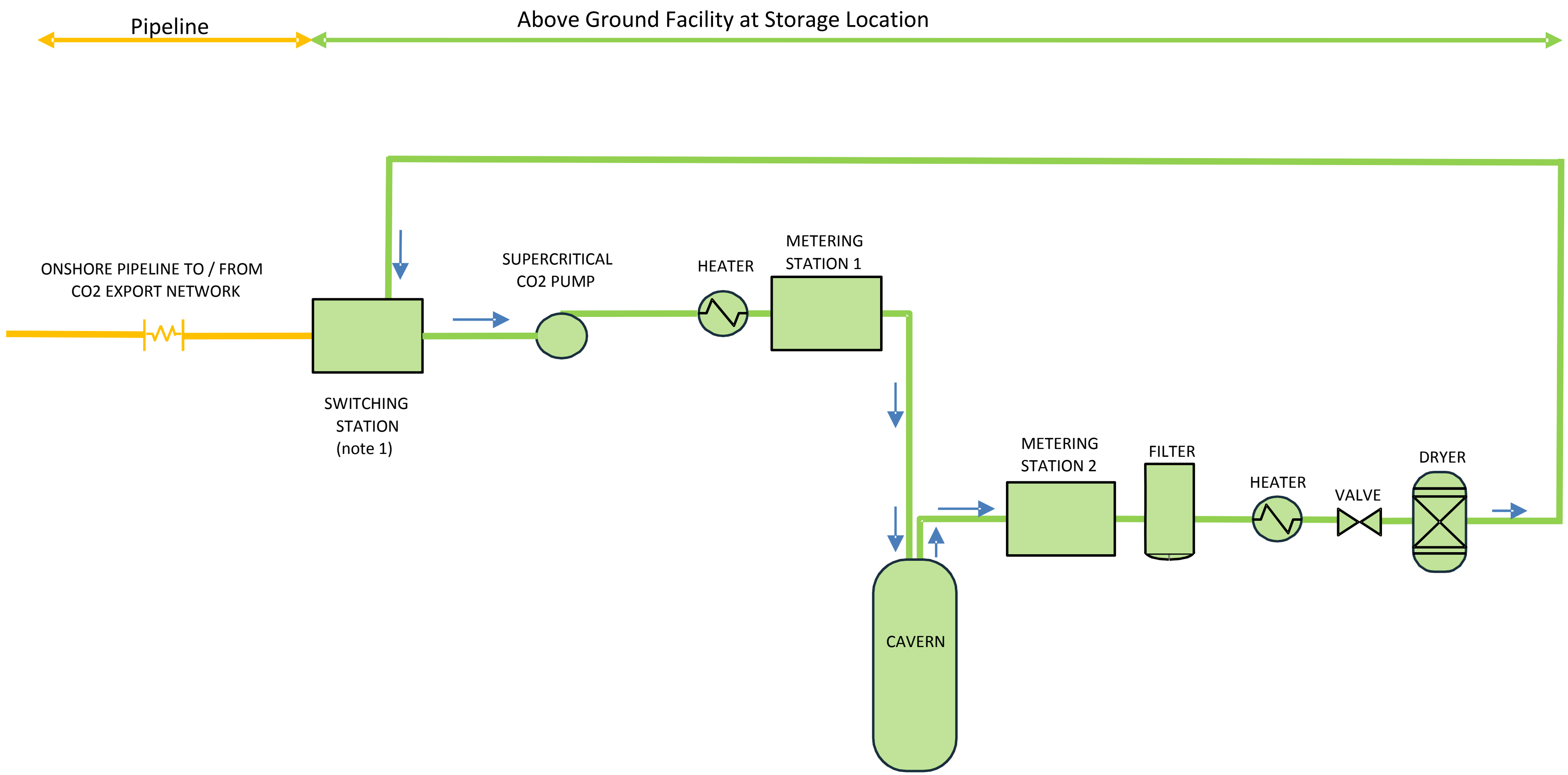
The Heat & Material Balance for this scheme is provided in Attachment 5.

The Utility Summary for this scheme is provided in Attachment 6.

Table 8 - Calculated Volume and Number of Salt Caverns (maximum cavern size 300,000 m3) required for supercritical CO_2 storage at 270 bara and 30°C

(4 GT System)	GT online (hrs)	CO_2 captured (kg/hr)	Flow of CO_2 to storage (kg/hr)	Injection Rate (m^3/hr)	CO_2 Working Volume (m^3)	Total CO_2 Volume incl cushion gas (m^3)	no. of caverns required	Size of Cavern (m^3)	Actual Cavern Size incl 25% sump (m^3)	Cavern Diameter (m)	Cavern Length (m)	Withdrawal Rate (m^3/hr)	Flow of CO_2 from storage (kg/hr)
Weekly Diurnal (off weekends and weeknights)	60	532,591	342,380	416	24,951	74,852	1	74,852	93,565	34	102	231	190,211

Figure 5 - BFD of a Typical Above Ground Installation for a CO2 Buffer Store



(1) When CCGT is online, a steady flow of CO_2 is routed to offshore transmission pipeline and remaining CO_2 is pumped to storage cavern. When CCGT is offline, CO_2 is withdrawn from the cavern and sent to offshore transmission pipeline.

5.4 Technical Performance Results

The plant performance for the CCGT case was assessed at 90% carbon capture. Table 9 represents the performance figures of the CCGT plant operating intermittently following weekly diurnal operation pattern, resulting in emissions to atmosphere of 41.71g CO_2/kWh$_{Net}$ peak electricity exported to the grid.

Table 9 - Summary of Technical Performance for Baseline CCGT Case on a Long Term Basis with Weekly Diurnal Operation Regime

Technical Performance			Hourly Operating Basis	Long Term Basis - Weekly Diurnal Operational Mode
	Feedstock Flow Rate	te/h	218.9	78.2
	Total Feedstock LHV	MWth	2884.8	1030.3
	Carbon in Feeds	te/h	160.9	57.5
	Carbon Captured	te/h	145.3	51.9
	% Carbon Captured		90.3%	90.3%
	CO_2 Captured	te/h	532.6	190.2
Power Balance				
	CCGT Gross Capacity	**MWe**	**1608.7**	**574.5**
	Gas Turbines	MWe	1223.7	437.0
	Steam Turbines	MWe	385.0	137.5
	Auxiliary Loads	**MWe**	**-234.9**	**-83.9**
	Power Island	MWe	-108.2	-38.6
	Acid Gas removal	MWe	-60.8	-21.7
	CO_2 Compression	MWe	-48.8	-17.4
	Offsites and Utilities	MWe	-17.1	-6.1
	Net Power Export	**MWe**	**1373.8**	**490.6**
	Overall Plant Efficiency (LHV)		**47.6%**	**47.6%**

Using an ambient air temperature of 32°C for this study affects the overall performance of the system. Figure 6 demonstrates the variation of gas turbine power output with the ambient combustion air temperature. As the air temperature increases, power output from gas turbine decreases and so the overall plant efficiency also decreases. The gas turbine power output and hence output of the whole plant can be expected to increase by approximately 12.9% for coal gasification case (GE Frame 9F machine) and approximately 13.2% for CCGT cases (MHI M701G2 machine) if an air ambient temperature of 15 ^{o}C is assumed instead of 32 ^{o}C.

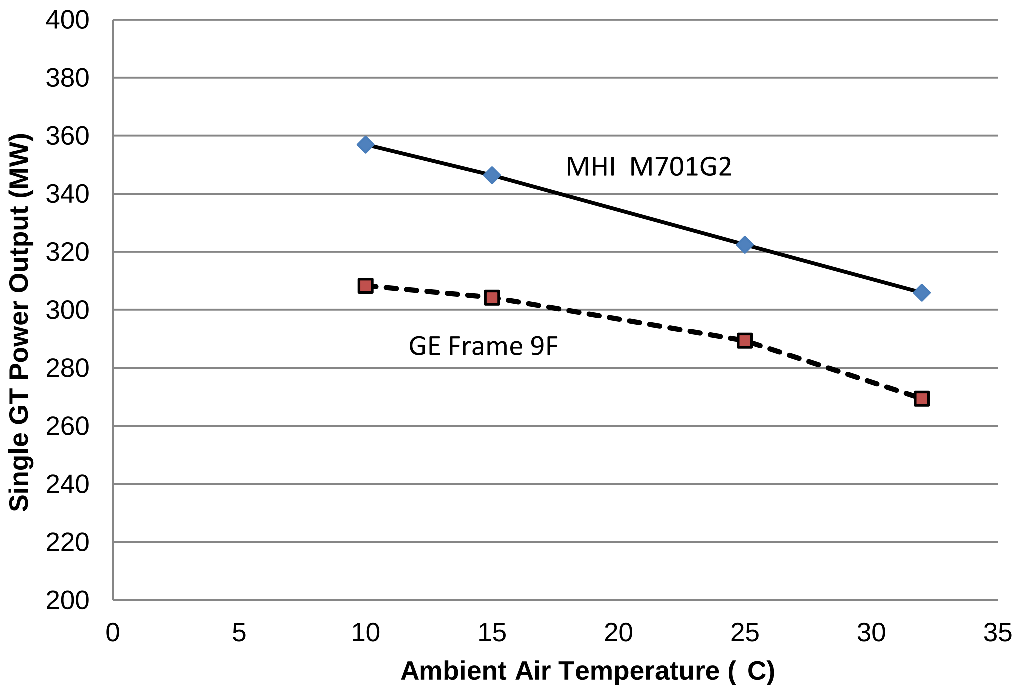


Figure 6 - Gas Turbine power output variation with ambient air temperature

5.5 Availability and Life of Plant

As described in 4.4 above, a natural gas fired combined cycle may have a typical availability of over 95%, but an overall plant availability of 90% is recommended for the first years of operation including the capture plant. This is expected to rise to 95% over time.

While the lifetime of conventional steam plant is almost indefinite, with the former CEGB 500MW units still in full-time operation after 40 years, it is considered prudent to assume a life of 20 years before major renovation of the combined cycle plants. While the gas turbines and HRSG are much more dependable than 10- 20 years ago, the continuous quest for efficiency improvements is leading to higher gas turbine firing temperatures, with perhaps not completely understood long term result on maintenance down-times.

Effects of Plant Operating Regime

It is being proposed to operate the CCGT with post-combustion carbon capture for 12 hrs per day, 5 days per week. It is assumed that the GTs would be 'off' for the remainder of the time. However, this simplistic assumption may have some implications on the CO_2 removal unit.

Up to now most amine-type CO_2 removal units operate continuously as part of a process in an oil refinery or chemical plant. The requirement for the amine plant to close down overnight and at weekends will need to be studied with dynamic simulation, but no insuperable difficulties are expected, even taking into account the large size of the amine plant needed for a 300MW gas turbine.

Two main factors will need to be addressed:

(1) The time required for the hydraulic flow pattern - including solvent hold-up in the absorber and stripper - to stabilise after restarting the solvent circulating

pumps. As a starting point we could assume starting the pumps 15 minutes before start-up of the gas turbine, but if found necessary, earlier starting of the pumps would not add significantly to OPEX, due to the stripper and absorber both operating at near-atmospheric pressure with resulting low impact on pumping power.

(2) It will be desirable for a supply of stripped solvent to be available on start-up of the gas turbine, to minimise excess emission of CO_2 during the start-up phase. A typical time from start-up of the gas turbine from cold to full electrical output being reached is probably about 30 minutes. Over this phase the gas turbine exhaust temperature will rise from ambient temperature to over 500°C. Most of the resulting heat content of the exhaust gas will be captured in the HRSG and can be made available to the amine plant reboilers in the form of LP steam. Nevertheless due to the heat capacity of the HRSG and steam piping and other factors, it is expected that a supply of fresh regenerated solvent will be required equivalent to operation at full load for a period of perhaps 15-30 minutes. One method of providing this solvent is to install an insulated storage tank which is gradually filled with fresh solvent when the plant is running and kept hot overnight and over the weekend. Another concept which could be applied is to install a natural gas fired heater to help regenerate the solvent over the time between start-up of the gas turbine and full availability of LP steam for the amine reboilers. The flue gas from the fired heater could be cooled and introduced into the absorber gas inlet, or perhaps just discharged to atmosphere

6. CAPITAL AND OPERATING COST ESTIMATES

Based on the technical definition developed in Sections 4 & 5, Capital and Operating Costs have been estimated for the representative system and the baseline CCGT case, both with and without CO_2 buffer storage.

6.1 Capital Cost Estimating Basis

The capital cost estimates contained within this study report have been based on the technical definition generated for each of the cases under consideration. These are factored estimates and are based on the scaling of previous similar estimates prepared using Foster Wheeler in-house data, including previous ETI Studies.

For all of the cases, reported the source estimate data has been adjusted to provide figures on a consistent and comparable) 1Q 2010 UK Basis.

Capital cost estimates prepared using this methodology and associated qualifications/exclusions are normally considered to have an accuracy of +/-40% at best. This accuracy is considered on the overall project cost (not individual lines items on the summary).

Estimate Format

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

Representative Case:

- Coal Gasification Plant with Pre-Combustion Capture
    - Coal handling, storage, milling and gasification;
    - Air separation / oxidant supply;
    - Acid gas removal;
    - Sulphur plant;
    - Syngas treatment unit;
    - CO_2 compression and dehydration;
    - Power Block (syngas production plant);
    - O&U / Common facilities;
- Cavern Topside Facilities;
    - Topside Facilities in Syngas Plant Area;
    - Topside Facilities at Inlet to Salt Cavern;
    - Topside Facilities at Outlet of Salt Cavern;
    - Topside Facilities in Power Island Area;
    - Mixed Gas Pipeline;
- Power Island.

CCGT Case:

- Acid gas removal;
- CO_2 compression and dehydration;
- Power Island;
- O&U / Common facilities.

CO2 Buffer Storage Topsides:

- Above Ground Facilities;
- Pipeline.

The common facilities area includes the following major items, as appropriate:

- Interconnecting piping;
- Electrical switchgear/transformers;
- 275 kV cables to new switchyard;
- DCS system;
- Demineralised water system;
- Seawater intake / outfall and associated piping;
- Natural gas system;
- BFW chemical injection;
- Condensate polishing package;
- Chemicals;
- Water treatment;
- Flare package;
- Instrument/utility air package;
- N_2 Generation Package (CCGT plant nitrogen)
- Fire fighting system.

Currency

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:

GB£ 1.00 = US$ 1.52

Escalation

The estimates have been escalated to the date of the reference project (1Q 2010), based on Foster Wheeler experience. No allowance has been made for future escalation.

Major Equipment

The equipment costs have been factored from major equipment of previous (carbon capture) projects of a similar nature. The costs are inclusive up to FOB.

Direct 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.

Bulk Materials

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. The costs include piping, instrumentation, electrical, catalyst and chemicals, spares (commissioning and two years operational) and shipping and freight.

Direct Material and Labour Contracts

These costs include for civil, steelwork, buildings and protective cover and have been factored from projects of a similar nature.

Where necessary, adjustments have been made if source data is from a different location to the UK.

No allowance has been made for seawater intake / outfall and associated piping.

Labour Only Contracts

These costs include for mechanical, electrical and instrumentation, pre-commissioning trade labour support and scaffolding labour costs and have been factored from projects of a similar nature.

Indirect Costs

These costs include for temporary facilities, heavy lifts, commissioning services and vendors engineers and have been factored from projects of a similar nature.

EPC Contracts

These costs include for home office engineering and procurement and construction management and have been factored from projects of a similar nature.

Land / Site costs

No Site specific costs have been included. The site has been assumed to be a generic site clear and level and free from underground obstructions.

The site is assumed to be a green field coastal location on the NE coast of the UK, with adjacent deep sea access, thus limiting the length of the sea water lines (both the submarine line and the sea water pumps discharge line).

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

Owner's Costs

Owner's 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 this estimate:

- 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.

6.2 Operating and Maintenance Cost Estimating Basis

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

- Feedstocks;
- Chemicals;
- Catalyst;
- Solvents;
- Direct labour;
- Maintenance;
- 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.

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:

- Feedstocks (coal or natural gas),
- Solvent consumption for the chemical or physical removal of the acid gases,
- Catalyst consumption for the CO shift reaction and the Claus/Scot unit,
- Chemicals for water/steam treatment and waste water treatment,
- CO_2 emissions,
- Waste disposal.

The following feedstock costs have been specified by the ETI for use on this project:

- Coal - £70/te (0.94p/kWh)
- Gas - $6.6/MMBTU (1.5p/kWh)

To cover the cost that the operator will pay to the storage company for disposal of CO_2, the following emissions costs have been specified by the ETI for use on this project:

- CO_2 - £10/te

Fixed costs

The fixed costs mainly include the following:

- Direct labour
- Administrative 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.

Based on Table 10 & Table 11 below it has been assumed that the Power Island section of the plant will require approximately 40 personnel. Subtracting 40 personnel from the figure required for a gasification plant with carbon capture plant gives an estimate of 88 personnel required for the syngas production plant block for the representative case.

Based on Table 11 below, the number of personnel required for the Combined Cycle Gas Turbine plants with post-combustion CO2 capture has been considered as 60.

Based on Table 12, the number of personnel required for operation of the underground storage facility (including above ground facilities) has been estimated at 19. This is applicable to both the representative case mixed syngas / nitrogen gas storage case and the CO_2 buffer storage case.

Table 10 - Personnel basis for Gasification plants with CO_2 capture

Operation	ASU	Gasification	CCU & Utilities	Total	Notes
Area Responsible	1	1	1	3	daily position
Assistant Area Responsible	1	1	1	3	daily position
Shift Superintendent		5		5	1 shift position
Electrical Assistant		5		5	1 shift position
Shift Supervisor	5	5	5	15	3 shift position
Control Room Operator	5	10	10	25	5 shift position
Field Operator	5	25	20	50	10 shift position
Subtotal				**106**	
Maintenance					
Mechanical group		4		4	daily position
Instrument group		7		7	daily position
Electrical group		5		5	daily position
Subtotal				**16**	
Laboratory					
Superintendent + Analysts		6		**6**	daily position
Total				**128**	

Table 11 - Personnel basis for Combined Cycle Gas Turbine plants without CO_2 capture

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**	

Table 12 - Personnel Basis for Underground Storage

Operation	Total	Notes
Area Responsible	1	daily position
Assistant Area Responsible	1	daily position
Electrical Assistant	1	1 shift position
Shift Supervisor	4	1 shift position
Control Room Operator	4	2 shift position
Field Operator	4	2 shift position
Subtotal	**15**	
Maintenance		
Mechanical group	1	daily position
Instrument group	1	daily position
Electrical group	1	daily position
Subtotal	**3**	
Laboratory		
Superintendent + Analysts	1	daily position
Total	**19**	

Administrative 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 an EPRI study, 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:

- 4.0% for solid handling units;
- 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 (LTSA) with the selected gas turbine manufacturer).

6.3 Cost of CO_2 Buffer Storage

The capital cost of constructing a salt cavern in East Yorkshire location for CO_2 storage has been estimated and presented in Table 13.

Table 13 – CO_2 Buffer Storage Location Parameters and Costs

Key Parameters		
Salt Cavern storage size	m^3	300,000
Salt cavern depth	m	1800
Salt cavern operating pressure	bara	270
Number of caverns required		1
Water/Brine pipeline length	km	5
Costs		
Geological Survey cost	Million £	3.0
Salt Cavern Construction Cost	Million £	26.8
Water pipeline cost	Million £	2.7
Brine pipeline cost	Million £	2.7
Installed Cost of Topside and above ground facility	Million £	25.5
Total Installed Cost	**Million £**	**60.7**
Land Costs (5%)	Million £	3.0
Owners Costs (10%)	Million £	6.1
Contingency (25%)	Million £	15.2
Total Project Cost	**Million £**	**85.1**

The costs of operating a salt cavern for CO2 buffer storage have been estimated and presented in Table 14.

Table 14 – CO_2 Buffer Storage Operating Costs

Million £/y	CASE 3 CO2 BUFFER STORAGE
Fixed Costs	
Direct Labour	1.0
Administration / General Overheads	0.3
Maintenance/ Insurance & Local Taxes Allowance	0.7
Total Fixed Costs	**2.0**
Variable Costs	
Feedstock (Gas)	0.6
Solvent, Catalysts and Chemicals	0.0
Waste Disposal	0.0
Electricity Import	2.1
Potable water import	0.0
CO_2 Emissions	0.0
Total Variable Costs	**2.7**
TOTAL OPERATING COSTS	**4.7**

6.4 Summary of Capital Cost Estimates

Table 15 – Capital Costs Estimate Summary

DESCRIPTION	CASE 1 COAL GASIFICATION	CASE 2 CCGT (without CO_2 Buffer Storage)	CASE 3 CCGT (with CO_2 Buffer Storage)
	Million £	**Million £**	**Million £**
MAJOR EQUIPMENT	747	638	638
DIRECT BULK MATERIALS	276	220	220
DIRECT MATERIAL & LABOUR CONTRACTS	150	111	111
LABOUR ONLY CONTRACTS	225	217	217
INDIRECTS	92	87	87
EPC CONTRACTS	106	108	108
INSTALLED PLANT COST	1596	1380	1380
SALT CAVERN CONSTRUCTION	111	-	61
TOTAL INSTALLED COST	1707	1380	1441
LAND COSTS, 5%	85	69	72
OWNERS COSTS, 10%	171	138	144
CONTINGENCY, 25%	427	345	360
TOTAL ISBL PROJECT COST	**2390**	**1932**	**2018**
CO_2 OFFSHORE TRANSPORT & STORAGE COSTS Note 1	**251**	**300**	**183**
OVERALL PROJECT COST	**2641**	**2232**	**2201**

Note 1: These only have moderate contingency (c15%) and no owners cost etc.

Capital Cost Summaries for each case are provided in the following Attachments:

- Att 7, Capital Cost Summary – Representative Case
- Att 8, Capital Cost Summary – CCGT without CO_2 Buffer Storage
- Att 9, Capital Cost Summary – CCGT with CO_2 Buffer Storage

There are differences in capital costs associated with the offshore transport and storage. ETI have provided a summary of cost data which reflects the capital costs of the offshore pipelines and facilities based on their own in-house data (See Attachment 10).

From Table 15 it can be seen that CCGT case with CO_2 buffer storage has the lowest overall project capital cost of the three options at £2.2 billion. The CCGT scheme without buffer storage has approximately 1.5% higher capital cost than with buffer storage. Thought this scheme does not have any associated underground storage cost but the higher cost is mainly due to the expensive offshore transport and storage which is based on the peak CO_2 load.

The overall project capital cost of the representative system using coal gasification is 17% higher than the CCGT with CO_2 buffer storage. This is mainly attributed to the higher storage cost (4 salt caverns compared to 1 salt cavern), more expensive cavern topside processing equipment and the capital cost difference of the syngas variant gas turbine (GE Frame 9A) compared to natural gas fired gas turbines (MHI M701G2). In addition, there are differences in capital costs associated with the offshore transport and storage.

6.5 Summary of Operating Cost Estimates

Table 16 - Operating Costs Estimate Summary

	CASE 1	CASE 2	CASE 3
Million £/y	**Coal Gasification**	**CCGT without CO_2 Buffer Storage**	**CCGT with CO_2 Buffer Storage**
Fixed Costs			
Direct Labour	7.4	3.0	4.0
Administration / General Overheads	2.2	0.9	1.2
Maintenance/ Insurance & Local Taxes Allowance	73.5	76.8	77.5
Total Fixed Costs	**83.1**	**80.7**	**82.7**
Variable Costs			
Feedstock (Note 1)	101.7	163.3	163.3
Solvent, Catalysts and Chemicals	2.8	0.9	0.9
Waste Disposal	1.4	0.0	0.0
Cavern Topside	1.8	-	0.6
Electricity Import (Note 2)	67.5	-	2.1
Potable water import	1.4	-	-
CO_2 Emissions	31.1	15.0	15.0
Total Variable Costs	**207.6**	**179.2**	**181.9**
TOTAL OPERATING COSTS	**290.7**	**259.9**	**264.6**

Notes 1: Assuming a cost of coal of £70/te (0.94p/kWh), natural gas of \$6.6/MMBTU (1.5p/kWh)
2: Assuming a cost of imported electricity of £72/MWh, from DECC, 2012.

Table 16 shows that the operating costs are dominated by the cost of purchasing feedstock, as would be expected, with gas costing approximately 60% more than coal. This effect is offset by the costs attributed to CO_2 disposal (storage), which are higher for the coal gasification case as there is a higher proportion of carbon in the feedstock. There are also significant costs associated with maintenance, which are similar across all three cases.

For the gasification case, where the syngas plant is operating continuously whilst the power export is intermittent, it has been assumed that the net power required to run the syngas plant will be imported, and that the imported electricity can be obtained at a price reflecting the long-term average grid electricity price (£72/MWh from DECC 2012 data). At £67.5m/yr, the costs of this electrical import are significant, but should be offset to some extent by the power island being able to sell almost all of its power during production at times of peak demand.

7. OVERALL PERFORMANCE RESULTS

Table 17 summarises the technical performance data for the coal gasification case and CCGT cases both with and without CO_2 buffer storage. Each is based on four gas turbines operating in a weekly diurnal operating regime to produce peak electricity. The coal gasification case assumes GE Frame 9A syngas variant turbines which require nitrogen diluent gas, whereas the CCGT cases assume use of natural gas fired MHI M701G2 gas turbines.

In the coal gasification case, hydrogen-rich syngas is produced continuously in the syngas production plant, and mixed with nitrogen from the ASU in the proportion required for the gas turbines. CO_2 is captured and exported continuously from the syngas production plant. During periods when the gas turbines are not operating, the mixed gas is compressed and routed to underground salt cavern storage. During periods when the gas turbines are operating, the mixed gas direct from the syngas production plant together with an amount withdrawn from the cavern and let down through expansion turbines, is consumed in the power island to produce peak power.

In the CCGT cases, the entire scheme for flexible power generation is subjected to the flexible operating regime. The requirement for the amine plant to close down overnight and at weekends and the sequencing and timings of start-up activities will need to be studied with dynamic simulation, but no insuperable difficulties are expected, even taking into account the large size of the amine plant needed for a 300MW gas turbine. CO_2 is exported intermittently to offshore transport and permanent storage.

In the CCGT case with CO_2 buffer storage, the CO_2 export stream from the CCGT plant is buffered by operating a salt cavern. While the CCGT system is operating, a steady flow of supercritical CO_2 is routed into the transmission pipeline system for permanent offshore storage. The remainder is pumped into the salt cavern at pressure for buffer storage. When the CCGT system is offline, CO_2 is withdrawn from the cavern and let down through a valve back into the transmission pipeline system. By introducing a temporary storage of CO_2, a constant CO_2 transmission flow is maintained while CCGT system is operating intermittently. This also allows the offshore transport and permanent storage facilities to be designed for the average flow rather than intermittent peak flow.

In order to quantify the relative merits of operating costs versus capital cost and efficiency it is necessary to perform a high level calculation of the project economic performance over a number of years of operation. In order to do this a simplified levelised cost calculation has been performed for each case. Based on the plant capital cost and plant operating cost (including both imported electricity cost and a cost of CO_2 disposal) over a 30 year period with a discount rate of 10%, we can calculate the Levelised cost of export electricity (LCOE). The LCOE values the overall system (including the salt cavern storage) as a producer of electrical power, by providing an estimate of the break-even price of electricity produced by the power island, assuming four gas turbines following weekly diurnal operating regime to produce peak electricity.

The LCOE values have been provided both excluding and including the costs of offshore Transport and Storage. This enables us to analyse the value of the CO2 buffer storage as it offsets some of the capital costs of offshore T&S.

Table 17 – Overall Summary Performance Data (Long Term Basis with Weekly Diurnal Operating Regime)

			Coal Gasification	CCGT without CO_2 buffer storage	CCGT with CO_2 buffer storage
Technical Performance					
	Feedstock Flow Rate	te/h	195.0	78.2	78.2
	Total Feedstock LHV	MWth	1408.6	1030.3	1030.3
	Syngas LHV	MWth	951.4	-	-
	Carbon in Feeds	te/h	126.4	57.5	57.5
	Carbon Captured	te/h	113.7	51.9	51.9
	% Carbon Captured	%	90.0%	90.3%	90.3%
	CO_2 captured	te/h	417.5	190.2	190.2
	Oxygen Consumption	te/h	146.8	-	-
	Availability	%	85%	90%	90%
Power Balance					
	Process Plant Note 1	MWe	-71.0	-77.8	-77.8
	Power Generation	MWe	558.8	574.5	574.5
	Offsites & Utilities	MWe	-3.2	-6.1	-6.1
	Cavern Plant	MWe	-38.1	-	-3.3
	Combined gas Compression + Drying	MWe	-51.7	-	-3.3
	Combined Gas Expansion Turbine	MWe	13.6	-	-
	Total Continuous Power Import	MWe	-112.4	-	-
	Total Intermittent Power Export	MWe	558.8	490.6	487.4
	Net Power Export	MWe	446.5	490.6	487.4
	Overall Plant Efficiency (LHV)	%	31.7%	47.6%	47.3%
Capital Costs					
	Process Plant Capital (TPC)	Million £	882	1038	1038
	Storage Cavern Capital (TPC)	Million £	435	-	85
	Power Island Capital (TPC)	Million £	1074	895	895
	Offshore CO2 Transport and Storage Capital (TPC)	Million £	251	300	183
	Total scheme capital (TPC)	Million £	2641	2232	2201
	Capital Intensity	Million £/MWe	4.73	4.55	4.52
Operating Costs					
	Process Plant Opex Note 2	Million £/yr	144	-	-
	Storage Cavern Opex	Million £/yr	25	-	3
	Power Island Opex	Million £/yr	23	245	245
	Cost of Import Electricity (continuous) Note 3	Million £/yr	68	-	2
	Total operating cost of CO_2 disposal (per year) Note 4	Million £/yr	31	15	15
	Total scheme OPEX	Million £/yr	291	260	265
	OPEX intensity	Million £/yr/MWe	0.52	0.48	0.49
Simplified LCOE Estimate					
	Project Life	years	30.0	30.0	30.0
	Discount Rate	%	10%	10%	10%
	LCOE Export (peak) – excluding Offshore T&S Capital	£/MWe	133.5	114.4	118.1

	LCOE Export (peak) – including Offshore T&S Capital	£/MWe	140.4	123.4	123.6

Notes 1: Process Plant includes the syngas production plant with CO_2 capture unit for the Coal Gasification scheme and the Power Island with CO_2 capture unit for the CCGT scheme
2: Assuming a cost of coal of £70/te (0.94p/kWh), natural gas of $6.6/MMBTU (1.5p/kWh)
3: Assuming a cost of imported electricity of £72/MWh, from DECC, 2012.
4: The operating cost of onshore/offshore CO_2 transport & offshore storage

The key differences between the technical performance, capital and operating costs and LCOE can be summarised as follows:

- The overall efficiency figures show that the natural gas fired CCGT case is more efficient (47.6%) than the coal gasification case (31.7%) due to the lower parasitic load requirement and higher gross power production by natural gas fired gas turbines. Higher parasitic demand for coal IGCC case can be attributed to the power required by the ASU and the mixed gas compressor to pressurise the gas up to the cavern pressure.
- Even with the operational uncertainty introduced by operating a CCGT with CO_2 capture plant in a flexible operating regime, a better overall availability is expected for the natural gas fired CCGT cases (90%) than the coal gasification and syngas-variant turbines (85%). This gives the CCGT cases a significant economic advantage over the Gasification case.
- The coal gasification case estimate gives a total project cost of £2641m, which is £440m more expensive than the CCGT case with CO_2 buffer storage. This is mainly due to the cost of constructing 4 salt caverns compared to 1 cavern required for CO_2 buffer storage; more expensive cavern topside processing equipment; and the capital cost difference between GE Frame 9A syngas variant gas turbines and natural gas fired MHI M701G2 gas turbines.
- The operating cost figures are heavily influenced by the price of the feedstock, where the difference between coal and natural gas prices results in higher costs for the CCGT cases. However, the costs of CO_2 emissions are higher for coal processes than gas. Also, the cost of importing electricity on a continuous basis to supply the parasitic load of the syngas production plant contributes a significant additional operating cost for the gasification case. Overall, the operating costs of the CCGT cases are therefore 9-11% lower than the gasification case.
- When offshore transport and storage costs are included in the LCOE calculation, the coal gasification case (£140.4/MWe) is 14% more than expensive the CCGT case (£123.4/MWe).
- The LCOE for the CCGT with and without buffer storage is almost equal when offshore transport and storage costs are included. This suggests that buffer storage of CO_2 as a means of stabilising the flows of CO_2 to storage and hence offsetting the costs of offshore facilities should not be ruled out. However, the increased stability of the flow of CO_2 to offshore storage may be a more important reason to consider implementing a CO_2 buffer store than cost alone.

Overall, the high LCOE of all of these schemes require electricity to be priced above £125/MWe for CCGT cases and above £141/MWe for coal gasification case 60hrs/week throughout the year.

It may be possible to improve the LCOE of these schemes by operating for longer periods and hence reducing the size of the buffer storage. However, any regime where the power island / CCGT operates for longer periods of time would also have to sell its electricity over longer periods, and would have to sell some of that power at lower prices.

ATTACHMENT 1
BASIS OF DESIGN

Contract Number:	1.17.13058
Client's Name:	The Energy Technologies Institute
Project Title:	Hydrogen Storage and Flexible Turbine Systems
Project Location:	Generic UK

REVISION	**0**	**1**	**Signature**
DATE	8th Mar 13	5th July 13	
ORIG. BY	A Price	T. Abbott	Tim Abbott
CHKD. BY	S. Ferguson	S. Ferguson	SFerguson
APP. BY	T. Abbott	T. Abbott	Tim Abbott

Hydrogen Storage and Flexible Turbine Systems
Basis of Design

CONTENTS

1.0 INTRODUCTION

The Energy Technologies Institute has employed the services of Foster Wheeler to undertake a study titled "Hydrogen Storage and Flexible Turbine Systems".

This purpose of this Basis of Design document is to provide a clear and consistent basis on which to evaluate each hydrogen storage and flexible turbine technology / configuration option in support of the study.

2.0 PLANT LOCATION

A specific site location is not defined, rather a generic coastal location in the UK is considered. Where applicable, the site is also assumed to be close to an existing harbour equipped with a suitable pier and coal bay to allow coal transport by large ships and associated ease of coal handling.

3.0 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.

4.0 PLANT CAPACITY

Each case considered as part of WP1 will be designed to produce electric energy (350 MWe nominal gross capacity with pre-combustion CO_2 capture) to be delivered to the UK National grid. For each of the cases considered, power generation will be intermittent and will vary according to variation in energy demand, through the use of hydrogen storage and flexible turbine systems.

5.0 PLANT OPERATING CONDITIONS

The following climatic conditions marked (*) shall be considered reference conditions for plant performance evaluation across all 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 32°C (*)

minimum -10°C

6.0 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:

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

7.0 FEEDSTOCK, PRODUCT AND UTILITY SUPPLIES

The streams available at plant battery limits are the following:

Coal;

Biomass;

Natural Gas;

CO_2 product;

Sea water supply;

Sea water Return;

Plant/Raw/Potable water;

Chemicals (including amine);

Sulphur product;

Limestone.

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

8.0 FEEDSTOCK SPECIFICATIONS

8.1 Coal

The coal specification is based on an open-cut coal from Eastern Australia:

Proximate analysis	(wt%)
Inherent moisture:	9.50
Ash:	12.20
Coal (dry, ash free):	78.30

Ultimate analysis	(wt%) (dry ash free)
Carbon:	82.50
Hydrogen:	5.60
Nitrogen:	1.77
Oxygen:	9.00
Sulphur:	1.10
Chlorine:	0.03

Gross CV:	27.06 MJ/kg
Net CV:	25.87 MJ/kg
Hardgrove Index:	45
Ash fusion point (reducing temperature)	1350°C

8.2 Biomass

The biomass used is wood pellets of the following specification:

Proximate analysis	(wt%)
Inherent moisture:	7.00
Volatile matter:	79.00
Fixed carbon:	13.80
Ash:	0.20
Gross CV:	18.70 MJ/kg

Ultimate analysis	(wt%)
Moisture:	7.00
Carbon:	43.50
Hydrogen:	4.50
Nitrogen:	0.20
Oxygen:	42.60
Sulphur:	0.01
Chlorine:	0.01
Ash:	0.2

Ash analysis	(wt%)
SiO_2:	13.70
Al_2O_3:	3.30
Fe_2O_3:	4.90
CaO:	34.40
MgO:	6.70
TiO_2:	0.40

Na_2O:	0.30
K_2O:	24.00
P_2O_5:	5.40
SO_3:	6.80

8.3 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”.

8.4 Back up fuel/power

Natural gas (as detailed in section 8.3) is available for back-up fuel.

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

9.0 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:	≤ 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	350 MWe nominal capacity
Voltage	275 kV
Frequency	50 Hz

9.3 Solid by-products

The power plant cases will produce saleable solid by-products, in particular:

IGCC Cases: slag, flyash

10.0 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.

n.b. Costs of seawater pipelines, intake and outfall are not included within comparative capital cost estimates for WP1.

The following seawater conditions marked (*) shall be considered reference conditions for plant performance evaluation across all WP1 cases. Individual case deliverables will be produced at reference conditions only.

Seawater conditions:

Average supply temperature:	17°C (*)
Average return temperature:	25°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 WP1 cases. Individual case deliverables will be produced at reference conditions only.

Closed loop cooling water conditions:

Average supply temperature:	21°C (*)

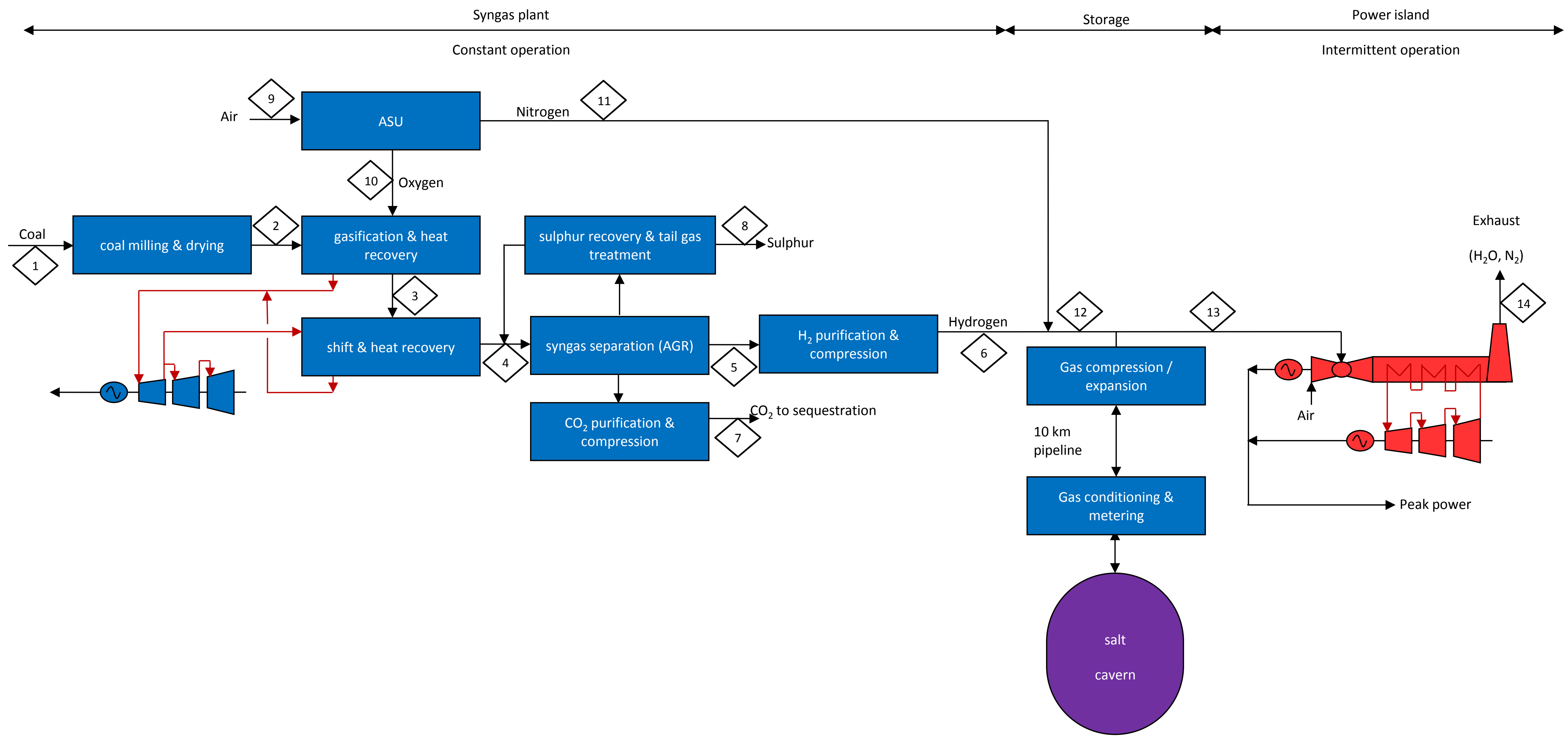
Average return temperature: 31°C (*)

Seawater/closed loop water interchanger ΔT: 4°C (*)

Operating pressure at users: 3.0 bar(g)

Maximum allowable ΔP for users: 1.5 bar

ATTACHMENT 2
OUTLINE HEAT & MATERIAL BALANCE – REPRESENTATIVE SYSTEM



Stream	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Temperature [C]	20.0	74.3	270.1	34.0	34.0	30.0	29.9	24.0	32.0	25.0	30.0	30.0	29.3	106.5
Pressure [kPa]	101.3	5000.0	3850.0	3420.0	3340.0	3340.0	15100.0	101.3	101.3	4950.0	3340.0	3340.0	3030.0	104.0
Mass Flow [kg/h]	195030	185798	702458	521056	85537	85537	417481	1671	606779	146781	389375	474912	1329754	10541804
Molar Flow [kgmole/h]	16731	16223	37119	26818	15544	15544	9650	52	21027	4590	13900	29444	82442	383757
Mole% Hydrogen	25.33	26.15	14.39	56.90	89.31	89.31	1.74	0.00	0.00	0.00	0.00	0.45	0.45	0.00
Mole% CO	0.00	0.00	27.44	1.00	1.57	1.57	0.03	0.00	0.00	0.00	0.00	0.01	0.01	0.00
Mole% CO2	0.00	0.00	0.78	38.68	4.23	4.23	98.14	0.00	0.03	0.00	0.00	0.02	0.02	0.68
Mole% Nitrogen	0.58	0.59	1.99	2.75	4.34	4.34	0.05	0.00	77.31	3.50	100.00	0.52	0.52	74.29
Mole% Oxygen	2.57	2.65	0.00	0.00	0.00	0.00	0.00	0.00	20.74	95.00	0.00	0.00	0.00	11.92
Mole% Argon	0.00	0.00	0.19	0.26	0.39	0.39	0.04	0.00	0.93	1.50	0.00	0.00	0.00	0.81
Mole% H2S	0.00	0.00	0.13	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole% COS	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole% Carbon	62.70	64.66	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% Sulphur	0.31	0.32	0.00	0.00	0.00	0.00	0.00	100.00	0.00	0.00	0.00	0.00	0.00	0.00
Mole% Ash	2.37	2.44	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	6.15	3.18	55.06	0.21	0.16	0.16	0.00	0.00	0.99	0.00	0.00	0.00	0.00	12.29

01	30/07/13	FIRST ISSUE	RR		
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REVISIONS

HYDROGEN STORAGE AND FLEXIBLE TURBINES PROJECT	BLOCK FLOW DIAGRAM
energy technologies institute	CASE 1: COAL FED IGCC WITH COMBINED H2 / N2 STORAGE

ATTACHMENT 3
MODELLING OUTPUT – REPRESENTATIVE SYSTEM

Project Title : Hydrogen Storage and Flexible Turbine Systems
FW Contract No: 1.17.13058

SCALABLE MODEL OF PROJECT PERFORMANCE AND ESTIMATED COSTS

Date: 08/08/2013
Version: 1.2

COST VARIABLES:

	Input	
Import		
Coal Import Price	70	£/te
Biomass Import Price	112.2	£/te
Natural Gas Import Price	196	£/te
Electricity Import Price (long term)	72	£/MWh
Potable Water Import Price	0.5	£/te
Export		
H2 Export Price	1307	£/te
CO2 Disposal Cost	-10	£/te
Offshore Transport and Storage CAPEX		
T&S CAPEX	0	M£
Levelised Cost of Electricity		
Project Life	30	years
Discount Rate	10%	
Cost Factors		
Syngas Plant Capital Cost Scaling Factor	100%	
Salt Cavern Capital Cost Scaling Factor	100%	
Power Island Capital Cost Scaling Factor	100%	
Operating Cost Scaling Factor (Fixed - Labour Related)	100%	
Operating Cost Scaling Factor (Fixed - Capital Related)	100%	
Operating Cost Scaling Factor (Variable - excl. Power & Water)	100%	
Operating Cost Scaling Factor (Variable - Power & Water)	100%	

FIXED ASSUMPTIONS:

Max allowable pipeline pressure drop	15	bar
Maximum allowable pipeline velocity	10	m/s
Recommended Operating Range for FW Velocity/Density Constant	15-50	
Pipeline Length Factor	1.2	
Pipeline design factor	0.5	
Cavern Storage Temperature	30	°C
Cavern Sump Volume	25%	
Expansion Turbine Discharge Pressure	30.0	bara
Water/Brine Pipeline Diameter	16	inches
Initial Syngas Plant Output Pressure	33.4	bar
Power Island Availability	85%	
Capital Cost Scaling Exponent	0.65	
Land Costs Factor	5%	
Owners Costs Factor	10%	
Contingency Factor	25%	

TECHNICAL VARIABLES:

		Input / Select		Selected Option:
A	Syngas Production Technology	1b. Coal Gasifier (Co-Storage)		1b. Gasification of Coal (Gas Co-Storage)
B	Separate or Co-Storage	Co-Storage		Co-Storage of a Syngas/Nitrogen mixture
C	Diluent Gas in Gas Turbine	N2		
D	Location of Salt Cavern	1. Yorkshire		1. Onshore - East Yorkshire
E	Gas Turbine Operating Regime	8. Wkly+D/N-12 (WP5 Basis)		Nitrogen Diluent Gas
F	Distance from Syngas Plant to Salt Cavern	10	km	8. Weekdays on with 12 hrs on/12hrs off, Weekends off
G	Number of Gas Turbines	4	Appropriate range assumed as 1-10	
H	Hydrogen Export Flowrate	0	kg/hr	

ECONOMIC SUMMARY:

Total CAPEX	**2390**	**M£**	
Total OPEX	**260**	**M£/yr**	
Feedstock Price	**101.65**	**£M/yr**	
Feedstock Type	Coal		
Levelised Cost of Electricity	**133.5**	**£/MWh**	
Cash position at end of Project Life	0.0	M£	If non-zero, LCOE requires updating

CALCULATED PARAMETERS:

Syngas Plant Capacity Calculation

SYNGAS - GENERAL

Syngas Thermal Input to Gas Turbine	2664	MWth
Syngas Lower Heating Value (LHV) to Gas Turbine	40,037	MJ/te
Operating Regime Scaling Factor	36%	
Syngas Production Required for GT (Plant Capacity)	85,537	kg/hr
Syngas Output Pressure from Syngas Plant	33.4	bara
Syngas Density at Syngas Plant Output Pressure	7.13	kg/m^3
Syngas Volumetric Flowrate to Cavern Top Side Compressor	11997	m^3/hr

NITROGEN - GENERAL

Nitrogen Production Required for GT	389,375	kg/hr
Nitrogen Pressure from ASU plant	33.4	bara
Nitrogen Density at ASU plant Output Pressure	37.48	kg/m^3
Nitrogen Volumetric Flowrate to Cavern Top Side Compressor	10389	m^3/hr

Hydrogen Export Calculation

Hydrogen Export Flowrate	0	kg/hr
Syngas Hydrogen Content	32.7%	wt fraction
Syngas Export Flowrate	0	kg/hr
Upscaled Syngas Plant Production Required	85,537	kg/hr

Working Volume Calculation at Storage Pressure

Salt Cavern Storage Pressure	270	bara
Density of Syngas at Storage Pressure	53.25	kg/m^3
Dynamic Viscosity of Syngas at Storage Pressure	0.011	cP
Molecular Weight of Syngas at Storage Pressure	5.50	kg/kmol
Syngas Volumetric Flowrate at storage pressure	1606	m^3/hr

Salt Cavern Storage Pressure	270	bara
Density of Nitrogen at Storage Pressure	278.76	kg/m^3
Dynamic Viscosity of Nitrogen at Storage Pressure	0.027	cP
Molecular Weight of Nitrogen at Storage Pressure	28.01	kg/kmol
Nitrogen Working Volume at storage pressure	1397	m^3/hr

Pipelines from Syngas Plant to Salt Cavern for Separate Storage Options

SYNGAS PIPELINE TO CAVERN

	16	inches	(Select Pipesize)
Syngas Pipeline Diameter (selected)	Not Required	mm	
Actual Syngas Velocity	Not Required	m/s	
FW Velocity/Density Constant (vel * sqrt(dens))	Not Required		
Syngas Pipeline Length	Not Required	km	
Syngas Volume in Pipeline	Not Required	m^3	
Syngas Pipeline Pressure Drop	Not Required	bar	
Syngas Pipeline Pressure Drop per unit Length	Not Required	bar/km	
Cavern Inlet Cp/Cv	Not Required	-	
Syngas Compression Power (long-term average)	Not Required	**MW**	

NITROGEN PIPELINE TO CAVERN

	18	inches	(Select Pipesize)
Nitrogen Pipeline Diameter (selected)	Not Required	mm	
Actual Nitrogen Velocity	Not Required	m/s	
FW Velocity/Density Constant (vel * sqrt(dens))	Not Required		
Nitrogen Pipeline Length	Not Required	km	
Nitrogen Volume in Pipeline	Not Required	m^3	
Nitrogen Pipeline Pressure Drop	Not Required	bar	
Syngas Pipeline Pressure Drop per unit Length	Not Required	bar/km	
Cavern Inlet Cp/Cv	Not Required	-	
Nitrogen Compression Power (long-term average)	Not Required	**MW**	

Pipeline from Syngas Plant to Salt Cavern for Combined Storage Options

COMBINED SYNGAS AND N2 PIPELINE TO CAVERN

Combined Syngas and N2 Working Volume at storage pressure	3,011	m^3/hr	
Density of Combined Syngas and N2 at Storage Pressure	157.72	kg/m^3	
Dynamic Viscosity of Combined Syngas and N2 at Storage Pressure	0.018	cP	
Molecular Weight of Combined Syngas and N2 at Storage Pressure	16.13	kg/kmol	
	22	inches	(Select Pipesize)
Combined Syngas and N2 Pipeline Diameter (selected)	549	mm	
Actual Combined Syngas and N2 Velocity	3.53	m/s	
FW Velocity/Density Constant (vel * sqrt(dens))	44.4		
Combined Syngas and N2 Pipeline Length	12.0	km	
Combined Syngas and N2 Volume in Pipeline	2841	m^3	
Combined Syngas and N2 Pipeline Pressure Drop	6.3	bar	
Combined Syngas and N2 Pipeline Pressure Drop per unit Length	0.52	bar/km	
Cavern Inlet Cp/Cv	1.435	-	
Combined Syngas and N2 Compression Power (long-term average)	**51.5**	**MW**	

SCALABLE MODEL OF PROJECT PERFORMANCE AND ESTIMATED COSTS

Calculation of Number of Caverns

SYNGAS/FUEL GAS CAVERN			NITROGEN CAVERN		
Working Syngas Volume in Storage Cavern	322,357	m^3	Working Nitrogen Volume in Storage Cavern	No N2 Cavern	m^3
Cushion Gas (% of cavern volume)	67%		Cushion Gas (% of cavern volume)	No N2 Cavern	
Cushion Syngas Volume in Storage Cavern	645,682	m^3	Cushion Nitrogen Volume in Storage Cavern	No N2 Cavern	m^3
Total Syngas Volume in Storage Cavern	968,040	m^3	Total Nitrogen Volume in Storage Cavern	No N2 Cavern	m^3
Required size of caverns	242,010	m^3	Required size of caverns	No N2 Cavern	m^3
Cavern volume including Sump	302,512	m^3	Cavern volume including Sump	No N2 Cavern	m^3
Approximate Diameter (ave)	50	m	Approximate Diameter (ave)	No N2 Cavern	m
Approximate Length	151	m	Approximate Length	No N2 Cavern	m
Cavern Depth	1800	m	Cavern Depth	No N2 Cavern	m
Total Number of Caverns Required	**4**				

Water/Brine Pipeline (Cavern Construction)

Water/Brine Pipeline Diameter (assumed)	406	mm	16	inches
Water/Brine Pipeline Length	5.0	km		
Water/Brine Volume in Pipeline	649	m^3		
Water/Brine Pipeline Pressure	5.0	bar		

Expansion Turbine

Expansion Turbine Inlet Pressure	200	bara	Initial expansion (270 bar to 200 bar) by expansion valve
Expansion Turbine Discharge Pressure (= GT inlet pressure)	30.0	bar	
Expansion Turbine Inlet Temperature	156	°C	
Expansion Turbine Discharge Temperature	15	°C	
Expansion Turbine Throughput Cp/Cv	1.545	-	
Expansion Turbine Throughput Molecular Weight	16.13	kg/kmol	
Expansion Turbine Power Output (long-term average)	**13.6**	**MW**	

GT Water Consumption

Syngas Plant Potable Water Input Flowrate	261.0	te/h
Power Island Potable Water Input Flowrate	104.4	te/h

TECHNICAL PERFORMANCE DATA:

Hydrogen Production			
	Feedstock flow rate	195.0	te/h
	Total Feedstock Lower Heating Value (LHV)	1409	MWth
	Carbon in feeds	126.4	te/h
	Carbon captured	113.7	te/h
	Carbon captured	90.0%	wt %
	CO2 to Transport & Storage	417.48	te/h
	Oxygen consumption	146.8	te/h
Power Balance (long term average)			
	Syngas Plant	-71.0	MWe
	Cavern Topsides - Syngas Compression	Not Applicable	MWe
	Cavern Topsides - Nitrogen Compression	Not Applicable	MWe
	Cavern Topsides - Combined Syngas and N2 Compression	-51.5	MWe
	Cavern Topsides - Combined Syngas and N2 Drying at Cavern Outlet	-0.2	MWe
	Cavern Topsides - Combined Syngas and N2 Expansion Turbine	13.6	MWe
	Power Generation	**558.8**	MWe
	Offsites & Utilities	-3.2	MWe
	Net Power Export	446.45	**MWe**
	Plant Efficiency (LHV basis) - excluding Storage	**34.40%**	**%**
	Plant Efficiency (LHV basis) - including Storage	**31.7%**	**%**
Availability			
	Syngas Plant Availability	85%	

Project Title : Hydrogen Storage and Flexible Turbine Systems
FW Contract No: 1.17.13058

SCALABLE MODEL OF PROJECT PERFORMANCE AND ESTIMATED COSTS

Date: 08/08/2013
Version: 1.2

CALCULATED COST / ECONOMIC DATA:

Capital Costs

Syngas Plant Capital Cost Scaling Factor	100%	
Gasification / Reforming (incl. coal handling, milling, storage etc.)	172.6	M£
Air Separation / Oxidant Supply	74.3	M£
Air Compression	Not Applicable	M£
Acid Gas Removal (Separate H2S & CO2 Removal)	87.5	M£
Sulphur Plant	23.9	M£
Syngas Treatment Unit (incl. CO Shift & Cooling)	47.7	M£
CO2 Compression	44.6	M£
Power Block	61.2	M£
Offsites & Utilities	118.3	M£
Total Syngas Plant Capital (IC)	**630.1**	**M£**
Salt Cavern Capital Cost Scaling Factor	100%	
Syngas Pipeline (IC)	Not Applicable	M£
Nitrogen Pipeline (IC)	Not Applicable	M£
Combined Syngas and N2 Pipeline (IC)	14.7	M£
Cavern Construction Cost - Drilling (IC)	90.8	M£
Cavern Construction Cost - Solution Mining (IC)	16.6	M£
Cavern Construction Cost - Water/Brine Pipelines (IC)	3.7	M£
Cavern Topsides - Syngas Plant Area (IC)	73.4	M£
Cavern Topsides - Salt Cavern Area (IC)	63.6	M£
Cavern Topsides - Power Island Area (IC)	47.9	M£
Total Salt Cavern Capital (IC)	**310.5**	**M£**
Power Island Capital Cost Scaling Factor	100%	
Power Island capital (IC)	**766.9**	**M£**
Land Costs Factor	5%	
Owners Costs Factor	10%	
Contingency Factor	25%	
Offshore T&S CAPEX	0.0	
Total scheme capital (TPC)	**2390.4**	**M£**
Capital Intensity	5.35	M£/MWe

Operating Costs

Fixed Costs - Labour Related		
Operating Cost Scaling Factor (Fixed - Labour Related)	100%	
Syngas Plant Labour/Admin/Gen O/H	5.72	M£/yr
Cavern Topsides Labour/Admin/Gen O/H	1.2	M£/yr
Power Island Plant Labour/Admin/Gen O/H	2.60	M£/yr
Fixed Costs - Capital Related		
Operating Cost Scaling Factor (Fixed - Capital Related)	100%	
Syngas Plant Maint/Ins/Taxes	32.24	M£/yr
Cavern Topsides Maint/Ins/Taxes	22.3	M£/yr
Power Island Maint/Ins/Taxes	18.97	M£/yr
Variable Costs - excl. Power & Water		
Operating Cost Scaling Factor (Variable - excl. Power & Water)	100%	
Syngas Plant Variable Costs - Feedstock	101.65	M£/yr
Syngas Plant Variable Costs - Solvent, Catalysts & Chemicals	2.30	M£/yr
Syngas Plant Variable Costs - Waste Disposal	1.15	M£/yr
Cavern Topsides Variable Costs	1.8	M£/yr
Power Island Variable Costs	0.7	M£/yr
Variable Costs - Power & Water		
Operating Cost Scaling Factor (Variable - Power & Water)	100%	
Electricity Import Cost	67.5	M£/yr
Syngas Plant Potable Water Import Cost	1.0	M£/yr
Power Island Potable Water Import Cost	0.4	M£/yr
Total Scheme OPEX	**259.5**	**M£/yr**
OPEX intensity	0.6	M£/yr/MWe

Income Estimate

Income from Peak Electricity Export	568.9	M£/yr
Cost of CO2 Disposal	-31.1	M£/yr
Income from H2 Export	0.0	M£/yr

LCOE Estimate

Annual Cash Flow	278.3	M£/yr
Levelised Cost of Electricity	**133.5**	**£/MWh**
Cash position at end of Project Life	0.0	M£

SPECIFIC INPUTS FOR ESME:

Syngas Production

Hydrogen Higher Heating Value (HHV)	140,353	MJ/te	
Syngas Plant Capacity (Syngas)	85.5	te/hr	
	0.024	te/s	
Syngas Hydrogen Content	32.7%	wt fraction	
Syngas Plant Capacity (Hydrogen)	0.0078	te H2/s	
Combustion value of Hydrogen in Syngas Plant	1,091,126	kJ/s H2	(kW H2 installed)
Capital Cost of Syngas Plant	724.6	M£	
Syngas Plant CAPEX	**664.07**	**£/kW H2 installed**	
Syngas Plant Fixed (non-fuel) OPEX	38.0	M£/yr	
	34.79	**£/yr KW H2 installed**	
Combustion Value of Hydrogen in Syngas Plant	9,558,260	MWh H2 installed/yr	
Syngas Plant Variable (non-fuel) OPEX	4.4	M£/yr	
	0.46	**£/MWh H2 installed**	
Total Feedstock Higher Heating Value (HHV)	27,189	MJ/te	
Feedstock Mass Flowrate	136.52	te/hr	
	0.0379	te/s	
Gross Combustion Value of Fuel	1,031,080	kJ/s fuel	(kW fuel)
Syngas Plant Variable (fuel) OPEX	101.7	M£/yr	
	93.16	£/kW H2 installed	
	99	£/kW fuel	
	0.945	**kW H2/kW fuel**	
Power Required by Syngas Plant	74.3	MWe	
Syngas Plant Variable (power) OPEX	39.8	M£/yr	
	36.48	£/kW H2 installed	
	536.11	£/kWe required	
	14.695	**kWe required/kW H2**	

Salt Cavern Storage

Syngas Pipeline per unit length (IC)	Not Applicable	M£/km
Nitrogen Pipeline per unit length (IC)	Not Applicable	M£/km
Combined Syngas and N2 Pipeline per unit length (IC)	1.2	M£/km
Water/Brine Pipeline per unit length (IC)	0.4	M£/km
Total Working Volume of Syngas in Caverns	322,357	m^3
Syngas Hydrogen Content	85.3%	vol. fraction
Total Working Volume of Hydrogen in Caverns	274,832	m^3
Hydrogen Density at Selected Pressure and 30C	19.34	kg/m^3
Gross Combustion value of Hydrogen in Working Volume of Syngas Caverns	207,261,287	kWh H2 working
Salt Cavern CAPEX	357.1	M£
	1.72	**£/kWh H2 working**
Salt Cavern Fixed OPEX	23.5	M£/yr
	0.11	**£/yr kWh H2 working**
Salt Cavern Variable (not incl. power) OPEX	1.8	M£/yr
	0.01	**£/yr kWh H2 working**
Power Required by Salt Cavern Facility	51.7	MWe
	452,973	MWh(e)/yr
Salt Cavern Variable (power required) OPEX	27.7	M£/yr
	0.13	£/yr kWh H2 working
	536.11	£/yr kWe required
	0.0002	**kWe required/kWh H2 working**
	61.20	**£/MWh(e)**
Power Produced by Salt Cavern Facility	13.6	MWe
	118,818	MWh(e)/yr
Salt Cavern Variable (power produced) OPEX	13.5	M£/yr
	113.50	**£/MWh(e)**

Power Island

Power Output	558,847	kWe installed
Power Island CAPEX	881.9	M£
	1578.06	**£/kWe installed**
Power Island Fixed OPEX	21.6	M£/yr
	38.59	**£/yr kWe installed**
Power Output	4,895,498	MWh(e)/yr
Power Island Variable OPEX	1.1	M£/yr
	0.22	**£/MWh(e)**
	0.512	**kWe installed/kW H2 installed**

ATTACHMENT 4
PROJECT EXECUTION SCHEDULE – REPRESENTATIVE SYSTEM

FOSTER WHEELER

Hydrogen Production & Storage

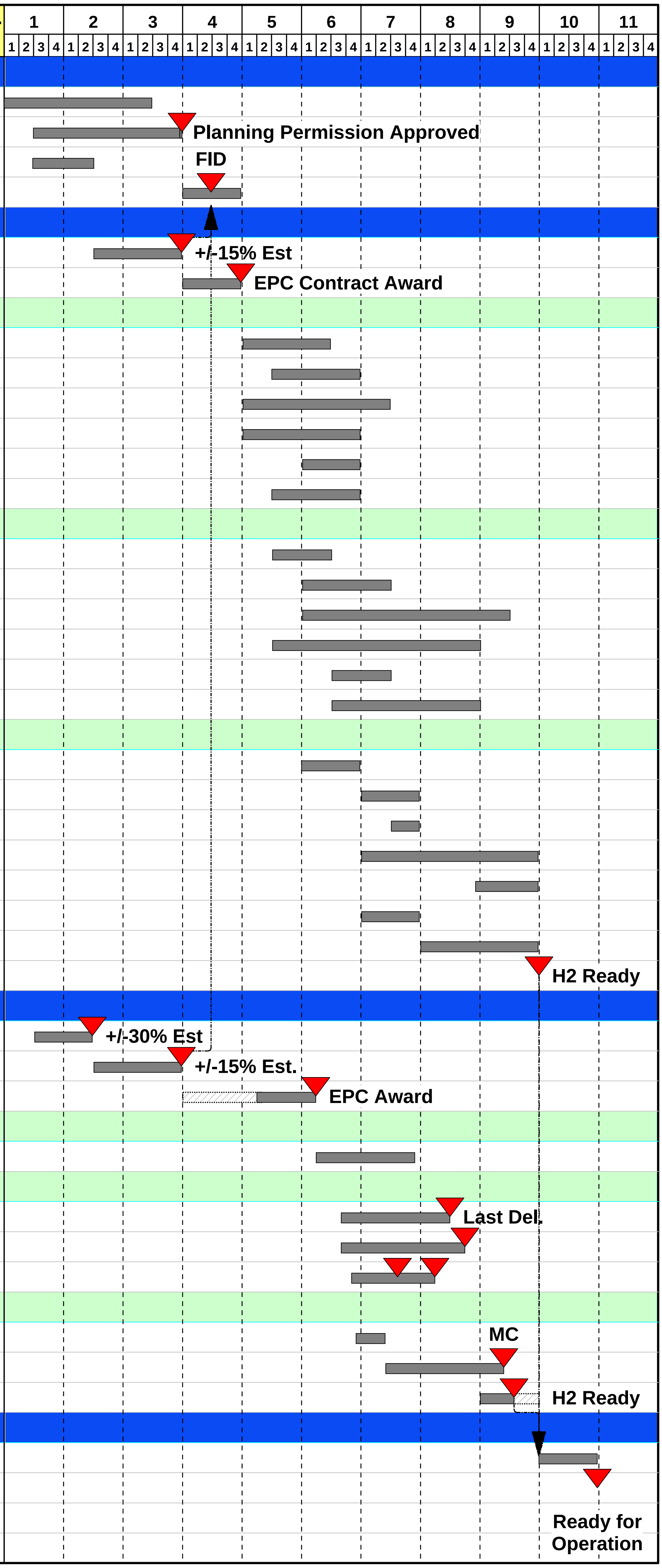
Coal IGCC (Case 1) & Onshore Salt Cavern Facilities

WP5 - Project Schedule

Rev. 0

Client : ETI
Project No. 13058
Location : UK

Task Num	TASK
1	**PLANNING**
2	Environmental Permits (EIA&ESIA)
3	Spatial Planning Permits
4	Initial Site Investigation
5	Evaluation and Sanction
6	**HYDROGEN STORAGE FACILITIES**
7	FEED
8	Bids and Tabulations EPC
9	**Engineering**
10	Site Preparation and Drilling
11	Leaching Facilities
12	Pipelines
13	Gas Facilities
14	Wellhead
15	Utilities, Infrastructure and Control
16	**Procurement**
17	Site Preparation and Drilling
18	Leaching Facilities
19	Pipelines
20	Gas Facilities
21	Wellhead
22	Utilities, Infrastructure and Control
23	**Construction**
24	Site Preparation
25	Leaching Facilities
26	Wellhead and Drilling
27	Gas Facilities
28	H2 Pipelines and Facilities
29	Seawater and Brine Pipelines
30	Caverns Formation
31	H2 Ready for Injection
32	**HYDROGEN PRODUCTION & POWER ISLAND**
33	Pre-FEED / Select
34	PDP / FEED
35	Bids & Award EPC
36	**Engineering**
37	Detail Engineering
38	**Procurement**
39	Equipment
40	Steam Turbine
41	Bulk Materials
42	**Construction**
43	Site Preparation
44	Construction
45	Handover, Commission & Start-up
46	**HYDROGEN INTRODUCTION & OPERATION**
47	Cavern Debrining and H2 Introduction
48	All Facilities Ready for Operation



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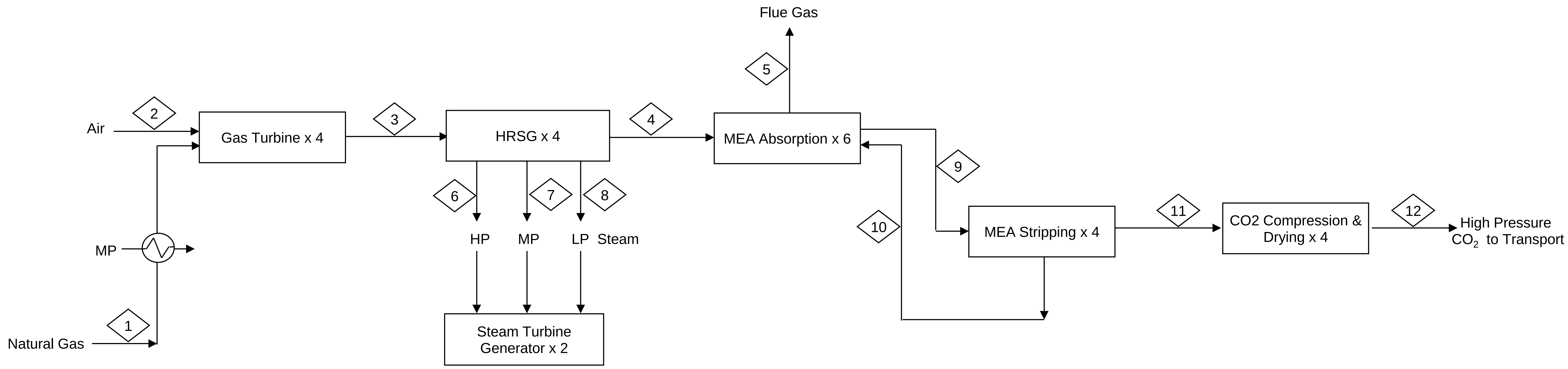
ATTACHMENT 5
OUTLINE HEAT & MATERIAL BALANCE – CCGT SYSTEM



Total 4 GT system with two trains.
Each train with two GTs, two HRSG, one ST, one condenser, one deaerator and BFW pumps in parallel.
Each Train with 3 MEA Absorbers, 2 Strippers and 2 CO2 compressors
Flows shown below are for the full facility capacity of 4 GT system

Stream Name	1	2	3	4	5	6	7	8	9	10	11	12
Pressure (kPa)	3500	101	104	104	1	13980	2689	417	453	140	138	15090
Temperature (°C)	1.0	32.0	613.0	93.4	80.0	566.0	565.6	291.7	93.0	30.0	30.0	30.0
Mass rate (kg/h)	218864	8708567	8927431	8927431	8267570	1047806	1222768	64483.2	8989924	8265600	539029.6	532591
Mole % Oxygen	0.00	20.73	11.39	11.39	12.12	0.00	0.00	0.00	0.00	0.00	0.01	0.01
Mole % Nitrogen	1.47	77.27	72.88	72.88	77.59	0.00	0.00	0.00	0.00	0.00	0.03	0.03
Mole % CO2	0.68	0.03	4.26	4.26	0.46	0.00	0.00	0.00	4.97	2.25	96.98	99.96
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
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
Mole % Argon	0.00	0.92	0.87	0.87	0.87	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
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
Mole % H2O	0.00	1.05	10.60	10.60	8.95	100.00	100.00	100.00	84.27	86.22	2.98	0.00
Mole % MEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.76	11.53	0.00	0.00
Molar rate (kmol/hr)	11939	303019	317829	317829	298729	58147	67856	3578	375483	350767	12469	12103

REV	DATE	TITLE	BY	CHK	APP
1	30/07/13	FIRST ISSUE	RR		

REVISIONS

HYDROGEN STORAGE AND FLEXIBLE TURBINES PROJECT

BLOCK FLOW DIAGRAM

FOSTER WHEELER ENERGY

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

DWG. NO.: XXXX-XX-XXX

REV: 0

ATTACHMENT 6
OUTLINE UTILITY SUMMARY – CCGT SYSTEM

FOSTER WHEELER ENERGY LIMITED
UTILITIES BALANCE SUMMARY

CCGT with 90% CO_2 Capture - Utility Balance while Gas Turbines operating

CLIENT: The Energy Technologies Institute
CONTRACT: 13058
NAME: HYDROGEN STORAGE AND FLEXIBLE TURBINES PROJECT

						SHEET
REV	O1					1 OF 1
DATE	30/07/2013					
ORIG. BY	RR					
APP. BY						

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)	-60833	0.0	0.0	-812.2	812.2	0.0	-54691	-259	0.0	0.0		
CO_2 Compression & Drying	-48754	0.0	0.0	0.0	0.0	0.0	-7697	0.0	0.0	0.0		
Process Units Total	-109587	0	0	-812	812	0	-62389	-259	0	0		
Power Island												
Gas Turbine	-96784	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
HRSGs	0	1047.8	1222.8	1287.3	-1287.3	0.0	0.0	0.0	-15.0	0.0		
Steam Turbine (Note 1)	-11431	-1047.8	-1222.8	-475.1	475.1	-31789.7	0.0	0.0	0.0	0.0		
Power Generation Units	1608668	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
Power Island Total	1500453	0	0	812	-812	-31790	0	0	-15	0		
Offsites & Utilities												
Demin Plant	-50.0								15.0			
Sea Cooling Water	-11968.0					109734.7						
Fresh Cooling Water	-3434.0					-77945.0	62388.5					
Utility water	-24.0							259.2				
Fire Water System	-80.0											
Condensate Treatment	-116.0											
Waste Water Treatment	-200.0											
Flare	0.0											
Storage	0.0											
Buildings	-1200.0											
Others	0.0											
Offistes & Utilities Total	-17072	0	0	0	0	31790	62389	259	15	0		
Grand Total	**1373794.3**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**		

NOTES
1. Includes Steam and water cycle balance of plant, generator and transformer losses.
108.28 tph intermittent LPS required during solvent reclaimation mode.

ATTACHMENT 7
CAPITAL COST SUMMARY – REPRESENTATIVE SYSTEM

Project: No 13058		Rev :	1
Client : ETI		Date :	08/08/2013
Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES		By :	RR
Location : UK			

ORDER OF MAGNITUDE ESTIMATE SUMMARY
Representative Case: Summary

COST CODE	DESCRIPTION		Syngas Production Plant Million £	Cavern Topside Facilities Million £	Power Island Million £	TOTAL Million £
	MAJOR EQUIPMENT		244.2	70.2	432.6	747
	DIRECT BULK MATERIALS		112.6	33.1	130.6	276
	DIRECT MATERIAL & LABOUR CONTRACTS		51.1	49.7	49.3	150
	LABOUR ONLY CONTRACTS		120.7	31.8	72.8	225
	INDIRECTS		37.3	6.1	48.4	92
	EPC CONTRACTS		64.1	8.5	33.1	106
	INSTALLED COST		**630.1**	**199.5**	**766.9**	**1,596**
	LAND COSTS	5%	31.6	10.0	38.4	80
	OWNERS COSTS	10%	63.1	20.0	76.8	160
	CONTINGENCY	25%	157.8	50.1	192.0	400
	TOTAL PROJECT COST		**882.1**	**279.7**	**1,073.6**	**2,235**

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 instantaneous 1 Q 2010

Project: No 13058 | Rev : 1
Client : ETI | Date : 08/08/2013
Project: H2 STORAGE STUDY | By : RR
Location : UK

ORDER OF MAGNITUDE ESTIMATE SUMMARY
Representative Case: Coal Gasification Plant with Pre-Combustion Capture

COST CODE	DESCRIPTION		Reforming / Gasification (coal handling, milling, storage, gasification etc.) Million £	Air Separation / Oxidant Supply Million £	Acid Gas Removal = Separate H2S & CO2 Removal Million £	Sulphur Plant Million £	Syngas Treatment Unit (including CO Shift & Cooling) Million £	CO2 Compression (to 150 Bar) Million £	Power Block Million £	U&O Million £	**TOTAL Million £**
	MAJOR EQUIPMENT		66.6	43.0	36.7	10.0	16.1	20.8	34.5	16.4	**244.2**
	DIRECT BULK MATERIALS		48.2	2.5	12.8	3.5	8.7	5.3	10.4	21.1	**112.6**
	DIRECT MATERIAL & LABOUR CONTRACTS		4.1	1.3	4.2	1.2	1.9	0.8	3.9	33.6	**51.1**
	LABOUR ONLY CONTRACTS		23.0	20.0	17.3	4.7	12.3	9.2	5.8	28.3	**120.7**
	INDIRECTS		10.4	4.3	5.3	1.5	2.8	2.8	3.9	6.4	**37.3**
	EPC CONTRACTS		20.2	3.3	11.1	3.0	5.9	5.6	2.6	12.5	**64.1**
	INSTALLED COST		**172.6**	**74.3**	**87.5**	**23.9**	**47.7**	**44.6**	**61.2**	**118.3**	**630.1**
	LAND COSTS	5%	8.6	3.7	4.4	1.2	2.4	2.2	3.1	5.9	**31.6**
	OWNERS COSTS	10%	17.3	7.4	8.7	2.4	4.8	4.5	6.1	11.8	**63.1**
	CONTINGENCY	25%	43.2	18.6	21.9	6.0	11.9	11.1	15.3	29.6	**157.8**
	TOTAL PROJECT COST		**241.7**	**104.0**	**122.5**	**33.4**	**66.7**	**62.4**	**85.7**	**165.6**	**882.1**

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 instantaneous 1 Q 2010

Project: No 13058 | Rev : 1
Client : ETI | Date : 08/08/2013
Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | By : RR
Location : UK

ORDER OF MAGNITUDE ESTIMATE SUMMARY
Representative Case: Cavern Topside Facilities

COST CODE	DESCRIPTION		Topside Facilities in Syngas Plant Area Million £	Topside Facilities at Inlet to Salt Cavern Million £	Topside Facilities at Outlet of Salt Cavern Million £	Topside Facilities in Power Island Area Million £	Mixed Gas Pipeline 10 km (22 inch) Million £	**TOTAL** **Million £**
	MAJOR EQUIPMENT		25.2	0.7	27.6	16.7		**70.2**
	DIRECT BULK MATERIALS		13.9	0.4	9.4	9.4		**33.1**
	DIRECT MATERIAL & LABOUR CONTRACTS		14.6	0.3	10.6	9.5	14.7	**49.7**
	LABOUR ONLY CONTRACTS		13.2	0.3	9.1	9.2		**31.8**
	INDIRECTS		2.3	0.1	2.2	1.5		**6.1**
	EPC CONTRACTS		4.1	0.3	2.4	1.7		**8.5**
	INSTALLED COST		**73.4**	**2.1**	**61.5**	**47.9**	**14.7**	**199.5**
	LAND COSTS	5%	3.7	0.1	3.1	2.4	0.7	**10.0**
	OWNERS COSTS	10%	7.3	0.2	6.1	4.8	1.5	**20.0**
	CONTINGENCY	25%	18.3	0.5	15.4	12.0	3.7	**50.1**
	TOTAL PROJECT COST		**102.7**	**3.0**	**86.1**	**67.0**	**20.5**	**279.7**

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 instantaneous 1 Q 2010

Project: No 13058 | Rev : 1
Client : ETI | Date : 08/08/2013
Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES | By : RR
Location : UK

ORDER OF MAGNITUDE ESTIMATE SUMMARY
Representative Case: Power Island

COST CODE	DESCRIPTION								Power Island Million £		TOTAL Million £
	MAJOR EQUIPMENT								432.6		432.6
	DIRECT BULK MATERIALS								130.6		130.6
	DIRECT MATERIAL & LABOUR CONTRACTS								49.3		49.3
	LABOUR ONLY CONTRACTS								72.8		72.8
	INDIRECTS								48.4		48.4
	EPC CONTRACTS								33.1		33.1
	INSTALLED COST								**766.9**		**766.9**
	LAND COSTS	5%							38.3		38.4
	OWNERS COSTS	10%							76.7		76.8
	CONTINGENCY	25%							191.7		192.0
	TOTAL PROJECT COST								**1,074**		**1,074**

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 instantaneous 1 Q 2010

ATTACHMENT 8
CAPITAL COST SUMMARY – CCGT WITHOUT CO_2 BUFFER STORAGE

Project: No 13058 | Rev : 0
Client : ETI | Date : 01/08/2013
Project: H2 STORAGE STUDY | By : RR
Location : UK

ORDER OF MAGNITUDE ESTIMATE SUMMARY
CCGT Case

COST CODE	DESCRIPTION		Acid Gas Removal = Separate H2S & CO2 Removal Million £	CO2 Compression (to 150 Bar) Million £	Power Island (GT+ HRSG +ST) Million £	U&O Million £	TOTAL Million £
	MAJOR EQUIPMENT		195.5	59.8	360.2	22.0	637.5
	DIRECT BULK MATERIALS		67.9	15.2	108.6	28.4	220.1
	DIRECT MATERIAL & LABOUR CONTRACTS		22.6	2.3	41.0	45.0	110.9
	LABOUR ONLY CONTRACTS		92.2	26.4	60.6	38.0	217.1
	INDIRECTS		29.0	8.1	41.2	8.8	87.1
	EPC CONTRACTS		49.7	13.5	27.6	16.8	107.6
	INSTALLED COST		**456.8**	**125.4**	**639.2**	**159.0**	**1,380.3**
	LAND COSTS	5%	22.8	6.3	32.0	7.9	69.1
	OWNERS COSTS	10%	45.7	12.5	63.9	15.9	138.1
	CONTINGENCY	25%	114.2	31.3	159.8	39.7	345.3
	TOTAL PROJECT COST		**639.6**	**175.5**	**894.9**	**222.5**	**1,932.5**

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 instantaneous 1 Q 2010

ATTACHMENT 9
CAPITAL COST SUMMARY – CCGT WITH CO_2 BUFFER STORAGE

Project: No 13058	Rev : 0
Client : ETI	Date : 01/08/2013
Project: H2 STORAGE STUDY ABOVE GROUND FACILITIES	By : RR
Location : UK	

ORDER OF MAGNITUDE ESTIMATE SUMMARY
Topside Facilities for CO_2 Buffer Storage

COST CODE	DESCRIPTION		ABOVE GROUND FACILITY	PIPELINE, 10 km (10 inch)	TOTAL
			Million £	Million £	**Million £**
	MAJOR EQUIPMENT		6.8		**6.8**
	DIRECT BULK MATERIALS		3.8		**3.8**
	DIRECT MATERIAL & LABOUR CONTRACTS		4.0	5.5	**9.4**
	LABOUR ONLY CONTRACTS		3.5		**3.5**
	INDIRECTS		0.6		**0.6**
	EPC CONTRACTS		1.4		**1.4**
	INSTALLED COST		**20.1**	**5.5**	**25.5**
	LAND COSTS	5%	1.0	0.3	**1.3**
	OWNERS COSTS	10%	2.0	0.5	**2.7**
	CONTINGENCY	25%	5.0	1.4	**6.6**
	TOTAL PROJECT COST		**28.1**	**7.6**	**36.2**

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 instantaneous 1 Q 2010

ATTACHMENT 10
COSTS OF OFFSHORE CO_2 TRANSPORTATION AND STORAGE

Basis : Purpose built T&S Facility for Each Case
Easington shore Terminus to Store 5/42
Injectivity 0.7 Mt/a per well

	Case 1	**Case 2**	**Case 3**
CO_2 Flowrate, te/hr	417.48	532.59	190.21
Transport Pipeline diameter	10"	10"	8"
Pipeline cost, £M	100	100	82
Compressor cost, £M	8	11	4
No of Injection Facilities	2	3	1
Cost of Injection Facilities, £M	40	60	20
No of Wells	4	6	2
Total cost of Wells, £M	36	55	18
Hub Requirement	yes	yes	yes
Total cost of Hub, £M	50	50	50
Appraisal allocation cost, £M	10	13	5
Distbn Pipes cost, £M	7	11	4
Total cost of CO2 transport and storage, £M	251	300	183

Notes: 1) Pipelines 40% of capex, so some closing of difference if these are shared with other users.
2) No costs for appraisal approvals or pre-appraisal work. Appraisal allocation above is appraisal wells and seismic only.

Use -£10/te to reflect the cost the operator pays for disposal (storage)