Programme Area: Carbon Capture and Storage

Project: Thermal Power with CCS

Title: D4.1 Plant Performance and Capital Cost Estimating

Abstract:

This report and its attachments provide detailed information on the design and performance of the 'template' plant, which comprises up to 5 identical trains of CCGT with carbon capture and compression. It presents a capital cost estimate for the plant and associated CO2 transport and storage at sites in five regions around the UK (Teesside, North Humber, South Humber, North West England and Scotland (Grangemouth)). Cost estimates are provided for each site for 1, 2, 3 and (where feasible) 4 and 5 trains. Costs have been benchmarked against as-built plant and/or detailed EPC quotes where available.

Context:

The ETI's whole energy system modelling work has shown that CCS is one of the most cost effective technologies to help the UK meet its 2050 CO2 reduction targets. Without it the energy system cost in 2050 could be £30bn per annum higher. Consequently, ETI invested £650,000 in a nine month project to support the creation of a business case for a large scale gas with CCS power plant, to include an outline scheme and a 'template' power plant design (Combined Cycle Gas Turbine with post combustion capture), identify potential sites in key UK industrial hubs and build a credible cost base for such a scheme, benchmarked as far as possible against actual project data and as-built plant. The ETI appointed engineering and construction group SNC-Lavalin to deliver the project working with global infrastructure services firm AECOM and the University of Sheffield's Energy 2050 Institute.

Detailed Report: Plant Performance and Capital Cost Estimating

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Disclaimer

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Executive Summary

The ETI's energy system modelling work has shown that Carbon Capture and Storage (CCS) is one of the most potent levers to help the UK meet its 2050 CO_2 reduction targets: without CCS the energy system cost in 2050 could be £30bn per annum higher.

The UK Government retains the belief that CCS could play a crucial role in the future energy system. However, stakeholders in CCS will need compelling evidence of the business case for a power with CCS project. The work carried out on this project as described in this report involves developing an outline scheme and 'template' power plant design (Combined Cycle Gas Turbine (CCGT) with post combustion capture) and identifying how this might be built and operated at selected sites around the UK.

In summary, the key objective of the Project is to enhance the evidence base on the realistic cost and performance of a large scale, low-risk CCGT with CCS Scheme, with such cost and performance being convincing to a wide range of stakeholders. This has been achieved by bringing together best available design information and benchmarking data for such a Scheme.

SNC-Lavalin has developed a template plant design and a cost estimate for a large-scale deployment of CCGT + CCS for the UK. SNC-Lavalin has been supported by AECOM who have identified potential site locations for such a plant and the University of Sheffield who have supported the project with technical and policy expertise.

This report provides a capital cost estimate for a generic plant design at a range of plant sizes deployed in a number of regions in the UK.[1]

The base design for a large-scale deployment of CCGT + CCS for the UK would be a 5-train plant exporting approximately 3 GW after losses.

The UK Government is committed to sharing the knowledge from UK previous Carbon Capture and Storage Projects. Documentation from a number of FEED studies, which is published on the UK Government's website, combined with SNC-Lavalin's experience from Boundary Dam CCS and

[1] The report does not cover operational costs (OPEX), abandonment costs (ABEX), or levelised cost of electricity (LCOE).

providing an EPC Tender for the Shell Peterhead CCS provides an important data source for this report.

Technology

The Power Generation Units use the largest credible Combined Cycle Gas Turbine (CCGT) Power Blocks available today. The Generic Business Case aims to capture around 10 million tonnes of CO_2 per annum from Combined Cycle Gas Turbines (CCGT). An engineered best in class amine has been selected for the plant in order to generate an optimised performance for the plant. The benchmark amine solvent (MEA) has a high energy penalty. Using engineered amines reduces this penalty, thereby maximizing the power output from the CCGT.

The best in class amine technology is licensed by the owners of the technology: the performance of the technology is confidential. Unable to publish a licensed technology design SNC-Lavalin have made use of publicly available information regards post combustion carbon capture from the Key Knowledge Documents published regarding the Shell Peterhead project in order to develop a design sized for the gas turbines of the Generic Business Case.

Scheme

The selected scheme is shown in the following block diagram consists of multiple trains of CCGT Power Generation each with a Carbon Capture and Compression Unit. A buried pipeline will transport the CO_2 to the shoreline.

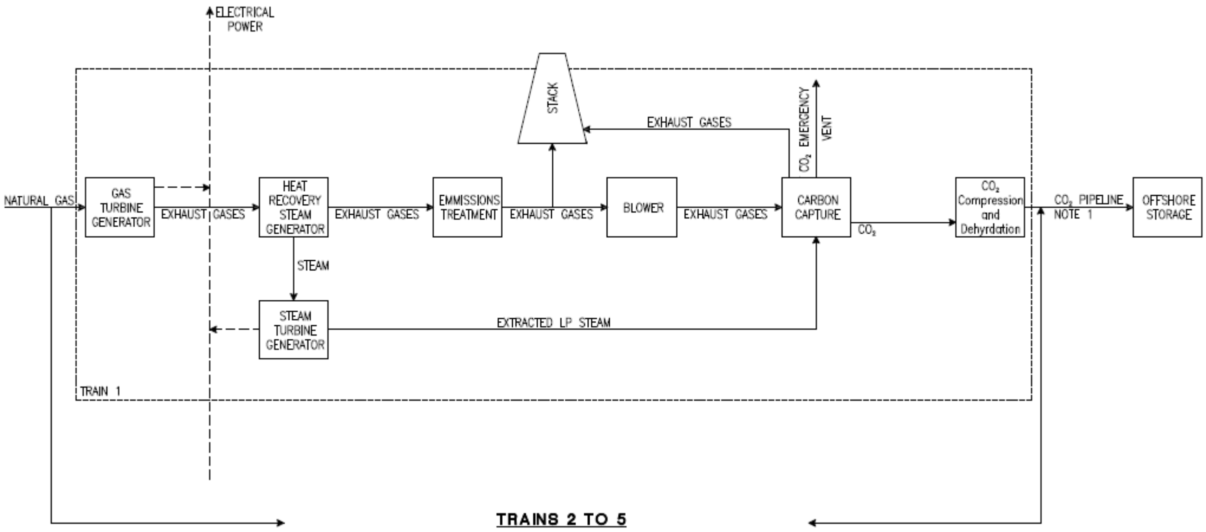


Figure 1 – Block Flow Diagram of Scheme

Designs and cost estimates were carried out for selected sites in 5 regions as per the following table:

Selected Region	Offshore Store	CO_2 Transport
Teesside	Endurance	New pipeline to Endurance
North Humber	Endurance	New pipeline to Endurance
South Humber	Endurance	New pipeline to Endurance
North West / North Wales	Hamilton	New pipeline to Hamilton
Scotland (Grangemouth)	Goldeneye and Captain X	Repurposed Feeder 10 Repurposed Offshore Pipelines New Connection Pipelines

Table 1 – Offshore Stores and CO_2 Transport

For the larger size plants exporting CO_2 to Endurance (4 or 5 trains) a second platform will be required in order to ensure that there is sufficient coverage over the aquifer to inject the volume of CO_2. A new connecting pipeline will be required to link the 2 Endurance Platforms. It is assumed that all the flow will go to the Alpha platform (nearer the English Shoreline) and that the Bravo platform will be fed from Alpha.

Current UK policy decisions are that Carbon Capture and Storage in the UK will use offshore storage locations, and these shall be for CO_2 storage only and not Enhanced Oil Recovery (EOR).

Wells will be drilled in the subsurface store: the store will either be a saline aquifer or a depleted gas field. The well heads will be located on an offshore platform.

The offshore platform will consist of a conventional structural steel jacket with unmanned minimum facilities topsides. The topsides will include filtering of CO_2, metering of CO_2, and systems to support the injection of CO_2 into the offshore store.

The offshore platform will be reached by boat for operations and maintenance. Safety systems will be installed on the platform for the safety of those working offshore. The boat will be of walk to work type and is intended to remain connected to the platform all the time personnel are working.

The facility will accommodate a number of wells (CO_2 injectors and for Saline Aquifers a provision for a brine producers). No new subsurface work was included within the scope of this project: The Injection Rates for wells has been taken from the referenced sources and provided within the report.

Each location will be served by a small normally unmanned wellhead platform. The Wellhead Platform will contain the wellheads, injection filtration, metering, and manifolds, utilities, Local Equipment Room (LER), and a muster area with adjacent temporary refuge.

Contract Strategies

There are a range of contract strategies that can be designed in order to maximise the probability of successful project delivery. The selected contract strategy needs to be aligned with the project scope, technology, complexity, and risk. The selected contract strategy also needs to be aligned with the competence, knowledge, and capability of the Project Owner (for example, a major oil international oil company will have a wide range of project management, project controls, engineering, technology, and commissioning competences, knowledge, and capability that would not be found within an investment bank).

A major lesson learnt from previous CCS proposals and projects is that the juncture between Power and Carbon Capture causes a lot of issues which affect CAPEX and reliability. It is strongly recommended that both Ownership and EPC Contracting not be split along a power generation to carbon capture battery limit: both should span the Power + Carbon Capture and Compression in order to deliver a seamless and integrated plant: for design, costing, reliability, and operation.

Maximum Reliability may not be delivered by a “lowest cost” mentality as this will drive behaviours towards minimum provision as opposed to considered design in order to meet a robust plant design. One risk control approach could be to use a FEED+ where the FEED is extended to ensure the reliability of design within “lowest cost” contract approach driving behaviours.

Capital Cost Estimating

The majority of the CAPEX cost estimate has been built up from a major equipment list. Modelling of the CCGT power plant and carbon capture and storage plant through specialist software has assisted with the equipment sizing, which was then compared to similar equipment used on prior projects. Where similar equipment existed, the vendor pricing was used.

In cases where the equipment was larger than equipment used on prior projects, a parametric model was created using sets of data for similar pieces of equipment, which provides a basis for recalculating equipment costs based on the change in size and existing vendor quotes. For the CCGT, CCC, and offshore equipment, approximately 72% of the equipment costs are based on vendor quotes or scaled up vendor quotes. The remaining 28% are derived from modelling software and SNC-Lavalin norms and estimating data.

The estimate has undergone review by an estimator, independent of the project, who has verified the methodology used and the accuracy of the output. In addition, the information has been subject to peer review throughout the estimating process by subject matter experts throughout the SNC-Lavalin organization.

Cost estimates for projects at this stage of development are normally built up by sizing and costing the major pieces of equipment then multiplying them by Lang Factors to reach a total installed cost. In this work a significantly more detailed, robust and hence accurate approach has been taken because of the data available to the project team.

The project team has CCGT execution knowledge and experience including access to plant cost / price data. The project team’s company has designed and built more than 49,000 MW of thermal power projects. The project team's company delivers and bids for EPC work including recent UK proposals: this provides real data which has been used in the production of this report.

The project team has Carbon Capture Project knowledge and real project experience including access to plant cost / price data. SNC-Lavalin have delivered an EPC contract for the Boundary Dam CCS. SNC-Lavalin were successful in bidding the Shell Peterhead CCS project before this project was stopped following the cancellation of the second CCS commercialisation competition. The data for Peterhead is real (as bid by SNC-Lavalin) and therefore provides a real UK basis for what a CCS scheme pricing would be in the UK market;

Whilst the work undertaken for this report is a study, and therefore does not have a level of detail down to a list of materials with quantities and types, SNC-Lavalin's work does make use of such information from previous projects and proposals and therefore does have more detailed basis of procurement costs, construction man hours, and construction materials that a typical study would not have access to.

Project costs in addition to the major equipment, bulk materials, and associated labour have been estimated as follows:

Site acquisition – Costs have been estimated using a report that is available in the public domain.

Site Enabling works – Site establishment has been estimated based on the layout design from the project and the use of recent UK unit rates for work.

Detailed design - Detailed engineering hours have been calculated as a percentage of total installed cost. This differs per section of the estimate and is determined based on SNC-Lavalin experience and data available from similar projects and proposals, including Peterhead, previous CCS, multiple power projects and significant offshore design experience. Detailed design engineering has been added to each section of the estimate.

Connection Costs - Connection costs have been estimated using data from the site selection process including distances, crossings, and types of terrain.

Commissioning and Start-up - Commissioning costs were built up from detailed estimates from prior CCS and power proposals. The bottom up commissioning estimate was compared against commissioning costs from the KKD's, SNC-Lavalin projects and proposals, and industry benchmarks.

Contractor's and Owner's Costs - Contractor's and Owner's costs have been established on a percentage basis from experience on other power and carbon capture projects. Owner's costs have been built up using information from the KKD's.

Regions - The cost difference between an example site for each region has been estimated using the length of each connection provided in the site selection report. The connections for high voltage electricity, water intake, waste water outfall, and natural gas pipelines are all dependent on the sample areas chosen in each region. The connections were estimated based on length, and basic topography, including number of crossings required.

Potential labour availability was reviewed and allowances were made for each region by construction management. An assessment of the local labour supply was made based on existing local industry, recently closed plants and completed projects, upcoming approved projects (such as HS2), site access (motorways, bridges, constricted access), and population base in the immediate area from which to draw a skilled workforce.

Differing Number of Trains - The cost estimate for each train has been built up as a block allowing for ease of estimation for 1 to 5 trains. The connection costs have been calculated based on capacity required for differing numbers of trains.

Subsurface work is beyond the scope of the Generic Business Case projects and therefore the project team have used publicly available information to provide costs for the DRILLEX.

Uncertainty

Three levels of uncertainty have been reviewed within this estimate: contractors' contingency, project contingency, and project risk.

The contractors' contingency is included as an amount expected to be within EPC contractor tenders. This includes detailed design allowance, small changes between FEED and detailed design that do not constitute a scope change, and inclement weather delay.

Project contingency is included to account for the lack of definition at the time the estimate was prepared. Theoretically, with enough data, time, and resources, no contingency would be required. It is intended to adjust for changes in material and equipment costs and labour overruns.

Project Risk considers events that may have an impact on project cost or schedule but are not considered as part of the project estimate. These may include changes to regulations, unexpected geotechnical survey results, or an unexpected problem with a supplier, such as insolvency.

A risk register has been developed based on SNC-Lavalin Risk Management Procedures. A Risk workshop was held to determine the high-level risks facing the project.

Contingency has been estimated to cover the undefined items of work that may have to be performed or the unexpected cost of items of work within the defined scope of work. The contingency costs by definition include items that may not be reasonably foreseen due to incomplete engineering, areas with a high probability of modification, or items that may change due to lack of data or change in local conditions.

Conclusions

Cost Estimate

The Project team were able to use data collected from Projects and Proposals to develop a robust UK based cost estimate for the Thermal Power with CCS project for different regions in the UK and for a range of plant sizes. The performance and cost estimate have been confirmed against benchmarks.

£	One Train (622 MW)	2 Trains (1244 MW)	3 Trains (1866 MW)	4 Trains (2488 MW)	5 Trains (3110 MW)
P50	1,764,392,521	2,753,873,823	3,762,523,003	4,983,906,265	5,965,844,832
P90	1,874,467,642	2,925,679,694	3,997,255,450	5,294,837,126	6,326,349,618

Table 2 – P50 and P90 Cost Estimates against Abated Output for Teesside Location

The overall CAPEX estimate is slightly sensitive to exchange rate fluctuations. A 5-point improvement in the pound over the USD and EUR rates results in a 1% improvement in CAPEX base cost.

Regions

The capital cost estimates for the Teesside, North Humber, and North West / North Wales regions are similar. The Humber region and North West / North Wales region have lower transportation costs than the Teesside region because they have shorter pipelines to their stores. However, the Teesside region benefits from the availability of a skilled local construction work force and sub-contract base. The Teesside side selected also benefits from access to dock / quay / shore side which allows extensive modularisation / prefabrication reduces the amount cost / risk / safety exposure on the construction site.

The South Humber region is higher than Teesside, North Humber, and North West / North Wales regions because a tunnel is required for the CO_2 pipeline route under the Humber adding significant cost to the transportation.

Scotland is the most expensive region analysed. This is because the selected site is in Southern Scotland which requires a long pipeline running up the East side of Scotland from the Forth to St Fergus. The cost estimate allows for the reuse of Feeder 10, however, the CO_2 pipeline route requires a new tunnel under the Forth, new above ground installations (AGIs), and compressor stations which add hundreds of millions of pounds to the estimate compared to other locations reviewed by the project team.

Size / Scale

The CCGT plant benchmark data shows an advantage in economies of scale in going for a larger plant. Although the cost estimate confirms some advantage in the economy of scale, it is not as much as the initial benchmarking work suggested: this may be because a CCGT plant layout cannot take advantage of keeping multiple units close together but would need to be larger, and more spread, in order to accommodate the carbon capture and compression units. The expansion of the layout requires more land purchase, and longer connections. Also, the spread layout of the CCGT plant for carbon capture does not allow for combined steam turbine buildings which would have helped an economy of scale cost estimate.

There is little economy of scale benefit between 3 and 5 trains for the regions where such developments are practical: this is because a second injection platform with injection wells would be required offshore for a 4 and 5 train plant size.

Location

The CCGT + CCS scheme is sensitive to location. There is a large cost element within the project for transportation and utility connection infrastructure. It is therefore advantageous to be near to the CO_2 store and to be near the utility connections. There is also a risk to health and safety from the high-pressure CO_2 hazard, and therefore a safety advantage to shorter onshore CO_2 pipeline.

Tunnels under major rivers and longer pipeline routes requiring compression stations have a significant impact on capital costs. Careful site selection can avoid these for 1st wave CCS projects.

With regard to Constructability the best GBC case becomes a large economy of scale plant, located near suitable infrastructure, ideally dock / quay side for constructability to allow large items to be transferred directly to plant, with the shortest feasible connection to storage, and in the vicinity of a large work force.

Layout

The site selection work ensured that there were no dwellings on the downwind side of the plant in order to manage the risks from the high-pressure CO_2 hazard.

Consideration should be given to the size of the plant footprint relative to the selected site(s) for the execution of thermal power with CCS. Should there be manned areas or public access into the high hazard zone drawn on the layout then consideration should be given as to whether expanding the site footprint by pushing out the boundary fence may be a useful way to excluding persons from CO_2 hazard areas.

1 Structure of This Report

Section 2 of this report aims to give the reader the oversight of the Project Scheme developed and the key attributes that form the basis of the CAPEX estimate as provided in this report.

This allows the reader to be able to understand the key Technical Performance parameters, the high-level summary of the scheme. This leads onto the reader being able to see how the locations and specific sites were reviewed and the rationale behind the thinking of these sites.

The design basis and the outline scheme design is then provided in summary description with links to further reading and material, the CAPEX methodology is then described and assumptions made and then the high-level summary of the cost estimate basis.

Sections 3 through to 7 have been separated into the segments that the project team have deemed appropriate for the specific audience who would be assumed to handle the specific packages.

The following are separate individual specialised segments of the project and therefore it is deemed that there would be specific interest from the specific investors and sectors related to these unique specialised packages

› Layout of the Plant and the Enabling Works
› Power Generation Station
› Carbon Capture Plant
› CO_2 Transportation
› Offshore Storage

Each section includes sizing information, a description, and a cost estimate. This would benefit development Engineers from the specific segments of the market who would be seeking to isolate those parts they are most familiar with.

Section 8 has the CAPEX estimate rolled up from Sections 4 through 7 to create a holistic view of the overall cost of the scheme as envisaged in the work carried out.

Section 9 provides benchmarking carried out to confirm the basis of the robustness of the estimates.

Section 10 provides for a conclusion to the overall scheme and for the reader any indications on future direction on future phases of the project work.

Section 11 provides a reflection from the Project Team on opportunities to improve the performance and cost of the project.

2 Introduction to Project Scheme

2.1 Motivation for this Project

The ETI's energy system modelling work has shown that Carbon Capture and Storage (CCS) is one of the most potent levers to help the UK meet its 2050 CO_2 reduction targets[2]: without CCS the energy system cost in 2050 could be £30bn per annum higher.

With planned retirements of the UK's existing fossil fuel and nuclear fleet, there will be a growing need for new, dispatchable power through the 2020s, with low CO_2 intensity to meet tightening carbon budgets.

The UK Government retains the belief that CCS could play a crucial role in the future energy system. However, stakeholders in CCS will need compelling evidence of the business case for a power with CCS project. Therefore, as noted above, the ETI has identified a need to develop a clear vision of what a cost-effective gas power with CCS scheme might look like and provide a clear and credible performance and cost information for such a scheme. To achieve this, the project as described in this report involves developing an outline scheme and 'template' power plant design (Combined Cycle Gas Turbine (CCGT) with post combustion capture) and identifying how this might be built and operated at selected sites around the UK.

In summary, the key objective of the Project is to enhance the evidence base on the realistic cost and performance of a large scale, low-risk CCGT with CCS Scheme, with such cost and performance being convincing to a wide range of stakeholders. This has been achieved by bringing together best available design information and benchmarking data for such a Scheme.

Whilst 1st generation Carbon Capture plants have demonstrated the Carbon Capture technology, the application of CCS has been, to date, too expensive for most of the world's energy markets: "cost-of-electricity increase of up to 80% and CO_2 capture price of US$60/t estimated for state-of-the-art technologies."(Toby Lockwood, 2016). A more cost-effective implementation is therefore required. The Generic Business Case incorporates the following approaches in order to reduce the cost of deployment of CCS in the UK Energy Market:

- Economies of scale (approximate 3 GW plant size);
- Higher efficiency gas turbines (H & J Class);
- State of the art amines that require the lowest energy penalty;
- Proven, low risk technologies which are attractive to investors and can attract low costs of capital.

SNC-Lavalin has developed a template plant design and a cost estimate for a large scale deployment of CCGT + CCS for the UK. SNC-Lavalin has been supported by AECOM who have identified potential site locations for such a plant and the University of Sheffield who have supported the project with technical and policy expertise.

[2] Provision 1 of the Climate Change Act 2008 states that "It is the duty of the Secretary of State to ensure that the net UK carbon account for the year 2050 is at least 80% lower than the 1990 baseline."

This report provides a capital cost estimate for a generic plant design at a range of plant sizes deployed in a number of regions in the UK. The report does not cover operational costs (OPEX), abandonment (ABEX), or levelised cost of electricity (LCOE).

2.2 High Level Summary of Technical Performance

The following is a summary of the technical performance of the designed Generic Business Case Plant.

Power Generation		
Item	**Per Train**	**5 Train Plant**
Gross	732 MW	3.66 GW
Efficiency @ Generator Terminals	62.0% (LHV)	
Net (Gross minus Parasitic Loads)	715 MW	3.58 GW
Efficiency Net	60.6% (LHV)	
Steam Abated (Gross Power with Abatement Steam Extracted)	691 MW	3.45 GW
CCGT Parasitic Electrical Load	17 MW	0.09 GW
CC Parasitic Electrical Load	52 MW	0.26 GW
Net Abated (Steam Abated minus CCGT & CC Parasitic Loads)	622 MW[3]	3.11 GW
Efficiency Loss for CC	-7.9% (LHV)	
Carbon Capture & Compression		
Item	**Per Train**	**5 Train Plant**
CO_2 Purity (Volume Basis)	98%	98%
CO_2 Mass Flow (@ 100% availability)	221 T/hr 1.93 MT/annum	1103 T/hr 9.66 MT/annum
Reboiler Service	2.99 GJ/tonneCO_2	
Compressor Service	0.38 GJ/tonneCO_2	

Table 3 – Summary of Technical Performance

[3] Please note that there are small differences between regions as shown in Table 21 – Gross Output for Each Region.

The performance is for a Combined Cycle Gas Turbine (CCGT) Power Generation plant. A CCGT generates electrical power from two sources – the gas turbine itself and extracting heat as steam from the hot exhaust gases to drive a steam turbine. It will have some parasitic loads (e.g. lube oil pumps) which take some of the power generated. Adding a Carbon Capture (CC) plant reduces power output in two ways: firstly, it uses some of the steam to heat a reboiler in the capture unit and secondly, it requires further electrical power, particularly to drive a fan to push the exhaust gases through the capture unit and a compressor to compress the CO_2.[4]

The Gas Turbine is modelled at site conditions, nominal gas turbine size, and in clean condition, and using the design basis natural gas composition.

Please note that there will be slight differences in parasitic consumption between plant locations. These numbers in the table above are drawn from Attachment 4 of this document.

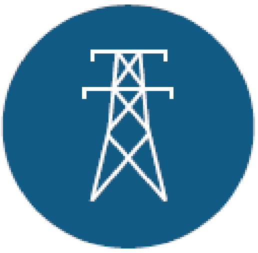
[4] The parasitic load for compression is higher than many other studies because of the higher pressure of 184 bar used for the Generic Business Case: for example the IEAGHG uses 110 bar. The higher pressure is necessary for most of the storage sites selected in this study.

2.3 High Level Summary of CCGT + CCS Scheme

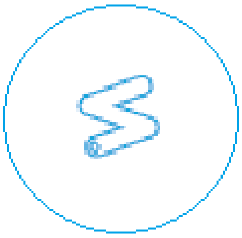
The Generic Base Case scheme consists of the following:

Power Generation Station	The power generation plant generates electrical power by burning natural gas in a gas turbine. Waste heat from the gas turbine exhaust is used to generate steam which is used to generate further electrical power using a steam turbine. The electrical power is exported to the UK National Grid from where is serves the needs of industry, commerce, and domestic homes.

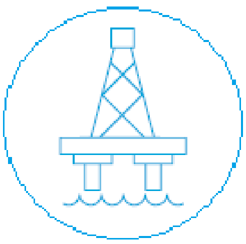
Carbon Capture and Compression	The carbon capture plant uses an amine solvent to separate carbon dioxide (CO_2) from the exhaust combustion gases produced by burning natural gas in the gas turbine. The CO_2 is then compressed and dried ready to be transported for storage.



Connections: › Electrical Power Export › Natural Gas Fuel › Make Up Water	The electrical power is exported to the GB Electricity Grid via an overhead line to supply the needs of homes and businesses. Natural gas fuel is brought in from the national grid by pipeline for use in the gas turbines. Make up water is brought into the plant to make up for evaporation and drift losses from the cooling towers on the plant.



CO_2 Transportation › Onshore Pipeline › Subsea Pipeline › Above Ground Installations	CO_2 is transferred by pipeline from the carbon capture plant to the offshore store. If the onshore pipeline is of extended length then block valve stations will be required in order to safely isolate sections of the pipeline. (A booster station will also be required for a Southern Scotland location in order to boost the pressure of the CO_2 before sending offshore.)



Offshore Storage	CO_2 is stored in an underground saline aquifer or depleted gas field deep under the seabed. Injection wells will be drilled to allow the CO_2 to flow into the underground store. The wellheads will be installed on an offshore platform.

2.4 Regions / Sites

The ETI's work on the Strategic UK CO_2 Storage Appraisal Project has identified a top 20 inventory sites. The following regions within the UK have been chosen for this project predicted by selected offshore stores.

Offshore Store	Selected Region
Endurance	Teesside
Hamilton	North West / North Wales
Endurance	North Humber
Endurance	South Humber
Goldeneye and Captain X	Scotland

Table 4 – Offshore Stores

To develop realistic cost information for a large scale CCGT + CCS project the connections and site works have been included for a selected site in each of the regions.

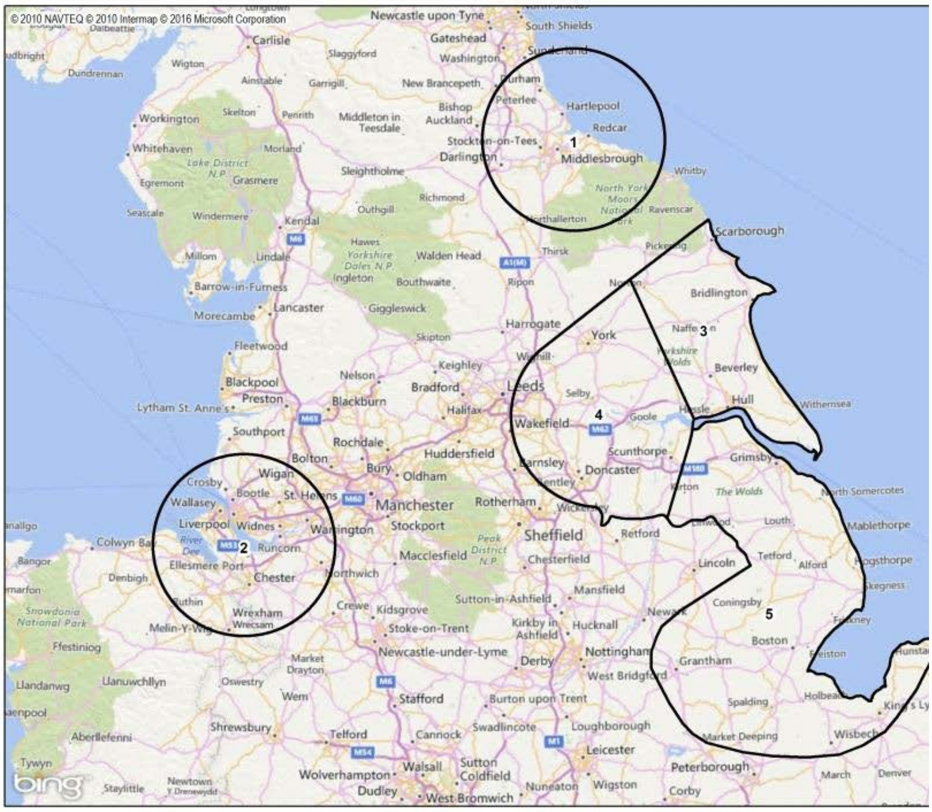


Figure 2 – Regions in Northern England and North Wales

Please refer to the Detailed Report - Site Selection, document reference 181869-0001-T-EM-REP-AAA-00-00002 (AECOM ref: 60521944-0702-000-GN-RP-00001, ETI Ref: D3.1) for information regarding the site selection.

The site selection process followed in the Site Selection Report has identified many sites, in each of the search areas selected for the study, which are considered suitable for the development of a CCGT with CCS project.

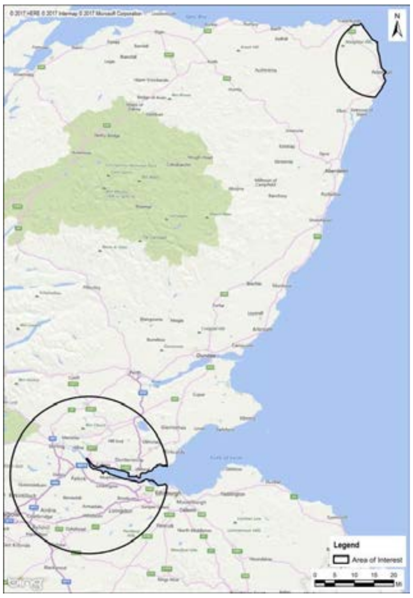


Figure 3 – Regions in Scotland

The preferred sites identified in each region are as follows:

Region	Sites within Region
Teesside	• Kemira Teesport (within Seal Sands) • Redcar Steelworks • Teesside (within Wilton International complex) • Wilton (within Wilton International complex)
North West / North Wales	• Carrington Business Park • Connah's Quay Power Station
North Humber	• Paull • Queen Elizabeth Dock • Salt End

Region	Sites within Region
South Humber	• Killingholme • Lincol Oil • Sutton Bridge
Camblesforth	• Eggborough • Guardian Glass • Keadby • Marconi Greenfield (Burn airfield)
Grangemouth	• Norbord Europe Ltd • Goathill Quarry • Kincardine Power Station • BP Kinneil CHP • Longannet Power Station
St Fergus	• Peterhead • St Fergus

Table 5 – Sites within Each Region

A representative site was selected from Teesside, North West / North Wales, North Humber, South Humber, and Scotland (Grangemouth) for cost estimation purposes: this allowed the connection route lengths and site conditions / constraints to be used for the cost estimate.

The Camblesforth region was explored with the assumption that the CO_2 export would connect to the multi-junction site location (as proposed for the Yorkshire & Humber CO_2 pipeline). During the preparation of this report, it was announced by the Planning Inspectorate that the Development Consent Order (DCO) for this pipeline had been refused, due to the lack of a needs case as a result of the termination of the White Rose Integrated Gasification Combined Cycle (IGCC) project. Without this pipeline, development of any project in the Camblesforth region would need to support the development of the Yorkshire and Humber CO_2 pipeline, or a similar pipeline to the East Yorkshire coast. This potential cost of c. £200m (based on the Key Knowledge Documents (KKDs) for the White Rose project) is not included in the cost estimates shown in the table above, and would make the development of a Thermal Power with Carbon Capture and Storage (TPwCCS) project in this region less attractive compared to other regions: a representative site was therefore not selected for the cost estimate work of this report.

2.5 Size of Scheme / Number of Trains

The base design for a large-scale deployment of CCGT + CCS for the UK would be a 5-train plant generating approximately 3 GW (abated).

Scheme Size

A large plant was envisaged by the ETI to explore the advantages of economies of scale. A maximum scheme size of 5 trains has been selected for the Generic Business case. five trains will deliver approximately 3.5 GW of unabated power (and around 3 GW of abated power). It was assumed that this is the maximum feasible size to be connected to the GB Electricity Grid and GB Gas Transmission Grid being of a similar scale to Hinkley Point C. The footprint for 5 trains is also of a size that can be accommodated on a reasonable number of sites (a larger footprint with a larger number of trains would limit the number of feasible sites).

Number of Trains

A maximum scheme size of 5 trains also allows a spread of size for analysis / comparison as this report includes cost estimates for 1 to 5 trains.

The project decided to make each train independent, identical, and repeatable:

- This allows for a chunky level of flexibility in that individual trains can be shut down without affecting the operation of other trains.
- This allows the repeatable deployment of different numbers of trains on multiple sites which is aligned with the intent of the Generic Business Case.
- This allows for economies of scale because engineering, design, equipment, and module purchases are repeatable, as opposed to being "handed[5]".
- Each major plant item in a train was at the limits of (or a modest scale up of) the largest available and proven equipment on the market.

Robust cost estimates have been produced for smaller plants with 4, 3, 2, and 1 trains to allow the economies of scale to be understood and to support economic studies for application of different size plants in each region.

Number of Trains	1	2	3	4	5
Approximate Abated Output	0.6 GW	1.2 GW	1.8 GW	2.4 GW	3.0 GW
Approximate CO_2 Capture	2 MTPA	4 MTPA	6 MTPA	8 MTPA	10 MTPA

Table 6 – Capacity for Differing Numbers of Trains

[5] Handed trains would have even numbered trains with the mirror image of the plot layout of odd numbered trains.

The maximum number of trains for the project was 5 to develop approximately 3 GW abated power output. Some of the regions however had restrictions on the number of trains that could be accommodated:

Region	Maximum Number of Trains	Storage Capacity (MT CO_2)[6]	Comment
Teesside	5	520	As per GBC Project intent
North West & North Wales	3	125	Limited to 3 trains by capacity of Hamilton Reservoir
North Humber	5	520	As per GBC Project intent
South Humber	5	520	As per GBC Project intent
Scotland	3	90	Limited to 3 trains by capacity of Feeder 10 pipeline, Goldeneye and Captain X Aquifer

Table 7 – Maximum Number of Trains per Region

2.6 Key Information Sources

The UK Government is committed to sharing the knowledge from UK previous Carbon Capture and Storage Projects. Documentation from a number of FEED studies is published on the UK Government's website (https://www.gov.uk/guidance/uk-carbon-capture-and-storage-government-funding-and-support).

Information on the following projects is published by the UK Government.

- Peterhead CCS Project FEED Study
- White Rose CCS Project FEED Study
- Kingsnorth FEED
- Longannet FEED

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- exploit the Information commercially and non-commercially for example, by combining it with other Information, or by including it in your own product or application.

[6] (Pale Blue Dot Energy and Axis Well Technology, 2016)

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The results of the Strategic UK CCS Storage Appraisal Project have been published by the ETI on their website (http://www.eti.co.uk/programmes/carbon-capture-storage/strategic-uk-ccs-storage-appraisal). The Information is available under the ETI Open Licence for the Strategic UK CCS Storage Appraisal Project with the following declaration "Information taken from the Strategic UK CCS Storage Appraisal Project, funded by DECC, commissioned by the ETI and delivered by Pale Blue Dot Energy, Axis Well Technology and Costain"

The Key Information Sources for the project are detailed below:

Peterhead CCS Project FEED Study	The Shell Peterhead project has provided process descriptions and technical information regarding a "Best in Class Amine Solvent design" for a Carbon Capture Plant used for CCGT post combustion capture. The design information includes equipment lists, utilities, layout, and H&M Balance information. The process design of the Amine Solvent based Capture Plant is "Black Box" with only inlets and outlets described. The design for the Licensed Amine Solvent process is confidential to Shell Cansolv: however, the publicly available information on the Peterhead project has been utilised by the project. The Shell Peterhead project also includes information on the condition of the Goldeneye Platform and existing pipelines, and the requirements and costing for modification and upgrade.
White Rose CCS Project FEED Study	The White Rose project was coal with oxyfiring and so it did not provide relevant data on carbon capture for this study. The information from the White Rose project does provide design and cost information on onshore pipelines, subsea pipelines, offshore platform, and Endurance well information.
Strategic UK CCS Storage Appraisal	The information available from the Strategic UK CCS Storage Appraisal project provided information on: › Subsea pipelines › Offshore platforms

	› Well and Subsurface design

The project scope did not include subsurface engineering and therefore was reliant on the Peterhead (Goldeneye), White Rose (Endurance), and Strategic UK CCS Storage Appraisal (Hamilton & Captain X) projects for platform pressure, well pressure, and well cost information.

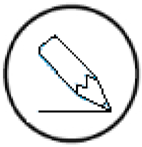
2.7 High Level Summary of Methodology Adopted for Project

The following describes the methodology used by the project to develop the design, performance prediction, and cost estimates.

Design

The project team produced an outline power scheme; this included selection of a small range of gas turbines chosen to meet the project intent of large scale, modern, high efficiency Gas Turbines. A template CCGT plant specification was developed from the outline power scheme.

There is a wealth of publicly available information regarding post combustion amine capture and of CO_2 storage. The project team made use of this, especially the Peterhead Basic Design and Engineering Package (Shell UK Limited, 2016) to develop a post combustion, compression, and storage system suitable for use with the specified CCGT plant.

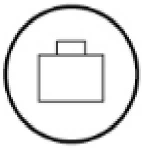


Subsurface engineering was not included in the scope of this project: assumptions have been made for the platform topsides interface with the CO_2 storage using information from the White Rose published Key Knowledge Documents and the ETI Strategic UK CCS Storage Appraisal Project.[7]

The design resulted in an estimate of the Onshore Plant layout for the CCGT and Carbon Capture Plant and a weight estimate for the offshore platform jacket and topsides.

Site Selection

The most promising locations, capable of development of a large scale (ultimately 2GW plus) CCGT with CCS project, were selected. The sites selected in each region minimise development cost, risk, transport, and storage costs.



The storage sites were selected based on publicly available information for the White Rose project and the Strategic UK CCS Storage Appraisal Project.

[7] (Capture Power Limited - K41, 2016) (Capture Power Limited - K43, 2016) (Pale Blue Dot Energy and Axis Well Technology, 2016).

Performance Prediction

The CCGT plant was modelled by the project to provide a performance prediction.

A scaling of the Peterhead Engineered Solvent post combustion amine plant using publicly available information was developed for the Carbon Capture Unit. A comparison with MEA models was used by the team to confirm the scaling approach used.

The compression, dehydration, pipeline transport, and storage was modelled to provide an estimate of compressor size, pipeline size, and platform arrival pressure.

Cost Estimate

A cost estimate for the generic plant was developed in blocks:

- Onshore Plant Site Enabling Works
- Each CCGT Train
- Carbon Capture & Compression (CCC) Train
- Utilities and Facilities
- Utility Connections (specific from each site location to connection point)
- CO_2 Transportation (specific from each site to its store)
- Offshore Infrastructure (specific to each storage location)
- Owner's costs and Contractor's pricing

The cost for the CCS scheme for each selected site was generated by combining the cost blocks into a complete estimate. The Site Enabling Works cost estimate was generated for the generic site and modifications to the cost were made for the individual selected sites. Site specific costs were applied for each site location.

Developing the cost estimate per train and per offshore facility allowed a logical build-up of the estimate for different numbers of trains at each location. Where required, cost blocks such as the connections were estimated based on the size required for a 1 to 5 train sized scheme.

2.8 Design Basis


Template Plant Specification

Doc Number: 181869-0001-T-EM-SPE-AAA-00-00001
Revision A03

ETI Number: D2.1
Version 2.0

Figure 4 – Template Plant Specification

The design of the CCGT + CCS Scheme is based on the Template Plant Specification, doc ref: 181869-0001-T-EM-SPE-AAA-00-00001 (ETI project deliverable D2.1) has been issued in order to:

- Define the end to end process scheme for the project.
- Provide sufficient input to location selection (plant footprint, inflow connections, out flow connections, utility connections), modelling (plant basis), and estimating (scope definition, contracting basis).
- Provide a convincing basis to a range of stakeholders.

The intention of the document is to mimic, at a high level, elements of an Enquiry Specification for an EPC Contract as this would provide a grounding for the cost estimate.

Life of Plant

The design life of the plant is described in the above referenced document. The economic life considered for the plant is 15 years: this would align with a revenue mechanism for a CCGT + CCS scheme (such as CfD). It can be expected that additional investment may be required after 15 years of operation such as the drilling of additional injection wells, replacement of repurposed infrastructure, or installation of additional injection platforms, and that this future investment is not included in this report.

(For economic analysis where construction time is required in addition to the economic life please refer to Attachment 12 for the construction schedule).

2.9 Outline Scheme Design

The Generic Business Case aims to capture around 10 million tonnes of CO_2 per annum from Combined Cycle Gas Turbines (CCGT). The overall plant configuration is expected to be as follows:

- Gas inlet to the CCGT's;
- 5 Gas Turbines (GT) - Nominal total single cycle capacity 2500 MW (each 500MW);[1,3]
- 5 Heat Recovery Steam Generators (HSRG);
- 5 Steam Turbines (ST) - Nominal total capacity 1000 MW (each 200 MW);[1,2]
- Flue gas treatment, with Selective Catalytic Reduction (SCR), for NOx removal;

- 5 Carbon Capture (CC) Units, i.e., there will be one CC Unit for each CCGT train;
- 5 CO_2 Compressors;
- CO_2 pipeline, with valve stations, for dense phase / gas phase CO_2 transport to the shoreline;
- Shoreline station (a pressure booster station is required for a Southern Scotland location, and a substation with future provision for chilling is required for a North West / North Wales location);
- Subsea CO_2 pipeline; and
- Offshore Platform (complete with risers, offshore equipment, and injection wells).

Notes:

1. Nominal figures are unabated.
2. Steam Turbine nominal capacity.
3. In a 1+1+1 multi-shaft configuration.

Block Diagram

The following block diagram shows the how the different elements of the Generic Business Case scheme design fit together.

Process Flow Diagrams

Process Flow Diagrams (PFD) are key documents for the process design of the scheme and show the relationships between major equipment. PFDs have been prepared for the scheme design and can be seen in Attachment 1. The PFDs are common for the Generic Business Case, however, notes have been added to the PFDs to show where the design for a region differs from the Generic Design.

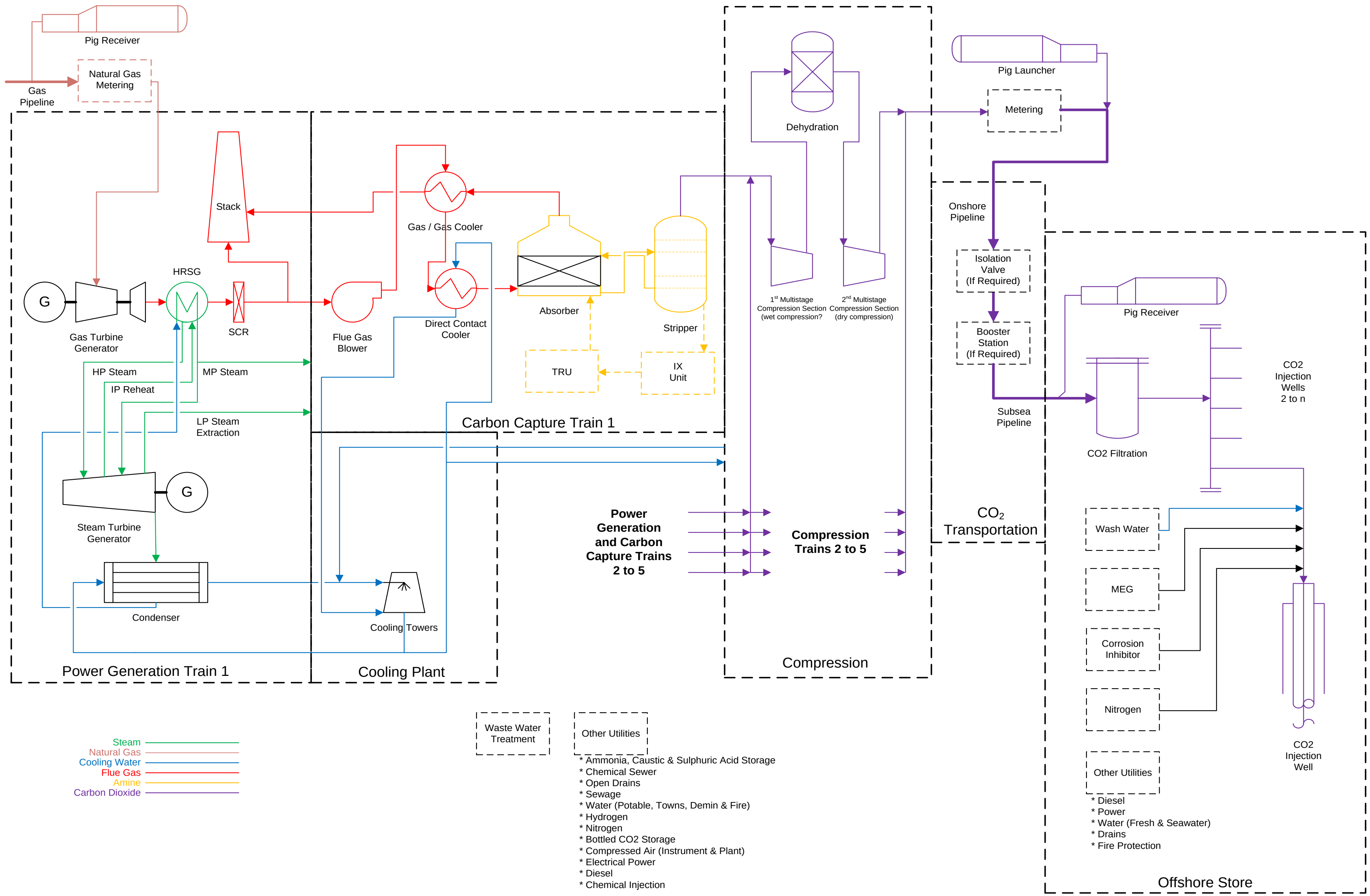


Figure 5 – Flow Diagram of Power Generation and CCS Scheme

2.10 Definitions

The Gas Turbines will fire natural gas to power the generators and raise steam through the Heat Recovery Steam Generator's (HRSG's). The steam from each HRSG is routed to a steam turbine. Flue gas, after treatment for NO_X removal, is routed to a CC plant, which uses engineered amine solvents, to capture 90% of the CO_2 in the CCGT flue gases. The captured CO_2 is recovered from the amine by steam stripping, compressed and conditioned before being transported via a pipeline to offshore for storage. The end to end chain links for the overall plant are:

- Power generation facilities including flue gas treatment
- Carbon capture, compression and conditioning
- Pipeline and transport
- Offshore storage

Key definitions relevant to these chain links are:

Capture efficiency - This is the percentage of CO_2 recovered from the flue gases entering the CCS plant.

Dense Phase - CO_2 above its critical temperature and pressure. This state is referred to as dense phase fluid, or supercritical fluid, to distinguish it from normal vapour and liquid.

Nominal Capacity - This is the target power output of the gas turbine and steam turbine generators; it is not a reflection of the actual power output from the machine.

Plant – The overall CCGT and CCC facility including up to 5 trains.

Train – 1 Gas Turbine, 1 HRSG, 1 ST, 1 CCC.

Unit – Each power or process block: these are the sub-sections of each train.

2.11 Design Capacity

The CCGT power generation facilities will be designed to produce, and deliver, with 5 trains around 3.5 GWe (nominal gross capacity without CO_2 capture) of electricity to the UK National grid.

The CCS facilities will be designed to capture and store around 10 million tonnes of CO_2 per annum (MTPA).

Heat and Material Balance

The Heat & Material Balance (H&MB) data for the design of the General Business Case is provided in the Overall H&MB, 181869-0001-D-EM-HMB-AAA-00-00001-01, which can be found in Attachment 2. The H&MB should be read in conjunction with the Process Flow Diagrams, 181869-0001-T-EM-PFD-AAA-00-00001, which can be found in Attachment 1.

A high level summary of the material balance is provided in the following figure.

Equipment

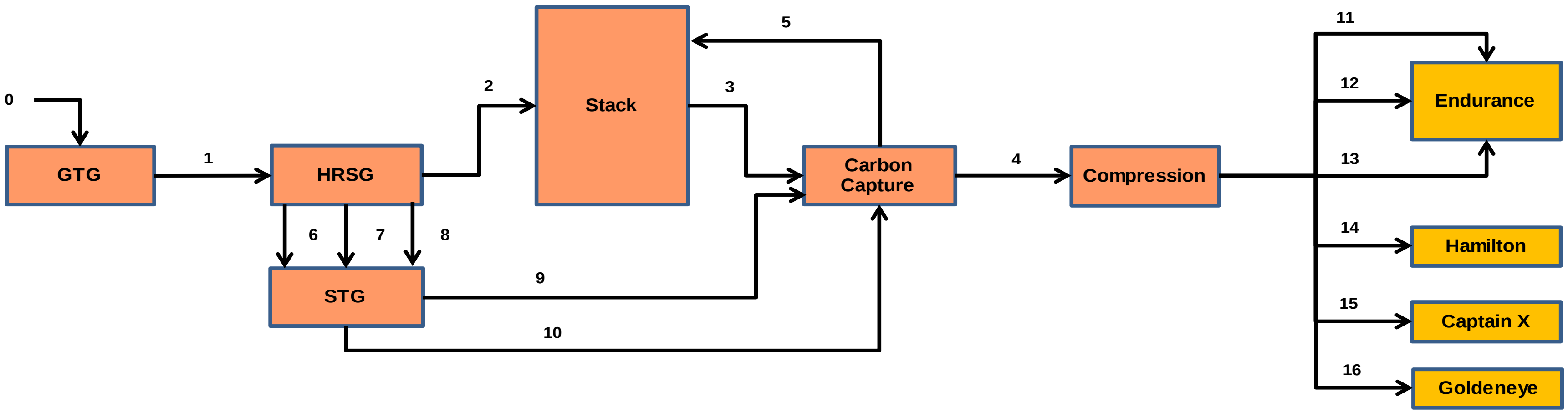
The major equipment for the plant, sized or scaled by the project team, is included in the Major Equipment List, 181869-0001-T-ME-MEL-AAA-00-00001, which can be found in Attachment 3.

The Major Equipment List is a key input to the cost estimate for the GBC scheme.

Turndown

- Turndown is 40% to 50% for each CCGT/CCC train based on the capability of modern CCGT equipment.
- The overall plant operates with multiple trains. This allows for different numbers of trains to be operated, For example, the Plant Turndown will be 20% if only one out of the five (5) trains runs (operates).

The Mass Balance is summarised below for the Generic Scheme below:



Overall Stream Number	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Stream Description	Natural Gas to Gas Turbine	Flue Gas to HRSG	Flue Gas to Stack /CCP	Flue Gas to CCP	CO_2 to Compression	Treated Gas to Stack	HP Steam to HP Casing	Reheat Steam to HP Casing	Steam to IP/LP Casing	MP Steam to CCP	LP Steam to CCP	CO_2 to from Teesside to Endurance	CO_2 to from South Humber to Endurance	CO_2 to from North Humber to Endurance	CO_2 to from North West to Hamilton	CO_2 to from Scotland to Captain X	CO_2 to from Scotland to Goldeneye
No Train	1						1			1		5	5	5	3	3	
Temperature (C)	25/204.4	646.5	89.7	87.8	26.3	64.6	573.9	573.9	291.9	235.0	138.7	36.0	36.0	36	65.2	36	36
Pressure (bar)	49.11	1.04	1.01	1.01	2.00	1.01	165.00	30.00	3.38	21.51	2.40	183.24	173.70	172.2	81.5	149.1	113
Platform Pressure (bar)												142.30	142.30	142.3	50.5	132.5	105.4
Mass Flow (tonne/h)	94.7	3550.5	3550.5	3550.5	230.2	3215.1	482.2	522.9	52.8	13.4	297.8	5715.0	5715.0	5715.0	3429.0	1714.5	1714.5
CO2 Mole Fraction	0.0191	0.0461	0.0461	0.0461	0.9809	0.0051	0.0000	0.0000	0.0000	0.0000	0.0000	0.9983	0.9983	0.9983	0.9983	0.9983	0.9983

Figure 6 – High Level Mass Balance

2.12 Design Criteria

Sparing Philosophy

The plant design has eliminated sparing of fabricated equipment, and the sparing of larger capital equipment such as gas turbines, steam turbines, HRSGs, main inlet booster fans, and the CO_2 compressors. These in addition to vessels, coolers and tanks constitute single point failures which will require adequate mitigation to ensure downtime and repair times are minimised. All other rotating equipment is spared and provided with appropriate isolation valves to effect online repairs. This has been reflected in the cost estimate for the plant.

Spared Equipment	Unspared Equipment
Injection Wells (additional well per platform)	Turbo Machinery
Filters	Heat Exchangers
Pumps	Electric Heaters
Weighbridges	Pressure Vessels
Air Compression	Coalescers
Thermal Reclaimer Vacuum Packages	Storage Tanks
	Cranes
	Pig Launcher / Receivers
	Main Electrical Equipment

Table 8 – Spared and Unspared Equipment Types

This approach follows typical guidelines for availability decisions before detailed reliability modelling data is available for a plant design (SNC-Lavalin, 2008): -

- For continuous service, it is normal practice to install spares for small and medium centrifugal pumps, as the life of seals can be unpredictable. It is also normal practice to install standby equipment for reciprocating machinery including compressors, pumps and diesel engines as regular maintenance of wearing parts is required. The level of sparing can be seen in the Equipment List in Attachment 3 to this document.
- It is not normal practice to install spares for centrifugal, axial or rotary positive displacement compressors and large engineered centrifugal pumps, except for critical systems. Care is required to ensure that items such as shaft seals will perform to expectations and spare auxiliary equipment such as duplex oil and gas filters, lube oil pumps etc. need to be considered to maintain the availability of the package or system. It is also usual to add additional condition monitoring instrumentation and systems in order to provide early indication of problems so that remedial action can be planned.
- Combustion equipment is not normally spared however ancillary equipment such as combustion air fans is normally spared.
- Static equipment is not normally spared because there are no wear parts; although filters and coalescers often have a standby to allow for the replacement or conditioning of the internals.

The decision not to spare the CO_2 Compressors and the Booster fans was supported on Shell Peterhead by a cost / benefit analysis performed during the FEED study. This is reflected in the cost estimate for the Generic Business Case. There is a change for the Generic Business Case design with multiple CCGT + CCC trains in that the CO_2 compression is fed from a common header so if one of the Carbon Capture (CC) units is not in operation or the CC units are turned down then there is spare CO_2 compression capacity available. In addition, if the entire plant is turned down, or has trains that are not operating, through lack of required demand then the plant has available capacity to account for failure of unspared items.

Design Margins

The design margins for the Carbon Capture and Compression equipment reflect the strategy applied to for the Peterhead FEED Study(Shell U.K. Limited, 2016):

Equipment	Design Margin %	Notes
Booster Fans	0	On design gas throughput
DCC Column	0	On gas throughput
DCC Pump	20	On flowrate
DCC Cooler	20	On surface area
Gas-Gas Exchanger	10	On flowrate and duty
CO_2 Absorber	5	On flue gas flowrate
Thermal Reclaimer Unit	50	On processing rate
CO_2 Compressors	0	On flowrate
LP Steam and Condensate Systems	10	On flowrate
Closed Loop Cooling System	10	On flowrate
CC Heat Exchangers	10	On surface areas
CC Pumps	10	On design flowrate
Demineralised Water	10	On peak flow rate

Table 9 – Design Margins for Different Equipment Types

No design margins were selected for the Booster Fans and the CO_2 Compressors to ensure that these were not over designed for service. Over design of large machinery results in less efficient operation and less efficient capital utilisation:

- Centrifugal Fans for Petroleum, Chemical, and Gas Industry Services, API 673, already includes a 10% margin on motor power.
- Axial and Centrifugal Compressors and Expander-compressors, API 617, already includes a 10% margin on motor power.

The Direct Contact Cooler tower is well understood from the Boundary Dam project and therefore a design margin is not required for the cooling and saturation of the flue gas.

Driver Selection

The driver selection philosophy used for the Generic Business Case design is the same as that employed for the Shell Peterhead Project.

The main driver selection is electric motor: with the exception of the Gas Turbines and Steam Turbines used for Power Generation.

The Variable Frequency Driver (VFD) selection is the same as used for Shell Peterhead with the exception of VFDs being added for the HV Feedwater Pumps.

A detailed driver selection study has not been carried out as part of the work for the Generic Business Case.

Control

The control philosophy for the Generic Business Case is to have one control room from which to monitor and control the entire CCGT + CCS chain. There will be remote monitoring and control for the offsite locations within the chain from the control room (Utilities connections, transportation, above ground installations (AGIs), and offshore storage.

2.13 Contracting Approach

This section of the report has been added to explain the contracting and execution basis for the project which results in a number of assumptions used for the cost estimate.

Contracting Strategy

There are a range of contract strategies that can be designed in order to maximise the probability of successful project delivery. The selected contract strategy needs to be aligned with the project scope, technology, complexity, and risk. The selected contract strategy also needs to be aligned with the competence, knowledge, and capability of the Project Owner (for example, a major oil international oil company will have a wide range of project management, project controls, engineering, technology, and commissioning competences, knowledge, and capability that would not be found within an investment bank).

The main contract types for the delivery of large projects are:

Contract Type	Comment
Turnkey EPC with Firm Price	• Useful for a lean Owner's team as the majority of the organisation is carried by the EPC Contractor – as are the risks. • Price should be fixed – and therefore certainty for investment. • Limited control of project: Owner at the mercy of EPC Contractor. • Cost premium for risk and contingency held by EPC Contractor. • Anything not specified will be reduced to lowest cost solution by Contractor. • Need sufficient definition in order to secure fixed price.
Turnkey EPC with Target Price	• Allows for transparency within pricing. • Shares risk and contingency between Owner and Contractor: Owner does not pay a high premium for this but takes on a share of the risk.
Multi Contract	• Project broken down into areas for more specialist contractors (rather than single contractor managing the whole project). • The Owner must have sufficient competence and resources to manage contractors and interfaces. • This approach can give the Owner more control.
Reimbursable	• Work executed at cost + fee. • Owner not paying excessively for risk and contingency: however, needs a large and competent organisation to control the project. • Difficult to raise competent organisation unless delivering successive projects. • Little cost certainty (risk and opportunity). Therefore, the Owner needs

Contract Type	Comment
	to retain risk and contingency within their budget.

Table 10 – EPC Contract Types

Business Drivers

The Contract Strategy should be designed to align with the business drivers for the project, and to align with the style of project (and any challenges that reside within it).

The Business Drivers assumed for this project are:

- Maximum Reliability – CfD only pays if CO_2 is sequestered;
- Minimum CAPEX is next most important driver in order to make the scheme feasible to build;
- Stepless flexibility is not so important based on preliminary modelling;
- 'Chunky' flexibility – e.g. allowing each train to be switched on and off – would be an advantage because CCGT + CCS would be ahead of Nuclear and Wind in being switched off in dispatch analysis;
- Deliver, operate, maintain, and decommission the project in accordance with HSSE goals.

A major lesson learnt from previous CCS proposals and projects is that the juncture between Power and Carbon Capture causes a lot of issues which affect CAPEX and reliability. It is strongly recommended that both Ownership and EPC Contracting not be split along a power generation to carbon capture battery limit: both should span the Power + Carbon Capture and Compression in order to deliver a seamless and integrated plant: for design, costing, reliability, and operation.

Maximum Reliability may not be delivered by a "lowest cost" mentality as this will drive behaviours towards minimum provision as opposed to considered design in order to meet a robust plant design. One risk control approach could be to use a FEED+ where the FEED is extended to ensure the reliability of design within "lowest cost" contract approach driving behaviours.

Change is the enemy of successful project delivery: it is therefore recommended that the following steps be taken to control the project from the current stage:

- Ensure design bases and design criteria are well tested and verified in the early stages of the project. There is a lot of experience, both industry and academic, which can assist.
- Consider early selection of technology and major OEMs so that FEED design is built around actual delivery.
- Maintain the train design as identical: this will mean that 1 train design can be replicated to 1, 2, 3, 4, or 5 train plant.
- Economics drives many decisions and changes for optimising business cases.
- Ensure that there is construction and operations experience within the FEED team: teams that just deliver FEED after FEED don't have a reality feedback loop to ensure what they are proposing can be efficiently built, operated, and maintained.

Key Project Parties

The Owner's and Contractor's cost build up, risk, and contingency are based on the following assumptions:

Area	Description / Assumption
OWNER	Single Entity Common Equity Not split chain (would cover whole Power to Sequestration) *This goal needs an integrated project and behaviours.* *i.e. no Power / CCS battery limit.* *Integrated Control Room.* Special Purpose Investment Vehicle (SPV) Would need to develop aligned cultural perspectives Preference is for an Oil and Gas (O&G) culture (knowledge led) but will have to include Power / OEM cultural aspects as well Result should be a lower EPC price compared to underfunded debt investment (with equity whole penalties and behaviours)
INVESTORS	Ideally several O&G Operators with offshore North Sea experience Potential that a Power Company would be needed (they have the knowledge and skills to understand regulatory and market compliance for Power Generation).
OEM	Preference for Original Equipment Manufacturer (OEM) to be a Subcontractor as this would allow freedom for equipment and technology selection to the project. OEMs have strongly negative views of UK Power and CCS opportunities following the CCS Commercialisation Competitions and Capacity Auctions so may be difficult to get early buy in The project would need to make a decision around the carbon capture technology because some OEM's are able to offer this as well as CCGTs: is a combined CCGT + CC offering an advantage? *A combined offering may provide an end to end guarantee to provide better certainty to project delivery for investors.*

Area	Description / Assumption
	A combined offering may not be the best technical combination to deliver best efficiency. *CCGT and CC groups in OEMs are separate entities – may not be a commercial or execution advantage in delivery from one company.* Potential for OEM to be part of Investment group: however, this would require OEM equipment selection and potentially OEM technology selection. OEMs tend to have strong balance sheets which may be an advantage
FEED CONTRACTOR	Preference for single entity that can cover whole CCGT + CCS chain. So FEED Contractor needs Power Generation, Carbon Capture, Pipelines, and Offshore experience. Construction and operations experience within the FEED team: not just theoretical consultant. UK based team so that can address UK specifics (e.g.): › Planning & Consents Limits › UK Regulations › Tighter layouts (space constraints compared to other geographies) › Congested terrain (pipeline routing) › Knowledge of local supply and construction contracting base › Offshore North Sea experience There are a number of Contractors in the UK who have this spread of experience
EPC CONTRACTORS	For contract types please refer to Table 10 – EPC Contract Types. EPC Lump Sum contracts are preferred by owners as this defines cost versus scope. Recommendation from experience would be: › Management, Engineering, and Procurement – Lump Sum › Construction – Pain / Gain Share Competent contractors will be able to control Management, Engineering, and Procurement costs against scope. UK Construction is a mature market with savvy and unionised workforce. Size of CCGT + CCC plant would make it a NAECI category 1 site for construction.

Area	Description / Assumption
	Weather profiles can have a significant influence on productivity e.g. shore / port area locations would have high wind days where cranes can't be operated. UK Construction Risk (and general Construction Health & Safety Risks) can be controlled by use of offsite fabrication, skidding, and modularisation. EPC Contractors shall be limited to those who can self-perform or directly subcontract the works in order to ensure control is retained within the project. By Tier 3 (where work is subcontracted to further subcontractors) a project would tend to lose control and also has to pay for overhead and profit on overhead and profit.
RISK	General principle – risk should live with the entity most capable / competent to influence / resolve. Risk cost increases exponentially the further it is removed from the competence / understanding to resolve / manage risk. Aim is to maximise value for Owner – manage risk effectively in order to minimise cost and delay GOVERNMENT RISKS (Dr Leigh A Hackett, December 2016) Post decommissioning CO_2 storage risk. Sub-surface CO_2 storage performance risks impacting on storage rates and capacity. Decommissioning cost sufficiency and financial securities related to the CO_2 storage permit. Insurance market limitations for CO_2 Transmission and Storage (T&S) operations OWNER'S RISKS Site Selection / Route Selection – Land Purchase / Lease / Easements / Wayleaves Environmental, Planning, Permits, Consents, DCOs, Storage, Offshore Project Development – Commercial / Legal / Financial) Front End Loading – FEED Contractor(s) and Consultants Technology Selection (& Warranty – supplied by Technology Supplier) Overall Project Management and Coordination of Main Contractors What is in the ground / seabed risk? – Expect full surveys to be done before enquiring for Main EPC Contracts EPC Cost – i.e. scope definition Interface / Tie In Agreements for Utilities Construction & Commissioning – shared with Contractor – some of Owner's decisions affect construction / constructability / workforce

Area	Description / Assumption
	CONTRACTOR'S RISKS Project Management, Design, Engineering, Procurement Construction Offices / Welfare / Laydown / Warehousing / Construction Utilities Construction & Commissioning – shared with Owner – some of the Contractor's decisions affect construction / constructability / workforce Warrant own work & Insurances

Table 11 – Assumptions on Key Project Parties

Contracts

It is assumed that the project delivery would be split into a number of EPC contracts: this is because contractors generally do not possess the range of competence and capability to execute all areas of the project. Also, the project becomes more controllable by splitting the delivery into a number of more manageable contracts.

The lower the level of contracting selected by the Project Owner, the more control the Project Owner will have over the execution of the project: however, the lower the level of contract selected the larger the team the Project Owner needs to employ. Typically, Project Owners want to contract at Tier 1[8] level: true Tier 1 level is where the EPC Contractor has direct control of works and is only subcontracting the majority of works down 1 level or directly performing. If the EPC Contractor is sub-contracting sub-contracts then control is quickly lost between the project owner and a sub-sub-subcontract layer. In such cases, the arrangement suggests that the contracting is set at too high a level and the Contracts need to be broken down.

A preliminary view of the contract breakdown for the project is given in the following Figure 7 – Contracting Strategy. It should be noted that there are many other ways of arranging the contracting approach to the delivery of the project. A description of the contracting approach is provided in each of the main sections.

Risk

There is however a balance is risk between the level of contracting and the size of contracts. Some organisations are happy to pass on all risks to their EPC Contractors, even if they lose some of the control because the EPC Contractor passes down scope to many different levels of sub-contract. There is a recent trend to some major energy companies controlling more work themselves (e.g. separate early works, site enablement, and ground works as these are seldom self-performed by EPC Contractors but usually sub-contracted to local Civils contractors).

[8] The Tier 1 Contractor works directly for the Owner. The Tier 1 Contractor hires Tier 2 Contractors to perform work on the Owner's project. The Tier 3 Contractor is hired by the Tier 2 Contractor to perform specific tasks. A Tier 4 Contractor works with the Tier 3 contractor. There is no contract between the Owner and the Tier 2, Tier 3, and Tier 4 Contractors: it is a risk that the Owner can lose control of a project is too much of the work is devolved too far down the Contracting Tiers.

The following is presented as a preliminary view of the contract breakdown for the project:

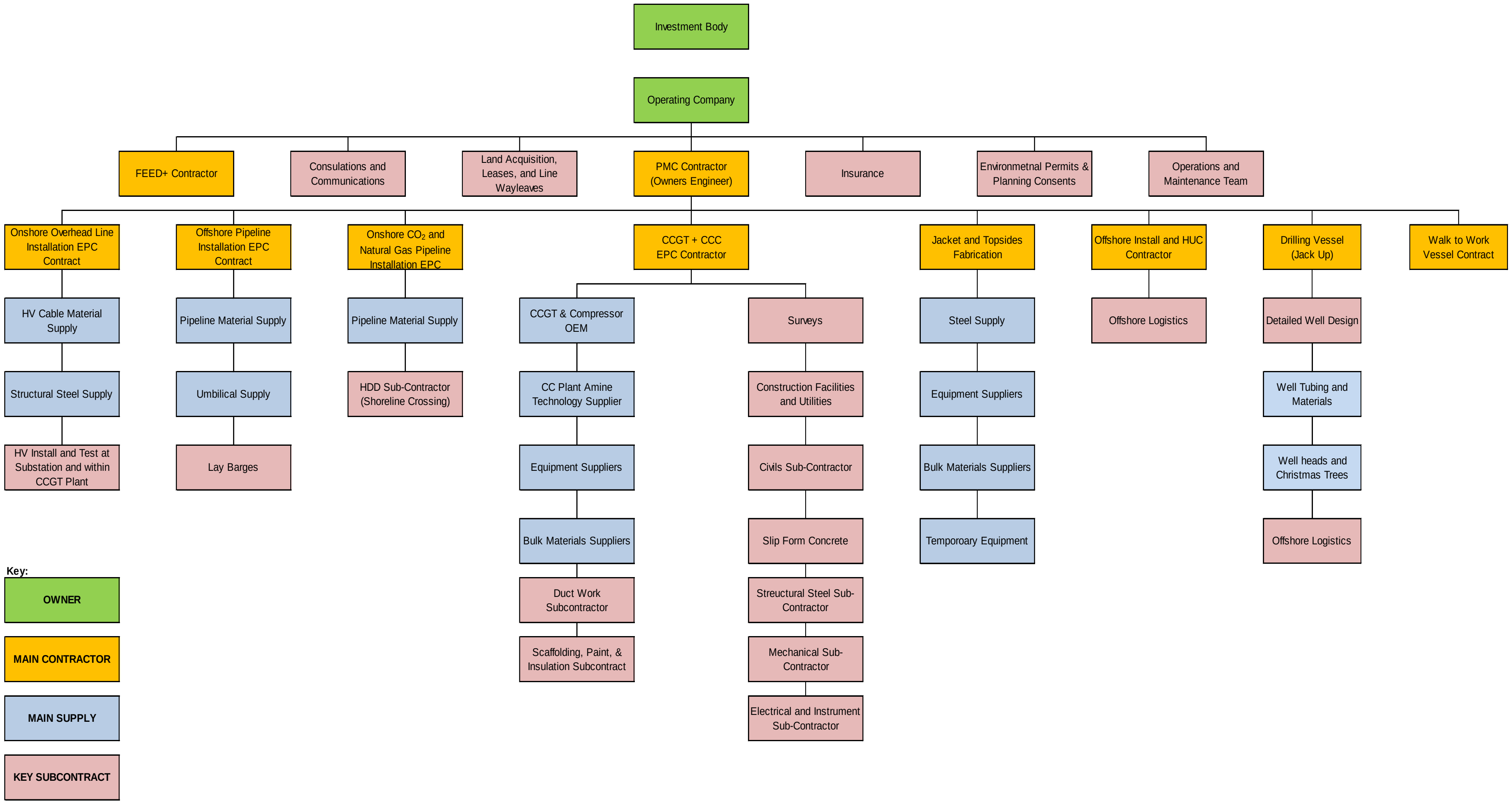


Figure 7 – Contracting Strategy

The following sub-sections provide the scope of works for the Cost Estimate build up.

Execution

The Project Scope of Supply for each of the contracts is as defined at a high level in the following documents which form part of the Template Plant Specification, reference 181869-0001-T-EM-SPE-AAA-00-00001 (ETI reference D2.1), the design contained within this document and its attachments.

The scope of each contract will generally include:

- Project Management,
- Project Controls,
- Detailed engineering,
- Procurement and Fabrication elements,
- Material supply within the boundary limits,
- Construction,
- Subcontracts,
- HSSE,
- Quality Assurance and Quality Control,
- Commissioning and Start-Up,
- Performance Testing and Handover,
- Cost of risk,
- Contingency for scope and contract type,
- EPC Contractor’s overhead and profit.

Contract Basis

It is assumed that the main contracts for the whole CCS chain would be competitively tendered on the following basis:

- Robust FEED study provided to Engineer, Procure and Construct (EPC) Contractor by Project Owner
- EPC contracting model
- Fixed price lump sum Engineering and Procurement. Construction as a form of pain / gain share
- Each of the EPC Contracts will be placed and managed by an Implementation Manager employed directly by the Project
- PMC and Owner’s Engineer services will support the Implementation Managers (assumption that Project Owner would not have sufficient staff to provide this)

The Project Management Contractor (PMC) would operate in support of the Implementation Managers and provide:

- Office support services;
- Project administration;
- Quality assurance;
- Design and construction safety management;

- Owner's Engineering,
  - Technical authority in support of technical decisions
  - Technical studies where required to evaluate options and alternatives
  - Response to technical queries from EPC Contractors
  - Design reviews and Design Audits to ensure design integrity and design sufficient to meet EPC Contract specification
  - Review of engineering deliverables
- Project services,
  - Project reporting,
  - Monitoring progress against plan with early identification of problems
  - Information management,
  - Risk management, and
  - Interface management;
- Supervision and personnel that may be necessary to manage and control the execution of their works.

Assumptions Carried Forward into Cost Estimate

The following assumptions generated from this section are carried forward into the cost estimate:

- OWNER is an SPV covering the whole chain: have priced for one set of Owner's costs not for multiple entities.
- CAPEX is prioritised over flexibility (e.g. steam cross connections not provided between trains).
- A joint culture is to be developed in order to break down a schism at the power / carbon capture boundary. The design and costing reflects this in a single control room for the whole chain (CCGT to well).
- The EPC contracts are Lump Sum Engineering and Procurement with a form of reimbursable Construction. The risk and contingency for construction is carried mainly by Owner which results in a larger risk and contingency allocation for the Owner (Owner's reserve). If the project were to be EPC lump sum then the uncertainty cost would need to be transferred from Owner to Contractor (and there may be a higher uncertainty provision from the Contractor) – please refer to section 8.14 and Attachment 14.
- Connections contracted directly to Owner – therefore not layering up profit, risk, and contingency by passing through the Main Contractor.
- Number of different contracts offshore as this is best practice for offshore type projects.

2.14 Procurement Approach

The Procurement approach assumed for the Generic Business Case cost estimate is similar to that proposed by SNC-Lavalin for similar projects and proposals such as the Shell Peterhead CCS:

- Equipment items assumed purchased directly by the EPC Contractor complete with spare parts. Site support for installation and commissioning provided at day rates (if applicable).
- Site built equipment items assumed purchased as a sub-contract by the EPC Contractors with the Manufacturer providing material and the installation at site.
- Installation would be procured as sub-contracts which would include the supply of bulk materials, labour, tools, and consumables. Construction welfare, stores, and fabrication shops would be supplied free issue to the sub-contractors.

- Logistics and transportation would be managed by the EPC Contractor to ensure safe and timely delivery of equipment and material to the construction site or to construction laydown.

General principles:

- Equipment and materials will be purchased from qualified and reliable vendors on a world-wide competitive basis. However, focus shall be on Local Regional or British Vendors and service providers wherever feasible.
- All equipment and material purchases shall be from the Owner's approved vendors list where possible. If this list were not available then most reputable EPC Contractors will have their own internally approved vendors list. Efforts would be made to qualify additional local regional or British vendors and services providers to increase local content and sustainability of the project.

2.15 Methodology Used to Build Up Estimates

The overall estimating methodology is illustrated in Figure 8 below. The majority of the CAPEX cost estimate has been built up from a major equipment list which can be found in Attachment 3 of this document. Modelling / Scaling of the CCGT power plant and carbon capture and storage plant has assisted with the equipment sizing, which was then compared to similar equipment used on prior projects. Where similar equipment existed, the vendor pricing was used.

In cases where the equipment was larger than equipment used on prior projects, a parametric model[9] was created using sets of data for similar pieces of equipment, which provides a basis for recalculating equipment costs based on the change in size and existing vendor quotes. For the CCGT, CCC, and offshore equipment, approximately 72% of the equipment costs were based on vendor quotes or scaled up vendor quotes. The remaining 28% were derived from modelling software and SNC-Lavalin norms and estimating data. Labour hours for mechanical installation were applied to each of the equipment items based on data from previous projects, and scaled up using a similar parametric model where required. Some mechanical installation costs have been based on supply and install subcontract estimates.

The remaining bulk materials have been estimated by using an analogous model based on prior projects and proposals.

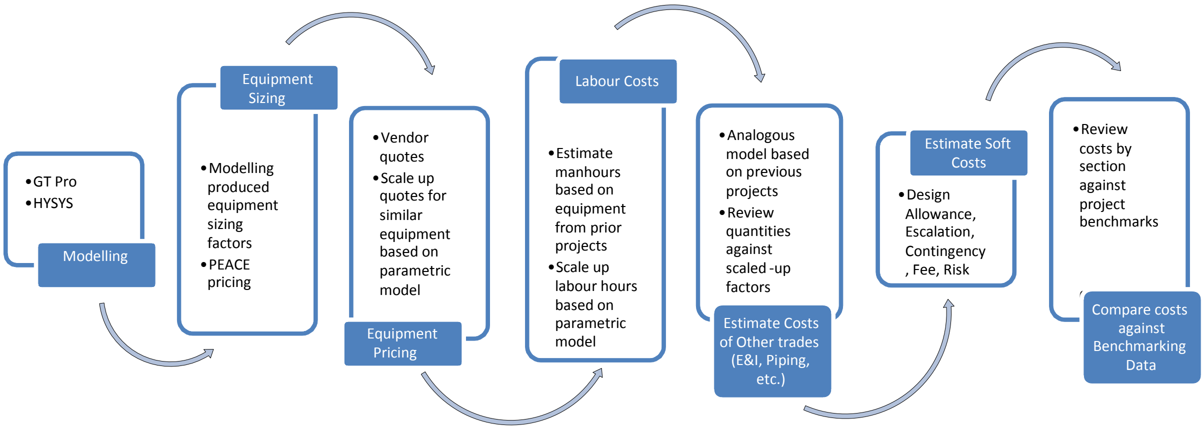


Figure 8 – Estimate Methodology

[9] A parametric model compares relationships between variables based on a set of data to determine costs. Parametric models were used to determine equipment size factor vs. equipment cost factor.

Project costs in addition to the major equipment, bulk materials, and associated labour have been estimated as follows:

- **Site acquisition**

Site acquisition costs have been estimated using a report that is available in the public domain estimating industrial land costs in the UK at £482,000 per hectare (UK Department for Communities and Local Government, 2015). Legal costs, permits, and consents are excluded from this figure, as they are factored elsewhere. The value of land has not been inflated based on the RICS Commercial Market survey Q1 2017 showing that the capital value expectations for industrial land are only just returning to mid-2015 levels following a significant decrease in June of 2016 (RICS, 2017).

- **Site Enabling works**

Site enabling and site establishment has been estimated based on generic site dimensions modified for each of the different number of trains and a construction schedule of five (5) years – a high level project schedule can be found in Attachment 12. Unit rates from prior project vendor quotes have been used for estimating site preparation, earthworks, roads, temporary facilities, and general site enabling works.

Additional site-specific consideration has been taken for differing levels of contamination between the sites, demolition works required, and additional flood defences required.

- **Detailed design**

Detailed engineering hours have been calculated as a percentage of total installed cost. This differs per section of the estimate and is determined based on SNC-Lavalin experience and data available from similar projects and proposals, including Peterhead, previous CCS, multiple power projects and significant offshore design experience. Detailed design engineering has been added to each section of the estimate.

- **Connection Costs**

Connection costs have been estimated using data from the site selection process including distances, crossings, and types of terrain. The costs have been built up using spreadsheets from prior projects and vendor unit based rates.

- **Commissioning and Start-up**

Commissioning costs were built up from detailed estimates from prior CCS and power proposals. The estimate includes subcontract costs for testing and vendor representatives, costs for first fills based on expected volumes and vendor quotes, performance testing, operator training, and a manpower plan for commissioning and start-up support. The proposed phased commissioning and start-up schedule runs 24 months, with the final 4 months being start-up.

The bottom up commissioning estimate was compared against commissioning costs from the KKD's, SNC-Lavalin projects and proposals, and industry benchmarks. These results were reviewed by an estimating consultant and a factor was recommended for commissioning to be applied to the total EPC cost per area. A total of 2.08% for contractor's commissioning, and 1.8% for owner's commissioning have been added to each relevant area of the estimate. Offshore hook-up and commissioning has been estimated separately using SNC-Lavalin norms.

- **Contractor's and Owner's Costs**

Contractor's and Owner's costs have been established on a percentage basis from experience on other power and carbon capture projects. Contractor's Costs include: permits and licensing, bonds and insurance, vendor representatives, site services and indirect field costs, project management and administration, contractor's contingency, and profit. The total of 29.79% has been added to each relevant section of the estimate.

Owner's costs have been built up using information from the KKD's. They include permits and licensing, legal costs, management and administration, owner's engineers and operators, insurance, and third party verification. Owner's costs of 9.3% have been added to each relevant section of the estimate.

- **Regions**

The cost difference between an example site for each region has been estimated using the length of each connection provided in the site selection report. The connections for high voltage electricity, water intake, waste water outfall, and natural gas pipelines are all dependent on the sample areas chosen in each region. The connections were estimated based on length, and basic topography, including number of crossings required.

Construction aspects for each site have been included in the costing for each site such as availability of labour, the degree of modularisation and pre-fabrication which can be employed for the site location, whether additional flood defence is required, and the degree of contamination present on the site.

For site enabling works, the sample sites were assessed for level of contamination, probability of existing structures for reuse or demolition, additional drainage or groundworks for flood defences, and provision of temporary power.

Modularisation depended on the availability of quayside access and the cost impact was determined based on SNC-Lavalin experience on previous projects.

Potential labour availability was reviewed and allowances were made for each region by construction management. An assessment of the local labour supply was made based on existing local industry, recently closed plants and completed projects, upcoming approved projects (such as HS2), site access (motorways, bridges, constricted access), and population base in the immediate area from which to draw a skilled workforce.

- **Differing Number of Trains**

The cost estimate for each train has been built up as a block allowing for ease of estimation for 1 to 5 trains. The connection costs have been calculated based on capacity required for differing numbers of trains. Site enabling and ground works have been calculated depending on the size of site required for the number of trains. For smaller number of trains the utilities estimate has been scaled from the Generic Plant. The offshore estimate has been adjusted for the number of wells and number of platforms required. The power generation includes a buy-down savings for multiple units and both the power generation and carbon capture and compression include a 50% savings on engineering for multiple units.

2.16 Assumptions on Estimates

The Generic Business case estimate has been built upon a set of key assumptions. This section will lay out those assumptions from an overall scheme perspective.

Any additional key assumptions per area are covered in the relevant sections of this report.

Overall Assumptions

- Estimate cost basis is Q1, 2016. Exchange rates for overseas equipment costs are typical of post Brexit referendum rates: USD/GBP – 1.2872, EUR/GBP – 1.13077
- Labour, equipment, and materials cost and availability were based on current market conditions. No uplift or savings have been considered based on future anticipated market activity (including commodity pricing), major supplier shop loading, or potential additional projects in each site selected.
- Local labour was assumed to be available for the duration of the project on each of the potential sites. No costs associated with construction camps have been included. The exception to this assumption was labour and subcontractor availability where major projects have been started. All sites have an uplift added to labour cost due to an anticipated requirement for trade labour to travel further to and from site. This uplift covers the anticipated daily rate set by the local unions to compensate for this occurrence. It has been applied as £17/day for craft labour and a pro-rata ratio for subcontract labour. The assumption was that at Teesside, 70% of labour will be local based on a good supply of skilled labour in the area due to a history of industrial activity. The North Humber has a moderate population base and increased large projects in the area. Scotland also includes 50% of labour with supplemented travel due to greater difficulty accessing the area and a moderate population base. The North West includes a supplement on 70% of labour due to major projects in the area drawing a large labour requirement and resulting in higher churn. South Humber includes an increase for 70% of labour due to personnel access issues with crossing river Humber.
- The project construction schedule was priced based on 5x10 hour days, with 75% working day shift, and 25% on afternoon shift.
- Escalation has been included only to bring the estimate to Q1 2016 cost. The inflation factor has been applied to labour, equipment, and subcontract costs to bring them to 2016 money of the day.
- Inflation has been applied using inflation rates published by the Office for National Statistics (ONS), and compared against BCIS rates by RICS, and reports on Construction industry by Turner and Townsend (Turner and Townsend, 2016) and Gleeds (Gleeds, 2017) . These numbers were so close to the ONS numbers that ONS numbers have been used throughout.
- No savings as a result of a learning curve have been assumed for the construction of subsequent units. It was not possible to determine the extent of this potential economy, if any, at this phase of the project. Advice from construction professionals was that learning by doing rarely yields savings as would be expected from a multi-train plant. This is because in practice construction crews may not move from one unit to the next working on the same pieces of equipment or areas, and a long construction duration may mean more personnel joining and leaving the project for

other employment opportunities. Other project opportunities such as infrastructure or rail and transit may provide better commuting/travel or pay than the GBC project.

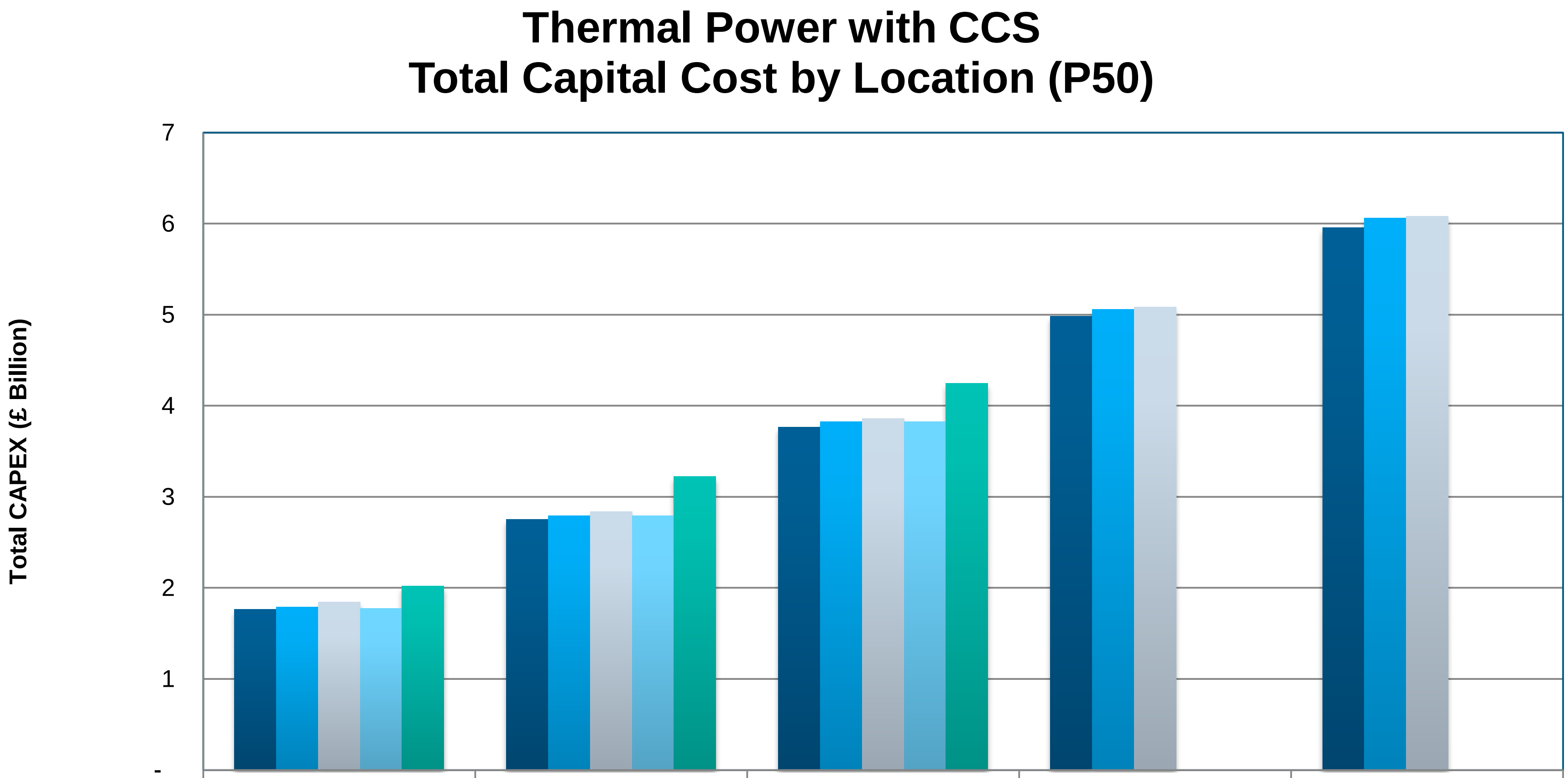
- Labour efficiency factor of 0.65 used to account for time lost walking to and from break rooms, safety talks, and weather delays, determined in consultation with SNC-Lavalin estimating team and Construction Manager. No site-specific productivity factors have been included. The labour efficiency factor is built up of:
  - 0.1 walk to work – time to move around large site
  - 0.1 inclement weather
  - 0.05 Compact work areas
  - 0.1 UK productivity factor
- Engineering and Detailed Design is to be conducted in contractor's home offices and no uplift for travel or accommodation was included.
- Site engineering and management will be available from local labour force. For each site a supplement is included for travelling support staff as the contractor's costs are calculated as a percentage of the overall costs. The increase in labour and subcontracts on these sites will result in an increase in contractor costs. It has been assumed that the travel supplement will apply to 30% of labour for Teesside, 50% for North Humber and Scotland, and 70% for North West and South Humber.
- Constructability savings at Teesside and Scotland location of 4% due to quayside/shore side location and ability to modularise elements of construction. This is based on previous project calculations.
- The civils and foundations estimate included within the Power Generation and CCC sections is based on geological conditions similar to those near Peterhead. Changes in geological conditions have been considered for the different sites; the civils and foundations estimates / pricing are therefore higher than would be established by estimating norms. The differences between pricing for additional piling for a waterlogged sandy area versus piling through rock were found to be immaterial to the overall Class IV estimate.
- Labour costs are based on current NAECI rates with additional allowances added for shift premium, employee benefits, PPE, small tools and consumables, and labour related overheads.
- Equipment costs are primarily based upon technically and commercially evaluated vendor quotations for similar equipment or vendor quotations scaled up for resized equipment. These make up 72% of the overall estimate. The remainder were based on SNC-Lavalin norms and estimating data and costs from modelling software.
  - 26% quote or cost
  - 46% scaled up
  - 4% modelling estimating software
  - 24% SNC estimating data and norms
- Buy down has been included for Gas Turbines (i.e. discount for buying multiple units) – refer to section 4.12. Buy down has not been included for other items.

2.17 High Level Summary of Cost Estimate

The capital cost estimate of the deployment of a large scale CCGT + CCS scheme is summarised in Figure 6 for a selected site in each of the regions and for different numbers of trains:

The information shown in follow Figure 9 – Summary of Cost Estimates is total project cost (P50). The information in Figure 9 – Summary of Cost Estimates also excludes the cost of project financing or debt.

Please note that an outcome of the work is the 4 and 5 train schemes could not be supported by the storage options chosen for Scotland and North-West regions (refer to section 2.5 for further detail).



	1 Train	2 Trains	3 Trains	4 Trains	5 Trains
Teesside	1,764,392,521	2,753,873,823	3,762,523,003	4,983,906,265	5,954,844,832
North Humber	1,790,712,600	2,791,340,822	3,825,913,921	5,057,852,402	6,060,173,852
South Humber	1,845,552,163	2,837,367,695	3,861,448,177	5,084,594,857	6,080,327,354
Northwest	1,774,268,678	2,794,512,308	3,825,398,048	-	-
Scotland	2,020,297,789	3,223,909,681	4,245,858,678	-	-

Figure 9 – Summary of Cost Estimates

2.18 Cost Estimate Basis

The Basis of Estimate for the Generic Business Case has been detailed in Document 181869-0001-T-PS-DBS-AAA-00-00001 (please refer to Attachment 10 of this document). The basis of estimate supports the Scope of Work as defined through the concept design phase of the work. The estimate addresses all phases of the capital cost from pre-development engineering through commissioning and start-up. This portion of the estimate excludes operating expenses (OPEX) and decommissioning and abandonment costs, which are specifically addressed in the Operation Modelling Report (ETI deliverable D5.1).

The estimate is based on the Association for the Advancement of Cost Engineering International guidelines for estimating, and follows the accepted criteria for a Class IV estimate. The Class IV estimate is used at the concept phase of a project and has an expected accuracy range of -15% to -30% and +20% to +50%(AACE, February 2005). The available documents for the preparation of the estimate were process flow diagrams, block layouts, and major equipment lists.

The CAPEX cost estimate has been built up using a combination of vendor quotes from previous projects for similar equipment and materials, scaled up vendor pricing, Guthrie Factors, specialist software with estimating capability, and SNC-Lavalin cost estimating norms. The estimates have been built up by plant section i.e. CCGT and CCC, and have been benchmarked against a robust set of data compiled from prior project experience, previous proposals, industry published information, and publicly available data.

The estimate has undergone review by an estimator, independent of the project, who has verified the methodology used and the accuracy of the output. In addition, the information has been subject to peer review throughout the estimating process by subject matter experts throughout the SNC-Lavalin organization.

Advantage of the approach taken for the Generic Business Case

Cost estimates for projects at this stage of development are normally built up by sizing and costing the major pieces of equipment then multiplying them by Lang Factors to reach a total installed cost. Such factors are based on research compiled by Hans J. Lang comparing the cost of major equipment to the overall project cost of 14 different process plants (Lang, 1947). These factors were first published in 1947 and continue to act as a rule of thumb estimating tool at the early stages of project development. In this work a significantly more detailed, robust and hence accurate approach has been taken because of the data available to the project team.

The project team has CCGT execution knowledge and experience including access to plant cost / price data. The project team's company has designed and built more than 49,000 MW of thermal power projects. The project team's company delivers and bids for EPC work including recent UK proposals: this provides real data which has been used in the production of this report;

- Site establishment, enabling, ground works, and costs for dealing with contamination
- CCGT costs from previous projects / proposals
- Engineering and Project Management pricing
- Commissioning costs

The project team has Carbon Capture Project knowledge and real project experience including access to plant cost / price data. SNC-Lavalin have delivered an EPC contract for the Boundary Dam

CCS. SNC-Lavalin were successful in bidding the Shell Peterhead CCS project before this project was stopped following the cancellation of the second CCS commercialisation competition. The data for Peterhead is real (as bid by SNC-Lavalin) and therefore provides a real UK basis for what a CCS scheme pricing would be in the UK market;

- Site establishment & enabling
- Equipment pricing
- Man hours
- Materials / bulks pricing
- Labour and sub-contract costs
- Engineering and Project Management pricing
- Guide to risk and contingency
- The project team has recent detailed design phase experience of UK North Sea projects;
- The project team made use of the design and cost information in the Key Knowledge Deliverables (KKDs) published by DECC (now BEIS) from the White Rose and Peterhead CCS projects;
- The project team had access to the Strategic UK CCS Storage Appraisal Project deliverables which provided information on the offshore stores, subsurface data, and information on the storage infrastructure and pipelines.

The SNC-Lavalin proposal for Shell Peterhead was a very important source of information for this report. The proposal provided equipment, sub-contract, material, labour rate, site establishment, engineering, procurement, construction, project management, and commissioning costs for a UK CCS plant at contract award phase (not study data).[10]

Whilst the work undertaken for this report is a study, and therefore does not have a level of detail down to a list of materials with quantities and types, SNC-Lavalin's work does make use of such information from previous projects and proposals and therefore does have more detailed basis of procurement costs, construction man hours, and construction materials that a typical study would not have access to.

[10] Shell UK Limited have provided permission for SNC-Lavalin to use the proposal information for this report.

3 Onshore Layout and Enabling

3.1 Onshore Footprint & Considerations

A plant layout has been developed for the scheme in order to ascertain the overall plant plot size for site selection and for the cost estimation.

Approach to Layout

Please refer to Figure 11 – Layout Option 1, Figure 12 – Layout Option 2, and Attachments 5 & 6 to follow the notes below against the layouts.

Combustion Turbines

The Combustion Turbines are located upwind of the plant so that the prevailing wind does not carry contaminants or flammable releases from the plant into the combustion air inlets of the machines.

Steam Turbines

An initial layout was considered with steam turbines located towards the side of the plant to minimise the cooling water pipe work runs from the condensers to the cooling towers. This was not the preferred solution. The steam turbines have been located adjacent to the gas turbines to minimise the length of the high-pressure steam pipe work from the HRSG to the STG.

There will be longer runs of cooling water pipe work around the plant, however, this is low pressure and standard materials as opposed to being high pressure and specialist metallurgy as required for the high-pressure steam pipework.

HV Switchyard

The HV Switchyard is located close to the generators. The plant edge location of this unit allows for HV power transmission lines to leave the plot without having to cross other process units.

Cooling Towers

Cooling Towers should ideally be located downwind of the Power and Process Plant so that the mist cloud from the towers will not contribute to the corrosion of the Plant, interfere with Electric / Instrument operation, obscure vision of the facilities, nor be ingested by Combustion Air Intakes.

However, this would extend the length of cooling water mains from the Steam Turbine Condensers. Instead, as a compromise in the Option 1 layout, the Cooling Towers have been located crosswind from the plant. The location of the cooling towers has been split in order to reduce the pipe runs from the STG condensers to the cooling towers. The cooling towers will be located either side of the Carbon Capture units. (The Cooling Towers have been located downwind of the plant, and located together, in the Option 2 Layout).

Carbon Capture Plant

The Carbon Capture Plant includes CO_2 which poses a hazard to operating personnel. The Carbon Capture Plant is therefore located downwind from the Power Plant so that any leakage would not drift onto the Power Plant and any operators located in this area.

The location of this unit is also logical with respect to plant flow.

The CO_2 emergency vents will be located on top of the Amine Strippers.

Compression and Dehydration

The Compression and Dehydration Units include high pressure CO_2 which poses a hazard to operating personnel: the higher pressure increasing the zone affected by any leak and the time available to react. As a high hazard unit of the plant this is located downwind of the rest of the facility, away from manned areas, and at the extremity of the plant plot.

The Owner should consider the risk impact posed by this unit to any activities on the other side of the site boundary.

The location of this unit is also logical with respect to plant flow.

Utilities

The key utilities (e.g. firefighting) will be located near the permanently manned areas of the plant for easy access. This location is also upwind of plant hazards. Dedicated consideration will be given to additional split of utilities in order to avoid common failures.

The remaining utilities are located between adjacent to the Cooling Towers. This is not an ideal location as it is not upwind of plant hazards (is cross wind): but this allows utilisation of an available area of plot.

Manned Areas

The permanently manned areas of the plant are near the plant entrance for easy access. This location is also upwind of plant hazards. Dedicated emergency gates will be provided to ensure safe evacuation of the plant for any operator in the field during an emergency.

Natural Gas

The natural gas intake to the plant is located on the right-hand side of the CCGT Units and at the extremity of the plant. This high hazard zone (explosion) is located at the opposite end of the plant to the permanently manned area.

The location of the natural pig receiver and metering allows easy access of the pipeline from the edge of the plant (i.e. the pipeline does not need to pass under any process units. The fuel gas pipe work serving the gas turbines can then run underground (lower risk) or along the pipe rack serving the power generation plant.

Maintenance

The plant footprint allows for maintenance based on the information available at this stage of a project – e.g. maintenance lay down areas next to Gas Turbines, free access around Gas Turbines, Steam Turbines, Compressors, Booster Fans, and HRSG. The road scheme allows general access around the site. Work shop, stores, and fixed cranage have been allowed for in the costing of the CCS scheme.

It is an assumption that the layout would allow major maintenance without a plant wide shut down. The assumption is based on the spacing of CCGTs being wider than other stations the project team know of (because the spacing is dictated by CC trains) and CC Trains being well spaced (road – flue gas duct rack – road spacing between each unit).

The CO_2 compression area is more problematic for maintenance without a plant wide shut down as it is the highest hazard area of the plant: the compressors are currently spaced >50m apart but the pipe racking and dehydration equipment in the vicinity carries the high hazard adjacent to any potential maintenance work. Controls would be needed to allow SIMOPs in the compression area.

<table>
<tr><th>Area</th><th>Source Information</th><th>Size</th><th colspan="2">Comments</th></tr>
<tr><td>Power Generation</td><td>SNC-Lavalin Thermal Power Group</td><td>8.4 Ha</td><td colspan="2"></td></tr>
<tr><td rowspan="3">Carbon Capture</td><td rowspan="3">Peterhead Plot Plan (Overall CCCC Project Area Plan), doc ref PCCS-00-TC-MP-4024-00002 rev K01.</td><td rowspan="3">12.6 Ha</td><td colspan="2">Plot size developed from Peterhead</td></tr>
<tr><td>5 x Carbon Capture
Deductions for plot not required
Plot Basis</td><td>11.5 Ha
1.5 Ha

10.0Ha</td></tr>
<tr><td colspan="2">26% additional plot space allowed for scale up of the carbon capture plot for GBC project.</td></tr>
<tr><td>HV Switchyard</td><td></td><td>3 Ha</td><td colspan="2">Scaled from previous power plants.</td></tr>
<tr><td>Cooling Towers</td><td>SNC-Lavalin Thermal Power Group</td><td>4 Ha</td><td colspan="2"></td></tr>
<tr><td>Water Treatment Plant</td><td>Peterhead Plot Plan (Overall CCCC Project Area Plan), doc ref PCCS-00-TC-MP-4024-00002 rev K01.</td><td>2.7 Ha</td><td colspan="2">Scaled up from Peterhead.</td></tr>
</table>

Area	Source Information	Size	Comments
CO_2 Compression and Dehydration	Peterhead Plot Plan (Overall CCCC Project Area Plan), doc ref PCCS-00-TC-MP-4024-00002 rev K01.	2.5 Ha	Assume 5 x Peterhead for CO_2 Compression and Dehydration
Utilities	SNC-Lavalin power plant bids	1.6 Ha	
Facilities	SNC-Lavalin power plant bids	1.4 Ha	
Total		**~40 Ha**	**Additional space for roadways and boundaries**

Table 12 – Plant Area Sizes for Layout

Construction Laydown

Area	Source Information	Size	Comments
Power Generation	SNC-Lavalin proposals	12 Ha	4,000 m^2 per 100 MW
Carbon Capture	Proposed Site Establishment and Laydown Area Layout, SNC-Lavalin drawing for Peterhead: PE15EF005UK-SK001 rev A	8 Ha	95m x 165m (1.6 Ha) for each Carbon Capture and Compression Train.
Total		**20 Ha**	

Table 13 – Construction Laydown Area

The EPC Contractor for the CCGT and CCC Plant would use large areas of the Plant Plot Plan as temporary construction lay down during the construction.

Cooling Tower, Utility, Water Treatment, Facilities, and Switchyard areas could be used as temporary lay down during the construction of the Power and Process Units: the construction duration of the Cooling Tower, Utility, Water Treatment, Facilities, and Switchyard areas will be much shorter than the other areas. On plot, temporary construction lay down would allow roughly 10 Ha to be available through a lot of the construction program.

An allowance of 10 Ha is advised by SNC-Lavalin for Construction Camp and Laydown outside of the Plant Footprint. This would make the site requirement approximately 50 Ha.[11]

[11] 50 Ha was used for the site selection in the selection of suitable sites with sufficient area to support a 5 train CCGT + CCS. A size of 60 Ha has been used for the pricing to allow for additional remote car parks, construction laydown, and safety separation to neighbours that might be required.

Figure 10 – Representation of the CCGT + CCC Plant

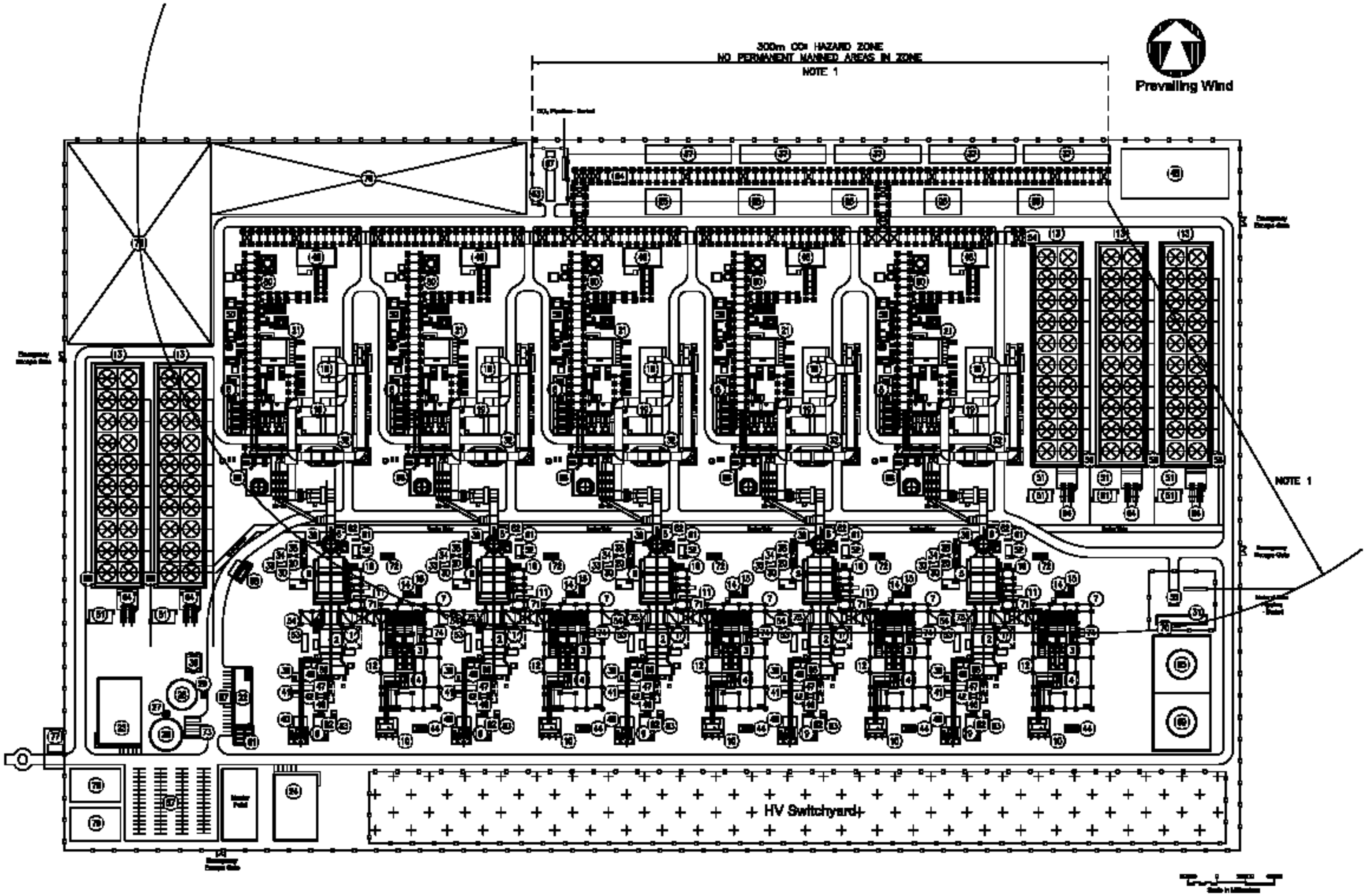


Figure 11 – Layout Option 1[12]

[12] The Cost Estimate is based on Layout Option 1

The cost estimate is based on the Option 1 Plant Footprint.

Thermal Plant with CCS – Option 2

The second version of the Plant Footprint was developed following a request from the ETI to push the site boundary beyond the inner (100m) CO_2 hazard zone around the high-pressure CO_2 area on the plant.

The original layout was configured to manage the CO_2 hazard to operating personnel on the plant: it did not consider the hazard for neighbours as the detail of what surrounded the GBC plant is not known.

Rather than having a dead zone the proposed Option 2 Layout moves the cooling towers into the space created by pushing out the boundary. This follows the layout philosophy of positioning cooling towers downwind of the plant so that drift does not obscure plant and does not lead to increased corrosion. The down side of this arrangement is that there is a longer distance between cooling towers and the steam turbine condensers (the cooling water runs are very large diameter).

The angled arrangement was used to reduce the length of the space required for the cooling towers and follows existing practice from other power plants.

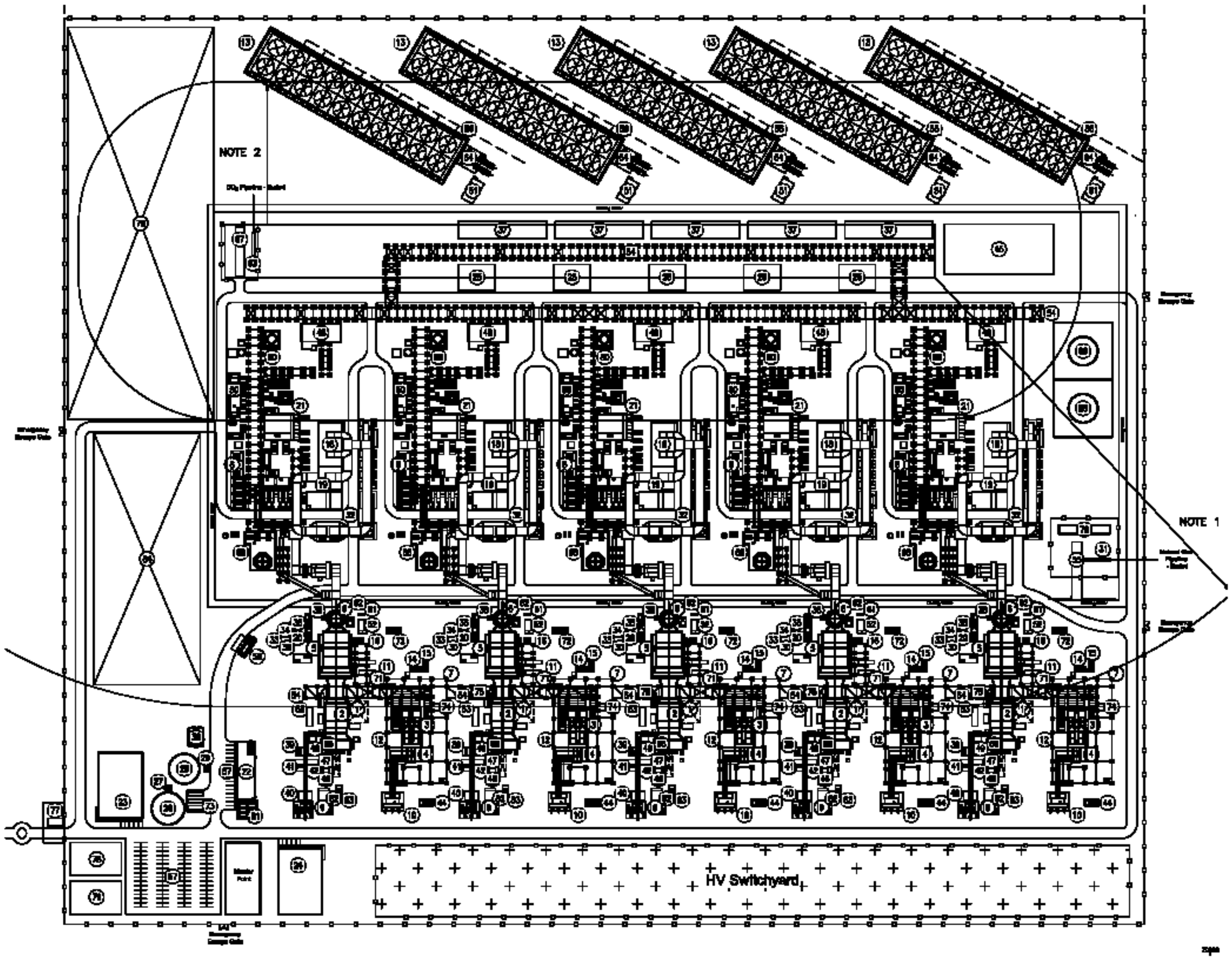


Figure 12 – Layout Option 2[13]

[13] Layout Option 2 has been developed to provide an on plot buffer around the high hazard CO_2 area of the plant.

3.2 Health, Safety & Environment

The following significant hazards have been identified in the design of the Layout and Site Enabling Works:

Area	Hazard	Control
Onshore Plant & Pipelines	Ground Contamination (e.g. Asbestos)	Costs included for surveys. Cost estimate includes allowance for high risk sites where contamination can be expected through previous industry based on prior proposal / project information.
Onshore Plant & Pipelines	WWII Ordnance in Historic Industrial Areas Near shore MOD ranges	Cost allowance for surveys. Specific areas of hazard would need further analysis in future phases of the project.
Onshore Plant, Pipelines, and Offshore	Terrorist Attack	Security included in design and estimate: guardhouse, access control, CCTV, emergency crash gates for down threat evacuation. Pipelines buried so that they cannot be easily accessed. 2 sets of gates (2 step security) and traffic route direction change as anti-terrorism security in design.
Whole Project	Construction	Construction Management included in cost estimate for Owner and Contractors of which part will be for Construction HSSE planning, control, and management. Construction Welfare in accordance with UK regulations has been included in the construction estimate. Productivity calculations for the costing of construction labour includes allowance for safety and welfare (e.g. tool box talks). Work flow and construction schedule allows for high level safe work practices. This is reflected in the cost estimate from the duration of construction.

Table 14 – Other Significant Hazards

The Owner's costs and the Engineering costs included in the estimate include for:

- Health, Safety, Security, and Environment (HSSE) planning, management, and control

- Risk assessment techniques, e.g. HAZID, HAZOP, ENVID
- Reviews, e.g. Process Safety, Constructability
- ALARP demonstration
- Environmental Impact Assessment (EIA)
- Regulatory compliance, permits, and consents
- Construction and Commissioning safety, e.g. Construction, Design, and Management Regulations (CDM), Permit to Work

Actions Taken to Control Hazards - Layout Design

Carbon Capture Plant

The Carbon Capture Plant includes CO_2 which poses a hazard to operating personnel. The Carbon Capture Plant is therefore located downwind from the Power Plant so that any leakage would not drift onto the Power Plant and any operators located in this area.

The location of this unit is also logical with respect to plant flow.

The CO_2 emergency vents will be located on top of the Amine Strippers.

Compression and Dehydration

The Compression and Dehydration Units include high pressure CO_2 which poses a hazard to operating personnel: the higher pressure increasing the zone affected by any leak and the time available to react. As a high hazard unit of the plant this is located downwind of the rest of the facility, away from manned areas, and at the extremity of the plant plot.

The developer should consider the societal risk impact posed by this unit to any activities on the other side of the site boundary.

The location of this unit is also logical with respect to plant flow.

Utilities

The key utilities (e.g. firefighting) will be located near the permanently manned areas of the plant for easy access. This location is also upwind of plant hazards. Dedicated consideration will be given to additional split of utilities in order to avoid common failures.

The remaining utilities are located between adjacent to the Cooling Towers. This is not an ideal location as it is not upwind of plant hazards (is cross wind): but this allows utilisation of an available area of plot.

Manned Areas

The permanently manned areas of the plant are near the plant entrance for easy access. This location is also upwind of plant hazards. Dedicated emergency gates will be provided to ensure safe evacuation of the plant for any operator in the field during an emergency.

Natural Gas

The natural gas intake to the plant is located on the right-hand side of the CCGT units and at the extremity of the plant. This high hazard zone (explosion) is located at the opposite end of the plant to the permanently manned area.

The location of the natural pig receiver and metering allows easy access of the pipeline from the edge of the plant (i.e. the pipeline does not need to pass under any process units. The fuel gas pipe work serving the gas turbines can then run underground (lower risk) or along the pipe rack serving the power generation plant.

Pipelines

Both high pressure CO_2 and natural gas pipelines will be buried to reduce the probability of damage.

A separation distance will be provided between the pipelines and any sensitive areas (schools, domestic dwellings, etc).

Design Safety Review

Outcomes of the Design Safety Review of Layout:

- CO_2 pipeline must be buried as soon as possible after pig launcher.
- Natural Gas pipeline must be buried as soon as possible after pig launcher.
- Additional secondary road to the ‘left’ of each CCGT to ensure 360° access for emergency and firefighting teams.
- Muster point to be located upwind of plant hazards.
- Locate emergency escape (crash) gates around perimeter of onshore plant to allow operators to leave plant in an emergency.
- Modify Entrance so that there are 2 sets of gates (2 step security) and traffic route direction change as anti-terrorism security in design.

A HAZID review has been conducted which outside the scope of this work. There is residual concern with regards to the outer CO_2 hazard distance shown in Figure 11 – Layout Option 1 and Figure 12 – Layout Option 2. A major finding of the HAZID is that the site for a large scale CCGT + CCC should be carefully selected with respect to neighbours, distance of CO_2 pipeline to shore, and as to whether the boundary of the plant should be expanded to include the whole of the high CO_2 hazard area.

Site Location

- The proximity of dwellings to the source of high CO_2 hazard has been considered in design: site selections with dwellings in the vicinity of the high hazard have been discounted.
- An option for the layout has been produced in order to relocate the cooling towers downwind of the site to create a buffer zone between the plant’s high CO_2 hazard and any neighbours. The cost estimate contains sufficient site preparation and ground works to account for this option.
- The high hazard zone resulting from high pressure CO_2 will extend beyond the boundary fence of the existing layouts. Depending on the selected site and any neighbours the size of the plant footprint may expand to keep the high hazard zone within the boundary fence of the CCGT + CCS plant. This is an issue to be resolved once the location(s) for the plant have been selected.

3.3 Construction Methodology

Introduction

Construction execution is based on SNC-Lavalin's experience of similar projects and interpretation and understanding of the Project requirements. The construction execution is reflected in the Construction Costs for the project.

The construction execution will achieve the following construction goals:

- The establishment and implementation of the highest standards of Health, Safety, Security, Environment and Social Performance (HSSE&SP) throughout the construction and commissioning phases of the project
- Compliance with all relevant legislation
- A target of zero accidents.
- A target of zero environmental incidents
- Achievement of Security requirements
- The establishment and maintenance of good relationships between the EPC Contractor, the Owner, and Sub-Contractors.
- Management and control of Site
- The delivery of the work within budget and schedule and to the required levels of quality by consideration, throughout this stage of the project, of construction, maintenance and operational requirements.
- The thorough and detailed planning and accurate reporting of all site activities.
- The achievement of consistently high levels of construction productivity and quality.
- The establishment and maintenance of harmonious industrial relations with a target of zero disruption.
- The achievement of a secure, safe, dynamic and innovative Site

Onshore Construction Scope

The EPC Contractor will carry out Project Management and Construction Management of the construction site.

The EPC Contractor will manage all aspects of the project and will co-ordinate the works to be undertaken by the Subcontractors to deliver the project, including:

- Civil Enabling Works for all Off-Plot Facilities
- Civil Enabling Works for all On-Plot Facilities
- Off Plot Facilities, to include Welfare, Storage Warehousing, Laydown etc.
- All and any additional Civils requirements required to support packages that require Civil Engineering Support
- Topographic Surveys
- Site Investigations
- Buildings and associated Civils Works

- Site Built Tanks and Vessels
- Structural Steel Fabrication and Erection
- Instrument, Control, Electrical and Telecommunications Installation
- Towers (slip form concrete)
- Piping Installation
- Equipment Installation
- Painting & Insulation
- Scaffolding
- Logistics requirements not covered by the equipment and package Suppliers

The Construction works will be based on the detailed work scopes as awarded to the various Subcontractors which will based on actual Detail Design deliverables and will be strictly in accordance with the approved design of the EPC Contractor, with reviews carried out by the Owner or Owner's Engineer.

The Construction Management aspect of the EPC Contractor project scope, including HSSE&SP, Security, Quality Assurance and Quality Control, will be managed by suitably qualified and experienced staff from the EPC Contractor's Construction and Completion Department supported, as required, by Engineering staff drawn from the EPC Contractor's Engineering department and ancillary staff as required.

The EPC Contractor's Safe System of Work will be in operation within the Off-sites and On-Site locations, defined by the Site fence lines. The EPC Contractor will also be responsible for the Security procedure and systems for maintaining control of the On and Off-Site Locations.

3.4 Site Enabling Works

Introduction

The site enabling works are the preparations needed to make the site ready for the construction of the plant. Site enabling covers activities from site preparation, earthworks, creation of access roads, securing the site (e.g. fencing), and the installation of facilities like temporary construction offices / welfare, ramps, and placing of signs.

Site Plant and Equipment Description

The plant process would consist of a series of trains, with each train containing a power production section and a carbon capture section.

The power production train would include, but is not limited to, the following equipment:

- Gas Turbine (and Generator);
- Heat Recovery Steam Generator (HRSG);
- Steam Turbine (and Generator);
- Stack;
- Cooling System.

The carbon capture train would include, but is not limited to, the following equipment:

- Absorbers;
- Heat Exchangers;
- Strippers;
- Coolers;
- CO_2 Compression;
- CO_2 Dehydration;

In addition, the site would contain:

- Water Treatment Plant;
- Substation and HV Switchyard;
- Utilities (Water, Nitrogen, Air, Steam, etc)
- Office Buildings, Workshops and Control rooms.

Site Preparation Works

The main preparation works required at the commencement of the construction of the project are described as the following:

Mobilisation

- Mobilisation of manpower, plant and equipment.

Site Preparation, Earthworks and Roads

- Clearing (Environmental works [Tree protection, etc] to take place before clearing);
- Grubbing;
- Stripping;
- Potential removal of contaminated materials;
- Cut and Fill;
- Drainage;
- Lay down area(s);
- Site Roadways;

Site Enabling

- Site Entrance / Exit
- Site Fences and Gates
- Site Services (including distribution):
    - Potable Water;
    - Sewer System;
    - Storm Water (or provisions to deal with onsite);
    - Electricity.
- Removal or re-routing of existing or neighbouring services;
- Parking;
- Lighting.

Site Facilities

- Administrative offices;
- Mess facilities;
- Wash facilities / toilets;
- Medical stations;
- Fabrication shop / storage
- Security station.

High Level Estimation of Quantities

The following material and equipment quantities have been estimated for 5 trains and pro rata for 1 to 4 trains:

Material and Equipment Quantities	
Site Preparation, Earthworks and Roads	
Material / Equipment	**Quantity**
Volume of Soil to be stripped and grubbed	60,000 m^3
Volume of Contaminated material to be removed	1,000 m^3
Cut and Fill Materials (No imported/removed fill)	80,000 m^3
V-notch drainage ditches	3,800 m
Holding pond volume	3,000 m^3
Laydown area	200,000 m^2
Site Roads (3m – 7m wide) including service ducts	39,200 m^2
Site Enabling Works	
Material / Equipment	**Quantity**
Access and Egress Areas	1,000 m^2
Fencing	4,200 m
Temporary fencing	15,000 m
Vehicle access gates	5 No
Personnel access gates	6 No
Temporary parking	6,600 m^2
Site Facilities	
Material / Equipment	**Quantity**
Office and welfare facilities	2500 Persons
Site stores	6 No
Security cabins	4 No
Medical cabins	2 No
Fabrication shops	2 No

Table 15 – High Level Estimate of Quantities

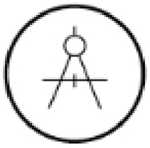
The size of the work force would make on site traffic management and parking difficult. The site enabling design is that off-site parking areas would be provided. Construction personnel would be bussed from their car parking area into the Construction Site welfare area. Due to the size of the Construction Site separate transport would carry Construction Personnel from the Site Welfare to their work areas.

Access to the Site in the main construction phase will be from the main site entrance. The traffic entering the site will comply with the current Public Highways legislation but with a speed restriction of 10 mph.

All site personnel will comply with site security and gate staff at all times. This may include vehicle or personal searches in accordance with the security policy of the existing facility. A security cabin will be located at the main entrance.

In the interests of security and safety, the construction sites will be fenced. During the main construction work it will be prohibited to interfere with the designated construction sites security fence without explicit instructions from the EPC Contractor.

3.5 Basis and Methodology of Estimates



Quantities

Quantities have been estimated based on the site layouts developed.

Where detail has not been sufficiently developed because of the study nature of the work for the Generic Business Case then quantities have been scaled from previous projects and studies.

Cost Estimate

Costs have been estimated based on quantities.

Unit rates have been applied to quantities based on unit rates used for recent UK proposals.

Where data is not available then costs have been supplemented with estimate norms.

SNC-Lavalin's Construction Team has reviewed the estimate and has updated a small number of the unit rates because of latest information (e.g. increase in land fill charging).

3.6 Assumptions on Estimates

Generic Site Details

For the purposes of the Generic Business Case, generic site criteria have been established. This serves the purpose of producing an estimate based on the most likely site conditions to be encountered for an onshore site located in the United Kingdom.

The standardised plant would most likely be located on a brownfield site and selected following an appraisal of a number of sites comparing factors including topography, geology, site access, proximity to grid connections and means of transporting and storing the captured carbon. A single shaft solution has been selected for the CCGTs in order to provide more flexibility on topography for the selected site.

Site Geometry and Size

Based on preliminary plant footprints (Please refer to Attachment 5 & 6) the site will likely have the following properties:

Site Shape	=	Rectangular
Site Dimensions (Approximately)	=	1000m x 600m
Site Area	=	60,000m²
Site Perimeter	=	3200m

Note: The plant Trains 1 – 5 are positioned such that they parallel to each other and the 600m site boundary.

Site Topography

It is assumed that a pre-concept site appraisal will be conducted and that, barring any extenuating circumstances, a site will be selected that in general is reasonably flat and requires only minor earthworks.

Site Geology

It is assumed an appraisal of existing brownfield sites will identify the geotechnical characteristics of the proposed area, and hence be suitable for heavy-industrial usage. It is assumed that geotechnical characteristics of such a site would consist of the following:

- Topsoil / rubble (0m to -1.0m);
- Silty/Sandy Clay layer (-1.0m to -5.0m);
- Weathered soft rock layer (-5.0m to -10.0m);
- High bearing bedrock (-10.0m and below).

Hence the following foundation strategy would typically be adopted:

Foundation Scheme	
Loading	**Foundation System**
Low	Pad or Strip
Medium	Pad, Raft or Piled
High	Raft or Piled
Extremely High	Piled (Including Tension Piles)

Table 16 – Foundation Scheme

Workforce

A site construction workforce of 2500 has been assumed for the project (5 trains of CCGT and CCC). This is based on the estimated construction man hours, assessment of previous CCGT and CCS projects, knowledge from CCGT and CCS projects/proposals, and the experience of the GBC Project Team.

This can be benchmarked against Carrington CCGT for three class H CCGT trains for which the planned workforce was 900 (Wainstones Energy Ltd) and 525 proposed for the Shell Peterhead CCS for a single CCS train. To this needs to be added the construction management team from the Contractor and the Owner.

3.7 Cost Estimate Data Provenance

The data for the estimate is based on proposals for the UK using 2015 and 2016 market unit rates and pricing.

3.8 CAPEX

Conceptual and Front-End Engineering Estimates

Please refer to Attachment 15 for the Conceptual Engineering and FEED Estimate which provides man hours and estimated costs against the different areas of the plant.

Site Acquisition

Site acquisition costs are based on a minimum required footprint for each number of sites as detailed in Attachment 5. Cost per hectare for industrial land has been estimated as £482,000 based on data published by the UK Department for Communities and Local Government (UK Department for Communities and Local Government, 2015).

The sizes and resulting costs per train are as follows:

Trains	Area of Plant	Cost £m
1 Train	157,890 m^2	7.6
2 Trains	268,420 m^2	12.9
3 Trains	379,850 m^2	18.2
4 Trains	489,470 m^2	23.5
5 Trains	600,000 m^2	28.8

Table 17 – Site Acquisition Costs

Generic sizing has been used for this estimate and the resulting cost is not site specific. No assumptions have been made based on current ownership status of the sites, potential value reduction for contamination and remediation required, or local government initiatives.

Enabling Works

Detailed estimates have been compiled for site establishment works based on the site sizes listed in the Site Acquisition section above. Based on these areas, unitised estimates have been built up for site preparation and earthworks, general contamination removal, cut and fill, and drainage. Additional costs for temporary site facilities, roads, fencing, access and egress, gates, and temporary site services have been established based on the expected workforce and project duration. The total cost of site establishment and enabling for the Generic Business Case is:

Site Enabling Costs by Train

Trains	Area of Enabling	Site Enabling (£m)
1 Train	157,890 m^2	38.9
2 Trains	268,420 m^2	43.8
3 Trains	379,850 m^2	48.6
4 Trains	489,470 m^2	53.5
5 Trains	600,000 m^2	58.4

Table 18 – Site Enabling Costs per Train

Site specific allowances have been made for additional contamination, demolition, supplementation of flood defences, and future use of warehousing / laydown facilities.

Site Specific Site Enabling Costs

Location	Characterisation	Change to GBC Cost Estimate (£m)
Teesside	Potential site likely to have significant ground contamination and remediation works will be required.	8.0
	Existing structures to be demolished and cleared on the potential site	1.2
	Reduction in Demobilisation due to ease of reuse of site establishment by future project/industry	-1.0
North Humber	Supplement existing flood defences	0.9
	Upgrade to surface water drainage	
	Construction Power Supply	4.0
South Humber	No differences for Generic Business Case Plant	-
North West / North Wales	Ex-industrial - potentially structures in ground, live services, ground contamination	7.2
	Construction Power Supply	4.0
Scotland	Ex-Industrial, potentially structures in the ground, live services, ground contamination	7.2

Table 19 – Site Specific Enabling Costs

The unit costs used for the site enabling estimate are based on recent Sub-Contractor pricing used for recent project proposals in the UK. No travel supplement has been added to the site enabling labour due to the nature of the subcontracts – the work is specialised and these teams often travel from site to site for work. As such, it is assumed travel costs are part of the subcontractors' unit rates.

Engineering for the site enabling work is factored at 3.8% of the subcontract cost based on experience with similar work in the UK. Contractor's costs are calculated to be less than the other plant areas as there is no allowance for vendor representatives and the administrative allowance is reduced. The overall Contractor's Costs are reduced from 29.8% to 26.1%.

Connections

Costs for the following site services have been included in the estimate above:

- Potable Water (Including Site Distribution)
- Sewerage
- Storm Water (Including Site Distribution)
- Electricity (Including Transformers and Distribution)
- Data/Telephone Cable

4 Power Generation Station

4.1 Technology Selection

The Power Generation Units use the largest credible Combined Cycle Gas Turbine (CCGT) Power Blocks available today. This selection prefers advantages to the overall Plant:

- High efficiency (in the range of 61% - 62% LHV)
- Reduction in CAPEX compared to delivering the same power with many smaller blocks
- Dispatchable as can change output in response to grid requirements
- Inertia which supports the stability of electrical grid(Storage, 2016)

Selected Machines

It is believed that the economic viability of CCS will be enhanced by the use of the new J Class and larger H-Class Gas Turbines because of their higher efficiency and higher capacity designs. J-Class and larger H-Class turbines have an approximate combined cycle output of approximately 700 MW. Large H and J class machines:

Manufacturer	Machine	Nominal Size (CC)[14]	Efficiency (CC)
Siemens	SGT5-8000H	570 MW	60.8 % (LHV)
Mitsubishi	M701J	680 MW	61.7 % (LHV)
GE	9HA.02	774 MW	62.7% (LHV)

Table 20 – Gas Turbine Selections

The selected machines have a track record in service:

- Siemens have an SGT5-8000H train in operation at E.ON's plant in Düsseldorf's harbour area of Lausward. With this plant, Siemens now has at least 17 SGT-8000H units in commercial operation. (Patel, 2016)
- MHPSA have shipped at least 28 J-Class machines. (Patel, 2016)
- GE have their first 9HA unit in commercial operation at EDF's site in Bouchain France (2016). This is a smaller 9HA.01 unit than the 9HA.02 unit quoted above.

Ansaldo also have a H-Class machine, the GT 36, which has completed validation tests.(Ansaldo Energia, 2017) The combined cycle 50 Hz performance is 720 MW at 61.5% (LHV) efficiency[15]. This machine may have an operational track record by the Procurement phase of the project.

The design is based on a nominal 500 MW Gas Turbine so as not to favour any of the OEMs and to provide the OWNER of the thermal power with CCS plant to freedom to choose the Combine Cycle offering than provides the best value for the project.

There is awareness that OEMs are targeting 65% efficient combined cycles by the mid-2020s. However, these would be emerging technology at the time of the commissioning of the plant and are therefore not deemed "bankable technology" by the project team. Class H & J machines are being rolled out now and, barring any significant failures, should be "bankable technology" by project financial investment decision.

4.2 Power Generation Unit

The power generation station is of the combined cycle gas turbine (CCGT) type.

Natural gas is burnt in the gas turbine. Each gas turbine has an air intake filter, an axial compressor to feed air into the combustion chamber. The hot gases from combustion are used to spin the turbine and generate electricity from a shaft mounted generator. The gas turbine combustion system will be of a dry low NOx type which limits the emissions of Nitrogen Oxides (NO_x) whilst maintaining low concentrations of carbon monoxide (CO). For this project, the latest generation (largest and most efficient) turbines have been assumed.

The exhaust gas from the gas turbine still has a lot of remaining energy: this is used to generate steam in a fin tube type heat exchanger. The steam is raised and superheated at 3 different pressure levels to optimise the heat recovered. The steam drives a steam turbine which generates additional

[14] Net Plant Output, Catalogue ISO Data without Carbon capture from start of project. Please be aware that latest 2017 figures are higher than those quoted
[15] Net Plant Output

electrical power from a shaft mounted generator. The Steam Turbine will be a two-casing, combined High Pressure / Intermediate Pressure section, double-flow Low Pressure section, triple pressure with reheat type. The Steam Turbine uses reheat to optimise the performance in the Heat Recovery Steam Generator (HRSG) where the exhausted High-Pressure steam is sent back to the Heat Recovery Steam Generator where its temperature is increased by the Gas Turbine exhaust gases.

Each train of power generation is arranged in a 1 + 1 + 1 configuration:

- Gas Turbine
- Single HRSG to serve the Gas Turbine
- Separate Steam Turbine driven by steam from the HRSG (Multi shaft arrangement)

Selective Catalytic Reduction (SCR) is used to further reduce the NO_x, CO, and Volatile Organic Carbon (VOC) levels in the exhaust gases before feeding them to the Carbon Capture Unit. There is a risk of degradation of the amine solvent and formation of carcinogenic salts if NO_x, CO, and VOCs are not removed.

A vertical stack is provided to release the exhaust gases from the gas turbine to atmosphere. In normal operation, the exhaust gases flow through the carbon capture unit before release: however, in off design operation such as start-up and shut down, the exhaust gases from the turbine may be released directly to atmosphere for short periods. The control between the two modes would be by means of a stack damper: a single stack damper would prevent the gas turbines being blocked in as the damper would swing from either directing flue gas to the CCS train or directing flue gas directly up the stack. The process application and technology is similar to that already used for HRSG bypass dampers on two stack CCGT systems.

Exhaust steam from the steam turbine will exhaust into a shell and tube condenser where the steam is condensed using cooling water from wet mechanical draft cooling towers.

Each train in the Power Generation Station consists of:

- One (1) gas turbine generator (GTG);
- One (1) three pressure, three drum heat recovery steam generator with reheat (HRSG);
- One (1) condensing, reheat steam turbine generator (STG);
- One (1) shell & tube condenser;
- Wet mechanical draft cooling towers for cooling water;
- Condensate and Feedwater Systems;
- Auxiliary Steam System;
- STG steam by-pass system;
- Natural Fuel system for each GTG;
- Continuous Emissions Monitoring System (CEMS) for the HRSG stacks.

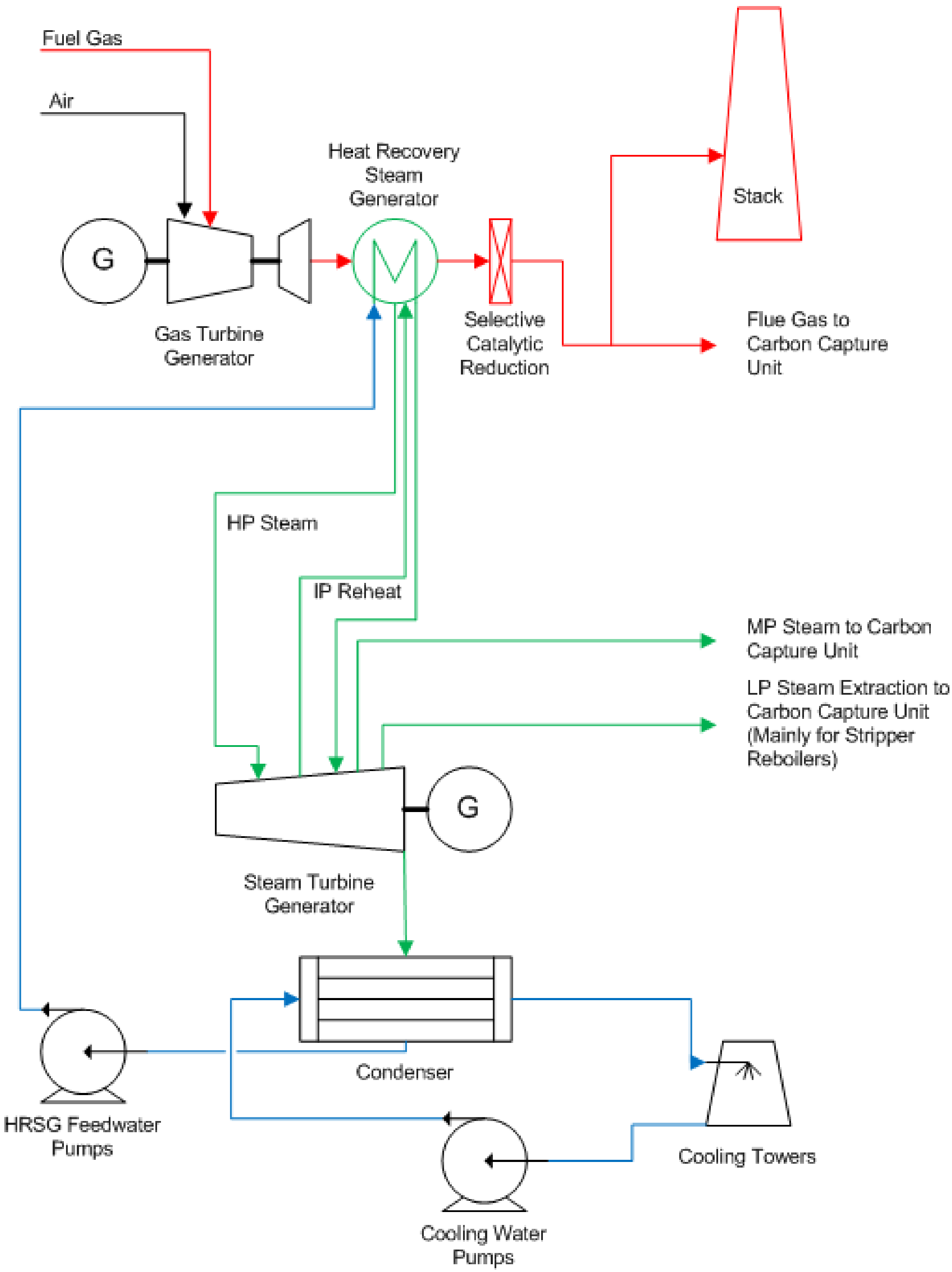


Figure 13 – Power Generation Scheme

The electrical power that can be exported will be reduced in normal operation due to the extraction of steam from the STG for the amine stripper reboilers and electrical power to drive Carbon Capture and Compression Unit loads such as the Booster Fan and the CO_2 compressor.

Design Decisions

The following key decisions were made during the specification of the Power Generation Unit for the Generic Business Case:

OEM Selection	Decided that to control CAPEX (to keep scheme competitive) the scheme would be open to the machines from the main OEMs for CCGT technology of class H and class J turbines: GE, Siemens, and MHI. Ansaldo was not originally considered however recent developments mean that the Ansaldo GT36 is also relevant for the time frame of this project.
CCGT Sizing	The Scheme design will be based on a nominal gas turbine size of 500 MW and approximate 62% LHV gross efficiency. It is understood that machine sizes and efficiencies from the OEMs are higher / lower than this figure. However, a scheme which is open for any major OEM machine would allow competition between the OEMs offering best value for a potential investor. Where specific calculations are to be undertaken SNC-Lavalin would tend towards GE as this is our recent class-H data. Future developments in turbine technology could tend to increase efficiency of combined cycle to 64% - 65% (LHV) using steam cooling and reheat, however this is a future generation of turbine.(Gulen, 2014)
Emissions Controls	Emissions controls are required as need to be able to run the CCGT without CC Plant. NOx control is required anyway to protect amine and to ensure safety. The design needs to ensure NOx control is located before gas turbine exhaust stack.
CCGT Configuration	A multi-shaft arrangement for the CCGT has been selected. The decision on the CCGT configuration was made in early in the project. › The Chief Technologist advised that the steam extraction balance from a previous CCS project was difficult. A 2+1 arrangement for the steam turbine would require a further balance of the steam extraction across multiple Carbon Capture Trains (if it is difficult for 1 then why magnify difficulties across 2 trains). › A 2 + 1 arrangement has a single steam turbine aligned to multiple trains. A single failure could eliminate the operation of 2 trains. The most important business driver of scheme reliability took precedence over the requirement to minimise CAPEX when a single steam turbine per train was selected.

	› Modelling showed a 0.1% improvement in efficiency for a 1+1 vrs a 2+1. › A 1+1 was decided to provide a train by train building block that would allow deployment of the GBC in 5-4-3-2-1 trains.
Steam Supply	Steam supply through steam extraction from the Steam Turbine has been selected over duct firing, separate CHP plant, steam let down from interstage IP/LP, or an auxiliary boiler[16]. The ETI's prior work has shown duct firing and external boilers to be less efficient. Also, it is common experience that duct firing would not meet the reliability Business Driver agreed with the ETI. A separate combined heat and power plant does not meet the train concept for the project. Steam let down from interstage IP/LP is not the most efficient use of energy. Note that the project is for a new build CCGT with CCS, not a conversion of existing CCGT to CCS, or a Carbon Capture Ready (CCR) design. The design of the steam turbine for steam extraction becomes a 2 casing and 5 stage machine; this would be a special design for the project and not standard model for an unabated CCGT.
Oversize Steam Turbine	Oversize the steam turbine and condenser in order to be able to operate near to a best in class CCGT should CCS not be in operation.
Variation of Natural Gas LHV on Gas Turbines	There is no clear relationship between fuel lower heating value (LHV) and power output of gas turbines. This has been demonstrated by modelling work and confirmed by an OEM.
Cooling	Direct seawater cooling would have provided the best performance for the CCGT + CCS scheme because the average temperature of seawater is lower than other conventional forms of cooling. Seawater cooling would potentially be lower cost to alternatives of cooling towers or air cooled condensing because less plot space and equipment is required (although there may not be advantage if there is a long route to the sea). The Generic Business Case design has been created to provide a template plant design that can be applied to a number of different locations. The potential locations might not be close to the sea or significant cooling water supplies. Experience from recent projects is that licenses to obtain seawater for cooling are difficult to obtain or that conditions will require long (and costly) offshore intakes and discharges.

[16] An auxiliary boiler is included in the design for the alternative reason of providing auxiliary steam for start-up, shut down, and standby operations.

	Mechanical Draft Cooling Towers were selected to be an alternative that could be applied to the range of sites for the Generic Business Case. The selection of Mechanical Draft Cooling Towers was a compromise between risk and plant performance. Cooling water supplied from Cooling Towers is lower temperature than that provided by Air Cooled Heat Exchangers providing a performance advantage, but the Cooling Towers still require some water abstraction to make up evaporation and drift loses, so still pose some risk on licensing. Cooling water will be provided for each train. Cooling water pumps will provide the pressure to supply cooling water to the Power Generation Plant (where the main cooling load is the steam turbine condensers) and to the Carbon Capture Plant. The cooling loads of the Power Generation and Carbon Capture Plants are about the same magnitude. The cooling water is cooled in mechanical draft cooling towers. The cooling water temperatures are defined in the Basis of Design (please refer to ETI deliverable D2.1). The cooling water temperature is related to the wet bulb ambient temperature. The carbon capture plant rejects a lot of low level heat. Therefore, increased cooling water temperatures will immediately impact the performance of the Carbon Capture Plant. The performance of the Carbon Capture Plant will also be affected by fouling. This can occur if the amine degrades and fouls exchanger surfaces (e.g. lean/rich exchanger). Monitoring, control and reclamation should minimise fouling. An additional 10% surface for the carbon capture plant heat exchangers has been included in the cost estimates.

4.3 Scheme Sizing

Scheme Modelling

SNC-Lavalin undertook the modelling for the Combined Cycle Gas Turbine CCGT Unit for a Thermal Power plant located in the UK using Thermoflow GT PRO and PEACE software to develop the heat and mass balance, and develop the equipment sizing.

The modelling work was carried out using a GE 9HA.02 machine with the results scaled to the nominal 500 MW Gas Turbine used for the design basis.

The figures in the table above are different than the figures for the Gas Turbine performance in the model. This is because the tabulated figures are catalogue data for ISO conditions (controlled conditions to allow for a fair comparison of machine performance) whereas the modelled data uses site conditions (such as air inlet ambient temperature) and uses a natural gas composition for the UK.

The performance of the plant has been calculated based on nominal consumption of extracted steam: intermittent usage figures are not included in the performance calculations of the plant.

Steam Extraction

Low Pressure (LP) and Medium Pressure (MP) steam are required by the Carbon Capture Plant.

MP Steam is taken as an uncontrolled extraction from the IP section of the steam turbine, LP Steam is taken as an uncontrolled extraction from the LP section of the steam turbine: the exhaust of the turbine at this stage is superheated and requires de-superheating to supply steam to the Carbon Capture Plant. The reduction of the steam flow into the LP stage of the Steam Turbine reduces the amount of electrical power that can be generated.

Typical steam turbines for CCGT applications are 2 casing units with 3 stages: HP, IP, and LP. The 2 casing 5 stage design of the steam turbine for the GBC design is required to provide the LP and MP Steam: the two additional extraction points for the MP and LP steam mean that this is not a standard machine for a CCGT offering from an OEM. A bespoke design for the equipment item would be required. Whilst the steam turbine design is not standard it is still well proven technology. The bespoke steam turbine is included in the cost estimate produced for the Power Generation Unit.

The LP Steam is used to provide heat at the bottom of the Stripper Column in order to boil of CO_2 gas from the Amine Solvent. The MP Steam is used for conditioning of the amine and for the CO_2 vaporiser.

To allow for short periods of unabated operation the steam turbine generator and its water-cooled condenser are sized for the whole steam flow from the HRSG without the steam extraction in normal operation for the carbon capture unit. This provides flexibility in the operation of the CCGT unit and allows the steam turbine and condenser to absorb additional steam, without altering the operation of the gas turbine, if the carbon capture unit were unable to take all of the steam (e.g. process trip and restart of carbon capture unit).

The design for the plant uses cooling water in order to return the condensate from the Carbon Capture unit at 49.5ºC. This allows an optimisation of the CCGT plant because the cooler condensate results in a lower temperature flue gas from the HRSG: the lower temperature causes a higher density, a lower actual volume flow rate, and thus smaller, lower cost equipment in the front end of the carbon capture unit.

The abated mode of the Power Generation unit is modelled using Thermoflex (a higher resolution version of GTPro) in order to better model the cooled condensate.

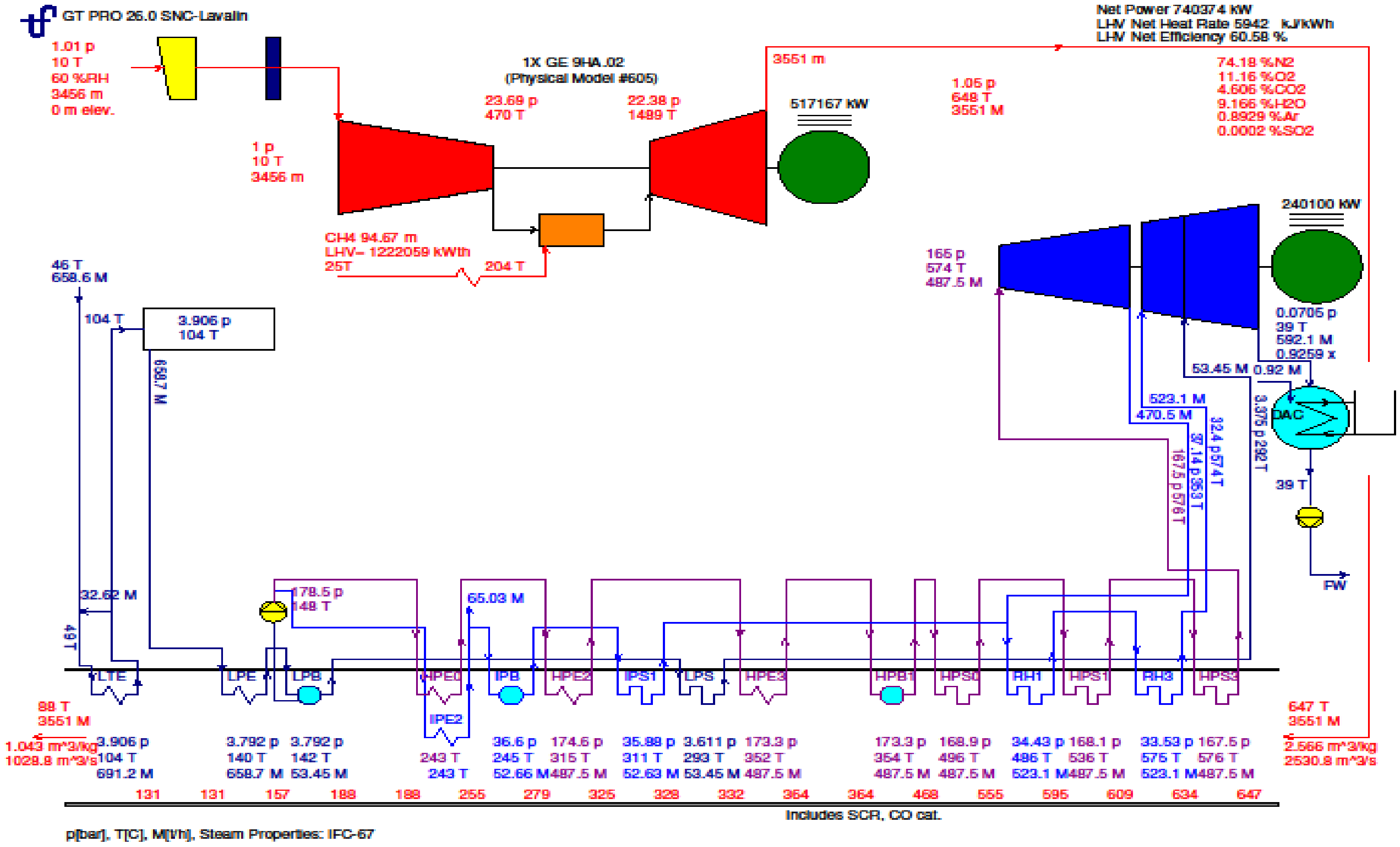


Figure 14 – Single Class H Power Generation Train (unabated mode)

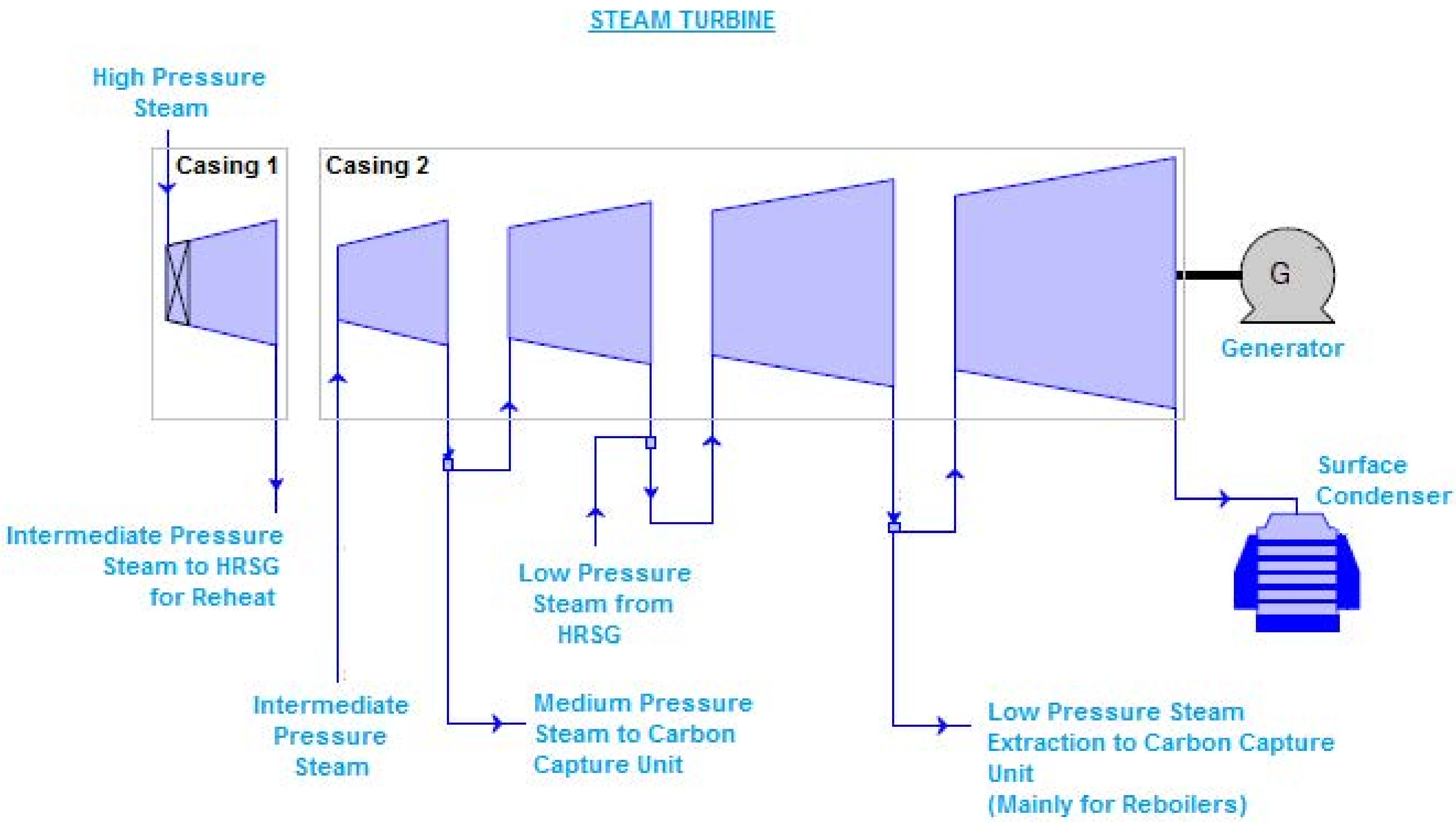


Figure 15 – MP and LP Steam Extraction

Scheme Output (CCGT + CCS)

The net output per train has been calculated for the sites selected for each of the regions. This output takes account of parasitic loads within the onshore CCGT + CCC plant, electrical loads for make up water pumping, and for transportation electrical loads (e.g. compression stations).

Region	Net Abated Output (MW)
Teesside	621
North Humber	621
South Humber	621
North West - Gas	623
North West - Liquid	621
Scotland	614[17]

Table 21 – Net Abated Output for Each Region

The net abated output from the CCGT + CCC plant is highest from the North West / North Wales Region during gas phase injection because this region needs the lowest compression power as a result of the lower injection pressure required into the Hamilton reservoir compared to that required into Endurance. However, there is additional parasitic load for the North West / North Wales region compared to the others: in gas phase injection because of the electric heating required on the offshore platform and in liquid phase injection because of additional chilling with a refrigeration package required at the shoreline.

The parasitic load for the Scotland (Grangemouth) region is higher because of the additional compression stations for Feeder 10 and at the shoreline: although the parasitic load for the onshore CCGT + CCC plant is lower than the other regions because of the lower pipeline inlet pressure.

Further details on the transportation design can be found in section 6.

4.4 Connections

Power from the Power Generation Station will be exported to the grid in a High Voltage (HV) double circuit. The connection will be by overhead cables supported off regular pylons. The routing for the HV connection is to the nearest substation with potential capacity: it is assumed that there are spare bays that can be modified for the new incoming circuits. An assessment of spare bays and connection capacity has been made in the Site Selection work: please refer to the Site Selection Final Report (ETI deliverable D3.1). However, the check is only valid for the 1st part of 2017 and not for the future: future power projects may take spare bays ahead of a Thermal Power with CCS project. No costs relating to major grid upgrades for a plant of this size have been considered.

Natural gas fuel for the gas turbines will be supplied by a steel pipeline buried underground. The connection to the National Transmission System (NTS) will be a hot tap and can be located at any

[17] The Scotland region location reuses Feeder 10 for CO_2 transportation which requires an intermediate Compression Station but only to overcome the pressure drop for a 3 train scheme.

convenient location with the agreement of National Grid. A block valve station with a pig launcher will be installed to the tie in to the NTS: this station will include an electrical isolation joint and telemetry station. Fiscal metering will be located at the CCGT + CCS plant.

Evaporation and drift losses from the cooling towers used for cooling water need to be replaced: water will be supplied to the site from buried Polyethylene (PE) pipes. The water intake requires a site compound housing motorised screens, screenings handlings, fish return system or marine life deterrent system, a pump-house, and a dedicated power supply. Treated water from the plant will be discharged: again, flowing through buried PE pipes.

Potable water and sewage connections will be made to local networks for the workers facilities at the site.

4.5 Health, Safety & Environment

  	**Natural Gas** • Danger to life from the explosion of escaping natural gas • Design in accordance to prevailing wind conditions • Design to limit inventory of natural gas on CCGT plant • Design to maximise natural ventilation and dispersion in order to minimise potential gas cloud and explosive atmosphere accumulation • Design to limit potential point of release (e.g. minimisation of flanges) • Design to contain gas (e.g. international design codes) • Fire and Gas detection, alarm, isolation, and blowdown system • Fire protection system • Design to minimise sources of ignition (ATEX) • Design manned buildings in area of hazard to be blast proof • All flue gas paths to be purged before ignition of gas turbine to prevent an explosive mixture of gas and air forming

	**HV Electricity** • Hazard from an electric shock when working on HV electrical • This may result in fatality • Electrical supplies shall be isolated and locked off before work commences • Isolations and subsequent works shall be carried out under a permit to work system • Terminals / cables shall be tested before work commences • Step back - check stop/start buttons are deactivated, isolated and/or locked off • Electrical protection systems to break circuits on fault detection

The following significant hazards have been identified in the design of the CCGT + CCS Scheme:

Area	Hazard	Control
Power Generation and Carbon Capture	High Pressure Steam	• Piping and equipment costs include for suitable metallurgy and pressure containment design. • Permanently manned areas of the plant are located away from process units. • Layout optimised for steam pipe work over cooling water runs in order to minimise length of steam pipe work and hence length of hazard.
Power Generation and Carbon Capture	Flue Gas	• The flue gas damper in each CCGT train must never be relied upon for positive isolation whilst maintenance is being carried out in the Carbon Capture Unit. This is because the thermal cycling in CCGT operation tends to ripple the seal edges leading to some leakage (% will depend on specification, quality of fabrication, and life of damper). • Flue gas is hazardous for maintenance personnel as it is potentially very high temperature, contains small amounts of toxic substances, and has depleted levels of oxygen. • Previous project experience is for a guillotine plate to be inserted into the duct path and a downstream duct section removed to isolate maintenance from flue gases. • The guillotine plate is not to protrude into gas path (no additional pressure drop).
Onshore Plant	Chemicals	• Range of chemicals required for the operation of the plant which pose a risk to environment and personnel. Please refer to Attachment 8 for an inventory of hazardous substances. • Civils estimate allows for bundling of amine storage and drainage under process plant. • Assumed 7 days storage only on site in order to minimise inventory. • Piping and equipment costs include for suitable metallurgy and pressure containment design.

Area	Hazard	Control
Power Generation	Hydrogen	• Risk of explosion • Hydrogen is used for Generator Cooling. • Bottled high pressure hydrogen is located away from equipment. • ATEX equipment and devices used within gas hazardous area created by the hydrogen system.

4.6 Construction Methodology

The following construction methodology will be used for the Power Plant.

Main Power Plant

- Foundations
- Main Structures
- Main Equipment supply and install:
- Gas Turbines
- Steam Turbines
- Generators
- Transformers
- Pumps
- Vessels
- HRSG
- Cooling Towers
- Modularised equipment to be used where logistics constraints will allow

Multi-discipline and Balance of Plants work to complete Power Generation Units:

- Balance of Plant Equipment
- Piping
- Structural Steel & Buildings
- Electrical and Instrumentation
- Control and Safety Systems
- Painting and Insulation
- Civils completion (e.g. road surfaces)
- HV Switchyard to be completed later in the construction program to allow the area to be used during construction

Gas and Water Pipelines

- Pipeline corridor, access routes, and pipe dumps cleared and prepared
- Mechanical excavation of trench
- Strings of pipeline delivered along route
- Strings of pipeline welded together and lowered into trench
- Completion welds between sections in the trench
- Tie into National Grid pipeline and above ground installation(s)
- Backfill
- Test
- Cleanup and restoration

HV Connection

- Pipeline corridor, access routes, and pipe dumps cleared and prepared
- Tower foundations
- Pylon assembly
- Substation tie-ins prepared
- Cable handing
- Test
- Re-cultivation

4.7 Modularisation (CCGT and CCC)

The base estimate uses a mix of stick build[18] and pre-fabrication: however, prefabrication is limited to that which can be safely transported on UK roads. Rough rule of thumb for maximum would be 150 tonnes, 6.1 metres in width, 4.9 metres height, and 27.4 metres long: although this would be completely dependent upon a route survey between unloading point and the site.

“By fabricating key components in a controlled environment, it is possible to minimise risk, improve quality and stabilise field construction costs, which are typically high and variable.”(Rentschler, Mulrooney, & Shahani, December 2016) The opportunity includes reducing Construction HSSE risks and schedule risk of the project.

The EPC Contractor for the project has the potential to make savings in the modularization of equipment, pipe racks, and buildings (e.g. modular substations).

[18] Stick build means the build is on the site which the plant is intended to occupy upon its completion rather than the build being in a fabrication shop or fabrication yards and shipped to site.

Modularisation Cost Savings	Modularisation will increase costs in some areas
› Modularisation carried out in a controlled environment (e.g. fabrication shop or yard) where there is protection against weather, the work force is local (it is their normal place of work), and tooling / facilities are close at hand. This tends to increase productivity which will lower costs. › Lower health and safety risk compared to a construction site due to controlled environment. › Lower cost because fabrication facility pay rates not construction site rates. Construction sites are itinerant by nature and therefore work on construction sites tends to command a higher rate.	› Engineering and Analysis › Steel work (approx 30% weight additional primary steel for transport & lift) › Fabrication yard supervision › Marine transportation › Heavy lift contractor › Marine insurance & inspection › Unloading berth and haul path

Work undertaken by SNC-Lavalin for a previous project showed a saving of approximately 4% of EPC Contractor's pricing: this was for an extensive level of modularisation which would need easy access from a deep-water port or quayside to the job site.

Site	Review	Outcome
Teesside	Assume can build an unloading berth close to the site. Would need a short heavy haul route onto the site	Cost and Schedule Advantage Obtainable from Heavy Modularisation Potential 4% and 4 months saving applied to equipment and direct labour Additional works required: • New unloading berth • Heavy haul route Assume peak manning reduced by 2 parallel trains 200 people each = -400 people reduction
North Humber	While the site is close to a port, there is no direct access to a deep-water quay, and therefore the potential for import of large modularized components by ship is limited.	Same level of modularisation as SNC-Lavalin's proposal for Peterhead assumed.
South Humber	While the site is close to parts of a port, there is no direct access to a deep-water quay, and therefore the potential for import of large modularized components by ship is limited.	Same level of modularisation as SNC-Lavalin's proposal for Peterhead assumed.

Site	Review	Outcome
North West / North Wales	The site is close to a waterway, although access to a deep-water quay on the waterway is via the public road network. Therefore, the potential for import of large modularized components by ship is limited.	Same level of modularisation as SNC-Lavalin's proposal for Peterhead assumed.
Scotland	Assume can build an unloading berth close to the site. Would need a short heavy haul route onto the site	Cost and Schedule Advantage Obtainable from Heavy Modularisation Potential 4% and 4 months saving applied to equipment and direct labour Additional works required: • New unloading berth • Heavy haul route Assume peak manning reduced by 2 parallel trains 200 people each = -400 people reduction

Table 22 – Assumptions on Level of Modularisation

4.8 Mechanical Completion (CCGT and CCC)

The major construction works are comprised of:

- Civil works – physical construction of the Project elements;
- Mechanical works – installation of mechanical elements and equipment such as pumps, fans and pipe work;
- Electrical and Instrumentation works – installation of electrical infrastructure including substations and cabling.

4.9 Commissioning (CCGT and CCC)

The Commissioning Works include the cleaning and testing of the Project prior to full start-up. Commissioning scope will include covering all stages of Pre-Operational Testing, Verification and Start-Up/Performance Testing Assistance:

- Implement Works Management Control Database;
- Complete Systemization of the plant, including Definition, Identification, References and Register;
- Coordination with Engineering and Procurement so as to "design for commissioning";
- Attendance at design reviews and HAZOPS;
- Attendance at Factory Acceptance Testing;

- Development and management of Mechanical Completion Packages. Arrange and manage Vendor Site Assistance;
- Conduct Pre-Commissioning - controlled checking and systematic cold testing of the functional readiness of the constructed equipment, systems, sub systems, area or facility following approved pre-commissioning plans and procedures;
- Prepare and manage punch lists and prepare commissioning procedure;
- Hand-Over to Client;
- Agree performance test procedures;
- Assist Owner in start-up and performance tests (Owner's operators and specialist subcontractors will perform tests. EPC contractor will assist);
- Provide Vendor Site Assistance.

4.10 Contracting Strategy (CCGT and CCC)

It was originally conceived that the CCGT and CCC plants would be delivered by separate contracts as the types of disciplines and plant approach is typically different for the Power Generation and Chemical / Hydrocarbons Industries. However, a key learning from previous CCS projects and FEEDs is that a failure to correctly manage the interfaces between the different elements of the CCS chain is detrimental to the delivery of CCS projects. It has been decided to manage the risk between Power Generation, Carbon Capture, Compression, Utilities, and Facilities of the Main Onshore Plant by assigning them as a single EPC contract: that would make the EPC Contract Entity responsible for seamless junctures throughout the onshore plant as opposed to having different EPC Contractors on either side of the battery limits between different sections.

It has been assumed that the Process Licensor for the Carbon Capture Plant and the OEM for the main machinery (CCGT and Compression) would supply to the EPC Contractor.

CCGT + CCC Plant

Power Generation and Carbon Capture plant located within the plot boundary as described in Plant Footprint, document reference 181869-0001-D-EM-LAY-AAA-00-00001-01, which can be found in Attachments 5 & 6. In the case of the North West region, this contract would also include the shoreline station required for the export to the Hamilton field because the skill set of this contractor is more aligned to the process equipment station than a linear asset pipeline installer. A common Contractor for both main plant and process equipment station would ensure commonality of specification, models, spares, etc, for ease of operation and maintenance.

It is assumed that due to the size of the CCGT + CCC scope the EPC Contractor would be a joint venture between 2 or 3 large contracting organisations (perhaps including a CCGT OEM).

The EPC Contractor shall provide an integrated and dedicated task team to execute the complete CCCC Project works on the following basis:

CONTRACTOR (Assume Self-Perform)

- Project Management
- Engineering and detail design

- Operations & Maintenance design reviews
- Constructability & Commissioning design reviews
- Procurement
- Permits and licences
- Support Owner with the application of special permits as necessary
- Interface management
- Logistics, custom clearance, expediting
- Construction management
- Overarching site construction responsibility
- Construction execution of discrete scope elements
- Management and execution of Pre-commissioning, Mechanical Completion, Ready for Start-up, Commissioning and Handover to Owner.

Key Services Subcontractors

- CCGT OEM
- Licensor Technology
- Logistics, Transportation and Customs clearance
- 3rd Party Consultants involved in Engineering Studies
- NoBo for Regulation compliance

Offsite Fabrication Subcontractors

- Duct Fabrication Works
- Structural Steel Fabrication Works
- Piping Fabrication Works
- Equipment Fabrication Works (i.e. Vessels, Drums, Reactors, Columns etc)
- Modular fabrications – pipe racks, process modules, modular buildings and switch rooms

Construction Subcontractors (Against defined work scopes)

- Civil Works (Site Grading, Cut & Fill, Main Foundations, Fencing, Roads, Paving, Landscaping works etc)
- Building Works
- Mechanical & Piping Installation Works
- Electrical, Instrumentation and Telecommunication Installation Works (also option to self-perform)
- Structural Steel Installation Works
- Site Fabricated Storage Tanks
- Scaffolding
- Painting & Insulation Works
- Support Services
- Temporary Construction Facilities and Utilities.

Local Labour and Services

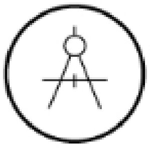
Local contractors, including material suppliers, equipment vendors and service subcontractors, and local labour forces are to be utilised in the Work to the maximum extent practicable in order to maximise the Local Content Plan and reduce the amount of accommodation required for itinerant workers.

Connections

It is assumed that the connections would be the responsibility of contractors – either sub-contracted to the Main EPC Contractor, or more likely, contracted directly to the Owner:

- **HV Overhead Line** connecting the power plant to the national grid. The contract will include HV installation and connections within the Power Plant and at the connection point to the national grid (either mods to existing substation or installation of a new substation);
- **Onshore Pipeline:** installation of the new natural gas pipeline connecting the onshore plant to the National Transmission System. Scope will include any Above Ground Installations;
- Raw water supply;
- Treated water discharge;
- Towns water supply;
- Sewer;
- Telecomms.

4.11 Basis and Methodology of Estimates



Quantities

Equipment is defined and sized in the equipment list (refer to Attachment 3).

Where detail has not been sufficiently developed because of the study nature of the work for the Generic Business Case then quantities have been scaled from previous projects and studies.

Cost Estimate

Costs have been estimated based on quantities.

Equipment costs have been estimated using vendor quotes and scaled vendor quotes from previous projects and EPC proposals. Additional cost data for equipment and bulk materials has been generated using the PEACE estimating tool alongside GTPro modelling software.

Labour hours have been based on prior project experience and modelling software with estimating capabilities. The labour rate was built up using NAECI current rates with burdens added for employee benefits, shift premium, small tools and consumables, PPE, and administrative costs.

Where these data sources were not available then costs have been supplemented with estimate norms.

4.12 Assumptions on Estimates

- The estimate assumes there is a 50% reduction in detailed design cost for each additional train. Though the drawings need to be reproduced for each subsequent train, a significant part of the engineering work can be reused.
- A reduction in cost has been applied to Teesside and Scotland sites to allow for the increase in modularisation made possible by their quayside locations. A reduction of 4% has been applied to major equipment procurement and installation based on prior project experience with cost reduction as a result of increased modularisation.
- Bulk materials have been estimated as a percentage of total installed cost. A set of comparative projects was established, including other power work, and percentages were ascertained for concrete and steel works, piping, electrical and instrumentation, painting, scaffolding, and site

transport and rigging. Additional bulk material costs were ascertained from estimating software for power projects.

- Contractor and Owner commissioning cost were estimated on a bottom up and top down basis. A bottom up estimate was built using estimated first fills, subcontracts, and labour rates over a period of 20 months for commissioning and 4 months for start-up. This estimate was compared to a set of estimating norms recommended by an external estimating consultant. Using this method, the contractor's commissioning costs was applied as 2.08% of EPC cost and owner's commissioning as 1.8% of EPC cost.
- Reinforcement of the grid, or alternative for connections to multiple sub-stations is not included.
- A buy down has been assumed for the purchase of multiple gas turbine units. The buy-down costing assumes that the OEM would provide a discount for multiple units, with the per unit discount increasing for each subsequent unit. The assumption is based on the OEM engineering cost being reduced by 50% for each additional unit, whilst factory overhead would decrease by 7%. The buy-down also assumes that the OEM will accept a 1% reduction in margin on the purchase of multiple units.

Buy down – Cost of Single Gas Turbine (£m)	Single Train	2 Trains	3 Trains	4 Trains	5 Trains
Gas Turbine	79.6	73.8	70.2	67.1	64.2
Percentage reduction from 1 train		-7.33%	-11.8%	-15.7%	-19.4%

Table 23 – Buy Down Savings for Gas Turbine

4.13 Cost Estimate Data Provenance

The power generation cost estimate is based on vendor quotations for similar equipment compiled from SNC-Lavalin's extensive international CCGT experience. Specialist estimating software has also been employed. All costs have had escalation added to bring to Q1 2016 equivalency.

4.14 CAPEX

Conceptual and Front-End Engineering Estimates

Please refer to Attachment 15 for the Conceptual and FEED Estimate which provides man hours and estimated costs against the different areas of the plant.

The early engineering for the project is described in section 8.3

The Conceptual Engineering (Pre-FEED) phase will develop the current study engineering package to prove the feasibility in technical and economics. This will form a basis of the front-end engineering design (FEED). The Conceptual Engineering phase for the Power Generation should result in a selection of the CCGT OEM and Model in order to provide a basis for sizing calculations, layouts, utilities consumption, and power output from the plant in the FEED phase.

The FEED phase of the project will provide resolution of any technical issues associated with the Power Generation Facilities, integrate the Unit design with the other units within the CCGT + CCS scheme (e.g. cooling water & steam), provide engineering design documentation (such as P&IDs), and confirm the cost estimate for the plant. The FEED will provide the basis for the EPC pricing. One-third of the early engineering costs have been applied to power generation.

Connections

Major connections are required for electricity, natural gas pipelines, and water intake and outfall. The approximate distances and routing were determined through the site selection process and details of the site-specific criteria determining the length and routing for each set of connections can be found in the Detailed Report – Site Selection 181869-0001-T-EM-REP-AAA-00-00002 (AECOM ref: 60521944-0702-000-GN-RP-00001, ETI Ref: D3.1).

High Voltage Electrical Connection costs vary between sites depending on the distance to the National Grid substation. All are based on a 275kV design with double circuit overhead lines. HV connection costs are based on previous UK proposals both in plant and at the substation. Pricing for major costs, including overhead line and transformers, was obtained from National Grid Transco (National Grid, 2012) (Parsons Brinkhoff, 2012). The remaining costs are based on previous Subcontractor quotations for UK proposals at unit rates tailored to the site-specific requirements. It is recognised that further reinforcement is likely to be required for the ‘main’ power grid: analysis of the reinforcement design and the cost of reinforcement has not been included in this work scope.

The criteria for estimating the waste water outfall and water intake prices include the volume of discharge from the waste treatment plant and cooling water make up flows, which varies by number of trains. The length of intake/outfall and elevation is provided by the Detailed Report – Site Selection 181869-0001-T-EM-REP-AAA-00-00002 (AECOM ref: 60521944-0702-000-GN-RP-00001, ETI Ref: D3.1). The trenching, bedding, and fill are determined by engineering practice. The diameter of pipe is determined by the allowable flow velocity, required pipe area for elevation change for outfall, and pump sizing against pressure drop for water intake. The number of crossings for each location is determined by the Site Selection Report. Unit rates are then applied to the materials required for procurement and installation based on Vendor pricing and prior project Sub-Contractor pricing.

Natural gas pipelines are costed based on distance, routing, crossings, pipeline size, wall thickness, and anti-corrosion coating. Materials and installation have then been estimated based on unit rates from similar SNC-Lavalin project cost estimates.

The significant outlier for the connection costs is the North Humber region due to the considerably longer distances required for the water intake and waste water outfall pipelines. Although the preferred site is close to the Humber estuary, the environmental restrictions may make it difficult to make direct connections to the estuary. The connection costs assume that new water intake and waste water outfall lines will be required to the North Sea coast.

Further information on connection costs can be found in Attachment 7 of this report.

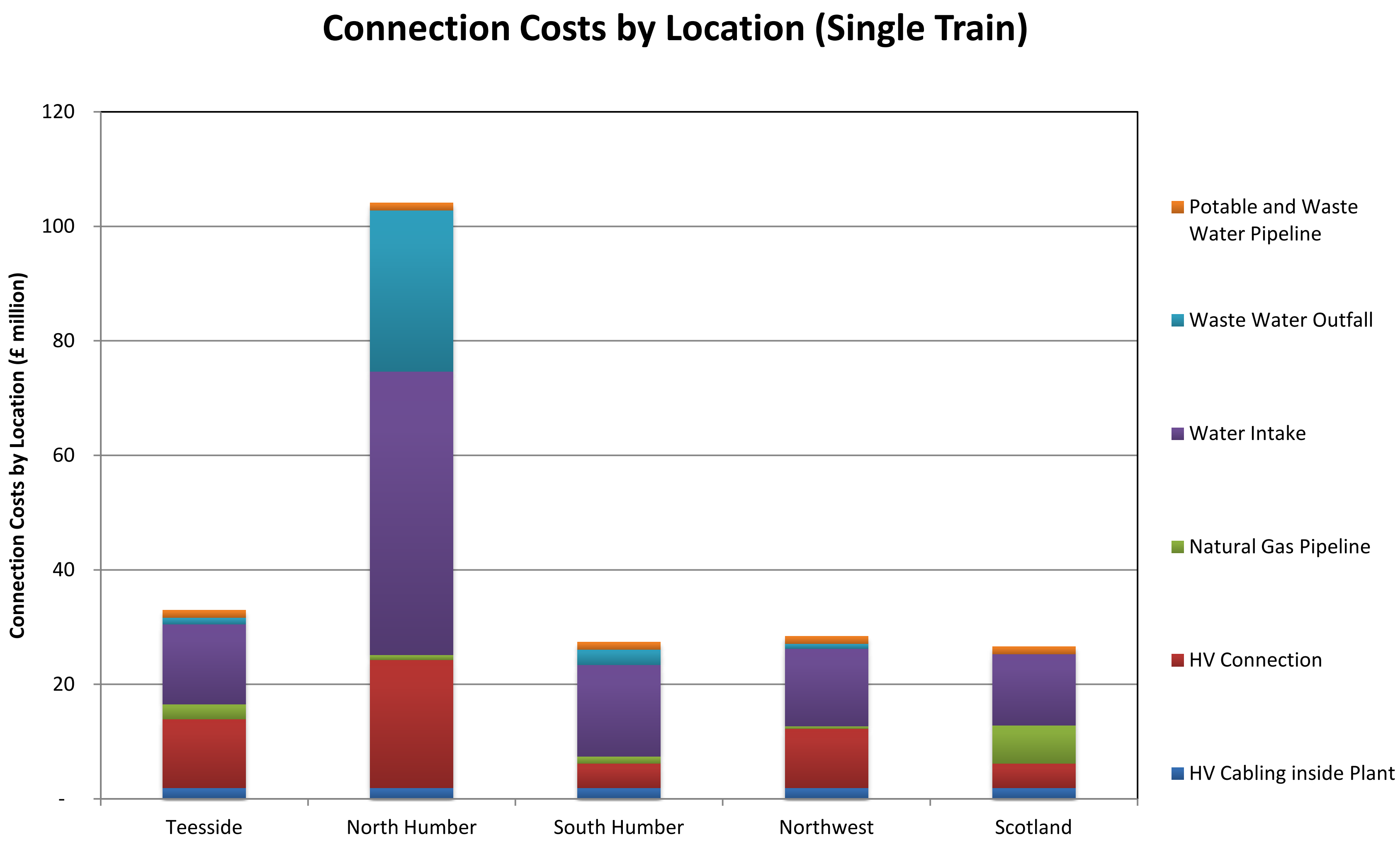


Figure 16 – Connection Costs

Teesside Site Five Train - Estimated Cost

Power Generation and CCGT Pricing

The CCGT equipment is a major part of the supply for the Power Generation Plant.

CCGT pricing used by SNC-Lavalin for the estimate is informed by five sources:

- Indicative pricing given by Original Equipment Manufacturers (OEM);
- Pricing of recent "sold projects" worldwide;
- Indicative pricing of unsuccessful projects in the UK capacity auction, determined from the drop out price;
- Monitoring of orders against manufacturing capacity of OEM's;
- Historic pricing of projects under development that have repeatedly entered the Capacity Market Auctions.

The current European market for large scale CCGT capital equipment is relatively flat, with ongoing investment in new equipment evident only in the UK and Poland. The current (non FSU and Chinese market) is centred on the US and South America, with recent large contract awards in Brazil (GE), Argentina (Siemens) and a number of mainland US projects. Other projects are evolving in Far East (Siemens, Thailand) but in a spasmodic fashion.

Only one project in the UK is about to enter construction, the refurbishment (with a new Siemens GT (333MW)) at Kings Lynn. A second open cycle project (Spalding Extension (299MW)), again using Siemens technology is expected to commence construction in late 2017.

The Capacity Market in the UK has promoted are large number of CCGT projects which are expected to continue to compete for funding in future auctions. Three of these projects are monitored very closely:

  - Knottingley (1500MW) – MHI Technology
  - Gateway (1200MW) – Siemens Technology
  - Thorpe Marsh (1500MW) – GE Technology

Other CCGT projects are being tracked, such as Abernedd (870MW), which has been openly bid on three occasions since 2013 and Eggborough (200MW) a new entrant into the market.

It should be noted that in the UK market a number of developers are proposing options for Open Cycle GT's on consented CCGT sites.

As with any subsidised market, success for a number of developers in the forthcoming (2017 and 2018) four year ahead capacity auction could have a significant impact on future market pricing for similar plants.

The balance of the Power Generation Plant has been estimated based on the major equipment list and analogous estimates for remaining bulk materials as detailed in the Estimating Methodology section above.

Savings have been included for reduced engineering requirements on trains 2-5. A buy-down savings on the gas turbine for multiple units has been included for the multiple train costs to account for the savings in OEM engineering and administration for each subsequent unit and a 50% reduction in detailed design has been applied for units 2-5. As a result, the Generic Business Case Pricing for the Power Generation Facility is as follows (excluding risk and owner's reserve):

Power Generation Costs by Train

Power Generation Costs (£m)	Single Train	2 Trains	3 Trains	4 Trains	5 Trains
Power Generation Plant	581.5	1,030.2	1,466.5	1,894.5	2,316.2

Table 24 – Power Generation Cost per Train

Capital and Insurance Spares

The estimate for the capital and insurance spares follows the sparing philosophy detailed in Section 2.12. Installed spares have been included in the equipment costs for each section. Capital and insurance spares are based on the assumption that the Owner would purchase one set per plant rather than per train.

Estimated Cost of Spares	£ m
Carbon Capture	3.3
Power	13.4
Utilities	0.2
Total	**16.9**

Table 25 – Cost of Capital and Insurance Spares

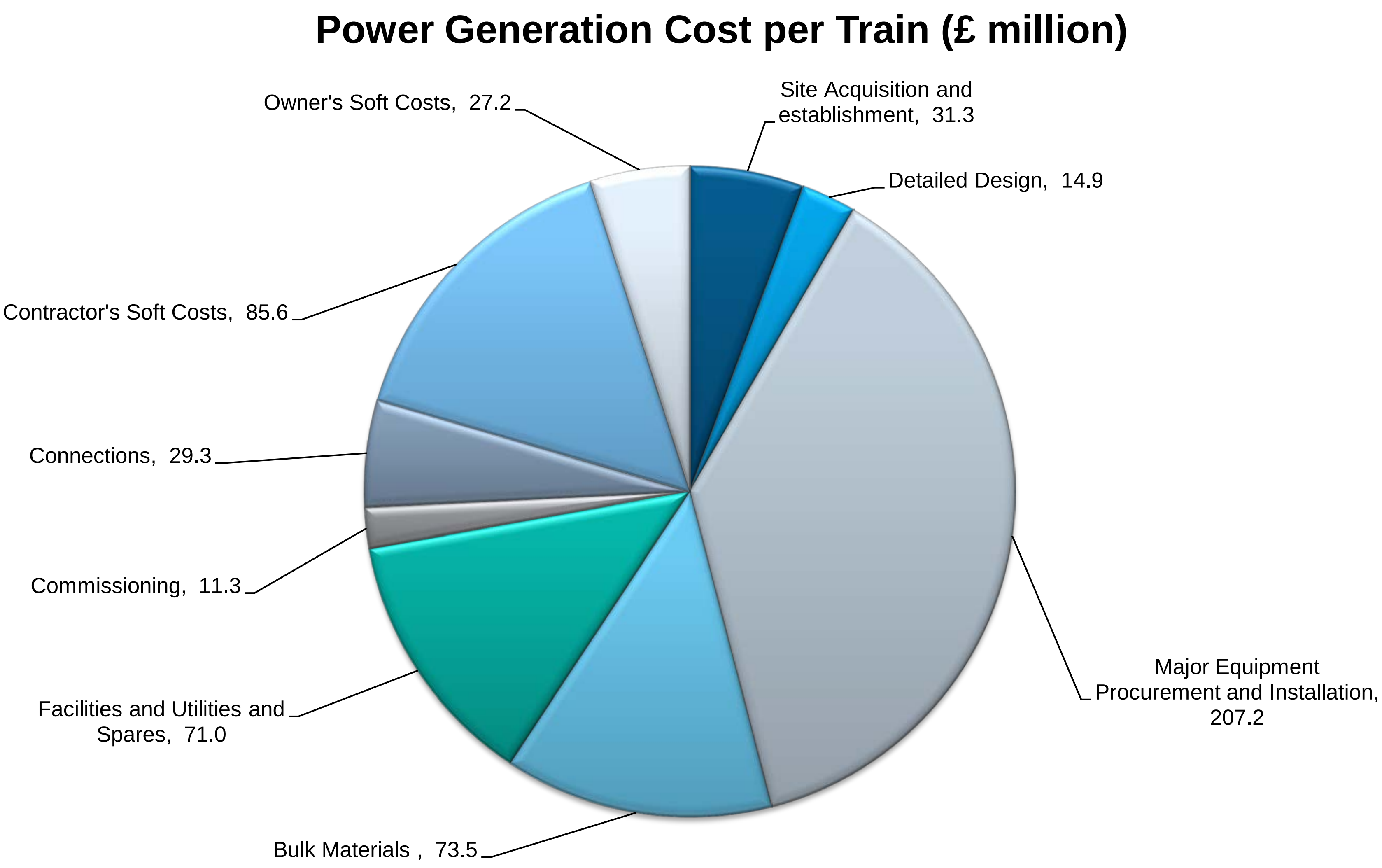
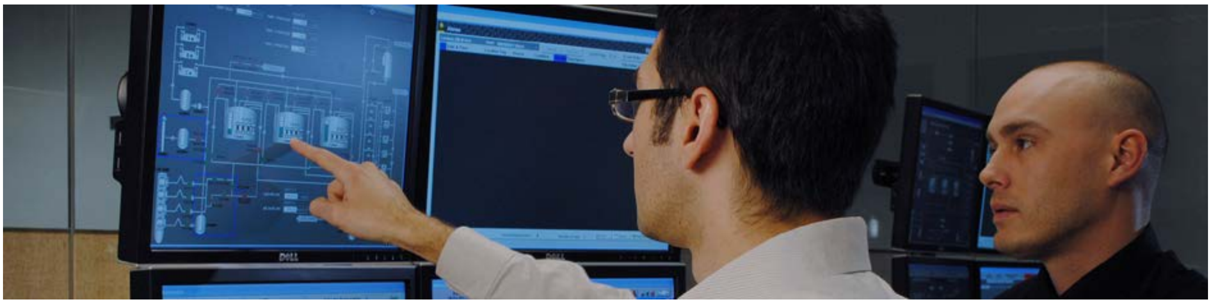


Figure 17 – Power Generation Costs



5 Carbon Capture and Compression Plant

5.1 Technology Selection

An engineered best in class amine has been selected for the plant in order to generate an optimised performance for the plant. The benchmark amine solvent (MEA) has a high energy penalty. Using engineered amines reduces this penalty, thereby maximizing the power output from the CCGT. Recent CCS projects such as Boundary Dam and Petra Nova have followed this approach in order to reduce the energy penalty associated with the carbon capture process and to reduce the rate of degradation of the amine solvent. There are a number of companies which offer such technology, including:

- Alstom (now owned by GE)
- BASF
- Fluor
- MHI
- Siemens
- HTC Purenergy
- Cansolv (owned by Shell)

The energy consumption and degradation rates of engineered amine solvents is expected to decrease with better amine formulations. There is now operating experience as well as experimental data to help this improvement; the project team cannot say when this improvement would be available and therefore have not included such an improvement into the design.

5.2 Carbon Capture

Flue gas is transferred from the HRSG to the Carbon Capture plant through large circular ducts. A booster fan provides sufficient pressure to drive the flue gas through the plant and back to the exhaust stack: the fan capacity control will be achieved using speed variation and recirculation. The flue gas leaves the booster fan and goes to a gas-gas heat exchanger (GGH). The gas-gas heat exchanger is used to optimise the efficiency of the plant by transferring heat from the gas going into the carbon capture plant to the exhaust gases being sent to the stack (this is because the gases going up the stack need to be heated to ensure they have sufficient buoyancy to disperse in the air and to control plume visibility, and the gases going to the carbon capture plant need to be cooled so as not to evaporate the carbon capture solvent).

Once the flue gas has left the gas-gas exchanger it is further cooled by water in a direct contact cooler. It is critical to saturate and cool the flue gas prior to feed to the CO_2 Absorber Tower to ensure proper CO_2 absorption and prevent excessive water evaporation from the amine solution in the CO_2 absorber tower.

The flue gas temperature entering the base of the stack will be 88°C for unabated operation and 65°C for abated operation. An initial buoyancy calculation showed that these temperatures work with selected stack diameter and height. The actual project will require on 3rd party dispersion modelling considering site location, stack location, stack height, site topography, background emissions, location of receptors. This work is too detailed for the needs of this study.

The CO_2 Capture System, which can be seen in the following figure is an amine solvent type, and comprises the following major components:

- CO_2 absorption section;
- Water wash section;
- Acid wash section;
- Lean / rich heat exchangers;
- CO_2 stripper;
- Stripper reboilers;
- Overhead condensers;
- Amine circulation pumps;
- Solvent conditioning and treatment.

Carbon dioxide (CO_2) is removed from flue gases by passing them through a large vertical absorber tower which contains packing filled with a cool liquid amine based solvent. The solvent absorbs the CO_2 from the flue gas.

Before leaving the absorber tower the CO_2-depleted flue gases are washed with water and acid in order to capture entrained amine and water.

The flue gas leaving the acid wash will be reheated in the gas-gas heat exchanger to prevent plume formation and enhancing dispersion before being discharged through the stack.

The amine solvent containing the absorbed CO_2 is collected at the bottom of the large vertical absorber tower and is pumped to a large vertical stripper pressure vessel. The amine solvent is heated which releases the CO_2 as a gas: the heating uses saturated LP steam from the Power Generation Unit. Once free of CO_2 the amine solvent is pumped back to the large vertical absorber tower to begin the process anew.

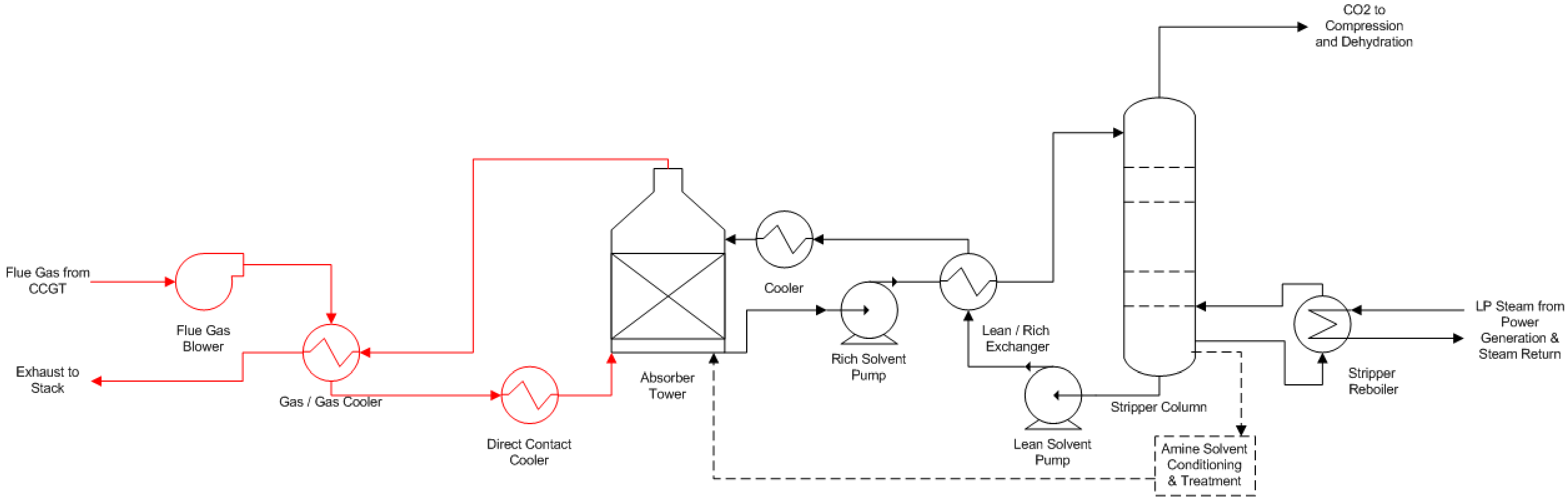


Figure 18 – Carbon Capture Unit

CO_2 is collected from the top of the stripper and is sent to compression.

The amine based solvent can be degraded by heat and trace contaminants present in the flue gas, such as NO_x. The amine is filtered and treated to maintain its condition. Degraded amine is removed from the system using a Thermal Reclamation Unit (TRU) and is topped up with fresh amine as required.

Design Decisions

The following are design decisions made in the development of the Carbon Capture and Compression (CCC) units:

Selection of Amine Post Combustion Capture	Amine Post Combustion Capture has been selected for the project as this process has already been utilised for Carbon Capture, and is based on a mature technology.
Simple Flow Scheme	The flow scheme for the Carbon Capture unit has not been optimised to improve the performance for an engineered amine design (for example optimisations such as recycles, intercooling in the absorber, or vapour recompression). A more complex, but optimised, flow scheme for Carbon Capture may result in slightly improved performance, but was not in accordance with the first two business drivers for the GBC of maximum reliability and minimum CAPEX.
Acid Wash	The Shell Peterhead CCS design in the KKDs used a proprietary amine solvent to capture CO_2 from Gas Turbine (GT) exhaust flue gases. Cansolv (process licensors) proposed an acid wash system for the Peterhead project in the KKDs. It is believed that this was included in the design due to the presence of nitrous oxides (NOx) in the flue gas to the Carbon capture (CC) plant capture; amines (particularly tertiary amines), when exposed to nitrous oxides, may form nitrosamines which are known to be carcinogenic.
Gas Gas Heater (GGH)	The Peterhead design had a GGH to reheat the CO_2 abated flue gases from the absorber, in order to minimize plume formation. Although the power plant flue gases lose some of their heat in the GGH, the heat transfer is poor, and the main cooling is done with cooling water in the Direct Contact Cooler (DCC). Consents generally require no visible plume from the exhaust stack – therefore the GGH is required.

Materials of Construction	Stainless Steel grade 316 has been assumed for the materials in contact with amine and wet CO_2 as both are corrosive services. Stainless Steel is good engineering practice for contact with Amine and wet CO_2. Grade 316 selection is in accordance with Shell Peterhead.
Amine Treatment	Amine degrades in service as it reacts with substances in the flue gas. One Ion Exchange (IX) unit is needed per train to remove Heat Stable Salts formed in the amine when amine reacts with SOx. This is required to maintain CO_2 the capture efficiency of the amine. One Thermal Treatment Unit (TRU) has been selected per train to remove amine degradation products. There is a potential to optimise the amine treatment: however, this would be a Licensor Design based on the selected Engineered Amine, and is therefore outside the scope of this project.

5.3 Scheme Sizing

The best in class amine technology is licensed by the owners of the technology: the performance of the technology is confidential. Unable to publish a licensed technology design SNC-Lavalin have made use of publicly available information regards post combustion carbon capture from the Key Knowledge Documents[19] (Shell U.K. Limited, 2016) published regarding the Shell Peterhead project in order to develop a design sized for the gas turbines of the Generic Business Case.

The equipment sizes for the GBC are required in order to develop the cost estimate. The equipment sizes can be scaled up from the Peterhead equipment list in the KKD's; the fundamental assumption is that the configuration of the GBC plant will be the same as Peterhead. The KKD's do not provide the H&MB of the CC plant since it uses a proprietary amine solvent, but they do include a Process Flow diagram (PFD) and sized equipment list of the CC plant in Peterhead.

Two approaches were taken in order to size the equipment for the Generic Business Case:

- Direct scaling: In the primary approach, the equipment sizes available in the Peterhead Design (KKD's) were scaled up (or down) based on the flue gas rates and CO_2 concentration in the Generic Business Case (GBC). This approach was good for scaling of the absorber and the stripper, but additional checks were needed to confirm the scaling up the amine loop equipment in the CC plant;
- Modelling in Aspen HYSYS: In this approach, the Peterhead design was modelled with MEA. The model extent was from the Booster fan through to the inlet to compression for CO_2 and to the return to the base of the stack for the flue gas. The MEA model included the Gas-Gas Heat Exchanger and the Direct Contact Cooler. The engineered solvent was substituted with 30% MEA solvent and the Peterhead CC plant was modelled using Aspen HYSYS. Initial estimates of the internal Heat & Mass Balance (H&MB) were made based on norms typically used in MEA capture

[19] Basic Design Engineering Package APPENDIX 3 11.003 CCC Documents (Shell U.K. Limited, 2016)

designs. The model was tuned to match the Heat & Mass Balance (H&MB) information available in the KKD's, i.e., the flue gas inlet stream and the CO_2 product stream details. The MEA model, with the same flow configuration as Peterhead was then rerun for the GBC case. Comparing the H&MB information in the two MEA models gives the ratio of flow rates, equipment duties, etc. This gives the direct factors needed for scaling up the equipment sizes in the Peterhead (PH) to the GBC. (Please note that the steam demand for the MEA design was necessarily higher than that for the engineered amine in the KKD).

The MEA model also allows the engineers to understand more about the Generic Business Case. The following Figure 19 – Scaling Approach for the Sizing of the Carbon Capture Unit illustrates the overall scaling approach.

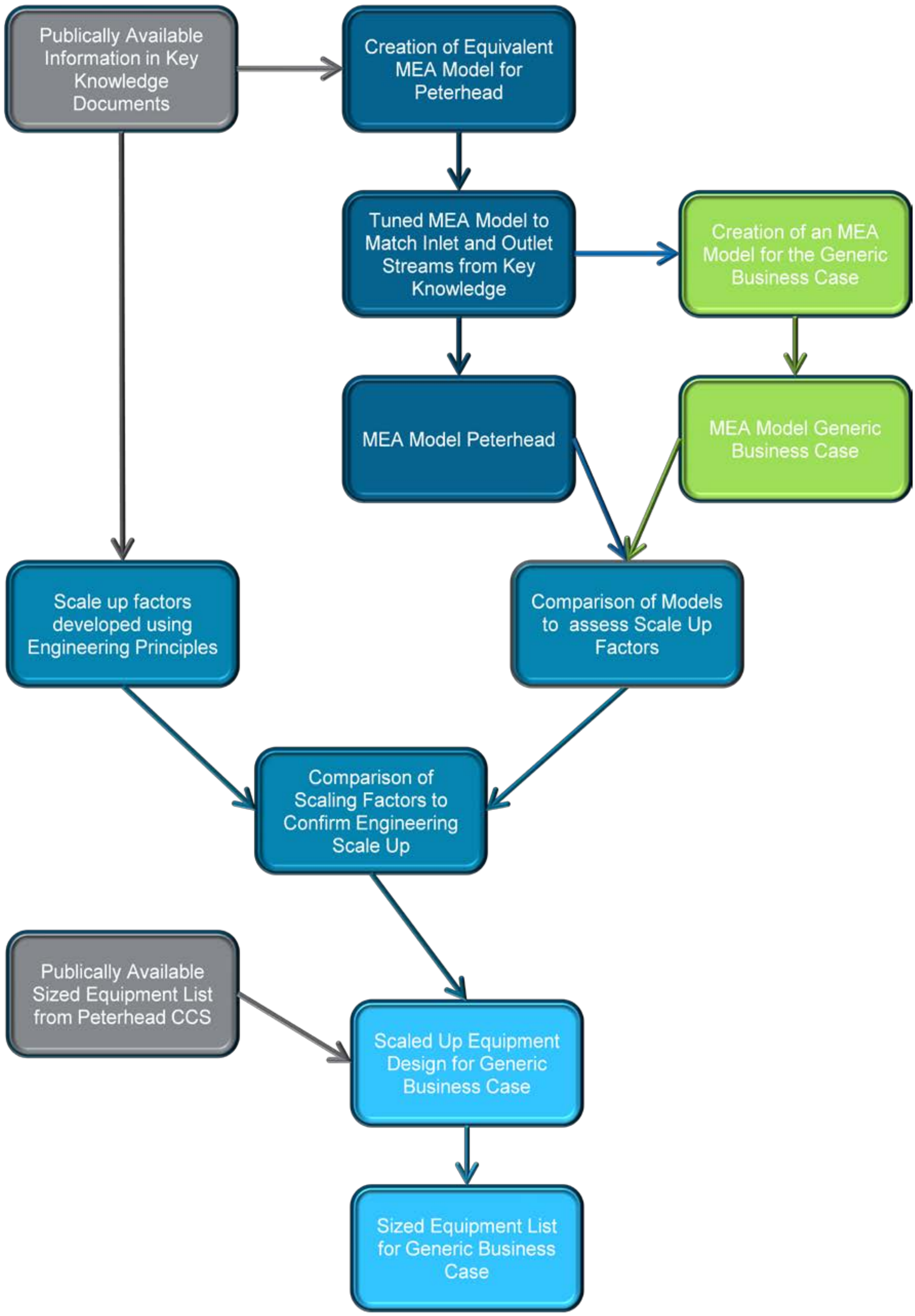


Figure 19 – Scaling Approach for the Sizing of the Carbon Capture Unit

Scale-Up Factors

The table below gives the scale-up factors derived using the modelling approach. Some are from modelling, some direct scale up 'using the above scaling approach':

Unit	Tag No	Parameter	Scale Factor	Remark
Booster Fan	K-101	Capacity	1.35	Based on actual flue gas volumetric flow rate. Differential head is kept the same in both cases (PH and GBC)
Gas – Gas Heat Exchanger	E-101	Duty	1.0	The PH design had a higher Gas – Gas Exchanger inlet temperature of 100°C with lower flow rate than GBC which has Gas – Gas Exchanger inlet temperature of 87°C. Therefore, the duty for both Peterhead and GBC are the same.
Direct Contact Cooler (Water Saturation Tower)	V-106	Cross Sectional Area	1.35	Cross Sectional Area based on actual flue gas volumetric flow rate.
		Height	1.0	The tower height will be the same in the PH and GBC designs. The scale-up ratio for the height of the water saturation tower is 1 because the flue gas inlet conditions in PH were very similar to those of the GBC and the tower (packing) efficiency does not depend on the flue gas rate.
DCC Cooler (Water Saturation Tower Cooler)	E-114	Duty	1.78	Scale factor from comparison of the MEA models of PH and GBC. The duty of water saturation tower cooler has increased in the GBC design compared to PH because the GBC rejects more heat.
DCC Pumps (Water Saturation Tower)	P-108	Capacity	1.66	Differential head kept the same as PH
CO_2 Absorber	V-107	Cross Sectional Area	1.35	Cross Sectional Area based on actual volumetric rate.
		Height	1.0	The tower height (amine, acid and wash water sections) will be the same in the PH and GBC designs.
Rich Amine Pumps	P-106	Capacity	1.66	Based on actual volumetric flows. Differential head kept the same as PH
Lean Amine Cooler	E113	Duty	1.93	Scale factor from comparison of the MEA models of PH and GBC.

Unit	Tag No	Parameter	Scale Factor	Remark
Wash Water Cooler	E-112	Duty	1.58	Scale factor from comparison of the MEA models of PH and GBC.
Absorber Wash Water Pumps	P-110	Capacity	1.51	Scale factor from comparison of the MEA models of PH and GBC.
Acid Wash Pumps	P-109	Capacity	1.66	Modelling did not include this section.[20] Differential head kept the same as PH
Rich /Lean Amine Exchanger	E109	Duty	1.66	Engineering Scale Up
CO_2 Stripper	V-108	Cross Sectional Area	1.66	Cross Sectional Area based on actual volumetric rate
		Height	1.0	The tower height will be the same in the PH and GBC designs.
Overhead Condenser	E111	Duty	1.66	Engineering Scale Up
CO_2 Stripper Reboiler	E110	Duty	1.66	Engineering Scale Up
Lean Amine Pumps	P-105	Capacity	1.66	Based on actual volumetric flows. Differential head kept the same in PH and GBC

PH = Shell Peterhead CCS
GBC = Generic Business Case

Table 26 – Scale-Up Factors

[20] MEA Systems do not need acid wash. The acid wash is part of a licensed system which was included in the publicly available information for the Shell Peterhead CCS Project.

5.4 Compression

Water-saturated CO_2 gas from the capture plant is compressed, cooled, and fed via a pipeline to the CO_2 Storage Site (Offshore Injection Platform). The compressor is a multistage, integrally geared, type machine with cooling between stages.

A dehydration system, located mid way through the compression system, is used to dry the CO_2 gas.

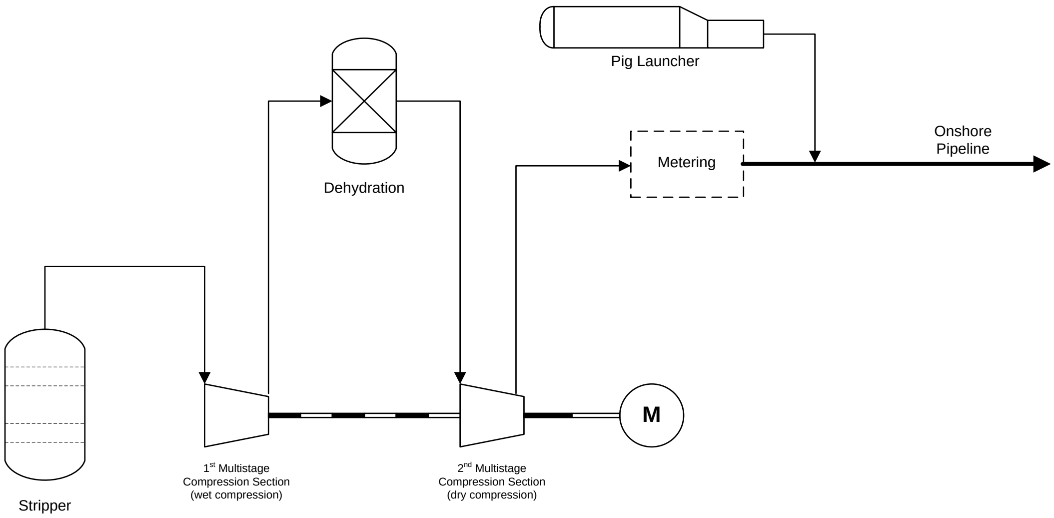


Figure 20 – Compression and Dehydration

Any potential liquid carryover is removed and sent back to the capture unit, together with all liquid water collected from other compression stages and dehydration packages.

The compressor inlet and discharge is on a common header for all the trains. Whilst there is not a spare compressor per train, should plant not be at full capacity, there is the ability in the design for one train's CO_2 compressor to take the CO_2 from another train.

The CO_2 gas is fiscally metered before entering the pipeline.

The sizing of the compression section of the plant can be found in section 6.2 on pipelines.

Design Decisions

The following are design decisions made in the development of the compression units:

Compression	Selection of 1 x Carbon Capture train per Gas Turbine with the compression sizing being approx.: 20 MW. This is lower CAPEX than multiple compressors per train and there are sufficient references for this size of CO_2 compressor.
Oxygen Removal	The corrosion rate for pipelines and wells needs to be controlled in order to minimise the risk of leakage of CO_2 : low oxygen levels are therefore specified. The Shell Peterhead H&MB showed very low O_2 in the product CO_2 leaving the Licensed Amine Carbon Capture Unit. Decision made to not to include an O_2 Removal Package.

5.5 Plant Utilities & Facilities

There are a range of utilities and facilities in order to keep the CCGT + CCS plant in operation. The following utilities will be provided for the overall CCGT and CCC Plant:

- Offices, administration buildings, and welfare facilities for the plant workers;
- Site security and guardhouse;
- Control systems and control room;
- Stores, workshop, and warehousing;
- Natural gas fuel system, including metering, and pig receiver to supply fuel to the gas turbines;
- Utility steam and condensate;
- Demineralised water system to provide high quality water for the steam circuit;
- Waste water treatment systems to ensure that any waste water is treated before either being reused or before leaving the site;
- Safety and firefighting systems;
- Instrument/service air system;
- Hydrogen;
- Nitrogen;
- Electrical power distribution system, switch rooms, and substations.

5.6 Connections

The main connections for the Carbon Capture and Compression Unit are:

- LP Steam (mainly for the Stripper Reboilers) and MP Steam supplied by steam extracted from the Steam Turbine in the Power Generation Unit.

- Condensate return to the Power Generation Unit.
- Cooling water supply and return.
- CO_2 export to the transport pipeline.
- Electrical power supplied from the Power Generation Unit.
- Effluent and waste water connected to the Waste Water Treatment Plant.

5.7 Health, Safety & Environment

	Carbon Dioxide (CO_2) › Danger to life from asphyxiation or toxicity of escaping CO_2 › Major Accident Hazard: The hazard range for an instantaneous release from storage may be in the range of 50 to 400 m with large, cold, liquid phase storage producing the larger distances. The hazard range for a continuous release through a 50mm hole may be up to 100 m.(Dr Peter Harper, 2011) › Design in accordance to prevailing wind conditions › Asphyxiation from approx 50% v/v in air. Toxicity > 15% v/v in air (50% fatalities for 1-minute exposure time)(Dr Peter Harper, 2011) › Design to limit inventory of CO_2 in onshore plant, pipeline segments, and offshore platform › Design to maximise natural ventilation and dispersion in order to minimise potential CO_2 accumulation › Design to contain CO_2 (e.g. international design codes) › CO_2 detection, alarm, isolation, and blowdown system › Risk of structural collapse following large release due to cooling effects and dry ice-cold jet effects.(Connolly & Cusco, 2007) › Design to avoid low spots on layout (or protect low lying areas with detectors).

The following significant hazards have been identified in the design of the CCGT + CCS Scheme:

Area	Hazard	Control
Carbon Capture Units	Release of Amine Exposure of Personnel to Amine	Civils estimate allows for bunding of amine storage and drainage under process plant. Piping and equipment costs include for suitable metallurgy and pressure containment design. Amine drains, contaminated drains storage, and waste water treatment included in the design, layout, and cost estimate. Acid wash added to the top of the Absorber to reduce the risk of amine (and nitrosamine) release to atmosphere via the flue gas stack. Permanently manned areas of the plant are located away from process units.

5.8 Dispersion

Dispersion modelling was not part of the Generic Business Case project scope. There is publicly available information on dispersion of CO_2 which has been used by the project team. Two sources are summarised below.

Hole Size (mm)	Pressure	Release	Dispersion Distance (15,000 ppm)	Source
20	73 bara	1000 kg	~ 35m	Peterhead CO_2 Vent Dispersion Report, PCCS-00-TC-HX-0580-00001 rev K03. ©Shell UK Limited 2015
50	73 bara	1000 kg	~ 80m	Peterhead CO_2 Vent Dispersion Report, PCCS-00-TC-HX-0580-00001 rev K03. ©Shell UK Limited 2015
100	73 bara	1000 kg	~160m	Peterhead CO_2 Vent Dispersion Report, PCCS-00-TC-HX-0580-00001 rev K03. ©Shell UK Limited 2015

Where 15000 ppm = allowable short-term exposure limit (15-minute reference period)

Table 27 – CO_2 Dispersion Distances

Scenario	Pressure	Release	Dispersion Distance (SLOT)	Source
1000 Te release	25 barg	1000 Te	~100m to ~300m (depending on software used)	Assessment of the major hazard potential of carbon dioxide (CO_2), A paper by: Dr Peter Harper, Health and Safety Executive (HSE) Advisers: Ms Jill Wilday (HSL) and Mr Mike Bilio (OSD).
2000 Te release	25 barg	2000 Te	~120m	Assessment of the major hazard potential of carbon dioxide (CO_2), A paper by: Dr Peter Harper, Health and Safety Executive (HSE) Advisers: Ms Jill Wilday (HSL) and Mr Mike Bilio (OSD).

Where SLOT = Specified limit of toxicity.

Table 28 – CO_2 Dispersion Distances

For land use planning the HSE has defined the SLOT as causing:

- severe distress to almost everyone in the area;
- substantial fraction of exposed population requiring medical attention;
- some people seriously injured, requiring prolonged treatment;
- highly susceptible people possibly being killed, likely to cause 1-5% lethality rate from a single exposure to a certain concentration over a known amount of time.

The data indicates between 100m and 300m dispersion zone is required around the high hazard area of the plant in order to provide a safe layout. This zone is shown in the figure below (300m). No permanently manned areas of the plant are within the high hazard zone. The hazard zone (green line) extends beyond the boundaries of the plant (solid line with dots). Specific sites are not identified for this report and therefore no decisions have been made with regards to extending boundary distances with regards to maintaining the CO_2 hazard within the plant boundary: however, any sites selected for the CCGT + CC Plant should not have dwellings or permanently manned buildings located within this zone.

Any specific site for a CCGT + CCS plant will need further assessment with regards to the CO_2 hazard on any neighbouring industrial or domestic sites. As can be seen in the information above there is a degree of uncertainty with regards to the dispersion modelling results which a specific project would need to address.

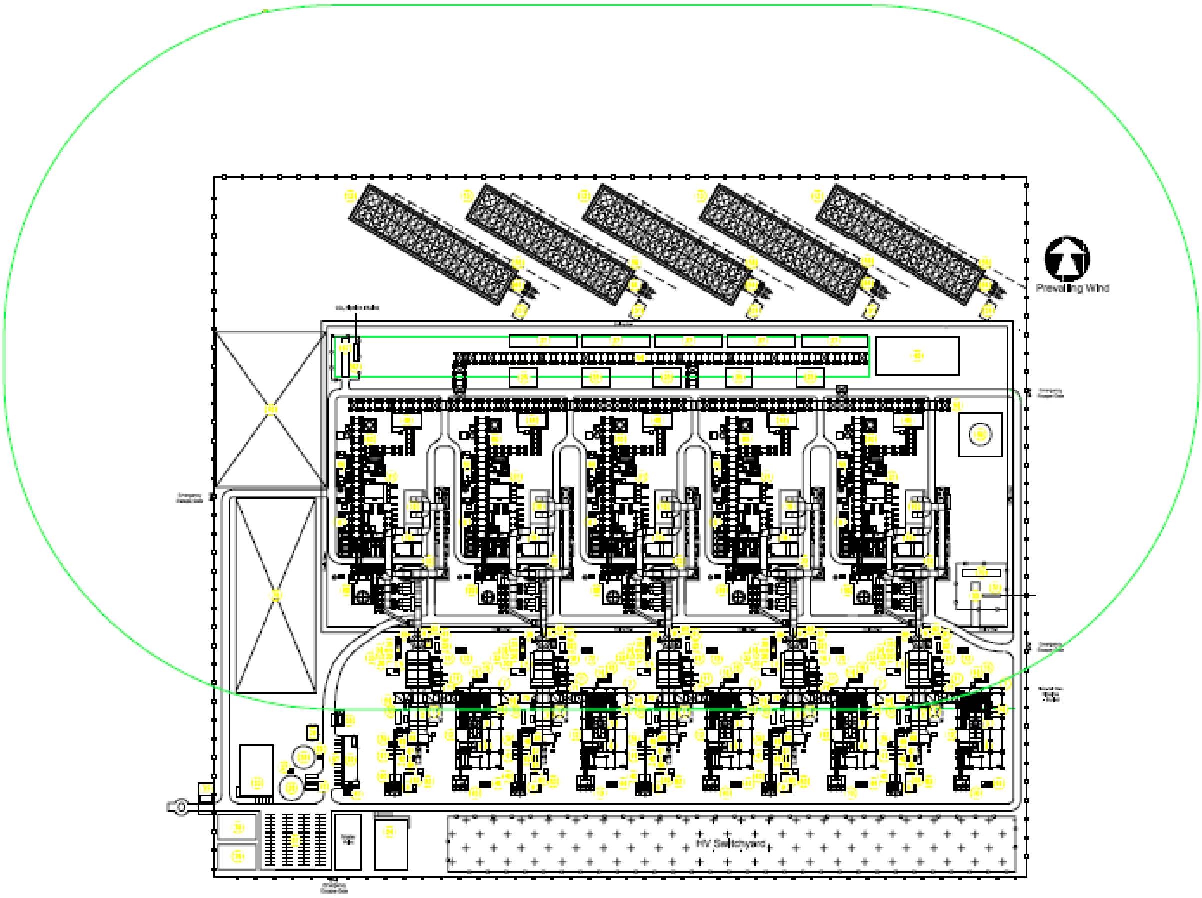


Figure 21 – 300m Limits Around High Hazard Area of Plant in Green

5.9 Construction Methodology

The following construction methodology will be used for the Carbon Capture Plant:

- Foundations;
- Slip form concrete absorbers. No major construction will occur around the absorbers until they are complete;
- Fixed tower cranes will be employed to support the construction of the absorbers and will be retained to complete the construction of the plant;
- Major Equipment;
- Main structural steel;
- Other equipment and buildings;
- Pipe work;
- Electrical and Instrumentation;
- Control and Safety Systems.

5.10 Modularisation

It is assumed that there are good opportunities for modularisation within the carbon capture and storage plant. For example:

- There is a significant length of pipe racking within the carbon capture unit. It is SNC-Lavalin's experience that there is an advantage prefabricating pipeline length for installation and connection at site.
- Substations can be built and fitted out as package buildings.
- Equipment and packages can be supplied as skid units.

5.11 Mechanical Completion

Please refer to similar sub-section in the Power Generation section.

5.12 Commissioning

Please refer to similar sub-section in the Power Generation section.

Commissioning of the CCC plant will have to follow the Power Generation Commissioning in order to have flue gas available.

Once flue gas is available then the use of Amine Solvent will allow CO_2 to be capture.

The flue gas path must be purged before commissioning to prevent gas / air explosive mixture forming.

Once compression and dehydration are in operation then high hazard will be present on site with controls required for any further works in the vicinity.

It is assumed that CO_2 would be vented during commissioning until the quality was assured (do not want to damage pipeline with offspec CO_2).

5.13 Contracting Approach

Please refer to section 4.10 for the contracting approach to be employed for the CCGT + CCC Plant.

5.14 Basis and Methodology of Estimates

Quantities

Equipment is defined and sized in the equipment list (refer to Attachment 3)

Where detail has not been sufficiently developed because of the study nature of the work for the Generic Business Case then quantities have been scaled from previous projects and studies.

Cost Estimate

Costs have been estimated based on quantities.

Equipment costs have been sourced from vendor quotes for similar equipment. Where sizes have changed, parametric models have been built for equipment types (vessels, heat exchangers, pumps), compiling sizing and cost data from many sources to produce factors by which similar equipment quotes could be scaled up or down based on new equipment sizes.

Where data is not available then costs have been supplemented with estimate norms.

Labour hours have been estimated based on prior project and EPC proposal experience. The labour rate was built up using NAECI current rates with burdens added for employee benefits, shift premium, small tools and consumables, PPE, and administrative costs.

5.15 Assumptions on Estimates

The estimate assumes there is a 50% reduction in detailed design cost for each additional train. Though the drawings need to be reproduced for each subsequent train, a significant part of the engineering work can be reused.

A reduction in cost has been applied to Teesside and Scotland sites to allow for the increase in modularisation made possible by their quayside locations. A reduction of 4% has been applied to major equipment procurement and installation based on prior project experience with cost reduction as a result of increased modularisation.

Bulk materials have been estimated as a percentage of total installed cost. A set of comparative projects was established, including other Carbon Capture work, and percentages were ascertained for concrete and steelworks, piping, electrical and instrumentation, painting, scaffolding, and site transport and rigging. As such, the bulk materials estimates have been scaled from vendor quotations on detailed MTO's, providing a significant improvement in expected accuracy over generic estimating factors commonly applied to a Class IV estimate.

Contractor and Owner commissioning costs were estimated on a bottom up and top down basis. A bottom up estimate was built using estimated first fills, subcontracts, and labour rates over a period of 20 months for commissioning and 4 months for start-up. This estimate was compared to a set of estimating norms recommended by an external estimating consultant. Using this method, the contractor's commissioning costs were applied as 2.08% of EPC cost and Owner's commissioning as 1.8% of EPC cost.

5.16 Cost Estimate Data Provenance

The carbon capture and compression major equipment pricing has been built up using vendor quotations for similar equipment, scaled where appropriate. The majority of the pricing is from 2015. Additional costs, such as bulk materials and labour, have been estimated based on similar EPC project data. Costs have been updated with an escalation factor to bring to Q1 2016 levels.

5.17 CAPEX

Early Engineering Estimates

Please refer to Attachment 15 for the Pre-FEED and FEED Estimate which provides man hours and estimated costs against the different areas of the plant. One-third of these costs are assigned to carbon capture and compression.

Carbon Capture and Compression

The carbon capture and compression element of the estimate has been primarily based on vendor quotations from prior project proposals for a similar project in the UK. The vendor quotations have been used for similar sized equipment or scaled up using a parametric estimating model based on changes in equipment sizes from the previous project.

In addition to the vendor quotations, an analogous estimating approach has been taken to determine the costs for engineering, civils, and other bulk material subcontracts. No savings have been assumed for subsequent trains as information is not available at this stage to determine constructability learning curves or procurement buy-downs for materials based on large quantity orders.

Site specific considerations have been included for each location. For Teesside, the availability of the quay nearby allows for significant modularisation, resulting in a savings of 4%. In the case of the North West, the shorter distance of the pipelines, lower required pressure on the offshore platform and sizing up to only three trains meant that the duty of the compression equipment could be reduced, resulting in a cost savings on the compression equipment and installation. For North and South Humber, the travel uplift has been applied to labour and subcontracts.

As can be seen in Figure 22 – Carbon Capture and Compression Costs below the Scotland and North West / North Wales regions have the highest Carbon Capture and Compression costs. For Scotland (Grangemouth) region the higher costs are a result of the additional shoreline compression that is required compared to the regions exporting CO_2 to Endurance and the reuse of Feeder 10 requires an intermediate compression station for the 3 train size scheme. For the North West / North Wales region the higher costs are the result of the shoreline station required to support offshore heating during gas phase injection and shoreline heating during the liquid phase injection (please see section 6.3 for further detail on CO_2 injection for the North West / North Wales region).

Savings for engineering on trains 2 to 5 have been incorporated into the estimate: trains 2 to 5 will be identical to train 1. Therefore, the additional cost of engineering for trains 2 to 5 will be overall site design, and the drawings and documentation showing tagging for individual trains.

Approximately 20% of the value of the equipment for the Carbon Capture and Compression area is based on vendor quotations for the same or similar equipment, whilst the remaining 80% is based on vendor quotes that have been scaled up based on updated equipment sizes.

Onshore Facilities and Utilities

Onshore utilities include the effluent treatment package, instrument air package, ICSS, gas and CO_2 metering, and the cooling plants. Facilities include the permanent site buildings, office facilities, substations, and distribution centres required within the plant. The utilities costs have been estimated based on scaled up vendor quotes from similar projects. The facilities figures are based on unit rates from vendor quotes from other SNC-Lavalin projects and proposals in the UK.

The only site-specific cost is an allowance for some modularization for the facilities and utilities on the Teesside and Scotland (Grangemouth) site resulting in a cost reduction on major equipment and labour of 4%.

Most facilities and utilities are a direct scale up for 1 to 5 trains as the equipment must be duplicated for each unit. The waste water treatment facility is the exception, with the single train package cost being £16 million and approximately £3 million additional cost added for each subsequent unit. Engineering and metering costs are constant regardless of the number of trains. The facilities estimate has been reduced in line with the number of trains, as there would be less operation and maintenance, personnel and therefore the size of offices, welfare, training, car parking, etc will be smaller.

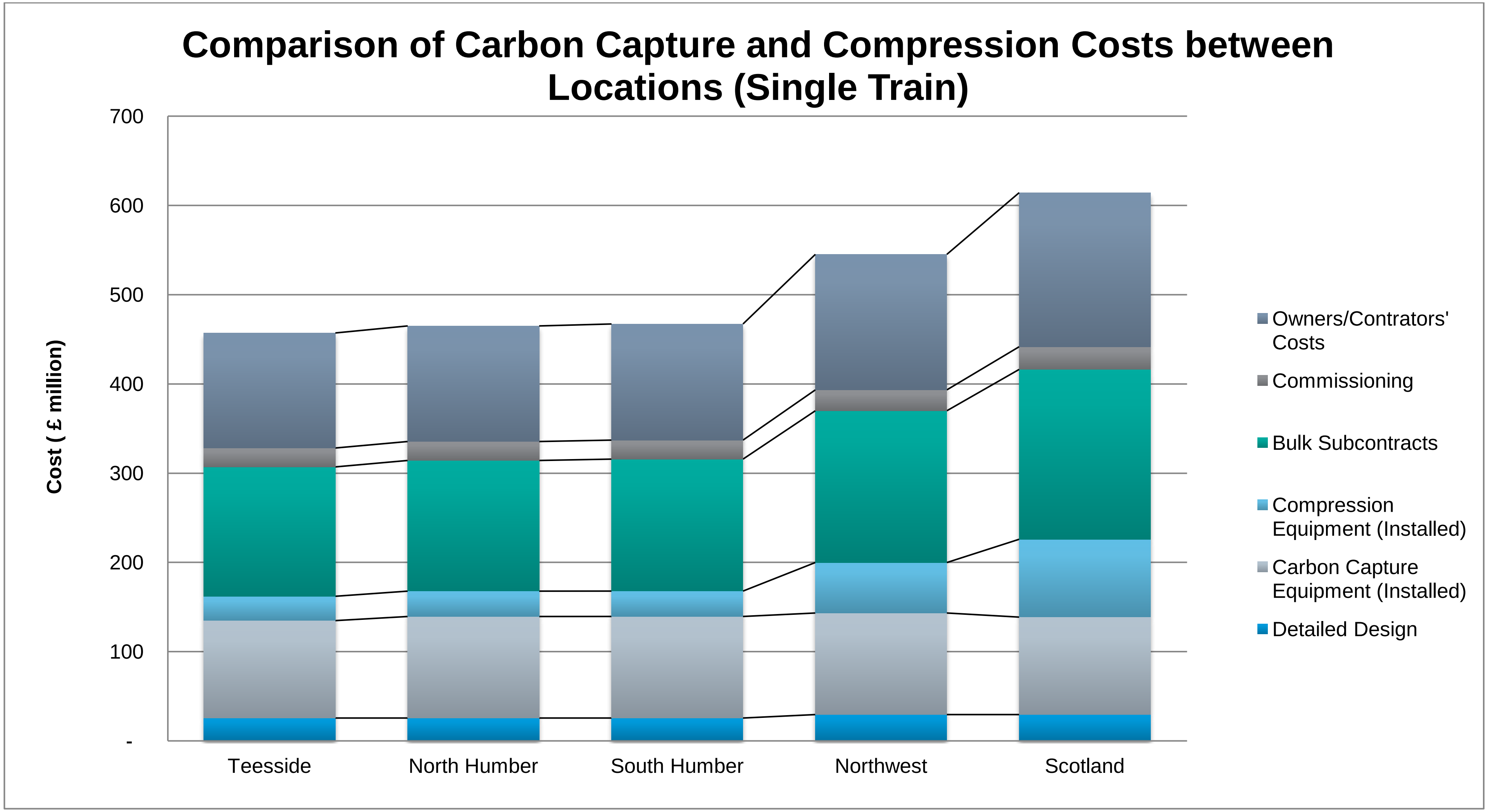


Figure 22 – Carbon Capture and Compression Costs

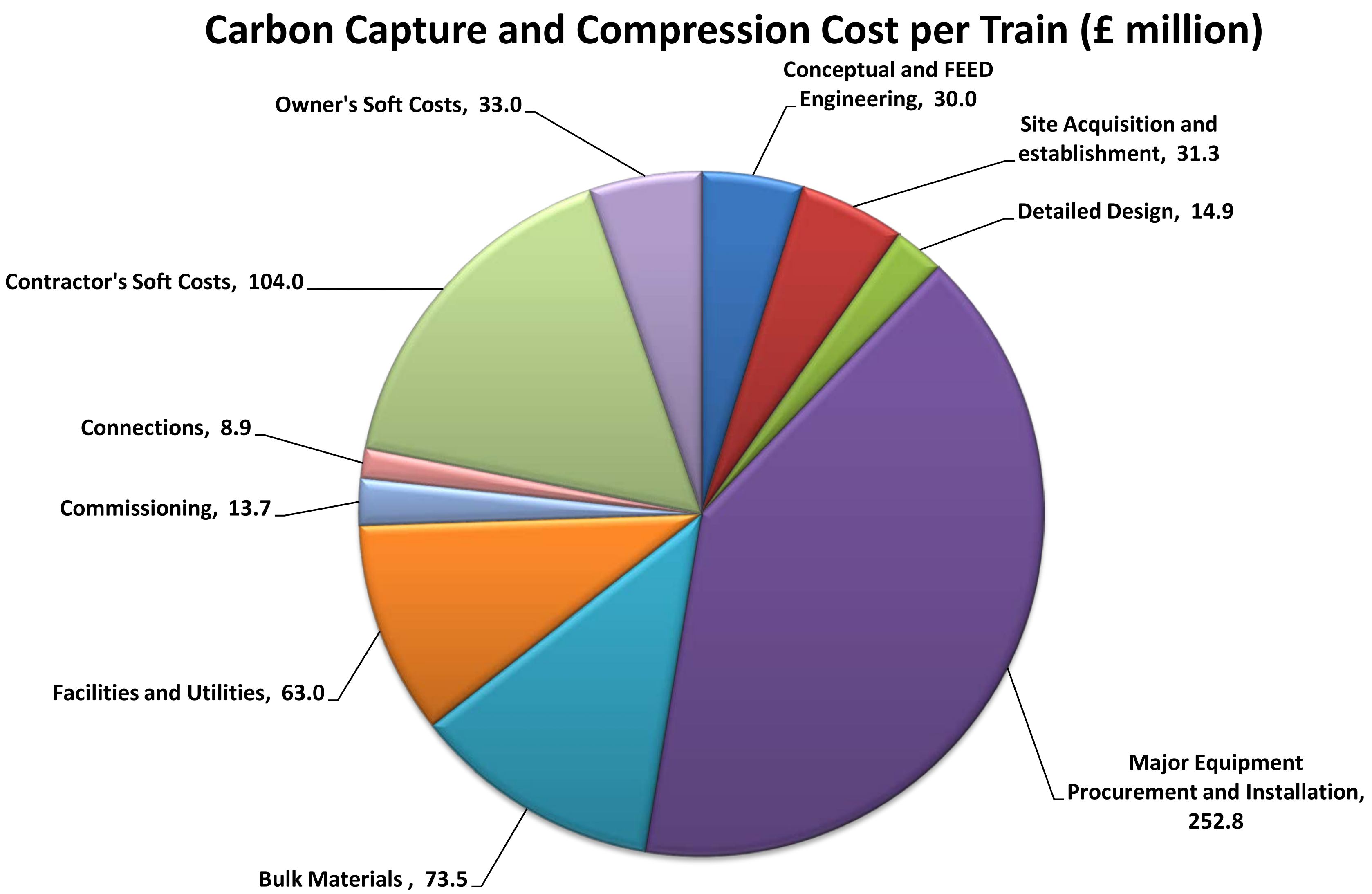


Figure 23 – Carbon Capture and Compression Costs per Train

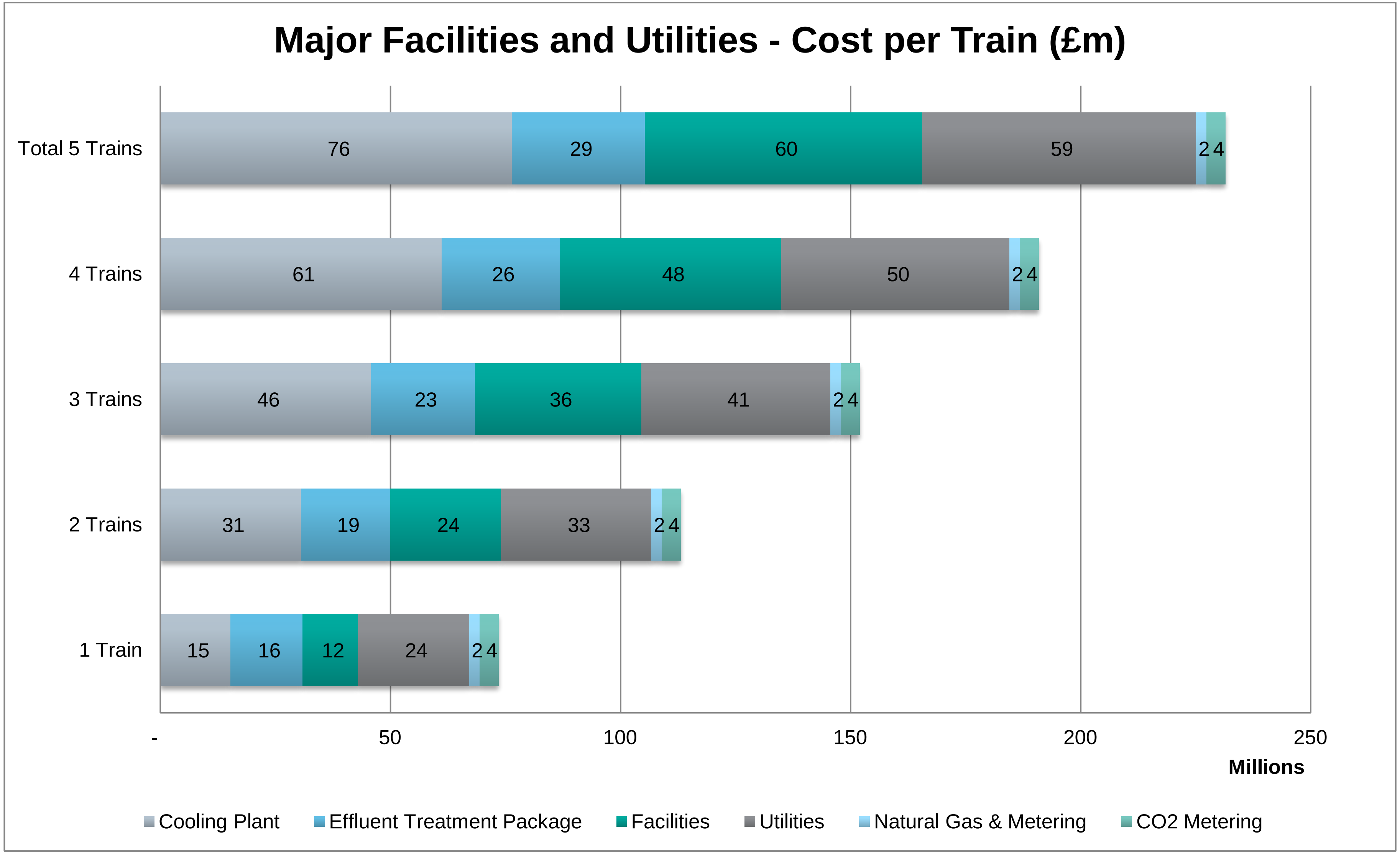


Figure 24 – Major Facilities and Utilities

6 CO_2 Transportation

6.1 Pipeline

CO_2 will be transported by steel pipeline from the CCGT + CCC onshore plant to the offshore store. The following sub-sections describe the different areas of the CO_2 transportation for the GBC project.

Onshore Pipeline

The onshore routing will be dependent on the site selected.

- TEESSIDE – The Teesside sites are close to the sea so that the pipeline route to the shoreline is likely to be short and therefore no isolation valves or above ground installations (AGIs) are required.
- NORTH HUMBER – The pipeline route to the shoreline is approximately 20km. An AGI will be required at the shoreline which will include an isolation valve and a pig launcher and receiver: the pig launcher and receiver are required to allow separate cleaning or inspection of the onshore and offshore sections of the pipeline.
- SOUTH HUMBER – A pipeline tunnel will be required underneath the Humber. Once North of the Humber the pipeline route is likely to follow the same as that selected for the North Humber pipeline with a similar requirement for an AGI.
- NORTH WEST – A significant length pipeline will be required to reach the shoreline. It is expected that there will be regular isolation valves along the pipeline route (approximately every 15 km) and there will be an AGI for an intermediate pigging station. Additionally, there will be a shore station for an isolation valve, pig launcher, and pig receiver. The shore station will also include a substation for the subsea power cable supplying power to the Hamilton Platform during gas phase injection. The shore station shall be used for a chiller and its refrigeration package during liquid phase injection (please refer to section 6.3 for further information).
- SCOTLAND - The onshore pipeline for Southern Scotland will follow the strategy used for the Longannet FEED study, which can be seen on the following figure, with a new connection from the selected site to Feeder 10 at Dunipace. Feeder 10 will be repurposed, complete with the existing isolation valve stations, to relay the CO_2 to St Fergus. The pressure drop through the pipeline will require an intermediate pressure boosting station, if the size of the Scotland plant is 3 trains. New pig launcher receiver stations will be required at the entrance to Feeder 10, part way along Feeder 10, and at the shoreline. The design pressure of Feeder 10 is much lower than the required injection pressure for the Captain X and Goldeneye platforms, therefore a shoreline

compression station will be required to pressurise the CO_2 from Feeder 10 before leaving the shore in a subsea pipeline.

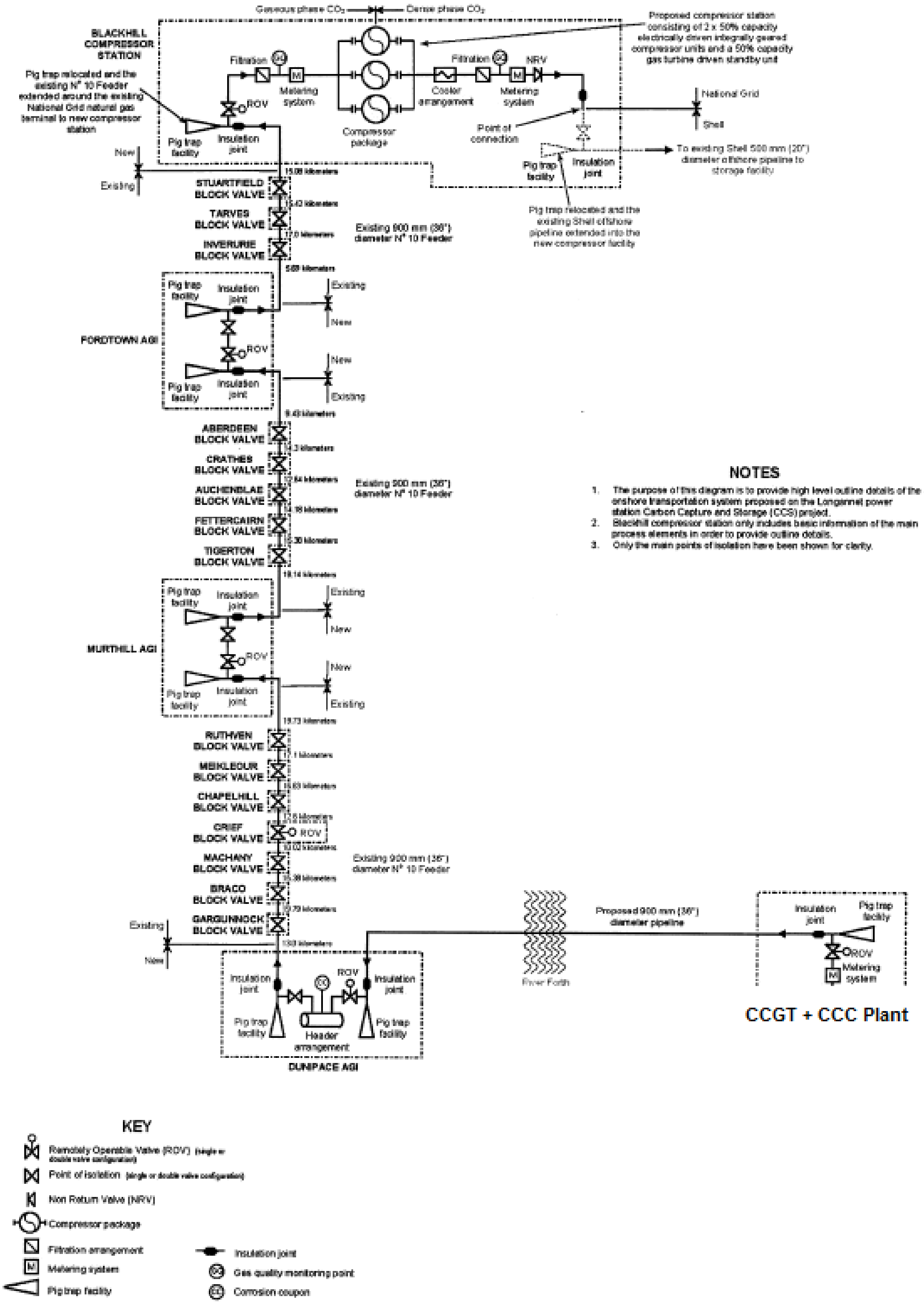


Figure 25 – South Scotland Onshore Pipeline (ScottishPower CCS Consortium, April 2011)

CO_2 pipelines will be routed away from housing areas and will be buried along the onshore route. Regular isolation valves will be installed where the CO_2 pipeline is of sufficient length.

Shore Crossings

The choice of shore crossing type is dependent on the shore crossing location selected for each region:

Site	Crossing Type	Brief Description
North Humber	Cofferdam	The interface between the onshore and the offshore pipeline would be the tie-in location between the two pipeline sections. The tie-in would be constructed in a cofferdam on the shoreline; the beach would be reinstated after completion of construction.
South Humber	Cofferdam	
Teesside	HDD	Approximately 1 km subsurface horizontal directionally drilled (HDD) pipeline. The HDD pipeline will be joined to the offshore line that would already be pre-trenched and floated onto the shore for connection.
North West / North Wales	HDD	
Scotland	Reuse Existing	

Table 29 – Shore Crossings

A cofferdam approach is cheaper and lower construction risk than a Horizontal Directional Drill (HDD) connection. The cofferdam approach allows direct construction access to the pipeline route and installation across the shoreline which makes it easier for the construction team to cope with any unforeseen ground or geotechnical conditions. However, the cofferdam approach requires invasive access and works which can be very damaging for sensitive ecological shoreline areas. HDD does not require invasive works or access to the shoreline and instead drills underneath creating a bore for the pipeline. HDD requires specialist drilling equipment and any unforeseen ground or geotechnical conditions can cause severe delays if it proves difficult or impractical to drill through these areas.

There are restrictions at Teesside, North West / North Wales, and Scotland that would prevent a cofferdam approach from being consented which would require HDD for shore crossing:

- Teesside: shoreline protected by Ramsar, SSSI, and SPA designations;
- North West / North Wales: shoreline protected by Ramsar, SSSI, SAC, and SPA designations. Maps also show a military range at shoreline.

CO_2 Transportation - Offshore

From the shoreline the pipeline will run subsea to the injection platform. New pipelines are required for the Endurance and Hamilton Platforms. The existing pipeline from St Fergus to Goldeneye will be reused as per the Shell Peterhead and Longannet FEED studies. The existing line from St Fergus to Atlantic will be used for Captain X with a subsea tie-in and new connection from Atlantic to Captain X.

Each subsea pipeline will have a Subsea Isolation Valve (SSIV) in order to isolation the offshore facility from the CO_2 pipeline in case of an incident on the platform or riser.

For the larger size plants exporting CO_2 to Endurance (4 or 5 trains) a second platform will be required in order to ensure that there is sufficient coverage over the aquifer to inject the volume of CO_2. A new connecting pipeline will be required to link the 2 Endurance Platforms. It is assumed that all the flow will go to the Alpha platform (nearer the English Shoreline) and that the Bravo platform will be fed from Alpha. An SSIV will be required at either end of the interconnecting pipeline to ensure that either platform is isolated from the pipeline CO_2 inventory in the case of an incident.

6.2 Pipeline Design

Design Decisions

The following decisions were made during the specification for the transportation for the Generic Business Case:

Compression, space, and line sizing	The Transportation infrastructure will be designed only for the GBC project: there will not be an allowance for future capacity or injectors. Should there be opportunities for a specific site then the costs and revenue streams can be included if an agreement can be reached. A good opportunity might be the Industrial CO_2 capture from the Teesside Collective in the North East of England.[21] It is not within the remit of the GBC project to investigate such opportunities as these will be site specific.
Hamilton Injection Temperature Management	Due to the low reservoir pressure CO_2 will initially be injected into Hamilton in gas phase. Once the reservoir is pressurised the CO_2 the injection will change to liquid phase. The gas phase injection will require heating on the topsides of the platform. This will require a subsea cable to connect a shoreline station (for an electrical substation) with the platform. Once the injection changes to liquid phase a chiller with a refrigeration package will be required at the shoreline station to reduce the temperature of the CO_2 in the subsea pipeline to ensure that it remains in liquid phase until it reaches the platform.
Feeder 10	It has been assumed that Feeder 10 can be reused to export CO_2 from Southern Scotland to St Fergus: this follows the approach used for the Longannet CCS FEED Study. Additional AGIs will be required for pig launcher / receiver stations, and for an additional pressure booster station for the larger size Scotland plant.

[21] http://www.teessidecollective.co.uk/

Connection to Feeder 10	For Southern Scotland sites that are on the North of the Forth Estuary it has been assumed that the pipeline routing will run underneath the Forth because the north bank of the Forth is congested between the Forth and the Ochil Hills. Detailed consideration should be given to see whether there is a potential CO_2 pipeline route to the valve station at Braco without the need for a pipeline tunnel under the Forth to reduce the cost of the onshore pipeline.
Offshore Scotland	Pipeline routes from shore to Captain X via Goldeneye, shore to Goldeneye via Captain X, and individual pipelines to both platforms from Shore were reviewed. The project decided to use individual pipelines to Goldeneye and Captain X because the existing pipelines to Goldeneye and Atlantic can be reused for the pressures and flows for the GBC design (with a new pipeline link from Atlantic to Captain X): reuse of existing infrastructure will provide a lower CAPEX solution than new pipelines. The SAP and the Shell Peterhead CCS projects made the same assumptions regarding reuse of the St Fergus to Atlantic and St Fergus to Goldeneye pipelines.

Design Conditions

Endurance

Pipeline Conditions – ENDURANCE FIELD

Design Pressure	200 barg
Operating Pressure	141 barg to 182 barg
Design Temperature	-46 / +50°C
Operating Temperature	4 to 36°C
Flow Rate	up to 10 MTPA
Composition	Per section 13.1 of the Basis of Design

Hamilton

Pipeline Conditions – HAMILTON FIELD

Design Pressure	110 barg
Operating Pressure	92 barg to 49 barg
Design Temperature	-29 / +100°C
Operating Temperature	13 to 74°C
Flow Rate	6 MTPA
Composition	Per section 13.1 of the Basis of Design

Goldeneye

Pipeline Conditions – GOLDENEYE FIELD

Design Pressure	132 barg
Operating Pressure	113 barg to 121 barg
Design Temperature	-29 / +50°C
Operating Temperature	2.9 to 29°C
Flow Rate	3 MTPA
Composition	Per section 13.1 of the Basis of Design

Captain X
Pipeline Conditions – CAPTAIN X FIELD

Design Pressure	170 barg
Operating Pressure	148.1 barg
Design Temperature	-46 / +85°C
Operating Temperature	36°C
Flow Rate	3 MTPA
Composition	Per section 13.1 of the Basis of Design

Material Selection

The selected material for the line pipe is carbon steel of L450 MO grade to BS EN ISO 3183 (Equivalent to API 5L X65).

Mechanical Design

The pipeline mechanical design has been carried out by SNC-Lavalin's pipelines team using the information from the sub-sections above.

Pipeline Wall Thicknesses (mm)					
	Teesside	**North Humber**	**South Humber**	**North West / North Wales**	**Scotland**
CO_2 Onshore	27.4	27.4	27.4	24.6	Existing
Shore Crossing	31	31	31	31	Existing
Offshore Pipeline	27.4	27.4	27.4	24.6	Existing

Table 30 – Pipeline Wall Thickness (mm)

Pipeline Safety

Pipelines containing high pressure CO_2 pose a toxicity and asphyxiation hazard. The frequency of incidents is significantly reduced by(McKenzie, 2009):

- larger diameters (>17")
- larger cover (>80 cm cover)
- larger thickness (>10mm)

The pipelines design meets the above criteria. The routing of the pipelines avoids proximity to domestic dwellings. The longer pipeline routes include block valve stations.

6.3 Sizing

The compression system and pipeline scheme is shown in the diagram below.

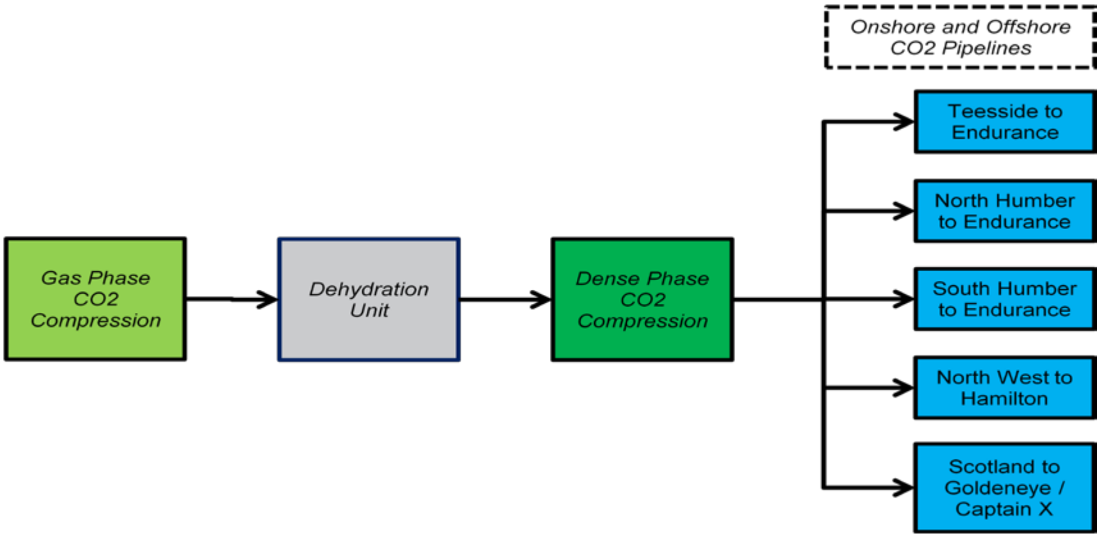


Figure 26 – Modelling of Compression and Transportation

The design process is shown in the following figure (Figure 27 – Offshore Design). The design work started by determining the required CO_2 arrival pressure and temperature at the platform (please refer to Table 30 – Platform Arrival Pressure). Subsurface Engineering was not part of the scope of this project; instead the information was sourced from publicly available information, such as the ETI's Strategic UK CCS Storage Appraisal Project (SAP). The discharge conditions from the compression was calculated from the pipeline route, pipeline size and hence pressure drop, and the arrival conditions on the offshore platform. The onshore pipeline routes were determined from the site selection work (please refer to the Site Selection Final Report, ETI Deliverable D3.1). Offshore pipeline routings were taken from publicly available information regarding previous projects and studies.

For Compression, Dehydration and Pipelines simulation setup detail please refer to Attachment 4.

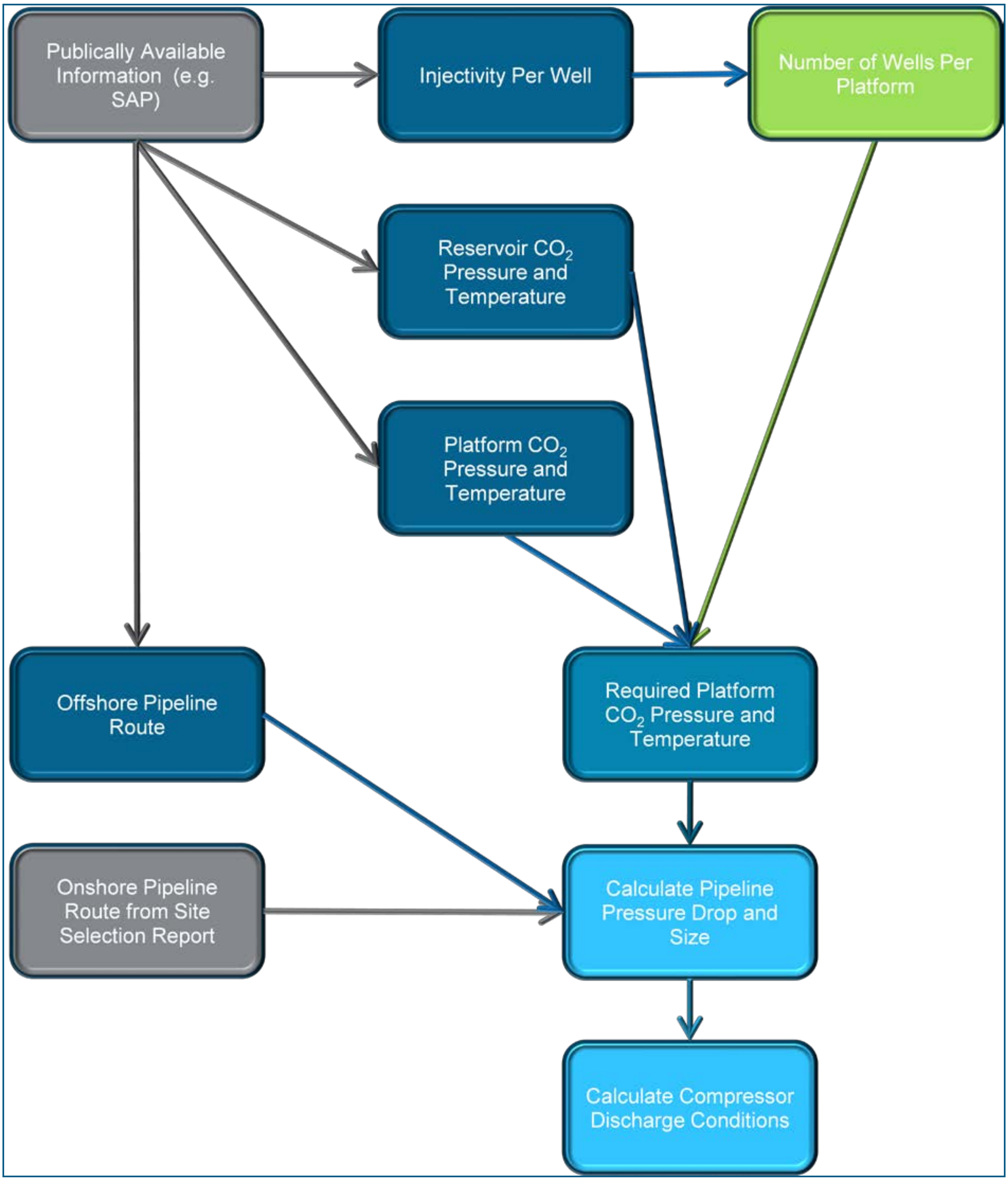


Figure 27 – Offshore Design

Platform Arrival Pressure

The following are the assumed maximum platform arrival pressures derived from publicly available sources for the CO_2 mass flow to the platform, the number of wells, and assumed injection rates:

Platform	Platform Arrival Pressure (bara)	THP (bara)	Source
Endurance	142.3		(Capture Power Limited, 2016)
Hamilton (Gas Phase)	51	47.5	(Pale Plue Dot Energy, Axis Well Technology and Costain, 2016)
Hamilton (Liquid Phase)	83.5	49.3	(Pale Plue Dot Energy, Axis Well Technology and Costain, 2016)
Goldeneye	105.4	101	Post-FEED End-to-End Basis of Design
Captain X	130	125.5	D13: WP5D – Captain X Site Storage Development Plan

Table 31 – Platform Arrival Pressure

ENDURANCE

The Endurance data is taken from the K34_Flow_Assurance_Report (Capture Power Limited, 2016). The data is based on Years 5 to 10 Pressure Profiles (10 MTPA) which can be seen in Table 5.3 / 5.4 of the Flow Assurance Report for the maximum reservoir pressure (178 bara) and 3+2 wells configuration which results in 142.3 bara platform pressure.

For Year 10 Onwards Pressure Profiles (17 MTPA) Table 5.5 / 5.6 the maximum reservoir pressure (195 bara) results in the following platform pressures being required:

- 3+2 wells configuration = 159.5bara platform pressure.
- 3+3 wells configuration = 139.7bara platform pressure.

Therefore for Endurance as there are 6 injection wells (split between 2 platforms) for the 5 train case the platform pressure is expected to be lower than 142.3 bara.

HAMILTON

Two rows in the above table are provided for Hamilton. This is based on the work done for the SAP (Pale Blue Dot Energy and Axis Well Technology, 2016) that identified that due to the depleted pressure the first stage of injection would be for gaseous CO_2 which would change to liquid phase injection once the reservoir pressure had increased sufficiently.

The pressure and temperature of the CO_2 in the pipeline to the Hamilton field need to be managed for the gaseous and dense phases of injection in order to keep the CO_2 in the phase that it is transferred. Two phase flow is undesirable as this could lead to choking of the flow or damage to the pipeline and wells. The phase also needs to be managed to ensure that during gaseous phase injection the THT needs to be high enough to maintain gaseous phase into the wells. The aim of the design is to keep the pipeline in gaseous phase, during gaseous phase injection, but at as high a temperature as possible to minimise the downstream heating requirements. The design for the GBC was to use the same pipeline for both the gaseous and liquid injection phases so that there would not be a cost for the replacement of the subsea pipeline at the end of the gaseous injection phase. Control of the phase of the CO_2 would be achieved through manipulation of the design of the compressor intercoolers, pipeline insulation, shoreline chiller (liquid phase) and offshore heater (gaseous phase)..

A 24 inch pipeline size with insulation on the offshore section has been selected for the GBC project in order to have a CO_2 pipeline inlet pressure below the pipeline choking condition for the Hamilton Gas Phase with a maximum pipeline inlet pressure 82 bara to 94 bara at the 7th Stage of the onshore plant Compressor discharge.

The sea in winter will tend to cool the CO_2 in the subsea pipeline below the target temperature during the gaseous phase injection and will tend to heat the CO_2 in the subsea pipeline during summer above the target temperature during liquid phase injection,

During the gaseous injection phase the Joule-Thompson cooling effect caused by the pressure drop across the well head choke valve would result in a low temperature that could cause damage: therefore the CO_2 gas requires heating to maintain an acceptable temperature. A range of options was reviewed by the GBC team and an insulated pipeline with an Offshore Heater on the platform was selected to maintain the target THT at 30ºC and 47.5 bara: the Offshore Heater duty is 2.230 MW for maximum flow of 6 MPTA.

During the liquid injection phase a Shoreline Pipeline Chiller between the onshore and offshore pipelines will be required to maintain the offshore pipeline within the Liquid phase and to meet the target THT at 10ºC. Without the Cooler, the THT is 13.61 to 13.65ºC for all flow conditions.

GOLDENEYE

As the fluid arriving at the Goldeneye Platform is in the liquid phase there is pressure static head proportional to the elevation. The pipeline low point / bottom of the riser is the maximum pressure location for the pipeline on which the design pressure of the pipeline shall be based. To keep the pipeline MAOP x1.1 within 133 bara the pipeline inlet pressure is kept at 115 bara which results in a pipeline low point / bottom of the riser pressure of 122.4/121.5 bara respectively. The maximum platform arrival pressure of 105.4 bara for the GBC based on 122.4 bara pipeline low point. In layman's terms the liquid head is greater than the pipeline pressure drop which is why the low point is the limiting pressure location for the pipeline design.

Pipeline Sizing Results

The CO_2 pipeline sizing was carried out using the required CO_2 export rate and the platform pressures from the table above.

The CO_2 pipelines with different sizes and flow rate were studied and the overall results are summarised in the tables below (for further detail please refer to Attachment 4).

Pipeline Sizing Summary

The summary of the Compression and CO_2 Pipeline simulation models are as follows:

ENDURANCE

The sizing of the pipelines to Endurance from Teesside, North Humber, and South Humber regions were similar:

- 24 inch CO_2 pipelines from Teesside, to Endurance with 183 bara maximum inlet pipeline pressure and 184 bara at the 8th Stage Compressor discharge for Teesside to Endurance.
- 24 inch CO_2 pipelines from South Humber to Endurance with 174 bara maximum inlet pipeline pressure and 175 bara at the 8th Stage Compressor discharge for South Humber to Endurance.
- 24 inch CO_2 pipelines from North Humber to Endurance with 172 bara maximum inlet pipeline pressure and 173 bara at the 8th Stage Compressor discharge for North Humber to Endurance.

HAMILTON

For the CO_2 transportation from the North West region to the Hamilton Field in gas and liquid phase the 8th Stage Compressor would not be required as the injection and hence pipeline pressure does not need to be as high as for Endurance.

Sizing for gas phase injection (early years operation):

- 24 inch pipeline (with insulated offshore pipeline) from North West to Hamilton gas phase with 82 bara maximum inlet pipeline pressure, 94 bara at the 7th Stage Compressor discharge and 2.23MW Offshore Heater to maintain the THT at 30°C.
- 46°C used as cooler outlet temperature for the 6th Stage Compressor (Dense Gas) Cooler to maintain Hamilton Gas Phase THT at 30°C.

During the gas phase injection the compressor discharge pressure is set higher than the required pipeline pressure in order to have a higher inlet temperature to maintain the offshore pipeline within the gas phase and to meet the target THT at 30°C. An upstream valve is required to drop the compressor discharge pressure to the required pipeline pressure.

Sizing for liquid phase injection (later years operation):

- 24 inch pipeline from North West to Hamilton Liquid Phase with 93 bara maximum inlet pipeline pressure, 94 bara 7th Stage Compressor discharge and 16MW Shoreline Pipeline Chiller to maintain the THT at 10°C.
- A 7th Stage Compressor (Dense Gas) Cooler with 36°C outlet temperature is required to maintain Hamilton Liquid Phase THT at 10ºC.

The Tubing Head Pressure (THP) at the offshore platform for the Liquid Phase will range from 49 to 72 bara. The compressor discharge pressure based on the design for the gaseous injection phase will provide a platform arrival pressure of 78.4 bara which is above that required for the liquid injection phase.

SCOTLAND

It is assumed for the GBC project that Feeder 10 will be repurposed for CO_2 transportation, and because of pressure limitations on Feeder 10, the onshore transport needs to be in gas phase. The sizing for the Scotland region:

- A new 36 inch pipeline (18km) will be required from the onshore CCGT + CCC Plant to No 10 Feeder.
- The existing 36 inch pipeline (280km) from No. 10 Feeder to St Fergus will be repurposed.

A new 1 x 100% booster compressor station at Kirriemuir will be required to boost the CO_2 pressure to 35 bara. Kirriemuir is located in Angus around half way between Grangemouth and St Fergus. The booster compressor at Kirriemuir would only be required when three trains in operation with a total capacity of 6 MTPA and is not required for 2 train or 1 train plant size as the lower flow would generate a lower pressure drop.

Two new compressor units located at St Fergus would be required to boost the CO_2 pressure to the offshore pipelines to meet the injection pressure required on the offshore platforms (1 x 100% compressor to serve Captain X and 1 x 100% compressor to serve Goldeneye).

- The existing 16 inch offshore pipeline (78km) from St Fergus to Atlantic would be reused and a new 16 inch pipeline (8km) extension to Captain X.
- The existing 20 inch Goldeneye pipeline (101 km) from St Fergus to Goldeneye Platform to be reused.

A shoreline compression station is provided for the Scotland region where it is required because of the limit on the design pressure of the reused Feeder 10: other regions do not need shoreline compression.

BENCHMARK

An indication for the best diameter for 10 MTA is a 20” pipeline diameter based on specific transportation cost at 81 bara (Kaufmann, 2009). However, the pressure profiles for the modelled pipelines show that pressure drops are too high for 20” size and therefore 24” pipelines are a more economic choice for the GBC project for 5 trains. The table below shows the output of pipeline sizing for the different plants and numbers of trains.

Pipeline Sizing for Differing Numbers of Trains				
Trains	Teesside	North Humber	South Humber	North West / North Wales
1 Train	16”	16”	16”	18”
2 Trains	18”	18”	18”	24”
3 Trains	20”	20”	20”	24”
4 Trains	24”	24”	24”	N/A
5 Trains	24”	24”	24”	N/A

Table 32 – Pipeline Sizes for Different Numbers of Trains

Pipeline	Mass Flow MTPA	Nominal size (inch)	Onshore Length (km)	Offshore Length (km)	Inlet / Outlet Velocity (m/s)	
Teesside to Endurance	10.0	24	2	154	1.6	1.4
North Humber to Endurance	10.0	24	24	79	1.7	1.4
South Humber to Endurance	10.0	24	18	79	1.6	1.4
North West to Hamilton (Gas Phase)	6.0	24	54	24	4.1	5.7
North West to Hamilton (Liquid Phase)	6.0	24	54	24	1.3	0.9
Scotland to Captain X via existing Atlantic pipeline	3	16	298	86	1.1	0.1
Scotland to Goldeneye via existing Goldeneye Pipeline	3	20	298	101	0.8	0.1

Table 33 – CO2 Pipeline Data

Pipeline	Compressor Discharge		Shoreline Arrival		Offshore Pipeline Inlet		Platform Arrival		Tubing Head	
	Temp (°C)	Press (bar)	Temp (°C)	Press (bar)	Temp (°C)	Press (bar)	Temp (°C)	Press (bar)	Temp (°C)	Press (bar)
Teesside to Endurance	120	184	36	183	36	183	4	142		
North Humber to Endurance	115	173	35	178	35	178	4	142		
South Humber to Endurance	116	174	35	168	35	168	4	142		
North West to Hamilton (Gas Phase)	74	94	45	62	45	62	27	51	30[22]	48
North West to Hamilton (Liquid Phase)	62	94	34	86	13	85	13	78	10[23]	49
Scotland to Captain X via existing Atlantic pipeline	117	39	15	20	36	149	11	133		
Scotland to Goldeneye via existing Goldeneye Pipeline	117	39	15	20	36	113	11	105		

Table 34 – CO_2 Pipeline Process Data

[22] A 2.23 MW Offshore Heater has been included in order to maintain the THT at 30ºC for the Hamilton gas phase.

[23] Included a 16 MW Shoreline Pipeline Chiller to maintain the THT at 10ºC for the Hamilton Liquid phase.

6.4 Health, Safety & Environment

	Carbon Dioxide (CO_2) › Danger to life from asphyxiation or toxicity of escaping CO_2 › Major Accident Hazard: The hazard range for an instantaneous release from pipeline may be in the range of 50 to 400 m with large, cold, liquid phase storage producing the larger distances. The hazard range for a continuous release through a 50mm hole may be up to 100 m.(Dr Peter Harper, 2011) › Asphyxiation from approx 50% v/v in air. Toxicity > 15% v/v in air (50% fatalities for 1-minute exposure time)(Dr Peter Harper, 2011) › Route pipeline away from areas of habitation › Design to limit inventory of CO_2 in pipeline segments › Design to contain CO_2 (e.g. pipeline design codes)

The following significant hazards have been identified in the design of the CCGT + CCS Scheme:

Area	Hazard	Control
Pipelines	Ground Contamination (e.g. Asbestos)	Costs included for surveys. Cost estimate includes allowance for high risk sites where contamination can be expected through previous industry based on prior proposal / project information.
Pipelines	WWII Ordnance in Historic Industrial Areas Near shore MOD ranges	Cost allowance for surveys. Specific areas of hazard would need further analysis in future phases of the project.
Pipelines	Terrorist Attack	Pipelines buried so that they cannot be easily accessed.

6.5 Construction Methodology

The following construction method will be used for the onshore CO_2 pipeline:

- Pipeline corridor, access routes, and pipe dumps cleared and prepared
- Mechanical Excavation of Trench
- Strings of Pipeline delivered along route
- Strings of pipeline welded together and lowered into trench
- Completion welds between sections in the trench
- Tie into National Grid pipeline and above ground installation(s)
- Backfill

- Test
- Cleanup and restoration

Crack arrestors are required for CO_2 service. These are periodic higher wall thickness pipeline joints. The change in hoop stress is designed to prevent unzipping of the CO_2 pipeline following a propagating fracture.

The following construction method will be used for the offshore CO_2 pipeline:

- S-Lay for pipeline installation.

6.6 Mechanical Completion

Mechanical completion of the pipelines will be achieved once the pipelines have been proof tested, the onshore pipeline route has been reinstated, the pipeline dried, and filled with preservation gas.

The offshore pipeline will need to be pigged in order to displace the seawater, dried, and charged with preservation gas.

The pipelines will need to be left dry (residual water could lead to corrosion on introduction of CO_2 or could be prone to freezing on depressurisation of CO_2).

6.7 Commissioning

Commissioning of the pipeline will require at least 1 compressor to be available at the CCGT and CCC plant.

The start of commissioning of the pipelines will need low pressure CO_2 (e.g. 10 barg):

- Low pressure CO_2 will not need pre-heating
- Only volume of CO_2 needed to sweep / purge the pipeline of preservation gas (does not need large mass of gas at higher pressure
- No risk of damage due to low temperatures caused by J-T effect on expansion

As each section of the pipeline will purged in turn (between pig launchers). A pig will maintain a barrier between purge gas and preservation gas. Once the CO_2 flowing through the pipeline section meets the required specification the commissioning will move onto the next section of pipeline until the pipeline is purged all the way to the platform topsides.

6.8 Contracting Approach

It is assumed that the connections would be the responsibility of contractors – either sub-contracted to the Main EPC Contractor, or more likely, contracted directly to the Owner:

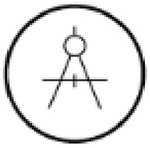
- **Onshore pipeline and shore crossing:** Installation of the new CO_2 pipeline to connect the plant to the shore crossing. Scope will include the shore crossing and any Above Ground Isolation Valve Stations;

- **Landfall and Subsea Pipeline:** Landfall, of the new offshore CO_2 pipeline to connect to the offshore Well Head Platform (WHP). Subsea pipeline lay will include installation of the Sub Sea Isolation Valve (SSIV) close to the platform, tie-in spools, installation of a new control and power umbilical, and a new Topside Umbilical Termination Unit (TUTU).

Subsea pipelines are typically delivered by different contractors than onshore pipelines because the offshore installation needs marine vessels and lay barges which are not typically owned by companies installing onshore pipelines.

Some of the companies that can offer onshore pipeline installation are also able to offer the installation of other linear assets such as water intake and outfall, potable water, sewer, and HV OHL connections. There may be a benefit during the execution of the project to combine these scopes in order to reduce the installation contractors fixed costs for the overall delivery of the connections.

6.9 Basis and Methodology of Estimates



Quantities

Quantities have been generated based on the material selection for pipelines, calculated thickness, and pipeline length.

Quantities include corrosion control (e.g. coatings and anodes)

Equipment for transportation has been included and sized in the equipment lists.

Cost Estimate

The connection costs are bottom up estimates generated on cost build up sheets with sections for materials, installation activities, and contractor costs.

Risk and contingency are not included: risk and contingency have been calculated and included elsewhere.

6.10 Assumptions on Estimates

Connection costs are based on estimated distances from an example site and allow for approximate routing only. A detailed assessment of routing once a final site is selected will impact costs.

Costs are based on per unit rates provided in prior project vendor quotations. Due to the nature of the subcontracts, it is assumed that travel supplementation and inclement weather allowance are included in the rates.

No allowance has been made for future changes in steel prices affecting the cost of the pipeline.

Increases in cost for 5-4-3-2-1 trains are based on increasing line sizes. Changes in compression requirements are included in the carbon capture section of the estimate.

6.11 Cost Estimate Data Provenance

CO_2 transportation costs for this project have been calculated based on previous project detailed estimates. Distances have been estimated based on example sites in each region and approximated routing. All costs are Q1 2016.

6.12 CAPEX

Early Engineering Estimates

Please refer to Attachment 15 for the Pre-FEED and FEED Estimate which provides man hours and estimated costs against the different areas of the plant.

Connections

The approximate distances and routing for the transportation pipelines and landfalls were determined through the site selection process and details of the site-specific criteria determining the length and routing for each set of connections can be found in the Detailed Report – Site Selection 181869-0001-T-EM-REP-AAA-00-00002 (AECOM ref: 60521944-0702-000-GN-RP-00001, ETI Ref: D3.1).

CO_2 pipelines are costed based on distance, routing, crossings, pipeline size, wall thickness, and anti-corrosion coating. Materials and installation have then been estimated based on unit rates from similar SNC-Lavalin project cost estimates.

Offshore CO_2 Pipeline

Region	Number of Trains				
	1	2	3	4	5
Teesside	£203,960,005	£212,121,959	£231,136,215	£275,185,814	£275,185,814
North Humber	£105,944,823	£114,802,883	£124,603,075	£147,306,558	£147,306,558
South Humber	£105,944,823	£114,802,883	£124,603,075	£147,306,558	£147,306,558
North West / North Wales	£48,982,358	£53,749,945	£57,114,169	N/A	N/A
Scotland[24]				N/A	N/A
New Link[25]	N/A	£21,391,035	£21,391,035		
Captain X[26]	N/A	£5,182,360	£5,182,360		
Goldeneye[27]	£15,209,100	£15,209,100	£15,209,100		

[24] Single train uses only Goldeneye Platform
[25] New link from the existing Atlantic pipeline to Captain X platform
[26] Reuse of Existing pipeline from St Fergus
[27] Reuse of Existing pipeline from St Fergus

Table 35 – Offshore Pipeline Cost Estimates

An infield pipeline is required for Endurance as the site has more than 1 platform. The calculation sheets are included in Attachment 10.

Site	Number of Trains				
	1	2	3	4	5
Endurance	N/A	N/A	N/A	£30,513,061	£30,513,061

Table 36 – Infield Pipeline Cost Estimates

Onshore CO_2 Pipeline

Region	Number of Trains				
	1	2	3	4	5
Teesside	£1,427,610	£1,639,142	£1,869,031	£2,388,947	£2,388,947
North Humber	£13,373,805	£15,523,174	£17,877,911	£23,260,173	£23,260,173
South Humber[28]	£141,422,339	£144,308,800	£147,471,760	£154,703,504	£154,703,504
North West / North Wales	£72,123,968	£90,394,162	£90,394,162	N/A	N/A
Scotland New Link[29]	£88,304,043	£90,723,092	£93,142,141	N/A	N/A
Feeder 10[30]	£88,888,740	£88,888,740	£88,888,740		

Table 37 – Onshore Pipeline Cost Estimates

[28] The South Humber region includes approx. £100m for a tunnel crossing under the Humber (3000m)
[29] New link from Scotland region site to Feeder 10 includes approx. £60m for a tunnel crossing under the Forth (1200m).
[30] Cost to reuse existing Feeder 10 from FEED Close Out Report, SP-SP 6.0 - RT015, April 2011, ScottishPower CCS Consortium, published under Open Government Licence v3.0.

7 Offshore Facilities

Current UK policy decisions are that Carbon Capture and Storage in the UK will use offshore storage locations, and these shall be for CO_2 storage only and not Enhanced Oil Recovery (EOR).

Four CO_2 stores have been identified for the Generic Business Case:

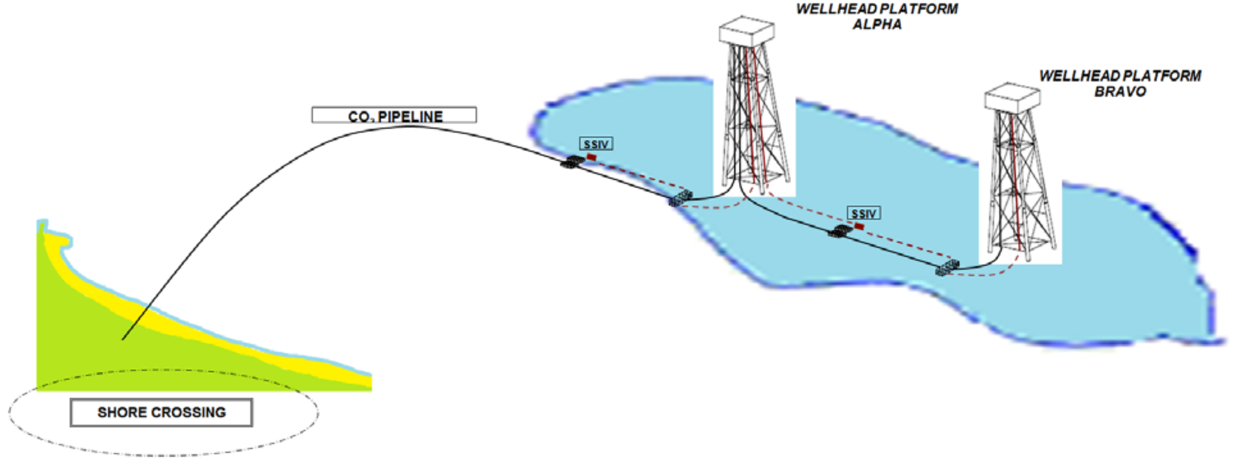
- East Coast – Endurance
- West Coast – Hamilton
- Scotland – Goldeneye and Captain X

Wells will be drilled in the subsurface store: the store will either be a saline aquifer or a depleted gas field. The well heads will be located on an offshore platform.

The offshore platform will consist of a conventional structural steel jacket with unmanned minimum facilities topsides. The topsides will include filtering of CO_2, metering of CO_2, and systems to support the injection of CO_2 into the offshore store.

The offshore platform will be reached by boat for operations and maintenance. Safety systems will be installed on the platform for the safety of those working offshore. The boat will be of walk to work type and is intended to remain connected to the platform all the time personnel are working.

NORTH EAST - ENDURANCE



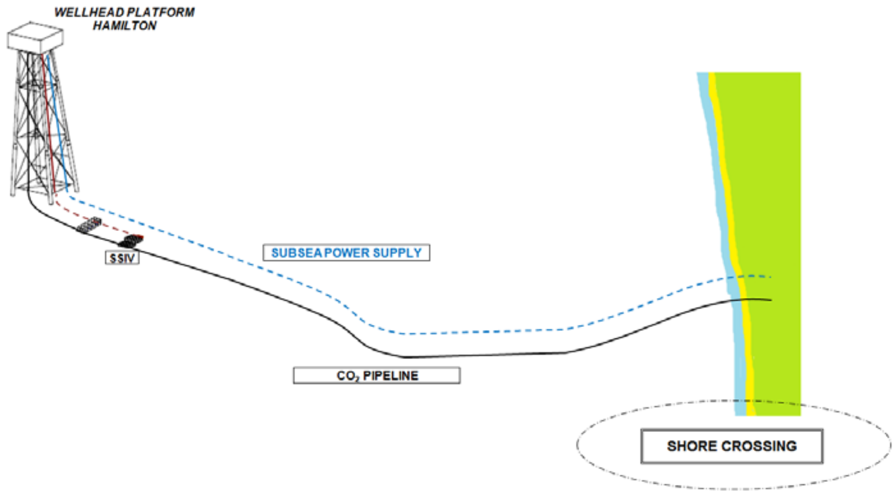
Wells cannot be widely deviated because of limitation of angle. Therefore two drill centres are selected for the Endurance aquifer.

Reservoir length is 22 km long. Assume that drill centres are 8 km apart to provide wide coverage of aquifer.

Shore Crossings are	Teesside =	Redcar Coast
	North & South Humber =	Southern Yorkshire Coast

Figure 28 – Offshore Facilities for North East England

NORTH WEST - HAMILTON



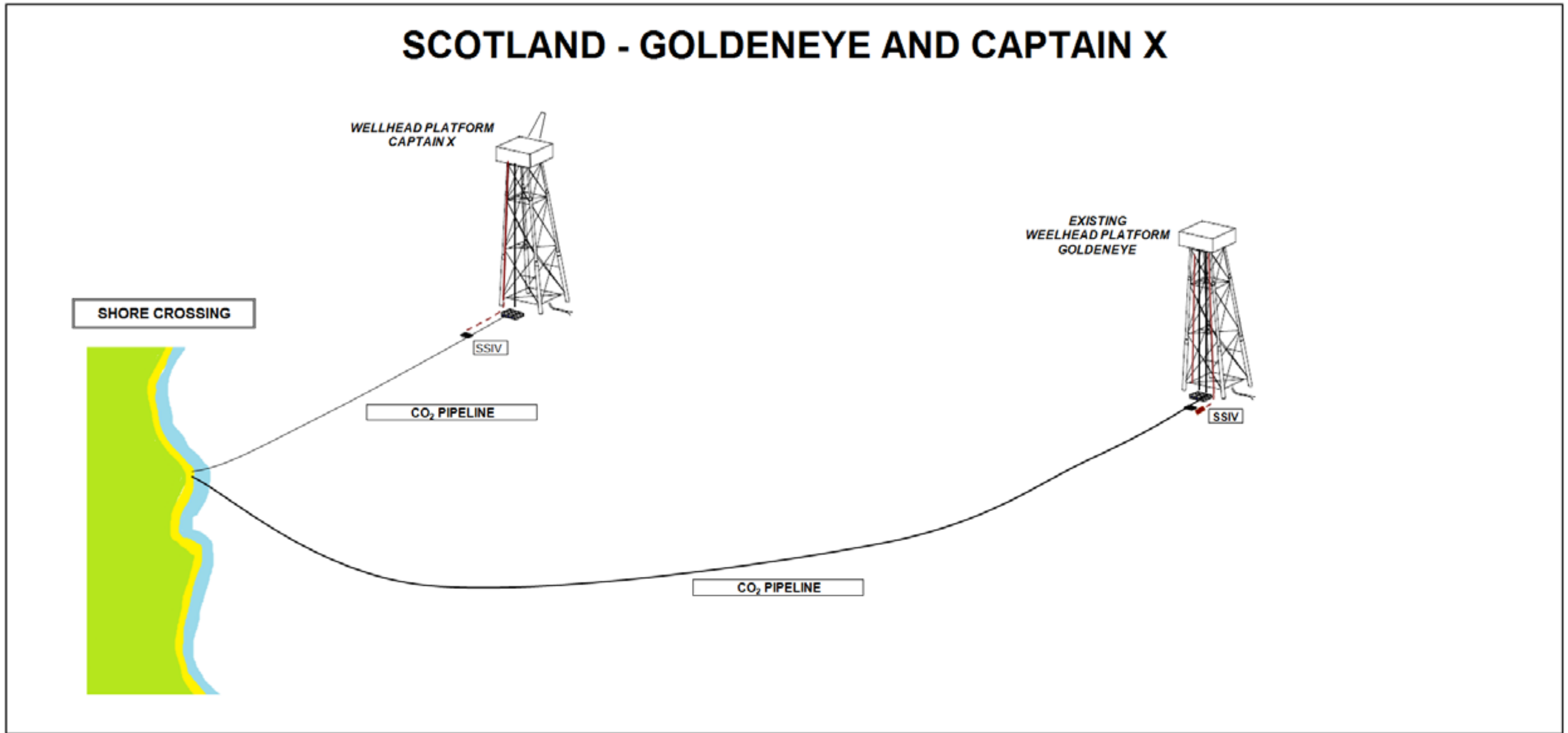
Assume Hamilton reservoir can be drilled from a single new platform.

Assume that existing facilities cannot be reused for CO_2 injection service.

Shore Crossing for North West is East Lancashire Coast

Subsea cabling to be installed to provide power to a platform mounted heater.

Figure 29 – Offshore Facilities for North West England & North Wales



Goldeneye does not have sufficient capacity for injection from a 3 train plant, therefore a new platform will be installed on the Captain X Aquifer.

Assume that existing facilities can be used as proposed in the KKDs for Peterhead.

Shore Crossing for Scotland - St Fergus.

Figure 30 - Offshore Facilities for Scotland

Endurance, Hamilton, and Captain X will be exploited using new platforms with 4 leg jackets.

Goldeneye will be exploited by reuse of the Goldeneye platform as set out in the Shell Peterhead FEED study. Future storage capacity will be attained by step outs from the Goldeneye platform.

Design Decisions

The following key decisions were made during the technical specification of the offshore storage for the Generic Business Case:

Locations	The ETI's work on the Strategic UK CO_2 Storage Appraisal Project has identified a top 20 inventory sites. The most promising stores have been selected for review by the GBC (refer to section 2.4 for stores and regions selected.) Two stores have been selected for the Scotland region because Goldeneye did not have sufficient storage capacity for the larger size plants in this region.
Subsea versus Platform	A review of subsea vs. platform wells was undertaken. For the number of wells selected a dry well (platform) solution appears to be lower cost. A dry well platform solution would also be a risk mitigation measure until offshore CO_2 injection wells are better understood because platform allows greater monitoring and intervention, and lower cost intervention, if there are issues with the injection wells. If a permanent gas heater is to be installed, a platform and dry wells is the only option. Dry wells tend to have a higher operational reliability than subsea wells; There is a lower project risk drilling through a wellhead platform in the North Sea as the operation is less weather dependent than a drilling subsea wells. As these will be the first CO_2 injection wells in the North / Irish Sea the improved accessibility to the wells would be prudent until some operating experience has been obtained. Better flexibility for future expansion.
CO_2 Well Injectivities	Subsurface engineering was not part of the scope for the GBC project. The well injection rates and platform pressures used for the GBC design have been taken from work in the KKDs and the SAP.

Reuse of Existing Facilities	The work done by the SAP decided that the existing facilities at Hamilton need to be replaced for a CCS project. Decision used for this study. The Shell Peterhead CCS planned to reuse the existing Goldeneye facilities. The GBC design reuses the pipeline and platform facilities in the same way. It is an assumption that the Goldeneye facilities are preserved and are in a safe condition for reuse in the time frame of the GBC (and it is assumed that the Goldeneye Facilities are not decommissioned and abandoned).
Platform Substructure	In general, a three-legged jacket used for the injection of Carbon Dioxide (CO_2) into a CO_2 store using either depleted reservoirs or saline aquifers in a North Sea environment will be around 5% (160Te and £1,280,000 less) lighter and cheaper compared with a four-legged jacket. However, four leg jackets offer a basic level of redundancy in the event of accidental loading (e.g. ship impact, etc), that three legged jackets do not. In addition, the foundations of a three-legged jacket will be required to be more substantial and withstand greater bearing and shearing forces, than on a four-legged jacket and hence the installation cost per pile may be greater given an increased weight, diameter and drive depth.
Maintenance Access	A walk to work access for maintenance has been selected as a lower safety risk alternative to helicopter access. On WHPs, maintenance is performed in a conventional manner, generally using a campaign type approach. When helicopter access is used, the most hazardous part of maintenance is access to and egress from the facilities and therefore to reduce risks strenuous efforts are taken to reduce manning requirements and visit frequencies. This is done by minimising the amount of equipment present and by maximising the interval between routine operational visits (e.g. using large consumable capacities). Additionally alternative access methods (e.g. walk-to-work type systems) can also be used to both reduce costs and improve safety, however these may not be usable in all sea states. Walk-to-work systems are well established for offshore UK: for example, Babcock International have undertaken over 18,000 safe personnel transfers in the Central North Sea UK sector without any lost time incidents. (Babcock International, 2017) Shell Peterhead planned to use a Walk to Work vessel for the Goldeneye Platform. (Shell UK Limited, 2016) A “walk-to-work” system will allow access to the facilities in sea states up to 2.5m. This means that for typical North Sea operations, in summer access can be achieved for virtually all of the time, however in winter this reduces to about 50% of the time. The time period in winter for which access cannot be achieved (for which helicopter operation will be required)

	would usually be the time for the storm to abate (typically 5 to 7 days), however it is not unusual for storm to occur in quick succession.
Brine Producer	The amount of CO_2 being injected into the Endurance aquifer may require a brine producer well. The injected CO_2 will displace water in the aquifer. If the water cannot migrate with sufficient speed through the aquifer as it is displaced the compression of the CO_2 and water will lead to an increase pressure in the store. A brine producer well may be required in future to relieve the increase in pressure. Provision is made on the Endurance platform design to allow for brine producer well and equipment (the equipment is assumed to be similar to produced water equipment). It is assumed that the brine would be produced up to the platform, measured and monitored, and sufficient hold up provided such that if the produced brine is out of specification it will not be released to the sea.
Well Water Wash Package	The equipment and hence maintenance offshore has been reduced as much as practical by the GBC team in order to reduce safety exposure to the O&M offshore operatives. It is planned by the GBC team for the Well Water Wash Package to be bought by the project and carried to the platforms by the supply vessel serving the platforms. It is assumed that this is feasible (it has not been detail designed). This also means that 1 set of equipment is required even if there are 2 platforms (as per the larger size Scotland and Endurance schemes).

7.1 Descriptions of Selected Stores

Endurance

The proposed storage solution from the White Rose Project was for Endurance to be a new build WHP and pipeline. There are a number of potential landfalls to reach Endurance: Teesside, North Yorkshire Coast, Lincolnshire Coast. Genesis produced a complete FEED for a platform which is available in the DECC KKD website under open license.

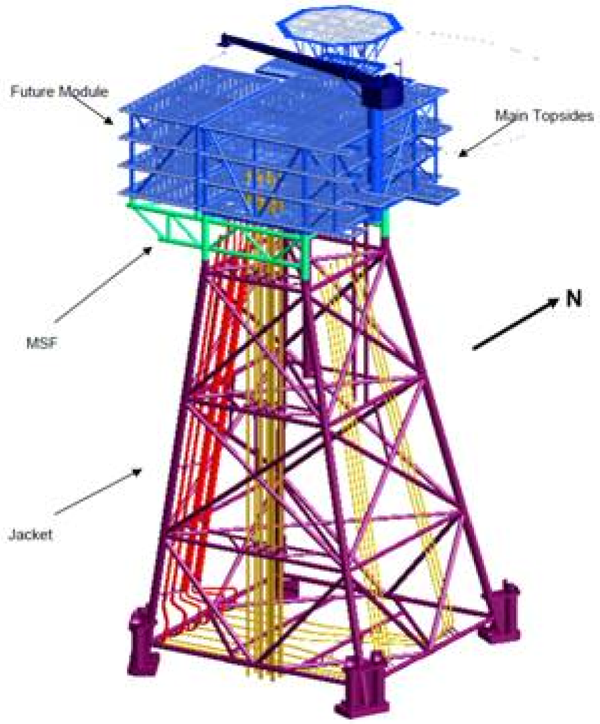


Figure 31 - 3D Model Shot of Endurance WHP (Capture Power Limited - K37, 2015)

The above platform was designed with 6 well slots – 3 injection wells and 3 future. White Rose planned to drill their 3 wells from the platform. There is a range of data on the injectivity of CO_2 wells: and therefore the number of wells required.

The GBC project has used a W2W philosophy for access which has resulted in the helideck, and attendance anciliaries, not being included in the design for Endurance. An additional well as an installed spare has been added to the Endurance design by the GBC and future provision for a brine producer has been included.

Hamilton

The Hamilton Gas Field is estimated to reach the end of its economic life in 2017. Whilst there is some possibility of re-using some components of the natural gas infrastructure such as the jacket the assumption made for the Generic Business Case is that the Existing Hydrocarbon Facilities at Hamilton would not be reused.

The base case would be new build WHP and pipeline: (Pale Blue Dot Energy and Axis Well Technology, 2016)

The facilities design proposed (Pale Blue Dot Energy and Axis Well Technology, 2016) was a platform comprising a new multi-deck, minimal facilities, unmanned platform on a three legged steel jacket in 24m of water. The platform would be connected to a beachhead at Connah's Quay with a new 26km 16" steel pipeline. The platform would have six well slots and also carry 10 MW of electrical heating to warm the CO_2 ahead of injection during Stage 1. Power will be supplied by a cable from the shore. The platform will be operated by satellite links and be capable of operating for up to 90 days between routine maintenance visits.

The GBC project has used a 4 leg jacket substructure as an ALARP alternative to the 3 leg jacket proposed by the SAP.

Due to the low reservoir pressure CO_2 will initially be injected into Hamilton in gas phase. Once the reservoir is pressurised the CO_2 the injection will change to liquid phase. This is assumed to be after 11 years of injection for a 3 train plant. It is assumed that new wells will require to be drilled for the liquid phase injection as per the Pale Blue Dot and Axis Well Technology report.

Gas phase injection will require heating on the topsides of the platform. The project team did review other options for shoreline heating or heated pipelines, but found that these solutions were not technically feasible. The electric heating and the electrical supply on the Hamilton platform will require a shoreline substation during the gas injection phase. Once the injection changes to liquid phase a chiller with a refrigeration package will be required at the shoreline station to reduce the temperature of the CO_2 in the subsea pipeline to ensure that it remains in liquid phase until it reaches the platform.

The GBC project has optimised the design of the Hamilton topsides to install only 2.6 MW of heating on the platform on the common CO_2 line to the well header; this has been achieved by including an insulated pipeline to the platform to reduce the pipeline temperature loss. The lower temperature loss requires less heating of the gas before injection. Whilst the solution increases the capital cost of the pipeline it reduces the amount of equipment to be installed on the platform and reduces the operating costs by reducing energy consumption.

The CAPEX estimate only includes drilling the gas wells. The investment for the change from gas phase injection to liquid phase injection is included in the OPEX Report.

Goldeneye and Captain X

The proposed solution for the Peterhead CCS project was reuse of the existing Goldeneye Platform. The higher flow rates for the GBC Project and the larger overall storage capacity compared to the Shell Peterhead CCS project will require a new platform on Captain X in addition to the reuse of Goldeneye.

Goldeneye

The CO_2 will be permanently stored in an underground store comprising the depleted Goldeneye gas field reservoir. The existing unattended production platform will require minimal modifications to be made suitable for the proposed CO_2 duty. The five existing wells, served by the Goldeneye platform, are suitable for conversion to CO_2 injection wells and will provide sufficient injectivity for CO_2 storage.

In practice, three primary injection wells are proposed with one well used for monitoring purposes. The fifth well will be abandoned.

Studies performed both prior to and during FEED indicate that the depleted field store can hold up to 34 Mt CO_2 and is adequate for the PCCS Project's required storage capacity of 15 Mt CO_2 over the 15-year operation period.(Shell UK Limited, 2016) however additional storage over and above this may also be required.

The Goldeneye platform, shown in Figure 30, consists of a four-legged steel structure, connected to the seabed with two vertical steel piles at each corner, that supports a topsides deck structure with a helideck, pedestal crane and vent stack. The jacket and topsides were installed during 2003.

Figure 32 – Goldeneye Platform (Shell U.K. Limited, 2016)

The topsides comprise two deck levels at elevations +22 m and +31.5 m with an intermediate mezzanine deck at elevation +27.15 m. The main plan dimensions of the decks are 31x16 m with the extra length cantilevered out to the west of the jacket, on the opposite side from the wellheads. This cantilever supports the helideck and contains the accommodation, control and equipment rooms.

The current operating weight of the topsides is approximately 1,680 tonnes but the design of the jacket structure allows for a topsides weight of up to 2,000 tonnes.

The jacket structure is a four-legged X-braced structure that was designed to be lift installed. The weight of the jacket is just under 2,500 tonnes.(Shell UK Limited, 2016)

Modification to the Offshore Facilities for PCCS

For PCCS, the operational life of the Goldeneye platform will be extended from 20 years to 35 years for the purpose of injecting CO_2 into the depleted reservoir for long-term storage. During the Execute phase a lifetime assessment will be carried out and based on the outcome of the assessment the facility will be refurbished as necessary to achieve the Project design life of 15 years. The platform is generally in good condition and no major works are anticipated to be required to achieve the lifetime extension.

A number of process and piping modifications are required to adapt the platform and pipeline for this change of use. The structural scope is limited to the offshore modifications to the Goldeneye platform in order to facilitate its change in operation from gas production to receiving and injecting CO_2 into the reservoir.

With the possible exception of strengthening the vent stack support structure, there are no major structural modifications required for this change in operation. The structural scope entails verifying the integrity of the structure for the extended design life in addition to supporting the modifications required by the other engineering disciplines, i.e., provision of access to the CO_2 filters, provision of equipment support trimmers and pipe supports. The estimated weight of structural steelwork additions is circa 23 tonnes.(Shell UK Limited, 2016).

The design of the existing Goldeneye pipeline will allow this pipeline to be used to send CO_2 from St Fergus to the Goldeneye platform. A pipeline condition survey will be needed to confirm the condition of the pipeline.

Captain X

Additional CO_2 storage will also be provided in a saline aquifer at the Captain X location. The injection conditions at this location are relatively similar to those required for the saline aquifer at Endurance, and a similar new build platform design will be used for Captain X to that proposed for Endurance.

CO_2 will be sent to Captain X from St Fergus via the (now redundant) Atlantic pipeline which will need to be extended by about 8km to reach the Captain X location. The design of the existing Atlantic pipeline will allow this pipeline to be used to send CO_2 from St Fergus to the Captain X platform. A pipeline condition survey will be needed to confirm the condition of the pipeline.

The facilities design proposed is (Pale Blue Dot Energy and Axis Well Technology, 2016) for CO_2 to be transported offshore in liquid-phase via an existing 78km 16” pipeline from St.Fergus to the area of the depleted Atlantic gas field and then via a new 8km 16” pipeline to a newly installed Normally Unmanned Installation (NUI), minimum facilities platform on a 4 legged steel jacket standing in 115m of water. During the main operational period, two wells are expected to be injecting at any point in time with the third as backup in the event of an unforeseen well problem. The facilities will inject 3 MT/year of CO_2 for a 20 year project life without breaching the safe operating envelope. The findings from the SAP was that the capacity and injectivity of Captain X is not limited by injection issues but by risks over migration of CO_2 beyond the licensed area. The platform will be operated by satellite links and be capable of operating for up to 90 days between routine maintenance visits.

For the GBC project the equipment on the topsides has been aligned with the other offshore platforms and the use of a W2W access philosophy.

7.2 Offshore Wells

The offshore facility will accommodate a number of wells (CO_2 injectors and for Saline Aquifers a provision for a brine producers). The number of wells for each platform is included below. No new subsurface work was included within the scope of this project: The Injection Rates for wells has been taken from the referenced sources on the table below.

The White Rose CCS Project subsurface information provided a limit on the angle of deviation for wells. The limit on angle of deviation limits the horizontal reach for wells from a single drill centre[31]: it is therefore assumed for the Endurance field that 2 platforms, equally spaced over the aquifer, will be required for a 4 or 5 train CCGT + CCC plant. Each Endurance platform would include future provision for a brine producer complete with space allowance for monitoring, hold up, and discharge (loosely based on produced water treatment).

The Injection Rate per well selected for Endurance is based on (Capture Power Limited - K43, 2016). This may be slightly conservative as a higher platform pressure may result in higher injection rates into the wells. However, the scope of this report did not include subsurface engineering and therefore the project has used the information provided in the KKDs for the White Rose project.

Due to the rate of injection for the Generic Business Case design it is considered a possibility that a brine producer may be required for the Endurance aquifer in order to prevent the pressure in the aquifer rising too much and to allow spread of CO_2. Therefore, future provision has been allowed in the cost estimate for a brine producer, brine hold up and monitoring, and brine discharge: the future provision is topsides steelwork to support future equipment and jacket design with capacity for future weight increase (but not the producer wells themselves and connecting pipelines).

Location	Injection Rate Assumed	Number of Wells Assumed	Source of Injection Rate and Wells
East Coast – Endurance Alpha	1.67 MTPA[32]	3+1 x 5.5” 1 x Provision for Future Brine Producer	White Rose documents K43: Field Development Report and K30 Storage Process Description.
East Coast – Endurance Bravo	1.67 MTPA	3+1 x 5.5” 1 x Provision for Future Brine Producer	White Rose documents K43: Field Development Report and K30 Storage Process Description.
West Coast – Hamilton – Gas Phase	2.50 MTPA	3+1 x 9$^5/_8$”	(Pale Blue Dot Energy and Axis Well Technology, 2016)
West Coast – Hamilton – Liquid Phase	2.50 MTPA	3+1 x 5.5” (new wells)	(Pale Blue Dot Energy and Axis Well Technology, 2016)
Scotland – Goldeneye[33]	1.14 MTPA	3+1 x 4.5”	Offshore Process Flow Scheme – Goldeneye Flows, Compositions and Operating

[31] There is a limit on the deviation for wells into the Endurance reservoir. The Endurance storage reservoir extent is approximately 22km long and 7km wide, and has a vertical depth of about 1100m. Therefore to cover the whole reservoir it is assumed that 2 drill centres will be required.
[32] A maximum rate per well of 2 MPTA but spread over 3 wells for 5 MPTA per platform.
[33] Goldeneye has 5 current wells and 3 spare slots.

Location	Injection Rate Assumed	Number of Wells Assumed	Source of Injection Rate and Wells
			Conditions, PCCS-04-PTD-PX-2366-00001-001, rev K01 & Well Technical Specification, PCCS-05-PT-ZW-7770-00001, rev K03
Scotland – Captain X	1.50 MTPA	2+1 x 5.5”	D13: WP5D – Captain X Site Storage Development Plan, ref: 10113ETIS-Rep-19-03, March 2016, available under ETI open license.

Table 38 – Offshore Wells

The strategy for Hamilton follows the information from the (Pale Blue Dot Energy and Axis Well Technology, 2016) work in that there will be a gas phase injection in order to re-pressurise the depleted reservoir. Once suitably pressurised (approximately 11 years after commencement of operation) then liquid phase injection can be used requiring 4 new wells (3 new liquid injection + 1 spare).

5-4-3-2-1

The largest cost influence to the platforms is the number of wells. Table 43 – Well Costs shows the output from the calculation for the number of platforms and wells depending on the number of trains within the CCGT + CCS plant. (Please note that a spare well has been included per platform in the number of wells in the table.)

7.3 Platform

Each location will be served by a small normally unmanned wellhead platform. The Wellhead Platform will contain the wellheads, injection filtration, metering, and manifolds, utilities, Local Equipment Room (LER), and a muster area with adjacent temporary refuge.

The main deck (weather deck) will incorporate well bay hatches to the well slots and shall have required clearance with no obstructions to allow for external drilling rigs (of the jack-up cantilevered type) to perform drilling, completion, and workover operations un-hindered.

The installation will be controlled from shore via dual redundant satellite links with system and operational procedures designed to minimise offshore visits.

Routine maintenance visits will be scheduled approximately every six weeks to replenish consumables (chemicals, etc.), and carry out essential maintenance and inspection activities. Normal access is envisaged to be Walk to Work. The installation will be capable of operating in unattended mode for up to 90 days: this is longer than the routine visits to allow for delays to scheduled visits to inclement weather or unavailability of the walk to work vessel.

Minimum Facilities Topsides

The topsides would be fabricated as a single lift module.

The topsides module would be multilevel consisting of:

› Main Deck (Weather Deck): platform crane, lay down, communications mast, temporary pig receiver, generator sets, storage tanks, hose reels, temporary refuge. Provision would be provided for laydown of temporary wiring lining equipment;

› Upper Mezzanine: LER, valves;

› Lower Mezzanine: injection manifold, battery room;

› Cellar Deck: Wellhead Xmas Trees, Wellhead Panel & Hydraulic Power Unit, process equipment including (CO_2 heaters – Hamilton), nav aids.

Access to platform will be walk to work (W2W) as opposed to having a helideck (except for the existing Goldeneye which has an installed helideck). W2W is considered a lower risk approach compared to helicopter transfers. Deletion of the helideck removes structural steelwork and safety systems associated with helicopter access.

Equipment and Systems	Description	Endurance	Hamilton	Goldeneye	Captain
Process					
SSIV	Subsea Isolation Valve designed to isolate platform from high pressure CO_2	1	1	Existing	1
SSIV Umbilical J-Tube	J-Tube for umbilical transfer from subsea to topsides. The J-Tube is mounted on the jacket	1	1	Existing	1
TUTU	Topsides Umbilical Termination Unit	1	1	Existing	1
ESD	Platform Isolation Valve designed to isolate platform from high pressure CO_2	1	1	1	1
Fines Filters	To prevent solid particles from the pipelines entering the well bores	2 x 100%	2 x 100%	2 x 100% (Retrofit)	2 x 100%
Injection Manifold	Manifold from Pipeline into wells	1	1	1	1
Wash Water Manifold	Manifold from Wash Water connection into wells	1	1	1	1
Well Heads	Christmas Trees and Dry Well Heads provided for CO_2 Injection Wells	5	4	3 (existing: these are to be recompleted)	3
Brine Production	Christmas Tree, Dry Well Head for Brine Production Well – facilities for monitoring, hold up, and discharge	Future Provision			
Pig Receiver	Temporary Pig Receiver for periodic pipeline inspection / cleaning	1	1	Existing	1
Pre-Injection Heating	Designed to maintain injection pressure above minimum wellhead temperature		1		
CO_2 Vent	Pressure relief and vent to providing emergency and maintenance depressurisation of the	1	1	1	1

Equipment and Systems	Description	Endurance	Hamilton	Goldeneye	Captain
	platform				
Utilities					
Crane	A diesel powered crane will provide loading / unloading and lifting between decks. Crane will also be sized to lift wireline unit on and off the platform	1	1	Existing	1
Diesel System	Diesel storage tank and pumps to supply crane and generators. Any water from diesel tank to be drained to Drains System	1	1	Existing	1
Drains	Drains systems to collect chemicals and oils from the platform (e.g. diesel, lubricants). The drains system will go to a drains tank. The drains tank will be unloaded to the supply vessel during O&M visits to the facility	1	1	Existing	1
Nitrogen	Nitrogen Quad for pressurisation of wells	1	1	1	1
Chemical Injection	Chemical injection for wells (MEG, etc). MEG storage tank will have desiccator in vent to prevent water absorption by MEG	1	1	Pipeline supply of MEG with new Filters	1
Wash Water	Wash Water Skid for washing of wells to prevent halite formation as routing maintenance and following shutdown	Locate package on supply vessel	Locate package on supply vessel	Locate package on supply vessel	Locate package on supply vessel
Hose Reels	Marine hose reels for transfer of Diesel, Wash Water, Chemicals, etc from Supply Boat	1	1	Existing	1
Instrument and Control					
ICSS	Integrated Control and Safety System –	1	1	Existing, Modified for	1

Equipment and Systems	Description	Endurance	Hamilton	Goldeneye	Captain
	designed for remote control from shore			New Service	
CO_2 Metering	Process metering provided on flow onto platform, flow off platform for step outs, and flow per well	Main + connection to 2nd Platform	Main Wells	Main + connection to 2nd Platform	Main Wells
Well Control Panels	Control Panels for Wellhead and SSIV including Hydraulic Power Pack. Includes well monitoring	1	1	Existing	1
Telecomms	Dual redundant satellite links. Platform CCTV, ACS, PAGA	1	1	Existing	1
Fire and CO_2 Detection	Detection of fire in electrical, diesel and power generation area. Detection of CO_2 leaks around the platform.	1	1	1 (New detectors for existing system to detect CO_2)	1
Nav Aids	Aids to Navigation – temporary following jacket installation – permanent installed on topsides. Purpose to identify structure to marine traffic to prevent collision	1	1	Existing	1
Wirelining	Wire line of wells for periodic investigation / intervention	Laydown provision for temporary equipment	Laydown provision for temporary equipment	Laydown provision for temporary equipment	Laydown provision for temporary equipment
Power					
Generation	On platform diesel generation	3 Normally one operating	Standby only – main power from subsea cable	Existing	3 Normally one operating
Transformer	Step down transformer from subsea cable voltage		1		
MV Switchgear	To serve MV loads (Heater)		1		

Equipment and Systems	Description	Endurance	Hamilton	Goldeneye	Captain
LV Switchgear	To serve LV loads	1	1	Existing	1
UPS	Uninterruptible power supply to provide emergency power to essential loads following loss of main power supply	1	1	Existing	1
Facilities					
Temporary Refuge	Emergency refuge for Operations and Maintenance personnel on the platform. Normal philosophy is W2W.	1	1	Existing	1
LER	Local Equipment Room for control and electrical equipment	1	1	Existing	1
Battery Room	Batteries for UPS	1	1	Existing	1
HVAC	Heating and ventilation systems for rooms	1	1	Existing	1
Evacuation	Life rafts for emergency evacuation of the facility	1	1	Existing	1
Safety Equipment	Safety shower, eye bath, first aid, and emergency equipment for the platform	1	1	Existing	1

Table 39 – Topsides Equipment and Systems

The following are the topsides weight estimates for the platforms:

Item	Endurance	Hamilton	Captain X	Unit
Equipment (Mechanical, Electrical, Instrument / Controls, Safety, and Telecomms)	373	435	237	Te
Piping	295	344	282	
Electrical bulk materials.	63	73	60	
Instrumentation bulk materials	127	149	122	
Telecommunications bulk materials	3	4	3	
Architectural	24	24	24	
Structural	2140	2,145	1,877	
Safety & Environmental	2	2	2	
HVAC	29	34	28	
Dry Insulation	4	4	4	
Passive Fire Protection (PFP)	0	0	0	
Painting	25	29	24	
TOTAL	**3,084**	**3,242**	**2,781**	**Te**

Table 40 – Topsides Weight Estimates

The Structural weight includes support and layout for the future equipment identified in the equipment list, ref: 181869-0001-T-ME-MEL-AAA-00-00001.

The figures in the table do not include future or temporary equipment.

7.4 Jacket

The structural steel jacket will support the topsides above the water depth.

A conventional 4-legged Steel Jacket has been assumed as being ALARP for the application. The jacket will be piled to the seabed and will be sufficiently tall to ensure an air gap is maintained between the topsides structure and the 10,000-year return period wave crest height.

The jacket will support the risers, J-tubes, and any caissons, and provide restraint for conductors.

Interface with the topsides will be by use of stab in connections.

The steel jacket will be piled to the seabed and provide conductor guides in conjunction with a 6 slot well bay. The Jacket will be fabricated onshore, loaded onto an installation barge, and towed to site. The jacket installation will be lifted. Mudmats will provide temporary stability once the jacket has been upended and positioned; with driven piles installed and grouted to provide load transfer to the piled foundations.

Corrosion protection will be provided by marine coat (e.g. NORSOK M501) and cathodic protection (sacrificial anodes).

Item	Endurance	Hamilton	Captain X	Unit
Water Depth (LAT)	59	24	115	m
TOTAL JACKET WEIGHT (IN-PLACE)	2,030	1,310	3,790	
Installation Aids (Lift Rigging)	234	158	434	
TOTAL JACKET WEIGHT (INSTALL)	2,264	1,468	4,224	Te
Piles	1,010	480	1,890	
Sea fastenings	55	34	103	
TOTAL	**3,329**	**1,983**	**6,218**	**Te**

Table 41 – Jacket Weight Estimates

7.5 Goldeneye

The Goldeneye platform is already installed.

It is assumed that the platform is generally in good condition and no major works are anticipated to be required to achieve the lifetime extension based on the Key Knowledge Documents for Peterhead.

There are a number of process and piping modifications which are required to adapt the platform for a change of use from gas production to CO_2 injection.

The structural scope is limited: support and access to CO_2 filters and valves and instrumentation. With the possible exception of strengthening the vent stack support structure it is assumed that there are no major structural modifications required.

“The estimated weight of structural steelwork additions is circa 23 tonnes.” (Shell UK Limited, 2016)

7.6 Health, Safety & Environment

	Carbon Dioxide (CO_2) › Danger to life from asphyxiation or toxicity of escaping CO_2 › Major Accident Hazard: The hazard range for an instantaneous release from storage may be in the range of 50 to 400 m with large, cold, liquid phase storage producing the larger distances. The hazard range for a continuous release through a 50mm hole may be up to 100 m.(Dr Peter Harper, 2011)

	› Design in accordance to prevailing wind conditions › Asphyxiation from approx 50% v/v in air. Toxicity > 15% v/v in air (50% fatalities for 1-minute exposure time)(Dr Peter Harper, 2011) › Design to limit inventory of CO_2 in subsea pipeline and offshore platform › Design to maximise natural ventilation and dispersion in order to minimise potential CO_2 accumulation › Design to contain CO_2 (e.g. international design codes) › CO_2 detection, alarm, isolation, and blowdown system › Risk of structural collapse following large release due to cooling effects and dry ice-cold jet effects.(Connolly & Cusco, 2007) › Unmanned offshore facility so there is no permanent workforce on facility. › ALARP design is for 4 leg jacket to reduce risk of ship strike leading to release. › Work on or near the platform will be controlled if maintenance is carried out whilst there is high pressure CO_2 in the topsides. Breathing apparatus and gas detection will be required whilst working on platform.

The following significant hazards have been identified in the design of the CCGT + CCS Scheme:

Area	Hazard	Control
Offshore	Terrorist Attack	Security included in design and estimate: access control and CCTV.
Offshore	Loss of Buoyancy	Risk from escaping CO_2 and loss of buoyancy with risk of ship sinking. Ship approach direction to be controlled.
Offshore	Travel	Helicopter travel is high risk. Substitute helicopter with walk to work transport in order to reduce risk to personnel.

Table 42 – Hazards Relating to Offshore Installation

7.7 Construction Methodology

The Jacket will be fabricated in a fabrication yard.
From the fabrication yard the Jacket will be barged to installation location.
A jacket of this size will be lifted into position, piles installed, and grouted.

Topsides will be fabricated in a fabrication yard.

The topsides will be loaded out onto a barge.
At this size the topsides will be installed by being lifted in position on the jacket.

The injection wells will be drilled by a heavy duty jack up drill rig cantilevered over the wellhead platform.

Pipelines, umbilicals, and cables will be hooked up to platform once installed.

(The exception will be Goldeneye which is an existing facility. A heavy duty jack up rig will recomplete existing wells for injection service).

The platform CO_2 system will be dried and filled with preservation gas.

The wells will be charged with methanol / MEG.

7.8 Commissioning

Commissioning of the platform will be at the end of the chain.

CO_2 will be introduced to the platform and vented until it meets the specification; following this the dry CO_2 will be introduced to the first injection well. Once each well is commissioned the next well will have CO_2 to be introduced in turn.

7.9 Contracting Approach

Offshore Infrastructure

It is assumed that these contracts would be directly with the Owner:

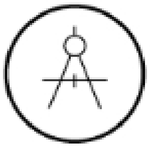
- **Fabrication of platform, jacket, and piles:** this would be fabrication in a yard and would include procurement and installation of equipment on the topsides, and pre-commissioning works on topsides to minimise offshore works. Scope of works would end at load out.
- **Installation of platform, jacket, and piles** for the offshore installation. Contract would include offshore hook up and commissioning. Some contractors may be able to combine with installation of subsea pipeline. Some contractors may be able to combine with fabrication of jacket and topsides.
- **Drilling:** drilling of CO_2 injection wells using a jack up and a cantilevered drilling rig to drill wells through the Well Head Platform.
- **Walk to Work Vessel:** Provision of walk to work (W2W) vessel. This could be a dedicated vessel for the CO_2 Injection Platform, or provision of Walk to Work Vessel services as part of a wider fleet serving other facilities. The assumption made for the GBC is that the W2W vessel would be subcontracted and that the costs are included in the Operating Cost Model and not the Capital Cost Estimate.

The contracts entities will be different from those used for the onshore works because the offshore fabrication and installation require specialist facilities, marine barges, marine vessels, and heavy lift vessels which are not typically available to the contractors undertaking onshore work.

There may be an opportunity to combine fabrication and installation of the platform, jacket, and piles (and this has been done on recent North Sea minimum facilities platforms).

Drilling and W2W Vessels are specialist disciplines which is not combined with other offshore contracts.

7.10 Basis and Methodology of Estimates



Quantities

Equipment for the topsides is included in the equipment list.

The number of injection wells has been estimated from the injection rates established from publicly available information.

Topsides and jacket weights have been estimated from the design conditions for each offshore facility.

Cost Estimate

Costs have been estimated based on quantities.

Equipment costs have been sourced from vendor quotes for similar equipment. Where sizes have changed, parametric models have been built for equipment types (vessels, heat exchangers, pumps), compiling sizing and cost data from many sources to produce factors by which similar equipment quotes could be scaled up or down based on new equipment sizes.

Total equipment costs and weights have been input into a specialised SNC-Lavalin model for estimating offshore facility costs. This model produces jacket and topside weights, bulk material costs, fabrication, transportation, installation, hook-up and commissioning costs.

The offshore costs were reviewed by an independent estimator and compared against industry equivalent data sets.

7.11 Assumptions on Estimates

Pre-FEED and FEED estimates do include well / sub-surface engineering based on available data; Subsurface appraisal work from previous operation, FEEDs, and studies would be utilised. No additional costs for these activities all included in the Front End of the Project. The estimates do not include reservoir investigations. Seismic and drilling activities are not included. Indications (with source) for costs are given on page 5 of Attachment 15.

The offshore facilities are based on market conditions neither too active nor too depressed. For example, it is assumed that installation rig costs will remain stable because as the local offshore industry has recessed; the availability of the installation rigs has decreased, restoring market equilibrium.

Potential changes in steel prices have not been applied to the cost of the jacket or topsides.

One offshore platform is assumed for the Northeast England regions for 1-3 trains, whilst a second platform is added with an infield pipeline for 4 and 5 trains.

For the Scotland location, the Goldeneye platform is to be modified for one train, whilst an additional platform at Captain X is required for 2 and 3 trains with an additional pipeline from shore.

Goldeneye modification costs have been assumed to equal those in the Cost Estimate Report included in the Carbon Capture and Storage Knowledge Sharing resources (Shell UK Limited, 2016).

Wash water equipment package would be purchased by Owner but deployed on W2W or support vessels under OPEX sub-contract.

7.12 Cost Estimate Data Provenance

Offshore costs have been calculated using SNC-Lavalin estimating tools and norms. Equipment costs were estimated using prior project data and equipment weights, water depth, wave height, and other parameters fed into a model to produce topside and jacket sizing. Costs were applied using SNC-Lavalin in-house estimating data and the results were verified by an independent estimator. All costs are Q1 2016.

7.13 CAPEX

Early Engineering Estimates

Please refer to Attachment 15 for the Pre-FEED and FEED Estimate which provides man hours and estimated costs against the different areas of the plant.

Storage – Offshore Facilities

Two separate offsite locations were considered for the estimate, with Teesside, North, and South Humber using the offshore facility Endurance described above, whilst the North West project will employ the use of the Hamilton facility. The cost estimate assumes southern European fabrication and load-out of the jacket and topsides as a cost basis. The estimate assumes current rates for transportation and installation subcontractors and makes no allowances for changes in oil prices affecting demand for specialised labour and equipment or potential political changes that could impact cost.

Offshore Costs by Location and Train

	Offshore Cost (£m)				
Location	**Single Train**	**2 Trains**	**3 Trains**	**4 Trains**	**5 Trains**
North West	184.2	194.4	204.5	n/a	n/a
Teesside + Humber Regions	206.2	222.8	239.4	427.4	444.3
Scotland	272.4	463.6	487.6	n/a	n/a

Table 43 – Offshore Facilities Cost

The overall estimate has been build up based on the jacket and topside weights and priced equipment list and applying established SNC-Lavalin norms and offshore estimating tools to determine detailed costs.

The three North East England locations assume an increase from one platform to two should the plant size be four or five trains to accommodate the increase in CO_2 sequestration required. The additional infield pipeline required for this configuration has been estimated using detailed unit rates for similar work (this is included in the Transportation cost estimate: please refer to Section 6.12).

The North West location requires an additional 24km subsea power cable, which has been estimated using prior vendor quotations for a similar scope of work.
The number of injection wells per train has been calculated based on the anticipated amount of CO_2 per annum. The cost of the injection wells was obtained from Pale Blue Dot data (Pale Blue Dot Energy and Axis Well Technology, 2016).

Injection Well Requirements by Location and Train (all well numbers include one spare well per drill centre).

Number of Wells Required for Train Turndown								Price per Well
Site	**Injection Rate Per Well (MTPA)**	**Number of Trains**	**5**	**4**	**3**	**2**	**1**	
		Total Flow (MPTA)	*10*	*8*	*6*	*4*	*2*	
East Coast – Endurance Alpha	1.67		4	4	5	4	3	£15.2m[34]
East Coast – Endurance Bravo	1.67		4	3	N/R	N/R	N/R	£15.2m
West Coast – Hamilton	2.5				4	3	2	£9.3m[35]
Scotland - Golden Eye	1.14				4	3	3	£22.1m[36]
Scotland – Captain X	1.5				3	3	N/R	£15.0m[37]

Table 44 – Well Costs

[34] Data for Bunter well costs from (Pale Blue Dot Energy and Axis Well Technology, 2016) (Pale Blue Dot, 2015)
[35] Data from (Pale Blue Dot Energy and Axis Well Technology, 2016)
[36] Data from (Shell UK Limited, 2016)
[37] Data from (Pale Blue Dot Energy and Axis Well Technology, 2016)

8 CAPEX Estimate

The overall CAPEX costs have been tabulated for four possible locations and each with multiple train options. Each location estimate is made up of eight (8) major sections, each built up using the methods detailed above. The estimate is based on technical information available up to 15 May, 2017. The following table summarises the costs per section for an example site at a Teesside location for a single train. The following costs represent the base case and contingency and risk elements will be discussed and added in the contingency and summary sections of this report.

8.1 Teesside Site Five Train - Estimated Base Cost

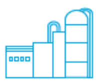
Area	Cost – Single Train (m)	Included
	£2,269	Power Generation Plant
	£2,367	Carbon Capture and Compression
	£303	CO_2 Transportation
	£444	Offshore Storage

Table 45 – Base Capital Cost Estimate Summary

The above costs are base costs and do not include risk or contingency.
The above costs work out as £5,384m for a 3.11 GW performance or £1722 per kW.

8.2 Site Acquisition

Site acquisition costs are included in section 3.8 of this document.

8.3 Early Engineering

Please refer to Attachment 15 for a detailed breakdown of the cost estimate for the Conceptual and FEED phases of the project.

The Pre-FEED engineering has been based on a schedule of 12 months and includes the work required to take the project from feasibility through conceptual design phase. The Pre-FEED cost is estimated as approximately 15% of FEED manhours, but at a slightly higher rate as more experienced consultants and engineers are likely to be employed on such a project. This estimate higher than a benchmark against Caledonia Clean Energy project which received £4.2m from DECC and the Scottish Government for a CCS project at Grangemouth: however, the GBC scheme is larger and requires more offshore infrastructure and so can be expected to be larger, though of the same order of magnitude.

The Pre-FEED cost estimate in Attachment 15 includes Project Management which is expected to be Owner's personnel (although some of this work could be delegated to the Conceptual Design Contractor).

The 18 month FEED+ estimate is based on an analysis of FEED engineering work for similar projects, including Shell Peterhead, White Rose, Kingsnorth, and SNC-Lavalin project experience, which have been referenced in Attachment 15.

The overall Concept Engineering phase is estimated at £7.6 M whilst the FEED+ Engineering cost is £82.4 M. Both the Concept and FEED engineering include Project Management, overheads, and owner's costs associated with each phase of development. The Early Engineering estimate is not site specific and does not change with the number of trains. Early Engineering Costs are not dependent on number of trains because the design is for one linear plant regardless of the number of trains (assuming that the trains are identical and that drawings are not required for each train in FEED to show different tag numbers on each train).

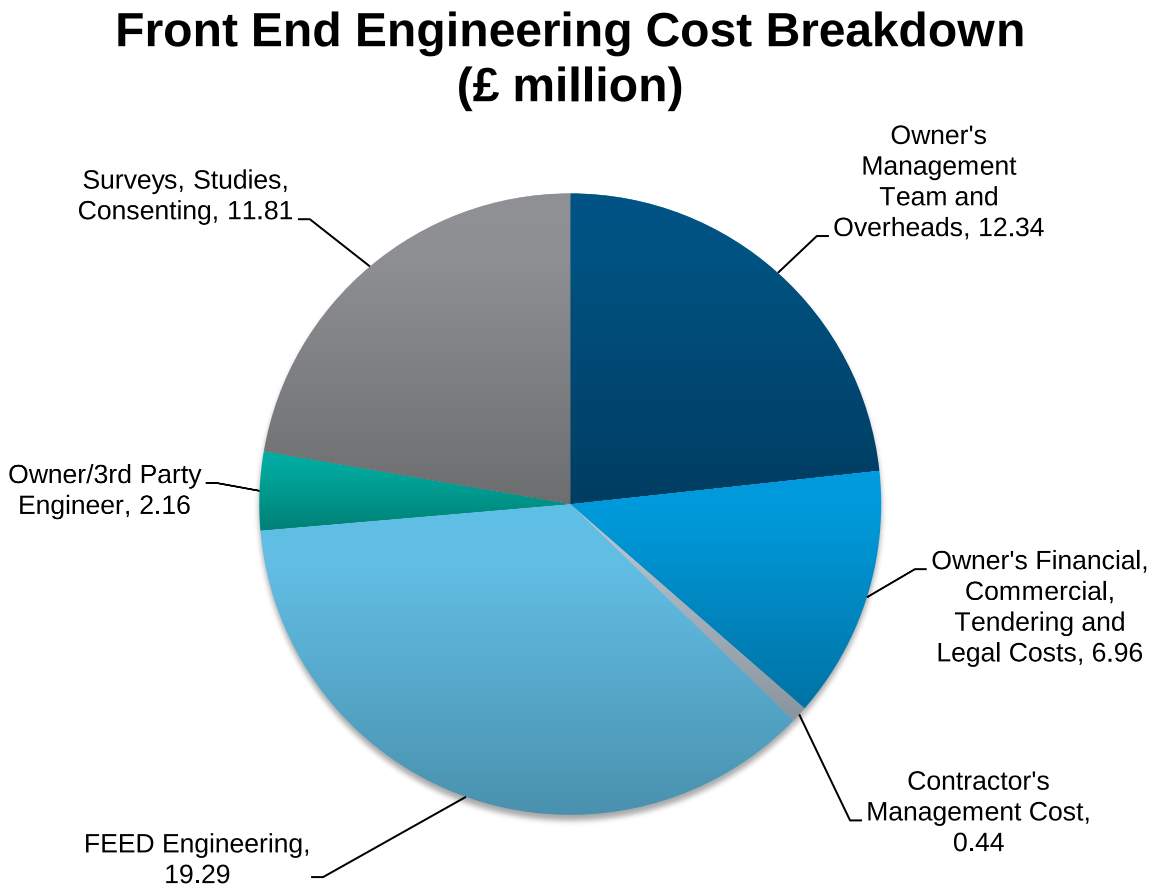


Figure 33 – FEED Engineering Cost Breakdown

FEED phase costs above do include for commercial activities:

- £5.59 million for commercial, financial, and legal costs associated with Terms & Conditions for the supply chain contracts and other services/trading agreements, pursuing land and property agreements, securing project funding, business model.
- £1.37 million for managing the tendering of EPC contracts.

The FEED estimate in Attachment 15 includes columns for the comparison FEED estimate produced by White Rose, Peterhead, Kingsnorth, and Longannet. The GBC scheme is larger and requires more offshore infrastructure and so can be expected to be larger, though of the same order of magnitude, than the comparison FEED studies.

Attachment 15 provides estimates for both a standard FEED and a FEED+. A FEED+ progresses the design and work with major equipment suppliers further than a standard FEED in order to reduce the Owner's risk for the EPC phase of the project. A FEED+ will allow major equipment suppliers to be selected by the Owner and key equipment data built into the design before the EPC phase of the project. (Typically the EPC Contractor has the freedom to select equipment supply, within specification and qualified vendor lists, after the contract award).

8.4 Site Enabling Works

Detailed estimates have been compiled for site establishment works based on the site sizes listed in the Site Acquisition section above. Based on these areas, unitised estimates have been built up for site preparation and earthworks, general contamination removal, cut and fill, and drainage. Additional costs for temporary site facilities, roads, fencing, access and egress, gates, and temporary site services have been established based on the expected workforce and project duration. The total cost of site establishment and enabling for the Generic Business Case is included in section 3.8 of this report.

8.5 Power Generation Plant

The Power Generation Plant Cost Estimate can be found in section 4.13 of this report.

8.6 Carbon Capture and Compression

The carbon capture and compression element of the estimate can be found in section 5.16 of this report.

8.7 Transportation

The transportation element of the estimate can be found in section 6.12 of this report.

8.8 Storage – Offshore Facilities

The offshore facilities cost estimate can be found in section 7.13

8.9 Onshore Facilities and Utilities

Onshore utilities include the effluent treatment package, instrument air package, ICSS, gas and CO_2 metering, and the cooling plants. Facilities include the permanent site buildings, office facilities, substations, and distribution centres required within the plant.

The Onshore Facilities and Utilities cost estimate can be found in section 5.16 of this report.

8.10 Connection Costs

Major connections are required for electricity, natural gas pipelines, and water intake and outfall. The connection costs can be seen in section 4.13, section 5.16, and in attachment 7 of this report.

8.11 Spares

The estimate for the capital and insurance spares follows the sparing philosophy detailed in Section 2.12. Installed spares have been included in the equipment costs for each section. Capital and insurance spares are based on the assumption that the Owner would purchase one set per plant rather than per train.

Estimated Cost of Spares	£ m
Carbon Capture	3.3
Power	13.4
Utilities	0.2
Total	**16.9**

Table 46 – Cost of Capital and Insurance Spares

8.12 Overall Project Base Cost

The overall project base cost is summarised in Figure 34 – Capital Cost Estimate per Region (1 to 5 Trains).

The capital cost estimates for the Teesside, North Humber, and North West / North Wales regions are similar. The Humber region and North West / North Wales region have lower transportation costs than the Teesside region because they are closer to the Endurance Injection Platforms and Hamilton Injection Platforms respectively. However, the Teesside region benefits from the availability of a skilled local construction work force and sub-contract base. The Teesside side selected also benefits from access to dock / quay / shore side which allows extensive modularisation / prefabrication reduces the amount cost / risk / safety exposure on the construction site.

The South Humber region is higher than Teesside, North Humber, and North West / North Wales regions because a tunnel is required for the CO_2 pipeline route under the Humber adding significant cost to the transportation.

Scotland is the most expensive region analysed. This is because the selected site is in Southern Scotland which requires a long pipeline running up the East side of Scotland from the Forth to St Fergus. The cost estimate allows for the reuse of Feeder 10, however, the CO_2 pipeline route requires a new tunnel under the Forth, new above ground installations (AGIs), and compressor stations which add hundreds of millions of pounds to the estimate compared to other locations reviewed by the project team.

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8.13 Base Cost per Kilowatt

Project cost by kilowatt has been calculated to allow for an easy comparison of CAPEX investment between sites and number of trains. The output is based on the table in section 4.3.

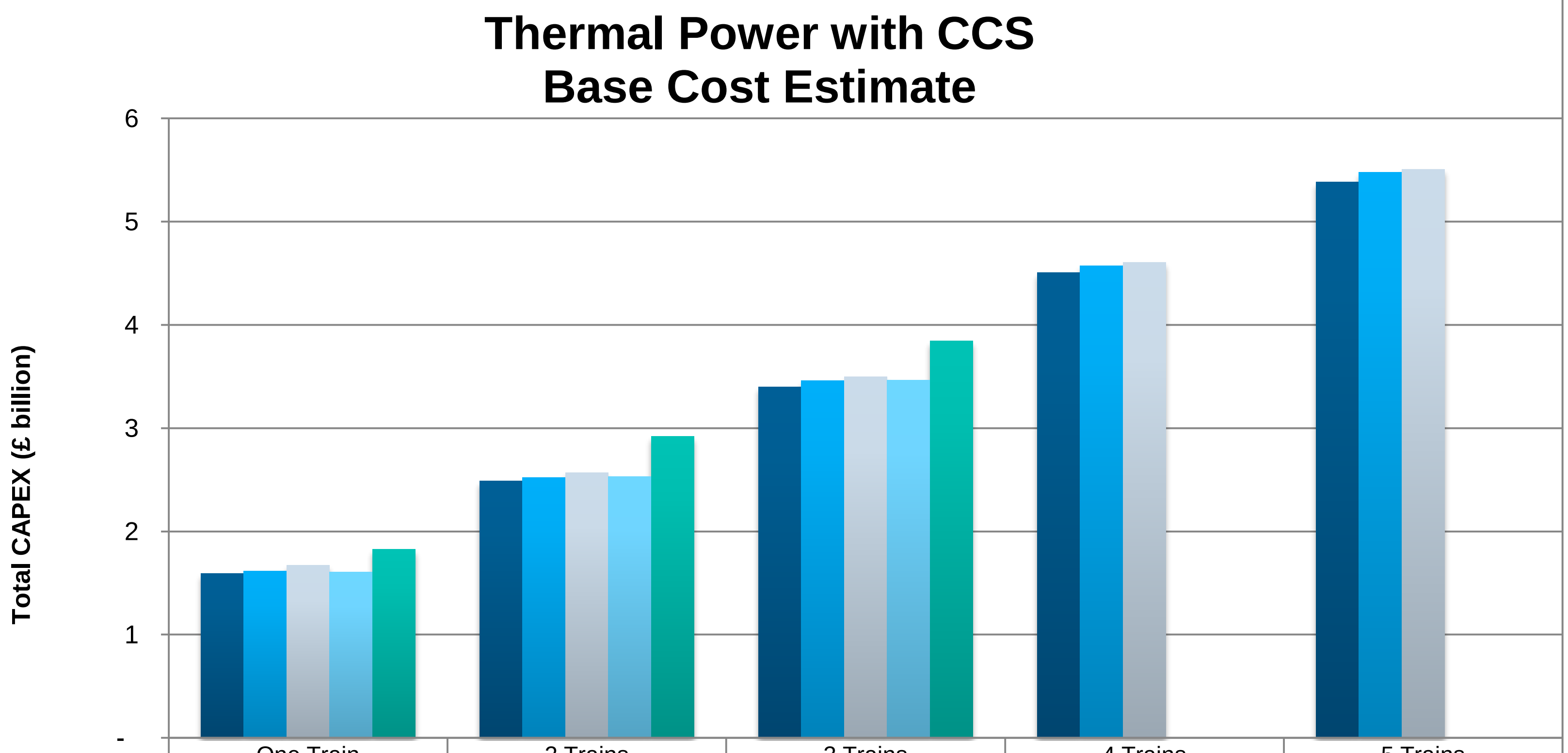
Location	One Train	2 Trains	3 Trains	4 Trains	5 Trains
Teesside	2,567	2,003	1,825	1,813	1,733
North Humber	2,605	2,031	1,856	1.840	1,763
South Humber	2,690	2,068	1,876	1,853	1,773
North West	2,586	2,037	1,859		
Scotland	2,945	2,350	2,063		

Table 47 – Plant Cost per kW

The most significant improvements in cost occur between one train and two. The following curves suggest a diminishing return on greater numbers of units as the connection costs and offshore facility costs increase. The initial cost savings is due to engineering savings on CCGT and CCC for 2 and more units, with the greatest savings between 1 and 2 trains, and costs which are constant or increase only incrementally, such as site acquisition, site enabling, connections, and spares, being spread across a greater output.

The costs for transportation do not show a large increase between a 1 train scheme and a 5 train scheme (approximately 35% increase); this is because much of the cost of installing the linear nature of a pipeline is similar for a large pipeline as for a smaller. Also, as the flow passes through the cross sectional area of a pipeline an increase in flow has a lesser effect on the diameter of the pipeline (a square root function).

There is a considerable increase in the storage costs between a 1 train scheme and a 5 train scheme (approximately double): this increase is dominated between 3 trains and 4 trains by the need for an additional offshore platform cost.



	One Train	2 Trains	3 Trains	4 Trains	5 Trains
Teesside	1,595,291,611	2,489,940,165	3,401,919,532	4,506,244,362	5,384,127,335
North Humber	1,619,089,150	2,523,816,295	3,459,235,010	4,573,103,438	5,479,361,530
South Humber	1,671,695,800	2,570,079,434	3,497,688,566	4,605,611,283	5,507,542,893
Northwest	1,607,127,426	2,531,261,149	3,465,034,464		
Scotland	1,829,979,882	2,920,208,044	3,845,886,483		

Figure 34 – Capital Cost Estimate per Region (1 to 5 Trains)

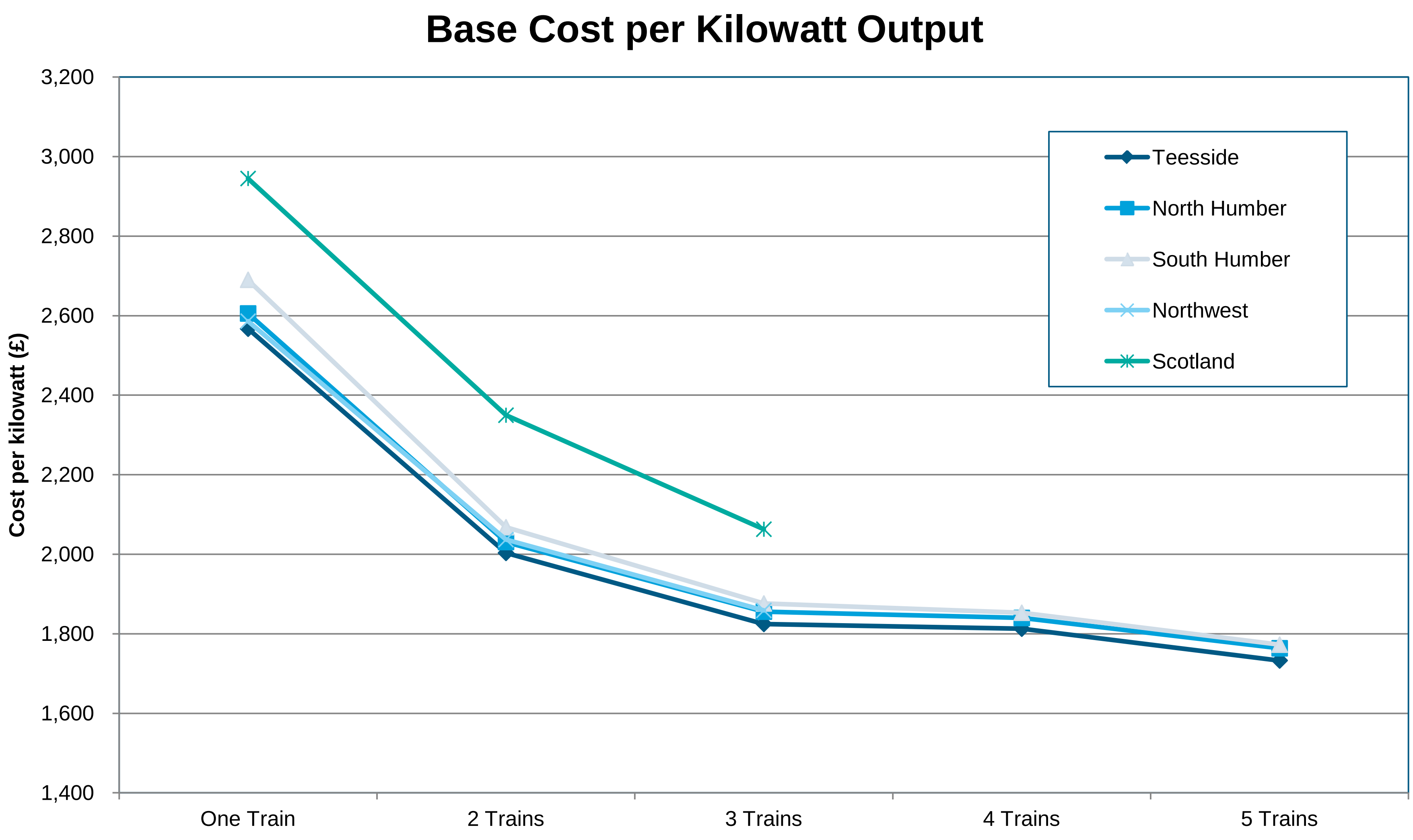


Figure 35 – Base Cost Per kW

8.14 Uncertainty

Three levels of uncertainty have been reviewed within this estimate: contractors' contingency, project contingency, and project risk.

The contractors' contingency is included as an amount expected to be within EPC contractor tenders. This includes detailed design allowance, small changes between FEED and detailed design that do not constitute a scope change, and inclement weather delay. Contractor's contingency has been included in the Base Cost estimates within contractor's soft costs at a rate of 10%.

Project Risk considers events that may have an impact on project cost or schedule but are not considered as part of the project estimate. These may include changes to regulations, unexpected geotechnical survey results, or an unexpected problem with a supplier, such as insolvency.

Project contingency should be added to account for the lack of definition at the time the estimate was prepared. Theoretically, with enough data, time, and resources, no contingency would be required. It is intended to adjust for changes in material and equipment costs and labour overruns.

Project Risk

A risk register has been developed based on SNC-Lavalin Risk Management Procedures. A Risk workshop was held to determine the high-level risks facing the project were defined. The risk register was then updated based on SNC-Lavalin risk registers for prior projects as well as risk data available from the KKD's. The top five risks identified are as follows:

Exposure Category	Risk Description	Risk Level
Market Conditions	High project risk if market is 'hot' and costs of labour and materials are all at the high end of the assessed range	Extreme
Construction	Connection routing may require significant adjustment as a result of geotechnical and topographical survey results	High
Technical	Plant may not meet performance requirements requiring additional time and resources to remedy	High
Construction	Interface Complexity may cause delay	High
Procurement	Steel prices are at an all-time low. Increases would result in a significant impact on the project cost.	High
EPC	Due to significant activity in the UK infrastructure sector, availability of labour and civils contractors may be limited	High

Table 48 – Top 5 Risks

Potential opportunities have also been evaluated and considered in the overall risk value. The most significant opportunities are as follows:

Exposure Category	Opportunity Description	Potential value
Procurement	Other than the gas turbine, no buy-down discounts have been considered in the project as the uncertainty is too great at this project stage. Potential opportunities exist to secure buy down discounts with suppliers.	£10m
Technical	There is potential for a better engineered solvent solution as this technology advances, which could reduce some equipment sizing and cost.	£6m
Geotechnical	Estimate assumes very rocky or very wet, sandy ground conditions. More favourable conditions could result in a cost savings on piling and foundations work	£2m

Table 49 - Opportunities

Each risk item was assessed to estimate a potential consequence, a probability of occurrence, and the manageability of the risk.

The risk consequences range from very low to very high, and may also be overridden with specific values should the data exist. The consequence range is defined as a percentage of overall project value as follows:

Risk Level	Minimum	Maximum
Very High	1.0%	n/a
High	0.75%	1.0%
Medium	0.5%	0.75%
Low	0.25%	0.5%
Very Low	0%	0.25%

Table 50 – Consequence of Risks

A probability figure is assigned to each item assessed based on the project team's belief that a particular item may change. A high probability reflects a well-defined scope, unlikely changes to design in that area, and good sources of estimating data. At the concept stage of a project, lower values for probability are likely as the project scope is not clearly defined (ie. no material take offs to estimate bulk materials, further engineering likely to impact some equipment sizing).

Manageability is assessed to highlight the team's belief that the risk may be mitigated with additional planning and efforts. These three values are combined to calculate the risk's probable consequence.

The data from the risk register was then put through a Monte Carlo simulation to determine the likely values associated with the risks. From this, P10/P50/P90 risk values were calculated. These are added to the contingency values and applied to the base case estimate to obtain the P10/P50/P90 estimate values.

Summary statistics - Overall	
Risk factor required for 90.0% confidence	11.3%
Risk factor required for 50.0% confidence	6.8%
Risk factor required for 10.0% confidence	4.1%

Table 51 – Risk Factor for Difference Confidence Levels

The full risk register and risk profile calculations can be found in Attachment 14.

Project Contingency

Contingency has been estimated to cover the undefined items of work that may have to be performed or the unexpected cost of items of work within the defined scope of work. The contingency costs by definition include items that may not be reasonably foreseen due to incomplete engineering, areas with a high probability of modification, or items that may change due to lack of data or change in local conditions.

The contingency percentage was chosen through a probabilistic approach and the judgement and experience of the project team. The amount of contingency may vary for the different areas of the estimate, such as engineering, procurement of equipment, bulk materials, contractor management, fabrication, and offshore installation, and each area has been weighted to determine the overall contingency value.

The deterministic approach requires three assigned values against each assessed item; minimum value, most likely, and maximum value. The 'most likely' value is the deterministic estimate used to calculate the base cost.

The assignment of the accuracy range represents the possible consequence of a change in the value of the estimate item. The estimate was assessed piece by piece and an accuracy range was assigned to each piece of equipment or group of equipment (ie. CCC pumps) based on the source of the estimating data. Bulk materials, engineering, and overhead costs have also been reviewed. As an example, an estimate derived from a prior project vendor quotation would have the lowest contingency range, a factored vendor quote slightly more, and an estimate based on norms or benchmarks would have the highest contingency value. These accuracy ranges are generally from -5%/+15% to -15%/+35%, with a few outliers. The application of the accuracy figures results in a skewed distribution, as the estimates are assumed to have a greater tendency toward upward movement than downward.

Once each item has been assessed and contingency values applied, the data is run through a Monte Carlo analysis to determine the P10/P50/P90 values of contingency to be added to each area of the estimate. The contingency will be assessed as an overall figure as well as summarised by project area ie) Power Generation, Carbon Capture, Offshore.

Summary statistics – Overall Project Contingency	
Probability of meeting base case value	1.03%
Contingency required for 90.0% confidence	6.4%
Contingency required for 50.0% confidence	3.8%
Contingency required for 10.0% confidence	1.6%

Table 52 – Summary of Contingency

The P50 is higher than the deterministic base cost because the cost distribution is skewed towards the higher cost values.

Further contingency statistics by area can be found in Attachment 14.

8.15 Foreign Exchange Consideration

Foreign exchange in this estimate has been applied to equipment costs for which the vendor quotations were provided in US dollars or Euro. Foreign exchange rates at the time of estimation were chosen based on live rates listed on xe.com, Due to the uncertainty around procurement and project execution dates, forward contract pricing was unavailable. The foreign exchange rates used were 1.28723 USD/GBP and 1.13077 EUR/GBP.

The project cost is only slightly sensitive to fluctuations in the pound against the Euro and US dollar. The following table depicts the percentage change in project cost based on percentage changes in both USD and EUR against GBP.

		EUR/GBP				
		-10%	**-5.00%**	**0**	**5.00%**	**10%**
USD / GBP	**-10%**	-2.4%	-2.0%	-1.7%	-1.4%	-1.2%
	-5%	-1.5%	-1.1%	-0.8%	-0.5%	-0.3%
	0%	-0.7%	-0.3%	0.0%	0.3%	0.6%
	-5%	0.1%	0.4%	0.7%	1.0%	1.3%
	10%	0.7%	1.1%	1.4%	1.7%	2.0%

Table 53 - Foreign Exchange Sensitivity

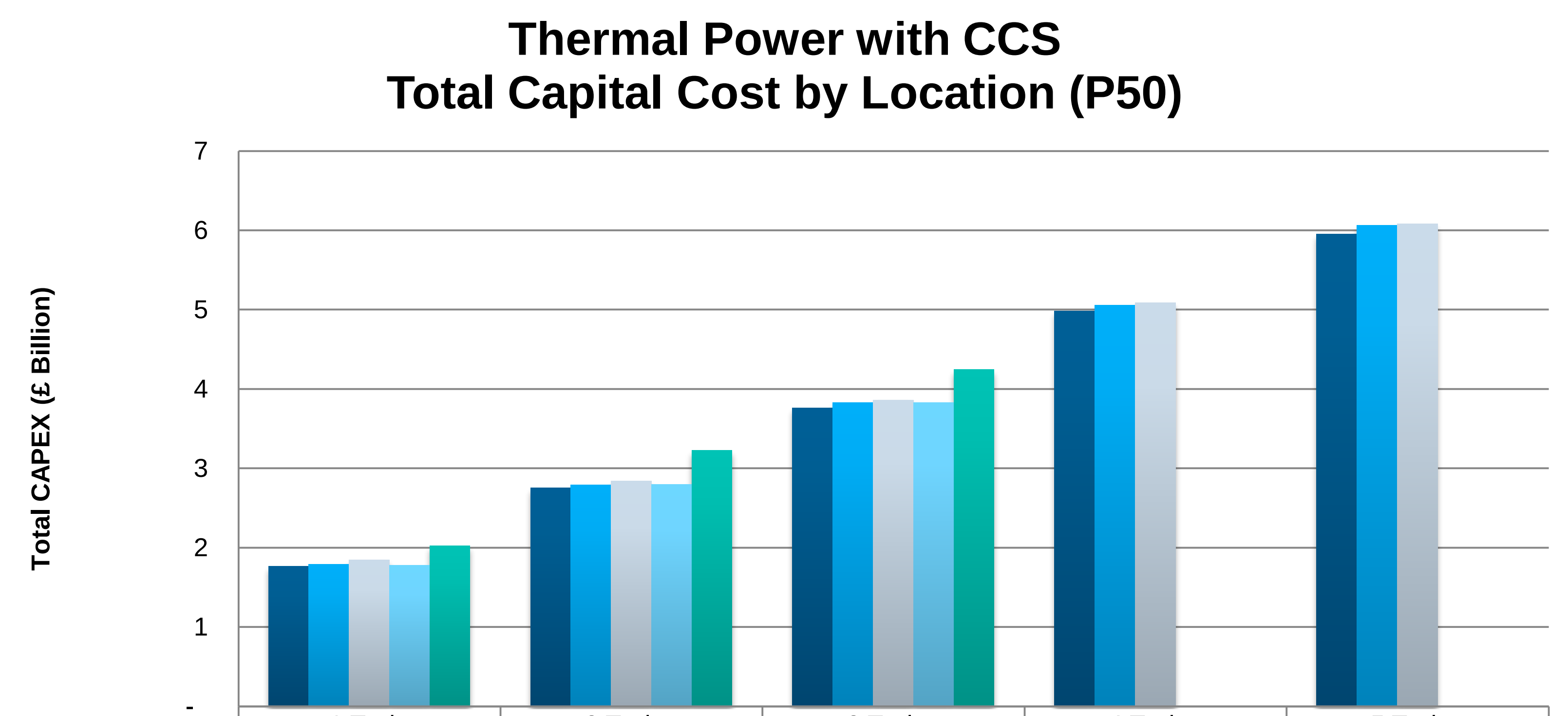
8.16 Overall Project Cost including Contingency

The following table is an example of the overall project cost with the Teesside location and Endurance platform,

Thermal Power with CCS	One Train	2 Trains	3 Trains	4 Trains	5 Trains
Power Generation (CCGT)	576,963,960	1,012,492,216	1,438,301,613	1,857,181,526	2,269,390,994
Carbon Capture	587,653,211	1,021,007,690	1,469,530,209	1,917,939,705	2,366,998,920
CO_2 Transportation	224,488,663	233,640,883	254,674,734	303,388,525	303,389,214
Offshore Storage	206,185,776	222,799,376	239,412,976	427,734,607	444,348,207
Total	1,595,291,611	2,489,940,165	3,401,919,532	4,506,244,362	5,384,127,335
Risk and Contingency	**One Train**	**2 Trains**	**3 Trains**	**4 Trains**	**5 Trains**
P50	1,764,392,521	2,753,873,823	3,762,523,003	4,983,906,265	5,954,844,832
P90	1,874,467,642	2,925,679,694	3,997,255,450	5,294,837,126	6,326,349,618

Table 54 – Over Project Capital Cost (Teesside)

Details of each site cost breakdown can be found in Attachment 11.



	1 Train	2 Trains	3 Trains	4 Trains	5 Trains
Teesside	1,764,392,521	2,753,873,823	3,762,523,003	4,983,906,265	5,954,844,832
North Humber	1,790,712,600	2,791,340,822	3,825,913,921	5,057,852,402	6,060,173,852
South Humber	1,845,552,163	2,837,367,695	3,861,448,177	5,084,594,857	6,080,327,354
Northwest	1,774,268,678	2,794,512,308	3,825,398,048	-	-
Scotland	2,020,297,789	3,223,909,681	4,245,858,678	-	-

Figure 36 - Total Cost by Location - P50

8.17 Scheduling of Project Costs

A high level schedule has been developed for the project which can be found in Attachment 12. This schedule was developed following discussions with OEMs, planning carried out for the Shell Peterhead projects, and information from the KKDs.

The philosophy for schedule is high level for the purposes of this study. The schedule is driven by 2 main critical paths:

- time to CCGT mechanical completion for which there is experience to advise and
- staggered absorber construction

Onsite lay down, offices, and lay down is outside these areas. There is a year between the end of the absorbers completion and CCS mechanical completion.

The schedule has been built up from the experience within the project team, advice from CCGT OEMs, and publicly available information.

The schedule for the Jacket and Topsides is based on a recent North Sea project for which SNC-Lavalin provided engineering and detailed design services, and for which the Jackets and Topsides weights were comparable. The schedule in Attachment 12 of this document attempts to meet the weather windows for the North Sea in order reduce the cost and risk of installation by heavy lift vessel.

The connections, pipelines, offshore, and drilling fit within the time frame: they are not on the critical path for a 5 train plant.

There is a reduction of approximately 2 months for each of the 4-3-2-1 train plants. A more detailed analysis of the schedule is not possible with the current level of definition at this stage of the project development.

At a high level this can be summarised as follows:

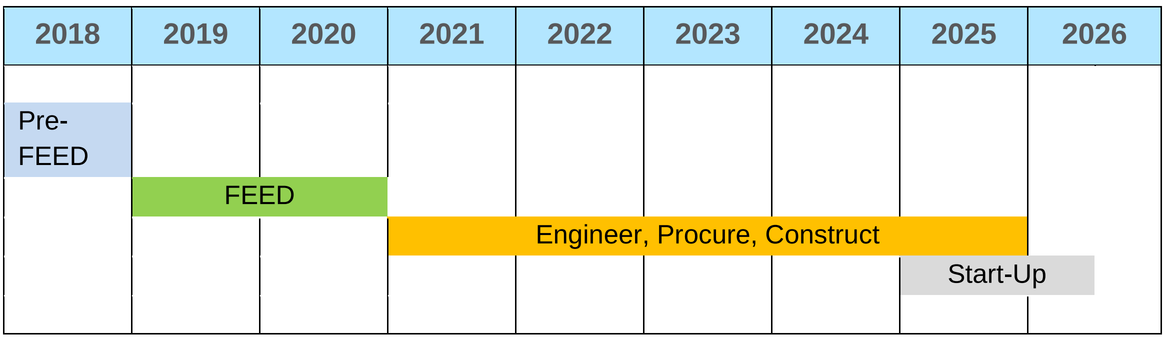


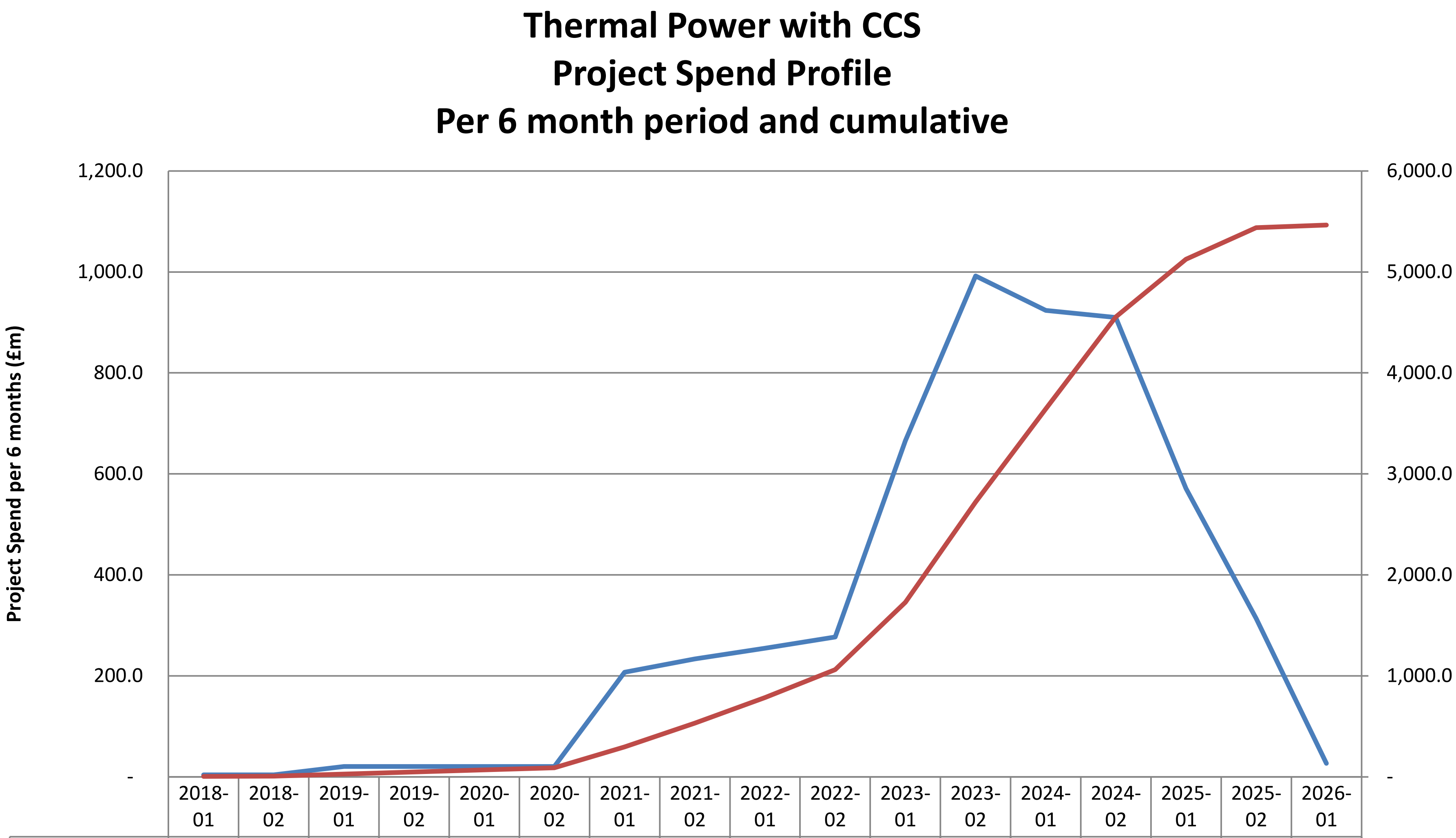
Figure 37 – High Level Project Schedule

The schedule has been used to develop the cost estimate:

- Duration of Pre-FEED
- Duration of FEED

- Duration of Construction:
- Estimate of Manning Levels
- Car Parking, Laydown, and Surface Transport estimate
- Construction Offices and Welfare estimate (both magnitude and time based)

The project costs for a 5-train plant have been scheduled for the duration of the project (base cost for the Generic Plant Design without risk and contingency):



	2018-01	2018-02	2019-01	2019-02	2020-01	2020-02	2021-01	2021-02	2022-01	2022-02	2023-01	2023-02	2024-01	2024-02	2025-01	2025-02	2026-01
Per period	3.8	3.8	20.6	20.6	20.6	20.6	207.1	233.4	254.5	277.2	666.0	992.0	923.9	909.7	571.2	313.4	26.6
Cumulative	3.8	7.6	28.2	48.8	69.4	90.0	297.1	530.5	785.0	1,062	1,728	2,720	3,644	4,553	5,124	5,438	5,464

Figure 38 – Project Spend Profile

8.18 UK Content

The project team were asked to assess the potential UK content for a Generic Business Case Scheme. This was difficult to determine. The currency portions of the cost estimate give an indication:-

- GBP = 83%
- USD = 12%
- EUR = 5%

Most of the significant machinery for the project will be sourced either in USD or EUR from North America or European supply. Significant fabricated equipment is typically sourced abroad because of the lower cost of manufacture, and this equipment is typically priced in USD even if being supplied from the Middle East or Far East. However, the manufacturing capability of the UK should not be overlooked and there is opportunity for the cost effective supply of smaller machinery and fabrication equipment from within the UK. This would also be of benefit to helping manage Brexit and Foreign Currency uncertainties related to project execution.

The GBP portion of the work would not all be manufactured or supplied from the UK: this is because equipment, material, and services may be priced in GBP and sold in the UK, but actually supplied from abroad: this makes the actual assessment of UK content difficult. The UK has sufficient expertise to delivery virtually all of the engineering, project, and construction management for the project. There may be an opportunity for lower cost detailed design work in lower cost engineering centres around the world, and most of the large EPC Contractors have source engineering and design services from their offices around the globe. However, knowledge of UK regulatory and consent requirement will be required and this is best supplied within the UK.

Much of the GBP portion of the work will be direct or sub-contract construction and material. The construction labour can only be supplied within the UK at the job site unless there is opportunity for modularisation and pre-fabrication (see previous sections in this report on the topic). The UK content of the project is increased by the selection of slip form concrete absorbers for the project as these have to be built on the UK construction site.

9 Benchmarking

9.1 Summary

This section seeks to benchmark the cost estimates and performance from the Generic Business Case scheme to ensure the credibility of the work that has been undertaken.

9.2 Combined Cycle Gas Turbine (CCGT)

SNC-Lavalin has the following cost benchmarking data for CCGT Plants developed from Market, Proposal, and Project Information. The data consists of actual cost data (built) or project cost data (future) for UK CCGT Plants with the exception of Bouchain which provides a French Class H CCGT cost (note that French construction conditions / costs will vary from UK equivalent). The data has been normalised to 2016 for comparison. Key projects have been pointed out in the data.

The Generic Business Case cost estimate has been added in green.

For the latest capacity auctions CCGT project developers claim to have been driving benchmark project costs from £700/kW down to £500/kW (Stokes & Spinks, 2015). Conversations within the Power Generation industry have confirmed similar figures achieved by using largest available frame size machines: however, there is scepticism as to whether figures as low as £500/kW can be achieved in practice. The unabated power generation size for the Generic Business Case design is 3.58 GW net. Using the benchmark figures above this would give:

- Maximum @ £700/kW for 3.58 GW plant = £2.506B
- Minimum @ £500/kW for 3.58 GW plant = £1.790B

£700/kW and £500/kW lines have been added to the following graph to compare against the data.

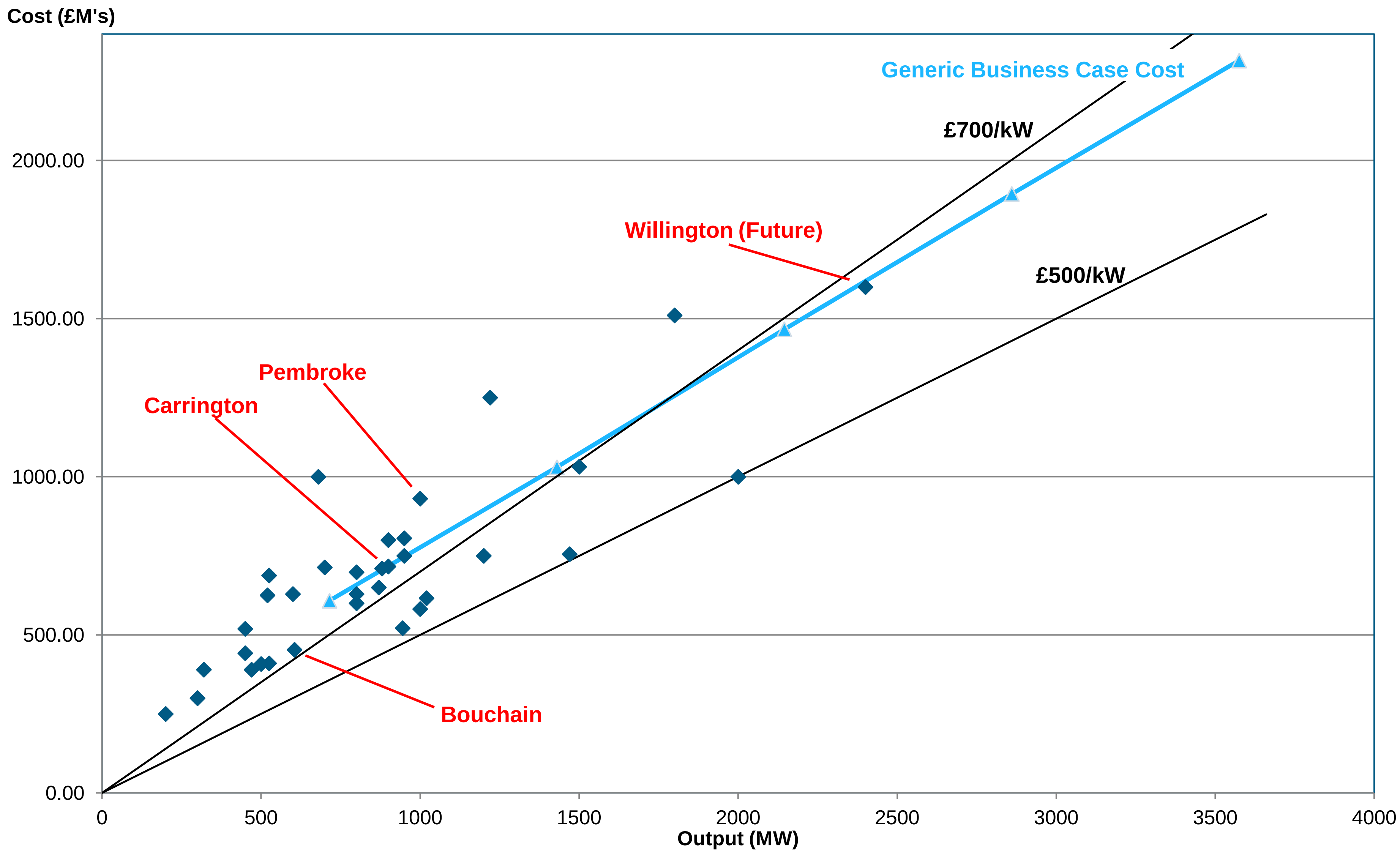


Figure 39 – Cost Benchmarking Data for UK CCGT Plant

The Generic Business Case estimates for 1 to 5 trains has been superimposed on the Cost Benchmarking data and shows a cost estimate for 5 trains of £2,316M or £647/kW. It should be noted that the GBC data includes the electricity export connection, the natural gas pipeline connection, and a proportion of water make up and return connections.

PEACE cost modelling was carried out by SNC-Lavalin's Power Generation Team: a summary of this cost estimate can be seen in Appendix 3 of Attachment 4 to this document. The PEACE model is for a single CCGT train without connections resulting in an estimate of £647/kW. The equivalent cost estimate for the GBC is £608M or £850/kW. The higher cost estimate for the GBC shows the impact of applying UK labour rates and productivity to the estimate.

At the smaller sizes (1 to 3 trains) the GBC costing appears to be a reasonable fit with the available benchmark data for CCGT plants. The cost curve for the GBC does pass through the cost estimate for Willington CCGT indicating the cost estimate is not unreasonable between a 3 and 4 train power generation facility. It was however expected before the cost estimates were compiled that there would be greater economies of scale with the larger GBC plant sizes (4 to 5 trains). However, the cost estimate was higher than had been assumed. This may be because at the larger size the GBC design is not a direct comparison with any of the CCGT plants which form the data for the benchmarking. The layout of the GBC CCGT trains are more widely spread than is normal for CCGT plants because the Carbon Capture units set the spacing between trains: CCGT plants tend to have a much tighter layout. The plant layout is also larger with the cooling towers being separated from the power plant due to the space taken up by the Carbon Capture units and the site facilities are moved well away from the High Hazard CO_2 areas of the plant: these factors add additional cost to the CCGT design of the GBC when compared to alternative sites because of the additional site area, connections, ground works, and roads.

The cost of the external connections may be higher than initially expected for the 4 and 5 train GBC plants because of the size required: this means that for many of the locations the natural gas, HV electricity, and water connection lengths may be longer to find a connection point with capacity to match the needs of a 3.58 GW (unabated) CCGT Power Plant than for a smaller plant where a local connection point might be available.

9.3 Carbon Capture and Compression (CCC)

SNC-Lavalin has the following cost benchmarking data for post combustion amine CCC Plants developed from market, proposal, and project information. There is not much commercial scale post combustion amine capture plant data available for analysis. Labels have been used to identify the stage of the project from which the data is collected. The FEED and Study data and the EPC estimate are from UK projects. The EPC project data is publicly available information for a Canadian and a US project.

The GBC project data has been added to the graph as a cost per train – the higher cost being for 1 train and the lower cost being the cost per train for 5 trains (benefitting from economy of scale).

It should be expected that larger plants are more expensive than small capacity plants as larger equipment and pipe work is required. The FEED cost estimates compared to EPC Estimate and EPC Project information suggests that the FEED / Study data is lower than expected (optimistic).

The project team is very familiar with the Shell Peterhead CCS Cost Estimate. SNC-Lavalin developed Build, Own, Operate (BOO) and EPC cost estimates for this project; these are important sources of information as they are for a UK CCS project. A rough rule of thumb is the estimating six tenths rule where if a ratio is known a cost estimate can be escalated to a new size.

$$Cost * (Ratio)^{0.6}$$

Applying this to the Shell Peterhead CCS overall Owner's cost = £415M * $(1.66)^{0.6}$ = £562M.

Whilst this is a very rough estimating approach it shows that GBC cost estimate is in the right area: the cost per train falls from this benchmark as there are savings for multiple trains such as common facilities and utilities.

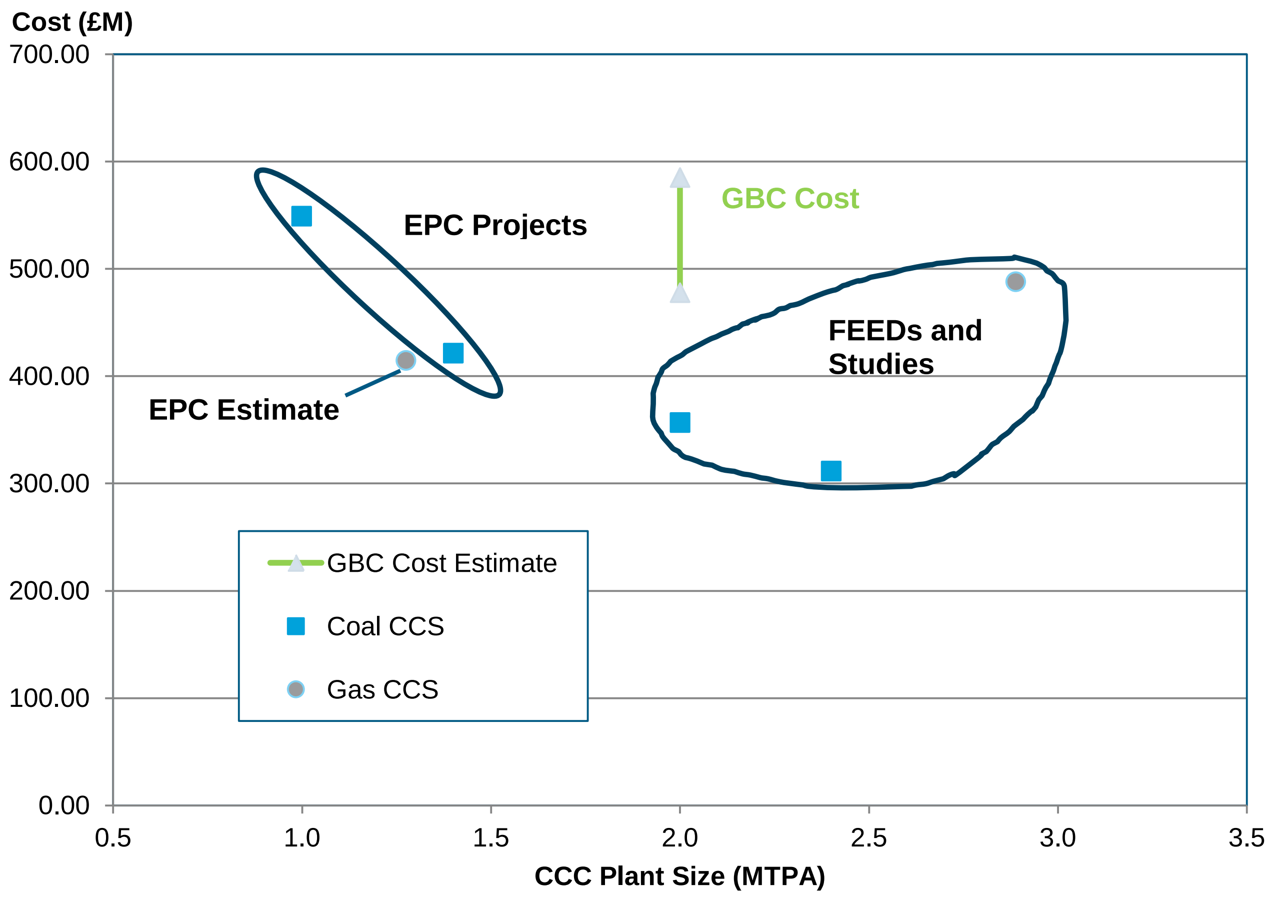


Figure 40 – Cost Benchmarking Data for Post Combustion Amine CCC Plants

The GBC carbon capture and compression unit is designed to export CO_2 at 184 bar. The export pressure is higher than the equivalent schemes which will require some additional cost for the GBC compared to the benchmarks, although this will be only of the order of £10m per train within the compression unit.

Coal vs. Gas Fired Plants

It should be noted that there could be a difference between a post combustion carbon capture unit for a coal fired and gas fired power station due to the concentration of CO_2 in the flue gases: this difference affects the flue gas path and the related carbon capture equipment but not the Amine Solvent Equipment nor the Compression plant which are sized on CO_2 flow.

Equipment affected in the Flue Gas Path:

- Flue Gas Ductwork
- Blower
- Direct Contact Cooler
- Absorber

The lower concentration of CO_2 in gas turbine exhaust gas could mean that a relatively higher solvent flow is required for a given mass of CO_2 captured compared to the flue gases from a coal fired plant: therefore heat and some power inputs are relatively higher, heat exchangers etc are larger, and possibly the stripper column too (although the stripper dimensions will also be a function of the amine formulation).

The effect of this is that Peterhead CCS becomes the better benchmark for the GBC as this project was for post combustion capture for a CCGT and was to be located in the UK.

9.4 Transmission & Storage

Onshore Pipelines

There is a wealth of data within SNC-Lavalin, in KKDs, and from Published Sources such as the IEAGHG Upgraded Calculator for CO_2 Pipeline Systems for Carbon Capture Transmission Systems. A lot of this information is for North America.

The IEAGHG CO_2 Pipeline Infrastructure report provides a benchmark for high population density pipeline installation of approximately £50,000/km-in (inflation has been applied to 2011 data to generate this number for 2016 comparison). This is a minimum cost benchmark as it does not include the costs for crossings or connections. The data in the table below shows that the pipeline estimates are above this minimum benchmark.

A similar benchmark of £61,036/km-in is available using an approach from Petroskills(Hairston & Moshfeghian, 2013) and the GBC project data.

Site	Teesside & Humberside 5 Trains and North West 3 Trains				
	Cost Estimate	Size	Length (km)	£/km-in	£M/km
Teesside	£2,388,947	24”	1.6	62,212	1.5
North West	£90,394,162	24”	53.7	70,138	1.7
North Humber	£23,260,173	24”	17.9	54,144	1.3

Table 55 – Onshore Pipeline Costs

The estimate for Teesside is higher than the benchmark due to the connections adding significant cost to a short length of pipeline. The North West pipeline estimate is higher than the benchmark due to the higher proportion of number of crossings compared to North Humber (length ratio = 3.0, whereas crossings ratio = 4.4). The South Humber pipeline is not benchmarked as the estimate is higher due to the cost of the Humber Crossing: however, the pipeline cost estimate uses the same method as the other onshore pipelines and follows the same route to the coast as for the North Humber pipeline. The Scotland pipeline is not benchmarked as the majority of the pipeline routing is reuse of existing pipelines.

Although natural gas pipelines are not identical in design to those used for CO_2 they can provide a useful benchmark for estimates within the UK for onshore pipelines. The South Wales Pipeline cost around £700M, at 48", and with a length of 317km, provides a benchmark of £58,000/km-in (allowing for inflation to 2016).

The data below is from UK CO_2 pipeline estimates. For example a crude benchmark from our data would be £2.2M/km onshore: however, it would depend upon a size, capacity, and length. A near coast pipeline would benchmark at £1.1M/km: this benchmark is confirmed by CO_2 – Transport – Design of Safe and Economic Pipeline Systems. (Kaufmann, 2009)

It can be seen from the above table that the pipeline cost estimates fall between the £1.1M/km and the £2.2M/km benchmarks for pipelines between close to shore and deeper in land.

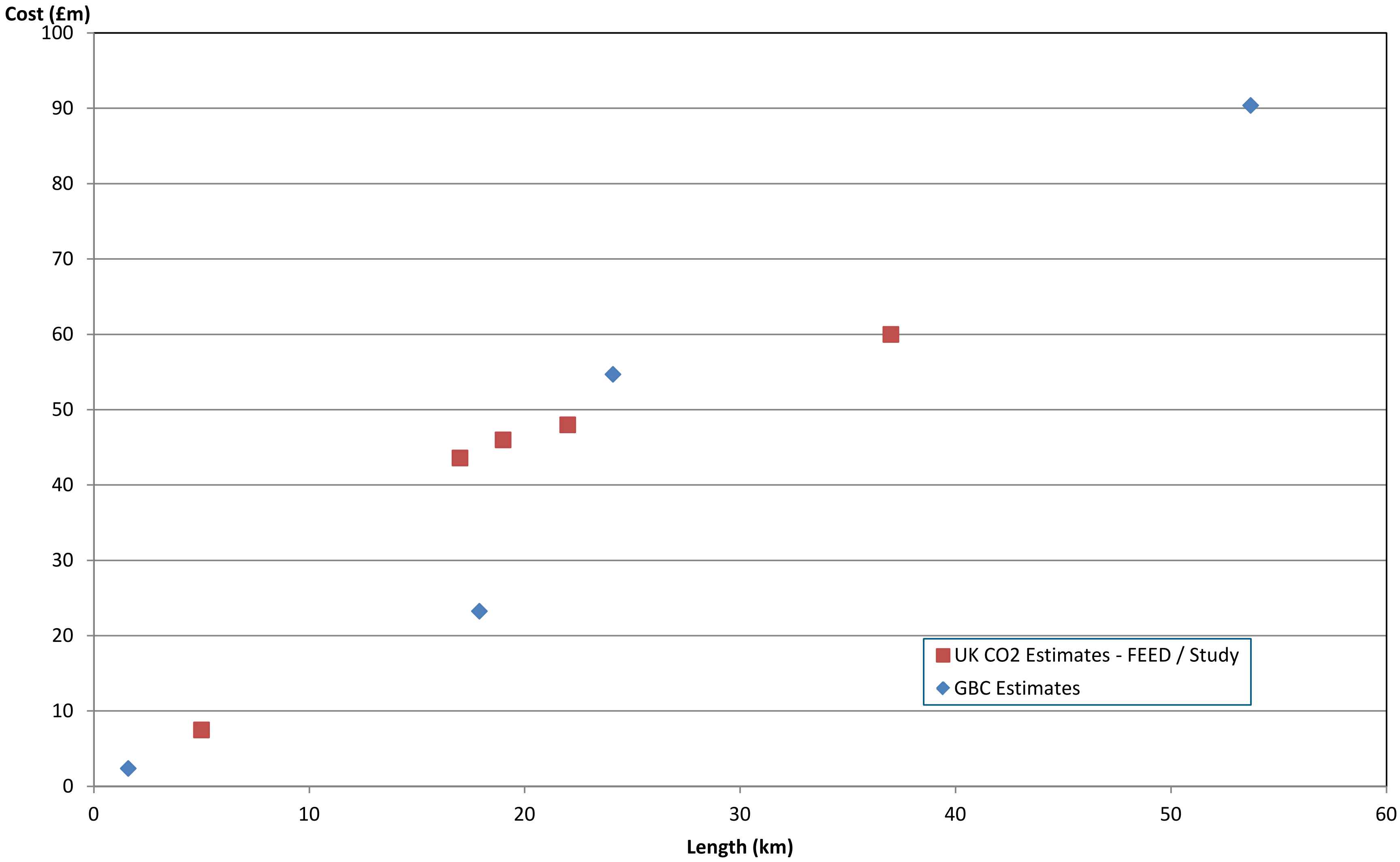


Figure 41 – Cost Benchmarking Data for Onshore CO_2 Transmission

Offshore Pipelines

There is less available data with regards to offshore pipelines for CO_2. SNC-Lavalin's submission for the Subsea Pipeline for an earlier phase of the Shell Peterhead yielded a cost estimate of £72,877 per in-km; the subsea pipeline cost estimates have been compared to this benchmark in the following table:

Site	Teesside & Humberside 5 Trains and North West 3 Trains				
	Cost Estimate	Size	Length (km)	£/in-km	Difference
Teesside	£275,185,814	24"	154	74,455	2%
North West	£57,114,169	24"	24.3	97,932	34%
Humberside	£147,306,558	24"	79	77,693	7%

Table 56 – Offshore Pipeline Costs

There is a good correlation between the benchmark and the pipelines to Endurance. The North West pipeline cost includes insulation for heat conservation whilst the CO_2 is in gas phase: the insulation cost is over and above that included in the benchmark.

The Teesside subsea pipeline was compared to the pipeline cost estimate produced for the Teesside Collective who have planned the same route and size (24") and similar pressure.

- £275,185,814 (this project – no risk and contingency)
- £252,266,000(Rider Hunt International, 2015)

The above comparison shows that the estimates from both projects have reached similar conclusions.

Storage

Subsurface work is beyond the scope of the Generic Business Case projects and therefore the project team have used publicly available information to provide costs for the DRILLEX.

The recent Statoil Oseberg project provides information on a supply and install cost for a wellhead platform (Offshore Post, 2016): the contract value was approximately £77m for a 4400Te jacket and 900Te topsides (5300Te total). This contract shows recent North Sea pricing for wellhead platforms. This data was selected as a benchmark over data from the White Rose FEED for Endurance and the SAP information because the Statoil Oseberg data is for an actual project as opposed to being Study or FEED data.

In order to use this cost as a benchmark the jacket and topsides costs should be split. As a rule of thumb, the topsides costs are four times the jacket costs per tonne. Using the benchmark cost and the rule of thumb the following comparison with the GBC cost estimates can be made. Industry norms of US$10,000 per tonne for jackets and US$40,000 per tonne for topsides accord well with the Oseberg and GBC data.

Oseberg	Weight (tonne)	Cost Attributed (£M)	Benchmark (£/tonne)	Benchmark (US$/tonne)
Jacket	4400	£42.35	£9,625	$12,031
Topsides	900	£34.65	£38,500	$48,125
Total		**£77.00**		
Endurance	**Weight (tonne)**	**Estimate (£M)**	**(£/tonne)**	
Jacket	2030	£19.36	£9,537	
Topsides	3084	£100.58	£32,614	
Total		**£119.94**		
Hamilton	**Weight (tonne)**	**Estimate (£M)**	**(£/tonne)**	
Jacket	1310	£12.68	£9,680	
Topsides	3242	£108.14	£33,356	
Total		**£120.82**		
Captain X	**(tonne)**	**Estimate (£M)**	**(£/tonne)**	
Jacket	3790	£34.13	£9,007	
Topsides	2781	£94.88	£34,117	
Total		**£129.01**		

Table 57 – Offshore Platform Cost Estimate

The overall topsides estimates for the GBC are 11% to 17% lower than the benchmark: however, the benchmark is for a significantly smaller topsides, and thus the fixed costs for the project will be less diluted for the weight: resulting in a higher cost per tonne. The Endurance topsides cost per tonne is slightly lower due to the topsides provision for future brine production. This results in there being a greater proportion of primary / secondary steel in the make up of the overall weight. The primary / secondary steel is lower cost than tertiary steel or equipment.

The jacket estimate for the GBC project are within 6% of the benchmark which is considered acceptable considering that there will be fluctuation in the offshore fabrication and installation market as a result of currency fluctuations, cost of steel, and price of oil (affecting North Sea Hydrocarbons Industry activity).

9.5 Performance Benchmarks

Gas Turbine Parameters

Benchmark	Result
H and J Class Combined Cycle Efficiency Benchmark > 60% (LHV) gross.	62% (LHV) gross as per performance modelling
Abatement efficiency loss for Carbon Capture and Compression = 9.1% (LHV)[38] – noting that this is dependent on the plant design parameters, such as compression discharge pressure, level of capture, type of packing, and degree of integration between the carbon capture plant and the power generation plant.	Abatement efficiency loss is 7.9% (LHV)

Carbon Capture Parameters

Benchmark	Result
Carbon Capture of 90% of CO_2 in flue gas is a widely accepted benchmark for carbon capture plant design.	90% achieved in modelling and scaling calculations
The energy to separate CO_2 from the solvent requires considerable steam usage: › MEA - 3.4[39] to 4.2 GJ/tCO_2 › Best in Class Amine – 2.4 to 2.5 GJ/tCO_2	Reboiler Service derived from information in the Peterhead KKDs as 2.99 GJ/tonneCO_2 Part of the difference between a Best in Class Amine and Reboiler calculation from the Peterhead CCS publically available information may be a tolerance for the Licensor's performance guarantee.

A CO_2 capture penalty of 6.5 to 6.9% is documented in NETL and IEAGHG reports for post combustion capture for natural gas fired plants (Cansolv and MHI solvents respectively).

[38] Detailed Benchmarking of Post Combustion CO2 Capture Technologies for Four Reference Power Plant Cases: Economic Assessment E Sanchez*, E.J. Bergsma, L Robinson, E.L.V. Goetheer, N Booth (TNO Science and Industry, Leeghwaterstraat 46, 2628 CA Delft, The Netherlands / E.ON New Build and Technology Ltd, Ratcliffe-On-Soar, Nottingham NG11 0EE UK)
[39] TCM releases amine CO2 capture benchmarks, 12 October 2014, Carbon Capture Journal (source: http://www.carboncapturejournal.com/news/tcm-releases-amine-co2-capture-benchmarks/3515.aspx?Category=all)

The calculated CO_2 capture penalty for the GBC plant is 7.9%. This figure is calculated for a compression pressure of 183 bar (higher than that used for benchmarks – MHI = 110 bar) and includes all utility and facility parasitic loads (e.g. make up water supply, cooling water, HVAC loads for larger buildings required for the additional personnel for carbon capture compared to just power generation).

It should also be noted that the 7.9% quoted in this report includes performance margins against liquidated damages: i.e. based on Shell Peterhead real contract scenario as per publicly available documents. Engineering reports may provide figures without this margin to provide best efficiency figures. A real project is unlikely to have engineering figures for performance as there will be some penalty for failure to meet the agreed performance and therefore a tolerance / margin included to provide some protection for Licensor and EPC Contractor.

10 Conclusions

Capital Cost

The Project team were able to use data collected from Projects and Proposals to develop a robust UK based cost estimate for the Thermal Power with CCS project for different regions in the UK and for a range of plant sizes. The performance and cost estimate have been confirmed against benchmarks.

£	One Train (622 MW)	2 Trains (1244 MW)	3 Trains (1866 MW)	4 Trains (2488 MW)	5 Trains (3110 MW)
P50	1,764,392,521	2,753,873,823	3,762,523,003	4,983,906,265	5,965,844,832
P90	1,874,467,642	2,925,679,694	3,997,255,450	5,294,837,126	6,326,349,618

Table 58 – P50 and P90 Cost Estimates against Abated Output for the Teesside Location

The overall CAPEX estimate is slightly sensitive to exchange rate fluctuations. A 5-point improvement in the pound over the USD and EUR rates results in a 1% improvement in CAPEX base cost.

Regions

Scotland is the most expensive region analysed. This is because the selected site is in Southern Scotland which requires a long pipeline running up the East side of Scotland from the Forth to St Fergus. The cost estimate allows for the reuse of Feeder 10, however, the CO_2 pipeline route requires a new tunnel under the Forth, new AGIs, and compressor stations which add hundreds of millions of pounds to the estimate compared to other locations reviewed by the project team.

The South Humber region is higher than Teesside, North Humber, and North West / North Wales regions because a tunnel is required for the CO_2 pipeline route under the Humber adding significant cost to the transportation.

The capital cost estimates for the Teesside, North Humber, and North West / North Wales regions are similar. The Humber region and North West / North Wales region have lower transportation costs than the Teesside region because they have shorter pipelines to their stores. However, the Teesside region benefits from the availability of a skilled local construction work force and sub-contract base. The Teesside side selected also benefits from access to dock / quay / shore side which allows extensive modularisation / prefabrication reduces the amount cost / risk / safety exposure on the construction site.

The large scale of the bigger plant sizes reviewed have large CO_2 inventories and pipelines. At the higher pressures after CO_2 Compression this creates a high hazard. An advantage of the Teesside region site is that it is closer to the shore crossing point into the North Sea resulting in a shorter onshore pipeline length, less proximity to others from the high hazard, and therefore potentially a safer solution than the Scotland (Grangemouth), North Humber, South Humber, and North West / North Wales regions sites where longer pipeline routes were required.

For Southern Scotland sites that are on the North of the Forth Estuary it has been assumed that the pipeline routing will run underneath the Forth because the north bank of the Forth is congested between the Forth and the Ochil Hills. Detailed consideration should be given to see whether there is a potential CO_2 pipeline route to the valve station at Braco without the need for a pipeline tunnel under the Forth to reduce the cost of the onshore pipeline (please refer to the following section for other potential optimisations for the performance and cost of the project).

Size / Scale

The CCGT plant benchmark data shows an advantage in economies of scale in going for a larger plant. Although the cost estimate confirms some advantage in the economy of scale, it is not as much as the initial benchmarking work suggested: this may be because a CCGT plant layout cannot take advantage of keeping multiple units close together but would need to be larger, and more spread, in order to accommodate the carbon capture and compression units. The expansion of the layout requires more land purchase, and longer connections. Also, the spread layout of the CCGT plant for carbon capture does not allow for combined steam turbine buildings which would have helped an economy of scale cost estimate.

There is little economy of scale benefit between 3 and 5 trains for regions where such developments are practical: this is because a second injection platform with injection wells would be required offshore for a 4 and 5 train plant size. Considering the additional risk, infrastructure, and project scale associated with the larger plant sizes the 3 train plant is recommended as the optimum economy of scale for the CCGT + CCS scheme, and attractiveness for potential Owner / Investors.

Whilst the overall base cost increases roughly 3.4 times for the 1 to 5 trains the transportation cost increases only 1.4 times and the storage cost only 2.2 times. This demonstrates that the transportation and storage element of the CCS benefits from an economy of scale. The storage economy of scale is stronger for 3 trains as the increase in storage cost is only 1.2 times against 2.1 times for the overall scheme.

Note that offshore costs are more affected by subsurface consideration such as well injectivity. There is future opportunity for reducing this by using subsea wells for smaller projects or for incremental increases in capacity over a single wellhead platform hub. As concluded in the Template Plant Specification work this is probably not appropriate for GBC as investors would prefer to have operational experience of UK offshore CO_2 injection wells (especially into aquifer stores) before committing to using subsea solutions.

Location

The CCGT + CCS scheme is sensitive to location. There is a large cost element within the project for transportation and utility connection infrastructure. It is therefore advantageous to be near to the CO_2 store and to be near the utility connections. There is also a risk to health and safety from the high-pressure CO_2 hazard, and therefore a safety advantage to shorter onshore CO_2 pipeline.

Tunnels under major rivers and longer pipeline routes requiring compression stations have a significant impact on capital costs. Careful site selection can avoid these for 1st wave CCS projects.

With regard to Constructability the best GBC case becomes a large economy of scale plant, located near suitable infrastructure, ideally dock / quay side for constructability to allow large items to be transferred directly to plant, with the shortest feasible connection to storage, and in the vicinity of a large work force.

Layout

The original layout (named Option 1) gave a reasonable estimate for the plant footprint required. However, this layout has been developed (named Option 2) to provide a safety distance between the high-pressure CO_2 on the plot and the plant boundary.

The site selection work ensured that there were no dwellings on the downwind side of the plant in order to manage the risks from the high-pressure CO_2 hazard – however, the Option 2 arrangement provides a buffer within the plant boundaries.

Consideration should be given to the size of the plant footprint relative to the selected site(s) for the execution of thermal power with CCS. Should there be manned areas or public access into the high hazard zone drawn on the layout then consideration should be given as to whether expanding the site footprint by pushing out the boundary fence may be a useful way to excluding persons from CO_2 hazard areas.

Design

Material of Construction (MOC): Previous CCS experience has provided good feedback on MOC. MOC upgrades from experience are included in the equipment list. The equipment list is based on Peterhead, 316 Stainless steel is primary selection for amine or wet CO_2 contact surfaces. 316 grade plate is roughly 30% more expensive than 304 grade plate. The challenge from the Chief Technologist is that a lot of 316 material selections could be optimised to 304 grade as a useful value engineering exercise.

Wet mechanical draft cooling towers do not offer the best value for the project. Evaluation carried out previously in WP1 shows that direct (once through) water cooling offers potentially the lowest CAPEX, smallest footprint, and best process efficiency for the project. However, obtaining extraction permits for once through cooling has been an obstacle to recent power projects and it was decided by the project team to select a lower risk option of Wet Cooling Towers as a compromise between cost / efficiency and project consenting risk. This decision can be optimised based on final site selection. For example, Peterhead and Longannet already have water intakes so it is assumed that it is possible that cooling would be licensed. Some recent power projects have not been allowed any abstraction or discharge except from public supplies and sewers so as to minimise environmental impact – in this case Air Cooled Condensers with a closed-circuit cooling would be required as make up water is still required for cooling towers: this would have a CAPEX, space, and OPEX penalty.

Dispersion modelling was not part of the scope for this project. Dispersion modelling should be undertaken during the next phase of the project to determine the extent of the high CO_2 hazard area. The layout developed during this early stage of the project may have to be expanded to keep the high hazard area within the boundary fence of the plant (depending on site location). The maintenance regime and the maintenance activities to be undertaken within the high hazard zone should also be reviewed: to control risks to maintenance personnel the plant layout may require expansion to move maintenance activities outside the hazard zone,

Technology: Assumptions have been made on the performance of the Class H/J Gas Turbines and Engineered Amine Solvent in this report based on what is viewed as bankable technology at the time of this project coming to FID. Future work on Thermal Power with CCS should reconsider these assumptions based on the latest progress with the operation of Class H/J Turbines and Engineered Solvents.

11 Opportunities for Performance or Cost Improvement

The following opportunities for performance or cost improvement of the CCGT + CCS scheme have been identified following a reflection on the GBC project:

Layout	The original concept for the layout was to separate the highest hazard location on the plant from the permanently manned areas of the plant. This positioned the highest hazard area of the plant against the downwind boundary of the onshore CCGT + CCC plant. Whilst this was an optimum for maintaining a safe design for those working on the onshore plant it presented a risk from the hazard to those who may be located on neighbouring sites. Once a final site is selected for a large CCGT + CCS project it is recommended that the layout be reviewed / optimised against the location of neighbouring sites. There is the potential for the permanently manned areas of the CCGT + CCC plant to be moved further from the CCGT area in order to allow higher pressure CO_2 units to be moved away from the fence line: the overall area of the CCGT + CCC plant may increase as a result.
Licensed Technology	The GBC Project has been developed without a licensed process design. It is recommended that a specific CCGT + CCS project select an engineered solvent and engage a process licensor to develop a design for the specific project.
Treatment of Amine Solvent	There is an opportunity to optimise the design of the TRU and the supporting vacuum Packages. The GBC design is from the publicly available Shell Peterhead information which is a 3 stage vacuum distillation unit sized to be continuously operating per train. Potential alternatives: › Single Stage unit per train. There could be an optimisation of the number of stages versus recovery of amine. This would be an economic optimisation of CAPEX expenditure on equipment versus the OPEX saving of reduced amine consumption. › No TRU: It is possible to operate the scheme with no TRU but bleed off spent amine and refresh with new. As per the previous point this is a CAPEX expenditure versus an OPEX cost optimisation. It is expected that the engineered amine and disposal costs would justify the CAPEX investment for a

	Recovery Package as the bled amine would contain only a fraction of degraded solvent. › Another option would be to use an offsite subcontracted treatment of amine i.e. another company makes the CAPEX investment in return for OPEX business – potentially more cost efficient than bleeding off amine in the above point. › The number of TRUs could be reduced. Amine from each train could be bled to a degraded amine tank. An optimised number of continuous or batch TRU packages could then treat degraded amine. Treated amine would then be returned to trains. The information to make the above optimisation is reliant on confidential Licensor information and therefore would have to be undertaken with the Process Licensor for the Engineered Amine Solvent.
Cooling	The majority of the potential sites are close to the sea shore or river estuaries. There would be a performance improvement using seawater cooling (with a lower temperature) compared to the GBC which used cooling towers. Once a final site is selected for a large CCGT + CCS project it is recommended that the cooling source be re-evaluated with respect to the availability of seawater or river estuary cooling. Seawater or river estuary cooling may have consent implications as the use of these water sources may be environmentally sensitive. Some existing sites with potential for reuse already have cooling water intakes and returns which may ease the consent process.
Pipeline Routing	The potential sites for both the South Humber and the Scotland (Grangemouth) regions required tunnels for major river crossings. The tunnels added significant cost to the CO_2 transportation element of the cost estimates. It is recommended that site selection try to avoid sites which require major river crossings (unless there are significant benefits which mitigate the cost and project execution risk of tunnels)
Pipeline Routing	For Southern Scotland sites that are on the North of the Forth Estuary it has been assumed that the pipeline routing will run underneath the Forth because the north bank of the Forth is congested between the Forth and the Ochil Hills. Detailed consideration should be given to see whether there is a potential CO_2 pipeline route to the valve station at Braco without the need for a pipeline tunnel under the Forth to reduce the cost of the onshore pipeline.

12 Abbreviations

The following abbreviations have been used in this document:

Abbreviation	Description
ACS	Access Control System
AGI	Above Ground Installation
ALARP	As Low As Reasonable Practicable
ATEX	Atmosphere Explosif
BCIS	Building Cost Information Service
BEIS	Department for Business, Energy & Industrial Strategy
CAPEX	Capital Expenditure
CC	Carbon Capture
CCC	Carbon Capture and Compression
CCGT	Combined Cycle Gas Turbine
CCR	Carbon Capture Ready
CCS	Carbon Capture and Storage
CCTV	Closed Circuit Television
CDM	Construction, Design, and Management Regulations
CEMS	Continuous Emission Monitoring System
CfD	Contract for Difference
CO_2	Carbon Dioxide
DCC	Direct Contact Cooler
DCO	Development Consent Order
DECC	Department of Energy and Climate Change (now BEIS)
E&I	Electrical and Instrumentation
EIA	Environmental Impact Assessment
ENVID	Environmental Aspects Identification
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement, and Construction
ESD	Emergency Shutdown

Abbreviation	Description
ETI	Energy Technologies Institute
FEED	Front End Engineering Design
FID	Financial Investment Decision
FSU	Former Soviet Union
GBC	Generic Business Case
GGH	Gas-Gas Heat Exchanger
GT	Gas Turbine
GTG	Gas Turbine Generator
H&M / H&MB	Heat and Material Balance
HAZID	Hazard Identification Study
HAZOP	Hazard and Operability Study
HDD	Horizontal Directional Drilling
HP	High Pressure
HRSG	Heat Recovery Steam Generator
HS2	High Speed 2 Railway
HSE	Health and Safety Executive
HSSE	Health Safety Security and Environmental
HSSE&SP	Health, Safety, Security, Environment and Social Performance
HV	High Voltage
HVAC	Heating Ventilation Air Conditioning
ICSS	Integrated Control and Safety System
IEAGHG	International Energy Agency Greenhouse Gas
IGCC	Integrated Gasification Combined Cycle
IP	Intellectual Property / Intermediate Pressure
IX	Ion Exchange
KKD	Key Knowledge Documents
LER	Local Equipment Room
LHV	Lower Heating Value
LLP	Limited Liability Partnership
LP	Low Pressure

Abbreviation	Description
LV	Low Voltage
MEA	Monoethanolamine
MEG	Monoethylene Glycol
MHI	Mitsubishi Heavy Industries (& Mitsubishi Hitachi Power Systems)
MOD	Ministry of Defence
MP	Medium Pressure
MTO	Material Take Off
MTPA	Million Tonne Per Annum
MV	Medium Voltage
NAECI	National Joint Council for the Engineering Construction Industry
NoBo	Nominated Body
NOx	Nitrous Oxides
NTS	National Transmission System
NUI	Normally Unmanned Installation
O&G	Oil and Gas
O&M	Operations and Maintenance
OEM	Original Equipment Manufacturer
ONS	Office for National Statistics
OPEX	Operating Expenditure
P10/P50/P90	The point on the probability distribution for estimated costs at which there is a 90% / 50% / 10% probability that costs will not exceed this value
P&ID	Piping and Instrument Diagram
PAGA	Public Address General Alarm
PE	Polyethylene
PEACE	Plant Engineering And Cost Estimator
PFD	Process Flow Diagram
PFP	Passive Fire Protection
PH	Peterhead
PMC	Project Management Contractor
PPE	Personal Protective Equipment

Abbreviation	Description
RICS	Royal Institution of Chartered Surveyors
SAC	Special Area of Conservation
SAP	Strategic Appraisal Project
SIMOPS	Simultaneous Operations
SCR	Selective Catalytic Reduction
SLOT	Specified Limit of Toxicity
SPA	Special Protection Areas
SPV	Special Purpose Vehicle
SSIV	Subsea Isolation Valve
SSSI	Site of Special Scientific Interest
ST	Steam Turbine
STG	Steam Turbine Generator
T&S	Transport and Storage
TCPA	Town and Country Planning Act
THP	Tubing Head Pressure
THT	Tubing Head Temperature
TPwCCS	Thermal Power with Carbon Capture and Storage
TRU	Thermal Recovery Unit
TUTU	Topsides Umbilical Termination Unit
UK	United Kingdom
UPS	Uninterruptable Power Supply
US / USA	United States of America
VFD	Variable Frequency Drive
VOC	Volatile Organic Hydrocarbon
W2W	Walk to Work

Table 59 - Abbreviations

13 References

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Images Appearing In the Text

Front Cover	Photomontage of the GBC Project developed by AECOM for the ETI.
Executive Summary	Newark Energy Center http://www.snclavalin.com/en/projects/newark-energy-center
Onshore Layout and Enabling	Fenix Power Plant http://www.snclavalin.com/en/fenix-power
Power Generation Station	Emal CCGT – image from SNC-Lavalin brochure for Asia Pacific Energy Solutions
Carbon Capture Plant	ICSS – Saskatchewan http://www.snclavalin.com/en/training-program-for-iccs
CO_2 Transportation	Kings North 36” Pipeline http://www.snclavalin.com/en/kings-north-connection
Offshore Facilities	Cygnus http://www.snclavalin.com/en/cygnus-jacket
References	Orlen http://www.snclavalin.com/en/pkn-orlen-thermal-power-plant

Table 60 – Photograph References

Acknowledgements

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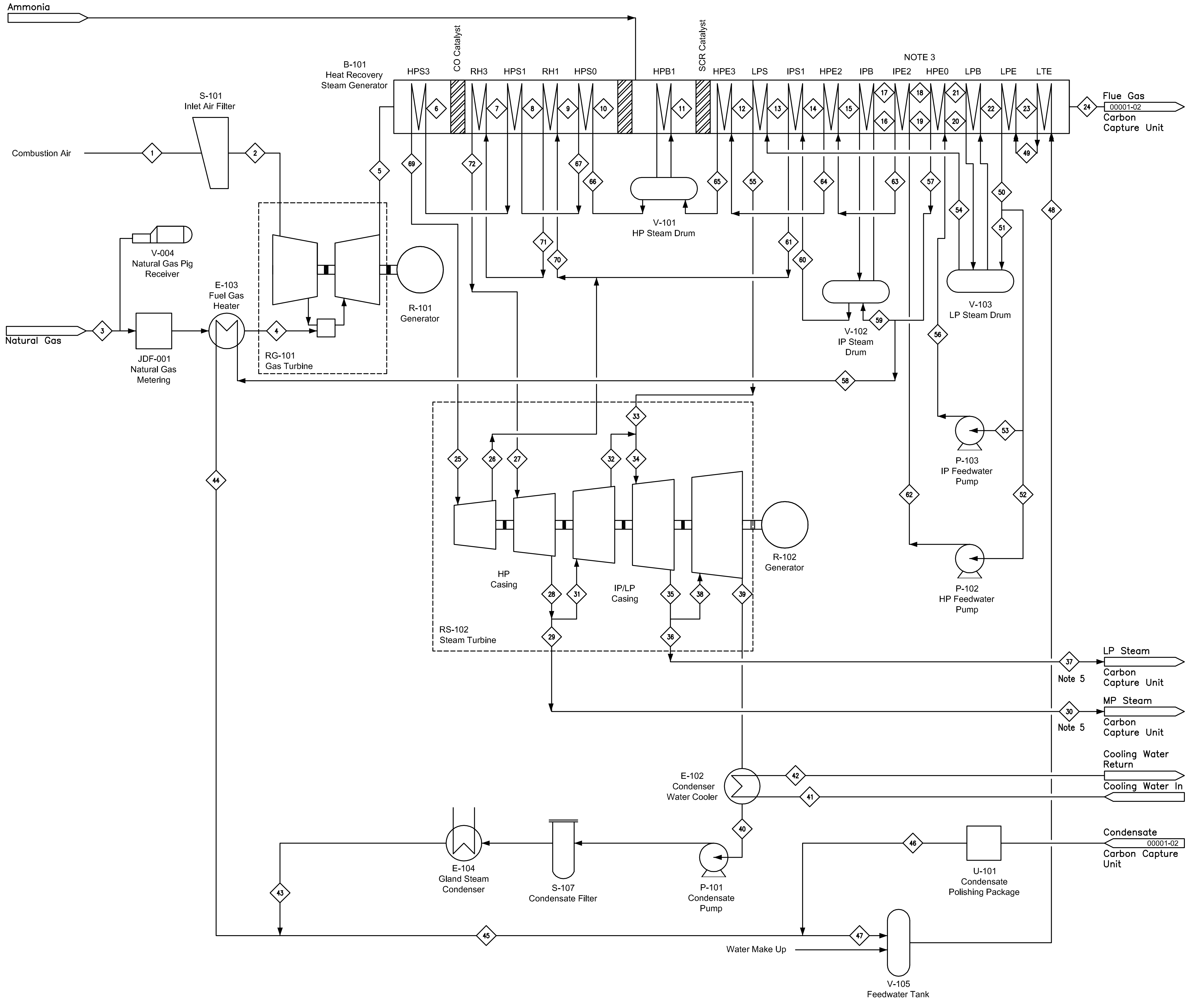
Attachment 1 – Process Flow Diagrams



NOTES:

1. TAGGING PER SNC–LAVALIN STANDARD 4001–HCST–LON.
2. PROCESS SCHEME FOLLOWS SCHEME MODEL IN 181869–0001–T–EM–TNT–AAA–00–00010.
3. STREAM 16 IS SPLIT INTO STREAM 17 & 19. STREAM 21 IS COMBINED FROM STREAMS 18 & 20.
4. FOR STREAM DATA REFER TO H & MB 181869–0001–D–EM–HMB–AAA–00–0001–01.
5. STREAMS 30 AND 37 ARE DESUPERHEATED STEAM FROM STREAMS 29 AND 36 RESPECTIVELY

This document has been electronically checked and approved. The electronic approval and signature can be found in FOCUS, cross referenced to this document under the Tasks tab, reference No: T072931

HOLDS:

1. DELETED.

REV	REVDATE	REVISION DESCRIPTION	PREP	CHK	ENG	APP
A04	17–05–17	ISSUE FOR USE	FR	TA	MW	MW
A03	25–04–17	ISSUE FOR USE	JB	TA	KS	MW
A02	13–01–17	ISSUE FOR INTERNAL USE	JXS	MW	KS	MW
A01	04–01–17	ISSUE FOR PEER REVIEW	JXS	MW	MW	

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181869–0001–D–EM–PFD–AAA–00–00001–01

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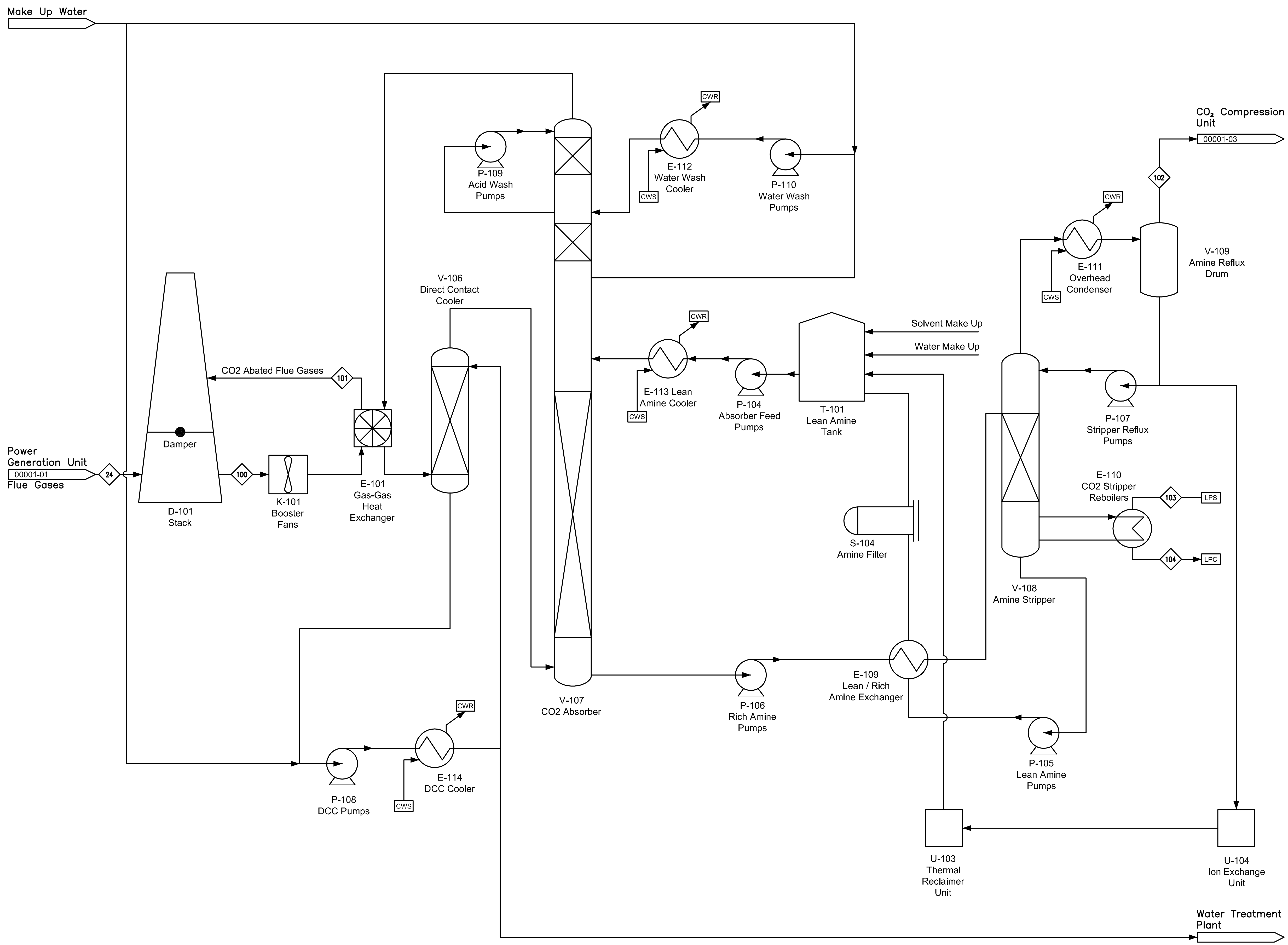

NOTES:

1. TAGGING PER SNC-LAVALIN STANDARD 4001-HCST-LON.
2. COOLING WATER.
   - CWS COOLING WATER SUPPLY
   - CWR COOLING WATER RETURN
   - LPS LOW PRESSURE STEAM
   - LPC LOW PRESSURE CONDENSATE
3. FOR STREAM DATA REFER TO H & MB 181869-0001-D-EM-HMB-AAA-00-0001-01.
4. THE CARBON CAPTURE PLANT IS DESIGNED AS A BLACK BOX AND DEPENDS ON THE AMINE SELECTED WITH ONLY SHOWN THE INLET OUTLET STREAMS

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REV	REVDATE	REVISION DESCRIPTION	PREP	CHK	ENG	APP
A04	16-05-17	ISSUE FOR USE	FR	TA	MW	MW
A03	25-04-17	ISSUE FOR USE	JB	TA	KS	MW
A02	06-02-17	ISSUE FOR INTERNAL USE	JB	MW	MW	
A01	04-01-17	ISSUE FOR PEER REVIEW	JXS	MW	MW	

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TITLE
PROCESS FLOW DIAGRAM
CARBON CAPTURE

REV
A04

DWG NUMBER
181869-0001-D-EM-PFD-AAA-00-00001-02

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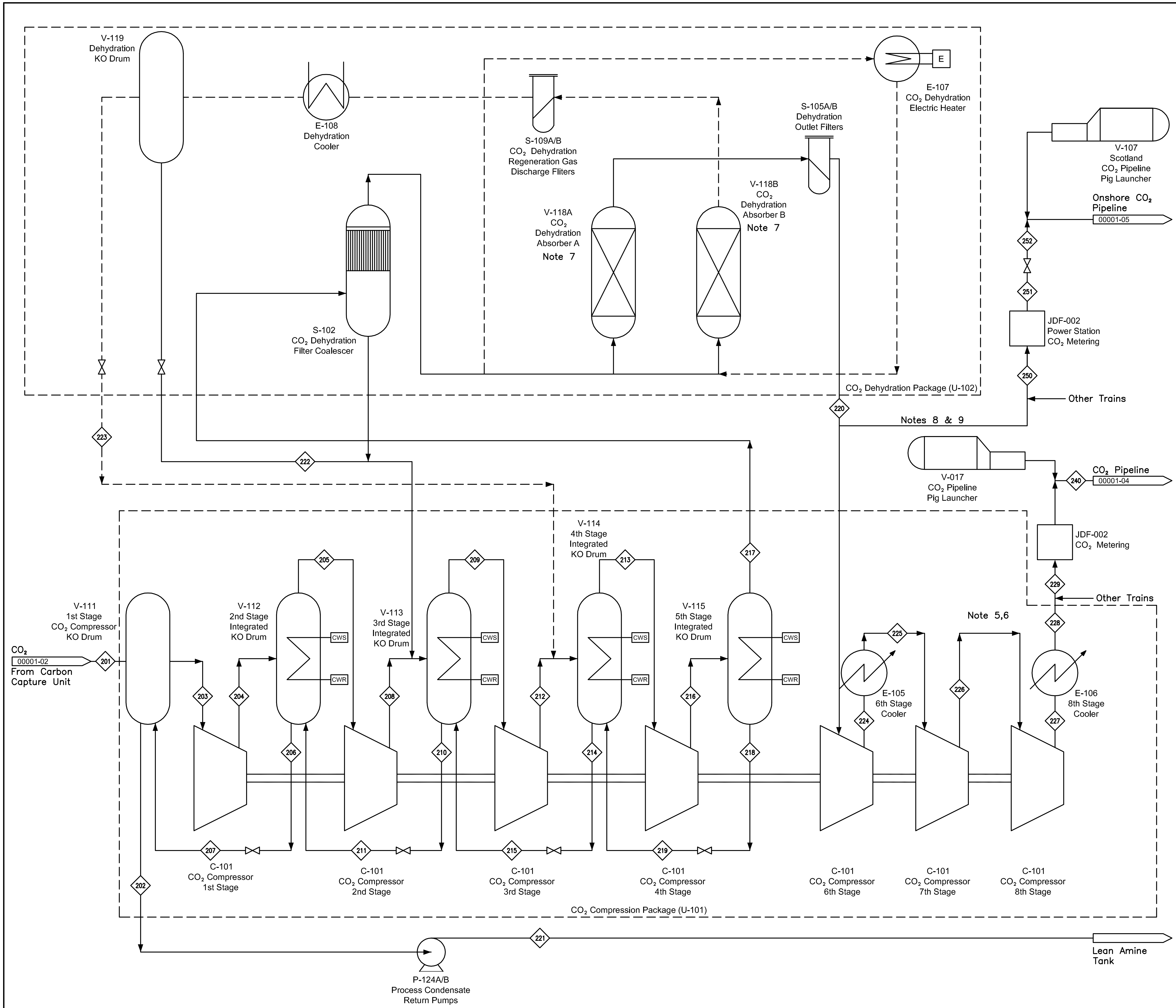

NOTES:

1. TAGGING PER SNC-LAVALIN STANDARD 4001-HCST-LON.
2. COOLING WATER.
   CWS COOLING WATER SUPPLY
   CWR COOLING WATER RETURN
3. FOR STREAM DATA REFER TO H & MB 181869-0001-D-EM-HMB-AAA-00-0001-01.
4. FOR NORTH WEST TO HAMILTON PIPELINE GAS PHASE, THE 6TH STAGE COOLER OUTLET TEMPERATURE KEPT AT 46°C TO MAINTAIN THE PIPELINE IN THE GAS PHASE.
5. FOR NORTH WEST TO HAMILTON PIPELINE LIQUID PHASE A 7TH STAGE COOLER IS REQUIRED TO MAINTAIN THE PIPELINE IN THE LIQUID PHASE. FOR STREAM DATA REFER TO STREAMS 226 AND 227 FOR INLET AND OUTLET RESPECTIVELY.
6. VALVE IS REQUIRED TO DROP PIPELINE INLET PRESSURE FOR THE NORTH WEST TO HAMILTON PIPELINE.
7. WHEN V-118A IS IN ABSORBING MODE, V-118B IS IN REGENERATION MODE AND VICE VERSA.
8. THIS ARRANGEMENT IS FOR THE GENERAL BUSINESS CASE LOCATED IN SCOTLAND WITH 3 TRAINS CAPACITY.
9. TRIP SYSTEM SHALL BE PROVIDED TO PROTECT THE ONSHORE TRANSPORTATION PIPELINE FROM PRESSURE EXCEEDING THE MAXIMUM INCIDENTAL PRESSURE OF 37.5 barg.

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REV	REVDATE	REVISION DESCRIPTION	PREP	CHK	ENG	APP
A05	11-07-17	ISSUE FOR USE	JB	TA	MW	MW
A04	16-05-17	ISSUE FOR USE	FR	TA	MW	MW
A03	25-04-17	ISSUE FOR USE	JB	TA	MW	MW
A02	06-02-17	ISSUE FOR INTERNAL USE	JB	MW	MW	
A01	04-01-17	ISSUE FOR PEER REVIEW	JXS	MW	MW	

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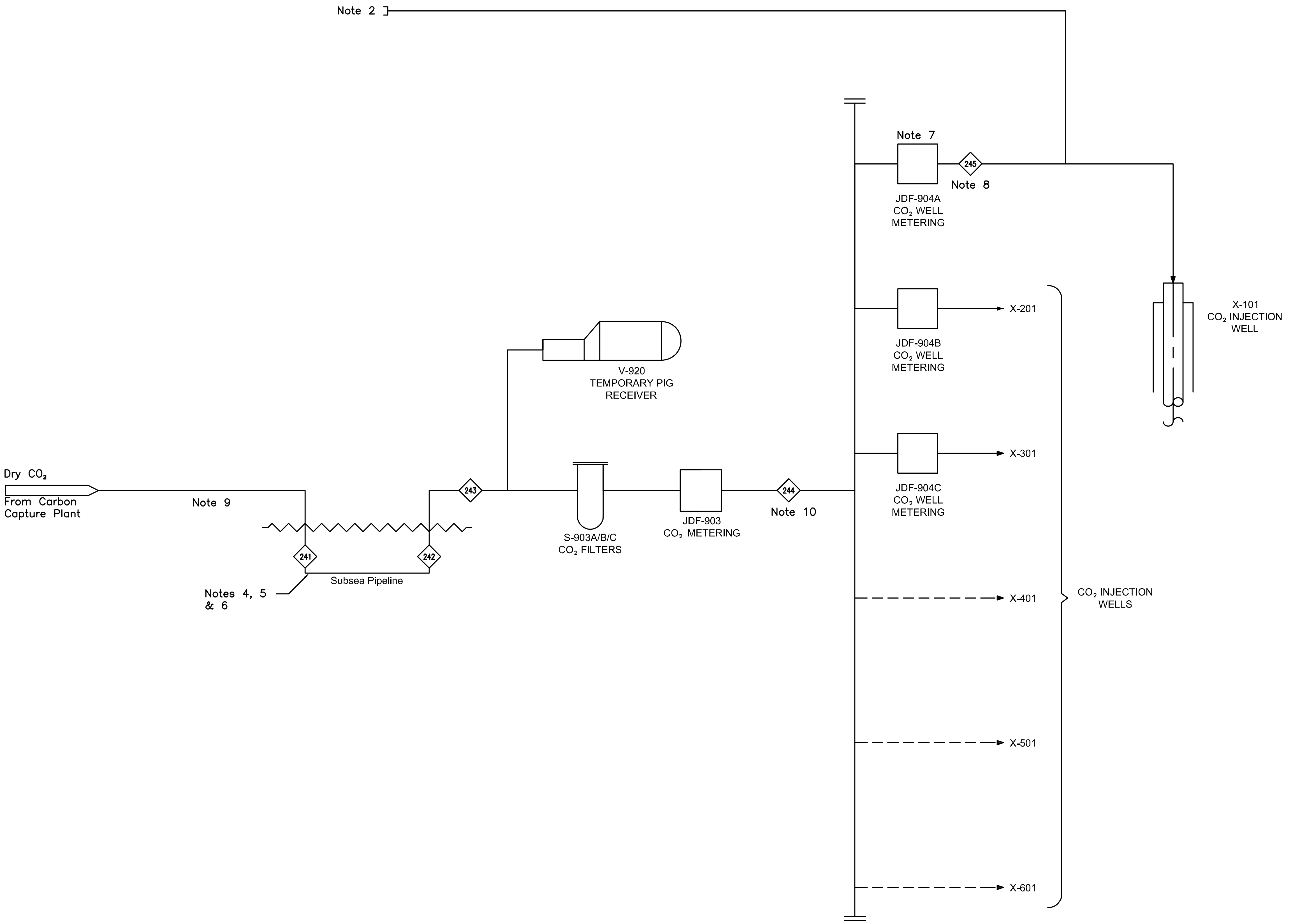
TITLE: PROCESS FLOW DIAGRAM
CO2 COMPRESSION

REV: A05

DWG NUMBER: 181869-0001-D-EM-PFD-AAA-00-00001-03



NOTES:

1. TAGGING PER SNC-LAVALIN STANDARD 4001-HCST-LON.
2. COUPLING TO WASH WATER SUPPLIED FROM WASH WATER PACKAGE ON SUPPLY BOAT.
3. FOR STREAM DATA REFER TO H & MB 181869-0001-D-EM-HMB-AAA-00-0001-01.
4. 2.23MW OFFSHORE HEATER FROM NORTH WEST TO HAMILTON IS REQUIRED TO MAINTAIN THE THT AT 30°C.
5. 16MW SHORELINE COOLER BETWEEN ONSHORE/OFFSHORE PIPELINE FOR NORTH WEST TO HAMILTON IS REQUIRED TO MAINTAIN THE OFFSHORE PIPELINE WITHIN THE LIQUID PHASE AND THT AT 10°C.
6. THE SHORELINE PIPELINE CHILLER INLET AND OUTLET STREAM ARE 241 AND 247 RESPECTIVELY.
7. THERE ARE DIFFERENT NUMBER OF CO_2 INJECTION WELLS FOR EACH PLATFORM.
8. H & MB STREAM 245 SHOWN THE MAX INJECTION RATE PER WELL.
9. HAMILTON HAS AN OFFSHORE HEATER FOR GAS PHASE INJECTION AND A SHORELINE PIPELINE CHILLER FOR LIQUID PHASE INJECTION.
10. THE OFFSHORE HEATER INLET AND OUTLET STREAM ARE 244 AND 247 RESPECTIVELY

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HOLDS:

1. DELETED.

REV	REVDATE	REVISION DESCRIPTION	PREP	CHK	ENG	APP
A05	11-07-17	ISSUE FOR USE	FR	TA	MW	MW
A04	16-05-17	ISSUE FOR USE	FR	TA	MW	MW
A03	25-04-17	ISSUE FOR USE	JB	MW	MW	
A02	06-02-17	ISSUE FOR INTERNAL USE	JB	MW	MW	
A01	04-01-17	ISSUE FOR PEER REVIEW	JXS	MW	MW	

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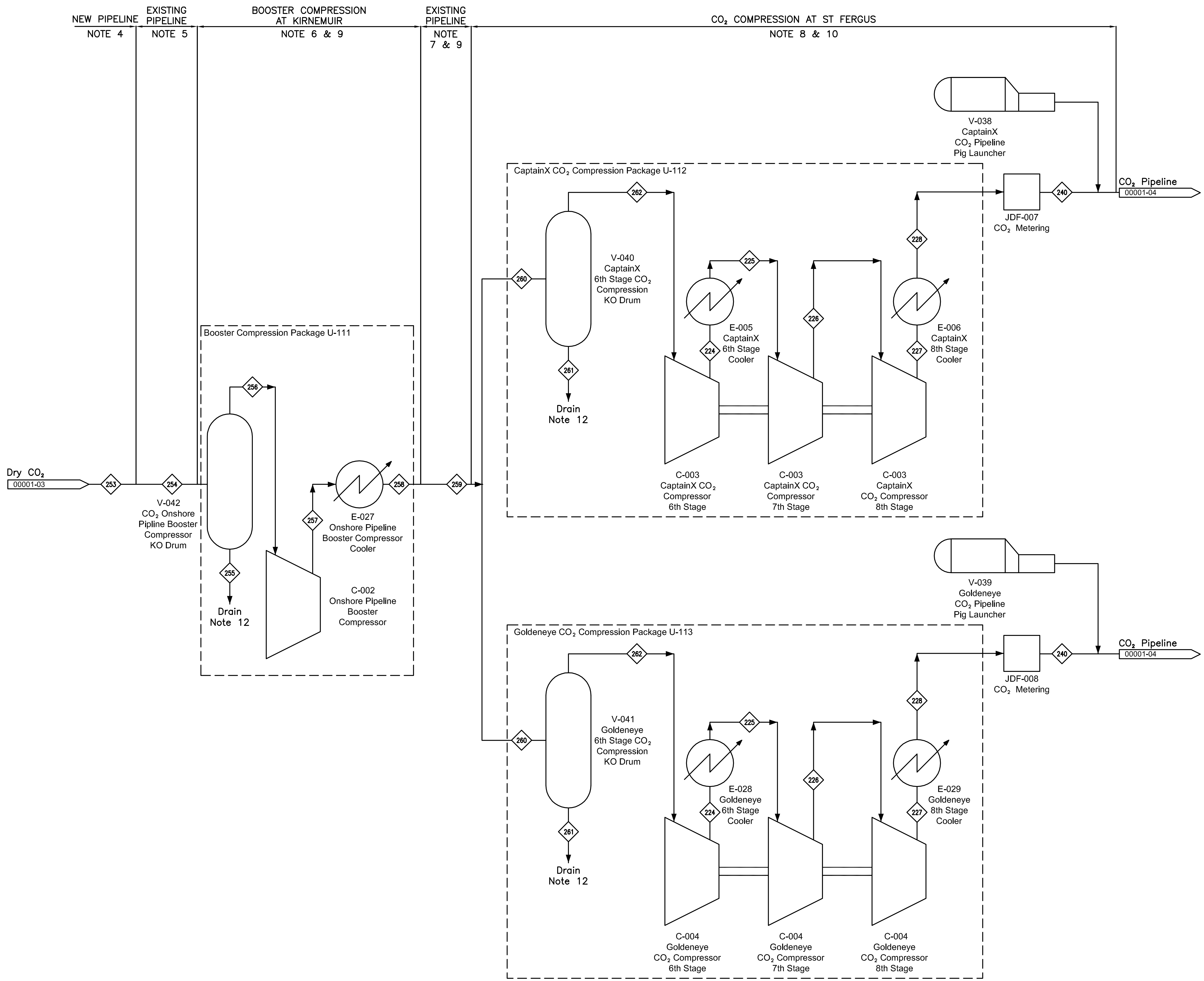
TITLE
PROCESS FLOW DIAGRAM
TRANSPORT AND STORAGE

REV
A05

DWG NUMBER
181869-0001-D-EM-PFD-AAA-00-00001-04



NOTES:

1. TAGGING PER SNC-LAVALIN STANDARD 4001-HCST-LON.
2. COOLING WATER.
   - CWS COOLING WATER SUPPLY
   - CWR COOLING WATER RETURN
3. FOR STREAM DATA REFER TO H & MB 181869-0001-D-EM-HMB-AAA-00-0001-01.
4. A NEW ABOVE GROUND PIPELINE FROM LONGANNET POWER STATION TO No 10 FEEDER.
5. EXISTING 36 INCH BURIED PIPELINE FROM No 10 FEEDER TO KIRRIEMUIR.
6. NEW BOOSTER COMPRESSOR AT KIRRIEMUIR TO BOOST THE PRESSURE TO 34 barg.
7. EXISTING 36 INCH BURIED PIPELINE FROM KIRRIEMUIR TO ST FERGUS.
8. TWO CO2 COMPRESSOR AT ST FERGUS TO BOOST THE PRESSURE TO THE OFFSHORE PIPELINES REQUIRED INLET PRESSURE.
9. TRIP SYSTEM SHALL BE PROVIDED TO PROTECT THE ONSHORE TRANSPORTATION PIPELINE FROM PRESSURE EXCEEDING THE MAXIMUM INCIDENTAL PRESSURE OF 37.5 barg.
10. 1 x 100% COMPRESSOR TO SERVE CAPTAIN X AND 1 x 100% COMPRESSOR TO SERVE GOLDEN EYE.
11. THERE ARE A NUMBER OF A PIG TRAP AND BLOCK VALVE ARRANGEMENT FOR THE NEW AND EXISTING ONSHORE PIPELINE.
12. DRAIN TO A SAFE LOCATION

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REV	REVDATE	REVISION DESCRIPTION	PREP	CHK	ENG	APP
A01	11-07-17	ISSUE FOR PEER REVIEW	JB	TA	MW	MW

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TITLE: PROCESS FLOW DIAGRAM SCOTLAND CO2 COMPRESSION AND PIPELINE

REV: A01

DWG NUMBER: 181869-0001-D-EM-PFD-AAA-00-00001-05

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Attachment 2 – Heat and Material Balance

HEAT AND MATERIAL BALANCE

Document No: **181869-0001-D-EM-HMB-AAA-00-00001-01**

1 OF 16

Revision **: A04** Date **: 12-JUL-2017**

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A04	12-JUL-2017	Re-Issued for Use	T.ALI	M.WILLS	S. DURHAM	M. WILLS
A03	17-MAY-2017	Issued for Use	T.ALI	K.SREENIVASAN	S. DURHAM	M. WILLS
A02	04-MAY-2017	Issued for Use	T.ALI	K.SREENIVASAN	S. DURHAM	M. WILLS
A01	24-APR-2017	Issued for Use	T.ALI	K.SREENIVASAN	S. DURHAM	M. WILLS
REV	**DATE**	**ISSUE DESCRIPTION**	**BY**	**DISC CHKD**	**QA/QC**	**APPVD**

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REVISION	COMMENTS
A01	Issued for Use Previous versions were issued as part of Technical Note - Scheme Modelling, document reference 181869-0001-T-EM-TNT-AAA-00-00010.
A02	Re-Issued for Use 1. Hamilton (North West to Hamilton Gas Case) updated for offshore heating.
A03	Re-Issued for Use Incorporate Client comment and match PFDs
A04	Re-Issued for Use 1. Incorporate Scotland locations 2. Incorporate Client comment

HOLDS	
HOLD DESCRIPTION / REFERENCE	

The Heat and Material Balance Table is presented for each of a number of locations as described below:

CONTENTS

1.0 NOTES

1. This Overall Heat & Mass Balance [181869-0001-D-EM-HMB-AAA-00-00001-01] for the Power Generation, Carbon Capture Plant, Compression and Pipelines for the General Business Case is to be read in conjunction with the Process Flow Diagrams [181869-0001-T-EM-PFD-AAA-00-00001].

2. The Carbon Capture Plant is designed as a black box and depends on the selected amine solvent. Only the inlet outlet streams are shown for the Carbon Capture Plant.

3. Streams 30 and 37 are desuperheated steam from streams 29 and 36 respectively.

4. There is a generic H&MB up to the Dehydration Package for all sites. There is a specific H&MB for each site downstream of the generic design.

5. 8^{th} stage of compression is not required to meet required pressure for Hamilton Store.

6. H&MB flow is for all trains from stream 229. (Up to stream 229 is per train)

7. For Hamilton gas phase the compressor discharge pressure is set higher than the required pipeline pressure in order to have a high inlet temperature to maintain the offshore pipeline within the gas phase and to meet the target THT at 30°C. Therefore an upstream valve is required to drop the compressor discharge pressure to the required pipeline pressure.

8. A 7^{th} Stage Compressor Cooler with 36°C outlet temperature is required to maintain pipeline to Hamilton within the liquid phase.

9. A Shoreline Pipeline Chiller between onshore/offshore pipelines is required to maintain the offshore pipeline within the liquid phase and to meet the target THT at 10°C.

10. Hamilton will be converting from gas to liquid phase injection mid way through the design life of the project.

11. Flow reduced as mass flow split between Captain X and Goldeneye.

PROJECT No.	181869	**DOCUMENT No.**	181869-0001-D-EM-HMB-AAA-00-00001-01
PROJECT NAME	THERMAL POWER WITH CCS	**REVISION**	A04
LOCATION	UK	**DATE**	JULY 2017

	Stream Description	Air to Inlet Air Filter	Air from Inlet Air Filter	Fuel Gas to Fuel Gas Heater	Fuel Gas to Gas Turbine	Flue Gas from Gas Turbine	Flue Gas to RH3	Flue Gas to HPS1	Flue Gas to RH1	Flue Gas to HPS0	Flue Gas to HPB1	Flue Gas to HPE3	Flue Gas to LPS	Flue Gas to IPS1	Flue Gas to HPE2	Flue Gas to IPB	Flue Gas to HPE0/ IPE2	Flue Gas to IPE2	Flue Gas to HPE0	Flue Gas from IPE2	Flue Gas from HPE0	Flue Gas to LPB	Flue Gas to LPE	Flue Gas to LTE	Flue Gas to CCP
	PFD Stream Number	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
	Vapour Fraction	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Temperature (C)	10.00	10.00	25.00	204.44	646.54	633.96	609.13	595.70	552.52	466.71	363.86	331.24	326.96	323.90	276.92	250.71	250.71	185.28	250.71	185.28	185.28	155.48	129.33	89.69
	Pressure (bar)	1.013	1.013	49.110	49.110	1.045	1.044	1.043	1.043	1.042	1.039	1.029	1.025	1.025	1.025	1.021	1.020	1.020	1.017	1.020	1.017	1.017	1.015	1.014	1.013
Overall	Actual Volume Flow (m3/h)	2777444.6	2777444.6	2254.2	4074.0	9158759.5	9039549.0	8798874.5	8668271.3	8243029.0	7404797.7	6441519.4	6133576.6	6090713.0	6061413.1	5602182.1	5343374.3	1091905.5	958357.3	4251468.8	3731480.4	4689839.8	4389130.4	4126381.1	3721592.0
	Mass Flow (tonne/h)	3455.8	3455.8	94.7	94.7	3550.5	3550.5	3550.5	3550.5	3550.5	3550.5	3550.5	3550.5	3550.5	3550.5	3550.5	3550.5	725.5	725.5	2825.0	2825.0	3550.5	3550.5	3550.5	3550.5
	Molar Flow (kgmole/h)	119636.8	119636.8	5115.6	5115.6	125084.2	125084.2	125084.2	125084.2	125084.2	125084.2	125084.2	125084.2	125084.2	125084.2	125084.2	125084.2	25560.6	25560.6	99523.5	99523.5	125084.2	125084.2	125084.2	125084.2
	Mass Density (kg/m3)	1.24	1.24	41.99	23.24	0.39	0.39	0.40	0.41	0.43	0.48	0.55	0.58	0.58	0.59	0.63	0.66	0.66	0.76	0.66	0.76	0.76	0.81	0.86	0.95
	Molecular Weight	28.89	28.89	18.50	18.50	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38
	Mass Heat Capacity (kJ/kg-C)	1.01	1.01	2.46	2.74	1.20	1.20	1.19	1.19	1.18	1.16	1.14	1.13	1.13	1.13	1.12	1.11	1.11	1.09	1.11	1.09	1.09	1.09	1.08	1.07
	Std Gas Flow (STD_m3/h)	2829000.0	2829000.0	121000.0	121000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	604400.0	604400.0	2353000.0	2353000.0	2958000.0	2958000.0	2958000.0	2958000.0
	Std Ideal Liq Vol Flow (m3/h)	3972.0	3972.0	289.1	289.1	4163.0	4163.0	4163.0	4163.0	4163.0	4163.0	4163.0	4163.0	4163.0	4163.0	4163.0	4163.0	850.6	850.6	3312.0	3312.0	4163.0	4163.0	4163.0	4163.0
	Viscosity (cP)	0.0180	0.0180	0.0125	0.0173	0.0407	0.0403	0.0393	0.0388	0.0372	0.0341	0.0305	0.0293	0.0292	0.0291	0.0274	0.0265	0.0265	0.0241	0.0265	0.0241	0.0241	0.0230	0.0219	0.0203
Vapour Phase	Actual Volume Flow (m3/h)	2777444.6	2777444.6	2254.2	4074.0	9158759.5	9039549.0	8798874.5	8668271.3	8243029.0	7404797.7	6441519.4	6133576.6	6090713.0	6061413.1	5602182.1	5343374.3	1091905.5	958357.3	4251468.8	3731480.4	4689839.8	4389130.4	4126381.1	3721592.0
	Mass Flow (tonne/h)	3455.8	3455.8	94.7	94.7	3550.5	3550.5	3550.5	3550.5	3550.5	3550.5	3550.5	3550.5	3550.5	3550.5	3550.5	3550.5	725.5	725.5	2825.0	2825.0	3550.5	3550.5	3550.5	3550.5
	Molar Flow (kgmole/h)	119636.8	119636.8	5115.6	5115.6	125084.2	125084.2	125084.2	125084.2	125084.2	125084.2	125084.2	125084.2	125084.2	125084.2	125084.2	125084.2	25560.6	25560.6	99523.5	99523.5	125084.2	125084.2	125084.2	125084.2
	Mass Density (kg/m3)	1.24	1.24	41.99	23.24	0.39	0.39	0.40	0.41	0.43	0.48	0.55	0.58	0.58	0.59	0.63	0.66	0.66	0.76	0.66	0.76	0.76	0.81	0.86	0.95
	Molecular Weight	28.89	28.89	18.50	18.50	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38	28.38
	Cp/Cv	1.40	1.40	1.49	1.24	1.32	1.32	1.33	1.33	1.33	1.34	1.35	1.35	1.35	1.35	1.36	1.36	1.36	1.37	1.36	1.37	1.37	1.37	1.37	1.38
	Std Gas Flow (STD_m3/h)	2829000.0	2829000.0	121000.0	121000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	2958000.0	604400.0	604400.0	2353000.0	2353000.0	2958000.0	2958000.0	2958000.0	2958000.0
	Viscosity (cP)	0.0180	0.0180	0.0125	0.0173	0.0407	0.0403	0.0393	0.0388	0.0372	0.0341	0.0305	0.0293	0.0292	0.0291	0.0274	0.0265	0.0265	0.0241	0.0265	0.0241	0.0241	0.0230	0.0219	0.0203
	Z Factor	0.9992	0.9992	0.8730	0.9849	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	0.9999	1.0000	0.9999	0.9999	0.9998	0.9996	0.9993
Liquid Phase	Actual Volume Flow (m3/h)																								
	Mass Flow (tonne/h)																								
	Molar Flow (kgmole/h)																								
	Mass Density (kg/m3)																								
	Molecular Weight																								
	Std Ideal Liq Vol Flow (m3/h)																								
	Surface Tension (dyne/cm)																								
	Viscosity (cP)																								
Aqueous Phase	Actual Volume Flow (m3/h)																								
	Mass Flow (tonne/h)																								
	Molar Flow (kgmole/h)																								
	Mass Density (kg/m3)																								
	Molecular Weight																								
	Std Ideal Liq Vol Flow (m3/h)																								
	Viscosity (cP)																								
Composition Mol	(CO2)	0.00030	0.00030	0.01910	0.01910	0.04606	0.04606	0.04606	0.04606	0.04606	0.04606	0.04606	0.04606	0.04606	0.04606	0.04606	0.04606	0.04606	0.04606	0.04606	0.04606	0.04606	0.04606	0.04606	0.04606
	(Nitrogen)	0.77512	0.77512	0.00990	0.00990	0.74178	0.74178	0.74178	0.74178	0.74178	0.74178	0.74178	0.74178	0.74178	0.74178	0.74178	0.74178	0.74178	0.74178	0.74178	0.74178	0.74178	0.74178	0.74178	0.74178
	(Oxygen)	0.20797	0.20797			0.11157	0.11157	0.11157	0.11157	0.11157	0.11157	0.11157	0.11157	0.11157	0.11157	0.11157	0.11157	0.11157	0.11157	0.11157	0.11157	0.11157	0.11157	0.11157	0.11157
	(H2S)			0.00004	0.00004																				
	(H2O)	0.00727	0.00727			0.09166	0.09166	0.09166	0.09166	0.09166	0.09166	0.09166	0.09166	0.09166	0.09166	0.09166	0.09166	0.09166	0.09166	0.09166	0.09166	0.09166	0.09166	0.09166	0.09166
	(Ammonia)																								
	(SO2)					0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
	(Argon)	0.00934	0.00934			0.00893	0.00893	0.00893	0.00893	0.00893	0.00893	0.00893	0.00893	0.00893	0.00893	0.00893	0.00893	0.00893	0.00893	0.00893	0.00893	0.00893	0.00893	0.00893	0.00893
	(NO2)																								
	(Methane)			0.87447	0.87447																				
	(Ethane)			0.06980	0.06980																				
	(Propane)			0.02190	0.02190																				
	(n-Butane)			0.00410	0.00410																				
	(n-Pentane)			0.00050	0.00050																				
	(n-Hexane)			0.00020	0.00020																				
	Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

Refer to Note 3.

PROJECT No.	181869	**DOCUMENT No.**	**181869-0001-D-EM-HMB-AAA-00-00001-01**
PROJECT NAME	THERMAL POWER WITH CCS	**REVISION**	**A04**
LOCATION	UK	**DATE**	**JULY 2017**

	Stream Description	Steam to HP Casing	Steam from HP Casing	Reheat Steam to HP Casing	MP Steam from HP Casing	MP Steam	MP Steam to CCP (Note 3)	MP Steam to IP Casing	Steam from IP Casing	Steam from LPS	Steam to IP/LP Casing	Steam from IP/LP Casing	LP Steam	LP Steam to CCP (Note 3)	LP Steam to LP Casing	Condensate from Turbine	Condensate from Condenser	Cooling Water Supply	Cooling Water Return	Condensate from Gland Steam	Condensate from Fuel Gas Heater	Condensate from E-103/104	Condensate from CCP	Condensate to Feedwater Tank	Water to LTE
	PFD Stream Number	**25**	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**	**41**	**42**	**43**	**44**	**45**	**46**	**47**	**48**
	Vapour Fraction	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Temperature (C)	573.89	342.37	573.89	522.71	522.71	235.00	522.71	270.72	291.90	272.66	234.41	234.41	138.70	234.41	39.16	39.15	17.50	35.50	39.67	104.44	51.47	49.50	50.58	50.58
	Pressure (bar)	165.000	34.390	30.000	21.510	21.510	21.510	21.510	3.375	3.375	3.375	2.400	2.400	2.400	2.400	0.071	0.429	2.986	2.308	4.023	33.890	4.023	4.023	4.023	4.023
Overall	Actual Volume Flow (m3/h)	10366.3	35853.9	67016.9	89891.2	1744.0	1323.6	88147.2	385993.3	40439.5	426436.1	561423.6	263641.8	230294.1	297781.8	6307545.4	311.6	9230.2	9275.6	311.6	71.0	382.0	314.9	696.9	668.4
	Mass Flow (tonne/h)	482.2	465.5	522.9	534.5	10.4	13.4	524.1	524.1	52.8	576.9	580.5	272.6	297.8	307.9	309.2	309.2	9217.5	9217.5	309.2	67.9	377.1	311.2	688.3	660.2
	Molar Flow (kgmole/h)	26766.4	25839.4	29025.7	29669.6	575.6	745.4	29093.9	29093.9	2929.8	32023.7	32223.0	15131.8	16530.6	17091.2	17163.4	17163.4	511654.1	511654.1	17163.4	3768.5	20931.9	17274.4	38206.3	36647.0
	Mass Density (kg/m3)	46.52	12.98	7.80	5.95	5.95	10.15	5.95	1.36	1.31	1.35	1.03	1.03	1.29	1.03	0.05	992.32	998.62	993.74	992.30	956.20	987.26	988.20	987.70	987.70
	Molecular Weight	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02
	Mass Heat Capacity (kJ/kg-C)	2.69	2.45	2.26	2.21	2.21	2.83	2.21	2.04	2.04	2.04	2.03	2.03	2.12	2.03	1.88	4.18	4.18	4.18	4.18	4.22	4.18	4.18	4.18	4.18
	Std Gas Flow (STD_m3/h)	632900.0	611000.0	686300.0	701500.0	13610.0	17630.0	687900.0	687900.0	69270.0	757200.0	761900.0	357800.0	390900.0	404100.0	405818.4	405818.4	12097772.8	12097772.8	405800.0	89100.0	419.5	408400.0	903400.0	866500.0
	Std Ideal Liq Vol Flow (m3/h)	483.2	466.4	524.0	535.6	10.4	13.5	525.2	525.2	52.9	578.1	581.7	273.2	298.4	308.5	309.8	309.8	9236.1	9236.1	309.8	68.0	57038.6	311.8	689.7	661.5
	Viscosity (cP)	0.0332	0.0222	0.0317	0.0295	0.0295	0.0171	0.0295	0.0190	0.0199	0.0191	0.0175	0.0175	0.0136	0.0175	0.0096	0.6621	1.0656	0.7113	0.6555	0.2665	0.5309	0.5488	0.5389	0.5389
Vapour Phase	Actual Volume Flow (m3/h)	10366.3	35853.9	67016.9	89891.2	1744.0	1323.6	88147.2	385993.3	40439.5	426436.1	561423.6	263641.8	230294.1	297781.8	6307545.4									
	Mass Flow (tonne/h)	482.2	465.5	522.9	534.5	10.4	13.4	524.1	524.1	52.8	576.9	580.5	272.6	297.8	307.9	309.2									
	Molar Flow (kgmole/h)	26766.4	25839.4	29025.7	29669.6	575.6	745.4	29093.9	29093.9	2929.8	32023.7	32223.0	15131.8	16530.6	17091.2	17163.4									
	Mass Density (kg/m3)	46.52	12.98	7.80	5.95	5.95	10.15	5.95	1.36	1.31	1.35	1.03	1.03	1.29	1.03	0.05									
	Molecular Weight	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02									
	Cp/Cv	1.42	1.39	1.29	1.30	1.30	1.45	1.30	1.32	1.31	1.31	1.32	1.32	1.35	1.32	1.33									
	Std Gas Flow (STD_m3/h)	632900.0	611000.0	686300.0	701500.0	13610.0	17630.0	687900.0	687900.0	69270.0	757200.0	761900.0	357800.0	390900.0	404100.0	405818.4									
	Viscosity (cP)	0.0332	0.0222	0.0317	0.0295	0.0295	0.0171	0.0295	0.0190	0.0199	0.0191	0.0175	0.0175	0.0136	0.0175	0.0096									
	Z Factor	0.9074	0.9324	0.9835	0.9849	0.9849	0.9040	0.9849	0.9902	0.9916	0.9904	0.9909	0.9909	0.9764	0.9909	0.9978									
Liquid Phase	Actual Volume Flow (m3/h)																								
	Mass Flow (tonne/h)																								
	Molar Flow (kgmole/h)																								
	Mass Density (kg/m3)																								
	Molecular Weight																								
	Std Ideal Liq Vol Flow (m3/h)																								
	Surface Tension (dyne/cm)																								
	Viscosity (cP)																								
Aqueous Phase	Actual Volume Flow (m3/h)																311.6	9230.2	9275.6	311.6	71.0	382.0	314.9	696.9	668.4
	Mass Flow (tonne/h)																309.2	9217.5	9217.5	309.2	67.9	377.1	311.2	688.3	660.2
	Molar Flow (kgmole/h)																17163.4	511654.1	511654.1	17163.4	3768.5	20931.9	17274.4	38206.3	36647.0
	Mass Density (kg/m3)																992.3	998.6	993.7	992.3	956.2	987.3	988.2	987.7	987.7
	Molecular Weight																18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02
	Std Ideal Liq Vol Flow (m3/h)																309.82	9236.10	9236.10	309.80	68.03	57038.57	311.80	689.70	661.50
	Viscosity (cP)																0.662	1.066	0.711	0.656	0.267	0.531	0.549	0.539	0.539
Composition Mol	(CO2)																								
	(Nitrogen)																								
	(Oxygen)																								
	(H2S)																								
	(H2O)	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
	(Ammonia)																								
	(SO2)																								
	(Argon)																								
	(NO2)																								
	(Methane)																								
	(Ethane)																								
	(Propane)																								
	(n-Butane)																								
	(n-Pentane)																								
	(n-Hexane)																								
	Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

Refer to Note 3.

HEAT AND MASS BALANCE

POWER GENERATION H&MB

SNC · LAVALIN

PROJECT No.	181869	**DOCUMENT No.**	**181869-0001-D-EM-HMB-AAA-00-00001-01**
PROJECT NAME	THERMAL POWER WITH CCS	**REVISION**	**A04**
LOCATION	UK	**DATE**	**JULY 2017**

	Stream Description	Water to LPE	Water to LPB/IP/HP Pumps	Water to LPB (V-103)	Water to HP Feedwater Pump	Water to IP Feedwater Pump	Steam to LPS	Steam from LPS	Water to HPE0	Water to IPB/ Fuel Gas Heater	Water to Fuel Gas Heater	Water to IPB (V-102)	Water to IPS1	Steam from IPS1	Water to IPE2	Water to HPE2	Water to HPE3	Water to HPB1 (V-101)	Steam from HPB1 (V-101)	Steam from HPS0	Steam from HPS3	Steam to RH1	Steam to RH3	Steam from RH3
	PFD Stream Number	49	50	51	52	53	54	55	56	57	58	59	60	61	62	63	64	65	66	67	69	70	71	72
	Vapour Fraction	0.000	0.000	0.000	0.000	0.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	1.000	0.000	0.000	0.000	0.000	1.000	1.000	1.000	1.000	1.000	1.000
	Temperature (C)	104.44	139.71	139.71	139.71	139.71	141.71	293.33	140.99	238.48	238.48	238.48	240.69	310.62	145.67	238.47	313.91	351.63	353.86	495.65	575.65	336.95	486.44	575.33
	Pressure (bar)	3.906	3.792	3.792	3.792	3.792	3.792	3.611	34.900	33.890	33.890	33.890	33.890	33.220	178.540	176.560	174.660	173.340	173.340	168.860	164.480	33.220	31.850	31.050
Overall	Actual Volume Flow (m3/h)	691.5	713.0	57.0	520.8	135.3	25658.8	37872.3	135.2	153.6	83.2	70.3	70.6	4271.2	518.4	581.1	688.7	842.7	3893.6	8647.4	10433.2	41326.8	55995.4	64830.0
	Mass Flow (tonne/h)	660.2	660.2	52.8	482.2	125.3	52.8	52.8	125.3	125.3	67.9	57.4	57.4	57.4	482.2	482.2	482.2	482.2	482.2	482.2	482.2	522.9	522.9	522.9
	Molar Flow (kgmole/h)	36647.0	36647.0	2929.8	26764.8	6952.5	2929.8	2929.8	6952.5	6952.5	3768.5	3184.0	3184.0	3184.0	26764.8	26764.8	26764.8	26764.8	26764.8	26764.8	26764.8	29025.7	29025.7	29025.7
	Mass Density (kg/m3)	954.70	925.90	925.90	925.90	925.90	2.06	1.39	926.50	815.70	815.70	815.70	812.40	13.43	930.20	829.70	700.10	572.20	123.80	55.76	46.22	12.65	9.34	8.07
	Molecular Weight	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02	18.02
	Mass Heat Capacity (kJ/kg-C)	4.22	4.29	4.29	4.29	4.29	2.25	2.05	4.28	4.76	4.76	4.76	4.78	2.59	4.25	4.62	5.79	10.62	18.86	3.02	2.68	2.45	2.24	2.26
	Std Gas Flow (STD_m3/h)	866500.0	866500.0	69270.0	632800.0	164400.0	69270.0	69270.0	164400.0	164400.0	89100.0	75280.0	75280.0	75280.0	632800.0	632800.0	632800.0	632800.0	632800.0	632800.0	632800.0	686300.0	686300.0	686300.0
	Std Ideal Liq Vol Flow (m3/h)	661.5	661.5	52.9	483.1	125.5	52.9	52.9	125.5	125.5	68.0	57.5	57.5	57.5	483.1	483.1	483.1	483.1	483.1	483.1	483.1	524.0	524.0	524.0
	Viscosity (cP)	0.2665	0.1954	0.1954	0.1954	0.1954	0.0136	0.0200	0.1935	0.1121	0.1121	0.1121	0.1111	0.0207	0.1869	0.1121	0.0858	0.0726	0.0467	0.0304	0.0333	0.0219	0.0282	0.0318
Vapour Phase	Actual Volume Flow (m3/h)						25658.8	37872.3						4271.2					3893.6	8647.4	10433.2	41326.8	55995.4	64830.0
	Mass Flow (tonne/h)						52.8	52.8						57.4					482.2	482.2	482.2	522.9	522.9	522.9
	Molar Flow (kgmole/h)						2929.8	2929.8						3184.0					26764.8	26764.8	26764.8	29025.7	29025.7	29025.7
	Mass Density (kg/m3)						2.06	1.39						13.43					123.80	55.76	46.22	12.65	9.34	8.07
	Molecular Weight						18.02	18.02						18.02					18.02	18.02	18.02	18.02	18.02	18.02
	Cp/Cv						1.37	1.31						1.41					5.07	1.54	1.42	1.39	1.32	1.29
	Std Gas Flow (STD_m3/h)						69270.0	69270.0						75280.0					632800.0	632800.0	632800.0	686300.0	686300.0	686300.0
	Viscosity (cP)						0.0136	0.0200						0.0207					0.0467	0.0304	0.0333	0.0219	0.0282	0.0318
	Z Factor						0.9628	0.9911						0.9181					0.4837	0.8535	0.9085	0.9324	0.9729	0.9831
Liquid Phase	Actual Volume Flow (m3/h)																							
	Mass Flow (tonne/h)																							
	Molar Flow (kgmole/h)																							
	Mass Density (kg/m3)																							
	Molecular Weight																							
	Std Ideal Liq Vol Flow (m3/h)																							
	Surface Tension (dyne/cm)																							
	Viscosity (cP)																							
Aqueous Phase	Actual Volume Flow (m3/h)	691.5	713.0	57.0	520.8	135.3			135.2	153.6	83.2	70.3	70.6		518.4	581.1	688.7	842.7						
	Mass Flow (tonne/h)	660.2	660.2	52.8	482.2	125.3			125.3	125.3	67.9	57.4	57.4		482.2	482.2	482.2	482.2						
	Molar Flow (kgmole/h)	36647.0	36647.0	2929.8	26764.8	6952.5			6952.5	6952.5	3768.5	3184.0	3184.0		26764.8	26764.8	26764.8	26764.8						
	Mass Density (kg/m3)	954.7	925.9	925.9	925.9	925.9			926.5	815.7	815.7	815.7	812.4		930.2	829.7	700.1	572.2						
	Molecular Weight	18.02	18.02	18.02	18.02	18.02			18.02	18.02	18.02	18.02	18.02		18.02	18.02	18.02	18.02						
	Std Ideal Liq Vol Flow (m3/h)	661.50	661.50	52.89	483.10	125.50			125.50	125.50	68.03	57.48	57.48		483.10	483.10	483.10	483.10						
	Viscosity (cP)	0.267	0.195	0.195	0.195	0.195			0.194	0.112	0.112	0.112	0.111		0.187	0.112	0.086	0.073						
Composition Mol	(CO2)																							
	(Nitrogen)																							
	(Oxygen)																							
	(H2S)																							
	(H2O)	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	
	(Ammonia)																							
	(SO2)																							
	(Argon)																							
	(NO2)																							
	(Methane)																							
	(Ethane)																							
	(Propane)																							
	(n-Butane)																							
	(n-Pentane)																							
	(n-Hexane)																							
	Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000				

Refer to Note 3.

PROJECT No.	**181869**	**DOCUMENT No.**	**181869-0001-D-EM-HMB-AAA-00-00001-01**
PROJECT NAME	**THERMAL POWER WITH CCS**	**REVISION**	**A04**
LOCATION	**UK**	**DATE**	**JULY 2017**

	Stream Description	Sour Gas Feed	Treated Gas to Stack	Treated Gas from Amine Reflux Drum	LP Steam to Reboiler	LP Condensate from Reboiler
	PFD Stream Number	**100**	**101**	**102**	**103**	**104**
	Vapour Fraction	1.000	1.000	1.000	1.000	0.000
	Temperature (C)	87.80	64.60	26.30	138.7	126.1
	Pressure (bar)	1.010	1.009	2.000	2.400	2.400
Overall	Actual Volume Flow (m3/h)	3714505.5	3170265.6	65083.0	233745.6	319.8
	Mass Flow (tonne/h)	3550.5	3215.1	230.2	299.9	299.9
	Molar Flow (kgmole/h)	125083.1	113959.6	5286.4	16647.2	16647.2
	Mass Density (kg/m3)	0.956	1.014	3.537	1.3	937.8
	Molecular Weight	28.39	28.21	43.55	18.0	18.0
	Mass Heat Capacity (kJ/kg-C)	1.06	1.04	0.86	1.9	4.6
	Std Gas Flow (STD_m3/h)	2957520.0	2694511.2	124994.2	393613.6	393613.6
	Std Ideal Liq Vol Flow (m3/h)	6292.1	5906.8	279.8	300.5	300.5
	Viscosity (cP)	0.0206	0.0199	0.0151	0.0141	0.2165
Vapour Phase	Actual Volume Flow (m3/h)	3714505.5	3170265.6	65083.0	233745.6	
	Mass Flow (tonne/h)	3550.5	3215.1	230.2	299.9	
	Molar Flow (kgmole/h)	125083.1	113959.6	5286.4	16647.2	
	Mass Density (kg/m3)	0.96	1.01	3.54	1.28	
	Molecular Weight	28.39	28.21	43.55	18.02	
	Cp/Cv	1.38	1.40	1.30	1.34	
	Std Gas Flow (STD_m3/h)	2957520.0	2694511.2	124994.2	393613.6	
	Viscosity (cP)	0.0206	0.0199	0.0151	0.0141	
	Z Factor	0.9994	0.9996	0.9890	0.9841	
Liquid Phase	Actual Volume Flow (m3/h)					
	Mass Flow (tonne/h)					
	Molar Flow (kgmole/h)					
	Mass Density (kg/m3)					
	Molecular Weight					
	Std Ideal Liq Vol Flow (m3/h)					
	Surface Tension (dyne/cm)					
	Viscosity (cP)					
Aqueous Phase	Actual Volume Flow (m3/h)					319.8
	Mass Flow (tonne/h)					299.9
	Molar Flow (kgmole/h)					16647.2
	Mass Density (kg/m3)					937.8
	Molecular Weight					18.02
	Std Ideal Liq Vol Flow (m3/h)					300.48
	Viscosity (cP)					0.216
Composition (Mol)	H2O	0.09166	0.04858	0.01749	1.000000	1.000000
	CO2	0.04606	0.00505	0.98090	0.000000	0.000000
	H2S	0.00000	0.00000	0.00000	0.000000	0.000000
	Oxygen	0.11157	0.12246	0.00002	0.000000	0.000000
	Nitrogen	0.74178	0.81417	0.00026	0.000000	0.000000
	SO2	0.00000	0.00000	0.00001	0.000000	0.000000
	Ammonia	0.00000	0.00000	0.00000	0.000000	0.000000
	Argon	0.00893	0.00974	0.00127	0.000000	0.000000
	NO2	0.00000	0.00000	0.00000	0.000000	0.000000
	Total	1.000	1.000	1.000	1.000	1.000

Refer to Note 2.

PROJECT No.	181869	DOCUMENT No.	181869-0001-D-EM-HMB-AAA-00-00001-01
PROJECT NAME	THERMAL POWER WITH CCS	REVISION	A04
LOCATION	UK	DATE	JULY 2017

	Stream Description	Gas to 1st Stage CO_2 Compressor KO Drum	Liquid from 1st Stage CO_2 Compressor KO Drum	Gas to 1st Stage CO_2 Compressor	Gas to 2nd Stage CO_2 Compressor KO Drum	Gas to 2nd Stage CO_2 Compressor	Liquid from 2nd Stage CO_2 Compressor KO Drum	Liquid to 1st Stage CO_2 Compressor KO Drum	Gas to 3rd Stage CO_2 Compressor KO Drum	Gas to 3rd Stage CO_2 Compressor	Liquid from 3rd Stage CO_2 Compressor KO Drum	Liquid to 2nd Stage CO_2 Compressor KO Drum	Gas to 4th Stage CO_2 Compressor KO Drum	Gas to 4th Stage CO_2 Compressor	Liquid from 4th Stage CO_2 Compressor KO Drum	Liquid to 3rd Stage CO_2 Compressor KO Drum	Gas to 5th Stage CO_2 Compressor KO Drum	Gas to CO_2 Dehydration	Liquid from 5th Stage CO_2 Compressor KO Drum	Liquid to 4rd Stage CO_2 Compressor KO Drum	Gas to 6th Stage CO_2 Compressor	Liquid from Process Condensate Return Pump	Liquid from Dehydration KO Drum	Gas from Dehydration KO Drum
	PFD Stream Number	201	202	203	204	205	206	207	208	209	210	211	212	213	214	215	216	217	218	219	220	221	222	223
	Vapour Fraction	1.000	0.000	1.000	1.000	1.000	0.000	0.001	1.000	1.000	0.000	0.002	1.000	1.000	0.000	0.004	1.000	1.000	0.000	0.007	1.000	0.000	0.006	1.000
	Temperature (C)	25.3	20.1	20.1	122.3	35.6	35.6	35.6	123.1	35.7	35.7	35.8	121.7	32.9	32.9	32.9	116.8	36.0	36.0	36.2	38.0	20.2	14.1	14.3
	Pressure (bar)	1.150	1.050	1.050	3.150	2.850	2.850	1.150	7.125	6.825	6.825	2.950	16.721	16.421	16.421	6.925	39.200	38.900	38.900	16.521	37.400	2.000	6.925	16.621
Overall	Actual Volume Flow (m3/h)	113349.4	1.6	122615.3	55064.8	47094.3	2.1	3.9	24150.3	19050.1	2.0	3.4	9920.6	8677.6	0.6	1.0	4629.7	3186.0	0.1	0.2	2883.8	1.6	0.6	1176.6
	Mass Flow (tonne/h)	230.2	1.7	230.7	230.7	230.6	2.1	2.1	230.6	229.4	2.0	2.0	229.4	269.3	0.6	0.6	269.3	269.2	0.1	0.1	228.5	1.7	0.3	40.4
	Molar Flow (kgmole/h)	5287.0	92.3	5313.0	5313.0	5306.0	118.8	118.8	5306.0	5244.0	111.4	111.4	5244.0	6134.0	32.9	33.0	6134.0	6128.0	6.2	6.2	5194.0	92.3	16.2	917.6
	Mass Density (kg/m3)	2.03	1011.00	1.88	4.19	4.90	999.80	547.00	9.55	12.04	1000.00	591.00	23.13	31.03	1004.00	589.30	58.17	84.49	1005.00	650.50	79.25	1011.00	494.00	34.29
	Molecular Weight	43.55	18.03	43.42	43.42	43.45	18.04	18.04	43.45	43.76	18.08	18.08	43.76	43.90	18.18	18.18	43.90	43.93	18.35	18.35	44.00	18.03	18.28	43.97
	Mass Heat Capacity (kJ/kg-C)	0.8826	4.3110	0.8807	0.9540	0.8996	4.3080	4.3060	0.9652	0.9156	4.2980	4.2950	0.9884	0.9743	4.2740	4.2670	1.0660	1.2160	4.2320	4.2200	1.1790	4.3110	4.2410	0.9832
	Std Gas Flow (STD_m3/h)	125000.0	2183.0	125600.0	125600.0	125400.0	2809.0	2809.0	125400.0	124000.0	2633.0	2633.0	124000.0	145000.0	778.5	780.8	145000.0	144900.0	147.5	147.5	122800.0	2183.0	382.5	21700.0
	Std Ideal Liq Vol Flow (m3/h)	278.4	1.7	278.9	278.9	278.8	2.1	2.1	278.8	277.7	2.0	2.0	277.7	326.0	0.6	0.6	326.0	325.9	0.1	0.1	276.8	1.7	0.3	48.9
	Viscosity (cP)	0.0145	0.9983	0.0141	0.0198	0.0150	0.7453		0.0200	0.0153	0.7406		0.0203	0.0156	0.7723		0.0209	0.0170	0.7165		0.0170	0.9981		0.0147
Vapour Phase	Actual Volume Flow (m3/h)	113349.4	0.0	122615.3	55064.8	47094.3	0.0	1.8	24150.3	19050.1	0.0	1.4	9920.6	8677.6	0.0	0.4	4629.7	3186.0	0.0	0.1	2883.8		0.3	1176.6
	Mass Flow (tonne/h)	230.2	0.0	230.7	230.7	230.6	0.0	0.0	230.6	229.4	0.0	0.0	229.4	269.3	0.0	0.0	269.3	269.2	0.0	0.0	228.5		0.0	40.4
	Molar Flow (kgmole/h)	5287.0	0.0	5313.0	5313.0	5306.0	0.0	0.1	5306.0	5244.0	0.0	0.2	5244.0	6134.0	0.0	0.1	6134.0	6128.0	0.0	0.0	5194.0		0.1	917.6
	Mass Density (kg/m3)	2.03	1.88	1.88	4.19	4.90	4.90	1.92	9.55	12.04	12.04	5.07	23.13	31.03	31.03	12.37	58.17	84.49	84.49	30.80	79.25		13.33	34.29
	Molecular Weight	43.55	43.42	43.42	43.42	43.45	43.45	42.69	43.45	43.76	43.76	43.48	43.76	43.90	43.90	43.81	43.90	43.93	43.93	43.89	44.00		43.94	43.97
	Cp/Cv	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.3	1.4	1.4	1.3	1.4	1.7	1.7	1.4	1.6		1.3	1.4
	Std Gas Flow (STD_m3/h)	125000.0	0.0	125600.0	125600.0	125400.0	0.0	1.9	125400.0	124000.0	0.0	3.9	124000.0	145000.0	0.0	2.8	145000.0	144900.0	0.0	1.1	122800.0		2.2	21700.0
	Viscosity (cP)	0.0145	0.0141	0.0141	0.0198	0.0150	0.0150	0.0146	0.0200	0.0153	0.0153	0.0150	0.0203	0.0156	0.0156	0.0152	0.0209	0.0170	0.0170	0.0158	0.0170		0.0142	0.0147
	Z Factor	0.9935	0.9937	0.9937	0.9930	0.9854	0.9854	0.9938	0.9843	0.9655	0.9655	0.9849	0.9636	0.9130	0.9130	0.9639	0.9124	0.7868	0.7868	0.9153	0.8026		0.9563	0.8918
Liquid Phase	Actual Volume Flow (m3/h)																							
	Mass Flow (tonne/h)																							
	Molar Flow (kgmole/h)																							
	Mass Density (kg/m3)																							
	Molecular Weight																							
	Std Ideal Liq Vol Flow (m3/h)																							
	Surface Tension (dyne/cm)																							
	Viscosity (cP)																							
Aqueous Phase	Actual Volume Flow (m3/h)		1.6	0.0		0.0	2.1	2.1		0.0	2.0	2.0		0.0	0.6	0.6		0.0	0.1	0.1		1.6	0.3	
	Mass Flow (tonne/h)		1.7	0.0		0.0	2.1	2.1		0.0	2.0	2.0		0.0	0.6	0.6		0.0	0.1	0.1		1.7	0.3	
	Molar Flow (kgmole/h)		92.3	0.0		0.0	118.8	118.7		0.0	111.4	111.2		0.0	32.9	32.9		0.0	6.2	6.2		92.3	16.1	
	Mass Density (kg/m3)		1011.0	1011.0		999.8	999.8	999.5		1000.0	1000.0	999.7		1004.0	1004.0	1003.0		1005.0	1005.0	1002.0		1011.0	1018.0	
	Molecular Weight		18.03	18.03		18.04	18.04	18.03		18.08	18.08	18.04		18.18	18.18	18.09		18.35	18.35	18.17		18.03	18.13	
	Std Ideal Liq Vol Flow (m3/h)		1.67	0.00		0.00	2.15	2.15		0.00	2.02	2.01		0.00	0.60	0.60		0.00	0.12	0.11		1.67	0.29	
	Viscosity (cP)		0.998	0.998		0.745	0.745	0.710		0.741	0.741	0.743		0.772	0.772	0.780		0.717	0.717	0.728		0.998	1.121	
Composition (Mol)	(CO2)	0.980901	0.000552	0.976031	0.976031	0.977429	0.001055	0.001055	0.977429	0.989035	0.002526	0.002526	0.989035	0.994518	0.006325	0.006325	0.994518	0.995517	0.013030	0.013030	0.998312	0.000552	0.010139	0.997061
	(Nitrogen)	0.000256	0.000000	0.000255	0.000255	0.000255	0.000000	0.000000	0.000255	0.000258	0.000000	0.000000	0.000258	0.000260	0.000000	0.000000	0.000260	0.000260	0.000000	0.000000	0.000261	0.000000	0.000000	0.000260
	(Oxygen)	0.000073	0.000000	0.000020	0.000020	0.000020	0.000000	0.000000	0.000020	0.000020	0.000000	0.000000	0.000020	0.000020	0.000000	0.000000	0.000020	0.000020	0.000000	0.000000	0.000020	0.000000	0.000000	0.000020
	(H2S)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	(H2O)	0.017490	0.999447	0.022368	0.022368	0.020968	0.998944	0.998944	0.020968	0.009343	0.997472	0.997472	0.009343	0.003851	0.993671	0.993671	0.003851	0.002850	0.986963	0.986963	0.000050	0.999447	0.989842	0.001302
	(Ammonia)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000001	0.000001	0.000000	0.000000	0.000002	0.000002	0.000000	0.000000	0.000015	0.000001
	(SO2)	0.000008	0.000000	0.000008	0.000008	0.000008	0.000001	0.000001	0.000008	0.000008	0.000001	0.000001	0.000008	0.000008	0.000003	0.000003	0.000008	0.000008	0.000005	0.000005	0.000008	0.000000	0.000004	0.000008
	(Argon)	0.001272	0.000000	0.001266	0.001266	0.001267	0.000000	0.000000	0.001267	0.001282	0.000000	0.000000	0.001282	0.001290	0.000000	0.000000	0.001290	0.001291	0.000000	0.000000	0.001295	0.000000	0.000000	0.001293
	(NO2)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

Refer to Note 4.

SNC·LAVALIN

HEAT AND MASS BALANCE

TEESSIDE TO ENDURANCE

PROJECT No.	**181869**	**DOCUMENT No.**	**181869-0001-D-EM-HMB-AAA-00-00001-01**
PROJECT NAME	**THERMAL POWER WITH CCS**	**REVISION**	**A04**
LOCATION	**UK**	**DATE**	**JULY 2017**

	Stream Description	**Gas to 6th Stage Cooler**	**Gas to 7th Stage CO_2 Compressor**	**Gas from 7th Stage CO_2 Compressor**	**Gas to 8th Stage Cooler**	**Gas from 8th Stage CO_2 Compressor**	**Gas to CO_2 Metering (Note6)**	**CO_2 to Onshore Pipeline**	**CO_2 to Offshore Pipeline**	**CO_2 to Pipeline Riser**	**CO_2 to Platform CO_2 Filter / Metering**	**CO_2 from Platform CO_2 Filter / Metering**	**CO_2 to injection well**
	PFD Stream Number	**224**	**225**	**226**	**227**	**228**	**229**	**240**	**241**	**242**	**243**	**244**	**245**
	Vapour Fraction	1.000	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Temperature (C)	97.5	36.0	75.0	120.3	36.0	36.0	36.0	35.9	4.2	3.6	3.6	3.5
	Pressure (bar)	69.190	68.990	110.000	183.940	183.740	183.740	183.240	182.460	151.480	142.310	141.810	139.810
Overall	Actual Volume Flow (m3/h)	1883.4	1074.8	835.5	650.1	274.6	1373.0	1373.7	1374.2	1163.1	1165.5	1165.7	233.3
	Mass Flow (tonne/h)	228.5	228.5	228.5	228.5	228.5	1143.0	1143.0	1143.0	1143.0	1143.0	1143.0	228.5
	Molar Flow (kgmole/h)	5194.0	5194.0	5194.0	5194.0	5194.0	25970.0	25970.0	25970.0	25970.0	25970.0	25970.0	5194.0
	Mass Density (kg/m3)	121.30	212.60	273.50	351.50	832.30	832.30	831.90	831.60	982.50	980.50	980.20	979.40
	Molecular Weight	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00
	Mass Heat Capacity (kJ/kg-C)	1.2610	2.7480	2.1900	1.8380	2.5030	2.5030	2.5060	2.5110	2.1960	2.2210	2.2230	2.2290
	Std Gas Flow (STD_m3/h)	122800.0	122800.0	122800.0	122800.0	122800.0	614100.0	614100.0	614100.0	614100.0	614100.0	614100.0	122800.0
	Std Ideal Liq Vol Flow (m3/h)	276.8	276.8	276.8	276.8	276.8	1384.0	1384.0	1384.0	1384.0	1384.0	1384.0	276.8
	Viscosity (cP)	0.0216	0.0210	0.0261	0.0331	0.0540	0.0540	0.0540	0.0539	0.1047	0.1054	0.1054	0.1055
Vapour Phase	Actual Volume Flow (m3/h)	1883.4	1074.8	835.5	650.1								
	Mass Flow (tonne/h)	228.5	228.5	228.5	228.5								
	Molar Flow (kgmole/h)	5194.0	5194.0	5194.0	5194.0								
	Mass Density (kg/m3)	121.30	212.60	273.50	351.50								
	Molecular Weight	44.00	44.00	44.00	44.00								
	Cp/Cv	1.6	3.6	2.7	2.1								
	Std Gas Flow (STD_m3/h)	122800.0	122800.0	122800.0	122800.0								
	Viscosity (cP)	0.0216	0.0210	0.0261	0.0331								
	Z Factor	0.8142	0.5554	0.6113	0.7037								
Liquid Phase	Actual Volume Flow (m3/h)					274.6	1373.0	1373.7	1374.2	1163.1	1165.5	1165.7	233.3
	Mass Flow (tonne/h)					228.5	1143.0	1143.0	1143.0	1143.0	1143.0	1143.0	228.5
	Molar Flow (kgmole/h)					5194.0	25970.0	25970.0	25970.0	25970.0	25970.0	25970.0	5194.0
	Mass Density (kg/m3)					832.30	832.30	831.90	831.60	982.50	980.50	980.20	979.40
	Molecular Weight					44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00
	Std Ideal Liq Vol Flow (m3/h)					276.8	1384.0	1384.0	1384.0	1384.0	1384.0	1384.0	276.8
	Surface Tension (dyne/cm)					0.0037	0.0037	0.0037	0.0037	6.9240	7.0830	7.0860	7.1010
	Viscosity (cP)					0.0540	0.0540	0.0540	0.0539	0.1047	0.1054	0.1054	0.1055
Aqueous Phase	Actual Volume Flow (m3/h)												
	Mass Flow (tonne/h)												
	Molar Flow (kgmole/h)												
	Mass Density (kg/m3)												
	Molecular Weight												
	Std Ideal Liq Vol Flow (m3/h)												
	Viscosity (cP)												
Composition (Mol)	(CO2)	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312
	(Nitrogen)	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261
	(Oxygen)	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020
	(H2S)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	(H2O)	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050
	(Ammonia)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	(SO2)	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008
	(Argon)	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295
	(NO2)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

Refer to Note 6.

PROJECT No.	**181869**	**DOCUMENT No.**	**181869-0001-D-EM-HMB-AAA-00-00001-01**
PROJECT NAME	**THERMAL POWER WITH CCS**	**REVISION**	**A04**
LOCATION	**UK**	**DATE**	**JULY 2017**

	Stream Description	**Gas to 6th Stage Cooler**	**Gas to 7th Stage CO_2 Compressor**	**Gas from 7th Stage CO_2 Compressor**	**Gas to 8th Stage Cooler**	**Gas from 8th Stage CO_2 Compressor**	**Gas to CO_2 Metering (Note6)**	**CO_2 to Onshore Pipeline**	**CO_2 to Offshore Pipeline**	**CO_2 to Pipeline Riser**	**CO_2 to Platform CO_2 Filter / Metering**	**CO_2 from Platform CO_2 Filter / Metering**	**CO_2 to injection well**
	PFD Stream Number	**224**	**225**	**226**	**227**	**228**	**229**	**240**	**241**	**242**	**243**	**244**	**245**
	Vapour Fraction	1.000	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Temperature (C)	97.5	36.0	75.0	115.5	36.0	36.0	36.0	35.0	4.2	3.6	3.6	3.5
	Pressure (bar)	69.190	68.990	110.000	174.380	174.180	174.180	173.680	167.530	151.480	142.310	141.810	139.810
Overall	Actual Volume Flow (m3/h)	1883.3	1074.7	835.4	666.6	279.1	1395.5	1396.2	1400.4	1163.0	1165.4	1165.7	233.3
	Mass Flow (tonne/h)	228.5	228.5	228.5	228.5	228.5	1143.0	1143.0	1143.0	1143.0	1143.0	1143.0	228.5
	Molar Flow (kgmole/h)	5194.0	5194.0	5194.0	5194.0	5194.0	25970.0	25970.0	25970.0	25970.0	25970.0	25970.0	5194.0
	Mass Density (kg/m3)	121.30	212.60	273.50	342.80	818.80	818.80	818.40	815.90	982.50	980.50	980.20	979.40
	Molecular Weight	44.00	44.00	44.00	44.00	*44.00*	44.00	44.00	44.00	44.00	44.00	44.00	44.00
	Mass Heat Capacity (kJ/kg-C)	1.2610	2.7480	2.1900	1.8650	2.5810	2.5810	2.5840	2.6240	2.1960	2.2210	2.2230	2.2290
	Std Gas Flow (STD_m3/h)	122800.0	122800.0	122800.0	122800.0	122800.0	614000.0	614000.0	614000.0	614000.0	614000.0	614000.0	122800.0
	Std Ideal Liq Vol Flow (m3/h)	276.8	276.8	276.8	276.8	276.8	1384.0	1384.0	1384.0	1384.0	1384.0	1384.0	276.8
	Viscosity (cP)	0.0216	0.0210	0.0261	0.0323	0.0534	0.0534	0.0534	0.0532	0.1047	0.1054	0.1054	0.1055
Vapour Phase	Actual Volume Flow (m3/h)	1883.3	1074.7	835.4	666.6								
	Mass Flow (tonne/h)	228.5	228.5	228.5	228.5								
	Molar Flow (kgmole/h)	5194.0	5194.0	5194.0	5194.0								
	Mass Density (kg/m3)	121.30	212.60	273.50	342.80								
	Molecular Weight	44.00	44.00	44.00	44.00								
	Cp/Cv	1.6	3.6	2.7	2.2								
	Std Gas Flow (STD_m3/h)	122800.0	122800.0	122800.0	122800.0								
	Viscosity (cP)	0.0216	0.0210	0.0261	0.0323								
	Z Factor	0.8142	0.5554	0.6113	0.6926								
Liquid Phase	Actual Volume Flow (m3/h)					279.1	1395.5	1396.2	1400.4	1163.0	1165.4	1165.7	233.3
	Mass Flow (tonne/h)					228.5	1143.0	1143.0	1143.0	1143.0	1143.0	1143.0	228.5
	Molar Flow (kgmole/h)					5194.0	25970.0	25970.0	25970.0	25970.0	25970.0	25970.0	5194.0
	Mass Density (kg/m3)					818.80	818.80	818.40	815.90	982.50	980.50	980.20	979.40
	Molecular Weight					44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00
	Std Ideal Liq Vol Flow (m3/h)					276.8	1384.0	1384.0	1384.0	1384.0	1384.0	1384.0	276.8
	Surface Tension (dyne/cm)					0.0037	0.0037	0.0037	0.0037	6.9240	7.0830	7.0860	7.1010
	Viscosity (cP)					0.0534	0.0534	0.0534	0.0532	0.1047	0.1054	0.1054	0.1055
Aqueous Phase	Actual Volume Flow (m3/h)												
	Mass Flow (tonne/h)												
	Molar Flow (kgmole/h)												
	Mass Density (kg/m3)												
	Molecular Weight												
	Std Ideal Liq Vol Flow (m3/h)												
	Viscosity (cP)												
Composition (Mol)	(CO2)	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312
	(Nitrogen)	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261
	(Oxygen)	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020
	(H2S)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	(H2O)	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050
	(Ammonia)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	(SO2)	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008
	(Argon)	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295
	(NO2)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

Refer to Note 6.

PROJECT No.	**181869**	**DOCUMENT No.**	**181869-0001-D-EM-HMB-AAA-00-00001-01**
PROJECT NAME	**THERMAL POWER WITH CCS**	**REVISION**	**A04**
LOCATION	**UK**	**DATE**	**JULY 2017**

	Stream Description	**Gas to 6th Stage Cooler**	**Gas to 7th Stage CO_2 Compressor**	**Gas from 7th Stage CO_2 Compressor**	**Gas to 8th Stage Cooler**	**Gas from 8th Stage CO_2 Compressor**	**Gas to CO_2 Metering (Note6)**	**CO_2 to Onshore Pipeline**	**CO_2 to Offshore Pipeline**	**CO_2 to Pipeline Riser**	**CO_2 to Platform CO_2 Filter / Metering**	**CO_2 from Platform CO_2 Filter / Metering**	**CO_2 to injection well**
	PFD Stream Number	**224**	**225**	**226**	**227**	**228**	**229**	**240**	**241**	**242**	**243**	**244**	**245**
	Vapour Fraction	1.000	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Temperature (C)	97.5	36.0	75.0	114.7	36.0	36.0	36.0	35.3	4.2	3.6	3.6	3.5
	Pressure (bar)	69.190	68.990	110.000	172.910	172.710	172.710	172.210	167.530	151.480	142.310	141.810	139.810
Overall	Actual Volume Flow (m3/h)	1883.3	1074.7	835.4	669.3	279.8	1399.2	1399.9	1403.2	1163.0	1165.4	1165.7	233.3
	Mass Flow (tonne/h)	228.5	228.5	228.5	228.5	228.5	1143.0	1143.0	1143.0	1143.0	1143.0	1143.0	228.5
	Molar Flow (kgmole/h)	5194.0	5194.0	5194.0	5194.0	5194.0	25970.0	25970.0	25970.0	25970.0	25970.0	25970.0	5194.0
	Mass Density (kg/m3)	121.30	212.60	273.50	341.40	816.60	816.60	816.20	814.30	982.50	980.50	980.20	979.40
	Molecular Weight	44.00	44.00	44.00	44.00	*44.00*	44.00	44.00	44.00	44.00	44.00	44.00	44.00
	Mass Heat Capacity (kJ/kg-C)	1.2610	2.7480	2.1900	1.8690	2.5940	2.5940	2.5980	2.6280	2.1960	2.2210	2.2230	2.2290
	Std Gas Flow (STD_m3/h)	122800.0	122800.0	122800.0	122800.0	122800.0	614000.0	614000.0	614000.0	614000.0	614000.0	614000.0	122800.0
	Std Ideal Liq Vol Flow (m3/h)	276.8	276.8	276.8	276.8	276.8	1384.0	1384.0	1384.0	1384.0	1384.0	1384.0	276.8
	Viscosity (cP)	0.0216	0.0210	0.0261	0.0321	0.0533	0.0533	0.0533	0.0531	0.1047	0.1054	0.1054	0.1055
Vapour Phase	Actual Volume Flow (m3/h)	1883.3	1074.7	835.4	669.3								
	Mass Flow (tonne/h)	228.5	228.5	228.5	228.5								
	Molar Flow (kgmole/h)	5194.0	5194.0	5194.0	5194.0								
	Mass Density (kg/m3)	121.30	212.60	273.50	341.40								
	Molecular Weight	44.00	44.00	44.00	44.00								
	Cp/Cv	1.6	3.6	2.7	2.2								
	Std Gas Flow (STD_m3/h)	122800.0	122800.0	122800.0	122800.0								
	Viscosity (cP)	0.0216	0.0210	0.0261	0.0321								
	Z Factor	0.8142	0.5554	0.6113	0.6909								
Liquid Phase	Actual Volume Flow (m3/h)					279.8	1399.2	1399.9	1403.2	1163.0	1165.4	1165.7	233.3
	Mass Flow (tonne/h)					228.5	1143.0	1143.0	1143.0	1143.0	1143.0	1143.0	228.5
	Molar Flow (kgmole/h)					5194.0	25970.0	25970.0	25970.0	25970.0	25970.0	25970.0	5194.0
	Mass Density (kg/m3)					816.60	816.60	816.20	814.30	982.50	980.50	980.20	979.40
	Molecular Weight					44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00
	Std Ideal Liq Vol Flow (m3/h)					276.8	1384.0	1384.0	1384.0	1384.0	1384.0	1384.0	276.8
	Surface Tension (dyne/cm)					0.0037	0.0037	0.0037	0.0037	6.9240	7.0830	7.0860	7.1010
	Viscosity (cP)					0.0533	0.0533	0.0533	0.0531	0.1047	0.1054	0.1054	0.1055
Aqueous Phase	Actual Volume Flow (m3/h)												
	Mass Flow (tonne/h)												
	Molar Flow (kgmole/h)												
	Mass Density (kg/m3)												
	Molecular Weight												
	Std Ideal Liq Vol Flow (m3/h)												
	Viscosity (cP)												
Composition (Mol)	(CO2)	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312
	(Nitrogen)	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261
	(Oxygen)	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020
	(H2S)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	(H2O)	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050
	(Ammonia)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	(SO2)	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008
	(Argon)	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295
	(NO2)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

Refer to Note 6.

SNC·LAVALIN

HEAT AND MASS BALANCE

NORTH WEST TO HAMILTON GAS

PROJECT No.	**181869**	**DOCUMENT No.**	**181869-0001-D-EM-HMB-AAA-00-00001-01**
PROJECT NAME	**THERMAL POWER WITH CCS**	**REVISION**	**A04**
LOCATION	**UK**	**DATE**	**JULY 2017**

	Stream Description	**Gas to 6th Stage Cooler**	**Gas to 7th Stage CO_2 Compressor**	**Gas from 7th Stage CO_2 Compressor**	**Gas to 8th Stage Cooler (Note 5)**	**Gas from 8th Stage CO_2 Compressor (Note 5)**	**Gas to CO_2 Metering (Note6)**	**CO_2 to Onshore Pipeline Upstream Valve (Note 7)**	**CO_2 to Onshore Pipeline Downstream Valve (Note 7)**	**CO_2 to Offshore Pipeline**	**CO_2 to Pipeline Riser**	**CO_2 to Platform CO_2 Filter / Metering**	**CO_2 to Offshore Heater**	**CO_2 from Offshore Heater**	**CO_2 to injection well**
	PFD Stream Number	**224**	**225**	**226**	**227**	**228**	**229**	**240**	**246**	**241**	**242**	**243**	**244**	**247**	**245**
	Vapour Fraction	1.000	1.000	1.000			1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Temperature (C)	97.5	46.0	73.8			73.8	73.5	65.2	45.2	27.8	26.5	25.9	32.2	30.0
	Pressure (bar)	69.190	68.990	94.000			94.000	93.500	81.527	62.139	51.821	51.000	50.500	49.500	47.500
Overall	Actual Volume Flow (m3/h)	1883.3	1265.3	1052.8			3158.5	3173.7	3597.8	4479.2	4965.0	5024.2	5074.5	5609.9	3411.9
	Mass Flow (tonne/h)	228.5	228.5	228.5			685.6	685.6	685.6	685.6	685.6	685.6	685.6	685.6	399.8
	Molar Flow (kgmole/h)	5194.0	5194.0	5194.0			15580.0	15580.0	15580.0	15580.0	15580.0	15580.0	15580.0	15580.0	9086.0
	Mass Density (kg/m3)	121.30	180.60	217.10			217.10	216.00	190.60	153.10	138.10	136.50	135.10	122.20	117.20
	Molecular Weight	44.00	44.00	44.00			44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00
	Mass Heat Capacity (kJ/kg-C)	1.2610	1.9320	1.8410			1.8410	1.8390	1.7600	1.6650	1.7010	1.6970	1.6870	1.4960	1.4660
	Std Gas Flow (STD_m3/h)	122800.0	122800.0	122800.0			368400.0	368400.0	368400.0	368400.0	368400.0	368400.0	368400.0	368400.0	214800.0
	Std Ideal Liq Vol Flow (m3/h)	276.8	276.8	276.8			830.3	830.3	830.3	830.3	830.3	830.3	830.3	830.3	484.1
	Viscosity (cP)	0.0216	0.0204	0.0235			0.0235	0.0234	0.0220	0.0195	0.0180	0.0179	0.0178	0.0178	0.0176
Vapour Phase	Actual Volume Flow (m3/h)	1883.3	1265.3	1052.8			3158.5	3173.7	3597.8	4479.2	4965.0	5024.2	5074.5	5609.9	3411.9
	Mass Flow (tonne/h)	228.5	228.5	228.5			685.6	685.6	685.6	685.6	685.6	685.6	685.6	685.6	399.8
	Molar Flow (kgmole/h)	5194.0	5194.0	5194.0			15580.0	15580.0	15580.0	15580.0	15580.0	15580.0	15580.0	15580.0	9086.0
	Mass Density (kg/m3)	121.30	180.60	217.10			217.10	216.00	190.60	153.10	138.10	136.50	135.10	122.20	117.20
	Molecular Weight	44.00	44.00	44.00			44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00
	Cp/Cv	1.6	2.5	2.3			2.3	2.3	2.3	2.2	2.3	2.3	2.3	2.0	2.0
	Std Gas Flow (STD_m3/h)	122800.0	122800.0	122800.0			368400.0	368400.0	368400.0	368400.0	368400.0	368400.0	368400.0	368400.0	214800.0
	Viscosity (cP)	0.0216	0.0204	0.0235			0.0235	0.0234	0.0220	0.0195	0.0180	0.0179	0.0178	0.0178	0.0176
	Z Factor	0.8142	0.6333	0.6605			0.6605	0.6608	0.6691	0.6749	0.6600	0.6601	0.6614	0.7020	0.7077
Liquid Phase	Actual Volume Flow (m3/h)														
	Mass Flow (tonne/h)														
	Molar Flow (kgmole/h)														
	Mass Density (kg/m3)														
	Molecular Weight														
	Std Ideal Liq Vol Flow (m3/h)														
	Surface Tension (dyne/cm)														
	Viscosity (cP)														
Aqueous Phase	Actual Volume Flow (m3/h)														
	Mass Flow (tonne/h)														
	Molar Flow (kgmole/h)														
	Mass Density (kg/m3)														
	Molecular Weight														
	Std Ideal Liq Vol Flow (m3/h)														
	Viscosity (cP)														
Composition (Mol)	(CO2)	0.998312	0.998312	0.998312			0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312
	(Nitrogen)	0.000261	0.000261	0.000261			0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261
	(Oxygen)	0.000020	0.000020	0.000020			0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020
	(H2S)	0.000000	0.000000	0.000000			0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	(H2O)	0.000050	0.000050	0.000050			0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050
	(Ammonia)	0.000000	0.000000	0.000000			0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	(SO2)	0.000008	0.000008	0.000008			0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008
	(Argon)	0.001295	0.001295	0.001295			0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295
	(NO2)	0.0000	0.0000	0.0000			0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	Total	1.000	1.000	1.000			1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

Refer to Notes 5 & 7.

PROJECT No.	181869		DOCUMENT No.	181869-0001-D-EM-HMB-AAA-00-00001-01
PROJECT NAME	THERMAL POWER WITH CCS		REVISION	A04
LOCATION	UK		DATE	JULY 2017

	Stream Description	Gas to 6th Stage Cooler	Gas to 7th Stage CO_2 Compressor	Gas from 7th Stage CO_2 Compressor	Gas from 7th Stage Cooler (Note 8)	Gas from 8th Stage CO_2 Compressor (Note 5)	Gas to CO_2 Metering (Note 6)	CO_2 to Onshore Pipeline (Note 10)	CO_2 to Pipeline Chiller (Note 9, 10)	CO_2 from Pipeline Chiller (Note 9)	CO_2 to Pipeline Riser	CO_2 to Platform CO_2 Filter / Metering	CO_2 from Platform CO_2 Filter / Metering	CO_2 to injection well
	PFD Stream Number	224	225	226	227	228	229	240	241	247	242	243	244	245
	Vapour Fraction	1.000	1.000	1.000	0.000		0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Temperature (C)	97.5	36.0	61.7	36.0		36.0	35.9	33.6	12.8	13.4	12.8	12.8	10.0
	Pressure (bar)	69.190	68.990	94.000	93.000		93.000	92.500	86.471	85.471	83.544	78.437	77.937	49.320
Overall	Actual Volume Flow (m3/h)	1883.3	1074.7	907.3	389.9		1169.8	1171.5	1166.4	771.5	777.0	777.7	777.9	459.8
Overall	Mass Flow (tonne/h)	228.5	228.5	228.5	228.5		685.6	685.6	685.6	685.6	685.6	685.6	685.6	399.8
Overall	Molar Flow (kgmole/h)	5194.0	5194.0	5194.0	5194.0		15580.0	15580.0	15580.0	15580.0	15580.0	15580.0	15580.0	9086.0
Overall	Mass Density (kg/m3)	121.30	212.60	251.90	586.10		586.10	585.20	587.80	888.60	882.40	881.60	881.30	869.40
Overall	Molecular Weight	44.00	44.00	44.00	44.00		44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00
Overall	Mass Heat Capacity (kJ/kg-C)	1.2610	2.7480	2.3440	6.2990		6.2990	6.3770	7.1150	2.8920	2.9550	3.0100	3.0170	3.5450
Overall	Std Gas Flow (STD_m3/h)	122800.0	122800.0	122800.0	122800.0		368400.0	368400.0	368400.0	368400.0	368400.0	368400.0	368400.0	214800.0
Overall	Std Ideal Liq Vol Flow (m3/h)	276.8	276.8	276.8	276.8		830.3	830.3	830.3	830.3	830.3	830.3	830.3	484.1
Overall	Viscosity (cP)	0.0216	0.0210	0.0242	0.0427		0.0427	0.0427	0.0426	0.0870	0.0858	0.0866	0.0866	0.0892
Vapour Phase	Actual Volume Flow (m3/h)	1883.3	1074.7	907.3										
Vapour Phase	Mass Flow (tonne/h)	228.5	228.5	228.5										
Vapour Phase	Molar Flow (kgmole/h)	5194.0	5194.0	5194.0										
Vapour Phase	Mass Density (kg/m3)	121.30	212.60	251.90										
Vapour Phase	Molecular Weight	44.00	44.00	44.00										
Vapour Phase	Cp/Cv	1.6	3.6	2.9										
Vapour Phase	Std Gas Flow (STD_m3/h)	122800.0	122800.0	122800.0										
Vapour Phase	Viscosity (cP)	0.0216	0.0210	0.0242										
Vapour Phase	Z Factor	0.8142	0.5554	0.5898										
Liquid Phase	Actual Volume Flow (m3/h)				389.9		1169.8	1171.5	1166.4	771.5	777.0	777.7	777.9	459.8
Liquid Phase	Mass Flow (tonne/h)				228.5		685.6	685.6	685.6	685.6	685.6	685.6	685.6	399.8
Liquid Phase	Molar Flow (kgmole/h)				5194.0		15580.0	15580.0	15580.0	15580.0	15580.0	15580.0	15580.0	9086.0
Liquid Phase	Mass Density (kg/m3)				586.10		586.10	585.20	587.80	888.60	882.40	881.60	881.30	869.40
Liquid Phase	Molecular Weight				44.00		44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00
Liquid Phase	Std Ideal Liq Vol Flow (m3/h)				276.8		830.3	830.3	830.3	830.3	830.3	830.3	830.3	484.1
Liquid Phase	Surface Tension (dyne/cm)				0.0037		0.0037	0.0037	0.0037	4.7330	4.5850	4.7440	4.7550	5.4540
Liquid Phase	Viscosity (cP)				0.0427		0.0427	0.0427	0.0426	0.0870	0.0858	0.0866	0.0866	0.0892
Aqueous Phase	Actual Volume Flow (m3/h)													
Aqueous Phase	Mass Flow (tonne/h)													
Aqueous Phase	Molar Flow (kgmole/h)													
Aqueous Phase	Mass Density (kg/m3)													
Aqueous Phase	Molecular Weight													
Aqueous Phase	Std Ideal Liq Vol Flow (m3/h)													
Aqueous Phase	Viscosity (cP)													
Composition (Mol)	(CO2)	0.998312	0.998312	0.998312	0.998312		0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312
Composition (Mol)	(Nitrogen)	0.000261	0.000261	0.000261	0.000261		0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261
Composition (Mol)	(Oxygen)	0.000020	0.000020	0.000020	0.000020		0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020	0.000020
Composition (Mol)	(H2S)	0.000000	0.000000	0.000000	0.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Composition (Mol)	(H2O)	0.000050	0.000050	0.000050	0.000050		0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050
Composition (Mol)	(Ammonia)	0.000000	0.000000	0.000000	0.000000		0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Composition (Mol)	(SO2)	0.000008	0.000008	0.000008	0.000008		0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008
Composition (Mol)	(Argon)	0.001295	0.001295	0.001295	0.001295		0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295
Composition (Mol)	(NO2)	0.0000	0.0000	0.0000	0.0000		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	Total	1.000	1.000	1.000	1.000		1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

Refer to Notes 5, 8, 9, 10.

PROJECT No.	181869	**DOCUMENT No.**	181869-0001-D-EM-HMB-AAA-00-00001-01
PROJECT NAME	THERMAL POWER WITH CCS	**REVISION**	A04
LOCATION	UK	**DATE**	JULY 2017

	Stream Description	Gas to Plant CO_2 Metering	Gas from Plant CO_2 Metering	Gas to Onshore Pipeline	Onshore Pipeline at No. 10 Feeder	Gas to CO_2 Pipeline Booster Compressor KO Drum	Liquid from CO_2 Pipeline Booster Compressor KO Drum	Gas to Pipeline Booster Compressor	Gas to Pipeline Booster Compressor Cooler	Onshore Pipeline at Kirriemuir	Onshore Pipeline at St Fergus	Gas to 6th Stage CO_2 Compressor KO Drum (Note 11)	Liquid from 6th Stage CO_2 Compressor KO Drum
	PFD Stream Number	**250**	**251**	**252**	**253**	**254**	**255**	**256**	**257**	**258**	**259**	**260**	**261**
	Vapour Fraction	1.000	1.000	1.000	1.000	1.000	0.000	1.000	1.000	1.000	1.000	1.000	0.000
	Temperature (C)	38.0	37.5	35.5	16.7	0.9	0.7	0.7	52.6	36.0	14.7	12.7	12.6
	Pressure (bar)	37.400	36.900	35.013	33.541	19.486	19.386	19.386	35.013	34.813	20.083	18.483	18.383
Overall	Actual Volume Flow (m3/h)	8651.5	8772.8	9262.3	8614.1	15466.2	0.0	15549.5	10196.7	9357.1	16120.8	8784.3	0.0
	Mass Flow (tonne/h)	685.6	685.6	685.6	685.6	685.6	0.0	685.6	685.6	685.6	685.6	342.8	0.0
	Molar Flow (kgmole/h)	15580.0	15580.0	15580.0	15580.0	15580.0	0.0	15580.0	15580.0	15580.0	15580.0	7792.0	0.0
	Mass Density (kg/m3)	79.25	78.15	74.02	79.59	44.33	889.90	44.09	67.24	73.27	42.53	39.03	38.81
	Molecular Weight	44.00	44.00	44.00	44.00	44.00	43.92	44.00	44.00	44.00	44.00	44.00	44.00
	Mass Heat Capacity (kJ/kg-C)	1.1790	1.1750	1.1560	1.2270	1.0330	3.2590	1.0320	1.1070	1.1510	1.0180	1.0030	1.0020
	Std Gas Flow (STD_m3/h)	368500.0	368500.0	368500.0	368500.0	368500.0	0.0	368500.0	368500.0	368500.0	368500.0	184200.0	0.0
	Std Ideal Liq Vol Flow (m3/h)	830.3	830.3	830.3	830.3	830.3	0.0	830.3	830.3	830.3	830.3	415.2	0.0
	Viscosity (cP)	0.0170	0.0170	0.0168	0.0158	0.0142	0.1037	0.0142	0.0176	0.0168	0.0149	0.0147	0.0108
Vapour Phase	Actual Volume Flow (m3/h)	8651.5	8772.8	9262.3	8614.1	15466.2	0.0	15549.5	10196.7	9357.1	16120.8	8784.3	0.0
	Mass Flow (tonne/h)	685.6	685.6	685.6	685.6	685.6	0.0	685.6	685.6	685.6	685.6	342.8	0.0
	Molar Flow (kgmole/h)	15580.0	15580.0	15580.0	15580.0	15580.0	0.0	15580.0	15580.0	15580.0	15580.0	7792.0	0.0
	Mass Density (kg/m3)	79.25	78.15	74.02	79.59	44.33	44.09	44.09	67.24	73.27	42.53	39.03	38.81
	Molecular Weight	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00
	Cp/Cv	1.6	1.6	1.6	1.7	1.5	1.5	1.5	1.5	1.6	1.5	1.5	1.5
	Std Gas Flow (STD_m3/h)	368500.0	368500.0	368500.0	368500.0	368500.0	0.0	368500.0	368500.0	368500.0	368500.0	184200.0	0.0
	Viscosity (cP)	0.0170	0.0170	0.0168	0.0158	0.0142	0.0142	0.0142	0.0176	0.0168	0.0149	0.0147	0.0147
	Z Factor	0.8026	0.8043	0.8109	0.7695	0.8488	0.8494	0.8494	0.8460	0.8133	0.8682	0.8767	0.8773
Liquid Phase	Actual Volume Flow (m3/h)						0.0	0.0					0.0
	Mass Flow (tonne/h)						0.0	0.0					0.0
	Molar Flow (kgmole/h)						0.0	0.0					0.0
	Mass Density (kg/m3)						889.90	889.90					38.81
	Molecular Weight						43.92	43.92					44.00
	Std Ideal Liq Vol Flow (m3/h)						0.0	0.0					0.0
	Surface Tension (dyne/cm)						8.0470	8.0470					4.7950
	Viscosity (cP)						0.1037	0.1037					0.0108
Aqueous Phase	Actual Volume Flow (m3/h)												
	Mass Flow (tonne/h)												
	Molar Flow (kgmole/h)												
	Mass Density (kg/m3)												
	Molecular Weight												
	Std Ideal Liq Vol Flow (m3/h)												
	Viscosity (cP)												
Composition (Mol)	(CO2)	0.998312	0.998312	0.998312	0.998312	0.998312	0.996187	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312
	(Nitrogen)	0.000261	0.000261	0.000261	0.000261	0.000261	0.000022	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261
	(Oxygen)	0.000074	0.000074	0.000074	0.000074	0.000074	0.000008	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074
	(H2S)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	(H2O)	0.000050	0.000050	0.000050	0.000050	0.000050	0.003550	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050
	(Ammonia)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	(SO2)	0.000008	0.000008	0.000008	0.000008	0.000008	0.000065	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008
	(Argon)	0.001295	0.001295	0.001295	0.001295	0.001295	0.000168	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295
	(NO2)	0	0	0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

	Stream Description	Gas to 6th Stage CO_2 Compressor	Gas to 6th Stage Cooler	Gas to 7th Stage CO_2 Compressor	Gas from 7th Stage CO_2 Compressor	Gas to 8th Stage Cooler	Gas from 8th Stage CO_2 Compressor	CO_2 to Atlantic Pipeline (to Captain X)	CO_2 to Offshore Pipeline	CO_2 to Offshore Pipeline Riser	CO_2 to Platform CO_2 Filter / Metering	CO_2 from Platform CO_2 Filter / Metering	CO_2 to injection well
	PFD Stream Number	**262**	**224**	**225**	**226**	**227**	**228**	**240**	**241**	**242**	**243**	**244**	**245**
	Vapour Fraction	1.000	1.000	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Temperature (C)	12.6	125.9	36.0	99.0	119.8	36.0	36.0	35.8	11.0	10.1	10.1	10.0
	Pressure (bar)	18.383	60.663	60.463	120.930	149.830	149.630	149.130	148.590	146.430	132.500	132.000	130.000
Overall	Actual Volume Flow (m3/h)	8833.8	3749.3	2103.3	1390.9	1238.1	440.6	440.8	440.9	361.8	363.4	363.5	181.7
	Mass Flow (tonne/h)	342.8	342.8	342.8	342.8	342.8	342.8	342.8	342.8	342.8	342.8	342.8	171.2
	Molar Flow (kgmole/h)	7792.0	7792.0	7792.0	7792.0	7792.0	7792.0	7792.0	7792.0	7792.0	7792.0	7792.0	3892.0
	Mass Density (kg/m3)	38.81	91.43	163.00	246.50	276.90	778.10	777.60	777.60	947.60	943.30	943.10	942.20
	Molecular Weight	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00
	Mass Heat Capacity (kJ/kg-C)	1.0020	1.1460	1.8910	1.7340	1.6790	2.8580	2.8630	2.8680	2.3170	2.3730	2.3760	2.3850
	Std Gas Flow (STD_m3/h)	184200.0	184200.0	184200.0	184200.0	184200.0	184200.0	184200.0	184200.0	184200.0	184200.0	184200.0	92020.0
	Std Ideal Liq Vol Flow (m3/h)	415.2	415.2	415.2	415.2	415.2	415.2	415.2	415.2	415.2	415.2	415.2	207.4
	Viscosity (cP)	0.0147	0.0224	0.0193	0.0262	0.0289	0.0516	0.0516	0.0516	0.0932	0.0941	0.0941	0.0942
Vapour Phase	Actual Volume Flow (m3/h)	8833.8	3749.3	2103.3	1390.9	1238.1							
	Mass Flow (tonne/h)	342.8	342.8	342.8	342.8	342.8							
	Molar Flow (kgmole/h)	7792.0	7792.0	7792.0	7792.0	7792.0							
	Mass Density (kg/m3)	38.81	91.43	163.00	246.50	276.90							
	Molecular Weight	44.00	44.00	44.00	44.00	44.00							
	Cp/Cv	1.5	1.5	2.5	2.1	2.0							
	Std Gas Flow (STD_m3/h)	184200.0	184200.0	184200.0	184200.0	184200.0							
	Viscosity (cP)	0.0147	0.0224	0.0193	0.0262	0.0289							
	Z Factor	0.8773	0.8797	0.6350	0.6976	0.7287							
Liquid Phase	Actual Volume Flow (m3/h)	0.0					440.6	440.8	440.9	361.8	363.4	363.5	181.7
	Mass Flow (tonne/h)	0.0					342.8	342.8	342.8	342.8	342.8	342.8	171.2
	Molar Flow (kgmole/h)	0.0					7792.0	7792.0	7792.0	7792.0	7792.0	7792.0	3892.0
	Mass Density (kg/m3)	38.81					778.10	777.60	777.60	947.60	943.30	943.10	942.20
	Molecular Weight	44.00					44.00	44.00	44.00	44.00	44.00	44.00	44.00
	Std Ideal Liq Vol Flow (m3/h)	0.0					415.2	415.2	415.2	415.2	415.2	415.2	207.4
	Surface Tension (dyne/cm)	4.7950					0.0037	0.0037	0.0037	5.1990	5.4280	5.4330	5.4550
	Viscosity (cP)	0.0108					0.0516	0.0516	0.0516	0.0932	0.0941	0.0941	0.0942
Aqueous Phase	Actual Volume Flow (m3/h)												
	Mass Flow (tonne/h)												
	Molar Flow (kgmole/h)												
	Mass Density (kg/m3)												
	Molecular Weight												
	Std Ideal Liq Vol Flow (m3/h)												
	Viscosity (cP)												
Composition (Mol)	(CO2)	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312
	(Nitrogen)	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261
	(Oxygen)	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074
	(H2S)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	(H2O)	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050
	(Ammonia)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
	(SO2)	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008
	(Argon)	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295
	(NO2)	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0	0
	Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

Refer to Note 11.

SNC·LAVALIN

HEAT AND MASS BALANCE

SCOTLAND GOLDENEYE

PROJECT No.	181869	DOCUMENT No.	181869-0001-D-EM-HMB-AAA-00-00001-01
PROJECT NAME	THERMAL POWER WITH CCS	REVISION	A04
LOCATION	UK	DATE	JULY 2017

	Stream Description	Gas to Plant CO_2 Metering	Gas from Plant CO_2 Metering	CO_2 to Onshore Pipeline	Onshore Pipeline at No. 10 Feeder	Gas to CO_2 Pipeline Booster Compressor KO Drum	Liquid from CO_2 Pipeline Booster Compressor KO Drum	Gas to Pipeline Booster Compressor	Gas to Pipeline Booster Compressor Cooler	Onshore Pipeline at Kirriemuir	Onshore Pipeline at St Fergus	Gas to 6th Stage CO_2 Compressor KO Drum (Note 11)	Liquid from 6th Stage CO_2 Compressor KO Drum	Gas to 6th Stage CO_2 Compressor	Gas to 6th Stage Cooler	Gas to 7th Stage CO_2 Compressor	Gas from 7th Stage CO_2 Compressor	Gas to 8th Stage Cooler	Gas from 8th Stage CO_2 Compressor	CO_2 to Goldeneye Pipeline (to Goldeneye)	CO_2 to Offshore Pipeline	CO_2 to Offshore Pipeline Riser	CO_2 to Platform CO_2 Filter / Metering	CO_2 from Platform CO_2 Filter / Metering	CO_2 to injection well
	PFD Stream Number	**250**	**251**	**252**	**253**	**254**	**255**	**256**	**257**	**258**	**259**	**260**	**261**	**262**	**224**	**225**	**226**	**227**	**228**	**240**	**241**	**242**	**243**	**244**	**245**
	Vapour Fraction	1.000	1.000	1.000	1.000	1.000	0.000	1.000	1.000	1.000	1.000	1.000	0.000	1.000	1.000	1.000	1.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Temperature (C)	38.0	37.5	35.5	16.7	0.9	0.7	0.7	52.6	36.0	14.7	12.7	12.6	12.6	116.0	36.0	90.6	104.3	36.0	35.9	35.8	11.0	10.0	9.9	9.7
	Pressure (bar)	37.400	36.900	35.013	33.541	19.486	19.386	19.386	35.013	34.813	20.083	18.483	18.383	18.383	55.148	54.948	98.906	113.700	113.500	113.000	112.610	119.470	105.370	103.870	101.010
Overall	Actual Volume Flow (m3/h)	8651.5	8772.8	9262.3	8614.1	15466.2	0.0	15549.5	10196.7	9357.1	16120.8	8784.3	0.0	8833.8	4014.6	2474.2	1706.4	1571.5	498.1	498.6	498.5	368.9	370.8	371.0	141.0
Overall	Mass Flow (tonne/h)	685.6	685.6	685.6	685.6	685.6	0.0	685.6	685.6	685.6	685.6	342.8	0.0	342.8	342.8	342.8	342.8	342.8	342.8	342.8	342.8	342.8	342.8	342.8	130.1
Overall	Molar Flow (kgmole/h)	15580.0	15580.0	15580.0	15580.0	15580.0	0.0	15580.0	15580.0	15580.0	15580.0	7792.0	0.0	7792.0	7792.0	7792.0	7792.0	7792.0	7792.0	7792.0	7792.0	7792.0	7792.0	7792.0	2958.0
Overall	Mass Density (kg/m3)	79.25	78.15	74.02	79.59	44.33	889.90	44.09	67.24	73.27	42.53	39.03	38.81	38.81	85.39	138.60	200.90	218.20	688.20	687.60	687.70	929.30	924.60	923.90	922.70
Overall	Molecular Weight	44.00	44.00	44.00	44.00	44.00	43.92	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	*44.00*	44.00	44.00	44.00	44.00	44.00	44.00
Overall	Mass Heat Capacity (kJ/kg-C)	1.1790	1.1750	1.1560	1.2270	1.0330	3.2590	1.0320	1.1070	1.1510	1.0180	1.0030	1.0020	1.0020	1.1340	1.6180	1.6050	1.5910	3.8290	3.8460	3.8550	2.4740	2.5550	2.5650	2.5850
Overall	Std Gas Flow (STD_m3/h)	368500.0	368500.0	368500.0	368500.0	368500.0	0.0	368500.0	368500.0	368500.0	368500.0	184200.0	0.0	184200.0	184200.0	184200.0	184200.0	184200.0	184200.0	184200.0	184200.0	184200.0	184200.0	184200.0	69930.0
Overall	Std Ideal Liq Vol Flow (m3/h)	830.3	830.3	830.3	830.3	830.3	0.0	830.3	830.3	830.3	830.3	415.2	0.0	415.2	415.2	415.2	415.2	415.2	415.2	415.2	415.2	415.2	415.2	415.2	157.6
Overall	Viscosity (cP)	0.0170	0.0170	0.0168	0.0158	0.0142	0.1037	0.0142	0.0176	0.0168	0.0149	0.0147	0.0108	0.0147	0.0216	0.0185	0.0238	0.0253	0.0476	0.0475	0.0475	0.0920	0.0930	0.0931	0.0932
Vapour Phase	Actual Volume Flow (m3/h)	8651.5	8772.8	9262.3	8614.1	15466.2	0.0	15549.5	10196.7	9357.1	16120.8	8784.3	0.0	8833.8	4014.6	2474.2	1706.4	1571.5							
Vapour Phase	Mass Flow (tonne/h)	685.6	685.6	685.6	685.6	685.6	0.0	685.6	685.6	685.6	685.6	342.8	0.0	342.8	342.8	342.8	342.8	342.8							
Vapour Phase	Molar Flow (kgmole/h)	15580.0	15580.0	15580.0	15580.0	15580.0	0.0	15580.0	15580.0	15580.0	15580.0	7792.0	0.0	7792.0	7792.0	7792.0	7792.0	7792.0							
Vapour Phase	Mass Density (kg/m3)	79.25	78.15	74.02	79.59	44.33	44.09	44.09	67.24	73.27	42.53	39.03	38.81	38.81	85.39	138.60	200.90	218.20							
Vapour Phase	Molecular Weight	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00	44.00							
Vapour Phase	Cp/Cv	1.6	1.6	1.6	1.7	1.5	1.5	1.5	1.5	1.6	1.5	1.5	1.5	1.5	1.5	2.2	2.0	2.0							
Vapour Phase	Std Gas Flow (STD_m3/h)	368500.0	368500.0	368500.0	368500.0	368500.0	0.0	368500.0	368500.0	368500.0	368500.0	184200.0	0.0	184200.0	184200.0	184200.0	184200.0	184200.0							
Vapour Phase	Viscosity (cP)	0.0170	0.0170	0.0168	0.0158	0.0142	0.0142	0.0142	0.0176	0.0168	0.0149	0.0147	0.0147	0.0147	0.0216	0.0185	0.0238	0.0253							
Vapour Phase	Z Factor	0.8026	0.8043	0.8109	0.7695	0.8488	0.8494	0.8494	0.8460	0.8133	0.8682	0.8767	0.8773	0.8773	0.8781	0.6788	0.7162	0.7307							
Liquid Phase	Actual Volume Flow (m3/h)						0.0	0.0					0.0	0.0					498.1	498.6	498.5	368.9	370.8	371.0	141.0
Liquid Phase	Mass Flow (tonne/h)						0.0	0.0					0.0	0.0					342.8	342.8	342.8	342.8	342.8	342.8	130.1
Liquid Phase	Molar Flow (kgmole/h)						0.0	0.0					0.0	0.0					7792.0	7792.0	7792.0	7792.0	7792.0	7792.0	2958.0
Liquid Phase	Mass Density (kg/m3)						889.90	889.90					38.81	38.81					688.20	687.60	687.70	929.30	924.60	923.90	922.70
Liquid Phase	Molecular Weight						43.92	43.92					44.00	44.00					44.00	44.00	44.00	44.00	44.00	44.00	44.00
Liquid Phase	Std Ideal Liq Vol Flow (m3/h)						0.0	0.0					0.0	0.0					415.2	415.2	415.2	415.2	415.2	415.2	157.6
Liquid Phase	Surface Tension (dyne/cm)						8.0470	8.0470					4.7950	4.7950					0.0037	0.0037	0.0037	5.1960	5.4610	5.4820	5.5230
Liquid Phase	Viscosity (cP)						0.1037	0.1037					0.0108	0.0108					0.0476	0.0475	0.0475	0.0920	0.0930	0.0931	0.0932
Aqueous Phase	Actual Volume Flow (m3/h)																								
Aqueous Phase	Mass Flow (tonne/h)																								
Aqueous Phase	Molar Flow (kgmole/h)																								
Aqueous Phase	Mass Density (kg/m3)																								
Aqueous Phase	Molecular Weight																								
Aqueous Phase	Std Ideal Liq Vol Flow (m3/h)																								
Aqueous Phase	Viscosity (cP)																								
Composition (Mol)	(CO2)	0.998312	0.998312	0.998312	0.998312	0.998312	0.996187	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312	0.998312
Composition (Mol)	(Nitrogen)	0.000261	0.000261	0.000261	0.000261	0.000261	0.000022	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261	0.000261
Composition (Mol)	(Oxygen)	0.000074	0.000074	0.000074	0.000074	0.000074	0.000008	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074	0.000074
Composition (Mol)	(H2S)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Composition (Mol)	(H2O)	0.000050	0.000050	0.000050	0.000050	0.000050	0.003550	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050	0.000050
Composition (Mol)	(Ammonia)	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000
Composition (Mol)	(SO2)	0.000008	0.000008	0.000008	0.000008	0.000008	0.000065	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008	0.000008
Composition (Mol)	(Argon)	0.001295	0.001295	0.001295	0.001295	0.001295	0.000168	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295	0.001295
Composition (Mol)	(NO2)	0	0	0	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0	0
	Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

Refer to Note 11.

Attachment 3 – Major Equipment List

MAJOR EQUIPMENT LIST

Document No: **181869-0001-T-EM-MEL-AAA-00-00001**

Revision **: A05** Date **: 07-JUL-2017**

This document has been electronically checked and approved. The electronic approval and signature can be found in FOCUS, cross referenced to this document under the Tasks tab, reference No: T072933.

A05	07-JUL-2017	Re-Issued for Use	T. ALI	M.WILLS	S. DURHAM	M. WILLS
A04	24-MAY-2017	Issued for Use	T. ALI	M.WILLS	S. DURHAM	M. WILLS
A03	09-MAY-2017	Issued for Use	M.WILLS	T. ALI	S. DURHAM	M. WILLS
A02	26-APR-2017	Issued for Use	M.WILLS	T. ALI	S. DURHAM	M. WILLS
A01	04-APR-2017	Issued for Internal Review	M.WILLS	T.ALI	S. DURHAM	M. WILLS
REV	**DATE**	**ISSUE DESCRIPTION**	**BY**	**DISC CHKD**	**QA/QC**	**APPVD**

Disclaimer

REVISION	COMMENTS
A01	Issued for Internal Review
A02	Issued for Use (updates in red) 1. Scaling Factors for DCC Cooler and Wash Water Pumps updated per modelling report. 2. Scaling factors for Lean / Rich Exchanger, compressor power, and Blowers corrected per modelling report. 3. Missing electrical loads added.
A03	Re-Issued for Use (updates in red) 1. Hamilton updated for offshore heating. 2. Additional launcher / receivers added from pipelines technical note.
A04	Re-Issued for Use (updates in red) 1. Incorporate Client comment and match PFDs 2. Addition of Captain X platform.
A05	Re-Issued for Use (updates in red) 1. Incorporate Scotland locations

HOLDS	
HOLD DESCRIPTION / REFERENCE	
<HOLD 1>	Deleted.
<HOLD 2>	Deleted.
<HOLD 3>	Deleted.
<HOLD 4>	Deleted.
<HOLD 5>	Deleted.
<HOLD 6>	Deleted.
<HOLD 7>	Deleted.

The Major Equipment List has been developed as an input to the cost estimate. The Major Equipment List is presented for each of a number of locations as described below:

CONTENTS

NOTES

1. Equipment List has been created using SNC-Lavalin template 181869-0001-Q-QA-TMP-0009.

2. Equipment tagging in line with the Equipment and Material Coding Standard, Document Reference 4001-HCST-LON rev 00.

Asset Designations	NE	North East
	NW	North West
	SC	Scotland
	EN	Endurance
	HA	Hamilton
	GE	Goldeneye
	CA	Captain X

Train Numbering	0	Common
	1	Train 1
	2	Train 2
	3	Train 3
	4	Train 4
	5	Train 5
	9	Offshore

Only Train 1 is shown on the attached equipment list for the study phase – however, any equipment details for train 1 would be identical for trains 2 to 5.

3. Main Process Equipment from the PFDs:
   - Process Flow Diagram – Power Generation, 181869-0001-D-EM-PFD-AAA-00-00001-01
   - Process Flow Diagram – Carbon Capture, 181869-0001-D-EM-PFD-AAA-00-00001-02
   - Process Flow Diagram – CO_2 Compression, 181869-0001-D-EM-PFD-AAA-00-00001-03
   - Process Flow Diagram – Transport and Storage, 181869-0001-D-EM-PFD-AAA-00-00001-04
   - Process Flow Diagram – Scotland CO_2 Compression and Pipeline, 181869-0001-D-EM-PFD-AAA-00-00001-05

4. The equipment sizing is an output from the modelling (please refer to Technical Note - Scheme Modelling, 181869-0001-T-EM-TNT-AAA-00-00010). Note that Power modelling was for a GE HA.02 machine and this has been scaled back to a 500 MW (nominal) machine which also affects utilities and steam side sizing.

5. Carbon Capture equipment originally sourced from Equipment List (Capture and Compression Plant), PCCS-02-TC-AA-4322-00001, rev K01.

6. Offshore equipment originally sourced from K36: Offshore Installation Plot Plan, November 2015.

7. CO_2 Absorber sized from 181869-0001-T-EM-CAL-AAA-00-00004 rev A02. Other equipment sizing calculations can be found in 181869-0001-T-EM-CAL-AAA-00-00016.

8. Work Breakdown Structure for the Equipment List (WBS):

   - Power
   - Natural Gas
   - Carbon Capture
   - Compression
   - Cooling Water
   - Waste Water Treatment
   - Utilities
   - Facilities
   - Transportation
   - Offshore

9. Carbon Capture numbers include overdesign margin (10% to 20%).

10. Unabated Standby column assumes turndown of carbon capture amine and washes to 40% flow, with no Flue Gas and CO_2 flow through the unit. The amine and wash flows are continued in ‘hot’ standby mode to keep the amine at temperature and to keep packings wetted in order to allow a quick restart of the carbon capture and compression process. Absorbed motor power is assumed at 60% of rated for 40% flow rate.

PROJECT No.	181869
PROJECT NAME	Thermal Power with CCS: Generic Business Case
LOCATION	UK

DOCUMENT No.	181869-0001-T-EM-MEL-AAA-00-00001
REVISION	A05
DATE	JULY 2017

PLANT AREA	EQUIPMENT NUMBER							ITEM DESCRIPTION	TYPE	PFD Number	ELECTRICAL POWER						OPERATING PRESSURE			OPERATING TEMPERATURE			DESIGN PRESSURE		DESIGN TEMPER-ATURE		DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit)	MATERIAL OF CONSTRUCTION	DIMENSIONS			WEIGHT		REMARKS
	ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT			181869-0001-D-EM-PFD-AAA-00-00001-XX	ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	CCS STANDBY (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	MIN (barg)	NORMAL (barg)	MAX (barg)	MIN (°C)	NORMAL (°C)	MAX (°C)	MIN (barg)	MAX (barg)	MIN (°C)	MAX (°C)			m^2		Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	DRY (tonnes)	OPERATING (tonnes)	
Steam Generation Equipment																																				
Power	NE		B	1	01			Heat Recovery Steam Generator	Horizontal Drum	01	0	0	n/a	n/a				173.3			647.6			190	-5	600	600718	kW		CS (TP409 / T91 / T22 on high temp side)	40.0	25.0	31.0			Includes SCR catalyst, CO calayst, and Ammonia System
Power	NE		B	1	02			Auxiliary Boiler	Package		112	167	LV	n/a				7			220			10	-5	250	23	T/hr		CS (SA 192 Tubes)	8.3	4.3	4.7	103	151.0	Assume 1 Auxiliary Boiler per Train
Compressors																																				
Compression	NE		C	1	01			CO_2 Compressor	Centrifugal	03	24297	27000	MV	0				See	Pkg	Below																Part of Package U-101 Motor sizing includes 10% API 617 Margin
Stack																																				
Power	NE		D	1	01			Stack	Self Supporting	02	0	0	n/a	n/a				0.013			87.77				-5	750	3551	T/hr		CS - outer 316Ti - liner		10.0	90.0			Includes baseplate, anchor bolting, inner liner, outer shell, top cover, insulation, Flue Gas Inlet, Access/cleaning doors, condensation drain, ladders, platforms, AWLs, sample points, earth points, lifting lugs,
Power	NE		D	1	03			Auxiliary Boiler Stack	Self Supporting		0	0	n/a	n/a				0.02			184				-5	750				CS		1.0	30.0			
Carbon Capture	NE		D	1	02			CO_2 Vent Stack	Self Supporting		0	0	n/a	n/a				0.72			-10				-79	250	229306	kg/hr		316L SS		30"	30.0	4.5		Sch 10S
Heat Exchangers																																				
Power	NE		E	1	02			Condenser (Water Cooled)	2 pass	01	0	0	n/a	n/a				-0.93			39.16		FV	1	-5	110	355487	kW	12055	304 SS Tubes	20.7	6.1		510.0		Including steam ejectors for vaccuum
Power	NE		E	1	03			Fuel Gas Heater	Shell & Tube	01	0	0	n/a	n/a				49.1 / 36.6			204.4 / 242.9			55 / 41	-5	310	10674	kW	500	CS / 316L SS Tube	12.4	0.9		23.9		Feedwater - Tubeside, Fuel Gas - Shellside
Power	NE		E	1	04			Gland Steam Condenser	Shell & Tube	01	0	0	n/a	n/a									FV/0	.45/34	-5	270 / 100	378	kW	14	SS Tubes	4.5	1.7	3.1	3.5		Part of Steam Turbine Supply
Power	NE		E	1	22			Electric Superheater	Electric Heater		0	4415	MV	n/a				49.1			70			55	-5	310	2677	kW		316L SS / Alloy 800 pockets	5.5	1.3				Start Up Heater (sized to provide superheat only), includes pressure vessel, thyristor control panel (safe area)
Power	NE		E	1	23	A-E		GT + Generator Lube Oil Cooler	Plate & Frame		0	0	n/a	n/a				3			37.5			6	-5	50	1417	kW								Part of RS-101
Power	NE		E	1	24	A-F		GT Generator Cooler	Plate & Frame		0	0	n/a	n/a				3			37.5			6	-5	50	6667	kW								Part of R-101
Power	NE		E	1	25	A/B		ST + Generator Lube Oil Cooler	Plate & Frame		0	0	n/a	n/a				3			37.5			6	-5	50	850	kW								Part of RS-102
Power	NE		E	1	26	A/B		ST Generator Cooler	Plate & Frame		0	0	n/a	n/a				3			37.5			6	-5	50	4000	kW								Part of R-102
Carbon Capture	NE		E	1	01			Gas-Gas Heat Exchanger	Rotary	02	15	15	LV	0										0.125	-5	130	30269	kW	13521	Weathering Steel	15.6	15.6	4.5	340.2		Purge and Scavenge Fan shall be part of this package
Carbon Capture	NE		E	1	09	A/B/C		Lean / Rich Amine Exchanger	Welded Plate	02	0	0	n/a	n/a				5.1 / 5.9			122.3 / 111			18	-20	140	77734	kW	14457	316L SS	2.5	3.5	18.0	400.0	430.0	e.g. Packinox type or equal. Duty was for 2 units - now split into 3 units
Carbon Capture	NE		E	1	10	A-F		CO_2 Stripper Reboilers	Welded Plate	02	0	0	n/a	n/a				2.1			122.3			5	-5	150	36847	kW	1403	316L SS	2.8	1.8		10.6		
Carbon Capture	NE		E	1	11	A/B		Overhead Condenser	Welded Plate	02	0	0	n/a	n/a				2			26			12	-5	160	32519	kW	1122	316L SS	3.1	1.7		7.5		
Carbon Capture	NE		E	1	12	A/B		Wash Water Cooler	Welded Plate	02	0	0	n/a	n/a										10	-5	85	53918	kW	1555	316L SS	5.8	1.6	3.8	13.7		
Carbon Capture	NE		E	1	13			Lean Amine Cooler	Welded Plate	02	0	0	n/a	n/a										12	-5	85	35740	kW	928	316L SS	5.0	1.5	2.0	29.0		
Carbon Capture	NE		E	1	14	A/B/C		DCC Cooler	Plate & Frame	02	0	0	n/a	n/a										9	-5	85	42097	kW	1927	316L SS	6.1	1.7	3.6	13.0		Duty was for 2 units - now split into 3 units
Carbon Capture	NE		E	1	15			CO_2 Vent Vapouriser	Inverted Kettle		0	0	n/a	n/a									FV	10 / 27	-79	270	3835	kW	111	CS / 316L SS	3.7	1.5		5.5		
Carbon Capture	NE		E	1	16	A/B		CC Unit Condensate Cooler	Plate & Frame		0	0	n/a	n/a										8	-5	160	18127	kW	383	316L SS	4.3	1.3	2.3	6.1		
Carbon Capture	NE		E	1	18			Thermal Reclaimer Pre-Heater	Welded Plate		0	0	n/a	n/a										8	-5	160	594	kW	61	316L SS				4.6		
Carbon Capture	NE		E	1	19			IX Amine Cooler	Welded Plate		0	0	n/a	n/a										12	-5	85	345	kW	60	316L SS	1.0	1.0		0.6		
Carbon Capture	NE		E	1	20			IX Demin Water Cooler	Plate & Frame		0	0	n/a	n/a										9	-5	160	2892	kW	9	316L SS	0.7	0.5	1.3	0.5		
Compression	NE		E	1	05			6th Stage Cooler	Shell & Tube	03	0	0	n/a	n/a				68.2			97.5 / 36						6216	kW		CS						Part of Package U-101
Compression	NE		E	1	06			8th Stage Cooler	Shell & Tube	03	0	0	n/a	n/a				182.9			119.8 / 36						13200	kW		CS						Part of Package U-101
Compression	NE		E	1	07			CO_2 Dehydration Electric Heater	Electric Heater	03	3488	3800	MV	0				37.4			22.9 / 290			47	-5	310	3488	kW		316L SS	5.6	1.6	2.4	4.0		Alternative DT= -79°C for Rapid Depressurisation
Compression	NE		E	1	08			Dehydration Cooler	Shell & Tube	03	0	0	n/a	n/a				36.6						47	-5	310	3323	kW	166	316L SS						Alternative DT= -79°C for Rapid Depressurisation
Cooling Plant	NE		E	1	21	A-T		Cooling Towers	Wet		0	0	n/a	n/a				3			13 / 23			6	-5	50	35849	kW	856 kg/s		15.0	15.0	25.0			Dimensions each cell
Utilities	NE		E	0	17			47WT% Caustic Storage Tank Electric Heater	Electric Heater		3	5	LV	n/a				15			ATM			ATM	-5	85	3	kW		316L SS	0.6	0.2		0.0		
Instrumentation and Control Equipment																																				
Power	NE		JDC	1	06	A-H		Sampling	Analyser		8	8	LV	n/a																304 SS	2.0	2.0	3.0	2.3		Feedwater and Steam Sampling
Power	NE		JDC	1	03			Continuous Emissions Monitoring System (CEMS)	Analyser				LV	n/a																						Measurements NOx, SO_2, CO_2, O_2, H_2O, ºC, and flow
Natural Gas	NE		JDF	0	01			Natural Gas Metering	Orifice	01	0		LV	n/a				65-85		1		38		85	-5	85	158	Nm^3/s		Carbon Steel	35.0	6.0	6.9	122.7		Metering - size based on similar scope pipeline meter
Natural Gas	NE		JCP	0	01			Natural Gas Panel	Panel		1	1	LV	n/a																	7.2	0.8	2.1	0.7		Safe Area Panel
Natural Gas	NE		JDC	0	01			Natural Gas Analyser House					LV	n/a																	2.0	2.0	2.7	2.3		Analyser House and Speciality Bottle House
Compression	NE		JDF	0	02			CO_2 Metering	Coriolis	03	0		LV	0				182.9			36			200	-5	100	1140	T/hr		316L SS	35.0	6.0	7.0	122.7		Metering - size based on similar scope pipeline meter
Compression	NE		JCP	0	02			CO_2 Metering Panel	Panel		1	1	LV	1																	7.2	0.8	2.1	0.7		Safe Area Panel

SNC·LAVALIN

EQUIPMENT LIST (MAJOR ITEMS)
ONSHORE PLANT - TEMPLATE PLANT

PROJECT No.	181869
PROJECT NAME	Thermal Power with CCS: Generic Business Case
LOCATION	UK

DOCUMENT No.	181869-0001-T-EM-MEL-AAA-00-00001
REVISION	A05
DATE	JULY 2017

PLANT AREA	EQUIPMENT NUMBER							ITEM DESCRIPTION	TYPE	PFD Number	ELECTRICAL POWER						OPERATING PRESSURE			OPERATING TEMPERATURE			DESIGN PRESSURE		DESIGN TEMPER-ATURE		DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit)	MATERIAL OF CONSTRUCTION	DIMENSIONS			WEIGHT		REMARKS
	ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT			181869-0001-D-EM-PFD-AAA-00-00001-XX	ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	CCS STANDBY (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	MIN (barg)	NORMAL (barg)	MAX (barg)	MIN (°C)	NORMAL (°C)	MAX (°C)	MIN (barg)	MAX (barg)	MIN (°C)	MAX (°C)			m^2		Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	DRY (tonnes)	OPERATING (tonnes)	
Compression	NE		JDC	0	02			CO_2 Metering Analyser House					LV																		2.0	2.0	2.7	2.3		Analyser House and Speciality Bottle House
Utilities	NE		JDC	0	05			DCS (ICSS)	Panel		110	110	LV																		36.8	0.8	2.1	31.5	31.5	ICSS for whole Power + CCS chain controlled from single control room. Price includes F&G and well as HIPPS
Fans																																				
Carbon Capture	NE		K	1	01			Booster Fan	Axial	02	13122	13900	MV	0				1.013 / 1.093			87.8						3551	T/hr	Δ 0.08bar	Steel Plate	9.9	9.3	8.1	111.4		
Carbon Capture	NE		KF	1	01	A-H		Booster Fan Motor Cooling Fans	Axial		24	60	LV	0																						Included in Booster Fans Supply
Carbon Capture	NE		KU	1	01	A/B		Booster Fan Lube Oil Skids			15	41	LV	15																						Included in Booster Fans Supply
Carbon Capture	NE		K	1	02			Damper Sealing Air Fan	Centrifugal		293	322	MV	0																Weathering Steel	4.0	2.2	3.2	10.7		Included in package with Gas Gas Heat Exchanger
Carbon Capture	NE		K	1	03			Damper Purge & Scavenge Air Fans	Centrifugal		6	7.5	LV	6													1500	m^3/hr	800 mmWG	Weathering Steel	1.0	1.0	2.5	0.3		Included in package with Gas Gas Heat Exchanger
Cooling Plant	NE		EF	1	01	A-T		Cooling Tower Fans	Axial		2107	2600	MV	632				ATM			10				-5		1578	T/hr								Total duty for CCGT + CCC
Mechanical Handling Equipment																																				
Power	NE		L	1	01			Gas Turbine Overhead Crane	Double Girder Gantry		0	164	LV	n/a		164									-5		100	T		CS						
Power	NE		L	1	02			Steam Turbine Overhead Crane	Double Girder Gantry		0	115	LV	n/a		115									-5		70	T	40m Span	CS						
Power	NE		L	1	03			Steam Turbine Auxiliary Crane	Double Girder Gantry		0	30	LV	n/a		20									-5		16	T	10m Span	CS						
Compression	NE		L	1	04			CO_2 Compressor Overhead Crane	Single Girder		0	30	LV	n/a		20									-5		35	T		CS						
Water Treatment	NE		L	0	05			Demin Plant Hoist	Single Girder		0	12	LV	n/a		10									-5		8	T		CS						
Water Treatment	NE		L	0	06			Waste Water Treatment Plant Hoist	Single Girder		0	12	LV	n/a		10									-5		8	T		CS						
Utilities	NE		L	0	07			Fire Fighting Pump Station Hoist	Single Girder		0	6	LV	n/a		6									-5		4	T		CS						
Facilities	NE		L	0	08			Workshop building Crane	Single Girder		0	22	LV	n/a		21									-5		10	T	30m Span	CS						
Facilities	NE		L	0	09	A/B		Weighbridge			0	1	LV	n/a		1									-5		60	T		CS	20.0	3.0		12.5		
Mixer																																				
Carbon Capture	NE		M	1	14			Thermal Reclaimer No 1 Feed Tank Mixer			5	5	LV	5				Atm			Amb			0.29	-5	85				316L SS		0.5		0.4		
Carbon Capture	NE		M	1	08			Amine Degraded Tank Mixer			5	5	LV	5				0.06			20			1	-5	160				316L SS		0.5		0.4		
Pumps																																				
Power	NE		P	1	01	A/B		Condensate Pump	Centrifugal	01	426	950	MV	n/a				4			39.7			19	-5	90	574	T/hr	@36.92m	Chrome Steel	4.0	1.8	1.8	10.0		Provides pressure for LP Stage - i.e. Operates as LP Feedwater Pump
Power	NE		P	1	02	A/B		HP Feedwater Pump	Ring Section	01	5143	11400	MV	n/a				250.5			147			400	-5	250	589	m^3/hr	@2438.4m	Chrome Steel	6.4	2.3	3.3	21.4		
Power	NE		P	1	03	A/B/C		IP Feedwater Pump	Ring Section	01	281	504	MV	n/a				58.5			143				-5		71	m^3/hr	@548.6m	Chrome Steel	6.0	2.2	1.5	7.0		
Power	NE		P	1	11	A/B		LTE Recirculation Pump	Centrifugal		1	1.5	LV	n/a				4.023			104.4				-5		32	m^3/hr	@1.2m	Chrome Steel	1.8	0.9	0.7	0.7		
Power	NE		P	1	12	A/B		Auxiliary Boiler Feedwater Pumps	Centrifugal		0	37	LV	n/a	14			7			105			10	-5	150	25	m^3/hr	@75m	Chrome Steel	1.8	1.1	0.8	1.1		
Power	NE		P	1	13	A/B		GT + Generator Lube Oil Pump	Centrifugal				LV	n/a																						
Power	NE		P	1	14	A/B		GT Generator Control Oil Pump	Centrifugal				LV	n/a																						
Power	NE		P	1	15	A/B		ST + Generator Lube Oil Pump	Centrifugal		0	0	n/a	n/a				6.5			40						248	m^3/hr								Shaft Driven
Power	NE		P	1	17	A/B		ST Generator Control Oil Pump	Centrifugal		30	39	LV	n/a																						
Power	NE		P	1	20	A/B		Clean Drains Return Pump	Centrifugal		26	60	LV	n/a				2.7			20			3.5	-5	85	316	m^3/hr	@15.2m	CS	2.1	1.1	1.0	1.6		
Cooling Plant	NE		P	1	16	A-F		Cooling Water Pump	Centrifugal		4984	6267	MV	1495				3			17.5			6	-5	85	12321	T/hr	@23.7m	CS	7.2	1.9	2.4	18.0		5 pumps operating, 1 spare
Carbon Capture	NE		P	1	04	A/B		Absorber Feed Pumps	Centrifugal	02	629	1400	MV	377				3.4			53			10	-5		2829	m^3/hr	@69.5m	316 SS	5.0	1.7	1.2	11.0		
Carbon Capture	NE		P	1	05	A/B		Lean Amine Pumps	Centrifugal	02	371	840	MV	222				4.1			122.4			10	-5		3042	m^3/hr	@39.3m	316 SS	5.0	1.9	1.4	9.1		
Carbon Capture	NE		P	1	06	A/B/C		Rich Amine Pumps	Centrifugal	02	711	1170	MV	427				5.6			41			13.8	-5		1417	m^3/hr	@129.4m	316 SS	3.5	1.8	1.0	13.0		3 x 50%
Carbon Capture	NE		P	1	07	A/B		Stripper Reflux Pumps	Centrifugal	02	21	60	LV	12				1			26			10	-5		78	m^3/hr	@61.1m	316 SS	1.8	1.1	1.0	1.1		1 Pump is a Spare for IX Transfer Pump
Carbon Capture	NE		P	0	17	A/B		Waste Wash Water Pumps	Centrifugal		10	22	LV	6										10	-5		64	m^3/hr	@22.8m	CS	1.8	1.1	1.0	1.0		
Carbon Capture	NE		P	1	19			Chemical Sewer Tank Pump	Centrifugal		8	11	LV	5										10	-5	85	46	m^3/hr	@19.5m	316 SS						
Carbon Capture	NE		P	1	18	A/B		CC Unit Condensate Pumps	Centrifugal		25	30	LV	15			7.5		8.5		50			10	-5		382	m^3/hr	@44.6m	CS / SS Impeller	1.6	0.5	0.7	0.7		
Carbon Capture	NE		P	1	08	A-D		Direct Contact Cooler Pumps	Centrifugal	02	501	575	MV	301				5.5			41			10	-5		2120	m^3/hr	@ 61.4m	CS	4.0	1.2	1.5	5.5		
Carbon Capture	NE		P	1	09	A/B		Acid Wash Pumps	Centrifugal	02	81	180	LV	49				7.4			85			10	-5		1195	m^3/hr	@18.7m	316 SS	3.5	1.0	1.0	6.0		
Carbon Capture	NE		P	1	10	A/B		Water Wash Pumps	Centrifugal	02	530	1200	MV	318				0.7			46			10	-5		4205	m^3/hr	@34.9m	316 SS	5.0	1.7	1.2	11.0		
Carbon Capture	NE		P	0	28	A/B		Fresh Amine Transfer Pumps	Centrifugal		3	5.5	LV	0				2.2			25			35	-5		28	m^3/hr	@22.8m	316 SS	1.8	0.8	0.7	0.6		
Carbon Capture	NE		P	0	29			Amine Container Pump	Centrifugal		1	2.2	LV	0				1			25			35	-5		20	m^3/hr	@11.3m	316 SS	1.5	0.8	0.7	0.4		
Carbon Capture	NE		P	1	25			IX Amine Pump	Centrifugal		36	45	LV	0				8.8			85			10	-5		118	m^3/hr	@74.3m	316 SS	2.1	0.8	0.8	0.6		
Carbon Capture	NE		P	1	26			Amine Drain Pump	Centrifugal		10	15	LV	0				4.4			160			10	-5		43	m^3/hr	@49.7m	316 SS	1.8	0.9	0.8	0.5		
Carbon Capture	NE		P	1	27			IX Transfer Pump	Centrifugal		27	37	LV	16				8.9			110			10	-5		90	m^3/hr	@60.8m	316 SS	1.8	1.1	1.0	1.1		

PROJECT No.	181869
PROJECT NAME	Thermal Power with CCS: Generic Business Case
LOCATION	UK

DOCUMENT No.	181869-0001-T-EM-MEL-AAA-00-00001
REVISION	A05
DATE	JULY 2017

PLANT AREA	EQUIPMENT NUMBER							ITEM DESCRIPTION	TYPE	PFD Number	ELECTRICAL POWER						OPERATING PRESSURE			OPERATING TEMPERATURE			DESIGN PRESSURE		DESIGN TEMPER-ATURE		DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit)	MATERIAL OF CONSTRUCTION	DIMENSIONS			WEIGHT		REMARKS
	ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT			181869-0001-D-EM-PFD-AAA-00-00001-XX	ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	CCS STANDBY (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	MIN (barg)	NORMAL (barg)	MAX (barg)	MIN (°C)	NORMAL (°C)	MAX (°C)	MIN (barg)	MAX (barg)	MIN (°C)	MAX (°C)			m^2		Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	DRY (tonnes)	OPERATING (tonnes)	
Carbon Capture	NE		P	1	21	A/B		Thermal Reclaimer NO. 1 MP Condensate Pumps	Centrifugal		4	11	LV	2				22			250		FV	27	-5	270	10	m^3/hr	@21m	CS	1.8	0.9	0.8	0.5		
Carbon Capture	NE		P	1	22	A/B		Thermal Reclaimer NO. 2 MP Condensate Pumps	Centrifugal		2	7.4	LV	1				22			250		FV	27	-5	270	1	m^3/hr	@19.8m	CS	1.8	0.9	0.8	0.5		
Carbon Capture	NE		P	1	23	A/B		Thermal Reclaimer NO. 3 MP Condensate Pumps	Centrifugal		2	7.4	LV	1				22			250		FV	27	-5	270	2	m^3/hr	@19.7m	CS	1.8	0.9	0.8	0.5		
Compression	NE		P	1	24	A/B		Process Condensate Return Pumps	Centrifugal	03	1	1.5	LV	0				1			20			35	-5		2.0	m^3/hr	@32m	316 SS	1.0	0.5	0.5	0.2		
Utilities	NE		P	0	13	A/B/C		Demineralised Water Pumps	Centrifugal		30	135	LV	n/a		90		5		5	8	20		10	-5	85	150	m^3/hr	@50m	316 SS	2.1	1.2	1.0	1.3		1 Normal Operation - 3 pumps in operation at start-up
Utilities	NE		P	0	14	A-D		Fire Water Pumps	NFPA 20		0		LV	n/a				11		5	8	20		15	-5	85	1000	m^3/hr	@1500kpag	CS / SS Impeller	6.6	1.5	3.0	8.7		Diesel Engine Driven
Utilities	NE		P	0	15	A/B		Fire Water Jockey Pumps	Centrifugal		38	45	LV	n/a				7		5	8	20		15	-5	85	132	m^3/hr	@73m	CS / SS Impeller	1.8	1.1	1.0	1.2		Keep fire water main pressurised
Utilities	NE		P	0	30	A/B		47WT% Caustic Transfer Pump	Centrifugal		7	11	LV	n/a				5.5			15			10	-5	85	14	m^3/hr	@36.2m	CS	1.3	0.5	0.5	0.3		
Utilities	NE		P	0	31	A/B		Concentrated Sulphuric Acid Transfer Pump	Positive Displacement		0.02	0.75	LV	n/a													0.2	m^3/hr	@34.4m	316 SS						
Utilities	NE		P	0	19	A/B		Service (Raw) Water Pumps	Centrifugal		9.20	11	LV	n/a				5		5	8	20		10	-5	85	27	m^3/hr	@31m	CS / SS Impeller	1.8	1.1	1.1	1.3		
Utilities	NE		P	0	32	A/B		Towns Water Pump	Centrifugal		40	110	LV	n/a				5.4		5	8	20		10	-5	85	91	m^3/hr	@ 56.7m	316 SS	1.3	0.5	0.5	0.3		
Power Generation																																				
Power	NE		R	1	01			Generator		01	0	0	n/a	n/a													500	MWe								
Power	NE		R	1	02			Generator		01	0	0	n/a	n/a													232	MWe						369.0		Unabated Performance
Utilities	NE		R	1	03			Standby Emergency Power Generator			0	0	n/a	n/a													2680	kVA			Incl	Incl	Incl	Incl		
Power	NE		RG	1	01			Gas Turbine	Class H/J	01	1001		LV	n/a													500	MW			33.0	6.0	6.0	1,050		Includes auxiliary equipment such as Lube Oil Consoles (Dims turbine only)
Power	NE		RS	1	02			Steam Turbine	Multi-Casing with Steam Extraction	01	123		LV	n/a													232	MW			40.0	15.0	23.0	752		Advice from Vendors that would be multi casing or multi shaft machine for steam extraction. Includes auxiliary equipment such as Lube Oil Consoles (Dims turbine only)
Utilities	NE		RE	1	03			Standby Emergency Power Generation Engine	Diesel Engine		3	13.2	LV	n/a																	12.0	3.0	3.4	43.0		
Filters																																				
Power	NE		S	1	01			Inlet Air Filter		01	0	0	n/a	n/a				ATM			ATM			ATM	-10	30	3342	T/hr		CS / PTFE	20.0	7.5	15.0			
Power	NE		S	1	07	A/B		Condensate Filter	Basket	01	0	0	n/a	n/a				4			40			30	-5	85	574	T/hr		CS	0.9	0.9	1.6	0.5		
Power	NE		S	1	06			Fuel Gas Coalescing Filter	Coalescing Elements		0	0	n/a	n/a				40			25			85	-5	85	92	T/hr	0.87 m^3	CS / 316L Internals		0.8	3.7	4.0		Removal of solid particles 100% > 3 micron and entrained liquids
Carbon Capture	NE		S	1	04	A/B		Amine Filter	Cartridge	02	0	0	n/a	n/a				7.1			40			12	-5	85	118	m3/hr		316L SS		0.5	2.3			99% removal > 10micron
Carbon Capture	NE		S	1	08			Amine Drain Filter	Cartridge		0	0	n/a	n/a				3.6			40			7	-5	160	33	m3/hr		316L SS		0.3	2.3			99% removal > 10micron
Compression	NE		S	1	02			CO_2 Dehydration Filter Coalescer	Disposable Catridge	03	0	0	n/a	n/a				37.9			36			47	-5	160	3186	m3/hr		316L SS		2.7	8.1	70.4		99.999% removal > 0.3micron Alternative DT= -79°C for Rapid Depressurisation
Compression	NE		S	1	05	A/B		CO_2 Dehydration Outlet Filter	Basket	03	0	0	n/a	n/a				36.6			36			47	-5	160	2884	m3/hr		316L SS		3.1	2.6	46.4		> 5micron Alternative DT= -79°C for Rapid Depressurisation
Compression	NE		S	1	09	A/B		CO_2 Dehydration Regeneration Gas Discharge Filters	Basket	03	0	0	n/a	n/a				36.6			36			47	-5	310	1162	m3/hr		316L SS		2.3	2.6	21.3		> 5micron Alternative DT= -79°C for Rapid Depressurisation
Cooling Water	NE		S	1	10	A-D		Cooling Water Filters	Basket		0	0	n/a	n/a				10			17.5			12	-5	85	20534	T/hr		CS	4.0	7.0	3.5	11.0		> 50 micron (4 x 33% units)
Tanks																																				
Carbon Capture	NE		T	1	01			Lean Amine Tank	Vertical - API 650	02	0	0	n/a	n/a				Atm			Amb			0.15	-5	85	3187	m^3		316L SS		14.2	22.0			* Pressure at top is 0.04 barg (vent connected to absorber) * Double walled tank * Lined carbon steel could be considered as a lower cost alternative
Carbon Capture	NE		T	0	03			Fresh Amine Tank	Vertical - API 620		0	0	n/a	n/a										0.2	-5	85	6516	m^3		316L SS		20.0	22.0			* Pressure at top is 0.04 barg (vent connected to absorber) * Dip Tubes * Sized for 5 trains
Carbon Capture	NE		T	1	07			Amine Drain Tank	Horizontal		0	0	n/a	n/a										1	-5	160	106	m^3		316L SS	9.0	3.9				Underground Horizontal Tank
Carbon Capture	NE		T	1	08			Degraded Amine Drain Tank	Horizontal		0	0	n/a	n/a				0.06			20		-0.5	1	-5	160	25	m^3		316L SS	5.8	2.4				Underground Horizontal Tank. Includes a mixer.
Carbon Capture	NE		T	0	09			Waste Wash Water Tank	Vertical		0	0	n/a	n/a				Atm			Amb			ATM	-5	85	13512	m^3		CS + 3mm CA		26.7	24.1			Sized for 5 trains
Carbon Capture	NE		T	0	15			Amine Maintenance Tank	Vertical		0	0	n/a	n/a				Atm			Amb			ATM	-5	85	6400	m3		316L SS		26.0	12.2	133	6,562.0	Sized to hold inventory of 1 train during maintenance
Carbon Capture	NE		T	1	10			Chemical Sewer Tank	Horizontal		0	0	n/a	n/a				Atm			Amb			ATM	-5	100	106	m^3		CS Lined	9.0	3.9		105.6		Underground Horizontal Tank
Carbon Capture	NE		T	1	14			Thermal Reclaimer No 1 Feed Tank	Vertical		0	0	n/a	n/a				Atm			Amb			0.29	-5	85	103	m^3		316L SS		4.4	6.8			Pressure at top = 0.04 barg (Vent connected to Absorber)
Utilities	NE		T	0	05			Aqueous Ammonia Tank	Horizontal		0	0	n/a	n/a				Atm			Amb			Atm	-5	85	150	m^3		CS	12.0	4.0				Originally sized for 2 off GTs - resized for 5
Utilities	NE		T	0	04			Demineralised Water Tank	Vertical - API 650		0	0	n/a	n/a				Atm			Amb			Atm	-5	85	7000	m^3		CS Lined		22.5	20.0			Sized for 5 trains
Utilities	NE		T	0	06			Raw / Fire Water Tank	Vertical - API 650		0	0	n/a	n/a				Atm			Amb			Atm	-5	85	75500	m^3		CS Lined		70.0	20.0			Sized for 5 trains
Utilities	NE		T	0	11			47WT% Caustic Storage Tank	Vertical - API 650		0	0	n/a	n/a				Atm			Amb			ATM	-5	85	1500	m^3		CS Lined		12.0	14.0			Sized for 7 days storage

PROJECT No. 181869
PROJECT NAME Thermal Power with CCS: Generic Business Case
LOCATION UK

DOCUMENT No. 181869-0001-T-EM-MEL-AAA-00-00001
REVISION A05
DATE JULY 2017

PLANT AREA	EQUIPMENT NUMBER							ITEM DESCRIPTION	TYPE	PFD Number	ELECTRICAL POWER						OPERATING PRESSURE			OPERATING TEMPERATURE			DESIGN PRESSURE		DESIGN TEMPER-ATURE		DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit)	MATERIAL OF CONSTRUCTION	DIMENSIONS			WEIGHT		REMARKS
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Utilities	NE		T	0	12			Concentrated Sulphuric Acid Tank	Vertical - API 650		0	0	n/a	n/a				Atm			Amb			ATM	-5	85	100	m^3		CS + 6mm CA		4.0	8.0			MOC: In accordance with NACE SP0294. Sized for 7 days storage
Utilities	NE		T	0	02			Towns Water Break Tank	Vertical - API 650		0	0	n/a	n/a				Atm			Amb			ATM	-5	85	208	m^3		CS Lined		6.0	8.0			
Packages																																				
Power	NE		U	1	13			Anti Icing Skid					LV	n/a																						
Power	NE		U	1	14			CO_2 / N_2 Storage Skid			0	0	n/a	n/a																						Fire Fighting for Gas Turbines
Power	NE		U	1	07			Condensate Polishing Plant		01	0	0	LV	n/a				10			30			19	90		311	T/hr		316L SS						Polishing of Condensate Return from Carbon Capture Unit
Power	NE		U	1	09			HRSG Chemical Feed Skid	API 675 Pumps		2	5	LV	n/a							20			12	-5	85				316L SS	8.0	3.0	2.7	7.0		Boiler Feedwater Dosing Chemicals - O2 Scavenger, Alkaline, Corrosion Inhibitor
Carbon Capture	NE		U	1	03			Thermal Reclaimer Unit		02	11	15	LV	7									FV	3.5	-5	335	93	m^3/hr		316L SS	38.7	19.3	25.0			
Carbon Capture	NE		U	1	15	A/B		Thermal Reclaimer Vacuum Packages			5	11	LV	3				-0.1			35		FV	3.5	-5	85 / 170	93	m^3/hr		316L SS				3.0		
Carbon Capture	NE		U	1	04			Ion Exchange Package		02	7	8	LV	4													6	m^3/hr			5.8	5.8	5.0			
Compression	NE		U	1	01			CO_2 Compression Package	Integral Geared	03	176	313.74	LV	106				0.2/183			123			200	-5	150	230	T/hr		316L SS	25.0	18.0	9.0	360.0		
Compression	NE		U	1	02			CO_2 Dehydration Package	Mole Sieve	03	0	0	n/a	0				37.9						47	-5	150	269	T/hr		316L SS	N/A	N/A	N/A	N/A		Equipment elsewhere - line item for price for design and mole sieve
Compression	NE		U	1	10			Tracer Dosing Package	API 675 Pumps		0	0.1	LV	0										200	-5	85	100	ppbv		316L SS	2.2	1.2	2.0	0.9		Addition to give CO_2 smell to allow leakage detection
Cooling Water	NE		U	0	11			Chemical Dosing Package	API 675 Pumps		33	37	LV	n/a										12	-5	85					11.0	3.5	4.0	30.0		Cooling Water Dosing Chemicals
Water Treatment	NE		U	0	05			Water Treatment Plant			6267	8671.8	MV	3760							20				-5	85	13844	m^3/hr		Various	644.2	128.8				Includes CCGT + Ion Exchange + Waste Wash Water + Acid Wash Effluent Treatment
Utilities	NE		U	0	06	A/B/C		Instrument Air Compression Package	Centrifugal		1690	2700	MV	n/a					8.5		20			10	-5	85	145	m^3/min	FAD		8.1	2.4		22.7		3 x 50% machines Sized for Carbon Capture and CCGT (Refer to Utilities Schedule)
Utilities	NE		U	0	12			Demineralisation Package	RO + Ion Exchange		60	360	LV	n/a													448	m^3/hr			40.6	12.7				Sized for 5 trains
Utilities	NE		U	0	08			Ammonia Tanker Unloading			0	0	LV	n/a									FV	9	-5	85				CS				0.8		
Drums and Vessels																																				
Power	NE		V	1	01			HP Steam Drum	Horizontal	01	0	0	n/a	n/a				173.3			353.9			206	-5	420				15NiCuMoNb5-6-4	17.0	1.9		130		Part of HRSG
Power	NE		V	1	02			IP Steam Drum	Horizontal	01	0	0	n/a	n/a				36.6			245.1									CS						Part of HRSG
Power	NE		V	1	03			LP Steam Drum	Horizontal	01	0	0	n/a	n/a				3.792			141.7									CS						Part of HRSG
Power	NE		V	1	31			Oil / Water Separator	Horizontal		0	55	LV	n/a		45											136	m^3/hr		CS	2.0	2.0	2.0	2.2		
Power	NE		V	1	23			Blowdown Vessel / Tank	Vertical		0	0	n/a	n/a				ATM			100		FV	3.5	-5	180	5	m^3		CS		1.3	4.0	2.2		
Power	NE		V	1	27			Fuel Gas Scrubber	Vertical		0	0	n/a	n/a				48	65	1	25	38		85	-29	55	2	m^3		CS		1.0	2.4	2.9		
Power	NE		V	1	05			Feedwater Tank	Horiz / Vertical	01	0	0	n/a	n/a				3			46			8	-5	200	659	T/hr		Alloy Steel	20.5	4.3	8.3	85.0		Including Deaerator
Power	NE		V	1	25	A/B		Flash Tanks (Start-Up & Shut Down)	Vertical		0	0	n/a	n/a				1.3			575			7	-5	600	16	m^3		Alloy Steel		2.0	4.8	18.5		
Power	NE		V	1	26			Drain Vessel	Vertical		0	0	n/a	n/a				1.3			575			7	-5	600	16	m^3		Alloy Steel		2.0	4.8	18.5		
Power	NE		V	1	22			Instrument Air Buffer Vessel - CCGT Area	Vertical		0	0	n/a	n/a				8.5			25			10	-5	85	90	m^3		316L SS		3.2	10.0	25.2		
Power	NE		V	1	24			Flash Drum	Vertical		0	0	n/a	n/a				17			200		FV	19	-5	230	6	m^3		CS		1.4	3.4	3.4		
Natural Gas	NE		V	0	04			Natural Gas Pig Receiver	Horizontal	01	0	0	n/a	n/a			45		65	1		38		85	-29	55	158	Nm^3/hr		CS	5.1	1.3	1.3	13.9		
Natural Gas	NE		V	0	32			Natural Gas Pig Launcher	Horizontal		0	0	n/a	n/a			45		65	1		38		85	-29	55	158	Nm^3/hr		CS	5.1	1.3	1.3	13.9		Located at NTS connection
Carbon Capture	NE		V	1	06			Direct Contact Cooler	Rectangular Tower	02	0	0	n/a	n/a				0.063			70			0.085	-5	85	254	T/hr (CO_2)		Lined Concrete 304SS Internals	18.1	17.0	28.2			Column lining design temperature 120°C which could be subject to 110°C flue gas during start-up Scale up using flue gas flow rate: refer to 181869-0001-T-EM-CAL-AAA-00-00004 rev A02
Carbon Capture	NE		V	1	07			CO_2 Absorber	Rectangular Tower	02	0	0	n/a	n/a				0.026			30			0.085	-5	85	254	T/hr (CO_2)		Lined Concrete 304/316SS Internals	34.0	17.0	64.3			* High efficiency mist eliminator at the top of the water wash * Knit mesh mist eliminator at the top of acid wash section * High quality gravity distributor * Leak & splash proof chimney tray * Structured packing * Shoepentouter inlet devices (two off)
Carbon Capture	NE		V	1	08			Amine Stripper	Vertical	02	0	0	n/a	n/a				1			122.3			3.5	-5	160	228	T/hr (CO_2)		CS with 316L Cladding		9.6	34.6	261.0		* Top =dia 5.9m, Middle = dia 10m, Top = dia 8m. * Upper rectification: predistributor, distributor (with chimney tray), splash plate, demister mat * Stripping: predistributor, distributor (with chimney tray), demisters * Structured packing
Carbon Capture	NE		V	1	09			Amine Reflux Drum	Vertical	02	0	0	n/a	n/a				1			26.3			3.5	-5	105	228	T/hr (CO_2)		316L SS		4.5	8.0	31.0		* Half open pipe inlet device * Mesh * Mist Eliminator
Carbon Capture	NE		V	1	21			Vent KO Drum	Horizontal		0	0	n/a	n/a									FV	10	-79	160	15	m^3		316L SS		1.9	4.5	2.8		Kept pressurised with Instrument Air
Carbon Capture	NE		V	1	38			CC Unit Condensate Drum	Vertical		0	0	n/a	n/a									FV	5	-5	160				CS + 3mm CA		2.6	5.0	7.4		Includes inlet hood and wear plate
Carbon Capture	NE		V	1	28			Thermal Reclaimer Column No 1	Vertical		0	0	n/a	n/a									FV	3.5	-5	160	6	m^3		316L SS		0.9	8.9	1.9		* Packed section * Predistribution, distributor (with chimney tray) * Vane collector * Structured packing
Carbon Capture	NE		V	1	29			Thermal Reclaimer Column No 2	Vertical		0	0	n/a	n/a									FV	3.5	-5	215	8	m^3		316L SS		1.0	9.4	2.2		* Packed section * Predistribution, distributor (with chimney tray) * Vane collector * Structured packing

PROJECT No. 181869
PROJECT NAME Thermal Power with CCS: Generic Business Case
LOCATION UK

DOCUMENT No. 181869-0001-T-EM-MEL-AAA-00-00001
REVISION A05
DATE JULY 2017

PLANT AREA	EQUIPMENT NUMBER							ITEM DESCRIPTION	TYPE	PFD Number	ELECTRICAL POWER						OPERATING PRESSURE			OPERATING TEMPERATURE			DESIGN PRESSURE		DESIGN TEMPER-ATURE		DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit)	MATERIAL OF CONSTRUCTION	DIMENSIONS			WEIGHT		REMARKS
	ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT			181869-0001-D-EM-PFD-AAA-00-00001-XX	ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	CCS STANDBY (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	MIN (barg)	NORMAL (barg)	MAX (barg)	MIN (°C)	NORMAL (°C)	MAX (°C)	MIN (barg)	MAX (barg)	MIN (°C)	MAX (°C)			m^2		Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	DRY (tonnes)	OPERATING (tonnes)	
Carbon Capture	NE		V	1	30			Thermal Reclaimer Column No 3	Vertical		0	0	n/a	n/a									FV	3.5	-5	335	11	m^3		316L SS		1.2	9.1	2.7		* Packed section * Predistribution, distributor (with chimney tray) * Vane collector * Structured packing
Carbon Capture	NE		V	0	33			Instrument Air Buffer Vessel	Vertical		0	0	n/a	n/a				8.5			25			10	-5	85				316L SS		3.4	10.1	23.8		
Compression	NE		V	1	11			1st Stage CO_2 Compressor KO Drum	Vertical	03	0	0	n/a	n/a				0.15			25			3.5	-7	105	228	T/hr (CO_2)		316L SS		3.4	5.5	11.5		Includes * Intlet hood and mist eliminator
Compression	NE		V	1	12			2nd Stage Integrated KO Drum	Vertical	03	0	0	n/a	n/a				1.95			122/36						228	T/hr (CO_2)		316L SS						Part of Package U-101 Includes integral water cooled tube bundle
Compression	NE		V	1	13			3rd Stage Integrated KO Drum	Vertical	03	0	0	n/a	n/a				5.925			123/36						228	T/hr (CO_2)		316L SS						Part of Package U-101 Includes integral water cooled tube bundle
Compression	NE		V	1	14			4th Stage Integrated KO Drum	Vertical	03	0	0	n/a	n/a				15.52			121.8/ 36						269	T/hr (CO_2)		316L SS						Part of Package U-101 Includes integral water cooled tube bundle
Compression	NE		V	1	15			5th Stage Integrated KO Drum	Vertical	03	0	0	n/a	n/a				38			116.7/ 36						269	T/hr (CO_2)		316L SS						Part of Package U-101 Includes integral water cooled tube bundle
Compression	NE		V	0	17			CO_2 Pipeline Pig Launcher	Horizontal	03	0	0	n/a	n/a				181.7			36			200	-46	85	228	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	
Compression	NE		V	0	34			CO_2 Pipeline Pig Receiver	Horizontal		0	0	n/a	n/a				181.7			36			200	-46	85	228	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Shore Crossing (except Teesside)
Compression	NE		V	0	35			CO_2 Pipeline Pig Launcher	Horizontal		0	0	n/a	n/a				181.7			36			200	-46	85	228	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Shore Crossing (except Teesside)
Compression	NE		V	1	18	A/B		CO_2 Dehydration Absorber	Vertical	03	0	0	n/a	n/a				37.7						47	-5	150	269	T/hr (CO_2)		316L SS		3.3	9.0			Internals = molecular sieves, cermaic balls, supports, grid support Material: CS clad with SS also acceptable
Compression	NE		V	1	19			Dehydration KO Drum	Vertical	03	0	0	n/a	n/a				35.4			36			47	-5	300	228	T/hr (CO_2)		316L SS		0.9	3.0			Includes Inlet Hood and Mist Eliminator Depressurisation = -79°C at 0 barg
Utilities	NE		V	0	36			Demin Water Expansion Vessel	Vertical		0	0	n/a	n/a										5	-5	85				CS + 3mm CA		1.9	4.0	3.9		
Utilities	NE		V	0	37			Instrument Air Dry Air Receiver	Vertical		0	0	n/a	n/a				8.5			25			10	-5	85	764	m^3		316L SS						
Miscellaneous																																				
Power	NE		XJ	1	01			Steam Jet Air Ejector			0	0	n/a	n/a																						Part of Water Cooled Condenser
Electrical Equipment																																				
								Low Voltage Equipment																												
Power	NE			1				Low Voltage Equipment			366		LV	n/a																						Transformers, Circuit Breakers, Switchgear, MCCs, etc
Carbon Capture	NE		ESG	1	01			LV Switchboard			342	446.9	LV	205																						
Carbon Capture	NE		ESG	1	02			LV Emergency Switchboard			147	290	LV	88																						
Compression	NE		ESG	1	03			LV Switchboard			557	681.9	LV	334																						Non-Process Equipment Loads
Compression	NE		ESG	1	04			LV Emergency Switchboard			145	260	LV	87																						
Utilities	NE		ESG	0	05			LV Switchboard			557	681.9	LV	n/a																						
Utilities	NE		ESG	0	06			LV Emergency Switchboard			145	260	LV	n/a																						
Facilities	NE		ESG	0	07			LV Switchboard			145	260	LV	n/a																						
								Transmission Voltage Equipment																												
Power	NE		ETR	1	08			Export Transformer			3660		HV	n/a																						
Power	NE		ETR	1	09			Unit Transformer					HV	n/a																						
Power	NE		ECB	1	10			Circuit Breakers					HV	n/a																						
Power	NE			1				Miscellaneous PEACE Electrical Equipment					HV	n/a																						**Cost Bookmark**
								Generating Voltage Equipment																												
Power	NE			1				Generator Buswork					MV	n/a																						
Power	NE		ECB	1	11			Circuit Breakers					MV	n/a																						
Power	NE			1				Miscellaneous PEACE Electrical Equipment					MV	n/a																						**Cost Bookmark**
								Medium Voltage Equipment																												
Power	NE			1				Miscellaneous PEACE Auxiliaries			2902		MV	n/a																						
Power	NE			1				Medium Voltage Equipment					MV	n/a																						Transformers, Circuit Breakers, Switchgear, MCCs, etc
Power	NE			1				HP Feedwater Pumps VFD					MV	n/a																						
Entire Plant	NE		ESG	1	12			MV Main Switchboard					MV	n/a																						
Carbon Capture	NE		ESG	1	13			MV Switchboard					MV	n/a																						
Carbon Capture	NE			1				Booster Fan VFD					MV	n/a																						Part of K-101 Supply

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PROJECT No.	181869
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DOCUMENT No.	181869-0001-T-EM-MEL-AAA-00-00001
REVISION	A05
DATE	JULY 2017

PLANT AREA	EQUIPMENT NUMBER							ITEM DESCRIPTION	TYPE	PFD Number	ELECTRICAL POWER						OPERATING PRESSURE			OPERATING TEMPERATURE			DESIGN PRESSURE		DESIGN TEMPER-ATURE		DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit)	MATERIAL OF CONSTRUCTION	DIMENSIONS			WEIGHT		REMARKS
	ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT			181869-0001-D-EM-PFD-AAA-00-00001-XX	ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	CCS STANDBY (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	MIN (barg)	NORMAL (barg)	MAX (barg)	MIN (°C)	NORMAL (°C)	MAX (°C)	MIN (barg)	MAX (barg)	MIN (°C)	MAX (°C)			m^2		Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	DRY (tonnes)	OPERATING (tonnes)	
Compression	NE		ESG	1	14			MV Switchboard					MV	n/a																						
Compression	NE		ESG	1	15			Switchgear					MV	n/a																	2.3	0.7	1.7	1.3		2 off - inlet and outlet. Part of Package U-101
Compression	NE		ETR	1	16			Transformer					MV	n/a																						Part of Package U-101
Compression	NE			1				CO_2 Com pressor VFD					MV	n/a																	2.2	9.4	1.0	5.0		Part of Package U-101
Buildings																																				
Facilities	NE		BLD	0	01			Warehouse			3	3	LV	n/a				+ve		5		35	N/A	N/A	N/A	N/A	8550	m^3			47.5	30.0	6.0			Height to Eaves
Facilities	NE		BLD	0	02			Workshop			5	5	LV	n/a				+ve		5		35	N/A	N/A	N/A	N/A	14250	m^3			47.5	30.0	10.0			Height to Eaves
Facilities	NE		BLD	0	03			Admin & Control Building			22	22	LV	n/a				+ve		20		25	N/A	N/A	N/A	N/A	2160	m^3			40.0	12.0	4.5			Height to Eaves
Facilities	NE		BLD	0	04			Office Block			164	164	LV	n/a				+ve		20		25	N/A	N/A	N/A	N/A	16500	m^3			33.0	25.0	20.0			Height to Top of Roof
Facilities	NE		BLD	0	05			Lockers, Welfare, & Training			49	49	LV	n/a				+ve		20		25	N/A	N/A	N/A	N/A	4950	m^3			33.0	25.0	6.0			Height to Eaves
Facilities	NE		BLD	0	06			Guardhouse			1	1	LV	n/a				+ve		20		25	N/A	N/A	N/A	N/A	135	m^3			10.0	3.0	4.5			Height to Eaves
Facilities	NE		BLD	0	07			Compression Electrical Substation			34	34	LV	n/a				+ve		10		40	N/A	N/A	N/A	N/A	11813	m^3			75.0	35.0	4.5			Height to Eaves
Facilities	NE		BLD	1	08			Carbon Capture Electrical Substation			4	4	LV	n/a				+ve		10		40	N/A	N/A	N/A	N/A	1350	m^3			25.0	12.0	4.5			Height to Eaves
Facilities	NE		BLD	1	09			Steam Turbine Building			34	34	LV	n/a				+ve		5		35	N/A	N/A	N/A	N/A	115200	m^3			72.0	40.0	40.0			Height to Top of Roof
Facilities	NE		BLD	1	10			Cooling Water Power Distribution Centre			2	2	LV	n/a				+ve		10		40	N/A	N/A	N/A	N/A	720	m^3			16.0	10.0	4.5			Height to Eaves
Facilities	NE		BLD	1	11			HRSG Power Distribution Centre			1	1	LV	n/a				+ve		10		40	N/A	N/A	N/A	N/A	225	m^3			10.0	5.0	4.5			Height to Eaves
Facilities	NE		BLD	1	12			Power Generation Power Distribution Centre			2	2	LV	n/a				+ve		10		40	N/A	N/A	N/A	N/A	720	m^3			20.0	8.0	4.5			Height to Eaves
Facilities	NE		BLD	1	13			HV / LV Power Distribution Centre			2	2	LV	n/a				+ve		10		40	N/A	N/A	N/A	N/A	720	m^3			20.0	8.0	4.5			Height to Eaves

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EQUIPMENT LIST (MAJOR ITEMS)

ONSHORE PLANT - DIFFERENCES FOR NORTH WEST

PROJECT No.	181869
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LOCATION	UK

DOCUMENT No.	181869-0001-T-EM-MEL-AAA-00-00001
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PLANT AREA	EQUIPMENT NUMBER							ITEM DESCRIPTION	TYPE	PFD Number	ELECTRICAL POWER						OPERATING PRESSURE			OPERATING TEMPERATURE			DESIGN PRESSURE		DESIGN TEMPER-ATURE		DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit)	MATERIAL OF CONSTRUCTION	DIMENSIONS			WEIGHT		REMARKS
	ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT			181869-0001-D-EM-PFD-AAA-00-00001-XX	ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	DUTY - CONTINUOUS (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	MIN (barg)	NORMAL (barg)	MAX (barg)	MIN (°C)	NORMAL (°C)	MAX (°C)	MIN (barg)	MAX (barg)	MIN (°C)	MAX (°C)			m^2		Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	DRY (tonnes)	OPERATING (tonnes)	
Compressors																																				
Compression	NW		C	1	01			CO_2 Compressor	Centrifugal	03	22212	24500	MV					See	Pkg	Below																Part of Package U-101
Heat Exchangers																																				
Compression	NW		E	1	05			6th Stage Cooler	Shell & Tube	03	0	0	n/a					68.2			97.5/36						6215	kW								Part of Package U-101
Compression	NW		E	1	27			7th Stage Cooler	Shell & Tube	03								94			62/36						23520	kW								Part of Package U-101 (used for Hamilton Liquid Phase only)
Compression	NW		E	1	07			CO_2 Dehydration Electric Heater	Electric Heater	03	3488	3800	MV					37.4			22.9 / 290			47	-5	310	3488	kW		316L SS	5.6	1.6	2.4	4.0		Alternative DT= -79°C for Rapid Depressurisation
Compression	NW		E	1	08			Dehydration Cooler	Shell & Tube	03	0	0	n/a					36.6						47	-5	310	3323	kW	166	316L SS						Alternative DT= -79°C for Rapid Depressurisation
Instrumentation and Control Equipment																																				
Compression	NW		JDF	0	02			CO_2 Metering	Coriolis	03	0		LV					93			74				-5	100	684	T/hr		316L SS	35.0	6.0	7.0	122.7		Metering - size based on similar scope pipeline meter
Compression	NW		JCP	0	02			CO_2 Metering Panel	Panel		1	1	LV																		7.2	0.8	2.1	0.7		Safe Area Panel
Compression	NW		JDC	0	02			CO_2 Metering Analyser House					LV																		2.0	2.0	2.7	2.3		Analyser House and Speciality Bottle House
Pumps																																				
Compression	NW		P	1	24	A/B		Process Condensate Return Pumps	Centrifugal	03	1	1.5	LV					1			20			35	-5		2.0	m^3/hr	@32m	316 SS	1.0	0.5	0.5	0.2		
Filters																																				
Compression	NW		S	1	02			CO_2 Dehydration Filter Coalescer	Disposable Catridge	03	0	0	n/a					37.9			36			47	-5	160	3186	m3/hr		316L SS		2.7	8.1	70.4		99.999% removal > 0.3micron Alternative DT= -79°C for Rapid Depressurisation
Compression	NW		S	1	05	A/B		CO_2 Dehydration Outlet Filter	Basket	03	0	0	n/a					36.6			36			47	-5	160	2884	m3/hr		316L SS		3.1	2.6	46.4		> 5micron Alternative DT= -79°C for Rapid Depressurisation
Compression	NW		S	1	09	A/B		CO_2 Dehydration Regeneration Gas Discharge Filters	Basket	03	0	0	n/a					36.6			36			47	-5	310	1162	m3/hr		316L SS		2.3	2.6	21.3		> 5micron Alternative DT= -79°C for Rapid Depressurisation
Packages																																				
Compression	NW		U	1	01			CO_2 Compression Package	Integral Geared	03	106	189	LV					0.2/93			123			140	-5	150	230	T/hr		316L SS	25.0	18.0	9.0	360.0		
Compression	NW		U	1	02			CO_2 Dehydration Package	Mole Sieve	03	0	0	n/a					37.9						47	-5	150	269	T/hr		316L SS	N/A	N/A	N/A	N/A		Equipment elsewhere - line item for price for design and mole sieve
Compression	NW		U	1	10			Tracer Dosing Package	API 675 Pumps		0	0.1	LV											140	-5	85	100	ppbv		316L SS	2.2	1.2	2.0	0.9		Addition to give CO_2 smell to allow leakage detection
Drums and Vessels																																				
Compression	NW		V	1	11			1st Stage CO_2 Compressor KO Drum	Vertical	03	0	0	n/a					0.15			25			3.5	-7	105	228	T/hr (CO_2)		316L SS		3.4	5.5	11.5		Includes * Intlet hood and mist eliminator
Compression	NW		V	1	12			2nd Stage Integrated KO Drum	Vertical	03	0	0	n/a					1.95			122/36						228	T/hr (CO_2)		316L SS						Part of Package U-101 Includes integral water cooled tube bundle
Compression	NW		V	1	13			3rd Stage Integrated KO Drum	Vertical	03	0	0	n/a					5.925			123/36						228	T/hr (CO_2)		316L SS						Part of Package U-101 Includes integral water cooled tube bundle
Compression	NW		V	1	14			4th Stage Integrated KO Drum	Vertical	03	0	0	n/a					15.52			121.8/36						269	T/hr (CO_2)		316L SS						Part of Package U-101 Includes integral water cooled tube bundle
Compression	NW		V	1	15			5th Stage Integrated KO Drum	Vertical	03	0	0	n/a					38			116.7/36						269	T/hr (CO_2)		316L SS						Part of Package U-101 Includes integral water cooled tube bundle
Compression	NW		V	0	17			CO_2 Pipeline Pig Launcher	Horizontal	03	0	0	n/a					181.7			36			199.9	-46	85	228	T/hr (CO_2)		CS	3.4	1.1	1.3	9.9		
Compression	NW		V	1	18	A/B		CO_2 Dehydration Absorber	Vertical	03	0	0	n/a					37.7						47	-5	150	269	T/hr (CO_2)		316L SS		3.3	9.0			Iternals = molecular sieves, cermaic balls, supports, grid support Material: CS clad with SS also acceptable
Compression	NW		V	1	19			Dehydration KO Drum	Vertical	03	0	0	n/a					35.4			36			47	-5	300	228	T/hr (CO_2)		316L SS		0.9	3.0			Includes Inlet Hood and Mist Eliminator Depressurisation = -79°C at 0 barg

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PROJECT No.	181869
PROJECT NAME	Thermal Power with CCS: Generic Business Case
LOCATION	UK
DOCUMENT No.	181869-0001-T-EM-MEL-AAA-00-00001
REVISION	A05
DATE	JULY 2017

PLANT AREA	EQUIPMENT NUMBER ASSET CODE	EQUIPMENT NUMBER AREA / UNIT CODE	EQUIPMENT NUMBER EQUIPMENT CODING	EQUIPMENT NUMBER TRAIN	EQUIPMENT NUMBER SEQUENCE	EQUIPMENT NUMBER REDUNDANCY	EQUIPMENT NUMBER TRIM OR AUX ELEC EQUIPMENT	ITEM DESCRIPTION	TYPE	PFD Number 181869-0001-D-EM-PFD-AAA-00-00001-XX	ELECTRICAL POWER ABSORBED (kW)	ELECTRICAL POWER INSTALLED (kW)	ELECTRICAL POWER VOLTAGE (HV, MV, LV)	ELECTRICAL POWER DUTY - CONTINUOUS (kW)	ELECTRICAL POWER DUTY - INTERMITTENT (kW)	ELECTRICAL POWER DUTY - STANDBY (kW)	OPERATING PRESSURE MIN (barg)	OPERATING PRESSURE NORMAL (barg)	OPERATING PRESSURE MAX (barg)	OPERATING TEMPERATURE MIN (°C)	OPERATING TEMPERATURE NORMAL (°C)	OPERATING TEMPERATURE MAX (°C)	DESIGN PRESSURE MIN (barg)	DESIGN PRESSURE MAX (barg)	DESIGN TEMPER-ATURE MIN (°C)	DESIGN TEMPER-ATURE MAX (°C)	DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit) m^2	MATERIAL OF CONSTRUCTION	DIMENSIONS Length-OVL/TT (m)	DIMENSIONS Width Or DIA (m)	DIMENSIONS Height-OVL / TT (m)	WEIGHT DRY (tonnes)	WEIGHT OPERATING (tonnes)	REMARKS
Compressors																																				
Compression	SC		C	1	01			CO_2 Compressor	Centrifugal	03	20720	24500	MV					See	Pkg	Below																Part of Package U-101 Dense phase compressor stages are part of Compressor Package U-112 at St Fergus
Instrumentation and Control Equipment																																				
Compression	SC		JDF	0	02			Power Station CO_2 Metering	Coriolis	03	0		LV					36.4			38			47	-5	70	684	T/hr		316L SS	35.0	6.0	7.0	122.7		Combined for three train plant Metering - size based on similar scope pipeline meter
Compression	SC		JCP	0	02			Power Station CO_2 Metering Panel	Panel		1	1	LV																		7.2	0.8	2.1	0.7		Safe Area Panel
Compression	SC		JDC	0	02			Power Station CO_2 Metering Analyser House					LV																		2.0	2.0	2.7	2.3		Analyser House and Speciality Bottle House
Packages																																				
Compression	SC		U	1	01			CO_2 Compression Package	Integral Geared	03	106	189	LV					0.2/37.9			116			42	-5	150	230	T/hr		316L SS	25.0	18.0	9.0	360.0		
Compression	SC		U	1	02			CO_2 Dehydration Package	Mole Sieve	03	0	0	n/a					37.9						47	-5	150	269	T/hr		316L SS	N/A	N/A	N/A	N/A		Equipment elsewhere - line item for price for design and mole sieve
Compression	SC		U	1	10			Tracer Dosing Package	API 675 Pumps		0	0.1	LV					36.4			38			42	-5	85	100	ppbv		316L SS	2.2	1.2	2.0	0.9		Addition to give CO_2 smell to allow leakage detection
Drums and Vessels																																				
Compression	SC		V	0	17			CO_2 Pipeline Pig Launcher	Horizontal	03	0	0	n/a					34			35.5			37.5	-5	70	684	T/hr (CO_2)		CS	3.4	1.1	1.3	9.9		Combined for three train plant

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PLANT AREA	EQUIPMENT NUMBER							ITEM DESCRIPTION	TYPE	PFD Number	ELECTRICAL POWER						OPERATING PRESSURE			OPERATING TEMPERATURE			DESIGN PRESSURE		DESIGN TEMPER-ATURE		DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit)	MATERIAL OF CONSTRUCTION	DIMENSIONS			WEIGHT		REMARKS
	ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT			181869-0001-D-EM-PFD-AAA-00-00001-XX	ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	DUTY - CONTINUOUS (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	MIN (barg)	NORMAL (barg)	MAX (barg)	MIN (°C)	NORMAL (°C)	MAX (°C)	MIN (barg)	MAX (barg)	MIN (°C)	MAX (°C)			m^2		Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	DRY (tonnes)	OPERATING (tonnes)	
Heat Exchangers																																				
Transportation	NW		E	0	01	A/B		Shoreline Pipeline Chiller	BKU Kettle Type Shell & Tube		0	0	n/a					87			34/12.8		FV / -	30 / 110	-46	85	8000	kW	419	LTCS	13.8	1.5		31.5	51.7	Hamilton Liquid Phase only. Significant PSV on Shell for Tube Rupture
Transportation	NW		E	0	02	A/B		Refrigation Package Condenser	Air Cooled Heat Exchanger		480	720	LV					22		60		36	FV	26	-46	85	14603	kW	2651	LTCS	54.0	9.4	5.0	274.8	290.0	Part of Refrigeration Package
Telecomms																																				
Transportation	NW		GLPL	0	01			Telecomms	Package Unit		4																							3.5	3.5	Installed in LER: scope includes telecomms, ACS, CCTV, PAGA, Mast System, and devices.
Instrumentation and Control Equipment																																				
Transportation	NW		JDC	0	03			DCS (ICSS)	Panel		10	10	LV																		3.2	0.8	2.1	2.6	2.6	ICSS Control of Station from Onshore Plant
Filters																																				
Transportation	NW		S	0	01	A/B/C		CO_2 Filters	Cartridge		0	0	n/a					141		4		36		200	-46	50	684	T/hr		LTCS		0.9	3.5	11.8	13.0	2 Duty and 1 Standby
Packages																																				
Transportation	NW		U	0	03	A/B		Shoreline Pipeline Refrigration Package	API 619 Screw Compressor		6300	7000	MV				2.2		22		36/60		FV	26	-46	85	8000	kW	Refrig Duty	LTCS	31.2	18.1	7.0	140.5	196.2	Part of Package U-101 for Hamilton Liquid Phase only
Transportation	NW		U	0	04			Instument Air Package	Screw		12	30	LV					8.5			Amb			11	-5	85	1	Nm^3/mir	@ 8.5 bar	CS	3.2	3.2	1.9	2.2		Package includes compressors, dryers, and air receiver - skid base mounted.
Drums and Vessels																																				
Transportation	NW		V	0	08			CO_2 Pipeline Pig Receiver	Horizontal		0	0	n/a	n/a				181.7			36			200	-46	85	684	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Shore Station
Transportation	NW		V	0	09			CO_2 Pipeline Pig Launcher	Horizontal		0	0	n/a	n/a				181.7			36			200	-46	85	684	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Shore Station
Transportation	NW		V	0	10			CO_2 Pipeline Pig Receiver	Horizontal		0	0	n/a	n/a				181.7			36			200	-46	85	684	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Above Ground Installation
Transportation	NW		V	0	11			CO_2 Pipeline Pig Launcher	Horizontal		0	0	n/a	n/a				181.7			36			200	-46	85	684	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Above Ground Installation
Electrical Equipment																																				
								Low Voltage Equipment																												
Transportation	NW		ESG	1	17			LV Switchboard			145	260	LV																							
Transportation	NW			1				Condenser Fan Motor VFDs					LV																							
								Medium Voltage Equipment																												
Transportation	NW		ESG	1	18			MV Switchboard					MV																							
Transportation	NW		ESG	1	19			Switchgear					MV																		2.3	0.7	1.7	1.3		
Transportation	NW		ETR	1	20			Transformer					MV																							
Buildings																																				
Transportation	NW		BLD	0	03			Admin & Control Building			2	2	LV	n/a				+ve		20		25	N/A	N/A	N/A	N/A	216	m^3			12.0	4.0	4.5			Height to Eaves
Transportation	NW		BLD	1	11			HRSG Power Distribution Centre			1	1	LV	n/a				+ve		10		40	N/A	N/A	N/A	N/A	216	m^3			12.0	4.0	4.5			Height to Eaves
Transportation	NW		BLD	1	09			Equipment Building			2	2	LV	n/a				+ve		5		35	N/A	N/A	N/A	N/A	8120	m^3			37.4	21.7	10.0			Height to Top of Roof
								Auxiliary Load and Losses	Total		6955																									

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PLANT AREA	EQUIPMENT NUMBER							ITEM DESCRIPTION	TYPE	PFD Number	ELECTRICAL POWER						OPERATING PRESSURE			OPERATING TEMPERATURE			DESIGN PRESSURE		DESIGN TEMPER-ATURE		DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit)	MATERIAL OF CONSTRUCTION	DIMENSIONS			WEIGHT		REMARKS
	ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT			181869-0001-D-EM-PFD-AAA-00-00001-XX	ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	DUTY - CONTINUOUS (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	MIN (barg)	NORMAL (barg)	MAX (barg)	MIN (°C)	NORMAL (°C)	MAX (°C)	MIN (barg)	MAX (barg)	MIN (°C)	MAX (°C)			m^2		Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	DRY (tonnes)	OPERATING (tonnes)	
Compressors																																				
Transportation	SC		C	0	02			Onshore Pipeline Booster Compressor	Centrifugal	05	7046	8000	MV					See	Pkg	Below																Part of Package U-111- Located at booster station
Transportation	SC		C	0	03			Captain X CO_2 Compressor	Centrifugal	05	13203	14750	MV					See	Pkg	Below																Part of Package U-112
Transportation	SC		C	0	04			Goldeneye CO_2 Compressor	Centrifugal	05	11536	13000	MV					See	Pkg	Below																Part of Package U-113
Heat Exchangers																																				
Transportation	SC		E	0	27			Onshore Pipeline Booster Compressor Cooler	Shell & Tube	05	0	0	n/a					34			53/36						3545	kW								Part of Package U-111- Located at booster station
Transportation	SC		E	0	05			Captain X 6th Stage Cooler	Shell & Tube	05	0	0	n/a					59.8			126/36						11350	kW								Part of Package U-112
Transportation	SC		E	0	06			Captain X 8th Stage Cooler	Shell & Tube	05								148.8			120/36						20790	kW								Part of Package U-112
Transportation	SC		E	0	28			Goldeneye 6th Stage Cooler	Shell & Tube	05	0	0	n/a					54.3			116/36						9673	kW								Part of Package U-113
Transportation	SC		E	0	29			Goldeneye 8th Stage Cooler	Shell & Tube	05								112.7			104/36						19280	kW								Part of Package U-113
Telecomms																																				
Transportation	SC		GLPL	0	01			Telecomms - Booster Station	Package Unit		4																							3.5	3.5	Installed in LER: scope includes telecomms, ACS, CCTV, PAGA, Mast System, and devices.
Transportation	SC		GLPL	0	02			Telecomms - St Fergus	Package Unit		4																							3.5	3.5	Installed in LER: scope includes telecomms, ACS, CCTV, PAGA, Mast System, and devices.
Instrumentation and Control Equipment																																				
Transportation	SC		JDC	0	03			DCS (ICSS) - Booster Station	Panel		10	10	LV																		3.2	0.8	2.1	2.6	2.6	ICSS Control of Station from Onshore Plant
Transportation	SC		JDC	0	04			DCS (ICSS) - St Fergus	Panel		10	10	LV																		3.2	0.8	2.1	2.6	2.6	ICSS Control of Station from Onshore Plant
Transportation	SC		JDF	0	07			Captain X Pipeline CO_2 Metering	Coriolis	05	0		LV					148.6			38			170	-5	155	342	T/hr		316L SS	35.0	6.0	7.0	122.7		Metering - size based on similar scope pipeline meter
Transportation	SC		JCP	0	07			Captain X Pipeline CO2 Metering Panel	Panel		1	1	LV																		7.2	0.8	2.1	0.7		Safe Area Panel
Transportation	SC		JDC	0	07			Captain X Pipeline CO2 Metering Analyser House					LV																		2.0	2.0	2.7	2.3		Analyser House and Speciality Bottle House
Transportation	SC		JDF	0	08			Goldeneye Pipeline CO2 Metering	Coriolis	05	0		LV					112.5			38			132	-5	140	342	T/hr		316L SS	35.0	6.0	7.0	122.7		Metering - size based on similar scope pipeline meter
Transportation	SC		JCP	0	08			Goldeneye Pipeline CO2 Metering Panel	Panel		1	1	LV																		7.2	0.8	2.1	0.7		Safe Area Panel
Transportation	SC		JDC	0	08			Goldeneye Pipeline CO2 Metering Analyser House					LV																		2.0	2.0	2.7	2.3		Analyser House and Speciality Bottle House
Packages																																				
Transportation	SC		U	0	04			Instument Air Package	Screw		12	30	LV					8.5			Amb			11	-5	85	1	Nm^3/min	@ 8.5 bar	CS	3.2	3.2	1.9	2.2		Package includes compressors, dryers, and air receiver - skid base mounted. At St Fergus
Transportation	SC		U	0	11			CO_2 Onshore Pipeline Booster Compressor	Integral Geared	05			LV					18.4/34			53			37.5	-5	90	684	T/hr		316L SS	25.0	18.0	9.0	360.0		Combined for three trains plant
Transportation	SC		U	0	12			CO_2 Captain X Compressor	Integral Geared	05			LV					17.5/148.8			120			165	-46	150	342	T/hr		316L SS	25.0	18.0	9.0	360.0		Combined for three trains plant
Transportation	SC		U	0	13			CO_2 Goldeneye Compressor	Integral Geared	05			LV					17.5/112.7			104			132	-46	140	342	T/hr		316L SS	25.0	18.0	9.0	360.0		Combined for three trains plant
Drums and Vessels																																				
Transportation	SC		V	0	08			CO_2 Pipeline Pig Receiver - St Fergus	Horizontal		0	0	n/a	n/a				17.5			12.7			37.5	-5	85	684	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Shore Station St Fergus
Transportation	SC		V	0	43			CO_2 Pipeline Pig Receiver - Feeder 10 Entry	Horizontal		0	0	n/a	n/a				34			36			37.5	-46	85	684	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Dunipace
Transportation	SC		V	0	44			CO_2 Pipeline Pig Launcher - Feeder 10 Entry	Horizontal		0	0	n/a	n/a				34			36			37.5	-46	85	684	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Dunipace
Transportation	SC		V	0	45			CO_2 Pipeline Pig Receiver - Feeder 10 Station	Horizontal		0	0	n/a	n/a				34			36			37.5	-46	85	684	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Murthill
Transportation	SC		V	0	46			CO_2 Pipeline Pig Launcher - Feeder 10 Station	Horizontal		0	0	n/a	n/a				34			36			37.5	-46	85	684	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Murthill
Transportation	SC		V	0	10			CO_2 Pipeline Pig Receiver - Booster Station	Horizontal		0	0	n/a	n/a				18.5			0.9			37.5	-46	85	684	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Kirriemuir
Transportation	SC		V	0	11			CO_2 Pipeline Pig Launcher - Booster Station	Horizontal		0	0	n/a	n/a				34			36			37.5	-46	85	684	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Kirriemuir
Transportation	SC		V	0	47			CO_2 Pipeline Pig Receiver - Feeder 10 Station	Horizontal		0	0	n/a	n/a				34			36			37.5	-46	85	684	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Fordtown
Transportation	SC		V	0	48			CO_2 Pipeline Pig Launcher - Feeder 10 Station	Horizontal		0	0	n/a	n/a				34			36			37.5	-46	85	684	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Fordtown
Transportation	SC		V	0	38			Captain X CO_2 Pipeline Pig Launcher	Horizontal	05	0	0	n/a	n/a				148.1			36			170	-46	85	342	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Above Ground Installation
Transportation	SC		V	0	39			Goldeneye CO_2 Pipeline Pig Launcher	Horizontal	05	0	0	n/a	n/a				112			36			132	-46	85	342	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	Located at Above Ground Installation
Transportation	SC		V	0	40			Captain X 6th Stage CO_2 Compressor KO Drum	Vertical	05	0	0	n/a					17.5			12.7			37.5	-46	85	342	T/hr (CO_2)		316L SS						Part of Package U-112 Combined for three trains plant Includes integral water cooled tube bundle
Transportation	SC		V	0	41			Goldeneye 6th Stage CO_2 Compressor KO Drum	Vertical	05	0	0	n/a					17.5			12.7			37.5	-46	85	342	T/hr (CO_2)		316L SS						Part of Package U-113 Combined for three trains plant Includes integral water cooled tube bundle

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PROJECT NAME	Thermal Power with CCS: Generic Business Case
LOCATION	UK

DOCUMENT No.	181869-0001-T-EM-MEL-AAA-00-00001
REVISION	A05
DATE	JULY 2017

PLANT AREA	EQUIPMENT NUMBER							ITEM DESCRIPTION	TYPE	PFD Number	ELECTRICAL POWER						OPERATING PRESSURE			OPERATING TEMPERATURE			DESIGN PRESSURE		DESIGN TEMPER-ATURE		DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit)	MATERIAL OF CONSTRUCTION	DIMENSIONS			WEIGHT		REMARKS
	ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT			181869-0001-D-EM-PFD-AAA-00-00001-XX	ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	DUTY - CONTINUOUS (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	MIN (barg)	NORMAL (barg)	MAX (barg)	MIN (°C)	NORMAL (°C)	MAX (°C)	MIN (barg)	MAX (barg)	MIN (°C)	MAX (°C)			m^2		Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	DRY (tonnes)	OPERATING (tonnes)	
Transportation	SC		V	0	42			CO_2 Onshore Pipeline Booster Compressor KO Drum	Vertical	05	0	0	n/a					18.5			0.9			37.5	-46	85	684	T/hr (CO_2)		316L SS						Part of Package U-111 Combined for three trains plant Includes integral water cooled tube bundle
Electrical Equipment																																				
								Low Voltage Equipment																												
Transportation	SC		ESG	0	17			LV Switchboard - Booster Station			145	260	LV																							
Transportation	SC		ESG	0	18			LV Switchboard - St Fergus			145	260	LV																							
								Medium Voltage Equipment																												
Transportation	SC		ESG	0	19			MV Switchboard - Booster Station					MV																							
Transportation	SC		ESG	0	20			Switchgear - Booster Station					MV																		2.3	0.7	1.7	1.3		
Transportation	SC		ETR	0	21			Transformer - Booster Station					MV																							
Transportation	SC		ESG	0	22			MV Switchboard - St Fergus					MV																							
Transportation	SC		ESG	0	23			Switchgear - St Fergus					MV																		2.3	0.7	1.7	1.3		
Transportation	SC		ETR	0	24			Transformer - St Fergus					MV																							
Buildings																																				
Booster Station																																				
Transportation	SC		BLD	0	08			Admin & Control Building			2	2	LV	n/a				+ve		20		25	N/A	N/A	N/A	N/A	216	m^3			12.0	4.0	4.5			Height to Eaves
Transportation	SC		BLD	0	09			Power Distribution Centre			1	1	LV	n/a				+ve		10		40	N/A	N/A	N/A	N/A	216	m^3			12.0	4.0	4.5			Height to Eaves
Transportation	SC		BLD	0	10			Equipment Building			0	0	LV	n/a				+ve		5		35	N/A	N/A	N/A	N/A	179	m^3			13.7	1.3	10.0			Height to Top of Roof
St Fergus																																				
Transportation	SC		BLD	0	11			Admin & Control Building			2	2	LV	n/a				+ve		20		25	N/A	N/A	N/A	N/A	216	m^3			12.0	4.0	4.5			Height to Eaves
Transportation	SC		BLD	0	12			Power Distribution Centre			1	1	LV	n/a				+ve		10		40	N/A	N/A	N/A	N/A	216	m^3			12.0	4.0	4.5			Height to Eaves
Transportation	SC		BLD	0	13			Equipment Building			2	2	LV	n/a				+ve		5		35	N/A	N/A	N/A	N/A	6480	m^3			30.0	21.6	10.0			Height to Top of Roof
								Auxiliary Load and Losses	Total		32122																									

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EQUIPMENT LIST (MAJOR ITEMS)
OFFSHORE FACILITIES - ENDURANCE

PROJECT No.	181869
PROJECT NAME	Thermal Power with CCS: Generic Business Case
LOCATION	UK

DOCUMENT No.	181869-0001-T-EM-MEL-AAA-00-00001
REVISION	A05
DATE	JULY 2017

PLANT AREA	EQUIPMENT NUMBER							ITEM DESCRIPTION	TYPE	PFD Number	ELECTRICAL POWER						OPERATING PRESSURE			OPERATING TEMPERATURE			DESIGN PRESSURE		DESIGN TEMPER-ATURE		DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit)	MATERIAL OF CONSTRUCTION	DIMENSIONS			WEIGHT		REMARKS
	ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT			181869-0001-D-EM-PFD-AAA-00-00001-XX	ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	DUTY - CONTINUOUS (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	MIN (barg)	NORMAL (barg)	MAX (barg)	MIN (°C)	NORMAL (°C)	MAX (°C)	MIN (barg)	MAX (barg)	MIN (°C)	MAX (°C)			m^2		Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	DRY (tonnes)	OPERATING (tonnes)	
Stack																																				
Offshore	EN		D	9	01			CO_2 Vent Stack	Self Supporting		0	0	n/a	n/a				0.72			-10				-79	250				316L SS		30"	30.0	4.5		Sch 10S
Offshore	EN		D	9	02			Degasser Vent Stack	Self Supporting									Atm			-10				-10	50				316L SS		20"	30.0	3.0		**FUTURE**
Telecomms																																				
Offshore	EN		GLPL	9	01			Telecomms	Package Unit		4							Amb			Amb													3.5	3.5	Installed in LER: scope includes telecomms, ACS, CCTV, PAGA, Mast System, and devices.
Instrumentation and Control Equipment																																				
Offshore	EN		JCP	9	02			Well Control Panels			5	5	LV					Amb			Amb										2.0	4.0	2.5	5.9	6.0	Includes Hydraulic Power Pack
Offshore	EN		JDC	9	01			Brine Analyser																	-10	50					2.0	2.0	2.7	2.3		**FUTURE**
Offshore	EN		JDF	9	03			CO_2 Metering		04																										
Offshore	EN		JDF	9	04	A-E		CO_2 Well Metering		04																										
Offshore	EN		JCP	9	05			Navaids			0	0.2	LV					Amb			Amb													0.5	0.5	Includes all devices as well as controls and power
Offshore	EN		JCP	9	06			ICSS										Amb			Amb													0.6	0.6	
Mechanical Handling Equipment																																				
Offshore	EN		L	9	01			Platform Crane	Pedestal		0.0	5.3	n/a		5			Amb			Amb				-10	50	22	T		CS	7.0	7.5	7.5	100.0	101.0	Diesel Engine Operated (500 kW)
Offshore	EN		L	9	02			Miscellaenous Mechanical Handling Equipment	Hoists and Davits		0	0	n/a					Amb			Amb				-10	50				CS				10.0	10.0	
Offshore	EN		L	9	03			Diesel Loading Hose Reel										2			Amb			10	-30	100	2"		@ 75m Length	CS / Rubber	2.5	0.9	2.8	1.0	0.2	
Offshore	EN		L	9	04			Drain Offloading Hose Reel			0	4	LV		4			2			Amb			10	-30	100	2"		@ 75m Length	CS / Rubber	2.5	0.9	2.8	1.0	0.2	
Fire & Gas																																				
Offshore	EN		NCP	9	01			Fire and CO_2 Detection										Amb			Amb															
Pumps																																				
Offshore	EN		P	9	02	A/B		MEG Injection Pumps	Reciprocating		37	45	LV				0		83	-3		20		200	-10	50	19	m^3/hr		CS	1.2	2.5	1.2	4.7	5.5	
Offshore	EN		P	9	03	A/B		Diesel Transfer Pumps	PD - Gear		0	0.55	LV				0		2	-3		20		6	-10	50	1	m^3/hr	@2 bar	CS / SS Rotor	0.7	0.7	0.7	0.4	0.8	Delivered together on duplex pump skid
Generators																																				
Offshore	EN		R	9	01	A/B/C		Diesel Engine Driven Generators Full marine specification and enclosure	Recip Engine		0	0	n/a					Atm			Atm				-46	50	100	kW		CS	6.0	2.5	2.9	12.0	12.3	2 Duty and 1 Standby
Filters																																				
Offshore	EN		S	9	03	A/B/C		CO_2 Filters	Cartridge	04	0	0	n/a					141		4		36		200	-46	50	571	T/hr	5 micron	CS		0.9	3.5	11.8	13.0	2 Duty and 1 Standby
Offshore	EN		S	9	04	A/B		MEG Filter	Cartridge		0	0	n/a				Atm		5	-3		20		10	-10	50	89	m^3/hr		CS		0.8	1.2	0.2	0.3	
Tanks																																				
Offshore	EN		T	9	01			Drain Tank	Horizontal		0	0	n/a					Atm			Atm			0.1	-10	50	100	m^3		316L SS	13.0	3.3		11.9	122.9	
Offshore	EN		T	9	02			MEG Storage Tank	Rectangular		0	0	n/a					Atm		-7		28		0.4	-10	50	203	m^3		316L SS	4.0	13.0	4.0	23.3	229.7	
Offshore	EN		T	9	03			Diesel Storage Tank	Rectangular		0	0	n/a					Atm			Atm			0.1	-10	50	68	m^3		Carbon Steel	3.0	8.0	3.0	9.8	77.5	
Offshore	EN		T	9	04			Water Tank	Rectangular		0	0	n/a					Atm			Atm			0.1	-10	50	32	m^3		316L SS	2.0	6.5	2.8	5.1	41.5	
Packages																																				
Offshore	EN		U	9	01			Chemical Dosing Package	Reciprocating		1	1	LV				98		128	-3		20		200	-10	50				Super Duplex (25% Cr)	2.5	4.5	2.0	4.0	4.3	Package includes reciprocating pumps, IRCDs, and Storage Tanks
Offshore	EN		U	9	02			Nitrogen Quads	Cylinders		0	0	n/a					300			Amb			330	-46	50	2	m^3			1.2	1.0	2.1	1.7	2.3	16 Cylinders
Offshore	EN		U	9	03			Heating and Ventilation Package	HVAC		12	12.1	LV																		1.1	3.0	2.2	0.7	0.7	Provides Heat and Ventilation to the Package Rooms
Offshore	EN		U	9	04			Well Wash Water Package	Centrifugal		0	0	n/a				0		80	4		19		15/200	-10	50	42	m^3/hr	@83 bar	Super Duplex (25% Cr)	11.0	10.0	5.0	59.0	64.9	**Mounted on Supply Vessel.** Includes: * Filters * Chemical Injection * Diesel Engine Driven Wash Water Pumps * Diesel and Wash Water Storage Tanks * Hose reel to connect to Injection Platform Diesel Tank sized for 7 day activity of washing water wells
Offshore	EN		U	9	05			Wire Line Equipment	Well Intervention		0	0	n/a																		8.0	4.5		52.7	52.7	**Space and Weight Provision Only** * Space and Weight per K24: Full Chain Equipment List * All temperorary Equipment is independent of Platform Power Supply

PROJECT No.	181869
PROJECT NAME	Thermal Power with CCS: Generic Business Case
LOCATION	UK
DOCUMENT No.	181869-0001-T-EM-MEL-AAA-00-00001
REVISION	A05
DATE	JULY 2017

PLANT AREA	EQUIPMENT NUMBER							ITEM DESCRIPTION	TYPE	PFD Number	ELECTRICAL POWER						OPERATING PRESSURE			OPERATING TEMPERATURE			DESIGN PRESSURE		DESIGN TEMPER-ATURE		DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit)	MATERIAL OF CONSTRUCTION	DIMENSIONS			WEIGHT		REMARKS
	ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT			181869-0001-D-EM-PFD-AAA-00-00001-XX	ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	DUTY - CONTINUOUS (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	MIN (barg)	NORMAL (barg)	MAX (barg)	MIN (°C)	NORMAL (°C)	MAX (°C)	MIN (barg)	MAX (barg)	MIN (°C)	MAX (°C)			m^2		Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	DRY (tonnes)	OPERATING (tonnes)	
Drums and Vessels																																				
Offshore	EN		V	9	20			Temporary Pig Receiver	Horizontal	04	0	0	n/a								10			200	-46	50	1142	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	
Offshore	EN		V	9	01			Brine Hold-Up & Degasser Vessel	Horizontal		0	0	n/a					Atm			Amb			7	-10	50	39	m^3	40 mins hold up	CS	7.0	2.5		8.6	47.1	**FUTURE**
Offshore	EN		V	9	02			Brine Discharge Caisson	Vertical		0	0	n/a					0.05						2	-10	50	58	m^3/hr		CS		0.9	39.0	29.7	31.0	**FUTURE ALLOWANCE ONLY** Note - operating weight is only for water above sea level.
Safety Equipment																																				
Offshore	EN		Y	9	01	A/B		Davit Launched Liferaft	Vertical		0	0	n/a												-10	50	10 persons				1.4	0.6		2.0	2.0	Includes liferaft davit
Offshore	EN		Y	9	02	A/B		Auto Launch Liferaft																	-10	50	12 persons				1.4	0.6		0.1	0.1	
Offshore	EN		Y	9	03			Safety Shower and Eye Wash Station			0	0	n/a												-10	50					1.0	0.7	3.6	0.0	0.1	
Miscellaneous																																				
Offshore	EN		X	9	01	A-E		Injection Wells	Vertical	04	0	0	n/a												-46	50	1.34	MPTA				2.0	10.0	14.4	14.4	Weight is for wellhead
Offshore	EN		X	9	02			Brine Production Well	Vertical		0	0	n/a												-10	50	5.00	MTPA				2.0	10.0	14.4	14.4	**FUTURE**
Electrical Equipment																																				
Offshore	EN		ESG	9	01			LV Switchgear																							1.0	7.4	2.4	4.0	4.0	
Offshore	EN		ECH	9	02			AC UPS System																							0.8	1.6	1.7	1.0	1.0	
Offshore	EN		EBA	9	03			AC UPS Batteries																			72	Hours			8.9	0.9	1.7	9.6	9.6	
Offshore	EN		ECH	9	04			DC UPS System																							0.8	1.6	2.0	1.0	1.0	
Offshore	EN		EBA	9	05			DC UPS Batteries																			72	Hours			0.8	4.0	2.0	3.5	3.5	
Buildings																																				
Offshore	EN		BLD	9	01			Local Equipment Room (LER)	Package BLD		8	7.9	LV										N/A	N/A	N/A	N/A					3.0	12.2	2.9	8.0	8.0	
Offshore	EN		BLD	9	02			Battery Room	Package BLD		5	4.7	LV										N/A	N/A	N/A	N/A					3.0	12.2	2.9	8.0	8.0	
Offshore	EN		BLD	9	03			Temporary Refuge	Package BLD		0	0	LV		0.6								N/A	N/A	N/A	N/A					3.0	12.2	2.9	8.0	8.0	
								Auxiliary Load and Losses			72																									

PROJECT No. 181869
PROJECT NAME Thermal Power with CCS: Generic Business Case
LOCATION UK

DOCUMENT No. 181869-0001-T-EM-MEL-AAA-00-00001
REVISION A05
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PLANT AREA	EQUIPMENT NUMBER: ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT	ITEM DESCRIPTION	TYPE	PFD Number (181869-0001-D-EM-PFD-AAA-00-00001-XX)	ELECTRICAL POWER: ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	DUTY - CONTINUOUS (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	OPERATING PRESSURE: MIN (barg)	NORMAL (barg)	MAX (barg)	OPERATING TEMPERATURE: MIN (°C)	NORMAL (°C)	MAX (°C)	DESIGN PRESSURE: MIN (barg)	MAX (barg)	DESIGN TEMPERATURE: MIN (°C)	MAX (°C)	DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit) m^2	MATERIAL OF CONSTRUCTION	DIMENSIONS: Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	WEIGHT: DRY (tonnes)	OPERATING (tonnes)	REMARKS
Stack																																				
Offshore	HA		D	9	01			CO_2 Vent Stack	Self Supporting		0	0	n/a	n/a				0.72			-10				-79	250				316L SS		30"	30.0	4.5		Sch 10S
Heat Exchangers																																				
Offshore	HA		E	9	02			Offshore Heater	Electrical Heater		2230	2600	kW		2600			50.5			25.5/49						2613.0	kW		316L SS / Alloy 800 pockets	5.5	1.3		12.2	12.2	
Telecomms																																				
Offshore	HA		GLPL	9	01			Telecomms	Package Unit		4							Amb			Amb													3.5	3.5	Installed in LER: scope includes telecomms, ACS, CCTV, PAGA, Mast System, and devices.
Instrumentation and Control Equipment																																				
Offshore	HA		JCP	9	02			Well Control Panels			5	5	LV					Amb			Amb										2.0	4.0	2.5	5.9	6.0	Includes Hydraulic Power Pack
Offshore	HA		JDF	9	03			CO_2 Metering		03																										
Offshore	HA		JDF	9	04	A-D		CO_2 Well Metering		04																										
Offshore	HA		JCP	9	05			Navaids			0	0.2	LV					Amb			Amb													0.5	0.5	Includes all devices as well as controls and power
Offshore	HA		JCP	9	06			ICSS										Amb			Amb													0.6	0.6	
Mechanical Handling Equipment																																				
Offshore	HA		L	9	01			Platform Crane	Pedestal		0.0	5.3	n/a		5			Amb			Amb				-10	50	22	T		CS	7.0	7.5	7.5	100.0	101.0	Diesel Engine Operated (500 kW)
Offshore	HA		L	9	02			Miscellaenous Mechanical Handling Equipment	Hoists and Davits		0	0	n/a					Amb			Amb				-10	50				CS				10.0	10.0	
Offshore	HA		L	9	03			Diesel Loading Hose Reel										2			Amb			10	-30	100	2"		@ 75m Length	CS / Rubber	2.5	0.9	2.8	1.0	0.2	
Offshore	HA		L	9	04			Drain Offloading Hose Reel			0	4	LV		4			2			Amb			10	-30	100	2"		@ 75m Length	CS / Rubber	2.5	0.9	2.8	1.0	0.2	
Fire & Gas																																				
Offshore	HA		NCP	9	01			Fire and CO_2 Detection										Amb			Amb															
Pumps																																				
Offshore	HA		P	9	01	A/B		MEG Injection Pumps	Reciprocating		37	45	LV				0		83	-3		20		200	-10	50	19	m^3/hr		CS	1.2	2.5	1.2	4.7	5.5	
Offshore	HA		P	9	02	A/B		Diesel Transfer Pumps	PD - Gear		0	0.55	LV				0		2	-3		20		6	-10	50	1	m^3/hr	@2 bar	CS / SS Rotor	0.7	0.7	0.7	0.4	0.8	Delivered together on duplex pump skid
Generators																																				
Offshore	HA		R	9	01	A/B		Diesel Engine Driven Generators Full marine specification and enclosure	Recip Engine		0	0	n/a					Atm			Atm				-46	50	100	kW		CS	6.0	2.5	2.9	12.0	12.3	2 Standby Main power from Shore
Filters																																				
Offshore	HA		S	9	03	A/B/C		CO_2 Filters	Cartridge	04	0	0	n/a					93		4		12.8		200	-46	50	342	T/hr	5 micron	CS		0.9	3.5	11.8	13.0	2 Duty and 1 Standby
Offshore	HA		S	9	04	A/B		MEG Filter	Cartridge		0	0	n/a				Atm		5	-3		20		10	-10	50	89	m^3/hr		CS		0.8	1.2	0.2	0.3	
Tanks																																				
Offshore	HA		T	9	01			Drain Tank	Horizontal		0	0	n/a					Atm			Atm			0.1	-10	50	100	m^3		316L SS	13.0	3.3		11.9	122.9	
Offshore	HA		T	9	02			MEG Storage Tank	Rectangular		0	0	n/a					Atm		-7		28		0.4	-10	50	203	m^3		316L SS	4.0	13.0	4.0	23.3	229.7	
Offshore	HA		T	9	03			Diesel Storage Tank	Rectangular		0	0	n/a					Atm			Atm			0.1	-10	50	68	m^3		Carbon Steel	3.0	8.0	3.0	9.8	77.5	
Offshore	HA		T	9	04			Water Tank	Rectangular		0	0	n/a					Atm			Atm			0.1	-10	50	32	m^3		316L SS	2.0	6.5	2.8	5.1	41.5	
Packages																																				
Offshore	HA		U	9	01			Chemical Dosing Package	Reciprocating		1	1	LV				98		93	-3		20		200	-10	50				Super Duplex (25% Cr)	2.5	4.5	2.0	4.0	4.3	Package includes reciprocating pumps, IRCDs, and Storage Tanks
Offshore	HA		U	9	02			Nitrogen Quads	Cylinders		0	0	n/a					300			Amb			330	-46	50	2	m^3			1.2	1.0	2.1	1.7	2.3	16 Cylinders
Offshore	HA		U	9	03			Heating and Ventilation Package	HVAC		12	12.1	LV																		1.1	3.0	2.2	0.7	0.7	Provides Heat and Ventilation to the Package Rooms
Offshore	HA		U	9	04			Well Wash Water Package	Centrifugal		0	0	n/a				0		80	4		19		15/200	-10	50	42	m^3/hr	@83 bar	Super Duplex (25% Cr)	11.0	10.0	5.0	59.0	64.9	**Mounted on Supply Vessel.** Includes: * Filters * Chemical Injection * Diesel Engine Driven Wash Water Pumps * Diesel and Wash Water Storage Tanks * Hose reel to connect to Injection Platform Diesel Tank sized for 7 day activity of washing water wells
Offshore	HA		U		08			Wire Line Equipment	Well Intervention		0	0	n/a																		8.0	4.5		52.7	52.7	**Space and Weight Provision Only** * Space and Weight per K24: Full Chain Equipment List * All temperorary Equipment is independent of Platform Power Supply

SNC·LAVALIN

EQUIPMENT LIST (MAJOR ITEMS)
OFFSHORE FACILITIES

PROJECT No.	181869
PROJECT NAME	Thermal Power with CCS: Generic Business Case
LOCATION	UK
DOCUMENT No.	181869-0001-T-EM-MEL-AAA-00-00001
REVISION	A05
DATE	JULY 2017

PLANT AREA	EQUIPMENT NUMBER							ITEM DESCRIPTION	TYPE	PFD Number	ELECTRICAL POWER						OPERATING PRESSURE			OPERATING TEMPERATURE			DESIGN PRESSURE		DESIGN TEMPER-ATURE		DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit)	MATERIAL OF CONSTRUCTION	DIMENSIONS			WEIGHT		REMARKS
	ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT			181869-0001-D-EM-PFD-AAA-00-00001-XX	ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	DUTY - CONTINUOUS (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	MIN (barg)	NORMAL (barg)	MAX (barg)	MIN (°C)	NORMAL (°C)	MAX (°C)	MIN (barg)	MAX (barg)	MIN (°C)	MAX (°C)			m^2		Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	DRY (tonnes)	OPERATING (tonnes)	
Drums and Vessels																																				
Offshore	HA		V	9	20			Temporary Pig Receiver	Horizontal	04	0	0	n/a					93			12.8			200	-46	50	684	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	
Safety Equipment																																				
Offshore	HA		Y	9	01	A/B		Davit Launched Liferaft	Vertical		0	0	n/a												-10	50	10 persons				1.4	0.6		2.0	2.0	Includes liferaft davit
Offshore	HA		Y	9	02	A/B		Auto Launch Liferaft																	-10	50	12 persons				1.4	0.6		0.1	0.1	
Offshore	HA		Y	9	03			Safety Shower and Eye Wash Station			0	0	n/a												-10	50					1.0	0.7	3.6	0.0	0.1	
Miscellaneous																																				
Offshore	HA		X	9	01	A-D		Injection Wells	Vertical	04	0	0	n/a					93			12.8				-46	50	1.34	MPTA				2.0	10.0	14.4	14.4	Weight is for wellhead
Electrical Equipment																																				
Offshore	HA		ESG	9	06			MV Switchgear																							2.0	1.5	2.0	2.3	2.3	
Offshore	HA		ETR	9	07			Transformer																							2.5	2.5	1.8	2.6	2.6	
Offshore	HA		ESG	9	01			LV Switchgear																							1.0	7.4	2.4	4.0	4.0	
Offshore	HA		ECH	9	02			AC UPS System																							0.8	1.6	1.7	1.0	1.0	
Offshore	HA		EBA	9	03			AC UPS Batteries																			72	Hours			8.9	0.9	1.7	9.6	9.6	
Offshore	HA		ECH	9	04			DC UPS System																							0.8	1.6	2.0	1.0	1.0	
Offshore	HA		EBA	9	05			DC UPS Batteries																			72	Hours			0.8	4.0	2.0	3.5	3.5	
Buildings																																				
Offshore	HA		BLD	9	01			Local Equipment Room (LER)	Package BLD		8	7.9	LV										N/A	N/A	N/A	N/A					4.5	12.2	2.9	12.0	12.0	
Offshore	HA		BLD	9	02			Battery Room	Package BLD		5	4.7	LV										N/A	N/A	N/A	N/A					3.0	12.2	2.9	8.0	8.0	
Offshore	HA		BLD	9	03			Temporary Refuge	Package BLD		0	0	LV		0.6								N/A	N/A	N/A	N/A					3.0	12.2	2.9	8.0	8.0	
								Auxiliary Load and Losses			2302																									

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PLANT AREA	EQUIPMENT NUMBER							ITEM DESCRIPTION	TYPE	PFD Number	ELECTRICAL POWER						OPERATING PRESSURE			OPERATING TEMPERATURE			DESIGN PRESSURE		DESIGN TEMPER-ATURE		DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit)	MATERIAL OF CONSTRUCTION	DIMENSIONS			WEIGHT		REMARKS
	ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT			181869-0001-D-EM-PFD-AAA-00-00001-XX	ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	DUTY - CONTINUOUS (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	MIN (barg)	NORMAL (barg)	MAX (barg)	MIN (°C)	NORMAL (°C)	MAX (°C)	MIN (barg)	MAX (barg)	MIN (°C)	MAX (°C)			m^2		Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	DRY (tonnes)	OPERATING (tonnes)	
Instrumentation and Control Equipment																																				
Offshore	GE		JDF	9	03			CO_2 Metering		04																										
Offshore	GE		JDF	9	04	A-D		CO_2 Well Metering		04																										
Filters																																				
Offshore	GE		S	9	03	A/B/C		CO_2 Filters	Cartridge	04	0	0	n/a					141		4		36		213	-80	50	342	T/hr	5 micron	316L SS		0.9	3.5	11.8	13.0	2 Duty and 1 Standby
Offshore	GE		S	9	05	A/B		Methanol Filter	Cartridge		0	0	n/a							-3		20		240	-10	50	5	m^3/hr		316L SS		0.2	1.2	0.2	0.3	
Packages																																				
Offshore	GE		U	9	02			Nitrogen Quads	Cylinders		0	0	n/a					300			Amb			330	-46	50	2	m^3			1.2	1.0	2.1	1.7	2.3	16 Cylinders
Miscellaneous																																				
Offshore	GE		X	9	01	A-D		Injection Wells	Vertical	04	0	0	n/a												-46	50	1.34	MPTA								Wells to be recompleted
								Auxiliary Load and Losses			0																									

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PLANT AREA	EQUIPMENT NUMBER							ITEM DESCRIPTION	TYPE	PFD Number	ELECTRICAL POWER						OPERATING PRESSURE			OPERATING TEMPERATURE			DESIGN PRESSURE		DESIGN TEMPER-ATURE		DUTY (Per Unit)	UNITS	BARE HEAT TRANSFER AREA or ΔP (Per Unit)	MATERIAL OF CONSTRUCTION	DIMENSIONS			WEIGHT		REMARKS
	ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT			181869-0001-D-EM-PFD-AAA-00-00001-XX	ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	DUTY - CONTINUOUS (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	MIN (barg)	NORMAL (barg)	MAX (barg)	MIN (°C)	NORMAL (°C)	MAX (°C)	MIN (barg)	MAX (barg)	MIN (°C)	MAX (°C)			m^2		Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	DRY (tonnes)	OPERATING (tonnes)	
Stack																																				
Offshore	CA		D	9	01			CO_2 Vent Stack	Self Supporting		0	0	n/a	n/a				0.72			-10				-79	250				316L SS		30"	30.0	4.5		Sch 10S
Telecomms																																				
Offshore	CA		GLPL	9	01			Telecomms	Package Unit		4							Amb			Amb													3.5	3.5	Installed in LER: scope includes telecomms, ACS, CCTV, PAGA, Mast System, and devices.
Instrumentation and Control Equipment																																				
Offshore	CA		JCP	9	02			Well Control Panels			5	5	LV					Amb			Amb										2.0	4.0	2.5	5.9	6.0	Includes Hydraulic Power Pack
Offshore	CA		JDF	9	03			CO_2 Metering		04																								0.5	0.5	
Offshore	CA		JDF	9	04	A-E		CO_2 Well Metering		04																								0.5	0.5	
Offshore	CA		JCP	9	05			Navaids			0	0.2	LV					Amb			Amb													0.5	0.5	Includes all devices as well as controls and power
Offshore	CA		JCP	9	06			ICSS										Amb			Amb													0.6	0.6	
Mechanical Handling Equipment																																				
Offshore	CA		L	9	01			Platform Crane	Pedestal		0.0	5.3	n/a		5			Amb			Amb				-10	50	22	T		CS	7.0	7.5	7.5	100.0	101.0	Diesel Engine Operated (500 kW)
Offshore	CA		L	9	02			Miscellaneous Mechanical Handling Equipment	Hoists and Davits		0	0	n/a					Amb			Amb				-10	50				CS				10.0	10.0	
Offshore	CA		L	9	03			Diesel Loading Hose Reel			0	4	LV		**4**			2			Amb			10	-30	100	2"		@ 75m Length	CS / Rubber	2.5	0.9	2.8	1.0	0.2	
Offshore	CA		L	9	04			Drain Offloading Hose Reel			0	4	LV		4			2			Amb			10	-30	100	2"		@ 75m Length	CS / Rubber	2.5	0.9	2.8	1.0	0.2	
Fire & Gas																																				
Offshore	CA		NCP	9	01			Fire and CO_2 Detection										Amb			Amb															
Pumps																																				
Offshore	CA		P	9	01	A/B		MEG Injection Pumps	Reciprocating		37	45	LV				0		83	-3		20		200	-10	50	19	m^3/hr		CS	1.2	2.5	1.2	4.7	5.5	
Offshore	CA		P	9	02	A/B		Diesel Transfer Pumps	PD - Gear		0	0.55	LV				0		2	-3		20		6	-10	50	1	m^3/hr	@2 bar	CS / SS Rotor	0.7	0.7	0.7	0.4	0.8	Delivered together on duplex pump skid
Generators																																				
Offshore	CA		R	9	01	A/B/C		Diesel Engine Driven Generators Full marine specification and enclosure	Recip Engine		0	0	n/a					Atm			Atm				-46	50	100	kW		CS	6.0	2.5	2.9	12.0	12.3	2 Duty and 1 Standby
Filters																																				
Offshore	CA		S	9	03	A/B/C		CO_2 Filters	Cartridge		0	0	n/a					141		4		36		200	-46	50	571	T/hr	5 micron	CS		0.9	3.5	11.8	13.0	2 Duty and 1 Standby
Offshore	CA		S	9	04	A/B		MEG Filter	Cartridge		0	0	n/a				Atm		5	-3		20		10	-10	50	89	m^3/hr		CS		0.8	1.2	0.2	0.3	
Tanks																																				
Offshore	CA		T	9	01			Drain Tank	Horizontal		0	0	n/a					Atm			Atm			0.1	-10	50	100	m^3		316L SS	13.0	3.3		11.9	122.9	
Offshore	CA		T	9	02			MEG Storage Tank	Rectangular		0	0	n/a					Atm		-7		28		0.4	-10	50	203	m^3		316L SS	4.0	13.0	4.0	23.3	229.7	
Offshore	CA		T	9	03			Diesel Storage Tank	Rectangular		0	0	n/a					Atm			Atm			0.1	-10	50	68	m^3		Carbon Steel	3.0	8.0	3.0	9.8	77.5	
Offshore	CA		T	9	04			Water Tank	Rectangular		0	0	n/a					Atm			Atm			0.1	-10	50	32	m^3		316L SS	2.0	6.5	2.8	5.1	41.5	
Packages																																				
Offshore	CA		U	9	01			Chemical Dosing Package	Reciprocating		1	1	LV				98		128	-3		20		200	-10	50				Super Duplex (25% Cr)	2.5	4.5	2.0	4.0	4.3	Package includes reciprocating pumps, IRCDs, and Storage Tanks
Offshore	CA		U	9	02			Nitrogen Quads	Cylinders		0	0	n/a					300			Amb			330	-46	50	2	m^3			1.2	1.0	2.1	1.7	2.3	16 Cylinders
Offshore	CA		U	9	03			Heating and Ventilation Package	HVAC		12	12.1	LV																		1.1	3.0	2.2	0.7	0.7	Provides Heat and Ventilation to the Package Rooms
Offshore	CA		U	9	04			Well Wash Water Package	Centrifugal		0	0	n/a				0		80	4		19		15/200	-10	50	42	m^3/hr	@83 bar	Super Duplex (25% Cr)	11.0	10.0	5.0	59.0	64.9	**Mounted on Supply Vessel.** Includes: * Filters * Chemical Injection * Diesel Engine Driven Wash Water Pumps * Diesel and Wash Water Storage Tanks * Hose reel to connect to Injection Platform Diesel Tank sized for 7 day activity of washing water wells
Offshore	CA		U	9	05			Wire Line Equipment	Well Intervention		0	0	n/a																		8.0	4.5		52.7	52.7	**Space and Weight Provision Only** * Space and Weight per K24: Full Chain Equipment List * All temperorary Equipment is independent of Platform Power Supply
Drums and Vessels																																				
Offshore	CA		V	9	20			Temporary Pig Receiver	Horizontal	04	0	0	n/a								10			200	-46	50	1142	T/hr (CO_2)		LTCS	11.4	1.1	1.3	15.6	19.0	

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	ASSET CODE	AREA / UNIT CODE	EQUIPMENT CODING	TRAIN	SEQUENCE	REDUNDANCY	TRIM OR AUX ELEC EQUIPMENT			181869-0001-D-EM-PFD-AAA-00-00001-XX	ABSORBED (kW)	INSTALLED (kW)	VOLTAGE (HV, MV, LV)	DUTY - CONTINUOUS (kW)	DUTY - INTERMITTENT (kW)	DUTY - STANDBY (kW)	MIN (barg)	NORMAL (barg)	MAX (barg)	MIN (°C)	NORMAL (°C)	MAX (°C)	MIN (barg)	MAX (barg)	MIN (°C)	MAX (°C)			m^2		Length-OVL/TT (m)	Width Or DIA (m)	Height-OVL / TT (m)	DRY (tonnes)	OPERATING (tonnes)	
Safety Equipment																																				
Offshore	CA		Y	9	01	A/B		Davit Launched Liferaft	Vertical		0	0	n/a												-10	50	10 persons				1.4	0.6		2.0	2.0	Includes liferaft davit
Offshore	CA		Y	9	02	A/B		Auto Launch Liferaft																	-10	50	12 persons				1.4	0.6		0.1	0.1	
Offshore	CA		Y	9	03			Safety Shower and Eye Wash Station			0	0	n/a												-10	50					1.0	0.7	3.6	0.0	0.1	
Miscellaneous																																				
Offshore	CA		X	9	01	A-C		Injection Wells	Vertical	04	0	0	n/a												-46	50	1.34	MPTA				2.0	10.0	14.4	14.4	Weight is for wellhead
Electrical Equipment																																				
Offshore	CA		ESG	9	01			LV Switchgear																							1.0	7.4	2.4	4.0	4.0	
Offshore	CA		ECH	9	02			AC UPS System																							0.8	1.6	1.7	1.0	1.0	
Offshore	CA		EBA	9	03			AC UPS Batteries																			72	Hours			8.9	0.9	1.7	9.6	9.6	
Offshore	CA		ECH	9	04			DC UPS System																							0.8	1.6	2.0	1.0	1.0	
Offshore	CA		EBA	9	05			DC UPS Batteries																			72	Hours			0.8	4.0	2.0	3.5	3.5	
Buildings																																				
Offshore	CA		BLD	9	01			Local Equipment Room (LER)	Package BLD		8	7.9	LV										N/A	N/A	N/A	N/A					3.0	12.2	2.9	8.0	8.0	
Offshore	CA		BLD	9	02			Battery Room	Package BLD		5	4.7	LV										N/A	N/A	N/A	N/A					3.0	12.2	2.9	8.0	8.0	
Offshore	CA		BLD	9	03			Temporary Refuge	Package BLD		0	0	LV		0.6								N/A	N/A	N/A	N/A					3.0	12.2	2.9	8.0	8.0	
								Auxiliary Load and Losses			72																									

Attachment 4 – Modelling and Scaling

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TECHNICAL NOTE

To:	The ETI	**Document No.:**	181869-0001-T-EM-TNT-AAA-00-00010
From:	Talal Ali	**Date:**	14-JUL-2017
Project:	Thermal Plant with CCS: Generic Business Case	**Project No.:**	181869
Subject:	Scheme Calculations and Modelling		
Distribution:	Kannan Sreenivasan (SNC-Lavalin) Don Ferns (SNC-Lavalin)		

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TECHNICAL NOTE

CONTENTS

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TECHNICAL NOTE

INTRODUCTION

Purpose

This technical note is a record of the calculation and modelling work undertaken, the basis of the input data, techniques used, assumptions made, limitations, results, and conclusions.

The calculation and modelling work is undertaken in order to provide equipment and plant sizing for use in the plant layout, major equipment list, and ultimately in the CAPEX and OPEX estimates.

The outcomes from this technical note will be summarised in the WP3 and WP4 formal reports.

Plant Configuration

The Generic Business Case aims to capture around 10 million tonnes of CO_2 per annum from Combined Cycle Gas Turbines (CCGT). The overall plant configuration is as follows:

- Gas inlet to the CCGT's;
- 5 Combustion Turbines - Nominal total capacity 2.5 GW (each 500MW);
- 5 Heat Recovery Steam Generators (HSRG);
- 5 Steam Turbines (ST) - Nominal total capacity 1000 MW (each 200 MW);
- Flue gas treatment, with Selective Catalytic Reduction (SCR), for NO_x removal;
- 5 Carbon Capture (CC) Units, i.e., there will be one CC Unit for each CCGT train;
- 5 CO_2 Compressors;
- CO_2 pipeline, with valve stations, for dense phase CO_2 transport to the shoreline;
- Shoreline compressor station, if required;
- Subsea CO_2 pipeline; and
- Offshore Platform.

Process Description

The GBC comprises of five (5) operating trains. Each train has a CCGT, HSRG, CC units and CO_2 compressors. The Combustion Gas Turbines (GT) will fire natural gas to power the electrical generators and generate steam through the HRSG's. The steam from each HSRG flows to a steam turbine for raising additional power. Flue gas from the HSRG's, after treatment for NOX removal, flows to a Carbon Capture Plant for CO_2 recovery. Amine solvents in the CC plants capture 90% of the CO_2 in the flue gases; steam stripping recovers the captured CO_2. The recovered CO_2, after conditioning to a purity of 98 % (vol.) is compressed and transported via a pipeline to offshore for storage. The end-to-end chain links for the overall plant are:

- Power generation facilities including flue gas treatment
- Carbon capture, compression and conditioning
- Pipeline and transport
- Offshore storage

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Abbreviations

Abbreviation	Description
CAPEX	Capital Expenditure
CC	Carbon Capture
CCC	Carbon Capture and Compression
CCGT	Combined Cycle Gas Turbine (Gas Turbine + Steam Turbine)
CCS	Carbon Capture and Storage
FEED	Front End Engineering Design
GBC	Generic Business Case
GBCM	General Business HYSYS Model
GW	Giga watts
GT	Gas Turbine
H&MB	Heat and Mass Balance
HP	High Pressure
HSRG	Heat Recovery Steam Generator
HV	High Voltage
IP	Intermediate Pressure
LP	Low Pressure
MEA	Monoethanolamine
MTPA	Million Tonne per Annum
MW	Mega watts
OPEX	Operational Expenditure
PFD	Process Flow Diagram
PH	Peterhead Design
PHM	Peterhead HYSYS Model
SCR	Selective Catalytic Reduction
ST	Steam Turbine
THP	Tube Head Pressure
THT	Tube Head Temperature
Vol. %	Volume Percent

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Reference Documents

Document Number	Document Title
181869-0001-D-EM-BLK-AAA-00-00001-01	Block Flow Diagram - Outline Scheme Design at Plant Level
181869-0001-D-EM-HMB-AAA-00-00001-01	Heat and Material Balance
181869-0001-SLI-C-MOM-ACM-0001	Call with AECOM - 12th October 2016
181869-0001-T-EM-CAL-AAA-00-00004	Calculation – Scale-Up of Carbon Capture Plant
181869-0001-T-EM-DBS-AAA-00-00001	Basis Of Design
181869-0001-T-EM-LST-AAA-00-00001	Utilities Schedule
181869-0001-T-EM-PFD-AAA-00-00001-02	Process Flow Diagram Carbon Capture
181869-0001-T-EM-PFD-AAA-00-00001-03	Process Flow Diagram CO_2 Compression
181869-0001-T-EM-SPE-AAA-00-00001	Template Plant Specification
181869-0001-T-EM-TNT-AAA-00-00002	Plant by Plant Description
181869-0001-T-EM-TNT-AAA-00-00009	Input to Cost Estimate from Site Selection
181869-0001-T-ME-MEL-AAA-00-00001	Major Equipment List
10113ETIS-Rep-17-03	D12: WP5C – Hamilton Storage Development Plan (Strategic UK CCS Storage Appraisal Project, funded by DECC. - ETI Open Licence for Materials. “Information taken from the Strategic UK CCS Storage Appraisal Project, funded by DECC, commissioned by the ETI and delivered by Pale Blue Dot Energy, Axis Well Technology and Costain”)
10113ETIS-Rep-19-03	D13: WP5D – Captain X Site Storage Development Plan
K34	Flow Assurance Report (Contains public sector information licensed under the Open Government Licence v3.0)
PCCS-05-PT-ZW-7770-00001	Well Technical Specification (© Shell U.K. Limited 2015. Any recipient of this document is hereby licensed under Shell U.K. Limited’s copyright to use, modify, reproduce, publish, adapt and enhance this document.)
UKCCS - KT - S7.1 - E2E – 001	Longannet Post-FEED End-to-End Basis of Design

Codes and Standards

None used in this document.

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MODELLING APPROACH

SNC-Lavalin's design has been overseen by our Chief Technologist for the project.

The plant design is broken into individual trains of CCGT + CCC. One train of CCGT and CCC is modelled only as the other trains are identical.

The Thermal Plant with CCS scheme has been modelled using a number of different techniques and tools as can be seen on the following diagram.

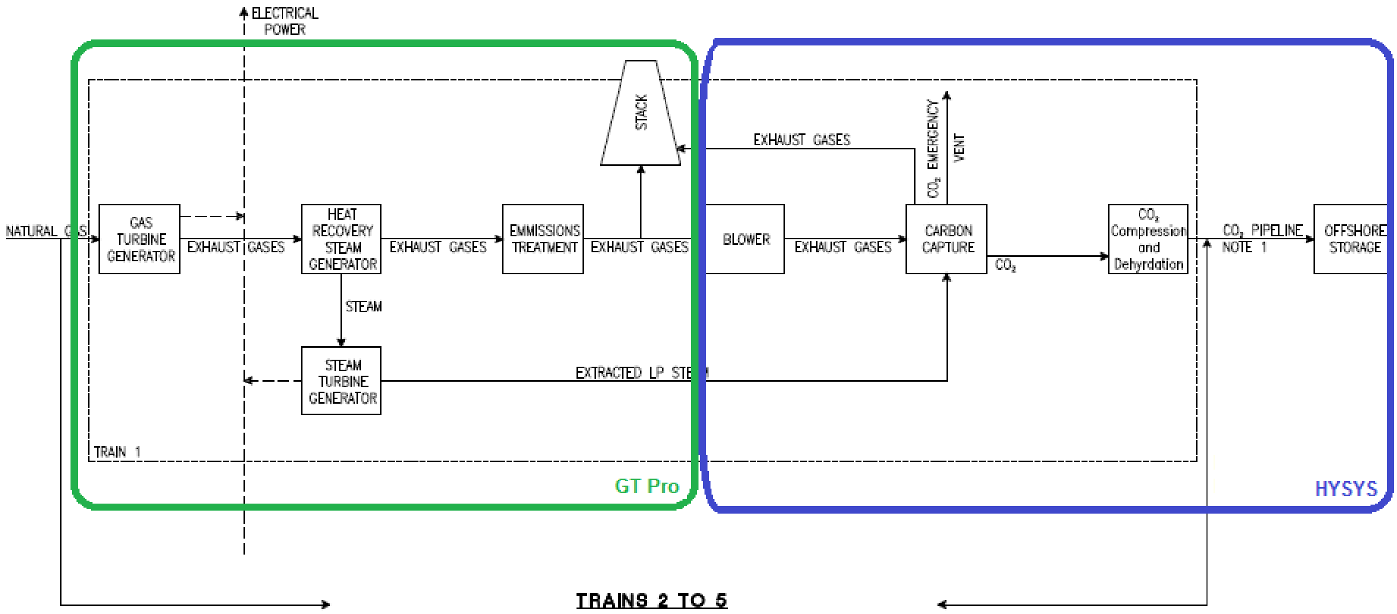

Figure 1 – Modelling Strategy

Input Data

The plant is modelled using the input data within the Template Plant Specification, document reference 181869-0001-T-EM-SPE-AAA-00-00001 revision A03 and its Appendices, in particular:

- Basis of Design, document reference 181869-0001-T-EM-DBS-AAA-00-00001 revision A03.
- Block Flow Diagram - Outline Scheme Design at Plant Level, document reference 181869-0001-D-EM-BLK-AAA-00-00001-01 revision A04.

Power Generation

SNC-Lavalin undertook the modelling for the Combined Cycle Gas Turbine CCGT Unit for a Thermal Power and Carbon Capture System CCS plant located in the UK using GT PRO and PEACE software to develop the heat balances and prices.

The modelling was carried out in SNC-Lavalin's Bothell office (Washington, USA).

2 passes of modelling for the Power Plant were carried out.

- The first was to define the size of plant that could be attained, to get of feel for some of the significant factors in the design, such as cooling, to ascertain layout and utility requirements, and to get a ball park for the cost of plant.

- The second pass was an unabated full power to export design in order to size the plant (e.g. steam turbine, condenser, and what grid connection size is required). Two further runs using the same model were undertaken for a 40% turndown case and an abated case. Full power unabated was used to ensure the correct sizing of the Power System equipment which must be sized for unabated operation in accordance with the Template Plant Specification. The abated case providing operating condition information for the running of the Thermal Power Plant with CCS.

Carbon Capture

The flue gases from the Power Plant, is the feed to the Carbon Capture (CC) plant. The CC plant aims to capture around 90% of CO_2 (around 10 million tonnes per annum) in the flue gases from five (5) identical Combined Cycle Gas Turbines (CCGT) power plants, with each train feeding five (5) identical CC plants. The modelling approach is as follows:

- Characterize the flue gas feed (temperature, pressure, flow and composition) to the CC plant, based on the CCGT operating mode and the fuel fired, i.e., CCGT modelling;
- Model the CC plant to achieve the desired product specifications. The CO_2 product from the CC plant model,, is the feed to CO_2 compression and storage.
- The LP steam requirement for the Carbon Capture Plant is based on Peterhead Design Case scaled up as per Utilities Schedule, document reference 181869-0001-T-EM-LST-AAA-00-00001. This is because the Peterhead design uses an engineered amine solvent compared to benchmark solvent MEA used in the Generic Business Case HYSYS simulation models

Compression and Transport

The Compression and Storage has been modelling in HYSYS based on inlet conditions to compression from the Shell Peterhead project, the pipeline lengths from KKDs, and using 24" pipeline.

Two passes have been carried out:

- 1st pass has been set up in order to test model and provide initial inputs for pipeline sizing.
- 2nd pass will be carried out when site locations are known and therefore pipeline lengths can be calculated.

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COMBINED CYCLE COMBUSTION TURBINE STUDY – 1ST PASS

First Pass Modelling

The CCGT configuration in the model is a 2 x 2 x 1 configuration combine cycle plant is a 2 Combine Cycle Gas Turbines (CCTG) x 2 Heat Recovery Steam Generators (HRSGs) x 1 Steam Turbine Generator (STG), with a nominal gross output of 1500MW.

To generate this electrical output, the exhaust gas from each CCTG was directed to the associated (HRSG) where energy is recovered from the exhaust gases to generate high, intermediate, and low-pressure (HP, IP, and LP respectively) steam. The HRSGs were supplied with duct-firing for the first pass modelling.

The Steam Turbine Generator was modelled as a single, triple pressure with reheat, with the STG exhaust either exhausting into a shell and tube condenser, or into an air cooled condenser, i.e., the modelling considered two options for condensing the STG exhaust steam and auxiliary cooling:. The options were:

1. STG steam, exhausting to a shell & tube condenser using a wet mechanical draft cooling tower for cooling water and a closed cooling water system for auxiliary equipment cooling;
2. STG steam exhausting to an Air Cooled Condenser with a closed loop Fin Fan Cooling System for auxiliary equipment cooling.

The option finally chosen in the final design (Second Pass Modelling) depended on make-up water availability and ambient conditions.

The steam piping system delivers steam from the HRSGs to the STG, where it produces additional power. The exhaust steam from the high-pressure section of the steam turbine is directed back to the HRSG to be mixed with IP steam, re-heated, and returned to the STG.

The model has a steam bypass system for bypassing steam to the hybrid cooling system. This allows the combustion turbine generator to operate when the steam turbine generator is out of service, which could be during start-up or shut down..

Energy will be generated from the 3 turbine generators at 11 kV, and the electrical terminal point is the High Voltage (HV) dead end structure.

For this study a GE 9HA.02 CCGT and a GE D600 steam turbine are considered firing only natural gas.

The first pass power plant model consists of:

- Two (2) General Electric 9HA.02 combustion turbine generator (CTG) sets with evaporator air inlet cooling.
- Two (2) three pressure, three drum heat recovery steam generators with reheat HRSG (duct firing)
- One (1) condensing, reheat steam turbine generator (STG)
- Two options for STG exhaust steam condensing and auxiliary cooling
- Condensate and Feedwater Systems
- STG steam by-pass system

The demineralized water system,will consist of onsite trailers and offsite regeneration by the Owner.

- Water for domestic purposes will be provided by the local water utility

- Water and wastewater systems. Process waste water will be sent to the Municipal waste water system.
- Sanitary waste water will be sent to the Municipal sanitary system
- Service water/fire water and Demineralized Water Storage
- Auxiliary Steam System
- Natural Fuel system
- Instrument/service air system
- Fire protection system
- Piping system
- Buildings and equipment
- Electrical distribution system
- Emergency Diesel Generator
- Instrumentation and control systems
- Continuous Emissions Monitoring System (CEMS) for the HRSG stacks

The combustion turbines will be outdoors with outdoor enclosures. The STG will be indoors. The HRSG will be outdoors, three pressure levels with reheat, furnished with a selective catalytic reduction (SCR) system for the control of NOx emissions, and an oxidation catalyst for the control of CO and VOC emissions. The SCR will use aqueous ammonia as the reagent.

The equipment and systems will be capable of operating continuously at all load conditions between minimum emissions compliance and peak operation. Operating conditions are expected to vary seasonally with periods of cycle operation including base load, minimum load, cold, warm, and hot starts, as well as daily duct firing.

GT Pro Assumptions:

- Default Natural Gas analysis for GT Pro, 100% methane was used. The Gas Quality from National Grid did not have the gas analysis constituents for the GT Pro input.
- ISO conditions: 15°C, 60% R.H. at sea level, 1.0 bara
- Nominal 1500MW gross output with duct firing.
- GE9HA.02 CTGs with evaporator cooling and GE D600 STG were used.
- All other equipment used, was from the GT Pro default.
- No Black Start

PEACE assumptions:

- GT Pro input
- Union Labour
- Two outputs: one for the ACC, and one for the condenser/cooling tower (for 1st pass).
- The electrical terminal point is at the high voltage dead-end structure.

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COMBINED CYCLE COMBUSTION TURBINE STUDY – FINAL

The CCGT modelling was repeated using the Basis of Design information, and decisions made in the Template Plant Specification, for modelling:

- Configuration is only for 1 train of 5 (noting that all trains are identical)
- 1 Combustion Turbines - Nominal 500MW;
- 1 Heat Recovery Steam Generator (HSRG);
- 1 Steam Turbines (ST) - Nominal 200 MW;
- Flue gas treatment, with Selective Catalytic Reduction (SCR), for NOx removal;
- No duct firing;
- Cooling using mechanical cooling towers;
- Configuration is 1 + 1 in a multishaft arrangement;
- Other assumptions and descriptions of plant are the same as for the 1st pass modelling.

In abated operation steam is extracted from the Rankine cycle for use in the Carbon Capture Plant. The total low pressure and medium pressure steam from the CCGT and the total condensate return to the CCGT used for modelling the abated performance of the power plant is summarized in the table below:

Steam / Condensate	Pressure bara	Temp In ºC	Temp Out ºC	Normal kg/hr
Total MP Steam	21.51	235	215	13,429
Total LP Steam	2.4	138.7	126.1	297,834
Total Condensate Return	8.5	126.1	49.5	311,263

POWER PLANT MODELLING RESULTS

RESULTS – 1St Pass (Note: 2 + 1 configuration)

CCGT Plant with ACC:

ISO Conditions: 15°C, 60% RH; 0.0m ASL					CO_2 Emissions		
PEACE GBP £1,046,686,954 GBP/kW: £717	Gross Output MW	Parasitic Load MW	Net MW	Plant Heat Value (Lower Heat Value) net kJ/kW-hr	kg/hr	Metric-ton/annum	kg/MW-hr
HRSG Duct Fired	1619	36	1583	6133	532,149	4.66	328.6
HRSG Un-Fired	1495	34	1461	5969	477,893	4.19	319.7

CCGT Plant with Cooling Tower:

ISO Conditions: 15°C, 60% RH; 0.0m ASL					CO_2 Emissions		
PEACE GBP £932,479,626 GBP/kW: £633	Gross Output MW	Parasitic Load MW	Net MW	Plant Heat Value (Lower Heat Value) net kJ/kW-hr	kg/hr	Metric-ton/annum	kg/MW-hr
HRSG Duct Fired	1635	37	1598	6074	532,149	4.66	325.4
HRSG Un-Fired	1507	34	1473	5920	477,493	4.18	317.4

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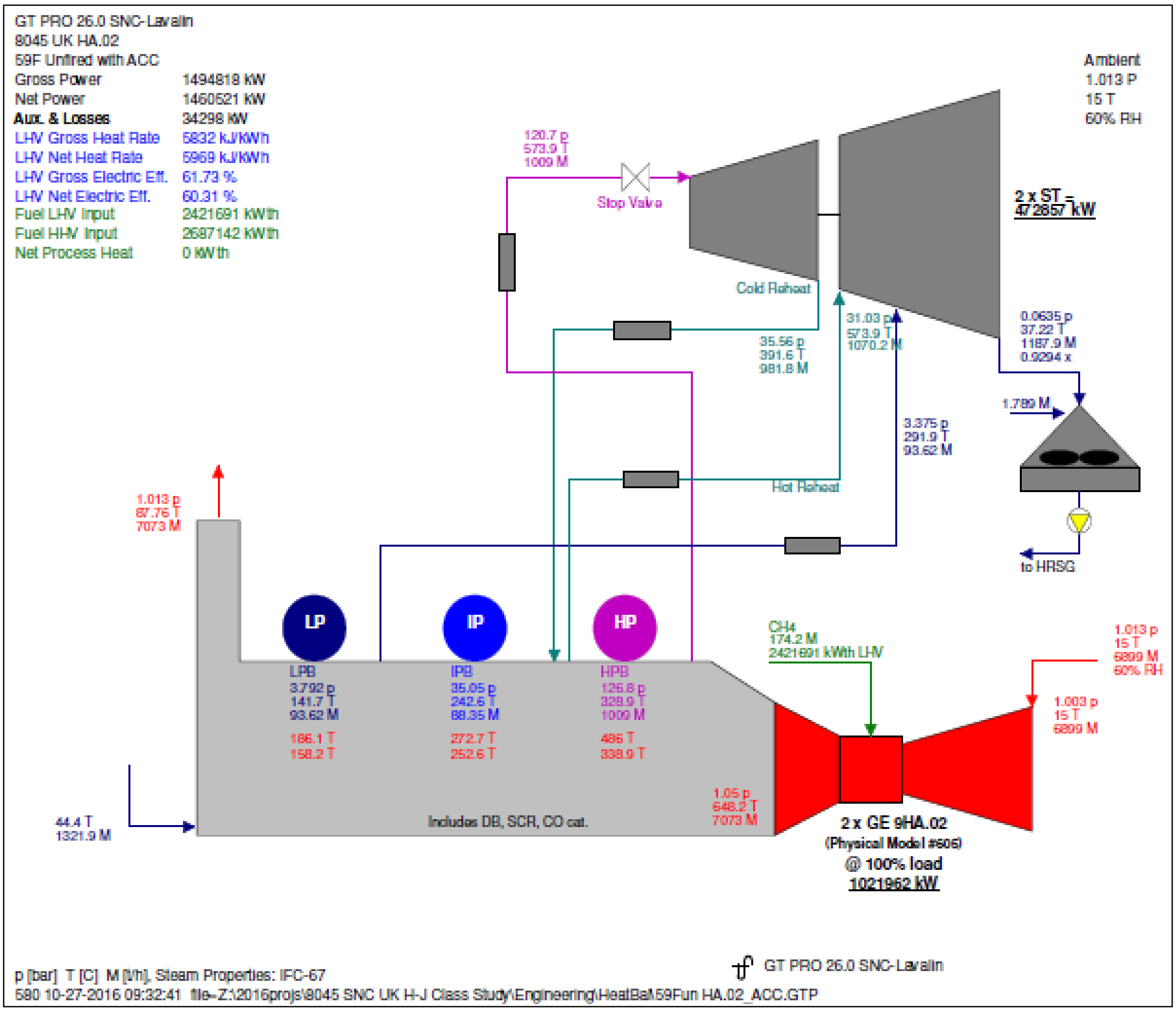

Figure 2 – CCGT in 2 + 1 Configuration with ACC (unabated mode)

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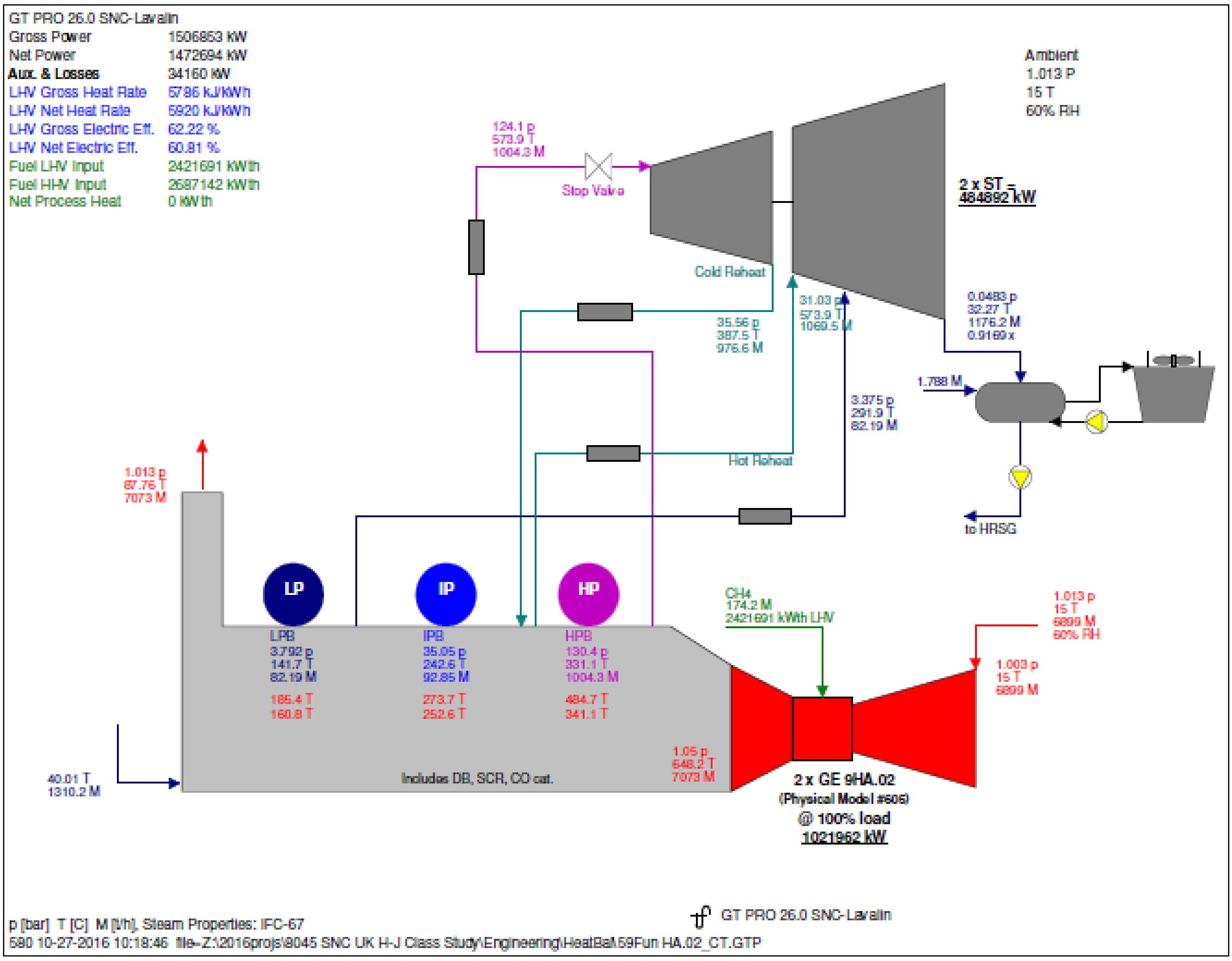

Figure 3 - Figure 2 – CCGT in 2 + 1 Configuration with CT (unabated mode)

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RESULTS – 2ND PASS

CCGT Plant with Cooling Tower – results are **per train**.

ISO Conditions: 15°C, 60% RH; 0.0m ASL					CO_2 Emissions		
	Gross Output MW	Parasitic Load MW	Net MW	Plant Heat Value (Lower Heat Value) net kJ/kW-hr	kg/hr	Metric-ton/annum	kg/MW-hr (gross)
100% unabated	757	17	740	5942	251,955	2.2	332.7

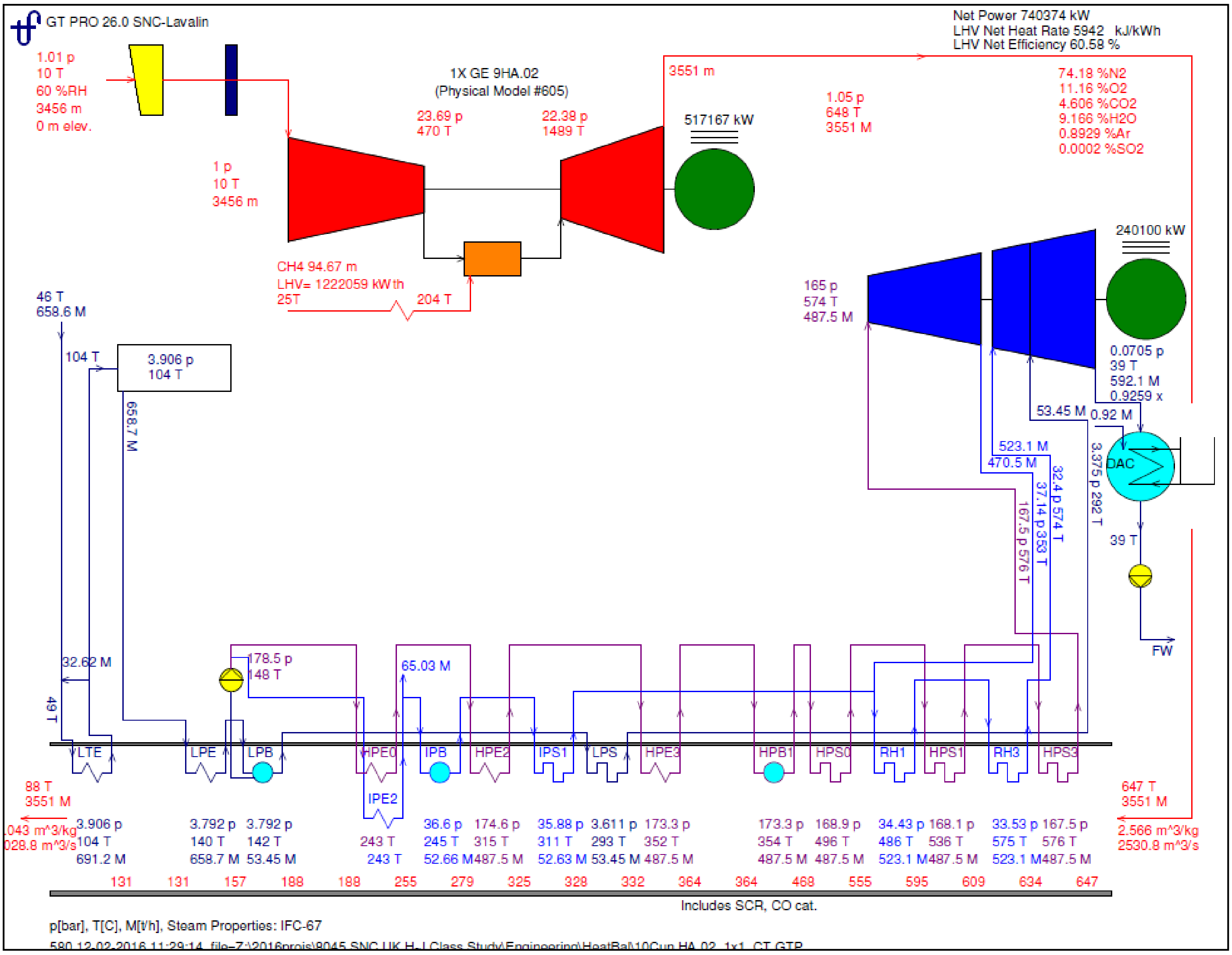

Figure 4 – Single Class H Power Generation Train (unabated mode)

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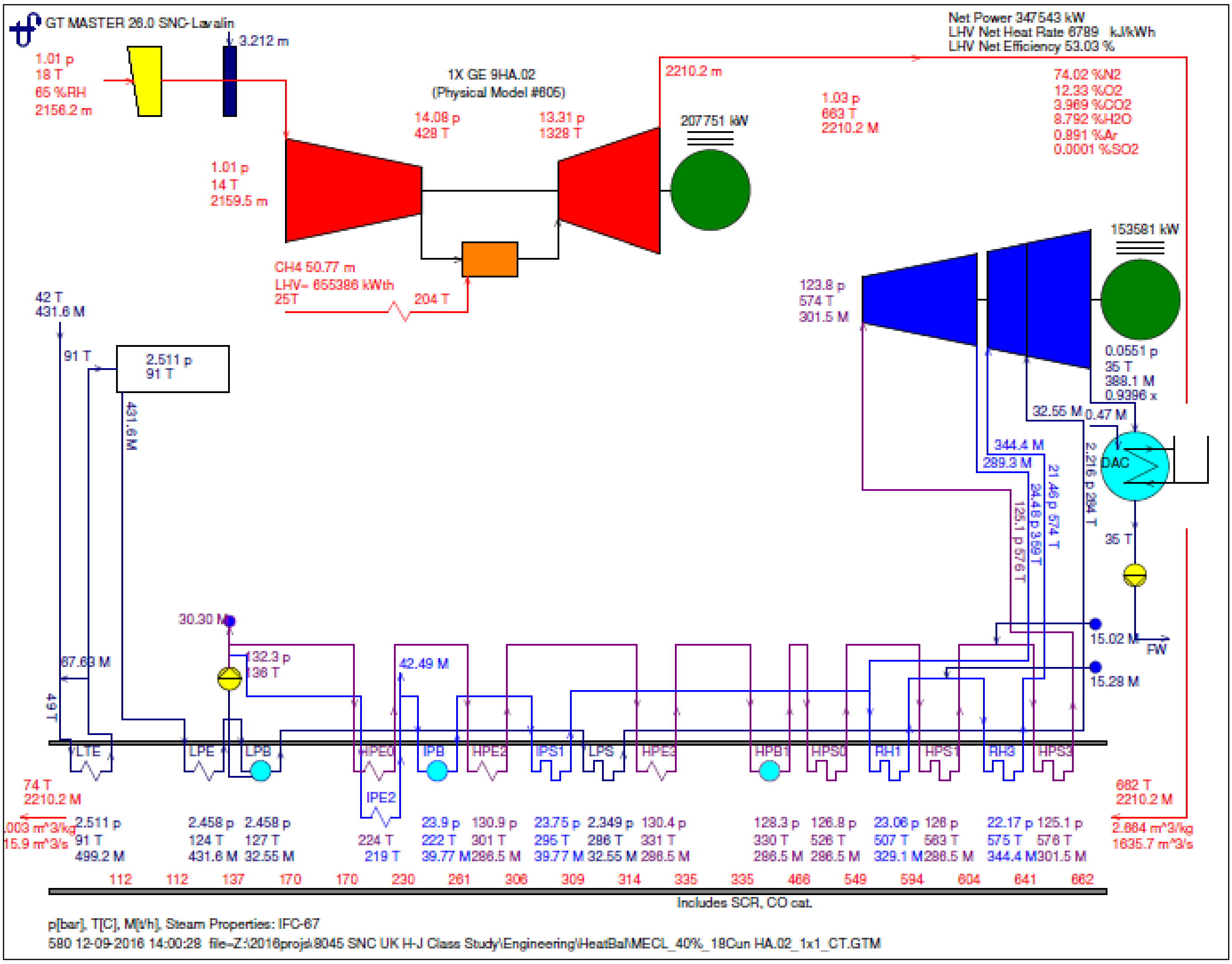

Figure 5 – Single Class H Power Generation Train (unabated mode) – 40% Turndown

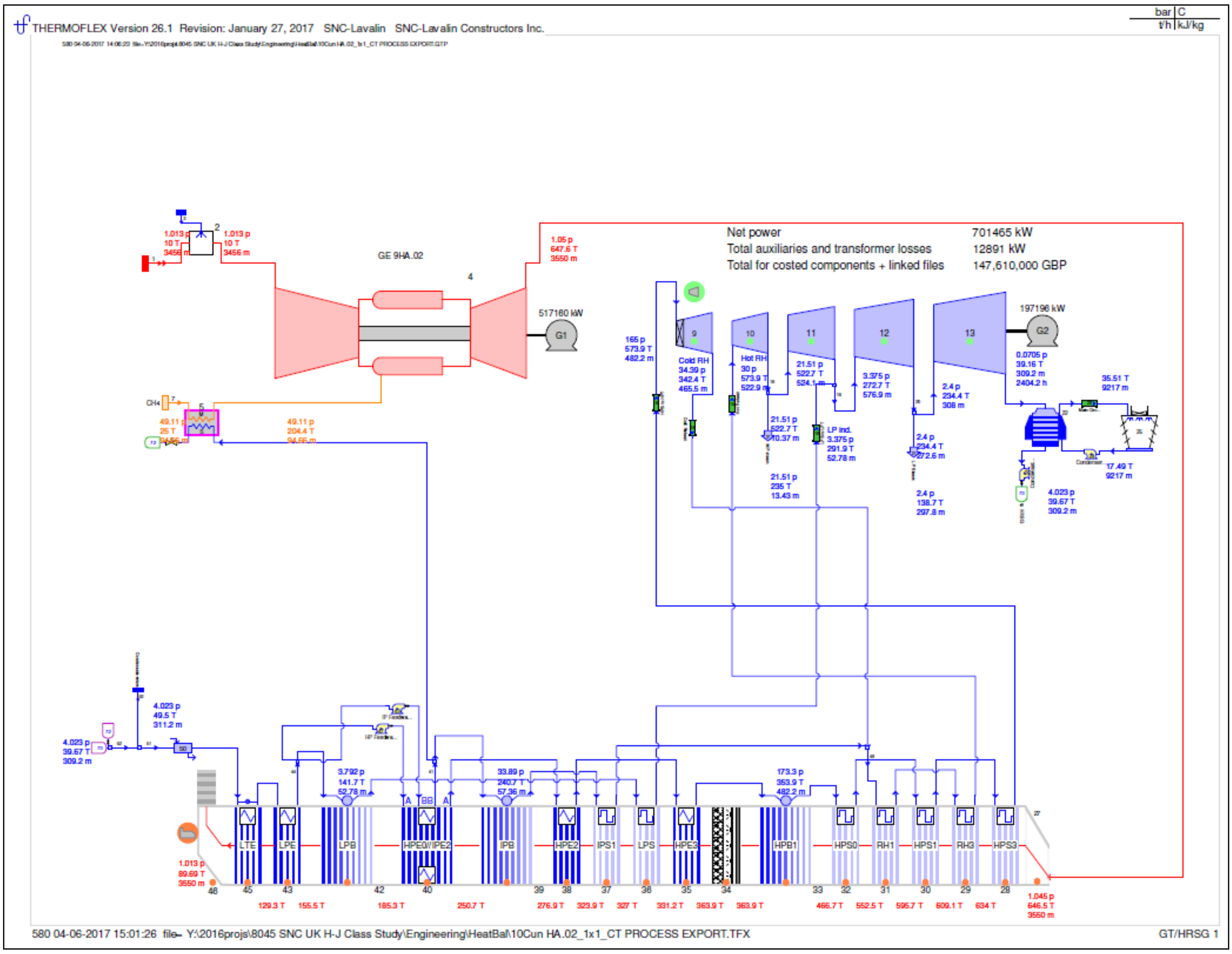

Figure 6 – Single Class H Power Generation Train (abated mode)

Emissions

Air Emissions:

The plant air emissions shall be in compliance with the Air Permit.

Near Field Noise Emissions:

The plant equipment will be designed and constructed, wherever practical, to meet the noise limit of a spatially averaged near free field sound level of 85 dB(A) or less when measured at a horizontal distance of one (1) meter from normally accessible major equipment surfaces at a height of two (2) meters above grade or operating floor.

Equipment that may not meet the above criteria includes the following: cooling towers, generator step-up transformers, feedwater pumps, combustion turbine generator vent fans, building ventilators, stacks, steam bypass piping, relief valve vents, and start-up valve vents.

Signage specifying hearing protection requirements will be provided in areas where the 85 dB(A) limit cannot be met.

Summary

1st Pass

The best overall plant configuration would be to use the cooling tower / shell & tube condenser option.

This configuration offers the best plant MW output, installed price, cost/kW, and heat rate kJ/kW-hr.

Duct Firing reduces power plant efficiency by around 3% and therefore is not recommended. This is in line with the Scheme Configuration meeting held with the ETI (document reference 181869-0001-SLI-C-MOM-ACM-0002).

What needs to be considered is:

- Amount of available make-up water.
- Ambient conditions (a plant in the UK this is probably not a concern).
- Amount of waste water discharge from the cooling tower blowdown based on permits.

2nd Pass

This presents the performance of the power plant against the design basis.

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CARBON CAPTURE (CC) PLANT

Introduction

The CC plant, located downstream of the CCGT's, will capture the CO_2 in flue gases from the HSRG's. The CC plant in the GBC will probably use an engineered amine solvent like Peterhead, Boundary Dam, or Petra Nova to capture CO_2. It should be noted that engineered solvents are proprietary and can be modelled only by the licensors offering the technology. For this reason SNC-Lavalin has modelled the CC plant in the GBC using a benchmark amine solvent. The purpose of this document is twofold: 1) Develop the HYSYS process simulation models of the Carbon Capture (CC) units, in the Peterhead Design (PH) and the Generic Business Case (GBC), using Monoethanolamine (MEA) as the absorbing solvent; and 2) Define the basis for scaling up the equipment sizes from the Peterhead Design to the GBC. SNC Lavalin believes that this modelling approach gives a rational basis for scaling up the equipment sizes since the Peterhead Design and the GBC have similar flue gas composition (CO_2 concentration).

Simulation Basis

This section describes the basis for setting up the HYSYS process simulation models for the Carbon Capture (CC) Plant in the Generic Business Case (GBC). For the process description and the Process Flow Diagram (PFD), refer to the Plant-by-Plant Description [181869-0001-T-EM-TNT-AAA-00-00002] and Process Flow Diagram Carbon Capture [181869-0001-T-EM-PFD-AAA-00-00001].

Setting up the HYSYS simulation models involves the following:

- Step one - Develop a HYSYS simulation model of the Peterhead Design with MEA. The model was tuned to match the inlet and outlet stream of Peterhead Design as given in the Peterhead CCS Project Heat & Material Balance Pre-Treatment Unit, And Compression And Conditioning Plant, PCCS-02-TC-PX-8240-00001, Rev K01.
- Step two - Develop a GBC simulation model with MEA. This done by updating the converged PH model as in step one with the GBC flue gas conditions.

The acid wash section is not considered in the HYSYS simulation modelling for MEA solvent. However acid wash is included in the equipment list and cost estimation.

The snapshot below gives HYSYS simulation models set-up.

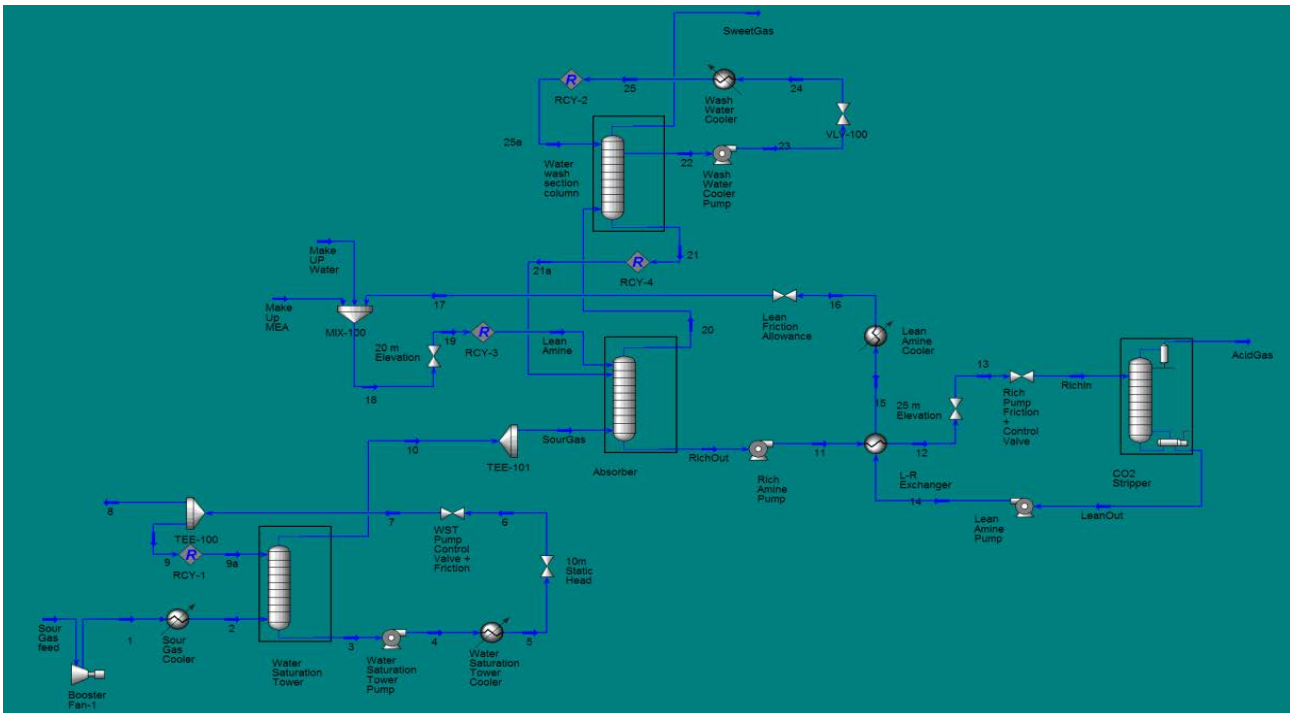

Figure 7 – HYSYS Model of Carbon Capture

Simulation Property Packages

Aspen HYSYS V8.6, with the new Acid Gas Property Package, is the simulation platform for modelling the CC plant process.

It is worth noting that the new Acid Gas Cleaning capability in version 8.6, allows users to rigorously simulate gas processing trains from beginning to end, including the removal of acid contaminants. This new feature allows users to model:

- Amine treating for gas sweetening
- Sulphur removal, including hydrogen sulphide, mercaptans, COS and CS_2
- Amine regeneration and Carbon dioxide (CO_2) removal

Units of Measurement

This document uses S.I. units, which match the units used in the Design Basis [181869-0001-T-EM-DBS-AAA-00-00001]. Standard conditions are defined as 15.6°C, 101.323kPa (1atm).

Simulation Specifications

The overall simulation target is to achieve the following benchmark specifications (Table 1):

Table 1 Overall Simulation Target Specification

Parameter	Unit	Peterhead Design Case (PH)	General Business Case (GBC)
Total CO_2 recovered	wt%	>90	>90
CO_2 purity in the stripper overhead	mole%	98.09	98.09
Rich amine CO_2 loading		<0.50	<0.50

Key Simulation Input Parameters

Key input parameters are summarised below (Table 2) for both the Peterhead Design Case HYSYS model (PHM) and the General Business Case HYSYS model (GBCM).

Table 2 Simulation Input Parameters

Stream / Equipment	Cases	Unit	PHM	GBCM
Sour Gas feed	Temperature	°C	100.0	87.8
	Pressure	Bar (a)	1.010	1.013
	Total mass flow	kg/h	2556000.0	3551000.0
	H_2O	Mole fractions	0.075300	0.091660
	CO_2		0.038800	0.046060
	H_2S		0.000000	0.000000
	O_2		0.128100	0.111570
	N_2		0.748792	0.741779
	SO_2		0.000001	0.000002
	NH_3		0.000005	0.000000
	Argon		0.009000	0.008930
	NO_2		0.000001	0.000000
Booster Fan	Outlet pressure	bar (a)	1.093	1.093
	Adiabatic efficiency	%	75.000	75.000
Sour Gas Cooler	Outlet pressure	bar (a)	1.074	1.074

Stream / Equipment	Cases	Unit	PHM	GBCM
	Outlet temperature	°C	70	70
Water Saturation Tower	Top pressure	Bar (a)	1.063	1.063
	Bottom pressure	Bar (a)	1.074	1.074
	Water recycle rate	kgmole/h	172000	286000
	Top temperature	°C	30.26	30.06
	Number of stages		2	2
Water Saturation Tower Cooler	Outlet temperature	°C	20	20
	Pressure drop	bar	0.45	0.45
Water Saturation Tower Pump	10m Static Head	bar	1.0	1.0
	Pump friction + control valve	bar	1.4	1.4
Water removal	Water in flue gas feed	kgmole/h	6753.4	11465.1
	Water in saturated flue gases	kgmole/h	3535.7	4788.7
	Water removed (spreadsheet)	kgmole/h	3217.7	6676.4
CO_2 Absorber with water wash tower	Top pressure	bar (a)	1.026	1.026
	Bottom pressure	bar (a)	1.063	1.063
	Number of stages		9 + 4	9 + 4
	Wash water side draw rate @ Standard Conditions	m^3/hr	2500	3620
Makeup MEA and water	Temperature	°C	25	25
	Pressure	bar (a)	3.036	3.036
	MEA mass flow	kg/h	0.00034	0.000062
	Water mass flow	kg/h	11160.0	15120.0
	Amine strength	wt%	30.0	30.0
	Lean amine mass flow	kg/h	2661000.0	4404000.0
Rich Amine Pump	25m static head	bar	2.5	2.5
	Pump fiction + control valve	bar	1.4	1.4
	Adiabatic efficiency	75	75	75
Rich/Lean Heat Exchanger	Tube pressure drop	bar	0.7	0.7
	Shell pressure drop	bar	0.7	0.7
	Rich amine outlet temperature	°C	111	111
CO_2 Stripper	Top pressure	bar (a)	2	2
	Bottom pressure	bar (a)	2.1	2.1

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Stream / Equipment	Cases	Unit	PHM	GBCM
	Pressure drop	bar	0.10	0.10
	Number of stages		10	10
	CO_2 mole% (stripper top)		98.09%	98.09%
Reboiler	Duty	MW	152.9	255.1
	Total CO_2 recovered %		90.02	90.01
Lean Amine Pump	20m Static Head	bar	2	2
	Pump friction + control Valve	bar	1.4	1.4
	Adiabatic efficiency	75	75	75
Lean Amine Cooler	Outlet temperature	°C	40	40
	Pressure drop	bar	0.7	0.7

Table 3 below gives the key simulation control parameters. These parameters were kept close to typical literature values in order for the simulation to converge with meaningful results.

Table 3 Simulation Control Parameters

Description	Unit	Typical values	PHM	GBCM
Absorber water wash section top temperature	°C	30	32.78	32.68
Lean amine loading		0.23 to 0.36	0.2339	0.2310
Rich amine loading		0.36 to 0.46	0.4735	0.4707
Amine strength (wt%)	wt%	<=30	30.0	30.0
Lean amine flow to absorber (actual)	m^3/h		2524	4179
CO_2 in feed gas to absorber	kg/h		153169	253547
Lean amine flow, litres MEA / kg CO_2		15 to 18	16.48	16.48
Condenser Duty	MW		46.59	78.18
Condenser temperature	°C		26.24	26.30
CO_2 flow from stripper	kg/h		137888	228220
Condenser Duty, GJ/h /ton of CO_2 recovered		0.5 to 1.5	1.216	1.233
Stripper bottom temperature	°C	120	122.3	122.3
Reboiler Duty	MW		153	255
Reboiler Duty, GJ/h /ton of CO_2 recovered		3.5 to 4.2	3.993	4.024

OVERALL COMPARISON OF SIMULATION MODELS

The overall comparison between Peterhead Design Case and Peterhead / General Business Case HYSYS simulation models, PHM and GBCM respectively, are summarised in Tables 4, 5 and 6 listed below. The observations from these tables are as follow:

- The Peterhead MEA HYSYS model matches the Peterhead design case data quite well with the exception of the MEA loop, which shows a higher value for reboiler duty 152.940MW vs 133.18MW. This is because the Peterhead design uses an engineered amine solvent compared to benchmark solvent MEA used in the HYSYS simulation models
- As the CO_2 mass flow in the GBC increases by 1.66 (Table 4) the pump capacities, cooler and reboiler duties (Table 5) increase by a similar ratio with the exception of the MEA loop. The reason for this difference, as explained before, is because the models do not use an engineered solvent.

Table 4 Simulation Models Comparison for Key streams

Description	HYSYS Model	PHM	GBCM	GBCM/PHM
Flue gas inlet (Sour gas feed)	Temperature	100.00	87.80	
	Mass Flow (kg/h)	2556009	3550500	1.39
	Mass Flow (MEA)			
	Mass Flow (H_2O)	121665	206547	1.70
	Mass Flow (CO_2)	153148	253554	1.66
CO_2 Absorber feed (Sour gas)	Temperature	30.26	30.06	
	Mass Flow (kg/h)	2498050	3430204	1.37
	Mass Flow (MEA)			
	Mass Flow (H_2O)	63697	86270	1.35
	Mass Flow (CO_2)	153169	253548	1.66
Treated sweet gas (CO_2 Absorber top)	Temperature	32.78	32.68	
	Mass Flow (kg/h)	2370120	3215107	1.36
	Mass Flow (MEA)	0.00034	0.00007	0.20
	Mass Flow (H_2O)	73857	99735	1.35
	Mass Flow (CO_2)	15280	25308	1.66
Rich amine out of CO_2 absorber bottom	Temperature	38.99	40.76	
	Mass Flow (kg/h)	2789419	4618947	1.66
	Mass Flow (MEA)	798477	1321814	1.66
	Mass Flow (H_2O)	1718314	2848400	1.66
	Mass Flow (CO_2)	272425	448410	1.65
Lean amine to CO_2 Absorber	Temperature	39.99	40.00	
	Mass Flow (kg/h)	2661489	4403868	1.65

Description	HYSYS Model	PHM	GBCM	GBCM/PHM
	Mass Flow (MEA)	798476	1321814	1.66
	Mass Flow (H_2O)	1728475	2861858	1.66
	Mass Flow (CO_2)	134535	220195	1.64
CO_2 from Stripper (Acid gas)	Temperature	26.24	26.30	
	Mass Flow (kg/h)	139092	230198	1.66
	Mass Flow (MEA)	8.91E-10	9.49E-10	1.07
	Mass Flow (H_2O)	1003	1666	1.66
	Mass Flow (CO_2)	137888	228211	1.66

Table 5 Simulation Models Comparison for Equipment

Case	PH (Note 1)	PHM	GBCM	PHM /PH	GBCM /PH	GBCM /PHM	Ratio (Note 5)	
Pump Capacity (m^3/hr) (Note2)								
Water Saturation Tower Cooler Pump	3141	3180	5315	1.01	1.69	1.67	1.66	0.78 %
Rich Amine Pump	1422	2519	4177	1.77	2.94	1.66	1.66	-0.1%
Absorber Wash Water Pump	2321	2422	3654	1.04	1.57	1.51	1.66	-9.1%
Lean Amine Pump	1527	2658	4405	1.74	2.89	1.66	1.66	-0.2%
Coolers/Reboiler Duty (MW) (Note 3)								
Booster Fan	10.000	8.226	11.094	0.82	1.11	1.35	1.66	-
Gas - Gas Heat Exchanger	30.269	30.661	29.748	1.01	0.98	0.97	1.66	-
Water Saturation Tower Cooler	70.950	70.238	125.062	0.99	1.76	1.78	1.66	7.3%
Wash Water Cooler	68.250	68.757	108.729	1.01	1.59	1.58	1.66	-4.7%
Lean Amine Cooler	18.518	29.712	57.248	1.60	3.09	1.93	1.66	16.1
Condenser	39.179	46.588	78.154	1.19	1.99	1.68	1.66	1.1%
Reboiler (Note 4)	133.183	152.94	255.100	1.15	1.92	1.67	1.66	0.5%
Lean amine/rich amine	140.483	192.88	312.160	1.37	2.22	1.62	1.66	-2.5%

Notes:

1. Values are from the Peterhead Design Case H&MB and equipment list in the KKD
2. Capacity is based on the normal rate given in the equipment list
3. Peterhead duty includes overdesign margin (10% or 20%) as stated in the equipment list. The scale-up ratio's for the sour gas cooler is lower than 1.66 because the GBC has a lower inlet temperature than the Peterhead Design Case
4. The reboiler duty is varied to get an overall CO_2 recovery of 90%.
5. Ratios are from 181869-0001-T-EM-CAL-AAA-00-00004 rev A03.

Table 6 Simulation Models Comparison for Equipment Inlet/Outlet Streams

Case		(PH)	(PHM)	(GBCM)	PHM/PH	GBCM/PH	GBCM/PHM
Booster Fan Inlet	**Stream (Note 1)**	**101**	**Sour Gas feed**	**Sour Gas feed**			
	Temperature, °C	100.00	100.00	87.80			
	Pressure, bar (a)	1.010	1.010	1.010	1.00	1.00	1.00
	Molar Flow, kgmole/h	89687	89687	125083	1.00	1.39	1.39
	Mass Flow, kg/h	2556000	2556009	3550500	1.00	1.39	1.39
	Actual Volume Flow, m3/h	2755778	2753910	3714505	1.00	1.35	1.35
	MEA	0.0000000	0.0000000	0.0000000	0.00	0.00	0.00
	H_2O	0.0753000	0.0753002	0.0916598	1.00	1.22	1.22
	CO_2	0.0388000	0.0388001	0.0460599	1.00	1.19	1.19
	Oxygen	0.1281000	0.1281003	0.1115698	1.00	0.87	0.87
	Nitrogen	0.7487900	0.7487919	0.7417785	1.00	0.99	0.99
Booster Fan Outlet	**Stream (Note 1)**	**102**	**P102**	**P102**			
	Temperature, °C	110.70	111.00	98.40			
	Pressure, bar (a)	1.093	1.093	1.093	1.00	1.00	1.00
	Molar Flow, kgmole/h	89579	89687	125083	1.00	1.40	1.39
	Mass Flow, kg/h	2552933	2556009	3550500	1.00	1.39	1.39
	Actual Volume Flow, m3/h	2616186	2619908	3533441	1.00	1.35	1.35
	MEA	0.0000000	0.0000000	0.0000000	0.00	0.00	0.00
	H_2O	0.0753000	0.0753002	0.0916598	1.00	1.22	1.22
	CO_2	0.0388000	0.0388001	0.0460599	1.00	1.19	1.19
	Oxygen	0.1281000	0.1281003	0.1115698	1.00	0.87	0.87
	Nitrogen	0.7487900	0.7487919	0.7417785	1.00	0.99	0.99
Sour Gas Cooler	**Stream (Note 1)**	**103**	**P103**	**P103**			
	Temperature, °C	70.00	70.00	70.00			
	Pressure, bar (a)	1.074	1.074	1.074	1.00	1.00	1.00
	Molar Flow, kgmole/h	89042	89687	125083	1.01	1.40	1.39
	Mass Flow, kg/h	2537615	2556009	3550500	1.01	1.40	1.39
	Actual Volume Flow, m3/h	2365117	2380902	3320166	1.01	1.40	1.39

Case		(PH)	(PHM)	(GBCM)	PHM/PH	GBCM/PH	GBCM/PHM
	MEA	0.0000000	0.0000000	0.0000000	0.00	0.00	0.00
	H_2O	0.0753000	0.0753002	0.0916598	1.00	1.22	1.22
	CO_2	0.0388000	0.0388001	0.0460599	1.00	1.19	1.19
	Oxygen	0.1281000	0.1281003	0.1115698	1.00	0.87	0.87
	Nitrogen	0.7487900	0.7487919	0.7417785	1.00	0.99	0.99
Circulation Water To Water Saturation Tower	**Stream (Note 1)**	**107**	**P107**	**P107**			
	Temperature, °C	20.00	20.11	20.11			
	Pressure, bar (a)	1.113	1.113	1.113	1.00	1.00	1.00
	Molar Flow, kgmole/h	171929	172008	286011	1.00	1.66	1.66
	Mass Flow, kg/h	3097953	3099544	5153027	1.00	1.66	1.66
	Actual Volume Flow, m3/h	3191	3105	5162	0.97	1.62	1.66
	MEA	0.0000000	0.0000000	0.0000000	0.00	0.00	0.00
	H_2O	0.9997400	0.9997126	0.9999267	1.00	1.00	1.00
	CO_2	0.0001300	0.0001356	0.0000225	1.04	0.17	0.17
	Oxygen	0.0000000	0.0000026	0.0000022	0.00	0.00	0.86
	Nitrogen	0.0000100	0.0000080	0.0000079	0.80	0.79	0.99
Water Removal	**Stream (Note 1)**	**108**	**P108**	**P108**			
	Temperature, °C	20.00	20.11	20.11			
	Pressure, bar (a)	1.113	1.113	1.113	1.00	1.00	1.00
	Molar Flow, kgmole/h	3293	3218	6676	0.98	2.03	2.07
	Mass Flow, kg/h	59344	57982	120287	0.98	2.03	2.07
	Actual Volume Flow, m3/h	60	58	121	0.97	2.01	2.07
	MEA	0.0000000	0.0000000	0.0000000	0.00	0.00	0.00
	H_2O	0.9997400	0.9997176	0.9999267	1.00	1.00	1.00
	CO_2	0.0001300	0.0001304	0.0000225	1.00	0.17	0.17
	Oxygen	0.0000000	0.0000026	0.0000022	0.00	0.00	0.87
	Nitrogen	0.0000100	0.0000080	0.0000079	0.80	0.79	0.99
FLUE GAS TO ABSORBER	**Stream (Note 1)**	**104**	**P104**	**P104**			
	Temperature, °C	30.00	30.26	30.06			
	Pressure, bar (a)	1.063	1.063	1.063	1.00	1.00	1.00
	Molar Flow, kgmole/h	85748	86469	118406	1.01	1.38	1.37
	Mass Flow, kg/h	2478263	2498050	3430204	1.01	1.38	1.37

Case		(PH)	(PHM)	(GBCM)	PHM/PH	GBCM/PH	GBCM/PHM
	Actual Volume Flow, m3/h	2032467	2050133	2805469	1.01	1.38	1.37
	MEA	0.0000000	0.0000000	0.0000000	0.00	0.00	0.00
	H_2O	0.0398000	0.0408899	0.0404431	1.03	1.02	0.99
	CO_2	0.0402800	0.0402495	0.0486559	1.00	1.21	1.21
	Oxygen	0.1330200	0.1328673	0.1178610	1.00	0.89	0.89
	Nitrogen	0.7775500	0.7766565	0.7836066	1.00	1.01	1.01
Treated Gas from Absorber	**Stream (Note 1)**	**248**	**Sweet Gas**	**Sweet Gas**			
	Temperature, °C	30.10	32.78	32.68			
	Pressure, bar (a)	1.026	1.026	1.026	1.00	1.00	1.00
	Molar Flow, kgmole/h	82972	83895	113959	1.01	1.37	1.36
	Mass Flow, kg/h	2341405	2370120	3215107	1.01	1.37	1.36
	Actual Volume Flow, m3/h	2038547	2078239	2822032	1.02	1.38	1.36
	MEA	0.0000000	0.0000000	0.0000000	0.00	0.00	0.15
	H_2O	0.0410000	0.0488668	0.0485798	1.19	1.18	0.99
	CO_2	0.0041000	0.0041384	0.0050461	1.01	1.23	1.22
	Oxygen	0.1379900	0.1369414	0.1224571	0.99	0.89	0.89
	Nitrogen	0.8169200	0.8004804	0.8141747	0.98	1.00	1.02
Acid Gas from CO2 Stripper	**Stream (Note 1)**	**233**	**P233**	**P233**			
	Temperature, °C	24.10	25.29	25.35			
	Pressure, bar (a)	1.150	1.150	1.150	1.00	1.00	1.00
	Molar Flow, kgmole/h	3174	3194	5287	1.01	1.67	1.66
	Mass Flow, kg/h	138136	139092	230208	1.01	1.67	1.66
	Actual Volume Flow, m3/h	67784	68479	113362	1.01	1.67	1.66
	MEA	0.0000000	0.0000000	0.0000000	0.00	0.00	0.65
	H_2O	0.0190200	0.0174356	0.0174905	0.92	0.92	1.00
	CO_2	0.9809000	0.9809039	0.9809012	1.00	1.00	1.00
	Oxygen	0.0000190	0.0000837	0.0000727	4.41	3.83	0.87
	Nitrogen	0.0000600	0.0002580	0.0002559	4.30	4.26	0.99

Notes:

1. For PHM and GBCM, the stream name as shown in the HYSYS models.

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Scale-Up Factors

The modelling results show that following factors give a rational basis for scaling up key equipment in the Peterhead Design to the GBC:

1. Booster Fan Capacity: 1.35 based on actual volumetric rate. Differential head is kept the same in both cases (PH and GBC)
2. Sour Gas Cooler Duty: 1.0
3. Water Saturation Tower Height: 1.0, i.e., the tower height will be the same in the PH and GBC designs;
4. Water Saturation Tower Cross Sectional Area: 1.35 based on actual volumetric rate
5. Water Saturation Tower Cooler Duty: 1.78
6. CO_2 Absorber Tower Cross Sectional Area: 1.35 based on actual volumetric rate
7. CO_2 Absorber Height: (amine, acid and wash water sections): 1.0
8. Absorber Wash Water Pump Capacity: Use 1.51
9. Wash Water Cooler Duty: 1.58
10. Wash Water Pump (Water Saturation Tower) Capacity: 1.66. Keep the differential head same as PH
11. Acid Wash Pump Capacity: Use 1.66 (modelling did not include this section). Keep the differential head same as PH
12. Rich/Lean Amine Pump Capacity: 1.66 based on actual volumetric flows. Keep the differential head in PH and GBC
13. Rich /Lean Amine Exchanger Duty: 1.66
14. Lean Amine Cooler Duty: 1.93
15. Stripper Cross Sectional Area: 1.66 based on actual volumetric flows. Keep the height ratio equal to 1.0
16. CO_2 Stripper Reboiler Duty: 1.66
17. Overhead Condenser Duty: 1.66

Heat & Mass Balance Documentation

The Carbon Capture Plant is designed as a black box which depends on the selected amine solvent. Only the inlet outlet streams are shown for the Carbon Capture Plant.

Heat & Mass Balance data for the Carbon Capture Plant for the General Business Case is provided in the Overall HMB, document reference 181869-0001-D-EM-HMB-AAA-00-00001-01 . The HMB should be read in conjunction with the Process Flow Diagram Carbon Capture, document reference 181869-0001-T-EM-PFD-AAA-00-00001.

The LP steam requirement for the Carbon Capture Plant is based Peterhead Design Case scaled up as per Utilities Schedule, document reference 181869-0001-T-EM-LST-AAA-00-00001. This is because the Peterhead design uses an engineered amine solvent compared to benchmark solvent MEA used in the Generic Business Case HYSYS simulation models.

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COMPRESSION, TRANSMISSION AND STORAGE

Introduction

Water-saturated CO_2 gas flows from the capture plant to the First Compression Stage Knockout Drum, where any potential liquid carryover is removed and sent back to the capture unit, together with all liquid water collected from other compression stages and dehydration packages. CO_2 gas is compressed in the first section and CO_2 gas at the outlet of each stage is cooled down by using cooling water.

A dehydration system, located after the fourth or fifth compression stage, is used to dry the CO_2 gas saturated with water. Dry CO_2 gas from the dehydration unit is compressed in the high pressure section of the compressor. Dry CO_2 gas is further compressed in the final compression stage, where CO_2 is in dense phase, and then cooled in the Aftercooler. The CO_2 is transported via pipelines to the CO_2 Storage Sites (Injection Offshore Platforms).

The platform arrival pressure plus the pipeline pressure losses determine the required compressor discharge pressure.

Simulation Basis

This section describes the basis for setting up the HYSYS process simulation models for the Carbon Capture Compression (CCC) Plant and CO_2 Pipelines to the CO_2 Storage Sites (Injection Offshore Platforms). For the Process Description and the Process Flow Diagram (PFD), refer to the Plant-by-Plant Description [181869-0001-T-EM-TNT-AAA-00-00002] and Process Flow Diagram Carbon Capture [181869-0001-T-EM-PFD-AAA-00-00001].

The HYSYS simulation models set up is in line with the following Overall Block Diagram.

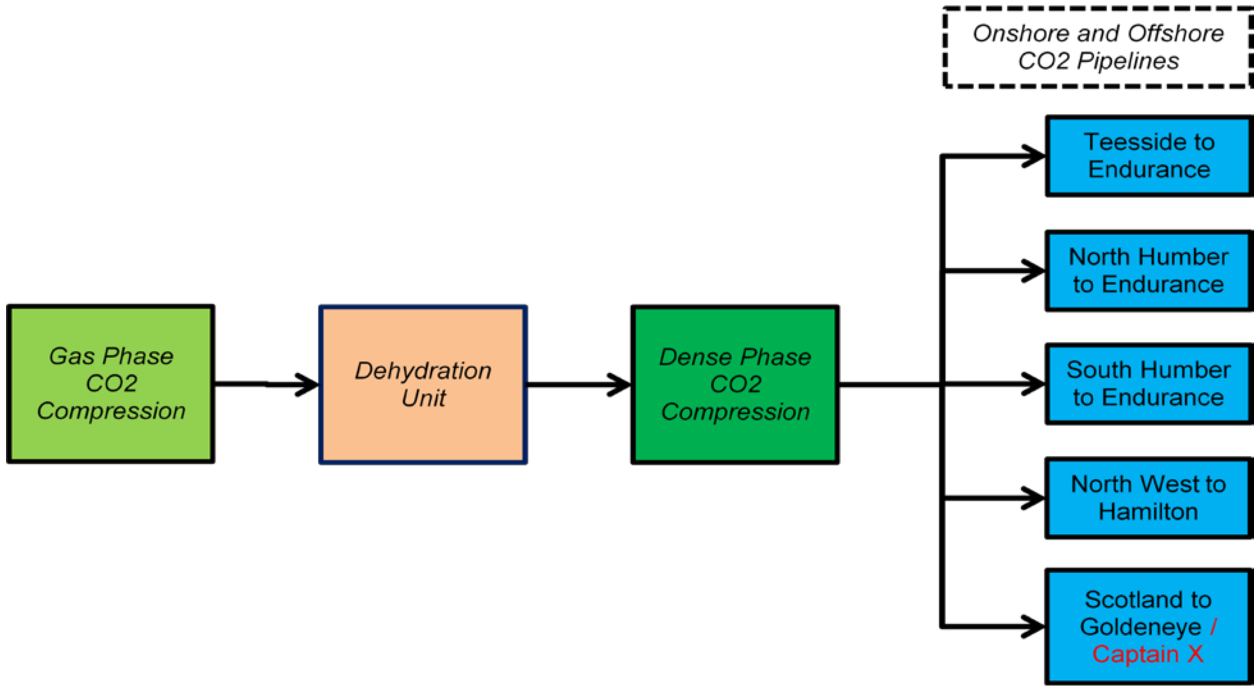

Figure 8 – Block Model for CO_2 Compression, Dehydration, and Transport

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Simulation Property Packages

The process simulations have been carried out in Aspen HYSYS V8.6. Peng-Robinson has been selected for the fluid package with the following parameters:

Parameter	Basis
Enthalpy	Property Package EOS.
Density	Costald
Modify Tc, Pc for H_2, He:	Modify Tc, Pc for H_2, He.
Indexed Viscosity:	HYSYS Viscosity
All other parameters are set to HYSYS default methods.	

The Peng Robinson (PR) Equation of state, with default parameters, was used to model the CO_2 compression and transport. SNC-Lavalin recognizes that impurities affect the default parameters and calibration is required to get good results and represent the system correctly. However, the PR EOS with default parameters is adequate for this level of study.

Units of Measure

S.I units are used and match the units used on the Process Design Basis [Ref 1]. Standard conditions are defined as 15.6°C, 101.323kPa (1atm).

Product Specifications

The overall simulation target is to achieve the specifications in Table 7 as per Basis of Design [181869-0001-T-EM-DBS-AAA-00-00001] and Table 14.

Table 7 Product Specification

Parameter	Unit	Basis
H_2O	ppmv	≤50
Oxygen	ppmv	≤10
Endurance Pipeline Capacity (5 Trains)	MTPA	10
Endurance Platform Arrival Pressure	bara	141.3
Endurance Maximum injection rate per well	MTPA	1.67
Hamilton Pipeline Capacity (3 Trains)	MTPA	6
Hamilton Gas Phase THP	bara	47.50
Hamilton Gas Phase Injection Rate Per Well	MTPA	2.5
Hamilton Gas Phase THT	°C	30
Hamilton Pipeline Capacity (3 Trains)	MTPA	6
Hamilton Liquid Phase THP	bara	49.32
Hamilton Liquid Phase THT	°C	10
Hamilton Liquid Phase Injection Rate Per Well	MTPA	2.5

Parameter	Unit	Basis
Scotland Power Station Capacity (3 Trains) to both Goldeneye and Captain X	MTPA	6
Goldeneye Pipeline Capacity	MTPA	3
Goldeneye Liquid Phase THP	bara	101
Goldeneye Liquid Phase THT	°C	3.7
Goldeneye Liquid Phase Injection Rate Per Well	MTPA	1.14
Captain X Pipeline Capacity	MTPA	3
Captain X Liquid Phase THP	bara	130
Captain X Liquid Phase Injection Rate Per Well	MTPA	1.5

General Simulation Assumptions

The following general parameters have been used to define the Compression and CO_2 Pipelines Simulation models.

Pressure

A margin for line pressure drop between units is added to upstream equipment pressure drop with the following:

- Vessels pressure drop = 0.1 bar
- Coolers pressure drop = 0.2 bar
- Onshore CO_2 metering package pressure drop = 0.5 bar
- Offshore platform CO_2 filter and metering packages pressure drop = 0.5 bar

Temperature

36°C used as coolers outlet temperature as per Basis of Design [181869-0001-T-EM-DBS-AAA-00-00001]

46°C used as cooler outlet temperature for the 6th Stage Compressor (Dense Gas) Cooler to maintain Hamilton Gas Phase THT at 30°C.

36°C is used as cooler outlet temperature for the 7th stage Compressor (Dense Gas) Cooler to maintain Hamilton Liquid Phase THT at 10°C.

Machinery Efficiency

75% Adiabatic Efficiency is assumed for compressors and pumps.

Dehydration Unit

Dehydration unit pressure drop = 1.5 bar

Temperature increase = 2°C

Water in vapour outlet = 50ppmv

Assumed 15% of the treated gas used as a regeneration gas

Compressor Pressure Ratio

Table 8 Compressor Pressure radio

Compressors		Pipelines to Endurance	Pipeline to Hamilton	Pipeline to Captain X	Pipeline to Goldeneye/
Gas Phase	C-101-1	3			
	C-101-2	2.5			
	C-101-3	2.45			
	C-101-4	2.387 (Pout = 39.2 bar)			
Kirriemuir Station	C-002	N/A		1.8 (P_{out} =35 bar)	
Dense Phase (bar)	C-101-6	1.85		3.3 (P_{out} =61)	3.0 (P_{out} =55)
	C-101-7	1.59 (P_{out} =110)	1.36 (P_{out} =94)	2.0 (P_{out} =121)	1.8 (P_{out} =99)
	C-101-8	1.67 (P_{out} =184)	N/A	124 (P_{out} =150)	1.15 (P_{out} =114)

Pipeline Elevation Change

Onshore Pipeline Elevation = 5m

Offshore Pipeline Elevation = 2m

The Goldeneye pipeline topography is as per Figure 4-9 in Longannet Post-FEED End-to-End Basis of Design UKCCS - KT - S7.1 - E2E – 001 and Peterhead Basic Design and Engineering Package PCCS-00-PTD-AA-7704-00002 Rev K05. The Atlantic pipeline topography to Captain X assumed same as the Goldeneye pipeline topography.

Offshore Pipeline Insulation

Thermal Conductivity =0.1 W/mK

Thickness = 76.2 (3) mm (in)

CO_2 Pipeline Simulation Input Specifications

The following parameters are specified in the HYSYS simulation model to size the CO_2 pipelines and establish the CO_2 pipelines operating conditions. This data is based on the general assumptions above, Basis of Design [181869-0001-T-EM-DBS-AAA-00-00001] and Input to Cost Estimate from Site Selection [181869-0001-T-EM-TNT-AAA-00-00009].

Table 9 Pipeline input specification

Selected Site		Teesside	North Humber	South Humber	North West	Scotland from St Fergus to:	
Injection Site		**Endurance**			**Hamilton**	**Goldeneye**	**Captain X**
Onshore Length	km	1.60	17.90	24.10	53.70	1	1
Onshore Elevation	m	5.00	5.00	5.00	5.00	5	5
Offshore Length	km	154.00	79.00	79.00	24.30	101 (Existing)	78 (Existing) +8 (New)

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TECHNICAL NOTE

Selected Site		**Teesside**	**North Humber**	**South Humber**	**North West**	**Scotland from St Fergus to:**	
Injection Site		**Endurance**			**Hamilton**	**Goldeneye**	**Captain X**
Offshore Elevation	m	2.00	2.00	2.00	2.00	See above	
Total Length	**km**	**155.6**	**96.9**	**103.1**	**78.0**	**102**	**87**
Water Depth	m	59.3			24.0	120	115
Outer Diameter	mm (in)	Refer to pipeline sizing section				508 (20)	406.4 (16)
Inner Diameter	mm	Refer to pipeline sizing section				479.4	375.4
Material		Mild Steel					
Roughness	mm	0.00457					
Pipe Wall Conductivity	W/mK	45.0					
Ambient Temperature	°C	10.0				1/21	
Ambient Sea Temperature	°C	4.2 / 19.4 (Minimum / Maximum)				4 / 11	
Current Velocity	m/s	1.10				1.1	
Onshore buried Pipeline							
Ambient Medium		Ground					
Ground Type		Dry Peat					
Ground Conductivity	W/mK	0.17					
Buried Depth	m	1.20					
Offshore Pipeline Insulation							
Thermal Conductivity	W/mK				0.10		
Thickness	mm (in)				76.20 (3)		

Scotland Pipelines from Scotland Site to St Fergus			
	Scotland Site to No. 10 Feeder	No. 10 Feeder to Kirriemuir Station	Kirriemuir Station to St Fergus
Pipeline	New	Existing	Existing
Length km	18	141	139
Size in	Refer to pipeline sizing section	36	36
Design pressure Barg	Refer to pipeline sizing section	37.5	37.5
Ambient temperature, below ground / design point °C	3 /15 / 8		

The Estimate Heat Transfer Coefficient model in HYSYS is selected to model the CO_2 pipeline heat transfer and establish the pipelines temperature profile based on the specified data mentioned in Table 5 above.

The ambient conditions for the Scotland pipelines are taken from the Post-FEED End-to-End Basis of Design UKCCS - KT - S7.1 - E2E – 001.

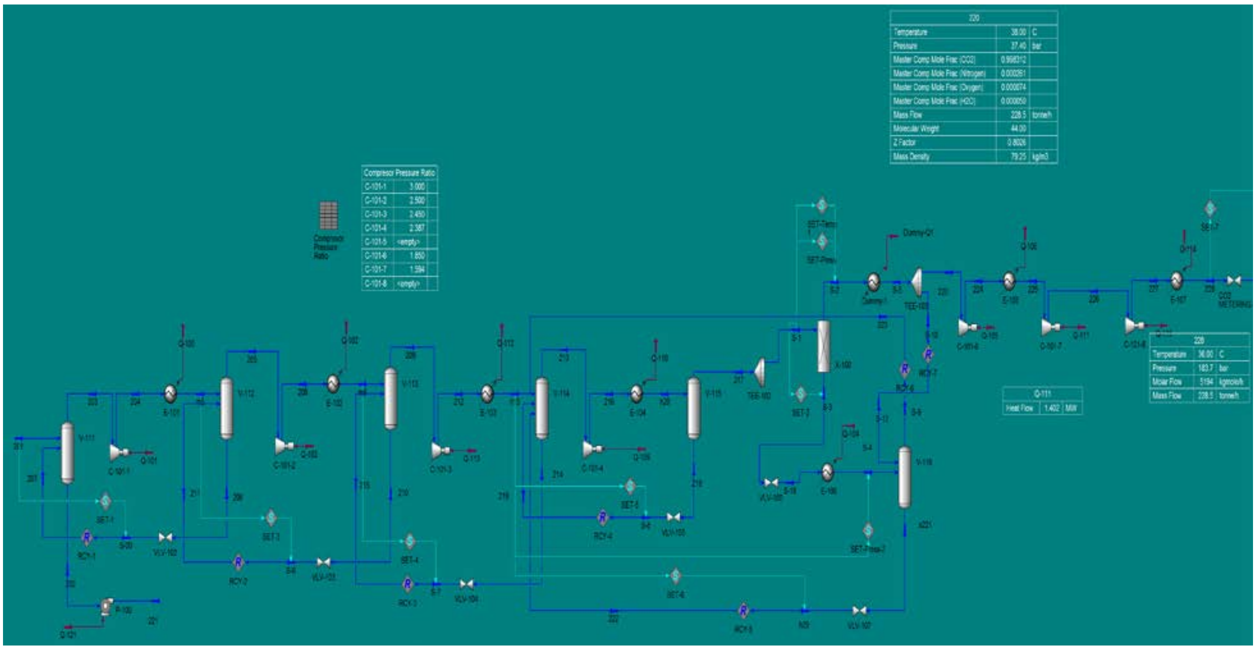

Figure 9 – HYSYS Model of Compression and Transport System

PIPELINE SIZING RESULT

The CO_2 pipelines with different sizes and flow rate were studied and the results are summarised as shown in Table 10 and Table 15 below.

For the CO_2 pipelines from Teesside, South Humber and North Humber to Endurance, 24 inch pipelines are recommended in order to give a CO_2 pipeline inlet pressure below 200 bara with a maximum pipeline inlet pressure for Teesside to Endurance is around 183 bara and 184 bara at the 8th Stage Compressor Discharge. 200 bara has been selected as this is the maximum used for a wide range of sources and is a limit for control of hydrate formation in CO_2.

For the CO_2 pipelines from North West to Hamilton Gas Phase, a 24 inch pipeline (with insulated offshore pipeline) recommended in order to have a CO_2 pipeline inlet pressure below the pipeline choking condition for Hamilton Gas Phase with a maximum pipeline inlet pressure around 82 bara and 94 bara at the 7th Stage Compressor discharge.

Note Table 10 below was done with a Shoreline Heater option for the Hamilton Gas phase to select the pipeline sized. As an Offshore Heater shall be considered for Hamilton gas phase instead of a Shoreline Heater to maintain the target THT at 30°C, the Offshore Heater duty is 2.230 MW for maximum flow of 6 MPTA, 1.785 MW for 2 MTPA to meet the target THT at 30°C and 47.5 bara and 2.613MW at 40% turndown of one train with a flow of 0.8 MTPA to meet the target HT at 30°C and 29.5 bara.

A Shoreline Pipeline Chiller between onshore/offshore pipelines is required to maintain the offshore pipeline within the Liquid phase and to meet the target THT at 10°C. Without the Cooler, the THT is 13.61 to 13.65°C for all flow conditions as shown in Table 10 below. A 16 MW Shoreline Cooler will be used to maintain the target THT at 10°C for all flow conditions.

The final results for the 24 inch CO_2 pipelines include the Offshore Heater and Shoreline Pipeline Chiller are shown in Table 11.

Table 10 Pipeline sizing result

Route	length km	Size inch	Parameters	MTPA	2.00	4.00	6.01	8.01	10.01
Teesside to Endurance	156	20	Pipeline Inlet Pressure	barg	154.55	165.74	184.04	209.27	241.23
			Platform Arrival Pressure	barg	141.30	141.30	141.30	141.30	141.30
			Pipeline Inlet Temperature	C	33.52	34.56	36.03	37.78	39.61
			Platform Arrival Temperature	C	3.65	3.61	3.59	3.57	3.56
			Pipeline Inlet Liquid Velocity	m/s	0.51	1.01	1.48	1.93	2.35
			Platform Arrival Liquid Velocity	m/s	0.42	0.84	1.26	1.68	2.10
		24	Pipeline Inlet Pressure	barg	151.97	155.76	161.96	170.53	181.46
			Platform Arrival Pressure	barg	141.30	141.30	141.30	141.30	141.30
			Pipeline Inlet Temperature	C	33.28	33.68	34.25	34.98	35.85
			Platform Arrival Temperature	C	3.64	3.61	3.59	3.58	3.57
			Pipeline Inlet Liquid Velocity	m/s	0.33	0.67	0.99	1.31	1.62
			Platform Arrival Liquid Velocity	m/s	0.28	0.55	0.83	1.10	1.38
South Humber to Endurance	103	20	Pipeline Inlet Pressure	barg	153.76	161.60	174.54	192.15	214.55
			Platform Arrival Pressure	barg	141.30	141.30	141.39	141.30	141.30
			Pipeline Inlet Temperature	C	33.57	34.28	35.36	36.69	38.16
			Platform Arrival Temperature	C	3.65	3.61	3.59	3.57	3.56
			Pipeline Inlet Liquid Velocity	m/s	0.51	1.01	1.50	1.96	2.40
			Platform Arrival Liquid Velocity	m/s	0.42	0.84	1.26	1.68	2.10
		24	Pipeline Inlet Pressure	barg	151.96	154.61	158.96	164.98	172.65
			Platform Arrival Pressure	barg	141.30	141.30	141.30	141.30	141.30
			Pipeline Inlet Temperature	C	33.41	33.65	34.04	34.57	35.21
			Platform Arrival Temperature	C	3.64	3.61	3.59	3.58	3.57
			Pipeline Inlet Liquid Velocity	m/s	0.34	0.67	1.00	1.32	1.64
			Platform Arrival Liquid Velocity	m/s	0.28	0.55	0.83	1.10	1.38
North Humber to Endurance	97	20	Pipeline Inlet Pressure	barg	153.57	160.89	172.86	189.39	210.33
			Platform Arrival Pressure	barg	141.30	141.30	141.29	141.30	141.30
			Pipeline Inlet Temperature	C	33.56	34.21	35.22	36.49	37.90
			Platform Arrival Temperature	C	3.65	3.61	3.59	3.57	3.56
			Pipeline Inlet Liquid Velocity	m/s	0.51	1.01	1.50	1.97	2.41
			Platform Arrival Liquid Velocity	m/s	0.42	0.84	1.26	1.68	2.10
		24	Pipeline Inlet Pressure	barg	151.90	154.37	158.42	164.03	171.18
			Platform Arrival Pressure	barg	141.30	141.30	141.30	141.30	141.30
			Pipeline Inlet Temperature	C	33.40	33.63	34.00	34.49	35.09

Route	length km	Size inch	Parameters	MTPA	2.00	4.00	6.01	8.01	10.01
			Platform Arrival Temperature	C	3.64	3.61	3.59	3.58	3.57
			Pipeline Inlet Liquid Velocity	m/s	0.34	0.67	1.00	1.32	1.64
			Platform Arrival Liquid Velocity	m/s	0.28	0.55	0.83	1.10	1.38
North West to Hamilton Gas	78	20	Pipeline Inlet Pressure	bara	62.36	86.35	116.22		
			Platform Arrival Pressure	bara	47.50	47.50	47.50		
			Pipeline Inlet Temperature	C	51.71	70.55	88.39		
			Platform Arrival Temperature	C	31.11	32.14	31.48		
			Pipeline Inlet Gas Velocity	m/s	2.57	3.76	4.34		
			Platform Arrival Gas Velocity	m/s	29.74	30.24	29.92		
		24	Pipeline Inlet Pressure	bara	56.10	67.15	82.26		
			Platform Arrival Pressure	bara	47.50	47.50	47.50		
			Pipeline Inlet Temperature	C	43.72	53.78	65.74		
			Tubing Head Temperature	C	27.63	30.52	30.67		
			Pipeline Inlet Gas Velocity	m/s	1.94	3.25	4.02		
			Platform Arrival Gas Velocity	m/s	2.04	4.19	6.30		
North West to Hamilton Liquid	78	20	Pipeline Inlet Pressure	bara	116.22	116.22	116.22		
			Platform Arrival Pressure	bara	49.32	49.32	49.32		
			Pipeline Inlet Temperature	C	36.00	36.00	36.00		
			Platform Arrival Temperature	C	13.56	13.59	13.60		
			Pipeline Inlet Liquid Velocity	m/s	0.53	1.06	1.60		
			Platform Arrival Liquid Velocity	m/s	3.79	4.03	4.14		
		24	Pipeline Inlet Pressure	bara	93.00	93.00	93.00		
			Platform Arrival Pressure	bara	49.32	49.32	49.32		
			Pipeline Inlet Temperature	C	36.00	36.00	36.00		
			Tubing Head Temperature	C	13.61	13.64	13.65		
			Pipeline Inlet Liquid Velocity	m/s	0.44	0.88	1.32		
			Platform Arrival Liquid Velocity	m/s	4.29	4.66	4.54		

Table 11 - 24inch Pipelines final results

Pipeline Section	Compressor Discharge		Pipeline														
	Temp [C]	Press [bar]	Nom Size [inch]	Outside /Inside Diameter [mm]		Length [km]	Elev [m]	Inlet /Outlet Temp [C]		Inlet /Outlet Press [bar]		Mass Flow [tonne/h]	Mass Flow [MTPA]	Actual Volume Flow [m3/h]	Inlet / Outlet Velocity [m/s]		Outlet Viscosity [cP]
Teesside- Onshore				609.6	547.7	1.60	5	36.0	35.9	183.2	182.5	1142.7	10.0	1373.7	1.6	1.6	0.054
Teesside- Offshore	120.3	183.9	24	609.6	547.7	154.0	2	35.9	4.2	182.5	151.5	1142.7	10.0	1374.2	1.6	1.4	0.105
Teesside- Riser				609.6	547.7	0.095	95	4.2	3.6	151.5	142.3	1142.7	10.0	1163.1	1.4	1.4	0.105
South Humber- Onshore			24	609.6	547.7	24.1	5	36.0	35.0	173.7	167.5	1142.6	10.0	1396.2	1.6	1.7	0.053
South Humber- Offshore	115.5	174.4	24	609.6	547.7	79.0	2	35.0	4.2	167.5	151.5	1142.6	10.0	1400.4	1.7	1.4	0.105
South Humber- Riser			24	609.6	547.7	0.095	95	4.2	3.6	151.5	142.3	1142.6	10.0	1163.0	1.4	1.4	0.105
North Humber- Onshore			24	609.6	547.7	17.9	5	36.0	35.3	172.2	167.5	1142.6	10.0	1399.9	1.7	1.7	0.053
North Humber- Offshore	114.7	172.9	24	609.6	547.7	79.0	2	35.3	4.2	167.5	151.5	1142.6	10.0	1403.2	1.7	1.4	0.105
North Humber- Riser			24	609.6	547.7	0.095	95	4.2	3.6	151.5	142.3	1142.6	10.0	1163.0	1.4	1.4	0.105
North West- Onshore Gas			24	609.6	560.4	53.70	5	65.2	45.2	81.5	62.1	685.6	6.0	3597.8	4.1	5.0	0.019
North West- Offshore Gas			24	609.6	560.4	24.3	2	45.2	27.8	62.1	51.8	685.6	6.0	4479.2	5.0	5.6	0.018
North West- Riser -Gas			24	609.6	560.4	0.059	59	27.8	26.5	51.8	51.0	685.6	6.0	4964.9	5.6	5.7	0.018
Offshore Heater (2.23MW)*	73.8	94.0						25.9	32.2	50.5	49.5	685.6	6.0				
Tubing Head Gas			$9^5/_8$”	244.5	228.6	0.75	-750	30.0		47.5							
North West- Onshore Gas Turndown			24	609.6	560.4	53.70	5	19.8	13.3	34.0	33.2	91.4	0.8	1155	1.3	1.3	0.016
North West- Offshore Gas. Turndown			24	609.6	560.4	24.3	2	13.3	5.1	33.2	32.8	91.4	0.8	1135	1.3	1.2	0.015
North West- Riser –			24	609.6	560.4	0.059	59	5.1	4.0	32.8	32.4	91.4	0.8	1075	1.2	1.2	0.015

Pipeline Section	Compressor Discharge		Pipeline														
	Temp [C]	Press [bar]	Nom Size [inch]	Outside /Inside Diameter [mm]		Length [km]	Elev [m]	Inlet /Outlet Temp [C]		Inlet /Outlet Press [bar]		Mass Flow [tonne/h]	Mass Flow [MTPA]	Actual Volume Flow [m3/h]	Inlet / Outlet Velocity [m/s]		Outlet Viscosity [cP]
Gas Turndown																	
Offshore Heater Turndown (0.308MW)*								3.3	12.8	31.8	31.6	91.4	0.8				
Tubing Head Gas Turndown			$9^5/_8$”	244.5	228.6	0.75	-750	10.0		29.5		91.4	0.8	1299	8.8	8.0	0.016
North West- Onshore Liquid			24	609.6	560.4	53.7	5	36.0	33.7	92.5	86.4	685.6	6.0	1177.9	1.3	1.4	0.042
Shoreline Pipeline Chiller (16MW)**								33.7	12.8	33.7	12.8	685.6	6.0				
North West- Offshore Liquid	61.7	94.0	24	609.6	560.4	24.3	2	12.8	13.4	85.4	83.5	685.6	6.0	771.5	0.9	0.9	0.086
North West- Riser Liquid			24	609.6	560.4	0.059	59	13.4	12.8	83.5	78.4	685.6	6.0	777.0	0.9	0.9	0.087
Tubing Head Liquid			$9^5/_8$”	244.5	228.6	0.75	-750	10.0		49.3							

* Included a 2.23MW Offshore Heater to maintain the THT at 30ºC for the Hamilton gas phase and 0.308MW for turndown case to maintain THT at 10ºC.

** Included a 16MW Shoreline Pipeline Chiller to maintain the THT at 10ºC for the Hamilton Liquid phase.

Existing Scotland Onshore and Offshore Pipelines

The General Business Case for Scotland location and CO_2 export pipelines arrangements are shown in Figure 10 below. The existing Scotland onshore and offshore pipelines are as follows:

- Existing 36 inch pipeline (280km) from No. 10 Feeder of the existing National Grid compressor stations at Avonbridge/Bathgate to the existing onshore natural gas terminal at St Fergus with a design pressure of 37.5barg.
- Existing 20 inch Goldeneye pipeline (101km) from St Fergus to Goldeneye Platform with a design pressure of 132 barg.
- Existing 16 inch Atlantic pipeline (78km) from St Fergus to Atlantic with a design pressure of 170 barg.
- Existing 12" export pipeline from Cromarty to Atlantic pipeline (12km) that passes in the vicinity of the Captain X NUI location.

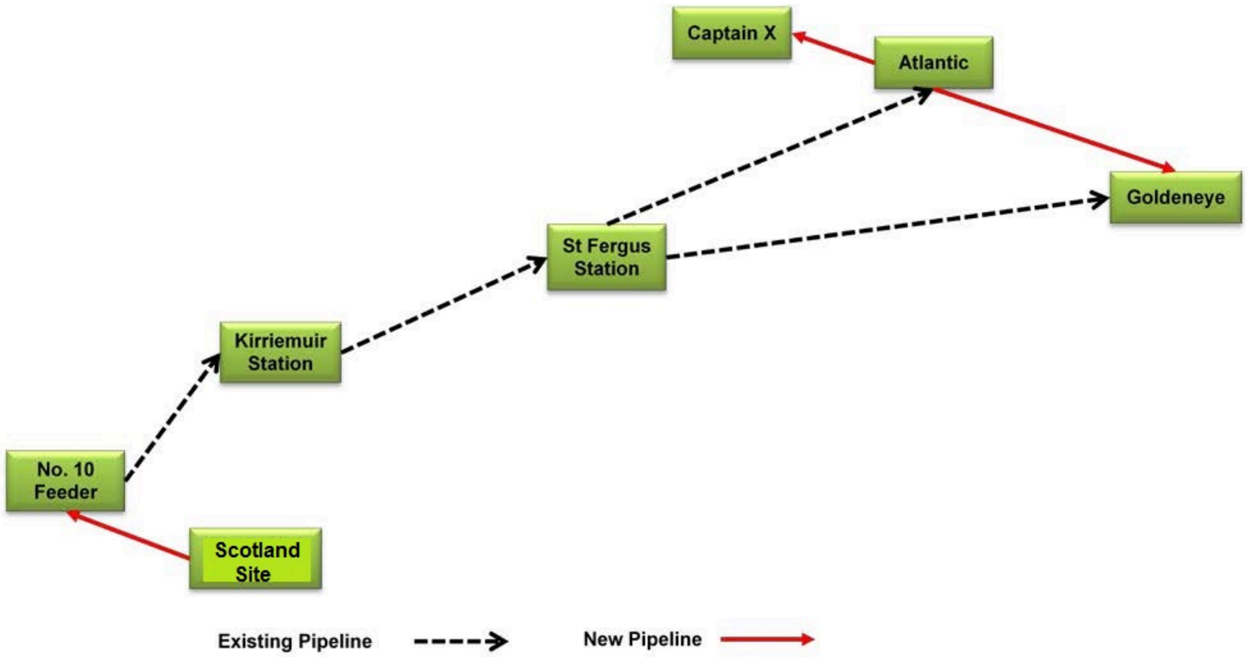

Figure 10 – Scotland Power Station and Export CO_2 Pipelines Arrangements

Onshore and offshore CO_2 Pipelines Transportation Scenarios

The following scenarios were considered to transfer the CO_2 from the Scotland site to St Fergus via onshore pipelines and from St Fergus to Goldeneye and Captain X injection sites via offshore pipelines:

- **Onshore Pipeline Scenario 1:** A new pipeline (18km) from the Scotland site to No 10 Feeder and existing 36 inch pipeline (280km) from No. 10 Feeder to St Fergus.
- **Onshore Pipeline Scenario 2:** Same as Onshore Pipeline Scenario 1 with a new booster compressor station at Kirriemuir to boost the pressure to the pipeline Maximum Allowable Operating Pressure (MAOP) of 34barg.

- **Offshore Pipeline Scenario 3:** using the existing 20 inch Goldeneye pipeline (101 km) from St Fergus to Goldeneye Platform and the existing 16 inch Atlantic pipeline (78 km) from St Fergus to Atlantic with a new 8km pipeline extended from Atlantic to Captain X.
- **Offshore Pipeline Scenario 4** using existing 16 inch Atlantic pipeline (78km) from St Fergus to Atlantic and with a new 8km pipeline extended from Atlantic to Captain X and new 30km extension pipeline from Atlantic to Goldeneye.

Note that there is a 12km 12” export pipeline from Cromarty to Atlantic that passes in the vicinity of the Captain X NUI location; however it has been assumed that a new pipeline will be required for the following reasons as per D13: WP5D – Captain X Site Storage Development Plan 10113ETIS-Rep-19-03

- Smaller diameter/reduced ullage (12” versus 16”);
- The 12” Cromarty pipeline was specified for a design life of 10 years (2016) whilst the 16” Atlantic pipeline was specified for a design life of 20 years (2026). Extending the design life until 2056 years may not be feasible;
- Trenched and buried therefore it would require excavation and cutting at the NUI location to facilitate tie-in;
- It will not be possible to inspect the line via intelligent pig due to large internal diameter changes (18”/16”/12”).

Consideration was initially also given to utilising the existing 20” Goldeneye pipeline to transfer CO_2 from St Fergus to Captain X. The selected location for the Captain X NUI is approximately 8km west of the Atlantic development and as such the existing Atlantic pipeline is the preferred choice (8km new pipeline versus a 38km new pipeline) provided its integrity can be confirmed. Furthermore the original design pressure of the 20” Goldeneye pipeline is 132 barg, which would likely lead to operability issues given the required tubing head pressures for CO_2 injection in the Captain aquifer is around 130 bara. The Goldeneye pipeline has therefore not been considered further herein.

For Goldeneye pipeline new SSSIV is required as the existing Sub-Sea Isolation Valve (SSIV) and umbilical connection are unsuitable as per Doc. no.: PCCS-00-PTD-AA-7704-00002, Basic Design and Engineering Package.

Note a full pipeline integrity and life extension study will be required to confirm suitability of the Atlantic and Goldeneye Pipelines. This will involve detailed internal and external inspection in order to re-qualify the pipeline and verify that it is suitable for re-use to transport CO_2.

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Scotland Pipeline Sizing Result

The CO_2 pipelines sizing was carried out using the required CO_2 export rate and the platform required pressures from the tables above. The CO_2 pipelines with different sizes were studied and the overall results are summarised in the Table 12.

Onshore Pipelines:

- The CO_2 compression and conditioning plant at the Scotland site shall include a high integrity trip system to protect the onshore transportation pipeline from pressures exceeding the Maximum Incidental Pressure (MIP) of 37.5 barg which corresponds to the Maximum Allowable Operating Pressure (MAOP) level + 10%.
- A new 36 inch pipeline (18km) from the Scotland site to No 10 Feeder. A 24 inch pipeline from the Scotland site to No 10 feeder was considered however due to high pressure drop (23.2 bar) a 36 inch line is selected
- The existing 36 inch pipeline (280km) from No. 10 Feeder to St Fergus with a new 1 x 100% booster compressor station at Kirriemuir to boost the pressure to 34barg for 6 MTPA (Million Tonne per Annum). Capacity (3 Trains Plant). The booster station is not required for 2 trains or 1 train plant. Therefore the compression is 1 x 100% (unspared) with turndown to 2 train output when it is no longer available.
- Two new compressor units located at St Fergus to boost the pressure to the offshore pipelines required pressure for both Captain X and Goldeneye pipelines with compressor discharge pressure of 149.1bara for Captain X and 113.7bara for Goldeneye (1 x 100% compressor to serve Captain X and 1 x 100% compressor to serve Goldeneye).

Offshore Pipelines:

- The maximum operating pressure for the existing 20 inch Goldeneye Pipeline from St Fergus to Goldeneye (120.4x1.1= 131.4barg) as shown in Table 12 Onshore Pipeline Scenario 3 is within the existing pipeline design pressure of 132 barg.
- The maximum operating pressure for the existing 16 inch Atlantic Pipeline from St Fergus to Atlantic with new 8km and 30km pipelines extended from Atlantic to Captain X and Goldeneye (178.4x1.1=195barg) as shown in Table 12 Onshore Pipeline Scenario 4 exceeds the existing Atlantic Pipeline design pressure of 170 barg therefore, the existing Atlantic pipeline cannot be used in this case.
- The recommended offshore pipeline for Captain X is to use the existing 16 inch Atlantic pipeline (78km) with a new 16inch pipeline (8km) extended from Atlantic to Captain X as in Onshore Pipeline Scenario 3 in Table 12.
- The recommended offshore pipeline for Goldeneye is to use the existing 20 inch Goldeneye pipeline as in Onshore Pipeline Scenario 3 in Table 12.

The final results for the CO_2 compressions and onshore and offshore pipelines are shown in Table 13.

Table 12 – Scotland Onshore/ Offshore Pipelines results

Scenarios		Onshore Scenario 1			Onshore Scenario 2			Offshore Scenario 3		Offshore Scenario 4	
Pipeline Segment		**New**	**Existing**	**Existing**	**New**	**Existing**	**Existing**	**Existing**	**Existing + New**	**Existing + New**	**New**
From		Scotland Site Note 1	No. 10 Feeder	Kirriemuir Station	Scotland Site Note 1	No. 10 Feeder	Kirriemuir Station	St Fergus	St Fergus	St Fergus	Atlantic
To		No. 10 Feeder	Kirriemuir Station	St Fergus	No. 10 Feeder	Kirriemuir Station	St Fergus	Goldeneye	Captain X	Captain X	Goldeneye
Size inch		36 Note 6	36	36	36	36	36	20	16	16	
Length km		18	141	139	18	141	139	101	78+8 Note 3	78+8 Note 3	30 Note 4
Flow Rate MTPA		6	6	6	6	6	6	3	3	3	3
Compressor Discharge	bara	N/A					35.0	113.7	149.8	180.1	
	°C						52.7	104.3	119.5	137.7	
Inlet Temperature °C		35.5	16.6	0.1	35.5	16.6	36.0	35.9	36.0	36.0	10.1
Outlet Temperature °C		16.6	0.1	-16.9	16.6	0.1	14.7	10.0	10.1	10.1	10.1
Inlet Pressure bara		35.0	33.5	19.5	35.0	33.5	34.8	113	149.1	179.4	147.0
Outlet Pressure bara		33.5	19.5	3 Note 2	33.5	19.5	20.1				
Pipeline Max Pressure bara Note 5		N/A			N/A			120.4	155.3	178.0	147.0
Riser bottom Pressure bara								119.5	146.4	146.4	143.5
Platform Arrival Pressure bara								103.5	132.5	132.5	129.1
THP Bara								101	130	130	101
THT °C								9.7	9.9	10.0	8.7
MAOP x 1.1 barg		37.5	35.9	20.4	37.5	35.9	37.3	131.4	169.8	196.4	160.7
Design Press bBarg		37.5			37.5			132	170	170	170

Notes:

1. The CO_2 compression and conditioning plant at the Scotland Site shall include a trip system to protect the Onshore Transportation Pipeline from pressures exceeding the Maximum Incidental Pressure (MIP) of 37.5 barg which corresponds to the Maximum Allowable Operating Pressure (MAOP) level + 10%.
2. The pressure and temperature are reduced at around 70 km from Kirriemuir and at the pressure shall be boosted to able to send the CO_2 to St Fergus
3. A new 8km subsea pipeline from Atlantic to Captain X.
4. A New 30km from subsea pipeline Atlantic to for Goldeneye.
5. Maximum pipeline pressure low point elevation
6. 24 inch pipeline from The Scotland Site to No 10 feeder was considered. Due to high pressure drop (23.2 bar) a 36 inch is selected.

Table 13 – Scotland Pipelines final results

Pipeline Sections		Compressor Discharge *		Pipeline													
		Temp [C]	Press [bar]	Size [inch]	Outside /Inside Diameter [mm]		Length [km]	Elevation [m]	Mass Flow [MTPA]	Actual Flow [m3/h]	Inlet /Outlet Temperature [C]		Inlet /Outlet Pressure [bar]		Inlet / Outlet Velocity [m/s]		Outlet Viscosity [cP]
One Train	Scotland Site to 10 Feeder	N/A	N/A	36	914	876	18	10	2.0	3087.4	35.5	9.4	35.0	34.8	1.4	1.2	0.016
	Bathgate to Kirriemuir						141	10	2.0	2565.0	9.4	12.2	34.8	33.6	1.2	1.3	0.016
	Kirriemuir to St Fergus						139	10	2.0	2764.6	12.2	13.2	33.6	32.4	1.3	1.4	0.016
	Captain X - Onshore	99.7	139.6	16	406	375	1		1.0	150.9	35.9	35.8	138.9	138.5	0.4	0.1	0.051
	Captain X Offshore						77		1.0	150.8	35.8	11.0	138.5	146.1	0.3	0.1	0.093
	New 8 km to Captain X						8		1.0	120.6	11.0	11.0	146.1	146.4	0.3	0.1	0.093
	Captain X - Riser						0.150	155	1.0	120.6	11.0	10.2	146.4	132.5	0.3	0.1	0.094
	Goldeneye - Onshore	70.0	113.7	20	508	479	1		1.0	166.2	35.9	35.7	113.0	112.7	0.3	0.0	0.048
	Goldeneye - Offshore						100		1.0	165.9	35.7	11.0	112.7	123.0	0.2	0.1	0.092
	Goldeneye - Riser						0.155	155	1.0	122.6	11.0	10.1	123.0	108.9	0.2	0.1	0.093
Two Trains	Scotland Site to 10 Feeder	N/A	N/A	36	914	876	18	10	4.0	6174.9	35.5	13.6	35.0	34.4	2.8	2.5	0.016
	Bathgate to Kirriemuir						141	10	4.0	5423.0	13.6	9.2	34.4	29.3	2.5	3.0	0.015
	Kirriemuir to St Fergus						139	10	4.0	6525.3	9.2	5.7	29.3	23.0	3.0	4.0	0.015
	Captain X - Onshore	95.8	143.5	16	406	375	1		2.0	298.7	35.9	35.8	142.8	142.3	0.7	0.1	0.051
	Captain X Offshore						77		2.0	298.6	35.8	11.0	142.3	146.4	0.6	0.1	0.093
	New 8 km to Captain X						8		2.0	241.2	11.0	11.0	146.4	146.4	0.6	0.1	0.093
	Captain X - Riser						0.150	155	2.0	241.2	11.0	10.1	146.4	132.5	0.6	0.1	0.094
	Goldeneye - Onshore	99.6	113.7	20	508	479	1		2.0	332.4	35.9	35.8	113.0	112.6	0.5	0.0	0.048
	Goldeneye - Offshore						100		2.0	332.2	35.8	11.0	112.6	121.7	0.4	0.1	0.092
	Goldeneye - Riser						0.155	155	2.0	245.5	11.0	10.0	121.7	107.5	0.4	0.1	0.093
Three Trains	Scotland Site to 10 Feeder	52.7	35.0	36	914	876	18	10	6.0	9262.3	35.5	16.7	35.0	33.5	4.3	4.0	0.016
	Bathgate to Kirriemuir						141	10	6.0	8614.1	16.7	0.9	33.5	19.5	4.0	7.1	0.014
	Kirriemuir to St Fergus						139	10	6.0	9357.1	36.0	14.7	34.8	20.1	4.3	7.4	0.015
	Captain X - Onshore	119.5	149.8	16	406	375	1		3.0	440.8	35.9	35.8	149.1	148.6	1.1	0.1	0.052
	Captain X Offshore						77		3.0	440.9	35.8	11.0	148.6	147.0	0.9	0.1	0.093
	New 8 km to Captain X						8		3.0	361.6	11.0	11.0	147.0	146.4	0.9	0.1	0.093
	Captain X - Riser						0.150	155	3.0	361.8	11.0	10.1	146.4	132.5	0.9	0.1	0.094
	Goldeneye - Onshore	104.1	113.7	20	508	479	1		3.0	498.6	35.9	35.8	113.0	112.6	0.8	0.0	0.048
	Goldeneye - Offshore						100		3.0	498.5	35.8	11.0	112.6	119.5	0.6	0.1	0.092
	Goldeneye - Riser						0.155	155	3.0	368.9	11.0	10.0	119.5	105.4	0.6	0.1	0.093

* The booster compressor at Kirriemuir is only required when three trains in operation with a total capacity of 6 MTPA. .

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Tube head Pressure and Temperature

The tube head pressures and temperatures for injection sites are derived from the following resources as listed below in Table 14.

Table 14 – Tube head Pressure and Temperature data

Site	Pipeline Capacity MTPA	Parameter	Unit	Min Case	Max Case	GBC Design	References Note 1	Remark
Endurance	10 (5 Trains)	Platform Arrival Pressure	barg	136.1	141.3	141.3	Table 5.3 Table 5.4	Note 2
		Reservoir Pressure	barg	171	177			
		Max Rate per well	MTPA	2	2	1.67		
Hamilton Gas Phase Injection	6 (3 Trains)	Tubing size	Inch			9-⅝	Table 3-21	Note 3
		Years in Operation	Year	0 -17	0 -17		Table 5-9	
		THP	bara	34	63	47.5	Table 5-9 & Table 3-21	
		THT	°C			30	Table 3-21	
		Reservoir Pressure	bara	9.8			Table 3-18	
		Max Rate per well	MTPA	2.5		2.5	Table 5-9 Table 3-21	
Hamilton Liquid Phase Injection	6 (3 Trains)	Tubing size	Inch			5-½''	Table 3-24	Note 4
		Years in Operation	Year	17 -25	17 -25		Table 5-9	
		THP	bara	46	72	49.32	Table 5-9 Table 3-23	
		THT	°C			10	Table 3-23	
		Reservoir Pressure	bar	73.77			Table 3-18	
		Max Rate per well	MTPA	2.5		2.5	Table 5-9 Table 3-24	
Captain X	6 (3 Trains)	Tubing size	Inch	5.5			Table 3-20	Note 5
		THP	barg	44.5	160	130		
		Reservoir Pressure		193			Table 3-16	
		Max Rate per well	MTPA	1.237	3.712	1.5	Table 3-20	
Goldeneye	6 (3 Trains)	THP	barg	50	120	100	Table 2-11 (Ref 4) Table 8-21 (Ref 5)	Note 6
		THT	°C	0.5	10.1	3.7		
		Max Rate per well	MTPA	0.787	1.211	1.14		

Note

1. Data in table above are source from the following references for the relevant each site:
    1. Endurance site refer to K34_Flow_Assurance_Report.
    2. Hamilton site gas and liquid phase refer to D12: WP5C – Hamilton Storage Development Plan 10113ETIS-Rep-17-03.
    3. Captain X site refer to D13: WP5D – Captain X Site Storage Development Plan 10113ETIS-Rep-19-03.
    4. Goldeneye site refer to both Peterhead Well Technical Specification (PCCS-05-PT-ZW-7770-00001
    5. Longannet Post-FEED End-to-End Basis of Design UKCCS - KT - S7.1 - E2E – 001 February 2011.

2. For Endurance the data shown are for both the min and max cases are based on Years 5 to 10 Pressure Profiles (10 MTPA) as per Reference 1. Year 10 onwards pressure Profiles is available for 17 MTPA but not for 10MTPA.

The 141.3barg platform pressure case is selected to keep the main compressor and pipeline within around 200barg design pressure for 10 MTPA.

3. For Hamilton Gas Phase reference 2 Table 5-9 does not show any wellhead temperature for both min and max cases. Table3-21 in reference 2 shown THP 47.5bara and THT 30°C which used as a design basis to determine the heating required to keep the CO_2 injection within the gas phase.
4. For Hamilton Liquid Phase reference 2 Table 5-9 does not show any wellhead temperature for both min and max cases. Table3-23 in reference 2 shown THP 49.32bara and 10°C which used as a design basis to determine the cooling required to keep CO_2 injection within the liquid phase. As the liquid phase Tubing Head Pressure increases towards the end of the operating life the Tubing Head Temperature (THT) expected to increases. Once the THT is above seabed temperature there is no longer a requirement for the Chiller.
5. For Captain X reference 3 stated the following:
   - The minimum tubing head pressure (44.5bara) is the minimum pressure required to ensure single phase liquid injection throughout the tubing.
   - The maximum tubing head pressure (160bara) represents the maximum pipeline delivery pressure.
   - The operating range for the 5.5" tubing (with a maximum THP of 130bar) is 1.1 to 3.4 Mt/y.
   - Pressure dissipation in the reservoir allows this rate to be sustained for the targeted 40 year injection life, with a maximum THP of 130bara reached at the end of injection.

   But if 160bara THP is used downstream the choke valve with 150m riser height (115m sea water depth +35 m platform height) with approximately 14bar pressure drop for the riser and 3bar across the choke valve, the pressure at the bottom of the riser will be around 176bar and incorporating a safety factor of 1.1 to account for uncertainties, the pipeline design pressure shall be 176*1.1=193barg which exceeds the existing Atlantic pipeline design pressure of 170barg. Therefore the 160bar THP is not achievable with existing Atlantic pipeline.

   130 THP is selected as a design basis for Captain X as it within existing Atlantic pipeline design pressure and complied with reference 3 validation work for existing Atlantic pipeline.

6. For Goldeneye
   - Peterhead reference 4 stated the following
     Maximum WHP =120 bara. This is the maximum arrival pressure at the platform limited by the offshore pipeline (design pressure is 132bar).

     But if 120bara THP is used downstream the choke valve with 155m riser height (120m sea water depth +35 m platform height) with approximately 14bar pressure drop for the riser and 3 bar across the choke valve, the pressure at the bottom of the riser will be around 137bar and incorporating a safety factor of 1.1 to account for uncertainties, the pipeline design pressure shall be 137*1.1=148barg which exceeds the existing Goldeneye pipeline design pressure of 132barg. Therefore the 120bar THP is not achievable with existing Goldeneye pipeline.
   - Longannet FEED Reference 5 stated the following: Downstream of Topside Chokes the pressure is 100 barg.

     100 barg HP is selected as a design basis for Captain X as it within existing Atlantic pipeline design pressure and complied with Longannet FEED Reference validation work.

     In the General Business Case (GBC) design as the flow rate increase compare to Peterhead, the maximum arrival pressure at the platform is 105bara with 2.5bar pressure drop across the choke valve and CO_2 metering package this give THP of 102.5bara which is within Longannet FEED WHP of 100barg.

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Number of Train and Pipeline Sizes Arrangement

The number of trains with different pipeline sizes and target platform arrival pressures for different injection sites are shown in Table 15 below. For Scotland the pipelines size are fixed as existing pipelines are used.

Table 15 –Number of train and pipeline sizes

Sites	Pipeline Inlet Pressure bara	Pipeline Outlet Pressure bara						Target Platform Arrival Pressure bara
		Inch/MTPA	1 Train	2 Train	3 Train	4 Train	5 Train	
Teesside to Endurance	183.2	24	178.8	174.4	167.1	157.0	144.0	142.3
		20	176.4	165.0	146.1	119.8	86.0	
		18	173.6	153.8	120.9	75.0	16.1	
		16	167.9	131.3	70.5	-Neg *	-Neg *	
South Humber to Endurance	173.7	24	169.8	166.9	162.0	155.1	146.4	142.3
		20	168.2	160.6	147.8	130.1	107.3	
		18	166.3	153.0	130.8	99.9	60.2	
		16	162.5	137.8	96.9	39.7	-Neg *	
North Humber to Endurance	172.2	24	168.4	165.6	161.0	154.6	146.3	142.3
		20	166.9	159.7	147.7	131.0	109.5	
		18	165.1	152.5	131.7	102.5	65.1	
		16	161.5	138.3	99.7	45.8	-Neg *	
North West to Hamilton Gas Phase	93.5	24	77.6	68.3	52.7			51
		20	72.6	48.2	7.6			
		18	66.5	24.0	-Neg *			
North West to Hamilton Liquid Phase	93.5	24	89.4	86.3	81.1			52
		20	87.7	79.6	66.2			
		18	85.7	71.6	48.3			

* Negative platform arrival pressures are indicated that the inlet pipeline pressure is not sufficient.

With a 20” pipeline for more than 3 trains the platform arrival pressure is below the target platform arrival pressure as shown in the Table15 above, this is due to high pressure drops therefore, 24” pipelines are a more economical selection for the GBC project as it has more than 3 trains arrangement.

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Pipeline Sizing Summary

The summary of the Compression and CO_2 Pipeline simulation models are as follows:

Endurance

- 24 inch CO_2 pipelines from Teesside, to Endurance with 183 bara maximum inlet pipeline pressure and 184 bara at the 8th Stage Compressor discharge for Teesside to Endurance.
- 24 inch CO_2 pipelines from South Humber to Endurance with 174 bara maximum inlet pipeline pressure and 175 bara at the 8th Stage Compressor discharge for South Humber to Endurance.
- 24 inch CO_2 pipelines from North Humber to Endurance with 172 bara maximum inlet pipeline pressure and 173 bara at the 8th Stage Compressor discharge for North Humber to Endurance.

Hamilton

- For CO_2 pipelines from North West to Hamilton Gas and Liquid Phase, the 8th Stage Compressor is not required.
- 24 inch pipeline (with insulated offshore pipeline) from North West to Hamilton Gas Phase with 82bara maximum inlet pipeline pressure, 94 bara at the 7th Stage Compressor discharge and 2.23MW Offshore Heater to maintain the THT at 30°C.
- 46°C used as cooler outlet temperature for the 6th Stage Compressor (Dense Gas) Cooler to maintain Hamilton Gas Phase THT at 30°C.
- 24 inch pipeline from North West to Hamilton Liquid Phase with 93bara maximum inlet pipeline pressure, 94 bara 7th Stage Compressor discharge and 16MW Shoreline Pipeline Chiller to maintain the THT at 10°C.
- A 7th Stage Compressor (Dense Gas) Cooler with 36°C outlet temperature is required to maintain Hamilton Liquid Phase THT at 10ºC.

Scotland

- A new 36 inch pipeline (18km) from the Scotland Site to No 10 Feeder.
- The existing 36 inch pipeline (280km) from No. 10 Feeder to St Fergus.
- A new 1 x 100% booster compressor station at Kirriemuir to boost the pressure to 34barg.
- The booster compressor at Kirriemuir is only required when three trains in operation with a total capacity of 6 MTPA and is not required for 2 trains or 1 train plant.
- Two new compressor units located at St Fergus to boost the pressure to the offshore pipelines required inlet pressure (1 x 100% compressor to serve Captain X and 1 x 100% compressor to serve Goldeneye)
- The existing 16inch offshore pipeline (78km) from St Fergus to Atlantic with new 16 inch pipeline (8km) extended to Captain X.
- The existing 20 inch Goldeneye pipeline (101 km) from St Fergus to Goldeneye Platform.

A review of in-line Booster Stations showed that the cost benefit to dropping a pipeline size (Reviewed North West as longer onshore pipeline) was 1/3 the cost increase for a Booster Station plus consenting risk.

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Heat & Mass Balance Documentation

Heat & Mass Balance data for the Compression and CO_2 Pipelines for the General Business Case is provided in the Overall H&MB [181869-0001-D-EM-HMB-AAA-00-00001-01]. These documents are to be read in conjunction with the Process Flow Diagram Carbon Capture [181869-0001-T-EM-PFD-AAA-00-00001].

UTILITIES

Fuel Gas Consumption

Fuel gas consumption is calculated as: 157.5 Nm^3/hr (nominal plant)

The fuel gas consumption results in a preliminary pipeline size selection of 24".

The fuel gas consumption is based upon:

- Heat rate of Gas Turbines from Appendix 1
- LHV of National Grid Transco Gas from the Basis of Design

(Ref: 181869-0001-T-EM-CAL-AAA-00-00007)

Power Consumption

Each train is defined in the Block Flow Diagram - Outline Scheme Design at Plant Level, document reference 181869-0001-D-EM-BLK-AAA-00-00001-01.

The power train modelling has been carried out using a GE model 9HA.02 Gas Turbine Power Generation Set. The power train modelling provides a calculation of parasitic load as summarised below.

The Carbon Capture and Storage parasitic load is the total from the equipment list (181869-0001-T-ME-MEL-AAA-00-00001) minus the parasitic load modelled for the Power Generation Plant.

The steam extraction losses are calculated from the unabated steam turbine generator output minus the abated steam turbine generator output.

The nominal plant design is defined in the Basis of Design, document reference 181869-0001-T-EM-DBS-AAA-00-00001.

Parasitic Loads	Per Train (GE 9HA.02)	Per Train (Nominal)	5 Trains (GE 9HA.02)	5 Trains (Nominal)
Power Generation	17.6 MW	17 MW	88 MW	0.09 GW
Carbon Capture and Compression	54 MW	52 MW	270 MW	0.26 GW
Steam Extraction	42.9 MW	41.5 MW	215 MW	208 MW
Total Losses	**114.5 MW**	**110.5 MW**	**573 MW**	**553 MW**

Steam Consumption

LP Steam = 297.8 T/hr (per train)

MP Steam = 13,429 kg/hr (per train)

(Ref: 181869-0001-T-EM-LST-AAA-00-00001)

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CONCLUSIONS

Summary

Each train is defined in the Block Flow Diagram - Outline Scheme Design at Plant Level, document reference 181869-0001-D-EM-BLK-AAA-00-00001-01.

The power train modelling has been carried out using a GE model 9HA.02 Gas Turbine Power Generation Set.

The nominal plant design is defined in the Basis of Design, document reference 181869-0001-T-EM-DBS-AAA-00-00001 rev A03.

	Per Train	Per Train (Nominal)	5 Trains	5 Trains (Nominal)
Power Generation				
Gross	757 MW	732 MW	3.74 GW	3.66 GW
Net	740 MW	715 MW	3.66 GW	3.58 GW
Steam Abated	714 MW	691 MW	3.57 GW	3.45 GW
Net Abated	643 MW	622 MW	3.22 GW	3.11 GW
CO_2 Recovery (90%)	228.2 T/hr	220.6 T/hr	1141 T/hr	1103 T/hr

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APPENDICES

Appendix 1 – Power Modelling – Text Output from Modelling (ABRIDGED FOR COST EST REPORT)
Appendix 2 – Power Modelling – Graphics (ABRIDGED FOR COST EST REPORT)
Appendix 3 – Power Modelling – PEACE Cost Estimate (ABRIDGED FOR COST EST REPORT)
Appendix 4 – Power Modelling – Graphics for Turndown (ABRIDGED FOR COST EST REPORT)
Appendix 5 – Power Modelling – Text Output for Turndown (ABRIDGED FOR COST EST REPORT)
Appendix 6 – Power Modelling – Abated Operation (ABRIDGED FOR COST EST REPORT)
Appendix 7 – Deleted – refer to 181869-0001-D-EM-HMB-AAA-00-00001-01
Appendix 8 – Deleted – refer to 181869-0001-D-EM-HMB-AAA-00-00001-01

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APPENDIX 1 – Power Modelling – Text Output from Modelling

System Summary Report

GT PRO 26.0 SNC-Lavalin
580 12-02-2016 11:29:14 file=Z:\2016projs\8045 SNC UK H-J Class Study\Engineering\HeatBal\10Cun HA.
02_1x1_CT.GTP
Program revision date: November 1, 2016
Plant Configuration: GT, HRSG, and condensing reheat ST
One GE 9HA.02 Engine (Physical Model #605), One Steam Turbine, GT PRO Type 9, Subtype 11
Steam Property Formulation: IFC-67

SYSTEM SUMMARY

	Power Output kW		LHV Heat Rate kJ/kWh		Elect. Eff. LHV%	
	@ gen. term.	net	@ gen. term.	net	@ gen. term.	net
Gas Turbine(s)	517167		8507		42.32	
Steam Turbine(s)	240100					
Plant Total	757268	740374	5810	5942	61.97	60.58

PLANT EFFICIENCIES

PURPA efficiency	CHP (Total) efficiency	Power gen. eff. on	Canadian Class 43
%	%	chargeable energy, %	Heat Rate, kJ/kWh
60.58	60.58	60.58	6425

GT fuel HHV/LHV ratio =	1.106	
DB fuel HHV/LHV ratio =	1.106	
Total plant fuel HHV heat input / LHV heat input =	1.106	
Fuel HHV chemical energy input (77F/25C) =	1351563	kW
Fuel LHV chemical energy input (77F/25C) =	1222059	kW
Total energy input (chemical LHV + ext. addn.) =	1222059	kW
Energy chargeable to power (93.0% LHV alt. boiler) =	1222059	kW

GAS TURBINE PERFORMANCE - GE 9HA.02 (Physical Model #605)

	Gross power	Gross LHV	Gross LHV Heat Rate	Exh. flow	Exh. temp.
	output, kW	efficiency, %	kJ/kWh	t/h	C
per unit	517167	42.32	8507	3551	648
Total	517167			3551	

Number of gas turbine unit(s) =	1	
Gas turbine load [%] =	100	%
Fuel chemical HHV (77F/25C) per gas turbine =	1351563	kW
Fuel chemical LHV (77F/25C) per gas turbine =	1222059	kW

STEAM CYCLE PERFORMANCE

HRSG eff.	Gross power output	Internal gross	Overall	Net process heat output
%	kW	elect. eff., %	elect. eff., %	kW
87.85	240100	38.85	34.13	0

Number of steam turbine unit(s) =	1	
Fuel chemical HHV (77F/25C) to duct burners =	0	kW
Fuel chemical LHV (77F/25C) to duct burners =	0	kW
DB fuel chemical LHV + HRSG inlet sens. heat =	703553	kW
Net process heat output as % of total output (net elec. + net heat) =	0	%

System Summary Report

ESTIMATED PLANT AUXILIARIES (kW)		
GT fuel compressor(s)*	0	kW
GT supercharging fan(s)*	0	kW
GT electric chiller(s)*	0	kW
GT chiller/heater water pump(s)	0	kW
HRSG feedpump(s)*	5609	kW
Condensate pump(s)*	440.5	kW
HRSG forced circulation pump(s)	0	kW
LTE recirculation pump(s)	1.277	kW
Cooling water pump(s)	1423.4	kW
Air cooled condenser fans	0	kW
Cooling tower fans	1089.7	kW
Dilution air fan(s)	0	kW
Aux. from PEACE running motor/load list	3002	kW
Miscellaneous gas turbine auxiliaries	1035	kW
Miscellaneous steam turbine auxiliaries	127.6	kW
Miscellaneous plant auxiliaries	378.6	kW
Constant plant auxiliary load	0	kW
Gasification plant, ASU*	0	kW
Gasification plant, fuel preparation	0	kW
Gasification plant, AGR*	0	kW
Gasification plant, other/misc	0	kW
Desalination plant auxiliaries	0	kW
Program estimated overall plant auxiliaries	13107	kW
Actual (user input) overall plant auxiliaries	13107	kW
Transformer losses	3786	kW
Total auxiliaries & transformer losses	**16893**	**kW**
* Heat balance related auxiliaries		

System Summary Report

PLANT HEAT BALANCE				
Energy In	**1377024**	**kW**		
Ambient air sensible	9715	kW		
Ambient air latent	10881	kW		
Fuel enthalpy @ supply	1356417	kW		
External gas addition to combustor	0	kW		
Steam and water	0	kW		
Makeup and process return	11.17	kW		
Energy Out	**1376788**	**kW**		
Net power output	740374	kW		
Stack gas sensible	91516	kW		
Stack gas latent	143518	kW		
GT mechanical loss	3161	kW		
GT gear box loss	0	kW		
GT generator loss	6281	kW		
GT miscellaneous losses	3699	kW		
GT ancillary heat rejected	0	kW		
GT process air bleed	0	kW		
Fuel compressor mech/elec loss	0	kW		
Supercharging fan mech/elec loss	0	kW		
Condenser	367574	kW		
Process steam	0	kW		
Process water	0	kW		
Blowdown/leakages	555	kW		
Heat radiated from steam cycle	5785	kW		
ST/generator mech/elec/gear loss	3479	kW		
Non-heat balance related auxiliaries	7058	kW		
Transformer loss	3786	kW		
Energy In - Energy Out	235.5	kW		
GT heat balance error (arising from GT definitions)	247.7	kW		
Steam cycle heat balance error	-12.26	kW	-0.0014	%
Zero enthalpy: dry gases & liquid water @ 32 F (273.15 K)				

System Summary Table

Plant Summary		
1. System Summary		
Plant total power output @ generator terminal	757268	kW
Total auxiliaries & transformer losses	16893	kW
Plant net power output	740374	kW
Plant LHV heat rate @ generator terminal	5810	kJ/kWh
Plant HHV heat rate @ generator terminal	6425	kJ/kWh
Plant net LHV heat rate	5942	kJ/kWh
Plant net HHV heat rate	6572	kJ/kWh
Plant LHV electric eff. @ generator terminal	61.97	%
Plant HHV electric eff. @ generator terminal	56.03	%
Plant net LHV electric efficiency	60.58	%
Plant net HHV electric efficiency	54.78	%
2. Plant Efficiencies		
PURPA efficiency, LHV	60.58	%
PURPA efficiency, HHV	54.78	%
CHP (Total) efficiency, LHV	60.58	%
CHP (Total) efficiency, HHV	54.78	%
Power generation eff. on chargeable energy, LHV	60.58	%
Power generation eff. on chargeable energy, HHV	54.78	%
Canadian Class 43 heat rate	6425	kJ/kWh
Plant fuel LHV chemical energy input (77F/25C)	1222059	kW
Plant fuel HHV chemical energy input (77F/25C)	1351563	kW
Total energy input (chemical LHV + ext. addn.)	1222059	kW
Energy chargeable to power, LHV	1222059	kW
Energy chargeable to power, HHV	1351563	kW
GT fuel chemical HHV/LHV ratio	1.106	
DB fuel chemical HHV/LHV ratio	1.106	
Plant fuel HHV heat input /LHV heat input	1.106	
3. Gas Turbine Performance (per unit) (Physical Model #605)	**GE 9HA.02**	**1 unit(s)**
Gross power output	517167	kW
Gross LHV efficiency	42.32	%
Gross HHV efficiency	38.26	%
Gross LHV heat rate	8507	kJ/kWh
Gross HHV heat rate	9408	kJ/kWh
Exhaust mass flow	3551	t/h
Exhaust temperature	647.6	C
Fuel chemical LHV input (77F/25C)	1222059	kW
Fuel chemical HHV input (77F/25C)	1351563	kW
4. Steam Cycle Performance (LHV)		
HRSG efficiency	87.85	%
Steam turbine gross power	240100	kW
Internal gross efficiency	38.85	%
Overall efficiency	34.13	%
Net process heat output	0	kW
Fuel chemical LHV (77F/25C) to duct burners	0	kW
Fuel chemical HHV (77F/25C) to duct burners	0	kW
DB fuel chemical LHV + HRSG inlet sens. heat	703553	kW
Net process heat output / total output	0	%
5. Plant Auxiliaries		

System Summary Table

Plant Summary		
GT fuel compressor(s)	0	kW
GT supercharging fan(s)	0	kW
GT electric chiller(s)	0	kW
GT chiller/heater water pump(s)	0	kW
HRSG feedpump(s)	5609	kW
Condensate pump(s)	440.5	kW
HRSG forced circulation pump(s)	0	kW
LTE recirculation pump(s)	1.277	kW
Cooling water pump(s)	1423.4	kW
Air cooled condenser fans	0	kW
Cooling tower fans	1089.7	kW
Dilution air fan(s)	0	kW
Aux. from PEACE running motor/load list	3002	kW
Miscellaneous gas turbine auxiliaries	1035	kW
Miscellaneous steam turbine auxiliaries	127.6	kW
Miscellaneous plant auxiliaries	378.6	kW
Constant plant auxiliary load	0	kW
Gasification plant, ASU	0	kW
Power to AGR	0	kW
Gasification plant, air boost compressor	0	kW
Gasification plant, fuel preparation	0	kW
Gasification plant, syngas recirculation compressor	0	kW
Gasification plant, Other/misc	0	kW
Desalination plant auxiliaries	0	kW
Program estimated overall plant auxiliaries	13107	kW
Actual (user input) overall plant auxiliaries	13107	kW
Transformer losses	3786	kW
Total auxiliaries & transformer losses	16893	kW

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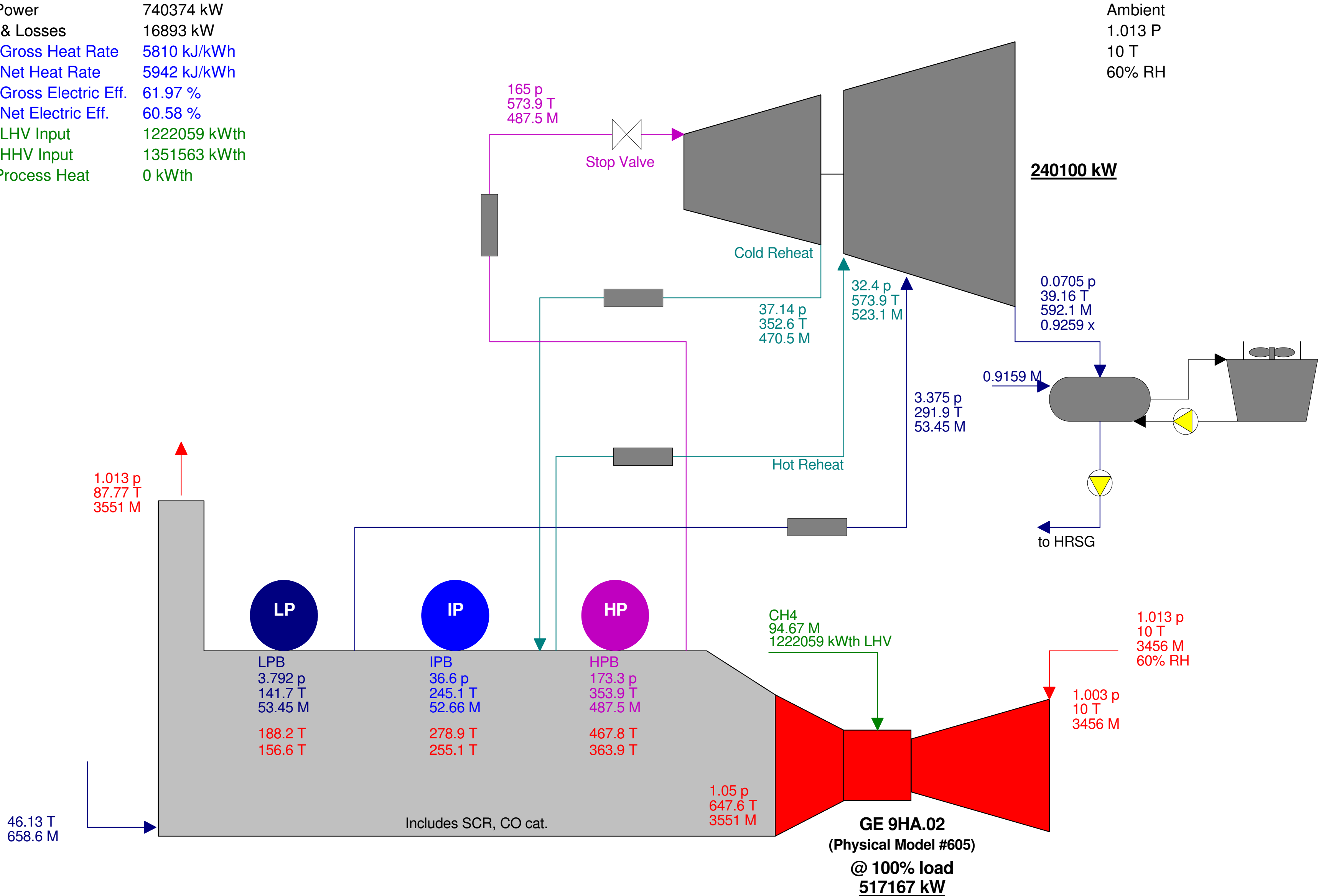
TECHNICAL NOTE

APPENDIX 2 – Power Modelling – Graphics

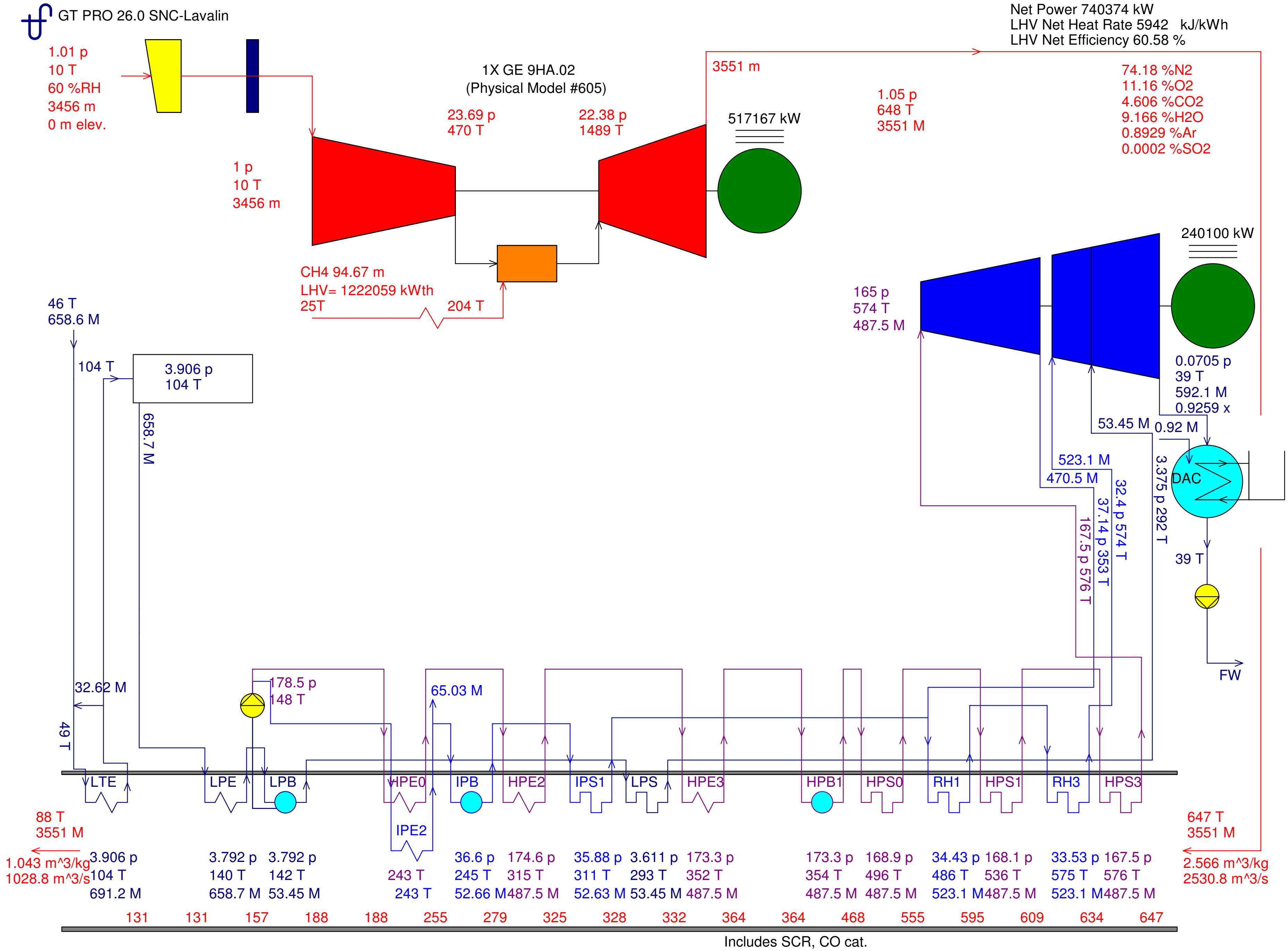
GT PRO 26.0 SNC-Lavalin

Gross Power	757268 kW
Net Power	740374 kW
Aux. & Losses	16893 kW
LHV Gross Heat Rate	5810 kJ/kWh
LHV Net Heat Rate	5942 kJ/kWh
LHV Gross Electric Eff.	61.97 %
LHV Net Electric Eff.	60.58 %
Fuel LHV Input	1222059 kWth
Fuel HHV Input	1351563 kWth
Net Process Heat	0 kWth



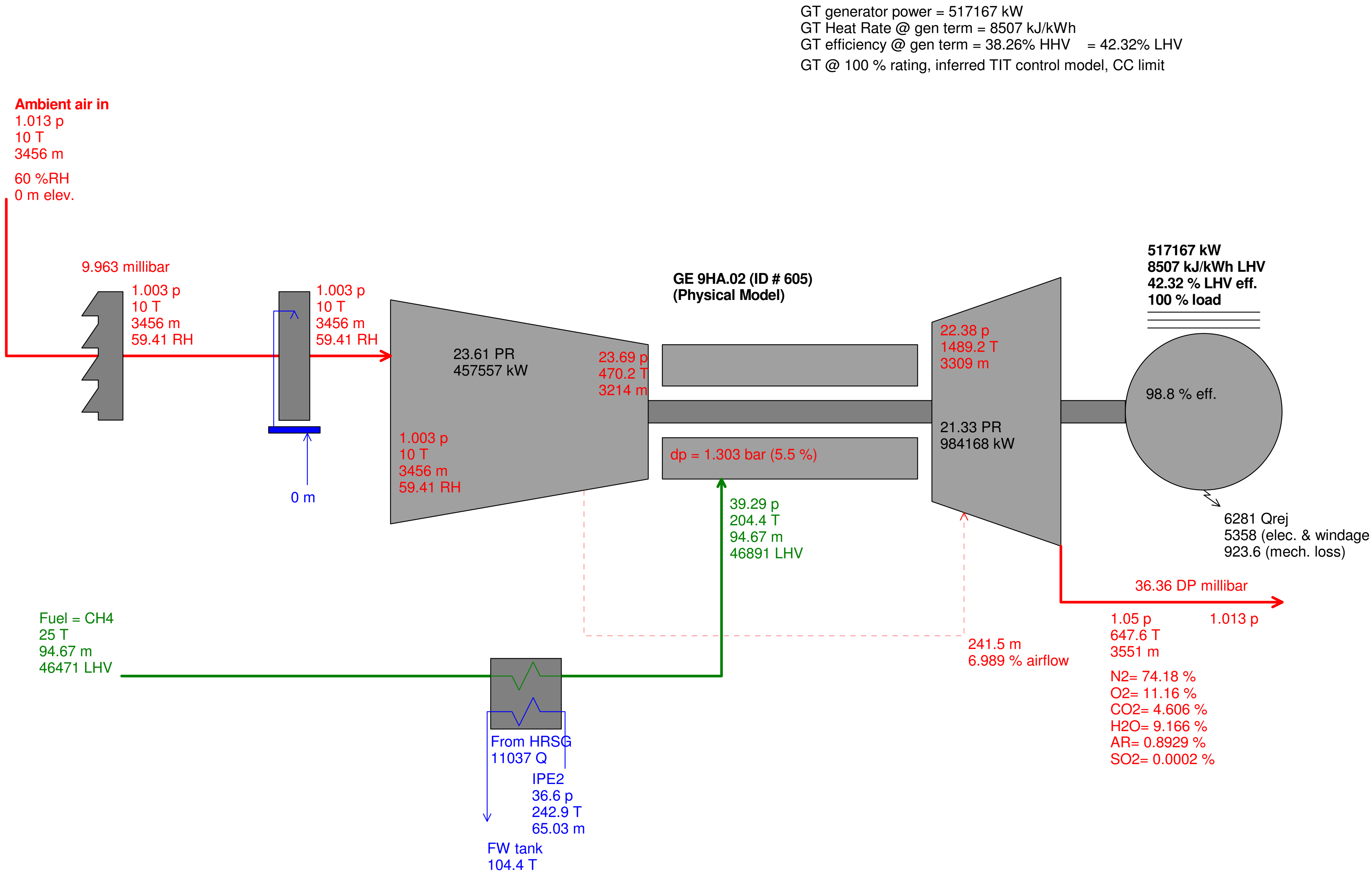
GT PRO 26.0 SNC-Lavalin

p [bar] T [C] M [t/h], Steam Properties: IFC-67
580 12-02-2016 11:29:14 file=Z:\2016projs\8045 SNC UK H-J Class Study\Engineering\HeatBal\10Cun HA.02_1x1_CT.GTP



p[bar], T[C], M[t/h], Steam Properties: IFC-67

580 12-02-2016 11:29:14 file=Z:\2016projs\8045 SNC UK H-J Class Study\Engineering\HeatBal\10Cun HA.02_1x1_CT.GTP



p[bar], T[C], M[t/h], Q[kW], Steam Properties: IFC-67

GT PRO 26.0 SNC-Lavalin
580 12-02-2016 11:29:14 file=Z:\2016projs\8045 SNC UK H-J Class Study\Engineering\HeatBal\10Cun HA.02_1x1_CT.GTP

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TECHNICAL NOTE

APPENDIX 3 – Power Modelling – PEACE Cost Estimate

Project Cost Summary	Reference Cost	Estimated Cost	
I Specialized Equipment	199,307,900	229,204,080	GBP
II Other Equipment	13,110,216	15,076,748	GBP
III Civil	22,708,472	31,871,790	GBP
IV Mechanical	26,398,363	39,261,892	GBP
V Electrical Assembly & Wiring	8,910,078	13,434,073	GBP
VI Buildings & Structures	2,966,580	4,308,958	GBP
VII Engineering & Plant Startup	17,377,480	17,461,450	GBP
Gasification Plant	0	0	GBP
Desalination Plant	0	0	GBP
CO2 Capture Plant	0	0	GBP
Subtotal - Contractor's Internal Cost	290,779,089	350,618,991	GBP
VIII Contractor's Soft & Miscellaneous Costs	60,233,371	79,288,517	GBP
Contractor's Price	351,012,460	429,907,508	GBP
IX Owner's Soft & Miscellaneous Costs	31,591,121	38,691,676	GBP
Total - Owner's Cost	382,603,581	468,599,184	GBP
Net Plant Output	740.4	740.4	MW
Price per kW - Contractor's	474	581	GBP per kW
Cost per kW - Owner's	517	633	GBP per kW

NOTE: Following totals refer to power plant only.
The gasification, desalination, and CO2 capture plants are not included.

Power Plant Totals (Reference Basis):	Reference Cost	Hours
Commodities	29,390,380	
Labor	29,370,342	877,338

Effective Labor Rates:	Cost per Hour
Civil Account	29.53
Mechanical Account	33.62
Electrical Account	34.44

Power Plant Buildings	% of Total Cost	Estimated Cost	Hours
Labor	50	1,483,290	
Material	50	1,483,290	
Labor Hours			47,973

Note: Totals may not tally due to round-off.

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APPENDIX 4 – Power Modelling – Text Output from Turndown

System Summary Report

GT MASTER 26.1 SNC-Lavalin						
580 02-10-2017 07:52:51 file=Z:\2016projs\8045 SNC UK H-J Class Study\Engineering\HeatBal\MECL_40%_						
10Cun HA.02_1x1_CT.GTM						
Program revision date: January 27, 2017						
Plant Configuration: GT, HRSG, and condensing reheat ST						
Steam Property Formulation: IFC-67						

SYSTEM SUMMARY

	Power Output kW		LHV Heat Rate kJ/kWh		Elect. Eff. LHV%	
	@ gen. term.	net	@ gen. term.	net	@ gen. term.	net
Gas Turbine(s)	210088		11321		31.80	
Steam Turbine(s)	156382					
Plant Total	366470	352622	6490	6745	55.47	53.37

PLANT EFFICIENCIES

PURPA efficiency	CHP (Total) efficiency	Power gen. eff. on	Canadian Class 43
%	%	chargeable energy, %	Heat Rate, kJ/kWh
53.37	53.37	53.37	7178

GT fuel HHV/LHV ratio =	1.106	
DB fuel HHV/LHV ratio =	1.106	
Total plant fuel HHV heat input / LHV heat input =	1.106	
Fuel HHV chemical energy input (77F/25C) =	730698	kW
Fuel LHV chemical energy input (77F/25C) =	660684	kW
Total energy input (chemical LHV + ext. addn.) =	660684	kW
Energy chargeable to power (93.0% LHV alt. boiler) =	660684	kW

GAS TURBINE PERFORMANCE - GE 9HA.02 (Physical Model #605)

	Gross power	Gross LHV	Gross LHV Heat Rate	Exh. flow	Exh. temp.
	output, kW	efficiency, %	kJ/kWh	t/h	C
per unit	210088	31.80	11321	2221	663
Total	210088			2221	

Number of gas turbine unit(s) =	1	
Gas turbine load [%] =	40	%
Fuel chemical HHV (77F/25C) per gas turbine =	730698	kW
Fuel chemical LHV (77F/25C) per gas turbine =	660684	kW

STEAM CYCLE PERFORMANCE

HRSG eff.	Gross power output	Internal gross	Overall	Net process heat output
%	kW	elect. eff., %	elect. eff., %	kW
90.46	156382	38.55	34.88	0

Number of steam turbine unit(s) =	1	
Fuel chemical HHV (77F/25C) to duct burners =	0	kW
Fuel chemical LHV (77F/25C) to duct burners =	0	kW
DB fuel chemical LHV + HRSG inlet sens. heat =	448379	kW
Net process heat output as % of total output (net elec. + net heat) =	0	%
HRSG characteristic time (Stored energy / Gas heat transfer), minutes	23.59	

System Summary Report

ESTIMATED PLANT AUXILIARIES (kW)		
GT fuel compressor(s)*	0	kW
GT supercharging fan(s)*	0	kW
GT electric chiller(s)*	0	kW
GT chiller/heater water pump(s)	0	kW
HRSG feedpump(s)*	4716	kW
Condensate pump(s)*	399	kW
HRSG forced circulation pump(s)	0	kW
LTE recirculation pump(s)	1.968	kW
Cooling water pump(s)	1433.9	kW
Air cooled condenser fans	0	kW
Cooling tower fans	1117.1	kW
Dilution air fan(s)	0	kW
Aux. from PEACE running motor/load list	3002	kW
Miscellaneous gas turbine auxiliaries	1035	kW
Miscellaneous steam turbine auxiliaries	127.6	kW
Miscellaneous plant auxiliaries	183.2	kW
Constant plant auxiliary load	0	kW
Gasification plant, ASU*	0	kW
Gasification plant, fuel preparation	0	kW
Gasification plant, AGR*	0	kW
Gasification plant, other/misc	0	kW
Desalination plant auxiliaries	0	kW
Program estimated overall plant auxiliaries	12016	kW
Actual (user input) overall plant auxiliaries	12016	kW
Transformer losses	1832.4	kW
Total auxiliaries & transformer losses	**13848**	**kW**
* Heat balance related auxiliaries		

System Summary Report

PLANT HEAT BALANCE				
Energy In	**746265**	**kW**		
Ambient air sensible	6101	kW		
Ambient air latent	6833	kW		
Fuel enthalpy @ supply	733322	kW		
External gas addition to combustor	0	kW		
Steam and water	0	kW		
Makeup and process return	9.528	kW		
Energy Out	**746124**	**kW**		
Net power output	352622	kW		
Stack gas sensible	46388	kW		
Stack gas latent	78541	kW		
GT mechanical loss	3003	kW		
GT gear box loss	0	kW		
GT generator loss	3607	kW		
GT miscellaneous losses	2000	kW		
GT ancillary heat rejected	0	kW		
GT process air bleed	0	kW		
Fuel compressor mech/elec loss	0	kW		
Supercharging fan mech/elec loss	0	kW		
Condenser/DA vent	244253	kW		
Process steam	0	kW		
Process water	0	kW		
Blowdown/leakages	478.3	kW		
Heat radiated from steam cycle	3827	kW		
ST/generator mech/elec/gear loss	2672.6	kW		
Non-heat balance related auxiliaries	6901	kW		
Transformer loss	1832.4	kW		
Energy In - Energy Out	140.8	kW		
GT heat balance error (arising from GT definitions)	122.8	kW		
Steam cycle heat balance error	20.77	kW	0.0038	%
Zero enthalpy: dry gases & liquid water @ 32 F (273.15 K)				

System Summary Table

Plant Summary		
1. System Summary		
Plant total power output @ generator terminal	366470	kW
Total auxiliaries & transformer losses	13848	kW
Plant net power output	352622	kW
Plant LHV heat rate @ generator terminal	6490	kJ/kWh
Plant HHV heat rate @ generator terminal	7178	kJ/kWh
Plant net LHV heat rate	6745	kJ/kWh
Plant net HHV heat rate	7460	kJ/kWh
Plant LHV electric eff. @ generator terminal	55.47	%
Plant HHV electric eff. @ generator terminal	50.15	%
Plant net LHV electric efficiency	53.37	%
Plant net HHV electric efficiency	48.26	%
2. Plant Efficiencies		
PURPA efficiency, LHV	53.37	%
PURPA efficiency, HHV	48.26	%
CHP (Total) efficiency, LHV	53.37	%
CHP (Total) efficiency, HHV	48.26	%
Power generation eff. on chargeable energy, LHV	53.37	%
Power generation eff. on chargeable energy, HHV	48.26	%
Canadian Class 43 heat rate	7178	kJ/kWh
Plant fuel LHV chemical energy input (77F/25C)	660684	kW
Plant fuel HHV chemical energy input (77F/25C)	730698	kW
Total energy input (chemical LHV + ext. addn.)	660684	kW
Energy chargeable to power, LHV	660684	kW
Energy chargeable to power, HHV	730698	kW
GT fuel chemical HHV/LHV ratio	1.106	
DB fuel chemical HHV/LHV ratio	1.106	
Plant fuel HHV heat input /LHV heat input	1.106	
3. Gas Turbine Performance (per unit) (Physical Model #605)	**GE 9HA.02**	**1 unit(s)**
Gross power output	210088	kW
Gross LHV efficiency	31.8	%
Gross HHV efficiency	28.75	%
Gross LHV heat rate	11321	kJ/kWh
Gross HHV heat rate	12521	kJ/kWh
Exhaust mass flow	2221.3	t/h
Exhaust temperature	663	C
Fuel chemical LHV input (77F/25C)	660684	kW
Fuel chemical HHV input (77F/25C)	730698	kW
4. Steam Cycle Performance (LHV)		
HRSG efficiency	90.46	%
Steam turbine gross power	156382	kW
Internal gross efficiency	38.55	%
Overall efficiency	34.88	%
Net process heat output	0	kW
Fuel chemical LHV (77F/25C) to duct burners	0	kW
Fuel chemical HHV (77F/25C) to duct burners	0	kW
DB fuel chemical LHV + HRSG inlet sens. heat	448379	kW
Net process heat output / total output	0	%
5. Plant Auxiliaries		

System Summary Table

Plant Summary		
GT fuel compressor(s)	0	kW
GT supercharging fan(s)	0	kW
GT electric chiller(s)	0	kW
GT chiller/heater water pump(s)	0	kW
HRSG feedpump(s)	4716	kW
Condensate pump(s)	399	kW
HRSG forced circulation pump(s)	0	kW
LTE recirculation pump(s)	1.968	kW
Cooling water pump(s)	1433.9	kW
Air cooled condenser fans	0	kW
Cooling tower fans	1117.1	kW
Dilution air fan(s)	0	kW
Aux. from PEACE running motor/load list	3002	kW
Miscellaneous gas turbine auxiliaries	1035	kW
Miscellaneous steam turbine auxiliaries	127.6	kW
Miscellaneous plant auxiliaries	183.2	kW
Constant plant auxiliary load	0	kW
Gasification plant, ASU	0	kW
Power to AGR	0	kW
Gasification plant, air boost compressor	0	kW
Gasification plant, fuel preparation	0	kW
Gasification plant, syngas recirculation compressor	0	kW
Gasification plant, Other/misc	0	kW
Desalination plant auxiliaries	0	kW
Program estimated overall plant auxiliaries	12016	kW
Actual (user input) overall plant auxiliaries	12016	kW
Transformer losses	1832.4	kW
Total auxiliaries & transformer losses	13848	kW

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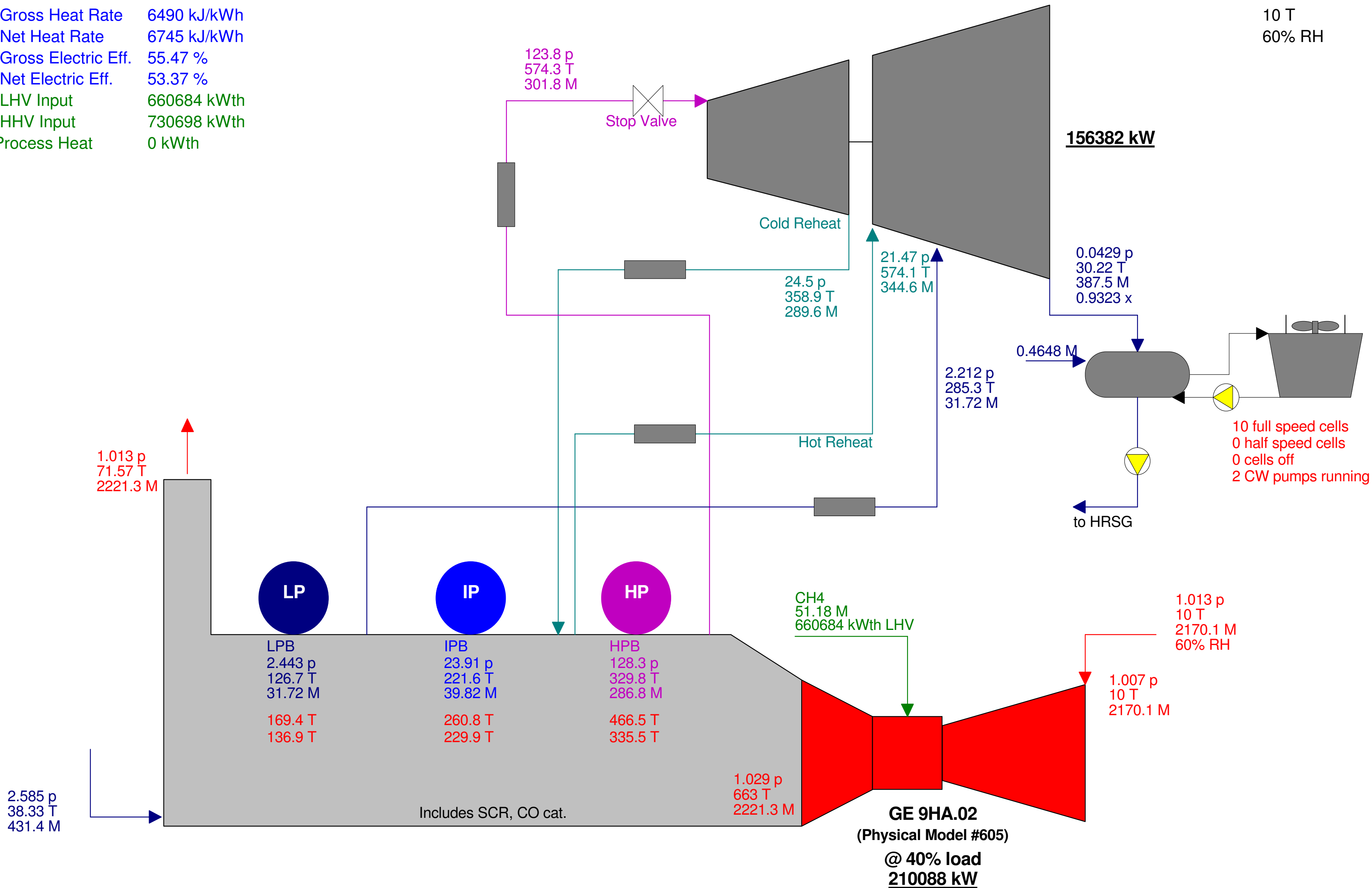
APPENDIX 5 – Power Modelling – Graphics for Turndown

GT MASTER 26.1 SNC-Lavalin

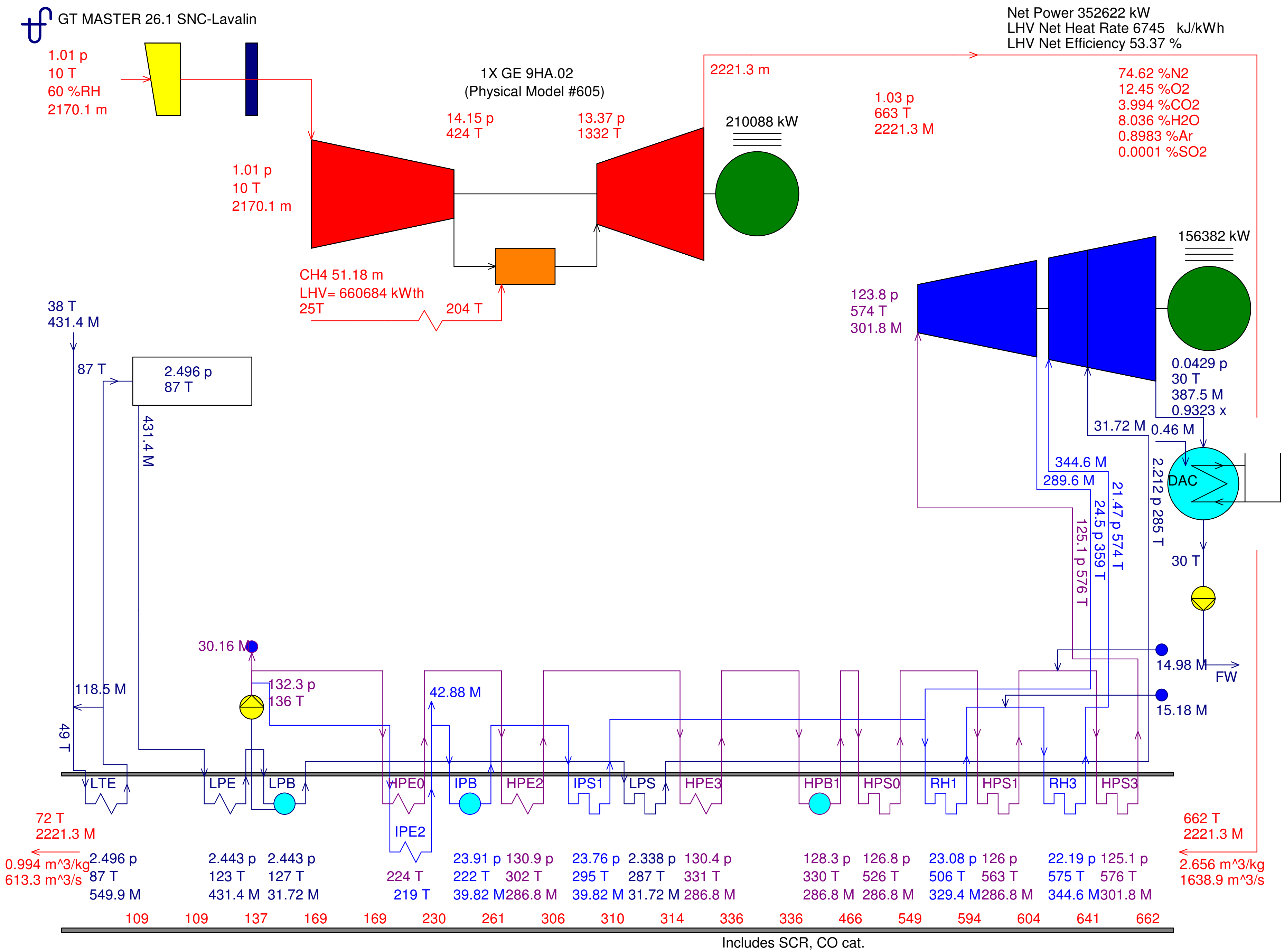
Gross Power	366470 kW
Net Power	352622 kW
Aux. & Losses	13848 kW
LHV Gross Heat Rate	6490 kJ/kWh
LHV Net Heat Rate	6745 kJ/kWh
LHV Gross Electric Eff.	55.47 %
LHV Net Electric Eff.	53.37 %
Fuel LHV Input	660684 kWth
Fuel HHV Input	730698 kWth
Net Process Heat	0 kWth



p [bar] T [C] M [t/h], Steam Properties: IFC-67

GT MASTER 26.1 SNC-Lavalin

580 02-10-2017 07:52:51 file=Z:\2016projs\8045 SNC UK H-J Class Study\Engineering\HeatBal\MECL_40%_10Cun HA.02_1x1_CT.GTM



p[bar], T[C], M[t/h], Steam Properties: IFC-67

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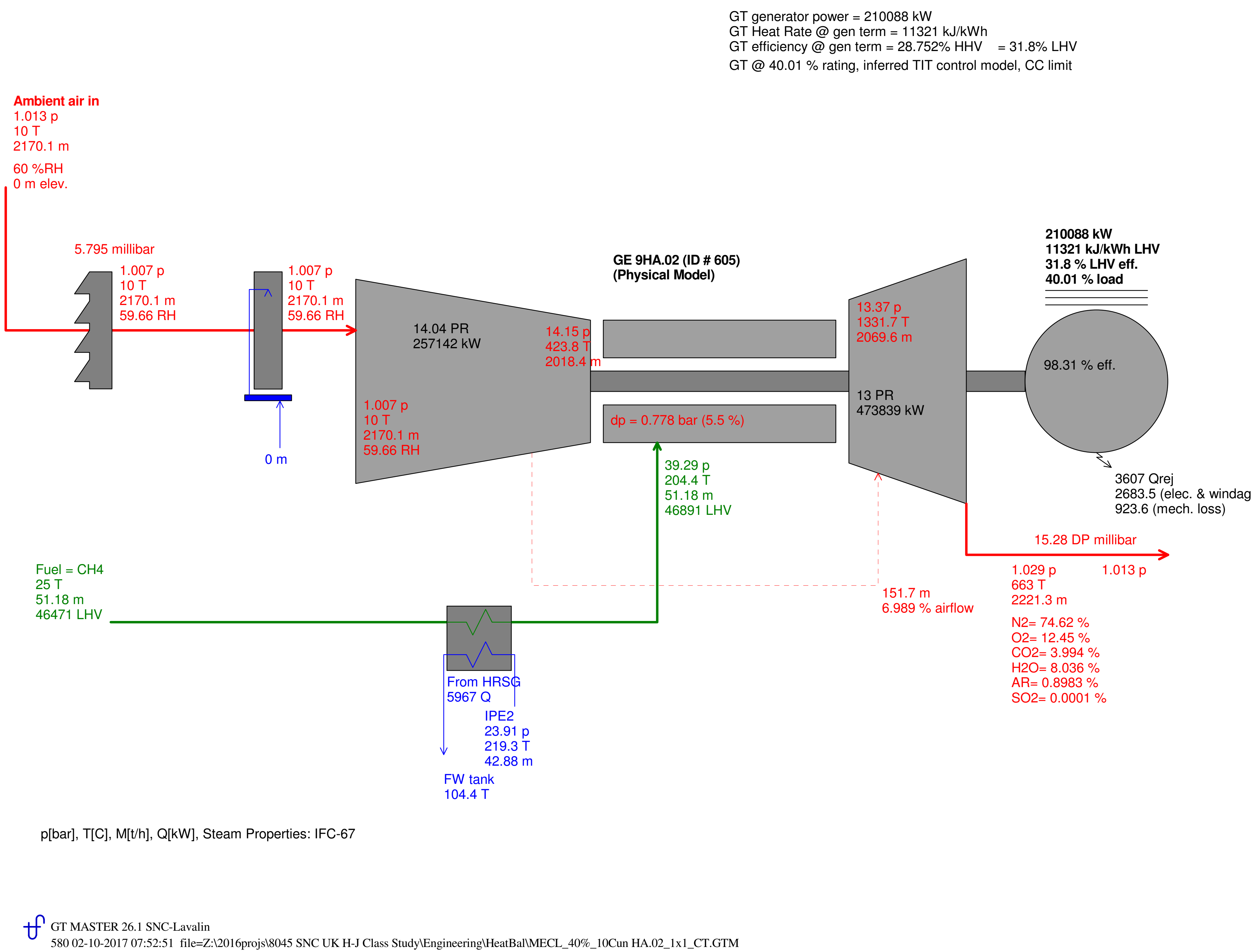

GT generator power = 210088 kW
GT Heat Rate @ gen term = 11321 kJ/kWh
GT efficiency @ gen term = 28.752% HHV = 31.8% LHV
GT @ 40.01 % rating, inferred TIT control model, CC limit
Ambient air in
1.013 p
10 T
2170.1 m
60 %RH
0 m elev.
5.795 millibar
1.007 p
10 T
2170.1 m
59.66 RH
1.007 p
10 T
2170.1 m
59.66 RH
0 m
GE 9HA.02 (ID # 605)
(Physical Model)
14.04 PR
257142 kW
14.15 p
423.8 T
2018.4 m
1.007 p
10 T
2170.1 m
59.66 RH
dp = 0.778 bar (5.5 %)
13.37 p
1331.7 T
2069.6 m
13 PR
473839 kW
210088 kW
11321 kJ/kWh LHV
31.8 % LHV eff.
40.01 % load
98.31 % eff.
3607 Qrej
2683.5 (elec. & windag
923.6 (mech. loss)
39.29 p
204.4 T
51.18 m
46891 LHV
15.28 DP millibar
1.029 p
663 T
2221.3 m
1.013 p
151.7 m
6.989 % airflow
N2= 74.62 %
O2= 12.45 %
CO2= 3.994 %
H2O= 8.036 %
AR= 0.8983 %
SO2= 0.0001 %
Fuel = CH4
25 T
51.18 m
46471 LHV
From HRSG
5967 Q
IPE2
23.91 p
219.3 T
42.88 m
FW tank
104.4 T
p[bar], T[C], M[t/h], Q[kW], Steam Properties: IFC-67
GT MASTER 26.1 SNC-Lavalin
580 02-10-2017 07:52:51 file=Z:\2016projs\8045 SNC UK H-J Class Study\Engineering\HeatBal\MECL_40%_10Cun HA.02_1x1_CT.GTM

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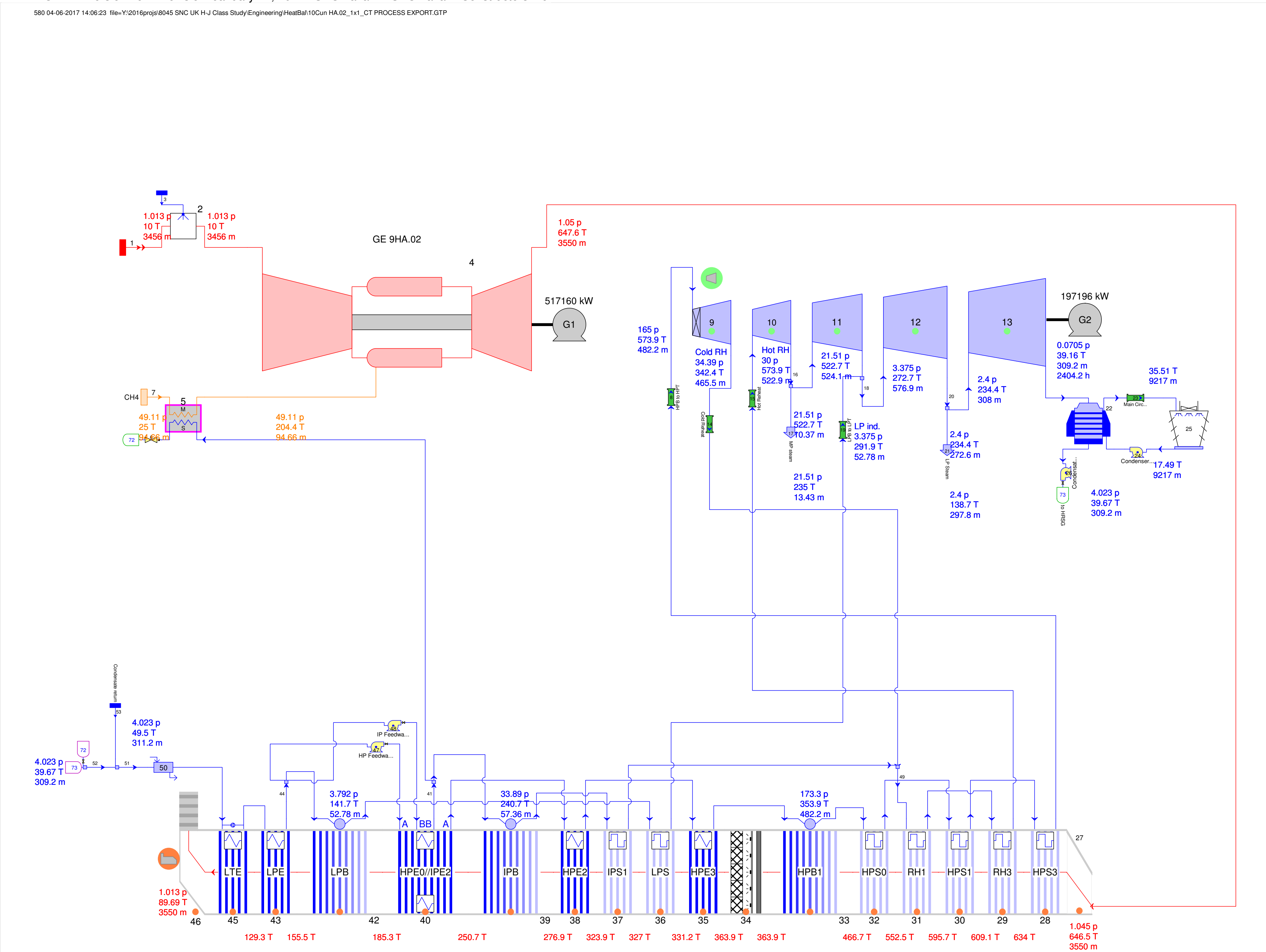
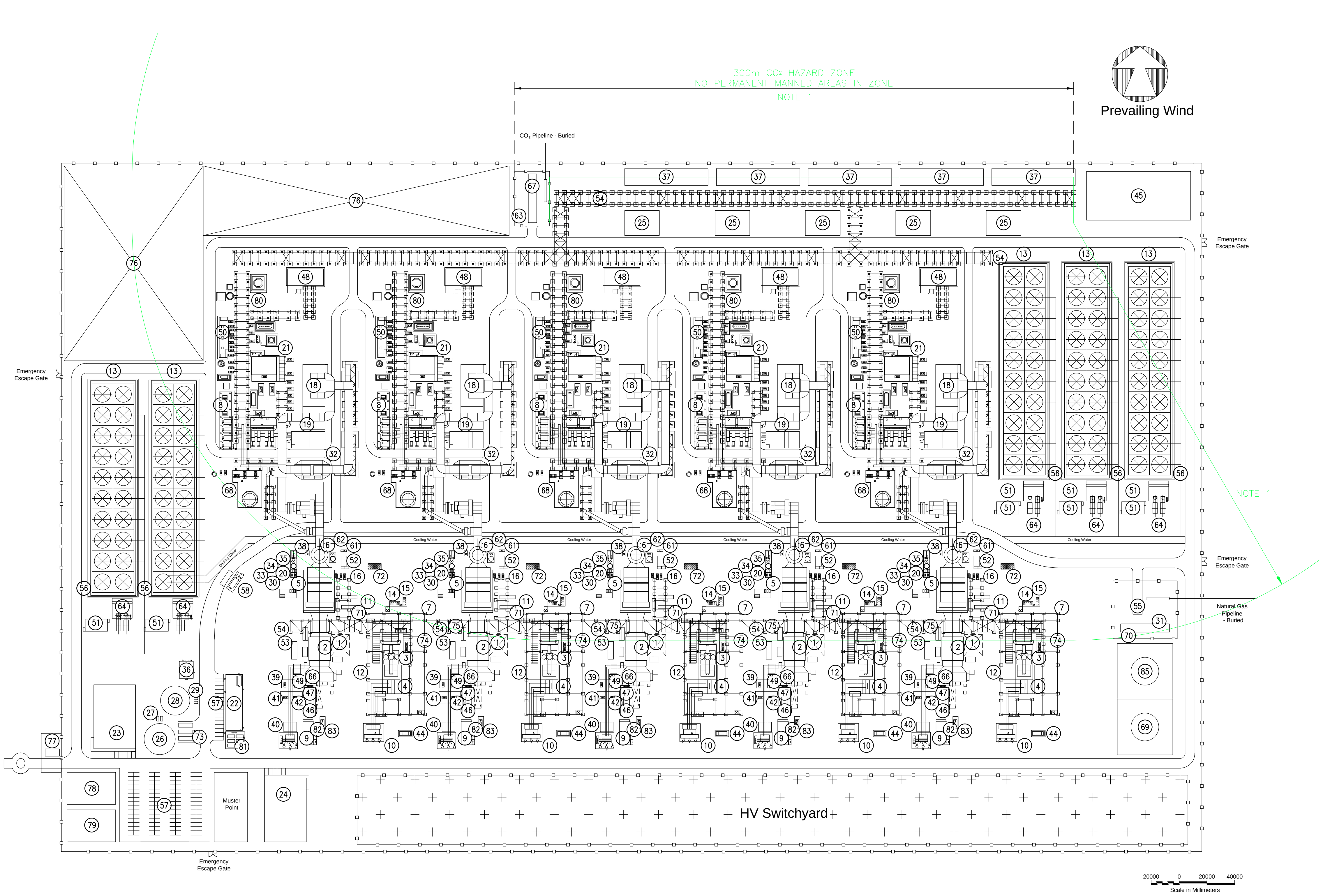
APPENDIX 6 – Power Modelling – Abated Operation


580 04-06-2017 14:06:23 file=Y:\2016projs\8045 SNC UK H-J Class Study\Engineering\HeatBal\10Cun HA.02_1x1_CT PROCESS EXPORT.GTP
GE 9HA.02
517160 kW
G1
1.013 p
10 T
3456 m
1.05 p
647.6 T
3550 m
CH4
49.11 p
25 T
94.66 m
49.11 p
204.4 T
94.66 m
165 p
573.9 T
482.2 m
Cold RH
34.39 p
342.4 T
465.5 m
Hot RH
30 p
573.9 T
522.9 m
21.51 p
522.7 T
524.1 m
21.51 p
522.7 T
10.37 m
21.51 p
235 T
13.43 m
LP ind.
3.375 p
291.9 T
52.78 m
3.375 p
272.7 T
576.9 m
2.4 p
234.4 T
308 m
2.4 p
234.4 T
272.6 m
2.4 p
138.7 T
297.8 m
197196 kW
G2
0.0705 p
39.16 T
309.2 m
2404.2 h
35.51 T
9217 m
17.49 T
9217 m
4.023 p
39.67 T
309.2 m
Main Circ...
Condenser
4.023 p
49.5 T
311.2 m
4.023 p
39.67 T
309.2 m
IP Feedwa...
HP Feedwa...
3.792 p
141.7 T
52.78 m
33.89 p
240.7 T
57.36 m
173.3 p
353.9 T
482.2 m
LTE
LPE
LPB
HPE0//IPE2
IPB
HPE2
IPS1
LPS
HPE3
HPB1
HPS0
RH1
HPS1
RH3
HPS3
1.013 p
89.69 T
3550 m
129.3 T
155.5 T
185.3 T
250.7 T
276.9 T
323.9 T
327 T
331.2 T
363.9 T
363.9 T
466.7 T
552.5 T
595.7 T
609.1 T
634 T
1.045 p
646.5 T
3550 m

Attachment 5 – Footprint of CCGT + CCS Plant - Option 1



LEGEND:

1. GAS TURBINE (GT)
2. GAS TURBINE GENERATOR (GTG)
3. STEAM TURBINE (ST)
4. STEAM TURBINE GENERATOR (STG)
5. HEAT RECOVERY STEAM GENERATOR (HRSG)
6. EXHAUST STACK
7. STG BUILDING
8. ION EXCHANGE UNIT
9. GTG MAIN TRANSFORMER
10. STG MAIN TRANSFORMER
11. BOILER FEED PUMPS
12. CONDENSATE PUMPS
13. COOLING TOWERS
14. CLOSED COOLING WATER PUMPS
15. CLOSED COOLING HEAT EXCHANGER
16. ECONOMIZER RECIRC PUMPS
17. AUXILIARY BOILER W/ FEEDWATER/DA SKID
18. ABSORBER TOWER
19. DIRECT CONTACT COOLER
20. ELECTRIC SUPERHEATER
21. CO_2 STRIPPERS
22. ADMIN & CONTROL BUILDING
23. WAREHOUSE BUILDING
24. WORKSHOP BUILDING
25. CO_2 COMPRESSION
26. DEMINERALISED WATER TANK
27. DEMINERALISED WATER PUMPS
28. RAW/FIRE WATER TANK
29. SERVICE WATER PUMPS
30. ANTI-ICING SKID W/ CONDENSATE PUMPS
31. FUEL GAS METERING AREA
32. GAS-GAS HEAT EXCHANGER
33. FUEL GAS PERFORMANCE HEATER
34. FUEL GAS SCRUBBER/START-UP HEATER
35. FUEL GAS COALESCING FILTER
36. FIREWATER, DIESEL, ELECTRIC AND JOCKEY PUMPS
37. CO_2 DEHYDRATION
38. CEMS ENCLOSURE
39. GENERATOR CIRCUIT BREAKER
40. UNIT AUXILIARY TRANSFORMER
41. ISOLATION TRANSFORMER
42. CT EXCITATION TRANSFORMER
43. UTILITIES AND AMINE STORAGE
44. ST EXCITATION TRANSFORMER
45. ELECTRICAL SUB-STATION (COMPRESSION)
46. CT EXCITATION COMPARTMENT GENERATOR
47. LCI EXCITER COMPARTMENT
48. ELECTRICAL SUBSTATION (CARBON CAPTURE)
49. BATTERY COMPARTMENT
50. THERMAL RECOVERY UNIT
51. COOLING TOWER POWER DISTRIBUTION CENTER (PDC)
52. HRSG POWER DISTRIBUTION CENTER (PDC)
53. PACKAGED ELECTRONIC/ELECTRIC CONTROL COMPARTMENT (PEECC)
54. PIPE RACK
55. PIG RECEIVER (NATURAL GAS)
56. COOLING TOWER BASIN
57. CAR PARKING
58. AQUEOUS AMMONIA TANK
59. DAMPER SEAL AIR FANS
60. BOOSTER FANS
61. OIL/WATER SEPARATOR
62. BLOWDOWN TANK/SUMP
63. PIG LAUNCHER (CO_2)
64. CIRCULATING WATER PUMPS
65. PLANT SUMP
66. AIR INLET FILTER HOUSE
67. CO_2 METERING
68. LEAN AMINE TANKS
69. RICH AMINE TANK
70. NATURAL GAS METERING
71. HRSG CHEM FEED SKID
72. CO_2/N_2 STORAGE
73. DEMIN TRAILERS (BY OTHERS)
74. STG LUBE OIL SKID
75. CTG LUBE OIL SKID
76. WATER TREATMENT PLANT
77. GATE HOUSE
78. OFFICE BLOCK
79. LOCKERS, WELFARE AND TRAINING
80. DEGRADED AMINE TANK
81. STANDBY DIESEL GENERATOR
82. MAIN POWER DISTRIBUTION CENTER (PDC)
83. MV/LV POWER DISTRIBUTION CENTER (PDC)
84. UTILITIES
85. AMINE MAINTENANCE TANK

NOTES

1. CO_2 HAZARD ZONE FROM 'ASSESSMENT OF THE MAJOR HAZARD POTENTIAL OF CARBON DIOXIDE (CO_2)', BY DR PETER HARPER, PUBLISHED BY SSE.MV/LV POWER DISTRIBUTION CENTER (PDC)

REV	REVDATE	REVISION DESCRIPTION	PREP	CHK	ENG	APP
A07	30-06-17	RE-ISSUE FOR USE	JB	MW	MW	
A06	27-04-17	RE-ISSUE FOR USE	JB	MW	MW	
A05	17-02-17	ISSUE FOR USE	JB	MW	MW	
A04	21-12-16	ISSUE FOR ETI REVIEW	MW		MW	
A03	12-12-16	ISSUE FOR PEER REVIEW	MW		MW	
A02	12-11-16	ISSUE FOR ETI REVIEW	MW		MW	
A01	04-11-16	ISSUE FOR INTERNAL REVIEW	MW		MW	

SNC·LAVALIN

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TITLE

PLANT FOOTPRINT
OPTION 1

REV

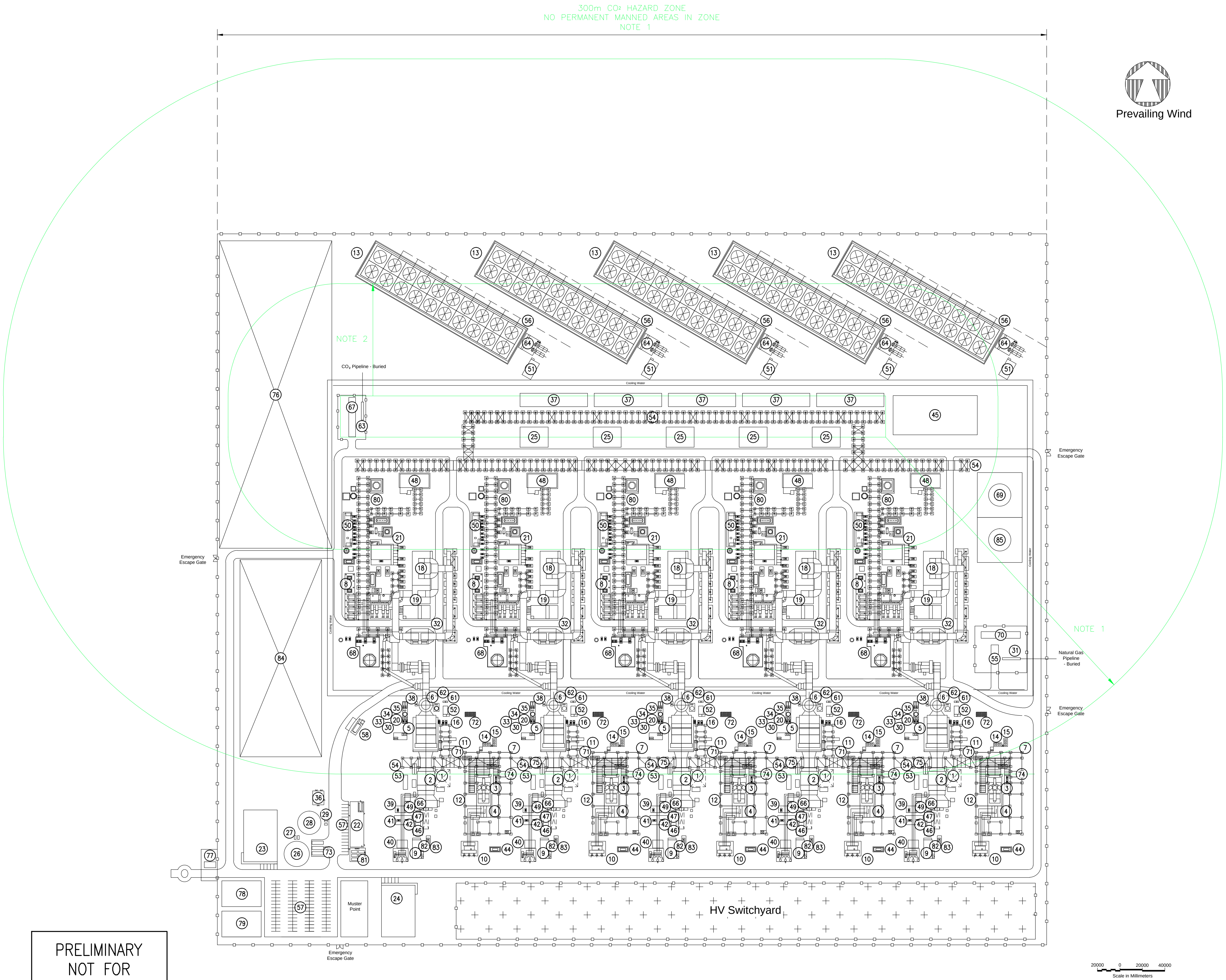
A07

DWG NUMBER

181869-0001-D-EM-BLK-AAA-00-00001-01

PRELIMINARY
NOT FOR
CONSTRUCTION

Attachment 6 – Footprint of CCGT + CCS Plant - Option 2



PRELIMINARY
NOT FOR
CONSTRUCTION

LEGEND:

1. GAS TURBINE (GT)
2. GAS TURBINE GENERATOR (GTG)
3. STEAM TURBINE (ST)
4. STEAM TURBINE GENERATOR (STG)
5. HEAT RECOVERY STEAM GENERATOR (HRSG)
6. EXHAUST STACK
7. STG BUILDING
8. ION EXCHANGE UNIT
9. GTG MAIN TRANSFORMER
10. STG MAIN TRANSFORMER
11. BOILER FEED PUMPS
12. CONDENSATE PUMPS
13. COOLING TOWERS
14. CLOSED COOLING WATER PUMPS
15. CLOSED COOLING HEAT EXCHANGER
16. ECONOMIZER RECIRC PUMPS
17. AUXILIARY BOILER W/ FEEDWATER/DA SKID
18. ABSORBER TOWER
19. DIRECT CONTACT COOLER
20. ELECTRIC SUPERHEATER
21. CO_2 STRIPPERS
22. ADMIN & CONTROL BUILDING
23. WAREHOUSE BUILDING
24. WORKSHOP BUILDING
25. CO_2 COMPRESSION
26. DEMINERALISED WATER TANK
27. DEMINERALISED WATER PUMPS
28. RAW/FIRE WATER TANK
29. SERVICE WATER PUMPS
30. ANTI-ICING SKID W/ CONDENSATE PUMPS
31. FUEL GAS METERING AREA
32. GAS-GAS HEAT EXCHANGER
33. FUEL GAS PERFORMANCE HEATER
34. FUEL GAS SCRUBBER/START-UP HEATER
35. FUEL GAS COALESCING FILTER
36. FIREWATER, DIESEL, ELECTRIC AND JOCKEY PUMPS
37. CO_2 DEHYDRATION
38. CEMS ENCLOSURE
39. GENERATOR CIRCUIT BREAKER
40. UNIT AUXILIARY TRANSFORMER
41. ISOLATION TRANSFORMER
42. CT EXCITATION TRANSFORMER
43. UTILITIES AND AMINE STORAGE
44. ST EXCITATION TRANSFORMER
45. ELECTRICAL SUB-STATION (COMPRESSION)
46. CT EXCITATION COMPARTMENT GENERATOR
47. LCI EXCITER COMPARTMENT
48. ELECTRICAL SUBSTATION (CARBON CAPTURE)
49. BATTERY COMPARTMENT
50. THERMAL RECOVERY UNIT
51. COOLING TOWER POWER DISTRIBUTION CENTER (PDC)
52. HRSG POWER DISTRIBUTION CENTER (PDC)
53. PACKAGED ELECTRONIC/ELECTRIC CONTROL COMPARTMENT (PEECC)
54. PIPE RACK
55. PIG RECEIVER (NATURAL GAS)
56. COOLING TOWER BASIN
57. CAR PARKING
58. AQUEOUS AMMONIA TANK
59. DAMPER SEAL AIR FANS
60. BOOSTER FANS
61. OIL/WATER SEPARATOR
62. BLOWDOWN TANK/SUMP
63. PIG LAUNCHER (CO_2)
64. CIRCULATING WATER PUMPS
65. PLANT SUMP
66. AIR INLET FILTER HOUSE
67. CO_2 METERING
68. LEAN AMINE TANKS
69. RICH AMINE TANK
70. NATURAL GAS METERING
71. HRSG CHEM FEED SKID
72. CO_2/N_2 STORAGE
73. DEMIN TRAILERS (BY OTHERS)
74. STG LUBE OIL SKID
75. CTG LUBE OIL SKID
76. WATER TREATMENT PLANT
77. GATE HOUSE
78. OFFICE BLOCK
79. LOCKERS, WELFARE AND TRAINING
80. DEGRADED AMINE TANK
81. STANDBY DIESEL GENERATOR
82. MAIN POWER DISTRIBUTION CENTER (PDC)
83. MV/LV POWER DISTRIBUTION CENTER (PDC)
84. UTILITIES
85. AMINE MAINTENANCE TANK

NOTES

1. CO_2 HAZARD ZONE FROM 'ASSESSMENT OF THE MAJOR HAZARD POTENTIAL OF CARBON DIOXIDE (CO_2)', BY DR PETER HARPER, PUBLISHED BY HSE (300m).
2. LOWER DISPERSION DISTANCE FROM STUDIES (100m)

REV	REVDATE	REVISION DESCRIPTION	PREP	CHK	ENG	APP
A07	30-06-17	RE-ISSUE FOR USE	JB	MW	MW	
A06	25-05-17	RE-ISSUE FOR USE	FR	MW	MW	
A05	17-02-17	ISSUE FOR USE	JB	MW	MW	
A04	21-12-16	ISSUE FOR ETI REVIEW	MW		MW	
A03	12-12-16	ISSUE FOR PEER REVIEW	MW		MW	
A02	12-11-16	ISSUE FOR ETI REVIEW	MW		MW	
A01	04-11-16	ISSUE FOR INTERNAL REVIEW	MW		MW	

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TITLE

PLANT FOOTPRINT
OPTION 2

REV

A07

DWG NUMBER

181869-0001-D-EM-BLK-AAA-00-00001-01

\\sli0524\sli0524_PROJECTS$\181869\0001\Interim\CADD\Plotplan\A07\181869-0001-D-EM-LAY-AAA-00-00001-01_A07.dwg30/06/2017 14:57:45Burns, Jackie

Attachment 7 – Connections

High Voltage Connection

The power connection costs include a build up for a double circuit in overhead line transmission. The build up includes equipment, material, and installation unit rates, along with HV connections at National Grid substation and at the power plant.

The selections for the project are all overhead lines.

Site	Number of Trains				
	1	2	3	4	5
Teesside	£11,998,840	£12,617,919	£13,236,998	£13,856,077	£14,475,156
North West / North Wales	£4,673,300	£4,700,512	£4,727,724	N/A	N/A
North Humber	£22,360,483	£23,816,340	£25,272,196	£26,728,052	£28,183,908
South Humber	£4,273,500	£4,273,500	£4,273,500	£4,273,500	£4,273,500
Scotland	£4,273,500	£4,273,500	£4,273,500	N/A	N/A

Natural Gas Pipeline

The pipelines are costed using spreadsheets developed on previous projects. The routing includes costs for different types of crossings and characterisation of terrain.

Design Conditions

Natural Gas
Pipe Conditions – NATURAL GAS SUPPLY

Design Pressure	85 barg
Operating Pressure	45 barg to 65 barg
Design Temperature	85°C
Operating Temperature	1 to 38°C
Flow Rate	157.5 Nm^3/sec
Composition	Per section 11.1 of the Basis of Design

Material Selection

The selected material for the line pipe is carbon steel of L450 MO grade to BS EN ISO 3183 (Equivalent to API 5L X65).

Mechanical Design

The pipeline mechanical design has been carried out by SNC-Lavalin's pipelines team using the information from the sub-sections above.

Pipeline Wall Thicknesses (mm)					
	Teesside	North West / North Wales	North Humber	South Humber	Scotland
Natural Gas Onshore	11.56	11.56	11.56	11.56	11.56

5-4-3-2-1

The sizing of the pipelines for Natural Gas is summarised in the following table:

Train	5	4	3	2	1	
Flow	2.36	1.888	1.416	0.944	0.472	Am^3/sec
Size	24	20	18	14	10	inch
Thickness	12.7	12.7	9.53	9.53	9.53	mm

Cost Estimate

Site	Number of Trains				
	1	2	3	4	5
Teesside	£2,587,982	£2,988,748	£3,389,515	£4,004,567	£4,492,063
North West / North Wales	£472,527	£555,886	£639,245	N/A	N/A
North Humber	£813,539	£965,900	£1,118,260	£1,322,031	£1,501,078
South Humber	£1,217,379	£1,445,641	£1,673,904	£2,003,344	£2,276,639
Scotland	£6,603,139	£7,445,516	£8,287,894	N/A	N/A

Water Intake and Treated Water Outfall

The power generation and carbon capture plants require cooling for plant operation. Cooling is provided by a closed circuit cooling water system using wet mechanical draft cooling towers. There are evaporation, drift, and blow down losses that need to be made up: the make up water is supplied from a nearby water source through a pipe. A pumping station is provided in order to generate sufficient pressure to feed the plant.

Blow down and contaminated water goes from the power generation and carbon capture units to the water treatment plant. Some of the water is treated and recycled: the remainder however will require discharge after treatment. A pipe is provided for this discharge.

The water flow rates are taken from Utilities Schedule developed for the project. The treated water discharge has been taken from the Peterhead project and scaled up for the Generic Business Case.

In discussion with the Construction team PE material was selected for the water pipelines: it is routinely used for water services in the UK and selected grade is suitable for the operating pressures.

A pumping station will provide pressure to the water intake to supply water to the plant. The pumping station is of concrete construction with inlet gates, inlet screens, and pump wells for each pumps. The water pumps are vertical centrifugal type with 1 pump per train plus a spare. The screens are provided with Acoustic Fish Deterrents to help prevent fish being ingested into the screens. An electrical substation is provided within the pump station with switchgear for the pumps and low voltage users.

	Flow	Pressure	Absorbed Power	Motor Size
	kg/hr	bara	kW	kW
Teesside	1,307,592	3.00	128	150
North West / North Wales	1,307,592	2.65	111	150
North Humber	1,307,592	6.55	325	340
South Humber	1,307,592	4.15	189	220
Scotland	1,307,592	2.65	111	150

Water Intake

Site	Number of Trains				
	1	2	3	4	5
Teesside	£13,957,202	£15,694,709	£17,499,543	£19,186,030	£20,907,602
North West / North Wales	£13,530,242	£15,153,377	£16,821,395	N/A	N/A
North Humber	£49,537,262	£59,623,982	£71,416,276	£80,210,466	£89,893,437
South Humber	£15,943,862	£18,138,861	£20,490,952	£20,490,952	£24,724,715
Scotland	£12,491,468	£13,885,860	£15,280,252	N/A	N/A

Treated Water Outfall

Site	Number of Trains				
	1	2	3	4	5
Teesside	£1,194,377	£1,214,283	£1,246,406	£1,322,503	£1,389,025
North West / North Wales	£877,155	£896,847	£928,702	N/A	N/A
North Humber	£28,142,923	£28,178,415	£28,230,124	£28,359,404	£28,460,726
South Humber	£2,702,863	£2,723,623	£2,756,819	£2,835,831	£2,904,259
Scotland	£3,229	£3,229	£3,229	N/A	N/A

Common Elements

Each of the connections includes percentage allowances for:

› Construction Management & Controls
› Site Engineering and Detailed Design
› Survey Costs
› CDM Co-ordination
› Insurance
› Third Party Verification and Certification
› Logistics (Helicopters, standby boats supply boats catering etc)
› Interface Engineering
› Consents & Permits

The percentage allowances are based on estimates from previous projects.

Contingency

Contingency is located elsewhere in the estimate.

Attachment 8 – Inventory of Hazardous Substances

Inventories of Hazardous Substances

The following are estimated inventories for hazardous substances. Unless covered by design the inventories are assumed as 7 days consumption for a 5 train plant:

Substance	Tonnes	Notes
Carbon Dioxide (CO_2)	598	Process Fluid
Natural Gas	15	Fuel
Amine	37,306	Working Fluid
Aqueous Ammonia	132	Selective Catalytic Reduction
47WT% Caustic Storage	3,150	Demineralisation Package, TRU, IX Package, Water Treatment"
Concentrated Sulphuric Acid	150	Acid Wash and Water Treatment
Hydrogen	7	Hydrogen for generator cooling Potentially over COMAH threshold for lower tier site (COMAH 15, Schedule 1, Part 2)
Oils	2,495	Machinery Lubrication and Transformer Oils
HCl	0.3	Demineralisation Package
Methanol	52	Water Treatment
Acetic Acid	71	Water Treatment
Sodium Bicarbonate	228	Water Treatment
Phosphoric Acid	77	Water Treatment
Anti Scalant	6	Water Treatment
Tracer	0.05	Tracer Dosing
Oxygen Scavenger	0.2	Boiler Feedwater
Phosphate	1	Boiler Feedwater
Alkali	16	Boiler Feedwater
Corrosion Inhibitor	5	Boiler Feedwater
Diesel	37	Emergency Generators and Fire Water Pumps

The following are the estimated pipeline inventories:

Location	Tonnes
Carbon Dioxide	
Teesside	37,790
North West / North Wales	3,432
South Humber	24,626
North Humber	23,144
Scotland	
Natural Gas	
Teesside	76
North West / North Wales	9
South Humber	23
North Humber	40
Scotland	

Attachment 9 – Owner and Contractor Costs

CLIENT:	ETI
PROJECT:	Thermal Power with CCS
LOCATION:	Croydon
Project NO.:	181869

Contractor's and Owner's Cost Breakdown

Thermal Power with CCS	Contractor Soft Costs			
	Percentage applied to Engineering, Procurement and Construction for CCGT, CCC, Facilities & Utilities	**Percentage applied to Engineering, Procurement and Construction for Site Enabling**	**Estimate Quality**	**Source**
Profit	7.00%	7.00%	1	SNC-Lavalin published profit target - http://ca.reuters.com/article/businessNews/idCAKBN1691N9
Permitry, Technology Licenses	0.70%	0.20%	2	EPC project data
Bonds	0.20%	0.20%	2	EPC project data
Insurance	0.50%	0.50%	2	EPC project data
Materials and Spare Parts	0.00%	0.00%		included in detailed estimates
Vendor Representatives	0.44%	0.00%	2	EPC project data
Site Services/Indirect Field Costs				
Construction Equipment and Tools	0.68%	0.51%	2	EPC project data
Construction Management and Supervisio	6.05%	4.54%	2	EPC project data
Construction Services	0.71%	0.53%	2	EPC project data
Project Management and Administration				
Project Management and Administration	3.09%	2.32%	2	EPC project data
Printing and Stationary	0.06%	0.05%	2	EPC project data
Communications	0.04%	0.03%	2	EPC project data
IT	0.32%	0.24%	2	EPC project data
Contractor's Contingency	10.00%	10.00%	2	EPC project data
Total	**29.80%**	**26.12%**		
Contractor's Commissioning	2.08%	1.80%	2 and 4	compared to prior project for fills and subcontracts, factor used for labour

Thermal Power with CCS	Owner's Costs			
	Percentage applied to Engineering, Procurement and Construction for CCGT, CCC, Facilities & Utilities	**Percentage applied to Engineering, Procurement and Construction for Site Enabling**	**Estimate Quality**	**Source**
Environmental/Regulatory Permitting, Site Permitry Oversight, Licensing (Excl. Technology license)	0.40%	0.40%	2 and 4	Peterhead Cost Estimate percentages
Legal Costs	0.50%	0.50%	2 and 4	Peterhead Cost Estimate percentages
Project Management Oversight and Adminis	1.50%	1.50%	2 and 4	Peterhead Cost Estimate percentages
Owner's Engineers and Operators	3.60%	1.80%	2 and 4	Peterhead Cost Estimate percentages
Insurance	1.20%	1.20%	2 and 4	Peterhead Cost Estimate percentages
Third Party Verification, HSSE	1.50%	0.50%	2 and 4	Peterhead Cost Estimate percentages
Owner's Specific Activity Allowance and Mis	0.60%	0.60%	2 and 4	Peterhead Cost Estimate percentages
Total	9.30%	6.50%		
Owner's Commissioning	1.80%	0.00%		Public data, Peterhead shared knowledge documents

Attachment 10 – Basis of Estimate

SNC-LAVALIN UK OPERATIONS

BASIS OF ESTIMATE

Document No: **181869-0001-T-PS-DBS-AAA-00-00001**

1 OF 15

Revision **: A03** Date **: 17-FEB-2017**

This document has been electronically checked and approved. The electronic approval and signature can be found in FOCUS, cross referenced to this document under the Tasks tab, reference No: T072894.

A03	17-Feb-2017	Issued for Use	S. DURHAM	M. WILLS	S. DURHAM	M. WILLS
A02	09-Feb-2017	Issued for Peer Review	S.DURHAM			
A01	03-Feb-2017	Issued for Internal Review	S. DURHAM	M. WILLS	S. DURHAM	M. WILLS
REV	**DATE**	**ISSUE DESCRIPTION**	**BY**	**DISC CHKD**	**QA/QC**	**APPVD**

REVISION	COMMENTS
A01	Issued for Internal Review
A02	Issued for Peer Review
A03	Issued for Use Peer review comments included.

HOLDS	
HOLD DESCRIPTION / REFERENCE	
Section 5.2	Estimating Uncertainty
Section 5.2.1.3	HOLD, - Quote from OEM

TABLE OF CONTENTS

1.0 INTRODUCTION

Gas-turbine combined-cycle (CCGT) power generation using natural gas fuel is considered the cleanest and most efficient power generating plant design in comparison with other fossil-fuel-burning alternatives. CCGT plants have the following advantages compared to other power plant designs:

- CCGT plants have been proven to b able to be constructed quickly, such as Pembroke CCGT construction complete in 26 months, and provide a stable source of electricity;
- Higher cycle efficiency;
- Load-absorbing capability to allow grid stability when working alongside a growth in renewable energy sources;
- Use of gas fuel (both natural gas and shale gas) supplied by existing National Grid infrastructure.

The ETI's energy system modelling work has shown that Carbon Capture and Storage (CCS) is one of the most potent levers to help the UK meet its 2050 CO_2 reduction targets: Without CCS the energy system cost in 2050 could be £30bn per annum higher (reference document 1).

Carbon Capture and Storage (CCS) will allow fossil fuel sources to continue to be used for power generation by eliminating CO_2 emissions to atmosphere. The UK has the geology and infrastructure to allow efficient implementation of CCS.

It is believed that the economic viability of CCS will be enhanced by the use of the new J Class and larger H-Class Gas Turbines. J-Class and larger H-Class turbines have an approximate combined cycle output of approximately 500MW.

The ETI issued a Request for Proposals for a Thermal with CCS Project – Generic Business Case on 31st May 2016. SNC-Lavalin successfully bid for the work in a team with AECOM and the University of Sheffield.

1.1 Purpose

The Basis of Estimate (BOE) has been developed to provide the methodology for estimating the CAPEX, OPEX, and decommissioning costs for the Thermal Power with CCS project. The basis of estimate supports and attempts to underpin the Estimate capturing the Scope of Work within the limits of the scope capture at Concept design phase. The BOE provides a breakdown of how the estimate has been derived based upon the given Scope of Work and specified constraints and assumptions.

1.2 Scope

This document covers the Engineering, Design, Procurement, Transportation, Construction, Commissioning, and Operations, Maintenance, Decommissioning, and Abandonment of the CCGT Power Plant with Carbon Capture and Storage Capability.

1.3 Definitions

Class of Estimate: Estimate classes are characterised within the Association for the Advancement of Cost Engineering International (AACEI) 18R-97 guidelines. The following table summarises the accepted classes of estimate:

	Primary Characteristic	Secondary Characteristic			
ESTIMATE CLASS	**LEVEL OF PROJECT DEFINITION** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges(a)	**PREPARATION EFFORT** Typical degree of effort relative to level to least cost index of (b)
Class 5	0% to 2%	Concept Screening	Capacity Factored Parametric Models, Judgment or Analogy	L:-20% to -50% H:+30% to +100%	1
Class 4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L:-15% to -30% H:+20% to +50%	2 to 4
Class 3	10% to 40%	Budget Authorization or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	L:-10% to -20% H:+10% to +30%	3 to 10
Class 2	30% to 70%	Control or Bid/Tender	Detailed Unit Costs with Forced Detailed Take-Off	L:-5% to -15% H:+5% to +20%	4 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Costs with Forced Detailed Take-Off	L:-3% to -10% H:+3% to +15%	5 to 100
Notes	(a) The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope				
	(b) If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools				

1.4 Responsibility

The creation and revision of this document is the responsibility of the Project Controls Manager.

2.0 ABBREVIATIONS

Abbreviation	Description
AACEI	Association for the Advancement of Cost Engineering International
BCIS	Building Cost Information Service
BOE	Basis of Estimate
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
DBEIS	Department for Business, Energy and Industrial Strategy
ETI	Energy Technologies Institute
EU	Estimating Uncertainty
FEED	Front End Engineering and Design
GBC	Generic Business Case
GT	Gas Turbine
H	High
HRSG	Heat Recovery Steam Generator
KKD's	Key Knowledge Deliverables
L	Low
MTO	Material Take Off
NAECI	National Agreement for the Engineering Construction Industry
NJC	National Joint Council for the Engineering Construction Industry
OEM	Original Equipment Manufacturer
OPEX	Operational Expenditure
STG	Steam Turbine Generator
TIC	Total Installed Cost
UCATT	Union Of Construction Allied Trades & Technicians

3.0 REFERENCE DOCUMENTS

Document Number	Document Title
181869-0001-T-EM-SPE-AAA-00-00001	Template Plant Specification
181869-0001-T-EM-MEL-AAA-00-00001	Major Equipment List
181869-0001-T-PC-CAL-AAA-00-00001	Benchmarking Data
181869-0001-SLI-C-MOM-ETI-0011	Contract Strategy Design

Document Number	Document Title
3935-MMG-E	Cost Estimating

4.0 CODES AND STANDARDS

Document Number	Document Title
(AACEI) 18R-97	Cost Estimate Classification System – as Applied in Engineering, Procurement, and Construction for the Process Industries

5.0 ESTIMATE METHODOLOGY

In this section, the components of the estimate are broken down by plant area and major system. The detail of the estimate will vary by system, becoming greater as the particulars of the systems and equipment required become more defined.

Estimate modelling techniques and factors to be used on this project may include Lang Factors, analogous modelling, parametric modelling, bottom up estimating, and vendor quote analysis.

The Construction component of the estimate is classified as a Class 4 overall; however, budgetary estimates will be requested from vendors for some major equipment items where sufficient technical detail is available and vendors are willing to participate. Other major equipment costs will be available from recent interactions with vendors and cost information available to SNC-Lavalin.

The Design/Engineering and Management component of the estimate is Class 4, Design/Engineering is where possible by Level of Effort/Apportioned Effort/Task Analysis

Resource estimates are either based on assessment of project requirements spread over durations, i.e., Level of effort/apportioned effort, this includes all Management, or based on benchmarked estimate data for like equipment and/or tasks from SNC-Lavalin estimating databases.

An independent arithmetic check is performed when inserting costs/resources into the spreadsheet model. Any errors, discrepancies found are addressed. A Notes Tab in the spreadsheet provides an audit tracker on any changes and build up of the estimate throughout the estimate generation process.

5.1 Estimating Approach

The flow of information for the cost modelling work can be seen in the following figure:

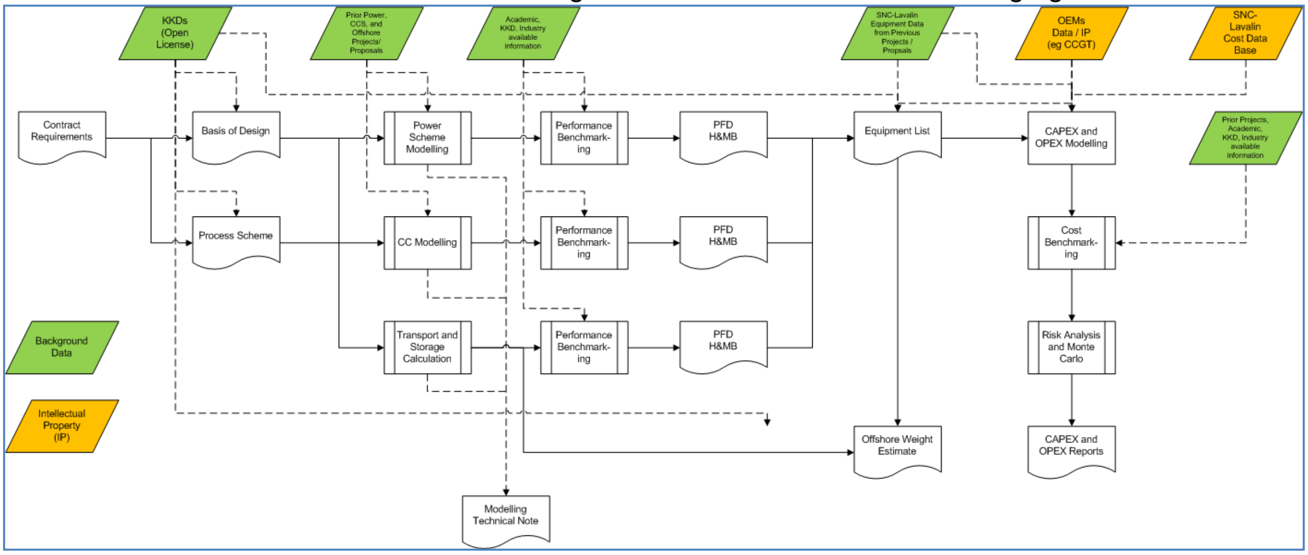


Figure 1 – Flow of Information

Estimate classes are characterised within the Association for the Advancement of Cost Engineering International (AACEI) 18R-97 guidelines. An estimate based on a concept study with a project definition between 1 and 15% would be categorised as a Class 4 Estimate, meaning the overall accuracy could be expected as -15% to – 30% and +20% to +50%. A Class 4 estimate is prepared when available documentation includes process flow diagrams, plant capacity, block schematics, layouts, and major equipment lists. With this level of estimate, costs are most often built up using system and equipment costs and applying equipment factors, Lang factors, and estimating norms and benchmarks. There is no requirement for vendor quotes for a Class 4 estimate; however, SNC-Lavalin will approach vendors for budgetary estimates on some pieces of major equipment to provide the highest achievable accuracy based on the level of project definition.

Further unit cost detail will be available based on work planned and executed by SNC-Lavalin on similar projects. As such, the estimate will be further refined by a more detailed unit pricing than is typical in a Class 4 estimate, with budgetary estimates and actual material and subcontract costs from vendors and subcontractors. Reference projects include Shell Peterhead Carbon Capture and Storage, SaskPower Boundary Dam, Rhourde Nousse II, UK power projects, and various power plants designed by the SNC-Lavalin Bothell office. This information will be used only under appropriate license and contractual terms and/or anonymised to ensure confidentiality of intellectual property is retained.

The PEACE model[1] for the Power Plant provide basic cost information / format. This information is overwritten with actual cost information in SNC-Lavalin's possession – e.g. equipment costs, UK material costs, UK labour costs, UK sub-contract costs, UK project management, engineering, construction management team, etc (This information is sourced from previous projects and proposals).

[1] PEACE is a module of our CCGT modelling software (Thermoflow GT PRO) that provides additional inputs to automate the preliminary engineering and cost estimation of the CCGT units, as designed in GT PRO.

The class of estimate will require some of the costing to be market place (e.g. we ask suppliers for information specific to GBC) and a significant amount of the costing will be 2015 / 2016 quotes / prices. A lot of information is unit rate (e.g. absorbers slip form) so it can be used with the GBC dimensions to provide representative costing.

The remaining information will be provided by estimating norms / estimating data base.

5.2 Key Areas of Estimation

The following areas represent the key areas which will build up the body of the estimate. Each area below will be broken into system components and major equipment packages. These areas will further be broken into effort by discipline, which will be rolled into overall manpower based estimates.

5.2.1 CAPEX

5.2.1.1 Pre-Development Costs

Estimation of costs up to Financial Investment Decision Stage gate. The front end (FEED) engineering costs will be estimated using SNC-Lavalin experience on power, carbon capture and storage, process, and pipeline, and offshore projects and benchmarked against Key Knowledge Deliverable data for Peterhead, White Rose, and Kingsnorth for verification.

Also included in the pre-development assessment will be permitry and consenting, including planning and environmental applications and additional owner's costs as specified in Section 6.1. These costs will be estimated using information from the KKD's, as well as estimates from specialist consultants.

5.2.1.2 Site Preparation

The estimate for site preparation assumes a brownfield site with minimum amounts of soil contamination and geotechnical characteristics suitable for heavy industrial usage. The preliminary plant footprint indicates a rectangular site approximately 1000m x 600m, reasonably flat, and requiring only minor earthworks. Brownflield elements can be removed should Greenfield sites be selected. This also includes mobilisation of manpower, and equipment to site, as well as the establishment of site facilities. The estimate has been prepared based on norms generated from SNC-Lavalin price data on Teesside and factored to 2016 rates.

5.2.1.3 Power Generation

Each train of the power generation plant will include the gas turbine (GT), heat recovery steam generator (HRSG), and steam turbine generator (STG) in the CCGT turbine set. <<Budgetary quotes will be obtained through engagement with the OEM's.>>

Costs for smaller pieces of equipment and materials are available from SNC-Lavalin databases based on similar projects undertaken in recent years. Additional costs will be built up using PEACE modelling software, as well as SNC-Lavalin internal estimating norms and benchmarks.

Cost for fuel supply and tie in and cost for tie in to electricity grid will be estimated from available data sources, including National grid and specialist consultants.

5.2.1.4 Carbon Capture, Cooling, and Compression

The carbon capture plant uses Amine to separate carbon dioxide (CO_2) from the exhaust combustion gases produced by burning natural gas in the gas turbine. The carbon capture train consists of major equipment items including the CO_2 absorber, stripper, thermal reclaiming unit, ion exchange unit, and flue gas coolers. Cooling is provided by cooling towers in a closed loop circuit.

Recent information is available from both actual project costs and proposal estimates from work done by SNC-Lavalin for this section of the overall cost estimate. Reference projects include Shell Peterhead Carbon Capture, and Rhoude Nouss II. This information will be used only under appropriate license and contractual terms and/or anonymised to ensure confidentiality of intellectual property is retained.

5.2.1.5 Waste Water Treatment Plant

The waste water treatment plant will be a single system to accommodate all trains. Two streams will be filtered by the waste water treatment plant; one from the direct contact coolers, which contains ammonia, and the second from the CO_2 absorbers, containing an acid wash solution. Vendor information is available for like systems from SNC-Lavalin past projects. Due to the increase in scale, additional vendor enquiry may be required.

5.2.1.6 Plant Utilities

The plant utilities provide the sub-systems required to run the power generation and carbon capture, such as compressed air, nitrogen, and water. Both actual cost and proposal cost estimates are available and scalable to build up the plant utilities estimates. Further recent vendor information is available through the SNC-Lavalin Global Procurement System. Associated piping, electrical, civil, structural, and mechanical work will be estimated based on SNC-Lavalin norms and benchmarks.

5.2.1.7 CO_2 Transportation

CO_2 is transferred by pipeline from the carbon capture plant to the offshore store. If the onshore pipeline is of an extended length then block valve stations will be required in order to safely isolation sections of the pipeline. A booster station may also be required in order to boost the pressure of the CO_2 before sending offshore. The costing of the CO_2 pipeline will be based on price information from White Rose, Peterhead information through DECC, now DBEIS, and prior project information from SNC-Lavalin.

5.2.1.8 Offshore Facilities

CO_2 is stored in an underground saline aquifer deep under the seabed. Injection wells will be drilled to allow the CO_2 to flow into the underground store. The wellheads will either be located on the seabed or will be installed on an offshore platform. SNC-Lavalin has extensive experience in the engineering and estimate preparation of various offshore facilities, including Johan Sverdrup, Cygnus, and Mariner developments. Actual and proposal cost information will be available for the estimate from SNC-Lavalin recent work and will be supplemented with information from public sources and KKDs. Drilling costs are based on benchmark data obtained from SNC-Lavalin databases as well as industry sources and Key Knowledge Deliverables (KKD's).

5.2.1.9 Demobilisation

Demobilisation of temporary site facilities, equipment and staff will be evaluated and included in the overall estimate. Rates will be based on SNC-Lavalin estimating norms applied to durations and quantities established during a constructability review of the planned CCGT + CCS site.

5.2.2 OPEX

SNC-Lavalin will determine the OPEX at a block level: The OPEX will be split into fixed per annum, and variable per MWhr and per start. SNC-Lavalin will consider 'regular' maintenance and expected major refurbishments during the plant lifetime. Plant OPEX costs will be derived following the modelling of the power plant and CCS systems. OPEX costs produced by the modelling software will be compared to benchmark OPEX costs available to SNC-Lavalin from other similar projects, both completed and proposed. OPEX benchmarking is also available in the public domain.

Operating and Maintenance costs will be broken into the following key areas:

- Pre-start-up costs and hand over from EPC contractors
- Operations staffing, operational spare parts, and consumables
- Fuel consumption
- Plant utility and waste costs
- Maintenance and shutdown costs
- Well monitoring, inspection of condition
- Local rates, taxes, insurance, utility tariffs
- Emissions, including CO_2, SO_x, NO_x, and effluents

- Decommissioning and turnover to abandonment contractors

Maintenance and shutdown schedules will be examined during the operations modelling phase of the project and recommendations made on routine maintenance and major shutdown requirements, which will in turn provide estimates for availability and efficiency of the plant.

5.2.3 Commissioning and Start-up

The commissioning and start up estimate will include labour and materials, provision of operations and maintenance training and manuals, critical and operational spare parts, and chemical 'first fills'. Pricing information is available from prior SNC-Lavalin projects, including recent UK power proposal and Peterhead proposal.

5.2.4 Decommissioning and Abandonment

Decommissioning costs will be estimated based on industry data and norms for offshore costs per tonne. North Sea offshore decommissioning is still in a growth stage of development, and significant improvements are being made in both efficacy and efficiency of the processes. Information is available through the public domain and without copyright constraints.

5.3 Risk

SNC-Lavalin have a detailed risk approach including risk review sessions, some of which would be open to the ETI. SNC-Lavalin would generate a risk register for the Generic Business Case (GBC): this would be informed by risk registers from previous proposals / projects. Once the risk register is approved then this would be used in a Monte Carlo simulation to provide P50 and P90 variance.

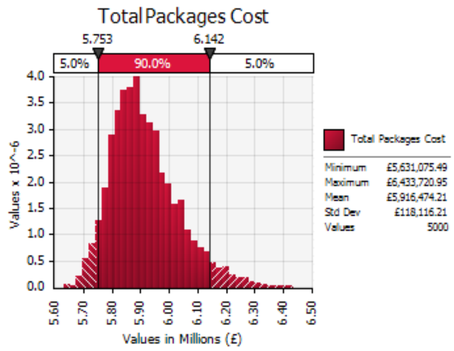


Figure 2 - Monte Carlo Simulation Generated by @Risk for a Project

In order to give credibility what is a real cost estimate? Do potential investors "really" like Commercial Data?
Real project costs tend to escalate between FEED phase and EPC phase because commercial risk and contingency are not usually added at FEED phase.

SNC-Lavalin analyses costs for its own business to understand uncertainties associated with pricing and executing projects. What are the things that keep CEOs and BU Presidents awake at night?:

- Quantities
- Productivity

- Technology
- Commercial (T+Cs) & Claims
- Bid Price Uncertainty

5.4 Contingency

Contingency will be estimated to cover the undefined items of work that may have to be performed or the unexpected cost of items of work within the defined scope of work. The contingency costs by definition include items that may not be reasonable foreseen due to incomplete engineering, areas with a high probability of modification, or items that may change due to lack of data or change in local conditions.

The contingency percentage is chosen through a deterministic approach and the judgement and experience of the project team. The amount of contingency may vary for the different areas of the estimate, such as engineering, procurement of equipment, bulk materials, contractor management, fabrication, and offshore installation.

5.5 Escalation

Accounted for in labour costs and estimated cost of materials.

Costs of labour and materials in Northern UK have risen 3.3% year on year from 2015 to 2016 based on a comprehensive survey of international construction costs undertaken by Turner and Townsend. This study also indicates a further increase of 3.1% in 2017 (Turner and Townsend, 2016).

Some labour unions in the selected areas, including UCATT and Unite the Union, have negotiated rate increases for the coming years of 2.0 to 2.75% (UCATT, 2016) (NJC, 2015).

A BCIS construction briefing published in September 2016 has estimated material cost escalation of 3 to 4% per annum (RICS, 2016).

Based on this information, an escalation factor of 3% per annum will be applied to labour and materials.

6.0 ASSUMPTIONS/CLARIFICATIONS/EXCLUSIONS

6.1 Key Assumptions

- Selected site is relatively free from contamination
- Local labour is available for duration of the project
- Political changes (Brexit) will not significantly alter material and equipment supply and pricing, duties, taxes, or change in laws
- Owners' Costs to be considered:
    - Costs associated with contracting strategy ie) fixed vs target price mark ups
    - Right of way access
    - Permitry and consenting
    - Project insurance, project financing
    - Owners' oversight team costs

    - Brownfield site clearance and remediation
    - Tie-in agreement with utilities
- Contracting and Owner Responsibilities Organised per 181869-0001-T-EM-SPE-AAA-00-00001 and 181869-0001-SLI-C-MOM-EIT-0011

6.2 Exclusions

- Currency fluctuations.
- Acceleration or deceleration of the project schedule.
- Allowance for industrial dispute or lost time arising from industrial actions.
- Costs outside battery limits.
- Project financing.
- Items additional to the specified scope of work
- Acquisition of site
- Infrastructure Costs
- Taxes

6.3 Estimate (Direct, Indirect, Services)

Direct costs consist of firm and budgetary estimates as well as actual cost data for equipment, labour costs against quantities provided by SNC-Lavalin.

Direct labour costs are build up using base rates, fringe benefits and payroll burdens, and where required, overtime and shift premiums, travel and living allowances and seasonal considerations.

Indirects are based on previous estimates and actual cost data, adjusted for site man-loading. Indirect labour costs include basic salary, payroll burdens, and any site uplift, travel, and allowances.

7.0 BENCHMARKS

Cost and price benchmark data has been established for the CCGT and carbon capture and storage phase of the project. Data from SNC-Lavalin prior project has been combined with information in the public sector, including DECC, now DBEIS, the ETI, and MIT to create baseline figures for the estimate. Analysis suggests significant savings as capacity increases.

Further benchmarking figures have been established from like sources for the offshore and onshore pipelines, as well as the offshore facilities. Teesside, White Rose, and National Grid, as well as SNC-Lavalin internal cost and price data have provided the bases for these areas. Though increasing the capacity of the pipeline has little effect on cost, benchmarking on pipelines suggests that the cost more than doubles for doubling the distance of the pipeline due to the increase of control valves, booster stations, and I&C required.

All data within benchmarks have been levelised to 2016 ensure like for like comparison of costs. Benchmarks and the benchmarking source data are available in document 181869-0001-T-PC-CAL-AAA-00-00001 Benchmark Data.

For further scrutiny, the estimate will be tested by a review process similar to SNC-Lavalin Permission to Bid, with reviews being conducted by senior management to ensure it meets the project objectives. The verification of the estimate at this level would cover, at a minimum, order of magnitude values, arithmetic accuracy, and presentation. This review process is followed to ensure a robust and defendable estimate is produced to a high standard.

8.0 WORKS CITED

NJC. (2015, 12 15). *NAECI Review 2016 - 2018 Agreement.* Retrieved 02 01, 2017, from Unite the Union: http://www.unitetheunion.org/uploaded/documents/NAECI%20Rates%20for%20Apprentices%20and%20Salaried%20Employees%202016-201811-26413.pdf

RICS. (2016, 09 06). *BCIS Construction Briefing, September 2016*. Retrieved 02 01, 2017, from http://www.rics.org/uk/knowledge/bcis/about-bcis/construction/bcis-construction-briefing/

Turner and Townsend. (2016). *International Construction Market Survey 2016.* turnerandtownsend.com.

UCATT. (2016, 01 08). *Construction Industry Joint Council: Working Rule Agreement*. Retrieved 02 01, 2017, from UCATT: https://www.ucatt.org.uk/cijc-construction-industry-joint-council-working-rule-agreement

Attachment 11 – Cost Estimate Sheets

CLIENT:	ETI
PROJECT:	Thermal Power with CCS
LOCATION:	Croydon
Project Number	181869
Currency	All Costs in GBP unless otherwise stated

Cost Estimate Summary

Generic Business Case

Thermal Power with CCS		One Train	2 Trains	3 Trains	4 Trains	5 Trains
1.0	Power Generation (CCGT)	581,549,345	1,030,169,593	1,466,523,359	1,894,515,324	2,316,175,085
2.0	Carbon Capture	584,859,032	1,026,176,824	1,480,163,506	1,934,037,167	2,388,560,448
3.0	CO2 Transportation	224,488,663	233,640,883	254,674,734	303,388,525	303,389,214
4.0	Offshore Storage	206,185,776	427,734,607	239,412,976	427,734,607	444,348,207
	Total	1,597,082,816	2,512,786,676	3,440,774,575	4,559,675,623	5,452,472,954
Risk and Contingency		**One Train**	**2 Trains**	**3 Trains**	**4 Trains**	**5 Trains**
	P50	1,766,373,594	2,779,142,063	3,805,496,680	5,043,001,239	6,030,435,087
	P90	1,876,572,308	2,952,524,344	4,042,910,126	5,357,618,857	6,406,655,721

The Generic Business Case is a baseline reference plant against which variances between regional cases can be compared. It assumes minimal site remediation, some modularisation (limited by road access), and no supplemental cost for labour travel. For a reference point, Endurance platform has been used, and CO2 transportation and other connections are based on a Teesside location.

Teesside

Thermal Power with CCS		One Train	2 Trains	3 Trains	4 Trains	5 Trains	Cost Delta to Generic Case - over (under)					Cost Delta
1.0	Power Generation (CCGT)	576,963,960	1,012,492,216	1,438,301,613	1,857,181,526	2,269,390,994	(4,585,385)	(17,677,377)	(28,221,746)	(37,333,798)	(46,784,091)	Modularisation savings, travel cost increase, enabling cost increase
2.0	Carbon Capture	587,653,211	1,021,007,690	1,469,530,209	1,917,939,705	2,366,998,920	2,794,180	(5,169,134)	(10,633,297)	(16,097,463)	(21,561,528)	Modularisation savings, travel cost increase, enabling cost increase
3.0	CO2 Transportation	224,488,663	233,640,883	254,674,734	303,388,525	303,389,214	-	-	-	-	-	
4.0	Offshore Storage	206,185,776	222,799,376	239,412,976	427,734,607	444,348,207	-	-	-	-	-	
	Total	1,595,291,611	2,489,940,165	3,401,919,532	4,506,244,362	5,384,127,335	(1,791,205)	(22,846,511)	(38,855,043)	(53,431,261)	(68,345,619)	Site enabling costs increase for contamination work
Risk and Contingency		**One Train**	**2 Trains**	**3 Trains**	**4 Trains**	**5 Trains**						
	P50	1,764,392,521	2,753,873,823	3,762,523,003	4,983,906,265	5,954,844,832	(1,981,073)	(25,268,241)	(42,973,677)	(59,094,975)	(75,590,255)	
	P90	1,874,467,642	2,925,679,694	3,997,255,450	5,294,837,126	6,326,349,618	(2,104,666)	(26,844,650)	(45,654,675)	(62,781,732)	(80,306,103)	

North Humber

Thermal Power with CCS		One Train	2 Trains	3 Trains	4 Trains	5 Trains	Cost Delta to Generic Case - over (under)					Cost Delta
1.0	Power Generation (CCGT)	653,543,827	1,078,125,025	1,518,577,098	1,950,026,919	2,375,165,938	71,994,482	47,955,432	52,053,739	55,511,595	58,990,852	site enabling and connections increase, travel cost increase
2.0	Carbon Capture	628,944,287	1,080,445,514	1,545,513,220	2,008,912,475	2,473,417,948	44,085,255	54,268,691	65,349,714	74,875,308	84,857,500	site enabling and connections increase, travel cost increase
3.0	CO2 Transportation	130,415,260	142,446,380	155,731,717	186,429,437	186,429,437	(94,073,403)	(91,194,503)	(98,943,017)	(116,959,088)	(116,959,777)	shorter pipeline than Teeside
4.0	Offshore Storage	206,185,776	222,799,376	239,412,976	427,734,607	444,348,207	-	-	-	-	-	
	Total	1,619,089,150	2,523,816,295	3,459,235,010	4,573,103,438	5,479,361,530	22,006,334	11,029,619	18,460,435	13,427,815	26,888,576	
Risk and Contingency		**One Train**	**2 Trains**	**3 Trains**	**4 Trains**	**5 Trains**						
	P50	1,790,712,600	2,791,340,822	3,825,913,921	5,057,852,402	6,060,173,852	24,339,006	12,198,759	20,417,241	14,851,163	29,738,765	
	P90	1,902,429,751	2,965,484,147	4,064,601,137	5,373,396,540	6,438,249,798	25,857,443	12,959,803	21,691,012	15,777,682	31,594,076	

South Humber

Thermal Power with CCS		One Train	2 Trains	3 Trains	4 Trains	5 Trains	Cost Delta to Generic Case - over (under)					Cost Delta
1.0	Power Generation (CCGT)	599,607,468	1,019,229,211	1,453,966,382	1,880,091,386	2,301,708,773	18,058,124	(10,940,382)	(12,556,978)	(14,423,938)	(14,466,312)	lower connection costs, higher travel costs
2.0	Carbon Capture	595,530,247	1,044,841,778	1,506,931,414	1,967,688,292	2,431,388,916	10,671,216	18,664,954	26,767,908	33,651,125	42,828,467	lower connection costs, higher travel costs
3.0	CO2 Transportation	270,372,308	283,209,070	297,377,795	330,096,998	330,096,998	45,883,645	49,568,186	42,703,061	26,708,473	26,707,784	longer CO2 pipeline
4.0	Offshore Storage	206,185,776	222,799,376	239,412,976	427,734,607	444,348,207	-	-	-	-	-	
	Total	1,671,695,800	2,570,079,434	3,497,688,566	4,605,611,283	5,507,542,893	74,612,984	57,292,758	56,913,991	45,935,660	55,069,939	
Risk and Contingency		**One Train**	**2 Trains**	**3 Trains**	**4 Trains**	**5 Trains**						
	P50	1,845,552,163	2,837,367,695	3,861,448,177	5,084,594,857	6,080,327,354	79,178,569	58,225,632	55,951,497	41,593,617	49,892,267	
	P90	1,964,242,565	3,019,843,335	4,109,784,065	5,411,593,258	6,471,362,899	87,670,256	67,318,991	66,873,940	53,974,400	64,707,178	

CLIENT:	ETI
PROJECT:	Thermal Power with CCS
LOCATION:	Croydon
Project Number	181869
Currency	All Costs in GBP unless otherwise stated

Cost Estimate Summary

Northwest

Thermal Power with CCS			One Train	2 Trains	3 Trains
1.0		Power Generation (CCGT)	611,212,593	1,030,501,175	1,466,551,673
2.0		Carbon Capture	679,333,241	1,148,833,187	1,632,714,007
3.0		CO2 Transportation	132,369,214	157,549,509	161,226,606
4.0		Offshore Storage	184,212,377	194,377,277	204,542,177
		Total	1,607,127,426	2,531,261,149	3,465,034,464
Risk and Contingency			**One Train**	**2 Trains**	**3 Trains**
		P50	1,774,268,678	2,794,512,308	3,825,398,048
		P90	1,888,374,725	2,974,231,850	4,071,415,495

Cost Delta to Generic Case - over (under)				
29,663,248	331,582	28,314		
94,474,209	122,656,363	152,550,501		
(92,119,449)	(76,091,374)	(93,448,128)		
(21,973,398)	(28,422,098)	(34,870,798)		
10,044,610	18,474,473	24,259,889		
7,895,084	15,370,245	19,901,368		
11,802,417	21,707,506	28,505,369		

Cost Delta
travel costs, lower power gen connections
higher compression costs and travel
shorter CO2 pipelines
smaller offshore platform, fewer wells.

Scotland

Thermal Power with CCS			One Train	2 Trains	3 Trains
1.0		Power Generation (CCGT)	601,460,803	1,011,046,733	1,437,425,420
2.0		Carbon Capture	745,857,726	1,203,532,449	1,676,253,667
3.0		CO2 Transportation	210,295,258	241,983,999	244,628,020
4.0		Offshore Storage	272,366,094	463,644,863	487,579,377
		Total	1,829,979,882	2,920,208,044	3,845,886,483
Risk and Contingency			**One Train**	**2 Trains**	**3 Trains**
		P50	2,020,297,789	3,223,909,681	4,245,858,678
		P90	2,152,056,341	3,434,164,660	4,522,762,505

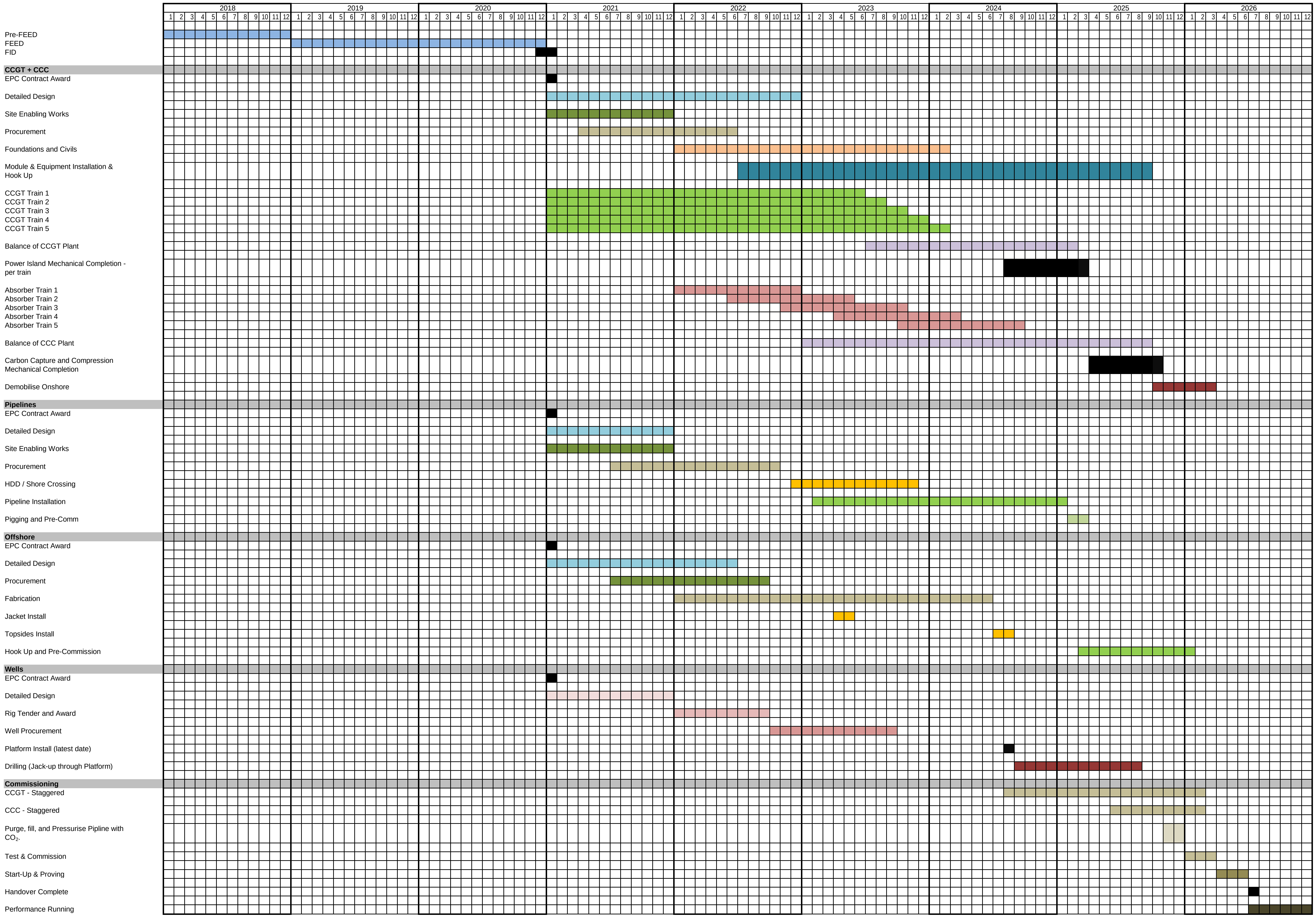
Cost Delta to Generic Case - over (under)				
19,911,458	(19,122,860)	(29,097,939)		
160,998,694	177,355,625	196,090,161		
(14,193,405)	8,343,116	(10,046,714)		
66,180,319	240,845,487	248,166,401		
232,897,066	407,421,368	405,111,909		
253,924,195	444,767,617	440,361,998		
275,484,032	481,640,316	479,852,379		

Cost Delta
modularisation savings, travel costs
additional compression equipment, modularisation savings
shorter pipeline
more wells, additional platform for 2+ units

Attachment 12 – High Level Schedule

EPC SCHEDULE

(Note that this is a key event schedule only to determine start of finish dates of different areas of the plant)



EPC SCHEDULE

(Note that this is a key event schedule only to determine start of finish dates of different areas of the plant)

Notes:
Intent is a single page summary schedule showing key constraints in order to derive overall schedule.

1. Pre-FEED and FEED duration as discussed with the ETI.
   The FEED duration is longer than estimated by SNC-Lavalin (however the longer FEED duration allows for Reservoir Appraisal work)

2. CCGT Duration order to Mechanical Completion was advised by OEM for Class H sized plant.
   It is assumed that the CCGT OEM would be selected before or during FEED so that orders could be placed on day 1 of CCGT + CCS contract.

3. Enabling works and Absorber durations advised by SNC-Lavalin Construction informed by Peterhead proposal.

4. Balance of Plant commences once key equipment installed.
   Intent is not to interfere with efficiency of installation of main equipment items.

5. Assume Mechanical Completion and hand over of CCGT plant to commissioining before handover of CCC plant.

6. Deleted

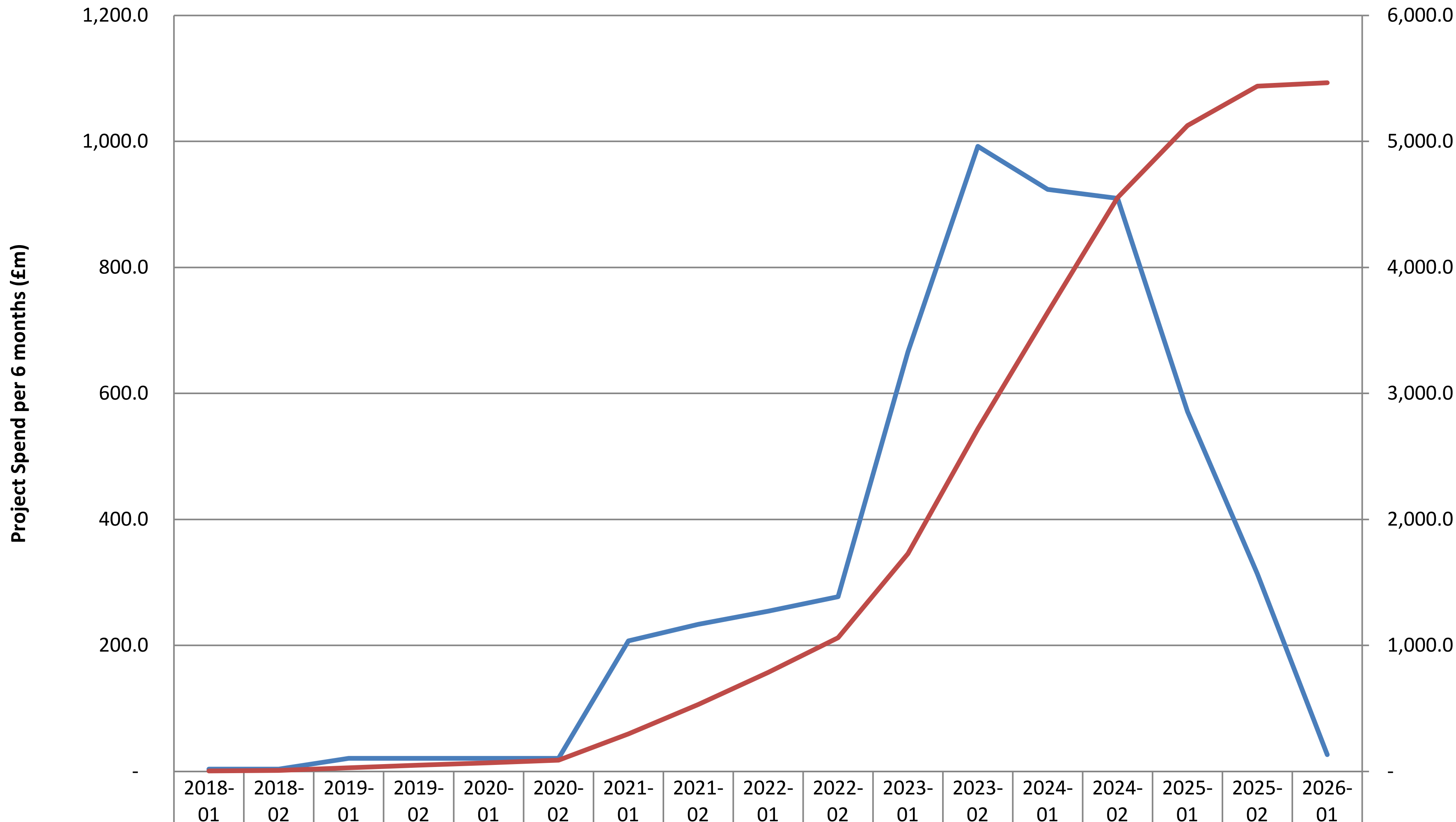
7. Pipelines, offshore, and drilling schedules informed by publically available KKDs.

8. Other connections assumed to be in parallel with Pipelines.

9. Do not know when will have permission for tie ins to existing infrastructure or permissions for crossings. Assumed to be within the scheduling above.

Attachment 13 – Scheduling of Price Through Construction

Thermal Power with CCS
Project Spend Profile
Per 6 month period and cumulative



	2018-01	2018-02	2019-01	2019-02	2020-01	2020-02	2021-01	2021-02	2022-01	2022-02	2023-01	2023-02	2024-01	2024-02	2025-01	2025-02	2026-01
Per period	3.8	3.8	20.6	20.6	20.6	20.6	207.1	233.4	254.5	277.2	666.0	992.0	923.9	909.7	571.2	313.4	26.6
Cumulative	3.8	7.6	28.2	48.8	69.4	90.0	297.1	530.5	785.0	1,062	1,728	2,720	3,644	4,553	5,124	5,438	5,464

Attachment 14 – Risk & Contingency

Thermal Power with CCS – Contingency by Area

Attachment 14 – Contingency Calculations

Summary statistics - Overall		
Probability of meeting base case value	0.46%	
		Contingency
Total budget required for 90.0% confidence	1,781,109,011	5.71%
Contingency required for 50.0% confidence	1,745,689,187	3.60%
P10	1,714,051,965	1.71%

Summary statistics CCGT		
Probability of meeting base case value	6.63%	
		Contingency
Total budget required for 90.0% confidence	459,527,178	7.26%
Contingency required for 50.0% confidence	444,413,711	3.73%
P10	430,570,707	0.50%
Summary statistics CCC		
Probability of meeting base case value	7.80%	
		Contingency
Total budget required for 90.0% confidence	491,368,753	6.77%
Contingency required for 50.0% confidence	475,800,780	3.38%
P10	461,772,116	0.34%

Summary statistics Facilities and Utilities		
Probability of meeting base case value	13.27%	
		Contingency
Total budget required for 90.0% confidence	114,122,661	7.31%
Contingency required for 50.0% confidence	109,746,457	3.20%
P10	105,872,032	-0.44%

Thermal Power with CCS – Contingency by Area

Summary statistics Connection Costs		
Probability of meeting base case value	30.25%	
		Contingency
Total budget required for 90.0% confidence	376,939,428	10.84%
Contingency required for 50.0% confidence	349,892,667	2.89%
P10	329,085,155	-3.23%

Summary statistics Offshore		
Probability of meeting base case value	6.12%	
		Contingency
Total budget required for 90.0% confidence	228,044,403	8.92%
Contingency required for 50.0% confidence	218,834,535	4.52%
P10	210,681,904	0.63%

Summary statistics - Other		
Probability of meeting base case value	35.10%	
		Contingency
Total budget required for 90.0% confidence	110,544,037	13.31%
Contingency required for 50.0% confidence	100,381,368	2.89%
P10	92,001,207	-5.70%

Attachment 14 – Summary Statistics for Contingency by Area

Based on Generic Business Case. Each section includes apportioned site acquisition, front end engineering, connection costs, and facilities and utilities where appropriate. The P10, P50, and P90 values are representative of the percentage of the CAPEX cost that must be added to the estimate in order to have 10, 50, and 90 percent confidence in the total cost.

Probability - Overall Summary	Contingency
Probability of meeting base case value	1.05%
P90	6.22%
P50	3.81%
P10	1.56%

Probability - Carbon Capture	Contingency
Probability of meeting base case value	8.05%
P90	7.52%
P50	3.66%
P10	0.28%

Probability - Carbon Capture	Contingency
Probability of meeting base case value	8.89%
P90	7.07%
P50	3.44%
P10	0.13%

Probability – CO2 Transportation	Contingency
Probability of meeting base case value	
P90	12.23%
P50	2.49%
P10	-4.88%

Probability - Offshore	Contingency
Probability of meeting base case value	
P90	9.80%
P50	5.36%
P10	1.43%

Attachment 14 –Risk and Contingency Profiles

Risk profile

Capex Threats (FIN)			
Project Name:		**Project Number:**	
File Name:	REVISED 19052017.xlsx	**Capital Cost:**	GBP 1600 m
Date:	Friday, May 19, 2017	**Operational Cost/Year:**	GBP m/y

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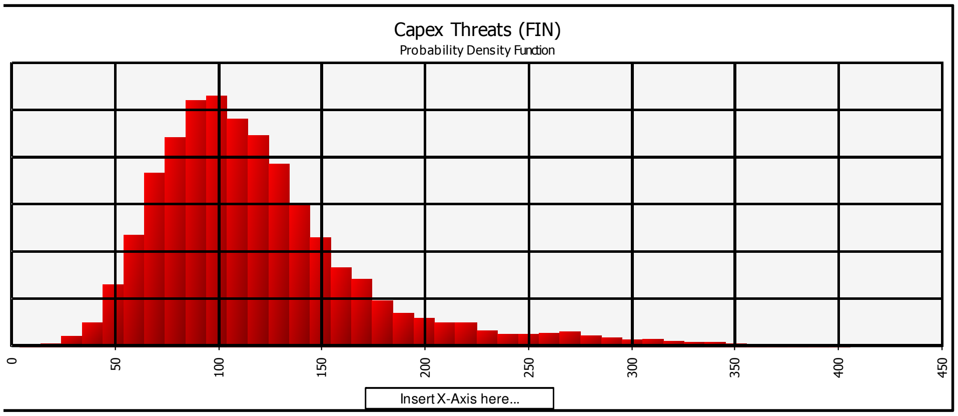
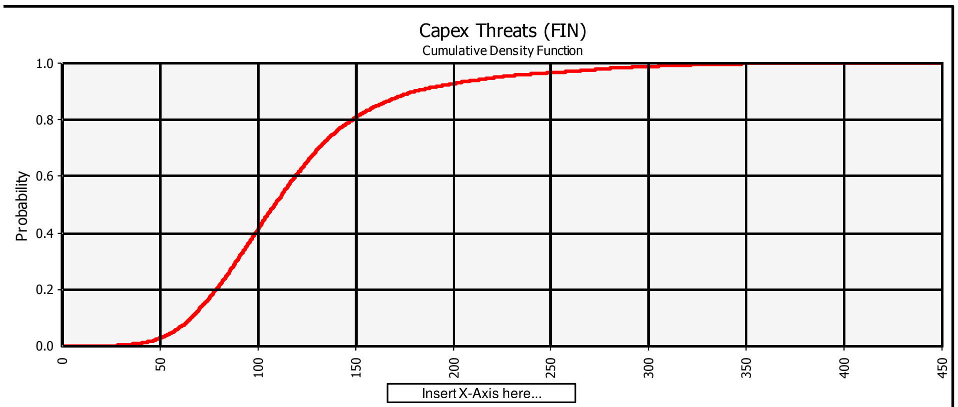
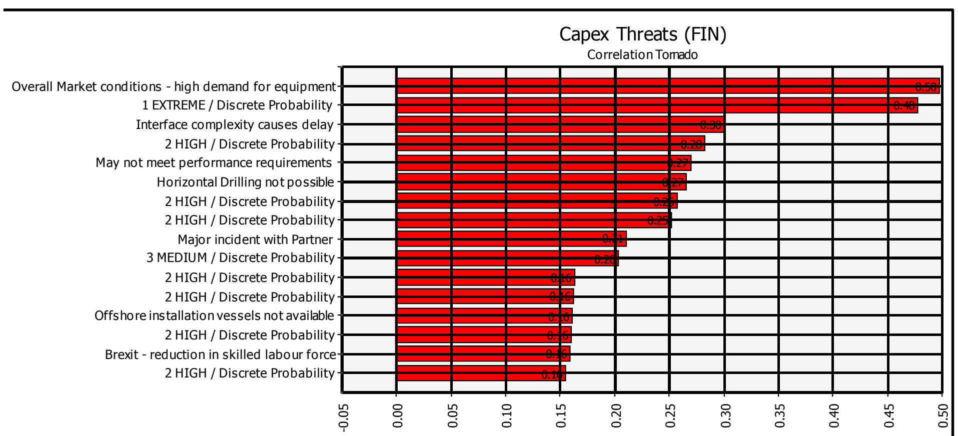


Percentiles	Values	Risk Value
5%	56.51378302	3.5%
10%	66.06179769	4.1%
15%	72.78661177	4.5%
20%	78.69876092	4.9%
25%	84.35069416	5.3%
30%	89.12885644	5.6%
35%	93.91896283	5.9%
40%	98.82828125	6.2%
45%	103.5202307	6.5%
50%	108.7459708	6.8%
55%	113.8540621	7.1%
60%	119.289095	7.5%
65%	125.0057932	7.8%
70%	131.0641545	8.2%
75%	138.6826193	8.7%
80%	148.3671799	9.3%
85%	160.9372697	10.1%
90%	180.0567318	11.3%
95%	221.6890947	13.9%

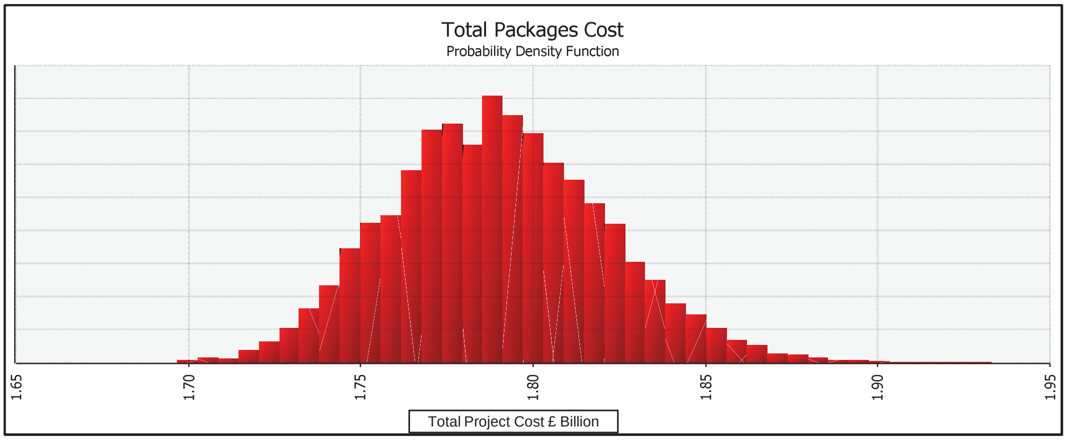




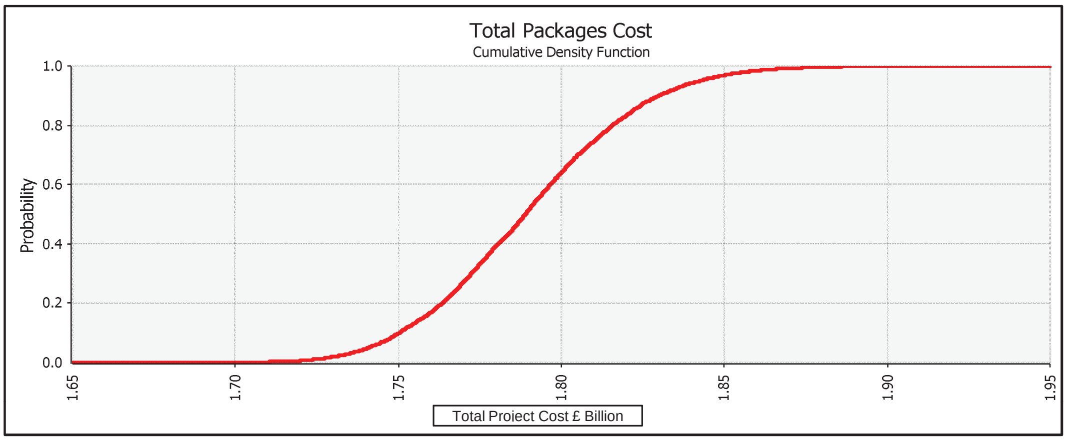
Attachment 14 - Risk and Contingency Profiles

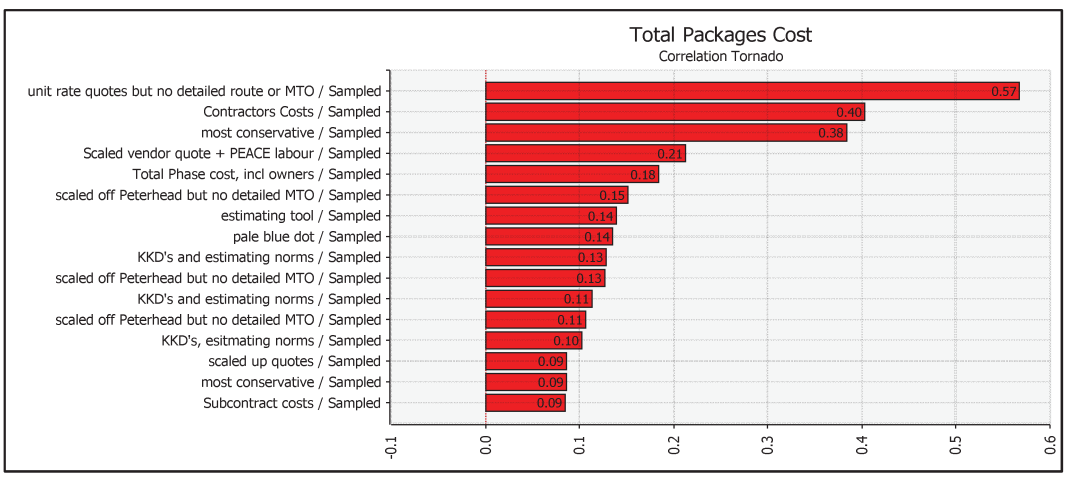
Contingency Analysis

Project Name:	Thermal Power with CCS Generic Business Case	**Project Number:**	181869
File Name:	Contingency Calculations 26 July 2017.xlsx		
Date:	Wednesday, July 26, 2017		



Percentiles	Values		Risk
5%	£	1,740,845,393	1.1%
10%	£	1,750,230,304	1.6%
15%	£	1,757,474,552	2.0%
20%	£	1,763,486,046	2.4%
25%	£	1,768,205,577	2.6%
30%	£	1,772,404,829	2.9%
35%	£	1,776,548,848	3.1%
40%	£	1,780,693,526	3.4%
45%	£	1,785,201,164	3.6%
50%	£	1,788,955,087	3.8%
55%	£	1,792,679,737	4.1%
60%	£	1,796,568,497	4.3%
65%	£	1,800,853,089	4.5%
70%	£	1,805,068,722	4.8%
75%	£	1,810,383,071	5.1%
80%	£	1,815,677,505	5.4%
85%	£	1,821,917,762	5.8%
90%	£	1,830,118,750	6.2%
95%	£	1,842,752,418	7.0%





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Risk Register

Risk Type: Financial **Component: All**

ID	Exposure Activity	Exposure Status	Risk ID	Component	Risk Title/Possible Outcome	Risk Description	Threat/Opportunity	Risk Status	Estimated Consequence (m's or days)	Qualitative Assessment			Post-Mitigation	
										Consequence	Probability	Manageability Exposure	Probable Consequence	Risk Level
1.	Technical	Active	1.1.		Scaled up technology does not perform as expected	Scale up of the CO2 technology has not been proven	T	Active	30.00	Very High	Medium	Medium	GBP 7.2 m	3 MEDIUM
			1.2.		Unforeseen challenges in commissioning phase	Lack of familiarity with the technologies within the consortium	T	Active		Medium	High	High	GBP 6.75 m	3 MEDIUM
			1.3.		Greater number of wells may be required		T	Active	17.50	Very High	Medium	Low	GBP 5.6 m	3 MEDIUM
			1.4.		Better engineered solvent	Any of the suppliers may come up with more efficient solvent - could reduce equipment size	O	Active		High	Medium	Very Low	GBP -15.75 m	OPPORTUNITY
			1.5.		Poor condition / interface of existing offshore sites		T	Active		High	Low	Medium	GBP 4.73 m	3 MEDIUM
			1.6.		May not meet performance requirements	Additional time and cost to meet performance specs	T	Active		Very High	Medium	High	GBP 21.6 m	2 HIGH
			1.7.		Horizontal Drilling not possible	Geological ground conditions may make HDD difficult	T	Active		Very High	Low	Medium	GBP 16.2 m	2 HIGH
			1.8.		Wells found to be unsuitable for CO2	Cement casings methodology is suitable for hydrocarbons and brines, but CO2 is unproven.	T	Active		Very High	Very Low	Medium	GBP 4.05 m	3 MEDIUM
			1.9.		Brine producers	May need to drill relief wells to release water form reservoirs	T	Active	35.00	Very High	Medium	Very High	GBP 2.8 m	4 LOW
2.	Procurement	Active	2.1.		Buy down discounts may be more favourable than expected	Bulk discount pricing on multiple trains may be more favourably negotiated than estimated	O	Active		High	Medium	Medium	GBP -25.2 m	OPPORTUNITY
			2.2.		Shipping problems	Loss or very late delivery of key equipment	T	Active		Medium	High	High	GBP 6.75 m	3 MEDIUM
			2.3.		Sole suppliers have little or no availability	High shop loading of major equipment suppliers (turbines, heat exchangers), could increase cost/delay schedule	T	Active		Very High	Very Low	Very High	GBP 1.35 m	4 LOW
			2.4.		Lack of competition or low availability of capable suppliers may drive up pricing	For both EPC contractors and major equipment suppliers	T	Active		High	Medium	High	GBP 6.3 m	3 MEDIUM
3.	Construction	Active	3.1.		Construction Delays	General construction delay - any cause	T	Active	50.00	Very High	High	High	GBP 12 m	2 HIGH
			3.2.		Offshore installation vessels not available	Improvements in oil price may lead to lack of availability in offshore installation rigs/vessels	T	Active		High	Medium	Very Low	GBP 15.75 m	2 HIGH
4.	Commercial	Active	4.1.		Major incident with Partner	One owner/partner has major compliance breach/bankruptcy/divorces from JV	T	Active		Very High	Low	High	GBP 10.8 m	3 MEDIUM
			4.2.		Steel Prices Change	Steel prices are at a long-time low.	T	Active		High	High	Low	GBP 18.9 m	2 HIGH
			4.3.		Labour and costs of civils	£300BN investment in UK infrastructure may lead to increase costs/decreased availability for civils contracts	T	Active		High	High	Low	GBP 18.9 m	2 HIGH
			4.4.		Union rate renegotiations	Union rates for construction period currently unknown - negotiation could result in higher than estimated costs	T	Active		High	Medium	High	GBP 6.3 m	3 MEDIUM
			4.5.		Interface complexity causes delay	the scale of plant and complexity of interfaces may cause significant schedule delay and cost increase	T	Active		Very High	Medium	High	GBP 21.6 m	2 HIGH
			4.6.		Pricing scale factors on equipment may not be perfectly accurate	Actual costs may differ from estimate	T							Not Yet Fully Analyzed
5.	Health & Safety		5.1.		Accident on Site	Accident on site would result in delay causing increase in costs	T	Active	1.00	Low	Low	High	GBP 1.35 m	4 LOW
6.	Regulatory	Active	6.1.		Regulatory authorities may change thresholds for emissions	Rework on engineering/construction causing delay and increased costs.	T	Active		High	Low	Medium	GBP 4.73 m	3 MEDIUM
			6.2.		Permits and Consenting Delays	Unanticipated roadblocks with permitry and consenting for site	T	Active		High	Low	High	GBP 3.15 m	3 MEDIUM
7.	Site Selection	Activ	7.1.		Ecological Risk	Site near protected areas - additional	T	Active		High	Medium	Very High	GBP 3.15 m	3 MEDIUM

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Risk Type: Financial **Component: All**

ID	Exposure Activity	Exposure Status	Risk ID	Component	Risk Title/Possible Outcome	Risk Description	Threat/Opportunity	Risk Status	Estimated Consequence (m's or days)	Qualitative Assessment: Consequence	Qualitative Assessment: Probability	Qualitative Assessment: Manageability Exposure	Post-Mitigation: Probable Consequence	Post-Mitigation: Risk Level
	Risks	e				engineering, further routing of pipelines, emissions/noise regulations								
			7.2.		Ground Conditions	Additional contamination, historical site (archaeological significance).	T	Active		Medium	Medium	Medium	GBP 6.75 m	3 MEDIUM
			7.3.		Flood Risk	Some elements of selected sites in flood risk areas - could delay construction	T	Active		Low	Low	High	GBP 1.35 m	4 LOW

PROJECT NAME:	181869	Ranges	1	Quote/unit cost/price	0.9		1.15
CLIENT:	ETI		2	Factored Quote	0.9		1.2
UPDATED:	12 May 2017		3	PEACE	0.85		1.25
			4	Norm.Analogous Estimate	0.8		1.5

#	Area	Cost Item	Total Item Cost (Equipment+Labour or Subcontract)	Chosen source	Data source	Included	Remarks	Min (%)	Most likely (%)	Max (%)	Min (value)	Most likely (value)	Max (value)	Sampled
1	Site Acquisition	Site Acquisition	7,578,720	4	4	Land Cost	Public data for land cost	80%	100%	200%	£ 6,062,976	£ 7,578,720	£ 15,157,440	£ 8,589,216
2	Early Engineering	Pre-FEED	7,609,342	4	4	Total Phase cost, incl owners	SNC-Lavalin estimating norms for similar work	80%	100%	130%	£ 6,087,473	£ 7,609,342	£ 9,892,144	£ 7,736,164
		FEED	82,371,310	3	2	Total Phase cost, incl owners	Data from White rose, Peterhead, power projects, Boundary Dam, and KKD's., small change in rate will dramatically change estimate	85%	100%	130%	£ 70,015,613	£ 82,371,310	£ 107,082,702	£ 84,430,592
2	Early Engineering	Site Enabling	38,900,922	2	1 and 2	Subcontract costs	Unit rates from vendor quotes, but scaled up to estimated size	90%	100%	130%	£ 35,010,830	£ 38,900,922	£ 50,571,199	£ 40,197,619
		Demobilisation	2,500,000	4	4	Subcontract cost	Estimated by constructability expert	80%	100%	130%	£ 2,000,000	£ 2,500,000	£ 3,250,000	£ 2,541,667
		Engineering	1,478,235	4	4	estimating norms	estimating norms	80%	100%	130%	£ 1,182,588	£ 1,478,235	£ 1,921,706	£ 1,502,872
		Contractors Costs	10,812,555	4	2 and 4	scaled compared to peterhead, power projects, estimated norms	scaled compared to peterhead, power projects, estimated norms	80%	100%	130%	£ 8,650,044	£ 10,812,555	£ 14,056,322	£ 10,992,764
		Owners Costs	2,691,060	4	2 and 4	estimated norms, KKD's	KKD's and estimating norms	80%	100%	130%	£ 2,152,848	£ 2,691,060	£ 3,498,378	£ 2,735,911
3	CCGT	**Specialised Equipment**									£ -	£ -	£ -	
		Gas turbine Package	79,569,308	2	2	Scaled vendor quote + PEACE labour		90%	100%	140%	£ 71,612,377	£ 79,569,308	£ 111,397,031	£ 83,547,773
		Steam Turbine Package	27,196,288	2	1	Vendor quote + PEACE labour estimate	Wider band selected because of uncertainty over price for multiple units, UK market	90%	100%	130%	£ 24,476,659	£ 27,196,288	£ 35,355,174	£ 28,102,831
		Heat Recovery Boiler	30,831,214	2	2	Scaled vendor quote + PEACE labour		90%	100%	130%	£ 27,748,093	£ 30,831,214	£ 40,080,578	£ 31,858,921
		Water Cooled Condenser	2,969,229	3	3	PEACE equipment and labour		85%	100%	125%	£ 2,523,845	£ 2,969,229	£ 3,711,536	£ 3,018,716
		Condensate Polisher	357,653	3	3	PEACE equipment and labour		85%	100%	125%	£ 304,005	£ 357,653	£ 447,066	£ 363,614
		CCGT Stack	2,510,664	2	1	Vendor quote - installed	Wider band selected because of uncertainty over subcontract installation price	90%	100%	120%	£ 2,259,598	£ 2,510,664	£ 3,012,797	£ 2,552,508
		Continuous Emissions Monitoring System	539,069	3	3	PEACE equipment and labour		85%	100%	125%	£ 458,209	£ 539,069	£ 673,836	£ 548,053
		Transmission Voltage Equipment	35,808,813	2	2	Scaled up vendor quotation + labour factor		90%	100%	130%	£ 32,227,932	£ 35,808,813	£ 46,551,457	£ 37,002,440
		Generating Voltage Equipment	18,015,264	3	1, 2 and 3	PEACE equipment and labour, vendor quotes, and scaled up equipment	chose most conservative	85%	100%	125%	£ 15,312,974	£ 18,015,264	£ 22,519,080	£ 18,315,518
		Other Equipment	-					0%	100%	0%	£ -	£ -	£ -	
		Pumps	2,114,899	3	2 and 3	PEACE and scaled up quotations	chose more conservative	85%	100%	125%	£ 1,797,664	£ 2,114,899	£ 2,643,624	£ 2,150,147
		Tanks / Vessel	804,452	3	3	PEACE equipment and labour	Peace	85%	100%	125%	£ 683,784	£ 804,452	£ 1,005,565	£ 817,860
		Auxilliary Heat Exchangers	2,487,346	3	3	PEACE equipment and labour	Peace	85%	100%	125%	£ 2,114,244	£ 2,487,346	£ 3,109,183	£ 2,528,802
		Deaerator/Feedwater Tank	546,134	1	1	Vendor quote plus peace labour		90%	100%	115%	£ 491,521	£ 546,134	£ 628,054	£ 550,685
		Auxilliary Boiler	1,553,605	1	1	Vendor quote plus peace labour		90%	100%	115%	£ 1,398,245	£ 1,553,605	£ 1,786,646	£ 1,566,552
		Bridge Crane(s)	1,552,568	1	1	Vendor quote plus peace labour		90%	100%	115%	£ 1,397,311	£ 1,552,568	£ 1,785,453	£ 1,565,506
		Misc Equipment	482,593	3	3	PEACE equipment and labour		85%	100%	125%	£ 410,204	£ 482,593	£ 603,241	£ 490,636
		Detailed Design	14,876,000	3	3	PEACE equipment and labour		85%	100%	125%	£ 12,644,600	£ 14,876,000	£ 18,595,000	£ 15,123,933
		Foundations	26,828,018	3	3	PEACE equipment and labour		85%	100%	125%	£ 22,803,816	£ 26,828,018	£ 33,535,023	£ 27,275,152
		Transport and Rigging	5,679,275	3	3	PEACE equipment and labour		85%	100%	125%	£ 4,827,384	£ 5,679,275	£ 7,099,094	£ 5,773,930
		Piping	11,101,645	3	3	PEACE equipment and labour		85%	100%	140%	£ 9,436,398	£ 11,101,645	£ 15,542,303	£ 11,564,213

PROJECT NAME:	181869	Ranges	1	Quote/unit cost/price	0.9		1.15
CLIENT:	ETI		2	Factored Quote	0.9		1.2
UPDATED:	12 May 2017		3	PEACE	0.85		1.25
			4	Norm.Analogous Estimate	0.8		1.5

#	Area	Cost Item	Total Item Cost (Equipment+Labour or Subcontract)	Chosen source	Data source	Included	Remarks	Min (%)	Most likely (%)	Max (%)	Min (value)	Most likely (value)	Max (value)	Sampled
		Steelwork	3,175,650	3	3	PEACE equipment and labour		85%	100%	150%	£ 2,699,302	£ 3,175,650	£ 4,763,474	£ 3,360,896
		Electrical	12,409,503	3	3	PEACE equipment and labour		85%	100%	140%	£ 10,548,078	£ 12,409,503	£ 17,373,305	£ 12,926,566
		Painting	3,569,881	4	2	Subcontract cost	Scaled up from other projects - no MTO	80%	100%	150%	£ 2,855,905	£ 3,569,881	£ 5,354,822	£ 3,748,375
		Insulation	3,569,881	4	2	subcontract cost	Scaled up from other projects - no MTO	80%	100%	150%	£ 2,855,905	£ 3,569,881	£ 5,354,822	£ 3,748,375
		Scaffolding	7,139,763	4	2	Subcontract cost	scale up from other projects	80%	100%	150%	£ 5,711,810	£ 7,139,763	£ 10,709,644	£ 7,496,751
		Commissioning	12,620,695	4	1 and 4	vendor quotes for subcontracts and fills, estimated durations and estimated norms	vendor quotes for subcontracts and fills, estimated durations and estimated norms	80%	100%	150%	£ 10,096,556	£ 12,620,695	£ 18,931,043	£ 13,251,730
		Contractors Costs	103,804,669	4	4	vendor quotes for subcontracts and fills, estimated durations and estimated norms	scaled compared to peterhead, power projects, estimated norms	80%	100%	150%	£ 83,043,735	£ 103,804,669	£ 155,707,004	£ 108,994,902
		Owner's Costs	32,970,837	4	4	estimated norms, KKD's	KKD's and estimating norms	80%	100%	150%	£ 26,376,670	£ 32,970,837	£ 49,456,256	£ 34,619,379
								0%	100%	0%	£ -	£ -	£ -	
		Specialised Equipment Packages						0%	100%	0%	£ -	£ -	£ -	
		CO2 Stripper - Column and Internals	2,890,005	2	1 and 2	unit rates, scaled vendor quote, scaled up labour	quote unit rates for column, scaled internals	90%	100%	130%	£ 2,601,005	£ 2,890,005	£ 3,757,007	£ 2,986,339
		CO2 Absorber - Column and Internals	30,550,666	2	1 and 2	unit rates, scaled vendor quote, scaled up labour	quote unit rates for column, scaled internals	90%	100%	130%	£ 27,495,599	£ 30,550,666	£ 39,715,866	£ 31,569,022
		Direct Contact Cooler - Column and Internals	5,370,892	2	1 and 2	unit rates, scaled vendor quote, scaled up labour	quote unit rates for column, scaled internals	90%	100%	130%	£ 4,833,803	£ 5,370,892	£ 6,982,160	£ 5,549,922
		Amine Treatment and Recovery Package	25,787,551	2	2	scaled vendor quote + scaled labour	scaled quote	90%	100%	130%	£ 23,208,796	£ 25,787,551	£ 33,523,816	£ 26,647,136
		Booster Fans	9,686,676	2	2	scaled vendor quote + scaled labour	scaled quote	90%	100%	120%	£ 8,718,008	£ 9,686,676	£ 11,624,011	£ 9,848,121
		Gas-Gas Heat Exchanger	3,688,505	1	1	vendor quote + labour	vendor quote	90%	100%	115%	£ 3,319,655	£ 3,688,505	£ 4,241,781	£ 3,719,243
		Lean/Rich Amine Exchanger	16,606,813	2	1	vendor quote + labour	vendor quote - engineering allowance	90%	100%	120%	£ 14,946,132	£ 16,606,813	£ 19,928,176	£ 16,883,593
		CO2 Stripper Reboilers	3,890,295	2	2	scaled vendor quote + scaled labour	vendor quote	90%	100%	120%	£ 3,501,266	£ 3,890,295	£ 4,668,354	£ 3,955,134
		Compression Package	20,590,254	2	2	scaled quote + scaled labour	scaled quote	90%	100%	120%	£ 18,531,229	£ 20,590,254	£ 24,708,305	£ 20,933,425
		Dehydration Package	573,011	2	2	scaled quote + scaled labour	scaled quote	90%	100%	120%	£ 515,710	£ 573,011	£ 687,613	£ 582,561
			-								£ -	£ -	£ -	
		Other Equipment	-								£ -	£ -	£ -	
		Pumps	4,006,423	2	1 and 2	actual and scaled quotes, scaled labour	more scaled items, assumption for all is based on scaled up model	90%	100%	120%	£ 3,605,781	£ 4,006,423	£ 4,807,708	£ 4,073,197
		Tanks	2,750,147	2	1 and 2	actual and scaled quotes, scaled labour	more scaled items, assumption for all is based on scaled up model	90%	100%	120%	£ 2,475,133	£ 2,750,147	£ 3,300,177	£ 2,795,983
		Heat Exchangers	3,806,439	2	1 and 2	actual and scaled quotes, scaled labour	more scaled items, assumption for all is based on scaled up model	90%	100%	120%	£ 3,425,795	£ 3,806,439	£ 4,567,726	£ 3,869,879
4	CCC	Drums and Vessels	1,393,275	2	1 and 2	actual and scaled quotes, scaled labour	more scaled items, assumption for all is based on scaled up model	90%	100%	120%	£ 1,253,948	£ 1,393,275	£ 1,671,930	£ 1,416,496
		Electrical Equipment	4,904,400	2	1 and 2	actual and scaled quotes, scaled labour	more scaled items, assumption for all is based on scaled up model	90%	100%	120%	£ 4,413,960	£ 4,904,400	£ 5,885,280	£ 4,986,140
		Other equipment	4,934,266	2	1 and 2	actual and scaled quotes, scaled labour	more scaled items, assumption for all is based on scaled up model	90%	100%	120%	£ 4,440,839	£ 4,934,266	£ 5,921,119	£ 5,016,504
		Detailed Design	25,766,253	2	2	scaled from prior project	scaled off Peterhead	90%	100%	120%	£ 23,189,628	£ 25,766,253	£ 30,919,504	£ 26,195,691
		Civils	26,791,199	4	2	Subcontract cost	scaled off Peterhead but no detailed MTO	80%	100%	150%	£ 21,432,959	£ 26,791,199	£ 40,186,799	£ 28,130,759
		Transport and Rigging	1,419,934	2	2	Subcontract cost	scaled off peterehad	90%	100%	120%	£ 1,277,940	£ 1,419,934	£ 1,703,920	£ 1,443,599
		Piping	44,423,048	4	2	Subcontract cost	scaled off Peterhead but no detailed MTO	80%	100%	140%	£ 35,538,438	£ 44,423,048	£ 62,192,267	£ 45,903,816
		Steelwork	6,008,103	4	2	Subcontract cost	scaled off Peterhead but no detailed MTO	80%	100%	150%	£ 4,806,482	£ 6,008,103	£ 9,012,154	£ 6,308,508
		Electrical	35,362,925	4	2	Subcontract cost	scaled off Peterhead but no detailed MTO	80%	100%	140%	£ 28,290,340	£ 35,362,925	£ 49,508,094	£ 36,541,689
		Ducting	10,882,601	4	2	Subcontract cost	scaled off Peterhead but no detailed MTO	80%	100%	150%	£ 8,706,081	£ 10,882,601	£ 16,323,902	£ 11,426,731
		Painting and Insulation	5,958,463	4	2	Subcontract cost	scaled off Peterhead but no detailed MTO	80%	100%	150%	£ 4,766,771	£ 5,958,463	£ 8,937,695	£ 6,256,386
		Scaffolding	11,916,927	2	2	Subcontract cost	scaled off peterhead	90%	100%	120%	£ 10,725,234	£ 11,916,927	£ 14,300,312	£ 12,115,542

PROJECT NAME:	181869	Ranges	1	Quote/unit cost/price	0.9		1.15
CLIENT:	ETI		2	Factored Quote	0.9		1.2
UPDATED:	12 May 2017		3	PEACE	0.85		1.25
			4	Norm.Analogous Estimate	0.8		1.5

#	Area	Cost Item	Total Item Cost (Equipment+Labour or Subcontract)	Chosen source	Data source	Included	Remarks	Min (%)	Most likely (%)	Max (%)	Min (value)	Most likely (value)	Max (value)	Sampled
		Commissioning	21,090,426	4	1, 2, 4	vendor quotes for subcontracts and fills, estimated durations and estimated norms	most conservative	80%	100%	150%	£ 16,872,341	£ 21,090,426	£ 31,635,639	£ 22,144,947
		Contractors Costs	97,154,963	4	2 and 4	scaled compared to peterhead, power projects, estimated norms	most conservative	80%	100%	150%	£ 77,723,970	£ 97,154,963	£ 145,732,445	£ 102,012,711
		Owner's Costs	30,844,547	4	4	KKD's and estimating norms	KKD's and estimating norms	80%	100%	150%	£ 24,675,638	£ 30,844,547	£ 46,266,821	£ 32,386,774
								0%	100%	0%	£ -	£ -	£ -	
5	Facilities and Utilities	Engineering	2,632,000	4	4	estimateing norm	estimated norms aggregated from prior projects	80%	100%	130%	£ 2,105,600	£ 2,632,000	£ 3,421,600	£ 2,675,867
		Cooling plant	14,859,474	2	2	scaled subcontract	Scaled vendor quote	90%	100%	130%	£ 13,373,527	£ 14,859,474	£ 19,317,316	£ 15,354,790
		Waste Water Treatment Facility	15,532,120	2	2	scaled subcontract	Scaled from Peterhead	90%	100%	130%	£ 13,978,908	£ 15,532,120	£ 20,191,756	£ 16,049,857
		Facilities	12,052,087	2	1	Vendor unit rates applied to new sizing	unit rates from quotes, sizes are scaled	90%	100%	130%	£ 10,846,878	£ 12,052,087	£ 15,667,713	£ 12,453,823
		Utilities	41,111,750	2	2	Scaled up vendor quotes + labour as subcontracts	scaled up quotes	90%	100%	130%	£ 37,000,575	£ 41,111,750	£ 53,445,275	£ 42,482,142
		Natural Gas & Metering	2,276,610	1	1	vendor quote + labour	vendor quote	90%	100%	130%	£ 2,048,949	£ 2,276,610	£ 2,959,593	£ 2,352,497
		CO2 Metering	3,890,305	1	1	vendor quote + labour	vendor quote	90%	100%	130%	£ 3,501,274	£ 3,890,305	£ 5,057,396	£ 4,019,982
		Commissioning	1,880,133	4	2 and 4	scaled compared to power & CCS projects and estimated norms	scaled compared to power & CCS projects and estimated norms	80%	100%	130%	£ 1,504,106	£ 1,880,133	£ 2,444,173	£ 1,911,469
		Contractor's Soft Costs	22,577,380	4	2 and 4	scaled compared to peterhead, power projects, estimated norms	scaled compared to peterhead, power projects, estimated norms	80%	100%	130%	£ 18,061,904	£ 22,577,380	£ 29,350,594	£ 22,953,670
		Owner's Costs	7,171,263	4	2 and 4	scaled compared to peterhead, power projects, estimated norms	scaled compared to peterhead, power projects, estimated norms	90%	100%	150%	£ 6,454,137	£ 7,171,263	£ 10,756,895	£ 7,649,347
								0%	100%	0%	£ -	£ -	£ -	
6	Connection Costs	HV inside plant	1,965,779	2	1	Subcontract cost	unit rate quotes but no detailed route or MTO	90%	100%	130%	£ 1,769,201	£ 1,965,779	£ 2,555,513	£ 2,031,305
		HV Connection	11,998,840	2	1	Subcontract cost	unit rate quotes but no detailed route or MTO	90%	100%	130%	£ 10,798,956	£ 11,998,840	£ 15,598,492	£ 12,398,801
		Water outfall	1,194,377	2	1	Subcontract cost	unit rate quotes but no detailed route or MTO	90%	100%	130%	£ 1,074,939	£ 1,194,377	£ 1,552,690	£ 1,234,190
		Offshore Pipeline	249,005,382	2	1	Subcontract cost	unit rate quotes but no detailed route or MTO	90%	100%	130%	£ 224,104,844	£ 249,005,382	£ 323,706,997	£ 257,305,561
		Onshore Pipeline	2,050,343	2	1	Subcontract cost	unit rate quotes but no detailed route or MTO	90%	100%	130%	£ 1,845,309	£ 2,050,343	£ 2,665,446	£ 2,118,688
		Natural Gas Pipeline	2,587,982	2	1	Subcontract cost	unit rate quotes but no detailed route or MTO	90%	100%	130%	£ 2,329,184	£ 2,587,982	£ 3,364,377	£ 2,674,248
		Water Intake	13,957,202	2	1	Subcontract cost	unit rate quotes but no detailed route or MTO	90%	100%	130%	£ 12,561,482	£ 13,957,202	£ 18,144,363	£ 14,422,442
		Owner's Costs	26,296,671	4	4	KKD's, esitmating norms	KKD's, esitmating norms	80%	100%	130%	£ 21,037,337	£ 26,296,671	£ 34,185,672	£ 26,734,949
								0%	100%	0%	£ -	£ -	£ -	
		Topside						0%	100%	0%	£ -	£ -	£ -	
		Management, Engineering, and Procurement Services	12,976,419	4	4	estimating norms	estimating tool	90%	100%	150%	£ 11,678,777	£ 12,976,419	£ 19,464,629	£ 13,841,514
		Equipment	9,483,063	2	1 and 2	vendor quotes and scaled quotes	vendor quotes	90%	100%	120%	£ 8,534,757	£ 9,483,063	£ 11,379,676	£ 9,641,114
		Materials	18,254,858	4	4	estimating norms	estimating tool	90%	100%	150%	£ 16,429,372	£ 18,254,858	£ 27,382,287	£ 19,471,849
		Fabrication	46,728,627	4	4	estimating norms	estimating tool	90%	100%	150%	£ 42,055,765	£ 46,728,627	£ 70,092,941	£ 49,843,869
		Pre-Commissioning Onshore	3,279,054	4	4	estimating norms	estimating tool	90%	100%	150%	£ 2,951,148	£ 3,279,054	£ 4,918,581	£ 3,497,657
		Transportation and Installation	833,397	4	4	estimating norms	estimating tool	90%	100%	150%	£ 750,058	£ 833,397	£ 1,250,096	£ 888,957
		Hook-up and Commissioning	7,933,021	4	4	estimating norms	estimating tool	90%	100%	150%	£ 7,139,719	£ 7,933,021	£ 11,899,531	£ 8,461,889
		Surveys, Warranty, Certification	1,094,554	4	4	estimating norms	estimating tool	90%	100%	150%	£ 985,099	£ 1,094,554	£ 1,641,831	£ 1,167,524
			-					0%	100%	0%	£ -	£ -	£ -	

PROJECT NAME:	181869	Ranges	1	Quote/unit cost/price	0.9		1.15
CLIENT:	ETI		2	Factored Quote	0.9		1.2
UPDATED:	12 May 2017		3	PEACE	0.85		1.25
			4	Norm.Analogous Estimate	0.8		1.5

#	Area	Cost Item	Total Item Cost (Equipment+Labour or Subcontract)	Chosen source	Data source	Included	Remarks	Min (%)	Most likely (%)	Max (%)	Min (value)	Most likely (value)	Max (value)	Sampled
		Jacket	-					0%	100%	0%	£ -	£ -	£ -	
7	**Offshore**	Management, Engineering, and Procurement Services	1,594,593	4	4	estimating norms	estimating tool	80%	100%	150%	£ **1,275,674**	£ **1,594,593**	£ **2,391,889**	£ **1,674,322**
		Equipment	-	4	4	estimating norms	estimating tool	80%	100%	150%	£ -	£ -	£ -	
		Materials	5,197,020	4	4	estimating norms	estimating tool	90%	100%	150%	£ **4,677,318**	£ **5,197,020**	£ **7,795,530**	£ **5,543,488**
		Fabrication	8,974,576	4	4	estimating norms	estimating tool	90%	100%	150%	£ **8,077,118**	£ **8,974,576**	£ **13,461,863**	£ **9,572,881**
		Pre-Commissioning Onshore	-	4	4	estimating norms	estimating tool	90%	100%	150%	£ -	£ -	£ -	
		Transportation and Installation	3,383,516	4	4	estimating norms	estimating tool	90%	100%	140%	£ **3,045,165**	£ **3,383,516**	£ **4,736,923**	£ **3,552,692**
		Hook-up and Commissioning	-	4	4	estimating norms	estimating tool	90%	100%	150%	£ -	£ -	£ -	
		Surveys, Warranty, Certification	210,462	4	4	estimating norms	estimating tool	90%	100%	150%	£ **189,415**	£ **210,462**	£ **315,692**	£ **224,492**
			-					0%	100%	0%	£ -	£ -	£ -	
		Injection Wells	45,600,000	4	4	estimating norms	pale blue dot	90%	100%	150%	£ **41,040,000**	£ **45,600,000**	£ **68,400,000**	£ **48,640,000**
		Owners Costs	35,513,061	4	2, 4	KKD's, esitmating norms	KKD's, esitmating norms	90%	100%	150%	£ **31,961,755**	£ **35,513,061**	£ **53,269,592**	£ **37,880,598**
		Infield pipeline	30,513,061	3	1 and 2	Subcontract cost	unit rates, estimated route	90%	100%	125%	£ **27,461,755**	£ **30,513,061**	£ **38,141,326**	£ **31,275,888**
		Subsea power cable	-	3	1 and 2	Subcontract cost	unit rates, estimated route	90%	100%	125%	£ -	£ -	£ -	
											£ -	£ -	£ -	
											£ 1,488,221,678	£ 1,722,685,047	£ 2,356,800,827	

Note - Labour added to cost items to anonymise vendor data. Contingency range for equipemt cost items chosen based on source of equipment cost data.

1,722,685,047

Delta £ -

Risk Output £ 1,789,293,782

£ 634,115,780 £ 634,115,780

Summary statistics - Overall

Probability		Contingency	Risk	Total
Probability of meeting base case value		1.2%		
P90	1,830,369,803	6.3%	11.3%	17.6%
P50	1,788,834,082	3.8%	6.8%	10.6%
P10	1,749,374,060	1.5%	4.1%	5.7%

Attachment 15 – PreFEED and FEED

SNC·LAVALIN

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WE CARE
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PRE-FEED AND FEED COST ESTIMATE

Document No: **181869-0001-T-EM-CAL-AAA-00-00014**

1 OF 5

Revision **: A03** Date **: 07-MAR-2017**

This document has been electronically checked and approved. The electronic approval and signature can be found in FOCUS, cross referenced to this document under the Tasks tab, reference No: T072900.

A03	07-MAR-2017	Re-Issued for Use	M WILLS	S DURHAM	S DURHAM	M WILLS
A02	14-FEB-2017	Issued for Use	M WILLS	S DURHAM	S DURHAM	M WILLS
A01	13-FEB-2017	Not Issued	M WILLS			
REV	**DATE**	**ISSUE DESCRIPTION**	**BY**	**DISC CHKD**	**QA/QC**	**APPVD**

REVISION	COMMENTS
A01	Not Issued
A02	Issued for Use
A03	Re-Issued for Use Work sheet added for Pre-FEED scope Comments from project wide review included.

HOLDS	
HOLD DESCRIPTION / REFERENCE	

DISCLAIMER

Pre-FEED Cost Estimate

	Activity Description							SNC-Lavalin			Notes
	Units							Hours	£ / hr	£M	
	Date							2016	2016	**2016**	
1	**Project Management**										
1.1	Pre-FEED Management (Design / Technical / Support Services / Government Liaison)							17,257	125	**2.16**	
1.2	FEED Contract Tendering Process							2,055	125	**0.26**	Also includes the costs of managing the tendering process including pre-qualification, supplier events and assessment of tender submissions.
1.3	Project Development (Commercial / Legal / Financial)							8,385	125	**1.05**	Terms & Conditions for the contracts and other agreements, investigation of land and property ownership, securing FEED funding, and business model.
2	**Pre-FEED**										
2.1	Investor's Engineer Review of Feasibility Study Reports							800	125	**0.10**	Investor's Engineer Review - Number given to Hamish at Stage Gate Review
2.2	Conceptual Design										
2.1.2	*Onshore Power Plant*							4,473	110	**0.49**	
2.1.3	*Onshore CCC*							7,800	110	**0.86**	
2.1.4	*Onshore Pipeline*							1,090	110	**0.12**	
2.1.5	*Subsea Pipeline*							1,140	110	**0.13**	
2.1.6	*Offshore Platform*							2,512	110	**0.28**	Well Head Platform Only
2.1.7	*Wells & Subsurface*							4,200	150	**0.63**	
2.1.8	*Other*							510	110	**0.06**	HSEQ and Procurement Support to Project
2.2	Consultant Engineering & Technical Support										
2.2.1	*Owner's Engineer*							324	125	**0.04**	
2.2.2	*Consultant Engineering*							2,916	125	**0.36**	Specialist engineering services to support Owner in decision making
4	**Project Commercial & Financial Advisors**										
4.1	Commercial and Financial Advice							957	200	**0.19**	External consultants providing legal, financial, insurance and tax structuring advice, market data to underpin the project's financial model and audit of the financial model, specialist trading advice and due diligence.
4.2	Due Diligence							957	200	**0.19**	Legal, technical and insurance advisors who performed due diligence on behalf of the project's lending community
4.2.1	*Conceptual Design Verification*							1,182	125	**0.15**	
5	**Other Costs**										
5.1	Overheads								20	**0.55**	Owner's office and IT costs Built up to £20 / hr against Project Management Hours - £12.50 / hr for office - £5.00 / hr for IT and Software - £2.50 / hr for Admin and Stationary
	Overall Total Cost									**7.6**	
	Total Man Hours							56,558			
	Duration (Months)									**12**	

Overall Manning Level = 29 Persons

Notes
1. Costs include personnel, overheads, profits, and expenses
2. Pre-FEED is the work taken to get to a proposition worth funding through FEED to FID.
   Assume previous studies provide "feasibility" (FEL 1)
   Pre-FEED = Conceptual Design Phase
   GUIDELINE FOR THE EXECUTION OF STUDIES, 3002-HCGU-LON, rev 01:
   Conceptual Design (FEL 2): The objective for a Concept Study is to evaluate, select and mature the preferred commercial and technical concept evaluation and selection sufficiently, i.e. to a level where only minor future changes can be expected. By identifying major risk elements, including construction & installation aspects, and bringing the design of the complete facilities further to a weight estimating accuracy of +/- 15% at 80% confidence level for offshore studies or an equipment definition for onshore studies, supporting a cost estimate accuracy of +/-30%.
   - ☐ Site Layout & Linear Asset Routing
   - ☐ Flow Assurance
   - ☐ Pipeline Sizing
   - ☐ Utility Schedule
   - ☐ SURF Design
   - ☐ Developed Process Flow Diagrams
   - ☐ H&M Balance
   - ☐ Philosophies
   - ☐ Sized Equipment List
   - ☐ Market Analysis (e.g. Dispatchability)
   - ☐ Procurement Market Knowledge
   - ☐ Licensed Technology
   - ☐ High Level Sized Equipment List (onshore)
   - ☐ Configuration / Capacity
   - ☐ Weight topsides / Jackets (offshore)
   - ☐ Pipeline Size / Length
   - ☐ Cost Estimating (using Market Data (Relative)
   - ☐ OPEX Modelling (IRR or NPV will be Client Driven)
   - ☐ Bases of Design - Process, Pipelines, Offshore, HSE
   - ☐ Regulatory / Permitting Requirements
   - ☐ Infrastructure Requirements
   - ☐ Electrical Power and Distribution
   - ☐ Building Types of Construction and Sizing
   - ☐ HAZID / ENVID Reports
   - ☐ Constructability and Modulariation Reports
   - ☐ Project Execution Plan with developed Risk Analysis
   - ☐ Estimate
3. References for conceptual designs:
   Caledonia Clean Energy £4.2M 18 months https://www.gov.uk/government/news/42m-for-ccs-research-at-grangemouth
4. Contingency included in man hour estimates from the original Lead Engineer's estimates.
   Owner's risk and contingency to be added separately.
5. Conceptual Engineering is roughly 15% FEED Man Hours - but at higher cost because of the increased calibre of engineers and consultants required for the work.
   15% has been applied to Project Management as well as Contractor and Support Hours.

FEED Cost Estimate

	Activity Description	White Rose	Peterhead	Kingsnorth			Longannet	SNC-Lavalin			Notes	FEED+		
	Units	£M	£M	Hours	£ / hr	£M	£M	Hours	£ / hr	£M		Hours	£ / hr	£M
	Date	2015	2015	2011	2011	2011		2016	2016	2016		2016	2016	2016
1	**Project Management**		11.31	28,254	94	2.66								
1.1	FEED Management (Design / Technical / Support Services / Government Liaison)	11.94												
1.1.1	*Owners Management Team*							115,050	100	**11.51**	full chain integration and coordination, including assurance, risk management and knowledge transfer activities. Government liaison with BEIS.	207,090	100	**20.71**
1.1.2	*FEED Contractors Management Team*							4,350	100	**0.44**	Includes project & engineering management, project engineering (e.g. Interface management), project admin (e.g. Secretariat), project controls (e,g, Planning), and project support services (e.g. Doc control)	7,830	100	**0.78**
1.2	EPC Contract Tendering Process	1.37						13,700	100	**1.37**	Also includes the costs of managing the tendering process including pre-qualification, supplier events and assessment of tender submissions.	13,700	100	**1.37**
1.3	Project Development (Commercial / Legal / Financial)	5.59						55,900	100	**5.59**	Terms & Conditions for the supply chain contracts and other services/trading agreements, pursuing land and property agreements, securing project funding, business model.	55,900	100	**5.59**
2	**Reservoir Investigation**													
2.1	Indentify Lead (Reservoir and Area)									**0**	Assume already known - £3M otherwise			**0**
2.2	Seismic Survey of Reservoir									**0**	Assume already known - £7M to £20M otherwise			**0**
2.3	Exploratory Drilling									**0**	Assume already known - £17M to £100M otherwise			**0**
2.4	Storage De-Risking									**0**	Containment needs to be demonstrated and an ability to monitor must be demonstrated. Assume already undertaken for known stores. Otherwise £10M			**0**
3	**FEED Engineering**													
3.1	FEED Engineering	20.52									Includes affiliates and 3rd party studies.			
3.1.1	*Overall Project Scheme*			14,995	93	1.39		29,069	100	**2.91**	e.g. Philosophies, Bases of Design, Scheme Modeling, Overall Layouts for CCGT+CCC, etc SNC-Lavalin estimate - I have included Lead Engineers here	52,324	100	**5.23**
3.1.2	*Onshore Power Plant*			4,543	108	0.49		29,820	100	**2.98**	20% of Total Engineering Hours Aligns with 0.2 of cost from PEACE.	53,676	100	**5.37**
3.1.3	*Onshore CCC*		17.1	9,012	90	0.815		52,000	100	**5.20**	Based on SNC-Lavalin Previous Project Experience	93,600	100	**9.36**
3.1.4	*Onshore CC Licensor*									**1.64**	The Licensor Engineering Fee is highly variable as it will depend on the 'opportunity' incentive of the actual project supply, license, and detailed engineering contracts. The lower the chance of success, the higher the upfront fees. SNC-Lavalin data is for Engineering Fees of US$1-2M for FEED phase. Assume that the Licence Fee is deferred to Execute Phase of the project.			**1.64**
3.1.5	*Onshore Pipelines*		0	1,625	386	0.627		7,266	100	**0.73**	Very dependent upon length and number of AGIs For SNC-Lavalin is included in the CCC man hours FEED hours for 24 km of onshore gas pipeline (no booster station)	13,079	100	**1.31**
3.1.6	*Subsea Pipeline*		3.4	4,789	448	2.147		7,600	100	**0.76**	For SNC-Lavalin - Process Engineering and Flow Assurance Man Hours in the Process Engineering for the WHP. Man Hours for Safety & Environmental in 2.1.1 Hours increased based on other data from previous proposals (CO2 specific and including SSIV and Shore Crossing)	13,680	100	**1.37**
3.1.7	*Offshore Platform*		2.1	3,943	94	0.37		16,746	100	**1.67**	Well Head Platform Only	30,143	100	**3.01**
3.1.8	*Wells & Subsurface*		2.8	7,132	168	1.2		28,000	100	**2.8**	SNC-Lavalin don't have benchmark - we often sub-contract parts of scopes, but our Clients hold the majority of this work as is commercially confidential.	50,400	100	**5.04**
3.1.9	*Construction, Ops, and Maintenance Support*							2,640	100	**0.26**		4,752	100	**0.48**
3.1.10	*Other*			9,262	82	0.76		3,400	100	**0.34**	On Kingsnorth this is HSEQ and Procurement	6,120	100	**0.61**
3.2	Consultant Engineering & Technical Support	2.16										-		
3.2.1	*Owner's Engineer*							2,158	100	**0.22**	Doubled to include offshore	3,884	100	**0.39**
3.2.2	*Consultant Engineering*							19,442	100	**1.94**	This included architectural and socioeconomic work for the White Rose Visitor Centre for White Rose	34,996	100	**3.50**
4	**Project Commercial & Financial Advisors**	2.15	3.34					12,760	200	**2.55**		12,760	200	**2.55**
4.1	Commercial and Financial Advice										External consultants providing legal, financial, insurance and tax structuring advice, market data to underpin the project's financial model and audit of the financial model, specialist trading advice and due diligence.			
4.2	Due Diligence										Legal, technical and insurance advisors who performed due diligence on behalf of the project's lending community			
4.2.1	*FEED Verification*							7,880	100	**0.79**		14,183	100	**1.42**
5	**Other Costs**													
5.1	Overheads		3.3											
5.1.1	*Office & Running Costs*	0.83								**0.83**	Owner's office costs			**0.83**
5.1.2	*Onshore Plant Geotech Survey*									**1.63**				**1.63**
5.1.3	*Onshore Plant Topo and Underground Services*									**0.48**				**0.48**
5.1.4	*Onshore Pipeline Route Surveys*									**0.19**	Prior project Quotation (basis per 500m)			**0.19**
5.1.5	*Onshore Pipeline Geotechnics*									**0.61**	SNC-Lavalin price for 66 km			**0.61**
5.1.6	*Offshore Pipeline Route Surveys*									**1.2**	Price from previous project - dependent on route length and survey vessel day rates.			**1.2**
5.1.7	*Offshore Platform Surveys*									**1.8**	Offshore windfarm project price - but for similar scope.			**1.8**
5.2	Land Acquisition, Permitting and Consents	2.42		12,648	102	1.29		52,000	100	**5.2**	Legal and application fees associated with obtaining those permits and consents required for the Implementation Phase of the Project (e.g. DCOs, Storage Permit, fees for securing land): • DCO scoping and consultation • Surveys • Land referencing and legal input associated with DCO • Environmental Permit application • Safety report / HazSubstance Consent • Land options agreement and access costs (obviously excluding land purchase costs) • Gas and Electrical connection agreements • Water connections • GHG permits • Abstraction licence • Habitats Regulations • Offshore licencing or consents.	52,000	100	**5.2**
5.3	Environmental and Safety Studies									**0.2**	Based on previous SNC-Lavalin proposals.			**0.20**
5.4	Environmental Impact Statement									**0.37**	Based on assessment of 63 SNC-Lavalin EIA contracts.			**0.37**
5.5	National Grid Connection Study									**0.13**	Study to determine the network as sufficient capacity (or the implications of upgrading) for a connection agreement to be confirmed.			**0.13**
	Overall Total Cost	47.0	43.4			11.7	38.6			**56.3**				**82.4**
	Total Man Hours			96,201			393,554	459,781				720,117		
	Duration (Months)	8	22			13	14			**12**				**18**

Overall Manning Level = 239 Persons

Notes
1. Costs include personnel, overheads, profits, and expenses
2. References
   Peterhead - PCCS-00-MM-FA-3101-00001, March 2016, revision K03, Cost Estimate Report (© Shell U.K. Limited 2015, licensed under Shell U.K. Limited's copyright to use, modify, reproduce, publish, adapt and enhance this document)
   White Rose - K.15 Full chain FEED cost breakdown, February 2016 (available on DECC KKD site under Open Government Licence V3.0)
   Kingsnorth - KCP-ARP-PMG-LIS-0003 Rev.: 01, Labour Costs and Other FEED Costs, E.ON (available on DECC KKD site under Open Government Licence V3.0)
   Longannet - SP-SP 6.0 - RT015, FEED Close Out Report, April 2011, ScottishPower CCS Consortium (available on DECC KKD site under Open Government Licence V3.0)
   Storage Development - Delivering CO_2 Storage at the Lowest Cost in Time to Support the UK Decarbonising Goals, UK Transport and Storage Development Group
   4th CCS Cost Netwrok, 2016 Workshop, ieaghg, Report: 2016/09 dated August 2016 (http://www.ieaghg.org/docs/General_Docs/Reports/2016-09.pdf)
3. Owner's Engineer cost from Kingsnorth = £107,886 but only for onshore scope.
4. Nothing in FEED costs for surveys - FEED will need Bathymetric, Topo, Geotech, etc site surveys.
   Noted that the pipeline rates for Kingsnorth pipelines are high - could it be that there are survey costs included here?
5. SNC-Lavalin man hours are from an actual offshore project WHP and Subsea Pipeline. Origin is Client confidential.
6. FEED Verification price for CCS (confidential client) not for CCGT or New Build Offshore - therefore 3 x cost.
7. Offshore benchmarks - previous subsea pipeline and offshore mods FEED proposals £2M to £3M.
8. Twelve month FEED program selected to allow surveys to be included in schedule. 18 weeks for onshore Geotechnical.
9. FEED man hours for CCGT based on Basic Engineering services from project (Client and Project Confidential).
10. FEED man hours CCC based on project (Client and Project Confidential)
11. FEED man hours for onshore pipeline based on project (Client and Project Confidential)
12. Multiplier from FEED to FEED+ was developed from previous SNC-Lavalin Experience.
13. Contingency included in man hour estimates from the original Lead Engineer's estimates.
    Owner's risk and contingency to be added separately.
14. FutureGen 2.0 Mega-FEED = US$90M (~£74M) - see reference above.

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Building what matters