Programme Area: Carbon Capture and Storage

Project: Thermal Power with CCS

Title: Final Project Report

Abstract:

This report provides an overview of the Thermal Power with CCS – Generic Business Case Project, summarising the three major reports (Site Selection Report, Plant Performance and Capital Cost Estimating, and Plant Operating Cost Modelling). The purpose of this project was to compare the feasibility and costs of a single design of large gas fired power plant fitted with CCS, at a range of sizes (modules of 1x 600 MWe to 5x 600 MWe), in five separate UK regions. For each region an optimal site was selected to establish the costs and feasibility of the chosen plant design. A set of common values, limitations and selection criteria were applied in the site selection process including:

- Approach to risk – for investability, a lower risk approach was taken.
- Approach to public safety – this affected CO2 pipeline routings for example.
- Scale (up to 2-3 GWe), to be comparable with nuclear scales of operation. This impacted, for example, CO2 store selection decisions while some sites were unable to host the largest scales of operation tested by the project.
- Ability to gain consents such as planning permission.
- Public acceptance – this impacted, for example, site locations near areas of high population in particular since the plant size is extremely large; and CO2 pipeline routing choices.

Through this approach, the project was designed to enable regional comparisons for the type of plant selected and incorporating the design criteria/values applied commonly across each of the regions. Hence, the reader will see in the report direct comparisons between regions – these statements relate specifically to the findings from the cases shown and the design criteria considered. It is possible that other plant types and other design criteria considered by different organisations may lead to different, and also valid, conclusions.

References to “Scotland” in the report should be read as “Scotland (Grangemouth)”. Northern Scotland projects may potentially benefit from eased infrastructure requirements and so deliver different outcomes.

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.

Final Report

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Disclaimer

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Table of Contents

Figures

Tables

Executive Summary

The ETI's energy system modelling work has shown that Carbon Capture and Storage (CCS) is one of the most cost effective 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, and confirmed its commitment to CCS in the Clean Growth Strategy published in October 2017.

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 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 involved 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.

To achieve a lower risk the plant is designed to use CCGT power generation with post combustion engineered amine solvent CO_2 capture technology and fixed platform offshore facilities.

SNC-Lavalin has developed a template plant design, a capital cost estimate, and an operating cost model 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.

The Generic Business Case (GBC) project reviewed the feasibility and costs of locating a power station with CCS at a range of sizes (1 x 600 MW to 5 x 600 MW) in 5 separate regions in the UK.

Design and Site Selection

A design has been produced by the Generic Business Case (GBC) for a large scale deployment of CCGT + CCS.

The design and technology for a large scale CCGT + CCS is technically feasible and can be based on technology currently in commercial operation.

A layout for the onshore plant has been produced as part of the design and has been used for site selection.

Five regions of the UK have been chosen for the site selection work based on their proximity to offshore CO_2 stores identified by the Strategic Storage Appraisal Project (a previous ETI project, funded by DECC/BEIS).

The site selection work for the GBC has shown that there is a range of potential sites in each region reviewed that could be used for the implementation of a large scale CCGT + CCS scheme.

Scale

Capital Expenditure (CAPEX), Operating Expenditure (OPEX), and Abandonment Expenditure (ABEX) estimates have been produced for the Generic Business Case.

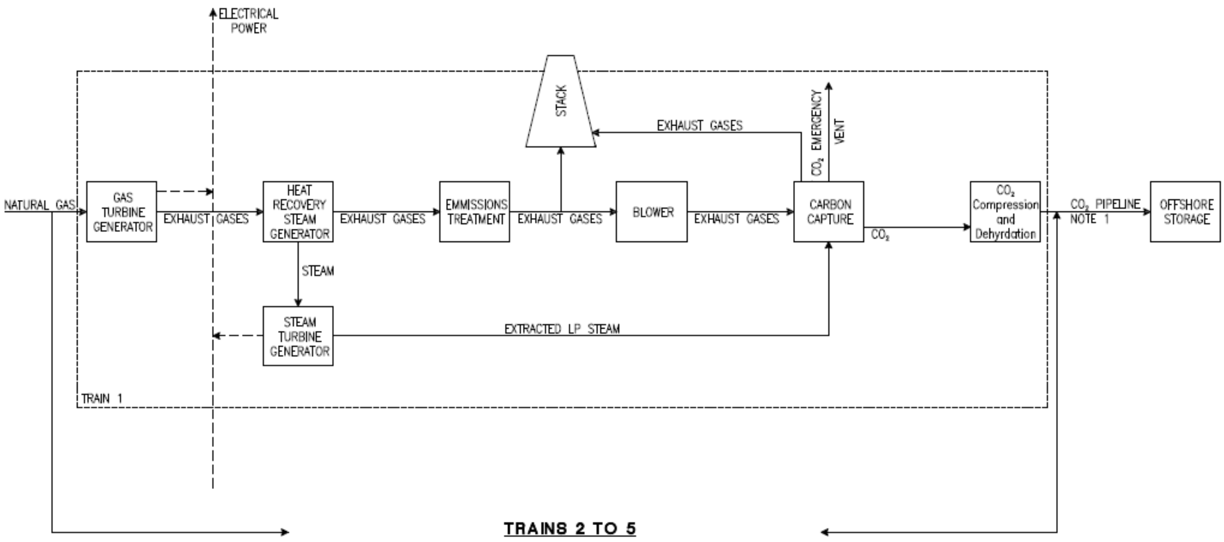


Figure 1 – Block Flow Diagram of Scheme

The estimates show that there is significant economy of scale for both CAPEX and OPEX moving from 1 to 2 to 3 trains (each train will be as shown in Figure 1 above). The economy of scale benefit is due to the following factors.

- There are common management, engineering, construction, facilities, and utilities costs which are shared between trains which offer an economy of scale for multiple trains compared to a single train (assuming a common design between trains).
- Pipeline costs are dominated by their length and only have a small dependence on their diameter, providing an economy of scale benefit for multiple trains (meaning the cost per tonne of CO_2 transported falls).

› For the stores considered in this project, one injection platform has enough capacity for CO_2 from up to 3 trains (3 x 600 MW): an additional cost for multiple trains would be for additional injection wells but not more platforms/facilities.[1]

The economy of scale benefit reduces for 4 or 5 train scheme as an additional offshore injection platform and infield subsea pipeline would be required.

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 had 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 would allow extensive modularisation / prefabrication which reduces the amount cost / risk / safety exposure on the construction site.

The capital cost estimate for 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 was because the selected site is in Southern Scotland which requires a long pipeline running up the East side of Scotland from the Firth of 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. There would be a cost benefit for the Scotland Region as a result of modularisation due to a potential quay/dock/shore side location; however, the CO_2 transportation costs significantly outweigh the savings.

CAPEX

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. Base costs were built up based on deterministic estimates of equipment, labour, materials, sub-contracts, contractors and Owners costs. Probabilistic P50 and P90[2] estimates were then made by adding in costs uncertainties and critical risk factors. The performance and cost estimate have been confirmed against benchmarks.

£ million	One Train (622 MW)	2 Trains (1244 MW)	3 Trains (1866 MW)	4 Trains (2488 MW)	5 Trains (3110 MW)
P50	1,764	2,754	3,763	4,984	5,966
P90	1,874	2,926	3,997	5,295	6,326

Table 1- P50 and P90 Cost Estimates against Abated Output for the Teesside Location

[1] An exception is the Scotland region where an additional platform is required for more than 1 train.
[2] P50 and P90 are the points on a probability distribution for estimated costs at which there is a 90% / 50% probability that costs will not exceed this value.

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

OPEX

The OPEX estimate for the Thermal Power with CCS project covers the phase from the end of the start-up period, or commercial operation date, to decommissioning and post-injection well monitoring, presented in two sections, Operating Expenditure (OPEX) and Decommissioning and Abandonment Expenditure (ABEX).

The OPEX model produced by the project team shows that OPEX per kW is not a strong function of plant size, though there is some reduction due to staffing optimisation for multiple units, one offshore platform servicing multiple trains, and economies of scale in administrative costs: this is shown in the following table. This table is based on a north east England location and includes both fixed and variable OPEX costs.

OPEX Costs	1 Train	2 Train	3 Train	4 Train	5 Train
£ / kW / year	£417	£390	£382	£381	£377
£ / MWhr	£50	£47	£46	£46	£45

Table 2 - OPEX Costs per kW

The decommissioning and abandonment costs (ABEX) have been estimated. These show that the abandonment costs for the Northwest/North Wales region is lower than the North East of England regions because the maximum plant size is smaller (3 trains compared to 5) and because there is only one offshore facility to abandon compared to two platforms for 4 or 5 train size plant over the Endurance Aquifer, whilst Scotland has a high cost due to decommissioning a second platform for a 3 train plant as well as the existing Feeder 10 pipeline.

No. Trains	5 Trains	5 Trains	5 Trains	3 Trains	3 Trains
Area	**Teesside**	**North Humber**	**South Humber**	**Northwest / North Wales**	**Scotland**
Total Cost (£m)	£270	£267	£267	£131	£251

Table 3 - Abandonment Costs per Region

1 Structure of Report

This report provides a summation of the Thermal Power with CCS Project – Generic Business Case – which is part of the ETI's CCS Program.

Section 2 provides an introduction to the report.

Section 3 introduces the project and the design of the CCGT + CCS scheme.

Section 4 explains the site selection process and the conclusions of potential sites.

Section 5 describes the capital cost estimate and section 6 the operating cost estimate.

The conclusions reached by the work are included in section 7.

2 Introduction

Carbon Capture and Storage (CCS) is the process of reducing emissions by collecting CO_2 from exhaust gases and storing it in a way that prevents it from entering the atmosphere. The ETI's energy system modelling work has shown that CCS is one of the most potent levers to help the UK meet its 2050 CO_2 reduction targets[3]: without CCS the energy system cost in 2050 could be £30bn per annum higher.

CO_2 has been extracted from hydrogen plants and natural gas plants for use in EOR since 1972. There are presently 21 large-scale CCS facilities in operation or under construction in eight countries that will be running full chain CCS technology spanning post combustion and pre-combustion coal, natural gas steam reforming, bioenergy CCS (corn to ethanol) and applications in the power, gas production, refining, chemicals and steel sectors according to the Global CCS Institute Project Database: these facilities can remove 37 million tonnes per annum (MTPA) of CO_2 that otherwise could have entered the atmosphere.

CCS is currently not in operation on a commercial scale gas fired power station; however, the risks of deployment are very low. Commercial scale post combustion capture technology on coal fired power plants is in operation on the SaskPower Boundary Dam Plant in Canada and Petra Nova Plant in the USA. The technology has been widely tested at large pilot scale (e.g. at Mongstad in Norway). A full design and costing has been produced for the application of the technology at a commercial scale to the Peterhead gas fired CCGT station.

Offshore storage of CO_2 has been in operation in the seas off of Norway at the Sleipner gas field since 1996 and at Snohvit since 2008.

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.

[3] 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."

3 Project and Plant Description

3.1 Description of Project

The UK Government retains the belief that CCS could play a crucial role in the future energy system, and confirmed its commitment to CCS in the Clean Growth Strategy published in October 2017. The ETI's analysis has shown that the best route to reliable, cost-effective and investable CCS in the UK is to build one or more power with CCS schemes, using best-proven technologies, in the most beneficial locations at size which maximises the benefits of scale. However, stakeholders in CCS would need compelling evidence of the business case for a power with CCS project. Therefore 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 involved 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.

To achieve a lower risk the plant is designed to use state-of-the art CCGT power generation with proven post combustion engineered amine solvent CO_2 capture technology (already being used at scale at the Boundary Dam facility in Canada and the Petra Nova plant in Texas) and fixed platform offshore facilities.

SNC-Lavalin has developed a template plant design, a capital cost estimate, and an operating cost model 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.

The GBC project reviewed and compared 5 separate regions in the UK for the deployment of CCGT + CCS and analysed the scale of such a scheme for 1 to 5 trains[4] of CCGT + CCS.

4 A 'train' in this context means a single gas turbine with a heat recovery steam generator (and steam turbine), a single capture unit with one absorber vessel and one stripper and a single compressor. Multiple trains then feed into a single CO_2 export pipeline.

3.2 Methodology Followed

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

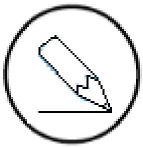
Design

The project team produced an outline power scheme; this included identification 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 capture, compression, and storage system suitable for use with the specified CCGT plant.

Design of the offshore platform for CO_2 storage was based on information from the White Rose published Key Knowledge Documents and the ETI Strategic UK CCS Storage Appraisal Project.[5] The work relied on well pressures and flows derived from these sources: no new subsurface engineering was undertaken in the study.

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 identified in five different regions of the UK. The sites selected in each region minimise development cost, risk, transport, and storage costs. Although greenfield sites were considered, all shortlisted sites were brownfield with former (or soon-to-be-decommissioned) industrial infrastructure.

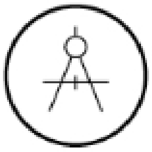
The storage sites were selected based on publicly available information for the White Rose project and the Strategic UK CCS Storage Appraisal Project.

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. Modelling 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.



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

Capital 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 a generic site and modifications to the cost were made for the individual sites identified for each region. 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.

Operating Cost Estimate
A cost estimate for the generic plant was developed split between fixed and variable OPEX costs:

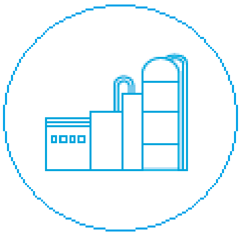
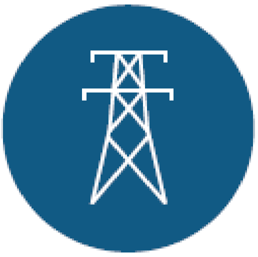
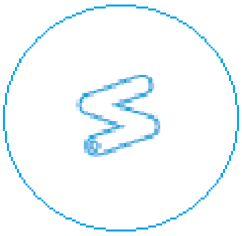
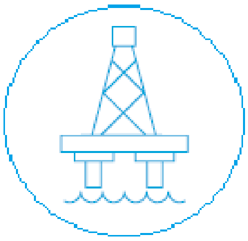
- Fixed Costs:
  - Labour
  - Maintenance
  - Administrative Expenses
  - Subcontracts
- Variable Expenses
  - Fuel Gas (fixed fuel cost of 50p/therm has been assumed)
  - Utilities
  - Consumables
  - Disposals
  - Carbon Tax

The operating cost for the CCS scheme was developed based on a foundation of anticipated routine maintenance schedules, utility and consumable requirements, and operation and maintenance staffing levels. Cost considerations have been made for plant availability and restarts. Each aspect has been scaled to meet the 1 to 5 train sized scheme.

SNC-Lavalin applied experience, knowledge, and data from the SaskPower Boundary Dam project and the Shell Peterhead CCS proposal, recent North Sea projects, UK onshore proposals, as well as its broader knowledge base from being an international EPC company, to provide a realistic cost estimate.

3.3 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.
	Connections: › Electrical Power Export › Natural Gas Fuel › Make Up Water	The electrical power is exported to the UK National Grid via an over head line from where is serves the needs of industry, commerce, and domestic homes. 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 would be required in order to safely isolate sections of the pipeline. (A booster station would 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 would be drilled to allow the CO_2 to flow into the underground store. The wellheads would be installed on an offshore platform.

3.4 High Level Summary of Technical Performance

The following is a summary of the technical performance of the designed Generic Business Case Plant. This 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 would have some parasitic loads (e.g. lube oil pumps) which take some of the power generated. Adding a Carbon Capture and Compression (CCC) 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.[6]

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	3.11 GW
Efficiency Net (abated)	52.7% (LHV)	
Efficiency Loss for CC	-7.9 percentage points (LHV)	

[6] 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.

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 4 – Summary of Technical Performance

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

There are slight differences in parasitic consumption between plant locations, for example due to differing compression requirements.

3.5 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 economies of scale. Each train of the plant was designed to produce approximately 0.6 GW of abated electrical power and capture 2 million tonnes per annum of CO_2. A maximum scheme size of 5 trains has been selected for the Generic Business case; it was assumed that this is the maximum feasible size which could be connected to the GB Electricity Grid and GB Gas Transmission Grid, and is 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[7]".
- 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.

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)[8]	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 5 – Maximum Number of Trains per Region

[7] Handed trains would have even numbered trains with the mirror image of the plot layout of odd numbered trains.
[8] (Pale Blue Dot Energy and Axis Well Technology, 2016)

3.6 Design Basis

The following Engineering Design Data was used as a basis for the Scheme Design.

Climatic Data - Onshore

	Average
Atmospheric Pressure, mbar	1013
Relative Humidity, %	60
Ambient Temperature, °C	10
Wet Bulb Temperature, °C	7

Table 6 - Climatic Data Onshore

Feedstock

The feedstock for the plant will be natural gas from the UK National Transmission System (NTS).

Carbon Dioxide Capture Rate

Each carbon dioxide abated case will be designed to achieve a target carbon capture level of at least 90% (at 98% purity).

Life of Plant

The design life of the CCGT with CCS plant will be 25 years.

The design life of new CO_2 transmission and storage infrastructure will be 40 years.

The design life of reused CO_2 transmission and storage infrastructure will be 15 years.

The design life above has been used for the design and costing of plant and infrastructure, 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, or installation of additional injection platforms, and that this future investment is not included in this report.

3.7 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 would be one CC Unit for each CCGT train;
- 5 CO_2 Compressors;
- Wet Mechanical Cooling Towers assumed for the design as would be suitable for the range of potential sites being considered;[9]
- 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 block diagram below shows the how the different elements of the Generic Business Case scheme design fit together.

[9] A site specific cooling design would be required for any selected location in the next phase of the project.

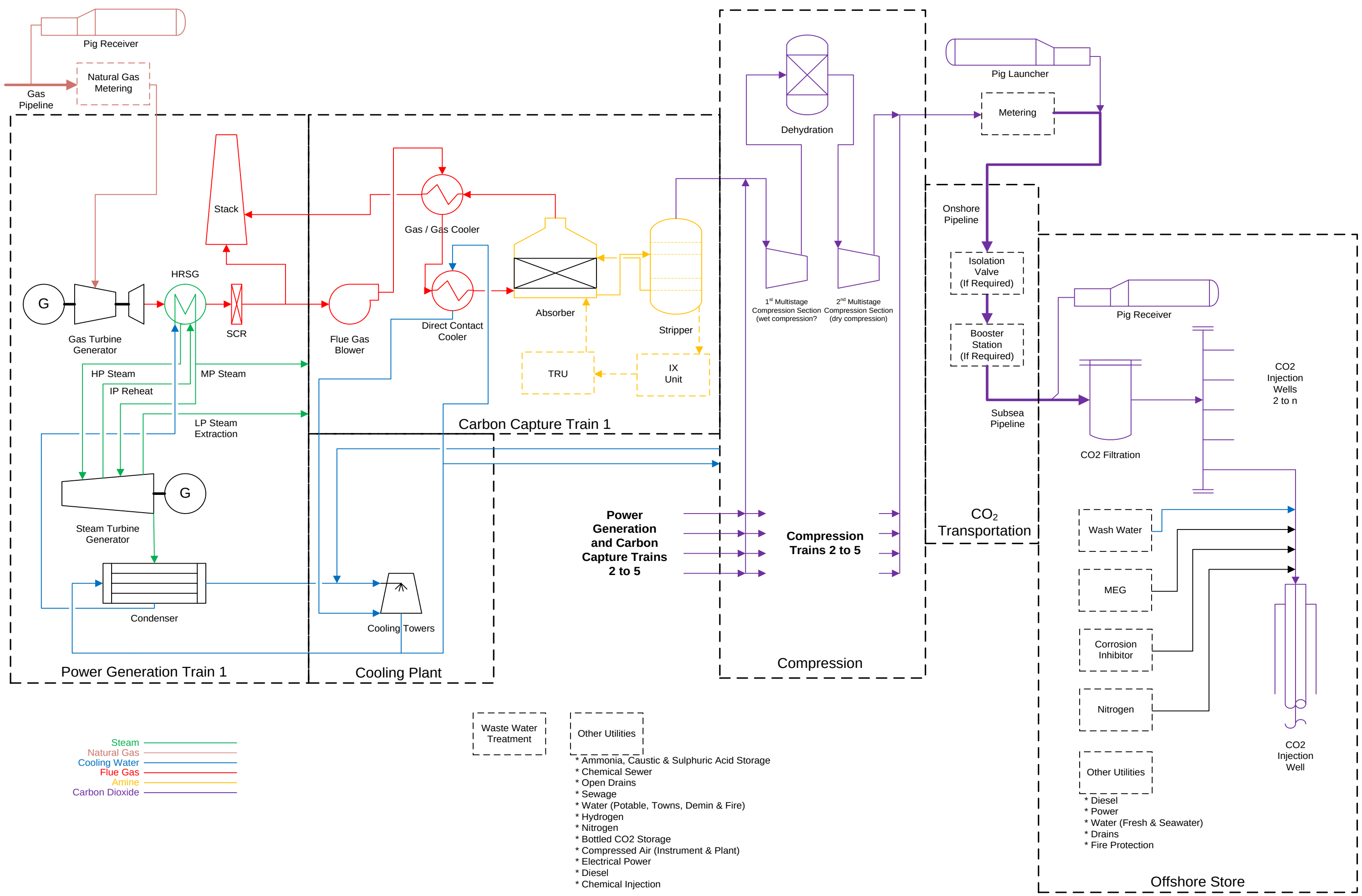


Figure 2 – Flow Diagram of Power Generation and CCS Scheme

3.8 Onshore Layout

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.

The plot size for the CCGT + CCC plant is approximately 40 Ha. It is estimated that 20 Ha would be required for Construction Facilities and construction lay down. Construction would not occur across the whole of the site simultaneously which would allow some areas to be used as temporary lay down during construction. Therefore, 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.[10]

The site layout is designed with highest hazards at opposite ends of the plant to the permanently manned area (including control room, welfare, and offices). This has resulted in the highest CO_2 hazard being located at the downwind boundary of the site: whilst this is the design intent within the plant layout, it may not be acceptable depending on neighbouring sites. Should there be a risk to neighbours then the layout would have to be rearranged, with cooling or utilities providing additional distance between CO_2 hazard and the boundary, and / or the boundary would have to be pushed out providing a dead zone between CO_2 hazard and the boundary fence.

Figure 3 – Representation of the CCGT + CCC Plant

[10] 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. This compares to about 170 Ha for Hinkley Point C (McAllister, 2013).

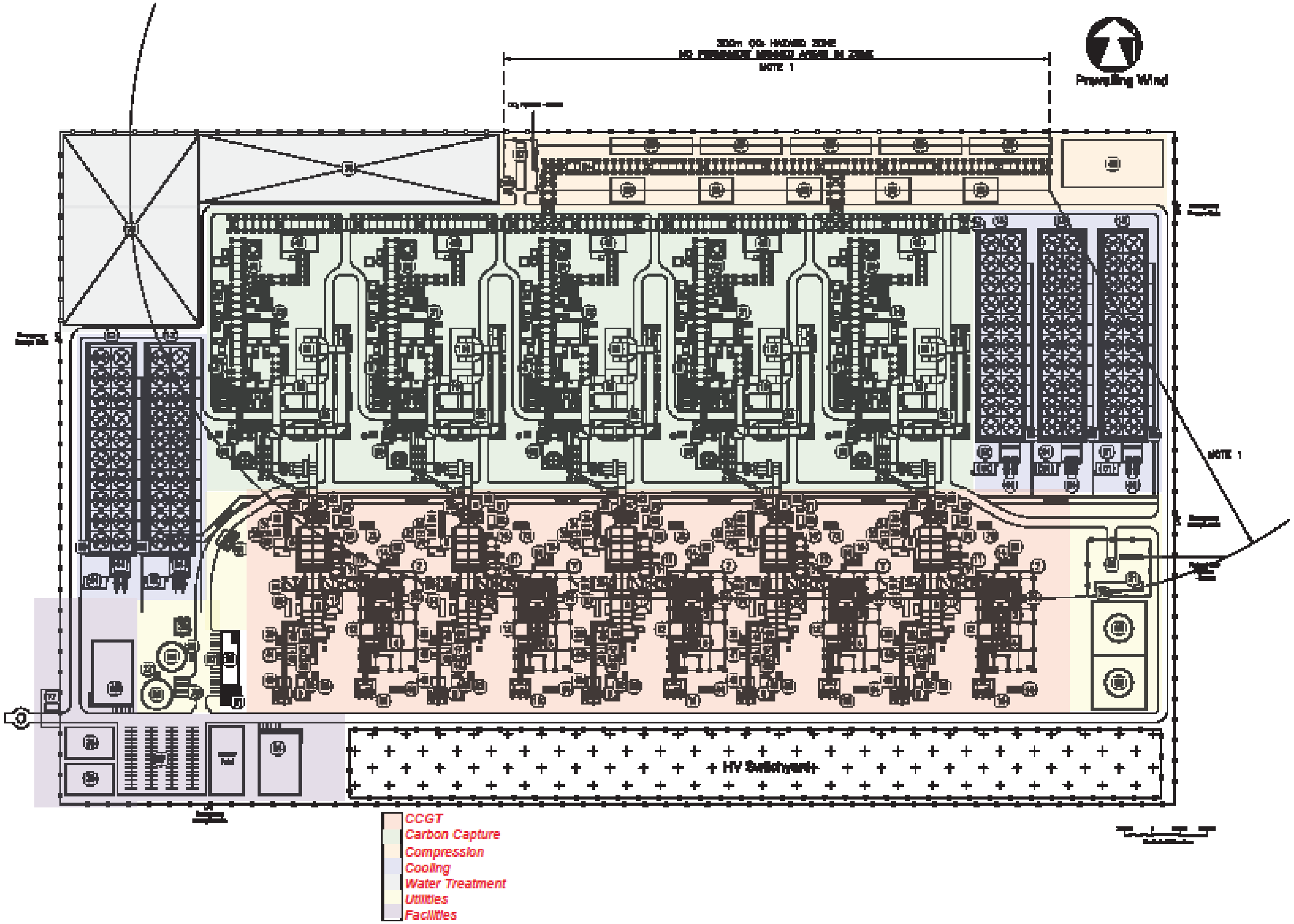


Figure 4 – Layout[11]

[11] The Cost Estimate is based on this layout

3.9 Offshore Facilities

Current UK policy decisions are that Carbon Capture and Storage in the UK would 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 saline aquifer
- West Coast – Hamilton depleted gas field
- Scotland – Goldeneye depleted gas field and Captain X saline aquifer

Wells would be drilled in the subsurface store: the well heads would be located on an offshore platform.

The offshore platform would consist of a conventional structural steel jacket with unmanned minimum facilities topsides. The topsides would 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 would be reached by boat for operations and maintenance. Safety systems would be installed on the platform for the safety of those working offshore. The boat would be of walk to work type and is intended to remain connected to the platform all the time personnel are working.

Platform

Each location would be served by a small normally unmanned wellhead platform.

Routine maintenance visits would 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 (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.

The installation would 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 containing the wellheads, injection filtration, metering and manifolds, utilities, Local Equipment Room (LER), and a muster area with adjacent temporary refuge.

Jacket

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

A conventional 4-legged Steel Jacket has been assumed for the application. A 3-legged design may suffice, but would increase risk (e.g. due to vessel damage of one leg) for only a small cost differential.

The steel jacket would be piled to the seabed and provide conductor guides in conjunction with a 6 slot well bay. The Jacket would be fabricated onshore, loaded onto an installation barge, and towed to site.

Offshore Wells

The offshore facility would 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 and required wellhead pressures for wells were taken from the Key Knowledge Documents (KKDs) and the Strategic Storage Appraisal Project (SAP).

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: it is therefore assumed for the Endurance field that 2 platforms, equally spaced over the aquifer, would 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 strategy for Hamilton follows the information from the (Pale Blue Dot Energy and Axis Well Technology, 2016) work in that there would be a gas phase injection in order to re-pressurise the depleted reservoir. Electric heating would be installed on the Hamilton Injection Platform to ensure the CO_2 stays in the gas phase during injection. Once the Hamilton Reservoir is suitably pressurised (approximately 11 years after commencement of operation) then liquid phase injection can be used requiring 2 new wells. During the liquid phase injection the electric heating on the platform would no longer be required but a chiller located onshore would be needed to keep the CO_2 in liquid phase in the subsea pipeline.

3.10 Safety In Design

The Thermal Power with CCS Scheme has a number of hazards associated with the Operation and Maintenance activities:

Carbon Dioxide (CO_2)

There is a danger to life from asphyxiation or toxicity of escaping CO_2. Engineering contractors in the UK have long experience of designing plants which contain hazardous materials and the design practices that have been developed, along with compliance with UK safety regulations, would ensure a safe design which eliminates or minimises the risk to operations of the plant and the general public.

The main impact on design is the location of the onshore plant and the routing of the CO_2 pipelines to maintain a safety distance to the nearest dwelling: this was applied in the site selection process for the different regions.

On the plant the manned areas are located at the opposite end of the site from the highest CO_2 hazard risk.

Natural Gas

There is a danger to life from the explosion of escaping natural gas. This hazard is present on all natural gas fired power stations and the power generation, hydrocarbon, and transmission industries in the UK are well practiced in the safe design, routing, operation, and maintenance of natural gas facilities.

The main impact on design was to have the natural gas supply pipeline buried until it is inside the boundary fence on the plant.

HV Electricity

High energy HV power transmission poses a threat to life. HV electrical systems are fenced off within the design to prevent unauthorised or uncontrolled access. HV power transmission is by overhead lines to separate people from power.

4 Site Selection

4.1 Site Selection Process

The objective of the site selection process was to apply a comprehensive and rigorous site selection methodology to identify credible sites for development of a CCGT + CCS plant of the type and size proposed for the Generic Business Case. The process considered a number of areas of the UK that are considered strategic with respect to CCS roll-out. The process identified sites which are preferred with respect to development and infrastructure costs, and were screened to avoid sites which may have prohibitive environmental or consenting constraints, in the context of risk mitigation for potential developers / funders of a project of this type.

The site selection was based on an objective assessment of all sites with the potential for development as a CCGT + CCS project. It was undertaken using a multi-stage process, as follows:

- Identification of search areas for potential sites.
- Long listing of brownfield sites that may have the potential for a CCGT + CCS development, i.e. existing or consented industrial / power plant sites, or land adjacent thereto.
- High-level estimate of available site area for the sites on the Long List, and exclusion of sites with <30 ha available area, to create a ‘medium list’ of potential sites with sufficient available area.
- Creation of a bespoke Graphical information System (GIS) model to score and rank the identified sites against a number of agreed selection criteria, and identify other areas which score favourably against these criteria (to identify potential greenfield sites). The output from this stage is a short list of high potential brownfield and greenfield sites for further review.
- Detailed desk-study review of the short-listed sites to assess their development potential.

4.2 Search Areas

The ETI’s work on the Strategic UK CO_2 Storage Appraisal Project has identified a top 20 inventory of sites. The site search areas considered sites that provide ready access to the identified preferred potential CO_2 stores, being Hamilton, Endurance, Goldeneye, and Captain (refer to Figure 5 below).

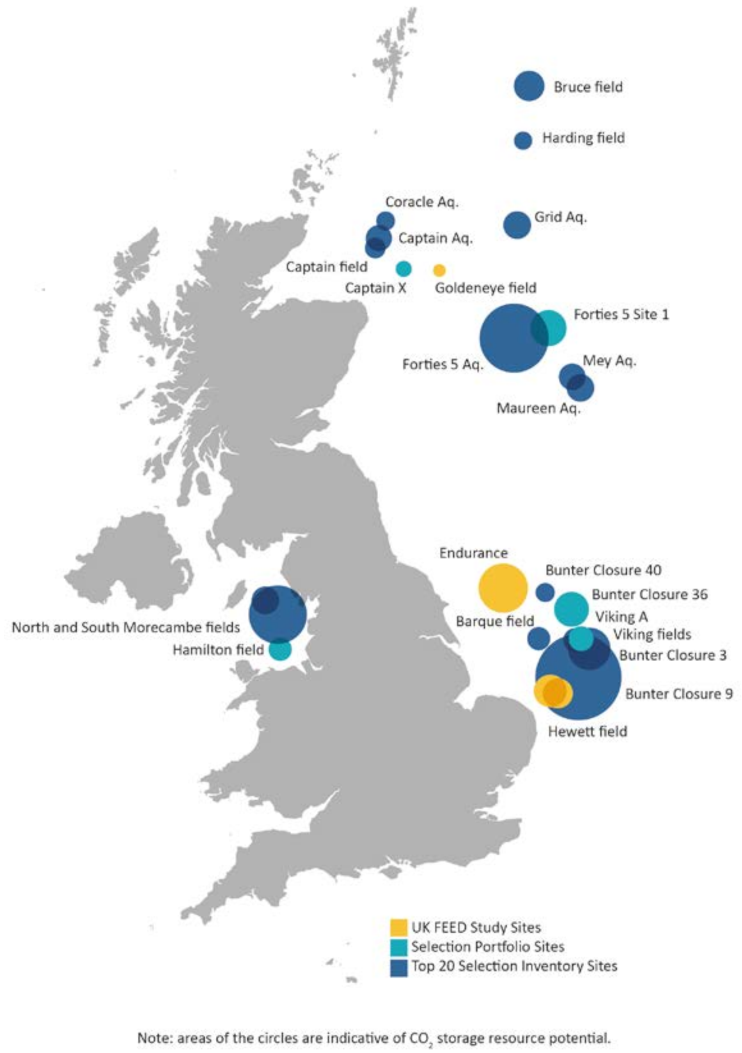


Figure 5 – CO_2 Storage Site Inventory (Pale Blue Dot Energy and Axis Well Technology, 2016)

The following regions within the UK have been chosen for this project.

Offshore Store	Selected Region (Number in Figure 6)
Endurance	Teesside (1)
Hamilton	North West / North Wales (2)
Endurance	North Humber (3)
Endurance	South Humber (5)
Goldeneye and Captain X	Scotland (see Figure 7)

Table 7 – Offshore Stores

To develop realistic cost information for a large scale CCGT + CCS project the connections and site works were determined for one of the shortlisted sites in each region and taken forward into the overall costing.

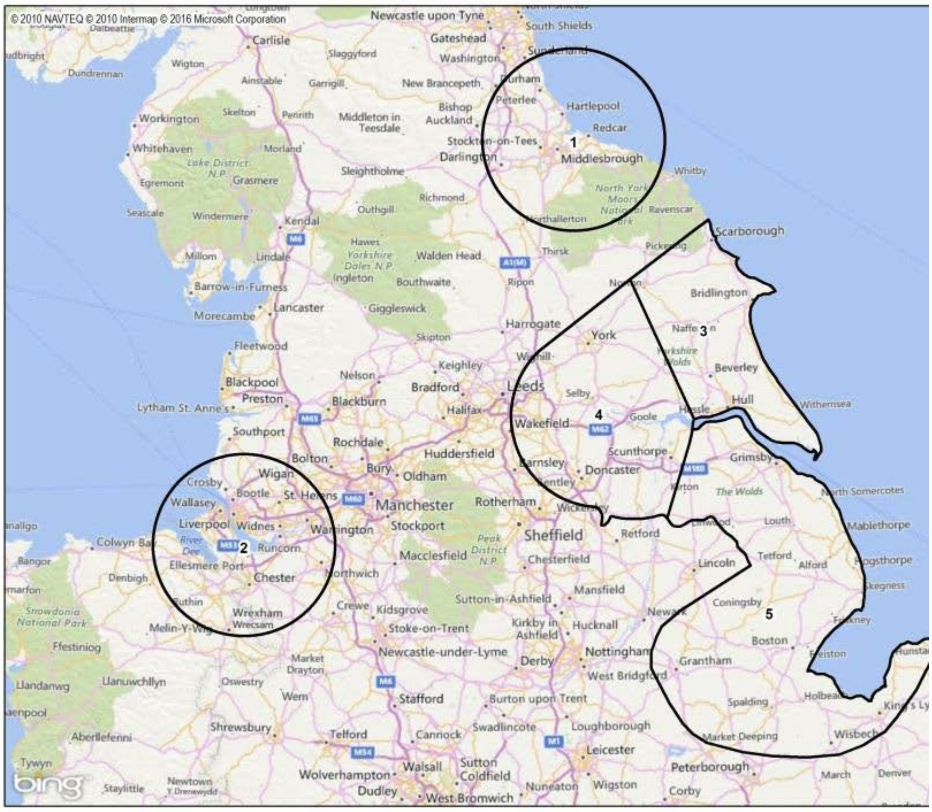


Figure 6 – Regions in Northern England and North Wales

The site selection process confirmed that there were multiple sites in each of the search areas selected for the study, which are considered suitable for the development of a CCGT with CCS project.

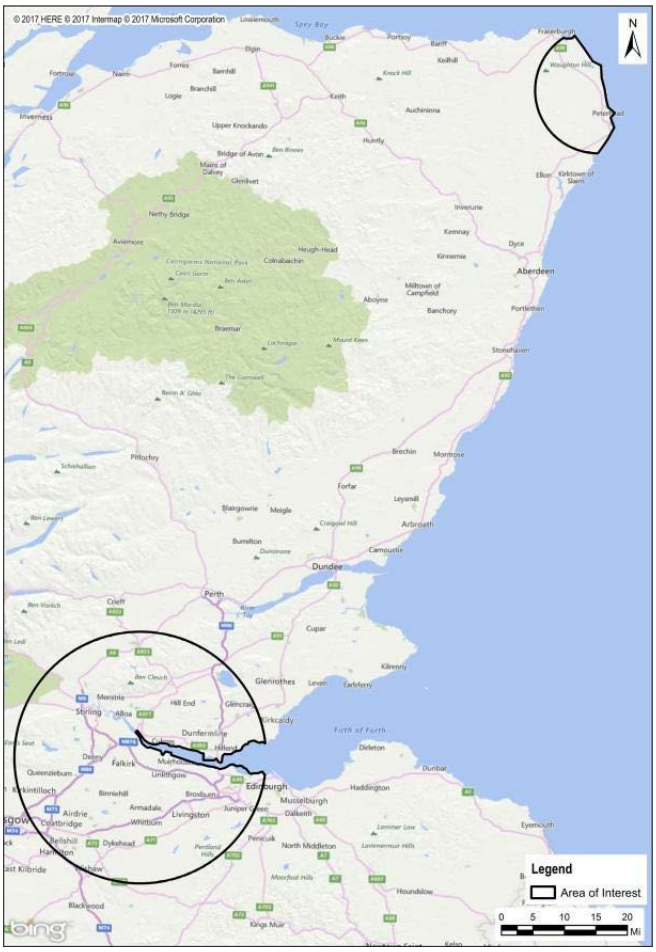


Figure 7 – Regions in Scotland

4.3 Long List to Short List Methodology

A Long List of brownfield sites within each search area was intended to identify all sites where the current or adjacent land use or consent status may be compatible with the development of a power generation project, and therefore the suitability and consentability of the site for power generation is anticipated to be favourable.

The Long List did not consider available site area at the identified location (this is considered as part of the down-selection of potential sites).

The Long List stage also did not consider land ownership, and / or openness of the land owners to the potential for a power generation development on these sites.

The initial Long List of potential brownfield sites was reviewed and, for the England and Wales search areas, was extended with a number of high potential greenfield sites that were identified from the GIS model. Down selection from the Long List has then been undertaken through the following steps:

› High-level estimate of available site area for each site; exclusion of sites with <30 ha available area to derive a ‘medium list’ of sites

- Manual identification of potential site boundary for:
  - remaining brownfield locations
  - high-ranking greenfield locations identified from the GIS model
- Inclusion of potential site boundaries into GIS model.
- Model analysis to score each 'medium list' site based on agreed selection criteria
- Manual review of the site scoring, and resulting ranking, to validate and finalise the identified short list

Assessment of available site area and potential site boundary was undertaken on the following basis:

- Map / aerial photography-based assessment to identify potential development areas with no significant existing constraints with respect to physical obstacles, existing infrastructure or development.
- No consideration was given to land ownership constraints or land acquisition potential.
- Site areas and boundaries were identified principally for the purpose of demonstrating the site area that may be available at each identified location, and as a means of applying the ranking criteria to the location.
- The site boundaries identified should therefore be considered as indicative only, and are not necessarily intended to illustrate the actual footprint of a potential plant to be developed in each location.

The bespoke GIS model used as part of the down-selection process was constructed including a range of significant constraints / parameters that may influence the site selection, with search criteria applied for each of these parameters. This included criteria relating to:

- Site topography
- Access for constructability and buffer to transport infrastructure
- Proximity to water supply
- Proximity to gas supply, and buffer to gas infrastructure
- Proximity to electrical grid connection, and buffer to grid infrastructure
- Proximity to carbon network / connection / landfall
- Environmental constraints
- Development constraints

Each of the criteria was weighted and scored between 0 and 2 (2 being preferred). The search area was divided into 25m x 25m cells, and the model then used to assess each of these cells against the various criteria, to obtain a total score for each cell. For the identified sites, statistical analysis of the scores for each of the cells within the site boundary was undertaken, with final site assessment based on the minimum score of any cell, the maximum score for any cell, and the mean score for all of the cells within the site boundary.

The Short List was derived by selecting the highest scoring sites in each region, based on mean site score from the GIS model, modified where considered appropriate by a manual review of the scoring and ranking.

4.4 Detailed Site Assessment

Further assessment and down-selection from the Short List of sites was based on a manual review of each of the short-listed sites, to consider in more detail the principal development constraints and opportunities for each site: this used qualitative and quantitative assessments and professional judgement.

This final down-selection used seven principal criteria, as follows:

- Consentability of site
- Environmental constraints / mitigation
- Land ownership
- Infrastructure capacity / connections
- Site development requirements
- Constructability
- Operability / Process Safety

These assessments were informed by:

- A site ‘drive-by’ visit to each site (excluding the Scotland search areas), to view the context and constraints around each site, with reference to the seven criteria above
- Review of publically available information regarding the sites and the infrastructure that would serve them
- Reference to AECOM in-house knowledge and experience from previous work undertaken that may be relevant to the proposed developments

4.5 Summary of Preferred Site Selection

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
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 8 – Sites within Each Region

With regards the naming of the sites it should be noted that, while some are named after the general area or specific location of the site, in many cases they are named after an adjacent, existing facility to reference the general location and / or existing land use on which the selection of the site is based. This naming does not necessarily mean that it is proposed that the CCGT + CCS development would be on the same site and / or in place of the existing facility.

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). However the Planning Inspectorate announced that the Development Consent Order (DCO) for this pipeline had been refused. Without this pipeline, development of any project in the Camblesforth region would need a potential c. £200m[12] new pipeline which would make the development of a CCGT + CCS 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.

[12] based on the Key Knowledge Documents for the White Rose project.

5 Capital Cost Estimation

This section 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 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 providing an EPC Tender for the Shell Peterhead CCS, provided an important data source for this project.

5.1 CCGT + CCS Scheme Design

Technology

The Power Generation Units for the GBC project use the largest credible Combined Cycle Gas Turbine (CCGT) Power Blocks available today. 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 maximising 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

Designs and cost estimates were carried out, using the scheme design described in section 3 of this report, 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 9 – Offshore Stores and CO_2 Transport

5.2 Capital Cost Estimating

The majority of the CAPEX cost estimate was built up from a major equipment list. Modelling of the CCGT power plant and carbon capture and storage plant through specialist software 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 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.

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 organisation.

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 used its 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 was 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 were estimated as follows:

Site acquisition – Costs were estimated using a report that is available in the public domain (UK Department for Communities and Local Government, 2015).

Site Enabling works – Site establishment were estimated based on the layout design from the project and used recent UK unit rates for work.

Detailed design - Detailed engineering hours were calculated as a percentage of total installed cost. This differs per section of the estimate and was 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 was added to each section of the estimate.

Connection Costs - Connection costs were estimated using data from the site selection process including distances, crossings, and types of terrain.[13]

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

Regions - The cost difference between an example site for each region was 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 were 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 was built up as a block allowing for ease of estimation for 1 to 5 trains. The connection costs were calculated based on capacity required for differing numbers of trains.

A buy down saving was considered for the purchase of multiple gas turbines but has not been considered for other procurement items.

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

Accuracy

The capital cost estimate was based on the Association for the Advancement of Cost Engineering International guidelines for estimating, and followed 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, 2005).

The OPEX estimate may be considered analogous to a Class IV estimate as the methodologies and accuracy ranges are in keeping with the AACE estimating standards for this level.

[13] For the power export connections, the costs to nearest appropriate substation were considered for the estimates, but not any grid-strengthening that might be required for a large new power generation station.

Uncertainty

Three levels of uncertainty were incorporated within this estimate: contractors' contingency, project contingency, and project risk.

The contractors' contingency was included as an amount expected to be within EPC contractor tenders. This included detailed design allowance, small changes between FEED and detailed design that do not constitute a scope change, and inclement weather delay. This is included in the 'Base Cost' estimates presented at a rate of 10% which is applied to detailed engineering, equipment procurement and installation, bulk material subcontracts, and contractor's commissioning and start-up costs.

Project contingency was 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.

The contingency percentage was estimated through a probabilistic approach and the judgement and experience of the project team. The amount of contingency will 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. A maximum, most likely, and minimum value were assigned to each cost item, and the resulting data was run through a Monte Carlo analysis, which produced the P50 and P90 values. For clarity, a P90 value means that a project should have a 90% probability of completion at or below the P90 figure.

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

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. Although many of the major equipment items (e.g. GT, compressor) were assumed to be sourced overseas, the local UK content was indicated to be ~80% of the Capital Cost Value based on GBP currency expenditure.

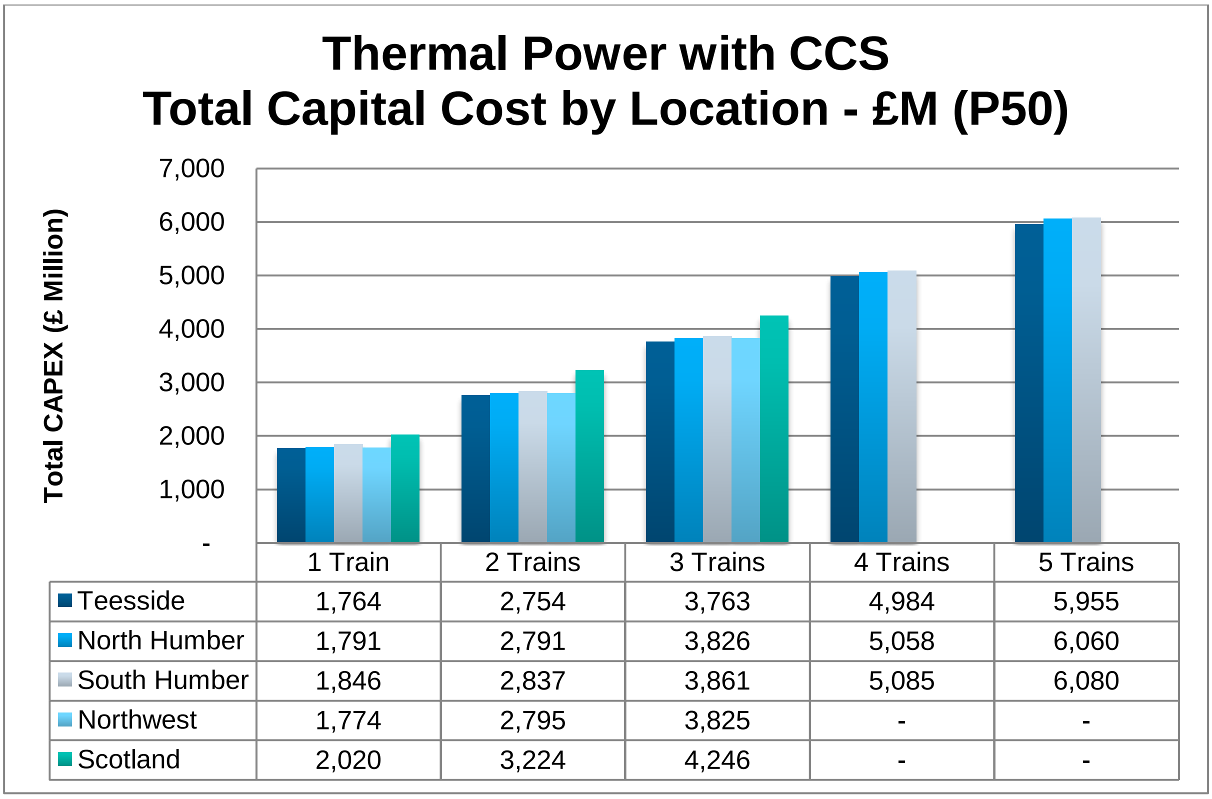
Thermal Power with CCS	One Train (£m)	2 Trains (£m)	3 Trains (£m)	4 Trains (£m)	5 Trains (£m)
Power Generation (CCGT)	577	1,012	1,438	1,857	2,269
Carbon Capture	588	1,021	1,470	1,918	2,367
CO_2 Transportation	224	234	255	303	303
Offshore Storage	206	223	239	428	444
Total Base Cost	1,595	2,490	3,402	4,506	5,384
Total Cost including Risk and Contingency	**One Train**	**2 Trains**	**3 Trains**	**4 Trains**	**5 Trains**
P50	1,764	2,754	3,763	4,984	5,955
P90	1,874	2,926	3,997	5,295	6,326

Table 10 – P50 and P90 Cost Estimates against Abated Output for Teesside Location (£m)

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

Regions

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



	1 Train	2 Trains	3 Trains	4 Trains	5 Trains
Teesside	1,764	2,754	3,763	4,984	5,955
North Humber	1,791	2,791	3,826	5,058	6,060
South Humber	1,846	2,837	3,861	5,085	6,080
Northwest	1,774	2,795	3,825	-	-
Scotland	2,020	3,224	4,246	-	-

Figure 8 – Summary of Cost Estimate Scale

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

Scotland was the most expensive region analysed. This was because the selected site is in Southern Scotland which required a long pipeline running up the East side of Scotland from the Firth of Forth to St Fergus. The cost estimate allowed for the reuse of Feeder 10, however, the CO_2 pipeline route required 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. The Scotland site selected also benefited from access to dock / quay / shore side which would allow extensive modularisation / prefabrication, reducing the amount cost / risk / safety exposure on the construction site.

Size / Scale

Publicly available CCGT plant benchmark data shows an advantage in economies of scale in going for a larger plant. Although the cost estimate for the GBC project confirms some advantage in the economy of scale, it was less than initially expected. This is discussed further in Section 5.3.

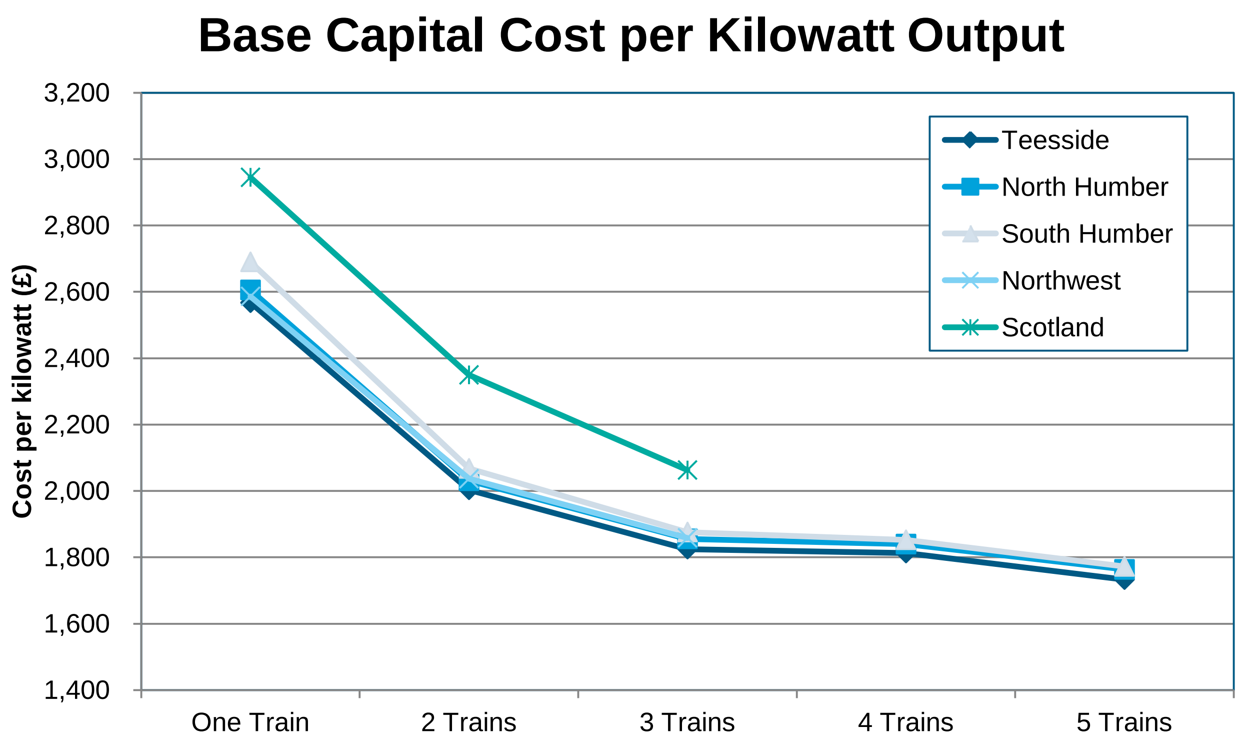


Figure 9 - Base Capital Cost per Kilowatt Output (kW net after CCS)

The estimates show that there is significant economy of scale for the Capital Costs moving from 1 to 2 to 3 trains (each train will be as shown in Figure 9 above). The economy of scale benefit is due to the following factors.

- There are common management, engineering, construction, facilities, and utilities costs which are shared between trains which offer an economy of scale for multiple trains compared to a single train (assuming a common design between trains).
- Pipeline costs are dominated by their length and only have a small dependence on their diameter, providing an economy of scale benefit for multiple trains (meaning the cost per tonne of CO_2 transported falls).
- For the stores considered in this project, one injection platform has enough capacity for CO_2 from up to 3 trains (3 x 600 MW): an additional cost for multiple trains would be for additional injection wells but not more platforms/facilities.

The economy of scale benefit reduces for a 4 to 5 train scheme as an additional offshore injection platform and infield subsea pipeline would be required.

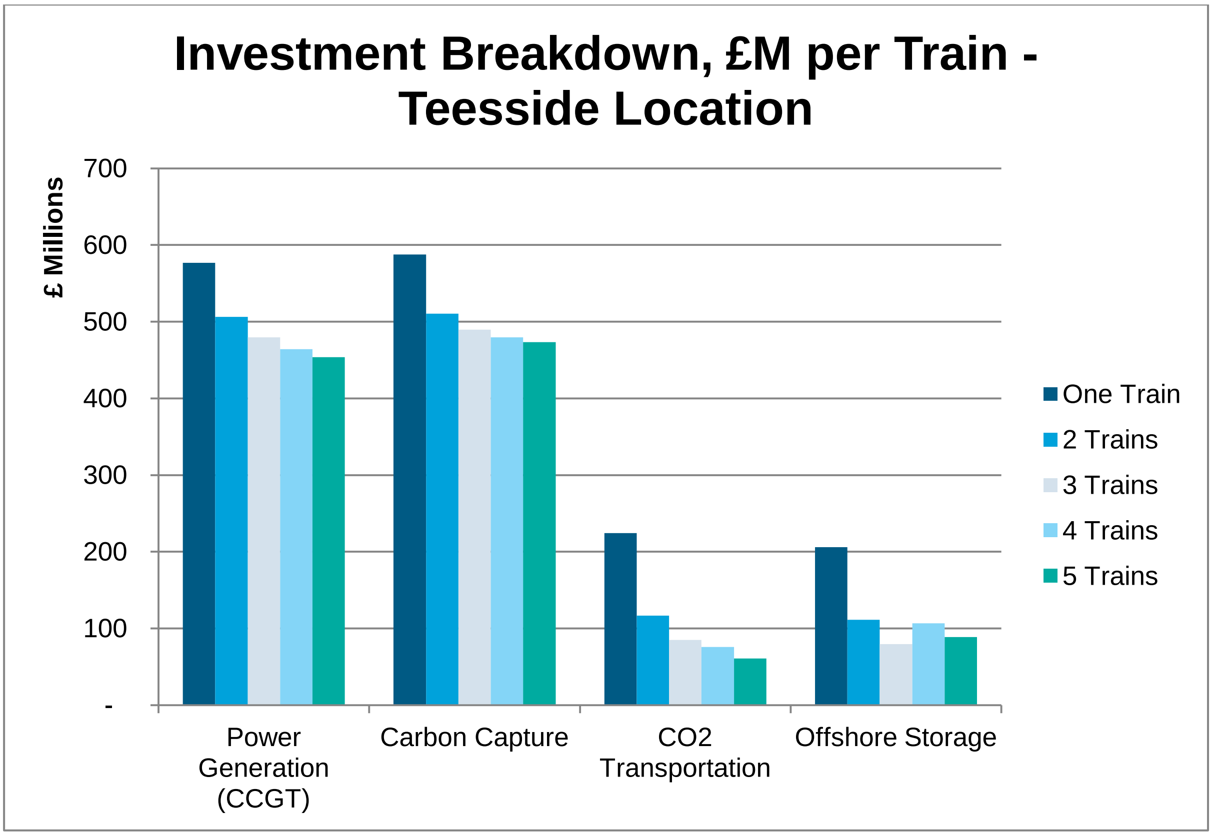


Figure 10 - Summary of Cost Estimate Scale

Location

A CCGT + CCS scheme is sensitive to location. There was a large cost element within the project for transportation and utility connection infrastructure. It was therefore advantageous to be near to the CO_2 store and to be near the utility connections. There was 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 became 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.

5.3 Benchmarking

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 in Figure 11 - Cost Benchmarking Data for UK CCGT Plant.

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. £700/kW and £500/kW lines have been added to the following graph to compare against the data.

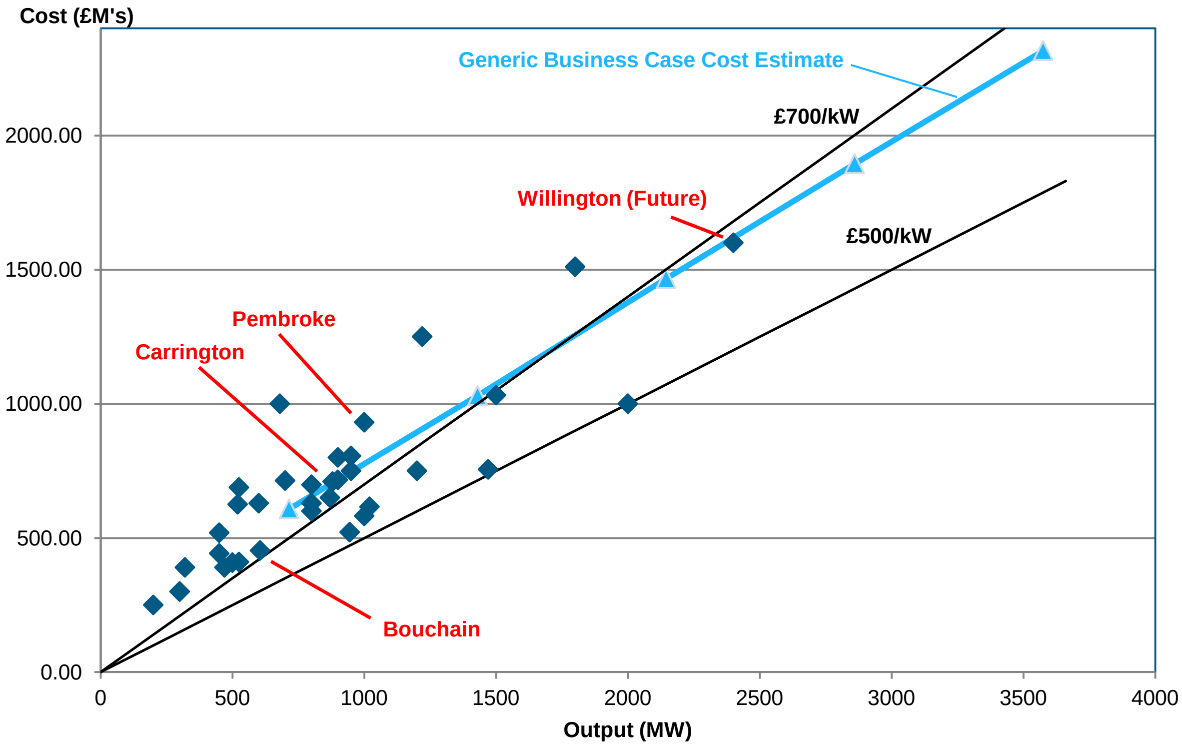


Figure 11 - Cost Benchmarking Data for UK CCGT Plant

The Generic Business Case estimates for 1 to 5 trains have 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. 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 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). The larger size of 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 is 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. In summary, the layout of the GBC is largely dictated by the capture and compression plant which in turn increases the CCGT costs 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.

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 (see Figure 12). 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.

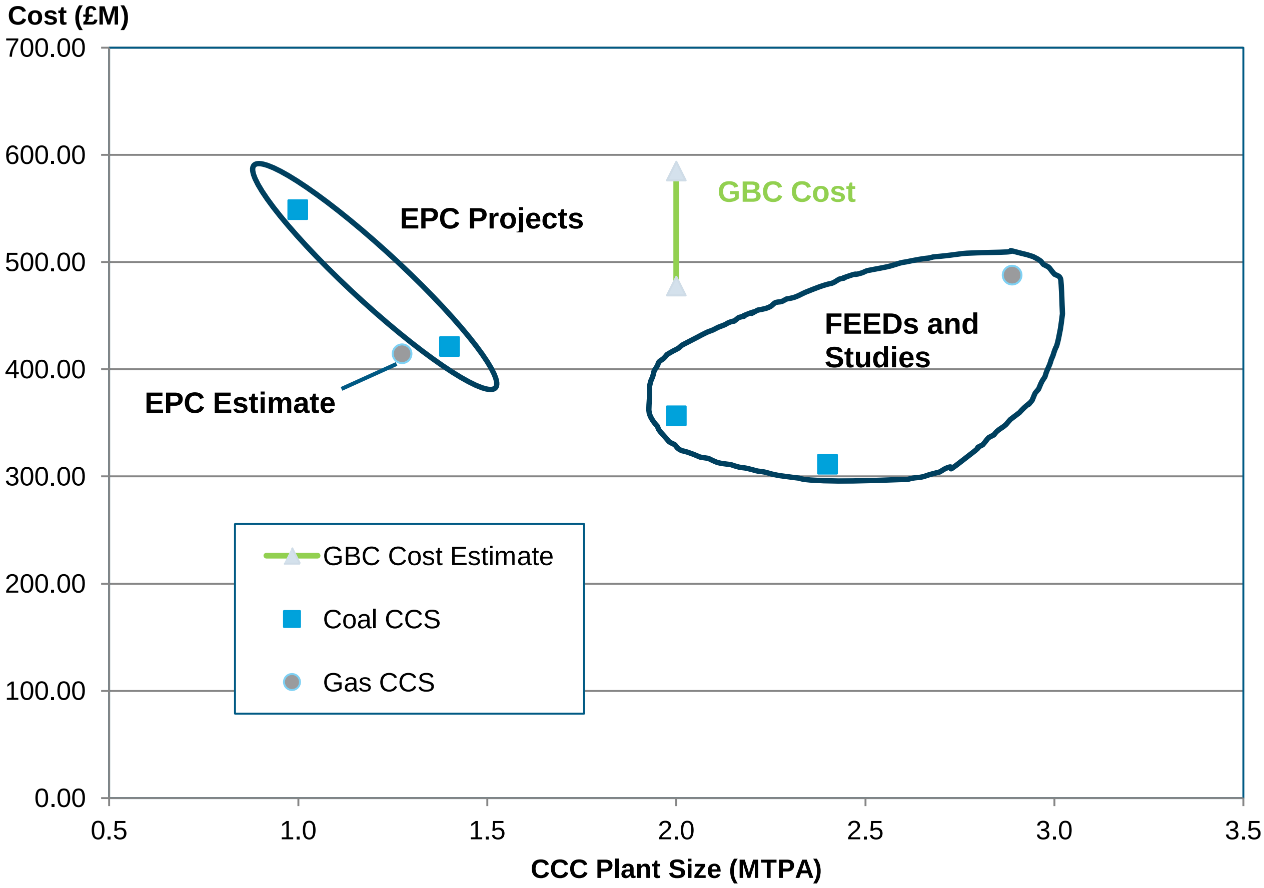


Figure 12 - Cost Benchmarking Data for Post Combustion Amine CCC Plants

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.

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. A similar benchmark of £61,036/km-in is available using an approach from Petroskills (Hairston & Moshfeghian, 2013) and the GBC project data.

The pipeline estimates produced for the GBC ranging from £54,144/km-in to £70,138/km-in are not inconsistent with these benchmarks.

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).

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 £73,387/km-in (adjusted to a 2016 basis); 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)	£/km-in	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 11 – 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 drilling wells; these range from £9.3 to £15.2 million per well.

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	Benchmark	Benchmark
		(£M)	(£/tonne)	(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 12 – 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. The provision for the future brine production is only supporting steelwork (without equipment or materials) and results in there being a greater proportion of main steelwork in the makeup of the overall weight. The main steelwork is lower cost per tonne than lighter steelwork 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).

Overall

There are no UK CCGT + CCS plants in operation for the purposes of benchmarking: the CAPEX has therefore been compared with 2 other types of sources – a report from the UK Government and the Shell Peterhead CCS Project.

Peterhead CAPEX was £999,750,000 (Shell UK Limited, 2016) for a post combustion amine CCS applied to a CCGT.

- The Peterhead Project CAPEX = £2516 per Gross kW compared to £2410 per Gross kW for 1 train (both at a P50 level). This shows that there is consistency between the projects noting that the Peterhead project intended to modify the CCGT and not build a new CCGT which is the basis of the GBC.
- The Peterhead Project CAPEX = £890 TPA of CO_2 stored compared to £914 TPA of CO_2 stored for 1 train (both at a P50 level). This shows that there is consistency between the projects noting again that the Peterhead project intended to modify the CCGT and not build a new CCGT which is the basis of the GBC.

The CCGT + CCS CAPEX was compared to the UK Government's latest energy generation costs (BEIS, November 2016). Using the medium pricing from pre-development to infrastructure the cost estimate was 2,150 per kW + £15.1M for infrastructure for a 963 MW sized plant. Including the infrastructure in the cost per kW yields £2,166 which compares to £2,410 per Gross kW for 1 train for the Generic Business Case, and £1,881 per Gross kW for 2 trains. The cost estimate for 1 train was 11% higher than the government cost presented which is considered satisfactory considering any differences in estimating approach (i.e. what is the difference between the length of the infrastructure connections between benchmark and GBC).

6 Operating Cost Modelling

This Section provides an operating cost estimate for a generic plant design at a range of plant sizes deployed in a number of regions in the UK.[14] The report includes abandonment costs at the end of the life of the facilities.

A robust estimate has been created from the bottom up, using detailed modelling work and industry expertise as the basis for the maintenance, utility and consumables, and staffing schedules used as the foundation of the cost model.

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. The OPEX estimate may be considered analogous to a Class IV estimate as the methodologies and accuracy ranges are in keeping with the AACE estimating standards for this level.

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.

Operation

The work undertaken by the project shows that the complexity of the CCS chain from CCGT flue gases, through carbon capture, compression, CO_2 transportation and injection makes frequent starting and stopping of the plant challenging, so that a CCGT+CCS scheme would be best suited to baseload or high load factor operation. Restarting once the capture plant has cooled and/or injection stopped could take many hours, meaning that operation of the plant for 'two-shifting' and 'peaking' operation would be impractical. Conversely the plant could potentially be operated under load-following conditions where GTs may be turned down to approximately 50% of their rated capacity (but not shut down).

Maintenance

The maintenance schedule is set by the intervals required for the CCGT equipment: the remainder of the chain would fit in with these maintenance intervals.

Careful consideration needs to given to effective HSE management during major maintenance / turnarounds. It may be necessary to shut down and depressurise the whole plant such that the larger population on site required for these activities is not exposed to the CO_2 hazard from the high pressure areas of the plant.

[14] The report does not cover revenues or Levelised Cost of Electricity (LCOE).

6.1 Annual OPEX Costs

OPEX costs vary year on year depending on the amount of operation and the maintenance tasks that are scheduled.

Table 13 provides a breakdown for OPEX for the first 6 years of the plant's life for a single train.

Operating Expenses (£million)	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Availability	88.33%	94.33%	86.91%	94.83%	95.08%	83.83%
Variable Expenses						
Utilities	0.21	0.24	0.25	0.27	0.27	0.24
Fuel Gas	133.32	153.32	158.01	172.41	172.87	152.40
Consumables	6.75	7.69	7.91	7.91	7.91	7.91
Disposals	0.19	0.19	0.19	0.19	0.19	0.19
Carbon Tax	3.64	4.00	4.08	4.34	4.35	3.98
Cost for Cold Starts	1.49	1.49	1.49	1.49	1.49	1.49
Costs for Warm Starts	1.19	1.19	1.19	1.19	1.19	1.19
Costs for Hot Starts	0.50	0.50	0.50	0.50	0.50	0.50
Total Variable Expenses	*£147.28*	*£168.61*	*£173.61*	*£188.29*	*£188.75*	*£167.89*
Fixed Expenses						
Labour	10.36	10.36	10.36	10.36	10.36	10.36
Maintenance	14.81	6.18	10.39	6.18	41.02	21.70
Regulatory Expenses	0.03	0.03	0.03	0.03	0.03	0.03
Subcontracts - Fixed	2.69	2.69	2.69	2.69	2.92	14.03
Administrative and Other Expenses	62.25	51.55	51.60	51.58	51.58	51.54
Total Fixed Expenses	*£90.14*	*£70.80*	*£75.07*	*£70.83*	*£105.90*	*£97.66*
Total OPEX	**£237.42**	**£239.41**	**£248.68**	**£259.13**	**£294.66**	**£265.56**

Table 13 - Operating Costs by Year for 1 Train (Year 1 to 6)

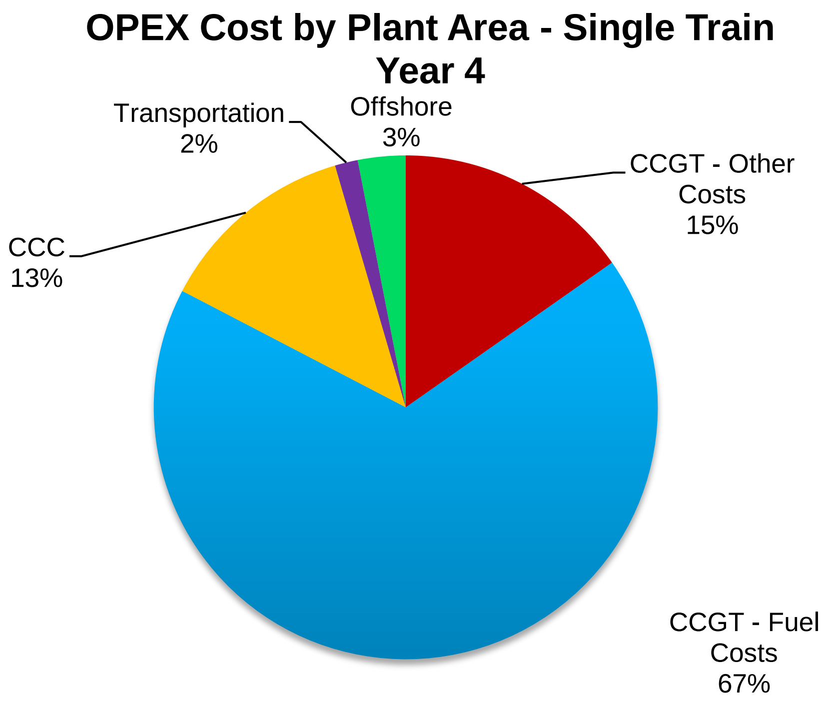


Figure 13 - OPEX Costs by Plant Area

Insurance is the largest component of the fixed OPEX costs, making up 12 to 15 % of the annual operating costs.

Onshore maintenance costs follow a rotating 6 year cycle, dominated by the gas turbine maintenance schedule. The maintenance offshore maintenance costs follow a 5-year cycle dominated by the measurement, monitoring, and verification (MMV) costs (see Figure 14). The shift pattern for operations and maintenance staffing assumed is for 24 hours operation by 6 teams, with one team rotating out to do offshore inspection and maintenance. Labour levels have been optimised for each number of trains, rather than directly scaled. Additional fixed costs are included for specialist maintenance contractors and regulatory expenses.

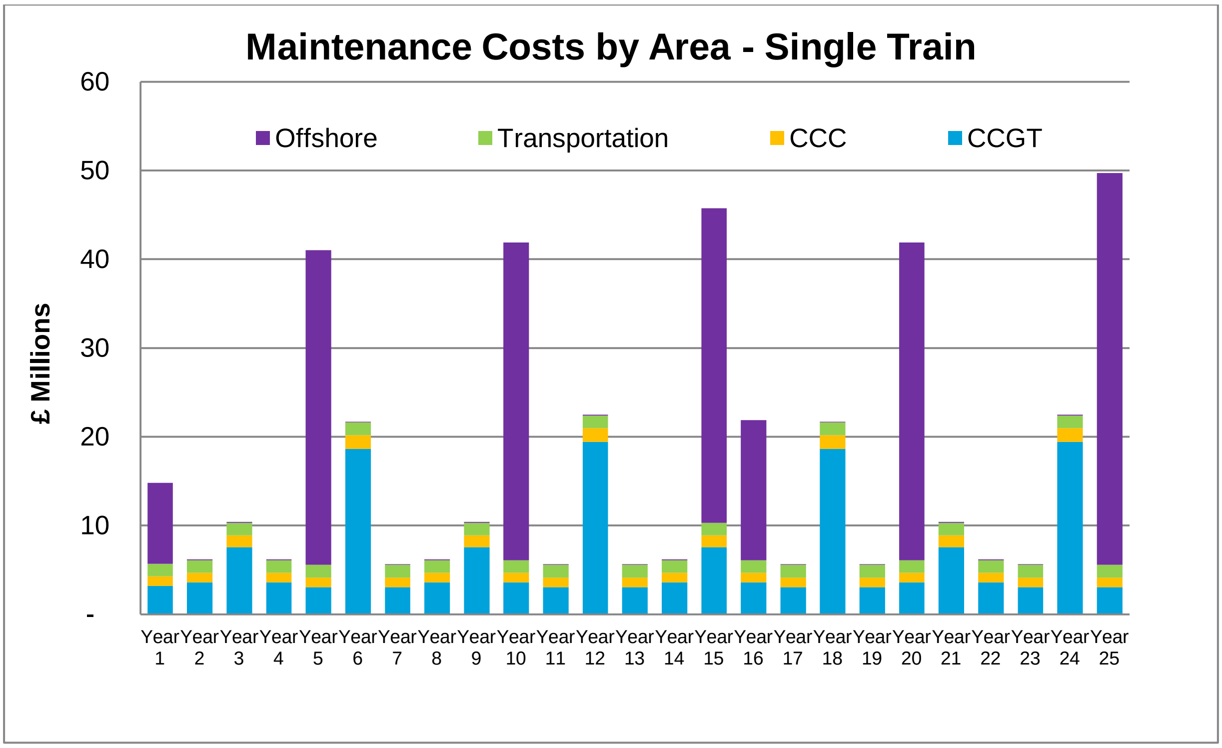


Figure 14 - Maintenance Costs by Year - Single Train

Additional sensitivity analysis has been performed on fuel cost as it makes up a significant portion of the overall OPEX. The OPEX model has been estimated on a fuel cost of 50.1 pence per Therm. This is representative of the 5-year average in the UK wholesale natural gas market (OFGEM, 2017). As the cost of fuel accounts for more than 65% of the total operating cost, the commercial operation of the plant is highly sensitive to a change in the natural gas price.

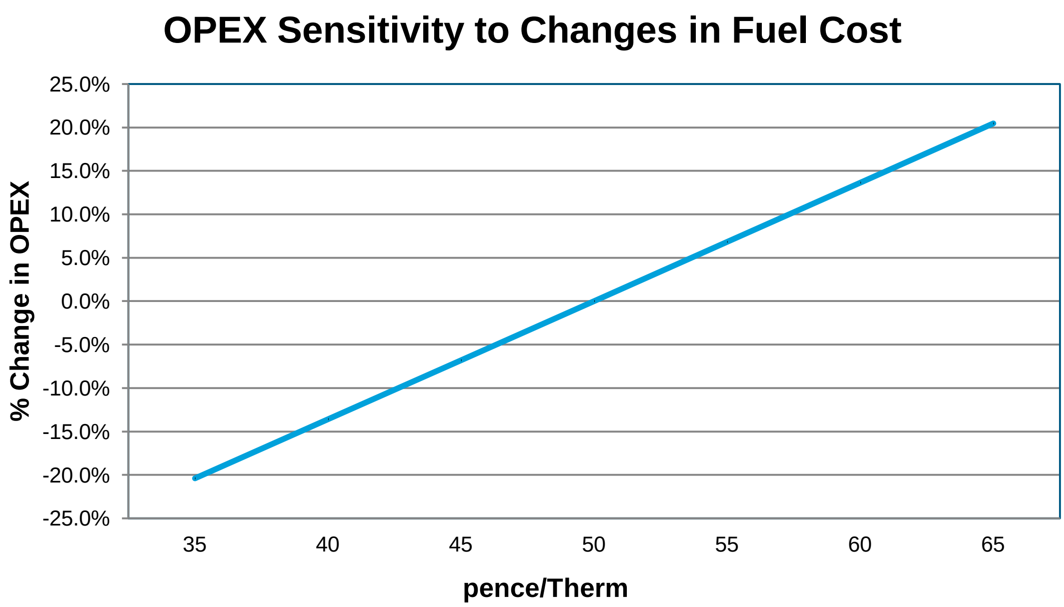


Figure 15 - Fuel Cost Sensitivity

Consumables included in the OPEX estimate include the chemicals and catalysts used in the general operations of the plant. Two main items are material to the overall cost: Engineered Amine and Sodium Hydroxide (NaOH), making up over 60% of the cost of consumables. Additional expenses have been included for utilities, such as raw and towns water.

Costs have been estimate for hot, warm, and cold starts which show that there is a significant cost for cold starts because of the time taken from the start of the CCGTs before export of CO_2 can recommence. Assuming that revenue cannot be earned against a CfD until the plant has reached abated operation each cold start would cost approximately £0.5M. This reinforces that a mode of operation with frequent stops and starts is not preferred to baseload operation.

The cost of carbon has been estimated at £18 per tonne as per UK government publications (HM Revenue and Customs, 2014). The carbon price is expected to remain capped until after 2020 (HM Treasury and Rt Hon Philip Hammond MP, 2016). For the purposes of this estimate, the current rates are assumed constant for the duration of the operating life.

Number of Trains

The OPEX model produced by the project team shows that OPEX per kW is not a strong function of plant size, though there is some reduction due to staffing optimisation for multiple units, one offshore platform servicing multiple trains, and economies of scale in administrative costs: this is shown in the following table.

OPEX Costs	1 Train	2 Train	3 Train	4 Train	5 Train
£ / kW	£423	£397	£389	£387	£384

Table 14 – OPEX Estimate per kW

Regions

Regional differences in operating costs are minimal with the exception of additional offshore consumables, maintenance, and monitoring costs for the addition of a second platform for the North East regions for 4 and 5 trains and Scotland for 2 and 3 trains (see Figure 16). An additional platform would result in increased consumables of £510,000 annually, and increased maintenance and inspection costs of £35 million.

Small differences may exist for utility costs or wayleave costs; however, this nuance has a negligible impact on the overall operating costs. Labour costs may also vary slightly between regions. A 5% increase in total labour costs would result in a 0.19% increase in OPEX for a single train plant.

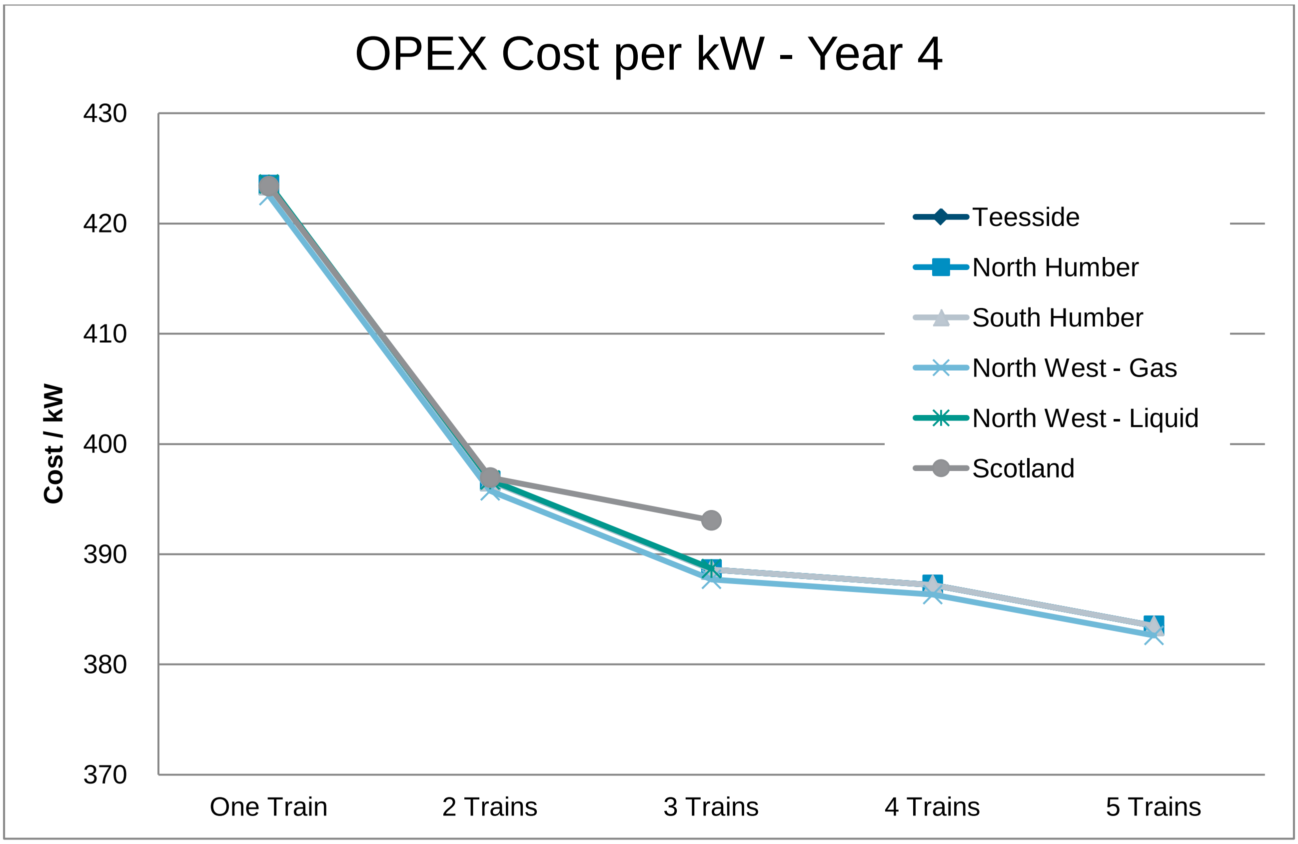


Figure 16 - OPEX Cost per kW

Increased electrical costs for the offshore heating and chiller required in the Northwest / North Wales region, and the shoreline booster and compression stations for the Scotland region are considered as parasitic load and thus not reflected in the absolute operating costs; these factors are captured in the nominal output per region.

6.2 Abandonment

The decommissioning and abandonment costs (ABEX) have been estimated. These show that the abandonment costs for the Northwest/North Wales region is lower than the North East of England regions because the maximum plant size is smaller (3 trains compared to 5) and because there is only one offshore facility to abandon compared to two platforms for 4 or 5 train size plant over the Endurance Aquifer.

Scotland has the highest cost, due primarily to the cost of abandoning two offshore platforms which are installed in deeper water than other regions. It also includes the abandonment of the existing 198 km Feeder 10 pipeline.

Offshore pipelines have been estimated using data from Oil and Gas's 2013 "Decommissioning Pipelines in the North Sea" and Offshore Magazine, and assuming that the lines would be flushed, cut, and lifted (Oil & Gas UK, 2013), (Borwell, 2014).

No. Trains	**5 Trains**	**5 Trains**	**5 Trains**	**3 Trains**	**3 Trains**
Area	**Teesside**	**North Humber**	**South Humber**	**Northwest / North Wales**	**Scotland**
Total Cost (£m)	£197	£192	£193	£130	£231

Table 15 – Abandonment Cost per Region

6.3 Benchmarking

There are no UK CCGT + CCS plants in operation for the purposes of benchmarking: the OPEX has therefore been compared with 2 other types of sources – a report from the UK Government and the Shell Peterhead CCS Project.

Peterhead OPEX was £3,668,700,000 (Shell UK Limited, 2016) for a 1.1 MTPA CCGT + CCS. Removing fuel costs (80% of Power Plant OPEX) this becomes £1,331,900 for 15 years. Fuel costs are removed because they are dependent on the cost for natural gas which can fluctuate widely.

- The Peterhead CCS OPEX without fuel is £88.8m per annum compared to £83.9m for a single train of the GBC project.
- This was £79 per TPA of CO_2 stored compared to £44 per TPA of CO_2 stored for the GBC project showing the economy of scale improvement for a larger scheme.
- This is £223/kW as an annual OPEX per net kW compared to £114.6/kW for the GBC project showing the economy of scale improvement for a larger scheme.

Economies of scale exist most significantly in the capital and operating cost of the offshore storage platform and connection costs. With one pipeline servicing up to 5 trains, changing only slightly for capacity, and 1 platform up to 3 trains, or 2 platforms for 5 trains, significant savings for larger plants can be observed, particularly compared to the benchmarks using one full set of connections and one platform for a single train.

The CCGT + CCS OPEX was compared to the UK Government's latest energy generation costs (BEIS, November 2016). Applying the BEIS costs to the GBC design yields an OPEX of £59.0m / year which compares to the GBC project OPEX estimate of £83.9m for a single train CCGT + CCS.[15]

[15] The OPEX of £59.0 / year is generated using the medium pricing from Fixed O&M, Insurance, and Connections from the BEIS document of £41,600/MW-year. 35% of the variable O&M is £3/MWhr assuming that 65% of the variable O&M estimate is fuel cost as per the GBC project. Applying these assumptions for the Fixed and Variable OPEX to the net GBC plant yields £30.5m fixed plus £28.5m variable = £59.0m / year.

7 Conclusions

Design and Site Selection

A design has been produced by the Generic Business Case (GBC) for a large scale deployment of CCGT + CCS.

The design and technology for a large scale CCGT + CCS is technically feasible and can be based on technology currently in commercial operation.

A layout for the onshore plant has been produced as part of the design and has been used for site selection.

Five regions of the UK have been selected for the site selection work based on their proximity to offshore CO_2 stores appraised by the Commercialisation Competition or the ETI Strategic UK Storage Appraisal Project.

The site selection work for the GBC has shown that there is a range of potential sites in each region reviewed that could be used for the implementation of a large scale CCGT + CCS scheme.

The work undertaken for the GBC considered safety in design issues such as the layout of the onshore plant, routing of pipelines, and proximity of hazards to dwellings. There is a safety in design and cost advantage to locating the onshore CCGT + CCC plant in close proximity to the CO_2 pipeline landfall, especially if this facilitates modularisation by allowing access to for large items to be brought onto site.

Scale

CAPEX, OPEX and abandonment expenditure (ABEX) estimates have been produced for the Generic Business Case.

The estimates show that there is significant economy of scale for both CAPEX and OPEX moving from 1 to 2 to 3 trains (each train will be as shown in Figure 9 and Figure 16 above). The economy of scale benefit is due to the following factors.

- There are common management, engineering, construction, facilities, and utilities costs which are shared between trains which offer an economy of scale for multiple trains compared to a single train (assuming a common design between trains).
- Pipeline costs are dominated by their length and only have a small dependence on their diameter, providing an economy of scale benefit for multiple trains (meaning the cost per tonne of CO_2 transported falls).
- For the stores considered in this project, one injection platform has enough capacity for CO_2 from up to 3 trains (3 x 600 MW): an additional cost for multiple trains would be for additional injection wells but not more platforms/facilities.

The CAPEX and OPEX show less improvement with scale for a 4 or 5 train scheme as an additional offshore injection platform and infield subsea pipeline is required for the selected storage site.

Regions

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

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

Scotland was the most expensive region analysed. This was because the selected site is in Southern Scotland which required a long pipeline running up the East side of Scotland from the Firth of Forth to St Fergus. The cost estimate allowed for the reuse of Feeder 10, however, the CO_2 pipeline route required 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. There would be a cost benefit for the Scotland Region as a result of modularisation due to a potential quay/dock/shore side location; however, the CO_2 transportation costs significantly outweigh the savings.

8 Abbreviations

The following abbreviations have been used in this document:

Abbreviation	Description
AACE	Association for the Advancement of Cost Engineering
ABEX	Abandonment Expenditure
AGI	Above Ground Installation
BEIS	Department for Business, Energy and Industrial Strategy
CAPEX	Capital Expenditure
CC	Carbon Capture
CCC	Carbon Capture and Compression
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CfD	Contract for Difference
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
DCO	Development Consent Order
DECC	Department of Energy and Climate Change (now BEIS)
DRILLEX	Drilling Expenditure
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement, and Construction
ETI	Energy Technologies Institute
FEED	Front End Engineering Design
FOAK	First of a Kind
GB	Great Britain
GBC	Generic Business Case
GIS	Geographic Information System
GT	Gas Turbine
HAZID	Hazard Identification Study
HAZOP	Hazard and Operability Study

Abbreviation	Description
HP	High Pressure
HRSG	Heat Recovery Steam Generator
HS2	High Speed 2
HV	High Voltage
ICSS	Integrated Control and Safety System
IEAGHG	International Energy Association – Green House Gases
KKD	Key Knowledge Documents
LCOE	Levelised Cost of Electricity
LLP	Limited Liability Partnership
MEA	Monoethanolamine
MMV	Measurement, Monitoring, and Verification
MTPA	Million Tonne Per Annum
OPEX	Operating Expenditure
SAP	Strategic Storage Appraisal Project
ST	Steam Turbine
TNUOS	Transmission Network Use of System
UK	United Kingdom
USA	United States of America
W2W	Walk to Work

Table 16 – Abbreviations

9 References

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Photos 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
Structure of the Report	Southcentral Power http://www.snclavalin.com/en/southcentral-power-plant
References	Kings North 36" Pipeline http://www.snclavalin.com/en/kings-north-connection

Table 17 – Images Appearing in the Document

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