SPALDING ENERGY EXPANSION LIMITED

SPALDING ENERGY EXPANSION
CARBON CAPTURE READINESS FEASIBILITY STUDY

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SECTION 1

INTRODUCTION

1 INTRODUCTION

1.1 Overview

1.1.1 This study is provided in addition to the initial Carbon Capture Readiness (CCR) Feasibility Study submitted in support of the application for consent under Section 36 of the Electricity Act 1989, for the proposed Spalding Energy Expansion (SEE), submitted on 31 March 2009 (the Section 36 Consent application). A copy of the initial CCR Feasibility Study is included in Appendix C.

1.1.2 Following submission of the Section 36 Consent application the Environment Agency (EA), in an email dated 17 September 2009, raised a number of questions relating to the initial CCR Feasibility Study. This study responds to the EA and DECC's questions and also addresses any need for additional information following the issuing of DECC's final CCR Guidance note issued in November 2009.

1.2 Guidance / Regulatory Background

1.1.3 Since the initial CCR feasibility study was submitted there have been a number of changes relating to the Government's requirements for CCR assessment. These include the Draft CCR Guidance note by DECC in April 2009, the finalised CCR Guidance note by DECC issued in November 2009 and the Draft National Policy Statements for energy, also issued in November 2009, linked to the impending introduction of the Infrastructure Planning Commission.

Guidance on Carbon Capture Readiness

1.2.1 The Section 36 Consent application preceded the response to the UK Government's consultation document "Towards Carbon Capture and Storage" which was published in April 2009 alongside the Draft Guidance[1] which aimed to reflect the UK Government's new CCR policy. The Draft Guidance was in turn subject to an eight week consultation period which ended on 22 June 2009. The responses from the consultation period were incorporated into Final Guidance[2] (The Guidance) which was issued in November 2009.

1.2.2 The Guidance means that SEE must supply additional information which includes:

- Technical Assessment – Space for Retrofit
- Technical Assessment – Retrofitting and Integration of CCS
- Economic Assessment

1.2.3 The information submitted in this study provides this additional information and, together with the information included in the initial CCR Feasibility Study in support of the proposed SEE, demonstrates that the criteria in The Guidance have been addressed.

Replacement of Section 36 Consent with Development Consent Order

1.2.4 The planning system in the UK is currently undergoing a number of changes, such that all planning applications for nationally significant infrastructure, including generating stations with a capacity of more than 50MWe after 1st March 2010 will be submitted in accordance with the requirements of the Planning Act 2008.

1.2.5 In anticipation of the implementation of the Infrastructure Planning Commission (IPC) the UK Government has published two Draft National Policy Statements (NPS) which aim to outline Policy for new Energy Infrastructure which will be applied by the IPC.

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[1] *Guidance on Carbon Capture Readiness and Applications under Section 36 of the Electricity Act 1989: A Consultation (April 2009)*

[2] *Carbon Capture Readiness (CCR): A Guidance Note for Section 36 Electricity Act 1989 Consent Applications (November 2009).*

These documents are currently the subject of a public consultation exercise but nevertheless are relevant to the SEE development.

1.2.6 The Draft NPS include:

- Draft Overarching National Policy Statement for Energy (EN-1); and
- Draft National Policy Statement for Fossil Fuel Generating Infrastructure (EN-2).

1.2.7 The applicability of these two documents to the SEE (in terms of demonstrating CCR) is discussed below.

Draft Overarching NPS for Energy (EN-1)

1.2.8 Government's Energy and Climate Change Strategy (EN-1, 2.1) requires investment to provide security of energy supply through a diverse and reliable mix of fuels and low carbon technologies, including fossil fuel plants fitted with carbon capture. It concludes that there is a significant need for new major energy infrastructure, including new fossil fuel generating stations (which must be CCR) and overall that the assessment of applications should be on the basis that need has been demonstrated (EN-1, 3.1).

1.2.9 Paragraphs 4.7.1 to 4.7.16 of NPS EN-1 set out the UK Government's overarching policies on CCR and largely repeat The Guidance, noting that applicants for a Development Consent Order for their power project will need to demonstrate:

- That sufficient space is available on or near the application to accommodate carbon capture equipment in the future;
- The technical feasibility of retrofitting their chosen carbon capture technology;
- That a suitable area of deep geological storage offshore exists for the storage of captured CO_2 from the proposed combustion station;
- The technical feasibility of transporting the captured CO_2 to the proposed storage area; and
- The economic feasibility (within the combustion station's lifetime) of the full CCS chain which will cover retrofitting, transport and storage.

1.2.10 In addition, applicants must make clear in their CCR Feasibility Study which retrofit, transport and storage technology options are considered the most suitable for their proposed development.

1.2.11 Once the IPC has granted a Development Consent Order, an operator will be required to retain control over sufficient additional space on or near the site on which to install the carbon capture equipment and will need to demonstrate the ability to use the land for that purpose.

1.2.12 The remainder of the commentary regarding CCR in EN-1 is dedicated to capturing CO_2 emissions from Coal Fired Power Stations and describing the current technologies.

Draft NPS for Fossil Fuel Electricity Generating Infrastructure (EN-2)

1.2.13 Paragraphs 2.3.4 to 2.3.14 of EN-2 deal with CCR in terms of Fossil Fuelled Generating Stations. EN-2 (1.7) includes gas fired electricity generating infrastructure over 50MWe among the categories of nationally significant infrastructure projects with which it is concerned, although the focus of much of the policy (2.3.6-2.3.14) is towards coal fired generating stations..

1.2.14 In particular, Paragraph 2.3.5 states that the IPC should impose conditions on any development consent orders requiring developers to:

- Retain control over sufficient additional space (whether on or near the site) for the carbon capture equipment;
- Retain the ability to build carbon capture equipment on the land in the future; and
- Periodically submit update reports to DECC on the technical aspects of its CCR status.

1.3 Study Structure

1.3.1 This study includes the following information:

Section 1: An introduction to the study discussing the need for the document in the light of the new CCR Guidance from DECC;

Section 2: Discussion of the spatial requirements of CC plant at SEE;

Section 3: Discussion of the considerations associated with the retrofit of CC at SEE additional to that included in the initial CCR Feasibility Study for SEE;

Section 4: Details of an economic assessment for the project with due consideration of the DECC Guidance;

Appendix A: A summary of where the information required by DECC can be found in the initial SEE CCR Feasibility Study and this study; and

Appendix B: Layouts for the CCR plant based on the sizing study discussed in Section 2 of this study.

SECTION 2

TECHNICAL ASSESSMENT – SPACE FOR RETROFIT

2 TECHNICAL ASSESSMENT – SPACE FOR RETROFIT

2.1 Introduction

2.1.1 This Section aims to provide the clarification requested by DECC / EA in their e-mail of the 17 September 2009 with regard to carbon capture (CC) plant spacing and land take. These are presented below together with the response from InterGen / Spalding Energy Expansion Limited (SEEL) / PB.

2.2 Technology introduction

2.2.1 The aim of CCS is to produce a concentrated stream of CO_2 which can be transported to a safe storage site, eliminating greenhouse gas emissions to the atmosphere.

2.2.2 There are a number of carbon capture technologies which have been proven on a small scale and, at the time of installation, it is then highly probable that the choice of technologies will have increased. These present carbon capture technologies are based on one of three potential methods, namely: pre-combustion capture, post-combustion capture or oxyfuel combustion.

2.3 Pre-Combustion Capture

2.3.1 As the name suggests, pre-combustion capture involves the conversion of a carbon-rich fuel stream into a carbon-lean fuel stream by a conversion and separation process prior to the fuel being combusted.

2.3.2 The first stage of this process typically involves a reaction producing a mixture of hydrogen (H_2) and carbon monoxide (CO). This mixture, called syngas, is formed from the primary fuel by either the addition of steam (known as 'steam reforming') or the addition of oxygen (known as 'partial oxidation' for gaseous / liquid fuels or 'gasification' for solid fuels).

2.3.3 The second stage of this process typically involves a 'shift' reaction to convert the CO in the syngas to CO_2 by the addition of steam, producing a mixture of CO_2 and H_2.

2.3.4 The concentration of CO_2 in this mixture can be in the range of 15 to 60 per cent (dry basis) and the total pressure is typically between 2 to 7 MPa. The CO_2 is separated from this mixture, leaving a virtually pure H_2 fuel. In order to regulate the combustion flame temperature, an inert dilution (such as nitrogen (N_2)) is added to the H_2 fuel, producing a fuel suitable for firing in a range of heaters, boilers, gas turbines or fuel cells. The separated CO_2 is compressed prior to transportation and storage.

2.4 Post-Combustion Capture

2.4.1 Post-combustion capture involves the removal of CO_2 from the flue gases following combustion of carbon rich fossil fuels.

2.4.2 The post-combustion approach is particularity suitable for retrofitting of carbon capture technology to existing power plants.

2.4.3 The capture of CO_2 from the flue gas is usually achieved by a chemical solvent scrubbing process. This capture process begins in an Absorber where the flue gas is exposed to a spray of lean chemical solvent which reacts with the flue gas to absorb CO_2. The 'clean' flue gas is vented to the atmosphere.

2.4.4 The rich CO_2 chemical solvent is regenerated in a Stripper through the addition of steam, which strips the CO_2 from the chemical solvent. The regenerated chemical solvent is then returned to the Absorber in order to continue the process. The stripped CO_2 and steam mixture is separated in a Condenser, prior to CO_2 compression and transportation.

2.4.5 The Absorber must operate at low temperature (typically around 35 to 50°C) in order to maximise the CO_2 absorption efficiency. This requires significant cooling duty in order to cool the incoming flue gas and the regenerated amine solvent.

2.4.6 The steam required to strip CO_2 from the solvent is supplied either by an auxiliary boiler unit or from the existing power plant steam cycle. The auxiliary boiler configuration is referred to as the 'non-integrated' option, whereas the extraction of steam from the existing power plant is referred to as the 'integrated' option.

2.5 Oxyfuel Combustion

2.5.1 In the Oxyfuel Combustion process, fossil fuel is burned in oxygen (O_2) instead of air. As a result, the flue gas consists of mainly CO_2 and water (H_2O) vapour, the latter of which is condensed.

2.5.2 Following removal of the H_2O vapour, the remaining flue gas, which is virtually pure CO_2, can be compressed prior to transportation and storage. In order to control the temperature of combustion to within reasonable limits, a proportion of flue gas can be re-circulated to the combustion chamber.

2.5.3 If the condensed H_2O vapour still contains a small quantity of CO_2, it may be possible to separately treat and dispose of this CO_2; this process has the potential to achieve zero CO_2 emissions to the environment.

2.6 Chosen Technology

2.6.1 Whilst the current understanding is that a carbon capture plant would not be installed until CO_2 capture is either mandated or economically beneficial, for the purposes of demonstrating CCR of SEE the carbon capture technology which is closest to commercial deployment is discussed.

2.6.2 As such, for the technology and spacing issues discussed in the initial CCR Feasibility Study and this study, the assessment has been based on that of the current best available technology.

2.6.3 Additionally, the initial CCR Feasibility Study and this study has been based on the assumption that the Power Plant is already in operation.

2.6.4 Therefore for carbon capture from flue gases (post-combustion capture), the current best available technology is chemical absorption using amine solvents. The amine solvents are typically based on monoethanolamine (MEA), diamine or sterically hindered amine.

2.6.5 It should be noted that this technology may be regarded as commercially available but has not yet been commercially proven for large-scale power plant applications.

2.7 Spacing and Sizing of Carbon Capture Plant

General Sizing Issues

2.7.1 Details from Table 4.2 in the initial CCR Feasibility Study indicate that 87 kg/s of CO_2 would be generated at the SEE CCGT plant. Therefore, based on 90% capture, the carbon capture plant would need to be capable of processing the CO_2 with a maximum output of 79 kg/s when the power plant is operating at full load.

2.7.2 This flow rate has been used to size the carbon capture equipment shown in the two layout drawings in Appendix B.

General Methodology

2.7.3 The carbon capture plant layouts produced for SEE shown in Appendix B to this study have been developed in two stages. These stages were:

- Process train and common plant sizing; and

- Cooling system sizing.

2.7.4 These stages are discussed further below.

Process Train and Common Plant Sizing

2.7.5 The process train and common plant sizing is based upon a post-combustion carbon capture plant layout developed by Fluor in their 2005[3] Study conducted for the Statoil ASA 800 MWe CCGT in Tjeldbergodden, Norway (the Fluor 2005 Study). This post-combustion carbon capture plant layout has been derived from internal studies conducted by Fluor, proprietors of the Econamine FG+ CO_2 Capture technology.

2.7.6 Detailed information from other carbon capture technology proprietors regarding CC plant layout spacing is not currently available. As such, the layout in the Fluor 2005 Study is considered the most reliable indication of CC plant size and layout to date.

2.7.7 The actual sizing of the individual CC plant items is determined by scaling of the dimensions given in the layout in the Fluor 2005 Study. This is done based on the reported flowrates in the Fluor 2005 Study in comparison with the expected flowrates calculated from the SEE.

2.7.8 In addition to the scaling, the layout and configuration of the CC equipment in the layout in the Fluor 2005 Study was also reviewed. This makes it possible to incorporate limitations imposed by site specific limitations. This has included, for example:

- The incorporation of a gas-gas heat exchanger at the flue gas inlet to the carbon capture plant with was not considered by the Fluor paper;
- The re-positioning of the blower / fan in the process train; and
- General flue gas duct routing.

2.7.9 The layouts provided in Appendix B reflect the above and assumes an integrated two process train configuration. This configuration may be adopted if the assumption is made that an Absorber column diameter of up to 20 m is possible allowing for the use of just two CC trains in the design. Confirmation has been received that this diameter for an Absorber would be feasible from equipment manufacturers.

2.7.10 Therefore, it is assumed that the dimensions for the layout and spacing in the Fluor 2005 Study can be scaled-up in two stages for application to the SEE. These are:

- Firstly, the entire CC equipment and spacing is scaled-up by an overall dimensional scaling factor; and,
- Secondly, the process train equipment is further scaled-up to account for the change from a three process train (shown in the Fluor 2005 Study) to a two process train configuration (shown in the layouts in Appendix B). The level of scaling applied here is calculated based on the requirement to maintain the same flue gas velocity throughout the process train.

Cooling System Sizing

2.7.11 The cooling system was sized for an Absorber inlet flue gas temperature of approximately 35°C. This would enable up to 90% capture to take place.

2.7.12 Thermoflex modelling software has been used to calculate the carbon capture plant net cooling duty. The calculated net cooling duty; from the Thermoflex model is an overall cooling requirement for the entire carbon capture plant. But within the CC plant, the CO_2 compressor intercoolers perform a small proportion of the total

[3] *Study and Estimate for CO_2 Capture Facilities for the proposed 800 MW Combined Cycle Power Plant – Tjeldbergodden, Norway', Fluor, April 2005.*

required cooling duty. As the compressor intercoolers are contained within the Compressor Plant area, the required area for the CC plant cooling system may be slightly reduced when further detailed design takes place.

Demonstration of Suitably Located Land

2.7.13 SEEL has the benefit of an unconditional call option to acquire, for a pre-agreed price, the freehold of land adjacent to and abutting the site of the SEE (the "Proposed CCR Site"). This right arises pursuant to an option agreement dated 22 December 2008 between the registered freehold proprietor of the Proposed CCR Site and SEEL's parent company, InterGen (UK) Limited ("InterGen"). The initial option period runs until 13 March 2010 and, upon payment of additional fees at defined intervals, InterGen has an unconditional right to renew this for a further 24 months (i.e. until 13 March 2012). Upon exercise of the call option, InterGen can require the owner of the relevant land to transfer the freehold to the Proposed CCR Site to InterGen or such other party as InterGen may nominate (e.g. SEEL).

2.8 Query and Response 1

DECC / EA Query

2.8.1 The EA has noted that the plant is a nominal 900 MW CCGT plant and that some 3.6 hectares have been set aside for the CC plant. The EA note that Table 1 of the draft guidance issued by DECC in June 2009 indicates that some 7.4 hectares (ha) would be required for capture plant for a CCGT of this size. The EA go on to say that on first inspection therefore the SEE project would not appear to have sufficient space set aside to be considered as being CCR. In addition, the EA highlights a lack of information in the initial CCR Feasibility Study detailing the sizing or location of individual units within the CC plant that might demonstrate how the plant may be fit on the available land.

InterGen / Spalding Energy Expansion Limited / PB Response:

2.8.2 Whilst it is noted that the spacing suggested in the Guidance (both the April 2009 and November 2009 versions) allows for some 7.4 ha for a CCGT plant of this size, PB has been involved in the development design of this project since its inception and are fully confident that the space available at the SEE site is sufficient for the purposes of the retrofitting carbon capture equipment to the CCGT plant.

2.8.3 The Guidance, as issued in both April 2009 and November 2009, refers to the IEA (Mott McDonald (MM)) Paper from 2006 "2006/8 - CO_2 Capture as a Factor in Power Plant Investment Decisions" in recommending the 7.4 ha of land take it identified as being potentially required for a carbon capture plant associated with a CCGT. PB / InterGen feel it is important that DECC notes the IEA/MM Paper, to which the Guidance makes reference, was not based on a detailed consideration of spacing and layout and as such is not an appropriate means of establishing carbon capture readiness in terms of space. This point is made by the Guidance itself which notes that:

"*Since capture technologies have not yet been demonstrated on a commercial scale, it is not appropriate for Government to impose prescriptive requirements on the amount of space which should be set aside*".

2.8.4 As part of our site spacing exercise for SEE, InterGen / PB have examined the IEA/MM 2006/8 Paper which reveals an inconsistency with The Guidance. The Guidance notes that the sizing in Table 1 (Page 11 of the November 2009 Guidance) is based on a 500 MW CCGT. Whilst an initial review of the IEA/MM paper (Page 3-62) suggests that this is correct, upon further inspection it would appear this is not the case with MM noting (Page 3-19) that this in fact is the sizing for a Plant sized anywhere between 440 MW and 776 MW.

2.8.5 This can be further called in to question with reference (Page 3-62) of the IEA/MM report which states that the spacing they refer to in their report is based on an IEA/Jacobs paper from 2005 "2005/1 - Retrofit of CO_2 Capture to Natural Gas Combined Cycle Power Plants" which has been combined with MM's own experience (Page 3-62). The IEA/Jacobs 2005/1 Paper highlights (Page i) that their spacing assessment is based on a 785 MW CCGT and not a 500 MW or smaller plant. The reason why MM has interpreted this to refer to a plant in the range 440 MW to 776 MW is not clear.

2.8.6 These inconsistencies with regard to the IEA/MM 2006/8 Paper are a cause for concern, especially when in the Paper IEA/MM contradict the Guidance spacing estimates with the suggestion (Page 3-24) that the actual area required for post combustion retrofit to a CCGT is between 0.9 and 4.0 ha (9,000 to 40,000 m^2).

2.8.7 Given the above, PB / InterGen have undertaken a thorough review of CCS spacing for the 900 MW CCGT proposed for SEE and attach layout drawings to this study in Appendix B, which detail the spacing requirements which reflects PB and InterGen's understanding of CC technology. This understanding has evolved from our discussions with CCS contractors and equipment suppliers, as well as other industry experts, who are endeavouring to gain a better understanding of the spatial requirements of CCS. It is understood that the SEE area is similar to those proposed by other parties such as Carlton Power / SKM (Carrington II CCGT) and is very similar to that identified by Jacobs in their 2005 IEA paper.

2.8.8 To help clarify some of our assumptions with regard to the spacing of our CC plant as shown in Appendix B, this is in addition to the detailed sizing justification for the CCS plant at SEE discussed in Section 2.7.

2.8.9 PB / InterGen would be happy to discuss this matter further with DECC and the EA to demonstrate this to be the case if required. We believe that sufficient information is available to demonstrate the spatial requirements of the plant are as per those identified in the appended figures.

2.9 Query and Response 2

DECC / EA Query

2.9.1 The EA highlights the lack of a plant layout giving the location of the capture equipment, CO_2 compression equipment, chemical storage facilities or the exit point for the CO_2 pipeline.

InterGen / PB Response

2.9.2 Appendix B contains two layout drawings which details the spacing requirements for the CC plant.

2.9.3 These two layouts include details on the position of individual pieces of equipment required for the CC plant.

2.10 Query and Response 3

DECC / EA Query

2.10.1 The EA identifies that there is no conceptual diagram available in the initial CCR Feasibility Study for SEE to explain how space is utilised. Also there are no calculations using known volumes of CO_2 to justify the sizing of vessels and chosen processing equipment.

InterGen / PB Response:

2.10.2 Within Section 4 of the initial SEE CCR Feasibility Study, Tables 4.1 and 4.2 detail the results of thermal modelling which were undertaken to provide an estimate of the amount of CO_2 expected from the SEE. A decision regarding the specific model of

gas turbine to be used at the SEE has not been made and therefore, for the purposes of the report, the gas turbine which produced the largest amount of CO_2 was used for the carbon capture plant sizing purposes.

2.10.3 Details from Table 4.2 indicate that 87 kg/s (kilograms per second) of CO_2 would be generated by the CCGT plant. Therefore, based on 90% capture, the carbon capture plant would need to be capable of processing the CO_2 with a maximum output of 79 kg/s when SEE is operating at full load.

2.10.4 This flow rate has been used to size the carbon capture equipment shown in the two layout drawings in Appendix B.

2.11 Space for Retrofit Conclusion

DECC / EA Conclusion

2.11.1 The EA concludes that from the information provided in the initial CCR Feasibility Study for SEE it cannot be said that 'there are no barriers' to CC with regards to the space requirements.

InterGen / PB Response

2.11.2 Two layout drawings are included in Appendix B which detail the spacing requirements for the carbon capture plant for SEE. A sizing justification is provided in Section 2.7 of this study.

2.11.3 The layout drawings include detail on the position of individual pieces of equipment required for the carbon capture plant. The layout drawings indicate that there is sufficient space on the SEE site for the installation of a carbon capture plant sized appropriately for the CO_2 produced from a 900 MW CCGT.

SECTION 3

TECHNICAL ASSESSMENT – RETROFITTING AND INTEGRATION OF CCS

3 TECHNICAL ASSESSMENT – RETROFITTING AND INTEGRATION OF CCS

3.1 Introduction

3.1.1 This Section aims to provide the additional information requested by DECC / EA with regard to the retrofitting and integration of CCS to the SEE plant. The questions raised in the e-mail on the 17 September 2009 are presented together with the response from InterGen / Spalding Energy Expansion Limited / PB.

3.2 Query and Response 4

DECC / EA Query

3.2.1 The report considers how best to provide the steam necessary to regenerate the amine scrubbing media from the combustion process. It rejects extraction of low pressure steam and a stand alone auxiliary boiler / CHP, and recommends supply ports to be fitted to allow 3 options for steam extraction for maximum flexibility, namely from the HRSG, Cold Reheat and the IP / LP crossover.

InterGen / PB Response

3.2.2 Whilst the EA do not pose a specific question it should be noted that (as recognised in the Guidance) CCS technology is still developing and as such operators are not bound to retrofit the carbon capture plant or technology specified in the CCR Feasibility Report.

3.2.3 As such, the method of steam provision (and indeed the steam requirements) will be decided at the time of detailed design and installation. Refer to Section 2.6 for Chosen Technology.

3.3 Query and Response 5

DECC / EA Query

3.3.1 The EA identify that additional cooling necessary to operate CC plant will be provided by air cooling which is an appropriate technology; the report acknowledges that the resources for once through cooling water is not available.

Intergen / PB Response

3.3.2 Whilst no response is required, it should be noted that the options for cooling medium were based on resources available at the time of writing the initial CCR Feasibility Study. As such, the method of cooling will ultimately be decided at the time of detailed design and installation However at the present time air cooling is most likely as it is used at the existing Spalding station and is proposed for the CCGT equipment for the SEE.

SECTION 4

ECONOMIC ASSESSMENT

4 ECONOMIC ASSESSMENT

4.1 Overview

4.1.1 This Section reviews the economic feasibility of incorporating carbon capture technology into the SEE Project. It tests a number of key industry and market sensitivities, and compares outputs with the findings of recent industry reference reports.

4.1.2 Assumptions used in the analysis are consistent with those used in recent reports by PB investigating Carbon Capture Readiness.

4.2 Guidance

4.2.1 Under the Government's new CCR Policy as detailed in The Guidance issued by DECC, developers are required to:

"Undertake an assessment into the technical and economic feasibility of retrofitting carbon capture technology"

In addition, they are also required to:

"Undertake an assessment into the technical and economic feasibility of transporting the captured CO_2 to their proposed storage area"

4.2.2 Additionally, the Directive on the Geological Storage of Carbon Dioxide suggests that:

"*The economic feasibility of the transport and retrofitting should be assessed taking into account the anticipated costs of avoided CO_2 for the particular local conditions in case of retrofitting and the anticipated costs of CO_2 allowances in the Community. The projections should be based on the latest evidence; review of technical options and uncertainty analysis should also be made*".

4.2.3 In terms of a retrofitting economic assessment, the Guidance states that a wide range of assumptions are likely to be involved, including:

- Future input fuel prices (both absolute and relative to other fuels);
- Electricity price levels;
- Rising carbon emissions prices; and
- The capture technology's likely capital and operating costs.

4.2.4 Given the unknowns surrounding CO_2 transport arrangements, DECC accepts that only a high level analysis of transport solutions will be possible. As such, the factors that we have taken into account include:

- Potential technical specifications of any onshore pipeline;
- Experience of the natural gas industry with pipeline routing;
- Appropriate allowances for potential route variations to avoid specific environmentally sensitive sites, or deeper burial or avoidance of certain inhabited areas;
- Existing experience with the costs of offshore pipelines;
- The approximate lengths of the onshore and offshore pipelines; and
- The need for compression booster stations.

4.2.5 The Guidance states that the main aim of the economic assessment is to provide an indication that the retrofit of carbon capture and storage is likely to be economically feasible during the lifetime of the proposed new station.

4.3 Assessment Methodology

4.3.1 To investigate the economic feasibility of the SEE Project with the addition of CCS, an economic model was developed to calculate the lifetime cost of electricity, expressed in terms of £/MWh, over the 35 year lifetime of the SEE Project.

4.3.2 Whilst the Guidance addresses the technical and economic feasibility of carbon capture technology and transport infrastructure separately, we consider these to be connected. Therefore the SEE Project with CCS has been modelled in its entirety. We have not considered the effects of taxation in our modelling.

4.3.3 The economic feasibility of the SEE Project was assessed by changing the price of EU Allowances under the EU Emissions Trading Scheme (EU ETS).

4.3.4 The assessment methodology, which accounts for all the economic assessment criteria set out in the Guidance, is as follows:

Step 1. The model is used to calculate the cost of electricity generation (in £/kWh), over the lifetime of the proposed SEE Project, without the addition of CCS. This assumes that EU Allowances must be purchased for 100 per cent of the residual CO_2 emitted to atmosphere by SEE Project. The cost of electricity generation is calculated with carbon prices ranging from €0/tonne to €150/tonne in €25/tonne increments.

Step 2. The model is used to calculate the cost of electricity generation (in£p/kWh), over the lifetime of the proposed SEE Project, with the addition of CCS. Again, this assumes that EU Allowances must be purchased for 100 per cent of the CO_2 emitted to the atmosphere by the SEE Project. The cost of electricity generation is calculated with carbon prices ranging from €0/tonne to €150/tonne in €25/tonne increments.

Step 3. The base case assumptions are then stressed to identify a potential cost range for the SEE Project through the combination of upside and downside scenarios. These include stressing the fuel pricing, the capital costs and the base-line costs for the transportation and storage elements.

Step 4. The range of the electricity generation costs for both the 'no CCS' and 'CCS' cases are then plotted graphically to present the range of carbon prices within which the SEE Project with CCS is economically feasible with present uncertainties.

4.4 Assumptions

4.4.1 The assumptions made in the economic assessment for the base case modelling are detailed in Table 4.1.

TABLE 4.1: ECONOMIC ASSESSMENT BASE CASE ASSUMPTIONS

Variable	*Assumption*
£:€ Exchange Rate	1.0973
Discount Rate	10%
Gas Price	46.1 p/therm[4]
Carbon Allocations	None for Power Sector – Full Purchase
Power Output Impact of Carbon Capture, Transportation and Storage :	
Net Power Output of SEE	878 MWe
Net Power Output of SEE with addition of Carbon Capture, Transportation and Storage	808 MWe
Lifetime load factor of the SEE project	75%
CO_2 emitted by SEE before Carbon Capture	87 kg/s
CO_2 emitted by SEE after fitting Carbon Capture Technology	9 kg/s

4.5 Scenarios

4.5.1 The model has been run using three scenarios relating to the possible CO_2 transport and storage infrastructure options, outlined below:

a) ***"2009, Dedicated New CO_2 Transport & Storage Assets"***
In this scenario we assume that all of the onshore and offshore infrastructure for capture and storage will be based on new assets. The storage sites targeted are existing gas fields in the Southern North Sea (SNS) Basin. It is assumed that the infrastructure will be sized to the project and would be 'dedicated' to the project.

b) ***"2009, Dedicated New CO_2 Transport assets, Re-use Storage Assets"***
The assumption in this instance is that the storage infrastructure can be re-used but both onshore and offshore pipelines are again new build and sized for the project, i.e 'dedicated'.

c) ***"2020, Shared New CO_2 Transport & Storage Assets"***
Whilst the Guidance states that outsourcing of CO_2 transport and storage cannot be assumed in this feasibility study, we have included such an option for comparative purposes. Given the location of the SEE Project there is a possibility that a shared CO_2 transportation and storage network could be developed to provide a "route-to-store" for the various power plants in the region. To recognise this possibility, the model has been run for a case where the transportation and storage system is shared. As this is only likely to be the case at some point in the future, the modelling is carried out on the basis of the 2020 cost projections[5] (2009 base prices). The power plants considered in this

[4] *Source: Average of Central Scenario of "Communication on BERR Fossil Fuel Price Assumptions; Update to present the latest fossil fuel price assumptions following the January 2008 Call for Evidence", BERR, May 2008; escalated to 2009 prices.*

[5] *The retrofit analysis has taken into account the costs associated with retrofitting CCS related to the present status (2009) of the CCS market (i.e., immature at utility scale), and to the future status (2020) of the CCS market (i.e., when it is likely that CCS will be proven at utility scale and economies of scale are beginning to be seen through the supply chain). Note that all costs are quoted on a 2009 base.*

hypothetical shared system include Kings Lynn A and B, Sutton Bridge, Spalding as well as the SEE Project. It is assumed the system will begin at Kings Lynn and run in series via the Sutton Bridge site then the Spalding site before heading to storage via Theddlethorpe gas terminal as was suggested in PB's initial CCR Feasibility Study for SEE[6]. Costs are shared on the basis of CO_2 volumes produced by each scheme on a pro-rata basis.

4.5.2 A number of sensitivities have been run on each of the three scenarios outlined above, to test the sensitivity of the results, listed below:

- **Gas Pricing –**
  Volatility in the gas market (assuming continued linkage with oil) in the UK in recent years has shown that there remains significant uncertainty in the longer term forward price. The economic assessment has modelled what is considered to be outlying possibilities for the gas price with a ±30 per cent range.
- **Capital Cost –**
  The capital cost for the SEE Project has been stressed with a ±10 per cent uncertainty range. This uncertainty is applied to the SEE Project, the capture plant retrofit costs and the transportation and storage. Additional cases have been modelled to understand the uncertainty relating to the timing of the CCS retrofit and the CO_2 transportation.
- **Discount Rate –**
  Whilst a 10 per cent discount rate is considered to be a reasonable indicative value for a base case analysis for a CCGT project, the addition of the CCS chain as a retrofit at some time in the future is considered to present an additional risk to developers of power plant, and therefore a higher discount rate of 12.5 per cent has been used to reflect this risk.

4.5.3 The scenarios for gas pricing, capital costs and discount factors are summarised in Table 4.2.

TABLE 4.2: UNCERTAINTY ANALYSIS SCENARIOS

Scenarios:	Gas Price	Capital Costs	Discount Rate
Low Gas Price	-30%	As Base Case	10%
High Gas Price	+30%	As Base Case	10%
Low Capital Cost	As Base Case	-10%	10%
High Capital Cost	As Base Case	+10%	10%
High Discount Rate	As Base Case	As Base Case	12.5%

4.6 Economic Assessment

4.6.1 The results of the assessment are shown in INSERT 4.1 and INSERT 4.2.

4.6.2 INSERT 4.1 shows the results of the modelling for procurement of the SEE Project and the CCS chain in 2009.

4.6.3 Note that:

- The carbon price (the price of the EUA's, in €/tonne) is shown along the x-axis, the lifetime cost of electricity (in p/kWh) is shown along the y-axis;

[6] *Initial Spalding Energy Expansion Carbon Capture Readiness Feasibility Study, Parsons Brinckerhoff (March 2009)*

- The solid line represents the Base Case scenario, the dotted lines represent the upper and lower limits of the sensitivity runs;
- The sensitivity runs illustrated show the cumulative affect of factors increasing the cost of electricity (high gas price, high capital cost, high discount rate), and of factors decreasing the cost of electricity (low gas price, low capital cost);
- For the SEE project without the addition of CCS (the black line), for an EUA price of €25/tonne the lifetime cost of electricity is around 5.4p/kWh; for an EUA price of €150/tonne the lifetime cost of electricity is around 9.5p/kWh;
- For the SEE project with the addition of CCS and new transport and storage assets (the purple line), for an EUA price of €25/tonne the lifetime cost of electricity is around 7.2p/kWh; for an EUA price of €150/tonne the lifetime cost of electricity is around 7.6p/kWh;
- For the SEE project with the addition of CCS and new transport and re-used storage assets (the red line), for an EUA price of €25/tonne the lifetime cost of electricity is around 7.1p/kWh; for an EUA price of €150/tonne the lifetime cost of electricity is around 7.5p/kWh; and
- For the Base Case, the minimum required price of one EUA under the EU-ETS, such that the cost of electricity over the life of the SEE project fitted with CCS remains the same value as that for the SEE project without the addition of CCS, is around €75/tonne.

4.6.4 INSERT 4.2 shows the results of the modelling for procurement of the SEE Project in 2009 and the CCS chain using 2020 price projections (in 2009 prices).

4.6.5 Note that:

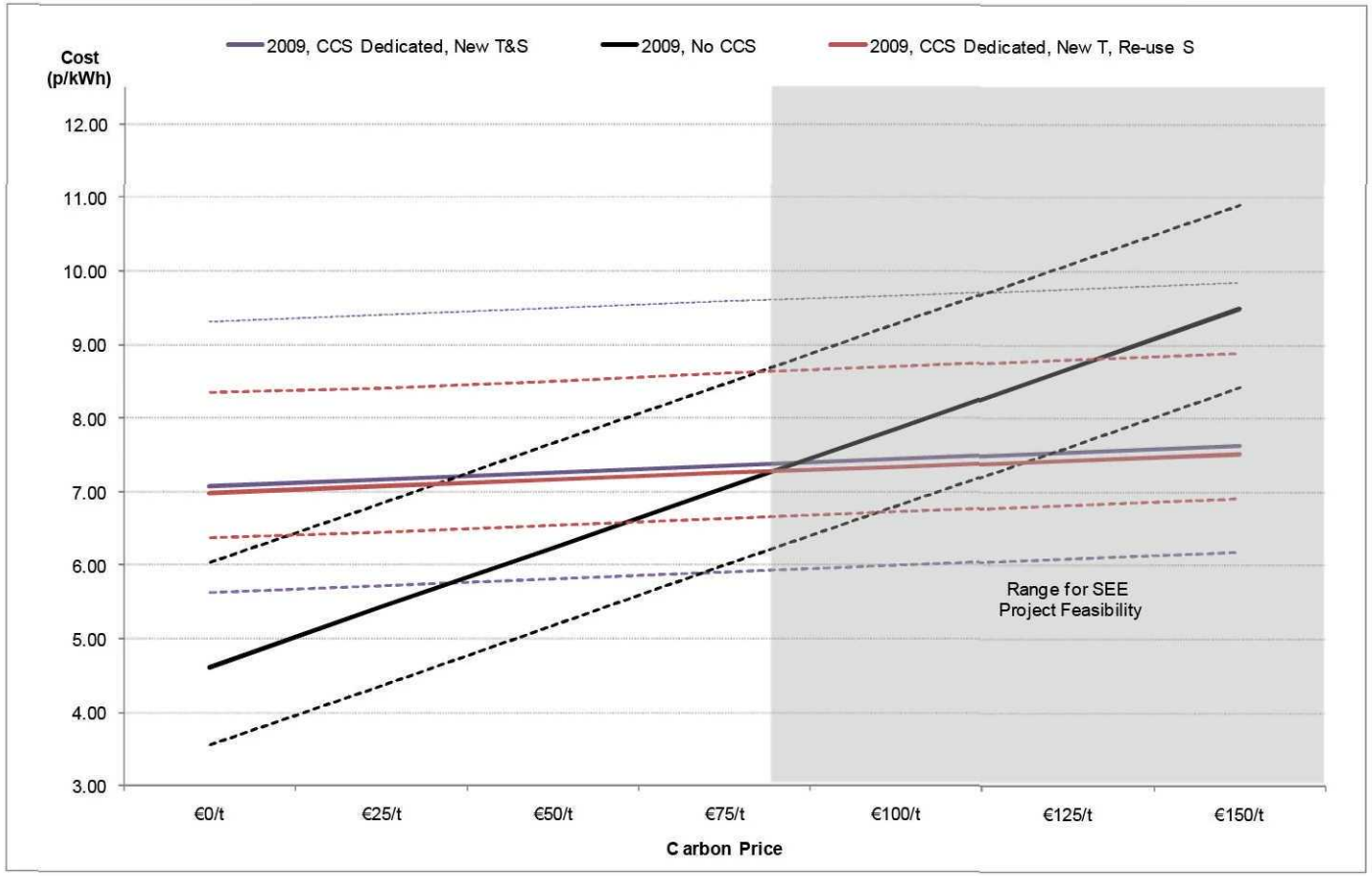
- The carbon price (the price of the EUA's, in €/tonne) is shown along the x-axis, the lifetime cost of electricity (in p/kWh) is shown along the y-axis;
- The solid line represents the Base Case scenario, the dotted lines represent the upper and lower limits of the sensitivity runs;
- For the SEE project without the addition of CCS (the black line), for an EUA price of €25/tonne the lifetime cost of electricity is around 5.4p/kWh; for an EUA price of €150/tonne the lifetime cost of electricity is around 9.5p/kWh;
- For the SEE project with the addition of CCS and new shared transport and storage assets (the red line), for an EUA price of €25/tonne the lifetime cost of electricity is around 6.5p/kWh; for an EUA price of €150/tonne the lifetime cost of electricity is around 6.9p/kWh; and
- For the Base Case, the minimum required price of one EUA under the EU-ETS, such that the cost of electricity over the life of the SEE project fitted with CCS remains the same value as that for the SEE project without the addition of CCS, using 2020 price projections, is around €75/tonne.

4.6.6 A summary of the results is provided in the table below.

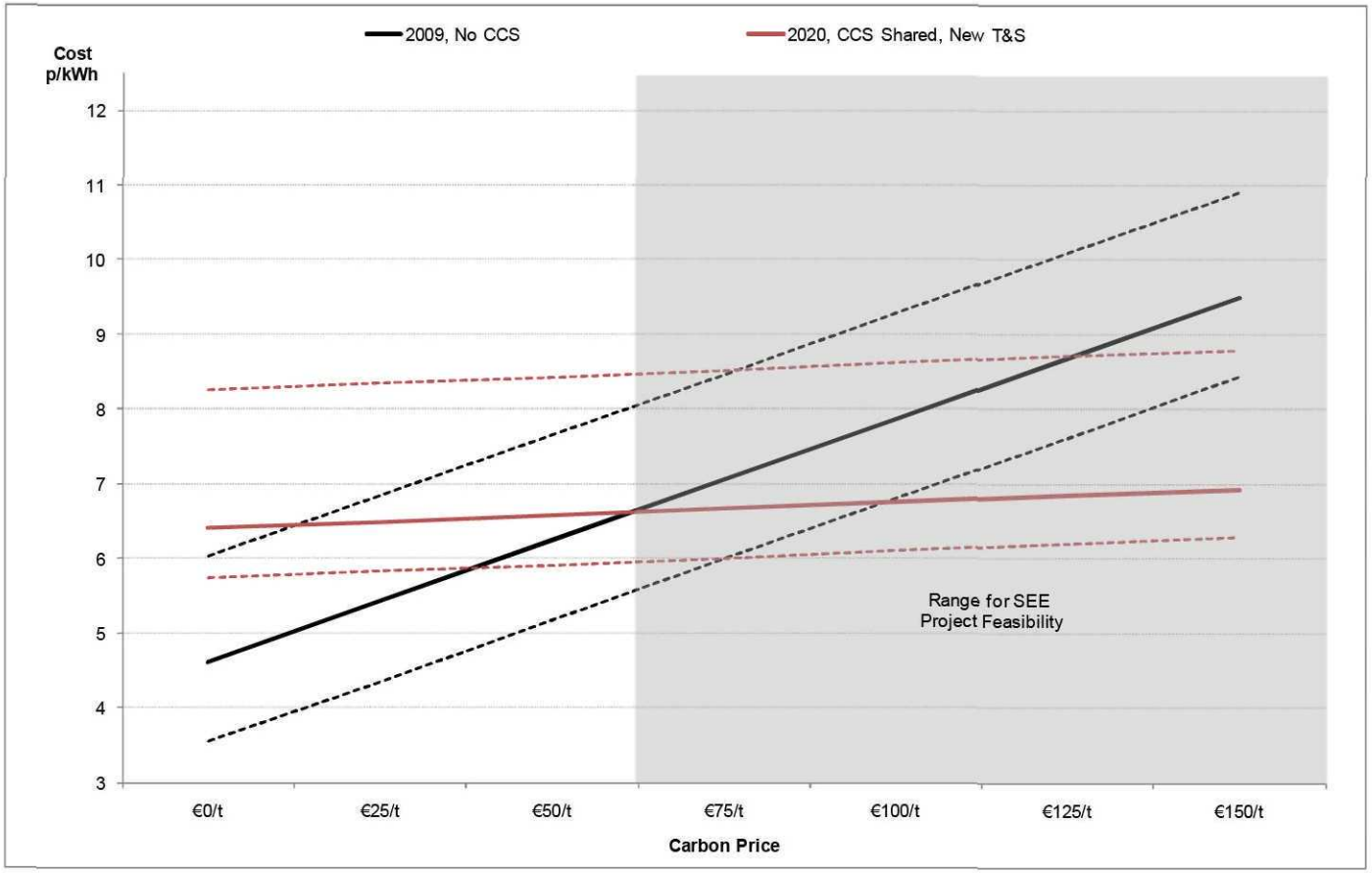
TABLE 4.3: UNCERTAINTY ANALYSIS SCENARIOS

Year	Scheme	Cost of electricity at EUA price €25 (p/kWh)	Cost of electricity at EUA price €150 (p/kWh)	Price of EUA for project feasibility (€/t)
2009	No CCS	5.4	9.5	-
	CCS dedicated, new T & S	7.2	7.6	-
	CCS dedicated, new T, re-use S	7.1	7.5	82
2020	CCS shared, new T & S	6.5	6.9	62

INSERT 4.1: SEE PROJECT – CCS FEASIBILITY 2009



INSERT 4.2: SEE PROJECT – LIKELY CCS FEASIBILITY 2020



4.7 Conclusions

4.7.1 The results of our modelling show that the retrofitting of carbon capture technology to the SEE Project becomes economic on the basis of EUA prices of €82/tonne, for plant using 2009 prices. Learning effects mean that the break even cost should fall to nearer € 62/t on the basis of 2020 costs.

4.7.2 These prices can be readily compared with data from external forecasters, e.g. the independent McKinsey Report "Pathways to a Low Carbon Economy" (2009) and the "Cost Abatement Curve". In particular Exhibit 8.1.4 of the McKinsey Report indicates an abatement cost of 50 Euros per tonne CO_2 for a gas CCS new build (by 2030). Over time, it is anticipated that the 75 Euros per tonne CO_2 may tend toward the order of 50 Euros per tonne (predicted by external forecasters) as knowledge on the carbon capture technology advances; given the current uncertainties as to the learning curve that will be seen as the knowledge and experience of utility scale CCS systems develops over time. It may also be considered that in the future some form of direct support for carbon capture facilities may be in place, e.g. feed-in tariffs, capital grants, soft loans on favourable terms, etc.

4.7.3 It should be noted that as recently as 2007/08 the wholesale electricity market was in the region of £80 to £90/MWh (8 to 9p/kWh). It is therefore considered possible that these pricing levels will become more prevalent as the time for the retirement of power plants approaches in 2015, due to the requirements of the Large Combustion Plant Directive (LCPD) (Directive 2001/80/EC).

4.7.4 Furthermore, the EU ETS Phase III will not provide any free allocation of EUA's to power generators within Europe. Therefore, whilst the full cost of carbon is presently recognised within the wholesale electricity pricing, the impact of the full auctioning for power plants (and the sliding scale cap from the mid point of EU ETS Phase II being applied to the remaining sectors within the EU ETS) means that there is likely to be significant upwards price pressure on EUA's from 2013 onwards. Therefore the high carbon prices required for CCS economic feasibility are considered to be within the present expectations of forward carbon pricing, and thus the SEE Project is likely to be economically feasible within its operating lifetime.

4.7.5 The costs we have used for the economic assessment are based on those for a carbon capture plant procured in 2009. These costs are expected to reduce in time, bearing in mind the recent and likely future developments in technology.

APPENDIX A

CCR REQUIREMENTS CHECKLIST

Guidance paragraph	Requirement for CCR Assessment	Study reference/additional comment
6	Applicant must demonstrate that there are no known technical or economic barriers which would prevent the installation and operation of its chosen CCS technologies.	See Section 4 of this study for economic discussion.
7	Applicant needs to demonstrate: - that sufficient space is available on or near to the site to accommodate carbon capture equipment in the future - the technical feasibility of retrofitting its chosen carbon capture technology - that a suitable area of deep geological storage offshore exists for the storage of captured CO_2 from the SEE - the technical feasibility of transporting the captured CO_2 to the proposed storage area; - the likelihood that it will be economically feasible within the SEE's lifetime to link it to a full CCS chain covering retrofitting of capture equipment, transport and storage.	- See Section 2.7 and 2.8 of this study for justification of spatial requirements for CC plant. - See Section 3 of this study for discussion of technical feasibility for CC retrofit. - Geological storage is discussed in Section 6 of the initial CCR Feasibility Study - Transport is discussed in Section 7 of the initial CCR Feasibility Study - See Section 4 of this study for economic discussion.
7	Applicant must make clear in its CCR assessment which CCS retrofit, transport and storage technology options are considered the most suitable for the proposed development.	Transport is discussed in Section 7 of the initial CCR Feasibility Study
11, 18 and 19	Applicant should be prepared to submit plans and supporting docs with initial S36 application to demonstrate that sufficient space is available to accommodate carbon capture equipment, sized so as to be capable of processing emissions from the entire SEE in future. Site plans should show: - the footprint of the combustion plant - the location of the capture plant inc. air separation units - the location of the CO_2 compression equipment - the location of any chemical storage facilities - the exit point for CO_2 pipelines from the site. Conceptual diagrams and a description of how space will be used should be submitted. Basic calculations using known CO_2 volumes could usefully be included in the space description to justify size/type of processing equipment chosen.	See Section 2.7 and 2.8 of this study for justification of spatial requirements for CC plant. A detailed site plan is included in Appendix B showing the CC plant in close up and with the SEE plant.
11	Applicant should explain percentage of CO_2 emissions it considers will be captured by proposed capture technology. The detail required will need to be such that S/S is confident that the applicant is allowing	See Section 2.7 and 2.8 of this study for justification of spatial requirements for CC plant. Specifically Section 2.10.3 details the % capture of CO_2.

	sufficient space on site and in appropriate areas on site for subsequent retrofit.	
13	Applicant should make reasoned justification for its proposed space allocation on the basis of its chosen capture technology.	See Sections 2.7 and 2.8 of this study for justification of spatial requirements.
15	Applicant must be able to demonstrate suitably located land will be available to it to use for the capture element of the CCS chain at the point of retrofit. If it does not already own or occupy the ancillary site, the applicant will need to satisfy S/S that it is in a position to ensure that it will be able to use the ancillary site when it moves to installing CCS.	See Section 2.7.13 of this study for further information.
20	Applicant should explain what percentage of CO_2 emissions it considers will be captured by its proposed technology. Applicant must include a clear statement on what type of technology is considered most appropriate for its power station. Applicants can discuss other options, but must make clear the option which is considered most appropriate. This technology will be the one assessed in the economic assessment.	See Sections 2.7 and 2.8 of this study for justification of spatial requirements for CC plant. Specifically Section 2.10.3 details the % capture of CO_2. Sections 2.2 to 2.6 of this study for discussion of technology options and the preferred technology at the time of preparation of this report.
21	Applicant should provide an assessment of its proposed plant designs as part of s36 application so that EA is able to advise S/S that there are no known technical barriers to a subsequent retrofit of the type of capture technology declared.	This is addressed by Section 5, 8 and 9 of the initial CCR Feasibility Study.
27	Applicant is asked to demonstrate that there are no known technical or economic barriers which would prevent the installation and operation of its chosen technology. Applicant must follow best practice as far as this knowledge is available and provide a reasoned justification of its choice.	This is addressed by both the initial CCR Feasibility Study and the study in detail considered being sufficient for the purposes of demonstrating CCR.
28	Requirements specific to post-combustion capture.	Sections 2.2 to 2.6 of this study for discussion of technology options and the preferred technology at the time of preparation of this report.
29	Applicant is only asked to compare efficiencies of its power station once capture is operational rather than before	Discussion is included in the initial CCR Feasibility Study as are heat balances for the CC process.
32	Applicant is responsible for making a short, reasoned, written justification of its proposed storage area, demonstrating that no known barriers exist to its use for CO_2 sequestration.	This is addressed by Section 6 of the initial CCR Feasibility Study.
33 and 42	Applicants must identify an offshore CO_2 storage area in its CCR storage assessment. The geographical extent of the area should be delineated.	This is addressed by Section 6 of the initial CCR Feasibility Study. Maps are included in appendix D of the report.
34	Applicants are advised to identify within the	Maps are included in appendix D of the

	delineated area (on a map) at least two fields or saline aquifers listed in either the "valid/viable" or "realistic" categories of the 2006 DTI Study. If other data source is used although will need to demonstrate equivalent levels of certainty.	initial CCR Feasibility Study.
39 and 42	Applicant should include a short summary including an estimate of the total volume of CO_2 that would be produced captured and stored as part of its CCR storage assessment. Assessment should include an estimate of the CO_2 storage potential of the area identified.	This is addressed by Sections 4 - 6 of the initial CCR Feasibility Study.
44 and 60	Applicant must demonstrate that a feasible route exists from site to storage area. Applicants are asked to identify a favoured route for their pipeline within a 1km corridor within a 10km radius of the power station. Applicant should identify major pre-existing obstacles arising because of safety of environmental concerns. Applicant should suggest methods by which the environmental impacts on an unavoidable designated site within the route corridor could be mitigated on the basis of current knowledge A map should be marked up at a scale sufficiently large for the proposed route corridors to be clear.	Pipe-line routing is addressed in Section 7 of the initial CCR Feasibility Study and also by the maps included in Appendix G of the same report.
46	After first 10 km from the power station, Applicant is asked to identify a 10 km wide corridor to the point on the coast where it envisages a pipeline going offshore or CO_2 going onboard a ship.	As above.
48	If pipeline options are limited, unavoidably impinge on a designated site etc, applicant should suggest how such impacts could be minimised.	There are considered to be no barriers in this regard to the eventual implementation of CC at SEE..
52	Applicant will need to demonstrate in its assessment that a feasible route from land to sea exists. Applicants should acknowledge potential barriers to the transport of CO_2 offshore and suggest how these factors might be mitigated.	Pipe-line routing is addressed in Section 7 of the initial CCR Feasibility Study and also by the maps included in Appendix G of the same report.
54 and 60	Applicant's assessment should contain a similar degree of detail for the offshore pipeline with the rest of the onshore route. Only broad corridors need be identified. Applicant should demonstrate that there are no barriers to the transport of CO_2 by the declared preferred method into any of the fields/aquifers in the storage area. Applicant should confirm that no unavoidable safety obstacles exist within the identified route corridor, on the basis of current	Pipe-line routing and storage of CO_2 is addressed in Section 7 of the initial CCR Feasibility Study.

	knowledge about the hazards posed by CO_2 transport.	
60	Requirements if applicant proposes to move CO_2 by ship	This is addressed in Section 7 of the initial CCR Feasibility Study.
64	Applicant should conduct a single economic assessment which encompasses retrofitting of capture equipment, CO_2 transport and the storage of CO_2. Applicants should demonstrate the full range of costs and benefits associated with the deployment of CCS to any given plant in a manner which takes full account of all relevant technical and economic factors and is not inconsistent with EU Directive 2009/31/EC.	See Section 4 of this study for economic discussion.
65	Applicant should provide evidence of reasonable scenarios, taking into account cost of capture technology and transport option chosen and the estimated cost of CO_2 storage which make operational CCS economically feasible for the proposed development.	See Section 4 of this study for economic discussion.
68	Sets out model assessment structure	The CCR study approach is detailed in the initial CCR Feasibility Study and this study.

APPENDIX B

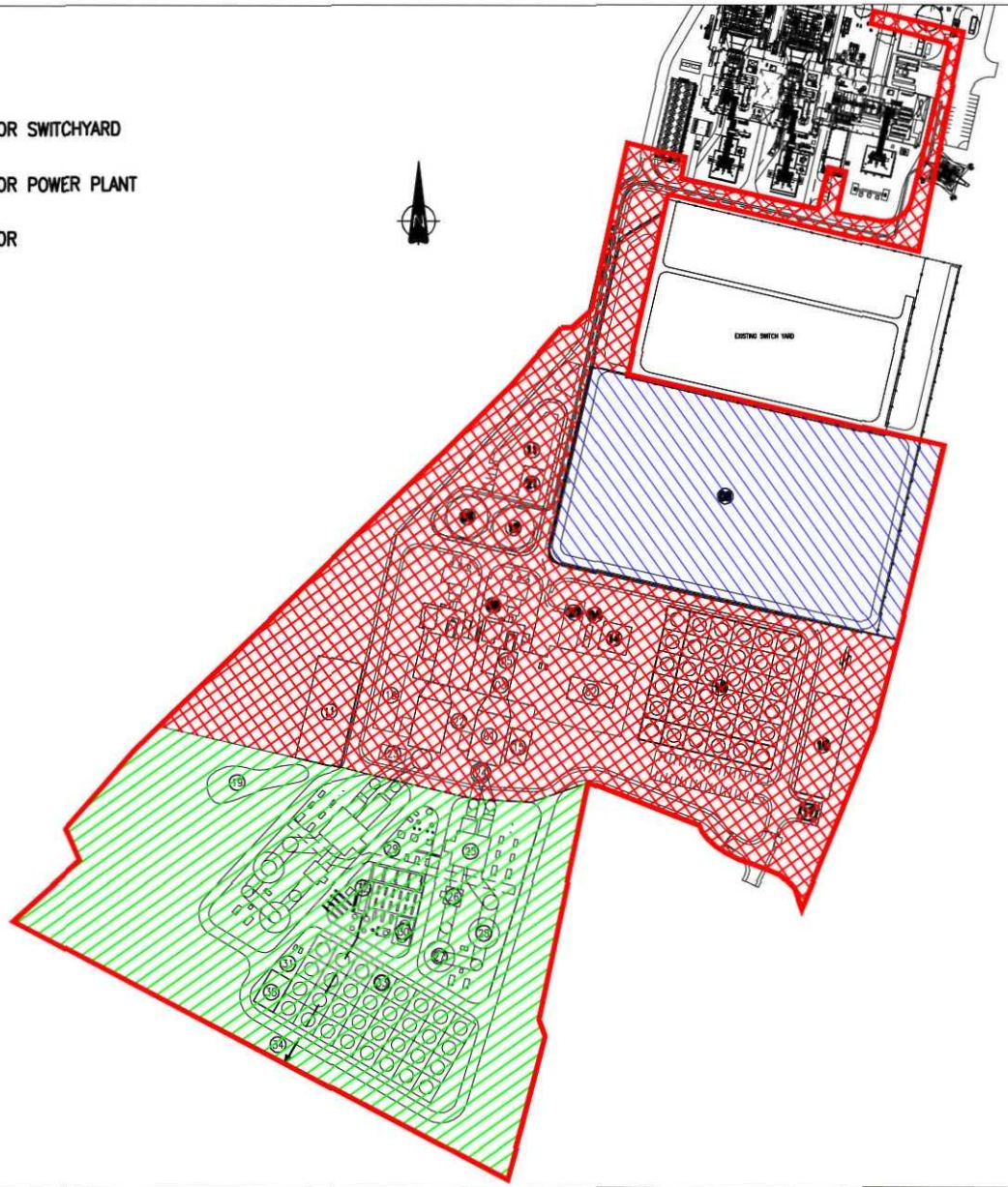
ILLUSTRATIVE CCS LAYOUTS

KEY

AREA ALLOCATED FOR SWITCHYARD

AREA ALLOCATED FOR POWER PLANT

AREA ALLOCATED FOR CARBON CAPTURE



LEGEND

01 HEAT RECOVERY STEAM GENERATOR
02 STEAM TURBINE AREA
03 GAS TURBINE AREA
04 CO2 LOW PRESSURE STATION
05 GAS TURBINE INLET FILTER
06 DEMINERALIZED WATER STORAGE TANK
07 CTG MAIN TRANSFORMERS
08 STATION SERVICE TRANSFORMER
09 SWITCHYARD
10 AIR COOLED CONDENSER
11 WAREHOUSE/MAINT/ADMIN/CONTROL BDLG
12 WATER/ FIREWATER STORAGE TANK
14 STG MAIN TRANSFORMER
15 AUXILIARY BOILER
16 GAS CONDITIONING FACILITY
17 REFUSE COLLECTION/STORAGE
18 FIN FAN COOLERS
19 SUDS POND
20 ELECTRICAL ANNEX
21 WATER TREATMENT PLANT
22 FUTURE SCR AMONIA SKID
23 FUTURE AMONIA STORE AND BUND
24 STACK
25 GAS/GAS HEAT EXCHANGER
26 BLOWER
27 DIRECT CONTACT COOLER
28 ABSORBER
29 STRIPPER
30 RECLAIMER
31 SOLVENT STORAGE TANK
32 CO2 COMPRESSOR
33 FIN-FAN COOLERS
34 CO2 BATTERY LIMIT
35 CW PUMP HOUSE

REV	DATE	DESCRIPTION	BY	CHKD	APPD

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• NOTES

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• CLIENT/PROJECT
INTERGEN
SPALDING ENERGY PROJECT

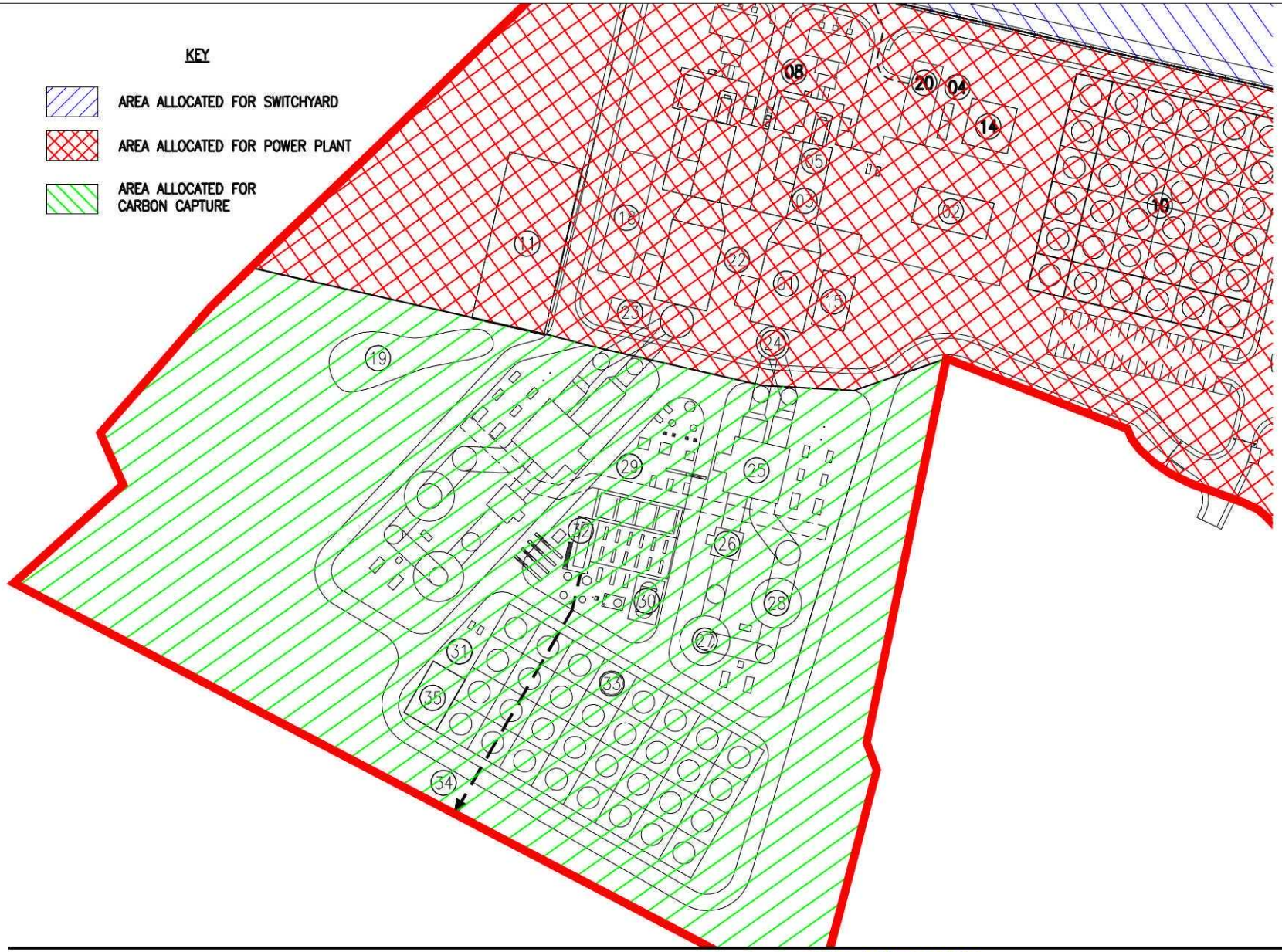
• TITLE
PROPOSED CCS LAYOUT
(ENTIRE RED LINE)

• DATE 14.01.10
• SCALE N/A
• CAD REF

DRAWN BY	DD
PRODUCED BY	DD
CHECKED	EA
APPROVED	EA

• DRAWING NUMBER
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LEGEND

01 HEAT RECOVERY STEAM GENERATOR
02 STEAM TURBINE AREA
03 GAS TURBINE AREA
04 CO2 LOW PRESSURE STATION
05 GAS TURBINE INLET FILTER
06 DEMINERALIZED WATER STORAGE TANK
07 CTG MAIN TRANSFORMERS
08 STATION SERVICE TRANSFORMER
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30 RECLAIMER
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32 CO2 COMPRESSOR
33 FIN-FAN COOLERS
34 CO2 BATTERY LIMIT
35 CW PUMP HOUSE

REV	DATE	DESCRIPTION	BY	CHKD	APPD

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SPALDING ENERGY PROJECT

• TITLE
PROPOSED CCS LAYOUT
(ENLARGED)

• DATE 14.01.10
• SCALE 1/1500
• CAD REF

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APPROVED	EA

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APPENDIX C

INITIAL SPALDING ENERGY EXPANSION CARBON CAPTURE READINESS FEASIBILITY STUDY MARCH 2009

SPALDING ENERGY EXPANSION LTD

SPALDING ENERGY EXPANSION CARBON CAPTURE READINESS FEASIBILITY STUDY

March 2009

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LIST OF ABBREVIATIONS

°	degree
°C	degree Celsius
Ar	Argon
bar a	bar absolute
BGS	British Geological Survey
CCGT	combined cycle gas turbine
CCR	carbon capture ready
CCS	carbon capture and storage
CO_2	carbon dioxide
DECC	Department of Energy and Climate Change
EA	Environment Agency
EU	European Union
GE 9FB	General Electric 9FB gas turbine
GJ	Gigajoule
GT	gas turbine
h	Hour
H_2O	water vapour
HDD	horizontal directional drilling
HP	high pressure
HRSG	heat recovery steam generator
HSC	Hazardous Substance Consent
HSE	Health and Safety Executive
k	Kilo
kg	kilogram(s)
LP	low pressure
m	metre
M	mega
MEA	MonoEthanolAmine
MHI	Mitsubishi Heavy Industries
MW	megawatt
MWe	megawatt electrical
MWth	megawatt thermal
N_2	nitrogen
NGC	National Grid
O_2	oxygen
PB	Parsons Brinckerhoff
s	second
SEE	Spalding Energy Expansion
SEEL	Spalding Energy Expansion Limited
t	tonnes
UK	United Kingdom

1. INTRODUCTION

Parsons Brinckerhoff (PB) has been retained by Spalding Energy Expansion Limited (SEEL) to prepare a Carbon Capture Ready (CCR) study to aid in its application for Section 36 Consent for the Spalding Energy Expansion (SEE) project. Whilst the European Union (EU) agreed the text of a new European Directive on the Geological Storage of Carbon Dioxide on 17 December 2008, at present the UK regulatory regime governing CCR is uncertain.

In the UK the relevant competent authority in respect of energy matters is the Department of Energy and Climate Change (DECC). DECC must ensure the EU Directive is implemented. It is also free to impose more stringent regulations on power plants within the UK. DECC has conducted a public consultation on CCS and CCR and is planning to issue the response to this shortly. It is anticipated that the UK CCR regulatory regime will be finalized in the first half of 2009.

It is assumed that the CCS approach most appropriate for the SEE project will be post-combustion capture. The pre-combustion capture is not considered appropriate for this project due to limited experience of 'F' class gas turbines (GTs) operating with hydrogen rich fuels (the product of pre-combustion technology). The SEE project plant configuration and available land also lends itself to the post-combustion CCS installation.

This report addresses the availability of suitable storage sites; the technical and economic feasibility of transport facilities, the technical and economic feasibility of retrofit for carbon capture; and establishes that there is suitable space for CCS equipment at the power plant site. In respect of the economic feasibility of retrofit and transport, it is considered that these aspects will become economically feasible at some point in the future given: (1) the recent and likely future developments in CCS technology, much of which will stem from the proposed carbon capture and storage competition to be funded by DECC and the EU; (2) the likely long-term movements in the price of carbon; (3) the proposed treatment in Phase III of the EU ETS of carbon which is emitted, captured and stored; and in particular (4) the UK Government's stated commitment to establishing the necessary economic and regulatory framework for CCS. Further consideration of CCR issues, including additional assessment of the economic feasibility of transport and retrofit for carbon capture, may be appropriate once the Government has clarified its CCR requirements.

2. APPROACH

In determining the Carbon Capture Readiness of the proposed power plant in the SEE project, PB utilized the following approach:

- Established a high level concept of the proposed power plant taking into consideration a number of alternative and competing 'F' class GT technologies;
- Carried out thermal modelling of the power plant without carbon capture to identify the 'F' class GT technology option that is likely to produce the most CO_2 (ie the greatest capture requirement);
- Established the main carbon capture equipment sizing using the above modelling and confirmed that it will fit into the land currently available, ie 3.6 hectares, for the CCS equipment at SEE.
- Identified a preferred carbon capture technology for retrofit and its likely impact on the performance of the proposed power plant;
- Identified a range of potential geological storage sites with storage capacities capable of accepting the carbon output from the plant over a 35 year period; and
- Identified a preferred route for the transportation of the CO_2 from the site to a geological storage site taking into account the drivers associated with pipeline, road or rail onshore transportation of CO_2 and existing gas / oil infrastructure locations (ie beach head sites).

3. LEGAL STATUS

3.1 Current arrangement

The EU Directive on the Geological Storage of Carbon Dioxide (the "Directive") requires an amendment to Directive 2001/80/EC (commonly known as the Large Combustion Plants Directive) such that Member States are to ensure that operators on all combustion plants with an electrical capacity of 300MW or more (and for which the construction/operating license was granted after the date of the Directive) have assessed whether:

- Suitable storage sites are available
- Transport facilities are technically and economically feasible; and
- It is technically and economically feasible to retrofit for CO2 capture.

An Assessment of whether these conditions are met is then to be submitted to the relevant competent authority. The competent authority shall then decide if these conditions are met on the basis of the assessment and other available information. If the conditions are met, the competent authority shall ensure that suitable space on the installation site for the equipment necessary to capture and compress CO_2 is set aside.

The relevant sections of the Directive are attached in Appendix A.

DECC's response to the public consultation on CCS is expected in mid 2009 with the UK regulatory regime being finalized shortly thereafter. Until the regulatory regime is finalized there will be uncertainty as to exactly how a Section 36 Applicant must prove that the plant is CCR. However, the best currently available information suggests that:

- It is extremely likely that DECC will require that the SEE project be built CCR, and will require demonstration of carbon capture readiness as part of the Section 36 application.
- There are four factors DECC is likely to consider for the assessment of CCR, which are considered in this report. These are:
    1. That there is provision of suitable space on the installation site for the equipment necessary for subsequent capture and compression of CO_2;
    2. That suitable storage sites are available;
    3. That transport facilities are technically and economically feasible; and
    4. That it is technically and economically feasible to retrofit for CO_2 capture.

In this report:

- Factors 1 and 4 are covered in Section 9 (Retrofitting CCS);

- Factor 2 is covered in Section 6 (Storage); and
- Factor 3 is covered in Section 7 (Transport).

The Environment Agency (EA) is currently developing a checklist to assist in judging the space and retrofit factors. At present this checklist only applies to coal-fired power plants, however a Combined Cycle Gas Turbine (CCGT) power plant checklist is expected to be very similar. SEEL is already aware of this checklist, which is attached in Appendix B. While this checklist represents the best currently available information on the possible DECC requirements for assessment of CCR, it should not be considered definitive. DECC has yet to publish the Government's response to the consultation document and the final UK Regulations may be more or less stringent than the checklist implies. The main points in the checklist are covered in Section 9 of this report.

4. POWER PLANT

The proposed SEE project is to be a CCGT plant, comprising two GTs and one (or two) steam turbine(s). Initial thermal modelling of the base case, using Thermoflow software, was undertaken using values for GTs from three different manufacturers. Details of the base case model can be found in Appendix C.

Carbon capture technology is essentially blind to the details of upstream power generation process, so the only output of the modelling process that was required for capture plant sizing is the flue gas analysis leaving the HRSG. As a decision has not yet been made regarding which specific GT will be used in the power plant, it was decided that this study should consider the GT type that produced the largest quantity of CO_2 to be captured i.e. the worst case from a carbon capture duty and power output reduction from the CCGT plant. The selected GT has the highest absolute CO_2 emissions directly as a result of it being the largest GT from the considered GT technologies and not because it is an inappropriate technology. The specific emissions per unit electrical output for all considered GTs are similar. The flue gas analysis for the operation of the selected GT is shown below in Table 4-1.

Table 4-1 - Flue Gas Analysis for Base Case

Component	N_2	O_2	H_2O	CO_2	Ar	Total
Molar/volume %	74.27	11.82	8.829	4.185	0.8931	100
Mass flow rate [kg/s]	982	178	75	87	17	1340

4.1 Sizing of CCS chain

It is expected that the carbon capture plant eventually installed would capture around 90%[1] of the CO_2 in the flue gas, which is typical of chemical absorption carbon capture technologies.

Sizing of the CCS Chain (namely capture, compression or liquefaction, transport and storage) is therefore based on the information on Table 4-2, below.

[1] This is the level that capture facility providers have indicated would be a performance guarantee level for a capture plant.

Table 4-2 - Sizing of CCS Chain

CO_2 Component	Amount
CO_2 generated at plant (from Table 4.1)	87 kg/s
CO_2 captured (90% of generated)	79 kg/s 283 t/h 6800 t/day
CO_2 stored (assuming 90% load factor)	2.23 Mt/a
Total CO_2 stored (35 years of capture)	78.1 Mt

The carbon capture chain needs to be capable of handling the maximum flow rate of 79 kg/s which occurs whenever the power plant is operating at full load. On this basis the capture chain would be able to process and store upto a maximum of 2.5 Mt pa; however, the total annual throughput for the capture chain will vary dependent upon the operational profile for the power plant – this would be expected to be around 2.23Mt pa with a 90 per cent load factor.

5. CAPTURE PLANT TECHNOLOGY

Currently there exist a number of carbon capture technologies and, at the time of carbon capture installation, it is highly probable that there will be more. SEEL has requested that the study focus solely on the technology that is closest to commercial deployment at present, and therefore demonstrate immediate Carbon Capture Readiness. As such, PB believes that it is appropriate that the study focuses on currently available technology, rather than speculate on any future developments. While many of these developments are likely, it would be hard to argue that a plant was carbon capture ready if it was dependent on assumptions around future technical development. Therefore, the technical feasibility has been assessed on the basis of currently available amine technology, rather than the technology that may be available when the plant is installed. The current best available technology for capture of carbon from flue gases is chemical absorption using amine solvents, typically based on monoethanolamine (MEA). This technology may be regarded as commercially available but has not yet been commercially proven for large-scale power plant applications. It is the belief of PB, however, that no real technical barriers exist to extending existing experience to a scale appropriate to the current study. Figure 5-1, below, shows a schematic of this process, commonly referred to as amine scrubbing.

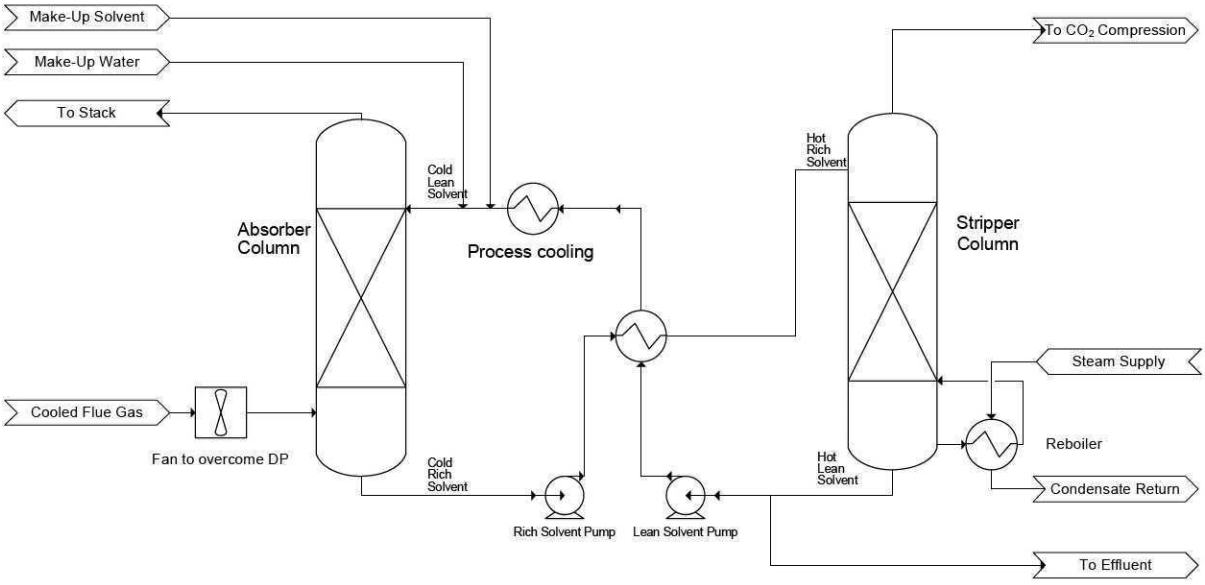


Figure 5-1 - The Amine Scrubbing Process

After cooling, the flue gas is blown through an absorber column where it comes into contact with the liquid amine solvent. Around 90 per cent of the acidic CO_2 in the flue gas is chemically absorbed through acid-base neutralization reactions with the basic amine, thus creating a CO_2 rich stream of liquid solvent. The rich solvent passes out of the absorber column and is heated in a heat exchanger before entry into a stripper column, where the solvent is further heated by the condensation of steam in the reboiler. The amine can absorb more CO_2 at lower temperatures, so heating the solvent releases the CO_2 as a gas. The lean liquid solvent is removed at the bottom of the stripper, is cooled in the heat exchanger, and further cooled before re-entry to the absorber. The CO_2 gas, containing a large quantity of steam, exits at the top of the stripper. It is cooled to remove the steam and

compressed or liquefied for transport. Steam and water removed from the CO_2 stream are returned to the capture plant.

Amine absorption plants typically capture approximately 90 per cent of the CO_2 in a CCGT plant flue gas stream and result in a product (CO_2) purity of over 99 per cent.

The capture technology itself requires power, for example to operate pumps and blowers and for the compression of the CO_2 product. A relatively small power demand is also required for the purposes of control and instrumentation. In addition to requiring power, steam is needed to regenerate the amine solvent. Usually this steam would otherwise be expanded in the steam turbine to generate power and, hence, the carbon capture plant imposes a power penalty on the CCGT plant export capability through its heat requirement. This combination of auxiliary loads and steam required by the chemical absorption technique has a potentially significant impact on the net electrical power output.

Substances such as particulate matter (PM), SO_2, NO_2 and oxygen (O_2) have a detrimental effect on the process. The effects range from reduction in efficiency to generation of solids (heat stable salts, HSS), which cause problems such as foaming and require filtration and addition of make-up solvent. Flue gases from CCGT plants such as the SEE project typically contain excess oxygen and small amounts of NO_2. NO_2 forms HSS when it reacts with amine, however when levels of NO_2 are below 10 ppm (21 mg/Nm^3) these can be effectively countered. EU legislation requires the NO_x level in the flue gas to be reduced to below 50 mg/Nm^3. As NO_x typically contains less than 10 per cent NO_2, the level of NO_2 in the SEE project flue gas should not cause difficulty for standard amine carbon capture processes. Oxygen is detrimental to the amine capture process, but the effect is well understood by process providers. The information presented on the amine process is based on information relevant to CCGT which takes into account the quantities of O_2 present in CCGT exhaust.

In addition to other technologies, capture process providers are considering a number of methods of improving their processes. There are many methods, ranging from the simple (incorporating heat recovery) to the more difficult (flue gas recirculation). One method is generation of the steam required through supplementary firing of the HRSGs. This supplementary firing not only reduces the impact of the capture process on the plant, but also reduces the quantity of oxygen in the flue gas. However, it also increases the quantity of CO_2 to be captured and therefore increases the scale of the capture plant. As with alternative technologies, these possible improvements to the process have not been included in this report.

Possible vendors for amine capture include Mitsubishi Heavy Industries (MHI), Fluor Daniel (licence holder of the Econamine FG process), Cansolv (recently acquired by Shell Global Solutions), Aker Kvaerner, HTC, C&I Lummus (previously ABB Lummus), and Powerspan. Recent discussions (2008) with both Fluor Daniel and Cansolv indicate that it is technically feasible to build a carbon capture plant for a 1000 MW power output scale on gas firing, with a development time in the region of 12 months, and a construction time of 36 months. As highlighted above, this technology may be regarded as commercially available but has not yet been commercially proven for large-scale power plant applications. It is the belief of PB, however, that no real technical barriers exist to extending existing experience to a scale appropriate to the SEE project.

In respect of the economic feasibility of retrofit, it is considered that carbon capture retrofit is expected to become economically feasible at some point in the future given: (1) the recent and likely future

developments in CCS technology, much of which will stem from the proposed carbon capture and storage competition to be funded by DECC and the EU; (2) the likely long-term movements in the price of carbon; (3) the proposed treatment in Phase III of the EU ETS of carbon which is emitted, captured and stored; and in particular (4) the UK Government's stated commitment to establishing the necessary economic and regulatory framework for CCS. Additional assessment of the economic feasibility of retrofit for carbon capture may be appropriate once the Government has clarified its CCR requirements.

6. STORAGE

In order to determine whether any suitable storage sites exist for this CCGT development, it was necessary to have an understanding of the amount of CO_2 that is potentially required to be stored. Assuming a 35 year life and a 90 per cent load factor for the power station, any storage site would have to be capable of storing approximately 78 Mt of CO_2 (see Table 4-2 in Section 4.1). In the event that carbon capture is retrofitted some years into the CCGT operating life the maximum requirement for storage would diminish.

6.1 Potential storage sites

Currently, only offshore storage of CO_2 is being considered in the UK. As such, the relative proximity of the South North Sea gas fields to the proposed SEE project, compared to the oil fields of the North North Sea and the potential storage sites in the Irish Sea, have led PB to only look at potential sites in the South North Sea region. Table 6-1 lists the storage sites in the South North Sea that have been identified by BGS as having a storage capacity that can be utilized for storage of CO_2 from the SEE project[2]. Some storage sites are below the maximum levels required but it is assumed that a combination of one or more sites could be used if necessary.

[2] http://www.berr.gov.uk/files/file35684.pdf

Table 6-1: Potential Storage Sites in the South North Sea Region

Field Name	CO2 Storage Capacity (Mt)
Amethyst	63
Audrey	53
Barque	108
Clipper	60
Galleon	137
Hewett L Bunter	237
Hewett U Bunter	122
Indefatigable	357
Leman	1203
Ravenspurn N	93
Ravenspurn S	52
V Fields	143
Victor	70
Viking	223
West Sole	143

These locations are identified on a map in Appendix D.

6.2 Competing industrial factors

The specific availability of a storage site will be dependent on a number of factors. If production of gas is still continuing at the time that CO_2 storage is required, it may be technically impossible to sequester CO_2 simultaneously. However, decreasing natural gas production in the SNS means that it is unlikely many of these fields will still be producing significant amounts of natural gas post 2020.

This too could pose a difficulty, as a gas field ceasing production before CCS is rolled out commercially would require the operator under the terms of their production licence to decommission all the equipment currently in the field. This would mean that all new equipment may be required when carbon is to be stored, increasing the burden cost on the overall economics of a carbon capture retrofit.

6.3 SEE project specific storage solutions

Competing interests for the storage sites is also possible, as other CCS projects and natural gas storage sites will all be competing for pore space. However, since natural gas storage is better suited to storage sites with a low capacity, as it does not require as much gas to be injected as a buffer gas, and CO_2 storage is better suited to larger storage sites, it appears that these may not be conflicting interests.

Clearly a large number of storage sites exist that are capable of storing the CO_2 from this project. While further investigation might indicate that some of the sites are not suitable for CO_2 storage, it is highly likely that a solution exists from the set of storage sites listed in Table 6.1, above. The decision as to which specific storage site to use will be optimized at the time when the decision to implement carbon capture is made.

6.4 Potential future schemes

In the event that infrastructure common to the SEE project and other CO_2 sources in the area were used, then the total CO_2 stored in the storage site could be much higher. Assuming a large diameter pipeline (36”) was run to the storage site; this would be capable of carrying up to 20 Mt of CO_2 per year. The storage site would therefore have to be capable of holding over 500 Mt if it was to be operational for a period of 35 years.

Another possibility is the availability of a CO_2 network in the region. In this case it is likely that CO_2 from the SEE project and other plants would be delivered to a “hub”, and from there delivered to a number of storage sites. A brief discussion on this possibility is provided in Section 7.1.

7. TRANSPORT

There are various options available for transporting CO_2. Onshore transportation includes pipeline, rail or road tankers, while offshore transportation comprises pipeline or shipping.

In the natural gas industry, transport using a network of pipelines has routinely been shown to be the most cost effective option when dealing with large volumes of gas to be transported over long distances to meet the commercial arrangements of producers and users. Road, rail or shipping are likely to have niche applications, as they are able to provide flexibility that pipelines are unable to achieve. As a result, they are particularly useful for early projects that may be demonstration scale, or where a suitable national infrastructure does not currently exist, ie at remote locations where the cost of such infrastructure cannot readily be socialized amongst a larger cluster of users.

The establishment of a national infrastructure of CO_2 pipelines, where a higher density of users are present, will be essential in driving economies of scale to bring down the socialized costs of CCS in the UK. For this reason, PB has studied neighbouring combustion facilities that are likely to apply CCS at some point in the future. This was undertaken to approximate the potential size of the pipeline that may be required to transport CO_2 from a number of nearby combustion sites to geological storage sites.

7.1 Additional CO_2 sources

There are a number of industrial and/or power generating plants that can be considered as significant CO_2 sources in the area of the proposed SEE project. These plants could potentially be required to fit carbon capture in the future and, thus, could impact on the route and capacity of any CO_2 pipeline connecting to the proposed SEE project site.

Details of these plants, and additional nearby facilities, which may be able to utilize a common CO_2 pipeline are provided in Appendix E. This Appendix includes a summary of the major emitters (>100,000 t CO_2 per annum) in the area, their distance from the proposed SEE project site and details of their emissions in recent years, where available, as reported to the EA as part of the Pollution Prevention and Control regime and to DEFRA[3] as part of Phase 1 of the UK's CO_2 National Allocation Plan for the years 2002 and 2003.

Many of the existing facilities detailed in Appendix E are likely to be no longer operational post 2020; indeed a number of these plants, including Peterborough and Corby, are early generation CCGT plants. The potential for carbon capture to be retrofitted to these plants is not easy to establish as it is likely that these plants will either require repowering with new gas turbines or are about to close at the time that any future requirement for CCS may be introduced. These existing plants may also require additional land for the carbon capture equipment. This additional land may not be readily available. The neighbouring coal plants, Cottam and West Burton, have been fitted with flue gas desulphurization (FGD) and will therefore remain open for the foreseeable future. However, it is debatable as to whether sub-critical plants such as these will be economic were they to fit carbon

[3] Department for Environment, Food and Rural Affairs, a UK Government Department

capture given the considerable auxiliary load that would be placed on the plants, both of which have overall plant efficiencies in the order of 32 per cent prior to fitment of CCS. There has also been speculation about the development of a clean coal, or perhaps CCGT, plant at High Marnham. However, the status of any such project is not known at this stage. The commissioning date for plants not yet built has been obtained from NGC public domain information. The timing of these commissioning dates may be brought forward in the event that capacity in the system becomes available earlier, for example if new nuclear plants are not built by 2016 as is currently anticipated by NGC.

However, for the purposes of this study, we have assumed that facilities will be replaced or refurbished at the same location at the time when the original facility reaches the end of its operating life.

Appendix F contains a map illustrating the approximate location of the sites listed in Appendix E.

Thus, in addition to the 1.9 Mt/annum of CO_2 that this project could potentially capture and transport, there is potential for the transport of over 45 Mt/annum from sources in the region around the proposed facility. This makes a strong case for the possible future installation of a common infrastructure in the region.

7.2 CO_2 transportation by pipeline

The CO_2 could be transported in pipelines as a vapour or as a dense fluid at high pressures, typically above the supercritical pressure. In the latter form, while pipeline pressures are likely to be in excess of the critical pressure (73 bar g), temperatures are likely to be below the critical temperature (31°C), particularly in the offshore segment of the pipeline. Thus the fluid transported will not actually be in the supercritical phase, but rather the liquid phase. Supercritical/liquid CO_2 occupies a smaller volume and has a very low friction loss, thus it can be transported in smaller diameter pipelines without any requirement for booster stations, resulting in reduced infrastructure costs. If CO_2 is transported at supercritical pressure, it will be compressed to ensure the required pressure at the injection wellhead while accounting for pressure drop along the pipeline. It is also possible to pump the supercritical/liquid CO_2 to pressures well in excess of the injection pressure, thereby reducing the diameter of the pipeline. A detailed optimization study would be required to determine whether this is warranted, and such optimization is outside the scope of this report.

It is yet to be seen if transportation of CO_2 at supercritical pressures is permitted onshore. If CO_2 is to be piped as a vapour, it will be compressed to the maximum permitted pressure to avoid two phase flow at the power plant, and piped directly to the storage site or to a beachhead facility where it will be compressed to a higher pressure for offshore transport. If appropriate, to cross the beach head horizontal directional drilling (HDD) or similar techniques will be used.

At the storage site the CO_2 may be compressed or expanded to the required injection wellhead pressure, which will depend on the pressure in the site. There may be a requirement for heating of the CO_2 at injection; again this would be site-specific.

7.2.1 Established technology

Transporting CO_2 via pipelines is an established technology with an excellent safety track record, and is similar to natural gas transportation via pipelines. Large volumes of CO_2 are transported in the United States via pipeline. The CO_2 is dehydrated to reduce the likelihood of corrosion. Pipelines are made of steel, which is not corroded by dry CO_2. A corrosion resistant alloy is used for short sections of pipeline before dehydration stations (IPCC, 2005). The oldest CO_2 pipeline is the 1972 Canyon Reef Pipeline, which carries 5 Mt of CO_2 a year from gas processing plants. The largest CO_2 pipeline in the United States is the Cortex pipeline. With its recent expansion to include more than a dozen new CO_2 wells, 17 km of additional pipeline and additional compression and pumping capacity, Cortez has a capacity of over 30 Mt per year of CO_2 carried over 800 km. CO_2 transport via pipeline therefore already exists at scales well in excess of the SEE project.

7.2.2 Risks

The risks associated with CO_2 pipelines have been extensively documented (IPCC, 2005). Whilst CO_2 presents no explosive or fire-related risks, gaseous CO_2 is denser than air and can accumulate in low-lying areas where, at high concentrations, it can create a health risk or be fatal. In addition, the presence of impurities such as hydrogen sulphide (H_2S) or sulphur dioxide (SO_2) can increase the risks associated with potential pipeline leakage from damage, corrosion, or the failure of valves or welds. External and internal monitoring for leaks and visual inspections, including the use of internal inspection devices (known as 'pigs') or distributed fibre optic sensors, can mitigate corrosion-related risks. The safety record of CO_2 pipelines up to 2006 shows a lower rate of leakage per kilometre of pipeline than gas pipelines, and no recorded injuries.

7.2.3 Legal and regulatory framework

The legal and regulatory classification of CO_2 is currently under consideration by a number of different authorities in anticipation of a large scale CCS industry. As such, CO_2 pipelines are not designated in the same way as natural gas and oil pipelines in most legal codes and are therefore not regulated in the same way as other large-scale pipeline systems. To draw on the United States experience, the Department of Transportation (DOT) regulations list CO_2 as a Class 2.2 hazardous material (non-flammable). Its designation as a commodity or as a pollutant will determine whether its transportation and the siting of pipelines falls under the authority of the US Surface Transportation Board or of the Federal Energy Regulatory Commission (FERC), which regulates natural gas and oil pipelines that are deemed common carriers.

7.2.4 Pipeline transport of CO_2 from the SEE project

At present, the regulatory status of CO_2 pipelines in the UK remains unclear. Interim guidelines have been published by the Health and Safety Executive (HSE) on CO_2 pipelines, and where uncertainty remains PB has assumed that CO_2 pipelines will be subject to similar regulations to natural gas pipelines, and so has assumed that any onshore CO_2 pipeline would be routed alongside the existing natural gas pipeline routes to a beachhead gas terminal. These routes are visible in Appendix D. PB therefore considered two possible pipeline routes: from the SEE project to Theddlethorpe or to Bacton.

Although Bacton is physically nearer, due to population densities and the current interim guidelines, PB believes that the most feasible route for the onshore pipeline is to the gas terminal at Theddlethorpe. As such, the proposed route for a pipeline from the proposed SEE project site to the Theddlethorpe gas terminal is shown in Appendix G. PB recommends that and further investigation of onshore pipeline routes be postponed until DECC requirements for demonstration of CCR are known.

7.3 CO_2 transportation by road

There are three potential motivations for transporting CO_2 by road. These are:

1. Flexibility, for example if shipping is required alternative ports can be used;
2. Safety, for example if future safety regulations allow onshore transport in tankers, but not in pipelines; and
3. Project timescales, for example if the project is only operational for a short period of time it may be cheaper to transport CO_2 in tankers which can then be re-used by another project, rather than build a pipeline.

Road transport requires captured CO_2 to be compressed to approximately 20 bar and liquefied by cooling to approximately -30ºC in a process similar to liquefied natural gas (LNG) production.

The CO_2 captured from the CCGT plant would be compressed, dried and refrigerated using an ammonia or propane refrigeration cycle. It would then be transferred in bulk tankers mounted on trucks, and transported from the SEE project to the storage site. Depending on the storage site, the CO_2 may be pumped to a higher pressure and heated before injection.

Transport of CO_2 by road is currently underway at small scales (9 t/hour) at Schwarze Pumpe, Germany, operated by Vattenfall. BOC Linde was involved in the design and construction of both the liquefaction plant and the CO_2 tankers used. BOC Linde is also currently involved in transporting CO_2 by road in Australia. The CO_2 tankers involved range in payload capacity, and include capacities of 20, 32 (b-double) and 40 - 45 (road train) tonnes. Regulations governing CO_2 transport by road in the UK will most likely be issued along with regulations governing pipeline transport.

As the potential storage sites are all offshore, road transport would be combined with offshore pipeline or shipping. Potential destinations for road transport from the SEE project are therefore Theddlethorpe (80 km), Bacton (130 km), or a nearby port or harbour, either on the coast, a river or canal. Ports within 100 km of the SEE project site are shown in Figure 7-1, below.



Figure 7-1: Ports within 100km of the SEE Project Site

For the scale of the proposed SEE project, assuming 32 tonne trucks travelling a distance of 80 km, it is anticipated that about 50 trucks would be needed, requiring over 100 additional full time staff to provide a 24-7 transport operation.

Therefore, while road transport may be technically feasible, it is highly unlikely to be economically feasible for a long-term, full scale project such as this, and so has not been considered any further in this report.

7.4 CO_2 transportation by rail

The motivations for transportation by rail are similar to the ones behind transportation by road. CO_2 transportation by rail tanker would be very similar to transportation by road tanker. The pressure and temperatures are identical. Rail transport of CO_2 could therefore be considered as similar to a number of road tankers connected together.

Very little information on rail transport of CO_2 is available. Air Products currently transport CO_2 in road tankers with a capacity of 20 – 22 tonnes in Europe, and believe that rail tankers would be a similar size (ie 20 – 22 tonnes), but it is unknown how many would make up a full train. Rail transport could be to a nearby port for shipping, or to Theddlethorpe or Bacton for offshore pipeline transport to the storage site. Only two nearby ports are currently accessible by rail, namely Boston and Kings Lynn. Rail transport to Theddlethorpe would require an additional 20 miles of track to be built from Skegness and to Bacton, an additional 5 miles of track from North Walsham. The potential rail transport routes are shown in Figure 7-2.

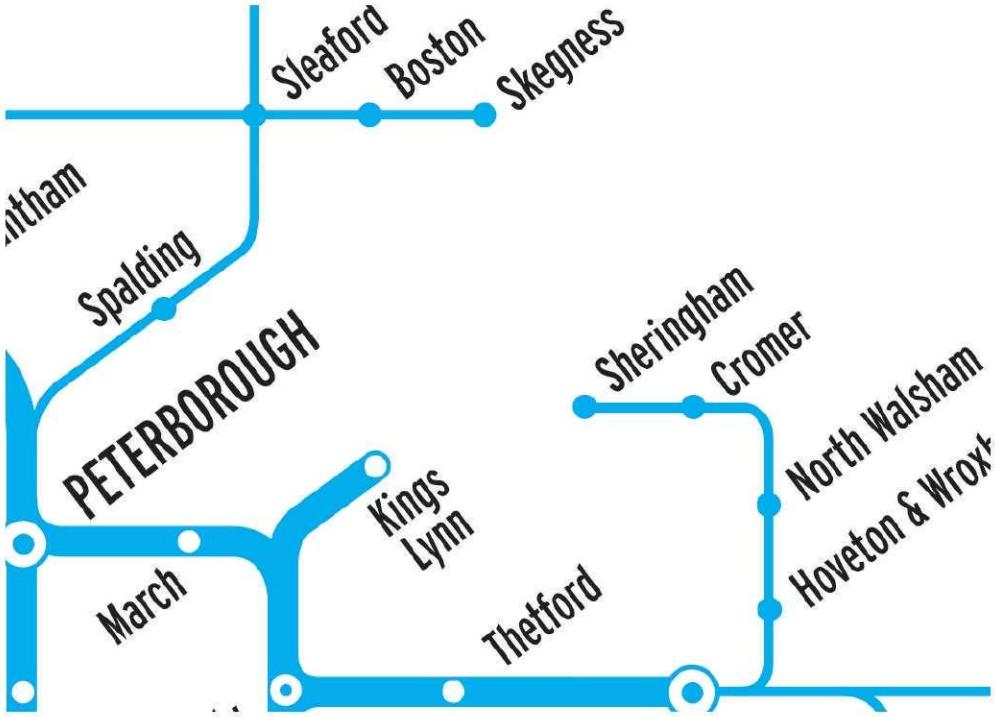


FIGURE 7-2 - POTENTIAL RAIL TRANSPORT ROUTES (NOT TO SCALE)

Rail transport is certainly technically feasible, but without a more in-depth study it is difficult to confirm if it is a realistic option for the SEE project.

7.5 Shipping

The shipping of CO_2 would be an alternative to offshore pipeline transport. While the natural gas industry primarily uses pipelines for large scale, long distance delivery, shipping of LNG and liquefied petroleum gas (LPG) does have a significant niche role to play in the industry, and this could be the case for CO_2 also. It provides a much greater flexibility over a pipeline, and therefore could be used where a cluster of smaller storage sites are to be used, that may reach full capacity in a reduced number of years.

Shipping of CO_2 is currently underway, using ships similar to LNG ships. For this method of transport by shipping, the CO_2 is liquefied at 6 - 7 bar a and -50ºC.

There are two reasons for considering shipping. These are:

1. Flexibility: different storage sites can be used; and

2. Project timescales, for example if the project is only operational for a short period of time it may be cheaper to transport CO_2 in reusable ships rather than build a pipeline.

Whether the CO_2 is transported to the dock by road, rail or pipeline the CO_2 would arrive at the port at a pressure in excess of that required for shipping, but at a lower temperature. It would have to be liquefied at the port before charging (loading) of the ship. Therefore space would be required at the port for a liquefaction plant. In addition, a significant imported power requirement for refrigeration would be required at the port in addition to compression at the plant.

At the injection site the CO_2 must be pumped to a pressure suitable for injection and may also require heating depending on the geology of the site and the pressure in the well. This is yet another power requirement for CCS. Shipping is technically feasible, but a more detailed investigation would also be required to assess if it is a realistic option for the SEE project.

7.6 Compression

Pipeline transport would result in a power requirement for compression of CO_2. Assuming compression to supercritical pressures using a currently available ManTurbo integrally geared centrifugal compressor, this would be of the order of 31 MW.

7.7 Liquefaction

Road or rail transport would result in a power requirement for liquefaction of CO_2 at the SEE site. This would be of the order of 40 MW.

Assuming road or rail transport is combined with shipping, the CO_2 would be expanded at the port from 20 bar to 6 bar, and further cooled to -50ºC, resulting in an additional power requirement of the order of 1.5 MW.

Compression, liquefaction and transportation of CO_2 are already in existence in other industries at the scale required for the SEE project.

7.8 Economic feasibility of CO_2 transportation

In respect of the economic feasibility of transport, it is considered that this is expected to become economically feasible at some point in the future given: (1) the recent and likely future developments in CCS technology, much of which will stem from the proposed carbon capture and storage competition to be funded by DECC and the EU; (2) the likely long-term movements in the price of carbon; (3) the proposed treatment in Phase III of the EU ETS of carbon which is emitted, captured and stored; and in particular (4) the UK Government's stated commitment to establishing the necessary economic and regulatory framework for CCS. Additional assessment of the economic feasibility of transport may be appropriate once the Government has clarified its CCR requirements.

8. INTEGRATION

The CCS process requires significant heat and electrical power. Typically the heat will be provided from the CCGT plant (Section 8.1). Power is also delivered from the CCGT plant by increasing the CCGT auxiliary load.

8.1 Steam

The amount of steam required for carbon capture is dependent on the specific technology supplier selected to provide the amine capture process. From discussions with three vendors, we have obtained the information shown in Table 8-1. The pressure of the steam required is dependent on the process temperature, as the steam will have to be slightly above its saturation point.

Table 8-1: Variation in Steam requirements for Amine Carbon Capture Process

	Units	Vendor A	Vendor B	Vendor C
Steam Pressure	bar a	unknown	3.6	4.5
Specific Heat	GJ/tonne of CO2	3.26	2.95	3.0
Steam Flow	kg/s	106.7	107.9	110.6

There will be a pressure drop due to the transfer of steam from the turbine to the carbon capture plant. To simulate a maximum steam extraction case from the CCGT plant to the carbon capture process the removal of 110 kg/s of 5.25 bar a steam was modelled for each manufacturer.

For the base case, this resulted in the High Pressure (HP) steam turbine operating at 100 per cent mass flow rate and the Low Pressure (LP) steam turbine operating at 60 per cent mass flow rate. It is unlikely that this would cause any operational difficulty for a standard CCGT installation, however it is necessary to include in the tender enquiry documents that the turbine design is capable of such operation.

The loss of this steam from the LP turbine reduces the net power output of the plant by about 71 MW. Figure 8-1 comprises the heat balance diagram for the maximum steam extraction case. Heat balances for the CCGT plant operating at base load with and without steam extraction for the carbon capture equipment can be found in Appendix C.

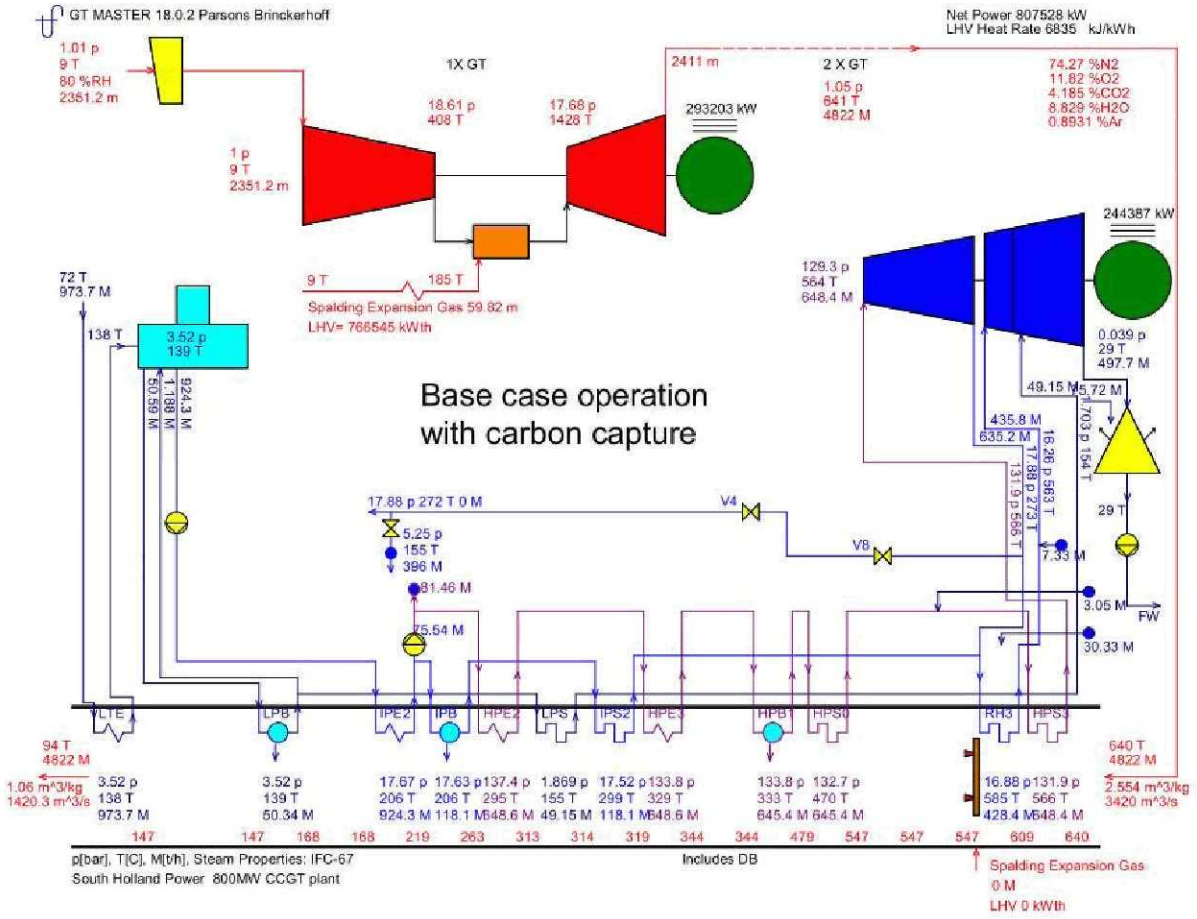


Figure 8-1: Model of Base Case with Capture

(Note: Power required for CCS is not shown)

Additional power will also be required for the capture process and the compression or liquefaction process, as described in previous sections of this report. This power loss is not shown in Figure 8-1. It could be provided by the grid, but would most likely be provided by the CCGT plant to realise maximum synergies with the CCGT plant.

8.2 Electricity

The majority of the electrical load in the carbon capture plant is required for the booster fan, which is used to raise the flue gas pressure to a point high enough to pass it through the absorber column. For the three vendors PB have approached, Table 8.2 gives an indication of the approximate electrical power consumption required for the booster fans in each vendor's design.

Table 8-2: Approximate Electrical Power required for Capture

		Vendor A	Vendor B	Vendor C
Capture Plant	MWe	22.1	29.4	19.9

In addition, further auxiliary loads relating to compression, liquefaction, transportation and heating of the CO_2 may account for a significant auxiliary load on the power plant, as described in previous sections. Considering heating and liquefaction relating to shipping would be performed at a distance from the plant, the likely total auxiliary load at the CCGT plant would be between 52 and 70 MW. Taking into account the 71 MW of gross CCGT power lost due to the steam extractions then the total electrical load lost from the carbon capture process could be up to 150 MW. Smaller power requirements would be required for carbon capture balance of plant equipment, such as cooling and control. Depending on the transport method additional electrical or fuel energy may be required at other geographical locations.

8.3 Space

SEEL has obtained additional land directly adjacent to the SEE CCGT plant solely for the future implementation of carbon capture equipment. Appendix H shows the indicative layout of the proposed SEE project with land assigned for carbon capture shown**.** PB considers that the CCS equipment can be located within the land based on current available information from CCS equipment suppliers.

As the equipment is located next to the HRSG stacks PB considers that the flue gases can be directed to the CCS plant without difficulty. The steam requirements can be provided from the steam turbine by running pipework a short unobstructed distance from the steam turbine hall using an above ground pipe rack.

8.4 Cooling

Any future carbon capture project to be retrofitted to the SEE project will require a source of cooling. Cooling is required in the carbon capture plant for:

- Cooling of lean amine before entry to absorber (process cooling).
- Cooling of flue gases to absorber temperature (flue gas cooling);
- Cooling of CO_2/condensing of water in CO_2 product before and between compressor stages (inter-cooling); and
- Cooling of carbon capture ancillary equipment (plant cooling)

Some of this cooling will be offset by reductions in power plant cooling, and some will be provided by evaporative cooling as described below. The rest must be provided by a cooling system.

The heat provided to the process as steam is 3 GJ/t of CO_2. The process cooling load is typically 110 per cent of the heating load. Assuming that this steam is removed from the steam turbine and that the cooling system for the capture plant can be tied in to the cooling system for the power plant, most of the process cooling load will be covered by the reduction in the cooling load for the power plant condenser. An additional 24 MWth of process cooling is required, which must be provided by the carbon capture cooling system.

The flue gas is cooled in a direct contact cooler. The flue gas will leave the cooler saturated with water vapour at the exit temperature. For the SEE project, this means that water will evaporate into the flue gas in the cooler, providing much of the cooling required.

As previously stated, CCGT equipment from three manufacturers were modelled. The base case formed the basis for sizing of the flue gas cooling load, as it represents a worst case scenario for flue gas cooling. Table 4-1 (see Section 4) shows the flue gas analysis for this case, where the flue gas temperature is 94ºC.

Cooling of this flue gas from 94°C to 50°C in the direct contact cooler would require 42 MWth of cooling. In addition to evaporative cooling, an additional 2 MWth must be provided by the cooling system.

Assuming compression to supercritical pressures, compressor intercooling is of the order of 68 MWth, all of which must be provided by the cooling system.

Assuming plant cooling is of the order of 1 per cent of total cooling, the total cooling load for the additional cooling system associated with the capture and compression plant, is therefore of the order of 96 MWth.

Although the SEE project will be air cooled it may be feasible for the capture plant to be cooled in a different manner. This would depend on the cooling options available at the site at the time that the capture equipment is installed.

A once-through cooling water system for the capture plant applied to the SEE project would require of the order of 8 000 – 10 000 m^3/h of cooling water. It is assumed that such quantities of water will not be available for cooling purposes based on the fact that the existing Spalding CCGT plant has investigated water sources for cooling purposes and concluded that insufficient cooling water is available for the Spalding CCGT power plants. Thus it is assumed that air cooling would be utilized on the carbon capture process. However, at the time of implementing the carbon capture scheme PB recommends that the cooling water sources are investigated further to determine if any feasible cooling water sources exist,

Regardless of the method of cooling chosen, the flue gas will leave the absorber saturated with water vapour. If the flue gas exits the absorber at 50ºC, 29 kg/s of water will evaporate into the flue gas (104 m^3/h). There are only two methods of avoiding this water loss, operating the capture process at temperatures below 35ºC, or cooling the flue gas after exit from the absorber in order to condense the water. Either of these options could result in a capture plant which is a net water producer.

Further investigation of cooling options may be required to demonstrate CCR, however PB recommends that any further investigation is postponed pending publication of DECC requirements for Section 36 application.

8.5 Summary

The CCGT plant tender enquiry specifications will need to consider the future retrofit of CCS and the possible integration points. The following would be considered as a minimum:

- Flanges on the HRSG stacks to allow ducts to be added for extraction and return of flue gases to/from the CCS plant. Until the CCS plant is constructed the flanges will be blanked off.
- Cold reheat and IP/LP crossover steam pipework with necessary 'T' pieces to allow future connection for steam extraction.
- The ability to increase the electrical supply to cover the auxiliary load requirements of the CCS plant. Space for additional 6.6kV boards and/or larger auxiliary load transformers may be required.

9. RETROFITTING CCS

9.1 Options for producing steam

9.1.1 Option 1 – LP steam turbine extraction

The pressure at which the steam must condense depends on the operating temperature of the reboiler, and for currently available amine technology this is between 3 and 5 bar. The most efficient method of producing this steam is removing it from the low pressure (LP) steam turbine at the pressure required. This would require a blanked-off offtake port to be included with the turbine at initial installation, and would mean that the pressure and mass flow rate of the steam would need to be chosen in advance of the turbine design completion. This is considered to be impractical as the future capture technology chosen for the retrofit may require steam at a different pressure than that which would be required for currently available amine scrubbing technology. Once the extraction ports are incorporated into the supplied steam turbine they cannot be moved and an alternative source will be required. It is difficult to optimise the LP steam turbine for prolonged operation with or without steam extraction for carbon capture. As such one of the operating cases will be affected in respect to efficiency. The different steam turbine manufacturer's have different maximum amounts of steam that can be extracted as there is a limit to ensure sufficient steam can still flow through the LP exhaust in order to prevent overheating effects. PB does not consider that LP turbines with extraction ports should be incorporated into the plant design given the unknown requirements at the future time of retrofit.

9.1.2 Option 2 – HP and/or IP steam turbine exhaust extraction

Alternatively the steam could be removed from the intermediate pressure (IP) steam turbine exhaust, commonly referred to as the IP/LP crossover pipe or the cold reheat pipe, which is the HP steam turbine exhaust. This can be expanded to the required pressure and desuperheated to the desired temperature. This would require an offtake port at the cold reheat or crossover pipe, which can be simply retrofitted, unlike an offtake from the LP turbine casing. Steam could be provided at any pressure up to the pressure at the cold reheat during minimum load. This would result a lower mass flow rate of steam removed from the steam turbine, but is less efficient, due to both the reduced mass flow rate in the higher pressure stages of the IP and/or LP steam turbines and the loss of enthalpy during expansion. However, at this stage of the project, where the steam requirements are unknown the cold reheat or crossover extraction is considered to be the preferred option for this project as it allows for the future capture technology that will be installed to have steam requirements different to the current best available technology. The cold reheat extraction option would result in the HP turbine operating with maximum steam flow rates at full load but the IP and LP steam turbines operating under part load conditions. If the crossover pipe is used to extract steam only the LP steam turbine will be affected. In practice extractions may be made available from the cold reheat and the crossover where the crossover extraction can provide steam at high loads and the cold reheat extraction being able to supply the required steam conditions at lower part loads. This should be acceptable for most steam turbine designs, however the requirement of such operation would be requested in the tender enquiry stage.

9.1.3 Option 3 – HRSG extraction

For full flexible plant operations, where the plant may have to operate for periods at minimum loads, the GTs and HRSGs may operate at a higher percentage of design rating than the steam turbine, with steam extracted direct from the HRSG to meet the carbon capture steam requirements at minimum loads. Further optimisation by the tenderers/manufacturers will be required to ensure the carbon capture requirements are met across the operating range.

Supplementary firing can also be used to produce some or all of the extra steam required. This mitigates the effect of the carbon capture plant on the power plant, but results in a larger scale capture, transport and storage chain. For this reason, supplementary firing was assumed not to be the preferred option.

9.1.4 Option 4 – External steam supply

A fourth option of obtaining the required steam demand for the carbon capture process is to install an auxiliary boiler or CHP unit to produce the steam required for the capture process. This would require additional gas consumption additional space on site and a larger capture plant. This option has not been considered further.

The method recommended for this plant is to supply ports which can later be retrofitted to extract the steam from the HRSG and cold reheat and IP/LP crossover. The steam can then be expanded and desuperheated to the required pressure and temperature. Providing the three ports allows for greatest flexibility of retrofit and operation with steam extraction.

9.2 EA checklist for coal plant

DECC and the EA have developed a checklist which lists requirements for the retrofitting of carbon capture to coal plant. This checklist is available from the EA and is based on a report published in 2007 by the International Energy Agency Greenhouse Gas Research and Development Program (IEA GHG). However, it should be noted that the checklist is subject to change, as the DECC response to the public consultation is not yet available. Nevertheless, this checklist does provide a good indication of what DECC might consider is required for a CCGT plant. The checklist is attached in Appendix B.

9.2.1 Main requirements for CCGT plant

The main requirements in the checklist that would apply to CCGT plants are summarized below. Consideration of these requirements must be included in the tender documentation for the plant to be considered CCR according to the EA checklist.

- There must be sufficient space adjacent to the CCGT plant to permit the construction and operation of the carbon capture plant, and the construction and operation of compression and/or liquefaction plant. In addition, there must also be sufficient space for the cooling requirements. The layout drawing in Appendix H shows the space available and the space required for carbon capture equipment.

- Additional space is required for:
  - Vehicle movement and storage of amines and/or CO_2.
  - Transformers, switchgear and cabling.
  - Roads, offices, buildings and storage
- There must be sufficient space within the CCGT plant for various other requirements, listed below. The tender specifications should state that these space requirements be considered in the CCGT design. PB expects that demonstration of CCR would include mention of these space requirements in the tender specifications, or if not yet available, a statement of intent to include these requirements.
  - the ductwork for the flue gas transfer to the absorber,
  - any ductwork back to the stack or to a new stack,
  - blank port of cold reheat header.
  - the steam pipe work from the HRSG or steam turbine extraction to stripper,
  - the condensate return pipe work,
  - CO_2 pipe to compressor if it impacts on the power plant site,
  - CO_2 pipe from compressor towards storage if it impacts on the power plant site,
  - switchgear,
  - cooling of capture plant if it impacts on the power plant site,
  - tie-in to existing power plant cooling system and laydown area.
  - If the control is to be from a separate control room then space for the control room must be included. If control is to be from the existing main control room then routes for signals, cables, etc needs to be reserved.
- Infrastructure that would be common to the CCGT plant and the CCS plant should be considered at the tender stage. This infrastructure would include cable ducts, pipe racks, control room sizing, utility systems (ie compressed air system, and demineralized water treatment and effluent plant), etc. Additional space may be required for individual parts. It is not required that equipment be oversized initially, however SEEL may wish to consider oversizing minor balance of plant equipment, ie pumps, during the initial power plant installation phase to reduce carbon capture installation costs later.

- Initial specification documents must state that plant is built CCR and should consider the above requirements.

In addition to these requirements, the checklist mentions that the steam extraction pressure at the turbine source (ie IP/LP crossover or cold reheat pressure) must be stated, and that a discussion is provided of how the turbine may operate with carbon capture. Section 9.1 would form the basis of this discussion, however PB recommends that further analysis is postponed pending information about DECC requirements for demonstration of CCR.

10. HEALTH AND SAFETY ISSUES

Risk assessment and reduction activities will need to be conducted which focus not only on the carbon capture technologies, but also on their associated integration interfaces with the power generation facility.

Mitigation measures will need to be developed to reflect both the risks associated with CO_2 and the associated chemical capture processes as required by the Health and Safety at Work Act 1974 and associated regulations.

PB has discussed with DECC's carbon capture readiness team the health and safety aspects of MEA, the primary chemical used in the capture process. DECC confirms that the HSE considers MEA to be non-toxic and therefore is not subject to any on-site storage volume limits or a Hazardous Substance Consent (HSC).

Whilst it is considered that, in this case, the carbon capture process does not result in CO_2 being stored on site, plant-wide/personal monitoring of CO_2 levels and specific engineering control/personal protection measures are to be taken. As the CO_2 is passed through and not stored at site and the HSE concludes that MEA used in the capture process is non-toxic PB opines that the Control of Major Accident Hazards (COMAH) Regulations 1999 does not apply to this CCS project. However, DECC has advised SEEL that the HSE considers dense phase CO_2 should be treated as hazardous. Based on this precautionary approach from HSE, DECC is advising Section 36 applicants that HSC may be required for CCS projects.

Additional safety issues related to CO_2 should be considered for various other aspects of the system. These are detailed below.

The Pipelines Safety Regulations (PSR) 1996 requires:

- A major accident prevention plan;
- A pipeline safety evaluation and technical safety risk assessment, including failure mechanisms, probability and consequence of failure. Mitigation measures should also be suggested;
- Operations, maintenance and emergency response policy, procedures and work instructions;
- Safe control of operations;
- Safe working in the vicinity of a high pressure pipeline;
- Asphyxiation risk assessment;
- Change of use notification required by HSE with a notification period up to 6 months;
- Emergency shut down valves to be fitted; and

- The relevant local authority to be notified and the local authority to have prepared an emergency plan.

This will require pipelines to be designed, constructed, installed, examined, and have safety systems in place which satisfy the statutory requirements for operational safety. Risk assessment and risk reduction processes and reviews will have been conducted in relation to the transport of hydrocarbon materials in existing pipelines, but these will need to be revisited in relation to the properties and risks associated with the transport of large volumes of CO_2.

There is also the potential for the CO_2 to be transported by ship, in which case safety considerations would be ensured by SOLAS (the International Convention for the Safety of Life at Sea) 1974 and subsequent amendments and MARPOL (International Convention for the Prevention of Pollution from Ships) 1973, as modified by the Protocol of 1978 relating thereto. It is likely that CO_2 would be classified as *Class 2.2: non-flammable, non-toxic gases* under the International Maritime Dangerous Goods (IMDG) Code. The IMDG Code is mandatory and includes such aspects as: packing and tank provisions; consignment procedures; and construction and testing of packagings, IBCs and large packagings; portable tanks and road tank vehicles; and transport operations. It is anticipated that the physical transfer and storage facilities on the ship would need specific risk assessment and risk reduction analyses, while quantitative risk assessments and consequence modelling for spillages would also be needed.

The Offshore Installations (Safety Case) Regulations 2005 (OSCR) require that an offshore installation cannot operate without a safety case accepted by the HSE. The safety case will have detailed how risks related to major accident hazards have been addressed, controlled and reduced. Risk assessment and risk reduction processes and reviews will likely to have been conducted in relation to the storage and production of hydrocarbon materials in existing offshore facilities, but these will need to be revisited in relation to the properties and risks associated with the storage of CO_2.

The Offshore Installations (Prevention of Fire and Explosion, and Emergency Response) Regulations 1995 require that an emergency response plan is prepared and implemented.

Safety issues of particular concern include:

- Venting of CO_2 at the platform wellhead. Such venting may be intentional, for example during planned or emergency well work-overs, or unintentional, for example as a result of infrastructure failure or unexpected reservoir pressure increase. Appropriate approaches will include early and detailed discussions with HSE, modelling of atmospheric CO_2 dispersion, monitoring CO_2 concentrations in confined spaces and around critical infrastructure points, provision of personal safety equipment, refuges and contingency planning.

- Source terms related to catastrophic releases of dense phase CO_2. The safety case will need to demonstrate that suitable modelling techniques and assumptions are being used, and that provision has been made for the validation and handling of uncertainty.

Risks associated with safety cases include:

- Dense phase CO_2 not allowed onshore
- Project cannot meet the safety requirements
- CO_2 re-classified as a dangerous substance
- Accidents during construction/operation

11. CONCLUSIONS

The Directive dictates that the requirement to consider CCR will apply to the SEE project. However, until the relevant UK implementing legislation has come into force, the requirements to be considered for the SEE project cannot be fully defined.

DECC's response to the public consultation on CCS is expected in mid 2009 and it is anticipated that the UK regulatory regime will be finalized shortly thereafter. Until the regulatory regime is finalized there will be uncertainty as to exactly how a Section 36 Applicant must prove that the plant is CCR. However, the best currently available information suggests that:

- It is extremely likely that DECC will require that the SEE project be built CCR, and will require demonstration of carbon capture readiness as part of the Section 36 application.
- That there are four factors DECC will consider for the assessment of CCR, each of which have been considered in this report. These are:
    1. There is provision of suitable space on the installation site for the equipment necessary for subsequent capture and compression of CO_2;
    2. That suitable storage sites are available;
    3. That transport facilities are technically and economically feasible; and
    4. That it is technically and economically feasible to retrofit for CO_2 capture.

This report demonstrates that it is technically feasible to retrofit post-combustion carbon capture equipment to the SEE project, subject to a commercial scale plant being demonstrated. Sufficient land is available adjacent to the plant for the installation of the CCS equipment necessary for the SEE project. The flue gases and steam can be provided to the CCS equipment without difficulty. The project location means that it is also technically feasible to transport the CO_2 to a suitable location on the East Coast (preferably by pipeline) and store the CO_2 offshore.

In respect of the economic feasibility of retrofit and transport, it is considered that these aspects will become economically feasible at some point in the future given: (1) the recent and likely future developments in CCS technology, much of which will stem from the proposed carbon capture and storage competition to be funded by DECC and the EU; (2) the likely long-term movements in the price of carbon; (3) the proposed treatment in Phase III of the EU ETS of carbon which is emitted, captured and stored; and in particular (4) the UK Government's stated commitment to establishing the necessary economic and regulatory framework for CCS.

The impact of fitment of the carbon capture chain, however, would be a reduction in the net power output form the proposed SEE CCGT plant of upto 150MWe (c.70MW due to steam extraction for use in the capture plant and upto 70MW as additional auxiliary electrical load for the capture and transportation chain). This is an 18% reduction in the plant net power output. Additional assessment

of the economic feasibility of transport and retrofit for carbon capture, may be appropriate once the Government has clarified its CCR requirements

APPENDIX A
RELEVANT SECTIONS OF EU DIRECTIVE
(1 page)

APPENDIX A
RELEVANT SECTIONS OF EU DIRECTIVE

ANNEX

(37) The transition to low-carbon power generation requires that, **in the event of fossil fuel power generation,** new investments **[…]** are made in such a way as to facilitate substantial reductions in emissions. To this end, Directive 2001/80/EC of the European Parliament and of the Council of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants should be amended to require that all combustion plants of a specified capacity, for which the original construction license or the original operating licence is granted after the entry into force of this Directive, have suitable space on the installation site for the equipment necessary to capture and compress CO_2 if suitable storage sites are available, and CO_2 transport and retrofit for CO_2 capture are technically and economically feasible. The economic feasibility of the transport and retrofitting should be assessed taking into account the anticipated costs of avoided CO_2 for the particular local conditions in case of retrofitting and the anticipated costs of CO_2 allowances in the Community. The projections should be based on the latest evidence; review of technical options and uncertainty analysis should also be made. The competent authority should determine whether these conditions are met on the basis of an assessment made by the operator and other available information, particularly concerning the protection of the environment and human health […].

[*Article 32*

Amendment of Directive 2001/80/EC

In Directive 2001/80/EC, the following Article 9a is inserted:

"Article 9a

1. Member States shall ensure that operators of all combustion plants with [...] a rated electrical output of 300 megawatts or more for which the original construction license or, in the absence of such a procedure, the original operating licence is granted after the entry into force of Directive XX/XX/EC of the European Parliament and of the Council.(*), have assessed whether the following conditions are met:
   - suitable storage sites are available;
   - transport facilities are technically and economically feasible;
   - it is technically and economically feasible to retrofit for CO_2 capture.

2. If the conditions in paragraph 1 are met, the competent authority shall ensure that suitable space on the installation site for the equipment necessary to capture and compress CO_2 [...] is set aside. The competent authority shall determine whether the conditions are met on the basis of the assessment referred to in paragraph 1 and other available information, particularly concerning the protection of the environment and human health.]

(*) OJ L..., ..., p. ..".

300MW provision.....

APPENDIX B
EA CCR CHECKLIST
(3 pages)

APPENDIX B
EA CCR CHECKLIST

a) Environment Agency verification of CCS Readiness – New Coal Fired Power Station

b) A Checklist

This checklist is being developed to assist EA staff, operators and stakeholders in judging what and how much information is required for a carbon capture readiness assessment. The aim is to ensure the EA can advise Government whether there are foreseeable barriers to the proposed carbon capture scheme. It is not envisaged that the EA will provide a report containing a detailed assessment of the proposals.

Capture Ready Features

IEA GHG Technical Report 2007/4 "CO_2 Capture Ready Plants" is used as a reference document. In the following sections the titles and relevant text from report 2007/4 is shown in italics. Notes on evidence expected to be provided are shown in bold normal font. Where it is not possible or not considered necessary to provide the evidence this should be justified.

c) Post-combustion (amine scrubbing)

7.2.21 Design, Planning Permissions and Approvals

Note 1: (This section is taken out of number order as it is the key evidence to present)

A brief conceptual study should be supplied for assessment - showing how the proposed CR features would make adding post-combustion capture technically feasible together with an outline level plan for the plant retrofitted with capture.

7.2.1 Power Plant Location

Note 2: The work undertaken on CO_2 transport and storage should be referenced; The exit point of gases from the curtilage of the plant and how this affects the configuration of the capture equipment is the important aspect for the Environment Agency.

Note 3: Health and Safety items are outside the Environment Agency remit.

7.2.2 Space Requirements

Space will be required for the following:

- *d) CO_2 capture equipment.*
- *e) Boiler island additions and modifications.*
- *f) Steam turbine island additions and modifications.*
- *g) Extension and addition of balance of plant systems to cater for the additional requirements of the capture equipment.*
- *h) Additional vehicle movement (amine transport etc.).*
- *i) Space allocation for storage and handling of amines and handling of CO_2.*

Note 4: It is expected that all of the provisions in a-f above will be implemented. A description is required. Further details will be requested in the following sections as appropriate.

7.2.3 ASC PF Boiler and Auxiliaries

Note 5: The proposed flue gas system modifications should be described.

7.2.4 DeNOx Equipment

Note 6: The expected configuration and anticipated performance of the DeNOx equipment should be confirmed and justified.

7.2.5 Particulate Removal Unit (ESPI Bag Filter)

Note 7: The expected configuration and anticipated performance of the particulate removal equipment (to maintain effective amine scrubber operation) should be confirmed and justified.

7.2.6 Flue Gas Desulphurisation Unit

Note 8: The expected configuration and performance of the DeSOx equipment (to maintain effective amine scrubber operation) should be confirmed and justified.

7.2.7 Steam Turbine Generator and Auxiliaries

Note 9: The IP/LP crossover pressure for the turbine should be stated together with a description of equipment modifications/additions and how the turbine might be operated with capture using amine systems with a range of steam requirements. The energy penalty involved in such steam extraction should be estimated, together with a description of any post-retrofit modifications that would be implemented to minimise this energy penalty.

7.2.8 Water - Steam - Condensate Cycle

Process integration opportunities to recover low grade heat from the capture equipment into the water-steam-condensate cycle will be available after capture retrofit. Utilising these opportunities will minimise the penalty from CO_2 capture.

Note 10: A statement confirming arrangements is required.

7.2.9 Cooling Water System

The amine scrubber, flue gas cooler and CO_2 compression plant introduced for CO_2 capture increase the overall power plant cooling duty.

Note 11: It is expected that necessary space and tie-ins for cooling water supplies to post-combustion capture equipment will be provided. A statement describing this is required. Cooling water requirements (flows and temperatures) with capture should be estimated and it should be stated how these will be met.

7.2.10 Compressed Air System

The capture equipment addition will call for additional compressed air (both service air and instrument air) requirements.

Note 12: A statement confirming how this will be accommodated is required.

7.2.11 Raw Water Pre-treatment Plant

Space shall be considered in the raw water pre-treatment plant area to add additional raw water pre-treatment streams, as required.

Note 13: A statement confirming how this will be accommodated is required.

7.2.12 Demineralisation / Desalination Plant

No essential capture-ready requirements are foreseen, as the demineralised water requirement is not expected to increase after CO_2 capture retrofit.

7.2.13 Waste Water Treatment Plant

Amine scrubbing plant along with flue gas coolers and FGD Polishing unit (if appropriate) provided for post combustion CO_2 capture will result in generation of additional effluents.

Note 14: A statement confirming that there is space to expand effluent treatment and to integrate additional treatments is required.

7.2.14 Electrical

The introduction of amine scrubber plant along with flue gas coolers, FGD polisher (if appropriate), booster fans (if required), and CO_2 compression plant will lead to a number of additional electrical loads (e.g. pumps, compressors).

Note 15: A statement confirming space for additional transformers, switching gear and cabling is required.

7.2.15 Chemical Dosing Systems and Steam Water Analysis System

This is not foreseen as an essential requirement.

7.2.16 Plant Pipe Racks

Installation of additional pipework after retrofit with capture will be required due to the use of a large quantity of LP steam in the amine scrubbing plant reboiler, return of condensate into the water-steam-condensate cycle and process integration of capture equipment with the water-steam-condensate cycle.

Note 16: It is expected that provision will be made for space for routing new pipework at the appropriate locations. A statement confirming this is required.

7.2.17 Control and Instrumentation

Note 17: It is expected that space and provisions for additional control equipment and cabling will be implemented. A statement confirming this is required.

7.2.18 Safety

Note 18: Outside Environment Agency remit

7.2.19 Fire Fighting and Fire Protection System

Note 19: Outside Environment Agency remit.

7.2.20 Plant Infrastructure

Space at appropriate zones to widen roads and add new roads (to handle increased movement of transport vehicles), space to extend office buildings (to accommodate additional plant personnel after capture retrofit) and space to extend stores building are foreseeable.

Note 20: It is expected that the provisions above will be implemented. A statement confirming this is required.

j) Other technologies

7.2 'Essential' Capture-Ready Requirements: Post Combustion Amine Scrubbing Technology based CO_2 Capture

The capture-ready requirements discussed in this section are the 'essential' requirements which aim to ease the capture retrofit of PF Bituminous Power Plants with post combustion amine scrubbing technology based CO_2 capture

Note 21: This section of the report was intended mainly for amine capture but can be adapted for chilled ammonia capture. A statement on where the requirements for chilled ammonia capture readiness differ from those for amine capture with respect to all of the IEA GHG report sections 7.2.2 to 7.2.21 is required, together with any additional CR features or other actions proposed, to be added as addenda to the responses to Notes 1-20.

APPENDIX C
HEAT BALANCE DIAGRAM OF BASE CASE MODEL
(3 pages)

APPENDIX C
HEAT BALANCE DIAGRAM OF BASE CASE MODEL

The heat balance diagrams have been included in this Appendix for the base case, using the GE 9FB GT technology.

Figure C1 shows the performance without carbon capture.

Figure C2 shows the performance with carbon capture.

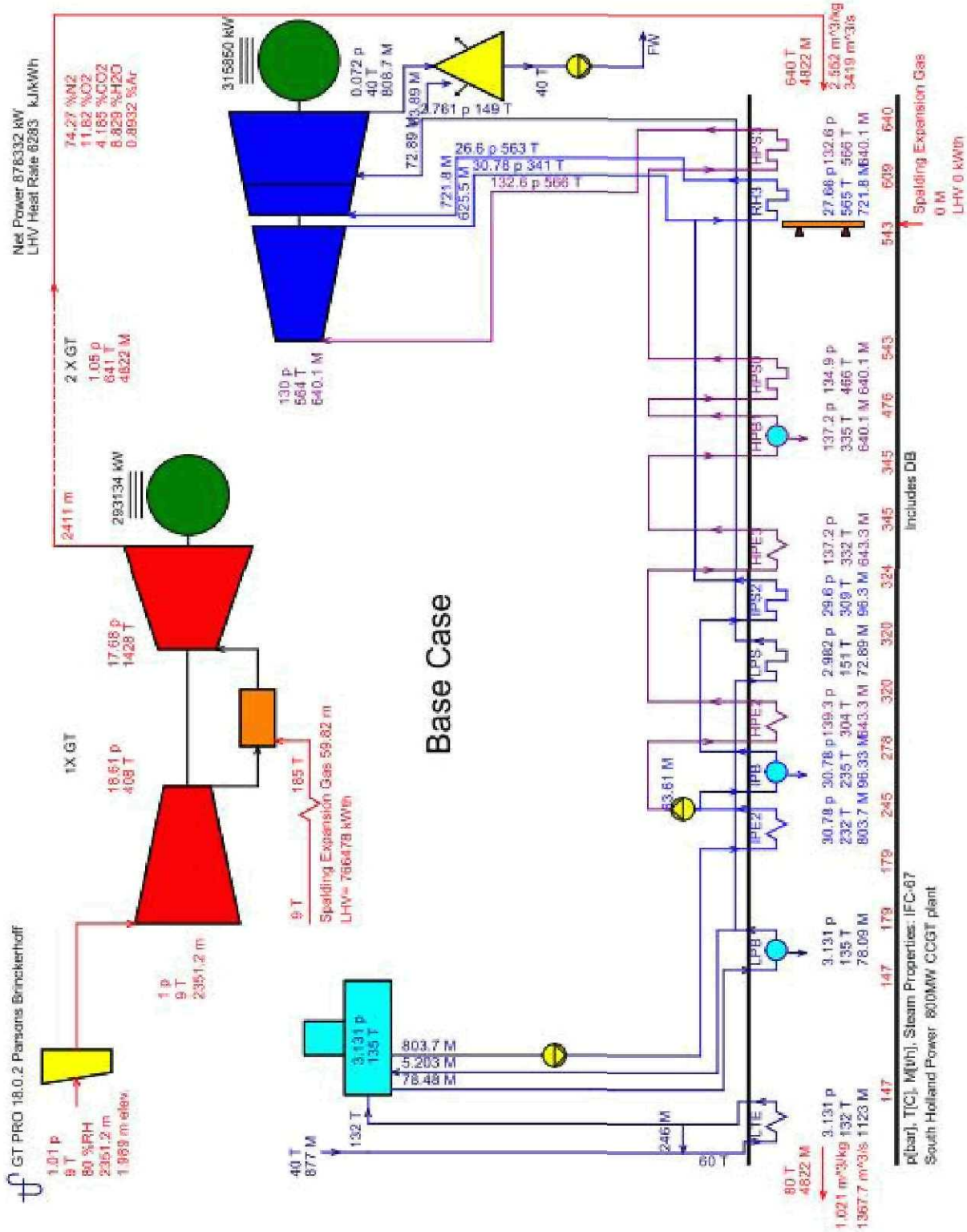


FIGURE C1 – HEAT BALANCE DIAGRAM FOR SEE PROJECT BASE CASE WITHOUT CARBON CAPTURE

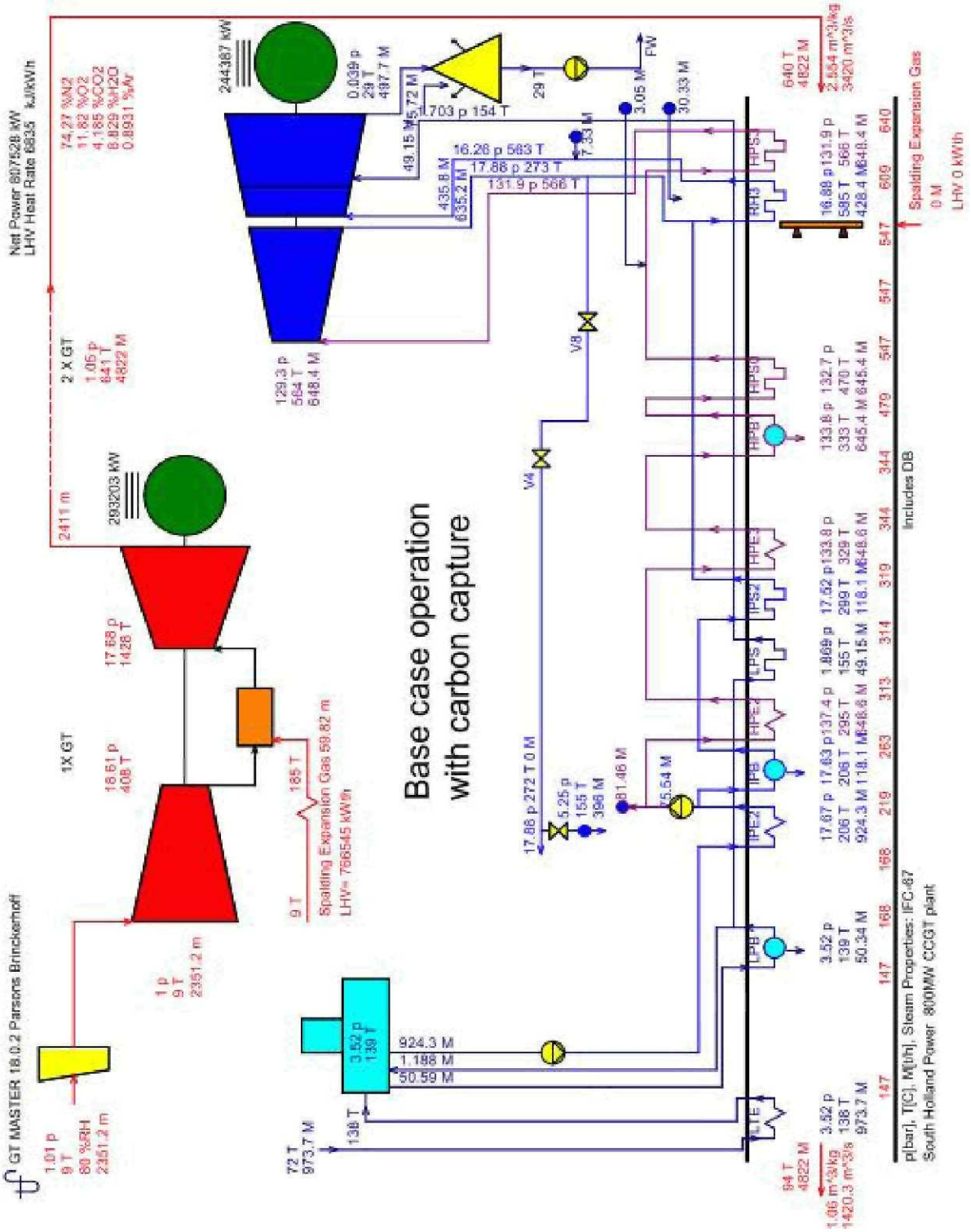



FIGURE C2 – HEAT BALANCE DIAGRAM FOR SEE PROJECT BASE CASE WITH CARBON CAPTURE (NOTE THAT POWER REQUIRED FOR CCS IS NOT SHOWN)

APPENDIX D
POTENTIAL STORAGE SITES
(2 pages)

D. POTENTIAL STORAGE SITES

The attached drawing shows the UK Carbon Storage Principle Infrastructure.


LIMITED DISTRIBUTION
UKCS Principal Infrastructure
September 2007
OFFSHORE
Oil
Gas
Gas condensate
Other
Terminal
Pipeline
Fields
Significant discoveries
Licensed area
Previously licensed area
Strategic Environmental Assessment area
SEA5
Windfarm sites
ONSHORE
Italics indicate planned
Terminals
OIL
GAS
TANKER
LNG
Storage
OIL
PETROCHEM
LNG
SALT CAVITY
Power Stations
OIL
GAS
COAL
CCGT
NUCLEAR
HYDRO
OTHER
Refinaries
OIL
Compressor Station
SIGNIFICANT LOCATION
ONSHORE PIPELINES ARE SCHEMATIC ONLY
Transco Gas
OPA
Avtur
OPA - Avtur
Esso
UKOP
MMM
Finaline
Crude oil
Condensate
Ethylene
Scale 1:1,200,000 Datum: ED50 Grid: UTM 31 N
0 10 20 30 40 50 Miles
0 10 20 30 40 50 60 70 80 Kilometers
DEPARTMENT FOR BUSINESS ENTERPRISE & REGULATORY REFORM
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© Crown Copyright
Faroese Waters
Norwegian Waters
Danish Waters
German Waters
Dutch Waters
Belgian Waters
French Waters
Irish Waters
Waters contained within Bay Closing Lines
SEA1
SEA2
SEA2 ext
SEA3
SEA4
SEA5
SEA6
SEA7
SEA8
FOINAVEN - SCHIEHALLION - SULLOM VOE EOR
SULLOM VOE - MAGNUS EOR
BRENT OIL
NINIAN OIL
FLAGS
FRIGG Norway (Vesterled)
FRIGG UK
PIPER - FLOTTA
SAGE
MILLER
BRITANNIA
FORTIES
FULMAR
CATS
LANGELED
NORPIPE
SEAL
Franpipe
Zeepipe
Bacton - Balgzand BBL Gas pipeline
Bacton - Zeebrugge Gas Interconnector
Gassled - Franpipe
Gassled - Zeepipe
UK - Irish Gas Interconnector
SNIP
Shetland Islands
Sullom Voe
Orkney Islands
Flotta
St Marys
Mongstad
Sture
Kollsnes
Nigg
Inverness
St Fergus
Peterhead
Cruden Bay
Aberdeen
Grangemouth
Finnart
Glasgow
Mossmorran
Longannet
Cockenzie
Torness
Hunterston B
Ballylumford
Belfast
Teesside
Teesside (oil)
Teesside (gas)
Teesside Gasport Norsea
North Tees Tees Storage Seal Storage
Wilton
Hartlepool
Immingham
North West
Manchester Warrington Farnworth Bramhall
Fiddlers Ferry
Rocksavage
Partington
Ellesmere Port
Ellesmere Port Bootle Birkenhead Eastham
Ellesmere Port Birkenhead
Birkenhead Bootle Eastham Stanlow
Stanlow
Shotton
Connah's Quay Deeside
The Wash
Kings Lynn
Kings Lynn Sutton Bridge
Milford Haven
South Hook Dragon
Pembroke Milford Haven
South Wales
Cardiff Barry
Barry
Baglan Bay
Aberthaw B
Avonmouth
Avonmouth (2) Westerleigh
Seabank 1&2
Thames
Canvey Isle of Grain
Grain
Grain Canvey
Coryton
Grain Littlebrook D
Grain Littlebrook Tilbury Kingsnorth
Tilbury B Kingsnorth
Coryton Medway
Fawley
Bacton
Easington
Theddlethorpe
Zeebrugge
Plymouth (2)
Portland
Poole
Hamble
Cowes

APPENDIX E
CO_2 SOURCES IN THE REGION OF THE SEE PROJECT
(8 pages)

E. CO_2 SOURCES IN THE REGION OF THE SEE PROJECT

There are a number of industrial and/or power generating plants that can be considered as significant carbon dioxide (CO_2) sources in the area of the Spalding Power Station. These plants could potentially be required to fit carbon capture in the future and this could impact on the route and capacity of any CO_2 pipeline connecting to the Spalding site. Details of these plants are provided in the tables below.

Table 5.1 includes a summary of the major power stations in the area, their distance from the Spalding site and details of their emissions of CO_2 between 2004 and 2007, where available, as reported to the UK Environment Agency (EA) as part of the Pollution Prevention and Control regime. General information on each of the plants is also presented which includes the Power Station's consenting date from which the likely closure date of the plants can be estimated based on an assumed lifetime of about 25 years.

For some power plants, information has not been available from the EA. For this reason the emissions reported to DEFRA as part of Phase 1 of the UK's CO_2 National Allocation Plan for the years 1998 to 2003 have been examined and presented in Table 3.2.

Table 5.3 presents a summary of other major Industrial emitters (> 100 000 tonnes of CO_2 per year) in the area, their distance from the existing Spalding Power Station and their estimated emissions of CO_2 between 2004 and 2007. These plants may ultimately chose to fit carbon capture though this would more than likely depend on the price of CO_2 in the future and the ease of any retrofit given the nature of the processes involved on any particular site.

Table 5.4 presents a summary of other minor industrial emitters (< 100 000 tonnes, but > 10 000 tonnes) of CO_2 in the area. Such plants are unlikely to fit carbon capture due to cost.

Figure 5.1 shows the location of the major emitters as identified from the Environment Agency Website.

TABLE E1: POWER STATIONS SUMMARY

EA Map	Grid Reference X	Grid Reference Y	Distance from Site	Name	Owner	Capacity	Commission Date	+ 25 Years	Emissions (Tonnes CO_2) 2007	2006	2005	2004
1	525800	324800	0	Spalding	Spalding Energy Company Ltd	860 MW	2004	2029	1802979	1740000	1756762	720712
2	548000	320000	23	Sutton Bridge A	EDF Energy	790 MW	1999	2024	1960905			
3	518500	257700	67	Little Barford	RWE nPower	680 MW	1996	2021	1650201			
4	539526	287884	39	Rye House	Scottish Power	715MW	1994	2019	1223000	727172		
5	560820	317050	36	King's Lynn A	Centrica KL Limited	325 MW	1997	2022	786480	363812		
6	481731	379231	70	Cottam Development Centre	EON PLC	400 MW	1999	2024	775760			
7	633030	334300	108	Bacton	Interconnector (UK) Ltd	-			84539	104234	84429	
	521810	299180	26	Peterborough	British Gas	360 MW	1993	2018				
	545190	279960	49	Elean	EPR Ely Ltd	38.5 MW						
	489600	291100	49	Corby	Corby Power Ltd	350 MW	1994	2019				
	480540	371040	65	High Marnham	TXU Europe Power Ltd	Closed						
	481700	379700	70	Cottam Power Station	EDF Energy	2008 MW						
	585200	286800	71	Thetford	FibroThetford Ltd	-						
	479110	385310	76	West Burton Power Station	EDF Energy	2000 MW						
	613250	275430	100	Eye	FirboPower Ltd	-						
	652900	305100	129	Great Yarmouth	Great Yarmouth Power Ltd	420 MW	2001	2026				

TABLE E2 – POWER STATIONS PRE-2004 EMISSIONS SUMMARY

EA Map	Grid Reference X	Grid Reference Y	Distance from Site	Name	Owner	Capacity	Emissions (Tonnes CO_2) 2003	2002	2001	2000	1999	1998
1	525800	324800	0	Spalding	Spalding Energy Company Ltd	860 MW						
2	548000	320000	23	Sutton Bridge A	EDF Energy	790 MW	2066001	2112086	2108394	2302943	1260311	
3	518500	257700	67	Little Barford	RWE nPower	680 MW	1776000	1793000	1577000	1458000	1938000	1569000
4	539526	287884	39	Rye House	Scottish Power	715MW						
5	560820	317050	36	King's Lynn A	Centrica KL Limited	325 MW	791088	730201	654167	635302	763806	954548
6	481731	379231	70	Cottam Development Centre	EON PLC	400 MW	914915	809938				
7	633030	334300	108	Bacton	Interconnector (UK) Ltd		197830	154011	146815	160046	70666	
	521810	299180	26	Peterborough	British Gas	360 MW	431477	663978	850381	1160448	1110412	1245700
	545190	279960	49	Elean	EPR Ely Ltd	38.5 MW	12018	17259	17600			
	489600	291100	49	Corby	Corby Power Ltd	350 MW	764154	1100596	1164490	1246258	1174654	1281463
	480540	371040	65	High Marnham	TXU Europe Power Ltd	Closed						
	481700	379700	70	Cottam Power Station	EDF Energy	2008 MW	926043	7169774	6274017	5987291	6034781	6943576
	585200	286800	71	Thetford	FibroThetford Ltd	-	3201	3877	4473	6043	8998	
	479110	385310	76	West Burton Power Station	EDF Energy	2000 MW	7061414	6601560	8648692	4051994	7286412	8621986
	613250	275430	100	Eye	FirboPower Ltd	-	592	614	602	1544	2182	1853
	652900	305100	129	Great Yarmouth	Great Yarmouth Power Ltd	420 MW	902940					

TABLE E3 – MAJOR INDUSTRIAL EMITTERS SUMMARY

EA Map	Grid Reference		Distance from Site	Description	Emissions (Tonnes CO_2)			
	X	*Y*			*2007*	*2006*	*2005*	*2004*
8	498939	305426	33	Castle Cement Ltd	992000	1028000	1020000	1098000
9	567105	297449	50	British Sugar PLC	324872	342530		
10	540782	249890	76	Cemex UK Cement Works	297000	295000	333000	311000
11	587623	266466	85	British Sugar PLC	279298	238710		
12	496770	239452	90	WRG Waste Services Ltd	227400	236600	238000	
13	496942	264045	67	Ancillary Components Ltd	160285	170000	132000	
14	524963	297484	27	Hanson Building Products Ltd	159902	170362	116322	117156
15	637812	303984	114	British Sugar PLC	133391	153991		

TABLE E4 – OTHER INDUSTRIAL EMITTERS SUMMARY

EA Map	Grid Reference		Distance from Site	Description	Emissions (Tonnes CO_2)			
	X	*Y*			*2007*	*2006*	*2005*	*2004*
	501413	242720	86	WRG Waste Services Ltd	93100	81100	93600	
	491176	290292	49	Roquette (Corby) Ltd	80417	80384		
	515793	303878	23	National Grid PLC	77400	63965		
	501813	242320	86	Hanson Building Products Ltd	73026	71996	57983	60096
	479615	354863	55	British Sugar PLC	70751	85710		
	486623	232573	100	WRG Waste Services Ltd	67200	54100	68400	81900
	545306	308614	25	HL Foods	34900	44800		
	612187	248964	115	Vindor Waste Management	29730	28100	24800	12700
	547714	310678	26	Nestle Purina Petcare UK Limited	29468	30922	19972	
	524563	297184	28	McCain Foods	28873	31285	34095	
	544446	322544	19	HL Foods	27700	27500		
	489680	274311	62	Weetabix Ltd	26000	31000		
	606856	257047	106	Muntons PLC	20573	20413		
	491476	290696	48	WRG Waste Services Ltd	20100	19200	61500	
	530411	281177	44	Fernside Waste Management	18600	18600		
	475697	318840	50	Masterfoods Ltd	17897	18507	34698	
	596222	327373	70	Crisp Malting Group PLC	17100	16600		
	518783	235840	89	Waste Group Recycling	16700	11500	36500	
	620442	310003	96	Bayer Cropscience Ltd	16486	19779		
	534433	241172	84	Johnson Matthey PLC	14869	18400		

	521520	268808	56	Anti Waste Ltd	14400	10700		
	619238	244836	123	White Rose Environmental	12530	11200	13630	
	546906	264138	64	Waste Group Recycling PLC	12400		21700	
	488448	291496	50	Solway Foods Ltd	12274			
	520264	302330	23	WRG Waste Services Ltd	11400	11500	29400	
	533955	342322	19	Lincwaste Ltd	11200			
	573496	291906	58	Waste Recovery Group Ltd	10700	10300	14100	
	604964	294697	85	Banham Poultry	10135			

The sources of most significance and thereby those most likely to be required to retrofit carbon capture are power generating plants greater than 300MWe. These include:

- Spalding I (860 MW)
- Sutton Bridge A (790 MW)
- Little Barford (680 MW)
- Rye House (715 MW)
- King's Lynn A (325 MW)
- Cottam Development Centre (400 MW)
- Peterborough (360 MW)
- Corby (350 MW)
- Cottam Power Station (2008 MW)
- West Burton Power Station (2000 MW)
- Great Yarmouth (420 MW)

A number of these plants, including Peterborough and Corby, are early CCGT plants which are close to the Spalding site. The potential for carbon capture to be retrofitted to these plants is not easy to establish as it is likely that these plants will either require re-powering with new gas turbines or to close at about the time that any future requirement for CCS may be introduced.

With regard to the coal plants both Cottam and West Burton have been fitted with flue gas desulphurisation (FGD) and will therefore remain open for the foreseeable future. However, it is debateable as to whether sub-critical plants such as these will be economic were they to fit carbon capture given the considerable auxiliary load that would be placed on the plants both of which have efficiencies of the order of 32 per cent

In addition to the existing plants there are plans for new generating plants at the following sites:

- King's Lynn B (1000 MW). Estimated connection date from National Grid Company (NGC) Transmission Entry Capacity (TEC) list is 2016
- Sutton Bridge B (1300 MW). Estimated connection date from NGC TEC List is 2013
- West Burton CCGT (1300 MW). Estimated connection date from NGC TEC List is 2009/10
- Staythorpe (1600 MW). Estimated connection date from NGC TEC list 2009

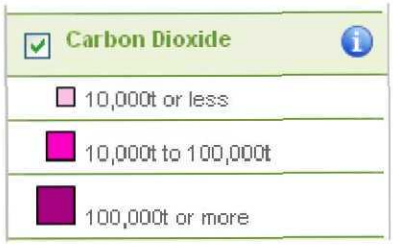
There have also been rumours about the development of a clean coal, or perhaps CCGT, plant at High Marnham. However, the status of any such project is not known at this stage.

The connection dates for the above projects represent the connection offer to the project developers for the plant from the NGC and may be brought forwards in the event that capacity in the system becomes available earlier. For example, if new nuclear plants are not built by 2016 as is currently anticipated by NGC.

APPENDIX F
MAP OF CO_2 SOURCES IN THE REGION OF THE SEE PROJECT
(1 page)

F. MAP OF CO_2 SOURCES IN THE REGION OF THE SEE PROJECT

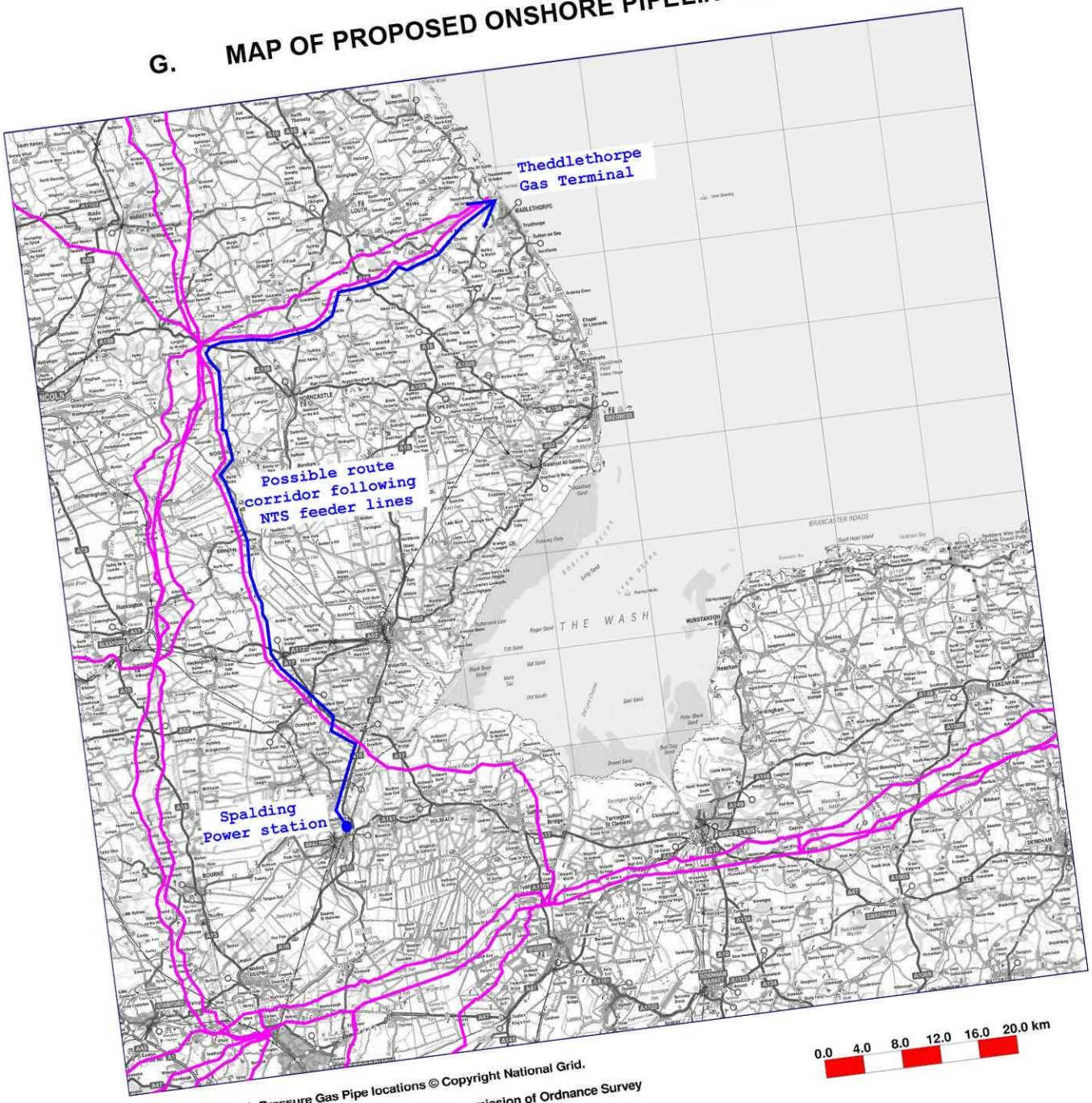




APPENDIX G
MAP OF PROPOSED ONSHORE PIPELINE ROUTE
(1 page)

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G. MAP OF PROPOSED ONSHORE PIPELINE ROUTE



National Grid High Pressure Gas Pipe locations © Copyright National Grid.

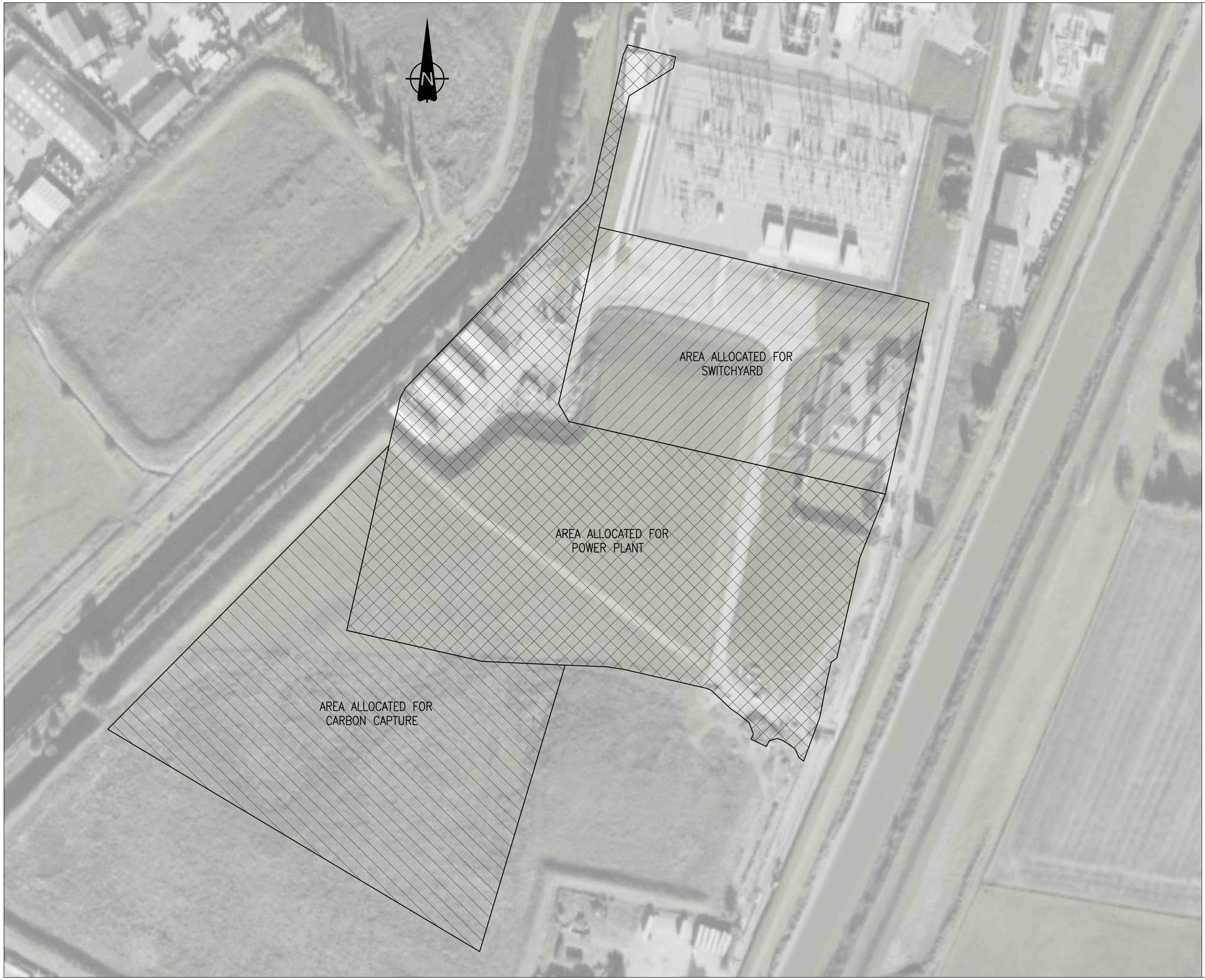
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APPENDIX H
LAYOUT OF SEE
(2 pages)

H. LAYOUT OF SEE

Attached is a layout of the SEE project with the area required for carbon capture equipment shown.



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REV	DATE		BY	CHKD	APPD
A	16.03.09	ORIGINAL ISSUE	DD	MLC	KB

NOTES

0 10m 20m 40m 60m

BAR SCALE 1:1000

- CLIENT
  INTERGEN
- PROJECT
  SPALDING ENERGY PROJECT
- TITLE
  SITE AREAS

- DATE 16.03.09
- SCALE 1:1000 @ A1
- CAD REF

DRAWN BY MLC
PRODUCED BY DD
CHECKED MLC
APPROVED KB

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