

SPALDING ENERGY EXPANSION LTD

**SPALDING ENERGY EXPANSION
CARBON CAPTURE READINESS
FEASIBILITY STUDY**

March 2009

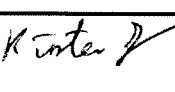

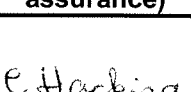

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LIST OF ABBREVIATIONS

°	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 ₂ O	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 CO₂ (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 CO₂ from the site to a geological storage site taking into account the drivers associated with pipeline, road or rail onshore transportation of CO₂ 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 CO₂ 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 CO₂;
 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 CO₂ 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 CO₂ 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 CO₂ 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 ₂ O	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 CO₂ 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

CO₂ 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.

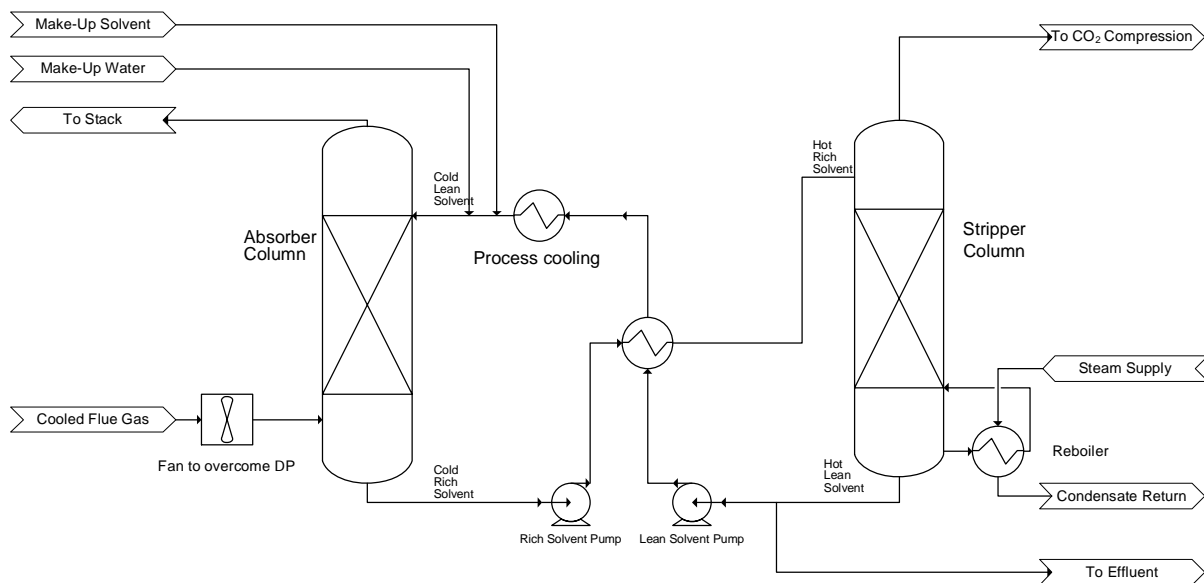


Figure 5-1 - The Amine Scrubbing Process

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 CO₂ in the flue gas is chemically absorbed through acid-base neutralization reactions with the basic amine, thus creating a CO₂ 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 CO₂ at lower temperatures, so heating the solvent releases the CO₂ 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 CO₂ 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 CO₂ stream are returned to the capture plant.

Amine absorption plants typically capture approximately 90 per cent of the CO₂ in a CCGT plant flue gas stream and result in a product (CO₂) 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 CO₂ 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), SO₂, NO₂ and oxygen (O₂) 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 NO₂. NO₂ forms HSS when it reacts with amine, however when levels of NO₂ are below 10 ppm (21 mg/Nm³) these can be effectively countered. EU legislation requires the NO_x level in the flue gas to be reduced to below 50 mg/Nm³. As NO_x typically contains less than 10 per cent NO₂, the level of NO₂ 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 O₂ 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 CO₂ 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 CO₂ 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 CO₂ (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 CO₂ 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 CO₂ from the SEE project². 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 CO₂ storage is required, it may be technically impossible to sequester CO₂ 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 CO₂ 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 CO₂ from this project. While further investigation might indicate that some of the sites are not suitable for CO₂ 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 CO₂ sources in the area were used, then the total CO₂ 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 CO₂ 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 CO₂ network in the region. In this case it is likely that CO₂ 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 CO₂. 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 CO₂ 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 CO₂ from a number of nearby combustion sites to geological storage sites.

7.1 Additional CO₂ sources

There are a number of industrial and/or power generating plants that can be considered as significant CO₂ 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 CO₂ pipeline connecting to the proposed SEE project site.

Details of these plants, and additional nearby facilities, which may be able to utilize a common CO₂ pipeline are provided in Appendix E. This Appendix includes a summary of the major emitters (>100,000 t CO₂ 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 DEFRA³ as part of Phase 1 of the UK's CO₂ 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 CO₂ 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 CO₂ transportation by pipeline

The CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ at supercritical pressures is permitted onshore. If CO₂ 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 CO₂ 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 CO₂ at injection; again this would be site-specific.

7.2.1 Established technology

Transporting CO₂ via pipelines is an established technology with an excellent safety track record, and is similar to natural gas transportation via pipelines. Large volumes of CO₂ are transported in the United States via pipeline. The CO₂ is dehydrated to reduce the likelihood of corrosion. Pipelines are made of steel, which is not corroded by dry CO₂. A corrosion resistant alloy is used for short sections of pipeline before dehydration stations (IPCC, 2005). The oldest CO₂ pipeline is the 1972 Canyon Reef Pipeline, which carries 5 Mt of CO₂ a year from gas processing plants. The largest CO₂ pipeline in the United States is the Cortex pipeline. With its recent expansion to include more than a dozen new CO₂ wells, 17 km of additional pipeline and additional compression and pumping capacity, Cortex has a capacity of over 30 Mt per year of CO₂ carried over 800 km. CO₂ transport via pipeline therefore already exists at scales well in excess of the SEE project.

7.2.2 Risks

The risks associated with CO₂ pipelines have been extensively documented (IPCC, 2005). Whilst CO₂ presents no explosive or fire-related risks, gaseous CO₂ 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 (H₂S) or sulphur dioxide (SO₂) 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 CO₂ 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 CO₂ is currently under consideration by a number of different authorities in anticipation of a large scale CCS industry. As such, CO₂ 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 CO₂ 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 CO₂ from the SEE project

At present, the regulatory status of CO₂ pipelines in the UK remains unclear. Interim guidelines have been published by the Health and Safety Executive (HSE) on CO₂ pipelines, and where uncertainty remains PB has assumed that CO₂ pipelines will be subject to similar regulations to natural gas pipelines, and so has assumed that any onshore CO₂ 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 CO₂ transportation by road

There are three potential motivations for transporting CO₂ 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 CO₂ in tankers which can then be re-used by another project, rather than build a pipeline.

Road transport requires captured CO₂ to be compressed to approximately 20 bar and liquefied by cooling to approximately -30°C in a process similar to liquefied natural gas (LNG) production.

The CO₂ 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 CO₂ may be pumped to a higher pressure and heated before injection.

Transport of CO₂ 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 CO₂ tankers used. BOC Linde is also currently involved in transporting CO₂ by road in Australia. The CO₂ tankers involved range in payload capacity, and include capacities of 20, 32 (b-double) and 40 - 45 (road train) tonnes. Regulations governing CO₂ 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

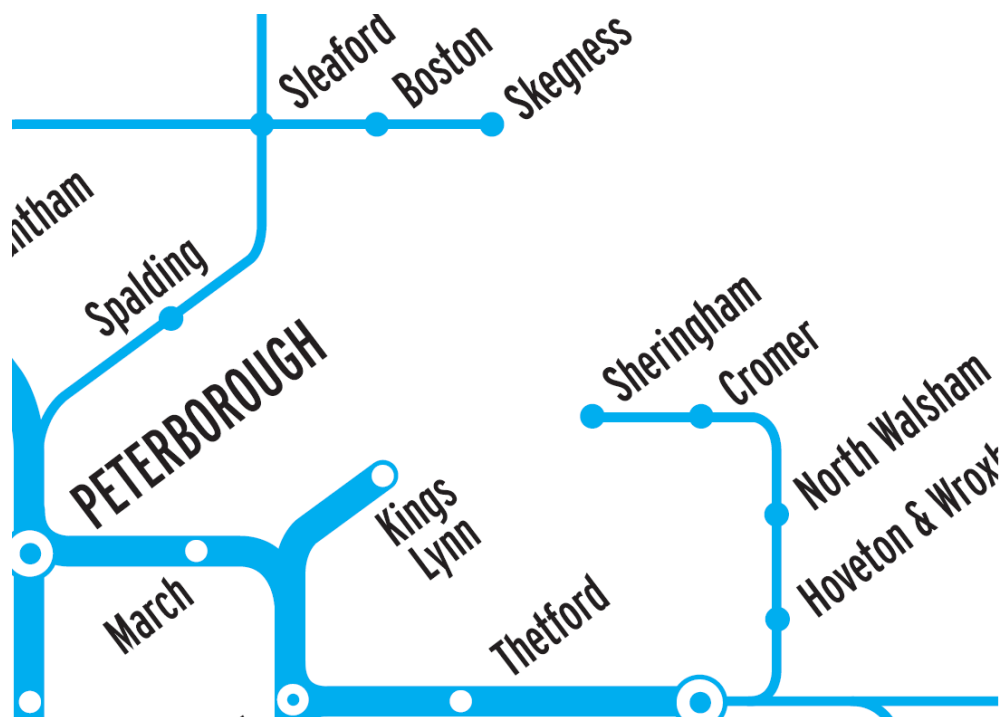
For the scale of the proposed SEE project, assuming 32 tonne trucks travelling a distance of 80 km, it is anticipated that about 50 trucks would be needed, requiring over 100 additional full time staff to provide a 24-7 transport operation.

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 CO₂ transportation by rail

The motivations for transportation by rail are similar to the ones behind transportation by road. CO₂ transportation by rail tanker would be very similar to transportation by road tanker. The pressure and temperatures are identical. Rail transport of CO₂ could therefore be considered as similar to a number of road tankers connected together.

Very little information on rail transport of CO₂ is available. Air Products currently transport CO₂ 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 CO₂ 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 CO₂ 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 CO₂ is currently underway, using ships similar to LNG ships. For this method of transport by shipping, the CO₂ is liquefied at 6 - 7 bar a and -50°C.

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 CO₂ in reusable ships rather than build a pipeline.

Whether the CO₂ is transported to the dock by road, rail or pipeline the CO₂ 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 CO₂ 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 CO₂. 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 CO₂ at the SEE site. This would be of the order of 40 MW.

Assuming road or rail transport is combined with shipping, the CO₂ would be expanded at the port from 20 bar to 6 bar, and further cooled to -50°C, resulting in an additional power requirement of the order of 1.5 MW.

Compression, liquefaction and transportation of CO₂ are already in existence in other industries at the scale required for the SEE project.

7.8 Economic feasibility of CO₂ 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 CO ₂	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.

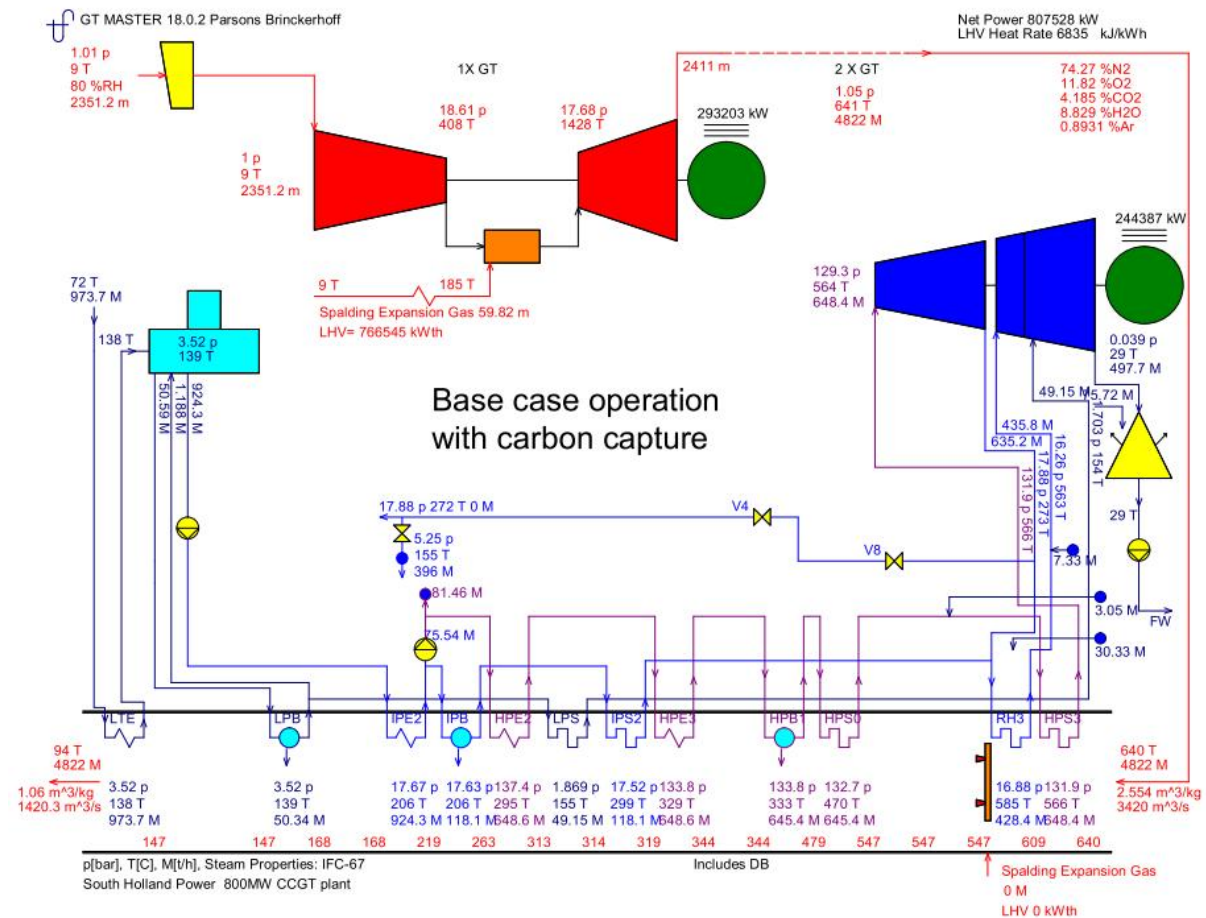


Figure 8-1: Model of Base Case with Capture

(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 CO₂ 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 CO₂/condensing of water in CO₂ 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 CO₂. 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 94°C.

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 m³/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 50°C, 29 kg/s of water will evaporate into the flue gas (104 m³/h). There are only two methods of avoiding this water loss, operating the capture process at temperatures below 35°C, 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 CO₂.
 - 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,
 - CO₂ pipe to compressor if it impacts on the power plant site,
 - CO₂ 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 CO₂ 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 CO₂ being stored on site, plant-wide/personal monitoring of CO₂ levels and specific engineering control/personal protection measures are to be taken. As the CO₂ 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 CO₂ 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 CO₂ 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 CO₂.

There is also the potential for the CO₂ 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 CO₂ 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 CO₂.

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 CO₂ 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 CO₂ dispersion, monitoring CO₂ 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 CO₂. 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 CO₂ not allowed onshore
- Project cannot meet the safety requirements
- CO₂ 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 CO₂;
 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 CO₂ 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 CO₂ to a suitable location on the East Coast (preferably by pipeline) and store the CO₂ 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 from 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 CO₂ if suitable storage sites are available, and CO₂ transport and retrofit for CO₂ 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 CO₂ for the particular local conditions in case of retrofitting and the anticipated costs of CO₂ 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 CO₂ 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 CO₂ [...] 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 “CO₂ 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 CO₂ 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) CO₂ 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 CO₂.*

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 CO₂ capture.

Note 10: A statement confirming arrangements is required.

7.2.9 Cooling Water System

The amine scrubber, flue gas cooler and CO₂ compression plant introduced for CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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.

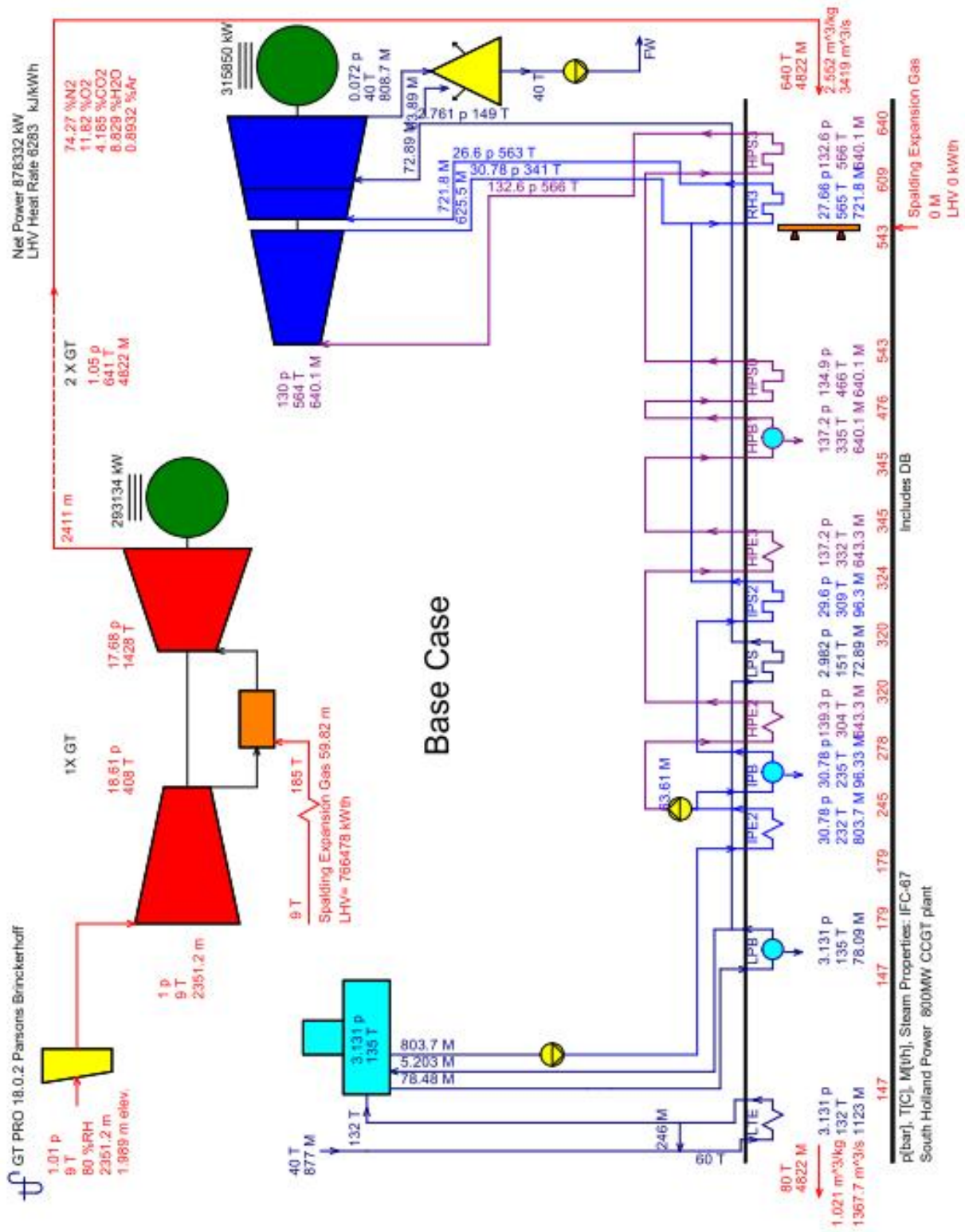
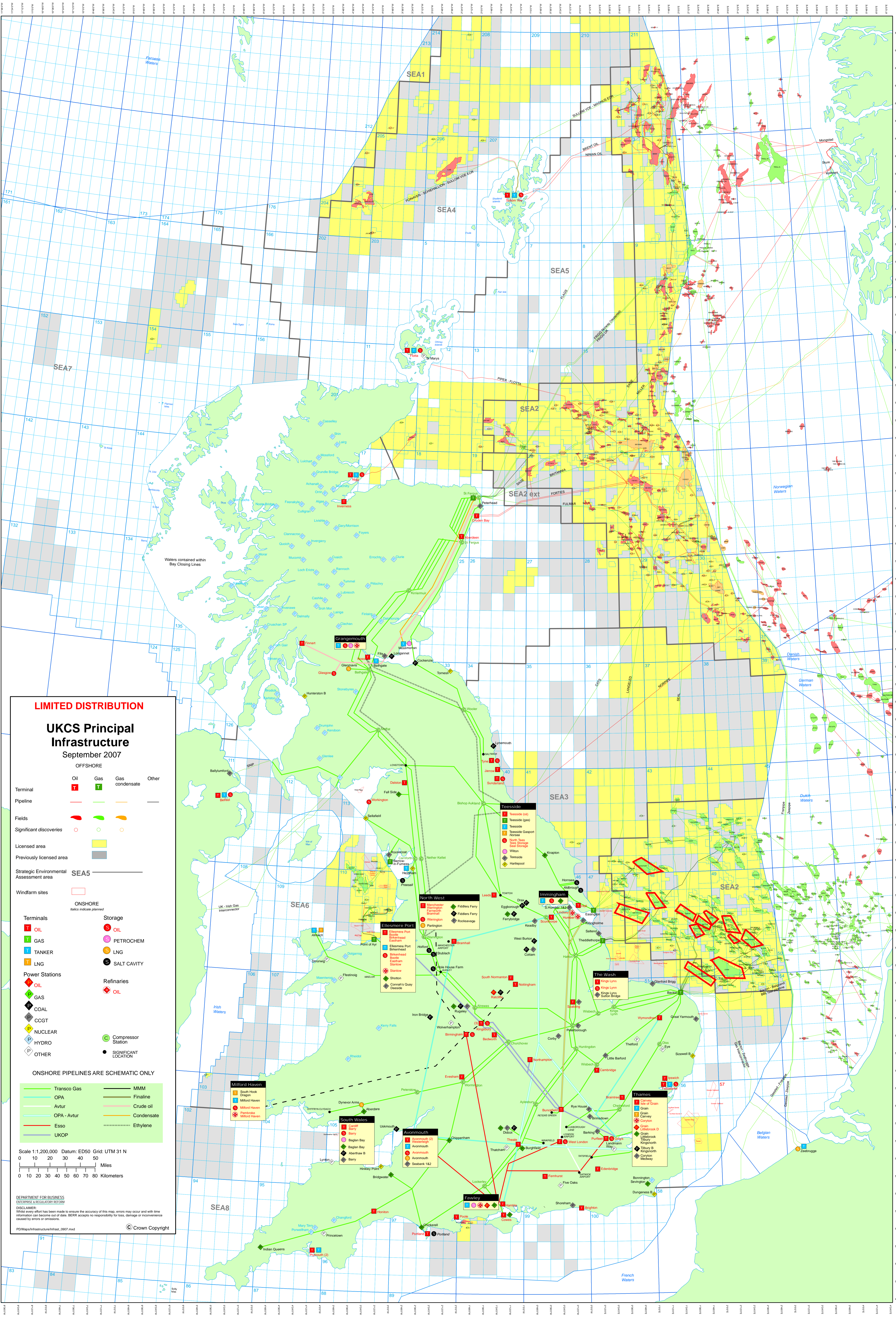


FIGURE C1 – HEAT BALANCE DIAGRAM FOR SEE PROJECT BASE CASE WITHOUT CARBON CAPTURE

**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

- Terminal
 - Oil
 - Gas
 - Gas condensate
 - Other
- Pipeline
 - Oil
 - Gas
 - Gas condensate
 - Other
- Fields
 - Oil
 - Gas
 - Gas condensate
 - Other
- Significant discoveries
 - Oil
 - Gas
 - Gas condensate
 - Other
- Licensed area
 - Licensed area
 - Previously licensed area
- Previously licensed area
 - Previously licensed area
- Strategic Environmental Assessment area
 - SEA5 Strategic Environmental Assessment area
- Windfarm sites
 - Windfarm sites

ONSHORE

- Terminals
 - OIL
 - GAS
 - TANKER
 - LNG
- Power Stations
 - OIL
 - GAS
 - COAL
 - CCGT
 - NUCLEAR
 - HYDRO
 - OTHER
- Storage
 - OIL
 - PETROCHEM
 - LNG
 - SALT CAVITY
- Refineries
 - OIL
- Compressor Station
 - Compressor Station
- Significant Location
 - 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
 DISCLAIMER: Whilst every effort has been made to ensure the accuracy of this map, errors may occur and with time information can become out of date. BERR accepts no responsibility for loss, damage or inconvenience caused by errors or omissions.
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**APPENDIX E
CO₂ SOURCES IN THE REGION OF THE SEE PROJECT
(8 pages)**

E. CO₂ 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 (CO₂) 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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ per year) in the area, their distance from the existing Spalding Power Station and their estimated emissions of CO₂ between 2004 and 2007. These plants may ultimately chose to fit carbon capture though this would more than likely depend on the price of CO₂ 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 CO₂ 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		Distance from Site	Name	Owner	Capacity	Commission Date	+ 25 Years	Emissions (Tonnes CO ₂)			
	X	Y							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		Distance from Site	Name	Owner	Capacity	Emissions (Tonnes CO ₂)					
	X	Y					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 CO₂ SOURCES IN THE REGION OF THE SEE PROJECT
(1 page)

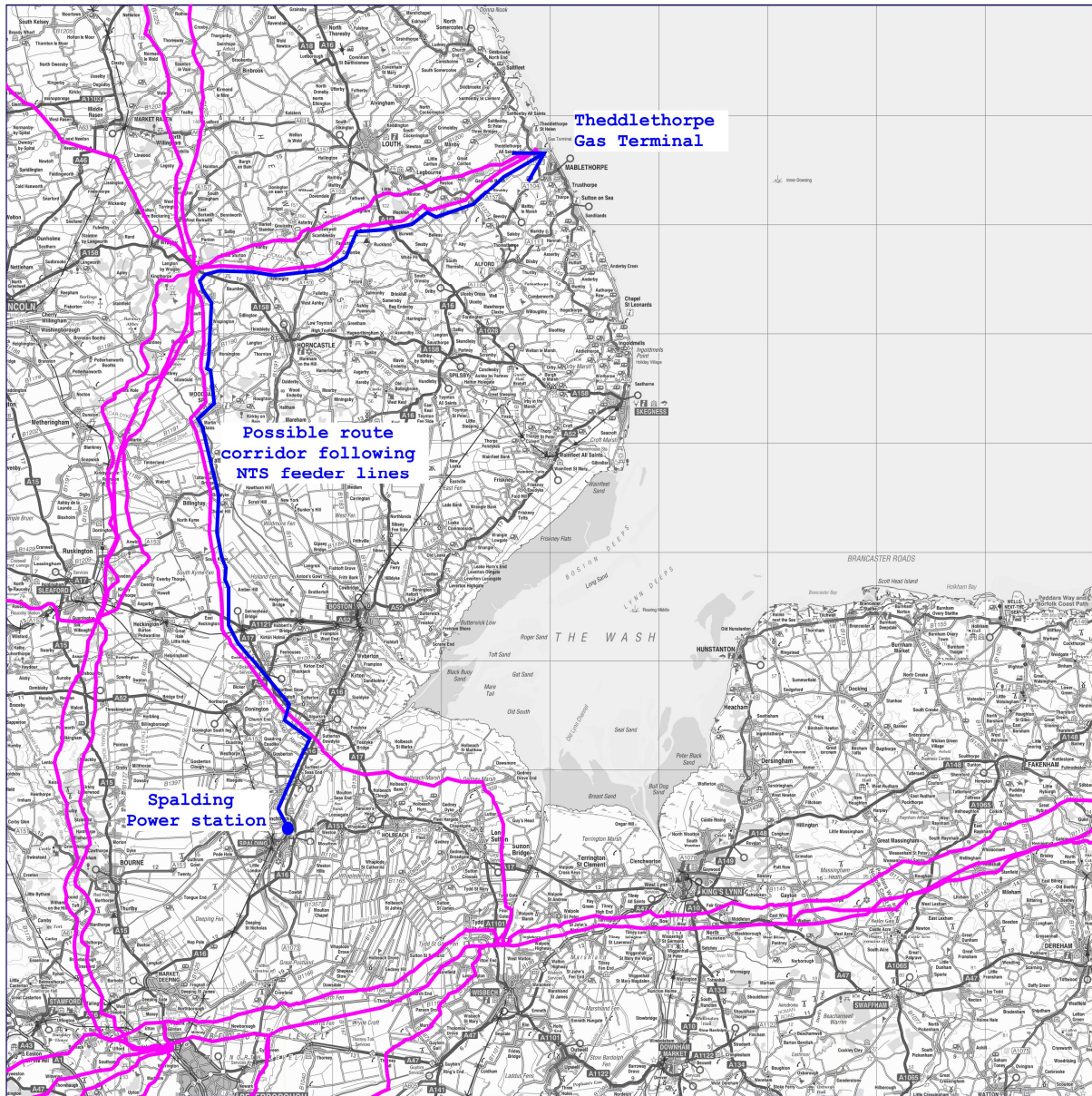
F. MAP OF CO₂ SOURCES IN THE REGION OF THE SEE PROJECT



<input checked="" type="checkbox"/> Carbon Dioxide	
10,000t or less	
10,000t to 100,000t	
100,000t or more	

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

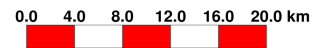
G. MAP OF PROPOSED ONSHORE PIPELINE ROUTE



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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A	16.03.09	ORIGINAL ISSUE	DD	MLC	KB

NOTES



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

• DATE	16.03.09	DRAWN BY	MLC
• SCALE	1:1000 @ A1	PRODUCED BY	DD
• CAD REF		CHECKED	MLC
		APPROVED	KB



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