The Planning Act 2008

The Infrastructure Planning (Applications: Prescribed Forms and Procedure) Regulations 2009 Regulation 5(1)(q)

The Proposed Knottingley Power Plant Order

Carbon Capture and Storage Report

PINS application document reference: 8.2
PINS project reference: EN010050
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Date: June 2013
Version A (submission – September 2013)

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Volume 1

CCGT Power Plant Environmental Statement

Appendix F.2 - Carbon Capture Readiness Report

June 2013

Knottingley Power Limited
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1. Introduction

1.1. Knottingley Power CCGT Project

1.1.1. Knottingley Power Ltd (KPL) is seeking to develop a gas-fired Combined Cycle Gas Turbine (CCGT) electricity generating station, approximately 1 km east of the village of Knottingley, West Yorkshire, within the Wakefield Council area. The new power station is expected to have a generating capacity of around 1500 MW and will be known as the Knottingley Power Project.

1.1.2. The proposed power station will be located on the site of a former chemical works (demolished in 2009) and adjacent land. The location of the site is shown in Figure 1. The proposed power station is expected to help displace power at present generated by less efficient and more polluting power stations elsewhere in the UK.

1.1.3. The Environmental Statement[1] submitted in support of a Development Consent Order (DCO) application under Section 31 of the Planning Act (2008) for the project contains detailed information about the site and the proposed development.

1.2. Updated Carbon Capture Readiness Report

1.2.1. The Department for Energy and Climate Change (DECC) published a Guidance Note in November 2009 relating to the requirement to submit a Carbon Capture Readiness (CCR) report alongside Development Consent Order (DCO) application for power stations of greater than 300 MWe output[2] submitted to the Infrastructure Planning Commission. This guidance note recommends that a CCR study should cover the following:

- That sufficient space is available on or near the site to accommodate carbon capture equipment in the future
- A review of the currently available and future methods of capturing CO2 from large combustion plants, and a description of the indicative capture method proposed (see Section 2);
- An assessment of the technical feasibility of retrofitting the indicative capture method to the proposed plant (see Section 3);
- An identification of a possible pipeline corridor from the site to a storage location, and an assessment of the technical feasibility of the route (see Section 4);
- An identification of suitable storage sites with sufficient capacity to store the capture CO2 over the lifetime of the plant (see Section 5); and
- An assessment of the economic feasibility of retrofitting carbon capture equipment to the proposed plant and the subsequent transport and storage of this CO2 (see Section 6).

1.2.2. The following report demonstrates that it is technically feasible to install a carbon capture plant on the site. A possible pipeline route corridor is proposed, transporting the captured CO2 to potential storage sites in the South North Sea with sufficient capacity for the anticipated volumes required for the proposed plant.

1.2.3. The report details the economic conditions which would be required to make the retrofitting of carbon capture equipment economically beneficial.

1.3. **2012 Energy Bill**

1.3.1. The Secretary of State for Energy has introduced the Energy Bill, Bill 100 55/2, into the House of Commons on the 29th November 2012. Chapter 8 of the Bill details the Emissions Performance Standard places with a duty not to exceed annual carbon dioxide emissions limit, which is linked by a formula to the installed generating capacity. It states that until (and including) 2044, the statutory rate of emissions is 450 g/kWh for fossil fuel plant. It is noted that in the subsequent discussions on this paper there is a suggestion that this value may be subject to review every 3 years.

1.3.2. The rate of carbon dioxide emissions from the proposed natural gas fired CCGT will be far lower than this value (450 g/kWh) and therefore under this Bill CCS will not be required to be installed at Knottingley Power CCGT plant before 2045. A modern large CCGT power plant achieving 58% thermal efficiency would produce approximately 342 g/kWh of CO2 depending on the fuel gas composition.

1.3.3. Owing to the significant advancements which have been made in CCGT power plants over the last few decades the economic lifetime of a CCGT power plant is typically considered to be of the order of 25 years. Therefore fitting of CCS at Knottingley after 2044 is likely to occur as part of a major repowering of the site.
2. CO2 Capture

2.1. Introduction

2.1.1. The following section discusses the available methods of post combustion CO2 capture from large combustion plant. It then discusses the proposed method of CO2 capture from the Knottingley plant. Section 3 discusses precisely how this method would be retrofitted to the plant, what impacts this would have on performance and the space requirements to accommodate the equipment.

2.2. CO2 capture technologies

2.2.1. A review of potential methods of post-combustion carbon capture has been conducted. This has shown that a number of technologies are currently available and that considerable research is being conducted into several further processes.

2.2.2. Technologies to capture CO2 from flue gases are based on absorption, adsorption, membranes or physical or biological separation. Amine based absorption methods are currently the most prevalent. Absorption processes involve the thermal regeneration of solvents with a strong affinity for CO2. On the scale required for the capture of CO2 from a large combustion plant there is therefore a requirement for a significant amount of thermal energy to be used in the process.

2.2.3. Of the amine based absorption methods currently used, aqueous monoethanolamine (MEA) is typically the preferred method for removing CO2 from the flue gas of large combustion processes. MEA has been used in the Fluor Daniel Econamine FG and FG Plus technologies[3] and the ABB Lummus Global technology. Siemens has also been developing a process which is similar to the MEA process but uses an amino-acid salt as the absorbing solvent, it claims a number of benefits associated with the solvent being biodegradable and having a lower environmental impact.

- Other alternatives to the use of MEA include the Mitsubishi Heavy Industries (MHI) process which uses a sterically hindered MEA, the chilled ammonia process, the Benfield process, using potassium carbonate/bicarbonate, and processes using other amines. All these processes have only been proven on a smaller scale than that required for the Knottingley plant.

- In addition there are a number of processes under development, many of which may be proven on a commercial scale before it is a requirement, or it is financially viable to retrofit carbon capture to Knottingley plant. These processes generally utilise the carbon dioxide and obviate the need for transport and storage. They include the use of algae and the catalytic conversion of carbon dioxide to either carbon, to methanol, to urea or to other reusable substances. It is therefore possible that, by the time carbon capture is retrofitted to Knottingley plant, there will not be any need for a CO2 pipeline to a storage site.

- The carbon capture design for this study has been based on the Fluor Daniel Econamine FG technology, i.e. a post-combustion amine capture process. The Econamine FG process has been proven in small scale plants for natural gas derived flue gases, as well as fuel oil and coal derived flue gases.

2.2.4. The alternative use of Siemens solvent process is expected to have a similar footprint (once Siemens has optimised it) and process impact.

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2.2.5. The study demonstrates that the Econamine FG process is feasible although the decision on the eventual process will be taken in consideration of the economic feasibility and the contemporaneous legislation, best practice and proven technology.

2.2.6. It is likely that advanced amine processes and alternative technologies will occupy less space, and will be more energy efficient, than the basic amine process considered below.

2.3. The proposed capture process

2.3.1. The amine process considered is illustrated in the flow diagram below.

Diagram 2.1: Process sketch of carbon capture plant

2.3.2. In this system an amine solution is passed through the flue gases to absorb the carbon dioxide. The carbon dioxide rich amine solution is then transferred to a stripper column where the solution is heated with low pressure steam releasing the carbon dioxide from solution. The stripped amine solution is then recycled back to the absorber.

2.3.3. At the top of the stripper the vapour stream comprises a mixture of steam and carbon dioxide, this is cooled to condense the water vapour leaving the carbon dioxide gas available for compression and pipeline transportation for subsequent sequestration.

2.3.4. So as not to over pressurise the high temperature components of the gas turbine exhaust and heat recovery steam generator (HRSG) a booster fan is included in the carbon capture plant (CCP) to overcome the pressure losses within the plant. This fan is shown at the inlet to the CCP but it could be located at other points in the plant following detailed design.

2.3.5. The proposed system requires that the flue gases being treated are not contaminated by sulphur dioxide (SO2) or dust. It is also intolerant of significant concentrations of nitrogen dioxide (NO2). As the sulphur dioxide and dust concentrations in the flue gas from the CCGT plant are both extremely low there is no provision for flue gas desulphurisation or dust removal.

2.3.6. The oxides of nitrogen in the flue gas consist of 90-95% nitric oxide and 5-10% nitrogen dioxide. The concentration of nitrogen dioxide is considered to be so low that no De-NOx facility is thought to be required.
2.3.7. The capture process discussed in this study is designed to capture 90% of the CO2 from the CCGT plant.
3. **Retrofitting Carbon Capture to the Knottingley Power CCGT**

3.1. **Introduction**

3.1.1. This section discusses how the indicative carbon capture process described in Section 2 above could be retro-fitted to the proposed Knottingley plant. The feasibility of a number of retro-fitting options is established, ranging from a CCS plant which is fully integrated with the CCGT to an entirely stand-alone CCS plant.

3.2. **Plant configuration options**

3.2.1. There are two basic alternatives for retrofitting a carbon capture plant (CCP) to the Knottingley plant. These are:

- To build the CCGT plant ready for a fully integrated CCP at some point in the future. This requires some significant alterations to the CCGT than would otherwise have been the case, with associated efficiency and capital cost impacts in the interim period (i.e. while the plant operates as a conventional CCGT, prior to the requirement/desire to fit a CCP); or

- To build the CCGT as normal, with the intention of installing a stand-alone CCP at some point in the future. The stand-alone CCP would provide all of its own steam and cooling water requirements and part of its electricity requirement. Additional electricity requirements would be supplied from the main high voltage switchyard of the CCGT plant or the grid. The benefit of this case is that the CCGT can operate at its highest efficiency in the interim period without the capital cost impacts of preparation for full integration. Also operation of the CCP is not dependent on the load conditions of the CCGT and can be held in a state of readiness to meet the variable dispatch requirements of the CCGT plant.

3.3. **Plant and site requirements**

3.3.1. This section discusses the plant and site requirements of either of the retrofitting alternatives outlined above. In order to consider a ‘worst-case’ scenario, calculations of vessel sizes are based on a CCP which captures CO2 from a standalone boiler as well as the Knottingley CCGT, although this design is not being proposed at this stage. As described in the following section the footprint of the equipment to be installed would occupy approximately 1.6 ha and a total area of 7.3 ha has been allowing in which to install this equipment. The area being well in excess of that required to locate the plant.

3.3.2. The land requirements for CCS presented in the Guidance Note4 of 170m x 140m (2.4 ha) for a 500MW unit (7.1 ha for 1500 MW) will remain available until such a time that DECC advise that less space is required during the preparation of future biennial CCR reports.

**Flue gas cooling**

3.3.3. So that the carbon dioxide is absorbed, the flue gases must be cooled prior to the absorber vessel, to a temperature of about 45°C. This can be done by either direct water spray cooling in a quench tower arrangement or by a combination of quench and flue gas/flue gas heat exchange.

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4 Carbon Capture Readiness (CCR), A Guidance Note for Section 36 Electricity Act 1989 consent applications, URN 09D/810, November 2009
3.3.4. In an integrated HRSG CCP option the temperature leaving the HRSG is close to 120°C. Then the action of the booster fan further increases this temperature, as the gas pressure is increased, to a temperature around 135°C. These temperatures are higher than would be the case in a scenario where additional steam was provided by a standalone boiler, where the HRSG flue gas exit temperature would be closer to 90°C, rising to around 105°C across the booster fan.

3.3.5. The flue gases leaving the absorber are at a temperature of about 35°C and are saturated with water from the scrubbing process. If these gases are discharged to atmosphere there would be a very visible water vapour plume from the stack. Also at the absorber temperature the flue gases will have little buoyancy in ambient air, such that a high chimney stack would be required to ensure effective dispersion of emissions so as to avoid high ground level concentrations.

3.3.6. One option for cooling of the flue gases is therefore to use a gas-gas heat exchanger to transfer some of the heat from the flue gases leaving the HRSG to the gases leaving the absorber. Assuming a 30°C approach in the heat exchanger this would cool the flue gases from 135°C to 65°C whilst raising the stack gases from 35°C to 100°C (or 85°C in the case with supplementary steam from a standalone boiler), depending on the effectiveness of the absorber demisters. This should be sufficient to minimise the plume visibility and provide reasonable dispersion with the existing stack height. The heat exchanger would be expected to operate through the dewpoint region of the flue gases and would need to be made of materials resistant to acid attack.

3.3.7. Final cooling of the gases would be achieved by direct spraying of cooling water in to the flue gases. The spray water achieves cooling partially by evaporation and partially by recirculating the water through a heat exchanger, thereby transferring heat to the cooling tower circuit.

3.3.8. Direct spray cooling could be employed to achieve the full cooling duty. It would represent the lowest cost (capital and maintenance) option and also the more thermally efficient (avoiding increased fan power) however, it would not address the issues with visible plume and flue gas dispersion.

**CO2 absorption**

3.3.9. The cooled flue gases are ducted to a CO2 absorber with a CO2 content in the flue gas of approximately 4.1%. The design calculations for the CO2 absorber show that a cross-sectional area of approximately 210 m² is required and a height of 35 m is sufficient to give 90% removal of CO2. It is proposed that the CO2 absorber vessel be manufactured from concrete on site and suitably internally coated. The dimensions of the absorber for one 500 MW CCGT unit with platforms will be approximately 18 m wide by 18 m long and 35 m high. The CO2 is removed from the flue gas by passing the gases up the absorber against a counter flow of MEA solution.

3.3.10. The MEA removes about 90% of the CO2. This equates to approximately 3,550 tonnes per day per 500 MW unit.

3.3.11. In the standalone CCP installation a separate flue gas scrubber will be required to treat the stack emissions from the standalone boilers. Including some allowance for air ingress, it is expected that the stack emissions from the stand alone boiler will have a CO2 concentration of 8.1%. At 90% scrubber capture efficiency, the quantity of CO2 captured by the standalone boiler is estimated to be 611 t/day/500MW CCGT unit.

3.3.12. Therefore for the worst case scenario considered of a CCGT unit with standalone CCP, capturing 90% of the CO2, the quantity of CO2 captured per day would be 4,161 t/day for each of the 500 MW units. Calculated as follows:

\[
\text{CO2 captured (tonnes/day)} = F_c \times E_f \times C_e
\]
Where $F_c =$ tonnes per day of fuel burned  
$E_f =$ CO2 emission factor in tonnes of CO2 per tonne of fuel burned  
$C_e =$ capture efficiency of the capture plant

### 3.3.13. Therefore,

- CO2 captured CCGT = $1435 \times 2.75 \times 90\% = 3,550$ tonnes per day
- CO2 captured standalone boiler = $247 \times 2.75 \times 90\% = 611$ tonnes per day

Total CO2 captured per CCGT Unit = $3550 + 611 = 4161$ tonnes per day

### 3.3.14. The flue gas velocity used in the design of the scrubber varies depending on the concentration of CO2 present, the higher the concentration the greater the quantity of absorbing solution flowing through the flue gases and the greater the potential temperature rise from the heat of absorption. The calculation of the absorber footprint for a square absorber is as follows:

Absorber width, length (m) = $A \times \sqrt{\frac{te}{d} \div \%CO2}$

Where

$A = 0.50$ at 3% CO2 to 0.55 for 13% CO2  
te/d = tonnes/day of CO2 recovered  
%CO2 = volume of CO2 in raw flue gas.

### 3.3.15. Therefore,

CCGT absorber width, length = $0.50 \times \sqrt{\frac{3550}{4.1}} = 14.7$ metres

### 3.3.16. Making some allowance for access platforms, a square footprint of 18m x 18m has been allowed for the absorber of each unit of the CCGT plant.

### 3.3.17. To provide some redundancy there would be at least two standalone boilers provided for the CCP, such that one can be stopped for maintenance whilst the other still maintains carbon capture capability.

Standalone boiler absorber width, length = $0.55 \times \sqrt{\frac{(3/2 \times 611)}{8.1}} = 5.8$ metres

### 3.3.18. Making some allowance for access platforms, the two square absorbers of the standalone boilers would occupy a footprint of 8m x 18m, located at the end of the boiler house.

**Flue gas discharge**

### 3.3.19. The stripped flue gases from the CO2 absorber will be passed through the gas/gas heat exchanger, raising their temperature, and ducted to the CCGT chimney stack.

**CO2 stripping**

### 3.3.20. The CO2 rich MEA is collected in the base of the absorber and pumped from there through a lean/rich MEA heat exchanger to the CO2 stripping column. There, the CO2 rich MEA is heated by steam (using a reboiler) and the CO2 desorbed. The CO2 leaves the top of the scrubber and passes through a cooler (condenser) to remove excess moisture before discharging to the CO2 compression plant.

### 3.3.21. The stripped MEA is pumped to the lean/rich MEA heat exchanger where it is cooled before discharging to the CO2 absorber for reuse.

### 3.3.22. The approximate diameter of the stripping column required for each 500 MW CCGT unit in the example above is calculated as follows:

Stripping column diameter = $0.13 \times \sqrt{te/d}$

### 3.3.23. Therefore,
CCGT unit stripping column diameter = 0.13 * sqrt(3550) = 7.7 metres
Standalone boiler stripping column diameter = 0.13 * sqrt(3/2*611) = 3.9 metres

**CO2 discharge**

3.3.24. The CO2 from the CO2 stripper column is ducted to the CO2 compressors/pumps where it is compressed to 100 bar and pumped to the CO2 transport system. There are inter-coolers on the CO2 compressors. There is no purification of the CO2 although the compression itself removes the majority of the water present within the CO2.

3.3.25. The compressed CO2 is then transported to the storage site.

**Steam supplies**

3.3.26. Based on current knowledge and technology each unit of the CCP at Knottingley would require around 210 t/h of low pressure (3.5 bar) steam for use in the reboiler of the stripping column. A total site steam demand of approximately 630 t/h. This steam is condensed in the reboiler, with hot condensate being returned at around 135°C.

3.3.27. There a number of options for supplying this steam, including:
   - Steam from the LP/IP/HP circuits of the CCGT water/steam cycle
   - Standalone boilers (with or without a backpressure steam turbine);
   - Vapour compression.

3.3.28. In the case of the standalone boilers option, the stripping column associated with each of those boilers would also consume about 55 t/h of steam.

3.3.29. These options are discussed in more detail in Section 3.4.1 below.

**Electricity supplies**

3.3.30. The electricity for operation of the gas/gas heater, the various MEA pumps and the CO2 compressors will be taken from new dedicated CCP transformers taking their supply from the main CCGT HV switchyard. It is not intended to install larger unit transformers to cater for the needs of the carbon capture plant at the initial construction stage of the CCGT plant. Space provision will be made for installing the CCP transformers and switchgear within the CCGT plant area.

3.3.31. The total power requirements of the CCP have been estimated at approximately 105 MW for the site, 35 MW per unit depending on the particular CCP configuration.

3.3.32. The major electricity users are:
   - Flue gas booster gas fan 14.6 MW per unit
     - This fan blows the flue gases through the CCP.
   - CO2 gas compressor (152 bar discharge) 14.3 MW per unit
     - Final product compressor discharging into CO2 gas pipeline.
   - Cooling tower fans 1.6 MW per unit

3.3.33. Heat is removed from the CCP by the final flue gas cooling stage, stripper condenser and compressor cooling this is discharged to atmosphere through cooling towers. The indicated auxiliary load assumes separate cooling towers are employed for the CCP. This load would be partially offset by savings on the existing CCGT cooling towers.
   - Circulating solvent pumps 0.9 MW per unit
     - This transfers the solvent between absorber and stripper vessel.
• Circulating cooling water pumps 1.0 MW per unit
  • This pump circulates the cooling water through the cooling plant and cooling tower.

Cooling water system

3.3.34. This will either be a hybrid cooling tower system, or an air-cooled radiator type system. A hybrid system would use make up water from the River Aire and would discharge purge water to the same water body. An air-cooled system would use air blast coolers with a closed circuit cooling water system.

3.3.35. The decision on which of these systems will be used will not be made until the detailed design of the carbon capture plant is considered. At that time the availability of water supplies from the Canal will be reviewed and the cooling system optimised.

3.3.36. Cooling is required for the following duties on the CCP, cooling of the:-
- Flue gas prior to the absorber;
- Solvent prior to the absorber;
- Vapours in the condenser after the stripper; and
- Gas compressor.

3.3.37. The cooling of the flue gases prior to the absorber can be achieved by several routes, including gas-gas heat exchangers, direct water evaporation or by cooling circulating water within the gas cooler. Depending on the particular cooling option, part of the heat of the flue gases will eventually be transferred in to the CCP cooling water system.

3.3.38. It has been calculated that the total quantity of cooling water being circulated in the CCP plant is similar to that which would be used in a standalone CCGT plant. Depending on the CCP plant configuration it is estimated that the cooling water flow required for a CCP of a single unit would be around 17,000 m³/h.

3.3.39. In the case of a CCP with integrated LP steam supply from the HRSG, approximately half of the CCGT condenser heat rejection load is transferred to the CCP plant, such that the steam turbine, condenser and cooling tower of the CCGT is smaller than for a standalone CCGT plant.

3.3.40. In installing the make-up water and blowdown water supplies for the cooling towers, in approximate terms, if a standard CCGT unit is the base cooling water requirement then a CCGT with integrated LP steam supply to a CCP plant will use around 50% more water and the option with a standalone boiler supply will use about 100% more water. The partially integrated version will fall between these depending on the level of integration.

3.3.41. Space provision for entirely new set of cooling towers is shown on Figure 2, allowing for cooling towers with a total footprint of 7,000 m². These are shown on the drawing as being three separate blocks of towers, although in practice these may be one block, or several smaller sets of fans.

3.3.42. During detailed design of the CCP the cooling cycle will be optimised to take advantage of the reduced condenser requirements of the main CCGT if appropriate.

Waste water treatment

3.3.43. The waste water treatment associated with the CCP will incur slightly different requirements to the main CCGT plant due to the potential leakage of amine solution and excess flue gas condensate. It is therefore envisaged that primary treatment systems will be constructed as part of the CCP.

3.3.44. The only allowance over the basic design of CCGT in the initial build is to cater for the slightly larger waste water flows being discharged off site, by sizing drains and blowdown systems accordingly.
3.3.45. The design of the carbon capture plant will include surface water drainage, contaminated surface water drainage which drains to oil interceptors, and process drainage.

3.3.46. The surface water drainage may be reused in the cooling tower system (if installed), discharged to the cooling tower of the CCGT plant or discharged to sewer.

3.3.47. The contaminated surface water drainage will be treated in oil separators and then either used in the cooling water system as described above or discharged to the Canal/River.

3.3.48. The process water drainage will discharge to sewer.

Fire system

3.3.49. The CCP does not represent any significantly greater fire risk than is the case with the CCGT plant. It is therefore envisaged that flanges would be provided to allow for an extension of the fire hydrant ring main to include the CCP buildings and cooling towers. That spare zones would be included in the master fire alarm system for future zones to be added.

DeNOx

3.3.50. There is not considered to be any requirement to reduce NOx in the flue gases to meet the requirements of the carbon capture plant.

Dust removal

3.3.51. There is not considered to be any requirement to reduce the dust in the flue gases to meet the requirements of the carbon capture plant.

Flue gas desulphurisation

3.3.52. There is not considered to be any requirement to reduce SO2 in the flue gases to meet the requirements of the carbon capture plant.

Compressed air

3.3.53. Any compressed air required by the carbon capture plant will be provided from two 100% duty dedicated air compressors.

Control and instrumentation

3.3.54. Modern plants use distributed control systems such that they can be upgraded to take account of the CCP. The transfer of signals between the CCP and the main CCGT plant control room will be by data highway (Ethernet) such that minimal provision need be made within the existing plant to accommodate the additional signals.

3.3.55. It is also worth noting that the rapid advance in computer control systems means that most undergo significant replacement every 15 years. Therefore, in the initial CCGT build only a standard control system is envisaged, but one which can be upgraded to take account of the CCP.

Balance of Plant

3.3.56. In terms of most other balance of plant items no special provision would be made in the initial CCGT construction.

MEA deliveries and storage

3.3.57. The usage rate of MEA of each of the three CCGT units is expected to be 7 tonnes per day. This will be supplied by road in 30 tonne tankers and stored in a 40 tonne storage tank on site. It is anticipated that the MEA used in the carbon capture process will be a 30% solution. The MEA delivered and stored will be diluted with deionised water to produce the necessary solution for make up to the carbon capture system. The quantity of deionised water required is minimal and will be provided by a dedicated demineralisation plant.
3.3.58. On average, less than one delivery of MEA per day is expected. The roads on the proposed CCGT plant will be designed to accommodate this vehicle.

**Storage and handling of MEA and CO2**

3.3.59. It is proposed to store only 40 tonnes of MEA on site. This will be in a dedicated tank located within an impermeable concrete bund. Delivery pipework and transfer pumps/pipework will, wherever possible, be located within the bunded area. Dilution of the MEA before use will occur within the bunded area. There will therefore be no concentrated MEA pipework within the CCGT plant.

3.3.60. There will be no storage of CO2 on site. The compression equipment is proposed to be located at the boundary of the site. Therefore, no dense phase CO2 will be present at the site and therefore the development does not require Hazardous Substances Consent (HSC).

**Staffing**

3.3.61. The staff required to operate the CCS plant is anticipated to be one person on shift (a total of 5 staff) plus four persons during the day (mechanical, electrical, control and instrumentation maintenance and one managerial staff).

3.4. **Modifications required to CCGT**

3.4.1. Depending on the choice of system there are a number of potential modifications which may be required to be made to the CCGT, both during its initial construction and during the subsequent retrofitting of CCS. These are discussed below.

**Steam supply**

3.4.2. Based on current knowledge and technology each unit of the CCP would require around 210 t/h of low pressure (3.5 bar) steam for use in the reboiler of the stripping column. A total site steam demand of approximately 630 t/h. This steam is condensed in the reboiler, with hot condensate being returned at around 135°C.

3.4.3. There a number of options for supplying this steam:

- Steam from the CCGT LP/IP/HP circuits of the water/steam cycle,
- Standalone boilers (with or without a backpressure steam turbine);
- Vapour compression.

3.4.4. The following subsections consider the merits of providing the steam heating duty from these sources.

**Steam from the CCGT water/steam cycle**

3.4.5. The CCP can be fully integrated with the CCGT plant’s steam water circuit, using the low grade heat available in the steam system. Providing steam from the LP circuit of the water/steam cycle, (a combination of LP steam from the HRSG and LP steam extracted from the steam turbine) or let down from another pressure.

3.4.6. This approach can be more thermally efficient than using standalone boilers to supply all of the steam to the CCP. However, the efficiency gain of the integrated system is reduced due to CCGT plant’s inability to make use of the high return condensate temperature from the CCP. The high return condensate temperature leads to a higher HRSG flue gas exit temperature and more cooling load on the CCP.

3.4.7. The measures which are needed to maintain constant steam pressure from the CCGT, once fitted lead to a slight efficiency loss when operating without the CCP in operation. For example valves to control the flow of steam through the LP turbine, when fully open still have some pressure loss.
3.4.8. It can reasonably be expected that with this integrated system approach that the availability of the CCGT plant to export electricity will be reduced slightly, as, for example, failure of the condensate return pump would directly impact on the CCGT operation or a steam leak on the CCP will lead to loss of water within the CCGT plant.

3.4.9. CCP would only be operational once sufficient steam was available from the CCGT, therefore on start-up the carbon capture plant would not be available until the steam circuit was operational, unless a standby boiler was also employed.

3.4.10. The electricity output of the station will reduce by some 105MW when the CCP is fitted.

Steam from standalone boilers with back pressure steam turbine

3.4.11. The standalone boiler would produce high pressure steam which would be letdown through a backpressure turbine and the steam would be supplied to the CCP facility.

3.4.12. In the standalone case there are no changes required to the CCGT plant over a standard configuration. As the supply of steam to the CCP is independent of the CCGT plant, the CCGT plant retains its flexibility to vary load and undertake two shift operation.

3.4.13. The power export from the site is not significantly reduced on that of the CCGT units, such that the grid connection infrastructure can be fully utilised.

Vapour compression

3.4.14. In principal the steam and carbon dioxide mixture leaving the top of the stripper could be mechanically compressed and used as part of the heating fluid in the reboiler. Compressing the steam in this manner would raise the temperature at which the steam condenses, making it suitable to supply the heat in to the reboiler.

3.4.15. Such a system would significantly reduce the quantities of steam required and would also reduce the size of cooling water circuit and cooling tower required. So, although such a system would use electricity to upgrade the steam quality it could prove to be significantly more efficient.

3.4.16. There are other variations on this option which would use a heat pump (chiller circuit) to transfer the heat between condenser and reboiler.

3.4.17. At the time of writing it is believed that none of the current systems being developed that would include this type of heat pump, however, such systems may become available as CCP technology develops.

3.4.18. As this is effectively a standalone solution there would be no significant modifications required to the steam water circuit to accommodate this option should it become viable in future.

Steam/water cycle

Integrated

3.4.19. The CCP steam requirement in this instance comes from the LP/IP/HP circuits of the steam/water cycle.

3.4.20. The relatively high return temperature of the condensate from the CCP would potentially cause boiling within the economiser of an efficient HRSG. Some of the existing designs of HRSG are able to accommodate higher condensate return temperatures by using economiser pressure to suppress boiling. One of these designs of HRSG would require no significant modifications as part of the initial build.

3.4.21. Some additional t-pieces and control logic would be required as part of the initial build to allow future connection of the steam and water circuits.
3.4.22. In the standalone case there are no changes required to the HRSG over a standard configuration.

**Steam turbine**

3.4.23. During the initial construction of the CCGT a standard steam turbine could be employed with allowances made for future retrofit. The extent of the modifications made to the turbine once CCS is retrofitted would depend on the steam requirements determined at the time.

3.4.24. Extracting large amounts of steam from a steam turbine changes the pressure profile through the steam turbine. In particular the pressure drop across the last row of blades prior to the extraction point can become very large placing mechanical stress on that row of blades. This can be overcome by inserting a control valve in the steam supply to the low pressure turbine which sustains steam supply pressure, but the pressure drop across the valve reduces generation efficiency in the LP turbine. Alternatively the LP turbine could be permanently changed out with smaller blade, optimised for the reduced steam flow, it would however, be unable to achieve full output if the CCP were not operational due to the small size of the modified LP turbine.

3.4.25. When the actual design of the CCP is finalised consideration could be given to more comprehensive modification of the steam turbine and water/steam cycle to supply the steam requirement of the chosen plant. This would be assessed on the basis of economic viability taking into account any efficiency, CO2 and capital cost benefits.

**Standalone**

3.4.26. In a standalone plant there are no changes to the steam turbine and a standard design can be employed.

**Flue gas ducting**

3.4.27. The flue gases discharging from the HRSGs will be ducted to the booster fan[5], from there they pass through the gas/gas heater to the direct contact cooler and on to the base of the absorber.

3.4.28. The scrubbed flue gases from the absorber will be ducted through the gas/gas heater to the proposed CCGT chimney stack.

3.4.29. Dampers will be installed in the flue gas ducts and in the lower section of the chimney to enable isolation and bypassing of the CCP.

3.4.30. If a standalone boiler is found to be appropriate the flue gas from this boiler, which have a higher CO2 content, will be ducted through a similar dedicated gas/gas heat exchanger and absorber system.

3.4.31. Note that some of the ducting will be of the order of 6-7 metres in diameter. This will be taken into account in the initial CCGT build and has been taken into account in the space allowance on site for the CCP.

**Cooling system**

3.4.32. Depending on the availability of water from the River Aire, the cooling system of the CCP will be by hybrid cooling towers or if cooling water is not available by direct air cooled heat exchangers.

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[5] Note that, following detailed design, the booster fan may be located elsewhere on the CCP.
3.4.33. In the integrated system part of the heat load from the CCGT will transfer to the CCP when it begins operation. The integrated approach therefore has the potential to combine the cooling water circuits of the CCP and CCGT plants, reducing the size of additional cooling towers required.

3.4.34. The main benefit from the integrated cooling system is the potential cost saving of reusing the existing towers. This has to be offset against the expected date of CCP installation 2044+ (at which time major refurbishment of the CCGT cooling towers is likely) and the potential for interruption to the operating CCGT units during the installation of the additional cooling tower capacity. It is therefore envisaged that for the integrated option, separate cooling tower systems would be employed on this project.

3.4.35. The make-up water and blowdown pipework would be installed suitable for the peak duty so as to avoid future cost on these items.

**Standalone**

3.4.36. In a standalone plant the initial build would include just the standard cooling tower and circulator system of a CCGT plant. The heat load of the CCP would be handled by a separate cooling tower and circulating water system when it is constructed as there is no transfer of heat loads warranting a common system.

3.4.37. The make-up water supply and blowdown discharge pipework would be installed suitable for the peak duty so as to avoid future cost on these items.

3.4.38. Sufficient space will be made available on site for either hybrid cooling towers or air cooled condensers.

**Electrical supply**

3.4.39. A substantial electrical load is required by all cases, warranting a medium (around 33kV) to high voltage supply to the CCP. It is envisaged that space should be allowed in the switchyards and switchgear to accommodate the extra supplies required. Similarly the underground cables route towards the area of the CCP needs to have sufficient space to accommodate these supplies.

3.4.40. It is envisaged that step down transformers and low voltage systems would be part of the CCP.

**Control systems**

3.4.41. In the initial plant a standard CCGT control system is envisaged, with space for future upgrading to accommodate the CCP system. The modern computer based distributed control system use data highways to connect to different subsystems such that they can be readily upgraded in future and do not require significant space in the control room to accommodate such an expansion.

**Raw Water/Demin Water Treatment Plant**

3.4.42. The CCP, depending on the temperature of the absorber could either be a net consumer or producer of clean water. The gases leaving the absorber will be saturated with water at the absorber temperature. At temperatures less than 35°C the absorber will tend to remove water from the flue gas stream from the CCGT.

3.4.43. If this water is taken out from the gas cooler then a relatively clean water is produced which with some basic water treatment would be suitable for use in a boiler. Surplus water would be added to the cooling tower circuit to reduce make-up requirements.

3.4.44. Water make-up facilities for the cooler (if required) and for the absorber will be installed to make-up any shortfall caused by evaporation within these systems.
Integrated

3.4.45. In the integrated system the amount of demin boiler water required is the same for CCGT and with CCP, therefore no special allowance is required. If it is found during detailed design of the CCP that additional standalone boilers are required to supplement the steam provided by the CCGT, an additional make-up will be required, but this will only be slightly more than the basic CCGT plant.

Standalone

3.4.46. In a standalone plant the demin water consumption will increase with the installation of standalone boilers, such that additional make-up will be required. The quantity of steam generated would be about 50% more than for the basic CCGT plant, such that space allowance for an additional demin stream should be allowed in the initial build. However, if water is extracted from the flue gases a dedicated water treatment plant to use this water as part of the CCP would also be a reasonable option.

3.4.47. The additional water treatment would be housed either within the existing water treatment plant building or within the standalone boiler house. It is therefore not separately illustrated in the site layout.

Plant Pipe Racks

Integrated

3.4.48. In this option the plant pipe racks and culverts which would carry the LP steam, condensate return, cooling water system and power cables would need to be enlarged to leave space for these services to be installed at a later date. So additional design and structural steelwork would be required over the basic CCGT plant.

Standalone

3.4.49. Other than the power supply and make-up water systems there is minimal additional work required on the pipe racks as compared to a standalone CCGT.

3.5. Proposed ‘Optimum Efficiency’ approach

3.5.1. It is considered likely that CCS will not be retrofitted to CCGT plants until possibly 2045, due to the prevailing economic and regulatory environment. It is also possible that an entirely different method of CO2 capture will be the standard choice for CCGT plants by the time CCS is retrofitted.

3.5.2. Preliminary modelling, based on current knowledge of CCP design and steam requirements, has found that there is a potential loss in efficiency of up to 1% in constructing a CCGT ready for a fully integrated CCP as opposed to constructing it as standard (in a worst-case where significant alterations are required to a standard CCGT design).

3.5.3. For this reason, it is proposed to design an “Optimum Efficiency” CCGT plant with provision for conversion to future CCP integration but avoiding loss of performance in the initial CCGT operation. The following principles would be adopted in the specification and design of the CCGT plant:

- Identify a layout to accommodate future CCP plant based on the largest area requirement (standalone boiler option).
- Identify steam extraction points in the LP steam system to allow for the future steam requirements of the CCP. If necessary enlarge extraction points in the steam turbine casing during manufacturer to cater for the high steam flow. There would be sufficient space allowed for the pipe work arrangements to route this pipe to the CCP;
- Identify further extraction points on the IP and HP systems to allow for changes in the CCP design/requirements;
• Make allowance in the cable routes and switchyard design for the future supply of the CCP, leaving the necessary space.

• Install a sufficient large water intake and discharge connection to the canal to accommodate the cooling water requirements of the CCP.

• Maintain the high efficiency of the steam turbine in the initial phase of operation by considering the non-CCP cycle conditions in the design;

• Make provision in the layout of the CCGT to ensure that future CCP conversion is feasible whilst considering the ‘up-front’ versus ‘at-retrofit’ expenditure and downtime.

3.5.4. This approach will leave the standalone and integrated options available for implementation when the CCP is installed. If the plant is frequently two shifting the flexibility of the standalone approach would be beneficial to high levels of CO2 capture, whereas for a base loaded plant the efficiency gains associated with an integrated system with a modified/replaced LP turbine could be justifiable based on the higher thermal efficiency.

3.5.5. The most likely solution to be implemented as a retrofit is a partially integrated option, where the available LP steam from the HRSG and a similar quantity extracted from the steam turbine is used, this is supplemented by standalone boilers through a back pressure turbine. Modelling suggests that this “partially integrated” route has reasonable flexibility and efficiency. This is modelled alongside the fully integrated option in the economic evaluation.

3.5.6. This overall approach will maintain compliance with the principles of Best Available Techniques (BAT) for the following reasons:

• BAT aims to achieve the highest possible efficiency for an installation;

• BAT aims to reduce CO2 emissions from an installation; and

• BAT aims to reduce the capital and operating costs of the plant as far as practicable (i.e. to improve its economic viability).

Efficiency

3.5.7. As discussed above, the efficiency of a CCGT constructed ready for a fully integrated CCP is up to 1% less than a standard CCGT. Such a plant could not therefore be considered to be BAT based on efficiency upon commercial operation if it was constructed ready for full integration at the time of construction.

3.5.8. The proposed “Optimum Efficiency” approach outlined above would maintain BAT whilst ensuring that the CCGT is carbon capture ready with CCGT to maintaining optimum plant efficiency both pre and post CCP installation.

CO2 emissions

3.5.9. CO2 emissions should play an important role in the consideration of BAT.

3.5.10. Given that there is no guarantee that post-combustion amine capture will be selected as the most attractive CO2 capture method, it is possible that constructing the plant ready for full integration would unnecessarily result in it operating at a lower efficiency for its entire life. The 1% reduction in efficiency that is predicted during this period would result in an increase of almost 2% in CO2 emissions per MWh of electricity generated. Over the 25 year life of the plant this could lead to millions of tonnes of CO2 being emitted which could otherwise have been prevented, again reinforcing the “Optimum Efficiency” philosophy.
A key element in the consideration of BAT is the economic viability of the installation.

Any loss in efficiency in the period before CCS is eventually retrofitted results in an increase in the cost of each MWh generated by the plant due to the increased cost of fuel per unit of electricity.

Preliminary modelling has found that, although after retrofit of a CCP a fully integrated plant is slightly more efficient than a plant with a standalone boiler and backpressure steam turbine, it exports significantly less electricity to the grid. While costing more to produce electricity due to increased fuel costs, this increase in output allows the plant to recover the capital costs of installing the CCP more quickly.

The increase in the lifetime cost of electricity caused by these factors would have either of two consequences; rendering the project less economically viable, or, increasing the price of electricity charged to the consumer. The decision would therefore neither be consistent with BAT nor one of the core aims of the Energy White Paper, which is to reduce fuel poverty.

It is therefore considered that the “Optimum Efficiency” approach, which ensures high efficiency and should result in minimal investment, would be more representative of BAT on economic grounds. This approach delays any major modifications to the standard CCGT until the final design and steam requirements of the CCP are known and enables the most appropriate economic decision to be made at the most appropriate time. This approach identifies sufficient space in the plant that it does not hinder the future conversion, leaving the optimisation of the low pressure steam turbine (reducing its flow capacity) until the actual demands of the CCP plant are known.

When the actual design of the CCP is finalised consideration could be given to more comprehensive modification of the steam turbine and water/steam cycle to supply the steam requirement of the chosen plant. This would be assessed on the basis of economic viability taking into account any efficiency, CO2 and capital cost benefits. This decision can be made at the time of installation with cognisance of the then current economic environment requirements while not frustrating any option at this time.

In light of the uncertainty regarding the year in which CCS may be retrofitted and the capture process that will be most attractive at that time, the selection of plant adaptations to prepare the CCGT ready for the future retrofit of a CCP should be one that is made on economic/market risk grounds by the owner of the project whilst maintaining the absolute requirement that this retrofitting can be achieved.

To detail design a fully integrated CCGT plant now based on the currently available technology for post-combustion amine capture would be unnecessarily restrictive and uneconomic. It is extremely likely that, by the time a CCP is retrofitted, the actual steam requirements of the process will be very different from those considered to date.

It is therefore proposed that an intermediate “Optimum Efficiency” approach is adopted which will maintain the highest possible initial efficiency of the plant whilst allowing optimisation and modification to an integrated CCP solution when the actual process requirements are available, during detailed design of the CCP.

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6 Department of Energy and Climate Change, Electricity Market Reform, White Paper 2011
3.6. **Space provision and plant infrastructure**

3.6.1. A possible layout of the CCP is shown in Figure 2. The estimated footprint of the plant items are presented in Table 3.2, which result in an approximate plant area of 1.6 ha. However, KPL are willing to allocate 7.3 ha of land for future installation of a CCP, with a view to reducing this as the area that is actually required becomes better understood.

**Table 3.2: Estimated CCP Footprint**

<table>
<thead>
<tr>
<th>Item of Plant</th>
<th>Length (m)</th>
<th>Width (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas-Gas Heaters x3</td>
<td>18</td>
<td>18</td>
</tr>
<tr>
<td>Direct Contact Coolers x3</td>
<td>18</td>
<td>18</td>
</tr>
<tr>
<td>Absorber Towers x3</td>
<td>18</td>
<td>18</td>
</tr>
<tr>
<td>Heat Exchangers x3</td>
<td>8</td>
<td>8</td>
</tr>
<tr>
<td>Stripper Towers x3</td>
<td>8 (diameter)</td>
<td></td>
</tr>
<tr>
<td>Compressors x3</td>
<td>7</td>
<td>16</td>
</tr>
<tr>
<td>Demin Water Plant</td>
<td>6</td>
<td>20</td>
</tr>
<tr>
<td>MEA Storage Tank</td>
<td>15</td>
<td>15</td>
</tr>
<tr>
<td>Cooling Towers x3</td>
<td>140</td>
<td>16</td>
</tr>
<tr>
<td>Control Room</td>
<td>4</td>
<td>6</td>
</tr>
<tr>
<td>Boiler and steam turbine</td>
<td>84</td>
<td>30</td>
</tr>
</tbody>
</table>

3.6.2. This is based on amine technology using the most conservative design data available i.e. the largest area, and also assumes an entirely stand-alone CCP. It is likely that, by the time the CCGT plant is converted to CCS operation, improvements in the technology of carbon capture will have reduced the space requirements significantly.

3.6.3. Space has been allowed for a control room dedicated to the CCP. There is sufficient room either on the CCP site or within the CCGT workshop building for a CCP workshop and store. As discussed in Section 3.4.19, the number of office staff is predicted to be low and can be accommodated within the proposed CCGT office building.

3.6.4. As discussed above only one road tanker delivery per day is anticipated. The design of the roads in the plant layout will take this into account.

3.6.5. The proposed location of the CCP equipment is easily accessed by the proposed CCGT access road and there is sufficient space for laydown during construction of the CCP.

3.7. **Carbon capture plant contract**

3.7.1. It is anticipated that a separate contract will be placed for the supply of the carbon capture plant. In the case of a fully or mostly stand-alone CCP, the inclusion of a dedicated gas fired boiler for steam supply and the provision of a separate transformer for electricity supply would minimise the interface between the carbon capture plant and the CCGT plant.

3.7.2. As with most major items of equipment on the plant, it is expected that by the time the CCGT plant is converted to CCS operation, dedicated companies will exist to offer their services to build and maintain such plant. KPL will most probably contract with such a company for the carbon capture plant.
4. CO2 Transport

4.1. Introduction

4.1.1. The following section outlines the considerations which have been given to the indicative pipeline route corridor, including technical and environmental constraints, as well as the presence of existing pipeline networks. Pipeline safety and accident hazard control regulations are also discussed.

4.2. Pipeline safety

4.2.1. It is likely that the onshore CO2 transport from the site will be in a ‘dense phase’, i.e. of the order of 70-100 bar pressure. The offshore transport of CO2 is likely to be at a higher pressure, with the CO2 in its ‘supercritical fluid’ state.

4.2.2. The Guidance Note7 states that, until the Health and Safety requirements of pipelines conveying dense phase CO2 have been considered in more depth, such pipelines should be considered as conveying ‘dangerous fluids’ under the Pipeline Safety Regulations 1996 (PSR), and ‘dangerous substances’ under the Control of Major Accident Hazards Regulations 1999 (as amended) (COMAH). The pipeline would therefore be considered to be a Major Accident Hazard Pipeline (MAHP).

4.2.3. Therefore, when undertaking the detailed design of the pipeline route, the pipeline operator must pay due attention to the following potential requirements:
   • Installation and frequency of emergency shut-down valves;
   • The preparation of a Major Accident Hazard Prevention Document (MAPD); and
   • Ensuring the appropriate emergency procedures, organisation and arrangements are in place.

4.2.4. In addition, the Local Authority, which is notified by HSE of a MAHP, must prepare an Emergency Plan.

4.2.5. As noted earlier, the CO2 compression equipment is proposed to be located at the site boundary. The power station development does not therefore require Hazardous Substances Consent (HSC).

4.3. Indicative pipeline route corridor

4.3.1. As required by the Guidance Note, an indicative route of the CO2 pipeline has been studied, with a 1 km wide corridor for the first 10 km from the site, and a 10 km wide corridor thereafter to the proposed storage area. The corridors selected are shown on Figures 3 and 4 and are described below.

Onshore section

4.3.2. The indicative route of the onshore pipeline corridor has taken into account the following considerations:
   • An exit point from the site that is unlikely to be blocked by future developments outside of the site boundary;
   • The presence of the existing high pressure natural gas pipeline network;

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- The proposed route identified by the National Grid for a common CO2 grid for the Yorkshire and Humber area8 and
- The presence of designated sites, such as Sites of Special Scientific Interest (SSSI), Special Areas of Conservation (SAC), Special Protection Areas (SPA), Ramsar Sites, National Nature Reserves (NNR), Designated Parks and Gardens, Scheduled Ancient Monuments (SAMs) and Areas of Outstanding Natural Beauty (AONB).

4.3.3. Figure 3 shows the proposed indicative pipeline route corridor out to 10 km from the plant, while Figure 4 show the indicative pipeline corridor from here to the shoreline.

4.3.4. The exit point from the site, shown on Figure 3, has been chosen as it is considered that a route Northwards from the site, passing under the canal and in the green fields between Knottingley and the Kellingley coal mine, through to the Aire river is less likely to be developed due to its close proximity to the mine and river.

4.3.5. The proposed route has been largely influenced by the presence of the existing high pressure natural gas network. It is not proposed to re-use any existing pipelines to convey CO2 from the proposed plant. The new pipeline will therefore be designed with the explicit intention of conveying CO2 at the pressure deemed appropriate at the time of detailed design.

4.3.6. The proposed route has also considered the work done by the National Grid to develop a route suitable for power stations in this area. The opportunity to share a common gas transmission net work to avoid the high cost of this component of transmission and storage is something which the project would wish to consider when the CCP is constructed.

4.3.7. As shown on Figure 3 the proposed route corridor out to 10 km from the site is free of designated sites.

4.3.8. Figure 4 shows the 10 km wide corridor to the shoreline to be largely free of designated sites, with the exception of scattered SAMs and ecological designations. These could be easily avoided such that their integrity and/or interest are not materially affected following construction of the pipeline.

4.3.9. At the shoreline the indicative pipeline corridor includes the Dimlington Cliff and The Lagoons SSSIs, as well as northern sections of the Humber Estuary SSSI/SPA/Ramsar site. It is envisaged that these can be easily avoided by the pipeline route, which it is expected may follow the route of the gas network to Easington, before being taken offshore. However, it is also noted that the designation of a site for ecological reasons does not forbid development in such an area, only to ensure that any developments are controlled such that they do not cause unacceptable harm to the interest of the site. Any potential impact must be weighed against the importance of the development. The potential impact of the installation of pipeline in the designated sites identified can also be minimised as far as practicable by the use of advanced drilling techniques, such as directional drilling.

4.3.10. Ultimately the decision on the appropriate shore point of the pipeline will be chosen based on technical and environmental considerations prevailing at the time of its construction.

4.3.11. The indicative route of the offshore pipeline corridor has taken into account the following considerations:
- The presence of proposed offshore wind farms and proposed Zones under Round 3 of the Offshore Wind Programme;

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8 Yorkshire and Humber Carbon Capture, Transportation and Storage Project, Selection of Preferred Corridor, National Grid, November 2011
• The presence of the existing network of pipelines associated with the gas/oil fields; and
• The presence of designated sites (see above).

4.3.12. Figure 5 shows the indicative pipeline route corridor from the shoreline to the proposed storage area. The route avoids existing offshore wind farms. However, it is noted that the Holderness Round 3 Offshore Zone, which covers a large section of the South North Sea oil and gas fields, covers part of the proposed storage area. Any offshore wind farms installed in this zone will therefore need to be taken into account in the selection of the route during the detailed design stage.

4.3.13. There is an existing network of pipes interconnecting the oil and gas fields in the South North Sea. At the time of detailed design the potential to re-use these pipelines, or to follow their routes, will be considered.

4.3.14. The presence of designated sites at the shoreline is discussed above.

4.4. Transport contract

4.4.1. Similarly to the CCP, it is expected that CO2 transport and storage companies will exist to accept the compressed CO2 from the carbon capture plant and transport/store this CO2. Currently, National Grid Company, Centrica, Shell, BP and Marathon are all investigating setting up such companies. Yorkshire Forward is known to be promoting the concept of an integrated CO2 pipeline network across the Yorkshire and Humber region, with the aim of transporting captured CO2 from the large number of power stations, oil refineries and other industrial facilities in this area to storage sites in the North Sea. Connection to any such networks would be considered at the relevant time.
5. **CO2 Storage**

5.1. **Introduction**

5.1.1. This section discusses the technical feasibility of the large scale storage of CO2. It establishes the volume of storage required for the Knottingley project and identifies storage sites which are considered to have sufficient capacity to store the CO2 captured from the plant.

5.2. **Storing CO2**

5.2.1. A number of options are considered possible for the large scale storage of CO2, including the following:

- Operational and depleted hydrocarbon reservoirs (oil and gas fields);
- Deep brine filled formations (saline aquifers); and
- Unminable coal beds.

5.2.2. All of these methods are currently being either tested or adopted at a commercial scale for various projects around the world.

5.2.3. The Guidance Note recommends that possible storage locations should be considered based on a review of the study undertaken by British Geological Survey on behalf of the DTI[9]. The Note suggests that only “valid” or “realistic” capacity sites as defined in the BGS study should be considered as appropriate for selection.

5.3. **Storage capacity required**

5.3.1. The volume of CO2 captured over the lifetime of the plant will depend on a number of factors. The most widely varying of these will be:

- The economic/useful life of the plant - the lifetime of a CCGT power plant is typically considered to be 25 years. This depends on the frequency and extent of maintenance and major overhauls and the prevailing economic conditions as the plant becomes older (i.e. gas and electricity prices, and the cost of alternative forms of generation, including more efficient gas turbines); and
- The load factor over the life of the plant - over the lifetime of the plant there may be extended periods in which it is operating at full load (i.e. exporting at maximum capacity), and other times when the plant operates at a reduced load in order to be able to ‘ramp up’ to a higher load at short notice to meet short term peaks in electricity demand.

5.3.2. In addition, the point in time at which CCS is either required by law or becomes economically advantageous cannot be predicted. It may be the case that the plant has operated for a number of years before carbon capture equipment is fitted and CO2 begins to be transported from the plant for storage. The plant may only require storage capacity for CO2 for a few years before being decommissioned.

5.3.3. It is not therefore possible to predict with any accuracy the volume of CO2 which will be required to be stored. The following assumptions have therefore been made and are deemed to be conservative estimates:

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- Year in which carbon capture equipment is fitted - 2020
- Plant load factor - 75%[10]
- Economic life of plant (following first operation in 2016) - 25 years

Assuming an annual average fuel consumption of 1.4 million tonnes (in the case of a 1500 MW CCGT with a standalone CCP), a CO2 production of 2.75 tonnes per tonne of fuel burned, and a capture efficiency of 90% the plant would therefore require the storage of 72 million tonnes of CO2.

5.4. Offshore storage in the North Sea

5.4.1. As mentioned above, the BGS study identifies “valid” or “realistic” storage sites in the North Sea. The following fields are proposed as potential storage locations for the estimated 72 million tonnes of CO2 which would need to be stored from the plant.
- Barque - 108,000,000 tonnes
- Ravenspurn North - 93,000,000 tonnes
- West Sole - 143,000,000 tonnes

5.4.2. Any of these storage sites are therefore estimated to have sufficient storage capacity to store captured CO2 transported from the plant. The location of these fields is shown on Figure 4, as is the indicative pipeline corridor from the shoreline to an approximate centre point of these fields.

5.5. Potential for onshore storage

5.5.1. It is noted that the BGS study states that the potential onshore storage locations for large quantities of CO2 are not currently sufficiently understood to be classified as “valid” or “realistic”. Therefore, while it is considered that the Sherwood Sandstone Group in Eastern England may be suitable for onshore storage of CO2, only offshore storage locations in the South North Sea have been considered in this study.

5.5.2. It is estimated that an onshore pipeline to an injection point at the nearest extent of the Sherwood Sandstone at a sufficient depth may be just 35 km in length, as opposed to the 109 km onshore pipeline to the coast and subsequent 82 km offshore pipeline to the injection point which would be required for storage of CO2 in the offshore storage area proposed above. The additional length of pipeline required for offshore storage could add of the order of £210 million to the capital cost of the CCS infrastructure, equivalent to approximately £3 per MWh of electricity exported over the lifetime of the plant.

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[10] The average load factor of CCGTs in the UK from 2006 to 2010 was 62.1% (Department for Energy and Climate Change; Digest of UK Energy Statistics 2011, Table 5.10). A 75% load factor is considered a conservative estimate to ensure that storage sites are chosen which are of a sufficient capacity for the captured CO2 from the plant.
6. Economic Feasibility

6.1. Introduction

6.1.1. This section establishes the cost of the retrofitting of CCS to the Knottingley CCGT. Having established this cost, it is then possible to estimate the economic incentive which would be required to enable the retrofitting to take place. This is presented as the market price to which CO2 allowances would have to rise under the EU Emissions Trading Scheme (ETS) to make it financially beneficial to capture and store CO2 from the plant.

6.2. Financial modelling

6.2.1. Financial modelling has been undertaken to estimate the prevailing economic conditions which would be required to incentivise the retrofitting of CCS to the Knottingley plant. It has been assumed that the cost of CO2 allowances under the EU Emissions Trading Scheme would be the key variable in determining whether retrofitting was appropriate (i.e. assuming that no further subsidies or regulatory measures were instigated, such as a Carbon Capture and Storage Obligation scheme or an increased electricity tariff paid to plants with CCS).

6.2.2. It is assumed that, when the Knottingley plant becomes operational (2016), allowances are required to be purchased for 100% of the CO2 emitted by the plant and that no free allowances are allocated. Therefore, the CO2 price at which it is beneficial for the plant to retrofit CCS, and therefore avoid paying for CO2 allowances for 90% of the CO2 it produces (i.e. the proportion of CO2 that is captured), can be identified.

6.2.3. It is considered that this is an easy-to-understand indication of the required market incentive to retrofit CCS.

Modelling methodology

6.2.4. The modelling takes the estimated capital and operating costs of the CCGT/CCS plant over its predicted useful life and estimates the Lifetime Cost of Electricity.

6.2.5. The Lifetime Cost of Electricity is the real price of electricity sold, which when received over the lifetime of the project would just offset all costs of constructing and operating the station, including a fair return to capital investors.

6.2.6. Three suites of modelling were undertaken. The first of these estimated the Lifetime Cost of Electricity of the Knottingley CCGT without preparation for CCS. The second suite of modelling estimated this value with the CCGT built ready for full integration, subsequently retrofitting CCS in 2020. The third suite of modelling estimated the value with the CCGT built with minor modifications, ready for the construction of a partially integrated CCP, with the CCP coming online in 2020.

6.2.7. The modelled inputs of plant performance (output, fuel burn and CO2 produced) are taken from the engineering modelling presented in Table 1. While a DCO is sought for a larger installed capacity and potentially more efficient CCGT technology, it is considered that these inputs are sufficiently accurate to give a realistic comparison of the economics of each option.

6.2.8. In each scenario, the required market price of CO2 allowances to incentivise retrofitting of CCS is then estimated.

Model inputs

6.2.9. The following basic model inputs were assumed in each scenario.
Table 6.1: Key fixed model inputs

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Input Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Discount rate</td>
<td>12%</td>
</tr>
<tr>
<td>CCGT</td>
<td></td>
</tr>
<tr>
<td>Development/construction period</td>
<td>5 years</td>
</tr>
<tr>
<td>Economic life of plant</td>
<td>25 years</td>
</tr>
<tr>
<td>First year of operation</td>
<td>2016</td>
</tr>
<tr>
<td>Availability</td>
<td>90%</td>
</tr>
<tr>
<td>Load factor (before availability)</td>
<td>83%</td>
</tr>
<tr>
<td>Heat rate degradation (over lifetime)</td>
<td>2%</td>
</tr>
<tr>
<td>Carbon Capture</td>
<td></td>
</tr>
<tr>
<td>Development/construction period</td>
<td>3 years</td>
</tr>
<tr>
<td>First year of operation</td>
<td>2020</td>
</tr>
<tr>
<td>Capture efficiency</td>
<td>90%</td>
</tr>
</tbody>
</table>

Note that costs and revenues are discounted to 2012 prices.

**CCS capital and operating cost estimates**

**Capital costs**

**Carbon Capture Plant**

6.2.10. The capital cost of a carbon capture plant of sufficient size to capture 90% of the CO2 from the proposed Knottingley CCGT cannot currently be accurately obtained, due to the emerging nature of the technology at this scale.

6.2.11. Fluor/Statoil released into the public domain a feasibility study for the retrofitting of the Fluor Daniel Econamine FG process (the proposed process assumed in this study for the Knottingley CCGT) to an 800 MW CCGT in Norway in April 2005[11]. The estimated capital cost of the CCP in this study was US$510 million. As this was for the retrofitting of a CCP plant to two CCGT units, it is reasonable to assume that the capital cost to retrofit three slightly larger units totalling 1500MW would be of the order of 176% of this cost, i.e. US$900 million. Using an average 2005 exchange rate of 1.6 US$/£ and allowing for a cost inflation of say 3% per annum from 2005 to 2012 results in a figure of £690 million.

6.2.12. The Intergovernmental Panel on Climate Change (IPCC) published a report in 2005[12] which estimated the cost of retrofitting a CCP to a number of different power plants, including natural gas fired CCGT.

6.2.13. The IPCC report presented a capital cost estimate for a standard CCGT of US$568/kW. Using an average exchange rate of 1.6 US$/£ and a cost inflation of 3% per annum this equates to £436/kW. Based on our knowledge of UK market prices it is considered that a figure of £540/kW is more appropriate for the construction of a standard CCGT in the UK, 24% higher than the IPCC estimate. Applying these adjustments to the IPCC’s estimate of the capital costs of a CCGT with CCS installed of US$998/kW results in a figure of £950/kW.

6.2.14. Taking these figures, the estimated capital cost of the CCP alone can be estimated at £410/kW. This equates to approximately £615 million for the size of plant required at Knottingley, which is a less than the factored-up Fluor/Statoil estimate of £690 million.

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11 Study and Estimate for CO2 Capture Facilities for the proposed 800MW Combined Cycle Power Plant – Tjeldbergodden, Norway
12 Carbon Dioxide Capture and Storage. Intergovernmental Panel on Climate Change. 2005.
6.2.15. Taking a reasonable mid-range value of these predictions, a figure of £650 million has been assumed in the financial modelling undertaken for this study in the case of a fully integrated CCP. It is estimated that the additional capital costs associated with the partially integrated option are of the order of £35 million for a standalone boiler, back pressure steam turbine and other items.

6.2.16. In addition, due to the bespoke nature of the modifications required to a standard CCGT to construct it to be ready for a fully integrated CCP, we estimate that manufacturers/contractors may charge as much as a 5% increase in design and construction costs.

\[ \text{CO}_2 \text{ Pipeline} \]

6.2.17. The Guidance Note recommends that reference is made to the document Carbon Capture & Storage: Assessing the Economics\[13\]. This report suggests a capital cost of an onshore pipeline of approximately €1.3 million per km, with a cost increase of 20% for offshore pipelines. Using an exchange rate of 1.2 €/£ and adjusting at 3% per annum to 2012 values, this equates to a cost of £1.22 million per km for the length of onshore pipeline and £1.46 million per km for the length of offshore pipeline.

6.2.18. Based on the adopted pipeline corridors discussed earlier in this study, the onshore pipeline length has been estimated at 109 km, with an offshore pipeline to the centre of the storage sites of 82 km.

6.2.19. For comparison, modelling was also undertaken with the cost of the onshore pipeline rising to £3 million per km. This is considered to be a high cost estimate should the entire route of the pipeline be required to be much thicker and/or to have significant road, rail or river crossings.

\[ \text{CO}_2 \text{ Storage} \]

6.2.20. The Carbon Capture & Storage: Assessing the Economics report includes indicative costs for CO2 storage. Capital costs quoted in the report are €18 m for the installation of an offshore well and €14 m for the costs of seismic monitoring. These costs have been assumed in this modelling study, using an exchange rate of 1.2 €/£ and adjusting at 3% annum to 2012.

6.2.21. Table 6.2 below presents the cost assumptions made in the base case model regarding the capital costs of the CCP equipment and CO2 pipeline. The fully integrated option is the additional cost for carbon capture assuming it is built fully integrated when the CCGT plant is constructed. The partially integrated option assumes that the plant is built ready for CCP as part of the initial build, but the integrated CCP is constructed later incurring some additional plant modifications.

\[ \text{Table 6.2: Base case CCP capital cost assumptions} \]

<table>
<thead>
<tr>
<th>Capital Cost Element</th>
<th>Capital Cost (£m)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Fully Integrated</td>
</tr>
<tr>
<td></td>
<td>Partially Integrated</td>
</tr>
<tr>
<td>Carbon Capture Plant</td>
<td>615</td>
</tr>
<tr>
<td></td>
<td>650</td>
</tr>
<tr>
<td>Pipeline Costs</td>
<td>253</td>
</tr>
<tr>
<td></td>
<td>253</td>
</tr>
<tr>
<td>Storage Costs</td>
<td>30</td>
</tr>
<tr>
<td></td>
<td>30</td>
</tr>
<tr>
<td>Capital Costs of Constructing CCGT Ready for Fully Integrated CCP</td>
<td>898</td>
</tr>
<tr>
<td></td>
<td>933</td>
</tr>
</tbody>
</table>

Operating costs

6.2.22. Based on the information provided in the Carbon Capture & Storage: Assessing the Economics report and our own estimates, the following operating cost assumptions have been made:

Table 6.3: Estimated annual operating costs

<table>
<thead>
<tr>
<th>Operating Cost Element</th>
<th>Estimated Annual Cost (£m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capture Plant O&amp;M</td>
<td>18.5</td>
</tr>
<tr>
<td>Pipeline O&amp;M</td>
<td>2.5</td>
</tr>
<tr>
<td>Storage O&amp;M</td>
<td>2.8</td>
</tr>
<tr>
<td>Salaries</td>
<td>0.2</td>
</tr>
<tr>
<td>Overheads</td>
<td>0.1</td>
</tr>
<tr>
<td>Insurance</td>
<td>9.0</td>
</tr>
</tbody>
</table>

Future commodity price scenarios

6.2.23. As it is not anticipated that the regulatory regime or market conditions will result in the retrofitting of carbon capture equipment to the proposed CCGT for a number of years, it is necessary to forecast potential natural gas price scenarios which may transpire during this time.

6.2.24. DECC regularly publish fuel price projections for future years, with their most recent report at the time of writing published in October 2012[14]. These projections have been adopted in the financial modelling undertaken and are presented in the table below.

Table 6.4: Forecast wholesale natural gas prices (@2012 prices)

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Forecast Price (2020) p/therm</th>
<th>Forecast Price (2025) p/therm</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low</td>
<td>41.1</td>
<td>41.1</td>
</tr>
<tr>
<td>Central</td>
<td>71.9</td>
<td>71.9</td>
</tr>
<tr>
<td>High</td>
<td>102.3</td>
<td>102.7</td>
</tr>
</tbody>
</table>

Base case model results

6.2.25. Using the input information provided above, the Lifetime Cost of Electricity has been estimated for the following plant options:

- A standard three x 500MW unit CCGT (without ever retrofitting CCS);
- A three x 500MW unit CCGT with a fully integrated CCP retrofitted in 2020; and
- A three x 500MW unit CCGT with a partially integrated CCP retrofitted in 2020.

6.2.26. For each of these options the Lifetime Cost of Electricity, before the cost of CO2 permits has been taken into account, is estimated to be as follows.

---

Table 6.5: Lifetime cost of electricity (w/o carbon costs)

<table>
<thead>
<tr>
<th>Commodity Price Scenario</th>
<th>Lifetime cost of electricity (£/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Standard CCGT</td>
</tr>
<tr>
<td>Low</td>
<td>43</td>
</tr>
<tr>
<td>Central</td>
<td>65</td>
</tr>
<tr>
<td>High</td>
<td>85</td>
</tr>
</tbody>
</table>

6.2.27. The incremental increase in the Lifetime Cost of Electricity for each £/tonne increase in the cost of CO2 permits for each of these plant options is calculated to be as follows:

Table 6.6: Incremental increase in lifetime cost of electricity for each £/tonne increase in the cost of CO2 permits

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Incremental increase in lifetime cost of electricity (£/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Standard CCGT</td>
<td>£0.42</td>
</tr>
<tr>
<td>CCGT with fully integrated CCP</td>
<td>£0.17</td>
</tr>
<tr>
<td>CCGT with partially integrated CCP</td>
<td>£0.17</td>
</tr>
</tbody>
</table>

6.2.28. Note that the carbon costs implied in the cases where a CCP is retrofitted are not just the 10% of CO2 which is still released following the retrofitting, but also all of the CO2 which is produced during the 4 years prior to commissioning of the CCP.

6.2.29. Using the figures provided above, the graph below presents the Lifetime Cost of Electricity for each case, under DECCs Central commodity price scenario, as the cost of CO2 permits is increased.
Analysing these results it is possible to estimate the cost of CO2 permits at which it becomes cheaper to generate electricity from a CCGT with CCS retrofitted in 2020 compared to a standard CCGT which never retrofits CCS. Based on the base case assumptions discussed above, these costs are estimated to be as follows.

**Table 6.7: CO2 permit price at which it becomes cheaper to generate electricity from a CCGT w/ CCS than a standard CCGT**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Required CO2 permit price (£/tonne)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CCGT with fully integrated CCP</td>
<td>£82.76</td>
</tr>
<tr>
<td>CCGT with partially integrated CCP</td>
<td>£58.52</td>
</tr>
</tbody>
</table>

The table above shows that at a CO2 permit price greater than £58.52 per tonne, guaranteed over the 25 year life of the CCGT, the Lifetime Cost of Electricity sold from a CCGT with partially integrated CCP retrofitted in 2020 is less than from a standard CCGT without carbon capture. For a CCGT retrofitting a fully integrated CCP in 2020, the CO2 permit price would need to be greater than £82.76 per tonne.

Note that the main reasons for the significant difference in these estimates are:

- The amount of electricity exported from a CCGT constructed ready for full integration is approximately 1.5% less than a CCGT constructed ready for partial integration, and is
subsequently 8% less following installation of the CCP. As a result, while the capital and operating costs over the lifetime of the plants are broadly similar, they are significantly higher per MWh of electricity sold from a fully integrated plant; and

- We predict an increased capital cost of a CCGT constructed ready for full integration of 5%. This is due to the bespoke nature of the CCGT. We expect that this will result in manufacturers requiring higher fees to design and construct such a plant. This cost increase occurs at the point of construction of the CCGT, whereas the additional capital costs associated with the partially integrated plant (i.e. auxiliary boiler, back pressure steam turbine etc) occur at the point of construction of the CCP. This delay in capital outlay is to the benefit of the project economics.

Sensitivity analyses

Capital costs - CCP

6.2.33. It is acknowledged that the estimated capital cost of the CCP is indicative at this early stage in the development of CCS at this scale. It is also likely that the first few large scale CCP to be built will be more costly than subsequent developments as contractors are able to learn and develop their systems to be less expensive.

6.2.34. For these reasons, a sensitivity analysis has been undertaken to establish the impact of changes in the capital cost of the CCP on the required cost of CO2 permits to incentivise the retrofitting of CCS to the Knottingley CCGT. The results of this sensitivity analysis are shown below.

Table 6.8: CO2 permit price at which it becomes cheaper to generate electricity from a CCGT w/ CCS than a standard CCGT – Sensitivity to capital costs of CCP

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Requirement CO2 permit price (£/tonne)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>-30% decrease in CCP capex</td>
</tr>
<tr>
<td>CCGT with fully integrated CCP</td>
<td>£68.08</td>
</tr>
<tr>
<td>CCGT with partially integrated CCP</td>
<td>£45.91</td>
</tr>
</tbody>
</table>

Capital costs - onshore pipeline

6.2.35. As discussed earlier, the design requirements of the onshore pipeline are currently open to change depending on health and safety requirements. For this reason we have estimated the impact of an increase in the capital cost of the 109 km length of onshore pipeline from £1.22 million per km up to £3 million per km. The impact of this increase on the required CO2 permit price is shown below.

Table 6.9: CO2 permit price at which it becomes cheaper to generate electricity from a CCGT w/ CCS than a standard CCGT – Sensitivity to capital costs of onshore pipeline

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Requirement CO2 permit price (£/tonne)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Base case</td>
</tr>
<tr>
<td>CCGT with fully integrated CCP</td>
<td>£82.76</td>
</tr>
<tr>
<td>CCGT with partially integrated CCP</td>
<td>£58.54</td>
</tr>
</tbody>
</table>
6.2.36. The table above shows that, were the cost of the onshore pipeline to increase from the base case assumption of £1.22 million per km to £3 million per km, the required CO2 price to incentivise the retrofitting of a partially integrated CCP would rise to £68 per tonne. For a fully integrated CCP the price would need to rise to £93 per tonne.

**Natural gas price**

6.2.37. The economic feasibility of retrofitting CCS to the Knottingley plant will also be determined to an extent by the wholesale price of natural gas. The natural gas price will, of course, influence the cost of generation from a CCGT with or without CCS, but does have a greater impact on the lifetime cost of electricity sold from a plant which has retrofitted CCS due to the less efficient use of natural gas to generate electricity. To establish how natural gas prices will influence the decision to retrofit CCS, a sensitivity analysis was undertaken based on DECC’s forecast gas price scenarios in 2020 (see Table 6.10).

**Table 6.10: CO2 permit price at which it becomes cheaper to generate electricity from a CCGT w/ CCS than a standard CCGT – Sensitivity to natural gas prices**

<table>
<thead>
<tr>
<th>Scenario</th>
<th>Required CO2 permit price (£/tonne)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Low Gas Price</td>
</tr>
<tr>
<td>CCGT with fully integrated CCP</td>
<td>£72.49</td>
</tr>
<tr>
<td>CCGT with partially integrated CCP</td>
<td>£55.14</td>
</tr>
</tbody>
</table>

6.3. Conclusion

6.3.1. It is considered that the above analysis demonstrates that it is economically feasible that CCS could be retrofitted to the proposed CCGT, given an appropriate CO2 permit price.
7. **Summary**

7.1.1. This study has discussed the currently available and potential future methods of capturing CO2 from a large combustion plant. A method of capturing CO2 from the flue gases of the proposed Knottingley CCGT has been described. The technical feasibility of retrofitting this method of CO2 capture has been demonstrated. KPL propose to make 7.3 ha available for the future retrofit of a Carbon Capture Plant (CCP), with a view to reducing this as the area that is actually required becomes clearer.

7.1.2. A pipeline corridor from the site has been identified to take the captured CO2 to two possible storage sites in the South North Sea.

7.1.3. An economic feasibility study has been undertaken to estimate the indicative cost of retrofitting CCS to the Knottingley plant. This has resulted in the estimation of approximate CO2 permit prices, guaranteed over the lifetime of the plant, which would result in the cost of generating electricity from such a plant being less than a standard CCGT (without CCS). It is considered that the analysis demonstrates the conditions when it is economically feasible that CCS could be retrofitted to the proposed CCGT.

7.1.4. The ultimate decisions on the CCS solution will be taken at the appropriate time, considering such matters as the contemporaneous legislation, proven technology, best practices and economic feasibility as are relevant. Should the contents of the Energy Bill be adopted then the plant would potentially not require CCS until at least 2045, unless the allowable CO2 emission limit was lowered.
8. **Annex 1C Checklist**

8.1.1. For ease of reference, the sections of this report which refer to each section identified in Annex 1C of the Guidance Note are shown below.

<table>
<thead>
<tr>
<th>Annex 1C Reference</th>
<th>Section of this CCR Report</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1 Design, Planning Permissions and Approvals</td>
<td>Sections 3, and Figure 2</td>
</tr>
<tr>
<td>C2 Power Plant Location</td>
<td>Sections 3, 4 and 5, and Figure 2</td>
</tr>
<tr>
<td>C3 Space Requirements</td>
<td>Section 3.6, with calculations of vessel and equipment sizes given throughout Section 3. Figure 2 shows the plot plan layout of this equipment.</td>
</tr>
<tr>
<td>C4 Gas Turbine Operation with Increased Exhaust Pressure (installation of a booster fan)</td>
<td>Section 2.3, 0 and 0</td>
</tr>
<tr>
<td>C5 Flue Gas System</td>
<td>Section 0 and 0</td>
</tr>
<tr>
<td>C6 Steam Cycle</td>
<td>Sections 0, 0, 0 and 0</td>
</tr>
<tr>
<td>C7 Cooling Water System</td>
<td>Sections 0 and 0</td>
</tr>
<tr>
<td>C8 Compressed Air System</td>
<td>Section 0</td>
</tr>
<tr>
<td>C9 Raw Water Pre-treatment Plant</td>
<td>Section 0</td>
</tr>
<tr>
<td>C10 Demineralisation / Desalination Plant</td>
<td>Section 3.4.8</td>
</tr>
<tr>
<td>C11 Waste Water Treatment Plant</td>
<td>Section 0</td>
</tr>
<tr>
<td>C12 Electrical</td>
<td>Sections 0 and 3.4.6</td>
</tr>
<tr>
<td>C13 Plant Pipe Racks</td>
<td>Section 0</td>
</tr>
<tr>
<td>C14 Control and Instrumentation</td>
<td>Sections 0 and 0</td>
</tr>
<tr>
<td>C15 Plant Infrastructure</td>
<td>Section 3.6</td>
</tr>
</tbody>
</table>
FIGURE 3
PROPOSED PIPELINE
ROUTE TO 10KM

Key
- Proposed Pipeline Route
- Non Pipeline Route Corridor
- Site Boundary
FIGURE 4
PROPOSED PIPELINE ROUTE FROM 10KM TO COAST
FIGURE 5
POTENTIAL CO2 STORAGE SITES AND INDICATIVE PIPELINE CORRIDOR

Key
- Indicative Pipeline Route
- Potential Storage Site Locations
- Oil and Gas Fields
- Proposed Offshore Storage Area
- Round 3 Offshore Wind Farm Zone
- Ravenspur North - 93 million tonnes capacity
- West Sole - 143 million tonnes capacity
- Barque - 108 million tonnes capacity
- Galleon - 137 million tonnes capacity

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